Attachment 1

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

MAIN OBSERVATIONS

1. Reserves Summary

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

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

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

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

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

2. Significant reserves changes

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3. Shell Canada's Athabasca Oil Sands

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

4. Enterprise Oil assets

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

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

Some of Enterprise's undeveloped reserves bookings were found to be premature and not in accordance with guidelines. Fields concerned are in:
- Norway, where a commercially viable gas export route is yet to be established for the Skarv and Idun fields,
- Italy, where the Tempa Rossa project is still poorly defined and faces significant commercial challenge,
- Russia (KMOC), where a funding shortage makes development of the sub-economic 'East Bank' fields uncertain.
For all of these fields the audits noted that, if these had been Shell operated fields, Shell guidelines would not have allowed booking of reserves. It is acknowledged that the KMOC Proved reserves are based on a Ryder-Scott SEC evaluation for these fields but it is the auditor's opinion that the authors have accepted the operator's assurance of 'reasonable certainty' of development without sufficient supporting evidence. The recommendation was therefore made not to book the associated reserves at end 2002.

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

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

5. Kazakhstan – Kashagan field

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

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

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

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

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

6. SNEPCO fields

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

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

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

7. 'Reasonable certainty' of development

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

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

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

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

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

8. Production licence duration constraints

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

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

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

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

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

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

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

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

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

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

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

PSC Reserves

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

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

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

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

10. Group Guidelines – mature fields

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

11. Group Guidelines – first time booking of new fields

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

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

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

12. Reserves Addition targets in Score Cards and Reserves Management

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

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

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

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

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

13. Annual production – consistency between Ceres and Reserves

Group share annual hydrocarbon production is reported separately through the Ceres (now FIRST) system by Group Finance and through the reserves submissions accumulated by SIEP. Both reports find their separate ways into the Group Annual Report and it is therefore important that the two reports are consistent. OUs are strongly advised (and indeed encouraged through a jointly signed submission sheet) to coordinate their respective submissions to Ceres/FIRST and reserves. However, the experience is that inconsistencies still arise. A comparison has been made to check for such inconsistencies and, where significant, these have been queried with the OU. Thus, a good overall match has been obtained between the two submissions, see Attachment 4.

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

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

14. SEC Reserves Audits

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

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

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

15. Electronic Workbooks

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

Recommendations to SIEP Reserves Coordination:

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

References

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

Attachment 2

SIGNIFICANT 2002 PROVED AND PROVED DEVELOPED RECOVERY CHANGES

(Shell Group share)

MAJOR TECHNICAL REVISIONS					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
USA	+7	+26	+5	+17	Field reviews in Mars, Ursa, Holstein, Auger, plus Mars WI
USA (Aera)	+6	+16			Belridge recovery review and field extensions
Brunei	+8	+8	+6	+8	New method, performance reviews and appraisal
UK	+4	+14	-5	+1	Performance and development reviews
Denmark	+4	+6	-2	+0	Field reviews and maturation
Russia - Sakhalin		+5			Oil viscosity revision
Canada AOSP	+95				(Near-) completion of Oil Sands Project (non-SEC!)
Nigeria (SPDC)	+26				EA on stream
USA (incl Aera)	+10		+12		Field development and drilling
UK	+11		+4		Field development and drilling
Nigeria (SPDC)			+12		New gas plant to supply LNG-3
Netherlands	+0		+11		Field drilling and development
Malaysia			+10		Devmt drilling plus E-11K-A compression installed
Denmark	+6		+3		Development drilling
Oman (PDO)	+7				Field development and drilling
New Zealand				-5	Pohokura volumetric revision
Thailand		-5		-1	Technical and economic revision of waterflood
Nigeria (SNEPCO)		-16		-4	Proved reserves review and audit
Total Major Techn'l	+184	+54	+56	+16	

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

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

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LON00142075

GROUP RESERVES SUBMISSIONS

Attachment 3

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

Country Name	Proved Resvs 1.1.2002	Rev'ns and Reclass-ific'ns	Improved Recovery	Ext'ns and Discoveries	Purchases in Place	Sales in Place	Prod'n (avail. for sales) 2002	Proved Resvs 1.1.2003	Beyond end of licence	Proved Dev'd Resvs 1.1.2002	Transf. Under to Dev'd	Revisions	Prod'n (avail. for sales) 2002	Proved Dev'd Resvs 1.1.2003	Minority Resvs incl. 1.1.2002	Minority Resvs incl. 1.1.2003	R/P Tot (yr)	Repl'mt Ratio TotRes (%)	Repl'mt Ratio DevRes (%)
Australia (Algeria)				.71				.71											
Australia (Direct)	26.7	1.69					3.31	25.08		12.29		1.7	3.31	10.68			8	51%	51%
Australia (WPL)	18.07	.32					2.06	16.33		6.85		.54	2.06	5.33			8	16%	26%
Bangladesh																			
Brunei (BSP)	72.24	6.49	.98	.47			5.83	74.35		35.66	2.6	7.72	5.83	40.15			13	136%	177%
Brunei (SDB)	.96	.09					.05	.99		.31	.33		.05	.59			20	180%	600%
China	6.05	.44					1.38	5.11		4.82	.85	-.21	1.38	4.07			4	32%	46%
Malaysia	25.36	-2.86	.62				3.45	19.67	1.1	13.6	1.54	-1.58	3.45	10.11	.17	.17	6	-65%	-1%
New Zealand	9.96	-.83	.37			1.67	1.61	6.22		5.62	.02	-.53	1.61	3.5			4	-132%	-32%
New Zealand (SPM/ex-FCE)	1.63					1.58	.05			1.06		-1.01	.05				0	-3160%	-2020%
Pakistan																			
Philippines	3.54	.61					.24	3.91		2.15		.41	.24	2.32			16	254%	171%
Thailand	15.14	-5.48					.9	8.76		4.37	.38	-.28	.9	1.57			10	-609%	11%
Angola	11.85		7.34					19.19											
Austria	.23	.01		.03			.03	.24		.21		.03	.03	.21			8	133%	100%
Cameroon (Pecten))	4.33						.98	3.35		4.12	.17	-.36	.98	2.95	87	.67	3	0%	-19%
Congo (DR)	3.05					3.01	.04			1.98		-1.94	.04				0	-7525%	-4850%
Denmark	52	4.51	1.35				8.14	49.72	10.69	36.15	6.48	4.22	8.14	38.71			6	72%	131%
Ireland (ex-EO)																			
Italy (ex-EO)		1.12			19.28		.67	19.73				8.08	.67	7.41			29	3045%	1206%
Gabon	16.23	.39					2.69	13.93	3.29	14.68	.38	.56	2.69	12.93	4.06	3.49	5	14%	35%
Germany	2.97	.06	.04			.06	.3	2.71		2.87	.01	.04	.3	2.62			9	13%	17%
Netherlands	4.04	.17	.22				.54	3.89		3.01	.07	.2	.54	2.74			7	72%	50%
Nigeria (SNEPCO)	89.97	-16.14						73.83											
Nigeria (SPDC)	417.66	-.73					12.47	404.46	13.83	116.74	26.66	7.93	12.47	138.86			32	-6%	277%
Norway	29.09	-3.86			42.61		8.49	59.35		22.21	1.48	30.15	8.49	45.35			7	456%	373%
K	87.59	14.21	.78	.06	44.16	.02	22.09	124.68		60.69	11.49	32.45	22.09	82.74			6	260%	199%
Ohabi	93.29	-1.09					5.81	86.39	149.9	77.58	.91	.66	5.81	73.34			15	-19%	27%
Egypt	4.08	.17					.65	3.6		2.98	.03	.29	.65	2.65			6	26%	49%
Russia (KMOC)					19.31	.16	.33	18.82			.33	2.41	.33	2.41			57	5800%	830%
an	33.46	-7.66	.17			9.82	.74	15.41		5.64	1.33	-2.58	.74	3.65			21	-2339%	-169%
Kazakhstan				60.41				60.41											
Oman (PDO)	162.3	-4.74	.34	1.49			15.72	144.17		65.8	7.27	4.92	15.72	62.77			9	-19%	80%
Oman (Gisco)	12.65	-2.07					3.28	7.3		10.48		-1.94	3.28	5.26	1.9	1.09	2	-63%	-59%
Russia (Sakhalin Holding)	30.94	10.43					1.71	39.68		8.45		.99	1.71	7.73	13.92	17.85	23	610%	58%
Syria	14.82	.82	2.07				2.87	14.84	1.46	9.01	1.8	2.1	2.87	10.04			5	101%	136%
Argentina	1.39		.03				.03	1.39		.46	.09	-.01	.03	.51			46	100%	267%
Brazil (ex-EO)		1.69			16.31			18.											
Brazil (Shell Oil WH)	.83	-.08					.09	.66		.83		-.11	.09	.63			7	-89%	-122%
Canada	53.17	-.9		.08			3.27	49.08		24.52	1.61	-2.29	3.27	20.57	11.79	10.94	15	-25%	-21%
Canada (AOSP)	95.4							95.4			95.41			95.4	21.15	21.26			
USA (SEPCo)	107.34	12.34	8.1	5.19	1.08	.55	19.07	114.43		68.26	3.36	6.75	19.07	59.3			6	137%	53%
USA (Aera)	56.55	10.43		5.23			6.58	65.63		52.32	6.41	5.78	6.58	57.92			10	238%	185%
Venezuela	36.17	1.81					2.66	35.32	8.4	12.75	3.76		2.66	13.85			13	69%	141%
Grand Total	1,601.04	21.35	22.41	73.67	142.75	16.87	137.63	1,706.72	188.67	688.67	174.73	105.11	137.63	830.87	53.86	55.47	12	177%	203%
Total excl Can. AOSP	1,505.64	21.35	22.41	73.67	142.75	16.87	137.63	1,611.32	188.67	688.67	79.33	105.11	137.63	735.47	32.71	34.21	12	177%	134%
Tot.excl.AOSP+Min.Resvs	1,472.93							1,577.11											

