1999 GROUP RESERVES SUBMISSIONS

Attachment 3.2

GAS (10^9 sm3) All volumes net Shell Group Share

Country Name	Proved reserves 1.1.1999	Revisions and Reclassifications	Improved recovery	Extensions and Discoveries	Purchases in place	Sales in place	Production (i.e. net sales) during 1999	Proved reserves at 31.12.1999	Proved developed reserves at 1.1.1999	Transfer Undeveloped to Developed	Revisions	Production (i.e. net sales) during 1999	Proved developed reserves at 31.12.1999	Minority Reserves included 1.1.1999	Minority Reserves included 31.12.1999	Replacement Ratio (%) DevRes	Replacement Ratio (%) TotRes
Argentina	6.22	1.09	.	.	.	.	.02	7.28	.05	.07	.45	.02	.55	.	.	2486%	5176%
Bangladesh	6.74	-1.7	.	.	.	.	.33	4.71	2.81	.	.37	.33	2.85	.	.	110%	-512%
Denmark	32.81	-1.63	.06	2.42	.	.	3.22	30.44	20.93	.25	.77	3.22	18.73	.	.	32%	26%
Egypt	29.48	.71	.	2.16	.	.	1.08	31.27	7.92	6.52	.69	1.08	14.06	.	.	669%	268%
Kazakhstan - Temir	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Nigeria (SNEPCO)	7.31	-1.61	.	.	.	.	.	5.7	.	.	.	.	.	.	.		
Nigeria (SPDC)	92.06	-.98	.	5.66	.	.	.81	95.93	39.14	.	-.49	.81	37.84	.	.	-61%	579%
Oman Gisco	59.32	-12.4	.	.	.	.	1.23	45.69	.	59.32	-12.4	1.23	45.69	8.9	6.85	3606%	-1005%
Pakistan	10.17	-.29	.	1.61	.	.	.16	11.34	2.13	.	1.37	.16	3.35	.	.	868%	839%
Philippines	39.2	-.7	.	.	.	19.06		19.44	.	.	.	.	.	.	.		
Russia Sakhalin	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Chad	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Venezuela	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Congo (DR)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Abu Dhabi	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Austria	1.24	-.01	.	.42	.	.	.17	1.48	1.2	.	.41	.17	1.44	.	.	243%	243%
Australia (Direct)	174.51	4.4	.	.	.	.	2.27	176.64	37.96	.	-17.11	2.27	18.58	.	.	-755%	194%
Australia (Indirect)	55.05	-13.38	.	.	.	.	1.47	40.21	23.64	.	-14.02	1.47	8.15	.	.	-957%	-913%
Brunei	103.56	2.16	.	1.59	.	.	4.7	102.61	40.29	2.65	2.5	4.7	40.74	.	.	110%	80%
Canada	78.42	19.	.	.03	.	3.34	5.81	88.31	43.41	21.9	12.69	5.81	72.2	17.23	19.4	596%	270%
China	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Gabon	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Germany	62.34	.66	.31	1.11	.	.	5.	59.42	50.69	1.32	-.59	5.	46.42	.	.	15%	42%
Malaysia	183.03	3.98	1.75	1.61	.	.	6.55	183.82	35.93	11.2	-2.84	6.55	37.75	.	.	128%	112%
Netherlands	424.81	4.38	.	.15	.	.	15.71	413.43	221.34	3.46	2.12	15.71	211.22	.	.	36%	29%
Norway	67.01	13.41	.	11.85	.	.	2.38	89.9	53.22	.	-8.65	2.38	42.19	.	.	-364%	1062%
New Zealand	11.97	1.86	.	.	.07	.	1.26	12.65	11.03	.	1.94	1.26	11.7	.	.	154%	153%
Oman	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Shell Oil (Aera)	4.42	1.58	.	.	.	.	.47	5.53	3.05	.25	.32	.47	3.15	.	.	121%	336%
Shell Oil (Altura)	5.88	2.71	.	.	.	.09	.43	8.07	5.51	.	1.91	.43	6.99	.	.	444%	609%
Shell Oil (MCC)	2.	.09	.	.02	.	.01	.55	1.55	1.73	.06	.26	.55	1.5	.	.	58%	18%
Shell Oil (TMR)	1.28	-.09	.	.69	.	.02	.17	1.69	.99	.	.37	.17	1.19	.	.	218%	341%
Shell Oil (EH) - China	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Shell Oil (EH) - Cameroon	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Shell Oil (EH) - New Zeala	2.58	.	.	.	.	.	.27	2.31	2.28	.	.	.27	2.01	.	.	0%	0%
Shell Oil (USA) cons	118.44	1.35	.	9.3	.01	14.78	18.09	96.23	88.2	11.42	-4.74	18.09	76.79	.	.	37%	-23%
Shell Oil (USA) - Oil Shale	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Shell Oil (WH) cons	4.82	.01	.	.	.	.	.45	4.38	4.82	.	.01	.45	4.38	.	.	2%	2%
Syria	3.46	-2.16	.	.	.	.	.28	1.01	2.56	.01	-1.7	.28	.6	.	.	-600%	-769%
Thailand	6.69	-.22	.09	.06	.	.	.39	6.23	3.74	.02	-.8	.39	2.77	.	.	-148%	-18%
UK	116.44	2.88	.	.	.12	.01	9.98	109.45	67.92	7.96	1.83	9.98	67.73	.	.	88%	30%
Total Gas	1,711.07	25.11	2.2	38.68	.2	37.31	83.24 Check	1,656.72 1656.72	772.51	126.43	-36.14	83.24 Check	780.57 780.57	26.13	26.26	110%	36%

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OUVol&Chgs-Anton.xls, Gas-sm3

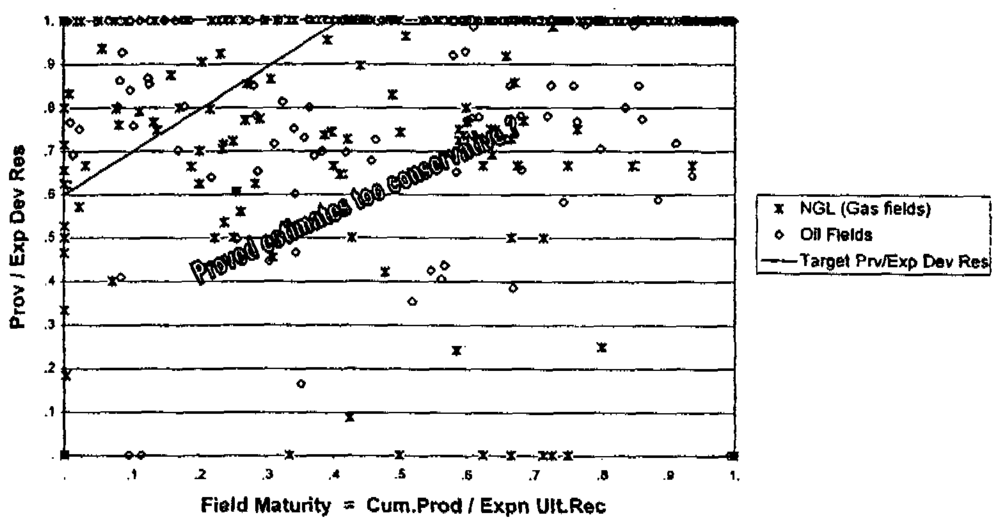
AAB 08/02/00, 14:23

DB 25130

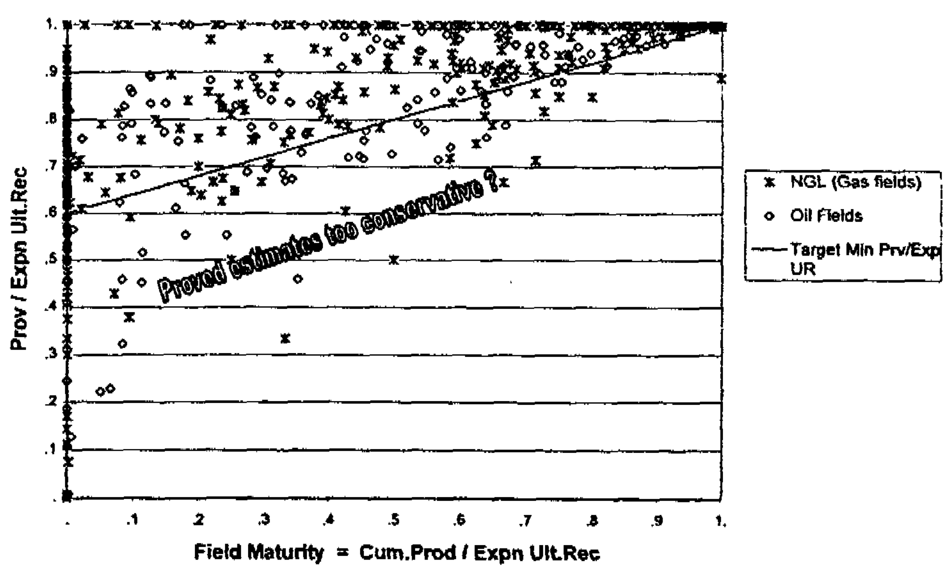
V00280138

Attachment 4.1

RATIO OF PROVED / EXPN RESERVES vs FIELD MATURITY
Developed - Oil+NGL



RATIO OF PROVED / EXP'N RESERVES vs FIELD MATURITY
Total Ultimate Recovery - Oil+NGL

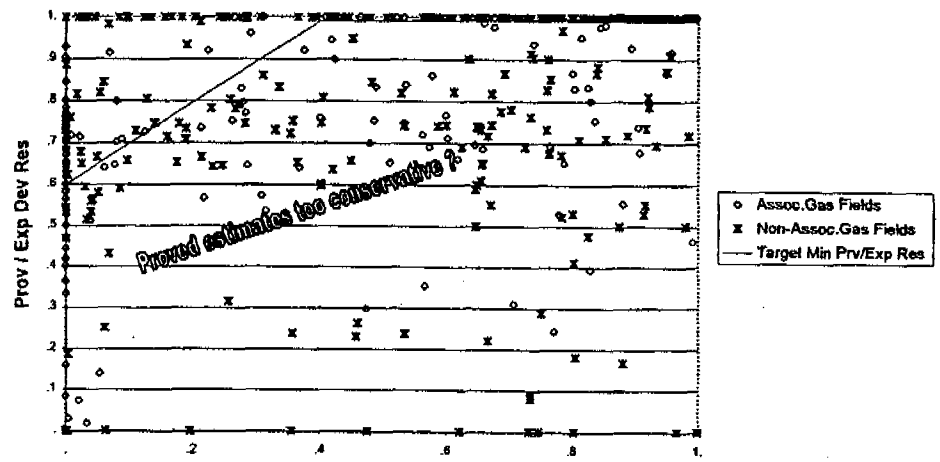


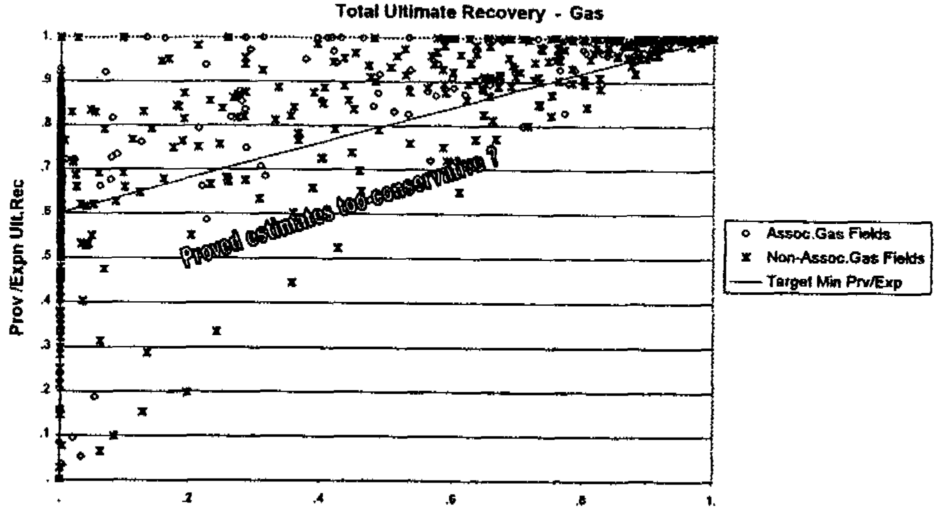
Plotted are proved reserves as a fraction of expectation reserves (vertical axis), against field maturity (horizontal axis).
Field maturity is represented by cumulative production as a fraction of expectation recovery.
Points plotting below the target line suggest a too conservative proved estimate
NB. Fields plotted in top left hand corner tend to be exceptional (e.g. too small, constrained by licence expiry etc.)

V00280139

DB 25131

Attachment 4.2





Plotted are proved reserves as a fraction of expectation reserves (vertical axis), against field maturity (horizontal axis).
Field maturity is represented by cumulative production as a fraction of expectation recovery.
Points plotting below the target line suggest a too conservative proved estimate
NB. Fields plotted in top left hand corner tend to be exceptional (e.g. too small, constrained by licence expiry etc.)

V00280140

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DB 25132

1999 PRODUCTION RECONCILIATION - OIL+ NGL

Attachment 5.1

Country	Org'l CERES mln bbl	Org'l CERES	Org'l CERES 10^6m3	Org'l Reserves	Org'l Reserves 10^6m3	Org'l diff'ce	Final CERES mln bbl	Final CERES 10^6m3	Final Resvs	Final Resvs 10^6m3	Difference 10^6m3		Comment
Argentina	1.614		0.26		0.26		1.614	0.26		0.26			OK
Denmark	43.128		6.86		6.85	-.01	43.128	6.86		6.86			Accept Ceres (SIEP will correct res. submission)
Egypt	2.353		0.37		0.37		2.353	0.37		0.37			OK
Nigeria (SPDC)	77.294		12.29		11.15	-1.14	77.294	12.29		12.29			SPDC claim Ceres figures are final. Reserves submission corrected.
Oman Glsco		0.90		0.88					0.90				Glsco claim that 0.88 is correct. Ceres not corrected; reserves submission updated.
Oman		16.46		16.37					16.46				PDO 16.37 volume excludes minor NGL production (produced in black oil stream) prior to start of Glsco contract. Reserves submission corrected.
Oman Total	109.176		17.36		17.25	-.11	109.176	17.36		17.36			
Russia Sakhalin	0.306		0.05		0.04	-.01	0.306	0.05		0.05			Accept Ceres (SIEP will correct res. submission)
Venezuela	14.932		2.37		2.37		14.932	2.37		2.37			OK
Congo (DR) Zaire	1.004		0.16		0.16		1.004	0.16		0.16			OK
Abu Dhabi	30.173		4.80		4.80		30.173	4.80		4.80			OK
Austria	0.161		0.03		0.03		0.161	0.03		0.03			OK
Australia (SDA direct)		1.98		2.68					1.97				
Australia (indirect)		0.71		1.21					0.79				
Australia Total	16.937		2.69		3.89	1.2	17.381	2.76		2.76			SDA reserves submission corrected, plus minor Ceres corrections.
Brunei	31.421		5.00		5.00		31.421	5.00		5.00			OK
Canada	22.396		3.56		4.16	.6	22.423	3.57		4.16	.59	I	Ceres updated, but still not matching. Ceres volumes exclude all royalties (cash and in kind), whilst reserves volumes include royalties in cash.
China				0.58					0.58				
Shell Oil (EH) - China				0.59					0.59				
China Total	7.329		1.17		1.17		7.329	1.17		1.17			OK
Gabon	32.571		5.18		5.19	.01	32.571	5.18		5.18			Accept Ceres (SIEP will correct res. submission)
Germany	2.086		0.33		0.33		2.086	0.33		0.33			OK
Malaysia	23.983		3.81		3.81		23.983	3.81		3.81			OK
Netherlands	4.809		0.76		0.77	.01	4.809	0.76		0.76			Accept Ceres (NAM to re-submit, together with Gas)
Norway	30.280		4.81		4.82	.01	30.280	4.81		4.81			Accept Ceres (SIEP will correct res. submission)
Syria	25.878		4.11		4.11		25.878	4.11		4.11			OK
Thailand	6.401		1.02		1.01	-.01	6.401	1.02		1.02			Accept Ceres (SIEP will correct res. submission)
UK	146.770		23.34		23.33	-.01	146.770	23.34		23.34			Accept Ceres (SIEP will correct res. submission)
New Zealand				0.45					0.44				
Shell Oil (EH) - New Zealand				0.11					0.11				
New Zealand Total	3.482		0.55		0.56	.01	3.482	0.55		0.55			Accept Ceres (SIEP will correct res. submission)
Shell Oil (Aera)		7.86		7.66					7.68				
Shell Oil (Altura)		2.64		2.64					2.64				
Shell Oil (MCC)		0.55		0.55					0.55				
Shell Oil (TMR)		0.18		0.18					0.18				
Shell Oil (USA) cons		18.32		18.20					18.21				USA cons prod'n submissions brought in line.
Shell Oil USA Total	184.682		29.36		29.23	-.13	183.911	29.24		29.24			Manually corrected
Shell Oil (WH) cons (Brazil)	0.766		0.12		0.12		0.766	0.12		0.12			OK
Shell Oil (EH) - Cameroon	8.208		1.31		1.30	-.01	8.208	1.31		1.31			Accept Ceres (SIEP will correct res. submission)
Total	828.120		131.67		132.08	0.41	827.820	131.62		132.22	0.60		

I Not reconciled or not yet closed out.

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ProdRecnci99.xls, OILShl

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DB 25133

V00280141

1999 PRODUCTION RECONCILIATION - GAS

Attachment 5.2

Country	Org'l CERES 10^9Nm3	Org'l Resvs 10^9Nm3	Org'l diff'ce	Final CERES 10^9Nm3	Final Resvs 10^9Nm3	Difference 10^9Nm3		Comment
Argentina	0.077	0.030	-.047	0.077	0.025	-0.052	1	Erroneous Ceres submission (figure of .077 is boe of 0.01178 mcm oil)? Reserves submission is production, not sales. Left unchanged due to lateness and immateriality.
Bangladesh	0.340	0.326	-.014	0.326	0.326			Bangladesh claim correction to Ceres needed; done.
Denmark	3.417	3.395	-.022	3.394	3.394			Denmark claim correct figure is 3.394 - Ceres updated.
Egypt	1.101	1.101		1.101	1.101			OK
Nigeria (SPDC)	0.844	0.959	.115	0.824	0.928	0.104	1	SPDC use 1.02 sm3/Nm3(9500) in Ceres and, correctly, 1.148 sm3/Nm3(9500) in reserves. Too late to change Ceres.
Oman Gisco	1.256	1.272	.016	1.272	1.272			Gisco claim that 1.272 is correct. Ceres updated.
Pakistan		0.136	.136	0.136	0.136			No Ceres submission by Pakistan. Now corrected.
Austria	0.184	0.181	-.003	0.164	0.164			Accept Ceres (SIEP will correct res. submission)
Australia (Direct)		2.497			2.497			
Australia (Indirect)		1.587			1.567			
Australia Total	3.617	4.084	.447	3.716	4.064	0.348	1	Difference between Ceres and Reserves due to Ceres reporting sales ex-LNG plant, i.e. excluding LNG plant fuel and losses. Correctly maintained in Reserves. Apart from minor correction, Ceres submission also unchanged.
Brunei	5.064	5.064		5.064	5.064			OK
Canada	5.714	5.626	-.088	5.714	5.604	-0.110	1	Ceres volumes are in sm3 tel quel and include all royalties (both incorrect), whilst reserves volumes are claimed to have been converted to Nm3(9500) correctly.
Germany	4.101	4.298	.197	4.101	4.298	0.197	1	Sales reported under reserves is net sales to downstream; Ceres figure is downstream sales, including storage movements etc. Both submissions maintained.
Malaysia	6.702	6.711	.009	6.702	6.702			Malaysia say that 6.711 is production, 6.702 is sales. Reserves submission corrected.
Netherlands	14.040	14.068	.028	14.040	14.040			Diference due to different GHV corrections in the two submissions. NAM has brought reserves in line with Ceres.
Norway	2.296	2.348	.052	2.348	2.348			Norway claim 2.348 is correct. Ceres updated.
New Zealand	1.130	1.130		1.130	1.130			
Shell Oil (EH) - New Zealand	0.266	0.250		0.266	0.250		1	SOC claim Ceres submission for Pecten NZ is 0.254, not 0.266. Difference claimed to be due to erroneous conversion factor (0.028738 vs 0.0283) used in SOC Finance.
Total New Zealand	1.396	1.380	-.016	1.396	1.380	-0.016		
Shell Oil (Aera)		0.450			0.446			Not corrected for 75% own use gas
Shell Oil (Altura)		0.410			0.408			Not corrected for 6% own use gas
Shell Oil (MCC)		0.520			0.520			
Shell Oil (TMR)		0.160			0.160			
Shell Oil (USA) cons		17.090			19.550		1	USA reserves submission taken as sm3 (not corrected for 1.9% own use), then converted by SIEP to Nm3 (*0.948), then GHV corrected (*1.14) to Nm3(9500).
Shell Oil Total	20.017	18.630	-1.387	20.017	21.084	1.067	1	Ceres submission includes re-purchased royalties-in-kind; off-set by reserves submission correction.
Shell Oil other WH (Brazil+7)	0.274	0.420	.146	0.274	0.420	0.146	1	Coral (Canada) 4Q correction of -0.157 made in Ceres. Should have been entered correctly under 'Canada' in Ceres?
Syria	0.286	0.284	-.002	0.286	0.286			Accept Ceres (SIEP will correct res. submission)
Thailand	0.419	0.416	-.003	0.419	0.419			Accept Ceres (SIEP will correct res. submission)
UK	8.816	9.622	.806	8.827	9.622	0.795	1	Difference (after small Ceres correction) mainly due to Kingfisher gas (produced and given as payment in kind for third party processing, hence not classed as sales in Ceres). In addition, Reserves submission has been correctly normalised to Nm3 (9500kCal/Nm3), while the Ceres submission has been (wrongly) maintained at un-normalised Nm3 (i.e. not corrected for GHV).
Total	79.941	80.311	0.370	80.198	82.677	2.479		

1 Not reconciled or not yet closed out.

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ProdRecnd99.xls, GAS Sht

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Attachment 6

1999 RESERVES AUDITS - MAIN OBSERVATIONS

Philippines: There was a possibility of a slight overstatement of proved reserves due to the non-allowance for own use, fuel and flare. The conversion of simulation models from Eclipse to MoReS was noted and commended. The use of rate dependent flowline inlet pressures (now possible in MoReS) was recommended. This could lead to a small increase in reserves, offsetting the allowance for fuel and flare. Audit opinion was **good**. It was noted that own use, fuel and flare had been properly accounted for in the 1999 submission.

