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11. Q2 RESULTS (OTHER THAN OP)

Tim Morrison and Simon Henry entered the meeting.

The Committee appreciated that the discussion was based on very preliminary figures and was intended to raise any areas of concern at the earliest possible stage.

Tim Morrison presented the preliminary second quarter results. In respect of Special Items, he noted that the $68 mln figure relating to the Enterprise acquisition was after tax. The power restructuring figure for GP related to turbines and the OP environmental provision included MTBE in California.

Walter van de Vijver presented the preliminary Q2 EP results. For EP the main impact was caused by the downward oil and gas price trend. The Committee suggested that the figure for Price and Associates should be addressed separately. EP's current ROACE stood at 15.9% normalised at a $16/bbl level. Production had increased by 8% (including Enterprise) and without Enterprise would stand at 1% which was still a good outcome. If both Enterprise and OPEC restraints were excluded, production would be up by 3%. On EP Opex, unit costs were higher by 1% compared to the same period for 2001. EP normalised earnings were roughly equivalent to the same 2001 period.

The key messages for EP were that, even including Enterprise, ROACE was higher than 15%. On production, EP stood 2% ahead of promise and on Enterprise the integration process was proceeding rapidly with the London office to be closed by the end of July. On new exploration discoveries, EP was very constrained as to what it could say about new finds. With regard to Erha in Nigeria and Block 18 in Angola, as they were both non-operated, they were difficult to announce but ExxonMobil may do so. In relation to Opex, underlying operating costs were 2% down on the first half of 2001 and were close to the target of 3%. On capital expenditure, if Enterprise were excluded, the year-to-date expenditure was 52% of the external promise.

In terms of Opex figures, it was important to achieve consistency in how these were calculated and presented. If underlying Opex figures were be to used, these needed to be explained.

The Committee queried whether, with exchange rates moving so markedly, it would be timely to initiate a debate on costs now with a review at the end of the year.

The Committee believed that it was necessary to do more work on costs on a business-by-business basis with consistent rules being applied. Each business needed to be able to say what it would achieve by the end of 2002 and, even though this was likely to be a different story in each part of the business, that was not of itself a problem. The $5 bln external figure had been given in a completely different environment. The 3% figure was also given in US Dollars. It may now be timely to convert to a target in local currency.

Turning to GP, lower prices were the main impact on LNG. Volumes were down against plan and, even though Q2 usually represented a dip in performance, in 2002 the dip was greater than usual. The Coral business was still positive but was down compared to its record Q2/ 2001. For GP, consideration should be given to taking each part of its business section by section and presenting them in that way to emphasise their respective strengths. Marketing and Trading were negative and this was due to Canadian legacy contacts. In particular it could be emphasised that Trading in Houston was in the black for Q2.

Turning to Chemicals, the story was very positive with adjusted earnings double underlying earnings for Q2/2001 although the ROACE was still 1.1%.

With regard to Others, Renewables overall was flat. Shell Consumer had incurred a number of shutdown costs due to withdrawing from certain businesses such as vehicle leasing. IT for Shell still had an under-recovery situation. Unless the costs were charged to individual businesses, it was not possible to get tax relief. The Committee noted that SITI needed to be prompter in allocating its costs to businesses and must make sure that this was achieved by the end of 2002 to enable it to reverse its position. Shell Internet Works' shutdown costs were also included in the "Others" figures. On Corporate, the interest amount had increased because of higher debt levels caused by, in part, the acquisition of Enterprise.

Copy of Minute to: W van de Vijver (EP), E Henkes (CH), L Cook (GP), T Morrison (all).

12. KEY EXTERNAL MESSAGES

Mary Jo Jacobi entered the meeting; Tim Morrison and Simon Henry were in attendance.

Simon Henry explained that the current proposed tone of the message was one of "robust profitability in uncertain times but mixed progress on key targets and areas for action and improvement". The Committee suggested that, especially in the current environment, openness and transparency would particularly be valued and this should dictate the tone. On the positive side, both EP and

Chemicals were displaying great resilience, the integration of Enterprise was going well, hydrocarbon production volumes were up by 8%, OP was delivering on both its US and DEA improvement programmes, Chemicals was recovering, portfolio actions had been implemented, and progress was being made on the $7 bln priority attention assets.

With regard to growth milestones, reference could be made to the Tarim Basin, Block 18 in Angola, Erha in Nigeria, Kashagan, Venezuelan LNG and DEA - significant items which ranged right across the businesses. On the negative side, ROACE overall stood at 12% (13% at a normalised level). Costs were up, especially in OP. Queries could be expected on capital discipline, although it could be demonstrated that this was still in place, and on whether the cultural change was permanent. The analysts may query whether pursuing a growth agenda has already compressed returns. It would be necessary to recognise current global concerns relating to governance and accounting issues.

On the draft presentation, the Committee suggested that it should not be called a "strategy" update. Thought needed to be given to the length of the presentation which currently stood at approximately 30 minutes.

The Committee believed that there would be value on this occasion in giving out a full copy of the text of the Chairman's speech. Doing so may enable the detail on the presentation slides to be reduced. It was suggested that the text be handed out at the end of the presentation so that it did not detract from the presentation itself. It was acknowledged by the Committee that handing out the text of the speech created an expectation for the future. The logistical difficulties of preparing a correct Dutch translation within the limited timescale available were acknowledged.

The Committee recommended that the consequences of the delisting of Royal Dutch from the S&P 500 should be discussed at the press conference, especially in The Netherlands. A chart needed to be prepared to demonstrate how Shell Transport and Royal Dutch had compared with their respective oil company peers and the market as a whole.

Simon Henry explained that Project "Respiration 2" may potentially be announced on 1 August. This would be combined with a stock exchange announcement. On InterGen restructuring, a separate press release was being prepared with Bechtel. The Committee commented that this was an occasion on which a virtue would have to be made out of a necessity. By flagging this now, Shell could take credit for taking action and giving forewarning of the likely costs involved. On the $7 bln Watch List, it was important to emphasise that a coherent action plan was in place and these actions could be listed. In respect of the Caspian, an announcement from Kerr McGee was expected that its interest in Kazakhstan was awaiting government approval.

Copy of Minute to: T. Morrison.

13. RESERVES OUTLOOK

Lorin Brass entered the meeting. He explained that some of the main challenges facing EP in respect of its reserves outlook related to securing extensions of licence periods, finding new material investment opportunities, and in developing a well thought through strategy on the timing of booking reserves. ~~For example, in 1996, it may have been preferable, instead of booking all the~~ reserves at once, to have booked these over a longer period.

With regard to when reserves could be booked, it was noted that the SEC was tightening its requirements in this area. It is considered unlikely that potential over-bookings would need to be de-booked in the short-term, but reserves that are exposed to project risk or licence expiry cannot remain on the books indefinitely if little progress is made to convert them to production in a timely manner. It was stressed that it is only appropriate to book reserves in cases where a specific project has been progressed to technical and commercial maturity, to the extent that funding is reasonably certain to be secured. The current internal process required that any reserves booked had to be approved by the Group Controller and also had to pass both an internal and external audit check. The presenter queried, however, whether EP could be better at smoothing out its booking profile.

The Committee recognised that a sizeable prize in reserves could be achieved by success in securing licence extensions without incurring capital expenditure. A major technical and operational excellence effort was already underway and a new bookings strategy needed to be devised, and implemented. The Committee queried whether EP had sufficient technical expertise in this area. The Committee considered that EP's overall technical expertise was of a very high quality but that the skills could still be better utilised. It was also recognised that some booking practices had been too aggressive in the past.

The Committee recognised that EP had been through some major upheavals organisationally in the past eight years. It was concluded that high transparency needs to be maintained both on the existing booked reserves base and on the emerging portfolio hydrocarbon resources, with a view to identifying areas of both value opportunity and risk for the overall performance of the EP business.

Copy of Minute to: W van de Vijver.

14. PROJECT "B"

Dominique Gardy, Neil Gaskell and Lynn Elsenhans entered the meeting; Lorin Brass was in attendance.

Dominique Gardy presented a status report on Project "B". The Committee made a number of comments. The Committee would consider project "B" further on 30 July.

Copy of Minute to: none.

15. TOWARDS A FRAMEWORK FOR GROUP GREENHOUSE GAS TARGETS BEYOND 2002

Lex Holst, David Hone and Laura Ann Jones entered the meeting. Lynn Elsenhans was in attendance.

David Hone explained that the Group story on greenhouse gas (GHG) reduction of the controlled portfolio had been a positive one to date although after 2007 the effects of growth in the business would outweigh reductions and emissions overall would start to rise.

The presenter suggested that a move to an equity reporting basis, which was the basis used by BP, and preferred by ExxonMobil, would give a truer reflection of the Group portfolio although the story would become one of continuously rising GHG emissions from 1990 onwards. In particular, including InterGen increased emissions significantly. However, this was in contrast to the Group product portfolio, which had "decarbonised" over the same period. This situation led the presenter to propose that the Group change its approach to GHG reporting to one that focussed on carbon intensity of its controlled operations and which also included reference to its product portfolio and the lower carbon energy solutions being developed. This approach also proposed the introduction of equity GHG reporting, initially only for information to demonstrate transparency.

The Committee acknowledged that externally there was a perception that the Group had committed to beating Kyoto by 2010. Although this commitment had never been given explicitly, it was nonetheless a real expectation. Therefore, the

Committee believed that an absolute commitment needed to be retained although this did not preclude moving towards intensity targets. Any change in external reporting of absolute emissions would be viewed with considerable suspicion. The Committee was concerned that a danger of setting targets in this area was that they could drive the business. GHG reduction should not become a distinct activity but rather should be part of normal business.

The Committee considered whether, if a target were to be selected, it should be one which placed the Group in the middle of the pack rather than ahead or behind relative to the competition. NGOs would scrutinise the leaders and tail enders more closely than other companies. If an intensity approach was adopted, it was important to compare like for like (e.g. gas with gas rather than with SMDS).

The Committee recognised that a danger of not participating in the discussion externally was that somebody else would determine the standard.

With regard to the proposal to begin discussing the Group's portfolio and its emissions, the Committee considered that essentially the Group's business was not to decarbonise but rather to take advantage of opportunities which had arisen as a result of the world's desire to decarbonise. Account needed to be taken of the changes in external perception and the Group should be responding to customer preferences. Nevertheless, given measures such as the LNG and the SMDS business, for example, it was not unreasonable to expect that the Group could pursue decarbonisation as a good business case.

The Committee did not support the proposals put forward for the establishment of a micro target to demonstrate Group commitment to greener energy solutions. The Committee did query whether there were actions already underway within the Group for which credit could be taken.

Lynn Elsenhans advised the Committee that she was concerned that in Europe the pressure from NGOs and from stakeholders generally on the Group's apparent lack of definition on this issue beyond 2002 could create difficulties. Stakeholders in Europe were expecting the Group to take a leadership role in this area and, if it did not do so, it could create reputational issues.

The Committee noted that the world was decarbonising and that the Group had a good business justification for reflecting this trend in its own operations by increased energy efficiency and reduction of GHG. The absolute basis of measurement, on the control portfolio, should be maintained to reflect the Group's track record, to establish that the 2002 target has been met and to maintain continuity and transparency with past measurement.

However, a shift to an intensity basis of measurement should be investigated going forward. Specific measures by business that have economic/operational relevance to the businesses should be developed and the resultant outcome at Group level should also be monitored and reported. However, this measuring and monitoring should not lead to specific targets, especially externally, and should not comprise an add on to the way in which business is conducted. The Group should be open in communicating externally that it is learning how to do things better, both in the context of a possible move to intensity based measures, and on measures on the equity based portfolio, not just the control portfolio. It would also be necessary to consider how emissions trading should fit into the overall picture.

Intensity might be reflected in one number or many, if compiled on a segmented basis within businesses, but should focus on the trend line and how the Group performed relative to the competition. If the Group's intensity was not flat or declining, it would be necessary to understand the size of offsets required to produce a flat or declining trend, the cost of those offsets and the opportunities available to ameliorate the costs with either emissions trading, operational efficiencies or capital projects with an expected return.

