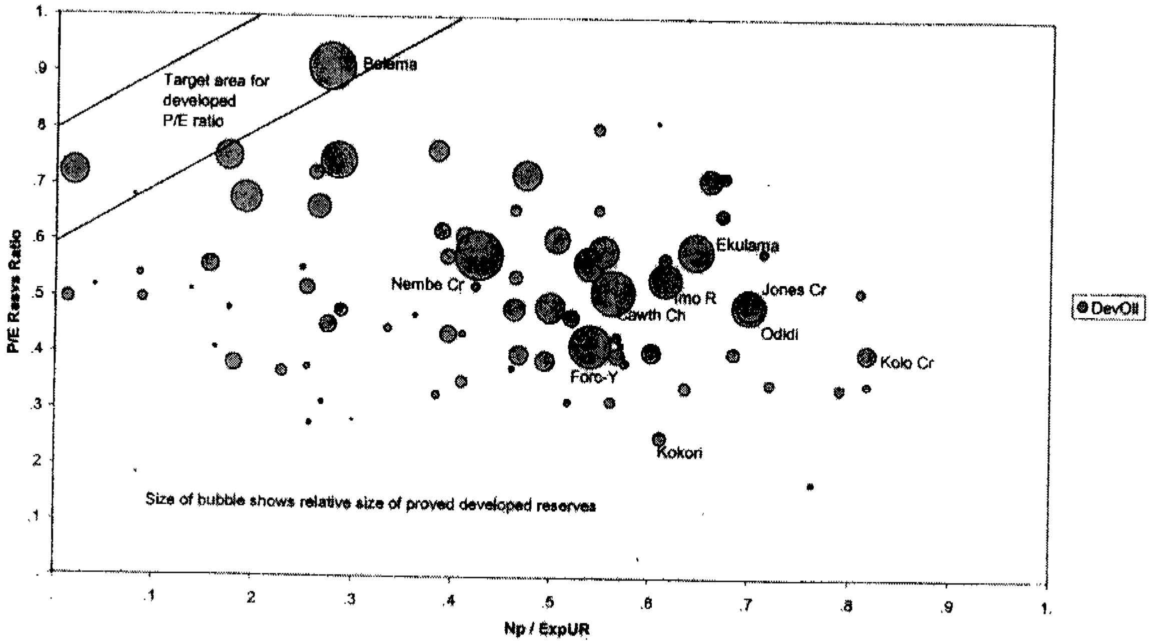
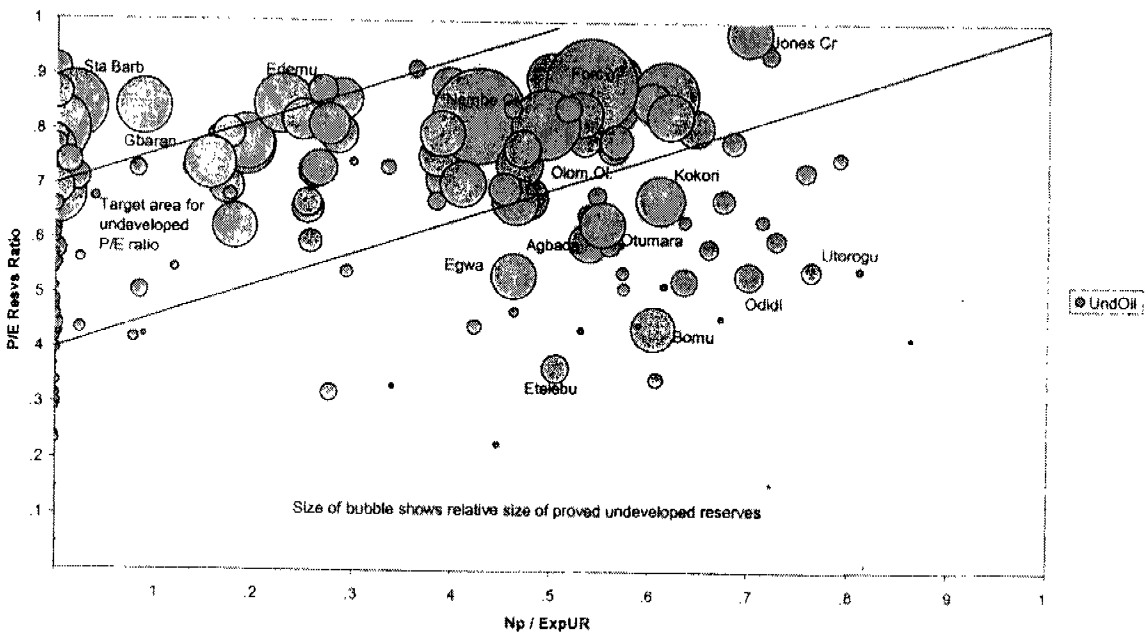
Attachment 3.1

SPDC - OIL DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - OIL UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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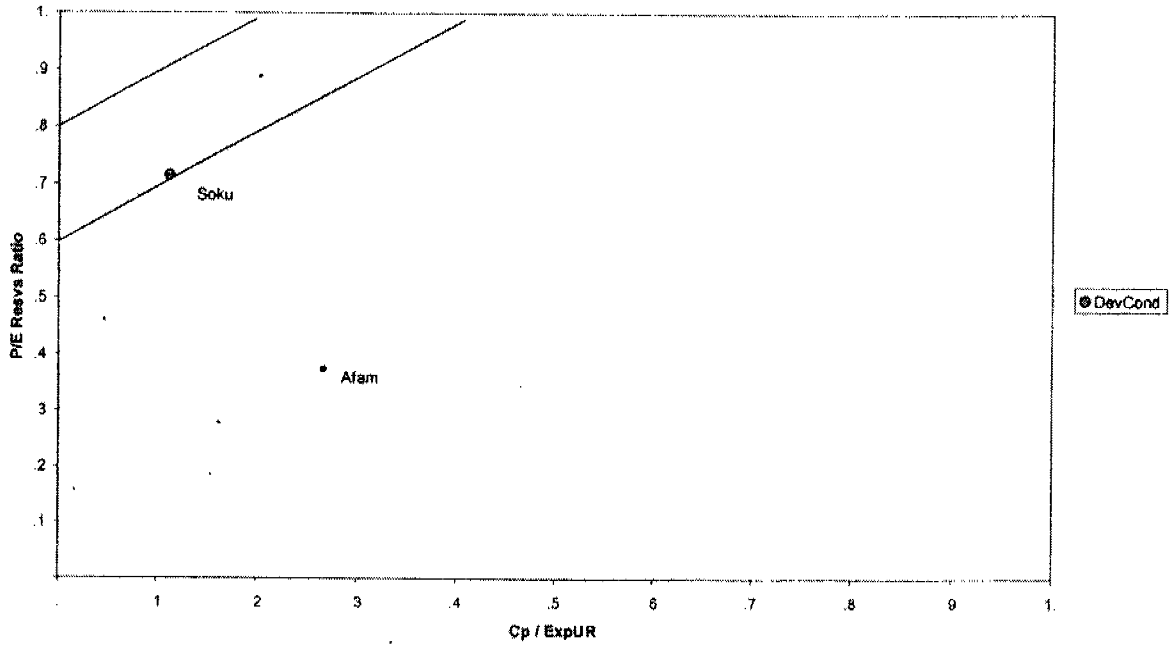
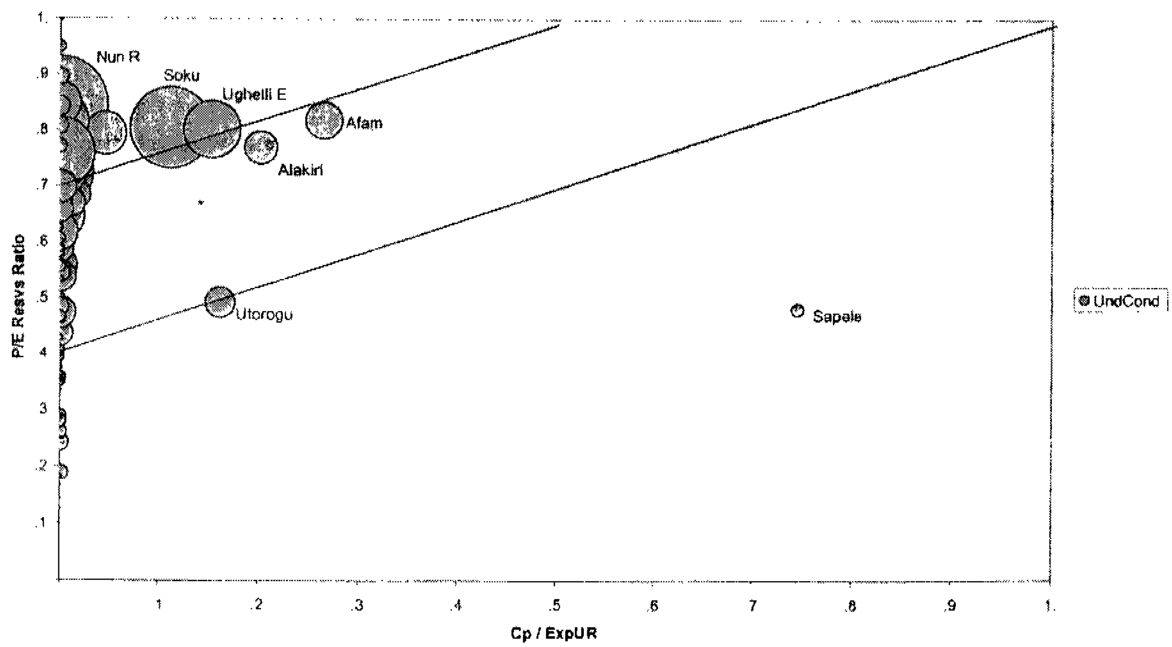
Attachment 3.2

SPDC - CONDENSATE DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - CONDENSATE UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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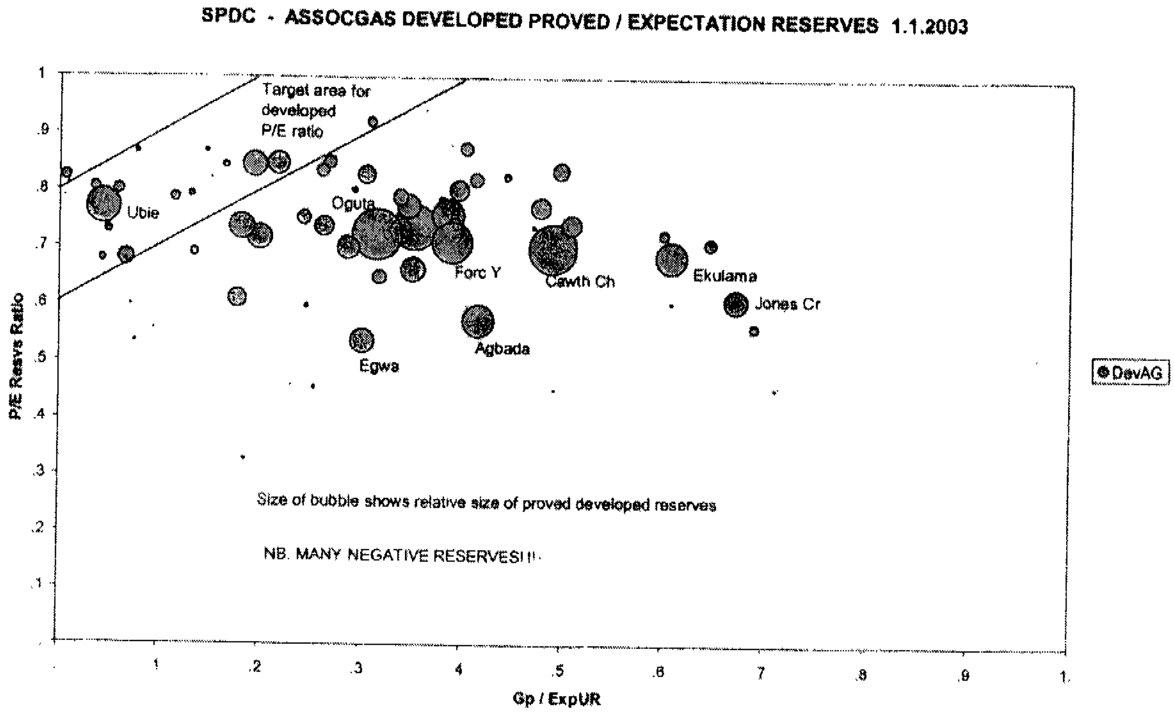
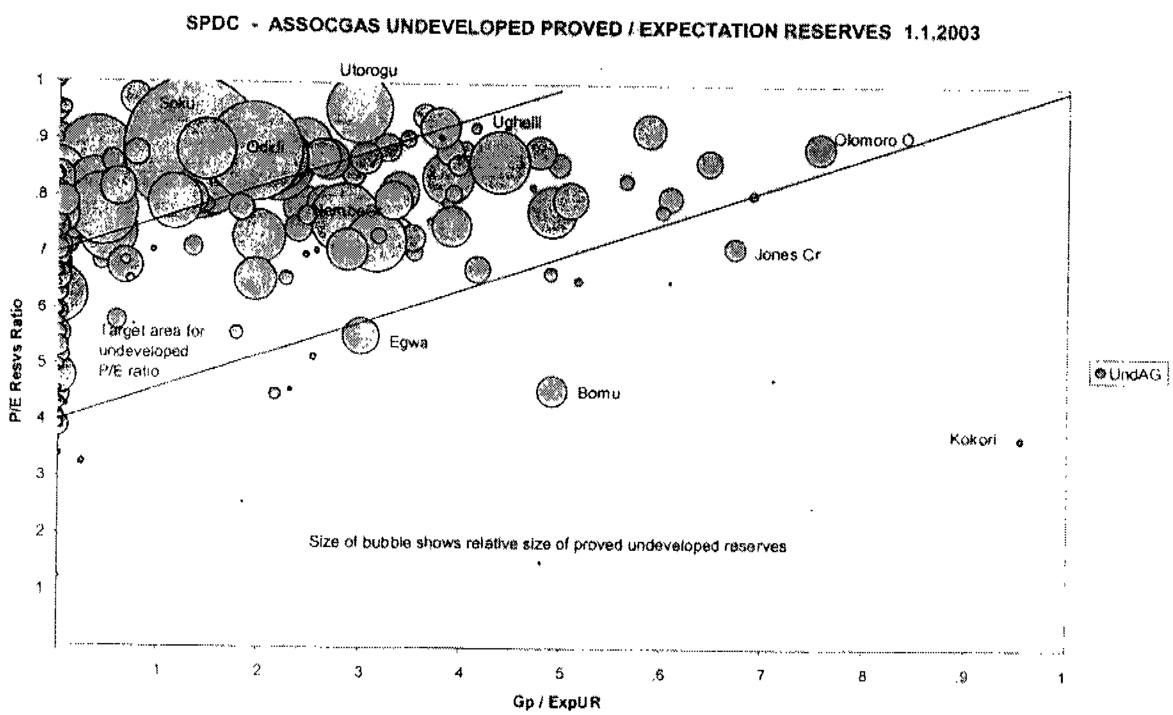
Attachment 3.3