Oman: The generally conservative nature of individual fields' proved and proved developed reserves estimates was noted. However, any scope for increase in proved reserves was offset by the fact that the expiration of the production licence in 2012 had not been properly accounted for. The net result was that reported Proved Developed entitlements were likely to be some 15% overstated, whilst the Total Proved entitlement reserves were probably of the right magnitude. Reserves reporting procedures and audit trail were excellent. Overall, in view of the exemplary standard of field study work and procedures, the audit opinion was therefore **good**. A proper correction for developed reserves was made in the 1999 submission.

Venezuela: Commendation was made of the extensive study work that had provided a much sounder basis for the new reserves estimates. It was noted that SVSA had booked 100% of field volumes, whilst their present reward fee equated to only some 50% of crude market value. This matter was not fully addressed in the SIEP reserves guidelines. Reserves reporting procedures and audit trail were good. Audit opinion was **good**. In view of higher future reward fees, a decision has been made to maintain the reserves submission at 100%.

SNEPCO: Commendation was made of the extensive modelling work (both static and dynamic) which had included a wide range of alternative reservoir and development realisations. It was noted that reservoir volumes within sub-groups in the field were added statistically in a fully independent mode. This assumption may not be fully appropriate and may have led to a too narrow range between Proved and Expectation volumes. Audit opinion was **satisfactory**. An appropriate correction was made in the 1999 submission.

Egypt: Commendation was made of the good use of electronic spreadsheets to preserve quality and audit trail of the reserves estimates. There was a lack of consistency between annual production figures in Finance (Ceres) submissions and reserves submissions. Further comments were made regarding the future fuel gas allowance in Badr-el-Din and the possibility for probabilistic addition of reserves in Rosetta. Audit opinion was **satisfactory**. Correspondence between Ceres and reserves submissions was perfect this year.

Thailand: The new 1998 reserves guidelines had been fully implemented, particularly by equating the proved developed reserves estimates in the S1 concession to the expectation developed volumes. It was noted that the proved undeveloped reserves estimates were originally based on arbitrary assumptions but that these had been made the subject of considerable ongoing study work. Maintaining the present estimates was supported until that work would have been completed. Audit opinion was **satisfactory**.

SPDC: The new SPDC corporate PE Group should be tasked with the production of a comprehensive and consistent annual audit trail note to avoid continuing unanswered questions about the basis of SPDC's reserves submission. The considerable scope for increasing SEC proved reserves in the fields is overshadowed by the aspirational assumption of a doubling of Nigerian production levels in the coming decade, prior to licence expiry in 2019. Correct end-of-licence cut-off dates should be applied to production forecasts to establish equity reserves. Audit opinion was **satisfactory**. Appropriate capping of reserves additions, to reflect the end-of licence and production constraint, has been applied in the 1999 submission.

Argentina: Reserves reporting procedures, although in place, were in the process of being re-defined following the recent divestment of assets and the acquisition in 1998 of shares in some gas properties with both discovered and undiscovered gas. It was noted that proved reserves were booked prematurely in one field, which was offset by an unnecessarily conservative booking in another field. Further comments were made regarding the scope for improvement in the reserves audit trails, for which internal guidelines are still under development. Audit opinion was **satisfactory**. Appropriate corrections were made in the 1999 submission.

Abu Dhabi: The Proved Developed reserves estimate submitted by SAD was queried. Because the operator, ADCO, did not customarily produce proper 'no further activities' forecasts, SAD had in first instance assumed a combined fields' production level of up to 1 MMstb/d over the period 1999-2014. At the time of the audit, hardly any data was available to support this figure. Forecast data provided subsequent to the audit did lend some support for this assumption, although it was the auditor's opinion that the implied watercut development is possibly too optimistic. Audit opinion was **satisfactory**. Subsequent, more refined forecast studies by ADCO have shown higher availabilities in early years, leading to an increase in proved developed reserves per 1.1.2000.

V00280143

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TIME TABLE SEC RESERVES AUDITS

Attachment 7

COUNTRY	Size*	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Comments
ABU DHABI	L			X				X				In The Hague (EPT-AM)
NIGERIA -SPDC	L	X				X		X				Combined with SNEPCO
OMAN	L			X				X				
VENEZUELA	M				$			X				Combined with Argentina
EGYPT	M		X					X				
NIGERIA - SNEPCO	M					$		X				Combined with SPDC
PHILIPPINES	M					$		X				Combined with Thailand
THAILAND	M		X					X				Combined with Philippines
ARGENTINA	S			X				X				Combined with Venezuela
AUSTRALIA	L				X				P			
NORWAY	L				X				P			
USA	L								P			
GABON	M			X					P			
BANGLADESH	S					$			P1			
RUSSIA - SAKHALIN	S					$			P1			In The Hague
NETH. NAM	L	X				X				P		
UK	L			X		X				P		
SYRIA	M	X			X					P		
AUSTRIA	S			X						P		
CHINA	S		$							P1		
BRUNEI	L		X				X				P	
MALAYSIA	L		X				X				P	
DENMARK	M	X				X					P	
GERMANY	M	X				X					P	
NEW ZEALAND	S				X						P	
NAMIBIA	M										P1?	
RUSSIA - SALYM	M										P1?	
KAZAKHSTAN-TEMIR	S							$			P1?	
KAZAKHSTAN-OKIOC	S										P1?	
CHAD	S			X								No proved reserves since 1999
COLOMBIA	-		X									Hocol/Homcol interest sold 1997
PERU	M											Camisea venture abandoned 1999
CANADA	L											No direct involvement
PAKISTAN	S					$						To be divested?
ZAIRE	S		X									To be sold during 2000
total nr. of audits		5	6	7	4	5	2	9	7	6	6	

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

* S = < 20 mln m3oe
M = 20-100 mln m3oe
L = > 100 mln m3oe

AudSch99Note.xls

2000 Programme

Date	Country
March 27-30	Gabon
April 17-20	Bangladesh
June 5/13	Norway
Aug	Russia-Sakhalin
Sept 18/25	Australia
Nov	USA

Consideration:

2-4 yrs after first submission,
depending on size of company.

Audit frequency;

Large OUs once every 4 years,
Medium OUs every 5 years,
Small OUs every 6 years,

unless recommended otherwise
in auditor reports etc,

or when combinable with other audits.

08/02/00

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Treatment Requested

DB 25136

V00280144

NOTE – 31 January 2003 CONFIDENTIAL

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP EPB-GRA
To:	Frank Coopman	Chief Finance Officer, SIEP EPF
	Lorin Brass	Director, EP Business Development, SIEP EPB
Copy:	Walter van de Vijver	EP Chief Executive Officer, SIEP
	Excom Members	SIEP EPA, EPB-X, EPG, EPM, EPN, EPT, EP-HR
	Malcolm Harper	Vice Pres. Strategy, Planning, Portfolio and Economics, SIEP EPB-P
	Han van Delden	Partner, KPMG Accountants NV
	Brian Puffer	PriceWaterhouseCoopers

REVIEW OF GROUP END-2002 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

In accordance with prescribed US FASB accounting principles, SIEP staff have prepared a summary of Group equity proved and proved developed oil and gas reserves for the year 2002. The summary (Att. 3) forms part of the supplementary information that will be presented in the 2002 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 Group 'Petroleum Resource Volumes Guidelines' which in turn are based on (but not fully identical to) the FASB definitions. Shell Canada's submissions are subject to their own procedures and reviews.

The end-2002 Group share Proved Reserves is summarised in the following table. The figures include the Canadian oil sands reserves (reportable as mining reserves) and the minority reserves in some consolidated companies (together 150 mln m3oe*).

Oil mln m3 Gas bln m3	1.1.2002 Proved Tot'l	2002 Prod'n	1.1.2003 Proved Tot'l	Repl.Ratio (RR) Tot'l	1.1.2002 Proved Dev'd	1.1.2003 Proved Dev'd	Rep. Ratio Dev'd
Oil+NGL	1,601	138	1,707	177%	689	831	203%
Gas	1,580	97	1,513	30%	729	696	67%
Total Oil Equivalent *	3,132	232	3,172	117%	1,394	1,505	148%

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

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 appropriateness of major reserves changes.

The most significant comment is that serious efforts have been made during 2002 towards further alignment of Group Proved reserves with SEC and Group reserves guidelines. Examples of these are the positive reserves revisions by BSP and SDAN, the negative revisions by SNEPCO and the corrections applied to ex-Enterprise reserves in the UK and Norway.

In spite of these significant efforts, there are a number of smaller items in the Group Proved reserves portfolio that are not (or not fully) supported by the present SEC or Group reserves guidelines. These include:

Russia (KMOC):	7.6 mln m3oe	'East Bank' fields are not economic and lack clear development funding sources.
Italy (Tempa Rossa):	3.9 mln m3oe	Phase 1 development is not yet mature (although FID is intended for 2003).
NAM (Waddenzee):	4.0 mln m3oe	Government moratorium on drilling is not likely to be lifted soon, if at all.
Oman (PDO):	10 mln m3oe	Proved forecast within-licence is unrealistic.
Kazakhstan:	5.6 mln m3oe	Best estimates of start-up and end-of-licence dates allow less volume produced.

If added together, these potential exposures would amount to 31 mln m3oe, or 1% of the Group Proved reserves portfolio.

Most of these items relate to new items that were either not carried or not known about last year. Only NAM's Waddenzee reserves were already recognised as a potential exposure before. In addition, it was found that SPDC Proved reserves had been significantly (some 100 mln m3oe) in excess of the production that could realistically be produced within the hitherto assumed licence duration. This historical overbooking has now been removed by the recent recognition that SPDC do possess a right to have the production licences extended upon their expiry in 2008 / 2019.

In previous years it was argued that any possible overstatements could be offset by possible understatements in areas like Brunei (BSP), but these understatements have now largely disappeared. Developments regarding the conditions surrounding these exposures should be closely followed in 2003 and their position should be reviewed if no material change is observed.

The presence of reserves addition targets in OU and departmental scorecards will require continued vigilance to preserve the integrity of reserves bookings. Suggestions are made to help tighten control in this respect.

During 2002 I made Reserves Audit visits to a total of nine Group OUs. Audit opinions on these varied between 'satisfactory' and 'good'. As far as observable, audit recommendations appear to have generally been followed in this year's submissions. In addition, reserves audits were made of all ex-Enterprise Oil assets. With some exceptions of premature bookings, the reported reserves were found to be in reasonable agreement with Group guidelines.

The overall finding from the audit visits and from the end-year review in SIEP is that there is a possibility of an overstatement of Group Proved reserves in cases where booked reserves are not fully in accordance with SEC or Group guidelines. The 2002 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.

A.A. Barendregt

DEPOSITION EXHIBIT 7
Barendregt
#16 2/20/07

Attachments 1-7

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Attachment 1 Main Observations End-2002 Reserves

Attachment 2 Significant Reserves Changes

Attachment 3 Group Proved Reserves Summaries

Attachment 4 Production Reconciliation Ceres vs. Reserves Submissions

Attachment 5 Proved Reserves Maturity – by OU

Attachment 6 Main Observations 2002 Reserves Audits

Attachment 7 Reserves Audit Plan 2003

Attachment 1

REVIEW OF GROUP END-2002 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

MAIN OBSERVATIONS

1. **Reserves Summary**

The 1.1.2003 Group share Proved Reserves can be summarised as follows:

Oil mln m3 Gas bln m3	1.1.2002 Proved Tot'l	2002 Prod'n	1.1.2003 Proved Tot'l	Repl.Ratio Total	1.1.2002 Proved Dev'd	1.1.2003 Proved Dev'd	Repl.Ratio Dev'd
Oil+NGL	1,601	138	1,707	177%	689	831	203%
Gas	1,580	97	1,513	30%	729	696	67%
Total Oil Equivalent*	3,132	232	3,172	117%	1,394	1,505	148%
Canada Oil sands	95		95				
Minority reserves	56		53				
Net Group m3oe	2,980		3,023				

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

The Replacement Ratios mentioned above are with respect to total Group reserves, i.e. including the Canadian oil sands and Minority reserves. They include the acquisition of Enterprise Oil assets per 1.4.2002.

A full overview of end-2002 Proved and Proved Developed Reserves is presented in Attachment 3.1-2.

2. **Significant reserves changes**

A summary of major changes is given in Attachment 2, while a full list by OUs is available in Att 3.1-2.

The most significant change was the acquisition of all Enterprise Oil assets worldwide (UK, Norway, Italy, Russia, Ireland, Brazil, USA). This added 136 mln m3 oil+NGL reserves and 32 bln sm3 gas reserves (total 167 mln m3oe or 1052 MMboe).

Field reviews, new well results and positive field performance in the USA led to major increases in the Mars, Pinedale, Holstein, Mensa, Princess and Ursa fields in the USA. The most significant of these was the booking of 8 mln sm3 of water flood reserves following FID of the Mars water injection project. Brief summaries of the reasons for these revisions have been obtained from SEPCo and the reserves changes could be fully supported. Increases were also booked in the Belridge heavy oil field in California, where the operator (Aera) was able to provide documented support for their future well production projections (see Aera reserves audit, Att.7).

Significant contributions were also made by BSP in Brunei, where less conservative methods of estimating Proved developed and undeveloped reserves have been agreed with the authorities. This action was strongly supported by the 2002 reserves audit.

Field and performance reviews in the UK and Denmark led to sizeable increases. Further contributions were made in Denmark by a revision in their 'growth to Expectation' procedure, allowing a more pronounced increase of Proved reserves with progressing field maturity (a 2001 audit recommendation).

An oil viscosity analysis and review in Sakhalin field (following more representative sampling) has led to the conclusion that reservoir oil viscosity was significantly lower and that larger recoveries could be expected than previously anticipated by the old Marathon simulation model. Further positive revisions could be made based on the higher oil price PSV and the inclusion of (cash paid) royalties in reserves.

A declaration of commerciality was made for the large Kashagan field in Kazakhstan, as a result of which some 60 mln m3 of Proved oil reserves have been declared, representing the Group share in a first phase 'experimental programme' development (see also below).

Development activities have led to significant increases in developed reserves in Canada (oil sands, see also below), USA, UK, Nigeria, Netherlands and Malaysia, Denmark and Oman.

Field analysis and review led to reserves reductions in the Pohokura field in New Zealand. Mapping uncertainties and the recognition that condensate dropout may have a significant negative effect on recovery has led to reserves being halved in this (partly ex-FCE) field.

Technical and economic reviews of ongoing and future waterflood projects in the Sirikit field lead to reserves reductions in Thailand.

Stricter application of SEC guidelines and a consequent revision of Group guidelines has led SNEPCo (Nigeria) to review Proved reserves assessments in a number of unappraised areas in the Bonga and Erha fields. The resulting reductions were supported by a reserves audit in September 2002.

Economic revisions led to significantly reduced Shell entitlement shares in the Malaysian gas contracts as a result of lower demand, lower cost projections and higher PSV oil prices.

Additional leases were acquired in the large Pinedale gas field in the USA. Divestments and portfolio dilutions were made in Congo (DR), Iran and New Zealand.

Although technical details were not available for the majority of the above changes, most appear reasonable and there seems to be no reason not to support them. Specific comments on some of these changes are however made below.

3. **Shell Canada's Athabasca Oil Sands**

Shell Canada's Athabasca Oil Sands Project (AOSP) is nearing completion. With less than 10% of the project capex outstanding and most wells drilled, Shell Canada have declared the project reserves as developed this year. However, the 95 mln m3 oil volumes from the project are considered to be mining reserves and not oil reserves by the US Securities and Exchange Commission (SEC). Hence, they will be excluded from the Group's submission of Proved oil and gas reserves to the SEC and this will be highlighted in the Group Annual Report.

4. **Enterprise Oil assets**

At the request of EPF, reserves audits were made of the assets included in the Enterprise acquisition in April 2002 (see summary in Att. 6). The audits found that the reserves volumes carried by EO could largely be confirmed with the following exceptions:

Enterprise Oil's bookings of Proved developed reserves did not seem to have received proper care and attention, as shown by a number of improper bookings in cases where development had either not been completed or not even been started (UK, Norway). Appropriate corrections have been made to Shell's end 2002 developed reserves bookings where needed.

Some of Enterprise's undeveloped reserves bookings were found to be premature and not in accordance with guidelines. Fields concerned are in:
- Norway, where a commercially viable gas export route is yet to be established for the Skarv and Idun fields.
- Italy, where the Tempa Rossa project is still poorly defined and faces significant commercial challenge,
- Russia (KMOC), where a funding shortage makes development of the sub-economic 'East Bank' fields uncertain.

For all of these fields the audits noted that, if these had been Shell operated fields, Shell guidelines would not have allowed booking of reserves. It is acknowledged that the KMOC Proved reserves are based on a Ryder-Scott SEC evaluation for these fields but it is the auditor's opinion that the authors have accepted the operator's assurance of 'reasonable certainty' of development without sufficient supporting evidence. The recommendation was therefore made not to book the associated reserves at end 2002.

SIEP have concurred with deferring the booking of the Skarv & Idun reserves and of the 50% of the Tempa Rossa volumes that were contingent on successful appraisal. Project maturity will be reviewed in future and bookings will be made only when 'reasonable certainty' of development has been assured. The Tempa Rossa Phase I booking, which is being maintained, will be reviewed again at end 2003 and the reserves will be de-booked if FID has not been taken in 2003 and is not likely to be taken in 2004 either. The Russian bookings have been maintained in full, pending the outcome of a strategic review of this participation.

The exposed volumes remaining booked amount to 11.5 mln m3oe (3.9 mln m3oe in Tempa Rossa and 7.6 mln m3oe in the KMOC fields).

5. **Kazakhstan – Kashagan field**

A Declaration of Commerciality was made in June 2002 by the consortium in charge of the large Kashagan field offshore Kazakhstan in the northern Caspian Sea. A full field development plan for the first phase of development (or 'Experimental Programme') has been submitted to the Kazakh authorities in December 2002. These actions imply a commitment to development making the latter 'reasonably certain' and they are therefore a sufficient reason to book reserves.

An important issue regarding the booking of Proved reserves in Kashagan is that the field is large (some 20 x 80 km2) and that the present four appraisal wells on the field are some 8 km apart. SEC conditions require the 'certainty' (not just 'reasonable certainty') of continuity of producibility in the field, before Proved volumes can be carried for the large unpenetrated areas between the existing wells. This would need to be shown by proof of pressure or fluid communication between wells. Well correlation and/or seismic evidence alone is not sufficient. This condition is seen as extremely onerous in large flat fields of the type of Kashagan. Group guidelines are less strict and tend to align more with SPE guidelines, requiring only 'reasonable certainty' that the areas between the wells are productive.

Group guidelines also allow the use of proven analogue fields and this is available in the form of the nearby (and geologically similar) Tengiz field, which has been in production for some 11 years and which has similar or poorer characteristics than Kashagan. In this field, long term production has shown well drainage radii of 1 km or more, i.e. approaching the intended primary development well distance of 2km. On the basis of this evidence (well documented by SKD), and bearing in mind the Group and SPE guidelines, it is concluded that carrying Proved Reserves beyond existing tested well drainage radii in the Kashagan field is reasonable.

The Group share volume carried for Kashagan is 380 MMstb (60 mln m3), based on the operator (ENI) estimate of 3.2 MMMstb producible through natural depletion from 42 +32 wells to be drilled in the 'Experimental Programme' area. Pressure maintenance through miscible gas injection will be tested in this area as well, but the associated volumes of this unproven process have (correctly) not been included in Proved reserves.

The volume of 380 MMstb (3.2 MMMstb full field) is seen by the operator as producible between start of production in 2006 and the assumed end-of-licence in 2043. Current Shell best estimates and interpretations are a start-up date of 2007 and an end-of-licence in 2041. The latter would bring producible within-licence volumes down from 380 to 345 MMstb, a difference of 35 MMstb (5.6 mln m3). The decision has been taken to maintain the (rather approximate) operator figure for the time being until more precise estimates are available, to which the then prevailing view (or evidence) as to start-up date and end-of-licence should be applied. This approach can be accepted as an interim measure. A SEC reserves audit will be carried out in 2003.

6. **SNEPCO fields**

During the end-2001 reserves submission process it was thought possible that some of the previous Proved reserves bookings by SNEPCO were no longer in accordance with the tightened Group guidelines regarding Proved reserves.

These had to be based exclusively on 'proved areas', i.e. areas with hydrocarbons proven by well penetrations. Early in 2002, SNEPCO commissioned SDS in Houston to carry out a review of proved reserves in their fields, paying particular attention to the new guidelines. The result was a 130 MMboe (20 mln m3oe) reduction in Proved reserves in the Bonga, Erha and Abo fields. These reductions and the new reserves volumes were supported during an audit in September 2002.

The audit also concluded that booking of Bonga SW reserves (rejected by SIEP last year) was still too premature in view of the continuing unresolved unitisation issue and the present marginal economics of the field.

7. **'Reasonable certainty' of development**

During 2001 the SEC re-clarified their interpretation of the FASB rules regarding the booking of Proved reserves (Refs. 4, 5). One of the stipulations was that Proved reserves could only be booked for projects whose development was not subject to 'reasonable doubt'. This excluded projects that still faced technical or commercial 'show stoppers'. Four projects were identified with such potential show stoppers and with Proved reserves already carried pre-2001in the Group portfolio: The Angola Block 18 project, the Ormen Lange gas discovery in Norway, the giant Gorgon gas field offshore NW Australia and the Waddenzee gas reserves in the Netherlands.

The Angola Block 18 project, although not fully meeting Group economic screening criteria, received project sanction (FID) in 2002 and development is now ongoing. Booking of Proved reserves (120 MMboe or 19 mln m3oe) is therefore now fully justified. Proved volumes are still low in comparison with Expectation volumes due to a number of areas still requiring confirmation of 'proved oil' through appraisal / development drilling.

The Ormen Lange gas discovery was situated below a continental shelf escarpment that was known to have been the source of a major sub-sea slump and tidal wave in the North Sea some 8000 years ago. This risk, if still present, could jeopardise the chances of a field development being undertaken. In the course of the last two years Norske Shell have spent major efforts and funds, involving universities and institutes in Norway and worldwide, to assess the danger of such a slump re-occurring. The unequivocal conclusion has been that the sands below the escarpment have been compacted to an extent whereby the risk of a future slump could be effectively ruled out. Thus, project development is now more than 'reasonably certain'. While a 50% discounted project volume was carried to date, it is expected that full project reserves will be booked next year, once the commercial framework for Ormen Lange gas sales has been established.