The Committee requested that the GHG team undertake a number of activities, namely to produce a data trend on equity portfolio intensity, history and projection; to define the control portfolio specifically; to establish what, if the reduction levels desired could not be achieved, would be the cost both to the Group, and to each business, of mitigating its exposure (whether through emissions trading or by other means); to develop a credible storyline for external use with stakeholders to explain the Group's future approach and how it related to its track record; and to develop a better understanding of how the Group compared on the intensity basis, by segment, relative to the competition. The GHG team was requested to return to the Committee in October for further discussion.

Copy of Minute to: L Elsenhans.

16. JULY CONFERENCE AGENDA

The agenda for the July Conference was approved subject to certain minor revisions.

Copy of Minute to: none.

17. PROJECT "NIKE" - POTENTIAL RETAIL ACQUISITION IN HUNGARY AND SLOVAKIA

Paul Skinner explained that the quality of the sites which BP was selling was very high. The Committee queried whether the Group, and OP in particular, could afford this. Paul Skinner explained that this transaction was within both the OP plan and budget. It did not amount to additional capex as Project "Iris" was now likely to be constructed as a swap with ExxonMobil. The Committee noted that if Nike proceeded, and if Iris ultimately had a cash component, Iris would have to be considered afresh. The Committee supported the proposal, subject to the comments made in respect of Project "Iris".

Copy of Minute to: none.

18. PROPOSED OIL PRODUCTS OFFICE - MIAMI

Subject to obtaining further satisfactory legal and tax advice, the Committee supported the proposal.

Copy of Minute to: none.

19. SHELL IN THE US REVIEW

The Committee commented that the note appeared to lack a holistic approach and had not given sufficient attention to the rebranding challenge and to the question of Shell's attractiveness as an employer in the US. It was hoped that improvements could be made in future to the process for compiling this report.

Copy of Minute to: none.

20. FLETCHER CHALLENGE

The Committee noted that this item was due to be considered by the GAC on 30 July. A cover note was required to be drafted by Walter van de Vijver in conjunction with Judy Boynton.

Copy of Minute to: none.

21. INFORMATION SECURITY IN SHELL

The Committee noted that the costs were higher than those discussed in the IT Business Council. Mike Rose believed that there were a number of crucial exposures in the security environment which had to be rectified urgently. The IT Business Council would review and endorse specific scope and cost. Of the costs listed, $8 mln related to secure components for business applications, $12 mln related to intrusion detection and $27 mln was for compliance auditing. Even with these additional costs, the overall level of spend would still be lower than the industry average. The Committee expected to see no overall increase in IT spend and looked to IT to find offsets for these amounts. Malcolm Brinded commented that there was an internal perception that IT security had become an optional extra. To redress the findings of the unacceptable audit would require not just money but a change of mindset. It was proposed that a VAR be conducted of the costs to test whether they were necessary. The outcome of the unacceptable audit will be discussed at the GAC with Mike Rose present.

Copy of Minute to: M Rose.

22. SHELL EXPRO - SCHIEHALLION CLAW DEVELOPMENT

Walter van de Vijver explained that, although the Schiehallion Claw Development would not involve additional expenditure in 2002, he had tabled this Note for Discussion to forewarn the Committee of additional expenditure which would be incurred in the future. Any proposal for future expenditure needed to be considered at the appropriate time in the overall context of capital discipline across the Group as previously discussed.

Copy of Minute to: W van de Vijver

23. TOLLING AGREEMENT ACCOUNTING

Phil Watts explained that he had asked for this note to be prepared to ensure that the Group position on tolling agreement accounting was clearly understood. Judy Boynton would be the focal point for any discussion on this point. Having one Group view on this issue would facilitate a quick response to problems such as the recent Coral issue. Judy Boynton explained that she had talked to KPMG as requested by the Committee but KPMG had indicated that they were not aware of other companies in a similar position to Shell. It was suggested that the key objective for Shell was to achieve convergence. Tim Morrison would be the focal point for contact with the relevant authorities.

Copy of Minute to: J.Boynton.

24. BUSINESS CONTROL INCIDENTS

The Committee noted that this note would be presented to the Group Audit Committee. In particular, concern was expressed that both Brazil and Marine had given rise to a significant number of incidents.

Copy of Minute to: none.

25. PROJECT "EAGLE"

The Committee noted that, while the mandate and the contract were both expressed in Euros, the basic deal had been expressed in US Dollars. Accordingly, care needed to be taken on currency conversion.

Copy of Minute to: L Cook.

26. PENNZOIL QUAKER STATE

Paul Skinner reported that it appeared that the FTC would be immoveable on the requirement to dispose of the interest in the EXcel base oils plant. If this proved to be the case, the discussion would focus on establishing a reasonable basis on which this could be achieved. If a satisfactory basis was agreed, the remedy should have relatively little impact on the value of the transaction.

Copy of Minute to: none.

27. SINOPEC JV

Paul Skinner reported that the joint venture contract has now been initialled together with side agreements on other key issues such as branding. The next step is to obtain formal government approval of the JVC. The likely timing of the start up is Q4/2002.

Copy of Minute to: none.

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28. SUDAN

Paul Skinner reported that terms have now been agreed with an acceptable local third party for the sale of the up country aviation facilities in Sudan with effect from the end of July. Thereafter, there will no longer be in any business with the Sudanese military except in Port Sudan (which is outside the conflict zone) where the sale completion awaits the arrival of ISO tank. Aviation fuel would continue to be supplied to the World Food Programme at Obeid.

Copy of Minute to: none.

29. ~~POTENTIAL P&O TANKER DRIVERS' DISPUTE~~

Paul Skinner reported that the UK tanker drivers' (who are employees of P&O) had called off their proposed strike at the last moment and a two-year deal has been agreed between P&O and the TGWU.

Copy of Minute to: none.

30. MOTIVA-DELAWARE CITY

Paul Skinner reported that the EPA in the US had filed a gross negligence claim against Motiva following the sulphuric acid tank accident in 2001. The potential scale of any negotiated settlement is thought likely to be approximately US$10 mln. There has been extensive media speculation suggesting that Motiva's liability could be considerably greater. However, the $10 mln figure is based on initial negotiations with the EPA.

Copy of Minute to: none.

31. TOGO - FATALITY

Paul Skinner reported, with regret, six third party fatalities on 11 July when a contractor (Ezonsou) road tanker on its way back to Lomé was involved in an accident which appears to have contributed to a second road tanker (contracted by TFE) colliding with the taxi, killing all six occupants of the taxi. The accident is being investigated.

Copy of Minute to: P Skinner.

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32. USA - FATALITY

Paul Skinner reported, with regret, a third party fatality on 17 July when a Shell employee's car was hit by a motorcyclist who was not wearing a crash helmet and was killed as a result of the accident. The accident is being investigated.

Copy of Minute to: P Skinner.

33. USA - FATALITY

Paul Skinner reported, with regret, a third party fatality on 11 July at a Motiva service station in New Jersey when a third party was pursued onto the service station and shot six times by an assailant. The incident is being investigated.

Copy of Minute to: P Skinner.

34. MALAYSIA - FATALITY

Paul Skinner reported, with regret, a third party fatality on 5 July, when a contractor lorry suffered a tyre blow out between Segawat and Juantan causing the driver to lose control and swerve into the path of an oncoming car killing the driver of the motor car and injuring his passenger. The accident is being investigated.

Copy of Minute to: P Skinner.

35. TURKEY - FATALITY

Paul Skinner reported, with regret, a third party fatality when a customer died when using a jet wash at a dealer service station in Ipsala. Although not yet determined, it appears that the customer's death may have been caused by electrocution. The incident is being investigated further.

Copy of Minute to: P Skinner.

36. BRAZIL - FATALITY

Paul Skinner reported, with regret, a contractor fatality which occurred in a bus garage in Osasco operated by Viacao Osasco to which Commercial Quality Service Systems (CQSS) provided a fuelling, lubrication and vehicle washing service. The victim, employed by CQSS, worked as a supervisor for the vehicle washing operations and was struck by a bus in the garage. The accident is being investigated.

Copy of Minute to: P Skinner.

37. PAKISTAN - FATALITY

Paul Skinner reported, with regret, a contract driver fatality on 9 July near Ranipur following a collision with a third party truck parked on the roadside. The accident is being investigated.

Copy of Minute to: P Skinner.

38. ETHIOPIA - FATALITY

Paul Skinner reported, with regret, a contract driver fatality on 10 July when a truck operated by Afrique Transport went off the road and overturned approximately 400 kms north of Addis Ababa. The accident is being investigated.

Copy of Minute to: P Skinner.

39. UK - FATALITIES

Walter van de Vijver reported, with regret, eleven staff and contractor fatalities on 17 July when a Bristow helicopter operating on behalf of Shell Expro crashed while flying from the Clipper platform to the Monarch platform, 30 miles off Cromer, Norfolk. All passengers and crew on the helicopter died and 10 bodies have been recovered so far. Although the cause of the accident is not yet known, it is currently believed that one of the rotor blades may have snapped. The two crew members worked for Bristow, three of the passengers were Shell staff, three worked for Amec, two for Amec sub-contractors and the remaining passenger worked for Oilfield Medical Services.

The Committee expressed its sincere appreciation for the excellent response shown by all concerned within Shell's UK operations in very difficult circumstances.

Copy of Minute to: W van de Vijver.

40. NIGERIA

Walter van de Vijver reported that he had recently been contacted by ChevronTexaco to request assistance from Shell's fire-fighters to assist with a fire at ChevronTexaco's Escravos Tank Farm which had been hit by lightening.

Copy of Minute to: W van de Vijver.

41. BOLIVIA - FATALITY

Malcolm Brinded reported, with regret, a fatality of an employee of Transredes (a non Shell operated joint venture) on 21 July involving a head-on collision between a motorcycle, which was in the wrong lane, and a Transredes vehicle near Sawaipata resulting in the death of the two motorcycle passengers. The accident is being investigated.

Copy of Minute to: M Brinded.

42. DYNERGY

Malcolm Brinded explained that, given the rumours in the market about the potential collapse of Dynergy, the Group was urgently managing down its potential exposure and this should be reduced to US$22 mln by the end of this week.

Copy of Minute to: none.

43. GUANGDONG

Malcolm Brinded reported that he understood that, as a result of the discussions between the Australian Prime Minister and the Chinese Ambassador to Australia, Australia had agreed to provide one "friendship" cargo a year of LNG to Guangdong as a way of finding some value to offer other than adjusting the headline price. This amounted to less than 2% of annual cargoes but would not be confirmed until the North West Shelf had been confirmed as a supplier.

Copy of Minute to: M Brinded.

44. EAST TIMOR

Malcolm Brinded reported that the recent statement by East Timor that it lay claim to a 200 mile territorial waters boundary, was a move which had been expected by Australia and which was still being discussed by it with East Timor. ~~It was viewed as an announcement made for domestic consumption and was~~ thought unlikely to delay the development of Sunrise.

Copy of Minute to: M Brinded.

45. NANHAI

Malcolm Brinded queried the extent to which progress with CNOOC on Nanhai should be linked to making progress on other substantial projects. The Committee felt that linkage should not be made unless the Group was absolutely sure that it was going ahead with Nanhai. The month leading up to final Conference review, currently anticipated to be at the end of October 2002, was the period when this could occur. The Committee commented that it would clearly be prudent to obtain as much advantage as possible in exchange for the Group's participation if it did decide to go forward with Nanhai.

Copy of Minute to: M Brinded.

46. CHILE - FATALITY

Jeroen van der Veer reported, with regret, a contract driver (FAMASA) fatality on 12 July caused by a collision between FAMASA truck and an on-coming truck which appears to have been in the wrong lane. The accident is being investigated.

Copy of Minute to: J van der Veer.

47. DEER PARK

Jeroen van der Veer reported that a cooling water tower at Deer Park refinery in Texas had collapsed internally causing significant impairment of operations. At present there was no clear explanation for the implosion of the water tower which he noted was an unusual event.

Copy of Minute to: J van der Veer.

48. MARKET UPDATE

Simon Henry entered the meeting. He reported on the day's stock market movements. The Committee requested that he prepare a one-page review of market movements since 9 July when the announcement was made that Royal Dutch was being removed from the S&P 500. This review should set out a comparison with both ExxonMobil and BP and with the indices. In addition, Simon Henry was requested to prepare a daily report on market movements for the members of the Committee.