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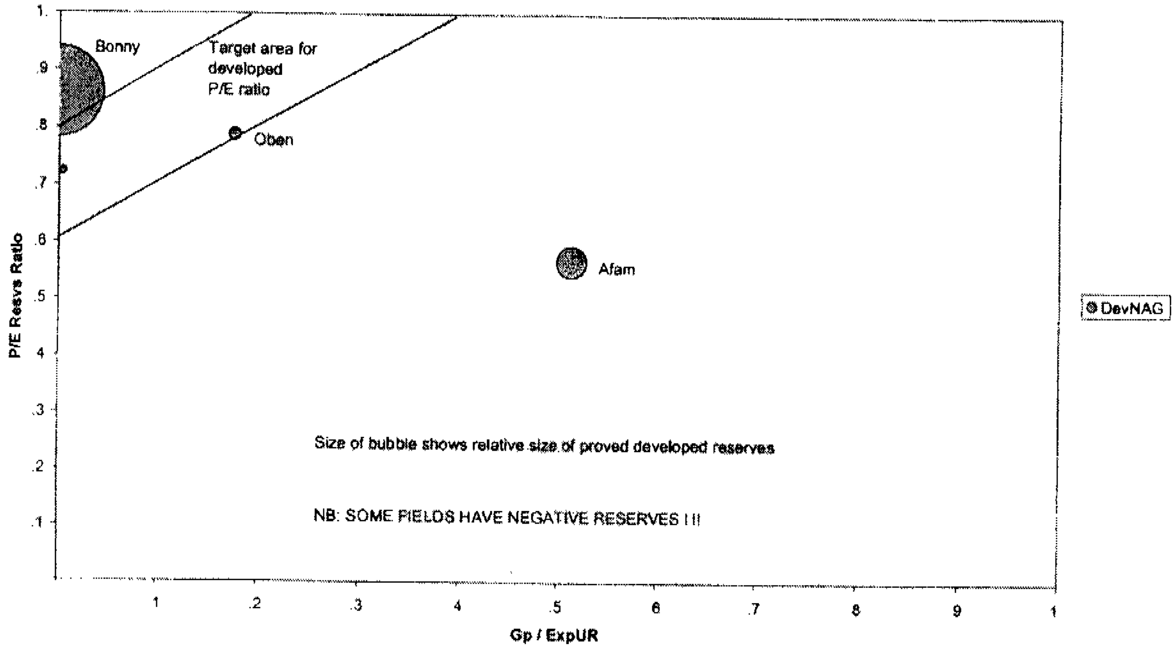
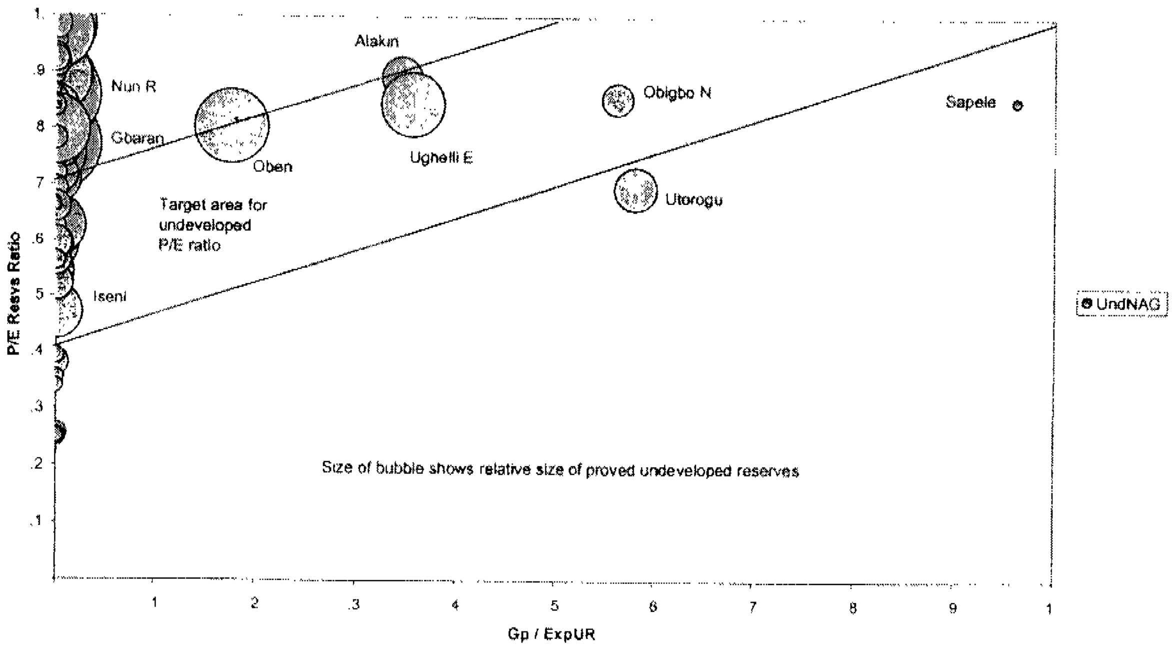
Attachment 3.4

SPDC - NAG DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - NAG UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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RJW00890500

NOTE – 30 Sept 2003

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From: Anton A. Barendregt — Group Reserves Auditor, SIEP & EPF - GRA

To:
Frank Coopman — Chief Financial Officer, SIEP – EPF
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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 (in The Hague), replacing a full audit, which has been deferred to 2004. The audit took the form of presentations and detailed discussions about the reserves reporting process with a small selection of 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, Capital Allocation / Business Plan volumes and end-year reserves submissions. 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 unsatisfactory. Efforts are underway to address this situation. Proved gas reserves at 1.1.2003 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 until the next decade. It seems 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.

A.A. Barendregt

Attachments 1, 2, 3

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DEPOSITION EXHIBIT
Barendregt
#20 2/21/07

V00010772

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 also 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) proved unrealistic due to investment level restrictions. With the perceived end-of-licence in 2019 this meant that considerable volumes of proved reserves would be produced after that date and thus became unbookable. 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. However, the integrity loss was reduced significantly by the realisation by SPDC during 2002 that Nigerian law does provide for a right to extend production licences 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.

   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 technical maturity of each of the reservoirs plus the maturity of their their development planning 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 only 44% of proved developed reserves and not more than 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 should be completed before end year. However, there is a strong indication that in particular the undeveloped proved reserves estimates have not kept pace with the increased requirements for booking such reserves as defined in the recent Group guidelines. The most significant of these is that the associated development projects must have passed either VAR3 (for small brownfield projects) or FID (for new field and major projects).

   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 ('proved area'). In addition, the inclusion of the intended year of start of development would allow a better assessment of the imminence (or otherwise) of the various development activities. The insertion 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 they may overlap to some extent and that their addition is not strictly valid. 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:
   - 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 without properly defined 'proved areas'
   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 proved (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 should 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 they do rarely show an increasing trend with field maturity,
   - The P/E ratios for undeveloped gas reserves are close to 1 in many fields, including some immature ones; this 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 (all 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 land based 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 next (Sept 2003) guidelines should be revised 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 kept condensate/LNG reserves artificially low and the link with actual field volumes should be re-established. SPDC condensate reserves should therefore 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 field 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 and a reduction in 1.1.2004 proved oil reserves will probably be necessary. The precise value of the reduction cannot be assessed at this stage as it will depend on SPDC's evaluation of the maturity spectrum of their portfolio by early December. At the least, all volumes in category G (fully immature or undefined, see 6 above) and probably those in category F (long term projects) will need to be removed from the proved reserves portfolio.

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 somewhat modified) reserves categories 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 exclude all volumes in category G (fully immature or undefined, see 6 above) and probably those in category F (long term projects). This should be reviewed jointly with SIEP EPS-P.
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 (Sept 2003) Group reserves guidelines should be revised 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 OIL RESERVES

Criterion (as included in SPDC's integrated reserves spreadsheet)	Proved Dev'd Resvs		Proved Undev'd Resvs					Comment
	Prov Resvs OK	'Proved area' not OK	Prov Resvs OK	Resvr OK FID <2 yr	Resvr OK FID 2-5 yr	Resvr OK FID >5 yr	Im-mature resvrs and projects	
3D Seismic available?								
OWC defined?								
No Proved volumes below LKH or OWC from pressures?	+	X	+	+	+	+		
Productivity proven?	+	+	+	+	+	+		
Property appraised?	+	X	+	+	+	+		
Near / far from existing infrastructure?							R	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 undeveloped reserves!
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')

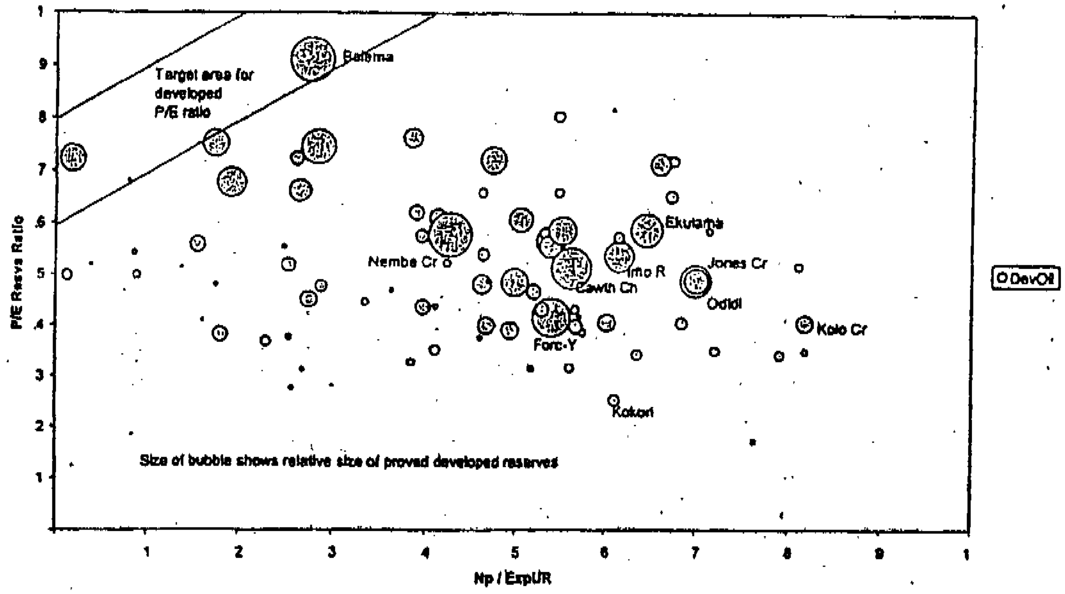
SPDC Group share oil reserves volumes (MMstb) as per data base Sept 2003

	Proved Dev'd Resvs	% of booked resvs	Proved Undev'd Resvs	% of booked resvs	Proved Total Resvs	% of booked resvs
In CA/BP, fulfilling 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%

Note: 'Unknown' and 'Unplanned' volumes may overlap – addition is not strictly valid!

Attachment 3.1

SPDC - OIL DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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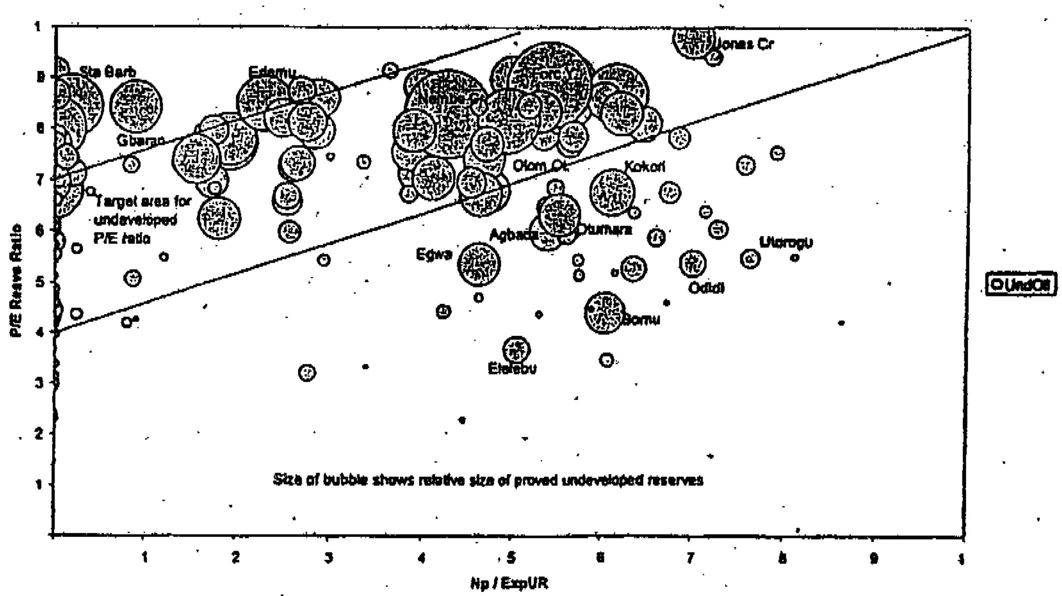
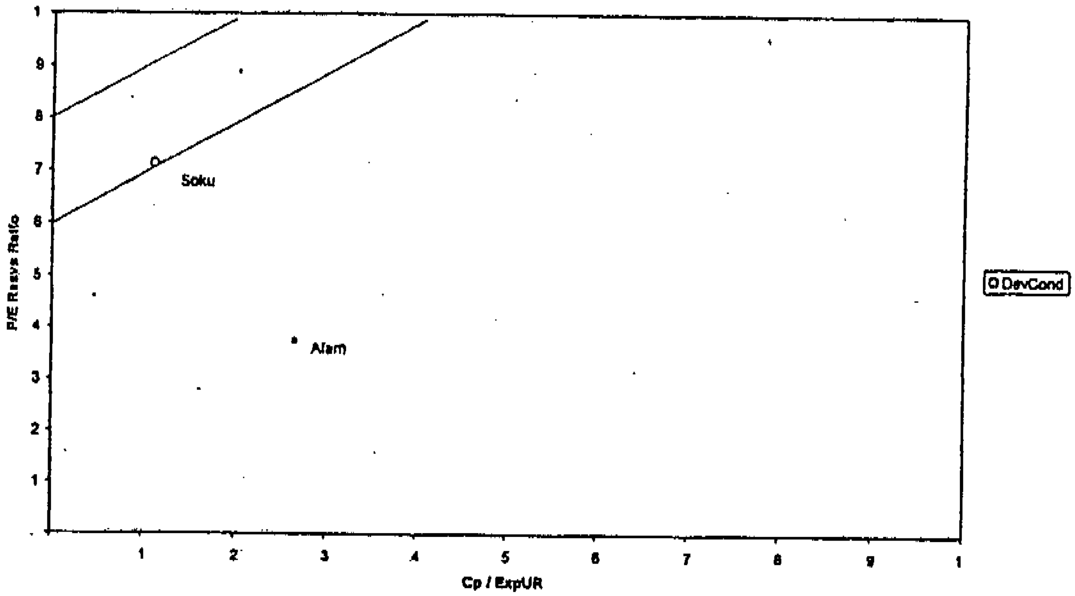
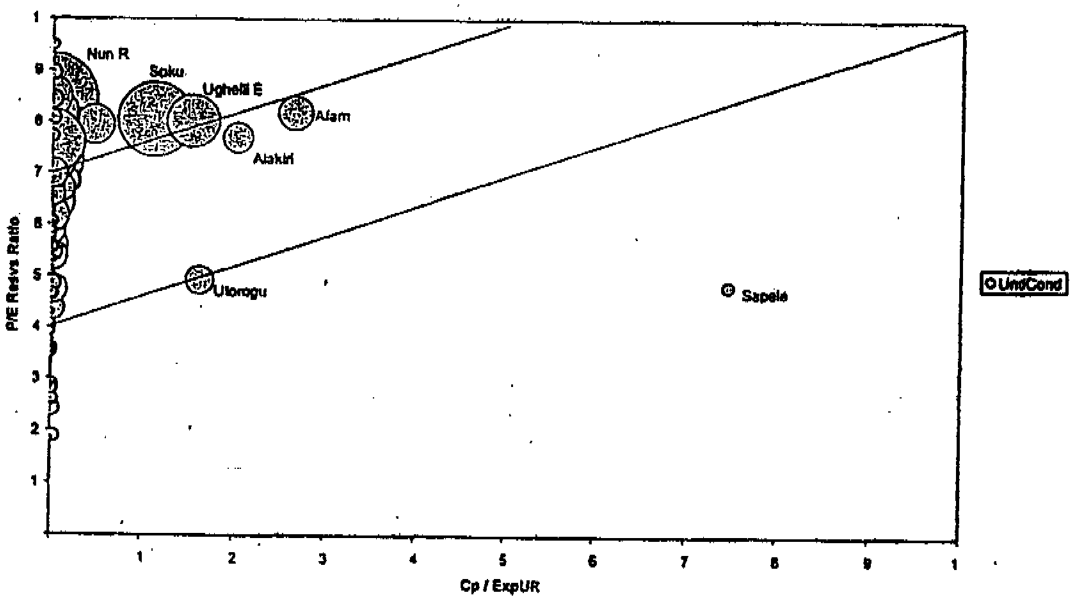