The Gorgon gas field is a major gas resource (currently booked at a conservative 570 MMboe or 90 mln m3oe Proved volume) whose size and relatively remote location have thus far prevented it from being developed. There are economic synergy development options with the present WPL operated LNG venture, but different ownerships have prevented an understanding to be reached. Even so, independent economic development scenarios have been formulated (either floating LNG or a dedicated on-shore plant), but such a project would need a sizeable opening in the Pacific Rim gas market, which is not likely to occur before 2010. There can be little doubt that Gorgon will be developed at some stage (i.e. development is 'reasonably certain'), but the timing of development is still in question. However, since there are no clear 'show stoppers' there seems to be insufficient reason to de-book the (partly discounted) reserves already carried.

NAM's Waddenzee fields (Proved volumes some 4 mln m3oe) are still facing a drilling and development moratorium by the Netherlands government until it can be demonstrated 'with certainty' (and publicly accepted) that there will be no damage to this ecologically sensitive area. This proof will be challenging to give and even more challenging to become accepted. However, public and government opinion are evolving and there are those that hold the view that these fields will, with time, become developed. The Group's exploration and pre-development costs for these fields have been written down in 2000. It is the auditor's opinion, taking note of the 2001 clarifications by the SEC requiring 'reasonable certainty', that reserves should be de-booked or at the very least be reviewed closely each year.

8. **Production licence duration constraints**

Externally reported Proved and Proved Developed Reserves need to be restricted to those volumes producible within the duration of current production licences and their extensions (if there are rights to extend). In addition, many OUs are constrained to maximum offtake rates set either by the authorities (e.g. OPEC restrictions), by contractual terms or by their own export facilities. If the total volume of the OU's recoverable reserves exceeds the 'box' of offtake and licence duration restrictions it will be difficult to book additional Proved reserves even if additional resources are found. OUs most affected by this are SPDC (Nigeria), Shell Abu Dhabi and PDO (Oman). Other OUs that see some of their resource volumes as non-producible within licence durations are Malaysia, Syria, Denmark and Venezuela. At present, some 1600 mln m3oe (45% of the Group's Expectation within-licence Reserves portfolio) is reported by OUs as being non-producible within existing licences. Similar beyond-licence volumes can be estimated for Proved reserves, i.e. the amounts by which Proved reserves would rise if there were no licence duration restrictions. OUs have been asked to provide this data also for Proved reserves but the submitted estimates for Proved reserves seem somewhat erratic (e.g. large variations from last year' submissions). This should be challenged with the OUs and rectified.

For a proper estimation of Proved reserves (which have to fulfil the criterion of 'reasonable certainty') it is important that OUs with large resources and faced with the above constraints make realistic assumptions regarding their future production profiles. The selected build-up and plateau levels should be in line with base case Business Plan assumptions. In addition, post-plateau tail-end profiles should be technically defensible. Shell Abu Dhabi, PDO and SPDC were asked to provide details of their assumed Business Plan and Proved forecasts in order to allow an assessment of the defensibility of the latter.

Abu Dhabi provided full details and showed that the Proved forecast was fully consistent with their latest BP, with the end-of-licence date in 2014 and with submitted Proved reserves.

PDO did not provide a clear answer to the query. Comparison of their stated Proved oil reserves volume against their latest Business Plan forecast showed that the Proved volume seems unrealistically high. The Proved developed volume has been set equal to the Expectation developed volume and this is reasonable for a mature area like Oman. However, the Proved undeveloped volumes which have been kept largely unchanged for the last few years in spite of production disappointments, have now become very close to the reduced Expectation (within licence) undeveloped volumes, with a Proved / Expectation ratio of 92%. This ratio seems too high when account is taken of the preliminary nature of some of the recently postulated projects, which make up the Expectation case. These projects include infill drilling, water- and gas injection and new EOR projects. Since at least some of these projects must at this stage still be considered un-proved, it is likely that PDO's Proved reserves are overbooked. A Proved estimate with an undeveloped P/E ratio of some 80% would seem more realistic and this should be reviewed.

The above would suggest that the amount of PDO's Proved reserves overbooking might be some (92-80)% of 550 MMboe unproved Expectation reserves, i.e. some 65 MMboe (10 mln m3oe). The resulting Proved reserves of some 840 MMboe (134 mln m3oe) would still be slightly in excess of the present 'Tranche 1' (Mature Projects) forecast from the 2002 Business Plan (820 MMboe or 130 mln m3oe).

SPDC did not provide any answer to the query at all. Calculation of their Proved Reserves / Annual Production ratio for oil and gas yields time spans of 32-34 years (see Att. 3). Since only 16½ years remain until the end of the majority of the current production licences (July 2019), this implies assumed average offtake rates that are double those of the current rate in the remaining licence period. In view of present OPEC constraints this seems highly unrealistic for the oil volumes. For the gas, where additional LNG plants are presently under construction, this would at least be highly challenging. It is noted that last year's data from SPDC already suggested that assumed Proved reserves forecasts were well in excess of their Business Plan. Because of lack of time, this could not be pursued further during last year's reserves submission and accumulation process.

The indications are therefore that the SPDC Proved reserves during recent years have been over-estimated in relation to then current licence duration assumptions. The magnitude of this over-estimation is difficult to assess but a conservative estimate, assuming an average rate that is 60% above the present rate (or an R/P ratio of some 26 years) would suggest a Proved reserves volume that is some 20%, or 600 MMboe (100 mln m3oe) smaller than the presently booked value.

The reason that such Proved reserves overbookings have arisen is that both OUs had at one stage Proved forecast assumptions that were highly ambitious, i.e. a continued plateau rate of 850,000 b/d in PDO and an aggressive rate increase in SPDC. When these assumptions turned out to be unfounded by subsequent disappointments (decline in PDO, stagnation in SPDC), both OUs failed to recognise (or chose to ignore) the full extent of the negative effects that this would have on bookable Proved reserves. Although PDO did make a -5 mln m3oe correction this year, this has not been sufficient. The challenges by the reserves auditor at end 2002 remained essentially unanswered.

The above suggests a breach of Proved reserves guidelines by PDO and, more seriously, by SPDC. However, their effects on current Group reserves may be mitigated by the fact that the present licence duration constraints may not apply for much longer. PDO will be entering shortly into discussions with the Omani government regarding an extension of the PDO licences beyond 2012. More significantly, SPDC have recently taken legal advice, which clearly indicates that Nigerian law does provide for a right to extend 'mining licences' at expiry "if the lessee has paid all rent and royalties due and has otherwise performed all his obligations under the lease". This will now allow the presently carried volumes to be maintained and possibly even to be expanded. However, it will not relieve either OU of the requirement to provide defensible and realistic composite Proved and Expectation forecasts for their hydrocarbon assets.

Both SPDC and PDO will be the subject of Proved reserves audits this year. The subjects of licence durations and that of realistic forecasting within the licence period will be addressed closely.

Finally, it is noted that, at present, the Group reserves guidelines (Ref. 3) do not provide any guidance about what assumptions to take for future forecasts in these cases, in spite of a recommendation by this auditor last year. This should be rectified.

9. **PSC Reserves**

Entitlement volumes that are bookable as Group share Proved reserves under more modern style government contracts (PSCs, PSAs, Revenue Sharing Contracts etc) are generally inversely dependent on the prevailing oil price. SEC/FASB guidance states clearly that end-year oil prices must be assumed for calculating future entitlement volumes and thus bookable Proved reserves. The Brent oil price at 31 Dec 2002 was 28.66 $/bl.

With the introduction of project based reserves by the Group in 1993 (Ref. 6) undeveloped reserves and their projects had to fulfil Group economic screening criteria, which included a conservative flat rate price assumption. This requirement was introduced to ensure that booked undeveloped reserves had a sound commercial basis. PSC projects had to be evaluated in a similar manner and this meant that their 'Proved' project economics were conservative, but that entitlement volumes were inflated. The current project screening value (PSV) for the oil price is 16 $/bl (Brent). The fact that this PSV is lower than the current end-year oil price means in principle that booked PSC Proved reserves have been overstated in comparison with SEC guidelines.

SIEP have evaluated this oil price effect on PSC reserves in the end-2002 Group portfolio and have concluded that, for the end-year price of 28.66 $/bl, the potential overstatement would amount to 296 MMboe (47 mln m3oe). The OUs most affected are Gisco (Oman), SEBV (Iran) and Malaysia – together accounting for 65% of this volume. Affected to a lesser extent are Egypt, Syria, SNEPCO (Nigeria), SKD (Kazakhstan) and SPEX (Philippines).

The effect of this overstatement of PSC reserves (in relation to SEC/FASB guidelines) is compensated by the conservative effect that the low PSV screening prices have on booked reserves in other areas. Some OUs (NAM, Thailand) have identified projects that are not economic at present PSVs but which would be undertaken if PSV prices were closer to actual oil prices. In addition, lower economic rate limits would mean longer economic life and higher produced volumes in many fields. There are also some tax and royalty entitlements that are presently excluded from PSC entitlements (e.g. Egypt), but which, at closer inspection, could be included. An evaluation among OUs at end 2000 showed that the understatement effects brought significant, but not full compensation of the overstatement effects. It is recommended that this evaluation be repeated at regular (bi- or tri-yearly) intervals. It is accepted that a proper evaluation may require some effort from the OUs concerned, but it is important that the present Group practice can stand up to challenge.

10. **Group Guidelines – mature fields**

In 1998, a revision was made to the Group guidelines for mature fields, requiring Proved and Proved developed reserves to align more closely with Expectation reserves, in line with prevailing industry practice. The Proved / Expectation reserves ratios shown in Attachment 5 show that most OUs adhere reasonably well to these guidelines, particularly for developed reserves. Good progress in this direction was made by BSP (Brunei) this year, following a SEC Reserves audit early in 2002. Reserves audits in other OUs with relatively low P/E reserves ratios have confirmed that there are generally good reasons for these low values. An example is SEPCo (USA) where proved reserves are held back because of strict adherence to the SEC 'proved area' concept in fields with low well density. The low P/E ratio for BEB Germany (ExxonMobil) is due to unjustifiably high levels of Expectation reserves.

11. **Group Guidelines – first time booking of new fields**

In last year's report it was observed that the introduction of reserves booking targets in OU score cards (see also below) did encourage some OUs to attempt booking Proved reserves in too early stages of project maturation. Following the clarification of SEC guidelines in 2001 (requiring 'reasonable certainty' of development) the Group reserves guidelines have set minimum requirements for booking new project Proved and Expectation reserves. For all major projects this would have to be the passing of a VAR3 (development concept selection) review, while for major projects needing maturation of a new gas market the taking of FID would be required.

In the auditor's opinion, the passing of a VAR3 review is too 'soft' a hurdle. An important reason is that VAR teams are rarely asked to make a clear statement whether the VAR was good, satisfactory or unsatisfactory. As a result of this hurdle 'softness' there is often a debate whether reserves can or cannot be booked (score cards being a strong motivator).

The auditor recommendation is therefore to strengthen the condition for booking Proved reserves for new major projects to either the passing of FID or to another strong public commitment by the OU (e.g. a binding declaration of commerciality to the authorities), which confirms that development is likely to go ahead. This would bring the Group guidelines in full accordance with the SEC 2001 clarifications. It is the auditor's understanding that such a move would have the support from SIEP EPB-P HC Resource Coordination.

12. **Reserves Addition targets in Score Cards and Reserves Management**

Group Proved Reserves receive increasingly close attention by Group Management. Reserves addition targets are set annually, both to OUs and to SIEP Directorates and these are reflected in individual and collective score cards affecting variable pay and bonuses of staff involved. This variable pay and management pressure may pose a threat to the objectivity of OU staff responsible for reserves estimating and booking. SPE guidelines specifically reject such dependence of staff rewards to reserves booked.

Following concern expressed by the auditor in the end-2001 reserves audit report SIEP have considered removing reserves addition targets from OU score cards, but this was rejected by ExCom members, who see these targets as essential in providing business focus to OUs. The reserves targets were therefore maintained, pending further review.

It is accepted by the auditor that score card targets are useful as powerful motivators for OUs and staff. However, it is the auditor's firmly held belief that the reserves addition targets in these score cards present a potential threat to the integrity of the Group's reserves estimates. The Reserves Coordination function in SIEP EPB-P, with its present staff numbers, can (and does) control only the major reserves additions, e.g. for new projects. Any smaller over-aggressive reserves bookings may be detected by the four-year cycle of SEC reserves audits but this is not effective in stopping these in a timely manner. Furthermore, it is rare for booked over-aggressive reserves additions, when detected, to be de-booked again (SNEPCO being the main exception this year). The practice tends to be to keep these volumes as 'exposed' on the books until they have either been overtaken by justified increases elsewhere or until they have been thoroughly re-evaluated.

The auditor comment is therefore that, if reserves addition targets should remain on the Group's score cards, the quality of the booked reserves additions can only be assured in full if a much tighter control is exercised on the annual reserves bookings submitted by OUs. Good examples of such tight control are the annual reserves audits carried out by SEPCo in their Divisions prior to reserves changes being accepted for booking. The SEPCo audit team consists of the two members of SEPCo's Reserves Management function, plus 1 to 3 selected staff drafted from the EPT function. In the international sphere, such audit teams could be drafted regionally, with participation by e.g. the SIEP Reserves Coordinator, and/or the Group Reserves Auditor and/or selected SIEP- EPT staff. It is understood that ExxonMobil maintain a 13-man team to carry out such annual reserves audits worldwide before reserves changes are accepted.

It would also be welcomed if ExCom members would maintain (and if necessary increase) awareness of the potential effects by score cards on reserves estimates and take steps to preserve their integrity when threatened.

13. **Annual production – consistency between Ceres and Reserves**

Group share annual hydrocarbon production is reported separately through the Ceres (now FIRST) 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. OUs are strongly advised (and indeed encouraged through a jointly signed submission sheet) to coordinate their respective submissions to Ceres/FIRST and reserves. However, the experience is that inconsistencies still arise. A comparison has been made to check for such inconsistencies and, where significant, these have been queried with the OU. Thus, a good overall match has been obtained between the two submissions, see Attachment 4.

The main item of exception this year was the 2002 second-quarter production from the ex-Enterprise Oil assets. Although the acquisition date was 1st April 2002, the respective OUs did not start reporting their production / sales to

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Ceres / FIRST until the third quarter. A composite figure of all Q2 Enterprise production was obtained from Enterprise central office staff and this was entered as one line 'Enterprise UK' in Ceres. Reserves submissions from OUs at the end of the year included the full Q2-4 production and this showed up some discrepancies in the two submissions. Since it was no longer possible to verify the Q2 production with Enterprise staff (the London office having been disbanded), the discrepancy, which was not material, was left uncorrected.

14. **SEC Reserves Audits**

A total of nine SEC Reserves audits were carried out by the Group Reserves Auditor during 2002. Of these, three audits received 'good' opinions, the others were 'satisfactory'. Summaries of the audit reports can be found in Attachment 6.

In addition, the auditor carried out audits on the reserves carried by six ex-Enterprise OUs. One OU (USA) was reviewed by SEPCo staff. Summaries of these audits are also included in Attachment 6.

The programme for planned SEC Reserves Audits in 2003 and beyond is included in Attachment 7.

15. **Electronic Workbooks**

As in previous years, much benefit was derived from the SIEP-developed electronic workbooks through which OUs had to make their submissions. As in previous years, EPB-P staff have made a significant effort this year to ensure that submissions were properly verified and that the accumulation process was completed accurately and on time. For this they are commended.

Recommendations to SIEP Reserves Coordination:

1. Maintain the present vigilance regarding the continued booking of Proved reserves volumes with poor justification, as highlighted in this report and re-consider the booking of these volumes as appropriate.
2. Consider a further tightening of conditions under which first-time booking of major project reserves can be allowed by Group reserves guidelines. The prime condition should be a clear public commitment by the Group that development will be undertaken. This could be FID, but also a Declaration of Commerciality if the latter is sufficiently binding.
3. Maintain and, if necessary, increase ExCom's attention to the preservation of the integrity of OU reserves bookings in the light of the potential threat emanating from reserves addition targets in score cards.
4. Consider a tightening of the control on reserves changes by introducing regional reserves audit teams which are to carry out annual reserves audits with OUs and which have the power to approve / disallow OU proposed reserves changes.
5. Re-evaluate the effect of using PSV oil prices instead of end-year oil prices on PSC and other reserves bookings at regular (bi- or tri-yearly) intervals.
6. Ensure that OUs, in particular PDO and SPDC, prepare proper composite production forecasts (built up from realistic individual field forecasts, both Proved and Expectation) demonstrating the reasonable certainty that Proved reserves can be produced within current licence durations. The annual forecast rates should not exceed those presented as the Base Plan in the latest Business Plan.
7. Challenge OUs with regard to their submissions of estimates of amounts by which Proved reserves should rise if there were no licence duration constraints.
8. Include guidelines with respect to appropriate methods of proved and Expectation forecasting in the next edition of the Group reserves guidelines.

References

1. 'Statement of Financial Accounting Standards No. 69', FASB, November 1982
2. 'Statement of Financial Accounting Standards No. 25', FASB, February 1979
3. 'Petroleum Resource Volume Guidelines', SIEP 2002-1100 / 1101
4. SEC Website: "Issues in the Extractive Industries" (dated 31st March 2001): www.sec.gov/divisions/corpfin/guidance/cfactfaq.htm#p279_57537
5. "Understanding US SEC guidelines minimizes reserves reporting problems", T.L.Gardner, D.R.Harrell, Oil&Gas Journal, Sept 24, 2001.
6. 'Petroleum Resource Volume Guidelines', SIPM EP93-0075, May 1993

Attachment 2

SIGNIFICANT 2002 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	
USA	+7	+26	+5	+17	Field reviews in Mars, Ursa, Holstein, Auger, plus Mars WI
USA (Aera)	+6	+16			Belridge recovery review and field extensions
Brunei	+8	+8	+6	+8	New method, performance reviews and appraisal
UK	+4	+14	-5	+1	Performance and development reviews
Denmark	+4	+6	-2	+0	Field reviews and maturation
Russia - Sakhalin		+5			Oil viscosity revision
Canada AOSP	+95				(Near-) completion of Oil Sands Project (non-SEC!)
Nigeria (SPDC)	+26				EA on stream
USA (incl Aera)	+10		+12		Field development and drilling
UK	+11		+4		Field development and drilling
Nigeria (SPDC)			+12		New gas plant to supply LNG-3
Netherlands	+0		+11		Field drilling and development
Malaysia			+10		Devmt drilling plus E-11K-A compression installed
Denmark	+6		+3		Development drilling
Oman (PDO)	+7				Field development and drilling
New Zealand				-5	Pohokura volumetric revision
Thailand		-5		-1	Technical and economic revision of waterflood
Nigeria (SNEPCO)		-16		-4	Proved reserves review and audit
Total Major Techn'l	+184	+54	+56	+16	

OTHER MAJOR CHANGES					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Worldwide	+64	+136	+18	+32	Enterprise Oil acquisition
Kazakhstan		+60			DOC Kashagan
Russia - Sakhalin		+6			Review of oil price and royalty
USA				+5	Pinedale additional acquisitions
DR Congo		-3			Divested
Iran	-3	-8			Dilution + review of costs and entitlements
New Zealand	-1	-3	-4	-7	Dilution of portfolio following 2001 FCE acquisition
Malaysia				-17	Reduced PSC entitlement due to lower offtake
Total Other Major	+60	+188	+14	+13	

OTHER MINOR CHANGES AND TOTAL					
	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Other Minor Chgs	+36	+1	-5	+1	
Grand Total Chgs	+280	+243	+65	+30	
Production	-138	-138	-98	-98	

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GROUP RESERVES SUBMISSIONS

Attachment 3

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

Country Name	Proved Resvs 1.1.2002	Rev'ns and Reclass-ific'ns	Improved Recovery	Ext'ns and Discoveries	Purchases in Place	Sales in Place	Prod'n (avail. for sales) 2002	Proved Resvs 1.1.2003	Beyond end of licence	Proved Dev'd Resvs 1.1.2002	Transf Under to Dev'd	Revisions	Prod'n (avail for sales) 2002	Proved Dev'd Resvs 1.1.2003	Minority Resvs incl 1.1.2002	Minority Resvs incl 1.1.2003	R/P Tot (yr)	Replmt Ratio TotRes (%)	Replmt Ratio DevRes (%)
Australia (Algeria)				.71				.71											
Australia (Direct)	26.7	1.69					3.31	25.08		12.29		1.7	3.31	10.68			8	51%	51%
Australia (WPL)	18.07	.32					2.06	16.33		6.85		.54	2.06	5.33			8	16%	28%
Bangladesh																			
Brunei (BSP)	72.24	6.49	.98	.47			5.83	74.35		35.66	2.6	7.72	5.83	40.15			13	136%	177%
Brunei (SDB)	.95	.09					.05	.99		.31	.33		.05	.59			20	180%	660%
China	6.05	.44					1.38	5.11		4.82	.83	-.2	1.38	4.07			4	32%	46%
Malaysia	25.36	-2.86	.62				3.45	19.67	1.1	13.6	1.54	-1.58	3.45	10.11	.17	.17	6	-65%	-1%
New Zealand	9.96	-.83	.37			1.67	1.61	6.22		5.62	.02	-.53	1.61	3.5			4	-132%	-32%
New Zealand (SPWes-FCE)	1.63					1.58	.05			1.06		-1.01	.05				0	-3160%	-2020%
Pakistan																			
Philippines	3.54	.61					.24	3.91		2.15		.41	.24	2.32			16	254%	171%
Thailand	15.14	-5.48					.9	8.76		4.37	.38	-.78	.9	3.57			10	-609%	11%
Angola	11.85		7.34					19.19											
Austria	.23	.01		.03			.03	.24		.21		.03	.03	.21			8	133%	100%
Cameroon (Pecten))	4.33						.98	3.35		4.12	.17	-.36	.98	2.95	.87	.67	3	0%	-19%
Congo (DR)	3.05					3.01	.04			1.98		-1.94	.04				0	-7525%	-4850%
Denmark	52	4.51	1.35				8.14	49.72	10.69	36.15	6.48	4.22	8.14	38.71			6	72%	131%
Ireland (ex-EO)																			
Italy (ex-EO)		1.12			19.28		.67	19.73				8.08	.67	7.41			29	3045%	1206%
Gabon	16.23	.39					2.69	13.93	3.29	14.68	.38	.56	2.69	12.93	4.06	3.49	5	14%	35%
Germany	2.87	.06	.04			.06	.3	2.71		2.87	.01	.04	.3	2.62			9	13%	17%
Netherlands	4.04	.17	.22				.54	3.89		3.01	.07	.2	.54	2.74			7	72%	50%
Nigeria (SNEPCO)	89.97	-16.14						73.83											
Nigeria (SPDC)	417.66	-.73					12.47	404.46	13.83	116.74	26.66	7.93	12.47	138.86			32	-6%	277%
Norway	29.09	-3.86			42.61		8.49	59.35		22.21	1.48	30.15	8.49	45.35			7	456%	373%
UK	87.59	14.2	.78	.06	44.16	.02	22.09	124.69		60.89	11.49	32.45	22.09	82.74			6	268%	199%
Abu Dhabi	93.29	-1.09					5.81	86.39	149.9	77.56	.91	.66	5.81	73.34			15	-19%	27%
Egypt	4.08	.17					.66	3.6		2.98	.03	.29	.66	2.65			6	26%	49%
Russia (KMOC)					19.31	.16	.33	18.82			.33	2.41	.33	2.41			57	5803%	830%
Iran	33.45	-7.86	.17			9.87	.74	15.41		5.64	1.33	-2.58	.74	3.66			21	-2339%	-189%
Kazakhstan				60.41				60.41											
Oman (PDO)	162.3	-4.74	.34	1.49			15.22	144.17		65.8	7.27	4.92	15.22	62.77			9	-19%	80%
Oman (Gisco)	12.65	-2.07					3.28	7.3		10.48		-1.94	3.28	5.26	1.9	1.09	2	-63%	-59%
Russia (Sakhalin Holding)	30.94	10.43					1.71	39.66		8.45		.99	1.71	7.73	13.92	17.85	23	610%	58%
Syria	14.82	.82	2.07				2.87	14.84	1.46	9.01	1.6	2.1	2.87	10.04			5	101%	136%
Argentina	1.39		.03				.03	1.39		.46	.09	-.01	.03	.51			46	100%	267%
Brazil (ex-EO)		1.69			16.31			18.											
Brazil (Shell Oil WH)	.83	-.08					.09	.66		.83		-.11	.09	.63			7	-89%	-122%
Canada	53.17	-.9		.08			3.27	49.08		21.52	1.61	-2.29	3.27	20.57	11.79	10.94	15	-25%	21%
Canada (AOSP)	95.4							95.4			95.4			95.4	21.15	21.26			
USA (SEPCo)	107.34	12.34	8.1	5.19	1.08	.55	19.07	114.43		68.26	3.36	6.75	19.07	59.3			6	137%	53%
USA (Aera)	56.56	10.43		5.23			6.58	65.63		52.32	6.4	5.78	6.58	57.92			10	238%	185%
Venezuela	36.17	1.81					2.66	35.32	8.4	12.75	3.76		2.66	13.85			13	88%	141%
Grand Total	1,601.04	21.35	22.41	73.67	142.75	16.87	137.63	1,706.72	188.67	688.67	174.73	105.1	137.63	830.87	53.86	55.47	12	177%	203%
Total excl Can. AOSP	1,505.64	21.35	22.41	73.67	142.75	16.87	137.63	1,611.32	188.67	688.67	79.33	105.1	137.63	735.47	32.71	34.21	12	177%	134%
TotexclAOSP-Min.Revs	1,472.93							1,577.11											