Copy of Minute to: J Boynton.

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49. NOTES FOR INFORMATION/DISCUSSION

The following matters were before the Committee as Notes for Information/ Discussion:

ITEMS FOR DISCUSSION
Forthcoming Items for CMD and Conference
Fletcher Challenge Energy Acquisition Post Investment Review
Information Security in Shell
Project "Nike"
Proposed Oil Products Office - Miami
Russia – Oil Value Chain
Shell Expro (UK) Schiehallion Claw Development
Shell in the US Review
Tolling Agreement Accounting – Update on Development of Standards
Towards a New Gasgebouw
Project "Respiration"
Corporate Governance (distributed electronically)

ITEMS FOR INFORMATION
2002 Interim Dividend and Revised 2002 Share Buyback Proposal
Annual HSE Council Meeting
Business Control Incidents
Corporate Restructuring of Shell Companies in New Zealand
Corporate Restructuring of the Shell Resources plc/Enterprise Oil plc Group
Delisting from S&P 500
Group Corporate Restructuring Proposal: Bulgaria, Czech Republic, Poland, Slovakia
Project "Eagle" – Update
Project "Figo"
Project "Puzzle"
Project "Spielberg" – Refining JV with ExxonMobil in Victoria, Australia
Shell Centre Redevelopment
Shell Energy (Australia) Pty Ltd; Group Divestment Proposal: Memorandum to the Board of SPCo
Shell Exploration and Production Namibia BV: Withdrawal from Kudu Licence and Liquidation of the Company
Shell Oil Products US
Tarim Gas Development

Unknown

From: Brass, Lorin LL SIEP-EPB
Sent: 27 August 2002 17:31
To: Van De Vijver, Walter SI-MGDWV
Subject: FW: Reserves 2002 and 2003

Walter, Hopefully answers your questions of this morning.

We'll work it a bit more tomorrow, but wanted to try to get you this before you took off.

-----Original Message-----
From: Pay, John JR SIEP-EPB-P
Sent: 27 August 2002 18:29
To: Brass, Lorin LL SIEP-EPB
Cc: Harper, Malcolm M SIEP-EPB-P; Nauta, Jaap J SIEP-EPB-P
Subject: Reserves 2002 and 2003

Lorin

Please find attached my response to your questions on Reserves.

John Pay
Group Hydrocarbon Resource Coordinator
Shell International Exploration and Production B.V.
Carel van Bylandtlaan 30, Postbus 663, 2501 CR The Hague, The Netherlands

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WvdV questions
27_08_02.ZIP

Incoming mail is certified Virus Free.
Checked by AVG anti-virus system (http://www.grisoft.com).
Version: 6.0.567 / Virus Database: 358 - Release Date: 24/01/2004

EXHIBIT
PENGAD 800-631-6989
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Brass

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Note for Information

RESERVES OUTLOOK: 2002, 2003

Two questions have arisen:

1) To what extent would Proved Reserves Replacement be different if no reserves had been booked until FID?

2) What options exist to raise the (organic) Proved Reserves Replacement Ratio for 2002 and 2003 to 100%?

Ad 1)

The current Organic (i.e. excluding A&D) Proved Reserves Replacement Ratio Latest Estimate for 2002 is 60%, while the Base Plan for 2003 is 51%. The latter figure excludes E&A follow-up and other modeled adjustments: with all modeled elements included the figure would be 65%. All the information that follows for 2003 will be with reference to the fully constrained 51% figure.

These figures equate to Proved Reserves Additions of 840 and 770 million boe in 2002 and 2003 respectively.

FID is expected on (Base Plan) projects in 2002 and 2003 for which respectively 1070 and 130 million boe Proved Reserves had already been booked by 1.1.2002. In other words, delaying the first booking of reserves until FID could have yielded a total of 1910 and 900 million boe additions in 2002 and 2003, with corresponding Proved RRRs of 135% and 59% and an average for the two years combined of 97%. With a modest amount of E&A follow-up in 2003, the average would clearly be capable of exceeding 100%.

Consequently, had Shell's historical policy been to defer first booking until FID, it appears likely that the current short-term outlook would have been more encouraging. Whilst 2002 performance would have been substantially higher than 100%, 2003 would still present problems in achieving the full replacement of production, although scope might also have existed to manage the situation to yield a more balanced annual performance.

Following from this, the question arises as to what impact this policy might have had on performance over recent years.

An attempt was made to identify, for the projects concerned, the point in time at which the Proved Reserves bookings were made. This was straightforward for major projects, associated with clearly defined ARPR "fields". However, it was less easy for "Tranche"-type projects: these represent aggregations of many smaller projects, including minor incremental developments of existing producing assets, and EPB-P does not have sufficient resolution in its data to pin-point the time at which the bookings were made.

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For the major projects, the actual reserves booked in each of the last 5 years were subtracted from the recorded volumes so as to yield a revised view of historical performance. For the "Tranche"-type projects it was conservatively assumed that half of the current reserves would have been booked over the last five years, evenly distributed, with the other half assumed to have been booked before 1997.

Major Base Plan projects (FID 2002 / 2003) with reserves booked prior to 1.1.2002 include:

Erha	SNEPCO	166 million boe	(booked in 1999)
Troll Gas Pre Compression	Norway	96	(1999 or earlier)
Greater Plutonio	Angola	75	(2000)
Champion West Ph 2 / 3	Brunei	29	(2000/2001?)
Sirikit West Waterflood	Thailand	21	(2000)
UGHELLI	SPDC	122	(unknown)
SOKU (T4/5)	SPDC	33	(unknown)

This adjustment of historical years was extended to include all Base Plan projects with FID planned later than 2003. With the exception of 114 million boe on Troll, these consist almost exclusively of "Tranche" projects, equating in total to 880 million boe.

The adjustment was further extended to include all projects that did not rank into the Base Plan as expressed to the OUs via the Investment Letters. This amounted to some 2300 million boe of Proved Reserves at 1.1.2002, the largest single contributor being Gorgon (Australia, 560 million boe, booked before 1997). Others are:

Bonga IFO	SNEPCO	130 million boe	(booked in 1998 and 2000)
Ormen Lange	Norway	110	(1999 and 2000)
Total	SPDC	660	(several years)
Total	Others	840	(several years)

The effect of each of these elements is illustrated in the plot on the following page.

1997 and 1998 were the most recent two "High Proved RRR" years, and would have retained reasonable performance had bookings been deferred (at around 130% RRR).

In 1999 and 2000, actual performance was just above 100% but these years would have fared considerably worse if pre-FID bookings had been deferred, reducing to 50 and 70% respectively. Including the effects of A&D these figures would have further reduced to only 5% for 1999 and 33% for 2000.

At only 51% actual organic Proved RRR, 2001 was a bad year to start with and would have slumped to only 24% without pre-FID bookings.

It should be noted that the plot does not include the effects of modeling the revised bookings policy backwards through time – it might be expected that 1997 and 1998 would reduce further, with 1999 - 2001 improving, if first bookings had been tied to the FIDs taken in the latter years.

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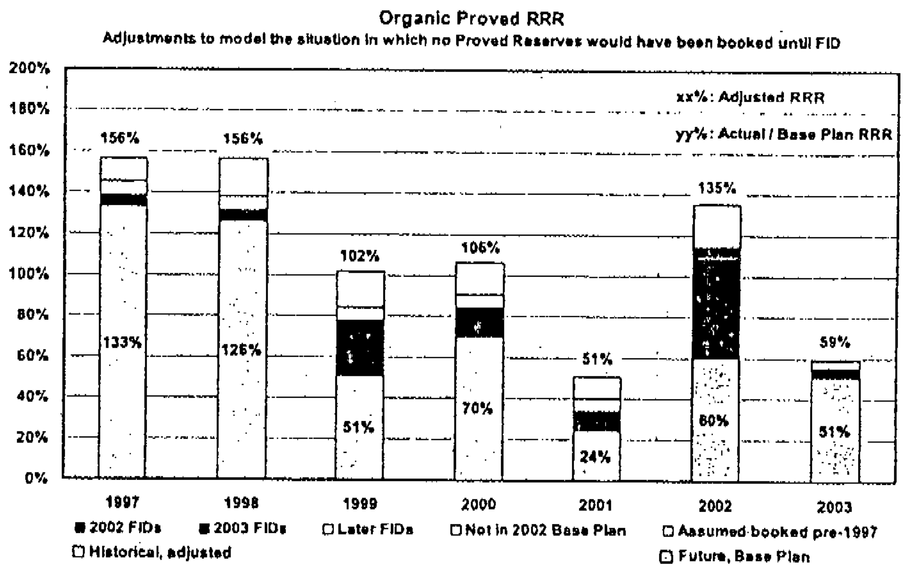
Delaying bookings until FID would not necessarily have yielded "acceptable" performance levels over the most recent 3 years, but it seems that scope might nevertheless have existed to smooth out the profile of Reserves Additions. The result would have been a more stable performance record.

Over the last ten years Shell has moved from the bottom position on Reserves Replacement compared with major competitors (early 1990s), to the top (1996 – 1998) and then back again to the bottom. An alternative might have been to steer a more steady "middle-of-the-pack" course, recognizing that our portfolio has not been sufficiently rich in recent years to sustain a leading position.

Potential lessons to be learned will be incorporated in recommendations for the future policy on Hydrocarbon Resource Maturation management, currently being drafted.



Ad 2)

For 2002, options to raise organic RRR to 100% do not appear to exist beyond the acceleration of Sakhalin bookings. On a total basis, including A&D activities (primarily Enterprise), the LE is 133%.

For 2003 the Base Plan including Sakhalin yields 51% (via Capex projects), rising to 65% with the inclusion of E&A follow-up and other modeled elements. The gap to 100% could be bridged to a certain extent by more aggressive bookings in Sakhalin, and / or by the release of (substantial) further funding.

Consequently, little has changed since the Reserves Outlook was discussed at CMD, 22 - 23 July 2002. In the note that supported this topic, the following options to improve performance in 2003 were highlighted.

Projects with major Proved Reserves Additions in 2004 – accelerate to 2003?

Project	POS to FID	Category	Unrisked PRA[1]	Unrisked RRR
Australia Ceduna	10%	E&A	130	+9%
Australia Sunrise LNG	15%	Development	340	+23%
Egypt NEMED gas	24%	E&A	130	+9%
Egypt NEMED Lc 59	11%	E&A	340	+23%
Iran Bangestan	15%	SO[2] (organic?)	300	+21%
Qatar SMDS	50%	SO (organic?)	350	+24%
Russia Zapolyarnoye Neocomian	50%	SO (organic?)	760	+53%
Saudi Arabia CV1 Upstream	10%	SO (organic?)	730	+51%

Other Upsides

Project	PRA	RRR
Secure Whale Strategic Option, de-risk, "organic"?	600	+42%
Secure Salym Strategic Option (de-risked)	120	+8%
Other Strategic Options (Itau, Kuwait OSA), risked basis	150	+10%
Retain Sakhalin consolidated	600	+42%
T&OE quick wins (highly uncertain)	up to 150	up to 10%
Total potential gain identified	up to 1630	up to 112%

EPB-P, 27 August 2002

[1] Proved Reserves Additions in 2004, million boe

[2] Strategic Option

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Unknown

From:	Brass, Lorin LL SIEP-EPB
Sent:	02 September 2002 08:01
To:	Van De Vijver, Walter SI-MGDWV
Cc:	Powell, Ceri CM SIEP-EPB; Pay, John JR SIEP-EPB-P; Harper, Malcolm M SIEP-EPB-P; Nauta, Jaap J SIEP-EPB-P
Subject:	Reserves 2002 and 2003

Walter,

A further update of the paper to the paper is attached which addresses your questions.

We have also added to the first question a look at "what if we had managed bookings differently...would we have been able to routinely beat competition?". Unfortunately closer scrutiny shows that all our main competitors achieved higher average RRR than us over the last 10 years.

The paper covers these, but just to put specific answers to your questions:

1) license extension Nigeria
Difficult to be precise on the Proved Reserves that would be delivered, but information from SCIN implies that at least 600 million boe should be possible, noting that it would still need to be supported by firm production growth within the existing license period (see 2 below).

2) quota in Nigeria
No additional reserves booking potential is considered likely to result from this until we have firm evidence that production has grown (or is certain to grow) by the amount needed to realize the reserves that have already been booked.

