Exhibit 88

NOTE – 2 Oct 2002 CONFIDENTIAL

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SEC PROVED RESERVES AUDIT - SHELL NIGERIA E&P Co (SNEPCO), 9-12 Sept 2002

I have audited the proposed Proved Reserves submissions of SNEPCO for the year 2002 and the processes that were followed in their preparation. These submissions are intended to present the SNEPCO contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 2002.

The last previous SEC proved reserves audit for SNEPCO was carried out in 1999. Since then, a number of changes have been made to the Group reserves guidelines ("Petroleum Resource Volume Guidelines, SIEP 2001-1100/1101", based, inter alia, on FASB Statement 69). These changes were instigated by statements issued by the Securities and Exchange Commission (SEC) during 2001 and did in particular relate to reserves bookings in new, as yet undeveloped fields. During 2002, SNEPCO have reviewed their reserves bookings in the light of these changes and it was deemed appropriate that these revised bookings were audited prior to their intended submission as Group returns at the end of 2002. The reserves revisions had been prepared by staff in Shell Deepwater Services (SDS). Hence, the audit took place in the SDS office in Houston.

The current audit followed the procedures laid down in the Group reserves guidelines. It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. It also included a verification that the annual production (sales) submission through the Finance system was consistent with the reserves submission. The audit took the form of detailed discussions about the reserves reporting process and the resulting volumes with SNEPCO and SDS staff.

The audit found that SDS had performed a commendable effort in re-evaluating the downside risk of poor lateral communication (a common feature in turbidites). Proved volumetric estimates were also reviewed in the light of their needing alignment with 'Proved Areas' as defined by FASB and recently re-asserted by SEC. The audit recommendation is that SNEPCO book a Group share Proved Undeveloped oil volume of some 72 mln m3 per 1.1.2003. This compares with a previously (1.1.2002) booked volume of 90 mln m3. The reason for the reduction is that SNEPCO had booked Proved reserves additions in recent years that were not in accordance with SEC guidelines. First time booking of Bonga SW per 1.1.2003 can still not be supported with the present marginal economics and unresolved unitisation issues.

The audit finding is that the proposed SNEPCO Proved reserves are now in line with the appropriate Group and SEC Guidelines. The overall opinion from the audit regarding the state of SNEPCO's 2002 Proved Reserves submission procedures, taking account of the scoring in Attachment 3, is satisfactory.

A summary of the findings and observations is included in the Attachments.

EXHIBIT 13
PENGAD 800-631-6989

A.A. Barendregt

Attachments 1, 2, 3

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RJW00830131

Attachment 1

SEC PROVED RESERVES AUDIT - SNEPCO, 9-12 Sept 2002

MAIN OBSERVATIONS

1. SNEPCO hold shares in three fields with presently declared Proved Reserves:

   Bonga, operated by SNEPCO with a Shell share of 55%,
   Erha, operated by Exxon/Mobil, with a Shell share of 43.75%,
   Abo, operated by Agip/ENI, with a Shell share of 49.81%.

   The fields are located in the Nigerian deep offshore with waterdepths of 800-1200 m. Development is underway in all three fields with first oil expected in Abo and Ehra during 2003 and in Bonga early in 2004. Oil Export will be via FPSOs with gas being re-injected in Erha and Abo, while gas export to NLNG is foreseen from Bonga.

   Production licences have PSC contracts with a duration of 20 years from day of granting. There is an option for a 10-year extension in the contract and the legal opinion in SNEPCO is that, barring default, the extension 'shall' be granted.

   No provision was originally made for gas production and sales in the deep offshore PSCs. For Bonga (OML118 licence) an agreement was reached with the authorities during 2002 that entitlement exists to only 50% of the gas, with the remaining 50% reverting to the Government.

   Oil production quota restrictions are a potentially serious threat to project economics. No agreements or guarantees have yet been obtained.

2. All three fields have reservoirs of turbiditic origin, varying from stacked meandering channels (e.g. Erha) to more sheet-like channels (e.g. Bonga). Reservoir permeabilities are excellent (1-10 D) and oil quality is generally sweet and light. Aquifer sizes are seen to be limited and water injection is planned in all three fields.

   Seismic quality is good to excellent. There is complete 3D coverage over all fields with proved reserves (and most prospects). Seismic amplitude / attribute mapping plays an essential role in reservoir delineations. In particular inversion techniques (predicting reservoir properties from amplitude / attributes maps) are highly successful.

   SNEPCO's initial evaluations of Proved recovery efficiencies in the turbidite reservoirs tended to be optimistic, taking insufficient account of the potential for reservoir compartmentalisation due to shale barriers and faults. This has been corrected in the recent study work by more detailed modelling of these barrier features (including experience from SEPCo GOM fields).

