Exhibit 79

NOTE – 6 Dec 2002

CONFIDENTIAL

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	(circulation)	SIEP – EPF: Rahim Khan
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SEC PROVED RESERVES AUDIT - SHELL DEVELOPMENT ANGOLA, 25-26 Nov 2002

I have audited the proposed Proved Reserves submissions of Shell Development Angola (SDAN) for the year 2002 and the processes that were followed in their preparation. These submissions will present the SDAN contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 2002.

Total Group share Proved Reserves proposed by SDAN at the end of 2002 are 19.2 mln m3 of oil. This represents an increase of some 7 mln m3 of oil from the end 2001 estimate. The increase was the result of the FID decision for a full five-field development that was taken during 2002.

The first reserves booking by SDAN was over the year 2000. This audit is the first SEC proved reserves audit for SDAN. The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 2001-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty where appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. It also included 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 with SDAN staff and with staff from SDS in Houston who are carrying out the subsurface evaluations on behalf of SDAN.

The audit found that the new Proved reserves estimates prepared by SDS during 2002 are in agreement with the Shell Group and SEC guidelines and that these estimates can be accepted. The Proved estimates are curtailed by the fact that some of the six exploration and appraisal wells have been drilled in not fully representative portions of the reservoirs (crestal and/or behind major barriers). Hence, in accordance with SEC and Group guidelines, some significant portions of these reservoirs have to be considered as unproved and their associated recoveries cannot be included in Proved reserves. Some limited portions of the unproved volumes could become proved if a proper procedure is developed for accepting seismic evidence of OWCs in channelised turbidite reservoirs. The planned temporary disposal of gas by re-injection into one of the reservoirs (none of which are suitable) may become an area of serious concern if the planned LNG plant should become delayed. no long

The audit finding is that the SDAN statements will fairly represent the Group entitlements to Proved Reserves at the end of 2002. The overall opinion from the audit regarding the state of SDAN's 2002 Proved Reserves submission, taking account of the scoring in Attachment 3, is therefore good.

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

EXHIBIT 13 Duhon

PENGAD 800-631-6989

A.A. Barendregt

Attachments 1, 2, 3

Attachment 1

SEC PROVED RESERVES AUDIT - SDAN, 25-26 Nov 2002

MAIN OBSERVATIONS

1. Shell Development Angola are a 50% non-operating partner in the Block 18 area offshore Angola. BP (operator) own the remaining 50% share. The area has seen some very successful exploration drilling during 1998-2000 (five wells, five discoveries) and the five fields have been declared commercial in April 2002. Project FID has been taken during 2002 and the project is due to come on stream in 2006. Committed Shell funds are some $1.5 bln. Although Shell FID was taken, the project does not fulfill Group project screening criteria. The decision to go ahead was taken largely for project materiality and because of the significant upside under higher oil price scenarios.

   Although not the operator, SDAN have committed SDS in Houston to carry out independent subsurface and development studies. During 2002, SDS have completed a new round of reservoir modeling and evaluations and these revised volumes were the subject of the present audit. The new volumes replace previous estimates based on a partial, selective field development (Plutonio and Cobalto only).

2. The reservoir sands are shelf-edge turbiditic in origin and of Oligocene age. The uppermost O72 sand, seen in the Plutonio and Cobalto fields is of sheet type, while the older sands (O73 and lower) are canyon fill channel sands. The gas-saturated oil is light, with GORs around 1000 scf/bl and of low viscosity, thus favouring water displacement. Core flood tests suggest favourable displacement to low oil saturations but the lowest values have been queried by peer reviews. Aquifer pressure support is expected to be limited and water injection will be required from the start. There is a small gas cap in the Plutonio O72/73 reservoirs (m=0.1).

   Oil pressures in the successive separate sands tend to line up on one common gradient, suggesting either an (unlikely) common OWC or separate OWCs against 'perched water' (small aquifers!) in the shallower sands. Seismic evidence clearly points to the separate OWC scenario.

   3D Seismic has been available from an early stage of field exploration and appraisal. Whilst its quality was good, this has been improved by a high resolution seismic survey (up to 60 Hz) that was acquired late 2001 and processed during 2002. This has allowed main channel bodies to be mapped individually, thus greatly enhancing the understanding of reservoir structural architecture. OWCs and reservoir pinch-outs are also clearly visible.