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

Country Name	Proved Resvs 1.1.2002	Rev'ns and Reclass-ific'ns	Improved Recovery	Ext'ns and Discoveries	Purchases in Place	Sales in Place	Prod'n (avail. for sales) 2002	Proved Resvs 1.1.2003	Beyond end of licence	Proved Dev'd Resvs 1.1.2002	Transf. Under to Dev'd	Revisions	Prod'n (avail. for sales) 2002	Proved Dev'd Resvs 1.1.2003	Minority Resvs incl. 1.1.2002	Minority Resvs incl. 1.1.2003	R/P Tot (yr)	Repl'mt Ratio TotRes (%)	Repl'mt Ratio DevRes (%)
Australia (Algeria)				.175				.175											
Australia (Direct)	175.41	1.815					2.365	174.86		29.644		1.174	2.365	28.453			74	77%	50%
Australia (WPL)	39.049	.766					1.494	38.32		12.971		.829	1.494	12.306			26	51%	55%
Bangladesh	4.745	-.345					.435	3.965		1.973		.001	.435	1.539			9	-79%	0%
Brunei (BSP)	100.461	4.891	.213	.866			4.806	101.645		36.677	1.296	7.776	4.806	40.942			21	125%	189%
ei (SDB)	5.648	.81					.442	6.014		3.174	1.124	.095	.442	3.501			14	183%	276%
a																			
Malaysia	164.31	-17.27	2.962				6.865	143.147	12.772	44.503	10.215	-1.938	6.865	45.925	2.029	2.398	21	-209%	121%
New Zealand	33.682	-6.12	1.29			2.041	4.627	22.184		20.251	.156	-1.173	4.627	14.606			5	-140%	-72%
New Zealand (SPM/ex-FCE)	4.771					4.641	.13			2.865		-2.725	.13				0	-3570%	-2096%
Pakistan	6.323	-1.204						5.119			3.839			3.839					
Philippines	17.718	.156					.369	17.505		10.711		.121	.369	10.463			47	42%	33%
Thailand	7.334	-1.277					.423	5.634		2.788	.073	-.07	.423	2.368			13	-302%	1%
Angola																			
Austria	1.345	.017		.097			.22	1.238		1.152		.151	.22	1.083			6	52%	69%
Cameroon (Pecten))																			
Congo (DR)																			
Denmark	28.173	.039	.25				3.238	25.224	5.647	20.858	2.972	-2.188	3.238	18.405			8	9%	24%
Ireland (ex-EO)		-.089			7.857			7.768											
Italy (ex-EO)		.153			2.581		.095	2.638				1.12	.095	1.025			28	2877%	1179%
Gabon																			
Germany	54.899	.909	.312				4.216	51.904		41.479	.204	.577	4.216	38.044			12	29%	19%
Netherlands	408.1	1.049	.93	.245			15.777	394.548		190.769	11.03	.796	15.777	186.818			25	14%	75%
Nigeria (SNEPCO)	7.02	-4.467						2.553											
Nigeria (SPDC)	89.173	-1.381					2.524	85.268		47.039	11.899	-2.861	2.524	48.353			34	-55%	350%
Norway	88.897	-1.971			6.577		2.588	90.915		35.045	.018	4.185	2.588	36.66			35	178%	162%
UK	91.261	1.37	.634	.569	13.378	.148	11.726	95.338		61.801	4.052	7.508	11.726	61.635			8	135%	99%
Abu Dhabi																			
Egypt	22.772	1.926					2.392	22.306		11.089		1.323	2.392	10.02			9	81%	55%
Russia (KMOC)																			
Iran																			
Kazakhstan																			
Oman (PDO)																			
Oman (Gisco)	35.364	-4.218					8.119	23.027		24.937		-3.796	8.119	13.022	5.305	3.454	3	-52%	-47%
Russia (Sakhalin Holding)																			
Syria	.337	.26					.177	.42	.05	.211		.361	.177	.4			2	151%	210%
Argentina	12.631		.003				.255	12.379		5.907	.477	-1.606	.255	4.523			49	1%	-443%
Brazil (ex-EO)		.082			1.666			1.748											
Brazil (Shell Oil WH)	4.798	-.427					.394	3.977		4.798		-1.276	.394	3.128			10	-108%	-324%
Canada	70.771	-2.553		.35			6.306	62.252		55.776	1.361	-8.064	6.306	42.777	15.691	13.865	10	-35%	-106%
Canada (AOSP)																			
USA (SEPCo)	104.552	4.38	.564	11.604	3.896	.274	17.292	109.63		66.875	11.655	4.295	17.292	65.533			8	179%	92%
USA (Aera)	.411	.206		.025			.054	.588		.318	.081	.126	.054	.471			11	428%	383%
Venezuela																			
Grand Total	1,579.948	22.324	7.158	13.952	37.954	7.184	97.314	1,512.27	18.469	728.552	60.25	4.751	97.314	696.739	23.824	19.717	16	30%	67%
Total excl Can. AOSP	1,579.948	22.324	7.158	13.952	37.954	7.184	97.314	1,512.27	18.469	728.552	60.25	4.751	97.314	696.739	23.824	19.717	16	30%	67%
Tot.excl.AOSP+Min.Resvs	1,556.124							1,492.553											