GAS (10^9 sm3) All volumes net Shell Group Share

Country Name	Proved Resvs 1.1.2002	Rev'ns and Reclass-ific'ns	Improved Recovery	Ext'ns and Discoveries	Purchases in Place	Sales in Place	Prod'n (avail. for sales) 2002	Proved Resvs 1.1.2003	Beyond end of licence	Proved Dev'd Resvs 1.1.2002	Transf Under to Dev'd	Revisions	Prod'n (avail. for sales) 2002	Proved Dev'd Resvs 1.1.2003	Minority Resvs incl 1.1.2002	Minority Resvs incl 1.1.2003	R/P Tot (yr)	Replmt Ratio TotRes (%)	Replmt Ratio DevRes (%)
Australia (Algeria)				.175				.175											
Australia (Direct)	175.41	1.815					2.366	174.86		29.644		1.174	2.366	28.453			74	77%	50%
Australia (WPL)	39.049	.765					1.494	38.32		12.971		.829	1.494	12.306			26	51%	55%
Bangladesh	4.745	-.345					.435	3.965		1.973		.001	.435	1.539			9	-79%	0%
Brunei (BSP)	100.461	4.891	.213	.886			4.806	101.645		35.677	1.295	7.776	4.806	40.942			21	125%	189%
Brunei (SDB)	5.646	.81					.442	6.014		3.124	1.124	.095	.442	3.901			14	183%	776%
China																			
Malaysia	164.31	-17.27	2.962				6.856	143.147	12.772	44.503	10.715	-1.938	6.856	45.925	2.629	2.388	21	-209%	121%
New Zealand	33.682	-6.12	1.29			2.041	4.627	22.184		20.251	.155	-1.173	4.627	14.608			5	-148%	-72%
New Zealand (SPWes-FCE)	4.771					4.641	.13			2.855		-2.725	.13				0	-3670%	-2096%
Pakistan	6.323	-1.204						5.119			3.838			3.839					
Philippines	17.716	.156					.369	17.505		10.711		.121	.369	10.463			47	42%	33%
Thailand	7.334	-1.277					.473	5.634		2.788	.073	-.07	.473	2.388			13	-307%	1%
Angola																			
Austria	1.345	.017		.097			.22	1.239		1.152		.151	.22	1.083			6	52%	69%
Cameroon (Pecten))																			
Congo (DR)																			
Denmark	28.173	.039	.25				3.238	25.224	5.647	20.859	2.972	-2.188	3.238	18.405			8	9%	24%
Ireland (ex-EO)		-.089			7.857			7.768											
Italy (ex-EO)		.153			2.58		.095	2.638				1.17	.095	1.075			28	2877%	1179%
Gabon																			
Germany	54.899	.909	.312				4.216	51.904		41.479	.204	.577	4.216	38.044			12	29%	19%
Netherlands	408.1	1.049	.83	.246			15.777	394.548		190.769	11.03	.786	15.777	186.818			25	14%	75%
Nigeria (SNEPCO)	7.02	-4.457						2.563											
Nigeria (SPDC)	89.173	-1.381					2.524	85.268		42.039	11.689	-2.861	2.524	48.353			34	-55%	350%
Norway	88.897	-1.371			6.577		2.588	90.915		35.045	.018	4.186	2.588	36.66			35	178%	162%
UK	91.761	1.37	.634	.589	13.378	.149	11.726	95.338		61.801	4.052	7.509	11.726	61.635			8	135%	99%
Abu Dhabi																			
Egypt	22.772	1.926					2.397	22.301		11.089		1.323	2.397	10.015			9	81%	55%
Russia (KMOC)																			
Iran																			
Kazakhstan																			
Oman (PDO)																			
Oman (Gisco)																			
Russia (Sakhalin Holding)	35.364	-4.218					8.119	23.027		24.937		-3.796	8.119	13.022	5.305	3.454	3	-52%	-47%
Syria	.337	.26					.172	.42	.05	.211		.361	.172	.4			2	161%	210%
Argentina	12.631		.003				.255	12.379		5.907	.477	-1.606	.255	4.523			49	1%	-443%
Brazil (ex-EO)		.092			1.656			1.748											
Brazil (Shell Oil WH)	4.798	-.427					.394	3.977		4.798		-1.276	.394	3.128			10	-108%	-324%
Canada	70.771	-2.583		.36			6.306	62.232		55.776	1.361	-8.054	6.306	42.777	15.89	13.865	10	-35%	-109%
Canada (AOSP)																			
USA (SEPCo)	104.552	4.58	.564	11.604	5.896	.274	17.292	109.63		68.875	11.656	4.295	17.292	65.533			6	129%	92%
USA (Aera)	.411	.206		.025			.054	.588		.318	.081	.126	.054	.471			11	470%	383%
Venezuela																			
Grand Total	1,579.948	22.324	7.158	13.952	37.954	7.104	97.314	1,512.27	18.469	770.552	60.25	4.751	97.314	696.239	23.824	19.717	16	30%	67%
Total excl Can. AOSP	1,579.948	22.324	7.158	13.952	37.954	7.104	97.314	1,512.27	18.469	770.552	60.25	4.751	97.314	696.239	23.824	19.717	16	30%	67%
TotexclAOSP-Min.Revs	1,556.124							1,492.553											

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2002 PRODUCTION RECONCILIATION - CERES/FIRST vs. RESERVES SUBMISSIONS

Attachment 4

OIL+NGL

Country	Original FIRST		Org'l Resvs Subm'n		Differ-ence	Final FIRST		Final Resvs Subm	Differ-ence	Comment
.159	mln bbl	10^6m3		10^6m3	10^6m3	mln bbl	10^6m3	10^6m3	10^6m3	
Australia (SDA)			3.31							
Australia (WPL)			2.06							
Australia Total	33.72	5.36		5.37	.01	33.72	5.36	5.37	.01	OK (Accept rounding error)
Brunei (BSP)	36.646	5.83		5.83		36.646	5.83	5.83		OK
Brunei (FCE)	.336	.05		.05		.336	.05	.05		OK
China	8.672	1.38		1.38		8.672	1.38	1.38		OK
Malaysia	21.664	3.44		3.45	.01	21.664	3.44	3.45	.01	OK (Accept rounding error)
New Zealand			1.61							
New Zealand (SPM/ex-FCE)			.05							
New Zealand Total	10.456	1.66		1.66		10.456	1.66	1.66		OK
Philippines	1.534	.24		.24		1.534	.24	.24		OK
Thailand	5.639	.9		.9		5.639	.9	.9		OK
Austria	.154	.02		.03	.01	.154	.02	.03	.01	OK (Accept rounding error)
Denmark	51.211	8.14		8.14		51.211	8.14	8.14		OK
Germany	1.857	.3		.3		1.857	.3	.3		OK
Italy	2.871	.46		.67	.21	2.871	.46	.67	.21	FIRST subm'n excludes 0.21 m3 Q2 ex-EO production
Netherlands	3.411	.54		.54		3.411	.54	.54		OK
Norway NSEP (incl ex-EO)	48.614	7.73		8.49	.76	47.867	7.61	8.49	.88	FIRST subm'n excludes 0.88 m3 Q2 ex-EO production. Error in FIRST - corrected
UK Expro (incl ex-EO)	127.657	20.3		22.09	1.79	127.657	20.3	22.09	1.79	FIRST subm'n excludes 1.79 m3 Q2 ex-O production
Cameroon (PPC)	6.153	.98		.98		6.153	.98	.98		OK
Congo (OR)	.273	.04		.04		.273	.04	.04		OK
Gabon	16.898	2.69		2.72	.03	16.898	2.69	2.69		Reserves submission was based on Working Interest, not PSC entitlement share - corrected
Nigeria (SPDC)	78.546	12.49		12.47	-.02	78.546	12.49	12.47	-.02	Ceres/FIRST submission in error (should be 78.405 MMstb), but too late to change. Resvs submission OK
Abu Dhabi	36.56	5.81		5.81		36.56	5.81	5.81		OK
Egypt	4.07	.65		.65		4.07	.65	.65		OK
Iran	4.677	.74		.74		4.677	.74	.74		OK
Oman PDO	95.718	15.22		15.22		95.718	15.22	15.22		OK
Oman Gisco	20.625	3.28		3.28		20.625	3.28	3.28		OK
Russia (Sakhalin Holding)	10.771	1.71		1.71		10.771	1.71	1.71		OK
Russia (KMOC)	.708	.11		.33	.22	1.33	.21	.33	.12	FIRST subm'n excludes 0.12 m3 Q2 ex-EO production - corrected (+0.622 MMstb)
Syria	18.022	2.87		2.87		18.022	2.87	2.87		OK
Argentina	.171	.03		.03		.171	.03	.03		OK
Brazil (SOC - Merluza)	.585	.09		.09		.585	.09	.09		OK
Canada	20.6	3.28		3.27	-.01	20.6	3.28	3.27	-.01	OK (Accept rounding error)
USA (SEPCo)			19.07							
USA (Aera)			6.58							
USA Total	161.312	25.65		25.65		161.312	25.65	25.65		OK
Venezuela	16.735	2.66		2.66		16.735	2.66	2.66		OK
Q2 Prodn Ex-EO UK, Norway, Italy, Russia	19.073	3.03			-3.03	19.073	3.03		-3.03	OUs claim Q2 prod'n is 3.00, FIRST submission of 3.03 originated from EO HQ - difference of 0.03 left unresolved
Total	865.839	137.684		137.66	-.02 -.02	865.814	137.66	137.63	-.03 -.03	

GAS

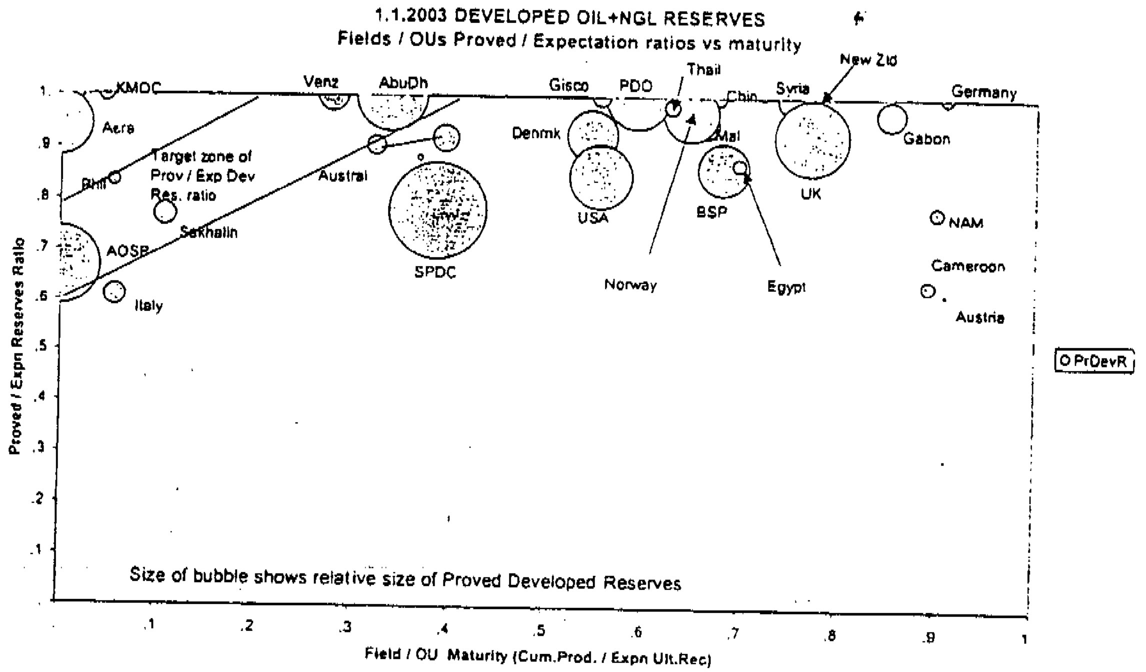
Country	Org'l FIRST	Org'l Resvs Subm'n		Differ-ence	Final FIRST	Final Resvs Subm'n	Differ-ence	Comment
	10^9sm3		10^9sm3		10^9sm3	10^9sm3		
Australia (SDA)		2.365						
Australia (WPL)		1.494						
Australia Total	3.858		3.859	.001	3.858	3.859	.001	OK (accept rounding error)
Bangladesh	.435		.435		.435	.435		OK (accept rounding error)
Brunei (BSP)	4.806		4.806		4.806	4.806		OK
Brunei (SDB/ex-FCE))	.442		.442		.442	.442		OK
Malaysia	6.856		6.855	-.001	6.856	6.855	-.001	OK (accept rounding error)
New Zealand (STOS)		4.627						
New Zealand (SPM/ex-FCE)		.13	*					
New Zealand Total	4.751		4.757	.006	4.757	4.757		Minor error in Ceres/FIRST - corrected
Philippines	.368		.369	.001	.368	.369	.001	OK (accept rounding error)
Thailand	.422		.423	.001	.422	.423	.001	OK (accept rounding error)
Austria	.251		.22	-.031	.224	.22	-.004	Ceres/First submission included .027 m3 traded gas - corrected. Minor discrepancy with reserves submission accepted in view of time constraint
Denmark	3.238		3.238		3.238	3.238		OK
Germany	4.216		4.216		4.216	4.216		OK
Italy	.073		.095	.022	.073	.095	.022	FIRST subm'n excludes 0.022 m3 Q2 ex-EO production
Netherlands	15.777		15.777		15.777	15.777		OK
Norway (NSEP)	2.499		2.588	.089	2.499	2.588	.089	FIRST subm'n excludes 0.089m3 Q2 ex-EO production
UK (Expro)	11.384		11.726	.342	11.384	11.726	.342	FIRST subm'n excludes 0.342 m3 Q2 ex-EO production
Nigeria (SPDC)	2.708		2.52	-.188	2.524	2.524		Original Ceres/FIRST submission in error - corrected; reserves submission adapted as well
Egypt	2.403		2.392	-.011	2.392	2.392		Conversion error in Ceres/FIRST subm'n - corrected
Oman Gisco	8.119		8.119		8.119	8.119		OK
Syria	.172		.172		.172	.172		OK
Argentina	.255		.255		.255	.255		OK
Brazil (SOC Merluza)	.395		.395		.395	.394	-.001	Original OK, late change in resvs submn - reason not clear
Canada	6.306		6.306		6.306	6.306		OK
USA (SEPCo)		17.292						
USA (Aera)		.054						
USA Total	17.346		17.346		17.346	17.346		OK
Q2 Prodn Ex-EO UK, Norway, Italy	.47			-.47	.47		-.47	OUs claim Q2 prod'n is 0.453, FIRST submission of 0.470 originated from EO HQ - difference of 0.017 left unresolved
Total	97.55		97.311	-.239 -.239	97.334	97.314	-.02 -.02	

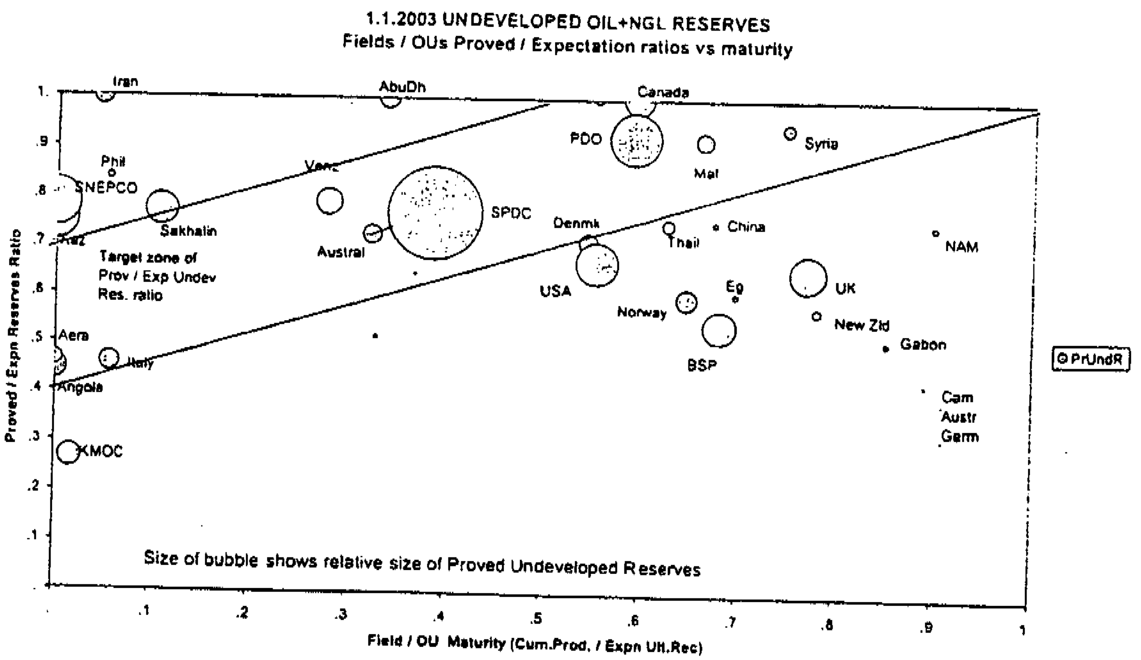
FOIA CONFIDENTIAL
TREATMENT REQUESTED

V00010660

MATURITY OF PROVED OIL+NGL RESERVES - BY OU

Attachment 5.1





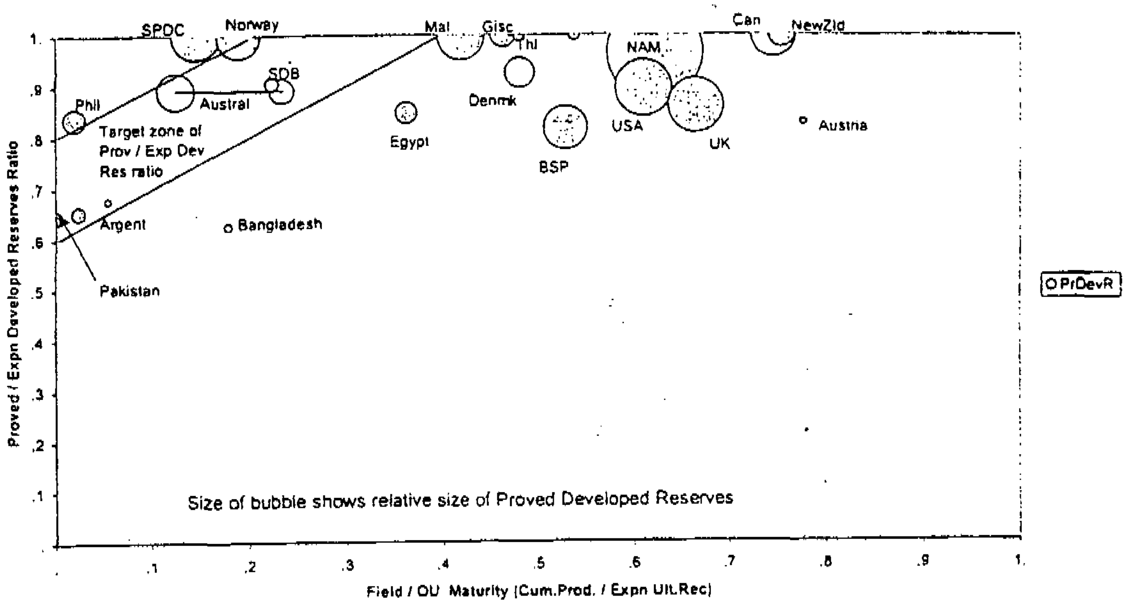
FOIA CONFIDENTIAL
REATMENT REQUESTED

V00010661

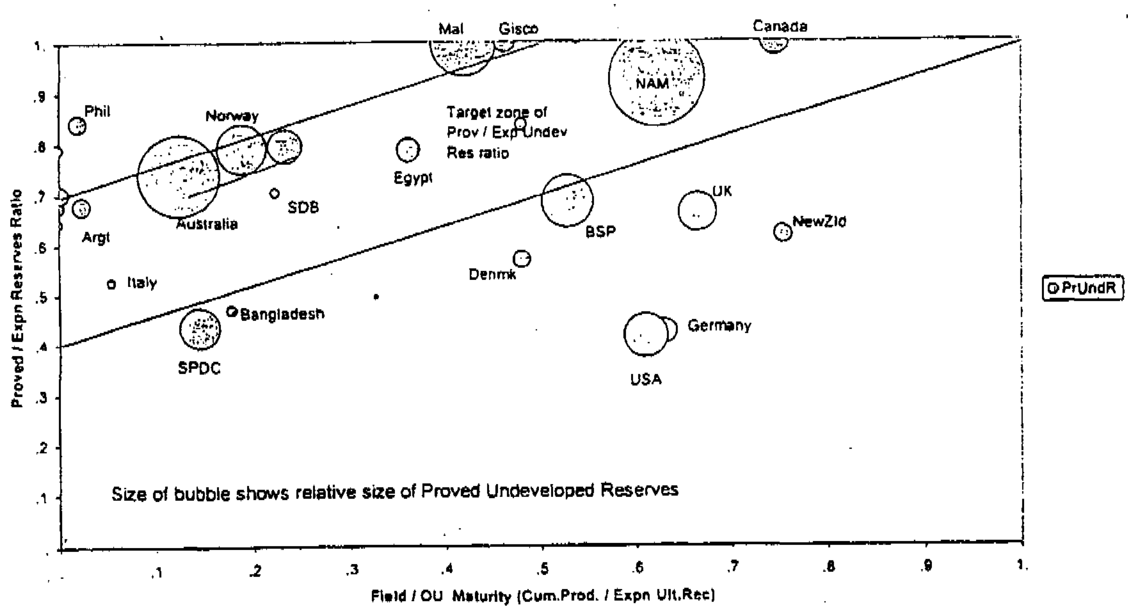
MATURITY OF GAS RESERVES - BY OU

Attachment 5.2

1.1.2003 DEVELOPED GAS RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



1.1.2003 UNDEVELOPED GAS RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



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TREATMENT REQUESTED

V00010662

Attachment 6

2002 SEC RESERVES AUDITS - MAIN OBSERVATIONS

SHELL MALAYSIA E&P: SMEP gas reserves were based on the ambitious postulation that proved gas reserves were equal to expectation reserves. The justification for this was the fact that a portion of lifecycle gas reserves was due to be produced after the end of current PSC licences (hence not part of reserves) and that any shortfall in gas would be compensated by gas being brought forward from this beyond-PSC gas, thus not affecting the within-PSC Proved gas reserves. The auditor opinion was that the scope for backup from beyond-PSC-licence production volumes could be more limited than thought. This could imply an overstatement of current Proved reserves and should be evaluated properly.

