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LORIN BRASS, November 9th, 2006

E R R A T A S H E E T

IN RE: ROYAL DUTCH/SHELL SECURITIES LITIGATION

RETURN BY:

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LORIN BRASS, November 9th, 2006

CERTIFICATE OF SHORTHAND REPORTER -- NOTARY PUBLIC

I, Laurie Bangart-Smith, Registered Professional Reporter, the officer before whom the foregoing deposition was taken, do hereby certify that the foregoing transcript is a true and correct record of the testimony given; that said testimony was taken by me stenographically and thereafter reduced to typewriting under my supervision; and that I am neither counsel for, related to, nor employed by any of the parties to this case and have no interest, financial or otherwise, in its outcome.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my notarial seal this 10th day of November, 2006.

My commission expires: March 14th, 2011

____
LAURIE BANGART-SMITH
NOTARY PUBLIC IN AND FOR
THE DISTRICT OF COLUMBIA

Unknown

From: Brass, Lorin L.
Sent: 20 December 1999 18:51
To: Watts, Phil B.; Cook, Linda L.Z.
Subject: RE: Exploration FRD

Phil, I understand and will ensure your involvement in the process.

-----Original Message-----
From: Watts, Phil B.
Sent: 20 December 1999 16:06
To: Cook, Linda L.Z.; Brass, Lorin L.
Subject: Exploration FRD

1998 exploration performance and the projected reserves replacement figures give cause for concern - not just in EXCOM but also Conference. The Exploration FRD will be critical in dealing with this matter. I met a delegation from the team and made just one point. I want to see the actual wells/costs/'reserves' found for the last 5 years - since I get tired of seeing "mumbo jumbo" presentations on this subject.
I want to be involved in the close out of the Exploration FRD since it will be a disaster if they produce recommendations not founded on the reality of actual performance.
Aside: My confidence in this exercise decreased when I asked these three people how many exploration wells we drill in a year .... and they didn't know!!!

Phil Watts
Group Managing Director
Royal Dutch/Shell Group of Companies
Shell Centre London SE1 7NA
Tel: +44 (0)171 934 5556 Fax: +44 (0)171 934 5557
Internet: Phil.B.Watts@SI.shell.com

EXHIBIT
1
Brass
PENGAD 800-631-6989

V00370938

FOIA Confidential
Treatment Requested

BRASS 0001

Strictly Confidential

Presentation ExCom 31st January 2000

Preliminary Summary of End 1999 Proved Reserves

The objective of this note and presentation is to inform ExCom of the end 1999 Group Resources, especially proved and proved developed reserves, prior to the finalisation and External Audit clearance of these numbers by the 4th February 2000, ahead of the Q4 press release. The numbers are still being finalised, but adjustments are expected to be minor.

Summary

- The 1999 proved reserves replacement ratio is 46% for oil/NGL (141% in 1998) and 23% for gas (255% in 1999). Total oil/NGL/Gas replacement ratio for 1999 is 37% (182% in 1998).
- Three year average proved reserves replacement ratio for 1999 is 106% for oil (146% in 1998) and 161% for gas (249% for gas), total replacement on boe basis is 126% (184% in 1998) (ref attachment 1). It should be noted that the implementation of the new Petroleum Resource Guidelines during 1998 accounted for roughly 50% of the 1998 proved reserves increase.
- Including the AOSP "mining reserves" the overall proved replacement ratio increases from 37% to 82% and further inclusion of the Iran "pseudo reserves" increases the replacement ratio to 94%.
- Regional proved reserves replacement indicates a trend of limited reserves replacement in the mature areas of EPN and EPA from production and divestment and reserves additions in the other two areas EPG and EPM.

There are a number of issues regarding proved reserves booking for 1999 which require endorsement by ExCom. The issues and recommendations are presented in this Note under "Issues".

Changes during 1999

Summary of Proved Reserves

The ESOSC proved reserves as of 1.1.2000 (assuming recommendations presented are endorsed) stand at 1523 mln m^3 oil/NGL (9581 mln bbl) and 1647 mrd sm^3 gas (10,037 mln boe), showing a decrease of 71 mln m^3 (449 mln bbl) and 64 mrd sm^3 (388 mln boe) for oil/NGL and gas respectively after taking account of 1999 production being 132 mln m^3 (831 mln bbl) oil/NGL and 82.6 mrd sm^3 (503 mln boe). Total proved reserves replacement ratio is 37% with a replacement ratio of 46% for oil and 23% for gas.

	Unit	Proved Reserves 1.1.1999	Proved Reserves 1.1.2000	Change	Proved Reserves Repl. Ratio
Oil/NGL	mln m3	1594.8	1523.4	-71.4	46%
Gas	mrd sm3	1711.1	1647.4	-63.7	23%
Total	mln boe	20.5	19.5	-1.0	37%

One new venture has booked first time proved reserves in 1999, Kazakhstan (*Saigak* +2 mln m3 oil) and one venture no longer books proved reserves Chad (-0.4 mln m3) as the Group has pulled out of the Doba-project end 1999.

EXHIBIT
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2
Brass

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Summary of Reserves by Region

The changes in proved reserves split by Region shows that only EPG has a significant replacement ratio for 1999 both oil/NGL and gas. As a result of production and divestments in the mature areas in EPN and EPA replacement ratio is very low with increases just offsetting the divested reserves. EPM replacement ratio is also low. (Gas replacement ratio's in EPM and EPG are 'distorted' due too low production).

	OIL/NGL [mln m3]						Gas [mrd sm3]					
	Proved 1.1999	Proved 1.2000	Prod 1999	Delta	Repl. Ratio		Proved 1.1999	Proved 1.2000	Prod 1999	Delta	Repl. Ratio	R.R. boe
EPN	578	480	70	-97	-39%		915	896	61	-19	69%	11%
EPM	316	308	27	-8	71%		109	94	3	-15	-391%	24%
EPA	157	159	14	2	115%		577	544	17	-33	-93%	4%
EPG	544	576	22	31	244%		110	113	1	3	321%	248%
Total	1595	1523	132	-71	46%		1711	1647	83	-64	23%	37%

Breakdown of Changes by Category

The decrease in both oil/NGL and gas reserves is the result of Production and Divestments (Sales in Place) from Portfolio Management recommendations, the reductions are only partly offset by increases from Discoveries & Extensions, Improved Recovery, Revisions & Reclassifications and Acquisitions (Purchases in Place).

	Oil/NGL [mln m3]	Gas [mrd sm3]
Proved Reserves 1.1.1999	**1594.8**	**1711.1**
Revisions & Reclassifications	39.2	15.2
Improved Recovery	18.7	2.2
Extensions & Discoveries	53.7	38.6
Purchases in Place	11.9	.2
Sales In Place	-62.8	-37.3
Production 1999	-132.1	-82.6
Proved Reserves 31.12.1999	**1523.4**	**1647.4**

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Major Changes by Category and Country

Breakdown of the major changes is as follows :

	Oil/NGL [mln m3]
Sales in Place (Divestments)	-63
USA (Enterprise&Apache)	-47
Philippines (Texaco)	-4
Canada (Plains)	-10
Purchases in Place (Acquisition)	11
Nigeria SPDC (EA/EJA)	11
Extensions & Discoveries	54
Nigeria SNEPCO (Ehra)	24
USA (Hickory, Spirit, Auger e.a.)	10
Norway (Ormen Lange)	1
Denmark (Halfdan)	6
Nigeria SPDC	5
Others (New Zealand, Oman e.a.)	8
Improved Recovery	19
Oman PDO	9
Others (Sakhalin, Altura, Brunei)	10
Revisions & Reclassifications	39
Nigeria SPDC (Shallow Offshore)	+18
Oman PDO	+12
Gabon	+5
Canada	+6
Others NET	-2

	Gas [mrd sm3]
Sales in Place (Divestments)	-37
USA (Enterprise&Apache)	-15
Philippines (Texaco)	-19
Canada (Plains)	-3
Purchases in Place (Acquisition)	0
Extensions & Discoveries	39
Nigeria SNEPCO (Ehra)	0
USA (Hickory, Spirit, Auger e.a.)	9
Norway (Ormen Lange)	12
Denmark (Halfdan)	2
Nigeria SPDC	7
Others (Egypt, Malaysia, Brunei, e.a.)	9
Improved Recovery	2
Malaysia (Lower Pressure)	2
Others	0
Revisions & Reclassifications	15
Canada (Royalties in Cash +14)	19
USA (Own Use)	-7
Norway (Troll gas contract e.a.)	13
Oman Gisco (Entitlement)	-12
Others NET	2

Impact AOSP and Iran

The proved oil/NGL and gas reserves exclude the Canadian OilSands *AOSP* – 95 mln m3 proved (600 mln bbl) as these under SEC rules are classified as "minning reserves" (volumes are incl. minority interest). Also exclude are the Iranian "Pseudo Reserves" *Soroosh/Nowrooz* – 24 mln m3 (150 mln bbl Shell share) as proved reserves booking is currently still very sensitive in Iran. Note the 100% project reserves volumes in Iran are 950 mln bbl (151 mln m3).

Although the externally reported proved oil/NGL and gas reserves will not include AOSP "Mining Reserves" nor the Iran "Pseudo Reserves" the overall hydrocarbon resource replacement performance is better represented if these volumes are included resulting in a replacement ratio of 94%.

	Initial Submission excl adj.	**Repl. Ratio Proved Reserves**	Repl Ratio Excl. A&D	Repl. Ratio Incl. AOSP	Repl. Ratio Incl. AOSP & Iran
Oil/NGL	71%	**46%**	84%	118%	136%
Gas	31%	**23%**	68%	23%	23%
Total	56%	**37%**	78%	82%	94%

The initially submitted reserves prior to the proposed adjustment gave a replacement ratio of 56%; after adjustments but excluding Acquisitions and Divestments the replacement ratio is 78%.

DB 04272

Proved Developed Reserves

The proved developed reserves as of 1.1.2000 stand at 795 mln m^3 oil/NGL and 775 mrd sm^3 gas, showing an increase of 15 mln m^3 and 2 mrd sm^3 for oil/NGL and gas after taking account of 1999 production. Proved developed replacement ratios are 111% for oil/ngl and 103% for Gas (108% total boe).

The proved developed reserves replacement ratio for 1999 indicated that production as well as divested developed reserves were replaced. Large contributions were made by from transfer of undeveloped reserves to developed reserves in Canada (Sable project start-up), Oman Gisco (production start-up), Malaysia (Compression Installation F23), USA and UK.

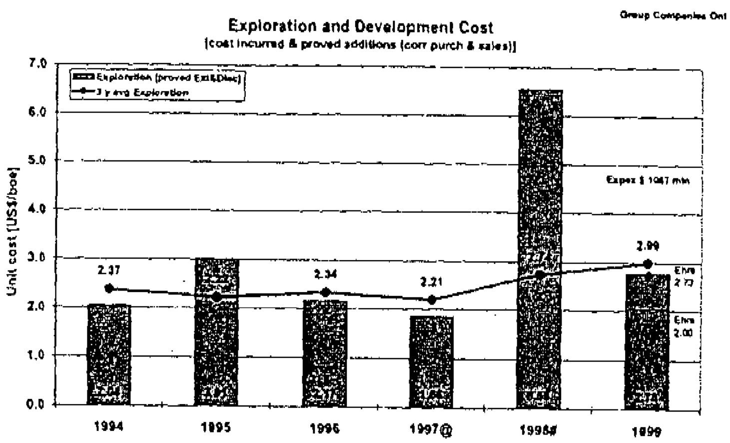
Issues

The following issues need endorsement from the ExCom before finalising the 1999 proved reserves:

Nigeria SPDC – Ehra Discovery

In their initial submission SNEPCO have booked the 1999 Ehra discovery (made by Exxon) as commercial SFR and not as reserves. Up to the November 1999 monthly reporting (MISCOM) by SNEPCO indicated booking of Ehra volumes as proved reserves for 1.1.2000. Ehra volumes, however, were excluded from the 1.1.2000 proved reserves as Exxon indicated mid December 1999 that they would not include the volumes in their proved reserves and did not present SNEPCO with a preliminary development plan. Subsequent challenge has indicated that volumes are sufficiently large and sufficient technical work has been done in Houston to support proved reserves booking for 1.1.2000. It is therefor recommended to advise SNEPCO to book Ehra proved reserves for 1.1.2000 of 24.0 mln m3 oil Shell PSC entitlement.

Booking of the Ehra discovery is also important in view of the external Unit Finding Cost (UFC) which is based on proved reserves additions and exploration expenditure disclosed. Preliminary figures indicate an 1999 exploration expenditure of 1087 mln US$ for Group companies. Based on the Group company proved additions form "discoveries & extensions" the UFC'99 would be 2.78 $/b excluding and 2.0 $/b including the Ehra discovery.



Nigeria SPDC

Nigeria SPDC has submitted an increase in proved reserves of 80 mln m3 proved reserves – this is believed to be too optimistic in view of the current licence expiry of 30th June 2019 for the Onshore (MOU) and Shallow Offshore Licences by 30th November 2008.

Under the alternative funding arrangement for EA/EJA Shell share of reserves increase for these fields from 30% to 77.14% and the licence has been extended to 350 million barrels cumulative production. Net result of these changes is an increase in proved reserves in the Shallow Offshore of 30 mln m3 (189 mln bbl). It is recommended to book these incremental volumes.

The Onshore Licence expires mid –2019 and it is recommended to freeze the onshore proved reserves at the 1.1.1999 level to prevent potential large proved reserves reduction in future, if the planned growth does not or only partly materialises. This means not book the 50 mln m3 oil proved reserves addition for

1.1.2000 as submitted by SPDC. As a consequence proved onshore oil reserves in SPDC will decline with cumulative production in future years until such time that significant growth in oil production volumes has been established or a licence extension has been secured.

Abu Dhabi

Abu Dhabi proved oil reserves have historically been booked on an expected growth scenario which still has not materialised under OPEC constraints. As a result of the Abu Dhabi licence expiry early 2014 reserves have to be de-booked with deferral of the expected production increase. It is recommended to differentiate between an expected (50/50) forecast and a proved (90/10) forecast when estimating proved reserves. An initial gap of two years delay in growth for 1.1.2000 requires a de-booking of 6.5 mln m3.

Canada

The Group Resource Guidelines prescribe in line with SEC rules that 'Royalties in Kind' should be excluded from the reserves but that 'Royalties in Cash' should be included in the reserves. Historically Canada proved reserves have been included net of all royalties, directly from the Shell Canada Annual Report data. Early 1999 it became clear that only oil royalties in Canada are due in Kind and that Gas royalties are due in Cash. For 1.1.2000 reserves gas royalties have been included in the SC reserves – addition of 13.8 mln m3. With the divestment of the Plains properties all oil fields have been divested and Royalties in Kind are no longer applicable.

Australia

Australia SDA have indicated that WAPET have re-evaluated the Gorgon reserves which has lead to a 20% increase in recoverable volumes. In view of the limited market availability and already large uncommitted proved gas reserves carried by SDA based on future market expectations it has been proposed and agreed with SDA and EPA not to include the additional 20 mrd sm3 for 1.1.2000. Booking of the additional volume in future is subject to further market development and capture.

Proved Gas volumes in Australia have been a point of challenge by the external Auditors (KPMG/PWC) for the last two years already and incremental booking at present would be hard to support.

USA

Shell Oil up to 1998 reported its financial performance externally separately from the Group, which included proved reserves based on Shell Oil's internal reserves Guidelines. The Shell Oil definition of proved reserves includes 'own use' gas in the proved gas reserves.

Following the Globalisation in 1999 and de-registration of Shell Oil from the SEC Shell Oil no longer individually publishes its results and reserves. The Group's definition of proved reserves explicitly excludes 'own use' gas form the reserves. To align reporting across the Group it is proposed that Shell Oil reserves for 1.1.2000 are reported excluding 'own use' gas in line with the Group Guidelines. This results in a reduction of 6.5 mrd sm3 versus the number submitted by Shell Oil (-1.9% for Shell Oil, -75% for Area and –7% for Altura).

The issue has been discussed with the Group Reserves Auditor and Group External Auditors who confirm that both interpretations are defendable under SEC rules but also acknowledge that reporting consistency across the Group is a strong consideration.

Excluding own Use gas from the USA reserves also aligns with the new gas definition proposed for 2000 "Gas Production Available for Sales (from own Reserves)" which also excludes own use and flared gas volumes.

It should be noted Shell Oil prefer not to adjust reserves and have submitted 1.1.2000 proved gas reserves including 'own use' gas.

DB 04274

The total of the above recommendations in terms of changes to the originally submitted proved reserves by the Group Ventures is as follows:

OIL	Proved Reserves
♦ Inclusion of Nigeria-SNEPCO 1999 Ehra discovery ('Exxon' block)	+ 24.0 mln m^3
♦ Increase Nigeria-SPDC Shallow Offshore Reserves (EA/EAJ) resulting from alternative funding agreement (77% share) and Licence extension post Nov-2008 (max of 350 MMb)	+ 30.0 mln m^3
♦ Limit Nigeria-SPDC Onshore (MOU) to currently booked proved reserves minus 1999 production reflecting doubling of production to 1,400 b/d by 2010 only with licence expiry in Jun-2019; Reduction form SPDC submission of	- 50.0 mln m^3
♦ Reduce Abu Dhabi proved reserves based on two year delay production increase and licence expiry in Jan-2014	- 6.5 mln m^3
	Total: - 2.5 mln m^3

GAS	
♦ Exclude USA 'own use' gas in line with Group Reserves Guidelines	-6.5 mrd sm^3
♦ Australia SDA, increase in Gorgon volumes are not included as proved reserves due to gas market limitations (19.7 mrd sm^3 increase from 86.1 to 105.8 mrd sm^3)	0.0 mrd sm^3
♦ Include Canada gas royalty in cash in line with Group Reserves Guidelines	+ 13.8 mrd sm^3
	Total + 7.3 mrd sm^3

Discoveries 1999

Two NVOs and sixteen OUs have reported a total of 59 successful exploration wells for 1998 versus 60 dry wells (note Shell Oil and Shell Canada statistics are not yet complete). Total Group share on equity basis (i.e. including carried Government take in PSC countries) of the discovered hydrocarbon resource volume is 136 mln m^3 oil/NGL (857 mln bbl) and 67 mrd sm^3 gas (411 mln boe), a combined total of 1,268 mln boe.

There are seven large oil finds one each in Nigeria-SNEPCO (Ehra 746 mln boe), Denmark (Halfdan 491 mln boe) and Oman (Ghafeer 85 mln bbl), plus two each in Australia-Woodside (Vincent 61 mln bbl and Enfield 72 mln bbl) and Angola (Platina 117 mln boe and Plutonia 283 mln boe).

A further seven gas fields were discovered one in Egypt (Obaiyed-South 74 mln boe), two in Malaysia (Kamansu East Upthrown 62, F23-SW 23 mln boe), Australia SDA (Geryon and Orthrus) and Norway (Ormen Lange South 125 mln boe). The large deepwater gas discovery in Nigeria SNEPCO (Doro) under current contractual terms does not give Shell any entitlement.

Total exploration expenditure for 1999 is currently estimated at US$ 1290 mln resulting in an internal unit resource finding cost of 1.02 $/b for the discovered expectation resource volume of 1268 mln boe.

If discovered resources form exploration in 1999 are limited to shell share expectation reserves booked for 1.1.2000 of 60 mln m3 oil/ngl (377 mln bbl) and 19.4 mrd sm3 (118 mln boe) a total of 495 mln boe this results in a unit reserves finding cost of 2.60 $/b.