3. Development will be through an FPSO and a total of 43 subsea wells (20 producers, 23 water injectors) is foreseen. In view of the prevailing reservoir uncertainties, provision has been made for up to 27 additional and/or replacement wells. Gas is planned to be exported to a future onshore LNG plant, with gas to be re-injected into one of the reservoirs as an interim measure.

   Active reservoir surveillance is foreseen in the development plan. Wells will be fitted with DTS fluid monitoring systems while water injectors will be flow controlled. Regular ('4D') seismic surveys are foreseen to monitor water flood front advance, thus allowing any unswept areas to be addressed by future wells.

4. The five structures are appraised by one (discovery) well each, plus a one well (2 holes) appraisal in Plutonio. This leaves a significant portion of some of the fields' STOIIPs 'unproved', i.e. not penetrated by the drill bit. 'Proved areas' have been defined in each of the fields. These are delineated by ODTs where no water was seen, by identified major faults with clearly visible throw and by channel cut-outs where present and continuous. Seismic evidence of OWCs outside and below proved areas is clearly visible (in some cases confirmed by other OWC evidence, eg pressures) but where not confirmed it is not used for proved estimates, in line with SEC and Group guidelines. However, the seismic is seen to provide sufficient evidence for the presence of oil to proceed with the project.

5. Proved recoveries are based on (P50) estimates of 'proved' STOIIPs and P85 estimates of recovery factors. The latter are derived from suites of alternative scenario simulation models (by SDS for the Plutonio and Cobalto fields, by BP for the other fields). Earlier peer review teams considered these RF ranges too narrow. The combination results in a low Proved/Expectation reserves ratio of 45%, largely influenced by the 'proved area' requirement of the proved STOIIPs. A widening of the RF range is therefore not likely to have a significant effect on the total proved reserves. The approach is in accordance with the guidelines.

6. According to the PSA, the contractor has title to the Block 18 gas. Gas disposal is foreseen to be via an LNG plant onshore Angola (destined to capture gas from all offshore industry projects). Present plan for the start-up date is 2007, but some slippage is deemed possible. With Block 18 first oil foreseen for 2006, the plan is to re-inject gas into the Plutonio O73 reservoir as an interim solution until the LNG outlet is available. No commitment has yet been made for the LNG scheme, nor have the commercial terms been established. Hence, no gas reserves are carried at this stage.

   The temporary gas injection is foreseen to be into a downflank position of the flat Plutonio O73 reservoir. This may pose a potentially serious threat to oil recovery if this is continued for too long, e.g. due to LNG plant delays. Calculations show that one year of gas re-injection may represent 1% pore volume of gas, rising more steeply after the second year.

Gas re-injection was considered to be inadequately modeled by a peer review team. Thinner gridblocks should be added at the top of the reservoir to model gas migration adequately.

Gas reserves can be booked upon start of when the gas disposal route through LNG is confirmed. Account should be taken of future FPSO own use and compressor fuel for deriving net Group share volumes. Provision should also be made for keeping track (through modeling) of any re-injected gas volumes that may still be recoverable at a later stage.

7. Water injection is required from the start of production. No water flood pilot has been carried out. However, a water flood has been underway since Dec 2001 in the neighbouring Girasol field (TFE operated, with BP participation). Cumulative water injected todate is estimated to amount to some 3-6% of subsurface STOIIP volume. Similar waterfloods in the GOM have all been quite successful. A water injection pulse test of several hours' duration has been carried out in well Plut 2A. In addition, water compatibility tests have been carried out (showing the need for sulphate reduction of the seawater) and core flooding tests tend to show low residual oil saturations. Hence, there is reasonable certainty that waterflood reserves will be realised. The SEC proved reserves guidelines require either a pilot in the field or a nearby analogue project in the area and the latter condition is now deemed to be fulfilled by the Girasol project.

   The suggestion is made to ask BP to keep SDAN informed of progress on the Girasol water injection, e.g. in terms of current average water cuts and cumulative pore volume percentage injected.