Recovery factors in some of the smaller undeveloped gas fields could be overstated in cases where 1- or 2-well subsea developments could be affected by premature well failure necessitating an earlier than planned abandonment.

The reserves audit trail was hampered by lack of ready access to a report or note showing the link between 100% lifecycle volumes via PSC licence volumes to Group share entitlements. The auditability of the reserves accumulation process was therefore inferior to that seen in the large majority of other OUs.

The audit opinion was satisfactory.

No specific response to the audit recommendations was made by SMEP prior to the end-2002 reserves submissions. However, SMEP have reduced their PSC gas entitlements following indications of lower future offtakes, pushing reserves beyond end-of-licence. This has mitigated the observation made regarding the possible overstatement of gas reserves.

BRUNEI SHELL PETROLEUM SDN BHD: BSP followed well documented procedures in their annual reserves reporting process. Audit trails have historically been a strong feature in BSP reserves reporting and their high quality was confirmed during the audit. The most significant comment related to the conservative nature of BSP's Proved reserves, in particular Proved developed reserves, many of which were too low and not in accordance with current Group guidelines. Although decreased substantially in recent years, the continued presence of 'legacy reserves' remains an area of concern. These are undeveloped reserves that have historically been booked in reservoirs but for which no clear activities had been identified (in line with prevailing practice at the time). These reserves should be addressed at the first available opportunity, while striving to avoid major reserves swings.

The audit opinion was satisfactory.

Very good progress has been made by BSP in addressing the conservatism in their Proved reserves estimates and in weeding out remaining Proved 'legacy' reserves. This is commended.

SYRIA SHELL PETROLEUM DEVELOPMENT: As a result of a previous lack of study effort, the undeveloped reserves portfolio was very thin (only 2 years' production). Many of the undeveloped recoverables were still booked in the 'scope' categories. The reserves reporting culture in AFPC tended to encourage conservative reserves booking. Both AFPC and SSPD maintained good audit trails and comprehensive process controls in their respective reserves estimates and submissions. However, there was no consistent procedure of determining the Low/Proved vs. Expectation reserves in AFPC and this should be developed and documented.

There was a possibility of an understatement of SSPD entitlement reserves due to the lack of maturation in the undeveloped reserves portfolio, and the conservative nature of AFPC reserves estimates. Appraisal ('Deep and Lateral') reserves should also lead to reserves additions when appropriate provisions will have been agreed under the PSCs.

The audit opinion was satisfactory.

Modest changes were made to SSPD's Proved and Expectation reserves portfolio during 2002. Reserves replacement ratios were 140% for Proved developed reserves and 103% for total Proved reserves.

SHELL NIGERIA E&P Co (SNEPCO): SDS in Houston had performed a commendable effort in re-evaluating the downside risk of poor lateral communication in the SNEPCO turbidite fields. 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. In line with these evaluations, the audit supported the SDS proposal to 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 was 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 could still not be supported with the present marginal economics and unresolved unitisation issues.

The audit finding was that the proposed Proved reserves were in line with the appropriate Group and SEC Guidelines. The audit opinion was satisfactory.

The reserves reductions have been fully reflected in the 1.1.2003 reserves submission.

SHELL BRAZIL EP (Merluza Field): The Proved Reserves submissions for the Merluza fields were made largely in accordance with guidelines, with only a few minor corrections being required. These related mainly to the correct (Business Plan) forecast to be used for the submission and the inclusion of own use and fuel in reported reserves and annual sales volumes.

The audit opinion was satisfactory.

A small (negative) correction was made to the Merluza reserves per 1.1.2003.

SHELL EXPLORATION BV (IRAN): SEBV followed good procedures with respect to the technical subsurface evaluations that are customary during oil field development. Evaluations of life cycle recoverables from the two fields (Soroosh and Nowrooz) were sound, although the history matches could be further refined. The relationship between life cycle reserves and Group share reported Proved reserves was very remote, as the reported reserves were derived from a fixed fee plus cost recovery remuneration that is hardly affected by (or robust to) downside and upside risk. The result was that booking of the reserves could be seen as disagreeing with the letter of the Group guidelines, and (less clearly) with the SEC guidelines, which apparently require a compensation that is more directly related to oil production levels. The as yet poorly defined status of SEBV involvement in IOOC operations in the field after completion of development is a further complicating factor. However, SEC staff have (unofficially) agreed with reporting of proved reserves in similar cases, seeing the exposure of invested capital to risk as an important factor. Hence, the SEBV booking can be accepted.

The present Group accounting and reserves booking rules lead to unrealistically low UOP depletion charges because of the disparity between current oil prices and PSV assumptions. This is an unavoidable effect of the present rules.

The audit opinion was good.

A significant reduction in Group share reserves was reported by SEBV at end 2002. These changes were due to a dilution of ownership during 2002 and a revised view of economic parameters. It is understood that other operators (TFE) disclose their Iranian reserves on a similar basis.

USA – SEPCo (AERA): SEPCo and Aera followed well prescribed procedures in their annual reserves reporting process and there were no apparent deficiencies in these procedures. Particular commendation was made of the comprehensive vetting of detailed Aera reserves volumes and changes by SEPCo staff who then apply their own view and selection to these volumes before submitting them to SIEP. Only minor comments were made regarding the accessibility of some of SEPCO's spreadsheets and on the usefulness of obtaining some further data from Aera (STOIIPs, cumulative productions, gas GHVs).

The audit opinion was good.

A significant increase was booked for Aera Proved reserves at end 2002, following a documented justification by Aera of their forward projections of well production rates in the Belridge field.

SHELL DEVELOPMENT ANGOLA: The new Proved reserves estimates prepared by SDS during 2002 were in agreement with the Shell Group and SEC guidelines and these estimates could be accepted. The Proved estimates were curtailed by the fact that some of the six exploration and appraisal wells were 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 had to be considered as unproved and their associated recoveries could not be included in Proved reserves. Some limited portions of the unproved volumes could become proved later 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.

The audit opinion was good.

The new Proved volumes have been fully reflected in the 1.1.2003 reserves submission.

SHELL DEVELOPMENT & OFFSHORE PAKISTAN BV: Proved reserves had been booked in two fields, The Bhit field (Pab reservoir) and the Badhra field (Moghul Kot reservoir). The Bhit field was under development (first gas expected in January 2003) and the booked proved reserves were largely sound. More detailed modelling, planned by the operator (Lasmo/ENI) should address reservoir connectivity issues in more detail. As for the Badhra field, the audit found that the booking of Proved reserves in that field since 1.1.2000 (following discovery of gas in the Moghul Kot reservoir in 1999) had been far too premature. A sizeable portion of Proved GIIP had been booked below Lowest Known Hydrocarbons but, more importantly, the Badhra development project is still very immature and more appraisal is needed before a development plan can be formulated. In addition, there are environmental issues which may prevent any development altogether. Booking of reserves under those circumstances is in conflict with SEC and Group guidelines.

The audit opinion was satisfactory.

Badhra reserves have been de-booked at end 2002.

EX-ENTERPRISE OIL OU AUDITS:

EO-UK: Total Proved and Expectation reserves originally booked by EOUK were largely confirmed but Proved developed reserves were not always prepared with due care. Developed gas reserves in Pierce and Nevis had to be re-classed as undeveloped by SUKEP because the necessary infrastructure is not yet in place. A major surprise was also the severe reduction proposed by SUKEP in Proved developed recoveries in Beryl, Skene and Scott. If confirmed, these would cause significant depletion charges against net income. The precise reason could not be established during the 2½-day audit and this should be investigated urgently. The most likely reason was too pessimistic Proved volumes forecasting by SUKEP (ex-EOUK) staff, but less than careful (and too optimistic) bookkeeping by EOUK in pre-Shell days could be a contributing factor. New proposed Proved volumes were in some cases too low in comparison with Expectation volumes and these should be reviewed. SUKEP are in the process of reviewing the fields and estimates concerned.

EO-Norway: The total Proved and Expectation reserves originally booked by EON had to be corrected downwards by NSEP in a number of cases because of undue optimism in some of the original EON estimates and because of disappointing (post-acquisition) reservoir evidence. These revisions were accepted as reasonable. The main exception item was the proposed booking of 14 mln m3oe EON share Proved reserves (18 mln m3oe Expectation) in the undeveloped Skarv and Idun fields. Development of these two fields still faced major decisions regarding gas export timing and route. Hence, the project was at the present stage too immature to allow reserves to be booked. EO's bookings could only be maintained if there were to be certainty that BP's aggressive schedule could be maintained and that a serious project commitment could be taken early in 2003. SIEP advice to NSEP (supported by Excom members) has been that Skarv and Idun volumes should not be booked this year and they have not been included in NSEP's submission.

There was confusion among the ex-EO staff regarding the precise volumes carried as Proved developed reserves in the respective fields. Data provided at the audit did not agree with data obtained directly from EO (see Att. 2.3). The issue has been resolved by NSEP's re-assessment of all Proved and Expectation reserves.

EO-Italy: The originally carried Expectation Reserves volumes in all three fields were based on reasonable assumptions and model calculations. However, the future production performance of the fields was still subject to a very wide range of uncertainty and this seemed insufficiently reflected by the ratio between Proved and Expectation reserves in the Monte Alpi and Tempa Rossa fields. Proved Reserves in these two fields seemed therefore too high. Since the audit, the field models have been re-run against negative scenarios but the OU claims that no realistic downside scenarios could be found which matched the present production performance and which resulted in recoveries that were materially lower than the present Proved volumes. Hence, the volumes have been maintained.

In addition, there were still significant unresolved commercial issues (including poor economic viability) in the development of the Tempa Rossa field. Reserves booking in Tempa Rossa should have been kept pending until these issues had been resolved. Subsequent to the audit, a VAR4 has been carried out and this confirmed the immature state of development (even a VAR3 would not have been passed). Hence, the Tempa Rossa volumes remain not bookable in accordance with the SEC and Shell guidelines. The SIEP advice (endorsed by ExCom members) has been that only Phase I reserves (some 50% of Tempa Rossa volumes) should remain on the books at 1.1.2003 since the operator (TFE) maintains that FID is imminent. However, it was advised that this booking should be critically reviewed at 1.1.2004 with a view to debooking all Tempa Rossa volumes if there should be a lack of substantive progress towards project sanction during 2003.

EO-Russia (KMOC): The audit found that the non-availability of documented and detailed field data prevented a proper full-scale assessment of the Enterprise / KMOC reserves evaluation process. However, it was clear that the assets were technically and commercially not mature and that, if this were a regular Shell asset, Proved and Expectation undeveloped reserves would not have been booked on the scale that they have been by Enterprise. The impending funding shortage raises significant uncertainty regarding the extent of further field development, particularly for the East Bank fields, which require a river crossing and new infrastructure to export the oil. The recommendation is to book undeveloped reserves only for the West Bank fields to the extent that development has been sanctioned by the authorities and to defer any booking of the remaining and East Bank reserves until the funding shortage has been resolved and until proper Field Development Plans have been issued by KMOC and approved by the authorities.

A rather superficial SEC Proved reserves review was carried out by Ryder Scott in 2001 and this was used by EO as the basis for the Proved reserves disclosed for the company (as an associate company holding) in its end-2001 submission (20-F) to the SEC. The undeveloped reserves reported by Ryder Scott took at face value KMOC's statement that development was certain and this seems now a too optimistic assessment.

SIEP advice, endorsed by Excom members, has been that the ex-EO volumes shall be included in Shell's externally reported Proved reserves on the same basis that EO reported them, i.e. on the Ryder Scott assessment.

EO-Brazil: Recoveries carried by EOB appeared to be on the high side when compared against empirical turbidite recovery efficiencies suggested by earlier BRC/EPT work. However, pressure observations in the recently drilled wells do seem to be more favourable than suggested by the lowest of the BRC scenarios and the present reserves estimates can therefore be maintained. Detailed simulation, based on information from the new wells and improved seismic modelling is underway and this must be completed in the course of 2003 to allow a better foundation of reserves estimates. The audit trail of water injection facilities design is poor (but necessary for booking water injection reserves) and a review may be appropriate. Because of a small royalty in kind payable to the State, the reportable net reserves share percentage is lower than the percentage share in the venture (77.6% vs. 80%).

EO-Ireland: EEI have made a comprehensive series of assessments of in-place and recoverable gas volumes. The only issue of some concern is that of the current appeal against the building permit for the onshore gas processing plant, which, if sustained, would bring the Corrib field development into serious jeopardy. In that case, which EEI consider unlikely, Proved reserves would probably need to be de-booked. Developments regarding the building permit approval process are being followed closely.

EO-USA: The audit was carried out by Rod Sidle (SEPCo Reserves Manager). Only one asset (Boomvang) carried Proved reserves. Although not well founded and somewhat optimistic, these reserves were accepted for the time being. They should be reviewed again following the availability of production performance in 2002 and 2003. The audit trail for the reserves is poor, e.g. with regard to volumes possibly not in EO acreage. Most reserves were booked as developed at 1.1.2002, even though wells had not been completed yet (against SEC and Group guidelines). This has now corrected itself since production has started in July 2002. The passing of a VAR4 in Llano in October 2002 will mean that reserves can be booked for this field per end 2002.

SEC RESERVES AUDIT PLAN - 2003

Attachment 7

COUNTRY	Size**	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
EGYPT	M/S		X					X				A			
PHILIPPINES	M/S					$		X				P			
BRUNEI (SDB)	M/S									$		A			
THAILAND	M/S		X					X				P			
CAMEROON (Pecten)	M/S						*		(X)			A			
NIGERIA -SPDC	L	X				X		X				P			
ABU DHABI	L			X				X				A			
OMAN	L			X				X				P			
KAZAKHSTAN-OKIOC	L										$	A			
RUSSIA - SALYM												P1 $?			
VENEZUELA	L				$			X				A			
ARGENTINA	M/S			X				X				P			
GABON	M/S			X					X				P		
BANGLADESH	M/S					$			X				P		
NORWAY	L				X				X				P		
RUSSIA - SAKHALIN	M/S					$			X				P		
EO - RUSSIA (KMOC)	M/S										X $		P		
AUSTRALIA	L				X				X				P		
USA (SEPCo)	L						*		X				P		
NETH. NAM	L	X				X				X				P	
GERMANY	L	X				X				X				P	
CHINA (SECL)	M/S		$							X				P	
UK	L			X		X				X				P	
DENMARK	L	X				X				X				P	
AUSTRIA	M/S			X						X				P	
EO - ITALY	M/S										X $			P	
EO - IRELAND	M/S										X $			P	
NEW ZEALAND	L				X					X				P	
MALAYSIA	L		X				X				X				P
BRUNEI	L		X				X				X				P
IRAN	L							$			X				P
SYRIA	M/S	X			X						X				P
BRAZIL (SBL)	M/S						*				X				P
USA (AERA)	L					$					X				P
NIGERIA - SNEPCO	L					$		X			X				P
ANGOLA	M/S								$		X				P
PAKISTAN	M/S					$					X				P
EO - USA	M/S										X $				
EO - UK	L										X $				
EO - NORWAY	L										X $				
EO - BRAZIL	M/S										X $				
CANADA	L														
DR CONGO (ZAIRE)	M/S		X												
NAMIBIA															

Audit Status:

X = Completed
A = Accepted
P = Proposed
()1 = First audit

$ = First SEC resvs subm'n
* = First SEC subm'n via SIEP
**L : > 30 mln m3oe S/S
M/S : < 30 mln m3oe S/S

Audit frequency:

All OUs once every 4 years.
First audit within 2 yrs after first submission.
Exceptions possible in case of major reserves changes,
critical audit reports or opportunities to combine with other audits

Unknown

From:	Regtien, Jeroen SIEP-EPT-LS
Sent:	09 January 2004 15:52
To:	Darley, John J SIEP-EPT
Subject:	Gorgon Reserves

John,

With all the disappointing news today and finally understanding the full scope of your recent work I went back to my files to check the facts on Gorgon. I found the following relevant documents:

1. E-mail from me to Anton Barendregt on the scope of the audit, highlighting our intention to debook Gorgon (June 2000)
2. Internal SDA message restating the intention that Gorgon should be de-booked (September 2000)
3. Final report from SEC Reserves Audit, which clear statement by the auditor that Gorgon bookings should be maintained (See Point 3 of Main Observations). (November 2000)

If it is no longer material or relevant, please discard.

Regards,

Jeroen

RE: SEC Reserves Audit - Austr...

RE: Gorgon Reserves vs SFR

SDA - Reserves Audit.ZIP

Jeroen Regtien
Manager TLT Support Team

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DEPOSITION EXHIBIT
Barendregt
#17 2/20/07

EXHIBIT
Darley 25
11/17/06

DARLEY 1097

FOIA Confidential Treatment Requested

V00321097

Unknown

From: Barendregt, Anton AA SEPIV-EPB-GRA
Sent: 05 June 2000 16:35
To: Regtien, Jeroen JMM SDA-EP/2
Subject: RE: SEC Reserves Audit - Australia 1 of 1

Jeroen,

Many thanks for your message. I'll read through your documents and I'll revert with questions if I have any. I'll also let you know which fields I'd like to have a closer look at.

I've got copies of your end-1999 submissions and note.

Anton

-----Original Message-----
From: Regtien, Jeroen SDA-EP/2
Sent: 25 May 2000 11:21
To: Barendregt, Anton SEPIV-EPB-GRA
Subject: FW: SEC Reserves Audit - Australia 1 of 1

resend due to size limitation error.

-----Original Message-----
From: Regtien, Jeroen SDA-EP/2
Sent: Thursday, May 25, 2000 5:13 PM
To: Barendregt, Anton SEPIV-EPB-GRA
Cc: Blaauw, Robert SDA-EP; Graham, Sheila SDA-FP/421
Subject: RE: SEC Reserves Audit - Australia

Anton,

We confirm your proposal to hold the audit in the week of October 9th. We are making the necessary arrangements to comply with the proposed structure of the audit and are already making arrangements with our Operators Chevron and Woodside to schedule interviews with field teams.

I would like to point out a possible sensitivity. As you may have heard in the press, Shell has recently made a significant but unsolicited business proposal to Woodside to sell SDA's plus some international assets in return for an increase in its shareholding in Woodside from 34% to 60% (ref attached). The proposal is being studied by Woodside and external advisers are involved. This means that the book value of SDA's and Woodside's assets is quite significant and as such a Shell Group audit on SDA assets operated (but co-owned) by Woodside could be a sensitivity. In that light we have explained to Woodside that the upcoming audit is part of a 5 year rolling plan, was scheduled long before the merger proposal was made and that the audit is with respect to SDA's reserves base only and not those of our Operators. Woodside has in the meantime indicated it will cooperate and Woodside's reserves coordinator Jan van Elk will coordinate from their end.

Some basic information on SDA:

- SDA has a large number of assets operated by Woodside (majority), Chevron (a few) and ourselves (small proportion, exploration permits only).
- Apart from Robert Blaauw (E&P Manager), Sheila Graham (Economist and reserves Coordinator) and myself (Development Manager) SDA does no longer have any petroleum engineering staff. We rely on Operators (Woodside, Chevron) and use technical and value assurance services from SIEP/SepTAR as and when required.
- We distinguish between a Direct interest (where we have equity in the permits) and Indirect interest (through our 34% shareholding in Woodside). Attached you will find two workbooks containing the submissions for both direct and indirect interests. The 'Field Data' sheet contains an overview of developed and undeveloped reserves by field.
- The majority of the assets operated by Woodside are covered by both a direct and indirect SDA interest, except the Legendre Field, in which we only have an indirect interest.
- The North West Shelf area is huge and comprises many oil fields (Wanaea, Cossack, Lambert, Hermes) and

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gas fields (Rankin, Goodwyn, Angel, Perseus, Egret).

- The Laminaria/Corallina field has come into production November 1999 and we are watching the pressure profile with great interest.
- With respect to Chevron operated assets, the giant Gorgon field is classified as proved undeveloped and we intend to downgrade that to SFR during the upcoming ARPR cycle. Also, the Thevenard and Barrow oil assets have been sold per 1/6/2000 to Santos as part of a portfolio rationalisation.