3. During 2001, the US Securities and Exchange Commission (SEC) have issued, at the request of the oil industry, some clarifications and guidance on the way in which the industry should interpret and apply the FASB rules regarding the booking of Proved and Proved Developed Reserves. These rules have remained essentially unchanged for many years and the continuing progress in oil field technology (particularly seismic) made the need felt for a clarification of required industry practices.

   The SEC clarifications did impact particularly on new, undeveloped fields. They re-asserted the strict requirement that Proved Reserves in fields should continue to be based only on 'Proved Areas', i.e. only those hydrocarbon volumes that had been 'seen' by the drill bit. In particular oil (or gas) below 'Lowest Known Hydrocarbons' (LKH) were to be excluded, even if seismic amplitudes showed a continuation of hydrocarbon-like amplitudes Downdip of the wel penetration. Exceptions were only allowed if hydrocarbon-water contact levels (HWC) could be inferred from pressure measurements in the water and in the oil zone of the reservoir.

   As a result of this new SEC guidance, the Group Reserves Guidelines (SIEP 2002-1100) have been updated in March 2002 and distributed to Group OUs. The Guidelines state that, for reserves to be booked in new fields (both Proved and Expectation) they must fulfil the following requirements:

   - Proved reserves must conform to the 'Proved Area' condition (with some allowance for 'below-LKH' volumes in cases of very good seismic) and must be based on a conservative ('reasonably certain') recovery scenario, reflecting the possible downside in reservoir performance
   - Projects producing these reserves must be reasonably certain to become executed, which means that they must have robust economics and must have passed a VAR3 review (if major) or be technically mature (if minor). FID can replace the need for a VAR3. In all cases, there must be no potential show stoppers, either technical, commercial or licence related.

   SNEPCO have recognised that some portions of their previously booked Proved Reserves may not have fulfilled the relevant requirements and have instigated a review of these reserves as part of the ongoing development studies and planning effort by SDS in Houston.

Specific Field Comments

4. **Abo**

The reserves estimates in Abo have not been reviewed since formulation of Agip's FDP. The Proved reseves volumes carried for Abo are not in line with SEC and Group requirements. In each of two sand bodies ('Polygon3' and 'Polygon 5') there is only one well in the extreme updip position, which means that the associated downdip oil volumes (interpreted to be present from seismic amplitudes) cannot be classed as Proved. The two remaining development wells, firmly planned early in 2003 are targeted for the downdip positions in the two sand bodies and are very likely to prove up both of these. Hence, to avoid major swings in Proved reserves, it can be accepted that both volumes be maintained as Proved until the two wells have been drilled. Any disappointing results must of course lead to an immediate debooking of the Proved volumes.

In addition, it appears that one of the sand bodies (Polygon 3) consists of two separate lobes, divided by an area with low amplitudes, which may be interpreted as a potential barrier. The existing well penetrates one of the two lobes only, while the new (sub-horizontal) well is planned to penetrate both lobes in a downdip position. Even if oil is found in the second as yet unpenetrated lobe, it can only prove oil between its ODT and OUT levels (the SEC require certain continuity of production). Hence the unpenetrated lobe (approximately half of Polygon 3, some 10 MMbls Proved UR) should be taken out of Proved reserves now as it cannot be considered Proved, even when the future well is successful.

5. **Erha**

The economics in Erha are marginal but, since FID was taken in June 2002, this does not affect the booking of porved Reserves. Economics may improve if the nearby Bosi structure (to be appraised 2003?) should be sufficiently attractive to justify a tie back into Erha.

The Erha structure has been comprehensively appraised by three wells and most of the oil can be considered as Proved. The exception is one fault block sliver, 'AE', in between two faults that are interpreted as sealing, which has not been penetrated and can therefore not be considered as Proved. The associated recovery volumes (some 8% of Erha STOIIP volumes or some 18 MMstb Proved UR) should be debooked now. A suggested 'period of grace' to await the results of Bosi appraisal would be too uncertain in both timing and result and is therefore not acceptable.

Proved recovery volumes are based on Expectation STOIIP ('best estimate'), as per guidelines. The Recovery efficiency range in Erha seems very narrow for a new field (P/E is 90%). This narrow range is the result of combined studies by SNEPCO and Exxon-Mobil and reflects the confidence that any shale barriers in the thick package of highly permeable channel sands ace of local extent only and will not significantly impair sweep efficiency and oil recovery. It is noted that Exxon-Mobils's own recovery estimates exceed Shell's estimates by 15-30%.