Attachment 3.2

SPDC - CONDENSATE DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - CONDENSATE UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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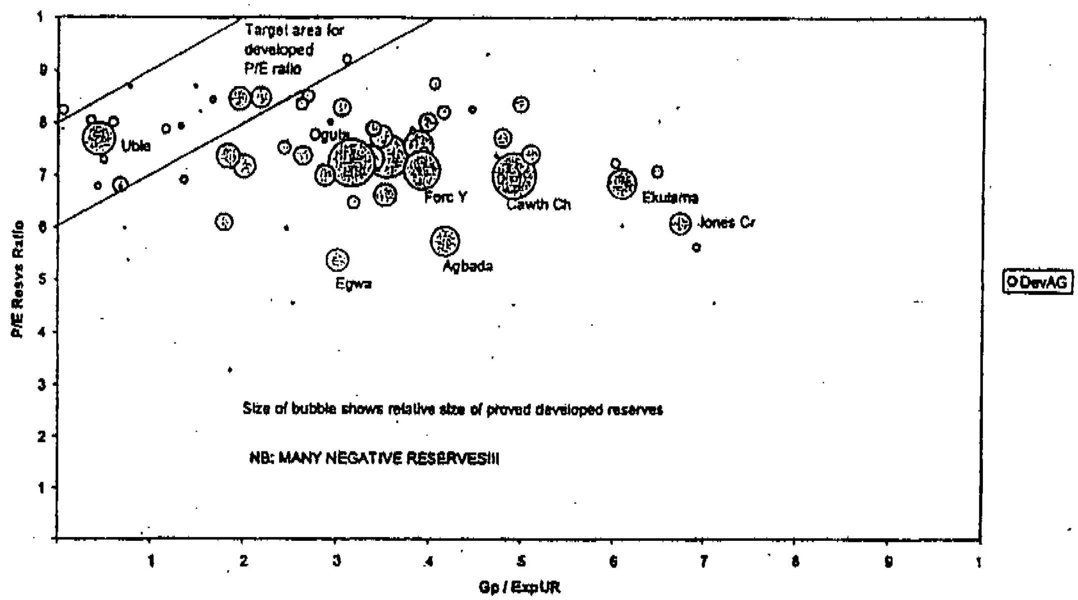
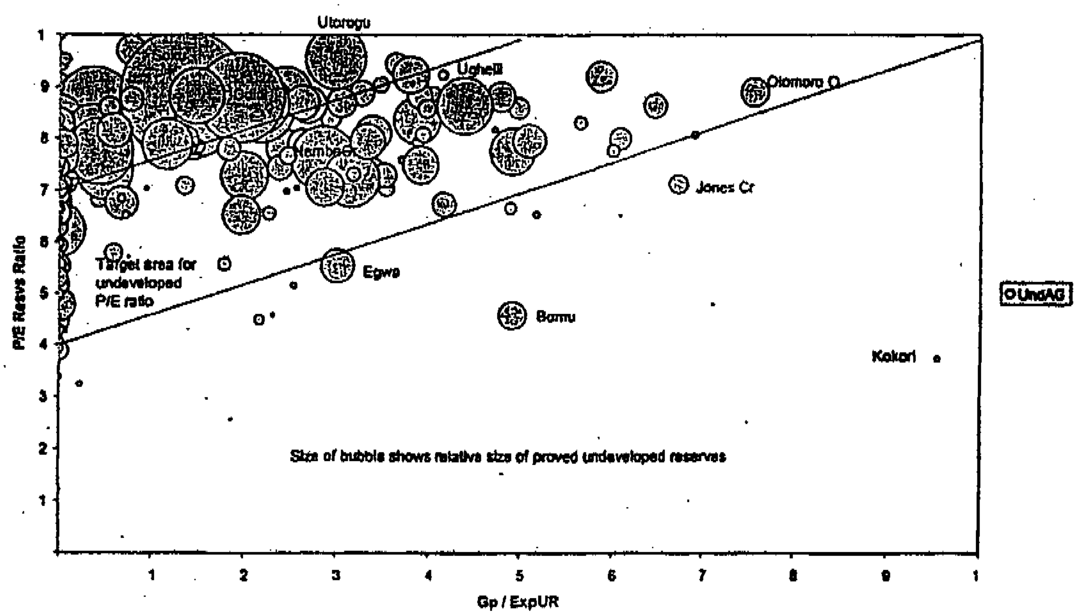
Attachment 3.3

SPDC - ASSOCGAS DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



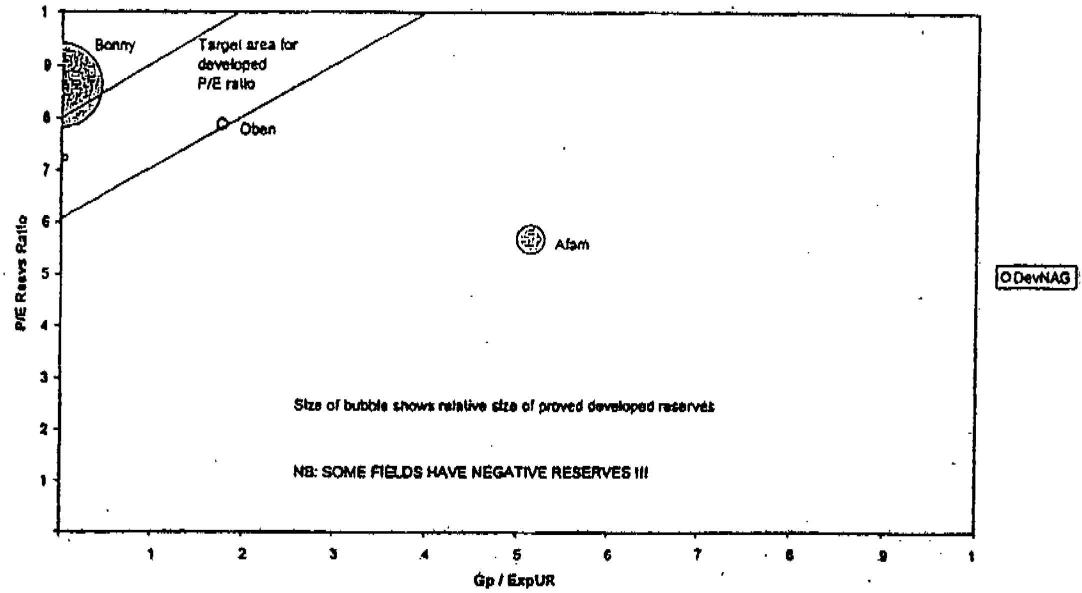
SPDC - ASSOCGAS UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



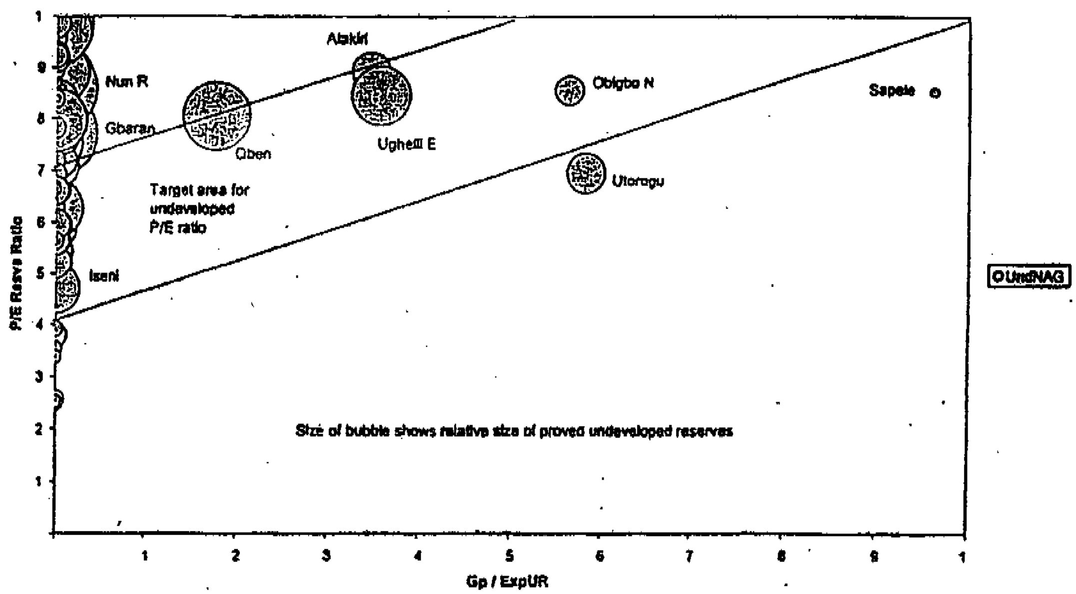
V00010780

Attachment 3.4

SPDC - NAG DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - NAG UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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V00010781

NOTE – 30 January 2001 **CONFIDENTIAL**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

30/1/01

A.A. Barendregt

Attachments 1 - 8

DEPOSITION EXHIBIT
Barendregt
#21 2/21/07

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

Attachment 1

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

MAIN OBSERVATIONS

1. Significant reserves changes during 2000 were as follows:

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

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

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

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

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

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

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

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

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

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

   A tabulation of these changes is given in Attachment 2.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Recommendations to SIEP Reserves Coordination:

1. Vigilance should continue to be applied by the SIEP Reserves Coordinator to ensure that all future Proved Reserves changes will be fully in accordance with Group Reserves Guidelines.

2. Confirm the viability of the 78% Proved Reserves increase booked by SVSA by a review of the planned VAR report and associated SVSA documentation during 2001.

3. Include the volume of Proved and Proved Developed Reserves not producible within current production licences in annual OU reserves submissions.

4. Strengthen the message that externally reported Proved and Proved Developed Reserves should be brought close to (made equal to) expectation reserves in mature fields in the Group Reserves Guidelines to be updated during 2001 and in the cover letter.

Attachment 2

SIGNIFICANT 2000 PROVED AND PROVED DEVELOPED RECOVERY CHANGES

(Shell Group share)

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

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

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

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2000 GROUP RESERVES SUBMISSIONS

Attachm 3.1

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

Country Name	Proved Resvs 1.1.2000	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2000	Proved Resvs 1.1.2001	Proved Dev'd Resvs 1.1.2000	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2000	Proved Dev'd Resvs 1.1.2001	Minority Resvs incl. 1.1.2000	Minority Resvs incl. 1.1.2001	R / P Tot (yr)	Repl'mt Ratio TotRes (%)	Repl.R. TotRes (%) Excl Pur/ Sales iP	Repl'mt Ratio DevRes (%)
Australia (SDA)	32.49	4.18		.07		3.5	4.2	29.04	14.76		.52	4.2	11.08			7	18%	101%	12%
Australia (WPL)	11.85	2.64		4.83			2.28	17.04	5.63		2.26	2.28	5.61			7	328%	328%	99%
Brunei	59.28	8.92	2.8	3.9			5.54	69.36	28.19	6.04	6.19	5.54	34.88			13	282%	282%	221%
China	3.24	4.16					1.43	5.97	2.83	.7	3.18	1.43	5.27			4	291%	291%	271%
China (Shell Oil EH)	3.29	-3.29							2.87		-2.87								
Malaysia	25.55	-.94	2.84	2.68			3.28	26.85	13.95	3.	.09	3.28	13.76			8	140%	140%	94%
New Zealand	4.6	-.17		.98			.41	5.	2.6	.11	-.04	.41	2.26			12	198%	198%	17%
New Zealand (Shell Oil EH)	.8	.05					.11	.74	.67		.06	.11	.62			7	45%	45%	55%
Philippines	3.82	.38				.7		3.5											
Thailand	14.17	.89	1.34				1.04	15.35	3.78	.95	.33	1.04	4.02			15	214%	214%	123%
Angola				11.85				11.85											
Argentina	3.43	.26		.07			.22	3.54	2.03	.06	-.03	.22	1.84			16	150%	150%	14%
Brazil (Shell Oil WH)	.81	.2					.09	.92	.81		.2	.09	.92			10	222%	222%	222%
Cameroon (Shell Oil EH)	7.75	-1.68	.2	.11			1.21	5.17	7.28	.29	-1.36	1.21	5.		1.03	4	-113%	-113%	-88%
Congo (DR)	3.22	-.01					.17	3.04	2.3		-.02	.17	2.11			18	-6%	-6%	-12%
Gabon	19.91	3.83				.81	3.99	18.94	17.45	1.12	2.5	3.99	17.08	4.97	4.74	5	76%	96%	91%
Nigeria (SNEPCO)	71.41	7.15		10.98				89.54											
Nigeria (SPDC)	448.1						13.93	434.17	113.19	4.29	13.33	13.93	116.88			31	0%	0%	126%
Venezuela	21.43	16.66					2.54	35.55	11.61	1.03	1.19	2.54	11.29			14	656%	656%	87%
Abu Dhabi	103.26	.02					5.58	97.7	83.71	2.11	.94	5.58	81.18			18	0%	0%	55%
Bangladesh																			
Egypt	9.06	-2.59					.58	5.89	5.73	.01	-1.69	.58	3.47			10	-447%	-447%	-290%
Iran	23.85	7.74						31.59											
Kazakhstan (Temir)	2.	.01				2.	.01			.01		.01				0	-19900%	100%	100%
Oman	139.5	34.88	18.43	3.21			16.62	179.4	85.	4.95	6.67	16.62	80.			11	340%	340%	70%
Oman Gisco	33.18	-12.34					2.36	18.48	27.32		-8.2	2.36	16.76	4.98	2.77	8	-523%	-523%	-347%
Pakistan																			
Russia (Sakhalin Holding)	7.69	-.01			7.93		.51	15.1	2.81	1.19	2.59	.51	5.88			30	1553%	-2%	741%
Syria	19.81	-1.17					2.92	15.72	12.29	.98	1.	2.92	11.35			5	-40%	-40%	68%
Austria	.23	.02		.01			.03	.23	.19		.03	.03	.19			8	100%	100%	100%
Canada	47.16	-1.42	14.43	.07		.01	3.36	56.87	29.13		1.11	3.36	26.88	10.36	12.49	17	389%	389%	33%
Canada (AOSP)	95.4							95.4						21.2	21.08				
Denmark	39.15	7.17	4.34	.41			7.53	43.54	27.63	1.41	11.44	7.53	32.95			6	158%	158%	171%
Germany	3.37	-.01					.31	3.05	3.07	.17	-.02	.31	2.91			10	-3%	-3%	48%
Netherlands	5.77	-.06					.75	4.96	3.93	.41	.1	.75	3.69			7	-8%	-8%	68%
Norway	33.26	5.34				.77	5.07	32.76	20.65	4.56	3.44	5.07	23.58			6	90%	105%	158%
Shell Oil (MCC)	1.86	-1.86							1.56		-1.56								
Shell Oil (TMR)	.93	.16		.13		.08	.16	.98	.56	.07	.14	.16	.61			6	131%	181%	131%
UK	129.92	.49	2.89	1.42		10.49	21.98	102.25	90.35	14.56	-7.35	21.98	75.58			5	-26%	22%	33%
USA	92.	2.24		20.04	.01	.94	16.18	97.17	54.12	11.54	6.34	16.18	55.82			6	132%	138%	111%
USA (Aera)	79.26	-3.07	.26			.13	7.23	69.09	59.01	4.08	1.39	7.23	57.25			10	-41%	-39%	76%
USA (Altura)	47.87	.61				47.78	.7		40.24		-39.54	.7				0	-6739%	87%	-5649%
Total excl Can. AOSP	1,554.28	79.38	47.53	60.76	7.94	67.21	132.32	1,550.35	777.05	63.64	2.36	132.32	710.72	20.31	21.03	12	97%	142%	50%
Grand Total	1,649.68	79.38	47.53	60.76	7.94	67.21	132.32	1,646.75	777.05	63.64	2.36	132.32	710.72	41.51	42.11	12	97%	142%	50%