Closer to the audit date we would like to have an indication of the fields you want to investigate in more detail as the allocated time would not be sufficient to cover them all. This would allow our operators Woodside and Chevron to make the appropriate staff and data available in a timely fashion.

Will you receive a copy of our ARPR explanatory note and formal ARPR submission to the Group from Remco Aalbers or do you expect a copy from us?

Looking forward to your response,

Jeroen Regtien

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Unknown

From: Chittleborough, Mark SDA-DCG
Sent: 19 September 2000 09:52
To: Regtien, Jeroen SDA-EP/2; Graham, Sheila SDA-FP/421
Cc: Blaauw, Robert SDA-EP
Subject: RE: Gorgon Reserves vs SFR

No problem with your approach. On Domgas we have recently signed an MOU and CA - whilst not bankable, it does demonstrate some action in the commercial area to support booking.

-----Original Message-----
From: Regtien, Jeroen SDA-EP/2
Sent: Tuesday, 19 September 2000 16:48
To: Graham, Sheila SDA-FP/421
Cc: Chittleborough, Mark SDA-DCG; Blaauw, Robert SDA-EP
Subject: RE: Gorgon Reserves vs SFR

Sheila,

My view is that we come to our own understanding first within the current guidelines. We then check with Barendregt who has got Gorgon reserves on his audit programme anyhow. Afterwards we can then discuss the matter with Aalbers.

My proposal to treat the Gorgon reserves is based on the following:

- We have booked the Gorgon volumes as reserves in 1998(?) following the certification by NSAI and whilst very close to signing an LOI with Korean LNG customers. The Asian crisis has evaporated the market and we do currently not have an outlook to signed LOIs or SPAs. Recent Domgas options fell through, we are now restarting a greenfield LNG effort
- We have a Gorgon case in our BP which meets screening criteria
- The Sunrise project is further in its commercialisation process (LOIs, VAR) and has no proved reserves in the books
- None of the JV partners has booked the Gorgon volumes as proved reserves.

I therefore recommend and am prepared to defend downgrading Gorgon from the proved undeveloped reserves category to SFR (commercial/proved techniques).

I realise this may carry some sensitivity in SIEP, but it was extensively discussed at the ASR and SDA was actioned to developed a plan to downgrade Gorgon reserves. I accept that timing may have to be discussed with SIEP and suggest Robert contacts Jager.

I also note that Remco may not have realised in his response that Barendregt is visiting in October anyhow for the audit, and may have thought we are bypassing him.

Looking forward to your response,

Jeroen

-----Original Message-----
From: Graham, Sheila SDA-FP/421
Sent: Tuesday, September 19, 2000 3:37 PM
To: Regtien, Jeroen SDA-EP/2; Chittleborough, Mark SDA-DCG
Subject: FW: Gorgon Reserves vs SFR
Importance: High

Gentlemen,
FYI, lets discuss and I will reply on Thursday.

Sheila

-----Original Message-----
From: Aalbers, Remco RD SIEP-EPB-P
Sent: Saturday, 16 September 2000 1:08

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V00321100

To: Graham, Sheila S SDA-FP/421; Maarse, Wim W SDA-FP/4
Cc: Jager, Rob RJ SEPI-EPA; McKay, Aidan A SIEP-EPB-P; Branson, David D SIEP-EPB-P
Subject: Gorgon Reserves vs SFR
Importance: High

Wim, Sheila,

I picked up the following comment on Gorgon reserves vs SFR in your BP'00 clarifications. This is a very important and sensitive point from both a principle point as well as in light of the Groups proved RRR target. The discussion should be with both Rob and myself, not with Anton Barendregt. Could you please clarify what your plans/issues/timing vs Gorgon reserves.

Q SFR Maturation zero?
We are acutely aware of our reserves replacement and SFR maturation KPIs. As you no doubt are aware, lack of a gas market makes it very difficult if not impossible to move our gas/condensate scope from SFR to reserves. Most of our oil opportunities have not made it through CA and hence no scope maturation can be expected. In actual fact if we decide to move Gorgon back to SFR (not included in BP as discussion is required with Barendregt). The SFR maturation will be negative.

Met vriendelijke groeten / With kind regards.

Remco D. Aalbers
Group Hydrocarbon Resource Coordinator
& Senior Economist

EPB-P SEPIV BV
Tel. +31 (0)70 - 377 2001 (fax: 2460)
e-mail: remco.rd.aalbers@sepivbv.shell.com

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DRAFT NOTE – 21 Nov 2000 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPB - GRA
To:	Lorin Brass	Director, Business Development, SIEP - EPB
	Alan Parsley	CEO, Shell Development Australia (SDA)
Copy:	Robert Blaauw	E&P Manager, SDA
	David Christie	Finance Manager, SDA
	Wim Hein Grasso	Commercial Director, SDA
	Jeroen Regtien	Development Manager, SDA
	(circulation)	SIEP – EPF: Gardy, van Nues
	(circulation)	SIEP - EPB-P: Bell, McKay, Aalbers
	Rob Jager	Business Advisor, SIEP (EPA)
	Egbert Eeftink	Director, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

SEC PROVED RESERVES AUDIT - SHELL DEVELOPMENT AUSTRALIA, 9-13 Oct 2000

I have audited the proved reserves submissions of SDA for the year 1999 and the processes that were followed in their preparation. These submissions present the SDA contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 1999.

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 99-1100/1101" (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 were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The last previous SEC proved reserves audit for SDA was carried out in 1996. The audit took the form of technical discussions with staff from Woodside Energy Ltd (the operator for a large part of the assets with SDA interest) and detailed discussions about the reserves reporting process with SDA staff.

Total booked Group share proved reserves at the end of 1999 were 44 mln m3 of oil + NGL (of which 20 mln m3 developed) and 217 bln sm3 of gas (of which 27 bln sm3 developed). 1999 Reserves replacement ratios were 48% for oil+NGL and -340% for gas.

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 on the grounds that a gas market was highly likely to be established in due course and that 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. This could increase Group entitlement by some 12 mln m3oe. 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.

The audit finding is that the SDA statements fairly represent the Group entitlements to Proved Reserves at the end of 1999. There is a possibility of a small (appr. 4%) understatement of entitlement reserves due to the reporting of P85 (proven) reserves instead of expectation reserves in mature fields. The overall opinion from the audit regarding the state of SDA's 1999 Proved Reserves submission, taking account of the scoring in Attachment 3, is therefore <u>satisfactory</u>.

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

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A.A. Barendregt

Attachments 1, 2, 3

Attachment 1

SEC PROVED RESERVES AUDIT - SDA, 9-13 Oct 2000

MAIN OBSERVATIONS

1. SDA report their Group share reserves in two separate submissions. The first contains the 'direct' share of SDA in the successive licences and ventures in which Shell have an interest, together with other co-venturers. The second submission relates to the 34.27% shareholding that Shell have in Woodside Petroleum Ltd, who are co-venturer and operator in many of the fields in which SDA have an interest. The effect is an increase in the net reported share of the Woodside operated fields.

2. Commendation is made of the excellent quality of the technical work carried out by Woodside Energy Ltd in assessing the subsurface risks and in evaluating and quantifying the probability ranges of the in-place and reserves estimates. The fact that production history in the mature fields largely confirmed the original estimates provides evidence for this quality. Woodside can be commended for a significant improvement of their internal work processes in this respect. It was also noted that co-venturer support, e.g. through regular peer reviews and SIEP reviews (VARs and others) helped to further contribute to this success.

3. Some 10 Tcf (or 86 bln m3 Group share) of proved gas reserves have been booked for the giant Gorgon field since 1.1.1999. This was done on the strength of work done by the operator (WAPET, later Chevron) showing that development of this field through an LNG facility (stand-alone or, preferably, shared with the existing Woodside / North West Shelf LNG facility) was commercially robust. An important challenge is finding a buyer in a market that is fully supplied until 2005 and in which there is still significant competition thereafter. In the long term, however, there can be little doubt that a market will be found for this gas in the East- or South Asian rim. Hence, the Group reserves reporting guidelines do in principle allow this gas to be reported as reserves.

   The outstanding issue is whether the stated Gorgon reserves can be shown to be producible within the prevailing production licence. Gorgon is presently held under a Retention Lease, renewable for successive periods of 5 years under the condition that the field can be considered likely to become commercially viable within the next 15 years and that the lessee is actively pursuing the evaluation of commercial viability, including the conclusion of long term sales contracts. The current Retention Lease expires in 2002. Although there is little doubt that, on the strength of the significant technical and commercial work done todate, an extension of the Retention Lease will be granted, there is no formal right to this extension. Hence the Group guidelines are not fully clear on this issue.

   The practical way forward (and recommendation from this audit) is to maintain the presently booked volume of Gorgon reserves (even when the actual volume has been superseded by a 20% larger volume, following new technical work) and not book any increases until either the Retention Lease has been extended or until e.g. a letter of intent with a prospective buyer has been signed.

4. Group reserves guidelines prescribe that externally reported 'Proved' reserves should be made equal to expectation volumes (in stead of P85 proven or Low volumes) in mature fields, i.e. fields with significant production in relation to their ultimate recovery. Hence, the externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) should be taken as equal to expectation reserves. The same reserves should then also be applied for asset depreciation calculations for Group accounting.

5. One of the requirements of a reserve audit is that OU Group share submissions can be reconciled with reserves volumes and changes in individual fields. The audit should also establish that Group share reserves changes have been reported in the correct category (revisions, field extensions and discoveries, purchases / sales in place etc.). This process was greatly hampered by the lack of a concise audit note, with full detail at field level and by the lack of a proper record of 1999 produced volumes by individual fields. As a result, only a very partial match could be obtained with individual field volumes and changes as reported by Woodside and Chevron, see Attachments 2.1-2.4. Bottom-line corrections, not necessarily linked to individual fields (e.g. those made for the revised Woodside share in Domgas sales), could (and should) also be addressed in such a note.

   New guidelines for preparing a proper audit trail have recently been published on the SIEP-EPB web site. It is the strong opinion of the auditor that a good audit trail will not only facilitate the auditor's task but also, and more importantly, will greatly enhance clarity and transparency of the reserves reporting process in the OU organisation. This will undoubtedly lead to less staff time being required during staff handovers, queries etc.

6. GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes for NWS fields. An attempt was made at reconciling the

SDA Nm3 submission with individual field's and Gorgon GHVs, but the resulting average GHV did not seem to match with the average GHV implied by the submission (Att. 2.4).

7. Asset depreciation for Group accounts is done correctly through proved developed reserves depletion (proved total reserves for the full North Rankin facilities, which act as a hub for the entire NWS offshore gas system). Correct reserves values are being used, but no copy could be found of the formal end-1999 note of advice to Finance with the proper new reserves volumes to be used.

8. Full monthly production and sales statistics (100% field volumes) are received by fax from Woodside, who are the only operator at present with fields in production in SDA-held acreage. A selection of these figures (e.g. totals by assets only, not fields) is manually transcribed into the Finance system for monthly / quarterly reporting. A parallel system (also with manual input) is maintained by the Development Manager for e.g. KPI and MIS reporting. There would appear to be opportunities for synergy and rationalisation, also through electronic transfer of data. Incorporation of data at field level could help the end-year audit trail.

Recommendations

1. Maintain the presently booked volume of Gorgon reserves until a clearly positive event (extension of the Retention Lease or LOI with a buyer) has occurred.
2. Raise externally proved and proved developed reserves in N-Rankin and Wanaea / Cossack, plus possibly those in Goodwyn and Laminaria / Corallina to expectation levels, in line with Group guidelines.
3. Prepare a proper audit trail note, in line with published guidelines, for the 1.1.2001 reserves reporting cycle.
4. Consider possible synergy and rationalisation between production / sales reporting through Finance and the Development function.

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Spare

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NOTE – 31 Aug, 1999

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1999 AUDIT "Satisfactory"

From:	Anton Barendregt	Group Reserves Auditor, SEPIV
To:	Linda Cook	Director, SEPIV
	Ron van den Berg	MD, SPDC, Lagos
Copy:	Egbert Imomoh	DMD, SPDC, Lagos
	Erik Vollebregt	Finance Director, SPDC, Lagos
	Joshua Udofia	Production Director, SPDC, Pt Harcourt
	John Barry	Development Director, SPDC, Pt Harcourt
	C.O.P. Nwachukwu	Petroleum Engineering Manager, SPDC, Pt Harcourt
	Bram Sieders	Chief Reservoir Engineer, SPDC, Pt Harcourt
	(circulation)	SIEP EPS-FX: Gardy, Renard
	(circulation)	SEPIV EPB-P: Platenkamp, van Dorp, Aalbers
	Kieron McFadyen	Business Advisor, SIEP (EPG)
	Egbert Eeftink	Director, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

DEPOSITION EXHIBIT
Barendregt
#18 2/21/07

SEC PROVED RESERVES AUDIT - SHELL PETROLEUM DEVELOPMENT CO (SPDC, Nigeria),

18-26 Aug 1999

I have audited the proved reserves statements of SPDC for the year 1998 and the processes that were followed in their preparation. These statements present the externally reported Proved and Proved Developed Reserves as at 31 December 1998 together with a summary of the changes in Proved Reserves during 1998.

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, EP 98-1100/1101" (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 were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The audit took the form of detailed discussions about the reserves reporting process with SPDC staff and technical discussions with some SPDC engineers regarding some major 1998 reserves increases in the SPDC portfolio.

A previous SEC reserves audit had been held in April 1997. This audit found weaknesses in the SPDC reserves definition and audit trail process and recommended a repeat of the audit in 1999.

Most significant comments from this present audit are as follows:

- The new SPDC corporate Petroleum Engineering Group in Port Harcourt should be tasked with the production of a comprehensive and consistent annual audit trail note to avoid unanswered questions about the basis of SPDC's reserves submission. Seeking answers to these questions took up an unnecessary length of time during the audit.
- The considerable scope for increasing SEC proved reserves in the fields is overshadowed by the assumption of a doubling of Nigerian production levels in the coming decade. Any deviation from this scenario could have a significant effect on proved Shell equity reserves, which can only be avoided by the granting of a production licence extension option.
- Reported gas volumes in normalised m3 (Nm3) should be based on the correct gas calorific values.
- Correct end-of-licence cut-off dates should be applied to production forecasts to establish equity reserves.

The audit conclusion is that the SPDC statements fairly represent the Group entitlements to Proved Reserves at the end of 1998. The overall opinion from the audit regarding the state of SPDC's 1998 Proved Reserves submission is therefore satisfactory.

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

A.A. Barendregt

Attachments 1, 2, 3

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31/08/99

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Attachment 1

SEC PROVED RESERVES AUDIT - SPDC, 18-26 Aug 1999

MAIN OBSERVATIONS

1. As part of the drive to implement the 1998 SIEP guidelines, a concerted effort has been made by SPDC during 1998 to identify 'proven fault blocks', based on criteria of known fluid contacts, sufficient number of well penetrations, and cumulative production in excess of 40% of UR. This has led to a significant increase (926 MMstb) in proved oil reserves during 1998. Further extension of the 'proven blocks' set to blocks with production greater than 25% of UR is planned. This is commended.

2. Experience has shown that older volumetric estimates based on 2D seismic tend to be conservative. This is being addressed by the (almost complete) 3D seismic coverage, of which the results are incorporated into the programme of field studies.

3. Present oil recovery factors are in the range of 30-60%. There is ample evidence that more favourable recoveries (in excess of 60%) are possible in many good quality reservoirs, where light oil is displaced at low rates by active aquifers. Evidence for this is the large amount of negative reserves (production exceeding booked recoveries), which had to be corrected in 1998. This is gradually being addressed through the field studies programme. However, even reserves based on relatively recent field studies show signs of being overtaken by production, e.g. Forcados-Yokri.

4. New wells and projects have to pass economic screening, in accordance with standard Group practice. The portfolio of long term life cycle projects is gradually being subjected to economic screening and adjusted if necessary. It is noted that development and infill drilling costs are low to moderate, resulting in UTCs of 1-2 $/boe.

5. On average, proved remaining reserves per field tended to be some 60-70% of expectation. This was a wider range than would be expected from a mature area as that operated by SPDC. This has been addressed by SPDC's application of the 1998 SIEP guidelines, bringing the average proved oil recovery to some 72% of expectation, with further additions planned.

6. Proved developed oil reserves are based on best estimate extrapolations of existing drainage points. It is noted that expectation developed oil reserves do also include effects of the short term remedial (rig-less) activities plan (stimulations, new perforations etc.). There seems to be no reason why these effects should not also be included in the proved forecast.

7. Reservoir blocks within fields are added arithmetically. It is recommended that probabilistic addition, assuming appropriate (in-)dependencies, be considered, in line with SIEP guidelines. This will mitigate the conservative effect of the SEC-required arithmetic addition of many individual fields' proven reserves in SPDC's acreage.

8. Forecasts have been made for all hydrocarbon streams and these have in principle been cut off at the end of the licence periods (30/11/2008 for offshore and 30/6/2019 for onshore). Minor errors have occurred in some instances in the precise date of the cut-off, by taking e.g. end 2019 and not mid-2019 as the date of cut-off (see also Att. 2.1).

9. The proved corporate total oil forecast used for the reserves submission has been based on the 5-year activity forecast, but beyond that it is notional and aimed at (just) producing all technical reserves by 2019. A proper life-cycle projects based forecast would have been preferable and this is intended for next year's submission.

10. There is no legal right to an extension in the present production licences and hence, no reserves can be booked that are produced beyond that period. The considered legal opinion within SPDC is that an extension is likely to be granted, at least for the fields still in production.

11. Present gas sales contracts are in volumes only. Energy accounting of gas sales is not done, although this will change for NLNG. Current sales contracts generally stipulate a minimum GHV of 8920 kcal/Nm3 (950 BTU/scf). Although gas streams are regularly sampled and analysed, no authoritative data base of GHV data seemed to be available. The average SPDC gas GHV was said to be around 9700 kcal/Nm3, a historically maintained figure, for which the basis is not clear. The 1998 submission implies a GHV of 10230 kcal/Nm3, apparently in error. The quarterly Ceres submissions, possibly based on the same conversion calculation, should also be checked.

12. The onset of NLNG sales and SPDC's ambitious plans to stop flaring of all associated gas by 2008 will require a stronger emphasis on close integration of gas supply and gas demand forecasts and on gas/NGL reserves in the reserves submissions and audit trail.

13. Proved developed reserves are used for asset depreciation in the end-year Group accounting submission. Up-to-date end-1998 reserves were advised to Capital Assets in January 1999. For audit purposes, it would have been preferable if a written record was kept of this advice.

14. Both East and West divisions have produced audit trail notes summarising the individual field changes for oil, but sparsely for NGL or gas changes. This is seen as an improvement over previous years. The usefulness of these notes could be further enhanced by a more rigorous consistency in format, such that the two notes report fully identical sets of data. SPDC also produce a four-volume annual Ultimate Recovery Changes Report (URCR), where full details of field changes, together with RISRES reports, are recorded. The RISRES reports have yet to include the updated proved (= expectation) reserves in proved blocks.

15. Although individual field changes are documented, there are still unexplained differences between the divisions' audit trail notes/spreadsheets and the corporate submission; see Atts.2.2-2.4. Due to lack of time, a corporate audit trail note, tying together the divisions' contributions into the corporate submission, has not been produced, in spite of an earlier audit's recommendation. Auditor's advice is that a rigorous reconciliation, e.g. in the format of Atts 2.1-2.4, will be a powerful tool in managing the annual reserves and their changes.

16. SEC rules require externally reported reserves to be technically and economically robust, producible within licence and (for gas reserves) committed, or likely to be committed, to sales contracts. Combined SPDC proved ultimate oil recoveries are likely to be understated due to the conservative nature of field estimates and due to the arithmetical addition of low reserves estimates for SPDC's large number of fields. This can be mitigated by probabilistic addition within fields. Gas reserves could be significantly boosted by the identification of further firm gas utilisation projects. However, any scope for increasing reserves is overshadowed by the assumption of a doubling of Nigerian production levels in the coming decade. Any deviation from this scenario could have a significant effect on proved equity reserves, which can only be avoided by the granting of a production licence extension.

17. Bearing in mind the above uncertainties, the reported SPDC proved and proved developed reserves can be considered to give a reasonably accurate reflection of shareholder value.

Recommendations:

1. Consider implementation of probabilistic addition of reservoir blocks within fields to bring field proved reserves to a more realistic level.
2. Apply correct cut-off dates (30/11/09 and 30/6/19) to offshore and onshore licence forecasts.
3. Strengthen ownership of gas and NGL forecasts and reserves, preferably within the Petroleum Engineering organisation. Those responsible should maintain close links with Gas Coordination.
4. Review and inventorise gas stream GHVs and apply correct gas GHVs to the reserves (and Finance/Ceres) submissions.
5. Keep a written record that up-to-date field reserves are used in the end-year asset depreciation calculations for Group Accounts.
6. Produce a comprehensive and consistent audit trail note for the corporate reserves submission, to be issued (and copied to SIEP/SEPIV) concurrently with the end-year reserves submission. It should be remembered that tables (cf. Atts 2.1-2.4) are more rigorous audit trails than text. It is noted that the new intended SPDC organisation, with a corporate Petroleum Engineering group in Port Harcourt, will help to ensure consistency.
7. Early agreement on extensions to existing production licences would help to boost Shell equity reserves, particularly if production levels in the coming years were to remain below those currently aspired.