6. **Bonga Main**

The 1.1.2002 Proved reserves in Bonga Main contained volumes in a mixture of sands. Some of these were penetrated by wells at the time, but some of them were not. Hence, prior to drilling of development wells, a significant portion of booked Proved reserves did not fulfil the SEC requirements. Following completion of the Bonga pre-development drilling campaign (14 wells) a comprehensive review was made of the volumes that could be considered Proved in accordance with guidelines and also of the downside risk that some areas with planned injector/producer locations would provide barriers to flow. This review was comprehensive and is highly commended.

The review showed that the four main sand horizons (690, 702, 710/740 and 803) can now all be considered fully Proved. In addition, Proved volumes can be booked in nine other, smaller sand horizons of more local extent (called 'in-field opportunities' or IFO). These are 702 Additional, 709, 710SE, 670-12, 670-14, 671S, 690-Ch4, 740SE, 803NW and 670-4. Using Expectation (best estimate) STOIIP volumes within 'Proved Area' constraints and Low recovery factors SDS have calculated a Proved reserves volume of 447 MMstb for the four main sands plus 90 MMstb for the nine additional sands. Using probabilistic addition (with a dependency factor of 0.5) this yields a Proved Reserves volume for Bonga Main of 637 MMstb. This volume, and its method of calculation, is fully accepted.

Recovery estimates were also made for a total of 11 unpenetrated sand bodies that are to be addressed by appraisal wells planned (but not approved yet) for 2003 and 2004. These volumes should remain in undiscovered SFR until the appraisal has been successful.

The Bonga IFO development (all sands, including those not yet penetrated) will be subject to a VAR2 review in October 2002. The main objective for this review will be to chart the way ahead for development of the North Western unproven sands, which will require new subsea manifolds, pipelines and facilities' modifications. The wells in the proved nine sands are all said to be economically robust and are expected to be drillable from currently available manifold slots, some possibly after a T-piece extension. The feasibility of this is expected to be demonstrated by the VAR2. If confirmed, these activities will not require major capex (other than drilling and completion) and their funding can be applied for as part of the annual field development drilling budget. The associated volumes in the nine sands can be carried as Proved reserves provided they are included in the next Business Plan. If the feasibility of drilling these wells from existing slots should not be confirmed, then their associated reserves should be debooked until the IFO activities pass a VAR3 review.

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7. **Bonga SW**

Two successful appraisal wells (including one sidetrack) have been drilled during 2002, bringing the total well count to three. Thus, the amount of oil that can be considered proved, has increased. However, field development is still subject to considerable uncertainty as economic viability of Bonga SW development is still marginal. In addition, there is an unresolved untisation issue with two adjacent licence blocks, OPL213 and OPL249, in the latter of which there is also a dispute (presently in the courts) regarding the licensee ownership rights. There are signs that the authorities will not allow any further activity in the field until the unitisation has been resolved.

A VAR3 was planned for October 2002, in anticipation of a first reserves booking per end 2002. However, in view of the mentioned uncertainties it will not be possible to support such a booking until the economic viability and the unitisation issues have been resolved.

8. **Total Reserves**

In summary, it is likely that the following approximate volumes will be booked as per 1.1.2003 (see also Att. 2.1-2)

	1.1.2002			1.1.2003		
	100% field Proved UR MMstb	Effective share % (PSC, equity etc)	Shell share Proved UR mln m3	100% field Proved UR MMstb	Effective share % (PSC, equity etc)	Shell share Proved UR mln m3
Abo	75	44.5%	5.30	65	44.5%	5
Erha	431	38.5%	26.41	362	38.5%	22
Bonga Main + IFO oil	803	45.6%	58.26	637**	45.6%	46
Bonga SW	-		-	-		-
Total oil	1309	43.2%	89.97	1064	43.6%	73
Bonga gas (oil equiv.)	92.75	46.1%	6.8	74	23.0%	3
Total oil equiv	1402	43.4%	96.77	1138	41.9%	76

** Bonga IFO to be debooked if it does not pass the VAR2 in Oct 2002!

Other comments

9. Proved and Expectation reserves depend critically on successful implementation of water injection in the turibidte reservoirs. No water injection pilot has been carried out, nor is there any water injection project in existence in the area. This would in principle plead against booking of SEC proved reserves. However, extensive core flood tests, induced fracture studies and scale potential studies (sea water and formation water) have been performed. Experience in similar reservoirs worldwide (particularly GOM, UK, but since recently also on the African coast) shows that reservoir sweep efficiency, not microscopic displacement efficiency, is the major performance driver in these high permeable sands. This has been addressed by a full suite of alternative simulation models, with varying assumptions regarding lateral reservoir continuity. Hence, carrying Proved rerserves for these waterfloods can be supported.

10. Bonga Proved volumes can be produced within the 20 year licence plus its 10-year extension. This assumes that there will be no production quota constraints.