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2000 GROUP RESERVES SUBMISSIONS

Attachment 3.2

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

Country Name	Proved Resvs 1.1.2000	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2000	Proved Resvs 1.1.2001	Proved Dev'd Resvs 1.1.2000	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2000	Proved Dev'd Resvs 1.1.2001	Minority Resvs incl. 1.1.2000	Minority Resvs incl. 1.1.2001	R / P Tot (yr)	Repl'mt Ratio TotlRes (%)	Repl.R. TotlRes (%) Excl Pur/ Sales iP	Repl'mt Ratio DevRes (%)
Australia (SDA)	176.638	2.576	.	.453	.	.394	2.356	176.917	18.583	.	1.824	2.356	18.051	.	.	75	112%	129%	77%
Australia (WPL)	40.205	1.274	.	.155	.	.	1.45	40.184	8.147	.	1.305	1.45	8.002	.	.	28	99%	99%	90%
Brunei	102.612	-2.08	.	4.023	.	.	4.656	99.899	40.744	5.442	-3.601	4.656	37.929	.	.	21	42%	42%	40%
China																			
China (Shell Oil EH)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Malaysia	183.819	-11.93	5.625	.	.	.	5.723	171.791	37.746	20.212	-1.27	5.723	50.965	.	.	30	-110%	-110%	331%
New Zealand	12.646	.031	.	3.361	.154	.	1.381	14.811	11.704	.016	.19	1.381	10.529	.	.	11	257%	246%	15%
New Zealand (Shell Oil EH)	2.314	-.312	.	.	.	.	.247	1.755	2.014	.	-.319	.247	1.448	.	.	7	-126%	-126%	-129%
Philippines	19.436	1.029	.	.	.	3.551	.	16.914	.	.	.	.	.	.	.				
Thailand	6.226	.338	.063	.	.	.	.437	6.189	2.769	.263	.238	.437	2.833	.	.	14	92%	92%	115%
Angola	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Argentina	7.284	1.522	.	.619	.	.	.036	9.389	.547	.056	-.501	.036	.066	.	.	261	5947%	5947%	-1236%
Brazil (Shell Oil WH)	4.384	1.083	.	.	.	.	.326	5.141	4.384	.	1.083	.326	5.141	.	.	16	332%	332%	332%
Cameroon (Shell Oil EH)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Congo (DR)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Gabon	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Nigeria (SNEPCO)	5.7	.57	.	.75	.	.	.	7.02	.	.	.	.	.	.	.				
Nigeria (SPDC)	95.93	-8.384	.	.	.	.	1.836	85.71	37.837	.	-1.987	1.836	34.014	.	.	47	-457%	-457%	-108%
Venezuela	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Abu Dhabi	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Bangladesh	4.713	.039	.	.457	.	.	.384	4.825	2.846	.	-.2	.384	2.262	.	.	13	129%	129%	-52%
Egypt	31.272	-2.326	.39	.	.	.	1.455	27.881	14.059	1.624	-.722	1.455	13.506	.	.	19	-133%	-133%	62%
Iran	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Kazakhstan (Temir)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Oman	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Oman Gisco	45.693	14.272	.	.	.	.	4.758	55.207	45.693	.	3.825	4.758	44.76	6.854	8.281	12	300%	300%	80%
Pakistan	11.339	-.752	.	.	.	.532	.189	9.866	3.347	.	.	.189	3.158	.	.	52	-679%	-398%	0%
Russia (Sakhalin Holding)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Syria	1.012	-.074	.	.	.	.	.234	.704	.596	.013	-.038	.234	.337	.	.	3	-32%	-32%	-11%
Austria	1.476	.191	.	.104	.	.	.175	1.596	1.441	.	.228	.175	1.494	.	.	9	169%	169%	130%
Canada	88.31	3.231	.	.206	.	.895	6.153	84.699	72.2	.	.688	6.153	66.735	19.402	18.608	14	41%	56%	-11%
Canada (AOSP)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Denmark	30.44	.941	.711	.365	.	.	3.105	29.352	18.73	.518	2.307	3.105	18.45	.	.	9	65%	65%	91%
Germany	59.422	1.225	.	.	.	.	4.659	55.988	46.423	1.565	1.023	4.659	44.352	.	.	12	26%	26%	56%
Netherlands	413.425	.132	.	1.122	.	.	14.828	399.851	211.215	3.23	.73	14.828	200.347	.	.	27	8%	8%	27%
Norway	89.897	2.15	.	.	.	.208	2.06	89.781	42.194	.224	-3.466	2.06	36.892	.	.	44	94%	104%	-157%
Shell Oil (MCC)	1.552	-1.552	.	.	.	.	.	.	1.504	.	-1.504	.	.	.	.				
Shell Oil (TMR)	1.693	-.364	.	.128	.	.113	.202	1.142	1.193	.062	-.16	.202	.893	.	.	6	-173%	-117%	-49%
UK	109.447	1.493	2.27	.075	.	3.096	11.583	98.606	67.734	11.532	-.223	11.583	67.46	.	.	9	6%	33%	98%
USA	96.232	-1.091	.	18.564	1.421	2.217	16.592	96.317	76.788	10.178	-3.968	16.592	68.406	.	.	6	101%	105%	37%
USA (Aera)	5.53	-4.036	.052	.	.	.142	.117	1.287	3.145	.761	-2.803	.117	.986	.	.	11	-3526%	-3405%	-1745%
USA (Altura)	8.068	.062	.	.	.	8.018	.112	.	6.985	.	-6.873	.112	.	.	.	0	-7104%	55%	-8137%
Total excl Can. AOSP	1,656.715	-.742	9.111	30.382	1.576	19.164	85.054	1,592.822	780.568	55.696	-14.194	85.054	737.016	26.256	26.889	19	25%	46%	49%
Grand Total	1,656.715	-.742	9.111	30.382	1.576	19.164	85.054	1,592.822	780.568	55.696	-14.194	85.054	737.016	26.256	26.889	19	25%	46%	49%

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LON01260659

2 PRODUCTION RECONCILIATION - OIL+

Attachm 4.1

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

Jan30Note-tbl.xls, OilNGLRecn-Att4.1

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FOIA Confidential Treatment Requested

LON01260660

2000 PRODUCTION RECONCILIATION - GAS

Attachment 4.2

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

Jan30' 'bl.xls, GasRecn-Att4.2

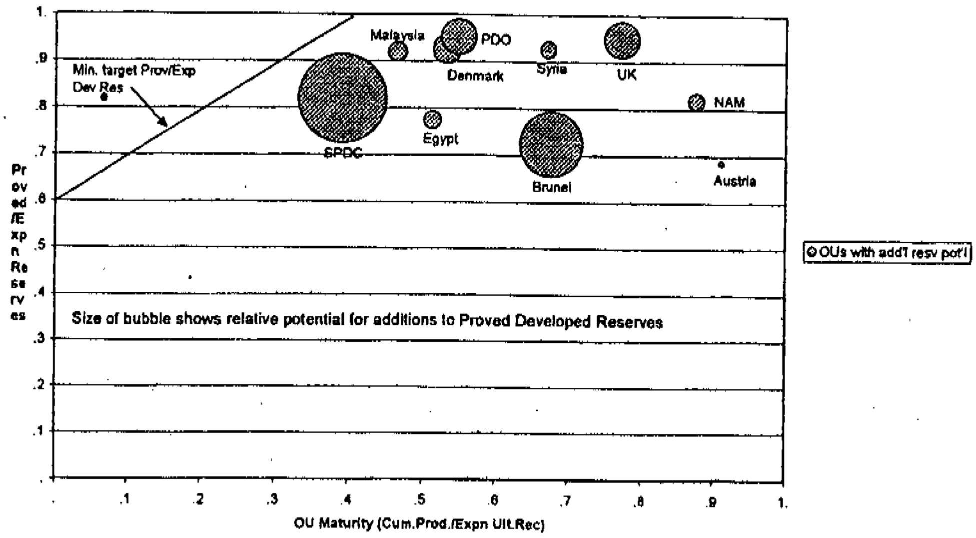
26/01/0' '0:05

FOIA Confidential Treatment Requested

LON01260661

Attachment 5.1

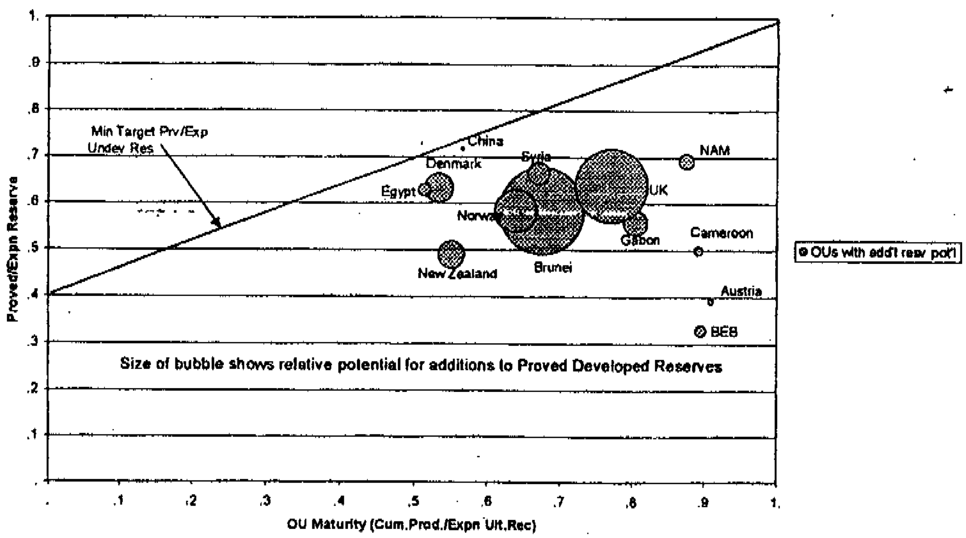
1.1.2001 DEVELOPED OIL+NGL RESERVES



old.

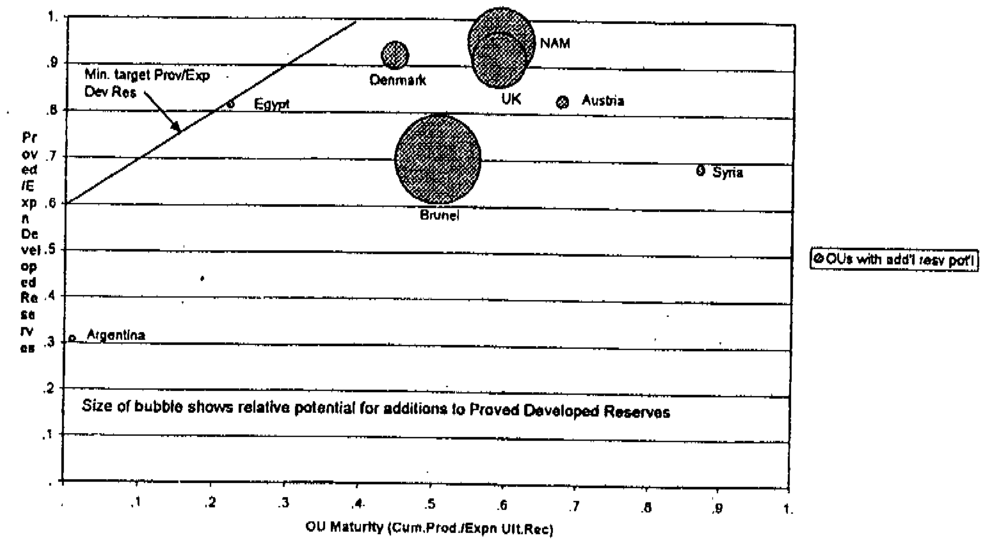
NEW

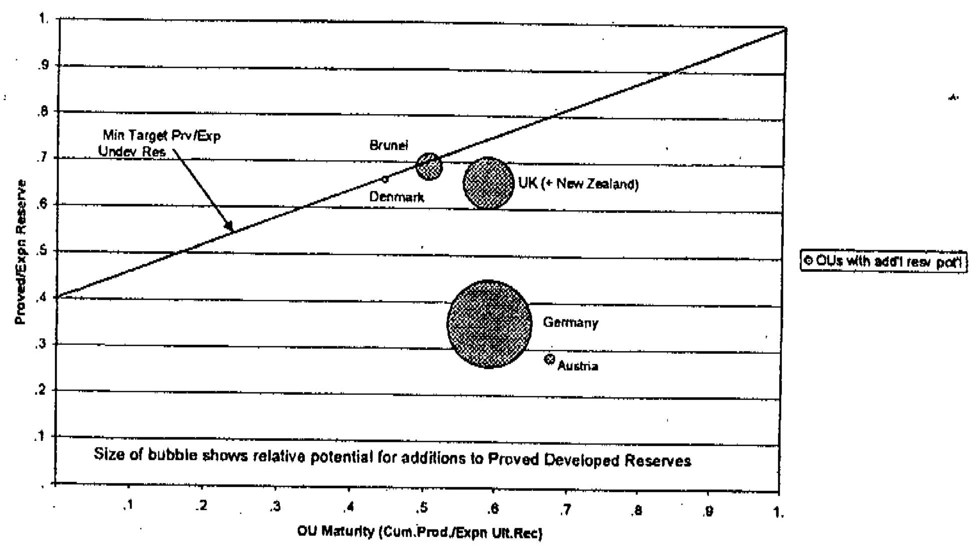
1.1.2001 UNDEVELOPED OIL+NGL RESERVES



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

Attachment 5.2





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

BP - [illegible]

Attachment 6

ANGOLA BLOCK 18 - INITIAL RESERVES BOOKING 1.1.2001
Group Reserves Auditor Comments

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

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

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

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

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

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

A.A. Barendregt, 17 January 2001

References:

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

Attachment 7

2000 RESERVES AUDITS - MAIN OBSERVATIONS

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

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

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

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

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

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

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TIME TABLE SEC RESERVES AUDITS

Attachment 8

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

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

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

Audit frequency:

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

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

Jan30Note-tbl.xls, AudSched-Att8

26/01/01

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DEPOSITION EXHIBIT
Barendregt
#22 2/21/07

NOTE – 30 January 2002

CONFIDENTIAL

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

REVIEW OF GROUP END-2001 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

In accordance with prescribed US FASB accounting principles, SIEP staff have prepared a summary of Group equity provi and proved developed oil and gas reserves for the year 2001. The summary (Att. 3) forms part of the supplementa information that will be presented in the 2001 Group Annual Reports and has been prepared on the basis of informatic provided by Group and Associated companies. The submissions by these companies (excluding those by Shell Canada) a based on the procedures laid down in the Group 'Petroleum Resource Volumes Guidelines' which in turn are based on (but n identical to) the FASB definitions. Shell Canada's submissions are subject to their own procedures and reviews.