3) license extension in Oman
Nominally 500 million boe Shell share, probably not deliverable by end 2002, but end 2003 a distinct possibility. I recommend not booking anything until we are certain we have a deal (i.e. there should be no risk that we will ultimately walk away due to poor terms, for example).

4) license extension Brunei
There is no reserves booking potential associated with the immediate two 15-year extensions - reserves have already been booked on the assumption that these rights would be exercised. If, as part of the detailed negotiations, we are able to secure rights to further extensions beyond that, then there may be a chance. However, the volumes would presumably be relatively small and it is noted that there may be pressure to reduce Shell equity at the imminent extensions, thereby offsetting any later gains.

5) T&OE projects (reserves + waterflood)
Quick wins are mainly studies-related. Note that new waterflood (and other major project) reserves need to be sufficiently mature (technical and commercial) AND be reasonably certain of attracting funding before they would qualify as Proved Reserves. This suggests to me that our ambitions in that direction are likely to be more in the medium term (although possibly with bookings in 2003 if we can get projects ranked in to the 2004 Base Plan this time next year).

WvdV questions 30_08_02.ZIP

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Note for Information EPB-P 30th August, 2002

RESERVES OUTLOOK: 2002, 2003

Two questions have arisen:

1) To what extent would Proved Reserves Replacement be different if no reserves had been booked until FID?

2) What options exist to raise the (organic) Proved Reserves Replacement Ratio for 2002 and 2003 to 100%?

Ad 1)

The current Organic (i.e. excluding A&D) Proved Reserves Replacement Ratio Latest Estimate for 2002 is 60%, while the Base Plan for 2003 is 51%. The latter figure excludes E&A follow-up and other modeled adjustments: with all modeled elements included the figure would be 65%. All the information that follows for 2003 will be with reference to the fully constrained 51% figure.

These figures equate to Proved Reserves Additions of 840 and 770 million boe in 2002 and 2003 respectively.

FID is expected on (Base Plan) projects in 2002 and 2003 for which respectively 1070 and 130 million boe Proved Reserves had already been booked by 1.1.2002. In other words, delaying the first booking of reserves until FID could have yielded a total of 1910 and 900 million boe additions in 2002 and 2003, with corresponding Proved RRRs of 135% and 59% and an average for the two years combined of 97%. With a modest amount of E&A follow-up in 2003, the average would clearly be capable of exceeding 100%.

Consequently, had Shell's historical policy been to defer first booking until FID, it appears likely that the current short-term outlook would have been more encouraging. Whilst 2002 performance would have been substantially higher than 100%, 2003 would still present problems in achieving the full replacement of production, although scope might also have existed to manage the situation to yield a more balanced annual performance.

Following from this, the question arises as to what impact this policy might have had on performance over recent years.

An attempt was made to identify, for the projects concerned, the point in time at which the Proved Reserves bookings were made. This was straightforward for major projects, associated with clearly defined ARPR "fields". However, it was less easy for "Tranche"-type projects: these represent aggregations of many smaller projects, including minor incremental developments of existing producing assets, and EPB-P does not have sufficient resolution in its data to pin-point the time at which the bookings were made.

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For the major projects, the actual reserves booked in each of the last 5 years were subtracted from the recorded volumes so as to yield a revised view of historical performance. For the "Tranche"-type projects it was conservatively assumed that half of the current reserves would have been booked over the last five years, evenly distributed, with the other half assumed to have been booked before 1997.

Major Base Plan projects (FID 2002 / 2003) with reserves booked prior to 1.1.2002 include:

Erha	SNEPCO	166 million boe	(booked in 1999)
Troll Gas Pre Compression	Norway	96	(1999 or earlier)
Greater Plutonio	Angola	75	(2000)
Champion West Ph 2 / 3	Brunei	29	(2000/2001?)
Şirikit West Waterflood	Thailand	21	(2000)
UGHELLI	SPDC	122	(unknown)
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The adjustment was further extended to include all projects that did not rank into the Base Plan as expressed to the OUs via the Investment Letters. This amounted to some 2300 million boe of Proved Reserves at 1.1.2002, the largest single contributor being Gorgon (Australia, 560 million boe, booked before 1997). Others are:

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At only 51% actual organic Proved RRR, 2001 was a bad year to start with and would have slumped to only 24% without pre-FID bookings.

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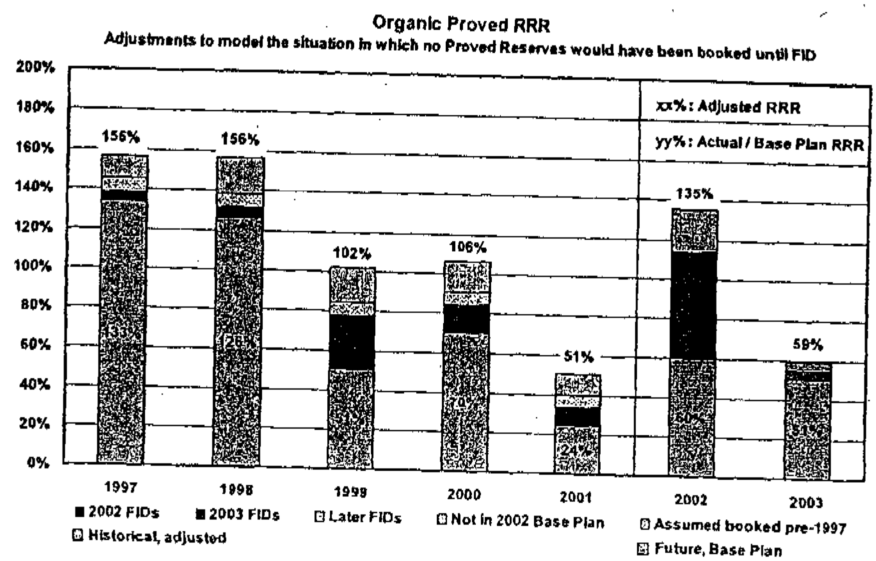
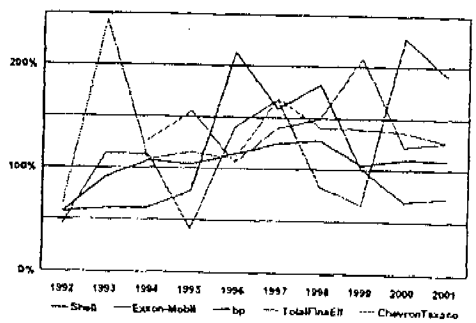
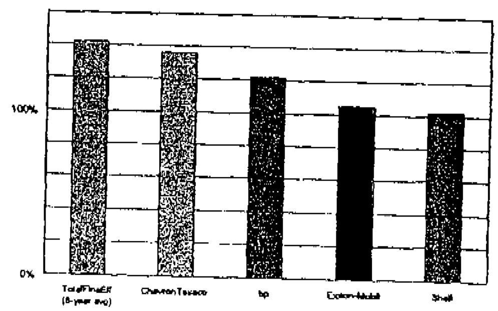
Delaying bookings until FID would not necessarily have yielded "acceptable" performance levels over the most recent 3 years, but it seems that scope might nevertheless have existed to smooth out the profile of Reserves Additions. The result would have been a more stable performance record.



Over the last ten years Shell has moved from the bottom position on Reserves Replacement compared with major competitors (early 1990s), to the top (1996 – 1998) and then back again to the bottom. On average over the same period, all our major competitors delivered a higher Proved Reserves Replacement Ratio. An alternative might have been for Shell to steer a more steady course, avoiding the peaks and troughs in annual performance and recognizing that our portfolio has not been sufficiently rich in recent years to sustain a leading position. Potential lessons to be learned will be incorporated in recommendations for the future policy on Hydrocarbon Resource Maturation management, currently being drafted.



Annual Proved RRR



1992 - 2001 Average Proved RRR

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Ad 2)

For 2002, the Latest estimate for organic Proved RRR is 60%, rising to 133% with the inclusion of A&D (mainly Enterprise). 100% organic RRR would require the addition of a further 560 million boe Proved Reserves.

For 2003 the Base Plan including Sakhalin yields 51% (via Capex projects), rising to 65% with the inclusion of E&A follow-up and other modeled elements. 100% organic RRR would require the addition of a further 530 to 740 million boe Proved Reserves.

The following inventory of "Big Ticket" opportunities with organic reserves additions potential can currently be identified (see also Reserves Outlook Note to CMD, 22 – 23 July 2002):

Project	FID	PRA[1]	RRR[2]	Note
Licence extension, Nigeria SPDC		600	40%	[3]
Quota increase, Nigeria		0	0%	[4]
Licence extension, Oman PDO		500	35%	[5]
Licence extension, Brunei		0	0%	[6]
T&OE-assisted "quick wins"		150	10%	
Retain Sakhalin consolidated and / or more aggressive booking		600	40%	[7]
Venezuela Cretaceous	2003	410	25%	
Kuwait OSA	2003	400	25%	organic?[8]
Russia Salym success case	2003	120	8%	organic?
Russia Zapolyarnoye Neocomian	2004	760	50%	
Libya Gas (Block 6 devt.)	2004	440	30%	
Iran Bangestan	2004	300	20%	
Venezuela LNG	2004	250	15%	
Saudi Arabia CV1	2004	70	5%	

1 Approximate Proved Reserves Additions, million boe, unrisked.
2 Approximate contribution to Proved Reserves Replacement Ratio in the year of reserves booking, assuming annual production of 1500 million boe total for EP, OA basis.
3 Any new reserves bookings will need to be justified with reference to production growth targets, see also (4) below.
4 A quota increase is necessary in any case to enable production to grow and thereby enable the currently booked Proved Reserves to be realized. No new within-licence reserves will be booked until clear evidence is available that the required higher production rate can be achieved and sustained.
5 Based on the currently reported post-licence Expectation Reserves (550 million boe). Certainty over the deal is unlikely to be achieved by end-2002: for reserves to be booked it is recommended that we be certain that a deal will occur and that there is no risk of detailed negotiations de-railing it.
6 Reserves are already booked on the basis that BSP's rights to two 15-year licence extensions will be exercised. Any reserves upside would therefore be in relation to the negotiation of further extensions beyond the 30-year window, but this may be offset by potential equity reduction in the first two 15-year extensions.
7 Bookings should in principle keep pace with "reasonably certain" market development and preferably with actual LNG sales contract fixtures.
8 Cash-based Service Agreement with little or no exposure to oil price. Consequently it might not be possible to book reserves.

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In addition, the following major projects currently do not rank in to the Base Plan, but might nevertheless mature (unrisked):

Project	FID	PRA	RRR	Note
China Changbei Upstream	2003	55	4%	
Nigeria SNEPCO Bonga SW	2003	70	5%	
Norway Ormen Lange	2004	160	10%	
Australia Sunrise	2004	340	20%	9

Furthermore, the following "Big Tickets" offer Proved Reserves Additions potential in the short-term but probably not qualifying as organic (unrisked):

Project	FID	PRA	RRR	Note
Iran Azadegan farm-in	2003	110	7%	
Abu Dhabi Whale	2003	550	35%	
Central Asia Cygnet	2003	220	15%	
Qatar SMDS	2004	300	20%	

DB 08090

9 Offset by Gorgon?

NOTE FOR DISCUSSION

Subject : EP PROVED RESERVES MANAGEMENT

Date : 3rd October 2002

FROM : EPB

TO : ExCom

Excom,

The attached note regarding reserves sets out some changes in process in an attempt to keep us abreast and better 'manage' reserves booking. I support the changes as I think they are not overly bureaucratic and can be helpful in all of us understanding and working the reserves issue with more clarity.

If you're rushed, the first two pages tell the story. Then the full story follows, and finally the appendices show the numbers and other details.

I'll appreciate your feedback.