11. An 'ARPR' document is published annually (that for 1.1.2002 was issued in August 2002). This is commendable. The document is reasonably comprehensive, but lacks a clear structure and uniformity between the successive tables. The impression is that of a collation of viewgraphs and tables from various sources, rather than an integrated document. This makes some reserves parameters less easy to find. A review of the layout of this document, preferably in a thinner form, is recommended. Appropriate guidelines are on the EPB-P web page.

12. PSC shares given in Tables 4, 8 and 10 of the SNEPCO ARPR report do not seem to match with PSC shares implied in its Att. 4, pages 1 & 2.

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13. A notional 15% reduction is applied to 100% field gas reserves for own use and fuel. The background for this percentage was not clear. A proper calculation should be made, e.g. from forecast FPSO fuel requirements and this allowance should be properly reflected in the audit trail.

14. Export gas GHVs have been evaluated from gas samples and process simulations. The 1.1.2002 GHV and gas (Nm3) submission is still based on a reference GHV of 9500 kCal/Nm3 - this should be 9400 kCal/Nm3 (or 1000Btu/scf).

Recommendations

1. Reduce Polygon 3 Proved reserves in Abo by half (approximately) to reflect the presence of a barrier area in that Polygon. Maintain the Proved reserves in the remaining part of Polygon 3 and in Polygon 5 for the time being, but debook these volumes if the 2003 development wells should be disappointing.
2. Debook Proved reserves in the 'AE' fault block in Erha (18 MMstb, already incorporated in the above table).
3. Accept the 637 MMstb Proved Reserves volume calculated for Bonga Main reservoirs 690, 702, 710/740 and 803, plus IFO activities in nine penetrated sands. However, if the Oct 2002 VAR2 for the IFO activities should shed doubt on the IFO activities in the nine sands, the associated Proved volumes should be de-booked. The Reserves Coordinator in SIEP should be passed a copy of the VAR2 conclusions.
4. Include an acceleration of the debottlenecking of Bonga water injection facilities in the 2003 Business Plan. The production forecast and volumes-within-licence must be reviewed if this acceleration should not be approved.
5. First booking of Bonga SW reserves should be deferred until the economic viability is more robust and until the unitisation issues have been resolved. It is unlikely that this will happen before 1.1.2003.
6. Improve the structure of the annual ARPR note, describing the background and reason for the end-year reserves bookings. Appropriate guidelines are on the EPB-P web page. Also, review the consistency between the reported and actually applied PSC shares.
7. Provide justification (in the ARPR note) for the assumption of a 15% reduction in the gas sales volumes due to own use and fuel.
8. In the 1.1.2003 submission the normalised gas volumes (in Nm3) should be based on a reference GHV of 9400 kCal/Nm3 (1000 Btu/scf), not 9500 kCal/Nm3 as at present.

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SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SNEPCO 1.1.2002

Attachment 2.1

Proved Oil / NGL / Gas Reserves as at 1.1.2002

Area / field	Proven HIIP MMstb / Bscf	Exp'n HIIP MMstb / Bscf	Cum. Prod = Sales 31.12.01 MMstb / Bscf	Proved Rem. Recov. Dev'd MMstb / Bscf	Proved Rem. Recov. Undev MMstb / Bscf	Exp'n Rem. Recov. Tot'l MMstb / Bscf	Maturity (Cum.pr / Exp'n UR) %	Dev. / Tot'l Proved UR. %	Proved RF Tot'l %	Exp'n RF Tot'l %	WI lic (oil) / Excl.fuel (gas) %	PSC share %	Block Licence Shell share % %	Shell Equity Pr.Dev. MMstb / Bscf	Shell Equity Pr.Tot'l MMstb / Bscf	Shell Equity Pr.Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Pr.Tot'l 10^6 sm3/ 10^9 sm3	1.1.2002 Subm'n Dev 10^6 sm3/ 10^9 sm3	1.1.2002 Subm'n Tot'l 10^6 sm3/ 10^9 sm3
Oil																			
Bonga	1720.00	2168.00			803.00	1042.00	0%	0%	47%	48%	99.0%	83.8%	55.00%	0.00	366.40	0.00	58.25		
Erha	1092.00	1283.00			431.00	659.00	0%	0%	39%	51%	99.1%	88.9%	43.75%	0.00	166.12	0.00	26.41		
Abo	180.00	220.00			75.00	94.00	0%	0%	42%	43%	98.1%	91.0%	49.81%	0.00	33.35	0.00	5.30		
Total Oil (MMstb)	2992.00	3671.00	0.00	0.00	1309.00	1795.00	0%	0%	44%	49%				0.00	565.87	0.00	89.97		89.97
NGL																			
Bonga																			
Erha																			
Abo																			
Total NGL (MMstb)																			
Gas (Dry, sales gas volumes)																			
Bonga	1204.000	1518.000			538.000	685.000	0%	0%	45%	45%	83.8%	100.0%	55.00%	0.000	247.984	0.000	7.017		
Erha							0	0	0	0				0.000	0.000	0.000	0.000		
Abo							0	0	0	0				0.000	0.000	0.000	0.000		
Total Gas (Bscf)	1204.000	1518.000	0.000	0.000	538.000	685.000	0%	0%	45%	45%				0.000	247.984	0.000	7.017		7.020