2002 PRODUCTION RECONCILIATION - CERES/FIRST vs. RESERVES SUBMISSIONS

Attachment 4

OIL+NGL

Country	Original FIRST		Org'l Resvs Subm'n		Difference	Final FIRST		Final Resvs Subm	Difference	Comment
.159	mln bbl	10^6m3		10^6m3	10^6m3	mln bbl	10^6m3	10^6m3	10^6m3	
Australia (SDA)			3.31							
Australia (WPL)			2.06							
Australia Total	33.72	5.36		5.37	.01	33.72	5.36	5.37	.01	OK (Accept rounding error)
Brunei (BSP)	38.846	5.83		5.83		36.846	5.83	5.83		OK
Brunei (FCE)	.336	.05		.05		.338	.05	.05		OK
China	8.672	1.38		1.38		8.672	1.38	1.38		OK
Malaysia	21.664	3.44		3.45	.01	21.664	3.44	3.45	.01	OK (Accept rounding error)
New Zealand			1.61							
New Zealand (SPM/ex-FCE)			.05							
New Zealand Total	10.456	1.66		1.66		10.456	1.66	1.66		OK
Philippines	1.534	.24		.24		1.534	.24	.24		OK
Thailand	5.639	.9		.9		5.639	.9	.9		OK
Austria	.154	.02		.03	.01	.154	.02	.03	.01	OK (Accept rounding error)
Denmark	51.211	8.14		8.14		51.211	8.14	8.14		OK
Germany	1.857	.3		.3		1.857	.3	.3		OK
Italy	2.871	.46		.67	.21	2.871	.46	.67	.21	FIRST subm'n excludes 0.21 m3 Q2 ex-EO production
Netherlands	3.411	.54		.54		3.411	.54	.54		OK
Norway NSEP (incl ex-EO)	48.614	7.73		8.49	.76	47.867	7.61	8.49	.88	FIRST subm'n excludes 0.88 m3 Q2 ex-EO production; Error in FIRST - corrected
UK Expro (incl ex-EO)	127.657	20.3		22.09	1.79	127.857	20.3	22.09	1.79	FIRST subm'n excludes 1.79 m3 Q2 ex-O production
Cameroon (PPC)	6.153	.98		.98		6.153	.98	.98		OK
Congo (DR)	.273	.04		.04		.273	.04	.04		OK
Gabon	16.898	2.69		2.72	.03	16.898	2.69	2.69		Reserves submission was based on Working Interest, not PSC entitlement share - corrected.
Nigeria (SPDC)	78.546	12.49		12.47	-.02	78.546	12.49	12.47	-.02	Ceres/FIRST submission in error (should be 78.405 MMstb), but too late to change. Resvs submission OK
Abu Dhabi	36.56	5.81		5.81		36.56	5.81	5.81		OK
Egypt	4.07	.65		.65		4.07	.65	.65		OK
Iran	4.677	.74		74		4.677	.74	.74		OK
Oman PDO	95.718	15.22		15.22		95.718	15.22	15.22		OK
Oman Gisco	20.625	3.28		3.28		20.625	3.28	3.28		OK
Russia (Sakhalin Holding)	10.771	1.71		1.71		10.771	1.71	1.71		OK
Russia (KMOC)	.708	.11		.33	.22	1.33	.21	.33	.12	FIRST subm'n excludes 0.12 m3 Q2 ex-EO production - corrected (+0.622 MMstb)
Syria	18.022	2.87		2.87		18.022	2.87	2.87		OK
Argentina	.171	.03		.03		.171	.03	.03		OK
Brazil (SOC - Merluza)	.585	.09		.09		.585	.09	.09		OK
Canada	20.6	3.28		3.27	-.01	20.6	3.28	3.27	-.01	OK (Accept rounding error)
USA (SEPCo)			19.07							
USA (Aera).			6.58							
USA Total	161.312	25.85		25.65		161.312	25.65	25.65		OK
Venezuela	16.735	2.66		2.66		16.735	2.66	2.66		OK
Q2 Prodn Ex-EO UK, Norway, Italy, Russia	19.073	3.03			-3.03	19.073	3.03		-3.03	OUs claim Q2 prod'n is 3.00, FIRST submission of 3.03 originated from EO HQ - difference of 0.03 left unresolved
Total	865.939	137.684		137.66	-.02 -.02	865.814	137.66	137.63	-.03 -.03	

GAS

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

LON00142077

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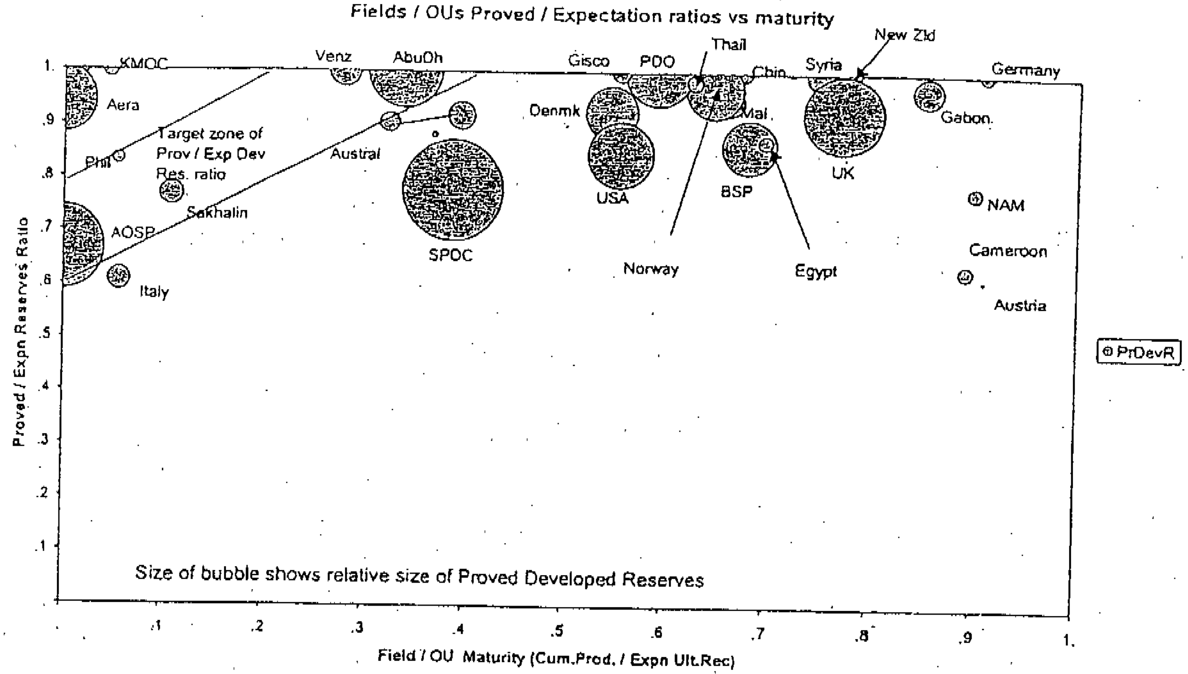
01/12/03