Lorin

EXHIBIT
16
Bross
PENGAD 800-631-6989

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Note For Discussion

EP PROVED RESERVES MANAGEMENT

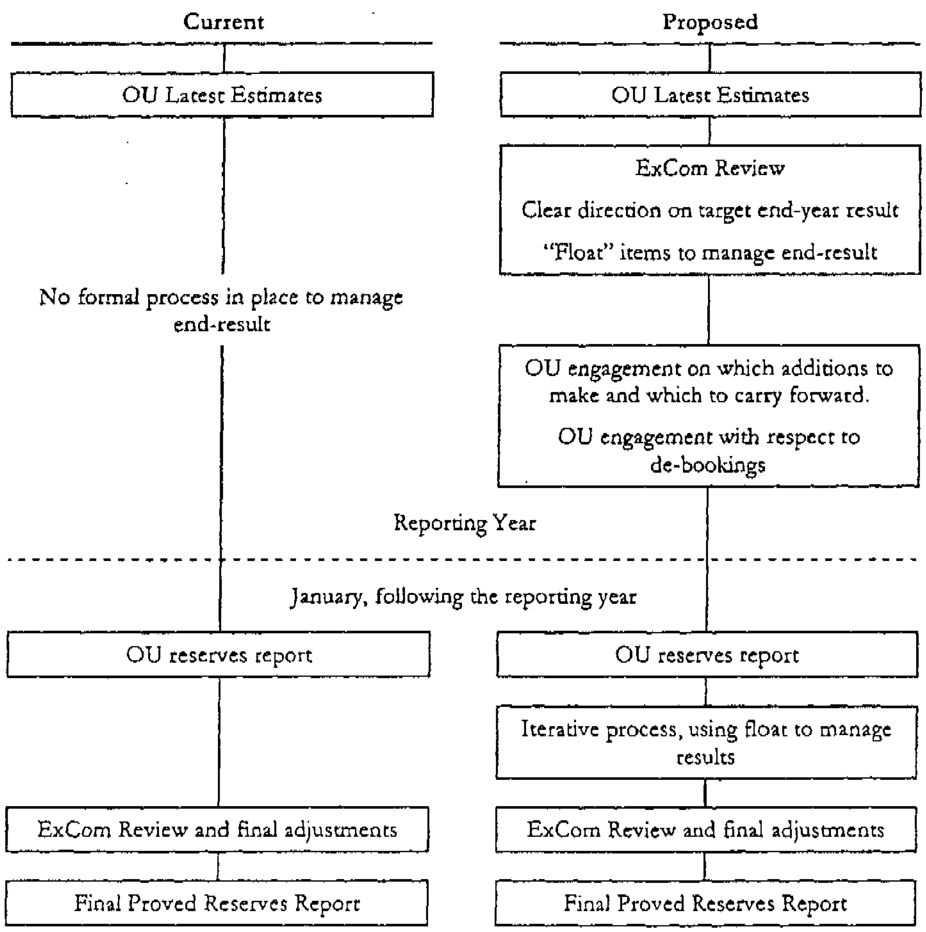
Over the last ten years, Shell has moved from bottom, to top (1996 – 1998) and back to bottom on proved reserves replacement performance compared with major competitors. Without significant new business being secured, licence extensions or major new discoveries, it is unlikely that proved reserves replacement will exceed some 70% on average during the plan period.

This being the case, the system that is used to manage proved reserves additions would benefit from revision with a view to:

a) Where possible and within the latitude of the SEC rules, avoid major swings in performance – in particular "peaks" in one year that exacerbate troughs in the next,

b) Maintain focus on new opportunities and actions required to mature them.

The overall changes to the process are summarized in the diagram below and on the following page.



Summary of Proposal

Please refer to the relevant section on the following pages for detail and note also that several items referred to below will require coordinated action by the OUs, RBDs, T&OE and the Hydrocarbon Maturation Leadership Team, making use of the Hydrocarbon Maturation Forum.

1) **Proved Reserves Replacement Management**

1a) **Major Reserves Changes**
Close tracking of both planned and unplanned changes by the EPB-P Hydrocarbon Resource Coordinator in consultation with the OU Reserves Focal Points will be reinforced.

1b) **ExCom Review**
Two formal ExCom reviews will be introduced in July and November of the reporting year, augmenting the final review in January of the following year. ExCom will be briefed on the outlook for the year and presented with opportunities and potential exposures for further consideration and action (where necessary) via the RBDs and new business development teams.

1c) **Latest Estimate**
Monthly tracking of progress against plan, plus uncertainties, will be improved to provide more project-focussed transparency.

1d) **Reserves Opportunities Catalogue**
An inventory of opportunities that are not in the plan for the current year will be maintained with the aims of identifying actions to address shortfall against target and ensuring appropriate focus on mid- to long-term opportunities.

1e) **Potential Reserves Exposure Catalogue**
An inventory of potential exposure (reserves at risk of debooking) will be reviewed at least annually at ExCom with actions being agreed.

1f) **Scorecards**
Within the Group there are mixed opinions on the inclusion of Proved Reserves Additions on OU scorecards. On the one hand it is seen to affect objectivity in reporting, on the other it is seen as a key means by which appropriate focus is maintained on this important business performance parameter. It is proposed to retain the item on OU scorecards for 2003 but to review the situation again in light of experience at the 2002 year-end reserves report.

1g) **Standardisation of Proved Reserves Estimating Methods**
Specific actions will be developed to further harmonize the approach to reserves reporting by the OUs and to improve benchmarking of reservoir performance across the Group.

2) **Reserves Administration System: Schedule of Authorities**

Authorities in the process leading to proved reserves disclosure to the SEC have been updated, although no new authority levels have been added pursuant to (1) above (none are deemed necessary).

3) **Competitive Intelligence**

Efforts will be redoubled to establish more fact concerning the actual practices of competitors, with a view to identifying issues that need to be resolved by the industry as a whole.

4) **Capability Management**

Several areas have been highlighted for further consideration and development by the technical community in Shell.

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1) Proved Reserves Replacement Management

Recent years have witnessed dramatic swings in Shell's performance on proved reserves replacement, with results in 1996 – 1998 being the highest of our main competitors but performance since then being the lowest. The period of high performance was partly the result of renewed focus on proved reserves replacement following poor performance in the early 1990s and partly due to the acceleration of revisions into the year 1998 after revised Shell internal guidelines were introduced.

Fluctuations of this magnitude can undermine investor confidence. Within the bounds set by the SEC rules, it would be prudent to level them out so as to create a more stable and predictable environment that is in keeping with the sustained performance potential of the portfolio. By strengthening the management of this aspect of business performance, improved focus will be created on options and actions required to generally increase performance going forward.

The system for managing additions to the EP proved reserves inventory was last updated in 2000 with the introduction of performance tracking during the year via EPMIS. This improved the predictability of the year-end result, but it did not remove the tendency of the OUs to report last-minute changes that either had not been foreseen or which, for various reasons, might have been suppressed in the EPMIS reporting. This feature of the reporting system is unlikely to be overcome, since most OUs do not complete their annual review of reserves on producing assets until the final quarter of the year. Nevertheless, further improvements to the overall management system have been identified as follows:

1a) Major Reserves Changes

The roles of the Hydrocarbon Resource Coordinator and the OU Reserves Focal Points should be reinforced to ensure that major changes to proved reserves (e.g. >30 million boe) are adequately worked prior to the end of the year in which they are reported. The objective is to allow time for clarification and discussion of the changes and so ensure that they are being treated correctly and consistently. The views of the Group Reserves Auditor will be sought where necessary, as will those of OU and EP management.

Thanks to the efforts of previous Hydrocarbon Resource Coordinators, it is already automatic practice in many OUs to seek the views of the Coordinator on reserves changes that are being contemplated, with supporting documentation being either volunteered or provided on request. This practice is to be further encouraged through personal communication and including in the Petroleum Resource Volume Guidelines a statement such as: "*First-time proved reserves bookings for major new projects, or any other substantial change to proved reserves estimates exceeding 30 million boe, must be raised and discussed with the Group Hydrocarbon Resources Coordinator as far as possible in advance of the intended disclosure date so as to allow for adequate review and support of EP management and, if necessary, the Group Reserves Auditor.*"

An alternative approach was considered which would introduce a formal *pro forma* notification of major reserves changes to the Hydrocarbon Resource Coordinator for discussion with the OU, Reserves Auditor and Regional Business Advisers as appropriate and culminating in ExCom sanction, or otherwise. This was rejected on the grounds that it might not be possible to enforce and that it would not substantially improve on the current system (with the reinforcement proposed). OU feedback suggests that the additional bureaucracy would be unwelcome and could be counter-productive.

Action: EPB-P Hydrocarbon Resource Coordinator to reinforce contacts with OU Reserves Focal Points and senior development engineers on reserves maturation matters. Arrangements are to be in place to ensure that cover would be provided in the event of prolonged absence (e.g. by involving T&OE hydrocarbon resource maturation staff in the regular consultation of OUs).

1b) **ExCom Review**

In addition to the existing reviews which take place in January each year (at which point it is generally too late to materially influence the result of the previous year), formal reviews will be introduced during the reporting year itself. These will provide ExCom with the opportunity to guide the end result for the year (within the margins that can be accommodated by the SEC rules) and to identify actions required to control either under-performance or unnecessary new bookings.

Allied to this, clear direction will be required on the minimum and maximum levels of reserves replacement that are to be targeted. In general, clear justification would be required for "accepting" performance below 100% reserves replacement in any given year. However, since the existing portfolio cannot sustain this level of performance going forward (based on knowledge and plans as currently defined), minimum targets must be set that fully take into account the "organic" growth potential of the portfolio. This will help to add clarity to the requirements for delivering new business to the portfolio. 140% annual reserves replacement is widely accepted to be consistent with Shell's current 3% a.a.i. production growth target. Consequently it would be prudent to constrain reserves additions to this figure (when circumstances allow) and to assist performance in future years by carrying forward as much as possible of the surplus, unless there are clear indications that the portfolio is capable of sustaining a higher level of performance.

January: EPB presents for approval the final results for the previous year (this review is already part of the established system and no changes are proposed).

July: EPB will present:

- The current Latest Estimate (see 1c below)
- The outlook for the plan period (based on Capital Allocation)
- The Reserves Opportunities Catalogue (see 1d below)
- The Potential Reserves Exposure Catalogue (see 1e below)
- Views and Comments of the Group Reserves Auditor
- Recommended Actions

ExCom will review the outlook for the year with reference to the aspired performance target (or target range). ExCom will endorse or otherwise amend the Recommended Actions, implementation of which will generally need to be secured via the RBDs and new business development teams.

November: Similar format to the July review, but with increased emphasis on targeting a specific end-year result or range of results. The review will yield:

- An endorsed list of major year-end reserves additions
- An endorsed list of major reserves de-bookings to be made (with reference to the Potential Reserves Exposure Catalogue, see 1e below)
- To the extent that the portfolio will allow (i.e. generally in the more buoyant years), a clear and endorsed list of projects or potential bookings that can be used as a "float" with which to control the year-end result. The EPB-P Hydrocarbon Resource Coordinator will direct OUs to include or exclude these from their final submissions as required.
- Review of Group Reserves Auditor views and comments on the foregoing.
- Agreed actions required of OUs and EPB and EPF in preparation for the year-end reporting of reserves data.

In implementing this additional level of "steer" of the year-end result, the following must be borne in mind:

(i) It is important at all times to stay within the interpretative margin of the SEC rules. As at present, post-FID reserves must be disclosed in full unless circumstances dictate that caution should be applied (e.g. lack of firmness on gas sales contracts). Similarly, as at present, reserves that are not yet technically of commercially mature cannot be disclosed. Consequently, the "float" will consist mainly of the limited number of projects that are between VAR3 and VAR4 / FID, since it is for these that latitude in the interpretation of the SEC rules exists. Shell historical practice has been to consider booking reserves as soon as a project is deemed to be mature (currently interpreted as having passed VAR3). The 2001 SEC clarification of its rules implies that booking at FID would be preferred, and this seems to be the practice adopted at least by BP and possibly other major competitors. As part of the revised management system, it is recommended that greater alignment between investment decisions and reserves impact be sought, implying that in general the Centre should encourage OUs to move reserves bookings towards FID.

(ii) Some OUs will inevitably have problems in accommodating requests from the Centre to include certain potential bookings in the "float" inventory. The problem will be most pronounced for joint ventures such as BSP and NAM, in which other shareholders approve the proposed reserves bookings in advance of year-end reporting, and in other cases such as SPDC and PDO in with the regulatory authorities pay particular attention to the year-end reserves situation. The timing of discussions between these OUs and their other stakeholders varies, but is generally in late November / early December. Consequently, the November ExCom review must take place in early November to allow for maximum alignment of Shell representation with ExCom requirements.