Conversion factors used by SNEPCO:
1 stb = 0.159 m3
1scf = 0.0283 sm3

Conversion factors used by SIEP:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Licence expiry dates: Bonga Main: 2020
Erha: 2023?
Abo: 2023?

Audit Trail:

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SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SNEPCO 1.1.2003

Attachment 2.2

Proved Oil / NGL / Gas Reserves as at 1.1.2003

Area / field	Proven HIIP MMstb / Bscf	Exp'n HIIP MMstb / Bscf	Cum. Prod = Sales 31.12.02 MMstb / Bscf	Proved Rem. Recov. Dev'd MMstb / Bscf	Proved Rem. Recov. Undev MMstb / Bscf	Exp'n Rem. Recov. Tot'l MMstb / Bscf	Maturity (Cum.pr / Exp'n URI) %	Dev. / Tot'l Proved UR. %	Proved RF Tot'l %	Exp'n RF Tot'l %	W/I lic (oil) / Excl.fuel (gas) %	PSC share %	Block Licence Shell share % %	Shell Equity Pr.Dev. MMstb / Bscf	Shell Equity Pr.Tot'l MMstb / Bscf	Shell Equity Pr.Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Pr.Tot'l 10^6 sm3/ 10^9 sm3	1.1.2003 Subm'n Dev 10^6 sm3/ 10^9 sm3	1.1.2003 Subm'n Tot'l 10^6 sm3/ 10^9 sm3
Oil																			
Bonga	1720.00	2168.00			637.00	813.00	0%	0%	37%	38%	99.0%	83.8%	55.00%	0.00	290.66	0.00	46.21		
Erha	1092.00	1283.00			350.00	426.00	0%	0%	32%	33%	99.1%	88.9%	43.75%	0.00	134.90	0.00	21.45		
Abo	180.00	220.00			65.00	94.00	0%	0%	35%	43%	98.1%	91.0%	49.81%	0.00	28.90	0.00	4.60		
Total Oil (MMstb)	2992.00	3671.00	0.00	0.00	1052.00	1333.00	0%	0%	35%	36%	0	43.2%	100.00%	0.00	454.46	0.00	72.26		
NGL																			
Bonga							0	0	0	0				0.00	0.00	0.00	0.00		
Erha							0	0	0	0				0.00	0.00	0.00	0.00		
Abo							0	0	0	0				0.00	0.00	0.00	0.00		
Total NGL (MMstb)	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00		
Gas (Dry, sales gas volumes)																			
Bonga	1204.000	1518.000			426.782	534.458	0%	0%	35%	35%	83.8%	50.0%	55.00%	0.000	98.352	0.000	2.783		
Erha							0	0	0	0			43.75%	0.000	0.000	0.000	0.000		
Abo							0	0	0	0			49.81%	0.000	0.000	0.000	0.000		
Total Gas (Bscf)	1204.000	1518.000	0.000	0.000	426.782	534.458	0%	0%	35%	35%	0	23.0%	100.00%	0.000	98.352	0.000	2.783		

Conversion factors used by SNEPCO:
1 stb = 0.159 m3
1scf = 0.0283 sm3

Conversion factors used by SIEP:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Licence expiry dates: Bonga Main: 2020
Erha: 2023?
Abo: 2023?

Note: Gas PSC entitlement share reduced to 50% as per recent agreement

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SNEPCO, Sept 2001 **CHECKLIST SEC RESERVES AUDITS** **Attachment 3**

