(Pause)
A. Yes. Yes, I did.
Q. So this was an issue that was existing at the time you conducted the '99 audit?
A. Yes, it was, yes.
Q. Now --
A. There is a plot which is referred to as Figure 2 in the report, which is the same plot as a similar plot that was produced in the '99 report, except this one, the message is -- should be clear that the ratio between proved and expectation reserves in the Oman fields were way too low.
Q. And this is the figure on page 178 at the bottom half of the page?
A. Correct, yes.
Q. Now, you graded PDO unsatisfactory.
Correct?
A. On this audit, yes. The status of
0595
the reserves was unsatisfactory, yes.
Q. Do you recall having any discussions with Mr. Coopman concerning this grade?
A. Not off-hand, no.
Q. Now, I'd like you to take a look at Exhibit 27. Do you recognize this document?
A. Yes. It would appear to be my final -- the final copy of my report of the 2003 audit on PDO Oman.
Q. Do you recall preparing this report?
A. Yes. Yes, I do.
Q. And you will notice that there is no signature on the bottom left-hand corner of the first page.
Do you recall distributing this note via E-mail to the recipients identified on page 1?
A. Yes, I do.
Q. And there are a number of people who are identified as direct and copied
0596

recipients. Do you recall receiving any comment from any of these recipients to your unsatisfactory grade for the Proved Reserves position at PDO Oman?
A. No. No. I would have expected any such comment, if there were any, to have been made to my Draft Note.
But I do not recollect and I would be surprised if anybody came back to me after issuing the final note.
Q. Other than the recipients that are identified on Exhibit 27, did you receive any comment to the note from Walter van der Vijver?
A. No. No.
Q. Same question with regard to Mr. Watts?
MR. BEST: Objection. Form. Asked and answered.
He testified one or two days ago that I don't believe he remembers having any conversation with Mr. Watts for years.
But you can answer.
0597
THE WITNESS:
A. No. I did not receive any comments from Phil Watts.
BY MR. HABER:
Q. Same question with regard to Ms. Boynton?
MS. WICKHEM: Object to form and foundation.
BY MR. HABER:
Q. You can answer.
A. I did not receive any comments from Ms. Boynton.
BY MR. HABER:
Q. Other than comments to this particular note, did Mr. Van der Vijver discuss with you your findings in Oman in 2003?
A. He did not discuss those with me at any point in time, before and after.
Q. And other than with regard to this specific note, did Ms. Boynton ever discuss with

you your findings of Oman in 2003?

MR. BEST: Objection, form. I

0598

believe he testified that he has never met Ms. Boynton.

THE WITNESS:

A. Correct. The answer to your question is no.

BY MR. HABER:

Q. Now, if you can turn to page 4 of Attachment 1 which ends in 18 under number 12, the auditor's suggestion for the way forward.

MR. FERRARA: I am sorry. What page number are you on? It ends 18 or the DB number 767.

THE WITNESS: Yes.

BY MR. HABER:

Q. Are you with me looking at number 12?

A. Yes. I am.

Q. The third dash reads, "Hence, it is suggested that the present proved developed and proved total Group share reserves volumes be continued in the 1.1.2004 submission correcting only for 2003 production and for transfers from

0599

developed to undeveloped. Total Proved Reserves replacement ratio should thus be 0%."

Why were you recommending -- withdrawn.

Can you explain what this recommendation is saying?

MR. TUTTLE: Are you limiting him to that specific dash or to the total recommendation that's reflected in all five or so of the dashes?

MR. HABER: Well, he can refer to that, but if it will help him to look at the whole thing for context, that's fine.

MR. TUTTLE: I just want to make sure the record is clear, if you are asking him to explain just a part of the recommendation as opposed to the entire thing?

MR. HABER: Well, the question is directed to that entire part.
However if it will make it easier for him to respond to the question, he is certainly free and I will encourage him to look at
0600
the full context.
THE WITNESS:
A. The situation that PDO Oman was in at that time is that as far as documentation and field evidence was concerned, there was only a modest amount of the carried Proved Reserves that could in fact be defended as Proved Reserves, particularly bearing in mind that these Proved Reserves of course would also have to be curtailed by the end of license in 2012.
There were development plans in place -- I am sorry. There were development plans being undertaken that, in my view, were such that it was highly likely that they would yield additional Proved Reserves in the course of the coming year.
In addition, and even more importantly as to its impact, discussions were ongoing with the Omani government regarding an extension of the license beyond 2012.
I had discussed that particular item with the Oman Managing Director, John
0601
Malcolm, and he assured me that he was fully confident that an agreement could be reached with the Omani government, if not before the end of the current year, which was 2002, then certainly early on into 2003.
He told me that he had been given verbal assurance by I believe the Oman minister that a deal would be struck.
I took that as an important piece of information, because that would mean that as soon as that license extension was there, then a sizeable amount of reserves would be fully in line with the requirement that Proved Reserves needed to be developed -- needed to be producible within

the license period.
I took that as an evidence of reasonable certainty. I based that reasonable certainty on the verbal assurance that I had been given by the highest person in the organization of PDO that this was likely to occur.
And therefore, I said it's abundantly clear that next year, you are going to
0602
have this production, if not this year, you are going to have this license extension and that, therefore, you have an instant increase in your Proved Reserves.
What I recommended here was in order to avoid swings in reserves, i.e., booking them or debooking them one year and then having them again booked the next year, that these reserves be maintained.
I will accept that if you look at the specific requirement, as they were in the Shell guidelines, of proven reserves being producible within existing licenses, this did not fully conform to that.
However, I looked more at the bottom line requirement of reasonable certainty and I felt that that particular condition was fulfilled.
But I will accept criticism that this particular recommendation was not wholly justified by the actual -- the actual conditions in the Shell guidelines. I will also say that
0603
this particular recommendation was not followed by -- in particular, by Frank Coopman.
Q. And do you recall what Mr. Coopman had said to you in deciding not to go along with your recommendation?
A. I believe he did. I believe he did.
Q. I am saying do you recall what he said to you?
A. Yes, I believe that he did say that to me.

Q. Just that he would not go along with the recommendation?
A. That he said that indeed, he was not going to go along with that particular recommendation, yes.
Q. Did he give you any explanation as to why he would not go along with your recommendation?
A. I believe it was on the basis of it not being in conformance with the letter of the guidelines.
0604
Q. Do you recall when you had this discussion with Mr. Coopman?
A. Not on a specific day. But it must have been somewhere between the draft reports and the end reports, somewhere in November.
Q. If I am understanding what your answer is and what the recommendation is, am I correct that the recommendation that's set forth in Exhibit 27 is only to debook a small portion of the total reserves that are overstated? Is that -- am I correct?
MR. TUTTLE: Object to the characterization.
THE WITNESS:
A. In fact the recommendation is to maintain the current proved volume, with the net effect that the total Proved Reserves replacement ratio should be zero, which means effectively that you deduct the reserves that you carried the last year, you deduct from that the annual production and then the reduced volume was to be maintained in the books.
0605
That's what I intend here.
BY MR. HABER:
Q. And did that include all of the reserves that you deemed to be overstated?
MR. TUTTLE: Object to the characterization.
THE WITNESS:
A. Yes. It would have, yes. I think

you should understand that what I was seeing as a situation to be avoided, i.e., to have the major reserves reduction in one year only to be followed by the reserves being replaced -- the same reserves being replaced the following year, that's where I was coming from.
But I will accept -- like I said, I will accept criticism that this is one of the, in my mind, very few occasions when my actions were potentially subject to criticism.
BY MR. HABER:
Q. And so now I think I got it. So then by maintaining the reserves, it would be at the point when they would be debooked, in effect,
0606
it would be offset by the extension of the license so that the net effect would be zero.
Is that correct?
MR. TUTTLE: Object to the characterization.
THE WITNESS:
A. It would be zero now, yes.
BY MR. HABER:
Q. Right. Okay.
Now, I think on the first day, I asked you a question or two about your involvement in Project Rockford.
A. Mm-Hmm. Are we done with this?
Q. Yes. We are done with it.
How did you come to become involved in Project Rockford?
A. As I mentioned on I believe the first day, in -- at the end of November of 2003, it became clear that sizeable reserves, corrections reserves, recategorizations were going to be required.
In the first instance, the first
0607
piece of concrete evidence was coming from SPDC.
And in the face of that, it was very quickly realized by, among others, Frank Coopman, that once you make a reduction like this, then you'd better make what by some was referred

to as a clean sweep across the board.
You'd better critically look at the Proved Reserves across the board. That of course was highly confidential information at that time.
And on similar occasions, when a highly confidential project was going to be undertaken, Shell had the habit of giving that particular project a name and of ensuring that everybody who was in the know on that project would be signing an additional declaration of confidentiality; and more stringent than the general declaration of confidentiality that everybody would have to sign and that I had to sign when I started my contract with Shell as reserves auditor.
That was a normal procedure for Shell. And therefore, this particular project of
0608
reserves recategorization was given a name for ease of reference without giving away the confidentiality of its content.
The players in there were -- in the very first instance, were Frank Coopman, John Pay, the reserves coordinator, and myself. But of course the circle very, very quickly spread to people first inside SIEP and soon after that, to people outside SIEP as well.
Q. Who invited you to work on Project Rockford?
MR. BEST: Objection to the form, and characterization.
THE WITNESS:
A. I don't think inviting was the right term. I was effectively having no choice. It was obvious that I had had an instrumental role in the previous reserves bookings. And it therefore was of little doubt, of no doubt in anybody's mind that I had to play a role in that particular project.
BY MR. HABER:
0609
Q. Now, during your involvement in Project Rockford, do you recall any discussion

about whether there was a breakdown in internal controls?
A. Yes. Vaguely, yes.
Q. And do you recall the sum and substance of those discussions?
A. If I recall, it went along the lines of the question: How did we manage to find this in this position? How did we -- we as a company that was, we felt and a lot of people felt, was well managed, how did we manage to find ourselves in the position that we are in now where we are having to restate or recategorize our reserves?
And one of the avenues of thought was the question: Was there a breakdown in controls? Did people anywhere along the line not do what they were meant to have been doing and what they were required to have been doing? According to terms of reference or whatever, controls were in place.
0610
That was an avenue of thought that was particularly undertaken by Frank Coopman.
Q. Did you have any involvement in the work that was done in connection with answering this question about internal control breakdown?
A. Early on, yes. I remember that Frank had drafted up some view graphs I believe, reflecting his initial thoughts on the issue, and he asked us for some comment.
Afterwards, he took the whole issue of controls further up the organization, and then it was beyond my perception. I stopped being involved.
MR. HABER: I would like to mark as Exhibit 31, I think.
(Barendregt Exhibit No. 31 marked for identification)
This is two E-mails, the last of which is from Mr. Barendregt. It's dated January 3, 2004. It's to Frank Coopman with a CC to John Pay, John Darley and John Bell. The subject line reads: "Re: Internal control weaknesses."

0611
Q. Mr. Barendregt, have you seen the last E-mail that's reflected on Exhibit 31, which is from you to Mr. Coopman?
A. What do you mean by the last E-mail? The top one?
Q. The top E-mail, yes.
A. Yes. Yes.
Q. And just for the record, since I haven't given the Bates range for this document, the document has two Bates ranges, the first one is V00101693 through V00101694. And the other one is GUI000798 through GUI000799.
Now, if you look at the bottom E-mail from Mr. Coopman to Curtis Frasier dated January 2, 2004, you will notice that your name appears in brackets.
Did you put those -- did you put your name in those brackets?
A. What it was is that an E-mail was sent, which was the one from Curtis to Frank Coopman -- from Curtis Frasier to Frank Coopman, and that we were asked to -- that that E-mail had
0612
a text that we were asked to comment on.
What I did was that in my reply, I think I pasted or somehow pasted the original E-mail and then made corrections to the text, and then it's a habit of Outlook, the E-mail program, that we -- that was in use in Shell, that the minute I changed the text in another E-mail, then immediately I would get -- or one would get my name between brackets, and then in a color, which it doesn't explain here, the changes that I made in the text.
So my way of commenting to that particular text would be to strike out certain bits and to add new bits. That is what I was asked to do.
So that's what it is. So that's why you see my name appearing as some sort of audit trail, not controlled by myself but controlled by Outlook, together with the color of

my changes, of the changes that I had made in that text.

Q. And do you recall if the changes

0613

that occur -- that appear after your name, do those reflect your changes?