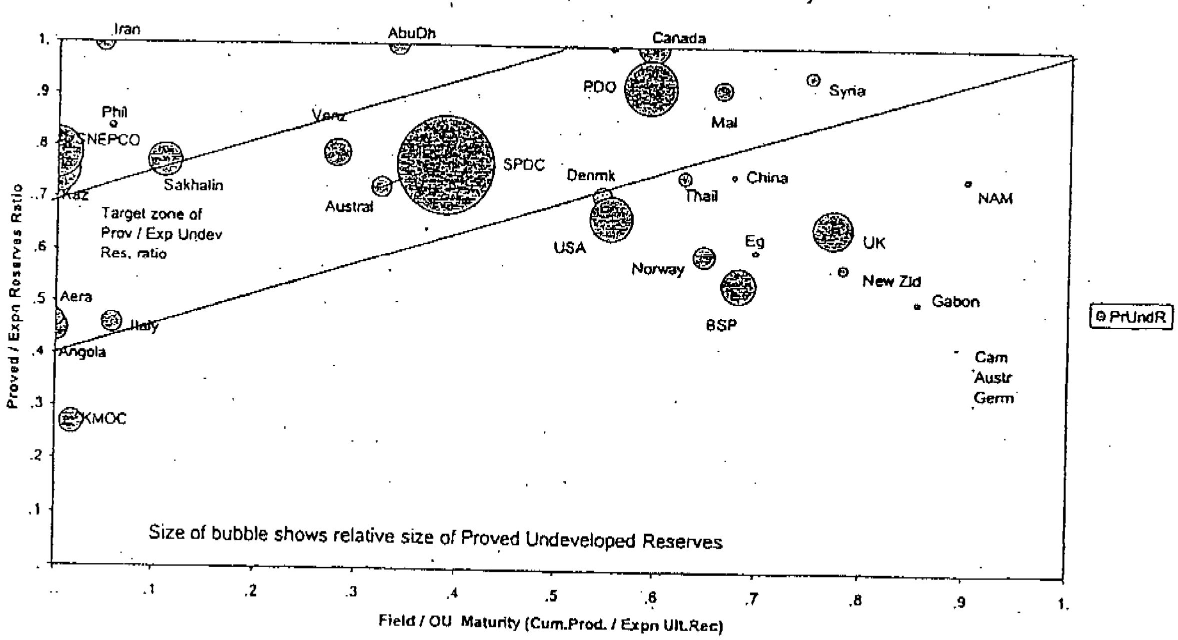
MATURITY OF PROVED OIL+NGL RESERVES - BY OU

Attachment 5.1

1.1.2003 DEVELOPED OIL+NGL RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



1.1.2003 UNDEVELOPED OIL+NGL RESERVES
Fields / OUs Proved / Expectation ratios vs maturity

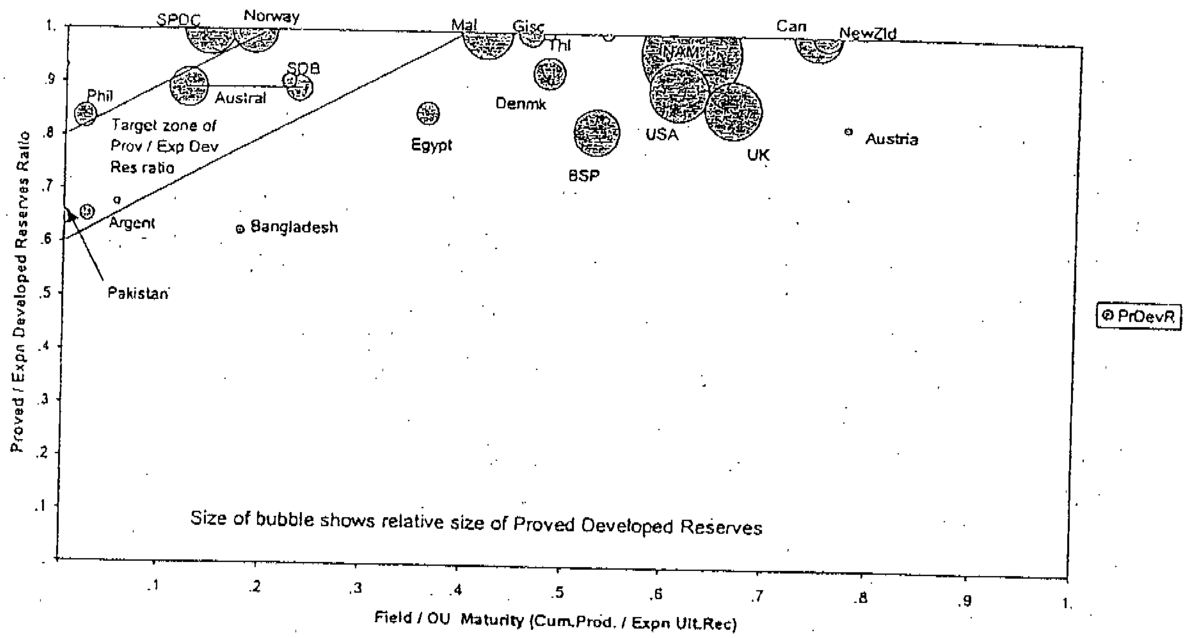


FOIA Confidential
Treatment Requested

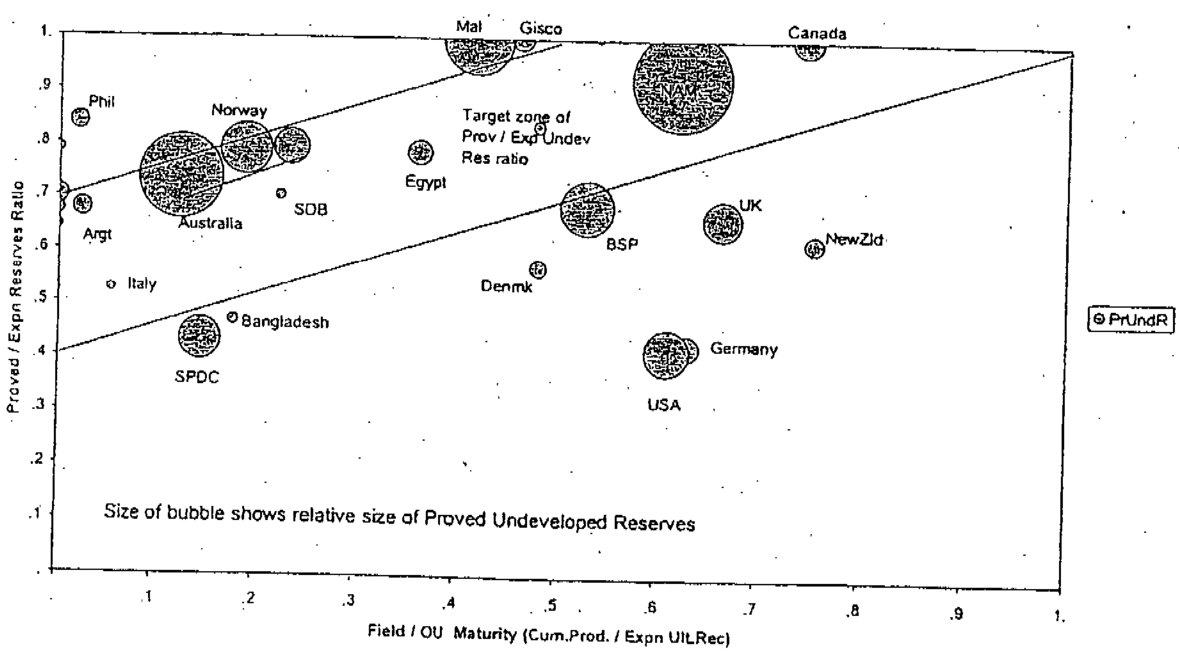
MATURITY OF GAS RESERVES - BY OU

Attachment 5.2

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



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



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Attachment 6

2002 SEC RESERVES AUDITS - MAIN OBSERVATIONS

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

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

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

The audit opinion was <u>satisfactory</u>.