COMPANY: SHELL NIGERIA E&P Co AREA / FIELD: All fields

	Audit criteria	Result	Comments
1	TECHNICAL MATURITY		
1.01	Is 3D seismic available and used for the field(s) in question?	+	There is complete 3D coverage over all the fields with proved reserves (and most prospects).
1.02	Are seismic processing and interpretation state-of-the-art?	+	Seismic amplitude / attribute mapping plays an essential role in field evaluations. In particular inversion techniques (predicting reservoir properties from amplitude / attributes maps) are highly successful.
1.03	Is well data coverage adequate?	+	All fields with proved reserves have been adequately appraised. Further appraisal (in particular in non-proved portions) is still required and will be undertaken as justified through Value of Information (VOI) evaluations.
1.04	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Proved areas' are defined from well penetrations, seismic amplitude maps and fluid levels, either observed or interpreted from pressure data. Following re-evaluation efforts by SDS during 2001/2002 all proposed 1.1.2003 Proved reserves will fulfil 'proved area' requirements.
1.05	Is this 'proved area' supported by seismic amplitude studies and/or reservoir analogues in the area?	+	Yes, see above
1.06	Are petrophysical well data quality and quantity adequate?	+	Well log suites specify modern tools and are fully adequate. Pressure data from MDTs play a particularly important role.
1.07	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Numerous production tests have been carried out in a range of appraisal wells. All showed excellent sand permeabilities in the range of 1-10 D.
1.08	Are there proper volumetric estimates?	+	Volumetric estimates are carried out through static modelling. Tools used are DEPSIM and PROMISE (Seismic Inversion) and Jason 'Rock trace', a simpler seismic inversion mapping tool.
1.09	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	PVT samples are taken during production testing and analysed in the appropriate manner. Delays sometimes occur due to export licence problems of samples (e.g. no proper analysis is available yet from Bonga SW - 2 well samples.
1.10	Are gas GHVs measured properly for sales gas conditions and accounted for in reserves submissions?	O	Export gas GHVs have been evaluated from gas samples and process simulations. The 1.1.2002 GHV and gas (Nm3) submission is still based on a reference GHV of 9500 kCal/Nm3 - this should be 9400 kCal/Nm3 (or 1000Btu/scf).
1.11	Are static models available / adequate?	+	Static modelling is standard practice - see 1.08 above.
1.12	Are dynamic models available / adequate?	+	All reservoirs / sands have dynamic models, initially relatively coarse, but succeeded by more refined models as detailed static modelling becomes available.
1.13	Are history matches available / adequate?	N.A.	First production will start in the Abo field in 2003. Bonga will follow late 2003 / early 2004.
1.14	Are the recovery factors for proved reserves realistic?	+	Initial evaluations of recoveries in the turbidite reservoirs tended to be optimistic, taking insufficient account of the potential for reservoir compartmentalisation due to shale barriers and faults. This has been corrected by more detailed modelling of these barrier features (including experience from SEPCo GOM fields), particularly in the recent study work.
1.15	Are developed reserves based on proper NFA (No Further Activity) forecasts?	N.A.	No developed reserves are carried yet.
1.16	Are developed reserves based on existing wells, completions and facilities, or do they require only minor costs (<10% project cost) to be hooked up?	N.A.	
1.17	Have development projects been defined for undeveloped reserves or can they be defined?	+	All (undeveloped) reserves are based on identified well targets.
1.18	Are there auditable development project plans with costs, benefits and economics?	+	Firm plans and costs + economics are available for the initial phases of development. Later phases (e.g. in Bonga IFO) tend to be more notional but are based on simulated well positions.
1.19	Are the projects technically mature or is further data gathering necessary?	O	Well maturity varies from very mature in Abo and Bonga (where some 14 development wells have already been drilled) to less mature in areas where well target and location optimisation still has to be done (e.g. Bonga IFO).