Action: EPB-P Hydrocarbon Resource Coordinator to prepare material for the first ExCom review in November 2002. EPB-P to develop a procedure for ensuring consistency between ExCom decisions and year-end OU reserves reports, with early engagement of OUs that might be required to assist in the management of the results.

1c) Latest Estimate

The EPB-P Hydrocarbon Resource Coordinator currently compiles the monthly Latest Estimate data provided by the OUs via EPMIS (although, in general, OUs do not significantly update their Latest Estimates in the months between quarter closing). This system, together with the dialogue between EPB-P and the OUs that goes with it, provides an adequate means of tracking progress against plan on major reserves additions. In principle it also provides some opportunity for EP management to "steer" performance for the year and as such the proposals described in section (1b) above should be seen as augmenting, rather than replacing, current practice.

A system was introduced in 2002 to better quantify the uncertainties in the Latest Estimate data – specifically the potential impact of opportunities that are not yet incorporated in the LE and those elements of the LE that are under threat. As the year progresses the LE should be definable with increasing certainty and consequently the uncertainties will become decreasingly significant. The current 2002 Latest Estimate and major remaining uncertainties are summarized in Appendix C.

Action: Starting with 2003, the Latest Estimate will be defined and tracked with reference to specific major elements in the plan, giving an increased level of transparency and resolution compared with the current system that is focussed on overall OU figures.

1d) Reserves Opportunities Catalogue

The EPB-P Hydrocarbon Resource Coordinator will maintain an inventory of opportunities for significant new reserves additions that may be realizable in the short to medium term (current year plus two). This will help to focus attention towards corrective action that is required to underpin current and plan year performance. The catalogue will be presented periodically to ExCom for review (see 1b). Input will be solicited at least quarterly from the RBDs, OUs, and from the T&OE, new business development and the Hydrocarbon Maturation Leadership teams.

In its fully developed form, it is expected that the inventory will include all opportunities, whether they form part of the plan or not, and therefore there will be some overlap with the Latest Estimate. The Reserves Opportunities Catalogue will go further, however, by including strategic options and other big ticket items that might be accelerated or otherwise secured through additional concerted effort.

It is acknowledged that time might not permit opportunities that are not already part of the plan to be matured in time to make a difference to the reporting year or the plan year. Nevertheless, rigour in capturing and summarizing the full inventory of opportunities can only serve to improve the quality of management information. This will help to ensure that decisions are taken and resources deployed in full knowledge of the alternatives that are available and with realistic expectations for the outcome.

Action: EPB-P (HRC) to consolidate the initial draft of the catalogue in time for the November 2002 ExCom review proposed under (1b). A working draft is included as Appendix A.

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1e) Potential Reserves Exposure Catalogue

The EPB-P Hydrocarbon Resource Coordinator will maintain an inventory of all proved reserves that could be under threat of debooking in the event of failure to execute projects or failure of projects to deliver as expected. This will promote transparency on these issues and will be reviewed at least annually by ExCom (see 1b).

The catalogue will be maintained in close consultation with the Group Reserves Auditor and the OUs as required. Each item will be reviewed at least once per year by EPB and the HMLT, recommended actions being put forward for ExCom consideration (see 1b).

In the event that a debooking is deemed necessary or unavoidable, consideration should be given to the manner in which this will be achieved. In general, the revision should be made in full and with immediate effect. However, bearing in mind the disproportionate impact that this could have on investor confidence (in the more severe cases), consideration may be given to phasing the revision over a period of years so as to weaken its impact and provide for attenuation of any performance swings that might arise should the corresponding project be resurrected.

Action: EPB-P (HRC) to consolidate the initial draft of the catalogue in time for the November 2002 ExCom review proposed under (1b). A working draft is included as Appendix B.

1f) Scorecards

When reviewing the end-2001 OU reserves reports, the Group Reserves Auditor observed:

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

The Society of Petroleum Engineers (SPE) has issued statements on such practices that it feels may be in conflict with objectivity in reserves estimation (ref. "Standards Pertaining to Estimating and Auditing of Oil and Gas Reserve Information", June 2001).

It is also observed that, under certain circumstances with the current system, OUs can in effect be penalized for accelerating reserves bookings from one year into the preceding year.

These observations prompted serious consideration of a proposal to remove Proved Reserves Additions from the OU scorecards with effect from 2003. In its place, higher weighting would be applied to milestones that are related to project delivery and in particular to those that can have reserves additions associated with them (i.e. VAR3, VAR4, FID and, if appropriate, confirmation of improved recovery performance).

However, strong recommendations to the contrary have come from several of the more mature OUs, who find that keeping Proved Reserves Additions on OU scorecards ensures that this important aspect of business performance receives and retains an appropriate level of attention. The onus is on the Centre and OU technical management to ensure that the system is not abused and that it is used as a stimulus for genuinely constructive behaviours. This would be augmented by a concerted long-term effort to increase the level of awareness of the importance of the issue within the technical community and the responsibilities that estimators have in relation to the SEC rules (see also section 4 below).

Consequently, it is recommended to retain the measure on OU Scorecards at least for 2003. This must be coupled with the development of a mechanism to ensure that OUs are not penalized for maturing genuine proved reserves earlier than planned (in fact they should receive a net reward for their achievement) or for moving reserves bookings relative to plan as part of the process proposed in section 1b above. If unreasonable attempted bookings continue to distract EPB-P coordination staff from the overseeing of genuine bookings, the situation may need to be reviewed and the recommendation changed.

Under all circumstances, Reserves Replacement Ratio should remain on the EP Global Scorecard, and possibly those of the RBDs. There should be clear definition and understanding of the target with respect to "organic" additions and changes made through Acquisition and Divestment activities.

Action: OU Scorecards should retain Proved Reserves Additions targets for 2003. RBDs should ensure that fit-for-purpose mechanisms are introduced to encourage behaviours that are generally helpful to EP objectives in this regard and discourage inappropriate behaviours or attempted reserves bookings.

1g) **Standardisation of Proved Reserves Estimation Methods**

The Shell Group Petroleum Resource Volume Guidelines are designed to promote consistency across the Group on the estimation of resource volumes in general and of proved reserves in particular. They are certainly helpful in so doing, yet evidence from Reserves Audits and superficial comparison of practices continues to suggest that the OUs are not yet as consistent in their approaches as one might expect.

The EPB-P Hydrocarbon Resource Coordinator, in close consultation with the Group Reserves Auditor, OU Reserves Focal Points and the Hydrocarbon Maturation Leadership Team, will investigate further development of the existing diagnostic tools that are routinely used to check the consistency of reserves reported across the Group. The continued emphasis that will be so created – particularly in the years between formal OU Reserves Audits – will help to ensure that every opportunity is taken to close the proved:expectation reserves gap for mature assets (in line with Group guidelines), as well as allowing improved comparison between OU submissions.

This is closely linked to Opportunity Identification: refer to section 4 below.

Action: EPB and T&OE to consolidate and further develop diagnostic tools for checking the consistency of OU reserves reports with each other and with the Group guidelines and to assist in identifying "outlying" field and reservoir performance for closer scrutiny. Where necessary, the guidelines may be further revised to remove any remaining ambiguity or to suggest specific techniques that might be considered for application. In certain circumstances, OUs may be requested to supply additional information as part of the year-end reporting process (e.g. rate – cumulative curves, historical and forecast, for major assets).

2) Reserves Administration: Schedule of Authorities

The system for administering year-end reserves reporting is tried and tested and no significant changes are considered to be necessary other than to include the processes described in section (1) above. The documentation describing the system has not been updated since 1996 and in the meantime numerous workflow and organizational changes have occurred. EPB-P (Hydrocarbon Resource Coordinator) will update and reissue the documentation in due course.

It is stressed that, whilst Latest Estimates may be prepared as the year progresses and investment decisions may be taken that will have an effect on the year-end results, no reserves changes can be considered finally "booked" until the annual submission, review, audit and approval cycle is completed. Under some circumstances local approval of minor major reserves additions is required during the year to ensure that ongoing development expenditure is correctly categorized (i.e. as Capex rather than Expex). This practice should continue under local authority levels, being subject to periodic review by the Group Reserves Auditor.

The current schedule of authorities in relation to proved reserves disclosure is included as Appendix D. This summarizes the approval process commencing with the preparation of data within the OUs, compilation and review by the Hydrocarbon Resource Coordinator and the Group Reserves Auditor, through to final sign-off by EPB, EPF and the external auditors. It is considered that no changes to the schedule are required.

Appendix E details the flow of work and information in preparing proved reserves information for external disclosure, together with the revisions that would be necessary to implement the recommendations of section (1) above.

Action: EPB-P to reissue the finalized schedule of authorities and process documentation after approval by EPB and EPF, by the end of 2002.

3) Competitive Intelligence

There is a significant amount of discussion within the Group on the practices of Shell compared with those of competitors. This focuses on (a) the way in which reserves bookings are managed and (b) the interpretation of the SEC rules and regulations.

The approach to managing reserves additions is known to vary considerably among competitors[1] and insight into alternative approaches might suggest further improvements to the Shell approach.

Interpretations of the rules do differ, particularly in areas that are not explicitly covered by the SEC regulations. Examples include:

- Calculation of entitlement under PSCs (practices seem to vary considerably).
- Treatment of entitlement under "innovative" contracts.
- The use of techniques that fully support the "reasonable certainty" intent of the SEC rules but on which there is currently no clear direction from the SEC as to the acceptability of such techniques.

To help sort myth from fact, efforts will be redoubled to gain intelligence on the actual practice of competitors. This is likely to concentrate on comparison (where possible) of bookings in joint ventures, or projects in which major competitors have an interest, and on industry networks and fora in which reserves and reserves management issues are discussed. The current technical staff pool will be polled for recent experience, particularly where this has been gained through working directly for competitors.

The initial objective will be to understand the practices of competitors and so to allow objective assessment of the degree to which Shell's practice differs from that commonly adopted in the industry. Further action to modify the Shell management system can then be considered on an informed basis.

Exposure of significant differences in interpretation of rules will help to inform our views on the apparent performance of competitors. In some (expected to be rare) cases it may prompt a reinterpretation of the SEC rules by Shell, but more likely it will help to focus attention on matters that need resolution across the industry as a whole.

It is recommended that cases of doubt be resolved by open dialogue with the SEC and active participation in industry fora where reserves issues are discussed.

Action: EPB to develop a network of contacts, bearing in mind the sensitivities inherent to the issue. Target to include status reports in ExCom reviews (see 1b above) and to propose actions at other times as required.

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1 For example, ExxonMobil is believed to use an elaborate reserves booking management system supported by a 13-strong internal organization that audits reserves worldwide. Other companies make use of independent reserves auditors and, with the SEC coming under increasing pressure to ensure that regulations are being adhered to, it cannot be ruled out that companies will be required to make more widespread use of independent assessors.

4) **Capability Management**

With the advent of T&OE, an opportunity is presented to address reserves reporting issues and in particular inconsistency of approach between the OUs. The following areas should be addressed by the technical reporting community, with the assistance of the Discipline Leads for Reservoir Engineering, the Hydrocarbon Maturation Forum (HMF) and Hydrocarbon Maturation Leadership Team (HMLT):

Commercial Awareness. There are examples of OU staff being unaware of the impact of reserves on external (investor) perceptions, the impact of reserves on NIAT (via depreciation), and of the net effect on investor confidence. It is not uncommon to hear the annual reserves exercise described as a "book-keeping exercise".

Technical Capability. In addition to engineering technique, a common understanding is required of the rules applicable to reserves reporting; the pros and cons of techniques that can be used in reserves estimating and of matters on which opinions differ across the industry (e.g. probabilistic aggregation). This will help both to promote convergence towards a "Group Common Approach" (to be documented in the Shell guidelines) and to identify issues to be addressed by the industry at large.

Training. All aspects of technical and "commercial" training should be reviewed to ensure that development engineers are given an appropriate balance of technical and commercial understanding.

Opportunity Identification. The recent concerted effort by the T&OE team to compile data on the technical performance of the existing field and reservoir inventory has yielded an invaluable resource for benchmarking and for diagnostic analysis of the portfolio. Refer also to section 1g above.