A. Yeah. They would have been except that you cannot see the colors. So somewhere along the line, I would expect the blue color to go back to the black which was the original text. But on a black and white print, you cannot see.

So you cannot precisely see what changes I have made. And I must have made -- I cannot honestly remember which it was, which words precisely that I changed.

Q. We will check to see if this has been produced in the native format so we can tell. But since it has got a Bates number on it, it certainly appears it was not produced in the format that would reflect the color changes that Mr. Barendregt has just testified to.

And if that's the case, we would request production of this document with the color changes so that we could see what changes Mr. Barendregt inserted.

Now, also this Exhibit 31, is this

0614

consistent with what you just testified to about Mr. Coopman preparing a view graph requesting some comments?

A. That's how I remember it, yes.

Q. And do you recall -- you'll notice in his E-mail of January 2nd, is a reference to a Note to the CMD.

Do you have a recollection that the comments that you were making were in the context of a Note that was deemed prepared for the CMD's review?

A. I don't remember that.

Q. You can put this document aside.

(Complying)

MR. BEST: Can we go off the record for like two seconds?

MR. HABER: Sure.
THE VIDEOGRAPHER: Going off the record at 1:20.
(Off the record)
THE VIDEOGRAPHER: Returning to the record at 1:22 from 1:20.

0615

BY MR. HABER:
Q. Mr. Barendregt, did you prepare a report, an annual report such as the ones that you have done in 2004?
A. No. I am sorry. At the beginning of 2004, yes, I would have prepared a report on 2003.
Q. And do you recall ever writing down, from your perspective, the events that led up to Project Rockford?
A. Yes, I did, in January. Yes.
(Barendregt Exhibit No. 32 marked for identification)
Q. The first Exhibit that I am marking as Barendregt Exhibit 32 is a document that was produced from a native drive.
It bears the Summation Document Number "100254267: Rockford - A historical perspective." It's from Mr. Barendregt to Frank Coopman. It was sent on January 16, 2004. The subject line reads, "Rockford - A historical perspective," and the Attachment is

0616

"Rockford-HistPersp.doc."
(Barendregt Exhibit No. 33 marked for identification)
The next document that I am marking is Barendregt Exhibit 33. It is a Note which is dated February 1, 2004. It's titled, "Review of Group End-2003 Proved Oil and Gas Reserves, Summary Preparation." Its Bates number is RJW01021058 through RJW01021076.
(Handing)
Mr. Barendregt, looking at Exhibit 33 for a moment, have you seen this document before today?

A. It would appear to be my end 2003 report. And yes that of course, I have seen it.

Q. And do you recall preparing this report?

A. Yes, I do.

Q. And you will notice in the bottom left-hand corner, your signature does not appear.

Do you recall distributing this report via E-mail to the recipients identified on

0617

this document?

A. Yes, I do.

Q. Now, looking at Exhibit 32, which is the historical perspective, why did you prepare this document?

A. When Project Rockford and the reserves categorization were becoming a reality, I very quickly realized that of all the players at the time, that is at the end of 2003, I was probably the one with a memory, if not an involvement, in the issue of reserves, that stretched out further into the past than anybody else.

I had been the only one that had been directly involved in reserves reporting matters for the last five years.

But also I had been one, as a result of my various steps in my career, I had been the one that had been closest and actively involved, as a matter of fact, in the issue of reserves reporting from time to time in the years before that.

0618

Q. Did someone ask you to prepare this -- a document like this?

A. No. Nobody did. I took it upon myself to reflect what my thoughts were in the position that, in my view was unique, like I said, because of the experience that I had had with reserves reporting over the years.

Q. Did you have any discussion with Mr. Coopman about this historical perspective?

A. Not a lot. Mr. Coopman had plenty

of other things on his mind at the time. And yeah, no. We didn't discuss it in great detail.

He made one or two general comments, the details of which escape me at the moment.

Q. Now, if you look at the first page of Exhibit 32, the last sentence. It says -- that's the E-mail, I am sorry.

A. Sorry.

Q. The very last sentence says, "I'm not sure yet whether this should be part of," in paren "(or an appendix to)," close paren, "my

0619

end-year report."

Did you decide to include this historical perspective in your year-end report?

A. Let's see. When was this? Yes. This was halfway during January, so at that time my annual report would by no means would have been finished.

It reflected precisely what it says there, that I could see it as a possibility of appending it to my end-year report or just leave it as an -- as a separate report for whoever would be interested in it.

In the end, but that was after this, I decided that it was probably best not to have it included as a -- in its full, and to have a brief summary of that included. I believe that's what I did, as a summary by summary in the text.

And I believe, if you go to deposition number 33 -- Exhibit No. 33, then my thoughts reflected in full in the note of Exhibit 32 are reflected in paragraph 2 of Attachment 1 of

0620

my end-year note.

Q. Did you receive any comments from any of the recipients to Exhibit 33 to what you had written on number 2 of Attachment 1?

A. Yes. I received several comments of people saying, look, you don't want to include all of this in your end-year report. So I received some resistance of including that in the report.

Q. And who provided the resistance?

A. Frank Coopman was one of them. I believe John Bell. I cannot remember who else. There was one lawyer over in the US who provided some comment and who also felt that this wasn't useful.

MR. FERRARA: Excuse me. If there is a lawyer in the US that was serving as counsel to Shell at the time and was providing legal advice with respect to reserve reporting issues that was confidential when given and was intended to remain confidential, then that may be a privileged communication belonging to Shell, and

0621

we are not at liberate to waive it.

So if in response to your answer, you are about to say what a lawyer advised Shell or one of its officials, then you can talk about that off of the record.

If not, you can continue.

MR. BEST: Or what you told the lawyer.

THE WITNESS:

A. What I told the lawyer --

MR. BEST: Stop.

MR. FERRARA: Excuse me.

MR. BEST: We don't want you to --

THE WITNESS: Sorry.

MR. FERRARA: I don't want this.

MR. HABER: Yes. And let me just say, you are free to inquire with him. All I want to know right now is who the lawyer is, who you spoke with.

THE WITNESS: I cannot remember his name. I am sorry.

BY MR. HABER:

0622

Q. Okay. That's okay.

A. The whole issue is not important whether or not he was a lawyer or not.

MR. BEST: It is for us.

BY MR. HABER:
Q. Because I want to get this done, if it's acceptable to you, when I conclude subject to everyone else's examination, if there is anything in there, as before, if he feels that he can testify to, about it, then that will be fine. If it is in fact privileged, then we will just leave it as is.
I just want to -- my point is I am trying to get through this so that we can break.
MR. FERRARA: I am sorry. So you were suggesting that on the break, we inquire as to what this --
MR. HABER: Correct.
MR. FERRARA: -- communication is, and then advise you after the break --
MR. HABER: Correct.
MR. FERRARA: -- whether in our
0623
judgment, this is a privileged communication?
MR. HABER: That's correct. If that's acceptable.
MR. FERRARA: Certainly we'll ask.
MR. HABER: Okay.
Q. I think I asked you the name of the attorney.
Do you recall who that was?
A. No, I don't.
Q. Does Curtis Frasier sound familiar?
A. No, it wasn't him.
Q. Other than the people you identified, can you think of anyone else who provided any resistance to you including a form of this perspective in your report?
A. Not off-hand, no.
Q. I just have one follow-up question from SPDC.
Yesterday you said that you had raised the license expiry concern with SPDC in 1999 during your audit.
Correct?
0624
A. Yes.

Q. And I think you also testified yesterday that SPDC sought to resolve the license expiry issue sometime in 2002.
Am I correct?
A. Yes. Yes.
Q. Do you have an understanding as to why it took SPDC approximately two years or so to address the issue that you had raised in 1999?
MR. TUTTLE: Object to the characterization.
THE WITNESS:
A. No, I do not. I do not.
MR. HABER: Again, subject to the questioning by other counsel, I am concluded for this examination.
MR. BEST: We take a, what, half-an-hour lunch break? How much, an hour?
MR. FERRARA: Well, it will be someplace between 30 minutes and an hour. But we need to --
MR. HABER: That's fine.

0625

MR. FERRARA: -- consult first. And if I could ask all of the other counsel to come into our break-out room? We are off the record.
THE VIDEOGRAPHER: Going off the record at 1:34.
(Lunch recess taken)
THE VIDEOGRAPHER: Returning to the record at 2:05 from 1:34.
MR. FERRARA: We have just concluded our lunch break.
And over the lunch break, we have considered the most productive way of proceeding with our opportunity to either redirect or cross, depending on one's perspective to Mr. Barendregt.
And we have consulted with all of the other lawyers here, and at least two of whom, maybe three have their own interests in asking questions of Mr. Barendregt.
And we, that is LeBoeuf and Debevoise, certainly have many questions we would

like to pose to the witness and we are expecting
0626
in the aggregate, that would take two or three more hours. And I think given -- and perhaps longer.

Given the very detailed examination that Mr. Barendregt has undergone for the past four days, detailed and exhausting as it has been, we have collectively determined that the appropriate and prudent thing to do is to adjourn this deposition rather than to close it, agree to resume the examination of Mr. Barendregt here in The Hague under the same terms and conditions as he has appeared these past four days, and to come to a date within the next several weeks that is agreeable to the parties present.

If anyone does not want to come, of course they need not, and then we will resume our examination or commence our examination of Mr. Barendregt at that time.

We will consult with the other defense lawyers who are here to see if we can streamline the examination so that it's not repetitive and doesn't take more time than is
0627
needed.

And we will consult with you, the Plaintiff's counsel, to come to an agreeable date.

MR. HABER: Okay. And everything that you've said is agreeable to us. We will, of course, sit down and discuss with you and any of the other defense counsel, how much time and a date on which the resumption of this proceeding, this examination will be.

And again, of course I will still continue to reserve my right to ask further questions subject to counsel's examination.

MR. FERRARA: Right. And we will further consider during this period the question you asked about the privilege objection that I raised, and we will consult with Mr. Barendregt on that and appear to respond to that when the deposition resumes.

MR. HABER: Okay.
MR. FERRARA: I want to first now -- I shouldn't say first. I now want to invite comments from any of the other defense counsel who

0628

may want to be heard on this point.
MR. ADLER: For PWC U.K., we are happy with that procedure.
MR. DAVIS: The same for KPMG B.V.
MR. GOLDSTEIN: Same for Philip Watts.
MS. WICKHEM: Same for Boynton.
MR. HABER: Okay.
MR. FERRARA: Au revoir.
MR. HABER: We are done for this week.
THE VIDEOGRAPHER: Going off the record at 2:09.
(Whereupon the deposition was adjourned at 2:09 p.m.)

0629

ERRATA

CORRECTION PAGE

____________________ ____________
Signature Date

0630

I, Anton Barendregt, am a deponent in the foregoing video deposition, Volume IV. I have read the foregoing video deposition, and having made such changes and corrections as I desired, I certify that the transcript is a true and accurate record of my responses to the questions put to me on Thursday, 22 February, 2007.

Signed__________________________
ANTON BARENDREGT

0631

CERTIFICATE OF COURT REPORTER

I, Frederick Weiss, CSR, CM, do hereby certify that I took the stenotype notes of the foregoing deposition and that the transcript thereof is a true and accurate record transcribed to the best of my skill and ability.

I further certify that I am neither counsel for, related to, nor employed by any of the parties to the action in which this deposition was taken, and that I am not a relative or employee of any attorney or counsel employed by the parties hereto, nor financially or otherwise interested in the outcome of the action.

____
FREDERICK WEISS, CSR, CM

____
DATE

Creating Value through Entrepreneurial Management of Hydrocarbon Resource Volumes

volumes to value

Quote

*" let's say you 'd just blown a million dollars on a project that went down harder than a drunken ninety year old lady with a broken hip. You're sitting in the challenge workshop meeting with the BUSCOM who would like to spend the entire meeting rubbing your face in the fiscal entrails. Your mission is to escape this fate, and –with luck- even enhance your position. Here's where some entrepreneurial skills are indispensable, whilst it may be a good test wh
ether management can really handle failure. The conversation might go something like this:*

You: "I spent a million dollars, but the project did not work out".
BM1: "You blew a million dollars"
BM2: "What were you thinking?"
BM3: "Hellooooo!! Is anybody managing that thing??"
You: (coolly looking at the big picture): "A million dollars is just noise when you consider the entire R&D budget. We're in a risky business.(At this point BUSCOM members realise they have been flanked by the Big Picture Manoeuvre, and they will scramble to compensate).
BM1: "For only a million dollars we learned a great deal."
BM2: "Compared to the group NIAT, it is a rounding error
BM3: "Can we talk about something important now"
Unquote

(slightly modified from The Dilbert Principle page 128)

1 Summary & recommendations

The Group is failing to create the maximum value out of its hydrocarbon resources because of intrinsic conservatism[1]. Without a transformation in hydrocarbon resources volumes management (HCRVM), the Group cannot hope to have a developed resource base, twice the size of today's, to support the desired production in the year 2010.