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1.20	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	O	No water injection pilot has been carried out. However, extensive core flood tests, induced fracture studies, scale potential studies (sea water and formation water) have been performed. Experience in analogue reservoirs worldwide (particularly GOM, UK) shows that reservoir sweep efficiency, not microscopic displacement efficiency, is the major performance driver. This has been addressed by a full suite of alternative simulation models, with varying assumptions regarding lateral reservoir continuity. In addition to the GOM/UK analogue reservoirs there is now a similar turbidite reservoir in operation under waterflood (Girasol, Angola). Start of production has been too recent to allow any significant conclusions.
1.21	Have the projects successfully passed a VAR3 review or are they otherwise ready for application for funding?	O	FID has already been taken in Bonga, Abo and Erha. Bonga IFO will be subjected to a VAR2 Oct 2002. From this it is expected that the activities in proved areas will need no major capex (other than drilling/completion). They will therefore be included in the 2003 BP as ongoing development activities, not as a new project requiring a VAR3 review.
1.22	Are the projects firmly planned to go ahead - are there any potential show stoppers?	+	Bonga Main, Abo and Erha are firmly planned to go ahead. Funding for Bonga IFO wells in proved areas will be requested in the year that they are needed. Bonga SW (no proved reserves) foresees a VAR 3 either late 2002 or early 2003. Its economics are presently marginal, while there are as yet unresolved unitisation issues with the neighbouring licence blocks OPL 213 and OPL 249 (where licensee rights are under dispute).
2	COMMERCIAL MATURITY		
2.01	Are the projects economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	O	Bonga Main and Abo are robust, as are most Bonga IFO activities. Erha is marginal at present (may become better with future Bosi satellite tie-back), but FID was taken in June 2002. Bonga SW (no proved reserves) is marginal.
2.02	Have forecasts been cut off when rates become uneconomic?	+	Yes, at the point where projected operating costs exceed oil proceeds.
2.03	Have the latest Group Screening / Reference Criteria been used?	+	Yes
2.04	Are assumed prices and costs RT (or justified if not)?	+	Yes
2.05	Is export infrastructure (pipelines, terminals etc) available or, if not, is it firmly planned and fully included in the economics?	+	Yes
2.06	Is project financing available or can it reasonably be expected to be available?	+	For the projects with proved reserves, yes.
2.07	Are developed reserves actually in production?	N.A.	
2.08	Have all proved gas reserves been contracted to sales?	O	No provision was originally made for gas production and sales in the deep offshore PSCs. For Bonga (OML118 licence) an understanding has recently been reached with the authorities that only 50% of the gas can be retained, while the remaining 50% reverts to the Government. A draft gas sales contract is in place, awaiting resolution of the Government share issue. The gas will be delivered into the third NLNG train, which has ample capacity to absorb all gas available for sales.
2.09	If not, can they reasonably be expected to be sold in existing markets and through existing / firmly planned facilities?	+	Yes, see above
2.10	If neither, is there a firm commitment (eg FID) that supports the assumption and maturing of a future market?	N.A.	
3	REASONABLE CERTAINTY		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	+	Many different scenario models have been built with the PROMISE seismic inversion tool, yielding an adequate spread of possible in-place volumes.
3.02	Is the uncertainty range of developed recovery adequate?	N.A.	All reserves are as yet undeveloped
3.03	Is the uncertainty range of undeveloped recovery adequate?	O	The range seems fully adequate in Bonga Main + IFO (excellent work of evaluating suites of appropriate L/M/H scenarios). However, in Erha the range seems very narrow (P/E is 90%, reflecting the anticipated range in RF, both taken with the Expectation STOIIP).
3.04	Have market / production constraint uncertainties been taken into account?	O	Opec production quota constraints pose a potentially serious threat, which is yet to be resolved. Some constraint is assumed in the base case forecasts.
3.05	What is ratio of field(s) cum.prod. / expectation total recovery?		0
3.06	Can the field(s) be considered mature?		No

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3.07	Are proved (developed and total) reserves consistent with 'proved areas'?	X	Bonga Main + IFO are OK; Erha not quite (EA block), while Abo has significant volumes below ODT, without pressure measurement support for assumed OWCs from seismic amplitudes.
3.08	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Yes
3.09	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	+	Yes
3.10	Is any assumed dependency in probabilistic addition appropriate?	O	Use has been made of moderate dependency between the respective scenarios, with a correlation factor 0.5 (on a scale of 0 -1). The justification for the selection of this factor, although intuitively appropriate, was not clear.
4	GROUP SHARE CALCULATION		
4.01	Are proved and proved developed reserves fully producible within the licence period (or its extension if there is a legal right) and within production ceilings/constraints?	O	Bonga Proved volumes can be produced within the 20 year licence (which started already in 2000, earlier than strictly necessary). However, this requires water injection capacity to be debottlenecked early, which is not yet in the present Business Plan. This also assumes that there will be no production quota constraints. The 20 years OML period can be extended according to the following wording in the PSC contract with NNPC: "At the end of the 20 years OML period [NNPC] shall seek renewal of the OML and if granted this contratc shall at the option of either Party [NNPC or SNEPCO] be extended for the duration of such renewal". The legal view in SNEPCO is that this amounts to a certain 10-year extension option to the 20 years' OML period.
4.02	Are the forecasts required to demonstrate the above condition consistent with the firm Base Case presented in the latest Business Plan?	X	The early debottlenecking of Bonga water injection is not yet in the Base Business Plan
4.03	Is the hydrocarbon Equity share calculated properly (regular production contracts)?	+	Yes, the block shares are 55% for Bonga, 49.81% for Abo and 43.75% for Erha.
4.04	Is the hydrocarbon PSC entitlement share (net cost oil + profit oil only) calculated properly?	X	The economics model has been verified by a number of internal and external checks. Shares are on Expectation basis. No separate PSC shares were said to have been calculated for the Proved reserves case. This statement is not consistent with the appropriate tables in SNEPCO's ARPR (Att 4, p. 1-2). The PSC shares implied in the reserves submission are also not consistent with those calculated and reported elsewhere in the ARPR (Tables 4, 8, 10).
4.05	Is the hydrocarbon Purchase Right share (to the extent that economic benefit is derived from production while still bearing share of risks and rewards) calculated properly?	N.A.	
4.06	Are royalties that are (formally or customarily) paid in cash included in reserves?	N.A.	(see below)
4.07	Are royalties paid in kind excluded from reserves?	+	Royalty will be paid in kind to NNPC (based on royalty rate and realised sales price). Hence royalty has correctly been excluded from reserves. It should also be excluded from reported production once production starts.
4.08	Are volumes delivered free of charge as fees in kind (e.g. for infrastructure used by third parties) included in reserves? Similarly, are volumes received as fees in kind excluded from reserves?	N.A.	
4.09	Has historic Group under-or overlift (e.g. compared with other co-venturers) been accounted for?	N.A.	
4.10	Have gas volumes produced from the reservoir but not yet sold (e.g. through UGS, gas re-injection into another reservoir or a swap deal with another field) been properly maintained in reserves?	N.A.	
4.11	Have gas volumes paid for by the buyer but not yet produced and sold ('take-or-pay' gas) been properly maintained in reserves?	N.A.	
4.12	Have separate submissions been made for Equity, Entitlement and Purchase Right volumes?	N.A.	
5	AUDIT TRAILS		
5.01	Are proved and proved developed reserves estimates up-to date?	+	Yes, they have been prepared recently, taking into account the latest well information
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	+	Yes, see Att. 2
5.03	Can reserves changes be reconciled with individual field changes?	N.A.	Since the audit did not focus on the historical (1.1.2002) reserves submission, no reconciliation of 2001 changes was made. At this stage, all changes are likely to be 'Revisions'.
5.04	Are reserves changes reported in the appropriate categories?	+	All changes will be in the category 'Revisions'