Best Practice. Several OUs have evolved proved reserves management practices that could be shared and potentially adapted in developing overall Group practices.

Reserves Reporting Community. Each OU has its own Reserves Focal Point that, depending on the size and complexity of the OU, may be dedicated full-time or only part-time to hydrocarbon maturation issues. It would be beneficial to the efficiency of this network in working towards Group common practices if occasional workshops could be held. As well as providing for enhanced networking and group cohesion, such events would be ideal for sharing Group-wide issues and local best practices, so helping to define best practice at the OU management level.

Technology Development. Currently there is only limited reserves estimating technology available within the Group that is focussed specifically at underpinning proved reserves. Active consideration of techniques that both allow more proved reserves to be booked and fully meet the SEC rules (or their intent) would help Shell to differentiate itself from the competition. An example of current success would be the SEPCo-sponsored development of seismic-based techniques for defining downdip water contacts for the Proved Area determination.

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Appendix A: Reserves Opportunities Catalogue

Project	FID	PRA[1]	RRR[2]	Note
Licence Extensions:				
Nigeria SPDC (mostly expiring in 2019)		530	35%	3
Oman PDO (2012)		500	35%	4
Malaysia (various years)		450 ?	30% ?	
Abu Dhabi (2014)		370	25%	
Denmark (2012)		80	5%	5
Norway (various years)		70	5%	
Venezuela (2013)		40	3%	
Syria (2009 – 2014)		10	1%	
Brunei (2003)		0	0%	6
T&OE				
Portfolio in definition		150 ?	10% ?	7
Big Tickets and Strategic Options				
Quota increase, Nigeria		0	0%	8
Retain Sakhalin consolidated and/or more aggressive booking		600	40%	9
Abu Dhabi Whale	2003	550	35%	A&D
Venezuela Cretaceous	2003	410	25%	
Kuwait OSA	2003	400	25%	organic?[10]
Russia Salym success case	2003	120	8%	organic?
Iran Azadegan farm-in	2003	110	7%	A&D
Russia Zapolyarnoye Neocomian	2004	760	50%	
Libya Gas (Block 6 devt.)	2004	440	30%	
Iran Bangestan	2004	300	20%	
Qatar SMDS	2004	300	20%	A&D
Venezuela LNG	2004	250	15%	
Saudi Arabia CV1	2004	70	5%	
Ranked out of the Base Plan 2002				
Nigeria SNEPCO Bonga SW	2003	70	5%	
China Changbei Upstream	2003	55	4%	
Australia Sunrise	2004	340	20%	
Norway Ormen Lange	2004	160	10%	

1 Approximate Proved Reserves Additions, million boe, unrisked.

2 Approximate contribution to Proved Reserves Replacement Ratio in the year of reserves booking, assuming annual production of 1500 million boe total for EP, OA basis.

3 Any new reserves bookings will need to be justified with reference to production growth targets, see also (8) below. Figure from 1.1.2002 ARPR: recent RBA advice suggests figure could be 600 MMboe.

4 Based on the currently reported post-licence Expectation Reserves (550 million boe). Reserves to be booked when there is certainty that a deal will occur with no risk of detailed negotiations de-railing it.

5 Not under Shell control: negotiation to be conducted exclusively by Concessionaires (A.P. Moller).

6 Reserves already booked assuming that BSP's rights to two 15-year licence extensions will be exercised. Any reserves upside would be in relation to the negotiation of further extensions beyond the 30-year window, but this may be offset by potential equity reduction in the first two 15-year extensions.

7 Notional "Quick Wins". A more detailed inventory will be developed.

8 A quota increase is necessary in any case to enable production to grow and thereby enable the currently booked Proved Reserves to be realized. No new within-licence reserves will be booked until clear evidence is available that the required higher production rate can be achieved and sustained.

9 Bookings should in principle keep pace with "reasonably certain" market development and preferably with actual LNG sales contract fixtures.

10 Cash-based Service Agreement with little or no exposure to oil price. Consequently it might not be possible to book reserves.

Appendix B: Potential Reserves Exposure Catalogue

Asset (Year booked)	Reserves at risk MMboe	Comment (reason not to de-book)
Australia Gorgon (1997)	560	Booked in 1997 in anticipation of imminent FID, subsequently deferred indefinitely by the downturn in Asian economics and the consequent reduction in demand for LNG. It is inevitable that a resource of this magnitude will be developed eventually.
SNEPCO Bonga IFO (1998, 2000)	128	IFOs (In-Field Opportunities) largely consist of unpenetrated reservoirs that would not qualify for inclusion in the Proved Area for reserves under the recently clarified SEC rules. A recent SEC Reserves Audit recommended that remaining unpenetrated reservoirs should be debooked.
SNEPCO Bonga Main (1998) SNEPCO Erha (1999) SNEPCO Abo (1997) Angola Block 18 (2000) Reserves potentially at risk estimated provisionally to be 75% of the current inventory.	up to 210 up to 125 up to 25 up to 55	Reserves rely on the successful implementation of water flood in reservoirs that have no, or at best tenuous, local supporting analogues. As such, the incremental recovery associated with water flood would not qualify for inclusion under the recently clarified SEC rules. However, given that the bookings have been made, they should be retained in the inventory pending acquisition of actual performance data. The Bonga Main booking was queried by the SEC (along with many others) in its routine review and challenge of the 31.12.1998 Form 20-F submission. Although the challenge was not pressed strongly by the SEC, it was not specifically disputed.
Norway Ormen Lange (1999, 2000)	109	Reserves have been partially booked ahead of VAR3 and FID, whilst it appears that there are issues that could prevent it proceeding. De-booking will be considered only when and if it becomes clear that development definitely will not proceed.
Netherlands, Waddenzee (?)	25	Government-enforced moratorium on Waddenzee drilling, due to environmental concerns, could ultimately prevent development from proceeding.
Brunei legacy (Various)	20	Historical reserves bookings that can no longer be supported are inventorized and actively managed, with a view to cushioning the impact of their de-booking. It is expected that the remaining balance will be reduced to zero over the next two or three years, in consultation with national regulatory authorities.
Total	840 - 1260	The total proved reserves balance at 1.1.2002 was 19100 MMboe.

In addition, reserves in some OUs would be at risk if planned production rate increases do not materialize. The OUs thus affected are SPDC Nigeria and Abu Dhabi. For illustration, if production were to remain constant year-on-year, instead of growing as planned, the reserves that would be placed at risk each year would be some 70 MMboe and 15 MMboe in each case. Furthermore, Oman PDO must sustain current production rates throughout the remaining lifetime of the licence to ensure production of the booked proved reserves.

The SEC provides no specific guidance on reserves disclosure for novel or "innovative" contract structures. Shell currently has four bookings in this category: the Venezuela service agreement, Iran buy-back contract, Oman Gisco and the booking of NGL reserves in connection with interests in Abu Dhabi GASCO.

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Appendix C

End-August 2002 Latest Estimate, Proved Reserves Additions

Million Boe	↑↓	Proved Reserves Additions Plan	LE	Delta	Reserves Replacement Ratio Plan, %	LE, %
Organic						
Kazakhstan	Kashagan Declaration of Commerciality + Arman		384	384		27.3
USA	Mars WF/Auger/Glider/OSO Martin↑ Shawnee, Crossbones& others↓	139	145	5	9.8	10.3
Brunei		67	66	0	4.7	4.7
Canada		50	50		3.5	3.6
Nigeria (SNEPCO)	Bonga SW challenge to reach VAR3 in 2002	116	49	-67	8.2	3.5
Angola	Block 18 FID ↑ Risked pending check with SEC rules	33	45	12	2.3	3.2
UK	Carrack West/Curlew↑, Shearwater/Cormorant N&S↓, Scoter deferred	68	38	-31	4.8	2.6
Denmark		24	32	8	1.7	2.3
Venezuela	Not a gain: Plan figure was inadvertently omitted from EP total		25	25		1.8
Netherlands		30	21	-9	2.1	1.5
Syria		13	15	2	0.9	1.1
Egypt		11	11		0.8	0.8
Gabon		7	7		0.5	0.5
Pakistan	Bahdra-3 well result(↑). Query Plan figure.	10	5	-5	0.7	0.4
Australia (SDA)		0	4	4	0.0	0.3
Brunei (FCE)		3	3		0.2	0.2
Argentina		3	3		0.2	0.2
Germany	Changed / deferred drilling programme	17	2	-15	1.2	0.2
Thailand	Reduction pending completion of studies Q3/Q4	4	1	-3	0.3	0.0
Australia (WPL)		0	0		0.0	0.0
Russia	Deconsolidation deferred	-92		92	-6.5	
USA (Ass Comp)	Aera included in USA LE	4		-4	0.3	
Bangladesh	Changed / reduced activity level	4		-4	0.3	
Brazil	BS-4 deferred	41		-41	2.9	
Oman (PDO)	Production forecast exposure / uncertainty	76		-76	5.4	
Namibia	Kudu appraisal	125		-125	8.8	
Brazil (Pecten)			-3	-3		-0.2
Norway		7	-8	-15	0.5	-0.5
Oman (GISCO)	Virtual PSV / PSC effect		-23	-23		-1.7
Iran	PSV effect		-28	-28		-2.0
Malaysia	PSV/PSC effect, Tiga Papan/Ubah/Ramin↓, D35/St Joseph↑	31	-39	-70	2.2	-2.8
New Zealand	Pohokura	4	-51	-54	0.3	-3.6
Total Organic		796	754	-42	56	54
Production	Includes ExCom adjustment	1419	1403	-16		
A&D						
	Adjust total RRR so far for effect of A&D production					-2.4
ENTERPRISE (KMOC@46%)	KMOC = 131 mln boe		1141	1141		77.7
Norway	Draugen		33	33		2.2
USA	Rockies		27	27		1.8
TOPCO NZ			9	9		0.6
UK	Goldeneye		7	7		0.5
DR Congo (Zaire)			-17	-17		-1.2
New Zealand	Portfolio rationalization + transfer to TOPCO NZ		-49	-49		-3.3
Iran	Farm out		-51	-51		-3.5
Total A&D			1100	1100		72
Total Organic + A&D		796	1854	1058	56	126
Production Organic + A&D		1419	1470	50		
Strategic Options						
Whale		154		-154	10.9	
Namibia Gas (FLNG) incremental		145		-145	10.2	
Libya gas		90		-90	6.3	
Venezuela light oil		86		-86	6.0	
AIOC notional		81		-81	5.7	
Libya Block 47		21		-21	1.5	
Stephenson		13		-13	0.9	
Alibekmola notional		13		-13	0.9	
OU projects		-2		2	-0.1	
Total Strategic Options		601		-601	42	
Grand Total		1397	1854	457	98	126
Production Grand Total		1419	1470	50		

End-August 2002

Million Boe		Proved Reserves Additions	Reserves Replacement Ratio %
Total LE Proved Reserves Additions		1854	126
Total LE Production		1470	
Downside:			
Enterprise	Corrib, Tempa Rossa, Skarv Area debooking	-184	-12.5
SNEPCO	Bonga SW fails to pass VAR3	-49	-3.3
Upside:			
Enterprise	Shell guidelines implementation upside	50	3.4
Whale	Deal secured in 2002: 50% Shell share, unrisked	450	30.6
Other SOs		33	2.2
Range	Minimum		110
	Maximum		162

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Appendix D: Proved Reserves Schedule of Authorities

Based on EP 86-0725, updated 1996 and 2002.