DB 04275

Attachment 1

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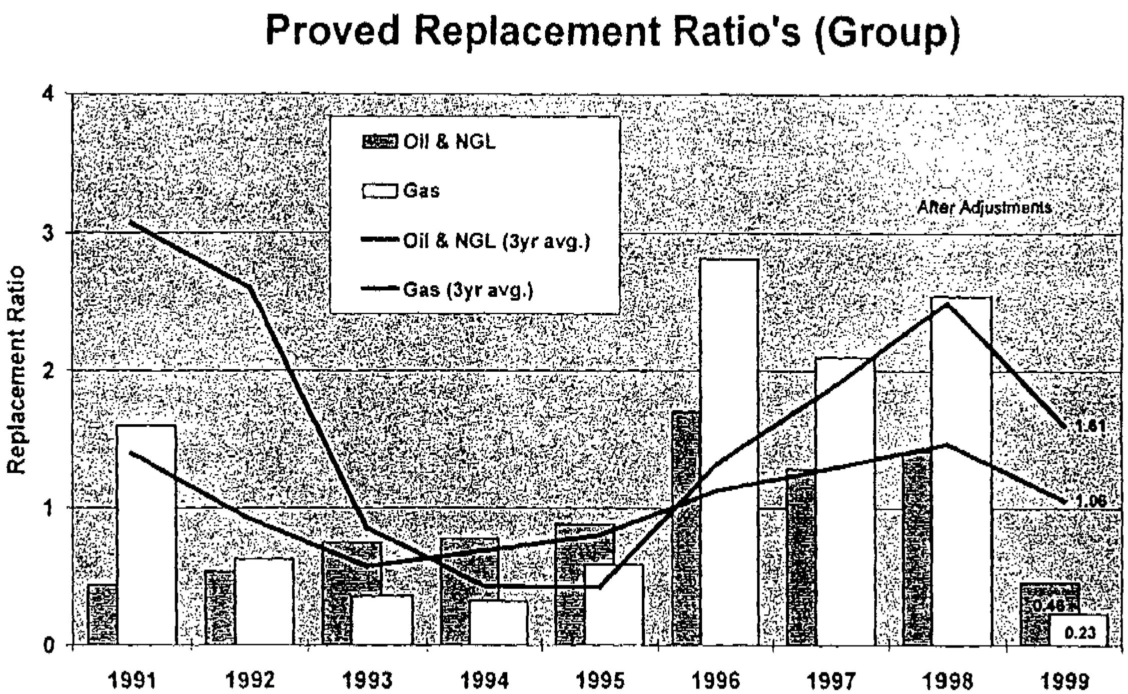
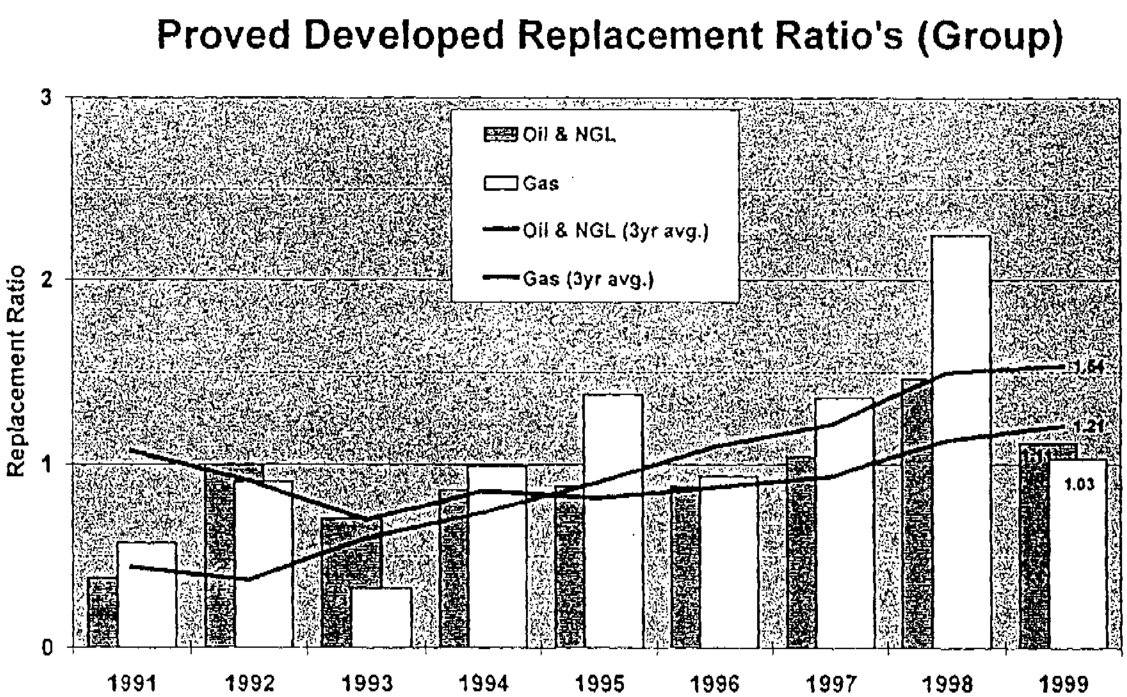
Historic Replacement Ratio's





Attachment 2

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Proved Reserves Summary

	Crude Oil and NGL in million M3					Gas in milliard SM3					
	Proved Reserves 01/01/99	Proved Reserves 31/12/99	Prod 1999	DELTA	Repl. Ratio	Proved Reserves 01/01/99	Proved Reserves 31/12/99	Prod 1999	DELTA	Repl. Ratio	BOE Repl. Ratio
Netherlands	6.09	5.77	0.76	-0.32	58%	424.61	410.64	15.71	-13.970	11%	13%
UK	156.40	129.92	23.34	-26.48	-13%	116.44	109.45	9.98	-6.988	30%	-1%
Norway	38.75	33.26	4.81	-5.49	-14%	67.01	89.90	2.38	22.884	1062%	334%
Denmark	35.57	39.15	6.86	3.58	152%	32.81	30.44	3.22	-2.374	26%	113%
Germany	4.04	3.37	0.33	-0.67	-103%	62.34	59.42	5.00	-2.919	42%	32%
Austria	0.25	0.23	0.03	-0.02	33%	1.24	1.48	0.17	0.240	243%	210%
Shell Oil (USA)	149.43	92.00	18.20	-57.43	-216%	118.44	94.40	17.75	-24.038	-35%	-128%
Shell Oil (Aera)	83.38	79.26	7.66	-4.12	46%	4.42	1.38	0.12	-3.038	-2485%	9%
Shell Oil (Altura)	42.03	47.87	2.64	5.84	321%	5.88	7.50	0.40	1.625	506%	345%
Shell Oil (MOC)	4.91	1.86	0.55	-3.05	-455%	2.00	1.55	0.55	-0.450	18%	-222%
Shell Oil (TMR)	0.67	0.93	0.18	0.26	244%	1.28	1.69	0.17	0.410	341%	291%
Canada	56.13	47.16	4.16	-8.97	-116%	78.42	88.31	5.83	9.891	270%	106%
EPN	577.65	480.78	69.52	-96.87	-39%	914.89	896.16	61.27	-18.727	69%	11%
Oman - (PDO)	134.09	139.50	16.37	5.41	133%	0.00	0.00	0.00	0.000		133%
Oman - (Gisco)	32.34	33.18	0.88	0.84	195%	59.32	45.69	1.23	-13.628	-1005%	-496%
Abu Dhabi	108.78	96.81	4.80	-11.97	-149%	0.00	0.00	0.00	0.000		-149%
Egypt	9.15	9.06	0.37	-0.09	76%	29.48	31.27	1.06	1.790	266%	216%
Syria	22.78	19.81	4.11	-2.97	28%	3.46	1.01	0.28	-2.443	-769%	-22%
Russia - (Sakhalin)	8.71	7.69	0.05	-1.02	-1940%	0.00	0.00	0.00	0.000		-1940%
Kazakhstan - (Temir))	0.00	2.00	0.00	2.00		0.00	0.00	0.00	0.000		
Pakistan	0.00	0.00	0.00	0.00		10.17	11.34	0.16	1.167	839%	839%
Bangladesh	0.00	0.00	0.00	0.00		6.74	4.71	0.33	-2.026	-512%	-512%
EPM	315.85	308.05	26.58	-7.80	71%	109.17	94.03	3.08	-15.140	-391%	24%
Australia - (SDA)	31.03	32.49	1.98	1.46	174%	174.51	176.64	2.27	2.129	194%	184%
Australia - (Woodside)	12.45	11.85	0.79	-0.60	24%	55.05	40.21	1.47	-14.846	-913%	-578%
Brunei	55.23	59.28	5.00	4.05	181%	103.56	102.61	4.70	-0.948	80%	133%
New Zealand	3.59	4.60	0.44	1.01	330%	11.97	12.65	1.26	0.672	153%	200%
New Zealand - (Pecten)	0.77	0.80	0.11	0.03	127%	2.58	2.31	0.27	-0.270	0%	38%
Malaysia	27.12	25.55	3.81	-1.57	59%	183.03	183.82	6.56	0.790	112%	92%
Philippines	7.40	3.82	0.00	-3.58		39.20	19.44	0.00	-19.763		
Thailand	12.73	14.17	1.02	1.44	241%	6.69	6.23	0.39	-0.464	-18%	171%
China	2.79	3.24	0.58	0.45	178%	0.00	0.00	0.00	0.000		178%
China - (Pecten)	3.84	3.29	0.59	-0.55	7%	0.00	0.00	0.00	0.000		7%
EPA	156.95	159.09	14.32	2.14	115%	576.60	543.90	16.91	-32.700	-93%	4%
Nigeria - (SPDC)	429.82	447.54	12.28	17.72	244%	92.06	95.93	0.84	3.871	564%	264%
Nigeria - (SNEPCO)	50.40	71.43	0.00	21.03		7.31	5.70	0.00	-1.612		
Gabon	20.20	19.91	5.18	-0.29	94%	0.00	0.00	0.00	0.000		94%
Venezuela	25.27	21.43	2.37	-3.84	-62%	0.00	0.00	0.00	0.000		-62%
Argentina	3.88	3.43	0.26	-0.45	-73%	6.22	7.28	0.02	1.066	5176%	308%
DR Congo (Zaire)	4.34	3.22	0.16	-1.12	-600%	0.00	0.00	0.00	0.000		-600%
Chad	0.42	0.00	0.00	-0.42		0.00	0.00	0.00	0.000		
Brazil - (Pecten)	0.93	0.81	0.12	-0.12	0%	4.82	4.38	0.45	-0.440	2%	2%
Cameroon - (Pecten)	9.04	7.75	1.31	-1.29	2%	0.00	0.00	0.00	0.000		2%
EPG	544.30	575.52	21.68	31.22	244%	110.41	113.30	1.31	2.885	321%	248%
EP World	1594.75	1523.44	132.10	-71.31	46%	1711.07	1647.38	82.57	-63.682	23%	37%
EP World (bbl/boe)	10029.9	9581.4	830.8	-448.5	46%	10424.5	10036.5	503.0	-388.0	23%	37%
EP Total Oil + Gas (boe)	20454.4	19617.9	1333.9	-836.5	37%						

DB 04277

EXHIBIT 3 Brass

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Exhibit 2

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EXCOM 1999 Proved Reserves
31st January 2000

Key Proved Reserves Messages

- **'99 Proved Oil/NGL and Gas Replacement Ratio 37%**
  - Low after three years high
  - Challenge to communicate externally
    - upside AOSP and Iran & excluding divestments
- **Unblocking Nigeria is Key**
  - Production Performance and Proved Reserves additions
- **2000 Scorecard**
  - SPDC Impact on proved reserves target equates to a 20% loss (LE 62%)
- **BP'99 2000-2004 Proved Reserves**
  - 25% additions promised by SPDC are unlikely to materialise
- **Need to resolve reporting of Innovative Contracts**
  - Booking Pseudo Reserves "Buy-backs"

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EXCOM 1999 Proved Reserves
31st January 2000

2000 EP Scorecard
(Including D/S Gas)

Business Result	Plan	Below	Mid-Point	Outstanding	Weight %	Actual (or LE)	Normalized Score	Weighted Score
ROACE (%)	15.6%	7.7%	15.6%	23.4%	100%	15.6%	1.00	1.00
Indicative oil price for ROACE		$10/b	$14/b	$18/b				
							A =	1.00

Business Performance	Plan	Below	Mid-Point	Outstanding	Weight %	Actual (or LE)	Normalized Score	Weighted Score
Core Measures Opex & Depreciation ($ mln)	6830	7170	6830	6490	20%	6830	1.00	0.20
Production Oil / NGL (kb/d)	2325	2246	2310	2376	10%	2310	1.00	0.10
Gas Sales (mrd Nm^3/y)	89.8	86.1	89.3	92.3	10%	89.3	1.00	0.10
Proved Reserves Replacement (Excluding divestments)	80%	50%	80%	110%	10%	80%	1.00	0.10
Performance vs. Competitors (Self appraisal)		0.0	1.0	2.0	10%	1.00	1.00	0.10
Additional Measures HSE, HR and SFR (Self-appraisal)		0.0	1.0	2.0	20%	1.00	1.00	0.20
Milestones		0.0	1.0	2.0	20%	1.00	1.00	0.20
Total Performance		0.0	1.0	2.0			B =	1.00

EP Score	Business Performance Factor (BPF) But, if A or B equal zero, Total EP Score will also be zero	0.5*A + 0.5*B =	1.00

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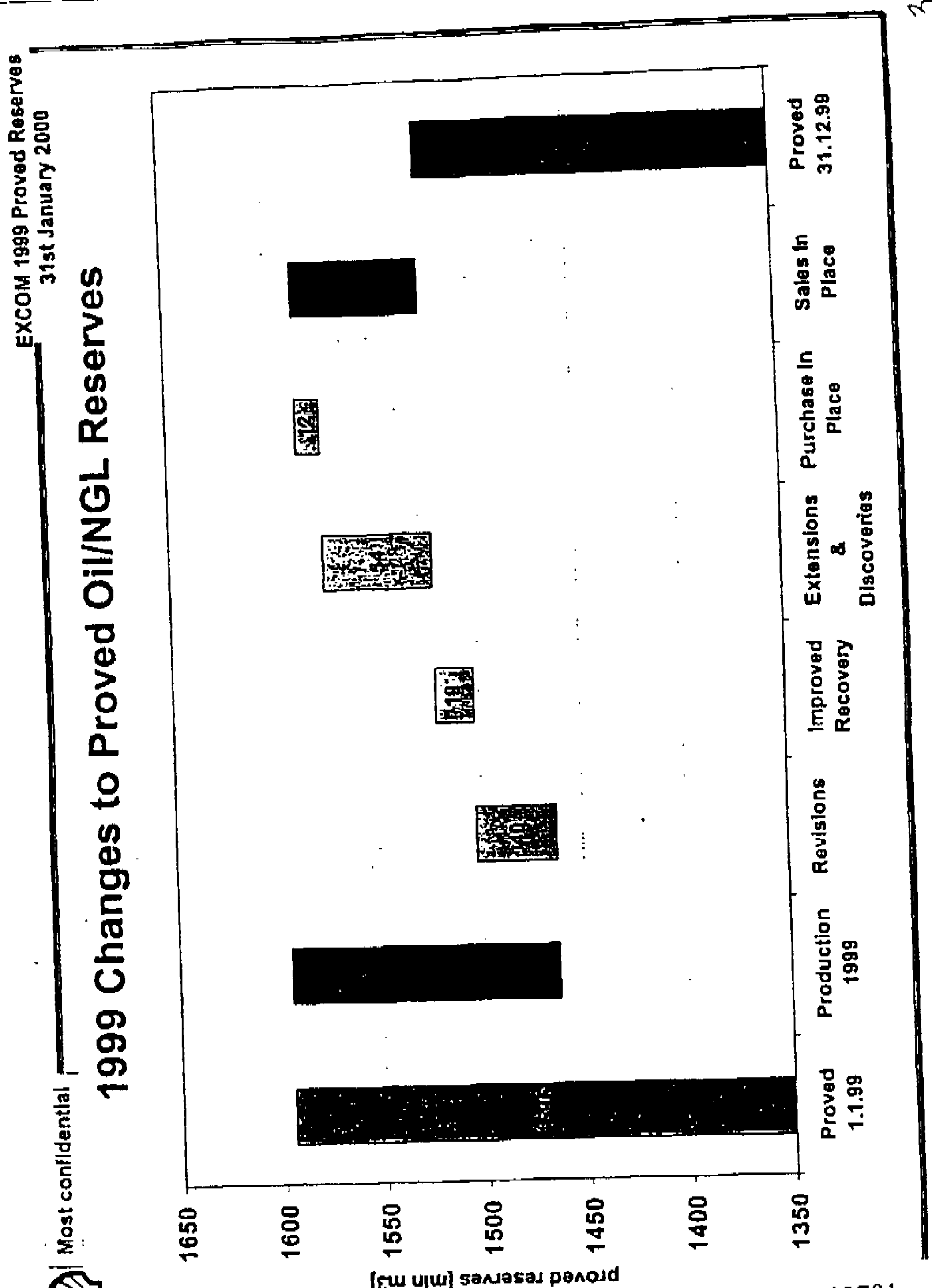

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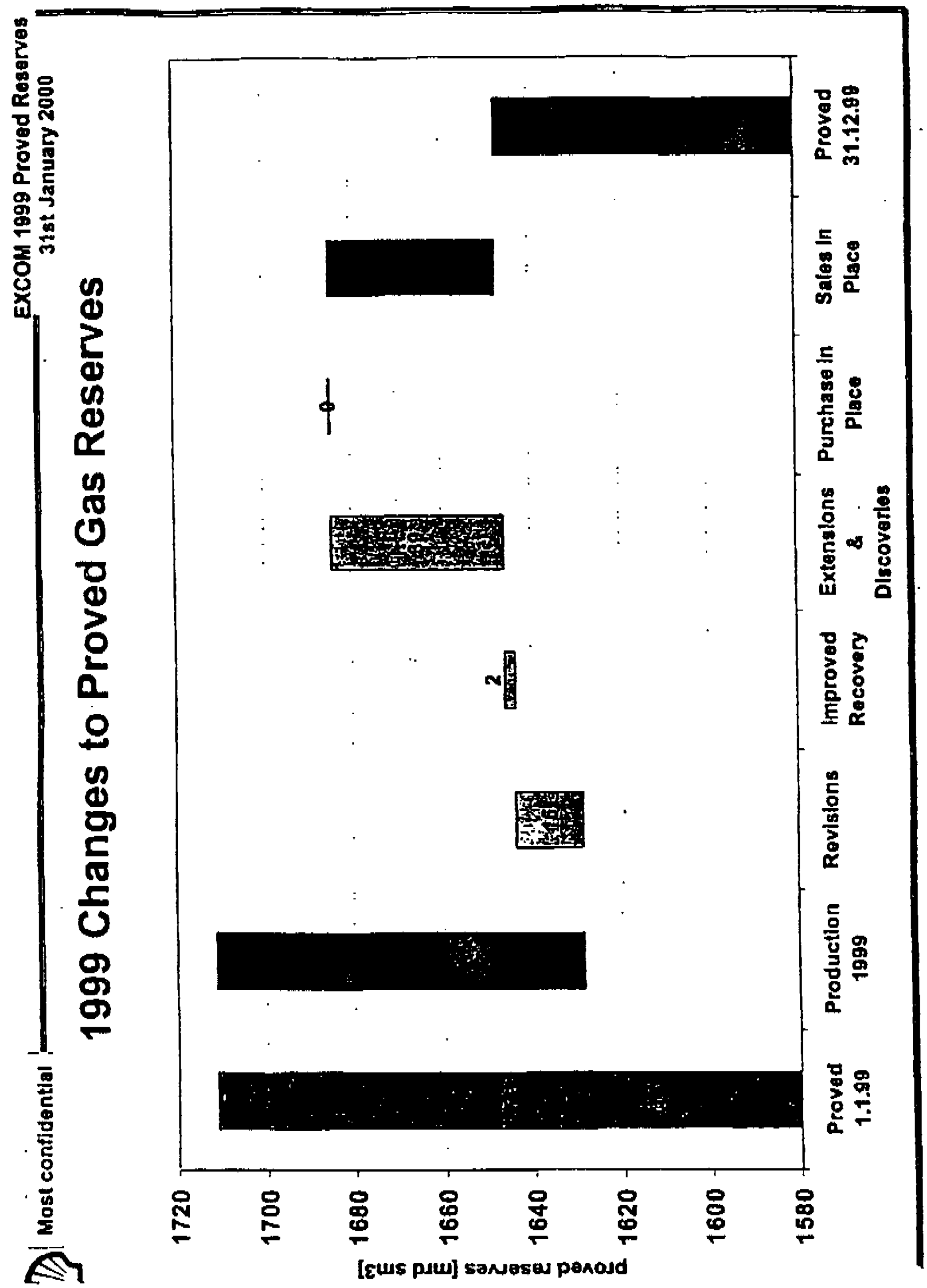