One underlying reason for this intrinsic conservatism is that it has served us well in the past since it guaranteed a steady supply of new additions to our resource volumes even in the absence of major new discoveries. Technology was our competitive edge. Conservatism has now become embedded in the corporate culture with[2]:

- An aversion to taking risks and a blame culture.
  "We need to improve on our handling of disappointment and managing performance-failure to meet targets. Raps on the knuckles will not result in increased performance"[3]
- Under-utilisation of human resource through failure to empower or capitalise on diversity.
  "In Shell, brain power no problem"[3]
- A lack of external focus even to the extent of not applying appropriate technology and knowledge available in other parts of Shell.
- A technical rather than a commercial or business focus to managing the surface assets.
  "We need to change mindset so that everyone realises they have a role to play in Shell being aware of what its competitors are doing"[3]

Earning the right to grow in a rapidly liberalising world economy, with growing competitive market forces and with much technology now readily available from Service Companies, cannot rely on a new "knock-out" technology. A transformation is clearly needed.

Recommendations

While access to, and deep understanding of, leading edge technology remains a *sine qua non* for growth, we propose to move towards an entrepreneurial style of management of the hydrocarbon resources with a clear **focus on value**. To achieve this requires the ongoing Group transformation to be effective but we make recommendations in six areas where we believe changes can underpin the transformation in HCRVM.

- New reserves reporting guidelines to reduce conservatism, increase awareness of the business impact and better represent the Group's reserves and NIAT externally.
- The shift from volumes to value realisation as the focus for maturing the asset is achieved by integrated risk and opportunity management through the life cycle Asset Reference Plan (ARP).
- Promotion of global knowledge sharing through a global network and face-to-face peer challenge, but also through,
- An "Open Development" platform on the SWW where staff may "surf the projects and assets" and put forward and be recognised for value creation ideas.
- New areas for competency development, e.g. decision-making, risk and opportunity management, are needed to complement traditional subsurface skills.
- Promotion of behaviours and culture changes required for the above recommendations to work through leadership and appraisal.

Potential benefits

As at 1.1.1998, greater than 75% of the remaining discovered resource volumes were undeveloped. There is hence significant potential for increasing production from this existing resource base complementing any increase from new resource volumes. Some of the presently undeveloped resource volumes will have been ascribed relatively low value and hence low priority. A change to nurturing and sharing ideas has the potential to increase the value and hence make the resources more attractive.

The transformation, particularly with respect to empowered teams and knowledge sharing, can also be expected to improve job satisfaction.

Measures of success with the transformation may hence be seen in:

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[1] Out of 600 mln m3 new oil acquisitions or discoveries over the past 10 years, we have only managed to produce 4%

[2] Results from a survey carried out by the VCT supported by Arthur Andersen; outside parties views of Shell; earlier VCTs

[3] Quote taken from stakeholder interviews

- increased developed reserves volumes;
- increased proved reserves;
- developed reserves as an increased percentage of discovered resources
- faster progression from acquisition to production;
- increase in Intrinsic Business Value;
- staff morale.
  More fun to work in - Shell is not seen as a very attractive company to work for. We should be able to attract different people if we are able to make Shell an exciting place to work [3]

2 Introduction and case for action

Hydrocarbon Resource Volumes Management (HCRVM) focuses on maximising value from the hydrocarbon volumes within a (potential) asset. Value is realised by (see also attachment 1, figure 3):

- adequately describing and reporting these volumes, including the true range of possible outcomes.
- identifying what needs to be achieved to create value by actively progressing volumes from identification of scope to actual production (or profitable divestment).
- managing the route through the value chain as a project.

It is evident that maximising asset value requires an integrated effort of project execution, well delivery and PE staff rather than considering subsurface development optimisation in isolation.

In general our intrinsic conservatism with respect to management of our subsurface resources is threefold:

1) We tend to be very slow in bringing our new assets to bear fruit: Historic Group reserves data show that of the more than 600 mln m³ of oil discovered over the last ten years only 4% has been produced. Out of our total remaining discovered commercial resource base of 3300 mln m³ recoverable oil we have only developed 650 mln m³ or 20% (whilst our proved only constitutes 480 mln m³ or 15%). Our reported proved developed reserves could only sustain 4 years production vs. 7 years for other majors. In addition to the total discovered resources there is identified potential to increase these by 50%.
2) We have a technical rather than commercial focus, and tend to be inward looking: There is often little appreciation at the coalface about how technical studies contribute to the bottom line. Also when trying to improve on our reported resource base we tend to focus on technical solutions, ignoring possible commercial options: At present some 25% of our developed reserves are beyond licence expiry. Also we tend to be conservative in our reported volumes (figure 1) as part of our total resource base, which has a negative impact on NIAT. These examples are in line with outside views that Shell is going for the 100% technical solution rather than trying to maximise value.

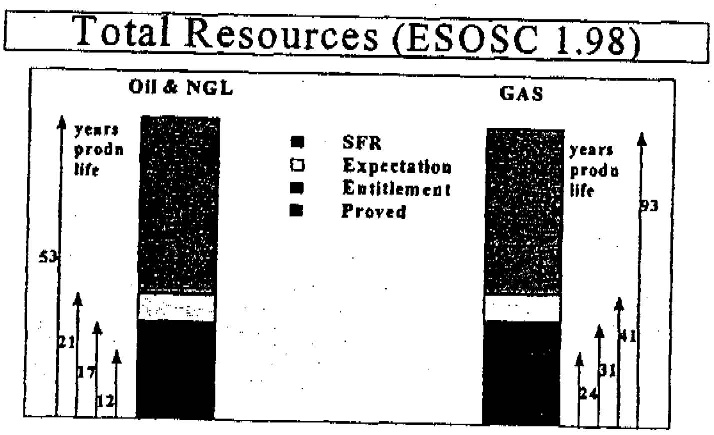

Figure 1: The Group's production future as function of resource volumes

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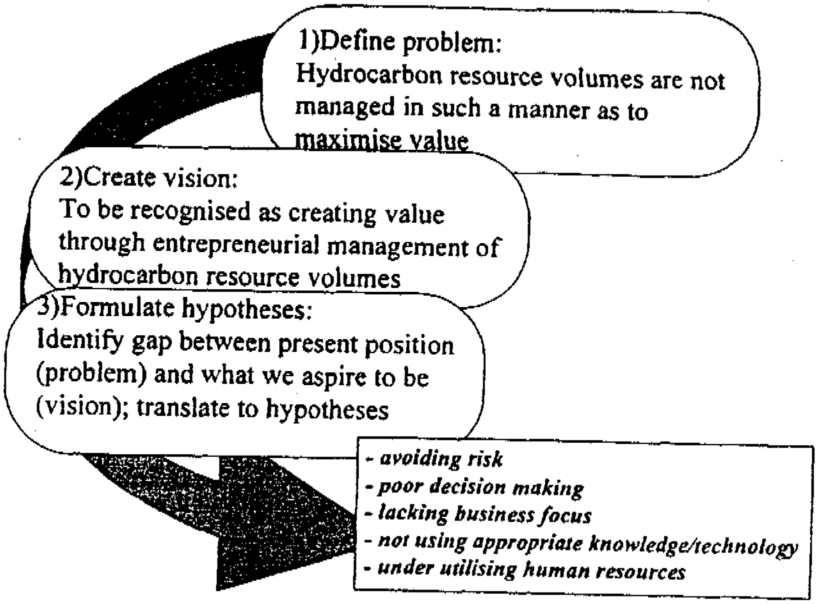
3) We under-appreciate true uncertainties (specifically upsides) and tend to be risk averse. A large number of case histories[4] reveal that the actual reserves figure is well outside the range of uncertainty initially carried.
4) We tend to underestimate the extent to which technology development and increasing understanding of the subsurface will in future contribute to higher recovery factors and decreased cost. This results in lost acquisition opportunities or development opportunities.

3 Methodology

Following visits to consultants, other oil companies and two business schools, the HCRM VCT worked along the lines of the following methodology[5].



A full overview of (sub) hypotheses and value leakage is given in attachment 2. Subsequently these hypotheses were tested by means of a series of interviews with key stakeholders, by a questionnaire sent to a wider audience, and by a review with the extended network. Results were used to either confirm or reject our problem statement and/or hypotheses. The problem statement was strongly supported, results (ranked order) were as follows:

• **under utilising human resources**	**most strongly supported**
• **avoiding risk**	**almost as strongly supported**
• **inappropriate knowledge & technology sharing**	**strongly supported**
• **lack of business focus**	**moderately supported**
• **poor decision making**	**moderately supported**

Two other hypotheses emerged during the stakeholder interviews, being **lack of clear leadership** and **lack of external focus.**
A more detailed overview of the survey results is given in attachment 3.

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[4] Reference 1991 SIPM study

[5] Adopted from INSEAD, Prof. M.Brim

4 Recommendations and implementation

We have translated our vision to the working environment of the asset team. The integrated asset team focuses on maximising asset value, and has full appreciation and ownership of its stakeholder's wishes. As a result of instilled entrepreneurialism there is a continuous drive to identify and mature upsides, not fearing occasional disappointments. Other asset teams may contribute to value creation, either by means of peer challenge, by submitting ideas via an 'open development platform' or through the network. The sector and OU should serve as centres of excellence, setting the strategic framework with respect to portfolio management and defining the Group value system (forming the basis for appraisal and recognition systems). The framework within which the asset team operates is illustrated by figure 2.

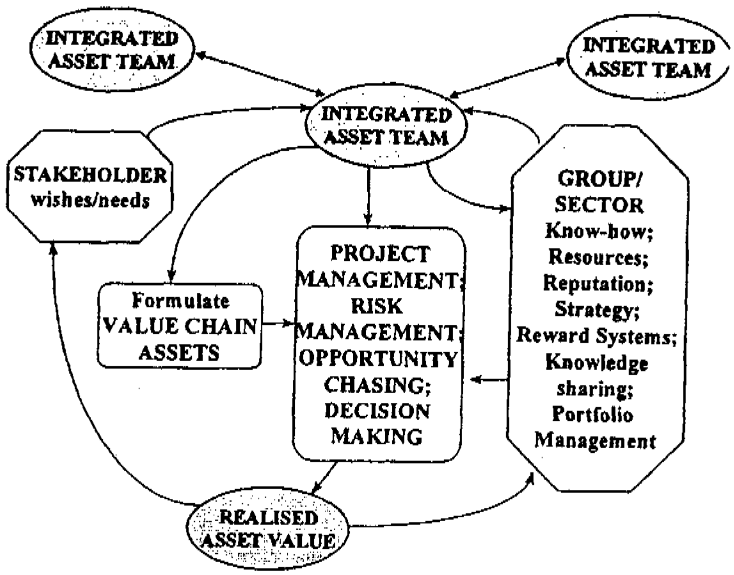

Figure 2: Entrepreneurial asset management

In order to achieve the above, we propose to implement changes as indicated in the summary, which were cross referenced to our main hypotheses:

	Risk taking	Knowl. sharing	Staff utilisation	Business focus	Decision making	Leadership
Guidelines				■		
Risk & opp't management	■			■	■	
Open development platform		■	■	■		
Competencies			■	■	■	■
Knowledge sharing		■	■		■	■
Leadership & appraisal	■	■	■	■		■

A more detailed overview of our recommendations is presented in the following tables.

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4.1 Recommendation : Resource Volumes Reporting Guidelines

Update Resource Volumes Reporting Guidelines to emphasise framework of Value Creation and the commercial impacts of reserves reporting.

Vision of the future

Shell is recognised as having a framework for resource volumes management which aggressively reinforces and underpins the EP sector focus on Value Realisation. This is achieved through a classification aligned with the business model and with Portfolio Management. It allows benefits of, for example, technology development to be identified. Uncertainty in the subsurface can be adequately represented for the purpose of risk and opportunity management.