The end-2001 Group share Proved Reserves is summarised in the following table. The figures include the Canadian oil san reserves (reportable as mining reserves) and the minority reserves in some consolidated companies (together 150 mln m3oe*

Oil mln m3 Gas bln m3	1.1.2001 Proved Tot'l	2001 Prod'n	1.1.2002 Proved Tot'l	Repl.Ratio (RR) Totl	1.1.2001 Proved Dev'd	1.1.2002 Proved Dev'd	Rep. Ratio Dev'd
Oil+NGL	1646	129	1601	65%	711	689	83%
Gas	1593	93	1580	86%	737	729	91%
Total Oil Equivalent *	3189	219	3132	74%	1425	1394	86%

* 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 a these relate to companies outside Canada. This review included, where possible, a verification of the appropriateness of maj reserves changes. The most significant conclusions are as follows:

A first time booking for the Bonga SW field (SNEPCO Nigeria) was not accepted by EPB-P staff because the propose volumes (21 mln m3oe) were technically not mature and did not fulfil present reserves guidelines. This view is fully supporte Further reserves additions in Angola block 18 (where marginal reserves were booked for the first time last year) were als disallowed by EPB-P because the project is economically still marginal, while gas disposal could become a show stopper. Thi view is also supported. Without any material change in this latter project, reserves may need to be de-booked next year.

Group reserves guidelines have been reviewed against industry practice during 1998 and this has resulted in a 200 mln m3o increase in Group share Proved reserves in mature fields in recent years. However, recent clarifications of FASB reserve guidelines by the US Security and Exchange Commission (SEC) have shown that current Group reserves practice regardin the first-time booking of Proved reserves in *new* fields is in some cases too lenient. The Group guidelines should be reviewe First time bookings should be aligned closer with SEC guidance and industry practice and they should be allowed only for fim projects with technical maturity and full economic viability.

The widespread use of reserves targets in score cards affecting variable pay is seen to affect the objectivity of staff in som OUs when proposing reserves additions. Reserves coordination staff in EPB-P have been alert to this and have successfull met the challenges with which they were faced. However, a shift in score card emphasis from reserves booking to successfull meeting project milestones is recommended.

Awareness of Group and SEC reserves booking guidelines was seen to be less than desirable at senior levels in OUs and i support functions in the centre (RBDs, SDS, SEPTAR). This should be improved by issuing appropriate high level guidelin summaries, organisation of workshops etc.

After some corrections, very good correspondence was obtained between annual production volumes as reported through th separate Finance (Ceres) and SIEP reserves systems. Both of these are reported (separately) in the Group annual report.

During 2001 I made Reserves Audit visits to a total of seven Group OUs. Audit opinions on these varied between 'satisfactory and 'good'. As far as observed, most audit recommendations appear to have been followed in this year's submissions.

The overall finding from the audit visits and from the end-year review in SIEP is that the SIEP statements fairly represent th Group entitlements to Proved Reserves at the end of 2001. There is a possibility of a minor overstatement of Group Proved reserves in some fields where historically booked reserves are not fully in line with recent SEC guidance. However, this overstatement is likely to be offset by reserves in areas where current Proved reserves are probably too conservative (e.g. Brunei). The 2001 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

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Attachments 1-7

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Attachment 1 Main Observations End-2001 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 2001 Reserves Audits
Attachment 7 Reserves Audit Plan 2002

Attachmei

REVIEW OF GROUP END-2001 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

MAIN OBSERVATIONS

1. **Reserves Summary**

The 1.1.2002 Group share Proved Reserves can be summarised as follows:

Oil mln m3 Gas bln m3	1.1.2001 Proved Tot'l	2001 Prod'n	1.1.2002 Proved Tot'l	Repl.Ratio Total	1.1.2001 Proved Dev'd	1.1.2002 Proved Dev'd	Repl.Rat Dev'd
Oil+NGL	1646	129	1601	65%	711	689	83%
Gas	1593	93	1580	86%	737	729	91%
Total Oil Equivalent*	3189	219	3132	74%	1425	1394	86%
Canada Oil sands	95		95				
Minority reserves	48		55				
Net Group m3oe	3046		2982				

* 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 share reserves, i.e. including the Canadian sands and Minority reserves.

A full overview of end-2001 Proved and Proved Developed Reserves is presented in Attachment 3.1-2.

2. **Significant reserves changes**

Significant reserves changes during 2001 were as follows:

Acquisition of assets from Fletcher Challenge Energy led to Group share reserves increases in New Zealand (+35 mln m3oe) and Brunei (+5 mln m3oe). In the USA, the Pinedale (Rocky Mountain) gas acquisition added 10 mln m3oe. Tl was partly offset by a net divestment in Pakistan (-3 mln m3oe) and by a revision of the Oman Gisco gas processing agreement (-16 mln m3oe).

Technical reviews led to reserves additions in the Netherlands (+23 mln m3oe), in the USA (+24 mln m3oe), in Denmai (+11 mln m3oe) and in Sakhalin (+3 mln m3oe), whilst reductions were seen in New Zealand (-11 mln m3oe), Canada 9 mln m3oe) and Egypt (-5 mln m3oe). New fields were booked in the USA (+10 mln m3oe) and Brunei (+5 mln m3oe) New field developments added developed reserves in the USA (+26 mln m3oe), Australia (+21 mln m3oe), SPDC (+17 mln m3oe of gas and NGL), Philippines (+13 mln m3oe) and Iran (+6 mln m3oe).

The reserves increase of +23 mln m3oe in the Netherlands was booked in the Groningen field. Field performance ovei the last ten years had allowed gradual increases in Proved developed reserves, but total Proved reserves were maintained unchanged. Booked undeveloped reserves (e.g. as a result of very low pressure compression) became thu ~~indefensibly low and this has now been rectified.~~

Further maturing of gas utilisation and development in SPDC (Nigeria) is allowing gradual increases in Proved developed and total gas reserves. Proved condensate (NGL) reserves do also increase, but these have to be largely offset by corresponding reductions in Proved oil reserves because of the overall constraint in offtake rate and licence duration (see also below).

A tabulation of these and some other changes is given in Attachment 2.

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

The 95 mln m3 oil volumes from Shell Canada's Athabasca Oil Sands Project (AOSP) are not strictly oil and gas reserves as defined 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. They are also mentioned separately in the Group Annual Report.

4. **Angola block 18**

A total of five discoveries were made in the Angola block 18 area during 1999 and 2000. Preliminary economics showe development to be marginal to unattractive and the 1.1.2001 booking of Proved reserves could only be justified through a notional small scale creaming project in the two largest accumulations. One further appraisal well and sidetrack durin 2001 allowed in principle an increase in these reserves by an enlargement of the 'proved area'. However, a VAR3 review in December 2001 showed project economics still to be 'marginal at best', while the continued lack of a viable ga disposal solution was seen as a potential show stopper. Hence, a further increase in reserves was not accepted by EPB-P and the possibility was recognised that, without further changes, the project reserves may have to be de-booked next year. This view is also supported.

5. **SNEPCO fields**

A significant increase in Proved reserves (+19 mln m3 oil, +2 bln sm3 gas) was proposed by SNEPCO (Nigeria) through a first time booking of reserves in their new discovered Bonga SW field (one discovery well in 2001). After a review of the available evidence and following advice from the Group Reserves Auditor and SEPCO's Reserves Manager, the reserves coordination function in SIEP EPB-P has declined to accept this proposal. Considerations were that the projec is still immature (failed a VAR2 in Sept 2001) and is not properly defined (no dynamic simulation studies, well targets, forecasts or cost estimates), while its development is uncertain (other fields could be developed in its stead). In addition the seismic response is generally of insufficient quality to support a large enough area as (SEC defined) 'proved area' on which to base Proved reserves. This view is fully supported.

It was furthermore noted that SNEPCO, upon seeing the Bonga SW reserves addition not accepted, withdrew a negative correction to Bonga Main reserves (-2 mln sm3 oil, -2 bln sm3 gas), emanating from a 2001 study which showed these volumes to be non-producible within the prevailing PSC licence. In addition, the technical basis for the reserves in the Erha field, at its first time booking in 1999, was said by SNEPCO staff to be of lower quality than that for Bonga SW. A SEC reserves audit is planned for 2003. Advancement of this audit is being considered.

6. **Production licence duration constraints**

Externally reported Proved and Proved Developed Reserves need to be confined to those volumes producible within the duration of current production licences, or their extensions if there is a right to extend. With progressing maturity, a number of OUs are seeing their possibilities for increasing Proved Reserves severely curtailed because any increase in field volumes cannot be produced within (generally constrained) future offtake profiles and licence durations. With ongoing annual production, these OUs will in fact see their remaining Proved reserves decline in future years until either offtake rates can be increased or until licence extensions have been agreed with Authorities. OUs most affected by this are SPDC (Nigeria), Shell Abu Dhabi and PDO (Oman) and, to a lesser extent, Malaysia, Syria, Denmark and Venezuela. At present, some 300 mln m3oe Proved field volumes (10% of the Group Proved Reserves portfolio) are reported by OUs as being non-producible within existing licences.

For a proper estimation of Proved reserves (which have to fulfil the criterion of 'reasonable certainty') it is important that OUs faced with the above constraints make realistic assumptions regarding their future production profiles. The selected build-up and plateau levels should preferably be in line with base case Business Plan assumptions and with profiles used for the SEC 'Standardized Measure' submission. In addition, post-plateau tail-end profiles should be technically defensible. It is noted that PDO still maintain a 850 kb/d plateau in their forecast, in spite of recent problems in maintaining that production level. SPDC seem to have included LNG trains 4&5 in their condensate forecast, while the associated gas reserves have not yet been included in gas reserves because of lack of market definition.

At present, the Group reserves guidelines do not provide any guidance about what assumptions to take for future forecasts in these cases. This should be rectified. Following that, the assumed forecasts should be reviewed with the OUs concerned.

During this year's reserves submission and accumulation process, the critical information about OU assumed production profiles could in some cases only be made available to the auditor after repeated requests and in a late stage, thus leaving insufficient time for a comprehensive review. This should be remedied in future submissions by ensuring that full life cycle production profiles are requested from and made available by OUs in an early stage.

7. **Group Guidelines – mature fields**

Group Guidelines for externally reported Proved reserves (Ref. 3) have historically been somewhat different from Proved reserves definitions as applied by the oil industry (Refs.1, 2). The reason for this was that the Group have long based their Proved reserves estimates on probabilistic methods, using the 85% confidence level criterion. This was found to lead to too conservative estimates in mature fields (in comparison with industry practice) and the guidelines were therefore changed for these fields in 1998. The updated guidelines prescribe that, in mature fields, externally reported ~~Proved and Proved Developed Reserves should be brought closer to, or made equal to Expectation Reserves.~~ Significant Group share Proved Reserves additions (+200 mln m3oe) have thus been booked by many OUs between 1998 and 2000.

A method of visualising the relative positions of OUs is through plotting the ratio between Proved and Expectation reserves versus average OU maturity. The latter is defined as cumulative production as a fraction of total life cycle Expectation Ultimate Recovery. Plots showing the OU positions for Developed and Undeveloped Oil+NGL and Gas reserves are presented in Attachments 5.1-5.2. From this it can be seen that most mature OUs show Proved / Expectation ratios close to 1 for their developed and undeveloped reserves. Most notable exceptions are:

- BSP, where Proved reserves have to be agreed with the Government (a reserves audit is planned for 2002),
- SEPCo, where undeveloped proved reserves are depressed because of low SEC proved areas in Pinedale, Brutus and Mars
- BEB, who tend to maintain unrealistically high Expectation reserves (much of it to be SFR),
- Expro UK, where uncertainties in undeveloped reserves are large in Schiehallion and some tight gas fields.

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

Group guidelines for fields at the other end of the maturity spectrum, i.e. new discoveries, have historically been less well defined. Probabilistic P85 estimates were generally used (which for sparsely appraised fields tended to be larger than the SEC guidelines allowed), but there was often no clarity as to the appropriate moment when first-time booking of reserves could be made. This situation improved somewhat in 1993 when the requirement for technical and commercial maturity was first introduced in the Group reserves guidelines. This was later strengthened by adding the requirement that large or frontier projects should 'in principle' first pass a VAR review (preferably VAR3 – Concept Selection) before any reserves could be booked. Large projects of a downstream nature (e.g. LNG plants), which would not be subjected to a VAR review, would 'in principle' need to wait until FID.

The experience since the introduction of these new guidelines has been that the large established OUs (SEPCo, Shell UK Expro, NAM) tended to follow these guidelines, generally deferring first time bookings for new fields until at least a proper Development Plan had been prepared and commercial viability had been assured. The approach followed by smaller OUs and SDS has in some cases been more aggressive, even to the point where technically and/or commercially immature projects, some of those not even passing VAR2 or VAR3 reviews, were put forward as reserves. The main drive behind this appears to be a lack of awareness or indeed a disregard for the guidelines, coupled with a strong drive from score card reserves targets.

The SEC Proved reserves guidelines, which all oil- and gas producing companies with a stock listing in the USA mus adhere to, prescribe that there must be a 'serious commitment' by the company to develop the reserves concerned. According to recent SEC clarifications (Refs. 4, 5) this should mean AFE, FID, the signing of fabrication or sales contracts or at least a firm plan that is likely to become implemented. The SEC often reminds the industry that individuals responsible for Proved reserves reporting and certification may be subject to 'potential civil liability' in case non-adherence of their rules. They also reserve the right to challenge reserves submissions by companies and to for companies to re-state their Proved reserves when necessary.

The observation can also be made that, for first reserves bookings, industry practice tends to follow the SEC guideline more closely than some of the Group cases mentioned. Examples are BP (who have not yet booked any reserves for Angola Block 18), Exxon and also SEPCo, both of whom tend to book Proved reserves only at or close to FID.

The auditor's conclusion is therefore that a tightening of the Group guidelines with respect to the timing of first reserve bookings is required. Particularly large or frontier developments must have successfully passed appropriate milestone (VAR3 review or a serious financial or contractual commitment) before first reserves bookings can be made for the project. This implies that economic viability must pass project screening (i.e. not just commercial viability) since only project viability can assure that the project is likely to become implemented. It also implies that identified show stoppe must have been resolved since these bring implementation in possible jeopardy. Smaller new fields in mature areas should have at least a documented Development Plan, with identified well targets and robust economics, before reserves can be booked. The guideline documents should be adapted accordingly.

The tightening of guidelines for first time booking of Proved reserves should not lead to a drive to book in first instance Expectation reserves only and let Proved reserves follow later (cf. SK-8 volumes booked by SSPC). If no Proved reserves can be booked then the development is technically or commercially not yet mature and no reserves, neither Proved nor Expectation, should be thus booked (Ref. 3). Exceptions to this could be made for smaller projects within existing mature fields.

It should be understood that tightening of the first time booking guidelines, necessary as they are from a SEC perspective, may affect reserves already booked in some major new fields (cf. Ormen Lange – Norway with 17 bln sm3 NAM's Waddenzee reserves with 4 bln sm3, Angola with 12 mln m3 and possibly Gorgon – Australia with 86 bln sm3 Group share Proved reserves).