Attachment 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SPDC - 18-27 Aug 99

Oil / NGL / Gas Proved Reserves as at 31.12.98

Area / field	Proved STOIIP	Cum. Prod	Proved Rem. Recov. Dev.	Proved Rem. Recov. Tot'l	Cum. Prod. / STOIIP	RF Tot'l	Within Licence Dev.	Within Licence Tot'l	Within Licence & comtd Dev.	Within Licence & comtd Tot'l	Venture Shell share perc.	Shell Equity Dev.	Shell Equity Tot'l	1998 Subm'n Dev	1998 Subm'n Tot'l
	MMstb/ Bscf	MMstb/ Bscf	MMstb/ Bscf	MMstb/ Bscf	%	%	MMstb/ Bscf	MMstb/ Bscf	MMstb/ Bscf	MMstb/ Bscf	%	10^6 m3/ 10^9 sm3	10^6 m3/ 10^9 sm3	10^6 m3/ 10^9 sm3	10^6 m3/ 10^9 sm3
Oil															
East	25732.80	5527.20	1235.70	5106.20	26.3%	41.3%	1227.40	5039.40	1227.40	5039.40	30.0%	58.54	240.36		
West	20492.60	5059.40	976.09	3870.50	29.5%	43.6%	901.26	3779.40	901.26	3779.40	30.0%	42.99	180.27		
Total Oil	46225.40	10586.60	2211.79	8976.70	27.7%	42.3%	2128.66	8818.80	2128.66	8818.80	30.0%	101.53	420.63	102.88	420.62
NGL															
East	2367.50	20.40		1042.20	0.9%	44.9%			4.40	81.12	30.0%	0.21	3.87		
West	712.90	30.50		330.70	4.3%	50.7%			3.30	108.19	30.0%	0.16	5.16		
Total NGL	3080.40	50.90		1372.90	1.7%	46.2%	0.00	0.00	7.70	189.32	30.0%	0.37	9.03	0.37	9.20
Gas															
East	84069.500	7195.700		40667.200	8.6%	56.9%	2443.780		1607.400	6408.200	30.0%	13.666	54.483		
West	38860.800	5376.800		16804.700	13.8%	57.1%	1146.790		1146.790	4126.140	30.0%	9.750	35.080		
Total Gas (Bscf / 10^9 sm3) GHV (kcal/Nm3) (10^9 Nm3 9500kcal/Nm3)	122930.300	12572.500		57471.900	10.2%	57.0%	3590.570		2754.190	10534.340	30.0%	23.416 9700 22.666	89.563 9700 86.693	39.137 10232 39.959	92.059 10232 93.996

Conversion factors used by SPDC:
1 stb = 0.1591 m3
1scf = 0.02834 sm3
1sm3 = 0.948 Nm3 (if GHV=9500kcal/Nm3)

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.02834 sm3
1sm3 = 0.948 Nm3 (if GHV=9500kcal/Nm3)

AUDIT TRAIL:

Oil: STOIIPs from RISRES print
Cum.oil from MRPW (Audit Pack)
Prov.Dev. oil from NFA FC (W), audit tr.note (E)
Prov. Tot'l oil from RISRES

Within Lic. Dev. oil from dev.oil (NFA) FC
(discrepancy between A/B/C NFA and NFA total in East - 1176 resp 1376)
Within Lic. Tot'l oil = Rem.Recov - 66.8 (H&K) - 91.1 (EA)
Prov.tot'l oil FC based on 5-yr act.plan and made to fit in licence

Incomplete match of oil dev. reserves probably due to mismatch of NFA forecasts.

NGL: CIIPs from RISRES print
Cum.NGLs from MRPW (Audit Pack)
Prov.Dev. NGL not available
Prov. Tot'l oil from RISRES

Within Lic. Dev. NGL not available
Within Lic. Tot'l NGL not available
Within Lic. Comtd Dev. NGL from Div. Gas FC (W only)
Within Lic. Comtd Tot'l NGL from Div. Gas FC

Incomplete match in NGL totals due to full 2019 assumed in submission (West only).

Gas: GIIPs from RISRES print
Cum.gas from MRPW (Audit Pack)
Prov.Dev. gas not available
Prov. Tot'l gas from RISRES

Within Lic. Dev. gas from dev.AG (NFA) FC + expn.dev. NAG from Risres
Within Lic. Tot'l gas (comtd.+ uncomtd.) from NFA FC (AG only avail.)
Within Lic.Com.Dev. gas from Div.gas FC (E) and dev.gas (W)
Within Lic. Comtd Tot'l gas from Div. Gas FC

Incomplete match in gas totals due to full 2019 assumed in submission (East and West).
Dev.gas volumes do not match
Apparent error in sm3/Nm3/GHV calculation

FOIA Confidential Treatment Requested

LON00820519

Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION

SPDC, 18-26 Aug 99

Oil Reserves Changes 1998 (100%, MMstb, unless otherwise specified)

Field	Prov.Res. 1.1.98	Revisons/ Reclasfns Guidelines	Revisons/ Reclasfns Licence	Revisons/ Reclasfns Studies etc	Revisons/ Reclasfns Total	Improved Recovery	Extens./ Discov's	Purchase In-place	Sales in-place	New Devel'd Reserves	Product'n 1998	Prov.Res 31.12.98	Shell Equity Share % 1997	Shell Equity Share % 1998	Net Shell Equity 1.1.98 (MMstb)	Net Shell Equity 31.12.98 (MMstb)	Comments
Proved Total Reserves																	
East	4459.90	470.40	-66.80	288.70	692.30						148.70	5039.40	30.00%	30.00%	1337.97	1511.82	
West	2651.10	456.10	-91.10	736.50	1103.50		53.50				130.70	3779.40	30.00%	30.00%	795.33	1133.82	Discovery Afuo - 33.0 MMstb Extension Seibu - 11.5 MMstb Extension Tunu - 9.0 MMstb
Tot'l Prov.Res (MMstb)	7111.00 7178.90				1795.80 1865.60		53.50				279.40	8818.80	186.89%	30.00%	2133.30	2645.64	
Proved Developed Reserves																	
East	797.30	469.70		117.40	587.10						148.70	1176.32	30.00%	30.00%	239.19	352.90	Reserves and reported field changes do not match.
West											130.70	980.62	30.00%	30.00%	0.00	294.19	
Prov.Dev.Resvs (MMstb)	1335.64				1100.70						279.40	2156.94	112.83%	30.00%	239.19	647.08	
Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^6 m3	63.71 342.41				52.50 88.99		2.55				13.33 13.33	102.89 420.63					
1998 Submission Prov.Dev.Res Prov.Tot'l Res 10^6 m3	63.71 342.41				88.99		2.55				13.33	102.88 420.62					

Conversion factors used by SPDC:
1 stb = 0.15899 m3
1scf = 0.02834 sm3
1sm3 = 0.948 Nm3 (if GHV=9500kcal/Nm3)

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.02834 sm3
1sm3 = 0.948 Nm3 (if GHV=9500kcal/Nm3)

Audit trail: Reasonable match between RISRES and submitted volumes.

Total revisions/classifications not directly reconcilable with division's statements

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SPDC 18-26 Aug 99

Attachment 2.3

NGL Reserves Changes 1998 (100%, MMstb, unless otherwise specified)

Field	Prov.Res. 1.1.98	Revisons/ Reclasfns Guidelines	Revisons/ Reclasfns Licence	Revisons/ Reclasfns Studies etc	Revisons/ Reclasfns Total	Improved Recovery	Extens./ Discov's	Purchase In-place	Sales In-place	New Devel'd Reserves	Product'n 1998	Prov.Res 31.12.98	Shell Equity Share % 1997	Shell Equity Share % 1998	Net Shell Equity 1.1.98 (MMstb)	Net Shell Equity 31.12.98 (MMstb)	Comments
Proved Total Reserves																	
East											2.00	81.12	30.00%	30.00%	0.00	24.34	
West							0.42				4.50	108.19	30.00%	30.00%	0.00	32.46	
Tot'l Prov.Res (MMstb)	6.71				188.68		0.42				6.50	189.31	0.00%	30.00%	0.00	56.79	
Proved Developed Reserves																	
East											0.20	4.40	30.00%	30.00%	0.00	#REF!	
West											4.50	3.30	30.00%	30.00%	0.00	1.32	
Prov.Dev.Resvs (MMstb)	6.71				5.69						4.70	7.70	30.00%	30.00%	0.00	#REF!	
Net Group Equity Prov.Dev. Res	0.32				0.27						0.22	0.37					
Prov Tot'l Res 10^6 m3	0.32				9.00		0.02				0.31	9.03					
1998 Submission Prov.Dev.Res	0.32											0.37					
Prov.Tot'l Res 10^6 m3	0.32				8.94		0.02				0.08	9.20					

Conversion factors used by SPDC:
1 stb = 0.15899 m3
1scf = 0.02834 sm3
1sm3 = 0.948 Nm3 (if GHV=9500kcal/Nm3)

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.02834 sm3
1sm3 = 0.948 Nm3 (if GHV=9500kcal/Nm3)

Audit trail:

1998 NGL production obtained from Division's production statement and forecast does not match with submission. (East: 2000 b/d from existing NAG plant - Afam/Alakiri; West: 4500 b/d from NAG plants)

Some mismatch in end-year volumes due to full inclusion of 2019 (see Att. 2.1)

No divisonal statements with individual fields' changes available for gas/NGL

No audit trail for developed NGL reserves in West (3.3 MMstb)

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SPDC 18-26 Aug 99

Attachment 2.4

Gas Reserves Changes 1998 (100%, Bscf unless otherwise specified)

Field	Prov.Res. 1.1.98	Revisons/ Reclasfns Guidelines	Revisons/ Reclasfns Licence	Revisons/ Reclasfns Studies etc	Revisons/ Reclasfns Total	Improved Recovery	Extens./ Discov's	Purchase In-place	Sales In-place	New Devel'd Reserves	Product'n (i.e. sales) 1998	Prov.Res 31.12.98	Shell Equity Share % 1997	Shell Equity Share % 1998	Net Shell Equity 1.1.98 (Bscf)	Net Shell Equity 31.12.98 (Bscf)	Comments
Proved Total Reserves																	
East											33.58	6408.200	30.00%	30.00%	0.00	1922.46	
West							62.67				77.75	4126.140	30.00%	30.00%	0.00	1237.84	Discovery Afuo - 34.2 Bscf Extension Seibu - 8.8 Bscf Extension Tunu - 19.8 Bscf
Tot'l Prov.Res (Bscf)	2616.90				7966.09		62.67				111.33	10534.34	30.00%	30.00%	0.00	3160.30	
Proved Developed Reserves																	
East											33.58	1607.40	30.00%	30.00%	0.00	482.22	
West											77.75	1146.79	30.00%	30.00%	0.00	344.04	
Prov.Dev.Resvs (Bscf)	532.23				2333.29						111.33	2754.19	30.00%	30.00%	0.00	826.26	
Net Group Equity																	
Prov.Dev. Res	4.525				19.838						0.946	23.416					
Prov Tot'l Res	74.163				15.812		0.534				0.946	89.563					
10^9 sm3																	
1998 Submission																	
Prov.Dev.Res	4.525											39.137					
Prov.Tot'l Res	74.163				18.228		0.534				0.866	92.059					
10^9 sm3																	

Conversion factors used by SPDC:
1 stb = 0.15899 m3
1 scf = 0.02834 sm3
1sm3 = 0.948 Nm3 (if GHV=9500kcal/Nm3)

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.02834 sm3
1sm3 = 0.948 Nm3 (if GHV=9500kcal/Nm3)

Audit trail:

Some mismatch in 1998 production (i.e. sales) obtained from Divison's sales statement and forecast (92 MMscf/d from East, 213 MMscf/d from West).

Mis-match in end-year volumes due to full accounting of 2019 (see Att. 2.1).

Mismatch in proved developed gas reserves

No divisonal statements with individual fields' changes available for gas.

FOIA Confidential Treatment Requested

LON00820522

CHECKLIST SEC RESERVES AUDITS Attachment 3

COMPANY: SHELL PETROLEUM DEVELOPMENT CO. (SPDC, Nigeria)

Dimensions:

Volumes are 100% sales, within licence period

1.1.99 Proved Oil Reserves	8818	MMstb
1.1.99 Proved Developed Oil Reserves	2157	MMstb
1998 Oil Production	279	MMstb
	764	Mstb/d
1.1.99 Proved Gas Reserves	10662	Bscf
1.1.99 Proved Developed Gas Reserves	1607	Bscf
1998 Gas Production	305	Bscf
	836	MMscf/d
Number of fields in area	206	More than 5000 reservoirs!
Number of wells drilled / in production	>1000/ 858	

	Audit criteria	Result	Comments
1	TECHNICAL MATURITY		
1.01	Is 3D seismic available and used for the field(s) in question?	+	3D Seismic now covers most of the producing fields (63% of acreage); a gradual programme is aimed at 100% coverage by early next decade.
1.02	Is pre-SDM available and used (when relevant)?	N.A.	Mostly not relevant (no complex overburden or steep dips).
1.03	Is well log data quantity and quality adequate?	+	In view of the large number of wells, well log suites in mature fields are selective. However, adequate field coverage is maintained.
1.04	Is well data coverage adequate?	+	See above.
1.05	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Fluid levels are generally well known in this stacked reservoir environment and any volumes below HDTs are discounted. Faults are generally sealing, and any unpenetrated fault blocks are not included as reserves (appraisal SFR). As part of the drive to implement the 1998 SIEP guidelines, a concerted effort has been made to identify 'proven fault blocks', based on criteria of known fluid contacts, sufficient number of well penetrations, and cum.prod. in excess of 40% of UR. This is commended.
1.06	Is reservoir producibility supported by production tests or other evidence?	+	Many of the fields are in a producing stage. New fields have at least one production or RFT flow test in one of the exploration / appraisal wells before they are developed.
1.07	Is there a proper volumetric estimate?	+	A comprehensive programme of field reviews has been in operation for many years, (re-)addressing the larger fields first and gradually addressing the smaller fields. A proper volumetric estimate (sometimes through a full static model, otherwise through digitised maps) is always part of such a review. Experience has shown that older volumetric estimates based on 2D seismic tend to be conservative. This is being addressed by the (almost complete) 3D seismic coverage, of which the results are incorporated into the field studies.
1.08	Is a static model available / adequate?	O	Full 3D static models are prepared for selected reservoirs in the field studies, particularly if lateral sand quality is variable (channel sands).
1.09	Is a dynamic model available / adequate?	O	If reservoirs have a static model, this is generally upgraded to a 3D simulation model. Dedicated simulation models are also prepared for other reservoirs on a selective basis (e.g. at least one per field).
1.10	Is a history match available / adequate?	O	A history match (or material balance) is a standard part of any field study if adequate production data is available. It is noted that gas measurements have historically been poor and this may sometimes hinder an adequate analysis.
1.11	Is the recovery factor for proved reserves realistic?	O	Present oil recovery factors are in the range of 30-60%. There is ample evidence that more favourable recoveries (in excess of 60%) are possible in many good quality reservoirs, where light oil is displaced at low rates by active aquifers. Evidence for this is the large amount of negative reserves (production exceeding booked recoveries), which had to be corrected in 1998. This is gradually being addressed through the field studies programme. However, even reserves based on relatively recent field studies show signs of being overtaken by production, e.g. Forcados-Yokri. Solution gas recovery factors are similar to those of oil, reflecting the predominantly strong water drive in the reservoirs. Free gas recovery factors are reasonable, based on primary THPs (2500-3000 psi), without further compression.

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

LON00820523

CHECKLIST SEC RESERVES AUDITS

Attachment 3

1.12	Are developed reserves based on existing wells, completions and facilities, or do they require only minor costs (<10% project cost) to be hooked up?	+	Yes. Developed oil reserves are based on a no-activity forecast, built up from individual existing drainage point extrapolations and cut off at end of licence. Developed gas reserves are constrained by firm gas sales contracts and their dedicated fields.
1.13	Has/have (a) development project(s) been defined for undeveloped reserves or can it/they be defined?	+	SPDC have set themselves the challenging task of defining full life cycle plans for most reservoirs. Present coverage is some 90% of reserves.
1.14	Is/are the project(s) technically mature or is further data gathering necessary?	+	All recovery methods are well established.
1.15	Is/are there (an) auditable development project plan(s) with costs, benefits and economics?	+	For new wells and/or projects a dedicated project proposal or FDP is always prepared.
1.16	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	+	Water and gas injection is applied in very few cases. These are in principle preceded by adequate studies and injection tests.
2	**COMMERCIAL MATURITY**		
2.01	Is/are the project(s) commercially mature (positive NPV for Group Ref. Crit. over a range of possible future scenarios / low case reserves)?	O	New wells and projects have to pass economic screening, in accordance with standard Group practice. The portfolio of long term life cycle projects is gradually being subjected to economic screening and adjusted if necessary. It is noted that development and infill drilling costs are low to moderate, resulting in UTCs of 1-2 $/boe.
2.02	Is/are the project(s) economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	O	See 2.01 above.
2.03	Has/have the project(s) been approved by Shareholders?	+	All development expenditure is approved by both Government and Shell (+ partners) on an annual and/or major project basis.
2.04	Have the latest Group Screening / Reference Criteria been used?	+	See 2.01 above.
2.05	Are assumed prices and costs RT (or justified if not)?	+	See 2.01 above.
2.06	Is project financing available or can it reasonably be expected to be available?	O	Restricted government shareholder development funding is currently constraining further field development.
2.07	Are developed reserves actually in production?	+	Yes.
2.08	Have all gas proved reserves been contracted to sales?	O	Most to firm contracts.
2.09	If not, can they reasonably be expected to be sold in existing markets and through existing facilities?	N.A.	
2.10	If neither, can they reasonably be expected to be developed and sold in a future market?	O	Yes, a third NLNG train is now committed to be put on stream by 2003. With the ambitious plans to extinguish all flares by 2008, it becomes crucial that all gas forecasts (particularly those for oil well gas) are fully tied in with the oil forecasts to ensure a consistent view on the needs for NAG support.
3	**REASONABLE CERTAINTY**		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	+	The average ratio between proved and expectation in-place volumes is some 80-85%. This is reasonable for a mature area with increasing 3D seismic coverage and ample well control.
3.02	Is the uncertainty range of total recovery adequate?	O	On average, proved remaining reserves per field tended to be some 60-70% of expectation. This was a wider range than would be expected from a mature area as that operated by SPDC. This has been addressed by SPDC's application of the new SIEP guidelines, bringing the average proved oil recovery to some 72% of expectation. Further additions are foreseen (see also 3.07). It is noted, that, in spite of these increases, arithmetic addition of the proved field reserves, as required by accounting standards, does not diminish any conservatism and results in a too low overall proved recoverable volume.
3.03	Is the uncertainty range of developed recovery adequate?	+	Developed oil recovery is based on 'deterministic' (i.e. best estimate) existing drainage point forecast. Developed gas sales volume (AG + NAG) is contract constrained.
3.04	Have market / production constraint uncertainties been taken into account?	O	The oil within-licence volumes depend critically on the assumed gradual increase of Nigerian production levels. Gas forecasts are based on firm contracts or firmly planned projects.
3.05	What is ratio of field(s) cum.prod. / proved total recovery?		25% for oil (10% for gas).
3.06	Can the field(s) be considered mature?	+	Largely, yes.

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

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LON00820524

CHECKLIST SEC RESERVES AUDITS **Attachment 3**

3.07	Are proved (developed and total) reserves benchmarked against expectation reserves for 'proved areas' when field(s) are mature (deterministic approach)?	+	Proved developed oil reserves are based on best estimate extrapolations of existing drainage points, see 3.04. It is noted that expectation developed oil reserves do also include effects of the short term remedial (rig-less) activities plan (stimulations, new perforations etc.). There seems to be no reason why these effects should not also be include in the proved forecast. Proved total oil reserves are made equal to expectation reserves for the 'proven reservoir blocks' (see 1.05). The current set of proven blocks is planned to be extended by blocks exceeding 25% of UR for the 1999 submission. Proved gas reserves (committed and within licence) are market-constrained.
3.08	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Yes. The consequence is that, with the large number of fields operated by SPDC, the resulting proved volumes tend to be too conservative. This is somewhat mitigated by the equalisation of proved and expectation reserves for proved blocks (see 3.07).7.
3.09	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	O	Reservoir blocks within fields are added arithmetically. It is recommended that probabilistic addition, assuming appropriate (in-)dependencies, be considered, in line with SIEP guidelines. This will mitigate the conservative effect of the SEC-required arithmetic addition of many individual fields' proven reserves in SPDC's acreage (see 3.08).
3.10	Is any assumed dependency in probabilistic addition appropriate?	N.A.	Not used in the present reserves estimates, see above.
4	**GROUP SHARE CALCULATION**		
4.01	Are proved and proved developed reserves producible within the licence period (or its extension if there is a legal right)?	O	Yes, forecasts have been made for all hydrocarbon streams and these have in principle been cut off at the end of the licence periods (30 Nov 2008 for offshore and 30 Jun 2019 for onshore). Minor errors have occurred in some instances in the precise date of the cut-off, by taking e.g. end 2019 and not mid-2019 as the date of cut-off (see also Att. 2.1). The proved corporate total oil forecast used for the reserves submission has been based on the 5-year activity forecast, but beyond that it is notional, to the point of being forced to produce all technical reserves by 2019. A proper life-cycle projects based forecast would have been preferable and this is intended for next year's submission. There is no legal right to an extension in the present production licences and hence, no reserves can be booked beyond that period. The considered legal opinion within SPDC is that an extension is likely to be granted, at least for the fields still in production.
4.02	Are proved and proved developed reserves producible within production ceilings / constraints etc.?	O	Yes, but see remark under 3.04.
4.03	Is the hydrocarbons equity share calculated properly?	+	Yes, 30% (fixed).
4.04	Is the hydrocarbons PSC entitlement share (net cost oil + profit oil only) calculated properly?	O	New funding arrangements for offshore fields, once formalised, will require an adjustment of the flat 30%.
4.05	Is the hydrocarbons 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 in cash (legally or customarily) counted as reserves?	+	Yes, royalties (although optionally in kind) have customarily been taken in cash in Nigeria.
4.07	Are royalties in kind excluded from reserves?	N.A.	
4.08	Are volumes received as fees in kind (e.g. for infrastructure use by third parties) excluded?	+	Yes.
4.09	Has Group under-or overlift been accounted for?	+	Yes
4.10	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?	+	Taking account of the large number of reservoirs, it is to be expected that not all reservoirs' proved total reserves are updated annually. However, a phased study programme, with appropriate priorities, is in place. Proved developed reserves are updated annually (see 3.07).
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	+	To the extent that they are relevant for the Group equity volume (i.e. only for oil), yes.
5.03	Can reported net Group equity reserves be reconciled with other relevant data (e.g. production constraints, gas markets, etc.)?	+	Yes, reserves are based on appropriate forecasts.