External reporting enhances Shell's image as an open, honest and entrepreneurial company with clear indication of the Group's success in maturing resource volumes with a value focus.

First practical steps, implementation strategy	Who/ When
Update the Reporting Guidelines to :	
a) emphasise the need to manage the maturing of resource volumes through the value chain in order to realise value. KPIs should look not only at reserves replacement but also at developed reserves replacement as the basis for production and the efficiency with which SFR is matured to reserves.	EPS-SE Aug 98
b) establish that probabilistic and deterministic approaches to resource volumes estimates are acceptable dependent on the circumstances. • Probabilistic methods, including probabilistic addition, is best used when the geological model and development concept are clear and the volumes in place are major uncertainties. • Deterministic methods are best used when the main uncertainty is in the dynamic behaviour of the reservoir or when performance based estimates are being used.	
c) define proved reserves to use the larger of either the P85 of the full field full lifecycle estimate (interim the P85 of the dependently added project estimate) or the expectation of the proved volumes. At all times be aware of the differences. Note all fields should have moved to the latter by the time expectation developed exceeds P85 of the total volumes.	
d) make clear to users of the guidelines the link between reserves and depletion charges and the need to involve finance in the reporting process.	
Initiate development via the network of guidelines with respect to : a) estimating ranges of uncertainty b) probabilistic addition c) establishing target recovery factors, i.e. recovery factor for UR + SFR d) moving from volumetric to performance based resource volumes estimating	VCT NET July 98
Contribute to the SPE publication on practices in evaluating reserves.	

Impact : Impact on end 1998 reserves of some 500 MMBoe and some $150 mln NIAT. In a growing company higher proved reserves will have a continued positive impact on NIAT.

Barriers : time required in OU to implement changes; tax and/or capital allowance issues; need to bring other stakeholders on board; lack of guidelines.

Enablers : the current low oil prices put a premium on implementing measures that positively impact NIAT; growth objectives support closer look at resource volumes potential.

4.2 Recommendation : Maturing The Asset - Risk And Opportunity Management

1. The Asset Reference Plan (ARP) is the vehicle for capturing the maximum value for an asset and defining the integrated requirements for maturing volumes through the value chain.
2. Scenarios are used to reliably represent subsurface uncertainty. Reservoir monitoring requirements will be specified against the opportunities and risks represented by the scenarios.
3. A full inventory of Scope for Recovery Volumes is available clearly linked to integrated activities, technical or commercial, by which they may be matured through the value chain. A potential value is ascribed to these volumes through a portfolio of opportunities. At the Sector and OU level there is portfolio management to identify where several assets could benefit from one technology or commercial arrangement.
4. Team appraisal will evaluate the process of risk and opportunity management rather than the outcome. For example a well managed field trial is rewarded regardless of whether the technology is successful.

Vision of the future

Hydrocarbon resource volumes will be project managed through the value chain - from undiscovered SFR to developed reserves and subsequently production - based on risk and opportunity management. New ideas are encouraged and built upon; managed risk taking is encouraged. By defining what is needed to make the necessary decisions, the work is kept to the required minimum.

Scenarios, and the imaginative options to respond to them as they unfurl, are core to the Asset Reference Plan (ARP) and accepted by all the asset leadership team.

Some assets are designated "launch customers" for integrated technology application, the benefits judged against the portfolio of similar asset types. Launch customers are rewarded for the learning they contribute.

The asset leadership team fully understand all stakeholders aspirations, which are included in the ARP, and manage licence agreements and other arrangements to realise the value of the resource volumes.

With technology increasingly available to all, it is the ability to manage the risks and opportunities through quality decision making and project management which gives competitive edge. Risk and Opportunity management is valued as a process. Staff and teams are appraised for the quality of this process.

The information in the ARP also provides the basis for portfolio management, e.g. acquisition and divestment.

First practical steps, implementation strategy	Who/ When
• Evaluate the use of external facilitators in asset teams to improve risk and opportunity identification and their incorporation in ARP and decision making. Develop this competency in-house.	OU/VCT
• Clarify difference between requirements for reserves reporting and for risk and opportunity management. Facilitate use of scenarios, e.g. deterministic proved, for reserves reporting to avoid double work. Open up network forum on estimating ranges for scenarios, e.g. start with "what the field is not" rather than the "most likely case".	EPS-SE NET 8/98
• Identify disseminate and develop best practice in ARP (template together with Major Projects)	EPT-AM 1998
• Peer Challenge ToR to include completeness of the SFR portfolio and the links to activity and hence value. Identify best practices and disseminate via network.	OU, EPT-AM, NET
• Portfolio management : there is a clear link with "Open Development", Technology Strategy and Planning and initiatives in difficult fields to identify assets with common opportunities	EPT
• Appraisal : develop team scorecard addressing issues of : nurturing ideas; risk taking; learning. Team on team appraisal for risk and opportunity management.	HR,OU

Impact : essential for reserves replacement in existing OU. Increase the speed with which resource volumes matured to developed reserves and production.

Barriers : OU not in asset structures; "initiative overload"; funding for on going EPT/NET work

Enablers : examples from OU where success has been achieved (PDO, Expro, SSB?)

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4.3 Recommendation : Open Development Platform

Create an Open Development platform on SWW akin to open resourcing. This will allow staff to submit ideas to create value in assets throughout the EP sector.

Organise an annual (virtual) "Technology Fair" gathering together best practices and integrated technology applications with strong potential for creating value. Also to celebrate staff who have contributed most to : creating value; maturing resource volumes; learning.

Vision of the future

Energised by the forthcoming technology fair, staff will every now and then browse the open development site to see whether there are any projects/assets on which they can improve, capitalising on their own area of expertise. E.g. if your area of expertise happens to be carbonate oil rims, you search projects on this keyword. Given that it improves your chances of success if you submit a team idea, i.e. integrated technology application, networking is actively encouraged. A reservoir engineer in BSP could team up with a drilling engineer in Expro whose area of expertise is multilateral horizontals, and a facilities engineer in NAM who is good at optimising mini-satellites, to jointly write a proposal for a project in Nigeria.
The top projects out of each category are invited to the annual fair, where at the award session, live on Shell business TV, the tension is rising until the winning names are revealed.
"Open development" scheme will result in the following benefits:

- True sharing of each other's best practices
- Recognition of technical excellence
- Allowing market forces to concentrate on those oil and gas projects where maximum value can be added, or where most reserves can be matured
- Creating a business environment where it is encouraged to put new ideas to test

Furthermore the system is self propelled: There will be a direct incentive for all technical staff to see where they can add value to group wide development scenarios.It will allow staff to contribute to development planning without actually being physically present. OU will be encouraged to participate through the benefits to their assets and motivation of staff. An OU may proactively solicit ideas after searching for analogues. Non-operated assets can be included and input sought from their operators where prudent.

First practical steps, implementation strategy	Who/ When
1. A number of target OU's should be selected (NAM, BSP, SSB, SPDC), each of them selecting a number of projects for the open development pilot. Pilot projects should pertain to assets preferably having an asset reference plan. Create websites and advertise to all staff	VCT work-group,
2. Creation of templates which will allow staff to submit ideas in a consistent format which will enable group wide comparison and ranking of ideas	
3. Staff and team contributions should be recognized in appraisal. Staff will need to show they are managing the balance of time/effort between their own assets and those in Open Development.	Q3/98
4. Creation of an ideas tender-board, consisting of one or two Buscom members, two or three OU asset managers or similar, relevant technical experts (although this is a bit dangerous since technical experts normally are not very supportive of breakthrough ideas). Ideas could be scored on typical indicators such as value added, number of barrels matured, innovation, team effort, etc. Non-prize winning ideas could be forwarded to the relevant OU, leaving it to their discretion to award a special bonus.	

Impact : Potentially large both in value and volumes with transfers from SFR to reserves.

Barriers : Initial effort to get sufficient data on the network due to time and effort involved; concerns on confidentiality and joint ventures; others have "no time" to participate with suggestions; ease of responding to ideas with reasons "why it will not work here".

Enablers : RBD to encourage OU to use this particularly for "underperforming" fields. OU must have commitment to follow through constructively on ideas. EPT and EPS encourage staff to "surf" for opportunities. Staff respond to celebrating success. Cross OU rewards.

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4.4 Recommendation : Competency Development and Acquisition

Essential organisational competencies will be acquired through :

- Traditional E&P courses : content should be expanded to provide a greater insight into those areas that are key to the future commercial and transformational success of the Company.
- On the job development through use and mentoring : most new graduates have some commercial skills but these need to be encouraged not made secondary to technology skills.
- Hire or buy competencies which are lacking : be prepared to hire facilitation to complete a teams competency profile; consider "acquiring" an entrepreneurial company for its skills (but be prepared to manage retention of the staff)

Vision of the future

Staff in the next Millennium will be at the forefront of technology but will possess commercial skills to achieve competitive edge. They will have the skills to firstly understand and assess the commercial impacts of their work and then apply the results such that value realisation is the primary driver. Leadership will demonstrate the value placed on such skills.

These value realisation competencies - risk and opportunity management; decision making; project management - will be regarded as core organisational competencies promoted by leadership and nurtured in a diverse staff from the beginning. Integrated teams will not be considered complete without such competency being present.

First practical steps, implementation strategy	Who /When
• The recently issued skills portfolio documents should be updated to explicitly include the above competencies.	Skills Manager 1998
• Skills Managers Liaise with Group Learning and Development to develop modules either suitable for inclusion in current courses or to be as a standalone options. This should not be fleeting overviews only (as some L&D has been in the past) but rather, should provide a comprehensive insight. Home learning modules (e.g. remote MBA) should be included. The impact on current training schedules should then be assessed and a "best way forward" adopted. This should be done as soon as possible.	SMs & EPT-LD VCT 1998
• Identify consultants who can provide facilitation in these competencies and enter into an alliance whereby there is mutual learning/benefit to develop skills in-house or to retain access to the right people.	EPT-LD
• Include acquisition of competency in evaluating potential acquisition targets.	EPS-AD
• Continue to develop appropriate leadership skills through LEAP	LEAP
Expand training facilities into India, Russia ….. where pools of untapped talent may exist.	HR

Impact : Enables the impact of maturing assets; improves staff retention, especially those with commercial skills.

Barriers : OU staff may be reluctant to take external facilitation. Otherwise none provided funding and resources are available

Enablers : Successes celebrated through EPNL etc. Promotion through major project assessments.

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4.5 Recommendation : Knowledge Sharing

- A global HCRVM network is being established to promote and provide a mechanism for the sharing of best practices and technology across all OUs. This will complement networks in specific technologies, e.g. petrophysics, which are essential to successful HCRVM. Experience from major consultancies on knowledge sharing systems will be incorporated.
- Peer Challenges (or Reviews) of Hydrocarbon Resource Volumes Management have commenced.
- Sharing outside of Shell is taking place through such opportunities as the SPE TIG on reserves. Other opportunities will be sought for sharing particularly on the non-technical skills.
- Increase emphasis on the sharing of problems and issues and follow-up in implementing solutions.

Vision of the future

Sharing knowledge and best practice is embedded in the EP culture and people will be proud to share information. Knowledge sharing via a global network and, in a more face to face mode, via Peer Challenge will be recognised as value adding mechanism for 'learning organisation'.
There is an open and trusting environment within EP to share knowledge Technology is recognised as an enabler only. An active worldwide network will operate in which people will post problems, requests for help, best practices, clever and innovative solutions. OU leadership teams will actively encourage this interactive transfer of knowledge recognising that they can benefit as much as they can contribute. The emphasis will not just be on sharing knowledge but also on helping in the implementation.
Professional bodies will seek opportunities to be part of Shells networks.
There will be reward mechanisms that function across OUs to recognise the contribution of individuals across geographical boundaries. Each individual will have tasks and targets that recognise their usage, both in giving and getting advice, from the network.

First practical steps, implementation strategy	Who/ When
• Appoint a network moderator (Done) who will review, edit, cajole to ensure the system kicks off and runs.	
• Review other active, successful networks and seek expert implementation advice, e.g. instrument engineering in SIOP.	NET NWW
• Define the initial scope of the network to get an initially manageable system active.	June 98
• Hold a second network meeting to progress issues in the network operation.	Oct 98
• Develop ToR and a contract to learn from existing Consultancy Groups which have excellent processes to promote knowledge sharing world wide e.g Arthur Andersen.	Group KM?
• BUSCOM will demonstrate their commitment to this New Way of Working at the EPSEC meeting in May.	
• Regional business directors to include network usage as scorecard items for their respective OU chief executives. It is expected that these targets would then be cascaded down the OUs as appropriate. This will provide a "top down" influence that will assist in overcoming any local resistance or scepticism.	OU/RBD
Refer also to the Open Development and Appraisal Recommendations.	