8. SEPCo have developed a procedure for incorporating seismic OWC evidence in proved estimates in ODT ('LKH') situations, by setting specific requirements for the quality of the seismic evidence before it can be 'allowed'. However, this procedure was developed largely for GOM sheet sand turbidites and hence it was not used for declaring proved volumes below ODTs in the turbidite channel environment in Angola Block 18. This is now being addressed by a special study by SDS that is seeking to adapt the SEPCo procedure for channel sand turbidites. However, even if a satisfactory procedure is obtained this will not allow booking of proved reserves in areas behind observed barriers (faults, channel cut-outs) in view of the SEC requirement of 'continuity of production'.

9. An ARPR summary report is to be issued shortly describing the basis for the new reserves estimates. This is good practice and is commended. In addition, various detailed reports on the successive subsurface evaluations (petrophysics, static and dynamic modeling etc) are in various stages of preparation. It is recommended that the summary report will include references to all these detailed reports (even if not fully completed yet) in order to provide a clear overview of the audit trail.

10. In view of the small number of fields, no formal data base has been set up. A spreadsheet solution should be fully adequate to provide the backup for the Group share volumes submitted. Arrangements should be made by SDAN to standardise this spreadsheet as much as possible over the years and to preserve the annual copies.

Recommendations

1. Add layers with thinner gridblocks (with appropriate 3-phase rel-perms) at the top of the present Plutonio O73 dynamic model to provide a more accurate representation of re-injected gas migration.
2. Provision should be made for keeping track (through modeling) of any re-injected gas volumes that may still be recoverable at a later stage.
3. Account should be taken of future FPSO own use and compressor fuel in future gas reserves.
4. Ask BP to keep SDAN informed of progress on the Girasol water injection, e.g. in terms of current average water cuts and cumulative pore volume percentage of water injected.
5. Ensure that all detailed reports are referenced in the ARPR summary note to be issued shortly.
6. Arrangements should be made by SDAN to standardise this spreadsheet as much as possible over the years and to preserve the annual copies.

Attachment 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDAN 1.1.2002

Proposed Proved Oil / NGL / Gas Reserves as at 1.1.2003

Area / field	Proven HIIP MMstb / Bscf	Exp'n HIIP MMstb / Bscf	Cum. Prod = Sales 31.12.01 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 %	PSA contr. share % Pr.Dev. %	PSA contr. share % Pr.Undv %	Within Licence comtd Pr.Dev. MMstb / Bscf	Within Licence comtd Pr.Tot'l MMstb / Bscf	Venture Shell share % %	Shell Equity Pr.Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Pr.Tot'l 10^6 sm3/ 10^9 sm3
Oil																	
Plutonio Olig 72	215.00	215.00			70.00	81.00	0%	0%	33%	38%	91.94%	91.94%	0.00	64.36	50.00%	0.00	5.12
Plutonio Olig73.	477.00	477.00			167.00	230.00	0%	0%	35%	48%	91.94%	91.94%	0.00	153.54	50.00%	0.00	12.21
Cobalto Olig72	12.10	157.00			4.00	62.00	0%	0%	33%	39%	91.94%	91.94%	0.00	3.68	50.00%	0.00	0.29
Cobalto Olig73/74	5.60	70.00			2.00	40.00	0%	0%	35%	57%	91.94%	91.94%	0.00	1.84	50.00%	0.00	0.15
Paladio	15.60	183.00			4.00	61.00	0%	0%	26%	33%	91.94%	91.94%	0.00	3.68	50.00%	0.00	0.29
Cromio	3.70	74.00			1.00	32.00	0%	0%	27%	43%	91.94%	91.94%	0.00	0.92	50.00%	0.00	0.07
Gallo	50.00	298.00			15.00	81.00	0%	0%	30%	27%	91.94%	91.94%	0.00	13.79	50.00%	0.00	1.10
Gallo NW	0.00	40.00				18	0%	0	0	45%	91.94%	91.94%	0.00	0.00	50.00%	0.00	0.00
Total Oil (MMstb)	779.00	1512.00	0.00	0.00	263.00	587.00	0%	0%	34%	39%	0	91.94%	0.00	241.80	50.00%	0.00	19.22
NGL																	
							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	0.00	0.00	0	0.00	0.00
Gas (Dry, sales gas volumes)																	
							0	0	0	0			0.000	0.000		0.000	0.000
Total Gas (Bscf)	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0.000	0.000	0	0.000	0.000