9. **Reserves Addition targets in Score Cards**

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 is leading to a noticeable increase in attempts to book reserves which are not technically or commercially mature and which do not fulfil Group reserves guidelines, cf. the new field bookings in Angola and Nigeria.

It is the auditor's opinion that the setting of reserves targets through variable pay score cards represents a potential integrity issue in the reserves estimation process. Objective judgment cannot always be assured if the pay of staff is influenced by the volumes of reserves that are booked. Although the Group reserves reporting system does provide for a variety of checks and balances (most notably that by the EPB-P reserves coordination), their effectiveness cannot always be complete, particularly not for the smaller reserves changes (cf. Erha field). Nevertheless, it was seen that the objectivity of the EPB-P staff was beyond question and that they successfully met the challenges with which they were faced.

A notable effect of setting reserves addition targets seems to be that they become targets in themselves and thus seem to deflect attention away from the real target, which should be advancement of development.

The recommendation is therefore to de-emphasise specific reserves addition targets in score cards and to strengthen targets relating to advancement of field development, e.g. the passing of clearly identifiable project milestones. These could be specific VAR reviews (with e.g. VAR3 becoming the milestone at which reserves can be booked, see also below) or other project decision points (e.g. FID).

10. **Awareness of Group guidelines**

The annual updates of the Group reserves guidelines documents are generally distributed to staff responsible for reserves estimation and reporting in the OUs and NVOs. This distribution tends to exclude staff at senior levels, both in the OUs and in the central support functions (RBDs, SDS, SEPTAR etc). There is evidence that this has led to a lack of awareness of the principles and constraints in the reserves booking process in these functions. It is recommended that this be remedied, e.g. through workshops, high level guideline summaries etc.

11. **Criterion for commerciality**

According to present Group guidelines, Proved reserves should fulfil the criterion for commerciality, i.e. a positive NPV for a sufficiently wide range of uncertainty scenarios, including the Proved case. This criterion is more lenient than that for economic viability, which is used for project screening. The distinction between the two criteria was introduced in 1993 in order to avoid too rapid reserves swings for projects that had become marginal. However, first-time reserves bookings had to 'demonstrate positive profitability' before they could be booked (Ref. 6). This requirement has gradually become ignored and uneconomic projects that only pass the commerciality test have been allowed as first-time bookings (cf. Angola block 18). This implies that reserves are being booked for projects that, being uneconomic, are not likely to be implemented, which is in conflict with SEC requirements (see above). The requirement that first-time bookings can only be made for projects that are economic (and thus likely to become implemented) should therefore be re-enforced in the guidelines.

The two criteria (for commercial and economic viability) used to be based on the same oil price assumption ($14/bl MOD flat). This was changed in 2001 when the price assumption for project screening was raised to $16/bl MOD flat (publicly announced in 2001), whilst that for reserves commerciality was kept at $14/bl. This introduced an inconsistency because the reserves commercially criterion could now, under some conditions, become less lenient than that for projects. During reserves audits it was found that this has created confusion among staff in some OUs and from this perspective it would be desirable if the two price assumptions would be made equal again. It is the auditor's understanding that a revision from $14/bl to $16/bl is being considered. The effect on reserves is likely to be limited in most cases, except for PSCs and other 'innovative contracts', where booked reserves volumes would reduce because they tend to be inversely proportional to the assumed oil price.

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

Group share annual hydrocarbon production is reported separately through the Ceres system by Group Finance and through the reserves submissions accumulated by SIEP. Both reports find their separate ways into the Group annual report and it is therefore important that the two reports are consistent. OUs are strongly advised (and indeed forced by a joint submission sheet) to coordinate their respective submissions to Ceres and reserves. However, the experience is still that inconsistencies continue to arise. Where significant, these inconsistencies have been addressed and a good match between the two has been obtained, see Attachment 4.

A remarkable observation is that in previous years any consistency errors tended to occur in the reserves submissions, but this year most of them occurred in the Ceres returns. One explanation is that known errors in previous quarters' Ceres returns had not been corrected, thus affecting the year-end total. The improved guidelines for reserves submissions (bringing clarity on e.g. conversion factors) could provide a further explanation.

13. **SEC Reserves Audits**

SEC Reserves Audits are carried out by the Group Reserves Auditor in all OUs every 4-5 years. All audits carried out during 2001 resulted in either 'satisfactory' or 'good' opinions (3 and 4 OUs respectively). A summary of audit findings is presented in Attachment 6. As far as can be observed, most audit recommendations appear to have been followed in this year's submissions. The forward Audit Plan is given in Attachment 7.

14. **Electronic Workbooks**

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

Recommendations to SIEP Reserves Coordination:

1. Change the Group reserves guidelines such that first reserves bookings for large and/or frontier projects can only be allowed after either successfully passing a VAR3 or another clear milestone implying project viability and commitment. Smaller fields in mature areas should as a minimum have a documented FDP.
2. In the Group reserves guidelines, include guidance on assumptions to use in future production profiles when these become important for OUs with constrained production licence durations. With such guidance, review the present assumptions used by e.g. SPDC and PDO.
3. De-emphasise reserves addition targets in individual and collective score cards and strengthen targets for reaching project development milestones (VAR reviews, FID, etc).
4. Spread the awareness of reserves booking principles and constraints to senior levels in OUs and central support functions (RBDs, SDS, SEPTAR etc), e.g. through workshops or high level summaries.
5. A revision of the oil price assumption for reserves commerciality ($14/bl MOD flat) to bring it back in line with that for projects' economic viability screening ($16/bl MOD flat) is encouraged.
6. Ensure that proved future production profiles for licence constrained OUs are made available to the auditor in a timely manner, in order to allow him to asses the validity of Proved reserves.

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 2001-1100
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 2001 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	
Netherlands				+23	Groningen review
Australia	+3		+18		Perseus devmt
Nigeria (SPDC)	+11		+6		Commissioning of gas plant
Nigeria (SPDC)		+15			Condensate devmt Soku + Nun River (offset by oil, see below
Philippines	+2		+11		Malampaya on stream
USA (SEPCo)		+9		+1	Holstein FID (first booking)
USA (SEPCo)	+7	+2	+2	+1	Brutus development
USA (SEPCo)	+5	+3	+2	+2	Mars field performance and drilling results
USA (SEPCo)	+4		+1		Crosby development
USA (SEPCo)	+4		+1		Oregano development
USA (SEPCo)		+9		+7	Various field reviews and drilling results
Denmark		+7		+0	Halfdan FDP approved (improved recovery)
Argentina	+0	+0	+6	+3	San Pedrito development
Netherlands			+6		Small fields development
Iran	+6				Soroosh on stream
Brunei (BSP)		+2		+3	Bugan discovery / appraisal
Malaysia		+0		+5	Lower abandonment pressure E11/F13W (offset by licence)
Denmark	+3	+3	+1	+1	Proved growth to Expectation (audit recommendation)
Russia Sakhalin		+3			Review (new reservoir model + external reserves audit)
Egypt		-1		-4	Obaiyed field performance
Canada	-0	-1	-6	-9	Sable review
New Zealand	-2	-2	-9	-9	Maui C sands revision
Nigeria (SPDC)		-17		+6	Field reviews and forecast review (backed out by NGL)
Total Major Techn'l	+43	+32	+39	+30	

OTHER MAJOR CHANGES					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
New Zealand	+7	+10	+16	+25	Acquisition of Fletcher Challenge equity (Maui + Pohokura)
New Zealand			+6	+6	Re-instatement of pre-paid Maui gas
USA (SEPCo)		+0		+10	Pinedale acquisition
Brunei (FCE)		+1		+5	Fletcher Challenge acquisition
Abu Dhabi	+5	+6			Introduce ADCO NGLs as reserves
Malaysia		-0		-4	E11/F13W reserves pushed beyond licence
Pakistan			-3	-3	Dissolution of PSP, acquisition in Bhit, Bhadra fields
Abu Dhabi	-4	-5			Oil profile adjusted for OPEC cuts (licence constrained)
Oman (Gisco)	-4	-4	-16	-17	New GISCO contract, incl PSC effects
Total Other Major	+4	+8	+3	+18	

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	+60	+44	+43	+32	
Grand Total Chgs	+107	+84	+85	+80	
Production	-129	-129	-93	-93	

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Attachment 3

	OIL + NGL (10^6 m3)	All volumes net Shell Group Share																	
Country Name	Proved Resvs 1.1.2001	Rev'ns and Reclass-ific'ns	Improved Recovery	Ext'ns and Discoveries	Purchases in Place	Sales in Place	Prod'n (avail. for sales) 2001	Proved Resvs 1.1.2002	Beyond end of licence	Proved Dev'd Resvs 1.1.2001	Transf. Undev to Dev'd	Revisions	Prod'n (avail. for sales) 2001	Proved Dev'd Resvs 1.1.2002	Minority Resvs incl. 1.1.2001	Minority Resvs incl. 1.1.2002	R/P Tot (yr)	Replmt Ratio TotRes (%)	Replmt Ratio DevRes (%)
Australia (SDA)	29.04	1.21					3.55	26.7		11.08	2.66	2.1	3.55	12.29			8	34%	134%
Australia (WPL)	17.04	2.41	.8				2.18	18.07		5.61	1.91	1.51	2.18	6.85			8	147%	157%
Brunei	69.56	4.48	1.25	2.74			6.89	72.24		34.66	3.8	2.77	6.89	35.66			13	152%	114%
Brunei (FCE)		.11			.89		.04	.95				.35	.04	.31			24	2475%	875%
China	5.97	1.44					1.36	6.05		5.27	.56	.35	1.36	4.82			4	106%	67%
Malaysia	28.85	-.28	1.27	.99			3.46	25.36	14.84	13.76	2.68	.72	3.46	13.6		.17	7	67%	95%
New Zealand	6.	-3.81	.23		10.		1.46	8.96		2.26		4.82	1.46	5.62			7	440%	330%
New Zealand (Pecten)	.74	-.74								.62		-.62							
New Zealand (SPM/ex-FCE)					1.9		.27	1.63				1.33	.27	1.06			6	704%	493%
Philippines	3.6	-.16	.73				.03	3.54			2.18		.03	2.15			118	233%	7267%
Thailand	15.35	.73					.94	15.14		4.02	1.15	.14	.94	4.37			16	78%	137%
Angola	11.85							11.85											
Argentina	3.54	.18		.07		2.26	.14	1.39		1.84	.47	-1.71	.14	.46			10	-1436%	-666%
Brazil (Pecten)	.92						.09	.83		.92			.09	.83			9	0%	0%
Cameroon (Pecten)	5.17	.04	.06	.16			1.1	4.33		5.	.27	-.05	1.1	4.12	1.03	.87	4	24%	20%
Congo (DR - Zaire)	3.04	.11		.09			.18	3.05		2.11		.05	.18	1.98			17	106%	28%
Gabon	18.94	.36	.17			.02	3.22	16.23		17.08	.98	.24	3.22	14.88	4.74	4.06	5	16%	25%
Nigeria (SNEPCO)	69.54	.43						69.97											
Nigeria (SPDC)	434.17	-1.97					14.54	417.66	83.86	116.88	14.88	-.38	14.64	116.74			29	-14%	99%
Venezuela	35.55	3.15					2.53	36.17	6.77	11.29	2.82	1.17	2.53	12.75			14	125%	158%
Abu Dhabi	89.7	1.04					6.45	83.29	68.32	81.18	1.71	.64	6.45	77.58			17	19%	34%
Bangladesh																			
Egypt	5.89	-1.03		.03			.81	4.08		3.47	.02	.3	.81	2.98			5	-127%	40%
Iran	31.59	1.87						33.46			5.64			5.64					
Oman (PDO)	179.4	-8.43	6.22	1.51			16.4	162.3	49.7	80.		2.2	16.4	65.8			10	-4%	13%
Oman Gisco	16.48	-3.27					2.56	12.65		16.76		-3.72	2.56	10.48	2.77	1.9	5	-128%	-145%
Pakistan																			
Russia (Sakhalin Assoc.)	16.1	-13.79					1.31			5.88		-4.57	1.31				0	-1053%	-349%
Russia (Sakhalin Consol.)		30.94						30.94				8.45		8.45		13.92			
Syria	15.72	1.91					2.81	14.82	1.7	11.35	1.82	-1.35	2.81	9.01			5	68%	17%
Austria	.23	.02		.01			.03	.23		.18	.02	.03	.03	.21			8	100%	167%
Canada	56.87	-.49		.01	.01	.01	3.23	53.17		26.88	.8	.06	3.23	24.52	12.49	11.28	16	-15%	27%
Canada (AOSP)	95.4							95.4							21.08	20.2			
Denmark	43.54	6.73	9.27				7.54	52.	10.89	32.85	4.78	5.96	7.54	36.15			7	212%	142%
Germany	3.05	.25					.33	2.97		2.91		.29	.33	2.87			9	76%	88%
Netherlands	4.96	-.33					.59	4.04		3.89		-.09	.59	3.01			7	-56%	-15%
Norway	32.76	1.52					6.19	29.09	.28	23.59	3.56	.26	6.18	22.21			6	29%	74%
UK	102.25	-.63	1.35	2.88			18.06	87.69		75.68	7.5	-4.13	18.06	60.89			5	19%	19%
USA (Aera)	69.08	-5.43	.08			.49	6.71	56.55		57.26	5.83	-4.05	6.71	52.32			8	-87%	27%
USA (SEPCo)	97.17	4.78		22.14	.47	.11	17.11	107.34		55.82	19.97	9.58	17.11	68.26			6	159%	175%
USA (TMR)	.98					.97	.01			.51		-.5	.01				0	-9700%	-5000%
Total excl Can. AOSP	1,550.35	23.36	20.93	30.42	13.26	3.85	128.82	1,505.64	227.46	710.72	84.62	22.14	128.82	688.67	21.03	32.18	12	65%	83%
Grand Total	1,645.75	23.36	20.93	30.42	13.26	3.85	128.82	1,601.04	227.46	710.72	84.62	22.14	128.82	688.67	42.11	52.30	12	65%	83%