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5.05	Is there a document in place describing the OU's reserves reporting procedures?	O	No; the SIEP guidelines are used.
5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	+	Yes; SDS have a good record of properly and comprehensively documenting their study work
5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	+	SDS have a library of their own reports. SNPE keeps copies of all relevant reports in Lagos.
5.08	Is the annual reserves submission supported by a sufficiently detailed summary note explaining the reserves changes (classified in revisions, extensions, sales-in-place etc) per field, with references to detailed reports as appropriate?	O	An 'ARPR' document is published annually (that for 1.1.2002 was issued in August 2002). This is commendable. The document is reasonably comprehensive, but lacks a clear structure and uniformity between the successive tables. The impression is that of a collation of viewgraphs and tables from various sources, rather than an integrated document. This makes some reserves parameters less easy to find.
5.09	Are electronic data bases containing both historic submissions' data and current reserves data in place and accessible?	O	In view of the small number of fields, a comprehensive data base (other than a set of spreadsheets) is at this stage not yet warranted.
5.10	Do these data bases also contain references to detailed reports?	O	No
6	CONSISTENCY WITH FINANCIAL REPORTING		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes, calculated for anticipated surface facilities' conditions.
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	NGL reserves are not administered separately as they are produced via the oil stream.
6.03	Are own use, fuel, losses etc excluded?	O	A notional 15% reduction is applied for own use and fuel. The background for this percentage was not clear. A proper calculation should be made.
6.04	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system? (Ceres line 0933, which is the sum of line 7385 (Reward Oil/NGL) and line 0871 (= 8462-Oil + 8464-NGL for Consolidated Companies + line 3596 (= 0931-Oil + 0932-NGL) for Assoc. Companies).	N.A.	No production yet
6.05	Are annual gas production volumes in reserves submissions consistent with Upstream Gas production available for Sales (GpafS) volumes reported into the Finance (Ceres) system? (Ceres line 9130).	N.A.	No production yet
6.06	Are the Financial and Reserves accounting of production / sales fully consistent with each other also in cases like royalties, fees-in-kind, underlift/overlift, gas re-injection/UGS, take-or-pay gas?	N.A.	Royalty should be excluded from future reported production, see 4.07.
6.07	Are the net Shell share reserves reported properly and consistently with Finance reporting (100% for consolidated Shell companies, with minority reserves reported separately, or actual percentage if less than 50%)?	N.A.	
6.08	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	N.A.	No production yet
7	OVERALL		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	The Abo and Erha reserves have been overstated. Those in Bonga are now reasonable.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	O	The overstatements in Abo and Erha are relatively small compared with the Bonga Main volumes.

		Weight	Score (0-100%)
1	TECHNICAL MATURITY	30%	87%
2	COMMERCIAL MATURITY	18%	80%
3	REASONABLE CERTAINTY	14%	56%
4	GROUP SHARE CALCULATION	12%	50%
5	AUDIT TRAILS	15%	76%
6	CONSISTENCY WITH FINANCIAL REPORTING	2%	75%
7	OVERALL OPINION	9%	50%
	TOTAL SCORE	100%	72%

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