Impact : Intangible but potentially significant through improved idea generation/development; improved staff retention.
Barriers : Time of extended team; non-standard or availability of IT infrastructure; initiative overload
Enablers : Committed, energetic and funded moderator for the network; early contributions from VCT; incentives.

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4.6 Recommendation : Leadership and Appraisal (Staff, Team and Leadership)

- Develop the concept of mandates, including budgets and other targets, to describe the freedom teams have to make decisions and to maximise value realisation.
- Implement 360 degrees feed-back system with particular emphasis on the leadership displaying the values they aspire to - Deliver as promised; Honesty (openness); Sharing (knowledge, resources, reward); Balanced risk taking - and asset teams being focused on value realisation.

Vision of the future

The work environment is rich in mutual trust where ideas are nourished, undue conservatism is not rewarded and managed risk taking is rewarded. Decisions are taken at the lowest possible level. The individuals or groups taking decisions will be free to move within a wide framework described by a mandate from the leadership team.
Mandates are developed looking at the global impact on Shell as a whole and not on the basis of what is best for a particular asset. For example, one team may be mandated to trial a new technology. Bureaucracy is a thing of the past.

There is no ambiguity about the values and principles of the diverse company. Leadership is prompted to "walk the talk" through 360 degree feedback.

All staff at all levels use the 360 feed-back using superiors, peers and subordinates, as a major contribution to their appraisal and personal development and recognise the value of this tool.

First practical steps, implementation strategy	Who/When
• Identify examples of best practice in mandates. Open a network discussion to develop these for HCRVM.	EPT-AM, NET, Q398
• The 360 degree appraisal recommendation is not specific to HCRVM and is expected to be implemented through transformation activities.	HR/LEAP

Impact : Personal development in staff; improved staff retention, especially those with entrepreneurial skills.
Barriers : Unwillingness to "let go" existing controls; cultural issues.
Enablers : Transformation drive from RBD, BusCom, CMD

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Attachment 1: The hydrocarbon resource volume value chain

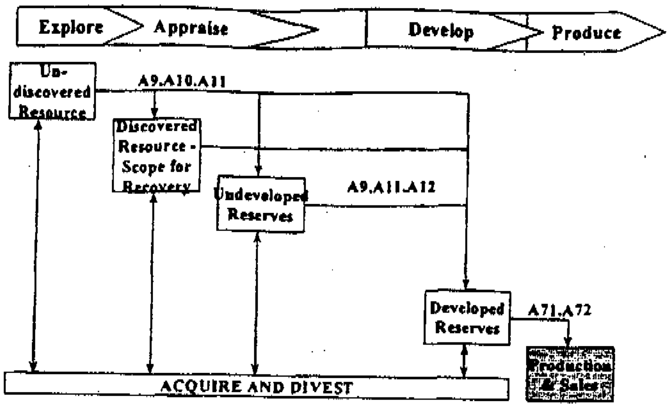

Figure 3: The resource volumes value chain as per classification in EP business model

An asset may have resource volumes at different levels of maturity at any one time, e.g. near facility exploration potential during the production phase. Integrated HCRVM will hence involve decisions at the asset level making trade-offs between, say, maturing risky Scope (SFR) and producing hydrocarbons.

Value leakage due to conservatism

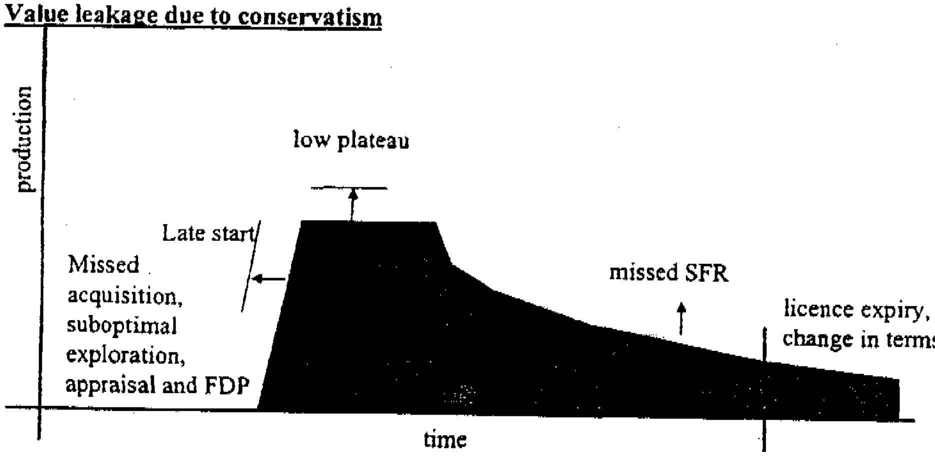

Figure 4: Value leakage during the asset life cycle an example

- Prior to discovery we may be concentrating on volumes rather than portfolio value, leading to following a volumes rather than value 'creaming curve'. Exploration may not be aligned with acquisition strategy leading to 'unconnected discoveries'.
- Over-engineering at FDP stage and not involving well engineers and project execution staff at an early stage may result in late start-up and consequential deferred revenues; furthermore lack of integration may result in not building fit for purpose facilities.
- Conservative reserve estimates result in a low production plateau or missed sales opportunities.
- In the decline period 'technology opportunities' may be missed resulting in untapped scope for recovery.
- Conservatism during licence negotiation time, or worse, unawareness of the licence terms at the coalface may result in significant resource volumes remaining after the licence expires or missing on reserves bonuses.
- Asset may be undervalued when divested.

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Attachment 2 Primary and secondary hypotheses related to value leakage

PRIMARY HYPOTHESES	IMPACT / CONSEQUENCES	SECONDARY HYPOTHESES
Not using appropriate knowledge and technology	Missed business opportunities	• Do not share knowledge • Individualistic attitude • Don't utilise Group / Industry knowledge. • Do not capture learning - making use of our past • High cost
Avoiding risk	Conservatism • Missing out on reserves bonus • Undersized facilities • Under reporting NIAT • Under value of assets at disposal • Leaving behind excess reserves at licence expiry • Late start up, over "engineer" – out the risk	• Blame culture; fear of failure; don't accept / recognise uncertainty. • Personal risk management; respond to message from the top. • Training – instils conservatism; technology biased as opposed to business; not around decision making. • Transition from management to leadership is not fast enough, our present reporting guidelines promote conservatism.
Poor decision making	• Sub-optimal development plan • Under / over appraisal • Wrong decisions in acquisition divestment • Slow maturation	• Not trained to make decisions • Organisational structure not supportive of decision making • Look for a technical solution • Lack of integration; silo mentality; surface and subsurface addressing different problems (leading to a late and resisted changes to scope) • Personal ambition associated with project • Not full-life cycle • Not prepared to look at analogues • The value as we "living" it do not support decision making
Under utilising HR Resources	• Resource constraints for growth	• HR systems – wrong persons recruited / promoted • Lack of trust in people / data • Personal risk management; respond to message from the top • Lack of integration; silo mentality; surface and subsurface addressing different problems (leading to a late and resisted changes to scope)
Lack of business focus	• Slow production build up • Not taking advantage of NIAT and reserves bonuses • Slow to chase upsides • Lack of portfolio management (D&A – divestment and acquisition) • Poor decisions	• Training – instils conservatism; technology biased as opposed to business; not around decision making. • Personal risk management; respond to message from the top • Reward system • Lack of integration; silo mentality; surface and subsurface addressing different problems (leading to a late and resisted changes to scope) especially with Finance

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Attachment 3: Survey results (summary from Arthur Andersen report)

Hypotheses Matrix	E-mail Survey	Stakeholder Meetings	Best Practice Research
	68% - fear/blame culture 77% - reward systems do not encourage risk 50:50 - on capacity to manage risk 92% - agree highly for future Engineers strongest view. SIEP most risk averse BSP least risk averse.	• We manage risk as if we own a 2 asset portfolio. • Not good at dealing with uncertainty. • Personal level: risk averse: conservative inhibited by blame culture. • Risk averse culture - tend to cover for all eventualities • Often good at assessing risk but not taking it.	• "Nothing ventured nothing gained" - people are encouraged to take risks with the acknowledgement that sometimes failure results - AES • Risks become calculated when knowledge is shared with experts who make the decisions - BP
	71% - lack training in decision-making 2/3 agree: •decisions are multi-disciplinary •focused on commercial needs •buy-in of key players obtained at critical stage •clear and integrated processes + 95% for future	• Slow process but when a decision is made it's generally a good decision. • There are too many people involved. • Inhibited by fear of blame & an extensive check loop • The more marginal the project the more the checking • Delay mean that sometimes opportunities are missed. • Sometimes need to be more dictatorial to make HCRVM more effective.	• Decisions should be made by those closest to the issues - Texaco • Empower employees to make their own decisions and calculate the risks in a 'no-blame' culture - 3M • Need to reward the desired behaviours - Siemens
	73% agree business activities strategically aligned. 50:50 on clarity of business vision, objectives, priorities 50:50 on integration of strategy 67% staff do not understand impact of individual acts/decisions +92% for future BPS least lacking /<5 years SPDC most /5-10 years	• We look at technical rather than commercial issues. • People don't know how what they do will effect the • business in money terms. • People have a keen understanding of how their job is done. • Lack of commercial acumen.	• Encourage open information disclosure so people are able to see the 'big picture' - AES • Reward employees for maintaining an outward focus and transferring best practice approaches - General Electric
	74% agree capture & apply existing knowledge and technology; 50:50 on culture supporting innovation & new ideas; 50:50 on clarity of processes for sharing knowledge and development learning; 50:50 on knowledge targeted to new opportunities 63% don't encourage/reward sharing of knowledge & technology Reward sharing knowledge and technology BSP most appropriate use, SIEP least Engineers + 5-10 service strongest view.	• Need to create a culture of sharing knowledge and best practice so that there is an <u>obligation</u> to share. • The biggest issue is attitudinal rather than better methods. • Often local bosses won't give staff the time to contribute to knowledge sharing.	• Technology is only an enabler to knowledge sharing; overcoming human resistance is the real challenge - BP, ICL • Make it easy for people to connect, communicate and share knowledge - BP, Oticon • Facilitate ways to improve information flow - USAir • Virtual teamworking can limit contributions as less obligation to perform - BT, IBM
	67-87% (+majority 1 of 2) do not feel reward, promotion, training & appraisal systems encourage entrepreneurial management 95-100% agreement for future Consensus: Expro 2.27; SIEP 3.52 BSP gap low (1.63) on appraisal systems	•Shell often recruits for diversity but then spends time turning each employee into a "Shell employee" & loses the benefits. •Still functional or discipline based structure. •Excellent people but not given room to run. •Could operate with fewer people.	• Nurture high-potential employees and improve their visibility across the organisation - SmithKline Beecham • Offer innovative and flexible working practices to attract fresh talent - Bank of Montreal • Put diversity on the agenda - 'uniform' workforce damages recruitment, retention and development practices - Amaco

red dots: strongly supported
orange dots: moderately supported
green dots: not supported