	GAS (10^9 sm3)	All volumes net Shell Group Share																	
Country Name	Proved Resvs 1.1.2001	Rev'ns and Reclass-ific'ns	Improved Recovery	Ext'ns and Discoveries	Purchases in Place	Sales in Place	Prod'n (avail. for sales) 2001	Proved Resvs 1.1.2002	Beyond end of licence	Proved Dev'd Resvs 1.1.2001	Transf. Undev to Dev'd	Revisions	Prod'n (avail. for sales) 2001	Proved Dev'd Resvs 1.1.2002	Minority Resvs incl. 1.1.2001	Minority Resvs incl. 1.1.2002	R/P Tot (yr)	Replmt Ratio TotRes (%)	Replmt Ratio DevRes (%)
Australia (SDA)	176.917	.901					2.409	175.41		18.051	13.548	.453	2.409	29.644			73	37%	691%
Australia (WPL)	40.184	.378					1.611	[illegible]		8.002	6.328	.552	1.511	12.971			26	25%	429%
Brunei	99.899	1.547	.48	3.257			4.722	100.481		37.529	1.785	1.866	4.722	36.677			21	112%	73%
Brunei (FCE)		1.303			4.801		.349	[illegible]			.8	[illegible]	.349	3.124			16	[illegible]	[illegible]
China																			
Malaysia	171.781	[illegible]	[illegible]	.31			6.88	164.31	[illegible]	[illegible]	2.128	[illegible]	6.88	44.608		2.629	27	[illegible]	-8%
New Zealand	14.811	3.917	1.713		26.420		4.363	[illegible]		10.829		14.165	4.363	20.361			8	[illegible]	327%
New Zealand (Pecten)	1.759	-1.759								1.448		-1.448							
New Zealand (SPM/ex-FCE)					5.26		.489	4.771				3.344	.489	2.855			10	1076%	684%
Philippines	16.914	-.303	1.161				.044	17.718			10.755		.044	10.711			403	1927%	24443%
Thailand	6.189	1.581	-.007				.429	7.334		2.633	.13	.254	.429	2.788			17	367%	90%
Angola																			
Argentina	9.389	.301	-.016	3.163		.08	.148	12.831		.098	6.043	-.098	.148	6.807			87	2321%	4101%
Brazil (Pecten)	5.141						.343	4.798		5.141			.343	4.798			14	0%	0%
Cameroon (Pecten)																			
Congo (DR - Zaire)																			
Gabon																			
Nigeria (SNEPCO)	7.02							7.02											
Nigeria (SPDC)	85.71	5.729					2.266	89.173		34.014	10.291		2.266	42.039			39	253%	454%
Venezuela																			
Abu Dhabi																			
Bangladesh	4.825	.344					.424	4.745		2.262		.135	.424	1.973			11	81%	32%
Egypt	27.881	-5.241		2.697			2.566	22.772		13.606	.389	-.151	2.566	11.280			9	-89%	6%
Iran																			
Oman (PDO)																			
Oman Gisco	55.207	-14.136					5.707	35.364		44.76		-14.116	5.707	24.937	8.281	6.305	6	-248%	-247%
Pakistan	9.866	-.006			1.916	5.134	.219	6.523		3.159		-2.839	.219				29	-1518%	-1342%
Russia (Sakhalin Assoc.)																			
Russia (Sakhalin Consol.)																			
Syria	.704	-.186					.186	.332		.397		.03	.186	.211			2	-100%	32%
Austria	1.595	-.14		.093			.204	1.345		1.494	-.082	-.046	.204	1.152			7	-23%	-89%
Canada	84.699	-8.485		.779	.394	.234	6.341	70.771		68.736	.888	-6.186	6.341	55.776	10.600	14.863	11	-120%	-73%
Canada (AOSP)																			
Denmark	29.352	2.255	.247				3.187	28.173	2.288	18.45	3.464	2.132	3.187	20.859			9	63%	176%
Germany	55.988	3.536					4.425	54.899		44.352	.164	1.388	4.425	41.479			12	75%	35%
Netherlands	399.651	21.804	1.06	1.651			16.066	408.1		200.347	5.612	.876	16.066	190.769			25	151%	40%
Norway	69.781	.834					1.818	68.807	10.565	36.892	.005	-.034	1.818	35.045			49	51%	-2%
UK	98.606	.339	.289	4.408			12.361	91.281		67.48	7.194	-.502	12.361	61.801			7	41%	54%
USA (Aera)	1.207	-.814	.001			.009	.054	.411		.866	.056	-.87	.054	.519			8	-1522%	-1137%
USA (SEPCo)	86.317	3.893		10.872	10.066	.244	16.441	104.653		66.406	10.916	5.995	16.441	66.876			6	150%	103%
USA (TMR)	1.142					1.129	.013			.893		-.88	.013				0	-8685%	-6769%
Total excl Can. AOSP	1,502.822	3.278	9.069	27.15	47.499	6.81	93.86	1,379.348	71.356	737.018	79.588	5.008	93.86	728.552	26.889	23.116	17	65%	91%
Grand Total	1,502.822	3.278	9.069	27.15	47.459	6.81	93.86	1,379.348	71.356	737.016	79.588	5.008	93.86	728.552	26.889	23.116	17	65%	91%

Atachment 3 -- 2001 Group Reserves Submissions

V00300315

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Attachment 4

	OIL + NGL										
Country	Original CERES			Org'l Resvs Subm'd		Difference	Final CERES		Final Resvs Subm	Difference	Comment
	mln bbl		10^6m3		10^6m3		mln bbl	10^6m3	10^6m3	10^6m3	
Australia (SDA)				3.55					3.55		
Australia (WPL)				2.18					2.18		
Australia Total		36.078	5.74		5.73	.01	36.078	5.74	5.73	.01	Rounding error? - not corrected
Brunei (BSP)				5.59					5.59		
Brunei (FCE)				.04					.04		
Brunei Total		35.47	5.64		5.63	.01	35.47	5.64	5.63	.01	Rounding error? - not corrected
China		8.516	1.35		1.36	-.01	8.533	1.36	1.36		Q1 error in Ceres - corrected
Malaysia		21.78	3.46		3.46		21.78	3.46	3.46		OK
New Zealand				1.46					1.46		
New Zealand (SPM/ex-FCE)				.27					0.27		
New Zealand Total		10.875	1.73		1.73		10.875	1.73	1.73		OK
Philippines		.165	.03		.03		.165	.03	.03		OK
Thailand		5.91	.94		.94		5.91	.94	.94		OK
Argentina		.907	.14		.14		.907	.14	.14		OK
Brazil (Shell Oil WH)		.56	.09		.09		.56	.09	.09		OK
Cameroon (Shell Oil EH)		6.966	1.11		1.1	.01	6.956	1.11	1.1	.01	Ceres figure incorrect (Govt penalty in Dec) - not changed
Congo (OR)		1.123	.18		.18		1.123	.18	.18		OK
Gabon		20.105	3.2		3.22	-.02	20.289	3.22	3.22		Error in Ceres - corrected
Nigeria (SPDC)		91.42	14.64		14.55	-.01	91.42	14.54	14.54		Reserves submission corrected
Venezuela		15.888	2.53		2.53		15.888	2.53	2.53		OK
Abu Dhabi		34.306	5.45		5.45		34.306	5.45	5.45		OK
Egypt		5.126	.81		.81		5.125	.81	.81		OK
Oman	103.14			16.4					16.40		
Oman Gisco	16.091			2.56					2.56		
Oman Total		119.231	18.96		18.96		119.231	18.96	18.96		OK
Russia (Sakhalin Holding)	8.255			1.31					1.31		
Kazakhstan (Temir)											
Russia Total		8.255	1.31		1.31		8.255	1.31	1.31		OK
Syria		17.689	2.81		2.81		17.689	2.81	2.81		OK
Austria		.2	.03		.03		.2	.03	.03		OK
Canada		20.321	3.23		3.23		20.321	3.23	3.23		OK
Denmark		47.423	7.54		7.54		47.423	7.54	7.54		OK
Germany		2.003	.32		.33	-.01	2.003	.32	.33	-.01	Error in Ceres - not corrected
Netherlands		3.71	.59		.59		3.71	.59	.59		OK
Norway		32.641	5.19		5.19		32.641	5.19	5.19		OK
UK		113.574	18.06		18.06		113.574	18.06	18.06		OK
USA (SEPCo)				17.11					17.11		
USA (Aera)				5.71					5.71		
Shell Oil (TMR)				.01					0.1		
USA Total		149.891	23.83		23.83		149.891	23.83	23.83		OK
Total		810.102	128.81		128.83	.02	810.273	128.83	128.82	.01	

	GAS							
Country	Org'l CERES	Org'l Resvs Subm'n		Difference	Final CERES	Final Resvs Subm'n	Difference	Comment
	10^9sm3		10^9sm3		10^9sm3	10^9sm3		
Australia (SDA)		2.408						
Australia (WPL)		1.511						
Australia Total	3.919		3.919		3.919	3.919		OK
Brunei (BSP)	4.722	4.722			4.722			
Brunei (FCE)	0.231	.348			0.348			Error in FCE Ceres - corrected
Brunei Total	4.953		5.07	-.117	5.07	5.07		
Malaysia	5.99		5.99		5.99	5.99		OK
New Zealand		4.363			4.363			
New Zealand (SPM/exFCE)		.489			0.489			
New Zealand Total	4.852		4.852		4.852	4.852		OK
Philippines	.044		.044		.044	.044		OK
Thailand	.429		.429		.429	.429		OK
Argentina	.146		.146		.146	.146		OK
Brazil (Shell Oil WH)	.343		.343		.343	.343		OK
Nigeria (SPDC)	2.381		2.266	.115	2.266	2.266		Error in Ceres - corrected
Bangladesh	.424		.424		.424	.424		OK
Egypt	2.582		2.565	.017	2.565	2.565		Error in Ceres - corrected
Oman Gisco	5.707		5.707		5.707	5.707		OK
Pakistan	.219		.219		.219	.219		OK
Syria	.186		.186		.186	.186		OK
Austria	.204		.208	-.004	.204	.204		Error in Resvs submission - corrected
Canada	6.297		6.341	-.044	6.337	6.341	-.004	Delay error in Foothills prod; Resvs vol = SCL press release!
Denmark	3.187		3.187		3.187	3.187		OK
Germany	4.425		4.425		4.425	4.425		OK
Netherlands	16.066		16.066		16.066	16.066		OK
Norway	1.818		1.818		1.818	1.818		OK
UK	12.351		12.351		12.351	12.351		OK
USA (SEPCo)		16.441						
USA (Aera)		.054						
Shell Oil (TMR)		.013						
USA Total	16.514		16.508	.006	16.508	16.508		Error in Ceres - corrected.
Total	93.037		93.064	-.027	93.056	93.06	-.004	

Attachment 4 - 2001 Production reconciliation – Ceres vs Reserves

V00300316

DB 29065

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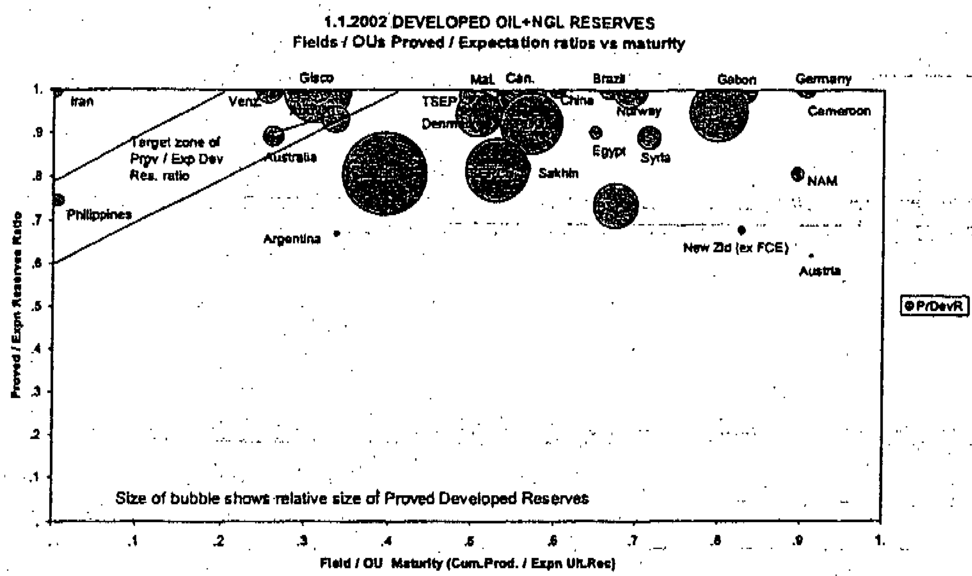
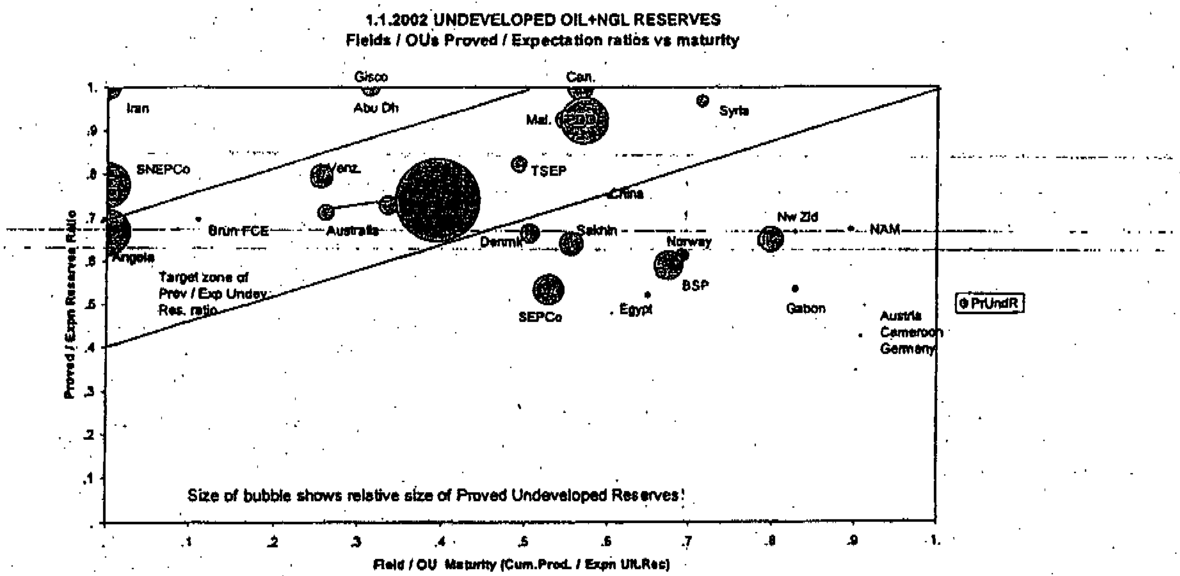
Attachment 5.1





Maturity of Proved Oil+NGL Reserves - by OU

V00300317

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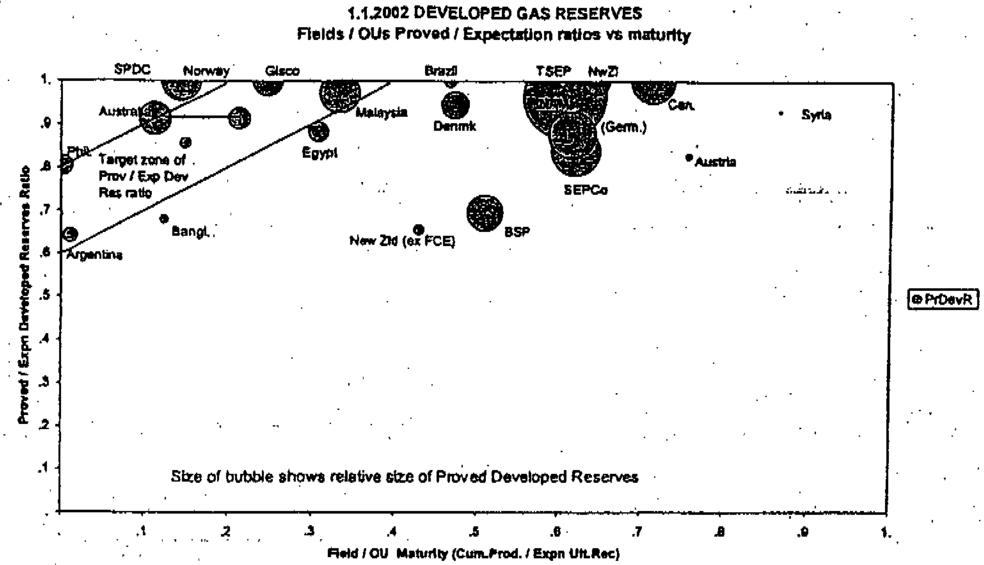
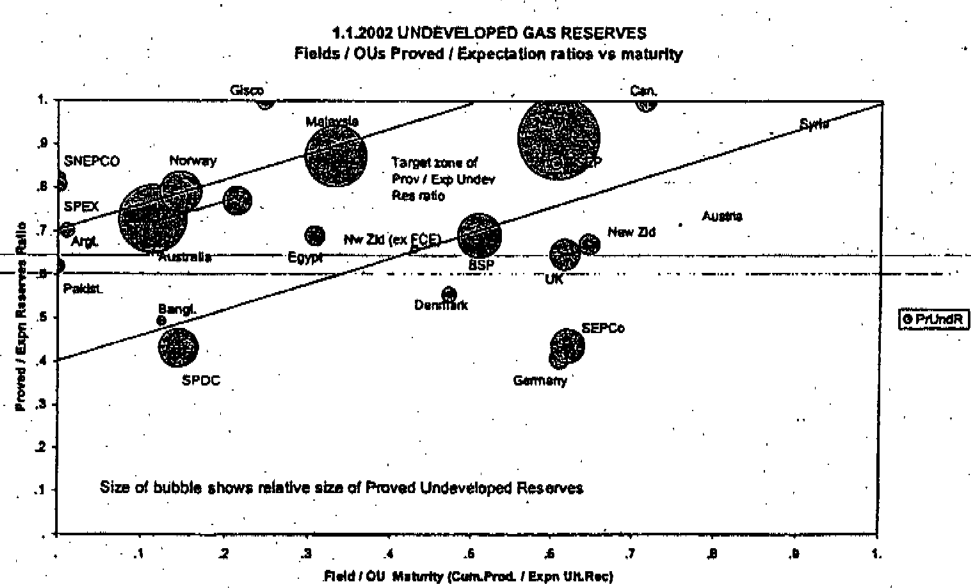
Attachment 5.2





Maturity of Proved Gas Reserves - by OU

V00300318

Attachment 6

2001 RESERVES AUDITS - MAIN OBSERVATIONS

UK (Shell Expro): Shell UK Expro follow very well established and documented procedures in their annual reserves reporting process. An example is the strict discipline enforced by Shell Expro's data base, which contains activities based reserves, forecasts and cost estimates. The Expro guidelines contain a strong recommendation that all Proved developed reserves must be set equal to Expectation developed estimates, regardless of field maturity. This approach is too rigorous for newly developed fields where uncertainties can still be considerable. There is thus a possibility of a slight overstatement of Proved Developed reserves. Proved undeveloped reserves are low compared to Expectation in some fields, but these uncertainty margins are justified. Overall audit opinion is good.