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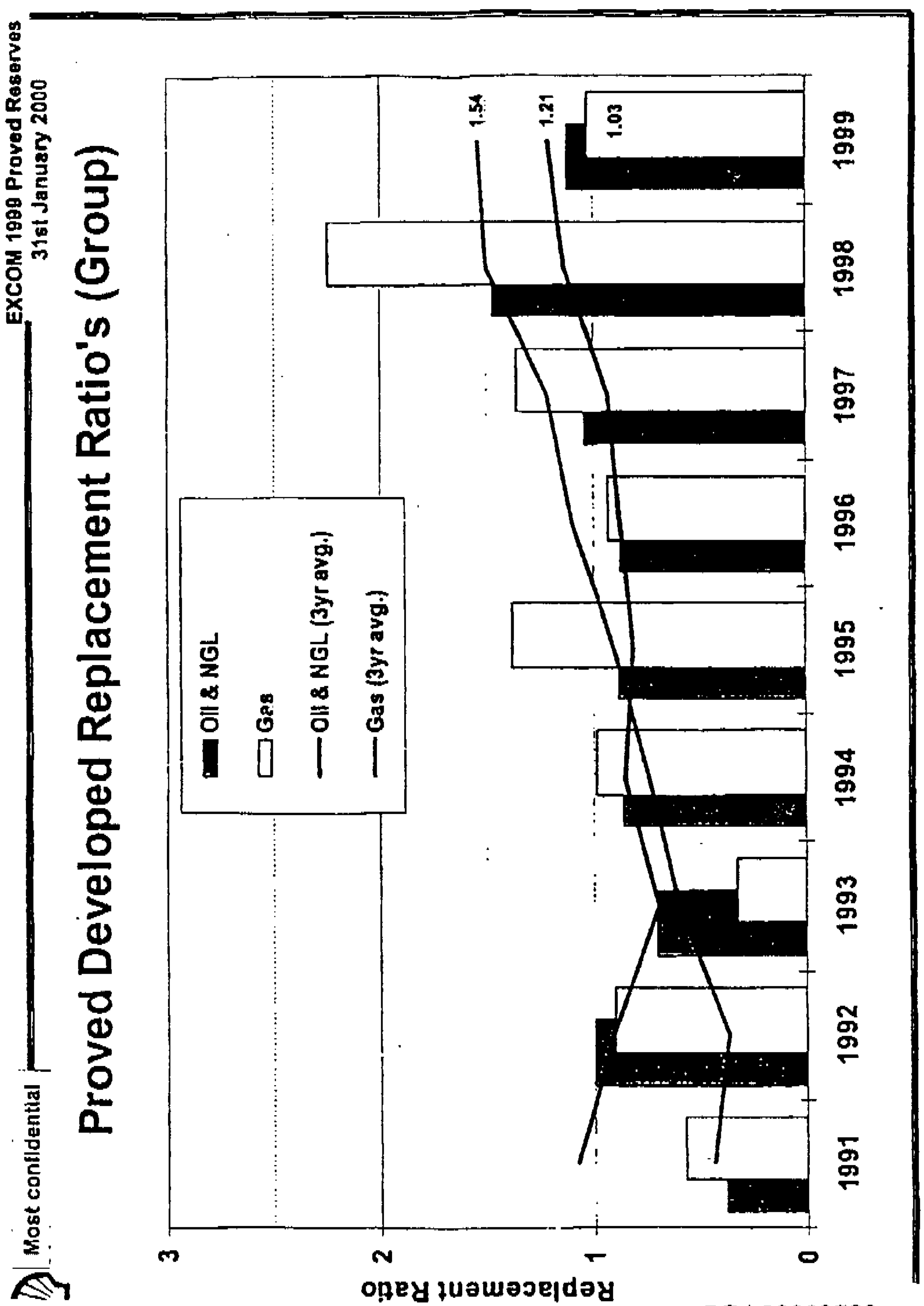

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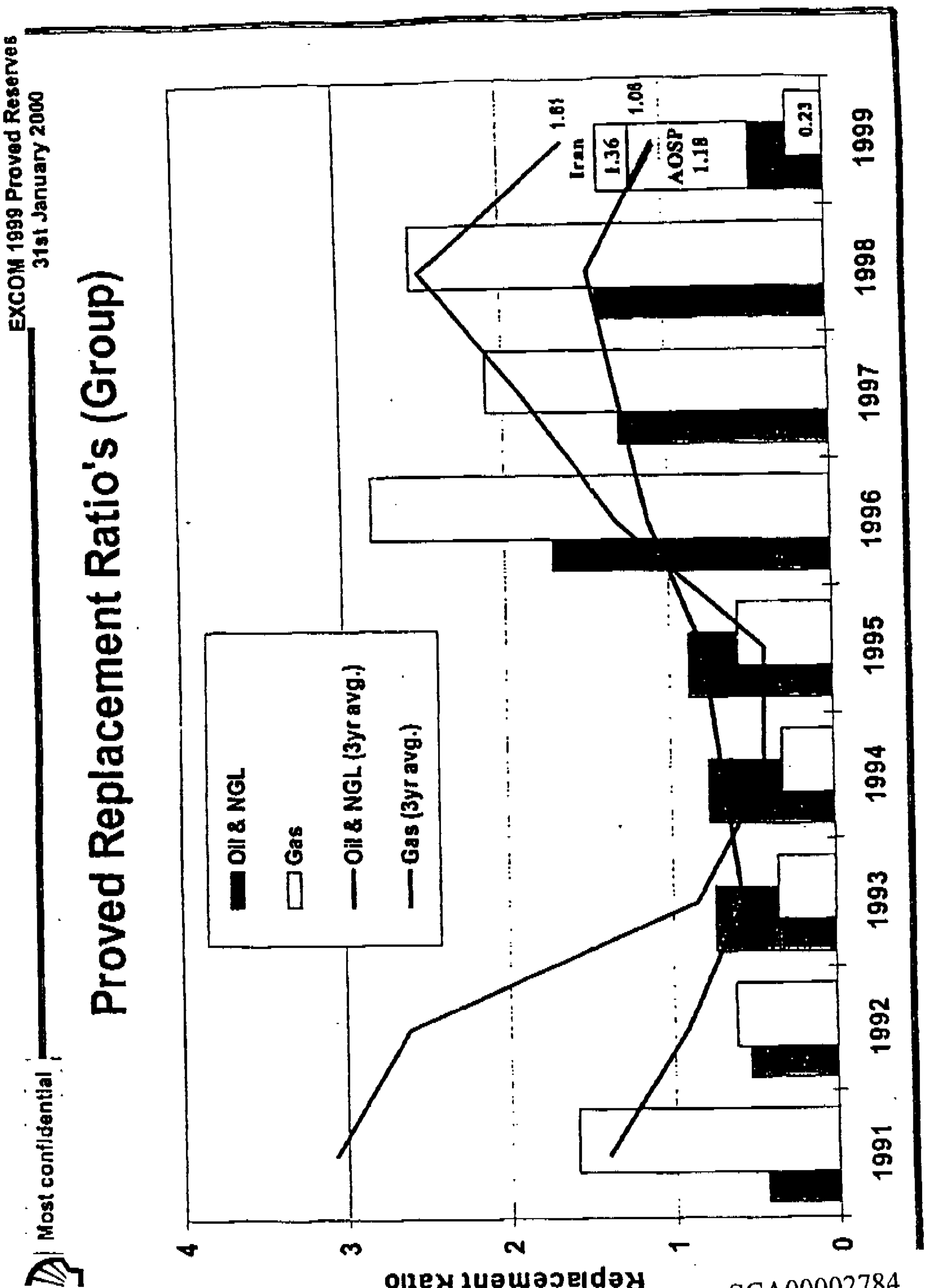

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EXCOM 1999 Proved Reserves
31st January 2000

1999 Proved Reserves Replacement Ratio

	Initial Data	Proposed Data	Excl. A&D	Incl. AOSP	Incl. AOSP & Iran	+AOSP +Iran Ex A&D
Oil/NGL	71%	46%	84%	118%	136%	175%
GAS	31%	23%	68%	23%	23%	68%
Total [boe]	56%	37%	78%	82%	94%	135%

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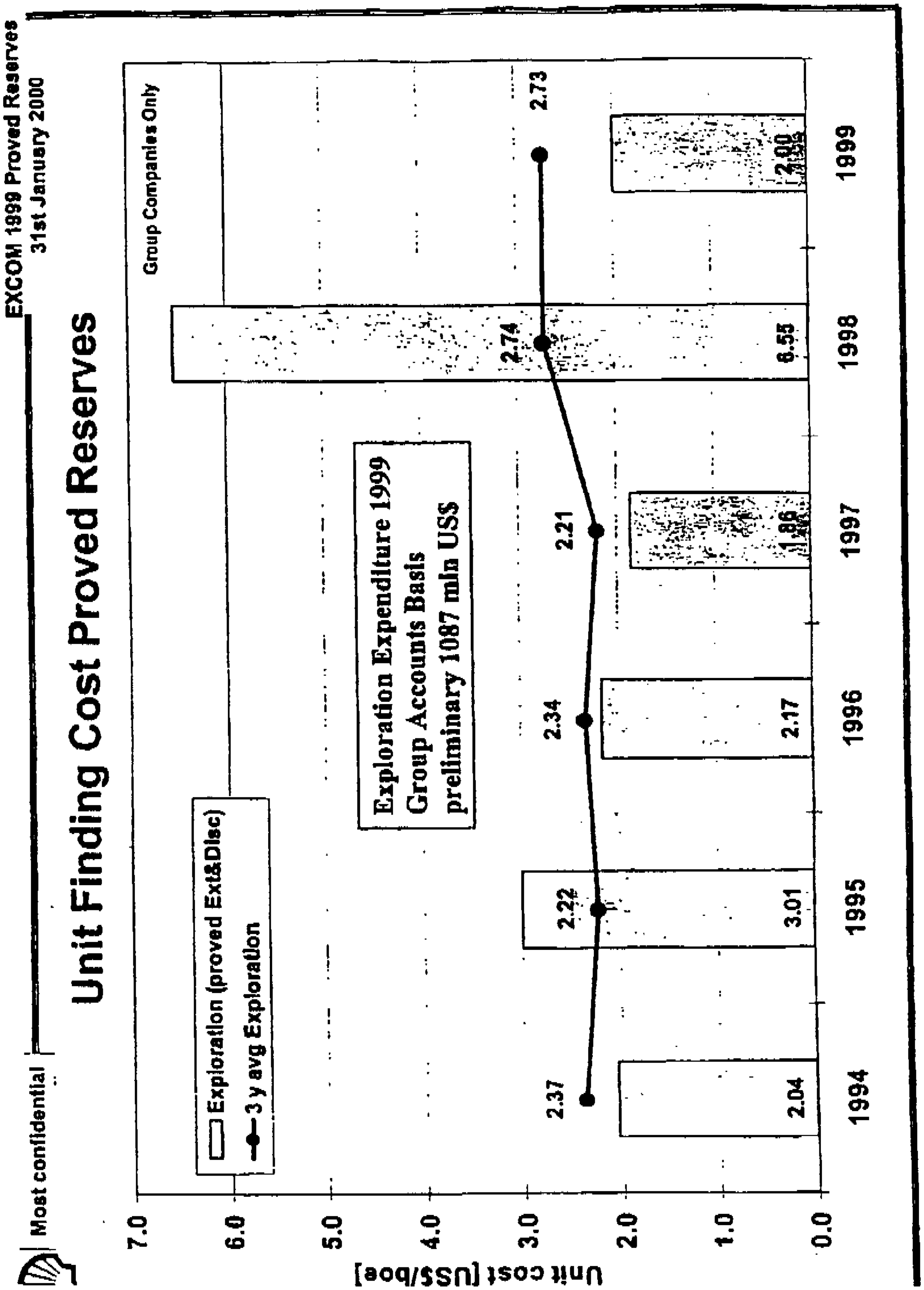

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EXCOM 1999 Proved Reserves
31st January 2000

Proved Oil/NGL Reserves Issues

- **Nigeria SPNEPO - Deepwater**
  - Book 1999 Ehra discovery (Exxon block) + 24.0
- **Nigeria SPDC - Shallow Offshore**
  - Book EA/EJA Alternative Funding/FID + 30.0
- **Nigeria SPDC - Onshore**
  - Do not book proposed increase MOU - 50.0
    Limit plateau proved forecast upto 1,400 b/d
    Licence expiry 30 June 2019
- **Abu Dhabi**
  - Reduce proved reserves - 6.5
    Delay growth scenario by 2 years
    Licence expiry Jan 2014

Total - 2.5 mln m3

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EXCOM 1999 Proved Reserves
31st January 2000

Proved Gas Reserves Issues

- **Canada**
  - Include Gas Royalties in Cash in line with Group Guidelines + 13.8
- **Australia**
  - ~~Do not book increase Gorgon (20%)~~ + 0.0
    Increase market take-up
- **USA**
  - Exclude own use gas volumes in line with Group Guidelines

Shell Oil	-- 1.9 %	- 1.8		
Area	- 75 %	- 4.1		
Altura	- 7 %	- 0.6		
			- 6.5	
		Total	+ 7.3 mrd sm3	

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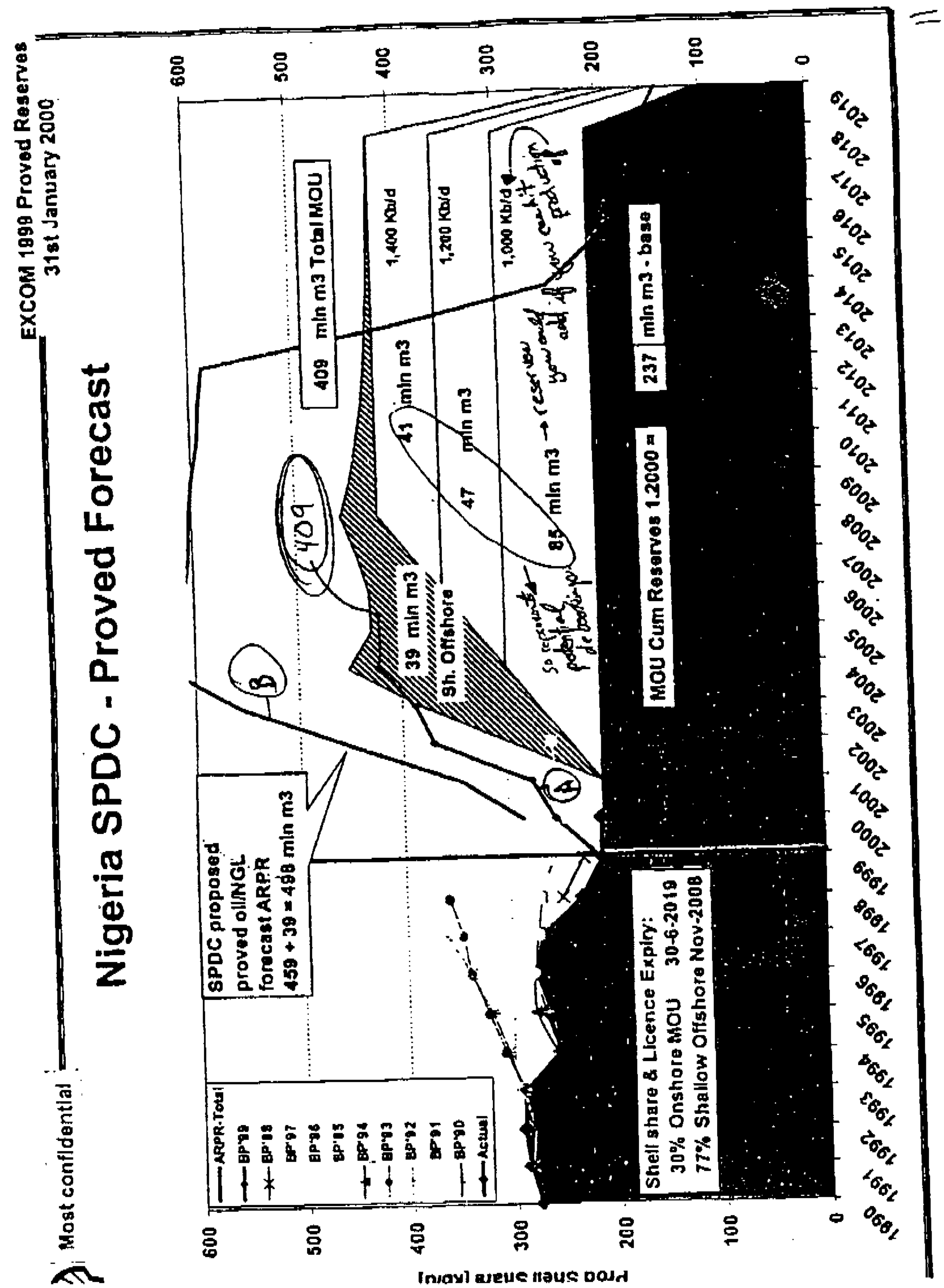

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EXCOM 1999 Proved Reserves
31st January 2000

BP'99 - SPDC Reserves Management

- **SEC Reserves Audit - August 1999**
  - Audit highlighted the issue of proved reserves forecast
  - Proved oil forecast assumes doubling of SPDC production levels
  - If growth does not materialise significant risk of de-booking proved reserves
  - Formal licence extension beyond 2019 would mitigate issue.
- **SPDC BP'99 resource plan repeatedly challenged**
  - Not taken up by SPDC at the time
  - Issue only fully recognized at end 1999

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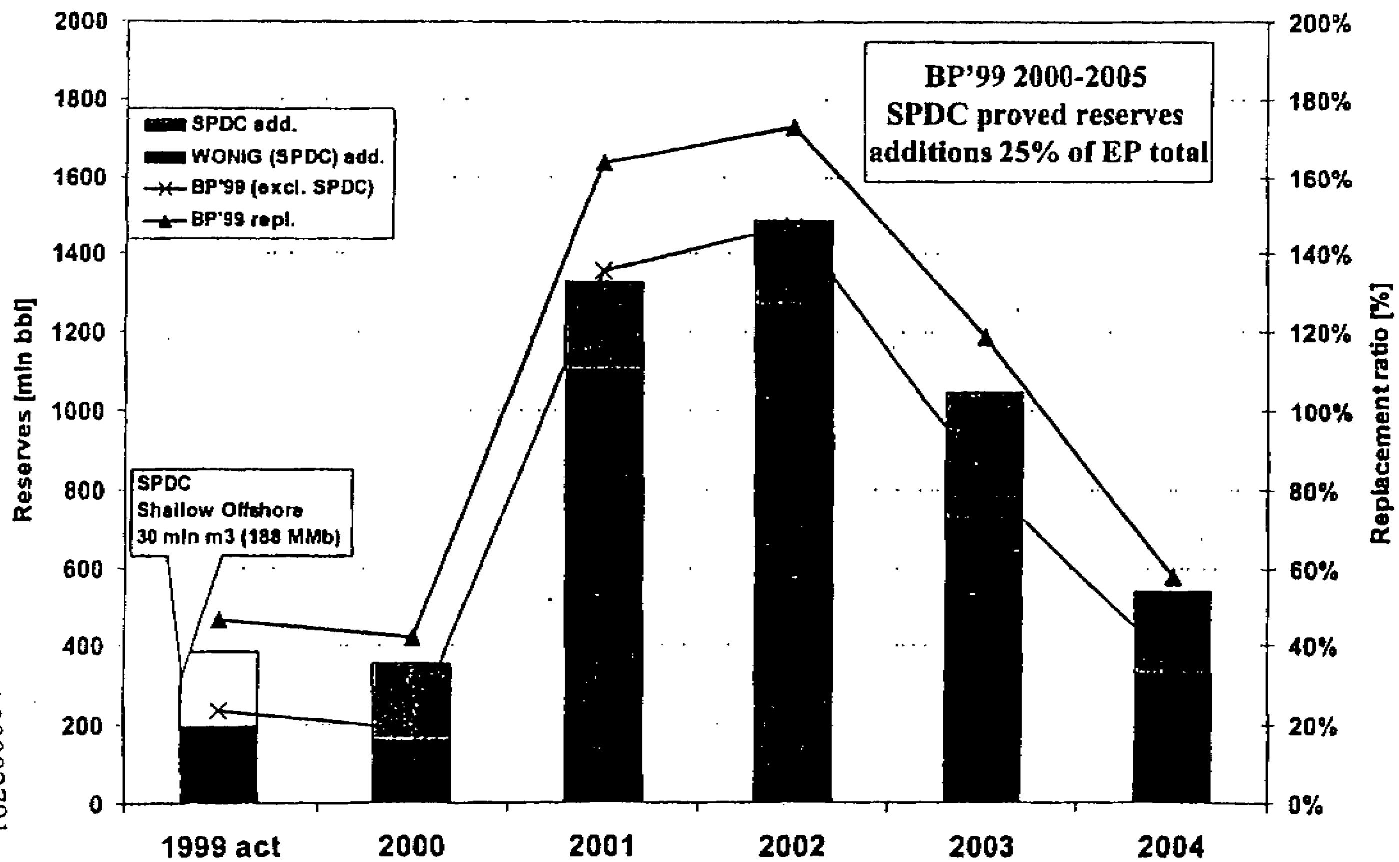
EXCOM 1999 Proved Reserves
31st January 2000