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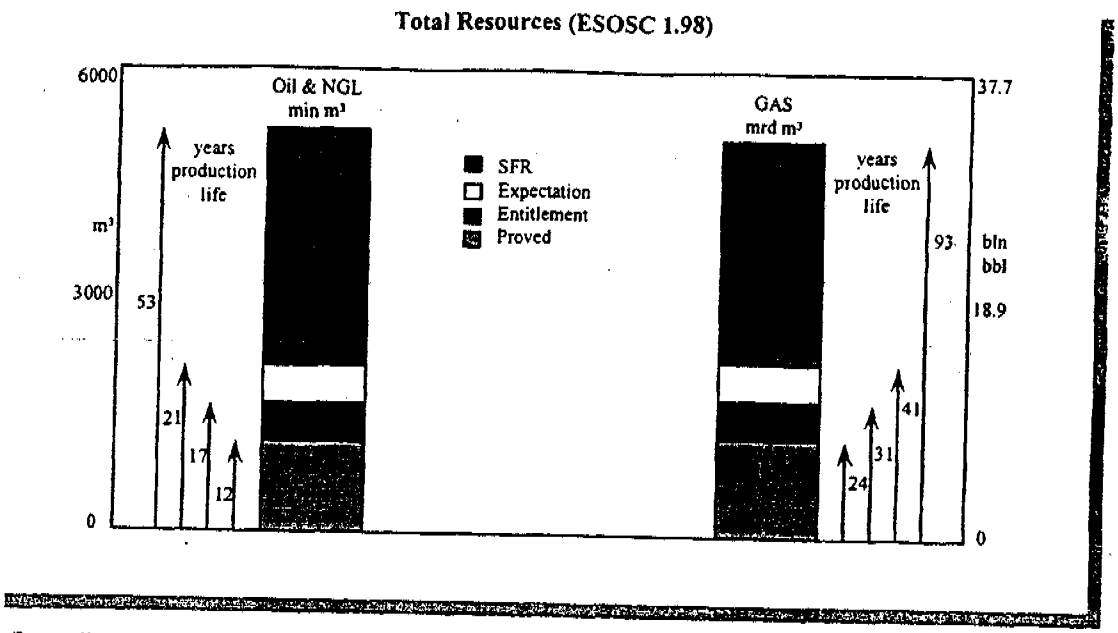
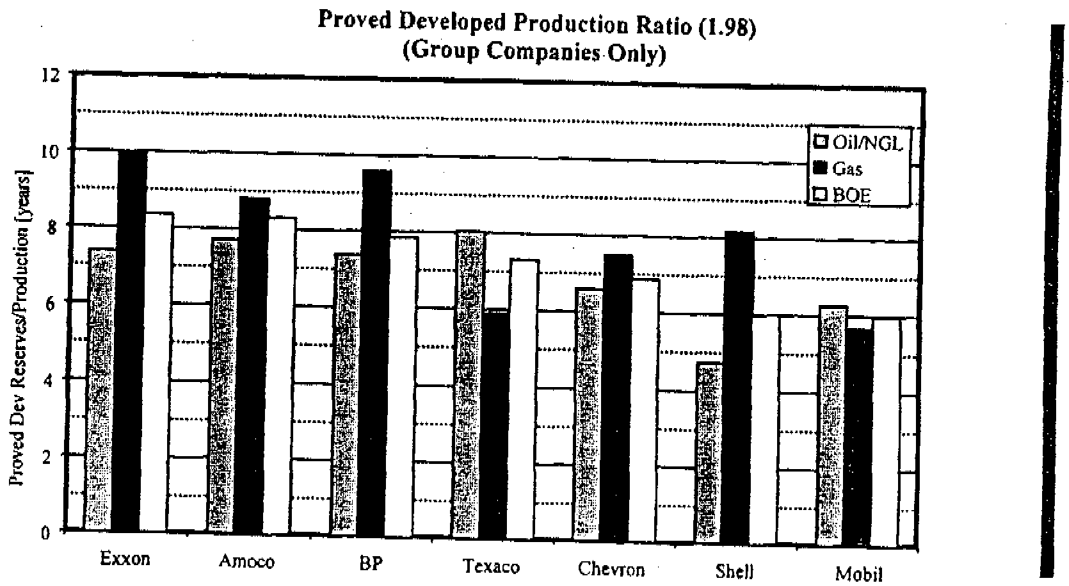
External Reporting of our Resource Base



- Externally reported (Proved) reserves are only 25% of our Resource Volumes Base.
- Shell (ESOSC) stand out as having the lowest reported Proved Developed Reserves compared to other Oil Companies - 4.8 years of current production vs. approx 7 years.
- This has a significant impact on depreciation and hence NIAT.

Do your Asset Holders make full use of the Resource Volumes Guidelines?



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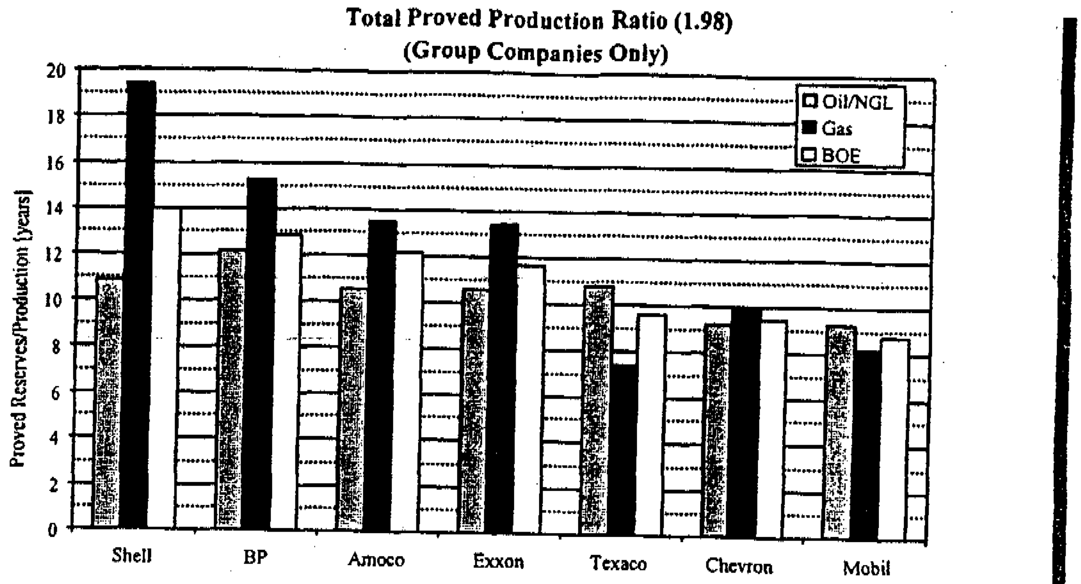
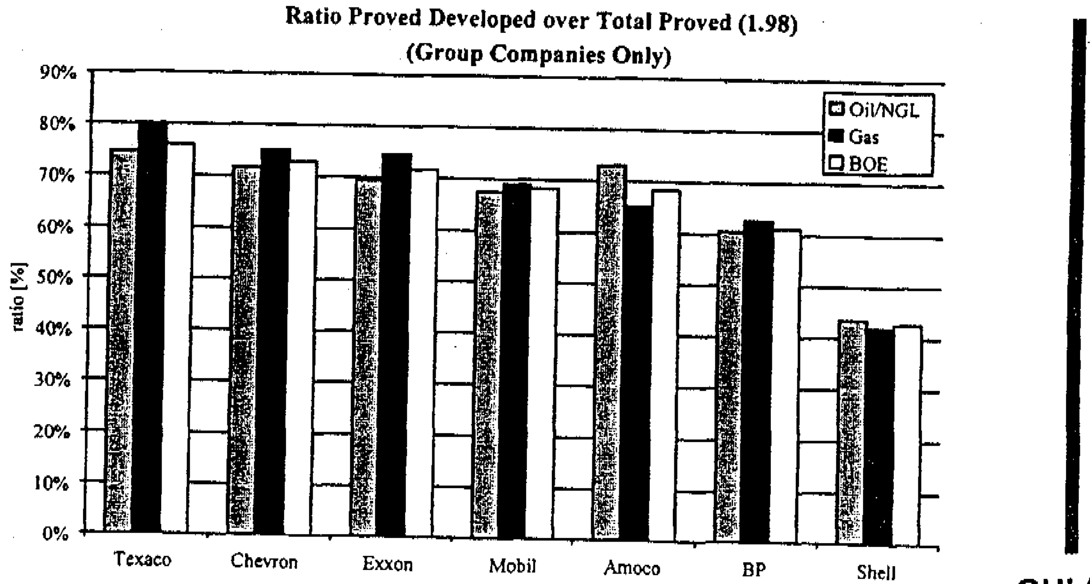
Externally Reported Reserves



Benchmarking externally reported reserves

- Shell has the highest proved reserves when normalised by production. However, backing out gas, weare in line.
- Shell's proved developed oil reserves are low when compared to others. Proved developed to production is a measure of the rate at which we depreciate our assets.
- For both oil and gas, Shell's ratio of developed to total stands out as very low.
- Discussion indicates that we are both early in registering reserves and conservative in reporting proved developed.



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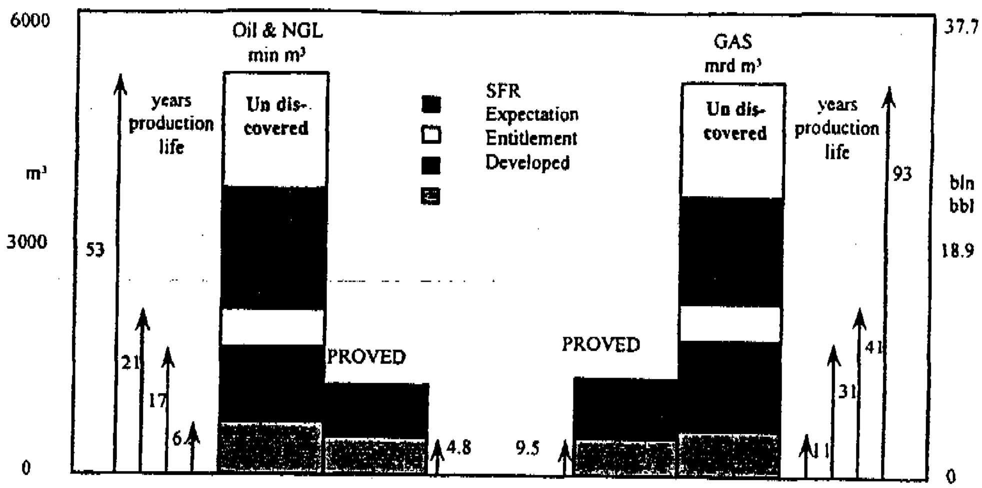
Maturing our Assets

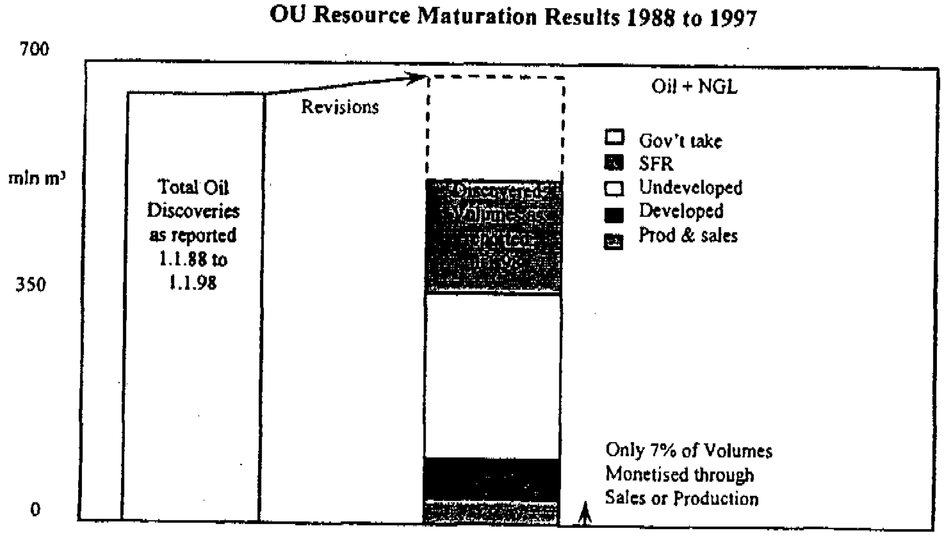
Total Resources (ESOSC 1.98)



- Only 22% of the discovered resource base is developed.
- If we doubled the developed reserves, to 44%, we could support double the production without any increase in total volumes.
- Only 6% of the volumes discovered between 1988 and 1997 have been monetised - produced or sold - to date.

Are your Resource managers going after Value Realisation?