Netherlands (NAM): NAM follow well prescribed procedures in their annual reserves reporting process, as shown through annual reserves challenge sessions, the high-quality reserves data base and the comprehensive ARPR documentation. Proved volumes in the Waddenzee fields, which are affected by the Dutch government moratorium on drilling, can be maintained as reserves (current guidelines, no restriction on licence duration), but need continuous review. Some fields contain too low Proved vs Expectation ratios. The method of booking NAM/Shell share reserves in UGS fields should be reviewed critically. Overall audit opinion is good.

Germany (DSAG/BEB): BEB is commended for their well organised data base of reserves data, with flexible facilities to satisfy all reserves reporting requirements. BEB procedures for declaring Proved and Proved Developed reserves are in line with Group guidelines. However, reported Expectation reserves tend to contain highly uncertain and poorly supported elements, which should be re-classified as SFR. Group internally reported Expectation reserves are therefore likely to be overstated. There is a possibility of a slight overstatement of Proved (Developed and Undeveloped) reserves in some new gas fields due to the too rigorous use of Expectation / P50 volumes, rather than P85 volumes in these fields. Overall audit opinion is good.

Denmark (SOGU): SOGU follow well prescribed and documented procedures in their annual reserves reporting process, as shown by their well organised spreadsheet system of tracking reserves volumes components and their changes. Since Maersk's Proved Reserves estimates tend to be too conservative and often not up-to-date, SOGU have devised a commendable method of allowing these to 'grow' towards Expectation levels with increasing field maturity. Some assumptions in this method are still somewhat conservative, thus leaving scope for increasing the Proved Developed Reserves. Overall audit opinion is good.

New Zealand (SPM/STOS): STOS prepare well-documented annual reserves evaluations in their producing fields. There is an urgent need for a reserves update for Maui gas, where negative field evidence in the last few years (drilling, production performance) has made a downward correction highly likely. STOS have also identified an urgent need for a field review in Kapuni, where significant additional gas could be present. Take-or-pay gas paid for but not taken by the gas buyers in Maui should be retained in reserves until actually produced and not excluded as at present. Overall audit opinion is satisfactory.

China (SECL): Undeveloped reserves should be based on a full (not a partial) set of future development activities and their uncertainties. This could lead to an increase in undeveloped reserves. A properly documented audit trail note should be prepared. Overall audit opinion is satisfactory.

Austria (RAG): RAG reserves still appear to show remnants from the previous Mobil reserves guidelines. Many undeveloped reserves volumes are not yet based on identified future well activities. There also appear to be some undocumented 'legacy' reserves, which may need to be de-booked after study. The quality of the audit trails should be improved by properly documenting critical stages of the reserves estimation process. Overall audit opinion is satisfactory.

In addition, a brief review was made of the reasons underlying the 17 mln m3 increase in Group share Proved reserves booked at end 2000 by **SVSA in Urdaneta West.** This represented a significant increase (+78%) of SVSA's reported Proved reserves and was deemed a subject for review by the Group reserves auditor. Documentation received during 2001 showed that these reserves additions were based on increasing the number of drainage points and lowering well inflow pressures through artificial lift in the tight Icotea/Misoa and Cogollo/Rio Negro reservoir, thus maximising oil recovery within the reservoir abandonment pressure window. Management commitment to this additional development was already given during 2000 and activities were started during 2001. Hence, these reserves additions could be supported.

V00300319

Attachment 7

COUNTRY	Size**	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Comments
MALAYSIA	L		X				X				A				15-19 Apr 2002
BRUNEI	L		X				X				A				22-26 Apr 2002
BRAZIL (Pecten)	M/S						*				P1?				Not yet accepted
SYRIA	M/S	X			X						A				2-6 June 2002
PAKISTAN	M/S					$					A1				Sept 2002
IRAN	L							$			A1				Oct 2002
USA (AERA)	L					$					A1				11-15 Nov 2002
ANGOLA	M/S								$		A1?				Dependent on project progress
NIGERIA - SNEPCO	L					$		X			P?				To be considered
ABU DHABI	L			X				X				P			
NIGERIA -SPDC	L	X				X		X				P			
OMAN	L			X				X				P			
EGYPT	M/S		X					X				P			
VENEZUELA	L				$			X				P			
ARGENTINA	M/S			X				X				P			Combine with Venezuela
CAMEROON (Pecten)	M/S						*					P1			
AUSTRALIA	L				X				X				P		
NORWAY	L				X				X				P		
USA (SEPCo)	L						*		X				P		
PHILIPPINES	M/S					$		X					P		
THAILAND	M/S		X					X					P		
KAZAKHSTAN-OKIOC											P1?		P1?		
RUSSIA - SALYM												$?	P1?		
GABON	M/S			X					X					P	
BANGLADESH	M/S					$			X					P	
RUSSIA - SAKHALIN	M/S					$			X					P	
NAMIBIA												$?		P1?	
NETH. NAM	L	X				X				X				P	
GERMANY	L	X				X				X				P	
UK	L			X		X				X				P	
DENMARK	L	X				X				X				P	
CHINA	M/S		$							X					
AUSTRIA	M/S			X						X					
NEW ZEALAND	L				X					X					
CANADA	L														No direct involvement
CHAD	M/S			X											Divested 2000
KAZAKHSTAN-TEMIR	M/S							$							Divested 2000
USA (ALTURA)	L					$									Divested 2000
ZAIRE	M/S		X												To be divested?

P = Proposed
A = Accepted
X = Completed
()1 = First audit
$ = First SEC resvs subm'n
* = First SEC subm'n via SIEP

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

Audit frequency:

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

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

Attachment 7 - SEC Reserves Audit Plan 2002

V00300320

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(7)

SPDC Resvs Discussion

Dave Kluesner EPT-VAR
John Pay
~~Koni Kuano~~ (?) Okon Ikono
Promise Eghele
~~Austin~~ Resvs Mgr Designate Oshin Olorunso
John Hoppe
(Peter Stephenson)

Reserves Maturation Study {Phase I Aug 13 - Sept 5 '03

Dave K + Peter Stephenson in PH to kickoff Phase I

- Some volumes not sufficiently mature for proved resvs

TOR defined - forecasts by drainage pt.
Maturity Plan to be defined.

Ph 2 Oct/Nov, Ph 3 Jan-Dec '04

Ph 1 only oil

2.5 MMbls (Shell share) Proved in ARPR, 1.8 only from projects
0.9 MMbls potential projects.

42% of base plan is <2 MMbls per drainage pt

(Some to-and-fro between 100% and Shell share volumes)

X Copy of DK presn

DEPOSITION EXHIBIT
Barendregt
#23 2/21/07

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RJW00112775

(2)

Shut Tm Activities

Dev'd = NFA
PrUndev - projects a CA (Cap Alloc) & BP with firm funding; STA, LTA
- "mature" - no resvr/fld/proj exposure
- "immature"

Ten criteria developed for 'maturity'; eg community disturbance; facilities vandalised.
(Resvr / field / project maturity & exposure)

Used for discounting expl to proved

P85 vals vs Exp'n taken from whatever (volumetrics) is available

Three groups: Prov=Exp, Prov=P85, Prov=0

"A lot of expectation volumes are likely to be SFR"

Exposure tranches defined

70-90 dev wells/yr, 9 rigs (max 2 per team), 50-60% of staff on well proposals. "No panic"
9-12 mths duration per well proposal (18 mths is [illegible])

Project is highest area of immaturity.
Currently 8-10 VARs p year, ≈2 people from Rwk (now being grouped into larger VARs).
? "Project" deficient fields - not clear where/which fields?
"Community" exposure is relatively small.

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(3)

Overlaps between exposure volumes?

Need to prioritise and weed out the multiple exposures? (not done yet)

Reservoir Categories: Marginal, Closed in, Producing, Part/Unappraised (mutually exclusive – by resm block)
"not available" as well – "sloppy housekeeping"
Concern is large vol's in "Marginal" (< 2MMbls) – appr ~~up to~~ 30 – 50%.

"Are getting mature on the creaming curve, need to look closer and closer".

In 'unplanned' there are some good projects, eg Sta Barbara which are not in BP eg because they need ullage that is not yet available – not addressed / captured.

Condensate is included in oil volume but not accounted for (300+ Mln bls).

"Unknown": used Prov = 0.87 × Expl
(0.87 is avge of ~~of~~ total Prov/Expl)

Unaccounted projects: in plan but not clear where from – probably coding errors.

Gas forecasts, three groups:
70% of total { – in AGG nodes: extensive modelling – quite good
– rough consistency check only
– not (yet) reviewed.

Overall, quality is better than 2 yrs ago
NAG; Soku, Gbaran, ~~[illegible]~~ Bonny mostly – extensively modelled

(4)

Soku - oil rims ~~at~~ being addressed and assessed, NAG mostly from non-oil rim fields.

Originally highly motivational projects

How did we get here? Major funding problems 5-6 yrs ago - not worked through a. reserves.
Ojo Sanni probably the only person keeping short & long term together.
Project ideas are mostly there but often not (yet) captured.

Dave K's work is 100% Shell - no reports to outsiders.

Corporate forecast

BP forecast 0.8 → 1.4 MMb/d 2003 → 2009

LIO - ~~Light~~ LockedIn Oil?

Options = eg AGG fac's - assumes a flat funding profile extension from BP.

~700 MMb/yr reserves addition target

Akri-Oguta: FID 2006, but unitised and Agip are determined to go ahead.

South Forcados: have funding but plan now changed, ie go through VAR3, 4, FID again.

Gbaran/Ubie: lots of pressure by EP to accelerate FID.

Need to set criteria to decide when we book reserves.

Overall forecast constraint determined by Opec quota's
Stream of FDDs 2006/7/8, technically minimum. But oil would only be needed post 2015 (end plateau), ie one would take FID only at eg 2011-13 ie reserves not until 2011?

"Flares-out" is now gov't imposed – 2008. Consequence not fully carried through in plan

NLNG trains 3 operating, 4 2005, 5 end 2005,
5 trains currently committed,
tr 6 FID next yr, 7+8 being discussed
9, 10, 11 mooted.
Train 1-3 re-rating (upward) is another option.

All gas to date committed to US contracts
Remainder spot market? – Reserves issue
improved metering, also of flared vol's.

GOP [illegible]

pushing back HC forecasts → initially more NAG needed

Trains 6+ = all/mostly AG.

Combined HFPT model of 3 NAG fields

Three separate gas streams: NLNG, Eastern DomGas, Western DomGas

6

300 MMscf/d
EastDom Gas: only two fields (Alakiri NAG, Obigbo NAG + AG) at present, filling only ~25% of presently ~~[illegible]~~ anticipated demand. Rest would come from other fields in the area.

West Dom Gas ~ 450 MMscf/d. Number of target fields, plus Utorogu NAG, Oben NAG (Egwa). No contract yet?
No long term ~~forecast~~ contracts, just short extensions
WAGP = West Africa Gas Pipeline, along shore to Ghana, Iv. Coast etc.

(increase!)
1.1.2004: Propose full 1-5 train volumes NAG
AG: essentially developed gas only (reduction!)
Net increase + 30 mrd m3 Shell share.

John Hoppe 0629 327247

Oil: Foresee to stay constant on oil issues for at least next 2 years.

Peter's results 19/9/03

(Base+Options)
377 ProvDev OK — Devd Unknow (178)

125 Prov Under OK — Un~~planned~~ Unknown = (198)
1324 Prov Under not OK

2155 = Dev + Base + Options
590 = "Unplanned" known
3112 = 178
198
Total data base

7

Questions / Remarks

1 SPDC has largest contrib to Group Proved Resv: 487 vs 3000 or 16% m^3oe.

2 Fully agree with approach:
- Complete portfolio of documented projects, prod forecasts, economics
~~... per drainage point~~

3. Previous audit noted that reserves kept going up, even in recently studied fields. Is this trend now broken?

4 How to discount from Exp'n to Proved f/cs / resvs?

5. Above still based on volumetric P85's - a weak link! May be conservative!

6. Many small/marginal projects?

7 R/P Dev'd (oil) = 11 yrs - normal
R/P Undev (oil) = 22 yrs - High!

8 Dev'd, Base, Options: OK for Proved Resvs
Unknown - N/A, Unaccounted, Unplanned - not OK, should be removed.

9 Very good set of criteria:
X Reservoir (4) → VAR2, 3D, OWC, productivity ; other?
Area/field (3) → AGG, community, fac's intact ; other?
Project (3) - Executing, VAR3 or FID ; showstoppers?
not exclusive/independent!

Note: Proved resvs require all criteria to be met.

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8

10 Why is SPDC P/E gas dev = 1, undev = 0.4?

11. Correct criteria for setting P - E (~~Np/UR > 25~~ Resvr mature + Np > 2

~~12 What are PAFs, UAD?~~

12. Discounting

~~Reservoir~~ Exposure to 10 criteria - overlaps

Maturity - Marginal

- Closed in
- Prod >10
- 5-10
- <5
- Unappraised - near
- far

13. Why couldn't the study differentiate Partially Appr'd Flds into near and far? (Unappr discoveries could!)

14 Multitude of sets of figures - consistency is there but not obvious.

Suggest:

1) Maintain 100% volumes only to gain easy acceptance by teams

2) But have SS figures available at all levels.

15 Not clear how maturity breakdown and Reservoir category interact.

Suggest:

16. Volumes without any exposures constitute only 22% of Proved Reserves!