Proved Repl. Ratio BP'99 - Impact Nigeria SPDC



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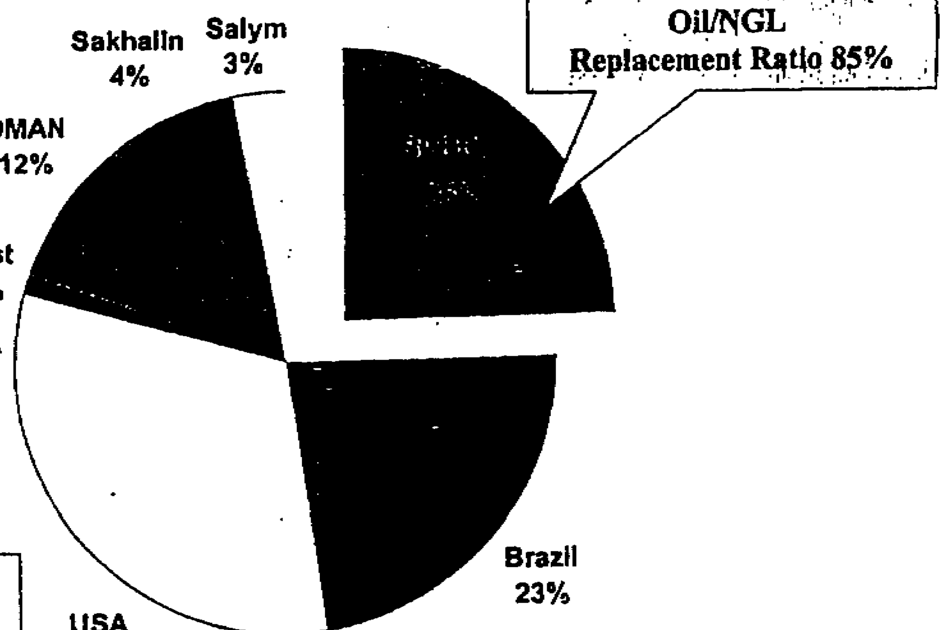
EXCOM 1999 Proved Reserves
31st January 2000

BP'99 Proved Reserves Additions 2000-2004



Total Proved Reserves
Addition 756 mln m3
(4755 mln bbl)
112% replacement ratio

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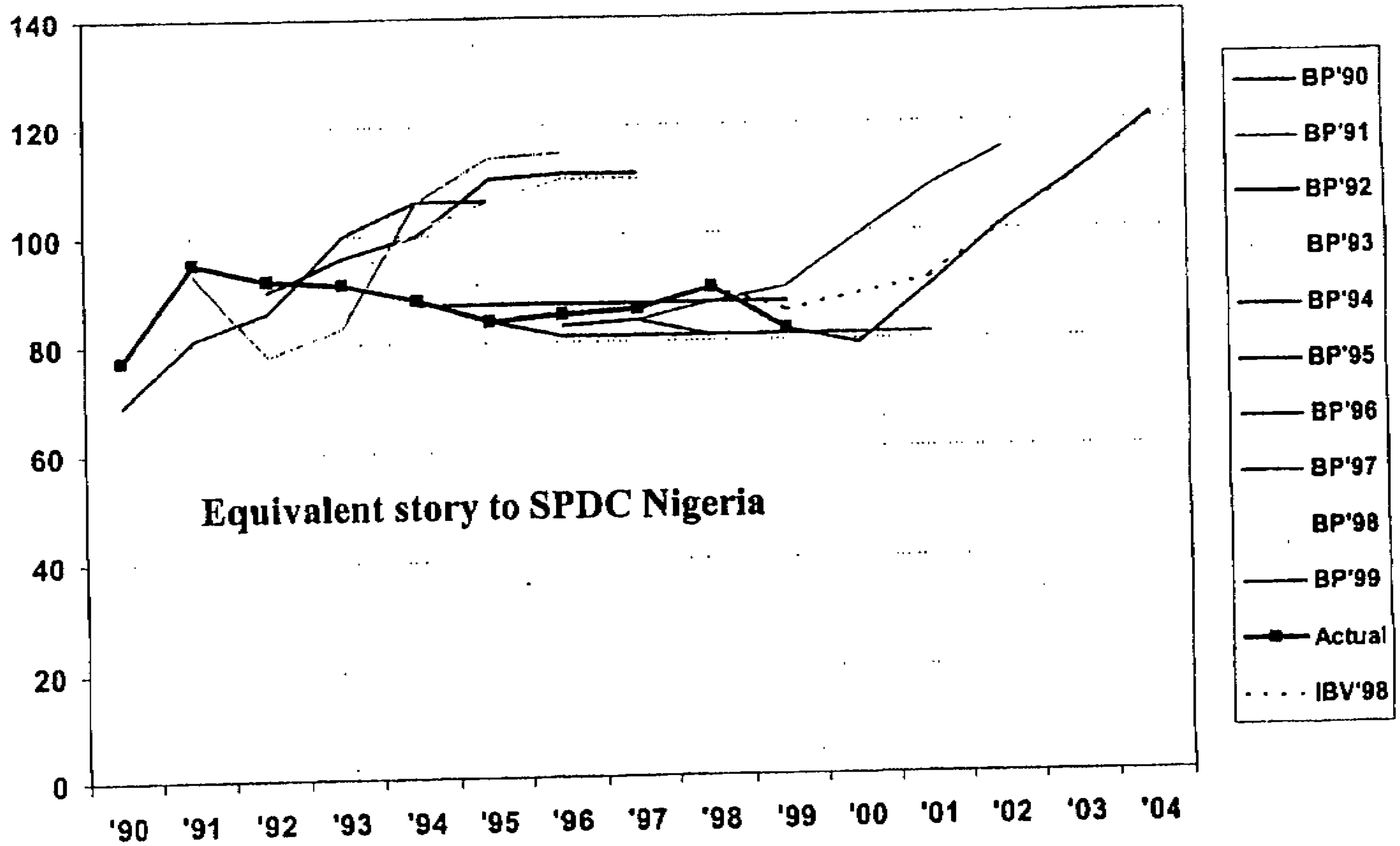
EXCOM 1999 Proved Reserves
31st January 2000

Abu Dhabi Oil Production



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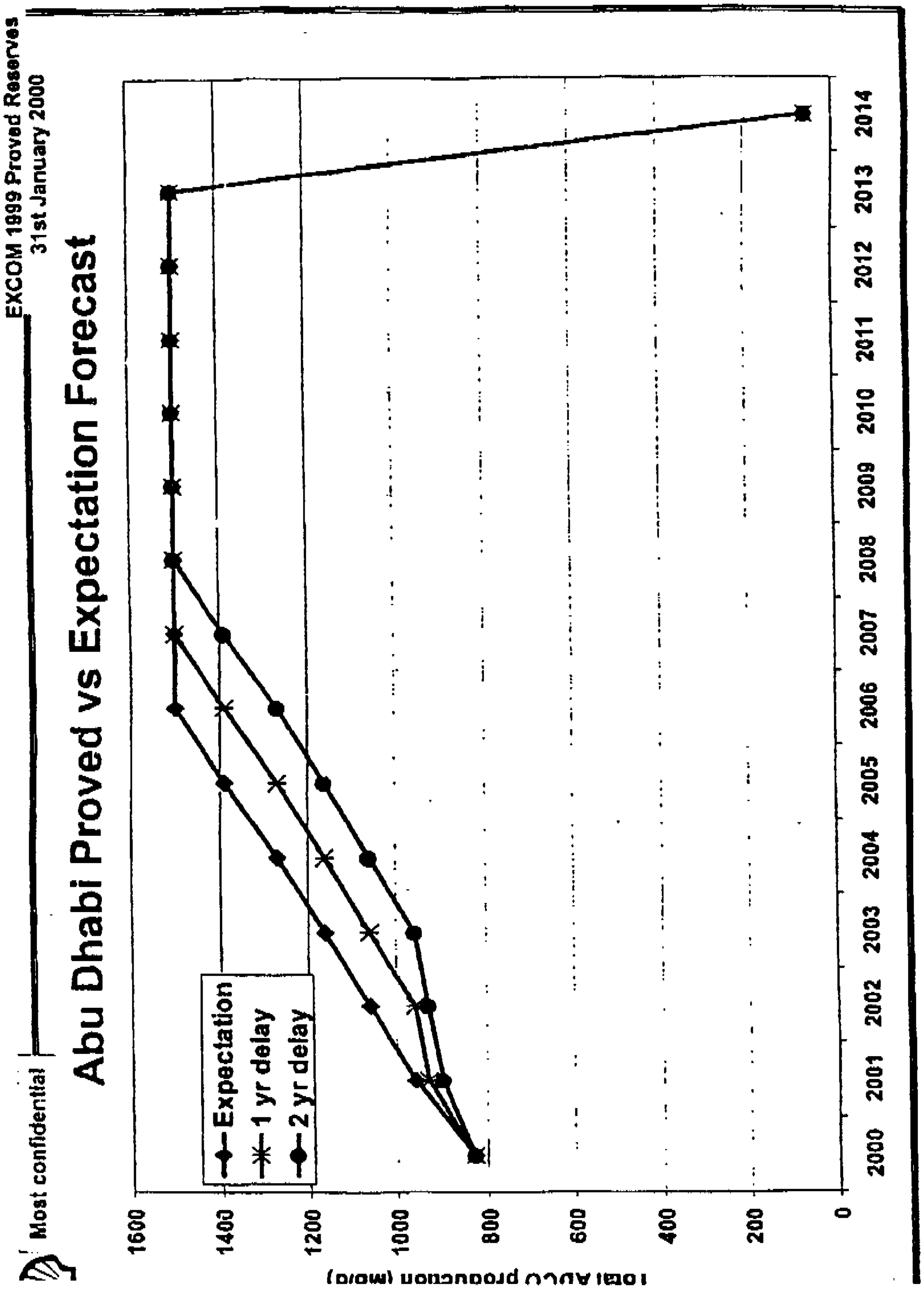

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EXCOM 1999 Proved Reserves
31st January 2000

ARPR versus Nov'99 Monthly LE

Country	Note nr.	GAS [mrd sm3] 1999 ARPR actual	NOV'99 LE	BP'99 LE	BP'98 Target	[redacted] ARPR actual			
Netherlands		1.7	0.3	2.4	2.4	0.4	0.0	0.0	0.0
UK		3.0	9.3	3.1	2.6	-3.1	2.4	5.6	4.4
Norway		25.3	26.6	26.6	-3.1	-0.7	1.1	1.4	0.2
Denmark		0.8	0.9	-2.7	0.0	10.4	3.8	4.0	2.7
Germany		2.1	0.8	1.3	3.0	-0.3	0.0	0.0	0.0
Rest of EPE		0.4	0.4	0.1	0.2	0.0	0.0	-0.1	0.0
USA		-6.5	-3.9	-4.0	7.2	-29.3	-28.5	-34.4	1.1
Canada		15.7	-3.1	0.0		-4.8	-11.2	-10.6	
Total EPN		42.5	31.1	26.8	12.3	-27.3	-32.4	-34.1	8.4
Oman (PDO/GISCO)		-12.4			0.0	23.5	21.9	21.1	15.6
Egypt		2.9	2.9	6.0	1.0	0.3	1.8	3.3	1.4
Syria		-2.2	-1.8	-1.7	0.0	1.1	1.5	0.0	1.1
Russia		0.0	0.0	0.0	0.0	-1.0	0.0	0.0	0.0
Pakistan		1.3	1.3	2.7	1.5				
Rest of EPM		-1.7	0.0	3.0	0.0	-5.2	-0.9	2.4	0.0
Total EPM		-12.1	2.4	10.0	2.3	18.8	24.3	26.8	19.1
Australia		-9.0	6.7	11.4	0.0	3.6	0.9	3.4	0.0
Brunei		3.7	0.0	0.7	0.0	9.1	6.1	7.8	6.2
New Zealand		1.9	1.7	-0.6	1.7	1.6	0.0	-0.1	0.0
Philippines		-19.6	-19.8	-21.8	-19.6	-3.6	-3.6	-4.1	-3.7
Malaysia		7.3	7.5	3.8	6.7	2.2	1.7	1.5	1.2
Thailand		-0.1	0.5	0.1	0.1	2.5	1.4	2.1	0.4
China		0.0	0.0	0.0	0.0	1.1	0.2	0.6	0.0
Rest of EPA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total EPA		-16.8	-3.4	-6.4	-11.1	16.6	6.7	11.2	4.1
Nigeria (SPDC)		4.7	0.3	0.3	0.0	30.5	56.6	43.0	19.9
Nigeria (SNEPCO)		-1.6	0.0	0.0	0.0	21.0	17.5	11.9	0.0
Gabon						4.9	0.0	0.6	4.0
Venezuela						-1.5	-2.2	-1.8	1.4
Argentina		1.1	1.1	3.8	0.0	-0.2	1.2	-2.6	0.0
DR Congo (Zaire)						-1.0	0.0	-4.1	-4.1
Rest of EPG		0.0	0.0	0.0	0.0	-0.4	0.0	-0.4	0.0
Total EPG		4.2	1.4	4.1	0.0	63.4	73.3	46.6	21.2
TOTAL		16.9	31.6	34.6	3.6	61.3	71.9	60.6	51.9

NOV LE'99 not accurately reflecting final reserves position ARPR'2000

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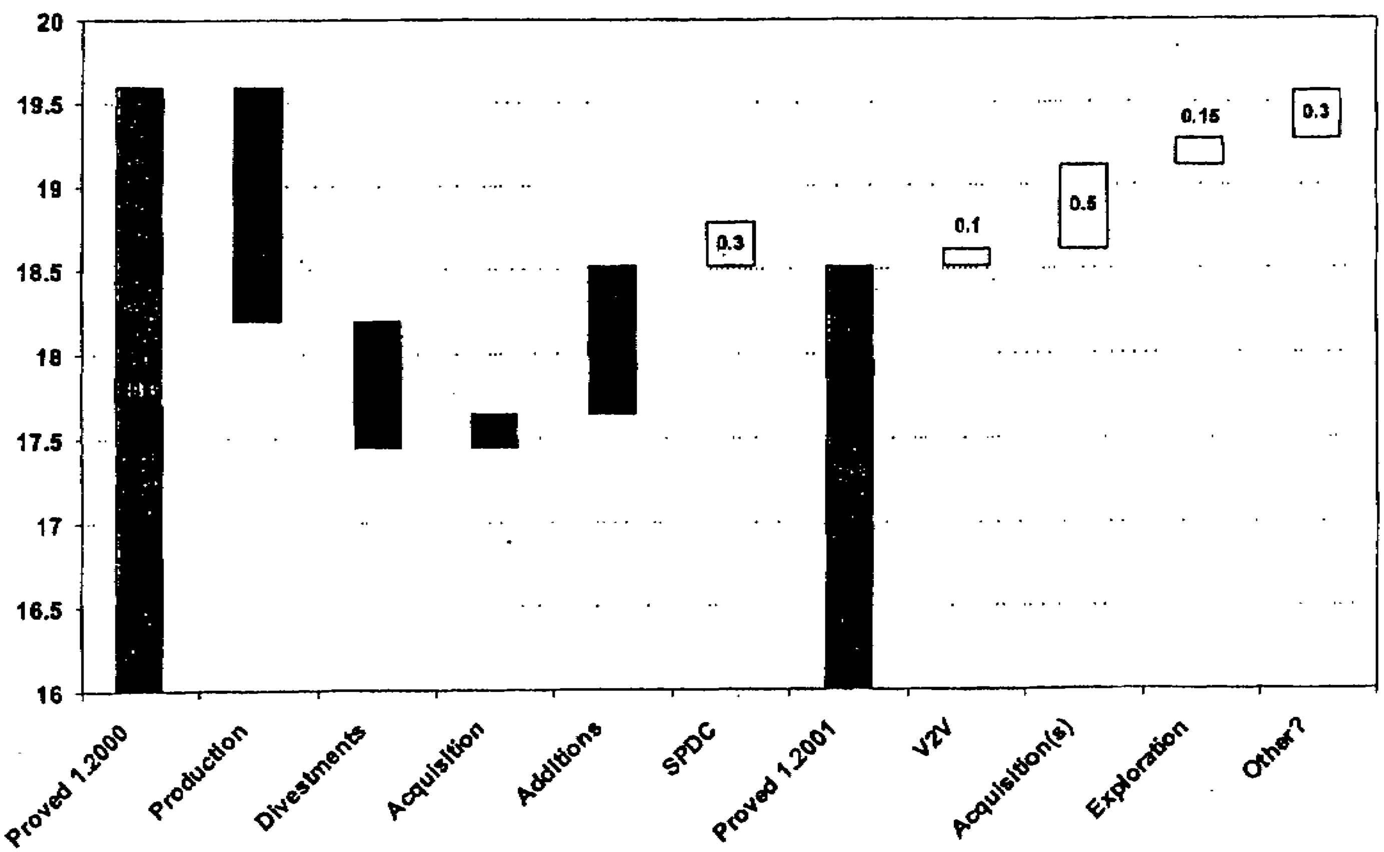
EXCOM 1999 Proved Reserves
31st January 2000

Proved Reserves Replacement 2000



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EP EXCOM

Minutes of meeting held 31st January 2000

1. Minutes and Highlights

- EP Procurement "table" distributed to Excom who committed themselves to use it when visiting OUs as a reference to review progress being made in implementing EP Procurement strategies.
- Excom on 7th February: videoconference confirmed; no Highlights.
- SBW/EPLF May 2000: **Warren** to give **Gardy** contact names in SIEP Inc. to help preparing logistics (when format finally agreed).
- Shell Capital financing proposals to third parties in EP and GP sectors: **Gardy** to contact Treanor to ensure EP and GP are made aware of such financing proposals beforehand. **Gardy** to propose guidelines for such co-ordination at the next Shell Capital Board.
- Valle Morado: **Rothermund** to review impact of sudden increase in water production and latest status of reserves.
- Brazil: **Rothermund** to review learnings from the unsuccessful joint Shell/ Enterprise farm-in bid for exploration block BC20.
- Nigeria:
  - country review in April to be confirmed by **Rothermund,**
  - value for money audit to be closely monitored by **Rothermund/Gardy.**
- "Stress Management" project: team to discuss with **Rothermund .**
- **Reminder**: agenda items for Excom need to be final on Thursday 9.00 (the Hague time) preceding Excom and pre-reading to be submitted by noon latest.

2. Technology Portfolio/Value Management

- Support given to move forward with proposed " pilots". However review with Nigeria the most effective way forward in the light of other priorities (production in particular),
- Proper balance between short term deliveries and medium term strategies is critical,
- Review possibilities to use Business to Technology maps as a potential "entry ticket" in new or existing ventures (Iran),
- Prepare a presentation focused on short term deliveries to be included in the March cost workshop,
- Progress to be reviewed at Excom in April and at May EPLF.

3. Sustainable Development

Megat/(Mann) to prepare a strawman on Vision ("Weave", "Infuse") and the way forward within EP: review at Excom in April in anticipation of discussion and release at May EPLF.

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4. Allegro

- Recommendation reviewed and way forward agreed,
- Achilles: should the ongoing merger not get FTC approval , what are the alternatives ?: review at 7th February Excom,
- Ulysses recommendation to be reassessed in the light of their balance sheet,
- **Brass** to send out a note for information on "financials" impact of potential deals to be reviewed at 7th February Excom.
-

Cairn-VAR to be conducted. **Megat** to redraft the note re the way forward.

5. Preliminary Summary of end 1999 proved reserves

- **Brass/(Gardy)** in liaison with de Vries to review with Schroders how to deal with AOSP/Iran reserves.
- Proposed revisions in reserves supported except for:
  - Abu Dhabi: no change
  - Gas in USA: "own use" still to be included.
  - **Brass/(Platenkamp)** to provide an analysis of exploration expenditure, discovered expectation volume and unit resource finding cost for sector , USA and WOUSA by 7th February.

6. New Nigeria MOU
Rothermund to review possibility to get new MOU valid for more than 3 years (up to 5 years) or at least get some insurance whereby this MOU would remain valid until a new one would be put in place.

7. Argentina Neuquen Exploration proposal resubmission
Proposal to be reviewed as part of the overall EXPEX 2000 LE at 21st February Excom.

8. Request for mandate to negotiate asset swap with USX/Marathon
Strategic support confirmed. Need to be on the driving seat with a "good" share (but not the 55% option). Any swap alternative should be based on the respective value/risk of the assets to be swapped.
Megat/(Tambozer) to redraft the request for mandate accordingly.

9. EP and Group Strategy process
Way forward to be decided at 1st February Excom(s) Strategy Workshop.

10. New gas Volumes Definition "Gas production available For Sale"
Supported.

11. Insurance
Supported. **Gardy** to prepare a note for information on Insurance covering scheme for EP. ✓

12. e-Business: Current status and next steps
Commitment to deliver Commerce One deal implementation to be developed by **Gardy/ (Henderson)**. Additional specific opportunities (Integrated Planning, EP industry ported, E-surplus, EP Expertise) on hold for the time being.

13. Future of Noordwijkerhout Learning Centre

Warren to tell Golden Tulip that current terms are off and alternative terms and conditions are expected by April. In the meantime **Warren** to come back with terms and conditions of alternative solutions in the light of Global/ EP Open University requirements.