OU Resource Maturation Results 1988 to 1997



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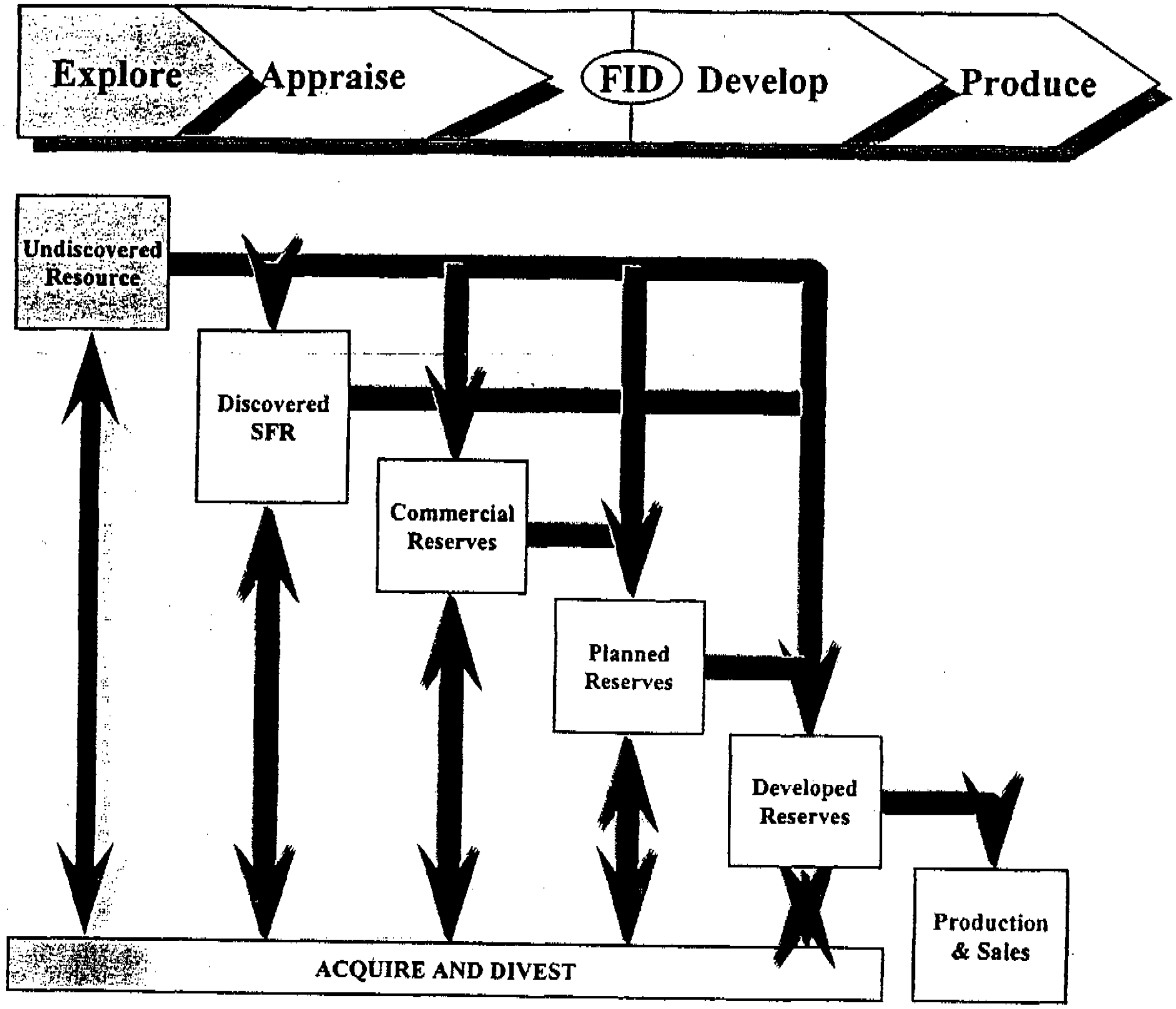
Treatment Requested

Resource Volumes Maturity Model the Value Chain



- Value Realisation is about moving down the Maturity Model
  -either to production or to divestment.
- Asset Reference Plans should include the value chain and identify the requirements for maturing the volumes.
- Volumes may be matured through new technology or comercial agreements - 50% of SFR and 20% of Reserves are beyond licence.

Part of transformation is a mindset shift from Volumes Description to Value Realisation!

Resource Volumes - Hypothesis Testing

Volumes to value

1) **Define problem:**
Hydrocarbon resource volumes are not managed in such a manner as to maximise value

2) **Create vision:**
To be recognised as creating value through entrepreneurial management of hydrocarbon resource volumes

3) **Formulate hypotheses:**
Identify gap between present position (problem) and what we aspire to be (vision); translate to hypotheses

- avoiding risk
- poor decision making
- lacking business focus
- not using appropriate knowledge/technology
- under utilising human resources

Hypotheses Testing Process

- Conduct key stakeholder interviews
- Conduct survey via E-mail questionnaire
- Review with the extended team in a workshop
- Carry out research to identify best practice

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Hypothesis Testing - Results

volumes to value

Hypotheses Matrix	E-mail Survey	Stakeholder Meetings	Best Practice Research
		Manage risk as if we own a 2 asset portfolio. Not good at dealing with uncertainty. Personal level: risk averse: inhibited by blame culture. Risk averse culture - tend to cover for all eventualities. Often good at assessing risk but not taking it.	"Nothing ventured nothing gained" - people are encouraged to take risks with the acknowledgement that sometimes failure results - AES Risks become calculated when knowledge is shared with experts who make the decisions - BP
		Slow process but when a decision is made it's generally a good decision. There are too many people involved. Inhibited by fear of blame & an extensive check loop. The more marginal the project, the more the checking. Delay mean that sometimes opportunities are missed. Sometimes need to be more dictatorial to make HCRVM more effective.	Decisions should be made by those closest to the issues - Texaco Empower employees to make their own decisions and calculate the risks in a 'no-blame' culture - 3M Need to reward the desired behaviours - Siemens
		We look at technical rather than commercial issues. People don't know how what they do will effect the business in money terms. People have a keen understanding of how their job is done. Lack of commercial acumen.	Encourage open information disclosure so people are able to see the 'big picture' - AES Reward employees for maintaining an outward focus and transferring best practice approaches - General Electric
		Need to create a culture of sharing knowledge and best practice so that there is an obligation to share. The biggest issue is attitudinal rather than better methods. Often local bosses won't give staff the time to contribute to knowledge sharing.	Technology is only an enabler to knowledge sharing; overcoming human resistance is the real challenge - BP, ICL Make it easy for people to connect, communicate and share knowledge - BP, Oticon Facilitate ways to improve information flow - USAir Virtual teamworking can limit contributions as less obligation to perform - BT, IBM
		Shell often recruits for diversity but then spends time turning each employee into a "Shell employee" & loses the benefits. Still functional or discipline based structure. Excellent people but not given room to run. Could operate with fewer people.	Nurture high-potential employees and improve their visibility across the organisation - SmithKline Beecham Offer innovative and flexible working practices to attract fresh talent - Bank of Montreal Put diversity on the agenda - 'uniform' workforce damages recruitment, retention and development practices - Amoco

strongly supported — moderately supported — not supported

Hypotheses Testing Process

- **Problem statement was supported**
- **Ranked order were:**
  - Under - utilising human resources
  - Avoiding risk
  - Inappropriate use of knowledge & technology
  - Lack of business focus
  - Poor decision making
- **Two additional hypotheses emerged**
  - Lack of clear leadership
  - Lack of external focus

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Slide 6

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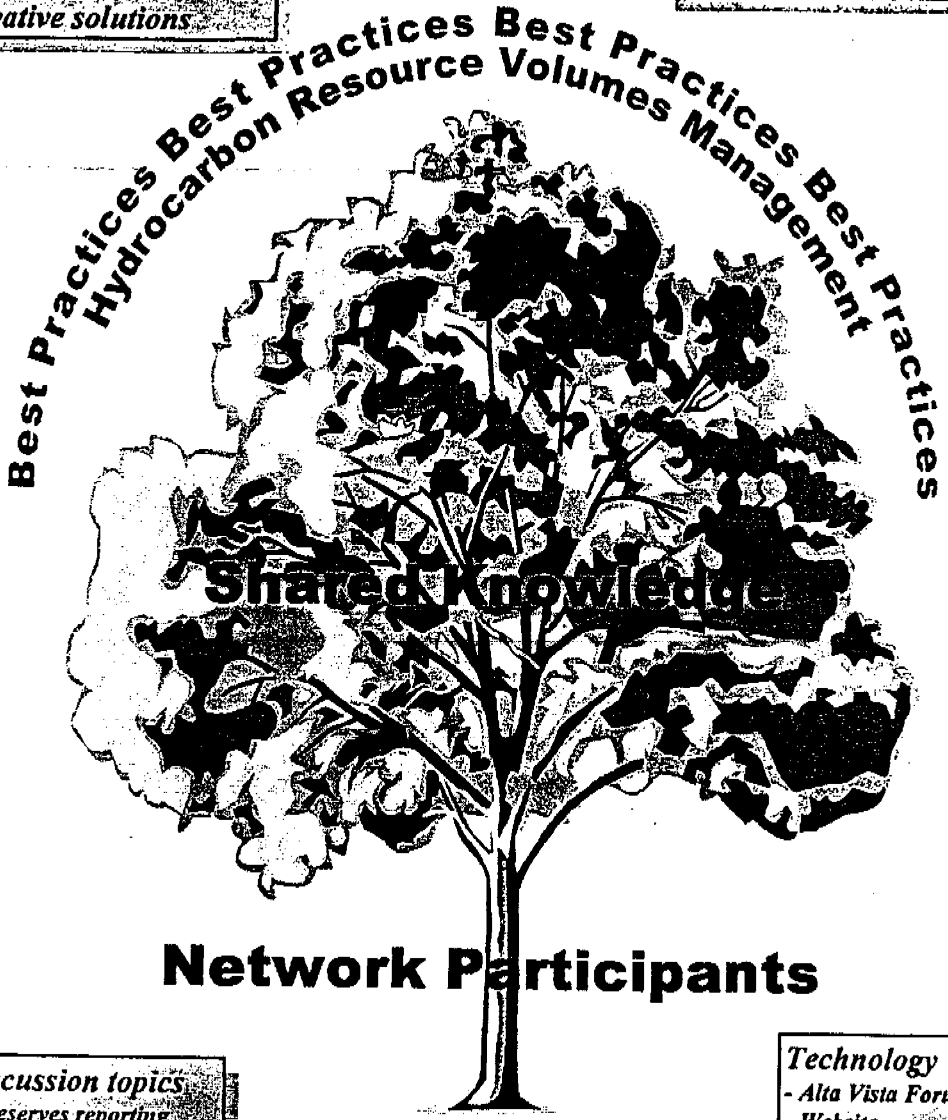
V00101312

Knowledge Sharing in Hydrocarbons Resource Management

Objective: Create value from volumes by sharing:
- *Best Practices*
- *Technology*
- *Innovative solutions*

Building the Community
- *Start; extended Value Creation Team*
- *Invite OU focal points*
- *Add "networked participants"*
- *Moderator provides QC*