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

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

The audit opinion was <u>satisfactory</u>.

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

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

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

The audit opinion was <u>satisfactory</u>.

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

SHELL NIGERIA E&P Co (SNEPCO): SDS in Houston had performed a commendable effort in re-evaluating the downside risk of poor lateral communication in the SNEPCO turbidite fields. Proved volumetric estimates were also reviewed in the light of their needing alignment with 'Proved Areas' as defined by FASB and recently re-asserted by SEC. In line with these evaluations, the audit supported the SDS proposal to book a Group share Proved Undeveloped oil volume of some 72 mln m3 per 1.1.2003. This compares with a previously (1.1.2002) booked volume of 90 mln m3. The reason for the reduction was that SNEPCO had booked Proved reserves additions in recent years that were not in accordance with SEC guidelines. First time booking of Bonga SW per 1.1.2003 could still not be supported with the present marginal economics and unresolved unitisation issues.

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

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

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

The audit opinion was <u>satisfactory</u>.

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

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

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

The audit opinion was good.

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

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

The audit opinion was good.

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

SHELL DEVELOPMENT ANGOLA: The new Proved reserves estimates prepared by SDS during 2002 were in agreement with the Shell Group and SEC guidelines and these estimates could be accepted. The Proved estimates were curtailed by the fact that some of the six exploration and appraisal wells were drilled in not fully representative portions of the reservoirs (crestal and/or behind major barriers). Hence, in accordance with SEC and Group guidelines, some significant portions of these reservoirs had to be considered as unproved and their associated recoveries could not be included in Proved reserves. Some limited portions of the unproved volumes could become proved later if a proper procedure is developed for accepting seismic evidence of OWCs in channelised turbidite reservoirs. The planned temporary disposal of gas by re-injection into one of the reservoirs (none of which are suitable) may become an area of serious concern if the planned LNG plant should become delayed.

The audit opinion was good.

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

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

The audit opinion was satisfactory.

Badhra reserves have been de-booked at end 2002.

EX-ENTERPRISE OIL OU AUDITS:

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

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

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

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

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

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

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

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

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

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

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

SEC RESERVES AUDIT PLAN - 2003

Attachment 7

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

Audit Status:

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

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

Audit frequency:

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

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Treatment Requested

Initial draft – 21 November 2003 – v1

Terms of Reference

External Commitments Audit

Auditee:

Principal auditee: Group Finance Director
Functional auditee: Group Controller

Background:

The Group has made substantial commitments to shareholders to reduce costs in its core businesses, achieve global savings through major projects in IT and HR, and synergies through acquisitions.

Scope:

An audit will be conducted in order to assess the level of assurance around the achievement of these objectives. The controls framework for tracking and monitoring savings and synergies will be assessed, as will the quality and integrity of the data underpinning the externally reported progress in achieving these.

In order to achieve the maximum possible coverage in a short time, reliance will be placed on audits conducted to date in these areas (see Appendix 1). An analysis will be performed on the overall findings from these audits as part of the report.

Two audits currently being conducted in GP *(Non-externally audited information disclosures)* and SOPUS *(PQS)* will include specific focus on these areas.

Finally, additional fieldwork will be performed to assess specifically the quality of:

- Feed through to the cost savings and data in these areas compiled by Group Reporting.
- Consistency over time and across businesses of cost and synergy reporting definitions.
- Specific studies conducted to date, such as KPMG's analysis of cost savings in EP and work done in 2001 by the Group Controller's department that assessed the quality of savings in the different Businesses.

Resourcing:

Lead:	Peter Elam, European Internal Audit Manager
Co-auditor(s):	Harrie van Dekken, EP Senior Auditor
	Additional resources (tbd)
Support:	2 auditors from European Internal Audit Team

Timing:

Analysis and fieldwork to be concluded by end December.

Appendix 1

AUDIT NUMBER	AUDIT NAME	YEAR	ACCOUNT MANAGER	
CC/2002.12	HR Galaxy Project Management	2002	Vincent Moolenaar	Opinion UNA not in Galileo
CHOE-OE11	OE T&R Process	2002	Peter Dix	Chemicals. O
CHPBU-12	IT Spending	2002	Seh Chong Chng	Chemicals. O
EPA-001	GCR Shell Exploration China Ltd.	2002	Ken Marnoch	E&P China. C
EPBRA-002	MIS/Cost control	2002	Sandra Saldanha	E&P Brazil. C
EPEXIAC/03-519-A15	Enterprise Oil Savings Review	2003	Harry Brekelmans	Review of syr
EPNIG/025-03	Strategic Cost Leadership	2003	Frank Numann	Opinion FAIR
EPNIG/122-03	Cost managemnet & management accounting	2003	Frank Numann	Opinion FAIR
EPSI/2003.68	Cost Management in EP Servcos plus STEP FS	2003	Ken Marnoch	Opinion FAIR
OP/007	SCITe Project Management Review	2002	Vincent Moolenaar	Opinion UNA
OP/2003.04	SCITe Project Follow-up Review	2003	Vincent Moolenaar	Opinion FAIR
OPEAZONIT/001	IT Cost Management	2002	Ian Crawford	Opinion FAIR
OPSE-03-070	DEA. Synergy realisation Program Office	2003	Peter Betker	Opinion GOO
OPSE-03-071	DEA. Synergy realisation Business Projects	2003	Peter Betker	Opinion GOO
OPSERE-03-117	DEA Poland	2003	Christophe Grolleau	Trial to combi (contribution f sanitised by C
OPSEMSD-03-301	Cost Management	2003	Lizette Upton	Cost manage FAIR
OPSERE-03-145	Cost management - overheads	2003	Christophe Grolleau	Cost manage Retail. Opinio
OPSE-HP	Simplification & Standardisation	2002	Peter Elam	SEOP Proces Simplification Opinion UNS.