14. Learning and Development co-operation with BP-Amoco
Supported.

15. Travel - Service expectations and measurement
Supported. Metrics to be in place during Q1 2000.

16. Oil Opportunity in Algeria
Support given to go into data room to find out if there is a business case. **Brass** to dedicate required resources.

17. Shell Business Week

- Format still to be validated by CMD,
- Each RBD to give **Gardy/(Kroes)** feedback on the proposed list of participants by Thursday 3rd February closing.

18. EP Procurement conference
Supported.

19. Economics of tax on Group Loans
Supported.

20. Project Screening criteria
Brass to prepare a note for discussion on the rationale for proposed changes in Gas PSV's and Power evaluation and screening criteria: review at 21st February Excom.

21. Technology Implementation FRD follow up plan
Supported.

22. Realising The Limit - status
Supported. Concern expressed about getting resources.

23. First Assignees – status
Supported. Opportunities to be identified with GP.

24. Shell Technology EP - Mandate to Negotiate a joint venture
Supported. Scope will have to be specifically defined.

25. Shell Technology EP - Mandate to Engage external financial partners
Supported. **Warren** to send the supporting strategy note to **Brass.**

26. Plans talk to staff in 2000
Supported.

27. Financial Analyst Expectation re EP Business
Supported.

Shell International Exploration & Production B.V.
Ep Business Development

23 February, 2000

PriceWaterhouseCoopers
Att.: Mr. Steve Johnson
No.1 London Bridge
LONDON SE1 9QL
England

Dear Sir,

In connection with your review in respect of the unaudited Standardised Measure of discounted future net cash flows and changes therein, relating to proved oil, natural gas liquids and natural gas reserve quantities as included in the supplementary information accompanying the 1999 financial statements of the Royal Dutch/Shell Group of Companies, we confirm, to the best of our knowledge and belief, the following representations made to you during your review:

1. We are responsible for the fair presentation of the Standardized Measure information mentioned above, and the assumptions used therein, in conformity with generally accepted US accounting principles.

2. The Standardized Measure information has been properly prepared and disclosed in accordance with FASB69.

3. The Standardized Measure information and the underlying data have been prepared and reviewed by employees having appropriate experience and qualifications for estimating the basis of future net cash flows.

4. No matters have come to our attention to the present time which would materially affect the Standardized Measure information included in the supplementary information referred to above.

The representations made under 2 and 3 do not apply to Shell Canada, as we do not participate directly in the estimation of their Standardized Measure.

In order to prepare the information in the required manner, a number of assumptions about future conditions are prescribed which do not take into account political, commercial and technical uncertainties. As a result the information so calculated does not provide a reliable measure of future cash flows from proved reserves, nor does it permit a realistic comparison to be made of one entity with another because the assumptions used cannot reflect the varying circumstances within each entity.

Yours faithfully,
Shell International Exploration & Production BV
EP Business Development

Lorin L. Brass

Lorin Brass
Director

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cc: KPMG Accountants N.V.

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2501 CR DEN HAAG
Nederland

Established at The Hague; Carel van Bylandtlaan 30
Commercial Register, The Hague 27002688
BTW/VAT number: NL004700996B04

Note : 23 February 2000

From : Remco .D. Aalbers EPB-P
Group Hydrocarbon Resource Coordinator & Senior Economic Analyst

To : Mr. Lorin Brass
Director EPB

Standardized Measure of discounted future net cash flows and changes therein relating to proved oil and gas reserve quantities for the Royal Dutch / Shell Group of Companies 1999.

The information given in the tables below has been prepared in accordance with FASB69 and United States generally accepted accounting principles (US GAAP). It provides a Standardized Measure of the estimated discounted future net cash flows and changes therein relating to proved oil and gas reserve quantities. The tables will be presented as supplementary information in the 1999 Annual Reports of both Royal Dutch Petroleum Company and Shell Transport and Trading Ltd. The tables have been prepared by Shell Exploration and Production International Ventures B.V. on the basis of information provided by Group and Associated Companies.

The following should be noted:

In order to prepare Standardized Measure information, a number of arbitrary assumptions are prescribed about the future for many years ahead, despite political, technical and economic uncertainty. It is therefore essential to appreciate fully the nature and limitations of Standardized Measure information, because it can easily be misinterpreted:

- Only net cash flows from **proved** oil and gas reserves are included in the estimates. Estimation of the level of Group Companies' proved oil and gas reserves is itself subject to several uncertainties, as discussed in the 'supplementary information - oil, gas reserves' section of the 1999 Annual Report. In addition, a substantial but unknown proportion of Group companies' future real net cash flows from oil and gas producing activities is expected to derive from reserves which have already been discovered but which cannot yet be regarded as proved.

- Estimates are made of future production levels for each of the many years over which proved reserves will be produced. However, these future production rates are uncertain for a variety of political, technical, technological and economic reasons.

- Future cash flows on the Standardized Measure basis are estimated using 1999 year-end oil and gas prices and production cost, current levels of development costs, current tax rates and regimes, and current exchange rates. Standardized Measure information therefore does not attempt to recognise that prices, costs, tax rates and regimes and exchange rates may change in the future.

- The prescribed standard rate of 10% per annum is used to discount all future net cash flows. The Group faces a variety of different risks and uncertainties in different locations. These risks and uncertainties may also be different from those faced by other oil and gas producers. Using a single standardised discount rate cannot fully reflect these varying uncertainties.

For all these reasons, users of the information in the tables below should have reservations about its relevance, reliability and comparability and are warned to be cautious in drawing conclusions from it. In particular, the Standardized Measure information should not be considered to give an indication of the market value of the Group's oil and gas reserves, of the manner in which oil and gas will in fact be produced in the future, or of the discounted expected future net cash flows. Nor does it permit a realistic comparison to be made of one entity with another because the assumptions used cannot reflect the varying circumstances within each entity.

Basis of preparation of the Standardized Measure

The Standardized Measure of discounted future net cash flows set out in the attached tables was computed on a country by country basis using the approximations of current prices and costs as described below. For the 1999 Standardized Measure the actual calculations were performed in each individual country rather than centrally based on standard input data. This has increased the quality of the calculation as local staff have the best knowledge on applicable local terms. Standard formats and checks in the electronic workbook ensure calculations are in line with FASB69 rules.

Future cash inflows from sales of oil and gas were computed from actual 'local' average fourth quarter revenues, adjusted, where necessary, for any incidental fluctuations which distort the fourth quarter prices, to the estimated future annual production of proved oil, natural gas liquids and natural gas reserve quantities as defined in the 'supplementary information – oil and gas reserves' section of the 1999 Annual Report. Proved reserves are reported net of Royalties due in Kind but inclusive of Royalties due in Cash, for the calculation of the Standardized Measure the Royalties due in Cash have been deducted (i.e. deducted from gross revenues).

For non-producing companies carrying proved oil or gas reserves the future cash inflows from oil and gas sales have been based on fourth quarter average Brent price of 24.07 US$/bbl adjusted for estimated local make-up.

Future development costs, which do not include any interest which may be capitalised in the Group financial statements, were derived from actual plans for producing both proved and unproved reserves, and have, therefore, been included after making appropriate estimated deductions for the development of unproved reserves. Similarly, abandonment costs were estimated based on abandoning both proved and unproved reserves, and have, therefore, been included after making appropriate estimated deductions for the abandonment of unproved reserves.

Future production costs for producing ventures have been computed based on actual average unit operating cost for the previous year (1999). For non-producing ventures unit operating cost have been estimated based on actual plans and cost models used for project and corporate planning.

For Venezuela, Oman-GISCO and Iran the Standardized Measure has been calculated on explicit future cash flows from the respective corporate models due to the special nature of the reward calculation in these contracts.

For Oman (PDO), Nigeria (SPDC) and Abu Dhabi the Standardized Measure calculations reflect the 'fixed margin' nature of these specific contracts.

Shell Oil provide the Standardized Measure output, reviewed by local auditors, instead of using one of the two general options provided in the electronic workbook. In addition Shell Oil has provided their calculations as audit trail.

Shell Canada provide the Standardized Measure output only, reviewed and agreed by local auditors. The Shell Canada Standardized Measure is translated to US Dollars at the year-end exchange rate. It should be noted that the Shell Canada Standardized measure does not include the Peace River proved oil reserves (bitumen recovered though wells by means of steam injection) valuation based on local FASB69 interpretation. The estimated 1999 value of the Peace River is CAN$ 265 million or US$ 183 million.

The Standardized Measure has been calculated based on input data expressed initially in the same currencies as those used in preparing the financial statements of individual Group companies and translated to US Dollars at year-end exchange rates.

Tax rates reflecting a combination of contractual arrangements and statutory tax rates applicable as at the year-end were used. These rates were derived from effective tax rates, whenever possible; as these are our best estimates of resulting statutory tax rates. Tax depreciation is assumed as 5 years straight line.

The Standardized Measure was computed by applying a 10% per annum discount factor to the mid year future net cash flows estimated on the above basis.

Standardized Measure for Production Sharing Agreements (PSC)

In previous years, consistent with the Standardized Measure calculation method, quantities of proved reserves under PSC were valued at average fourth quarter prices, while proved reserves (cost and profit oil respectively gas) estimates were determined based on the 'oil price' screening rate advised by the Group. The inconsistency so introduced was noted in 1998 and discussed at the time with the external auditors, KPMG. The statement of the Standardized Measure 1998 due to this inconsistency was judged to be conservative and not materially affect the reported aggregate figure for Standardized Measure with an end-year price of 11.15 US$/bbl Brent versus an advised screening price of 14.00 US$/bbl Brent. It was however also agreed to review Standardized Measure calculations for PSC countries for 1999.

For 1999 the Standardized Measure for all PSC countries have been calculated using an adjusted PSC entitlement proved reserves estimate calculated at year-end price of 24.07 US$/bbl Brent equivalent and subsequent valuation at the same 24.07 US$/bbl equivalent oil and gas prices price, eliminating the 'inconsistency'.

Basis of preparation of the aggregate change in the Standardized Measure

The following sources of change in the Standardized Measure are presented separately:

- net changes in sales and transfer prices and in production (lifting) costs related to future production. Differences between period actuals and estimates for the realised margin due to sales and transfers during the period will be reported here;
- net change due to extensions, discoveries and improved recovery;
- net change due to purchases and sales of minerals in place;
- movement of reserves to associate companies USA;
- net change due to revisions of previous reserves estimates;
- changes in estimated future development costs. Differences between period actuals and estimates for development cost incurred during the period will be reported here;
- sales and transfers of oil and gas produced during the period;
- previously estimated development costs incurred during the period;
- accretion of discount;
- net change in income tax.

Actual development cost, and sales and transfers during the period are disclosed in the annual report in note 24b and 24c respectively. These disclosures have been reconciled with the corresponding sources of change in the Standardized Measure.

The large negative change to 1999 Standardized Measure 'revisions of previous estimates' is largely the effect of delayed gas production in Australia resulting in a reduced value due to the effect of the discount factor.

Changes to Oman Gisco price and volume effect have been all grouped under price effect due to the specific nature of the Gisco contract. The initially calculated large positive change under "price" was largely offset by a large negative change under "reserves revisions"; the latter not match by a equivalent negative reserves revision in the proved reserves table.

Restatement of the Standardized Measure 1997 and 1998

The Standardized Measure calculations prior to 1998 were originally calculated and published in British Pounds (GBP) in line with publication of all financial numbers in the annual report in the same currency. For the 1998 Annual Report the 1997 Standardized Measure was restated along with all other financials in US Dollars (USD).

The restatement calculations were made on the original data expressed initially in the same currencies as those used in preparing the financial statement of individual Group companies and translated to US Dollars at year-end exchange rates.

The presentation of the Standardized Measure data for 1997 and 1998 has also been adjusted to the new 1999 Annual Report region grouping; reporting Canada under "Other Western Hemisphere', where Canada in the 1998 annual Report was included under 'USA and Canada'.

The "Changes in Standardized Measure" have been restated for both 1998 and 1997 'development cost incurred during the year', reflecting the restatement in note 24. Note 24 has been updated for Oman Gisco and Venezuela where Capex was incorrectly booked as 'acquisition of proved property'. The opposite delta has been booked to 'development cost related to future production'.

In line with the reply provided to the SEC versus their questions on the 1998 20-F development cost and operating cost are show separately for 1998 and 1997 as well as for 1999. Average end-year oil and gas prices are included as a footnote for all three years.

The Hague, February 2000

Standardised measure for : 1999 Statement Feb-2000 for AR'99 (split Opex and Capex)

Standardised Measure of Discounted Future Cash Flows

United States accounting principles require the disclosure of a standardised measure of discounted future net cash flows, relating to proved oil and gas reserve quantities evaluated at year-end prices. In order to prepare the information a number of arbitrary assumptions are prescribed about the future, despite political, technical and economic uncertainty. As a result the information so calculated does not provide a reliable measure of future cash flows from proved reserves, nor does it permit a realistic comparison to be made of one entity with another because the assumptions used cannot reflect the varying circumstances within each entity. In addition a substantial but unknown proportion of future real net cash flows from oil and gas producing activities is expected to derive from reserves which have already been discovered, but which cannot yet be regarded as proved.

USD million	Eatern Hemisphere		Western Hemisphere		
Group Companies:	Europe	Other	USA	Other	Total 1999
Future cash inflows	83,826	155,408	19,957	12,436	271,627
Future development costs	3,168	18,289	1,256	956	21,669
Future production costs (incl. Aband.)	18,126	18,101	3,057	2,804	41,888
Future tax expenses	24,928	72,218	5,580	2,559	105,285
Future net cash flows	37,604	48,800	10,064	6,317	102,785
Effect of discounting cash flows at 10%	15,920	26,196	3,107	2,763	47,986
Standardised measure of discounted future net cash flows	21,684	22,604	6,957	3,554	54,799
Associated Companies - Group Share:					7,188
Minority Interests Included	-	337	-	500	837
Weighted Average End Year Price					
Oil/NGL [USD/bbl]					21.13
Gas [USD/boe]					11.06

USD million	Eatern Hemisphere		Western Hemisphere		
Group Companies:	Europe	Other	USA	Other	Total 1998
Future cash inflows	70,770	86,910	17,664	9,001	184,345
Future development costs	4,551	18,884	2,591	1,026	27,034
Future production costs (incl. Aband.)	21,340	18,115	5,973	2,781	48,209
Future tax expenses	17,989	27,227	2,614	1,812	49,642
Future net cash flows	26,890	22,704	6,466	3,380	59,460
Effect of discounting cash flows at 10%	12,592	12,587	2,030	1,582	28,791
Standardised measure of discounted future net cash flows	14,298	10,117	4,456	1,798	30,669
Associated Companies - Group Share:					1,854
Minority Interests Included	-	106	-	324	430
Weighted Average End Year Price					
Oil/NGL [USD/bbl]					10.68
Gas [USD/boe]					10.44

USD million	Eatern Hemisphere		Western Hemisphere		
Group Companies:	Europe	Other	USA	Other	Total 1997
Future cash inflows	86,265	123,787	27,085	12,183	249,320
Future development costs	4,788	12,606	2,958	1,833	22,185
Future production costs (incl. Aband.)	19,410	22,450	6,577	3,215	51,652
Future tax expenses	27,068	53,650	5,380	2,928	89,046
Future net cash flows	34,879	35,081	12,170	4,207	86,437
Effect of discounting cash flows at 10%	15,884	19,281	3,859	2,137	41,161
Standardised measure of discounted future net cash flows	19,095	15,800	8,311	2,070	45,276
Associated Companies - Group Share:					5,208
Minority Interests Included	-	219	-	251	470
Weighted Average End Year Price					
Oil/NGL [USD/bbl]					16.55
Gas [USD/boe]					12.74

Change In Standardised Measure of Group Companies Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	1999	1998	1997
SM 1.1.YEAR	30,669	45,276	57,439
Net changes in prices and production costs	63,847	(43,260)	(23,598)
Extensions, discoveries and improved recovery	3,684	1,628	5,256
Purchases and sales of minerals in place	(5,943)	615	(841)
Movement to associate companies USA	0	(148)	(5,207)
Revisions of previous reserves estimates	(4,994)	6,012	5,194
Development cost related to future production	(773)	(3,800)	(3,739)
Sales and trsfrs of oil and gas, net of prod. csts	(12,837)	(9,821)	(15,309)
Development cost incurred during the year	3,773	5,149	4,638
Accretion of discount	3,167	8,442	10,060
Net change in income tax	(25,794)	20,574	11,383
Other (should be zero)	0	0	0
Total change in standardised measure during the year	24,130	-14,607	-12,163
SM 31.12.YEAR	54,799	30,669	45,276

Shell International Exploration and Production B.V.

The Hague, 1 February, 2001

Royal Dutch/Shell Group Auditors
c/o KPMG Accountants N.V.
Attn.: Mr. E. Eeftink
Churchillplein 6
2517JW THE HAGUE

Dear Sirs,

In connection with your limited procedures, in respect of the unaudited oil and natural gas reserves information included in the supplementary information accompanying the 2000 financial statements of the Royal Dutch/Shell Group of Companies, we confirm, to the best of our knowledge and belief, the following representations made to you during your review:

1. We are responsible for the fair presentation of the oil and natural gas reserves information mentioned above in conformity with generally accepted US accounting principles.

2. The information has been properly prepared and disclosed in accordance with SFAS 69 and SEC Rules and Regulations, and as clarified by subsequent SEC staff accounting bulletins and interpretive guidance issued by the SEC.

3. The information and the underlying data have been prepared and reviewed by employees having appropriate experience and qualifications for estimating oil and natural gas reserves.

4. No matters have come to our attention to the present time which would materially affect the information in respect of oil and gas reserves included in the supplementary information referred to above.

The representations made under 2 and 3 do not apply to Shell Canada as we do not participate directly in their reserves estimating process.

Yours faithfully,
Shell International Exploration and Production B.V.

Lorin L. Brass
Director

P.B. Watts
Chief Executive Officer

EXHIBIT
6
Brass
PENGAD 800-631-6989

NOTE – 30 January 2001

CONFIDENTIAL

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP EPB-GRA
To:	Lorin Brass	Director, EP Business Development, SIEP EPB
Copy:	Phil B. Watts	EP Chief Executive Officer, SIEP
	Dominique Gardy	Chief Finance Officer, SIEP EPF
	John Bell	Vice Pres. Strategy, Planning, Portfolio and Economics, SIEP EPB-P
	Remco D. Aalbers	Group Hydrocarbon Resource Coordinator, SIEP EPB-P
	Egbert Eeftink	Partner, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

REVIEW OF GROUP END-2000 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

In accordance with prescribed US Accounting Principles (SFAS69), SIEP staff have prepared a summary of Group equity proved and proved developed oil and gas reserves for the year 2000. The summary (Att. 3) forms part of the supplementary information that will be presented in the 2000 Group Annual Reports and has been prepared on the basis of information provided by Group and Associated companies. The submissions by these companies (excluding those by Shell Canada) are based on the procedures laid down in the "Petroleum Resource Volumes Guidelines" (EP 2000-1100/1101) which in turn are based on the requirements of SFAS 69. Shell Canada's submissions are subject to their own procedures and reviews.

I have reviewed the process of preparing the above summary of proved and proved developed oil and gas reserves in as far as these relate to companies outside Canada. This review included, where possible, a verification of the reasonableness of major reserves changes and any omissions of such changes, as appropriate.

The end-2000 Group share Proved Reserves (excluding Canadian oil sands) can be summarised as follows:

Oil mln m3 Gas bln m3	1.1.2000 Proved Tot'l	2000 Prod'n	1.1.2001 Proved Tot'l	Repl.Ratio (RR) Totl	RR Tot'l ex-A&D	1.1.2001 Prov. Dev'd	RR Dev'd	RR Dev'd ex A&D
Oil+NGL	1554	132	1550	97%	142%	711	50%	86%
Gas	1657	85	1593	25%	46%	737	49%	57%
Oil Equivalent	3157	215	3091	69%	105%	1424	49%	75%

Following the issue of new Group Reserves Guidelines in 1998, some 150 mln m3oe (oil equivalent) had been added to Proved Reserves in mature fields over 1998 and 1999. A further 50 mln m3oe has been added this year. Although most OUs have now implemented the new guidelines, some still offer scope for reserves additions. The issue will continue to be addressed by SIEP staff and by myself during forthcoming SEC Reserves Audits.

Externally reported Proved and Proved Developed Reserves need to be confined to those volumes producible within the duration of existing production licences. With progressing maturity, a number of OUs are seeing their scope for increasing Proved Reserves severely curtailed because any increase in field volumes cannot be produced within constrained production forecasts and licence durations. At present, some 25% of total Group Expectation Reserves is deemed to be non-recoverable within current licences. The corresponding figure for Proved Reserves is not reported.