Conversion factors used by SDAN:
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:

Audit Trail:

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Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDAN 1.1.2002

Proposed Proved Oil Reserves Changes 2002 (100%, MMstb)

Field	Prov.Res. 1.1.2002	Revisions/ Reclassfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves (Transf.	Productn 2002	Prov.Res 1.1.2003	Shell Equity Share % 1.1.2002	Shell Equity Share % 2002 Prod	Shell Equity Share % 1.1.2003	Net Shell Equity 1.1.2002 (10^6 m3)	Net Shell Equity 1.1.2003 (10^6 m3)	Comments
Proved Developed Reserves															
Plutonio Olig 72		0.00							0.00	45.43%	45.97%	45.97%	0.00	0.00	
Plutonio Olig73		0.00							0.00	45.43%	45.97%	45.97%	0.00	0.00	
Cobalto Olig72		0.00							0.00	45.43%	45.97%	45.97%	0.00	0.00	
Cobalto Olig73/74		0.00							0.00	45.43%	45.97%	45.97%	0.00	0.00	
Paladio		0.00							0.00	45.43%	45.97%	45.97%	0.00	0.00	
Cromio		0.00							0.00	45.43%	45.97%	45.97%	0.00	0.00	
Galio		0.00							0.00	45.43%	45.97%	45.97%	0.00	0.00	
Galio NW		0.00							0.00	45.43%	45.97%	45.97%	0.00	0.00	
Prov.Dev.Resvs (MMstb)	0.00	0.00 0.00					0.00	0.00	0.00	%	%	%	0.00	0.00	
Proved Undeveloped Reserves															
Plutonio Olig 72		70.00							70.00	45.43%		45.97%	0.00	5.12	
Plutonio Olig73	91.00	76.00							167.00	45.43%		45.97%	6.57	12.21	
Cobalto Olig72	73.00	-69.00							4.00	45.43%		45.97%	5.27	0.29	Reduction mainly by strict application of 'proved area'
Cobalto Olig73/74		2.00							2.00	45.43%		45.97%	0.00	0.15	
Paladio		4.00							4.00	45.43%		45.97%	0.00	0.29	
Cromio		1.00							1.00	45.43%		45.97%	0.00	0.07	
Galio		15.00							15.00	45.43%		45.97%	0.00	1.10	
Galio NW		0.00							0.00	45.43%		45.97%	0.00	0.00	
Prov.Undev.Res (MMstb)	164.00	99.00 99.00	0.00	0.00	0.00	0.00			263.00	45.43%		45.97%	11.85	19.22	
Net Group Equity Proved Developed Reserves Proved Total Reserves 10^6 m3	0.00 11.85	0.00 7.38	0.00	0.00	0.00	0.00	0.00	0.00 0.00	0.00 19.22	0.00 19.22					

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

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

Audit Trail:

Angt-Alt2.xls, OilResvChg

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SDAN, Nov 2001 **CHECKLIST SEC RESERVES AUDITS** **Attachment 3**