OPSE-SP	Strategy & Portfolio	2002	Peter Elam	SEOP Strate(GOOD.
OPSEFN/CP	Contracting & Procurement	2002	Peter Elam	SEOP C&P - contracts in N UNSATISFA(
OPSOCCA-02-IA0003	Structured cost reduction	2002	Hector Hernandez	SCCA Structu Initiative. Opi
RN-004	RN Global Governance	2002	Frank Lemmink	Renewables.
SITIDS-009	ITDS GI Operations	2002	Doug Webster	Opinion UNS.
SITIDS-010	ITDS/ITPS Manage cost & recovery	2002	Doug Webster	Opinion UNS.
SITIPS-001	SAP Megacentres	2001	Doug Webster	Project audit.
SPS-2003.01	Shell People US Implementation Project Management	2003	Frank Lemmink	Opinion FAIR

From:	Sidle, Rod RE SEPCO
To:	Pay, John JR SIEP-EPB-P
CC:	
BCC:	
Sent Date:	2003-04-04 22:18:51.000
Received Date:	2003-04-04 22:18:55.000
Subject:	FW: Organisation Option: "Reserves Manager"
Attachments:	Oil & Gas Reserves Committee Meeting 4-9-03 , Reserve Mgmt Proposal Staircase.ppt

EXHIBIT
Sidle
12
10-31-06

John,

To keep you informed, I am sending a note I have provided to key parties in the EPW reorganisation to express my thoughts about a Reserve Manager position regionally. If I am not shot (or even if I am), I hope this is seriously considered to help you and Shell make improvements in our situation.

Regards,
Rod

Rod Sidle
Manager, Oil and Gas Reserves
Shell Exploration & Production Company
P. O. Box 576, Houston, TX 77001-0576, United States of America

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Internet: http://www.shell.com/eandp-en

-----Original Message-----
From: Sidle, Rod RE SEPCO
Sent: Friday, April 04, 2003 4:14 PM
To: Banister, Gaurdie GE SEPCO; Haines, John E SEPCO; McKay, Aidan A SEPCO; Jefferis, Bob G SEPCO; Ryan, Rob R SEPI-EPW; Williams, Charlie CR SEPCO
Subject: Organisation Option: "Reserves Manager"

To all,

Some of you have seen the one-page diagram (attached below) developed to propose a change to our current organisational structure working HC Resources. As you know, this is now a network headed by the Group HC Resource Coordinator, John Pay, in EPB-P with links to OU staff (eg, many OU just have a part-time resource coordinator) or an OU group (some OU's, eg, SEPCo, have full-time persons). This has been fine when all we want is reporting of volumes.

However there is evidence to suggest we may need to change our approach. Consider:
* RRR for 2002 impacted by major reserve reduction for volumes booked incorrectly (outside Group and SEC guidelines) while our competitors (XOM, BP) continue to report reserve additions more than their production
* Group Reserve Auditor recommends several changes to Shell proved reserve booking process including regional "challenge" sessions before reserve changes are booked
* A recent survey of 20 larger OU's on reserve reporting processes shows some OU's do not understand the fundamental SEC "proved area" concept (and one OU believes it does not apply to them!) and several OU's provide no training to staff on proper reserve booking practices including new guideline changes.
* Recent inquiries by the SEC to Shell (and other O&G companies) show a heightened interest in "assisting" SEC registrant companies in understanding and complying with SEC reserve rules

One option - change our mission from reserve reporting to reserve management. This means change from the "reactive" work of just reporting to the "proactive" work of training, consulting, identifying and challenging to assure complete and accurate capture of our reserves. Then use this data to help steer work activities to increase understanding of options to further increase reserves. This has been the mission in SEPCo for some time. It was explained to Group-wide audience at a recent workshop on reserves including 10 OU reserve coordinators and was recognized as a best practice. Likewise the combined Global T&OE Reservoir Engineering and Petrophysics DL Leadership Teams in considering processes needing to be global standards recommended a Reserve Management process like SEPCo's be implemented under a Regional Manager.

For EPW, this may seem like a modest change from our current situation and not a full-time job for such a manager. However, the proposed role of the EPW Reserves Manager would be expanded in two areas:
* External to EPW/Internal to Shell - It is critical the "regional" reserve manager be a "dual-citizen" of both the region and EP Centre. This means representing the region interests to the Centre and Centre interests within the region. The collective regional managers will act as a reserves team led by the HC Resource Coordinator to assure proactive methods such as annual and Group-consistent training is provided, local expertise is available to provide consultation, reserve issues are understood and addressed in major projects, etc. The Group Reserve Auditor recommended "challenge" sessions would review proposed major changes before ARPR submittal using a panel of the local regional reserve manager and others from this reserves team. Additionally the EPW reserve manager will initially also work to provide SEPCo learnings and practices to other regions to assist in their developing a global process based on our practices.
* External to Shell - Much of the industry resources and activities related to reserve reporting are US-based. This includes the SPE Reserves Committee and several recurring professional society meetings which focus on reserve issues (SPEE annual SEC Reserve Definition Forum, SPE bi-annual HEES). Active participation keeps Shell's information on industry concerns and practices (and competitor situations) current and allows Shell to help steer industry efforts to resolve common issues. (Example: see attached SPE Reserve Committee agenda with two topics included at Shell's request). The EPW member of the proposed Shell reserves team can most easily participate representing our global interests and issues. Currently this is done informally with low priority by the SEPCo Reserve Manager with no official mandate to represent global Shell interests (in fact, some in Shell Centre refuse to allow such sharing of global Shell reserve issues with "just a OU staff" -- thus another reason to be a "dual citizen").

This proposal may not be what we choose to do -- that is fine, as long as we do something to change our reserves results. Remember the old adage about the person who does the same things the same way again and again but expects a different outcome......

Thanks for reading this far. I am very pleased to have the chance to be "heard". Please advise if you would like to discuss this further.

Regards,
Rod

Rod Sidle
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EP Global Processes:- Hydrocarbon Resource Volume Management

April 2003

Shell International Exploration and Production B.V.
Shell EP International BV

CONTENTS

1. FOREWORD

Summary

As part of the ongoing globalization efforts, Hydrocarbon Resource Volume Management has been identified as one of the key process that would require a review. This review will provide an assurance that this process and its sub-processes are appropriately standardized based on global,regional and local needs. It is envisaged that this effort, spanning the next few weeks, best practices can be identified from OU's which will form the blueprint for defining standards. If your OU is considered to have elements of best practices in one of the sub-processes, we strongly encourage that your OU post to the SKS forum a high level process map for discussion and acceptance by the joint EP Reservoir Engineering community.

The review format will ensure that both the Reservoir Engineering Leadership Team and the Reserves Coordinators via the SKS platform contribute via discussions and exchange of ideas. To ensure that the wider global RE community is involved; we would expect that feedback and discussions be held at an OU level prior to posting contribution on to the SKS platform. Please bear in mind that a lot of ground work has already been done by yourselves during the Hydrocarbon Resource Volume Management Survey earlier; and we have extracted key elements to populate the matrix to assist you in your deliberations

Some key milestones of this review are

- Finalise Draft Framework :- 23rd April
- Framework posted on SKS :- 24th April
- Review/Discussion Period :- 24th April - 7th May
- Finalise Document for RELT review :- 8th – 9th May
- Issue Final Document :- 15th May

With the following deliverables

- Identifying which sub-processes needs to be of a global standard
- Providing for a high level description (process map) for sub-processes that are to be global standards utilizing best practices.
- Set of global KPI's to measure success of these new global standard processes
- A high level implementation plan (guidelines, management systems, cost , resource effort etc.) for these global standards.

Lim Min Teong, Rod Sidle and Thomas Henry will serve as focal points for queries and management of this SKS forum.