Group Proved Reserves receive increasingly close attention by Group Management. Target reserves additions are set annually, both to OUs and to SIEP Divisions and progress is monitored throughout the year. With future Proved Reserves additions becoming much more challenging, the resulting pressure on staff raises possible concerns with respect to the quality of future reserves bookings.

Excellent correspondence was found this year for the first time between annual production volumes as reported through the separate Finance and SIEP systems. SIEP and Finance staff are highly commended for their efforts.

The system of monthly monitoring of OU reserves bookings, plus strictly controlled electronic reserves submissions has led to a particularly smooth process of preparing Group reserves statements this year.

During 2000 I made Reserves Audit visits to a total of six Group OUs. Audit opinions on all of these were 'satisfactory'. Many of the audit recommendations have been followed up in the 2000 submissions, particularly those aimed at raising Proved Reserves in mature fields.

The overall finding from the audit visits and from the end-year review in SIEP is that the SIEP statements fairly represent the Group entitlements to Proved Reserves at the end of 2000. The 2000 changes in the Proved Reserves can be fully reconciled from the individual OU submissions.

A more detailed list of findings and observations is included in Attachment 1.

30/1/01

A.A. Barendregt

Attachments 1 - 8

EXHIBIT 7 Brass

PENGAD 800-631-6989

Attachment 1	Main Observations end-2000 Reserves
Attachment 2	Significant Reserves Changes
Attachment 3	Group Proved Reserves Summaries
Attachment 4	Production Reconciliation Ceres vs. Reserves Submissions
Attachment 5	Scope for increasing Proved Reserves – by OU
Attachment 6	Angola Block 18 Initial Reserves Booking
Attachment 7	Main observations 2000 Reserves Audits
Attachment 8	Reserves Audit Plan 2001

Attachment 1

REVIEW OF GROUP END-2000 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

MAIN OBSERVATIONS

1. Significant reserves changes during 2000 were as follows:

   New Group Reserves Guidelines, issued in 1998 prescribe that expectation values should be used for externally reported Proved Reserves in mature fields. This year, **PDO(Oman), SOGU(Denmark) and SDA(Australia)** were able to add in total some 50 mln m3oe* to Proved Reserves.

   SEPCo(USA) were able to add some 39 mln m3oe to Proved Reserves, following project maturation and/or drilling in Oregano, Brutus, Nakika and Mars.

   Improved recovery was identified by **PDO(Oman)** in Qarn Alam, Al-Huwaisa and Lekhwair (+18 mln m3), by **Shell Canada** in Peace River (+14 mln m3) and by **SOGU(Denmark)** in Halfdan and other fields (+5 mln m3oe). Opportunities for further development through additional drilling were identified by **SVSA(Venezuela)** in the Urdaneta West field (+17 mln m3).

   A **first-time reserves booking** was made by **SDAN(Angola)** in Block 18 (+12 mln m3). This volume reflects a first attempt at defining an economically viable development plan for the area. In its present form, the plan is marginally commercial but not economic, i.e. the economics present positive NPVs for a majority of scenarios, but the project does not pass Group investment screening criteria. For a more detailed note on Angola reserves see Attachment 6.

   A field extension and a discovery were identified by **SNEPCO(Nigeria)** in Bonga and Abo (+11 mln m3)

   Field Studies led to increased reserves bookings by **SPDC(Nigeria)** (+15 mln m3oe developed), **BSP(Brunei)** (+8 mln m3) and **Norske Shell** (+7 mln m3oe).

   Corrections had to be made to Proved Gas reserves in the **USA (SNEPCo and Aera),** to exclude **own use / fuel** volumes, in line with a 2000 Audit recommendation and SEC requirements (-6 mln m3oe).

   Economic revisions led to a shift from NGL to gas reserves by **Gisco(Oman)** (+22 mln m3oe net), which was offset by a reduction due to lower future cost projections (-17 mln m3oe). Improved future cash flow projections led to additions in **Iran** (+8 mln m3) and tax gross-up volumes were included in Proved Reserves by **SNEPCO(Nigeria)** (+8 mln m3oe).

   Acquisitions and divestments led to additions being booked by **Shell Sakhalin** following an increase in Astokh equity (+8 mln m3) and to reductions in the **USA** due to the sale of Altura (-48 mln m3) and in the **UK** (-13 mln m3oe), following divestments in Foinaven, Franklin and Elgin.

   Development activities led to increased Proved Developed Reserves being booked by **Shell UK Expro** (+27 mln m3oe), **SSB/SSPC(Malaysia)** (+23 mln m3oe), **SEPCo(USA)** (+22 mln m3oe) and **BSP(Brunei)** (+11 mln m3oe).

   A tabulation of these changes is given in Attachment 2.

2. The 1.1.2001 Group share Proved Reserves (excluding Canadian oil sands) can be summarised as follows:

Oil mln m3 Gas bln m3	1.1.2000 Proved Tot'l	2000 Prod'n	1.1.2001 Proved Tot'l	Repl.Ratio (RR) Totl	RR Tot'l ex-A&D	1.1.2001 Prov. Dev'd	RR Dev'd	RR Dev'd ex A&D
Oil+NGL	1554	132	1550	97%	142%	711	50%	86%
Gas	1657	85	1593	25%	46%	737	49%	57%
Oil Equivalent	3157	215	3091	69%	105%	1424	49%	75%

   Hence, the Oil+NGL replacement ratio target of 100% has been largely met, but the replacement ratios for Gas fell short.

   Group share Proved Reserves divided by Group share annual production **(R/P ratio)** stands at 12 years for Oil+NGL and at 19 years for Gas.

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* 1 mln m3oe = 1 mln m3 oil equivalent = 1.03 bln sm3 gas

A full overview of end-2000 Proved and Proved Developed Reserves is presented in Attachments 3.1-3.2.

3. Although the tabulations in Attachment 3 include volumes for **Shell Canada's Athabasca Oil Sands** Project (AOSP), these volumes are not strictly oil and gas reserves as defined by the SEC. Hence, they will be reported separately as 'mining reserves' to the SEC and excluded from the Group's SEC submission of oil and gas reserves.

4. The 17 mln m3 additional development identified by **SVSA in Urdaneta West** amounts to a significant rise in SVSA's Group share Proved Reserves (+78%). Whilst the end-1999 Reserves Audit confirmed the scope for significant upside, an increase of this magnitude should be supported by a technical review and it is noted that a VAR review is planned early in 2001. The viability of these reserves should be confirmed by the SIEP Reserves Coordinator and the Group Reserves Auditor through review of the VAR report and relevant SVSA documentation during 2001.

5. As mentioned before, new Group Reserves Guidelines were issued in 1998, which prescribed that externally reported **Proved and Proved Developed Reserves** should be brought closer to, or made equal to, **Expectation Reserves in mature fields**. The reason for this change was to align Group practice more to that of other major oil operators. Significant Proved Reserves additions (+150 mln m3oe) have been booked by many OUs over 1998 and 1999. PDO(Oman), SOGU(Denmark) and SDA(Australia) have followed suit this year (+50 mln m3oe). OUs that still seem to offer significant scope for raising Proved Reserves are BSP(Brunei), Shell UK Expro, BEB(Germany, gas only) and NAM and SPDC (both for developed reserves only). Some smaller targets are still left in Norske Shell and SOGU. Potential additions could amount to more than 100 mln m3oe. The issue will be addressed during SEC Reserves Audits with Shell UK Expro, SOGU, NAM and BEB during 2001. BSP are addressing the issue with the authorities but point out that raising Proved Reserves will result in higher tax and reduced cashflow.

   A method of visualising the relative position of OUs and their fields is through plotting the ratio between Proved and Expectation reserves versus field / OU maturity. The latter is defined as cumulative production as a fraction of total Expectation Ultimate Recovery (not constrained by e.g. licence expiry). Plots showing the OU positions for Developed and Undeveloped Oil+NGL and Gas reserves, plus their respective target volumes, are presented in Attachments 5.1-5.2.

   Uptake of the new Reserves Guidelines in the OUs has in some cases been somewhat slower than anticipated. The issue is raised continuously by SIEP staff with OUs with potential for Proved Reserves additions, and by the Group Reserves Auditor during SEC Proved Reserves Audits. The latter approach, with its higher profile, tends to be the most effective. During the audits, it was found that the slow uptake could partly be due to the new rules for Proved Reserves in mature fields not being emphasised enough in the Group Guidelines. Although these rules are certainly explained in the text, it is possible that their impact may not be immediately obvious to casual readers. In addition to their ongoing efforts of keeping the issue alive with OUs concerned, SIEP staff are encouraged to consider ways of strengthening the message in the updated Guidelines due out in 2001 and re-emphasise it in the cover letter.

6. Externally reported Proved and Proved Developed Reserves need to be confined to those volumes **producible within** the duration of **current production licences**, or their extensions if there is a right to extend. With progressing maturity, a number of OUs are seeing their scope for increasing Proved Reserves severely curtailed because any increase in field volumes cannot be produced within (generally constrained) production forecasts and licence durations. With ongoing annual production, these OUs will in fact see their remaining Proved reserves decline either until forecast production rates can be lifted or until licence extensions have been agreed with Authorities. OUs most affected by this are **SPDC(Nigeria), Shell Abu Dhabi** and **PDO(Oman).**

   At present, some 1200 mln m3oe Expectation Reserves are reported by OUs as being non-producible within existing licences. This corresponds to 25% of the current Group portfolio. The corresponding Proved volumes are not captured by the present submissions and are difficult to assess from centrally available data, but could exceed 100 mln m3oe. This volume is likely to increase in coming years. Consideration should be given to capturing this data properly through the annual submissions, to assist in focusing attention towards early agreements on licence extensions.

7. Group Proved Reserves receive increasingly close attention by Group Management. **Target reserves additions** are set annually, both to OUs and to SIEP Directorates and progress is monitored throughout the year. Targets are also set in scorecards for those on variable pay. Whilst these measures are effective in ensuring proper attention to Proved Reserves bookings, the resulting pressure on staff does raise **concerns** with respect to the **quality of future reserves bookings.**

In future, finding additions to Proved and Proved Reserves will be more of a challenge than hitherto. The reason is that the scope for relatively easy further additions due to the new Reserves Guidelines (Proved close to Expectation in mature fields) will reduce in the coming years, whilst a number of OUs will find themselves constrained to volumes producible within existing production licences. Finding genuine reserves additions will become an increasing challenge and the Group's desire to maintain future reserves additions at the same level as annual production (100% Replacement Ratio) will raise pressure on the staff responsible. Such pressures have this year led to the extremely marginal reserves booking for Block 18 fields in Angola, where e.g. the operator (BP) has considered the fields still to be too immature for any bookings at this stage. Further development along this trend should be closely watched by the SIEP Reserves Coordinator, who continue insisting on adherence to Group Reserves Guidelines in all cases. A similar role will be played by the Group Reserves Auditor.

8. Group share **annual hydrocarbon production** is reported separately through the **Ceres** system by Group Finance and through the reserves submissions accumulated by SIEP. Both reports find their separate ways into the Group annual report and it is therefore important that the two reports are **consistent**. In previous years, this consistency often presented problems, particularly with respect to reported gas sales / production volumes. Three important improvements have been made during 2000:

   – The definition for the reported gas stream under Ceres has been changed from Gas Sales (which could be affected by e.g. LNG plant losses and UGS storage swing in integrated OUs) to Upstream Gas Production available for Sale. This aligns it with the definition of Proved Reserves and thus with production as reported through the SIEP system.
   – The unit of reporting for gas production in Ceres has been changed from Normalised m3 (Nm3, at 9500 kCal/m3) to standard m3 (sm3), thus avoiding numerous conversion errors.
   – The paper copies of the OU reserves submissions, to be signed by a senior member of OU management, now include a statement confirming that the OU's Ceres and reserves submissions are consistent.

   These three measures have resulted in a significant improvement in consistency between the two reported production streams, particularly those for gas. As far as can be ascertained, this is the first year that full consistency has been obtained between the two streams, after some minor errors (mostly rounding) had been forced out or cleared up. This is a significant achievement and SIEP / Finance staff must be commended for their efforts. A summary table of the two submissions and their reconciliation is presented in Attachments 4.1-4.2.

9. **SEC Reserves Audits** are carried out by the Group Reserves Auditor in all OUs every 4-5 years. All audits carried out during 2000 resulted in 'satisfactory' opinions. The audits have been particularly successful at identifying scope for increasing Proved and Proved Developed Reserves in mature fields. A summary of audit findings is presented in Attachment 7. The forward Audit Plan is given in Attachment 8.

10. Since end 1998, OU reserves submissions are made by means of strictly controlled electronic workbooks, which greatly accelerate and streamline the process of accumulation of Group reserves within SIEP. The process of gathering and accumulating OU submissions has been particularly smooth this year, not least because the Reserves Coordinator has urged the OUs to address potential problems and issues with him well ahead of the submission dates. In addition, the system of monthly monitoring of OU reserves bookings tends to avoid end-year surprises. This is commended. The submissions provide also good detail on major reserves changes and on individual field Proved and Expectation volumes. Both represent excellent audit trails and SIEP staff are commended for their continuing efforts.

Recommendations to SIEP Reserves Coordination:

1. Vigilance should continue to be applied by the SIEP Reserves Coordinator to ensure that all future Proved Reserves changes will be fully in accordance with Group Reserves Guidelines.
2. Confirm the viability of the 78% Proved Reserves increase booked by SVSA by a review of the planned VAR report and associated SVSA documentation during 2001.
3. Include the volume of Proved and Proved Developed Reserves not producible within current production licences in annual OU reserves submissions.
4. Strengthen the message that externally reported Proved and Proved Developed Reserves should be brought close to (made equal to) expectation reserves in mature fields in the Group Reserves Guidelines to be updated during 2001 and in the cover letter.

 RJW00151347

Attachment 2

SIGNIFICANT 2000 PROVED AND PROVED DEVELOPED RECOVERY CHANGES

(Shell Group share)

MAJOR TECHNICAL REVISIONS					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Oman - PDO	+7	+31			Full alignment with Group guidelines - exp'n values for mature fields (following 1999 Audit)
USA		+20		+19	Transfers to Proved due to project maturation or drilling (Oregano, Brutus, Nakika, Mars a.o.)
Oman - PDO		+18			Improved recovery (Qarn Alam, Al-Huwaisa, Lekhwair)
Venezuela		+17			Urdaneta-West – go ahead for further development
Canada	+2	+14			Peace River - revised development plan, based on new technology
Nigeria - SPDC	+13		-2		Field reviews
Angola		+12			First Block 18 reserves booking
Nigeria - SNEPCO		+11		+1	Bonga (in-field opportunities) and Abo (discovery)
Denmark	+12	+10	+1	-0	Alignment with Group guidelines
Brunei	+3	+8	-1	+0	Performance reviews (Champion, SW-Ampa)
Australia	+7	+6	+3	+3	Alignment with Group guidelines (following 2000 Audit)
Norway	+3	+5	-3	+2	Technical studies (Troll, Draugen a.o.)
Gabon	+3	+4			Alignment with Group guidelines (following 2000 Audit)
Denmark		+4		+1	Improved recovery (Halfdan a.o.)
USA (SEPCo, Aera)			-5	-6	Corrections for own use & fuel (following 2000 Audit)
UK	+15		+12		Development in Shearwater, Schiehallion, Gannet a.o.
Malaysia	+3		+20		Development in F6 (compression installed) a.o.
USA (SEPCo)	+12		+10		Development in Conger, Ursa, Europa a.o.
Brunei	+6		+5		Development in Champion, Iron Duke, SW-Ampa a.o.
Others	+27		+9		New developments (Transfers from undev)
Total Major Techn'l	+114	+160	+49	+20	

OTHER MAJOR CHANGES					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Oman - Gisco	-7	-11	+19	+32	Re-apportionment Gisco reserves between NGL and gas
Russia - Sakhalin	+3	+8			Astokh equity increase to 55%
Iran		+8			Improved future cashflow
Nigeria - SNEPCO		+7		+1	Ehra + Bonga - tax gross-up recalculations
UK	-5	-10		-3	Divestments (Foinaven, Franklin, Elgin)
Oman Gisco	-0	-0	-18	-17	Revisions to economic model (lower future cost estimates)
USA	-40	-48	-7	-8	Altura venture sold
Total Other Major	-49	-46	-6	+5	

OTHER MINOR CHANGES AND TOTAL					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Other Minor Chgs	+1	+14	-1	-3	
Production	-132	-132	-85	-85	
Grand Total	-66	-4	-43	-63	

2000 GROUP RESERVES SUBMISSIONS

Attachment 3.1

OIL + NGL (10^6 m3) All volumes net Shell Group Share

Country Name	Proved Resvs 1.1.2000	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2000	Proved Resvs 1.1.2001	Proved Dev'd Resvs 1.1.2000	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2000	Proved Dev'd Resvs 1.1.2001	Minority Resvs incl. 1.1.2000	Minority Resvs incl. 1.1.2001	R / P Tot (yr)	Repl'mt Ratio TotlRes (%)	Repl.R. TotlRes (%) Excl Pur/ Sales iP	Repl'mt Ratio DevRes (%)
Australia (SDA)	32.49	4.18		.07		3.5	4.2	29.04	14.76		.52	4.2	11.08			7	18%	101%	12%
Australia (WPL)	11.85	2.64		4.83			2.28	17.04	5.63		2.26	2.28	5.61			7	328%	328%	99%
Brunei	59.28	8.92	2.8	3.9			5.54	69.36	28.19	6.04	6.19	5.54	34.88			13	282%	282%	221%
China	3.24	4.16					1.43	5.97	2.83	.7	3.18	1.43	5.27			4	291%	291%	271%
China (Shell Oil EH)	3.29	-3.29							2.87		-2.87								
Malaysia	25.55	-.94	2.84	2.68			3.28	26.85	13.95	3.	.09	3.28	13.76			8	140%	140%	94%
New Zealand	4.6	-.17		.98			.41	5.	2.6	.11	-.04	.41	2.26			12	198%	198%	17%
New Zealand (Shell Oil EH)	.8	.05					.11	.74	.67		.06	.11	.62			7	45%	45%	55%
Philippines	3.82	.38				.7		3.5											
Thailand	14.17	.89	1.34				1.04	15.35	3.78	.95	.33	1.04	4.02			15	214%	214%	123%
Angola				11.85				11.85											
Argentina	3.43	.26		.07			.22	3.54	2.03	.06	-.03	.22	1.84			16	150%	150%	14%
Brazil (Shell Oil WH)	.81	.2					.09	.92	.81		.2	.09	.92			10	222%	222%	222%
Cameroon (Shell Oil EH)	7.75	-1.68	.2	.11			1.21	5.17	7.28	.29	-1.36	1.21	5.		1.03	4	-113%	-113%	-88%
Congo (DR)	3.22	-.01					.17	3.04	2.3		-.02	.17	2.11			18	-6%	-6%	-12%
Gabon	19.91	3.83				.81	3.99	18.94	17.45	1.12	2.5	3.99	17.08	4.97	4.74	5	76%	96%	91%
Nigeria (SNEPCO)	71.41	7.15		10.98				89.54											
Nigeria (SPDC)	448.1						13.93	434.17	113.19	4.29	13.33	13.93	116.88			31	0%	0%	126%
Venezuela	21.43	16.66					2.54	35.55	11.61	1.03	1.19	2.54	11.29			14	656%	656%	87%
Abu Dhabi	103.26	.02					5.58	97.7	83.71	2.11	.94	5.58	81.18			18	0%	0%	55%
Bangladesh																			
Egypt	9.06	-2.59					.58	5.89	5.73	.01	-1.69	.58	3.47			10	-447%	-447%	-290%
Iran	23.85	7.74						31.59											
Kazakhstan (Temir)	2.	.01				2.	.01			.01		.01				0	-19900%	100%	100%
Oman	139.5	34.88	18.43	3.21			16.62	179.4	85.	4.95	6.67	16.62	80.			11	340%	340%	70%
Oman Gisco	33.18	-12.34					2.36	18.48	27.32		-8.2	2.36	16.76	4.98	2.77	8	-523%	-523%	-347%
Pakistan																			
Russia (Sakhalin Holding)	7.69	-.01			7.93		.51	15.1	2.61	1.19	2.59	.51	5.88			30	1553%	-2%	741%
Syria	19.81	-1.17					2.92	15.72	12.29	.98	1.	2.92	11.35			5	-40%	-40%	68%
Austria	.23	.02		.01			.03	.23	.19		.03	.03	.19			8	100%	100%	100%
Canada	47.16	-1.42	14.43	.07		.01	3.36	56.87	29.13		1.11	3.36	26.88	10.36	12.49	17	389%	389%	33%
Canada (AOSP)	95.4							95.4						21.2	21.08				
Denmark	39.15	7.17	4.34	.41			7.53	43.54	27.63	1.41	11.44	7.53	32.95			6	158%	158%	171%
Germany	3.37	-.01					.31	3.05	3.07	.17	-.02	.31	2.91			10	-3%	-3%	48%
Netherlands	5.77	-.06					.75	4.96	3.93	.41	.1	.75	3.69			7	-8%	-8%	68%
Norway	33.26	5.34				.77	5.07	32.76	20.65	4.56	3.44	5.07	23.58			6	90%	105%	158%
Shell Oil (MCC)	1.86	-1.86							1.56		-1.56								
Shell Oil (TMR)	.93	.16		.13		.08	.16	.98	.56	.07	.14	.16	.61			6	131%	181%	131%
UK	129.92	.49	2.89	1.42		10.49	21.98	102.25	90.35	14.56	-7.35	21.98	75.58			5	-26%	22%	33%
USA	92.	2.24		20.04	.01	.94	16.18	97.17	54.12	11.54	6.34	16.18	55.82			6	132%	138%	111%
USA (Aera)	79.26	-3.07	.26			.13	7.23	69.09	59.01	4.08	1.39	7.23	57.25			10	-41%	-39%	76%
USA (Altura)	47.87	.61				47.78	.7		40.24		-39.54	.7				0	-6739%	87%	-5649%
Total excl Can. AOSP	1,554.28	79.38	47.53	60.76	7.94	67.21	132.32	1,550.35	777.05	63.64	2.36	132.32	710.72	20.31	21.03	12	97%	142%	50%
Grand Total	1,649.68	79.38	47.53	60.76	7.94	67.21	132.32	1,645.75	777.05	63.64	2.36	132.32	710.72	41.51	42.11	12	97%	142%	50%