COMPANY: SHELL DEVELOPMENT ANGOLA **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?	+	3D Seismic has been available from an early stage of field exploration and appraisal. Whilst its quality was good, this has been greatly improved by a high resolution seismic survey (up to 60 Hz) that was acquired late 2001 and processed during 2002. This has allowed main channel bodies to be mapped individually, thus greatly enhancing the understanding of reservoir structural architecture. OWCs and reservoir pinch-outs are also clearly visible. In view of the good quality of the seismic (mostly non-complex overburden, visible OWCs), 4D seismic is planned upon start of production to monitor advancement of water flood fronts.
1.02	Are seismic processing and interpretation state-of-the-art?	+	Seismic processing (by Western Geophysics) is commensurate with the high quality of the seismic acquired.
1.03	Is well data coverage adequate?	O	The five structures are appraised by one (discovery) well each, plus a one well (2 holes) appraisal in Plutonio. Whilst this leaves a significant portion of some of the fields' STOIIPs 'unproved', the seismic evidence provides sufficient evidence to proceed with the project.
1.04	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Proved areas have been defined in each of the fields. These are delineated by ODTs where no water was seen, by identified major faults with clearly visible throw and by channel cut-outs where present and continuous.
1.05	Is this 'proved area' supported by seismic amplitude studies and/or reservoir analogues in the area?	N.A.	Seismic evidence of OWCs is clearly visible (in some cases confirmed by other OWC evidence, eg pressures) but this is not used for proved estimates. SEPCo have developed a procedure for incorporating seismic OWC evidence in proved estimates in ODT ('LKH') situations, by setting specific requirements for the quality of the seismic evidence before it can be 'allowed'. However, this procedure was developed largely for GOM sheet sand turbidites and was not deemed to be appropriate in the turbidite channel environment in Angola Block 18. This is now being addressed by a special study by SDS that is seeking to adapt the SEPCo procedure for channel sand turbidites. However, even if a satisfactory procedure is obtained this will not allow booking of proved reserves in areas behind observed barriers (faults, channel cut-outs) in view of SEC requirement of 'continuity of production'
1.06	Are petrophysical well data quality and quantity adequate?	+	Full suites of cores have been taken in all the exploration wells. Ample core data has also been taken.
1.07	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Proper production tests have been taken in most of the wells. A pulse test was also carried out in the two holes of the Plutonio appraisal well.
1.08	Are there proper volumetric estimates?	+	Probabilistic volumetric estimates have in first instance been made for all fields through Fastrack. For Plutonio and Cobalto this was followed up by detailed Depsim static modelling, which confirmed the earlier estimates.
1.09	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	Ample PVT samples have been taken in the production tests and oil PVT properties are well established. Evidence of a grading column with higher viscous oil near the OWC was seen in the Plutonio O73 reservoir.
1.10	Are gas GHVs measured properly for sales gas conditions and accounted for in reserves submissions?	N.A.	According to the PSA, the contractor has title to the Block 18 gas. Gas disposal is foreseen to be via an LNG plant onshore Angola (destined to capture gas from all offshore industry projects). Present plan for the start-up date is 2007, but some slippage is deemed possible. With Block 18 first oil foreseen for 2006, the plan is to re-inject gas into the Plutonio O72 reservoir as an interim solution until the LNG outlet is available. No commitment has yet been made for the LNG scheme, nor have the commercial terms been established. Hence, no gas reserves are carried at this stage.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

SDAN, Nov 2001 **CHECKLIST SEC RESERVES AUDITS** **Attachment 3**

1.11	Are static models available / adequate?	+	Full static Depsim models have been made for the O72 and O73 reservoirs in Plutonio and for the O72 reservoir in Cobalto. Sand parameters were obtained from seismic inversion and well data. The model for the Plutonio O73 sand has detailed channel geometry with barriers thus providing an adequate assessment for reservoir connectivity. The two O72 models did not contain individual sand body and barrier geometry because these features were below seismic resolution.
1.12	Are dynamic models available / adequate?	+	SDS have developed detailed dynamic models (MoReS) for the three sands with Depsim static models. Models were constructed through downloading from Depsim, thus preserving reservoir architecture. That for the Plutonio O73 reservoir was geometrically the most complex (multiple channels). Barrier conductivity between the channels was matched from the Plutonio 2a/b appraisal well pulse test.
1.13	Are history matches available / adequate?	N.A.	
1.14	Are the recovery factors for proved reserves realistic?	O	Recovery factors are based on identified well locations and dynamic models. Reservoir connectivity issues were addressed by the detailed channel geometry with barriers in the Plutonio O73 model. RFs in the two O72 sheet sand models are based on SDS's simulation models, with results discounted by BTC established 'connectivity curves' (discount factors vs. well spacing). RFs in the three Northern fields were established from SDS P50 proved STOIIPs and P85 recovery factors from BP simulation studies. The latter do not take the same account of connectivity issues as addressed in the Plutonio and Cobalto SDS evaluations and they may therefore be somewhat optimistic.
1.15	Are developed reserves based on proper NFA (No Further Activity) forecasts?	N.A.	
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?	+	Yes, all recoveries are based on identified development well locations - 20 producers (many sub-horizontal) and 23 water injectors. Provision has been made for up to 27 additional wells, to account for well failures and incomplete reservoir sweep.
1.18	Are there auditable development project plans with costs, benefits and economics?	+	Yes, a full FDP (by BP) is available.
1.19	Are the projects technically mature or is further data gathering necessary?	+	The project is technically mature.
1.20	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	O	Water injection is required from the start of production (all fields are at or close to bubble point and aquifers are seen to be of limited strength). No water flood pilot has been carried out. However, a water flood has been underway since Dec 2001 in the neighbouring Girasol field (TFE operated, with BP participation). Cumulative water injected todate is estimated to amount to some 3-6% of subsurface STOIIP volume. Similar waterfloods in the GOM have all been quite successful. A water injection pulse test of several hours' duration has been carried out in well Plut 2A. In addition, water compatibility tests have been carried out (showing the need for sulphate reduction of the seawater) and core flooding tests tend to show low residual oil saturations. Hence, there is reasonable certainty that waterflood reserves will be realised.
1.21	Have the projects successfully passed a VAR3 review or are they otherwise ready for application for funding?	+	A VAR3 was carried out in December 2001, which endorsed progression to FEED, FDP and funding application, subject to certain recommendations being fulfilled. On the subsurface side, these included a more comprehensive assessment of the downside scenarios. The proved reserves presently proposed take account of any downside through strict adherence to 'proved area' STOIIPs and using low case RFs.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