2. KEY ELEMENTS OF PROCESS REVIEW 1/3

2.1 Terms of Reference and Scope

The OBJECTIVE of the review is to perform an assessment of the existing Hydrocarbon Resource Volume Management process (Main Process) with focus on its sub-process by examining the organisation, procedures, work flow and its technical systems associated with it. From this assessment, a collective proposal to standardize processes into either global, regional or local ; thus ensuring

(i) that they are working well and are achieving the desired and/or stated objectives

(ii) that they are most appropriate to the tasks identified

(iii) that it encompasses best practices

(iv) that they provide improved resource volume understanding, resource data accuracy (including consistency) and completeness, the reporting processes across all EP Group organisations

The scope of this review is to evaluate the current activities and practices employed by each EP Operating Unit with coverage of issues on the entire process/sub-processes activities, including management & staff issues, challenge/controls and application of technology as well as improvement initiatives.

2.2 Structure of Process Review

STEP 1

After having read this document, please provide input in the following areas;

- Please record OU Views, Issues on our initial* read of the matrix for all the 6 sub-process. * Please note this is a limited view from a few select staff.
- Download and Populate XLS spreadsheet; initially columns C,D and H and then providing comments on some of the challenges and constraints that might surface or issues we need to manage.

STEP 2

For all the sub-processes we have initially suggested some best practices we could learn or steal shamelessly from.

- If your OU is mentioned, please post under the best practice folder your high level process map (key steps/flow)
- Also provide key issues/elements under the columns of Organisational Structure/Resourcing and Tools/Systems relating to that best practice.
- If your OU is NOT mentioned as a best practice but realise that there are some critical elements/issues required for that sub-process to be successful; please also populate the columns OrganisationalStructure/Resourcing and Tools/Systems

2. KEY ELEMENTS OF PROCESS REVIEW 2/3

2.3 Action Plan

STEP 1 & 2

Based on the review structure, proposed overleaf we have pre- populated the following matrix (see Section 3) for all the sub-processes based on your contributions from the Reserves Volume Management Survey 2003. Your role as the reviewer is to assist EP identify what are some of the processes that should be global/regional/local such that it would improve EP's and OU's performance.

Main Process	Importance to EP (high, medium, low)	Impact of global standardization (high medium, low)	Best Practice Identification	Organisational Structure/Resourcing	Tools,Systems	Should this be a global standard process in the future?
Resource Volume Management **Sub Process** 6 sub processes- see Section 3	HIGH ?	HIGH ?	Is there a best practice you have seen or know of.	How should the organisation structure/resourcing be to effect this process to standardized/ improve its performance	Some of the Key Tools and Systems issues that need to be addressed for this process to be standardized/improve	Global standard process are those with a medium/ high importance to EP and where the impact of introducing global standards is medium/high

Challenges & Constraints

As part of STEPS 1 & 2 provide comments on challenges and constraints with the following in mind;

- Main management, process and technical strengths
- Significant weakness in the organisation
- Options for improvement and associated risks
- Important constraints & sensitivities
- Key drivers for value creation and performance

Wrap-Up, Action Plan, Proposal

Post discussion on SKS forum

- Evaluate results
- Identify best practices; post process-maps
- Recommend actions for improvement
- What are the key change management issues e.g. need for a Hydrocarbon Resource Volume Manager for each region?
- List of agreed short, medium and long term action items

2. KEY ELEMENTS OF PROCESS REVIEW 3/3

2.4 Critical Success Factor of Process Review

When doing this review please use the following ground rules

Do

- Go for 80/20 solution:
  - Quickly attempt to fill matrix for sub-processes first
  - For key sub-processes, roll-out existing best practice standards as far as possible
- Identify which core sub-process need to be global and which can be left to regional/local OUs
- Ensure buy-in of wider organization for identified best practice standards to ensure they are accepted later

Don't

- Try to standardize all processes, but identify sub-process where standardization will have greatest impact
- Perform process redesign unless absolutely critical
- Assume all sub-processes must be global and nothing can be left to regional/local OUs
- Decree best practice standards from Center without allowing for discussion within SKS forum

Here are a few other questions that can used to assist you in the review of the sub-processes

- The business needs & requirements
- Status of current practice, capabilities and know-how
- Evidence that the sub-process value is being maximised
- Evidence for any shortfalls or imbalances
- Evidence for technical/systems needs & innovation
- Key problem areas

3. PROCESS ELEMENTS

3.1 General Process

Premise & Assumptions

Resources

- Regional Hydrocarbon Resource Volume Managers (RVM) -Provide for a single point responsibility for resource volume management at a regional level with focus on issues in process, training, audit functions, challenge/reviews, health checks etc. *Note: In most cases this will be a new position*
- OU/Region Reserve/Hydrocarbon Resource Coordinator (ORC) -Create increased importance by leveraging dedicated resources at OU level to manage volumes;assure proper data administration; liase with RVM on local resource volume issues/activities.. ***Note: These are existing positions in the current organisation. In future, each region will decide if this will be either a part-time or full time role and if this position resides at a region or OU level.***
- Group Hydrocarbon Resource Coordinator (GHC) – Group focal point for resource volume data management. *Note: This position already exist*
- Global Hydrocarbon Resource Volume Management Team (GRT) - A team of RVM members led by GHC
- Global Hydrocarbon Resource Volume Network (RVN) - The community of ORC, RVM & GHC.

Global Standard Measures of Success *(not exhaustive; appreciate your recommendations)*

- Improvement in LE and ARPR reporting – minimal follow and correction after initial submission (to be judged by GHC)
- EP Reserves Replacement Ratio >1 (5 year rolling average)
- Trend of proved reserves technical revision (as a % of total proved) both magnitude & direction
- Review grade by external auditor or JV partners/ governments as GOOD
- Increase integration and consistency of resource volume data across all database platforms- reduction in duplicative data submission requirements to the Group.

3. PROCESS ELEMENTS

3.2 Sub-Process:- Communication & Training

Objective:- To ensure that we have a common and consistent approach to the understanding and application of Hydrocarbon Resource Volume Management techniques, guidelines and procedures

Description:-1. To develop Group Guidelines & Rules; Both the Global Guidelines (EP-1100) & Reporting Rules (EP-1101) document are quite mature in its delivery & use, what is required is probably local/regional adaptations 2. To develop and deliver training & communication modules to OU staff on Hydrocarbon Resource Volume Management; the Who, What,When and How of training & communication

Matrix:-

Importance to EP (high, medium, low)	Impact of global standardization (high medium, low)	Best Practice Identification	Organisational Structure/Resourcing	Tools,Systems	Should this be a global standard process in the future?
High	High	Practices as defined in SM-EP, SEPCO, BSP, EXPRO	Need for a structured approach to in-house training Responsibility lies with ? line managers, local discipline leaders,etc	Use of website access and Group Training courses* *needs revision /adaptation; part of EP00 course?	Yes Example: Utilise process flow & training techniques from EXPRO, SEPCO & BSP

Challenges & Constraints:-

- -Need for Group guidelines to be better understood by staff including adaptations to local situations
- -Frequency & medium of training at OU's & Group
- -Whose responsibility ; RVM? line manager? discipline leader? group trainers?
- -Level of exposure to training e.g. include CEO, CFO?

3. PROCESS ELEMENTS

3.3 Sub-Process:- Latest Estimate

Objective:- Assess current "LE" process for effectiveness & potential improvements with proactive management from resource focal-point

Description:-This process defines the monthly/quarterly update of the company resource estimates that gets reported to the Group MIS (externally) and internally. The estimates are generated by individual asset teams reviewing volumes at field/reservoirs level.