2000 GROUP RESERVES SUBMISSIONS

Attachment 3.2

Country Name	GAS (10^9 sm3) All volumes net Shell Group Share Proved Resvs 1.1.2000	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2000	Proved Resvs 1.1.2001	Proved Dev'd Resvs 1.1.2000	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2000	Proved Dev'd Resvs 1.1.2001	Minority Resvs incl. 1.1.2000	Minority Resvs incl. 1.1.2001	R / P Tot (yr)	Repl'mt Ratio TotlRes (%)	Repl.R. TotlRes (%) Excl Pur/ Sales iP	Repl'mt Ratio DevRes (%)
Australia (SDA)	176.638	2.576		.453		.394	2.356	176.917	18.583		1.824	2.356	18.051			75	112%	129%	77%
Australia (WPL)	40.205	1.274		.155			1.45	40.184	8.147		1.305	1.45	8.002			28	99%	99%	90%
Brunei	102.612	-2.08		4.023			4.656	99.899	40.744	5.442	-3.601	4.656	37.929			21	42%	42%	40%
China																			
China (Shell Oil EH)																			
Malaysia	183.819	-11.93	5.625				5.723	171.791	37.746	20.212	-1.27	5.723	50.965			30	-110%	-110%	331%
New Zealand	12.646	.031		3.361	.154		1.381	14.811	11.704	.016	.19	1.381	10.529			11	257%	246%	15%
New Zealand (Shell Oil EH)	2.314	-.312					.247	1.755	2.014		-.319	.247	1.448			7	-126%	-126%	-129%
Philippines	19.436	1.029				3.551		16.914											
Thailand	6.226	.338	.063				.437	6.189	2.769	.263	.238	.437	2.833			14	92%	92%	115%
Angola																			
Argentina	7.284	1.522		.619			.036	9.389	.547	.056	-.501	.036	.066			261	5947%	5947%	-1236%
Brazil (Shell Oil WH)	4.384	1.083					.326	5.141	4.384		1.083	.326	5.141			16	332%	332%	332%
Cameroon (Shell Oil EH)																			
Congo (DR)																			
Gabon																			
Nigeria (SNEPCO)	5.7	.57		.75				7.02											
Nigeria (SPDC)	95.93	-8.384					1.836	85.71	37.837		-1.987	1.836	34.014			47	-457%	-457%	-108%
Venezuela																			
Abu Dhabi																			
Bangladesh																			
Egypt	4.713	.039		.457			.384	4.825	2.846		-.2	.384	2.262			13	129%	129%	-52%
Iran	31.272	-2.326	.39				1.455	27.881	14.059	1.624	-.722	1.455	13.506			19	-133%	-133%	62%
Kazakhstan (Temir)																			
Oman																			
Oman Gisco	45.693	14.272					4.758	55.207	45.693		3.825	4.758	44.76	6.854	8.281	12	300%	300%	80%
Pakistan	11.339	-.752				.532	.189	9.866	3.347			.189	3.158			52	-679%	-398%	0%
Russia (Sakhalin Holding)																			
Syria	1.012	-.074					.234	.704	.596	.013	-.038	.234	.337			3	-32%	-32%	-11%
Austria	1.476	.191		.104			.175	1.596	1.441		.228	.175	1.494			9	169%	169%	130%
Canada	88.31	3.231		.206		.895	6.153	84.699	72.2		.688	6.153	66.735	19.402	18.608	14	41%	56%	11%
Canada (AOSP)																			
Denmark	30.44	.941	.711	.365			3.105	29.352	18.73	.518	2.307	3.105	18.45			9	65%	65%	91%
Germany	59.422	1.225					4.659	55.988	46.423	1.565	1.023	4.659	44.352			12	26%	26%	56%
Netherlands	413.425	.132		1.122			14.828	399.851	211.215	3.23	.73	14.828	200.347			27	8%	8%	27%
Norway	89.897	2.15				.206	2.06	89.781	42.194	.224	-3.466	2.06	36.892			44	94%	104%	-157%
Shell Oil (MCC)	1.552	-1.552							1.504		-1.504								
Shell Oil (TMR)	1.693	-.364		.128		.113	.202	1.142	1.193	.062	-.16	.202	.893			6	-173%	-117%	-49%
UK	109.447	1.493	2.27	.075		3.096	11.583	98.606	67.734	11.532	-.223	11.583	67.46			9	6%	33%	98%
USA	96.232	-1.091		18.564	1.421	2.217	16.592	96.317	76.788	10.178	-3.968	16.592	66.406			6	101%	105%	37%
USA (Aera)	5.53	-4.036	.052			.142	.117	1.287	3.145	.761	-2.803	.117	.986			11	-3526%	-3405%	-1745%
USA (Altura)	8.068	.062				8.018	.112		6.985		-6.873	.112				0	-7104%	55%	-6137%
Total excl Can. AOSP	1,656.715	-.742	9.111	30.382	1.575	19.164	85.054	1,592.822	780.568	55.696	-14.194	85.054	737.016	26.256	26.889	19	25%	46%	49%
Grand Total	1,656.715	-.742	9.111	30.382	1.575	19.164	85.054	1,592.822	780.568	65.696	-14.194	85.054	737.016	26.256	26.889	19	25%	46%	49%

2000 PRODUCTION RECONCILIATION - OIL+ NGL

Attachment 4.1

Country	Original CERES mln bbl	Original CERES 10^6m3	Org'l Resvs Subm'n	Org'l Resvs Subm'n 10^6m3	Difference	Final CERES mln bbl	Final CERES 10^6m3	Final Resvs Subm 10^6m3	Difference 10^6m3	Comment
Australia (SDA)			4.2							
Australia (WPL)			2.28							
Australia Total	40.749	6.48		6.48		40.749	6.48	6.48		OK
Brunei	34.84	5.54		5.54		34.84	5.54	5.54		OK
China										
China (Shell Oil EH)			1.37							
China Total	9.024	1.43		1.37	-.06	9.024	1.43	1.43		Errors in SEC submission - corrected.
Malaysia	20.618	3.28		3.27	-.01	20.618	3.28	3.28		Rounding error - SEC submission corrected
New Zealand			.42					.41		
New Zealand (Shell Oil EH)			.12					.11		
New Zealand Total	3.573	.57		.54	-.03	3.27	.52	.52		Correction to Ceres plus minor corr'n for gasolines (excluded) in SEC submission.
Thailand	6.548	1.04		1.04		6.548	1.04	1.04		OK
Argentina	1.397	.22		.22		1.397	.22	.22		OK
Brazil (Shell Oil WH)	.562	.09		.09		.562	.09	.09		OK
Cameroon (Shell Oil EH)	7.595	1.21		1.21		7.595	1.21	1.21		OK
Congo (DR)	1.064	.17		.17		1.064	.17	.17		OK
Gabon	25.117	3.99		3.91	-.08	25.117	3.99	3.99		SEC subm'n omitted production from Echira (sold) - corrected
Nigeria (SPDC)	87.585	13.93		13.93		87.585	13.93	13.93		OK
Venezuela	15.998	2.54		2.54		15.998	2.54	2.54		OK
Abu Dhabi	35.108	5.58		5.58		35.108	5.58	5.58		OK
Egypt	3.632	.58		.58		3.632	.58	.58		OK
Oman			16.61							
Oman Gisco			2.36							
Oman Total	119.34	18.98		18.97	-.01	119.34	18.98	18.98		Rounding error - SEC submission corrected
Russia (Sakhalin Holding)	3.12		.51					.51		
Kazakhstan (Temir)	.016							.01		
Russia Total	3.136	.5		.51	.01	3.246	.52	.52		Ceres based on unreconciled volumes - corrected; Rounding correction for Temir SEC submission
Syria	18.349	2.92		2.92		18.349	2.92	2.92		OK
Austria	.176	.03		.03		.176	.03	.03		OK
Canada	21.142	3.36		3.36		21.142	3.36	3.36		OK
Denmark	47.38	7.53		7.54	.01	47.38	7.53	7.53		Rounding error; SEC submission corrected
Germany	1.965	.31		.31		1.965	.31	.31		OK
Netherlands	4.701	.75		.75		4.701	.75	.75		OK
Norway	31.908	5.07		5.07		31.908	5.07	5.07		OK
UK	138.239	21.98		21.97	-.01	138.239	21.98	21.98		Rounding error - SEC submission corrected
USA										
USA (Aera)			16.18							
USA (Altura)	.6375	.1	7.23							
Shell Oil (MCC)			.8							
Shell Oil (TMR)			.16							
USA Total	152.638	24.27		24.37	.1	152.638	24.27	24.27	!	Ceres submission excluded Altura prodn - too late to correct, hence SEC submission corrected
Total	832.384	132.35		132.27	-.08	832.191	132.32	132.32	!	Not fully reconciled - match forced

Jan30Note-tbl.xls, OilNGLRecn-Att4.1

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FOIA Confidential Treatment Requested

RJW00151351

2000 PRODUCTION RECONCILIATION - GAS

Attachment 4.2

Country	Org'l CERES	Org'l Resvs Subm'n		Difference	Final CERES	Final Resvs Subm'n	Difference	Comment
	10^9sm3		10^9sm3		10^9sm3	10^9sm3		
Australia (SDA)		2.355						
Australia (WPL)		1.45						
Australia Total	3.806		3.805	-.001	3.806	3.806		Rounding error; SEC submission corrected
Brunei	4.656		4.656		4.656	4.656		OK
Malaysia	5.723		5.722	-.001	5.723	5.723		Rounding error; SEC submission corrected
New Zealand	1.381		1.381		1.381	1.381		OK
New Zealand (Shell Oil EH)	.247		.247		.247	.247		OK
Thailand	.455		.437	-.018	.437	.437		Ceres corrected
Argentina	.021		.036	.015	.036	.036		Ceres submission in error - corrected
Brazil (Shell Oil WH)	.326		.325	-.001	.326	.326		Rounding error; SEC submission corrected
Nigeria (SPDC)	1.836		1.838	.002	1.836	1.836		Rounding error; SEC submission corrected
Bangladesh	.384		.38	-.004	.384	.384		Rounding error; SEC submission corrected
Egypt	1.455		1.455		1.455	1.455		OK
Oman Gisco	4.758		4.758		4.758	4.758		OK
Pakistan	.189		.191	.002	.189	.189		Rounding error; SEC submission corrected
Syria	.425		.236	-.189	.234	.234		Ceres corrected + minor correction to SEC
Austria	.175		.182	.007	.175	.175		SEC submission corrected (own use etc)
Canada	6.182		6.15	-.032	6.153	6.153		Q4 correction in Ceres (adjusted plant yields) to be applied - corrected (+ minor correction to SEC)
Denmark	3.105		3.105		3.105	3.105		OK
Germany	4.692		4.659	-.033	4.659	4.659		Ceres corrected
Netherlands	14.828		14.828		14.828	14.828		OK
Norway	2.06		2.06		2.06	2.06		OK
UK	11.583		11.583		11.583	11.583		OK
USA		16.615						
USA (Aera)		.117						
USA (Altura)		.112						
Shell Oil (MCC)								
Shell Oil (TMR)		.202						
USA Total	17.023		17.046	.023	17.023	17.023		Difference due to different conversion factors; SEC submission corrected
Total	**85.31**		**85.08**	**-.23**	**85.054**	**85.054**		

Jan30Note-tbl.xls, GasRecn-Att4.2

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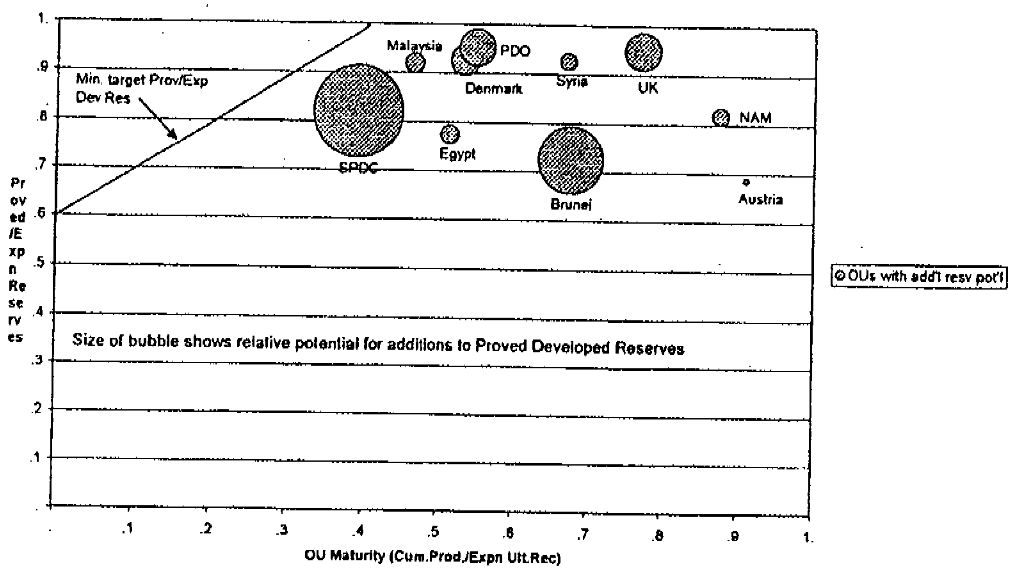
FOIA Confidential Treatment Requested

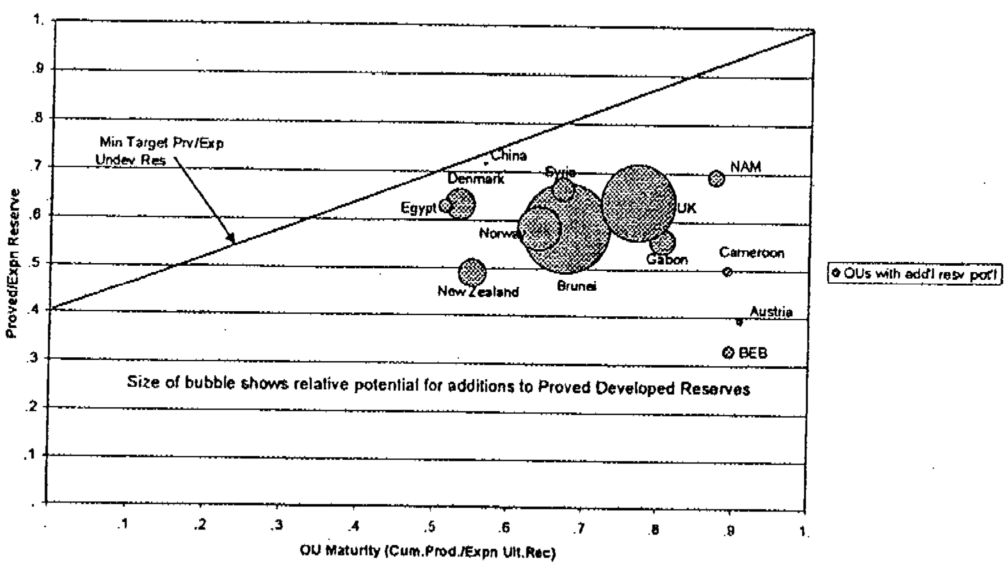
RJW00151352

Attachment 5.1

1.1.2001 DEVELOPED OIL+NGL RESERVES



1.1.2001 UNDEVELOPED OIL+NGL RESERVES

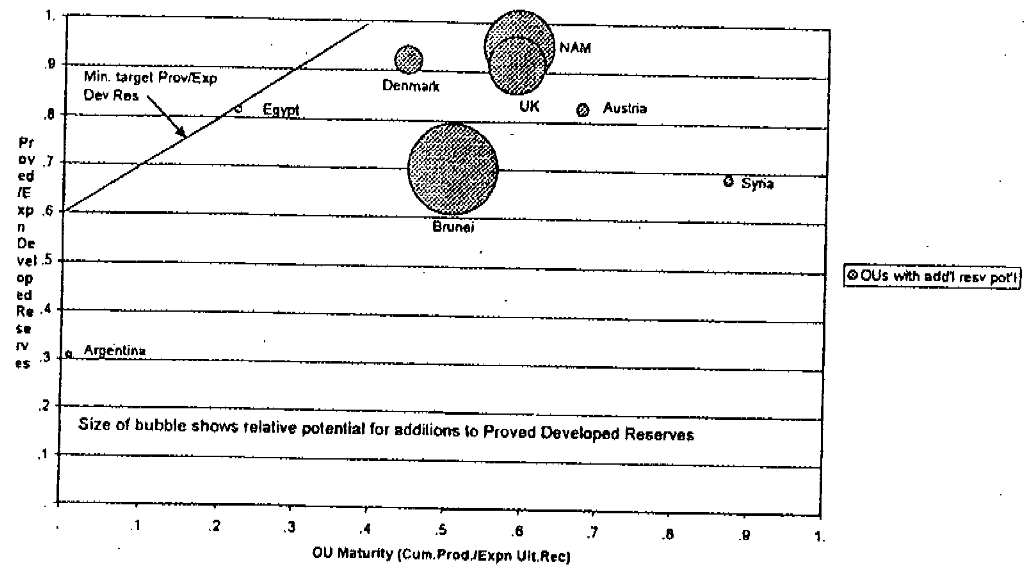


Scope for additions to Proved Oil+NGL Reserves - by OU
(overall 50 mln m3 Developed plus 35 mln m3 Undeveloped)

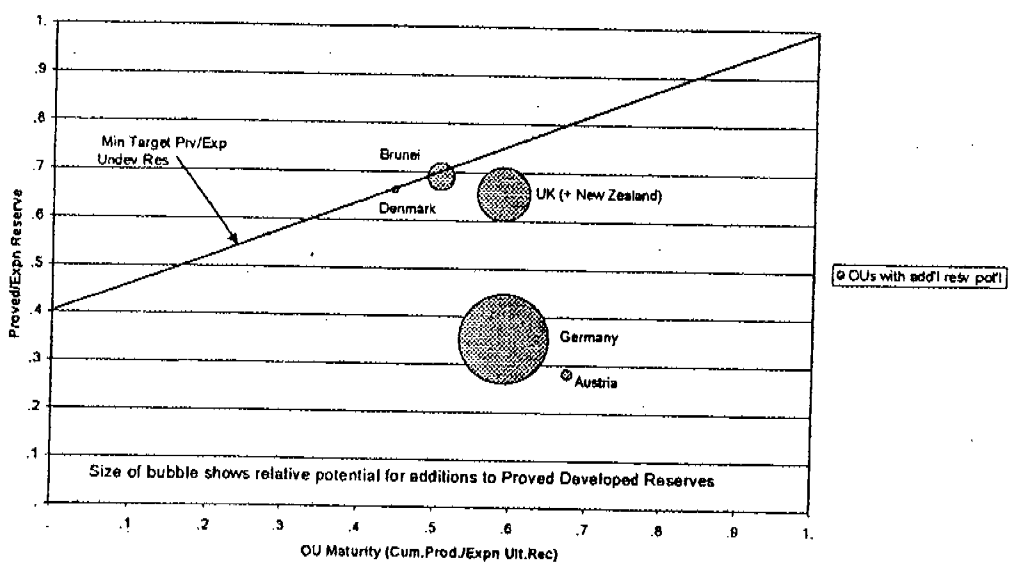
FOIA Confidential Treatment Requested

Attachment 5.2

1.1.2001 DEVELOPED GAS RESERVES



1.1.2001 UNDEVELOPED GAS RESERVES



Scope for additions to Proved Gas Reserves - by OU
(overall approx. 30 mln m3 Developed plus 15 mln m3 Undeveloped)

Attachment 6

ANGOLA BLOCK 18 - INITIAL RESERVES BOOKING 1.1.2001

Group Reserves Auditor Comments

Shell Development Angola (SDAN) intend to book Proved (and Expectation) reserves volumes for some of their deep water turbidite discoveries in the deep offshore Block 18 area per 1.1.2001. This is the first booking of reserves for this venture, following a series of six successful exploration wells drilled during 1999 and 2000. The necessary development planning work has been carried out by Shell Deepwater Services (SDS) in Houston, at the request of SDAN. SDS have produced a report (Ref. 1) documenting the basis for a reserves booking for two structures, Plutonio ('73' Channel Sand) and Cobalto ('72' Sheet Sand). For other sands and for the other four discovered structures in the area it was not possible to define a commercial development at this stage.