SDAN, Nov 2001 CHECKLIST SEC RESERVES AUDITS Attachment 3

1.22	Are the projects firmly planned to go ahead - are there any potential show stoppers?	X	The project has progressed to FID and is under implementation. Commited Shell funds amount to some $1.5 bln. The intended gas injection into a downflank position of the flat Plutonio O72 reservoir may pose a potentially serious threat to oil recovery if this is continued for too long (eg due to LNG plant delays). This should be modelled more accurately to evaluate the effects.
2	COMMERCIAL MATURITY		
2.01	Are the projects economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	X	Although Shell FID was taken, the project does not fulfil Group project screening criteria. The decision to go ahead was largely taken for strategic reasons and because of the upside under higher oil price scenarios.
2.02	Have forecasts been cut off when rates become uneconomic?	+	The project forecast is cut off at minimum economic rate (zero cash flow). Individual well rates are cut of at watercuts of 80-90% when well lift starts to fail (no provision for gas lift in present plans).
2.03	Have the latest Group Screening / Reference Criteria been used?	N.A.	See 2.01
2.04	Are assumed prices and costs RT (or justified if not)?	N.A.	See 2.01
2.05	Is export infrastructure (pipelines, terminals etc) available or, if not, is it firmly planned and fully included in the economics?	+	Yes; all export infrastructure (FPSO, gas line to shore) are included in the project economics.
2.06	Is project financing available or can it reasonably be expected to be available?	+	Yes
2.07	Are developed reserves actually in production?	N.A.	
2.08	Have all proved gas reserves been contracted to sales?	N.A.	No gas reserves are carried (yet) in view of the indeterminate nature of gas disposal / export, see also 1.10.
2.09	If not, can they reasonably be expected to be sold in existing markets and through existing / firmly planned facilities?	N.A.	
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?	+	No realistic low or high STOIIP estimates were presented. Those that had been prepared were considered far too narrow by earlier peer review teams. However, the SEC 'proved area' concept has been strictly adhered to and this means that proved STOIIPs (some 51% of expectation) are in accordance with guidelines.
3.02	Is the uncertainty range of developed recovery adequate?	N.A.	
3.03	Is the uncertainty range of undeveloped recovery adequate?	O	Proved recoveries are based on (P50) estimates of 'proved' STOIIPs and P85 estimates of recovery factors. The latter are derived from suites of alternative scenario simulation models (by SDS for the Plutonio and Cobalio fields, by BP for the other fields). Earlier peer review teams considered these RF ranges too narrow. The combination results in a low Proved/Expectation reserves ratio of 45%, largely because of the 'proved area' requirement of the proved STOIIPs. A widening of the RF range is therefore not likely to have a significant effect on the proved reserves. The approach is in accordance with the guidelines.
3.04	Have market / production constraint uncertainties been taken into account?	N.A.	
3.05	What is ratio of field(s) cum.prod. / expectation total recovery?		0
3.06	Can the field(s) be considered mature?		No
3.07	Are proved (developed and total) reserves consistent with 'proved areas"?	+	Yes, fully.
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?	N.A.	
3.10	Is any assumed dependency in probabilistic addition appropriate?	N.A.	
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?	+	All proved forecasts fall within the licence period (ending in April 2027).