Matrix:-

Importance to EP (high, medium, low)	Impact of global standardization (high medium, low)	Best Practice(BP) Identification	Organisational Structure/Resourcing	Tools,Systems	Should this be a global standard process in the future?
High	Low	Practices as defined in SEPCO, BSP, TSEP & SMEP	Need for LE to be reviewed by RVM and or ORC	Need for database to link LE deviations to asset activities	**No** Design of appropriate "proactive management dependent on local situation **BUT** a generic process flow extracted from BP's could help OU's that don't have one

Challenges & Constraints:-

-time consuming;

-maybe inefficient to design this globally until impact of better communication (sub-process 3.2) and planning process (sub-process 3.7) are understood.

3. PROCESS ELEMENTS

3.4 Sub-Process:- Link to Business Plan Data / Database Management

Objective:-To minimise the "manual integration" of technical asset data with economic parameters to create business decisions and plans. To have a complete database that allows for transparency at all levels (from OU asset holders to RVM and GHC) and some consistency

Description:-The need to adapt or develop "standard" data requirement and links for volume information that allows for seamless integration with business tools (BP), finance database, staff info systems and Group data requirements This process allows for a"common thread" thru the entire Hydrocarbon Resource Volume Management Process.

Matrix:-

Importance to EP (high, medium, low)	Impact of global standardization (high medium, low)	Best Practice Identification	Organisational Structure/Resourcing	Tools,Systems	Should this be a global standard process in the future?
Medium	**Medium**	Practices as defined in EXPRO (Alladin); TSEP (PLATO); SEPCO (Oracle database)	Initial effort could be spearheaded by both PMI & T&OE with ultimate custodian residing with the RVM or ORC	Ensure linkage with Group database (RISRES) allows for easy access and extraction of data	**Yes** a generic process flow showing what links are crucial and a common database and reports template **But** with local adaptation for PSC, tax, govt needs

Challenges & Constraints:-

-what form/type of database?; common features/functionalities we would like to have across OU's

-level of database; asset/reservoir/drainage point?

-link OU database with Group's? what are the common reporting requirements

-confidentiality issues?

- feedback loops with the other sub-processes e.g. the challenge/review process

3. PROCESS ELEMENTS

3.5 Sub-Process:- Review / Challenge Process

Objective:- Develop reserve change “challenge” process to provide consistent, global review of major changes before being booked in the ARPR, reported in the MIS/LE or submitted as projects for the Business Plan

Description:-This process defines a suite of activities that provide for a prudent and robust review of resources within an OU which comprises of peer reviews, audits, Business Plan project challenge, external reserves audits, asset level challenges, V2V process, VAR’s, special audits, etc.

Matrix:-

Importance to EP (high, medium, low)	Impact of global standardization (high medium, low)	Best Practice(BP) Identification	Organisational Structure/Resourcing	Tools,Systems	Should this be a global standard process in the future?
High	High	Practices as defined in BSP, SEPCO, NAM, & Woodside	A suite of levels required for the review process, bu with single point accountability residing with the RVM/ORC ?	Link via database all formal reviews to reflect as part of reserves tracking in MIS.	**Yes** (e.g. as a requisite for entry to Capital Allocation or ARPR reporting) Local adaptations being tailored for frequency and level of detail

Challenges & Constraints:-

- what should be the threshold volume prior to initiating changes;
- what type of KPI’s should we have to monitor our review effectiveness ?
- what level of detail& frequency should the review be ?
- who is the custodian (Accountability) for this review process?, RVM; ORC or even line management or local discipline/capability leaders.
- quality & professionalism of people conducting the review

3. PROCESS ELEMENTS 6/7

3.6 Sub-Process:- Documentation of Analysis on Resource Volume Changes

Objective:-To define standard practices in documentation required for recording resource volume changes and subsequently minimum standard reports. This allows for an audit trail

Description:-The process is beyond the standard documentation of the ARPR, which includes also how we capture uncertainty ranges related to these resource volumes changes.

Matrix:-

Importance to EP (high, medium, low)	Impact of global standardization (high medium, low)	Best Practice Identification	Organisational Structure/Resourcing	Tools,Systems	Should this be a global standard process in the future?
High	**High**	Practices as defined in BSP, EXPRO, SMEP	T&OE and GRT to initially define standard guidelines…then accountability resides with RVM/ORC	Need to also link documentation as part of database management of all formal reviews to ensure accurate tracking of uncertainties ranges to volume changes.	**Yes** (define some minimum standards, as part of submission to Group?) Local adaptations being tailored for frequency and level of detail

Challenges & Constraints:-

- -what volume threshold levels do we require before analysis and documentation of changes?
- -what level of detail should the documentations be? Field, reservoir basis?
- -who is the custodian (Accountability) for this process?, RVM, ORC, line managers, local capability/discipline leaders, GHC, etc.
- -what type of documentation is required ;minimum standards? and where does it resides, who is allowed access (confidentiality issues)

3. PROCESS ELEMENTS

3.7 Sub-Process:- Hydrocarbon Resource Maturation Planning

Objective:-To enhance and embed existing process whereby longer term planning (5 years) to Hydrocarbon Resource Volume Management is emphasised i.e life cycle approach.

Description:-To define key activities that provide input to the development of the 5 year HCM plan, which may include updating asset reference plans, developing KPI's, discipline reviews, X-OU reviews, best practice assimilation, Business-Technology Mapping; V2V and Xtl peer assist etc.

Matrix:-

Importance to EP (high, medium, low)	Impact of global standardization (high medium, low)	Best Practice Identification	Organisational Structure/Resourcing	Tools,Systems	Should this be a global standard process in the future?
High	High	Practices as defined in BSP, SMEP, AFPC	T&OE and GRT to initially define standard guidelines…then accountability resides with ? RVM,ORC or GHC	Need to also link documentation as part of database management of all formal reviews to Business Plan and ARPR	Yes (define some minimum standards, as part of submission to Group?) Local adaptations being tailored based on size of OU's

Challenges & Constraints:-

-What are some of the intermediate tollgates that are required to measure this effectively

-Consistency between asset reference plan, resource maturation plan, business plan and ARPR

-Effectiveness of feedback-loop to the asset activities i.e. what/how mitigation plans go into effect

-who is the custodian (Accountability) for this process?, RVM, ORC,GHC, etc.

4. CHANGE MANAGEMENT ISSUES

4.1 Change Management

What are some of the new enablers and changes required to happen during the EP Globalisations ?

Resources:- ***What are the requirements, at what level, roles and responsibilities,competencies etc.***

OU/Region Reserve/Hydrocarbon Resource Coordinator (ORC)

- Role & Responsibilities : **Some of their key duties include a focus on data flow,accuracy, management (follow similar to SEPCO description of a Resource Data Administrator)**
- Key Interfaces: **To liase with line managers; Reservoir Engineering LT (RELT), GHC, RVM**
- Requirements: **No new position envisaged; maybe the extent of the roles might overlap between OU and Regions**

Group Hydrocarbon Resource Coordinator (GHC)

- Role & Responsibilities : **(John Pay's current job description)**
- Key Interfaces: **To liase with all ORC; RELT, RVM, T&OE, HCM Forum**
- Requirements: **No new position**

Regional Hydrocarbon Resource Volume Manager (RVM)

- Role & Responsibilities : **Some of the key duties include managing process, audit,challenge/reviews, health checks, training etc.**
- Key Interfaces: **To liase with other ORC;GHC; T&OE HCM Forum; RTL Groups.**
- Requirements: **Possible new position**