In spite of the exploration successes (six discoveries from six wells) the area is severely challenged to define a technically and commercially robust development. The root causes for this are the high development costs, the modest size of the discovered accumulations (150-400 mln stb STOIIP), the potentially poor lateral reservoir connectivity in the turbiditic sands and the relatively wide spread of the accumulations (40 km overall). The most likely development concept at this stage is an FPSO with vertical sub-sea wells tied back via sub-sea manifolds. This concept has been used for the presently postulated ('Phase I') development plan, which foresees a net Shell share Proved Reserves volume of 74 mln stb (12 mln m3). SDS have made it clear that this postulated plan is only designed to support a reserves booking at this stage. Further work (and appraisal drilling) is foreseen during 2001-2002 with the objective of defining an integrated development plan for most of the Block 18 area.

Prior to preparation of the present Stage I development plan, two meetings were held late in 2000 between SDS/SDAN and SIEP/SEPCo advisers, including myself. In the face of prevailing uncertainties, marginal to poor economics, plus a failed VAR2 review in October 2000, SDS were advised to look for a 'creaming' development plan. This plan should be aimed at the largely crestal areas of high seismic amplitude around the existing wellbores, where reservoir properties would probably be best and unit development costs lowest. This confinement to 'high confidence areas' would also have the benefit that associated recoverables could all be classed as Proved Reserves (a SEC requirement: Proved reserves should be associated with a 'Proved area' around existing wells). In addition, SDS were advised to look at the valuable set of turbidite reservoir connectivity data available within SEPTAR (BTC) and SEPCo to verify the well and reservoir recoveries that were obtained from other sources. This advice was largely followed and the resulting work has been documented in Ref. 1.

My remaining comments to Ref. 1 and the associated Proved Reserves are as follows:

1. The development plan, even if notional at this stage, is well documented and SDS must be commended for preparing this within a short time frame. In particular the relatively detailed reservoir simulations are noted.
2. The 'high confidence areas' defined by SDS may not all fulfil the stringent requirements for defining 'Proved areas' as used by SEPCo (Ref. 2). This should be verified in due course.
3. Simulator recoveries in the Cobalto sheet sand have not been corrected for potential lateral connectivity effects (SEPTAR data set). With the postulated well spacings this could expose this reservoir to a potential downside of a 10-30% lower recovery or a correspondingly higher well count.
4. Recoveries depend critically on successful water injection from the start of the project. If the viability of water injection is not proven by a pilot injection, Group guidelines require "a comprehensive assessment of uncertainties". Although well injectivity and bottom hole injection pressure have been correctly modelled, further evaluation work (e.g. sea water / formation water compatibility tests, potential well plugging) has not yet been done. However, experience in turbidite reservoirs off the Angolan coast and elsewhere suggest that any water injection problems cannot be expected to be a show stopper.
5. Gas re-injection (for conservation purposes) is postulated from the start of the project. No injection is intended into any of the oil reservoirs but a potential target reservoir has not been identified yet. Hence, no studies have been done yet regarding possible reservoir over-pressuring effects.
6. Project economics are marginal (VIR of 5%, UTC of 8 $/bl in the mid-case). Some 70% of postulated alternative cost and well scenarios have positive NPVs. Well count variations (+/- 20%) are probably too narrow, particularly for the P85 case. Hence the project barely passes commerciality criteria for reserves.

In conclusion, the Proved Reserves booked for Block 18 are extremely marginal with respect to criteria for technical and commercial robustness and hence are only just supportable. Much appraisal and study work will be required to address reservoir connectivity (i.e. well counts) and further cost reductions before a Block 18 project can be put forward for FID in 2002, as presently planned.

A.A. Barendregt, 17 January 2001

References:

1. "Angola Block 18: Phase I Development Area, Reserve Report Documentation", EP2001-4002, SEPTAR, Houston, January 2001.
2. "Estimating Pay Probability Downdip from Well Control Using Seismic amplitudes", A. Jackson, SEPTAR, Houston, 2000.

Attachment 7

2000 RESERVES AUDITS - MAIN OBSERVATIONS

Australia: The audit commended the high quality technical work that had been carried out by Woodside, particularly in assessing the subsurface uncertainties and in evaluating the ranges of in-place and reserves estimates. Intensive SIEP assistance through VAR- and other reviews was noted. Maintaining the preliminarily booked volume of Gorgon gas reserves (first done at 1.1.1999) was supported because a gas market was highly likely to be found in due course and because it must be considered likely that an extension of the current 5-year Retention Lease will be granted in 2002. Proved reserves in some mature fields (N-Rankin, Goodwyn and the four oil fields) should be increased to expectation levels, in line with the guidelines. Concern was expressed about the lack of a concisely documented audit trail, which hampered a proper assessment of the reasons for the end-1999 reserves changes. Audit opinion was **satisfactory**. Proved Reserves have been increased by some 9 mln m3oe, in line with recommendation.

Bangladesh: The most significant comment related to the conservative nature of the proved and proved developed reserves estimates. Recovery factors tend to underestimate the recovery efficiencies obtainable through compression, whilst discounting of in-place volumes in some undrained reservoirs tends to be conservative. Audit opinion was **satisfactory**. Apart from an 0.5 mln m3oe addition due to successful appraisal, no changes were made in Proved Reserves, pending further field performance.

Gabon: Commendation was made of the well organised set of field notes and annual ARPR report, providing the basis for a good audit trail. The most significant comment related to the unnecessarily conservative (and somewhat arbitrary) assumption of proved developed and undeveloped reserves for producing fields being a flat 85% of expectation values. Group guidelines prescribe that, for mature fields like those in Gabon, the proved values should be taken as equal to expectation values. The Rabi production licence expires at 30 June 2007. Until a new agreement (possibly a PSC) has been signed, some 2 mln m3 of Group share proved oil reserves remain out-of-licence and thus unbookable. Audit opinion was **satisfactory**. Proved Reserves have been increased by some 4 mln m3oe, in line with recommendation.

Norway: It was noted that operators Norsk Hydro and Statoil (Troll and Statfjord fields) appeared strangely reluctant to provide no-further-activities forecasts on which to base developed reserves. As a result, Troll developed gas reserves could be somewhat overstated. The reserves audit trail was incomplete due to table inaccuracies in the respective reserves notes. Commendable development option screening work had been done on the Ormen Lange field. Although seabed stability could still be a show stopper, a first discounted slice of gas reserves was booked for this field in 1999. Audit opinion was **satisfactory**. Troll Proved Developed Reserves have been reduced by some 4 mln m3oe.

Sakhalin: Presently carried oil recoveries are low because of the need to re-inject associated gas into the oil reservoir, but significant upside exists through lifting of this need and through optimisation of wells and application of horizontal wells. Comments were made regarding the incomplete state of the audit trail and the overdue completion of important EPT reports. Audit opinion was **satisfactory**.

USA (SEPCo): The comprehensive system of quarterly and annual internal reserves audits was noted and commended. Main deviations from Group reserves guidelines are due to SEPCo adhering to strict interpretations of the SEC rules, which are enforceable in the US. These differences relate mainly to government royalties in cash (excluded from reserves), fuel and flare gas volumes (included) and 'behind-pipe' developed volumes (over-included). The latter two are to be corrected, but the present SEC rules forbid the inclusion of US royalty volumes, even if paid in cash. Audit opinion was **satisfactory**. The correction for fuel-and-flare has led to a 6 mln m3oe reduction in gas volumes, mainly in the Aera venture.

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TIME TABLE SEC RESERVES AUDITS

Attachment 8

COUNTRY	Size**	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Comments
NETH. NAM	L	X				X				P				P	March 2001
GERMANY	L	X				X				P				P	April 2001?
UK	L			X		X				P				P	June 2001
DENMARK	L	X				X				P				P	April / June 2001?
CHINA	M/S		$							P1					Sept 2001?
NEW ZEALAND	M/S				X					P					Oct 2001?
AUSTRIA	M/S			X						P					Nov 2001
BRUNEI	L		X				X				P				Combine with Malaysia
MALAYSIA	L		X				X				P				Combine with Brunei
USA (AERA)	L					$					P1				
BRAZIL (Pecten)	M/S						•				P1				In Houston?
CAMEROON (Pecten)	M/S						•				P1				In Houston?
IRAN	L							$			P1				)
SYRIA	M/S	X			X						P				) Combine?
PAKISTAN	M/S					$					P				)
ABU DHABI	L			X				X				P			
NIGERIA -SPDC	L	X				X		X				P			
NIGERIA - SNEPCO	L					$		X				P			
OMAN	L			X				X				P			
EGYPT	L		X					X				P			
NAMIBIA											$?	P1?			
RUSSIA - SALYM											$?	P1?			
AUSTRALIA	L				X				X				P		
NORWAY	L				X				X				P		
USA (SEPCo)	L						•		X				P		
VENEZUELA	L				$			X					P		
ARGENTINA	M/S			X				X					P		
PHILIPPINES	M/S					$		X					P		
THAILAND	M/S		X					X					P		
GABON	M/S			X					X					P	
BANGLADESH	M/S					$			X					P	
RUSSIA - SAKHALIN	M/S					$			X					P	
KAZAKHSTAN-OKIOC												$?		P1?	
CANADA	L														No direct involvement
CHAD	M/S			X											Divested 2000
COLOMBIA			X												Hocol/Homcol interest sold 1997
KAZAKHSTAN-TEMIR	M/S							$							Divested 2000
USA (ALTURA)	L					$									Divested 2000
ZAIRE	M/S		X												Divested 2000 (subject govt approval)

X = Completed
P = Planned
P1 = First audit
$ = First SEC resvs subm'n
• = First SEC subm'n via SIEP

** L : > 30 mln m3oe ss
M/S : < 30 mln m3oe ss

Audit frequency:

Large OUs once every 4 years,
Medium/Small OUs every 5 years,
First audit within 2 yrs after first submission,

Exceptions possible in case of:
- major reserves changes,
- critical audit reports etc,
- when combinable with other audits.

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Dictionary Thesaurus Translations *

A B C D E F G H I J K L M N O P Q R S T U V W X Y Z

pressure

pressure

pres·sure [préshər]

noun (*plural* pres·sures)

Definition:

1. **process of pressing steadily:** the applying of a firm regular weight or force against somebody or something
• *The pressure of her hand on his was comforting.*

2. **constant state of worry and urgency:** powerful and stressful demands on somebody's time, attention, and energy, or a demand of this sort
• *They were under constant pressure to achieve increased output targets.*

3. **force that pushes or urges:** something that affects thoughts and behavior in a powerful way, usually in the form of several outside influences working together persuasively

4. PHYSICS **force per unit area:** the force acting on a surface divided by the area over which it acts.
Symbol p

5. METEOROLOGY

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Same as atmospheric pressure

transitive verb (*past and past participle* pres·sured, *present participle* pres·sur·ing, *3rd person present singular* pres·sures)

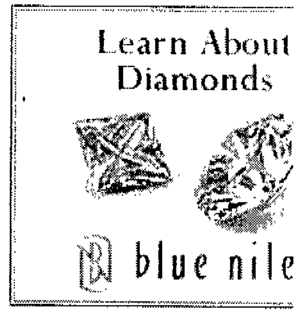
Definition:

make somebody do something: to apply great persuasion or a strong influence on somebody in order to force him or her to do something

- *They were pressured into selling by the rest of the family.*

[14th century. < Latin *pressura* < *press-* (see press[1])]

- pres·sure·less *adjective*



Note For Information

CMD 11th February 2002

EP Hydrocarbon Resources Update 1/2002

This note summarises the end 2001 Group resources situation, cleared by external audit, and in part reported in the Q4'01 and FY'01 press release. All numbers include the effects of A&D activities unless otherwise indicated.

Summary

The total barrel of oil equivalent proved hydrocarbon reserves replacement ratio (RRR) for 2001 was **74%** (52% excluding A&D), leading to a proved RRR three year rolling average, including AOSP additions (mining reserves) in 1999 of **81%**, 101% excluding A&D). The 2001 RRR is below the results quoted by our main competitors (BP 191%, XOM 110%), and highlights a portfolio that is under-performing in terms of adding reserves through exploration and maturing existing scope. Future RRR performance over the plan period relies on the delivery of 'big ticket' bookings, *e.g.* Kudu, Sakhalin LNG and Kashagan.

Our overall resource base contains some 20 bln boe of proved reserves (c.f BP 16 bln boe, XOM 22 bln boe) , some 13 bln boe of expectation reserves (of which some 8 bln boe currently fall outside of license expiry), some 17 bln boe of discovered Scope for Recovery (SFR). Our total discovered resources base is thus ca. 50 bln boe (c.f. XOM 70 bln boe) and additionally we have some some 27 bln boe of undiscovered SFR. Together with any volumes resulting from new exploration licenses and acquisitions these volumes represent a significant opportunity to increase our proved reserves replacement performance and the EP organization is being geared up to tackle each and every element.

Reserves and Resources

2001 Actual Additions (See Table 1)

The Group proved reserves base at end 2001 is 19.1 bln boe (19.7 incl. AOSP) and remains split at 50:50 oil/gas. The 2001 proved RRR of 74% amounts to a reserves addition of 1020 mln boe, which in Figure 1 is broken out by type of revision;

- 360 mln boe of Discoveries & Extensions, mainly in USA, UK and Brunei
- 350 mln boe of Revisions & Improved Recovery, mainly Netherlands, Denmark and Sakhalin offsetting negatives from Canada (50 mln boe based on field performance), New Zealand (50 mln boe based on studies on Maui field) and Oman Gisco (110 mln boe as a consequence of the renegotiation of the GISCO contract and acceleration of repayments)
- 310 mln boe of Acquisitions & Divestments, mainly Fletcher and Pinedale.

The proved **oil** RRR is 65%, taking the 3 year average to 102% including mining reserves and 77% without, and the proved **gas** RRR is 86% contributing to a 3 year

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average of some 50%. During 2001 there were no changes to the reserves for AOSP. Including AOSP, the three year average proved **boe** RRR is 81% (101% excl A&D) and excluding AOSP, the equivalent numbers are 67% (86%).

The Total Resource base (the sum of expectation reserves and commercial discovered SFR) has increased by 2.7 bln boe to 49.4 bln boe (see Table 2); this includes a 1.3 bln boe addition from Venezuela Urdaneta West which falls outside of the current licence period. It should be further noted that total resources include some 1.1 bln boe from the consolidation of Sakhalin.

The Unit Finding and Development Cost (UFDC) for 2001 defined as the exploration and development cost incurred ($6.1bln) divided by Group oil and gas additions, excl. purchases and sales, (0.73 bln boe) now stands at $8.3/boe for the year 2001, and $4.8/boe on a 3-year rolling average base (up from $3.50/boe in 2000, see Figure 2). An increase in UFDC was forecast at the time of developing the Business Plan in 2000 when it was recognised that there would be a lag between stepping up capital spending and the increase in subsequent reserves bookings. Together with the lower than planned bookings in 2001 this impacts directly on our competitive position on this indicator where, up until this year, we were the leading player. The Unit Finding Cost (funding share) is $1.0/boe yielding a 3-year average of $0.62/boe, reflecting a continuation of an improving trend. Unit Finding Costs on a proved reserves additions basis are $ 3.8/boe.

Comparison versus Business Plan

The EP scorecard target for 2001 was 80% (excl. A&D and strategic options), or 1120 mln boe at target production. The actual addition excl. A&D and strategic options was 710 mln boe, or 52% RRR at actual production. The main contributors to the lower than planned RRR are detailed in Figure 3.

None of the strategic options associated with reserves bookings in 2001 materialised, *e.g.* Saudi Gas, T2T, Salym, Bangestan, China, Libya.

Total SFR maturation to expectation reserves over 2001 was 0.92 bln boe or 2.2% of the commercial SFR.

Exposures

Securities and Exchange Commission (SEC) Alignment

Recently the SEC issued clarifications that make it apparent that the Group guidelines for booking Proved Reserves are no longer fully aligned with the SEC rules. This may expose some 1,000 mln boe of legacy reserves bookings (*e.g.* Gorgon, Ormen Lange, Angola and Waddenzee) where potential environmental, political or commercial 'showstoppers' exist.

End of License

In Oman PDO, Abu Dhabi and Nigeria SPDC (18% of EP's current production) no further proved reserves can be booked since it is no longer 'reasonably certain' that the proved reserves will be produced within license. The overall exposure should the OU business plans not transpire is 1,300 mln boe. Work has begun to address this important issue.

Appraisal

Historical Perspective

In 1999 - 2001 the proved reserves additions have not fully replaced production and the 2001 3-year rolling average RRR's no longer benefit from the recent 'bookings rich' period of 1996-98 (see Figures 4/5, reflecting performance with and without the effects of A&D and showing the impact of AOSP). Over that period, substantial proved reserves additions were realised from major discoveries (Australia,Gorgon, SNEPCo (Bonga), total 1.2bln boe), major revisions (Venezuela 0.3mln boe) and new business (Oman GISCO, 0.4bln boe). In addition, in 1998 significant bookings were made by bringing proved reserves closer to expectation in mature fields (total 1.2 bln boe) - this action brought us to industry standard from a much more conservative position.

Competitive Landscape

The Group RRR of 74% is low in comparison with competitors who all posted RRRs in excess of 100% (Figure 6). The competitors are able to draw benefit from portfolios which, following the rounds of industry rationalisation, appear to offer wider choices in key exploration and scope maturation targets.

2002 and Beyond: Outlook for RRR

The outlook for Group reserves replacement in 2002 and beyond remains challenging (see Figure 7);

- We can expect fewer additions through the base plan, because of OUs affected by 'end of license', OUs with limited remaining exploration potential and the challenge to find ways to increase expectation reserve levels in mature fields.
- And an increased reliance on strategic options and other big-ticket bookings. Control on timing of these bookings is an issue, as they are commonly occur in frontier areas (Kashagan), face fierce competition for markets (T4/T5, Sakhalin LNG), rely on emerging technologies (Kudu, SURE), or are in areas with limited control (Saudi, Whale). The subsequent reserves booking profile may be "lumpier" than in the past and these major bookings will require additional steer to ensure delivery of new reserves within the tighter SEC framework.

Actions taken

In Q4 2001 and Q1 2002 a number of actions have been initiated to address this emerging issue;

- even greater focus is being placed on succeeding in exploration, a key challenge is to focus on the maturation of our 27 bln boe of undiscovered scope for recovery
- similarly EP is refocusing the organization to reinstate Technical and Operational Excellence across the whole of its core operations; hydrocarbon resources maturation is a key element of this drive
- EP is looking again at the opportunities to accelerate the maturation of our 17 bln boe of discovered scope for recovery and specifically with GP looking at the opportunities to monetize gas SFR

- Stepping up the drive to extend licenses e.g. in Abu Dhabi, Nigeria, Brunei, Oman and open up the opportunity to move the 8 bln boe expectation reserves which currently fall outside of license expiry back into our within license resource base and ultimately move to proved reserves.

Conclusion

Our reserves replacement performance over the past few years clearly illustrates the emerging problems with our resource base and is becoming a source of competitive disadvantage. Over the plan period, the challenge will be to secure sufficient volumes from major bookings to supplement additions from a base plan portfolio and ensure that existing exposures, if they transpire, are adequately offset.

However, we do have some nearly 50 bln boe of SFR and expectation reserves currently outwith license in our overall resource base which presents a significant opportunity. We are refocusing our efforts on exploration and will pursue more aggressively the transfer from SFR to reserves but this will not be sufficient to reverse the trends – success in major strategic options in MRH's or a major acquisition is necessary.