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

4.02	Are the forecasts required to demonstrate the above condition consistent with the firm Base Case presented in the latest Business Plan?	+	The base case BP forecasts present the expectation volumes but they are based on the same premises regarding development scenarios.
4.03	Is the hydrocarbon Equity share calculated properly (regular production contracts)?	N.A.	
4.04	Is the hydrocarbon PSC entitlement share (net cost oil + profit oil only) calculated properly?	+	PSA terms provide for 55% cost oil, 45% profit oil of which one fifth (i.e. 9% of the barrel) is Sonangol's share. After 5 years the cost oil ceiling rises to 65%. The lifetime average contractor PSA entitlement share for the present expectation forecast is thus calculated as 91.94%, out of which the Shell share is 50%, thus net 45.97% of field volumes.
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.	No royalties are payable under the Block 18 PSA contract
4.07	Are royalties paid in kind excluded from reserves?	N.A.	No royalties are payable under the Block 18 PSA contract
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.	Upon start of production (and when the gas disposal route through LNG is confirmed), provision should be made for keeping track of any re-injected gas volumes that may be still recoverable at a later stage.
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?	+	All of the present recovery estimates have been prepared during the second half of 2002.
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?	+	Yes, see Att. 2
5.04	Are reserves changes reported in the appropriate categories?	+	All changes will be in the category 'Revisions'.
5.05	Is there a document in place describing the OU's reserves reporting procedures?	O	No; The Group guidelines are used.
5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	+	A summary report is to be issued shortly describing the basis for the new reserves estimates. In addition, various detailed reports on the successive subsurface evaluations (petrophysics, static and dynamic modelling etc) are in various stages of preparation. It is recommended that the summary report will include references to all these detailed reports (even if not fully completed yet) in order to provide a clear overview of the audit trail.
5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	+	Reports will receive SIEP / SDS index numbers.
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?	+	The summary report (see 5.06) will be fully adequate to fulfil this purpose. No major changes are foreseen in the coming years, i.e. until start of development drilling. Simpler notes-for-file should then suffice.
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, no formal data base has been set up. A spreadsheet solution should be fully adequate to provide the backup for the Group share volumes submitted. Arrangements should be made by SDAN to standardise this spreadsheet as much as possible over the years and to preserve the annual copies.
5.10	Do these data bases also contain references to detailed reports?	O	No, but the annual reserves notes should.
6	CONSISTENCY WITH FINANCIAL REPORTING		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Oil shrinkage factors are based on proper simulations of anticipated surface facilities' conditions.

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SDAN, Nov 2001 **CHECKLIST SEC RESERVES AUDITS** Attachment 3

6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	No gas reserves are carried at this stage. NGL reserves are unlikely to be carried even in the future since the gas will be produced through the oil facilities and any liquids will be produced as oil.
6.03	Are own use, fuel, losses etc excluded?	N.A.	Account should be taken of future FPSO own use and compressor fuel once gas reserves are carried.
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 3598 (= 0931-Oil + 0932-NGL) for Assoc. Companies).	N.A.	Production is due to start in 2005/2006.
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.	
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.	
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.	
7	OVERALL		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	+	Proposed proved reserves are fully in line with SEC/FASB and Group requirements.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	+	The SEC/FASB requirements contain some conservative elements that do not take full account of modern data acquisition technology. As a result, these requirements may force the industry to carry initially low proved reserves for new developments which do not fully reflect confidence in the "reasonable certainty" of the project.

		Weight	Score (0-100%)
1	TECHNICAL MATURITY	33%	78%
2	COMMERCIAL MATURITY	10%	57%
3	REASONABLE CERTAINTY	14%	85%
4	GROUP SHARE CALCULATION	8%	100%
5	AUDIT TRAILS	22%	90%
6	CONSISTENCY WITH FINANCIAL REPORTING	1%	100%
7	OVERALL OPINION	11%	100%
	TOTAL SCORE	100%	84%

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