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

LON00820525

CHECKLIST SEC RESERVES AUDITS Attachment 3

5.04	Can reserve changes be reconciled with individual field changes and are they reported in the appropriate categories?	O	Both East and West divisions have produced audit trail notes summarising the individual field changes for oil, but sparsely for NGL or gas changes. This is seen as an improvement over previous years. The usefulness of these notes could be further enhanced by a more rigorous consistency in format, such that the two notes report fully identical sets of data. SPDC also produce a four-volume annual Ultimate Recovery Changes Report (URCR), where full details of field changes, together with RISRES reports, are recorded. The RISRES reports have yet to include the updated proved (= expectation) reserves in proved blocks (see also 5.08).
5.05	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	+	URCR reports are produced annually. These refer further to detailed field study reports as necessary.
5.06	Are reports numbered / indexed properly and is there a central library where copies are kept?	O	Reports are not numbered. A central store is available in the East and a proper library is in place in the West. The latter contains all Western reports and a good selection of Eastern reports. Backup copies of most reports are sent to Lagos.
5.07	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?	X	Although individual field changes are documented, there are still unexplained differences between the divisions' audit trail notes/spreadsheets and the corporate submission, see Atts.2.2-2.4. A corporate audit trail note, tying together the divisions' contributions into the corporate submission, has not been produced, in spite of an earlier audit's recommendation. Auditor's advice is that a rigorous reconciliation, e.g. in the format of Atts 2.1-2.4, will be a powerful tool in managing the annual reserves and their changes.
5.08	Are data bases containing historic submissions' data and current reserves status (e.g. RISRES) in place and accessible?	O	A RISRES data base has been fully implemented. This is an essential requirement with the large number of reservoirs in SPDC and is commended. Individual field changes and updates are introduced as and when field study work is completed. There is some doubt about the reliability of developed reserves estimates in the data base; no-activity forecasts seem to provide a better estimate. A comprehensive retrieval report, properly listing e.g. expectation estimates (iso P85 estimates) for 'proven' blocks, is not yet available, but is being worked on. 'Frozen' versions of RISRES are only archived for the ARPR (targeted to coincide with reserves submissions, but hitherto always late and hence further updated and changed). Only a paper copy of the RISRES submission version was kept.
5.09	Do these data bases also contain references to detailed reports?	O	RISRES provides the option of storing references to reports, but this is not used in SPDC. Instead, the URCR reports contain all necessary references.
6	**CONSISTENCY WITH FINANCIAL REPORTING**		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes.
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes. NGL volumes are reported separately, even though they are spiked back into the crude stream.
6.03	Are own use, fuel, losses etc excluded?	+	Yes.
6.04	Are gas GHVs properly measured for sales gas conditions and accounted for in reserves submissions?	X	Present sales contracts are in volumes. Energy accounting of gas sales is therefore not done (will change for NLNG). Sales contracts generally stipulate a minimum GHV of 8920 kcal/Nm3 (950 BTU/scf). Although gas streams are regularly sampled and analysed, no authoritative data base of GHV data seemed to be available. The average SPDC gas GHV was said to be around 9700 kcal/Nm3, a historically maintained figure, for which the basis is not clear. The 1998 submission implies a GHV of 10230 kcal/Nm3, apparently in error. The quarterly Ceres submissions, apparently based on the same conversion calculation, should also be checked.
6.05	Are reported proved developed reserves consistent with those used for asset depreciation?	O	Proved developed reserves are used for asset depreciation in the end-year Group accounting submission. Up-to-date end-1998 reserves were advised to Capital Assets in January 1999. For audit purposes, it would have been preferable if a written record was kept of this advice.

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

CHECKLIST SEC RESERVES AUDITS **Attachment 3**

6.06	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream production volumes reported into the Finance (Ceres) system, i.e. Ceres line 0871 (= 8462-Oil + 8464-NGL) for Consolidated Companies + line 3596 (= 0931-Oil + 0932-NGL) for Assoc. Companies?	+	Both Ceres and reserves submissions use the same MRPW (EPPROMS) end-year run. Reported volumes are consistent.
6.07	Are annual gas production (sales) volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0323 = 0934 (GroupCy net NG sales) + 3596 (Assoc.Cy NG sales), corrected for 1404+4796 (Gas purchases) and 4100+4510+4575+0873 (Trade, other Sales and Transfers)?	X?	Although both Ceres and reserves submissions use the same MRPW (EPPROMS) end-year run, making reported volumes in principle consistent, the Ceres submission (in Nm3) could include the same GHV-based sm3/Nm3 conversion error as that in the reserves submission. This should be verified.
7	**OVERALL**		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Combined SPDC proved ultimate oil recoveries are likely to be understated due to the conservative nature of adding low reserves estimates for a large number of fields. This can be mitigated by probabilistic addition within fields. Gas reserves could be significantly boosted by the identification of further firm gas utilisation projects. However, any scope for increasing reserves is more than overshadowed by the assumption of a doubling of Nigerian production levels in the coming decade. A lack of realisation of this scenario could have a significant downward effect on proved equity reserves, which could only be avoided by the granting of a production licence extension.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	O	Bearing in mind the above uncertainties, the reported SPDC proved and proved developed reserves can be considered to give a reasonably accurate reflection of shareholder value.

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

LON00820527

DRAFT NOTE – 23 Sept 2003 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPF - GRA
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	John Bell	Corporate Support Director, SIEP – EPS
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PROVED RESERVES PROCESS AUDIT - SPDC (NIGERIA), 18-19 Sept 2003

I have audited the processes underlying the Proved Reserves submissions of SPDC for the year 2002 and the current measures undertaken by SPDC to introduce improvements in these processes. The reserves submissions present the SPDC 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 booked by SPDC at the end of 2002 were 404 mln m3 of Oil+NGL and 85 bln sm3 of gas. This represents some 16% of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratios for SPDC over 2002 were -6% for oil+NGL and -55% for gas.

The last previous SEC proved reserves audit for SPDC was carried out in 1999. This current audit is a partial audit of reserves reporting processes only, replacing a full audit, which was deferred to 2004 for medical reasons. The audit took the form of two days of presentations and detailed discussions about the reserves reporting process with SPDC staff.

The audit found that SPDC's portfolio of proved oil reserves estimates appears far less mature than during the last (1999) reserves audit. One important reason for this is that the Group guidelines for Proved reserves have been tightened considerably with respect to the need for properly defined FDPs and the passing of either VAR3 or FID hurdles. It was also found that SPDC's annual proved oil reserves submissions during the years 1999-2002 have been 'managed' as a total sum only, without taking heed of the underlying individual field estimates.

SPDC have realised these shortcomings and have taken steps to set up a full inventory of oil project forecasts and reserves with the ultimate aim of obtaining complete consistency between the reserves data base and Capital Allocation / Business Plan volumes. By end this year it should be possible to have a good overview of the maturity of the project portfolio, in terms of development hurdles passed or to be passed. Under the present circumstances there can be no doubt that the portfolio of proved oil reserves per 1.1.2003 has been overstated due to insufficient maturity in the underlying future projects. The precise correction that will be needed per 1.1.2004 will depend on further evaluations to be undertaken by SPDC during the remainder of 2003.

The audit finding is therefore that the present status of SPDC's proved oil reserves is <u>unsatisfactory</u>. Efforts are underway to address this situation. Proved gas reserves appeared insufficiently founded on firm contracts but this will now be corrected with the commitment to a fourth and a fifth LNG train.

It must be realised that the scope for increasing SPDC proved oil reserves beyond present (inflated) levels is probably limited. The reason is that many projects will not be required before the next decade. It is very unlikely that these projects will be matured in the next few years (VAR3 or FID), which means that proved reserves for these cannot yet be booked.

A summary of the findings and observations is included in Attachment 1.

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A.A. Barendregt

DEPOSITION
EXHIBIT
Barendregt
#19 2/21/07

Attachments 1, 2, 3

RJW00890491

Attachment 1

PROVED RESERVES PROCESS AUDIT - SPDC, 18-19 Sept 2003

MAIN OBSERVATIONS

1. **SPDC's portfolio of proved oil reserves** estimates appears **far less mature** than during the last (1999) reserves audit. The two main reasons for this are:
   - The Group guidelines for Proved reserves have been tightened considerably with respect to the need for properly defined FDPs and the passing of either VAR3 or FID hurdles,
   - SPDC's annual proved oil reserves submissions during the years 1999-2002 have been 'managed' largely by keeping the sum of oil and condensate recoveries constant and by presenting declining reserves through subtraction of annual production only, without taking heed of the underlying individual field estimates.

   The latter approach did not take sufficient account of the fact that realised offtake rates during 1999-2002 remained well below those originally planned (due to OPEC quota's, local community disturbances etc), while future planned rates (up to a doubling of offtake over a period of some 5-7 years) also proved unrealistic due to investment level restrictions. With the perceived end-of-licence in 2019 this meant that considerable volumes of proved reserves became unbookable during these years. This was not reflected in the reported estimates.

   This approach would have amounted to a serious loss of integrity of SPDC's proved reserves submissions over this period. However, the integrity loss was reduced significantly by the realisation by SPDC during 2002 that the present production licence agreements with the Nigerian authorities clearly do provide for a right to extend these permits and that such extensions have been granted without any serious hindrances in the past. Thus, any shortfalls in current or future production levels would no longer have any effect on producible volumes within-licence, and therefore not on bookable proved reserves either

   However, the above does not imply that all of SPDC's currently (1.1.2003) reported reserves are sound.

2. To date, SPDC have maintained **three separate sources of proved reserves estimates:**
   - The annual reserves submissions ('managed' separately, as described above),
   - The ARPR reserves volumes data base, built up from individual reservoir estimates
   - The annual Capital Allocation / Business Plan ('CA/BP') submissions, which provide production forecasts and proved and expectation reserves estimates for developed fields and future projects.

   Consistency between these three sources has been incomplete at best and, in the case of the annual reserves submissions, it was allowed to deteriorate further. SPDC have now realised this and steps have recently been taken to bring the three in closer alignment, aiming for full alignment in the course of 2004. This is strongly supported.

3. The approach taken by SPDC (with assistance by SIEP EPT-OE-VAS) has been to link the inventories of **CA/BP project data with individual reservoir data through a large combined spreadsheet.** The reservoir data was obtained directly from the Petroleum Engineering field teams, not from the ARPR, whose current volumes are seen as less reliable in many cases.

   This spreadsheet was enhanced by the addition of a set of criteria checks, which give a reflection of the maturity of each of the reservoirs and their development and reserves estimates. These checks relate e.g. to the appraisal status and general knowledge of the reservoirs, but also to the passing of development hurdles and to the potential for community disturbances (see Att. 2). These criteria checks should provide significant insight into the appropriateness of SPDC's proved reserves submissions and they are strongly supported.

   A number of the criteria checks coincide with necessary conditions for booking proved reserves, in accordance with the most recent (2003) Reserves guidelines. These are highlighted in Att. 2. A first pass run through the spreadsheet data seemed to indicate that 44% of proved developed reserves and only 7% of proved undeveloped reserves fulfil the criteria for proved reserves. It is likely that these percentages are too low: there are still a considerable number of 'empty' entries in the spreadsheet and these are planned to be completed before end year. However, there is a strong indication that in particular the undeveloped proved reserves have not kept pace with the increased requirements for booking such reserves as defined in the recent Group guidelines.

   It is noted that the availability of 3D seismic (one of the spreadsheet criteria) is not strictly a necessary condition for booking proved reserves. However, it is unlikely that fields without modern seismic will have passed recent VAR2/3 reviews and/or FID.

   The insertion of two additional criteria would be useful. There should be a check to indicate whether the proved volumes are consistent with 'known' fluid levels (from logs and/or pressures) as this is one of the key requirements for proved reserves. In addition, the intended year of start of development would allow a better assessment of the imminence (or otherwise) of the various development activities. The inclusion of both criteria into the spreadsheet is recommended.

4. **The incomplete alignment between CA/BP and individual field forecasts** and plans implies that not all fields and reservoirs carrying reserves are taken up into the CA/BP, nor are all CA/BP forecasts tied into specific fields. Both of these 'orphaned' forecasts and reserves are at present included into the spreadsheet. It is possible that to some extent they may cancel each other out. In any event, both groups should be eliminated from the spreadsheet (and indeed from the CA/BP data). SPDC have recognised this and are aiming towards full alignment between CA/BP and reserves data in the course of 2004. This is fully supported.

5. There are some obvious redundancies in the spreadsheet's criteria. This provides scope for **automatic checking for consistency** of the various entries. Examples are:
   - If VAR3 or FID has been passed, VAR2 must have been passed as well
   - Brown-field developments must have developed reserves / production in the same field,
   - New field developments must have no developed reserves and zero production,
   - Productivity is always proven if cumulative production is >0, etc.

   Use should be made of these redundancies to enhance the quality and robustness of the spreadsheet entries.

6. To provide better insight into the maturity of SPDC's proved oil reserves portfolio it is suggested that, following completion and validation of all spreadsheet entries, a distinction is made into **seven categories of proved oil reserves**:
   A. Proper proved developed reserves
   B. Proved developed reserves in reservoirs that are not yet mature
   C. Proper proved undeveloped reserves
   D. Reservoirs / projects that are likely to pass VAR3/FID in the next 2 years
   E. Reservoirs / projects that are likely to pass VAR3/FID between 2 and 5 years from now,
   F. Reservoirs / projects that are likely to pass VAR3/FID more than 5 years from now,
   G Reservoirs / projects that fall into none of the above and hence are completely immature.

   It is possible that a slightly different set of reserves categories may be more descriptive of the portfolio's maturity spectrum. This should be discussed between SPDC and SIEP EPS-P when the spreadsheet data set is complete (early December). The proven (and expectation) oil reserves volumes for each of the categories should be reported in a table format similar to that presented in the lower half of Attachment 2.

7. With a few exceptions for the more mature fields, the proved reservoir and field reserves are largely based on probabilistic volumetric estimates. Although the **ratio between proved and expectation reserves** is expected to show an increasing trend with field maturity (i.e. with the ratio between cumulative production and expectation ultimate recovery), this trend is not apparent in the current field data, see Attachments 3.1-3.4. In particular it is noted that:
   - P/E ratios for developed oil reserves are generally lower than for undeveloped oil reserves (the reverse is expected) and do rarely show an increasing trend with field maturity,
   - The P/E ratios for undeveloped gas reserves are in many fields (also some immature ones) close to 1, which cannot give a proper reflection of remaining uncertainties.

   It is suggested that plots as presented in Att. 3 are used to verify the appropriateness of proved vs. expectation estimates.

8. During the presentations it was mentioned by SPDC that a large amount of the reservoir/project proved oil reserves showed **volumes below 2 MMstb per reservoir** (100%). Their combined volume was said to amount to some 30-50% of total proved oil reserves. The reason for this could not be made clear during the audit. SPDC should investigate whether this is due to inappropriate conservatism in the estimates, to genuine end-of-life maturity ('scraping the barrel') or to the small size of the many (>3000) reservoirs. The subject should be addressed during the 2004 Proved Reserves Audit.

9. **SPDC's gas reserves** are in principle based on committed volumes to date. A gas strategy is in place. Booked reserves volumes at 1.1.2003 included contracted volumes for NLNG trains 1-3 (all now operating), a 42 bln sm3 allowance for the DomGas-East project and a small (notional) allowance of 4 bln sm3 for the West Africa Gas Pipeline (volumes Shell share). The latter two projects' volumes have not been secured by contract yet and are at this stage uncertain. These will be reduced / debooked per 1.1.2004. On the other hand, volumes for NLNG trains 4 and 5 have now been secured and these will allow an increase of some 54 bln sm3 in proved reserves, while a modest commitment for the DomGas West project will allow booking of 16 bln sm3 of gas. The net increase by 1.1.2004 could be some 30 bln sm3 Shell share. The precise status of contractual commitments for all these volumes was not discussed in detail during this audit and this should be addressed more fully during the 2004 audit.

10. As for further future gas reserves volume bookings, there is the potential problem that future **NLNG sales** may be more **on a spotmarket basis** rather than a firm long term gas sales contract. This brings the NLNG marketing closer to that of a mature gas market, similar to the land markets in the USA and Europe. Present reserves guidelines still require firm sales commitments for LNG gas reserves volumes, although gas volumes into existing (mature) gas markets can be booked without such commitments. It is suggested that the guidelines should be reviewed in such a manner that 'existing markets' are defined more precisely and may include mature LNG markets.

11. **SPDC's condensate reserves** (associated with non-associated gas (NAG) production, have been 'managed' in conjunction with the oil reserves, i.e. their combined volume was made to increase with the annual liquids production, without a specific link to actual field volumes. This link should be re-established. SPDC condensate reserves should be based fully on foreseen (and committed) NAG field gas sales and should be administered fully separately from the oil reserves.

12. The Nigerian authorities are now vigorously pursuing a **'flares out' policy, to be reached by 2008.** This means that Associated Gas Gathering ('AGG') plans must be in place for each of the major processing centres and their associated fields, and that implementation must be assured by 2008 before the associated post-2008 oil forecasts (and hence reserves) can be accepted as proved. SPDC have rightly included this criterion into their spreadsheet. Current improved modelling runs (and fields gas measurements) indicate that GOR trends may rise more slowly than originally thought. In addition, there are continuing delays in the on-stream dates of new oil projects. There is said to be sufficient NAG capacity in initial years to take up the shortfall.

13. In summary, **the way forward for SPDC's oil, condensate and gas reserves** booking per 1.1.2004 is suggested to be as follows:
    - Proved gas reserves can be booked as per plan, i.e. for NLNG trains 1-5 and appropriate, committed volumes for domestic gas,
    - Proved condensate reserves should be evaluated in line with foreseen NAG sales and should be administered to their full (proved!) extent, independently from oil reserves,
    - Proved oil reserves are at present overstated, pending maturation of a large number of future oil projects. In first instance, the 1.1.2004 proved oil volumes should be set at a level whereby the sum of proved oil and condensate reserves does not exceed the 1.1.2003 sum of these volumes, minus the combined 2003 production (similar to previous years). However, a further reduction in 1.1.2004 proved oil reserves may be necessary. At the least, all volumes in category G (fully immature, see 6 above) and possibly those in category F (long term projects) will need to be removed from the proved reserves portfolio. The precise reduction will depend on the project portfolio's maturity spectrum, as it will emanate from the updated spreadsheet in the coming months (see 6 above).

14. A fundamental consideration is that the Reserves / Production ('R/P') ratio for SPDC's proved reserves submission per 1.1.2003 is 11 years for developed reserves and 22 years for undeveloped reserves. Both these ratios are considerably in excess of the Group average, which are 6 and 7 years respectively. To some extent this reflects the present constraints to SPDC's current and future offtake rates. However, it also suggests that **the scope for a further increase in SPDC's proved reserves is rather tenuous.** Many of the presently foreseen developments are not required until well into the next decade, even at a favourable upturn in offtake levels (an increase from 0.8 MMb/d to 1.4 MMb/d in 100% SPDC offtake levels is assumed by 2009). Also, some projects need to be delayed because they require ullage in presently fully utilised facilities. This means that investment decisions (VAR3/4's and FID's) for these projects are not likely to be taken in the near future and hence, that proved reserves for these activities cannot properly be booked at this stage.

Recommendations

1. Verify and complete all entries in the SPDC reserves/ projects spreadsheet such that a proper scan of the maturity of the reserves portfolio can be made.

2. Add (and complete) two additional maturity criteria to the spreadsheet:
   - Confirmation that proved reserves are consistent with 'known' fluid levels (logs and/or pressures)
   - The intended year of start of development.

3. Use should be made of data redundancies to verify and enhance the quality and robustness of the spreadsheet entries.

4. The proved and expectation oil reserves volumes for each of the seven suggested (or slightly modified) reserves categories (representing varying degrees of maturity) should be reported in a table format similar to that presented in the lower half of Attachment 2.

5. SPDC condensate reserves should be based on foreseen (and committed) NAG field gas sales and should be administered fully separately from the oil reserves.

6. Proved oil reserves per 1.1.2004 should, in first instance, be set at a level whereby the sum of proved oil and condensate reserves does not exceed the 1.1.2003 sum of these volumes, minus the combined 2003 production. Further reductions may be necessary, i.e. all volumes in category G (fully immature, see 6 above) and possibly those in category F (long term projects).

7. Plots as presented in Att. 3 should be used to verify the appropriateness of proved vs. expectation estimates.

8. The 2004 audit should specifically look at:
- The status of the maturity of future projects in SPDC's portfolio and the effect that this will have on bookable proved reserves,
- The reason why small (<2 MMbl) reservoir reserves volumes occur in a large majority of cases,
- The precise status of gas contractual sales commitments,
- The reasons for the low Proved/Expectation reserves ratios in many fields (Att. 3).

These issues are already covered by the general Reserves Audit Terms of Reference, but in the case of SPDC reserves they require particular attention.

9. The Group reserves guidelines should be reviewed in such a manner that 'existing markets' are defined more precisely and may include mature LNG markets (action: SIEP EPS-P).

ATTACHMENT 2 - SPDC – SPREADSHEET CRITERIA FOR PROVED <u>OIL</u> RESERVES

Criterion (as included in SPDC's integrated reserves spreadsheet)	Proved Dev'd Resvs		Proved Undev'd Resvs					Comment
	Prov Resvs OK	Resvr not mature	Prov Resvs OK	Resvr OK FID <2 yr	Resvr OK FID 2-5 yr	Resvr OK FID >5 yr	Im-mature projects	
3D Seismic available?								
OWC defined?								
No Proved volumes below LKH or OWC from pressures?	+	X	+	+	+	+		
Productivity proven?	+	+	+	+	+	+		
Properly appraised?	+	X	+	+	+	+	R	
Near / far from existing infrastructure?								Not relevant if VIR OK?
AGG plans defined?	+	+	+	+	+	+	e	Needed for all post-'flares out' (2008) reserves
Community disturbance non-critical?	+	+	+	+	+	+		
Facilities not vandalised?	+	+	+	+	+	+	m	
VAR2 passed recently?			+	+	+	+		
VAR3 passed (if brown-field)?			+				a	
FID passed (if new field)?			+					
Project executed / executing?	+	+						
In production now (or shortly)?	+	+					i	
VIR / economics OK?			+	+	+	+	n	Only used for 'Unplanned' at present -- should be inserted for all
Volume < 2 MMstb (100%)?			+	+	+	+	d	Crude screening only – should be replaced by VIR/economics-check
Intended year of project's start of execution				≤2005	2006-2009	≥2010	e	
CA/BP 'Developed'	+	+	X	X	X	X	r	Prov Dev must be in CA/BP 'Developed'
CA/BP 'Base'	X	X	+	+	+	X		Prov Undev must be in 'Base' if pre-2010, otherwise in 'Options'
CA/BP 'Options'	X	X	+	X	X	+		
CA/BP Unplanned?	X	X	X	X	X	X		All proved reserves projects must be in CA/BP!
CA/BP 'Not known'?	X	X	X	X	X	X		All CA/BP projects must be 'known'

In italics *Criteria not yet in spreadsheet!*
+: Necessary criterion (must be 'Yes')
blank: Not needed
X: Not allowed (must be 'No')

SPDC Group share <u>oil</u> reserves volumes (MMstb) as per data base Sept 2003

	Proved Dev'd Resvs	% of booked resvs	Proved Undev'd Resvs	% of booked resvs	Proved Total Resvs	% of booked resvs
In CA/BP, fulfilling all proved reserves requirements	**377**	**44%**	**125**	**7%**	**502**	**20%**
In CA/BP, not fulfilling requirements	319	37%	1325	79%	1644	65%
In CA/BP, 'unknown' reservoirs	178	21%	198	12%	376	15%
Not in CA/BP, 'known' reservoirs ('Unplanned')			590	35%	590	23%
Total in data base	874	102%	2238	134%	3112	123%
Total actually booked 1.1.2003	**854**	**100%**	**1670**	**100%**	**2524**	**100%**

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