	Title of document	Responsible, Preparation	Responsible, Approval	Final submission for use to
1	Proved Reserves Replacement Target Setting	HRC, ExCom	ExCom	HRC
2	Reserves Audit Reports	GRA		EPB, RBD and OU
3	Resource Management and Reporting Guidelines			
	a) Process, responsibilities, definitions, requirements	HRC, GRA	EPB	OU
	b) Technical methodologies	EPB / EPT	EPT	OU
	c) Matters relating to proved and proved developed reserves estimating procedures	GRA, HRC	EPB	SI-FCGB and OU
4	Annual reserves return from OU.	OU Technical, Finance	OU TM / FM	GRA, HRG
5	Audit trail in support of annual reserves return from OU.	OU Senior RE	OU PE Manager	OU TM
6	Standardized Measure Report			
	- OU annual submission	OU Technical, Finance	OU TM / FM	HRC
	- Group submission to SEC Form 20-F	HRC	EPB, EPF	SI-FCGB
7	Preliminary report on year-end proved reserves to ExCom	HRC	EPB	ExCom
8	Reserves Auditor Report	GRA		ExCom
9	Proved reserves "Letter of Comfort" to external Group Auditors.	GRA	EPB, EPF	Group Auditors
10	Statement of crude oil and natural gas reserves for inclusion in Annual Report submission to the US Securities and Exchange Commission (Form 20-F) and other Parent Company publicly disclosed reports.	HRC, GRA	EPB, EPF	SI-FCGB

HRC: EPB-P Hydrocarbon Resource Coordinator

GRA: EPB-P Group Reserves Auditor

Appendix E: Schematic of Reporting Procedure: Proved Reserves

Part 1: Prior to the end of the Reporting Year

Action party	Activity	Comments
ExCom December, previous year	Establish target Proved Reserves Additions and target range for the reporting year	
OUs, HRC Monthly	Maintain Latest Estimate of Proved Reserves Additions and SFR Maturation during the reporting year	Via EPMIS. Report to ExCom monthly.
HRC, GRA September, October	Update Petroleum Resource Volume Guidelines (reports EP yyyy-1100 and EP yyyy-1101)	Distributed to all OUs during the reporting year by EPB
HRC October	Distribute pre-populated Reserves Reporting Workbooks to OUs	
ExCom, EPB, GRA July, November	Review LE, Opportunities Catalogue and Potential Exposure Catalogue. Specify actions required for year end reporting	ExCom to review outlook for the reporting year and to direct bookings strategy (within the bounds of the SEC rules) with a view to managing the end result. To include GRA Comments.
HRC to OUs via RBDs November	Advise OUs on ExCom decisions regarding the management of Proved Reserves bookings	Advise on major bookings to be accelerated or deferred and debookings to be made.
HRC, OUs December	Agree detailed procedures for managing 'float' projects/reserves bookings	

Continued on the following page

New activities that are proposed are shown in shaded boxes.

A detailed timetable is prepared annually by HRC in consultation prepared annually by HRC in consultation with SI-PXX (External Affairs), SI-FCG (Group Reporting) and SIEP-EPF.

HRC: EPB-P Hydrocarbon Resource Coordinator

GRA: EPB-P Group Reserves Auditor

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Appendix E

Part 2: After the end of the Reporting Year

Continued from the previous page

OUs and RBDs January, weeks 1 & 2	Notification of reserves	Reserves Reporting Workbooks placed on EPB global server or e-mailed to HRC.
HRC, GRA January weeks 2 & 3	Clarify and challenge OU submissions as required	Verify that changes reported for the year can be supported.
HRC, OUs January week 3	[redacted]	Inclusion / exclusion of "float" bookings to manage year-end result
HRC January weeks 3 & 4	Provide summary data to external auditors for review	
HRC, GRA. FCGB January week 4	Agree final production data	Production reported in the Reserves Reporting Workbook must be consistent with Ceres reporting.
HRC, EPB January week 4	Preliminary report and presentation to ExCom	Note for Discussion plus presentation. Last opportunity for ExCom to influence the final result.
GRA, External Auditors End of January	Agree final proved reserves for external disclosure	
GRA, HRC End of January	Present final reserves to EPB, EPF	Declaration of satisfaction with the figures to be reported at year-end for proved and proved developed reserves. EPB & EPF sign "Letter of Comfort" to external auditors, sent via SI-FCGB
HRC, GRA End of January	Reserves Meeting	Report and Presentation of proved reserves information to external auditors and Group Controller (FCGB).
KPMG End of January	Confirmation to PWC from KPMG	Letter to Group External Auditors.
HRC, EPB Early February	Final report to ExCom and CMD on year-end proved reserves	Note for Information plus presentation if required.
HRC Early February	Parent Company Annual Report	Reserves figures passed to SI-FCGB. Including copy of initialled schedules from External Auditors.
HRC, EPB End of May	EP Reserves and Scope For Recovery	Reference report describing changes in Group Hydrocarbon Resources during the reporting year.

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Unknown

From: Van De Vijver, Walter SI-MGDWV
Sent: 29 November 2002 14:06
To: Pay, John JR SIEP-EPB-P
Cc: Brass, Lorin LL SIEP-EPB; Harper, Malcolm M SIEP-EPB-P
Subject: RE: Group Plan questions/reserves

John,

Indeed a difficult judgment call.Thanks for a very informative note.
We will have to get a storyline together not only to close our books but also for explaining to analysts (6 febr and end March) our RRR.Happy to be transparent about it to raise our overall credibility.

One other question: if we talk 5 year average RRR are we than still OK 1998-2002 and 1999-2003?

Regards,
Walter

-----Original Message-----
From: Pay, John JR SIEP-EPB-P
Sent: 22 November 2002 09:47
To: Van De Vijver, Walter SI-MGDWV
Cc: Brass, Lorin LL SIEP-EPB; Harper, Malcolm M SIEP-EPB-P
Subject: RE: Group Plan questions/reserves

Walter

I'm sure you realize that this is a difficult question to answer with precision. As a best estimate, I think it reasonable to say our RRR performance over the next 5 years will be depressed by some 25 points as the result (1) of taking accelerated bookings in the past and (2) of changing our internal reporting guidelines (partly as the result of the SEC clarification, but also of our own volition).

I would characterize the contributions as being:

15 - 20 points: aggressive booking, of which perhaps 5 points (i.e. 5% RRR) overlap with the 2001 SEC clarification.
5 - 10 points: the legacy effect of changing our booking practices in 1998

The following explains how I came to these figures:

1) What historical bookings did we make that we would consider more carefully today?
At 1.1.2002 we had some 3800 MMboe (actually 3769) reserves that had been booked pre-FID. Of these, I think about 60% can be categorized as definitely not subject to "leadership behaviour" at a Group level, whereas the remaining 40% (1400 MMboe) **possibly** were. 3800 MMboe is an attention-grabbing figure, and our 5-yr average RRR going forward would be improved by some 50 percentage points if we had left everything until FID. However, our performance during the previous 5 - 10 years would obviously have been reduced by a similar amount. Also note that it is not common practice in the industry to defer **all** bookings to FID - only bookings for major projects and frontier areas. I am sure (but cannot prove it) that our competitors adopt a similar approach to us for minor projects and infill type activities - they book when they feel the project is sufficiently defined, which could be well before project sanction.

Therefore I think that the 1400 MMboe is a more reasonable figure to talk about in this context - we booked it aggressively and had we not done so we might have been able to show a +/- 15 - 20% better RRR for the plan going forward.

There is more detail on this at the end of this message.

2) By how much would RRR performance be different if we continued to apply the bookings procedure in force pre-1998?
In 1998 / 1999 we changed our reporting basis and adopted a deterministic approach for mature fields that we believe to be consistent with industry practice. This gave us a one-off gain of 1200 MMboe. If we had left our

practices unchanged, we would have trickled some of this gain in gradually and perhaps registered new bookings ahead of FID for some of our major upcoming projects (W2E, possibly Kashagan and Sakhalin and a few others). However, I would be very surprised if this would have yielded a total reserves balance higher than the one we have today - in other words, I do not believe that our old approach would have caused more than 1200 MMboe to have been added in the years since the new approach was introduced. As a rough estimate, you could say that it would have taken some 10 years to book the 1200 MMboe that we took as a one-off gain in 1998/1999, so performance might be depressed on average by 5 - 10% RRR during the period that we now find ourselves in the middle of.

3) What effect has the 2001 SEC Clarification had on our performance?
Following on from (2) above, it was noted at the time that we had corrected our under-reporting of mature fields, but not addressed our over-reporting of immature fields. The latter was only addressed by the new guidelines introduced this year, spurred by the SEC Clarification. We see the effects of it in the SNEPCO debooking, which is the biggest single effect. I see this as partially offsetting the 1998 gain - if we had addressed all of our procedures in one step instead of taking the good news first and the bad news later, we might have been looking at a net gain of, say, 900 - 1000 MMboe instead of 1200 MMboe. We are taking this hit now and we may see a small depression of RRR performance over the plan period. However, I do not believe that these effects are very significant - we must be talking about a few percentage points on the 5-yr average RRR at most - this is a subset of the reserves covered by (1) above.

Please let me know if there's more I can do to clarify these figures,

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Detail on 1) above

The total volume of reserves booked pre-FID at 1.1.2002 was **3769 MMboe.** The following major components stand out:

Nigeria SPDC: 969 MMboe. For many years reserves bookings were influenced considerably by the Reserves Additions Bonus. This drove us towards early booking of reserves, but at the time this was not considered to be at odds with practice elsewhere in the Group and nor did it lead to undue concern about compliance with SEC rules. Indeed, the practice might be seen as a key enabler in helping Nigeria to claim additional OPEC quota share and consequently SPDC production growth. The problem is that we overshot a little - we reached a situation in which the Proved Reserves cannot plausibly be produced within the remaining licence period.

Oman PDO: 313 MMboe. Similar situation to SPDC, PDO revenue was linked to reserves additions. We now have a situation in which an external production promise has been made to the Omani authorities, with the corresponding reserves having been booked ahead of development activity identification. I trust that you are well aware of the efforts currently ongoing in PDO to build substance into delivery of the production promise.

Other Base Projects: 852 MMboe. Bookings which seem to have been made in line with the Shell interpretation of the rules at the time and which are difficult to dispute in hindsight, given that they are included in our current Base Plan. A large number of minor bookings, but with a few large items such as Troll further development (210 MMboe in total).

Other Option Projects: 197 MMboe. Bookings similar to above but which might now be questioned on the grounds that they rank only as Options. Again a large number of small projects, the biggest being Bugan (Brunei) - 50 MMboe.

Total so far: 2331 MMboe, 62% of the total. It is probably fair to say that, on balance, none of the above were the direct result of "leadership behaviour" in the context of your question, although obviously the SPDC and PDO bookings were part of a clear strategy at the time.

The remaining 38% of the bookings could be questioned with hindsight and some or all of them could be judged as being influenced by "leadership behaviour". I have not questioned those involved at the time, but I would not be surprised to find that each was the subject of management determination. All could be defended on the basis of the Shell interpretation of the SEC rules at the time, but might not be accepted under the revised / clarified interpretation.

Australia: 560 MMboe. Gorgon - the booking was made in the expectation that project would imminently be sanctioned.

Angola Block 18: 75 MMboe. Booked on the basis of a rather flimsy project definition - now firmed up and subtantially different to the basis on which first booking was made.

SNEPCO Erha: 166 MMboe - FID in 2002.

SNEPCO Bonga IFO: 130 MMboe - most to be debooked?

Denmark Sif / Igor / Halfdan Danian Gas: 19 MMboe. I include this because I made the booking myself under the influence of "leadership behaviour" and felt somewhat uneasy about it (also the larger booking for Halfdan Phase II oil development, now post-FID). The project was not well defined and, although there was no doubt that the resources are there, we did not have rigour in the audit trail to be able to defend against a serious challenge of the booking. There may be other examples in the 62% above that I have not captured.

Other Projects Ranked "Out": 489 MMboe. Bookings that might be seen as suspicious and possibly the subject of "leadership behaviour", on the grounds that the projects concerned do not rank for capital allocation as currently defined. Biggest items are Ormen Lange (109 MMboe), Venezuela further development (91 MMboe), Pohokura (71 MMboe, this figure being revised to only +/-20 MMboe at 1.1.2003).

Total: 1439 MMboe, 38% of total.

-----Original Message-----
From: Van De Vijver, Walter SI-MGDWV
Sent: 21 November 2002 01:01
To: Pay, John JR SIEP-EPB-P
Cc: Brass, Lorin LL SIEP-EPB; Harper, Malcolm M SIEP-EPB-P
Subject: RE: Group Plan questions/reserves

John,

Thanks.

Just to have it all together.
How much of the historic bookings (both aggressive/early) that constrain our proved reserves booking in 2001-2005,are related to"leadership behaviour" and how much are they related to new SEC rules/scrunity introduced in early 2001?!
Please clarify soonest to the best of your now vast knowledge of our reserves!
Regards,
Walter

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