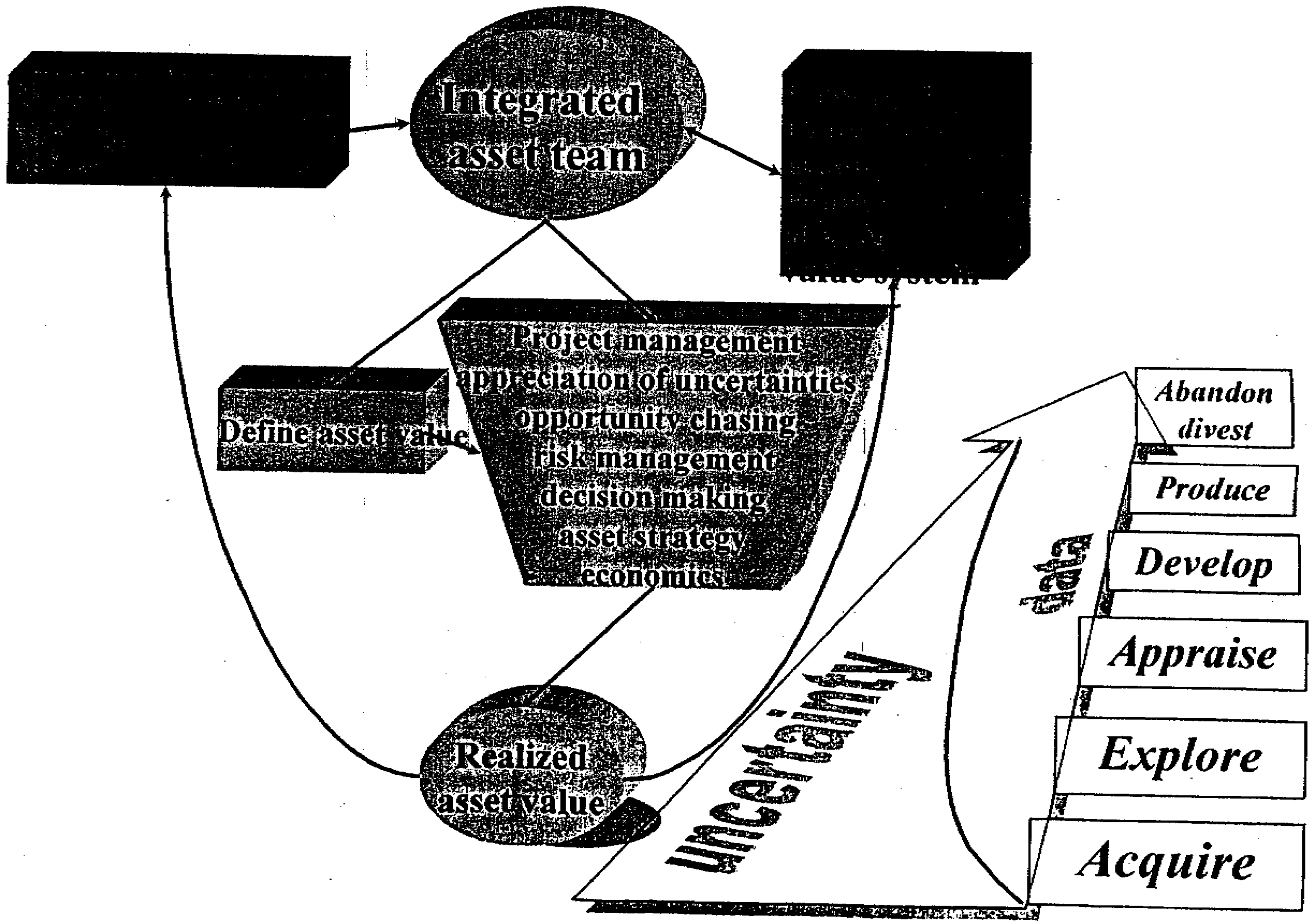


Sample discussion topics
- *Guidelines reserves reporting*
- *Benchmark recovery factors*
- *Ranges for development scenarios*
- *Best Practices in Asset mgmnt*

Technology
- *Alta Vista Forum*
- *Website*
- *Links to other sites*
- *Email notification and 'shadowing'*

Organic Growth !

Volumes to Value - the Vision



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Slide 8

Competency Development and Acquisition

Where do we want to be?

- Staff will be at the forefront of technology and will possess commercial skills to achieve competitive edge.
- Staff will understand the commercial impacts of their work and make value the primary driver

Core Competencies:
Project Management
Risk Management
Decision Making

The first steps!

- Add commercial skills to skills portfolio
- Integrate commercial training as an essential part into training modules
- Seek help from consultants to provide facilitation
- Include acquisition of competencies in evaluating potential acquisition targets
- Continue to develop appropriate leadership skills through LEAP

Knowledge sharing

- Best ARP practices via EPT-AM
- Guidelines for reserves and strategies EPB-S
- Cross OU peer challenge
- Set up of network (alike SIOP)
- Difficult field initiative
- Future: Open development platform

Hydrocarbon Resource Management Proposed Way Forward

Transformation Programme

- Volumes to Value Relalisation
- Entrepreneurial project management and decision making
- Asset Reference Plan as basis for integrated scenario based risk management

Update Guidelines

- bring into line with industry practice
- emphasize value realisation through cascade model

Develop Action Learning for competencies

Establish Network to support implementation

DRAFT NOTE – 5 May 2002 CONFIDENTIAL

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPB - GRA
To:	Lorin L. Brass	Director, Business Development, SIEP – EPB
	Chris G. Finlayson	Managing Director, BSP
Copy:	Brian E. Straub	Technical Director, BSP
	Reidar W. Saugstad	Finance Director, BSP
		Exploration Manager, BSP
	Chris C. Kennett	Discipline Head, Reservoir Engineering, BSP
	(circulation)	SIEP – EPF: Dominique Gardy, Rahim Khan
	(circulation)	SIEP - EPB-P: Malcolm Harper, Jaap Nauta, John Pay
	Paul G. Tauecchio	Business Advisor, SIEP – EPA
	Han van Delden	Senior Manager, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

SEC PROVED RESERVES AUDIT - BRUNEI SHELL PETROLEUM SDN BHD, 29 Apr - 3 May 2002

I have audited the Proved Reserves submissions of Brunei Shell Petroleum Sdn Bhd (BSP) for the year 2001 and the processes that were followed in their preparation. These submissions present the BSP contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 2001.

Total Group share Proved Reserves booked by BSP at the end of 2001 were 72 mln m3 oil+NGL and 100 bln sm3 of gas. This represents some 5.6 % of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratios for BSP over 2001 were 152% for oil+NGL and 112% for gas.

The last previous SEC proved reserves audit for BSP was carried out in 1998. This current audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 2001-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. It also included a verification that the annual production (sales) submission through the Finance system was consistent with the reserves submission. The audit took the form of detailed discussions about technical details of many of BSP's fields with BSP Asset Unit staff and about the reserves reporting process with BSP reserves coordination staff.

The audit found that BSP follow well documented procedures in their annual reserves reporting process. Audit trails have historically been a strong feature in BSP reserves reporting and their high quality was confirmed during the audit. The most significant comment was regarding the conservative nature of BSP's Proved reserves, in particular Proved developed reserves, many of which were not in accordance with current Group guidelines. <u>Although the total volume of "legacy" reserves has decreased substantially in the past few years.</u> ~~T~~the continued presence of 'legacy reserves' remains an area of concern. These are undeveloped reserves which had historically been booked in reservoirs and for which no clear activies had been identified (in line with then current practice). These reserves should be addressed at the first available opportunity, while striving to avoid major reserves swings.

The audit finding is that the BSP statements fairly represent the Group entitlements to Proved Reserves at the end of 2001. There is a possibility of a small understatement of entitlement reserves due to the conservatism in particularly the Proved developed reserves. The changes in the Proved Reserves during 2001 can be reconciled from the documents at hand. The overall opinion from the audit regarding the state of BSP's 2001 Proved Reserves submission, taking account of the scoring in Attachment 3, is therefore <u>satisfactory</u>.

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

A.A. Barendregt

Attachments 1, 2, 3, 4

DEPOSITION EXHIBIT
Barendregt
#2 2/19/07

FOIA Confidential Treatment Requested

RJW01001167

Attachment 1

SEC PROVED RESERVES AUDIT - BRUNEI SHELL PETROLEUM SDN BHD, 29 Apr - 3 May 2002

MAIN OBSERVATIONS

1. Brunei Shell Petroleum Sdn Bhd are a 50% Group company with their established head office in Seria, Brunei Darussalam. The remaining 50% of the company is held by the Brunei Government. The company operates a large number of offshore fields and some onshore fields. The three largest fields are the onshore Seria field, with first production in 1929 and the offshore SW Ampa and Champion fields where first production started in 1964 and 1972 respectively. Although the area is therefore mature, there are still some smaller, recently discovered fields awaiting development.

   Reserves are approximately evenly divided between oil+NGl and gas. Gas production has been taking place to the Brunei LNG plant since 1972. The 20-year gas contract with Japanese buyers was extended for another 20 years in 1992 on the basis of then available proved gas reserves. This base, being somewhat conservative, has since then grown and there is now a surplus of some 1.5 Tcf proved gas and some 5 Tcf of expectation volumes.

2. The Brunei fields consist of stacked near-shore reservoir sequences, broken up by clay diapir induced or tectonically induced faulting, resulting in numerous small reservoirs that show variable but generally poor communication. Initial fluid levels are therefore largely individual to reservoirs and each needs separate evaluation, although sometimes in conjunction with its neighbours. A total of some 4000 reservoirs is currently recognized, presenting a challenging task for reserves evaluation and development planning.

   All of the fields are in relatively shallow offshore areas (up to 100 m water depth). Exploration focus is shifting towards deep offshore turbidite sequences, in which one field (Merpati) is carrying proved undeveloped reserves at this stage.

   With the largest reservoirs developed first, BSP have faced several cycles of active development. Development tended to become temporarily reduced when the then available technology slowed down the maturation of new economically viable well targets. A recent upturn in development has been seen in the late 1990's when a number of factors contributed to an enhanced capability of reservoir performance modeling and development planning. These factors included enhanced 3D seismic acquisition (with Ocean Bottom Cable) and seismic processing (PSDM), more recently followed by geological modeling through the Petrel package, yielding greatly improved speed and accuracy of reservoir definition. Automatic downloading into MoReS dynamic simulation models allows this improved accuracy yield its benefits in dynamic modeling too. Through-tubing C-O logs allowed a much more widespread monitoring of dynamic fluid levels, greatly improving the accuracy of simulation models and predictions. Significant progress has been made in reducing drilling costs and improving drilling flexibility in well targeting, eg through short-radius horizontal drilling and multi-target sub-horizontal wells.

   The result of these successful technological developments is that new reserves developed per well show a steady trend, with no signs of any levelling off as yet.

3. Expectation developed ultimate recoveries (URs) are determined from performance decline extrapolations in those cases where there is no active history matched simulation model. The standard method of determining Proved developed URs is through fitting a symmetrical triangular distribution around the Expectation estimates with the lower end point halfway between cumulative production and expectation UR. This tends to result in a Proved developed reserves volume that is some 70-78% of Expectation (see Att. 4.1). This is highly artificial and not in accordance with current Group guidelines (which in turn follow SEC guidelines).

   It is strongly recommended that proved developed reserves are derived from expectation developed reserves by multiplying the latter by a factor that is dependent on reservoir maturity and which approaches or equals 1 for the more mature reservoirs, where in-place volumes are well known.

4. Historically, BSP have tended to determine total reservoir recoveries from volumetrics with recovery factors either assumed or derived from analogues, obtained from analytical reservoir studies or obtained from assumed well numbers and notional recoveries per well. After the start of field development, the developed reserves became based on performance extrapolations but undeveloped reserves remained poorly defined as they were calculated as the difference between total URs (which were kept unchanged) and developed URs.

   With the introduction of new Group guidelines in 1993, requiring all reserves to be based on identified projects (i.e. well targets, numbers, costs and forecasts) the undeveloped reserves thus calculated became non-conformant with Group reserves guidelines. BSP have long recognized the non-conformance of these 'legacy' reserves. However, any temptation to 'wipe the slate clean' (i.e. set all undefined undeveloped reserves to zero) was resisted because it was considered likely that in many reservoirs it would be possible to replace them by properly defined reserves, i.e with well targets and forecasts. It was felt that major reserves swings needed to be avoided and the decision was therefore taken to keep these reserves in the books until the proper studies had been made. Significant progress has been made in this respect and the amount of reserves now covered by simulation models and studies is some 70% on average. As a result, the portion of 'legacy' reserves in undeveloped reserves (currently some 9% of Expectation, much less of Proved) is now considerably reduced.

A further reason why 'legacy' reserves have reduced in size was the conservatism in the original field in-place estimates (caused possibly by too rigorous petrophysical cut-offs?). As a result, developed URs continued to grow and in many cases they overtook the original total proved (and sometimes even expectation) UR estimates. Hesitation was observed in simply zeroising these negative reserves because reservoir crossflow was a common phenomenon and it was possible that the underestimate in one reservoir could be due to an overestimate in a neighbouring reservoir. A regional study was therefore required before proper updates could be made. Lack of resources and priority caused a continuous deferment of such studies in a number of areas. Negative reserves continued in many reservoirs (particularly in the Champion Main field), until concerted efforts in 2000/2001 brought back the total of such reserves to more reasonable, but still low proportions.

The continued existence of 'legacy' undeveloped reserves is still a cause for concern. BSP have therefore started and resourced a study that will address this issue and that of the too conservative Proved developed and undeveloped reserves that are not in accordance with Group guidelines. This study is supported, with the annotation that, in the auditor's opinion, probabilistic addition of reservoirs is not a viable option (see below). BSP are also strongly supported in their present drive for complete coverage of all developed and to-be-developed reservoirs by proper studies. Developed and undeveloped reserves should both be defined separately and properly, preferably by a joint simulation model.

5. In the original approach followed by BSP, Proved undeveloped reserves were simply the difference between proved total and proved developed reserves. In the new approach, whereby undeveloped reserves are determined independently, the method of determining proved volumes is less well defined. The impression is that in many cases, a conservative approach is still followed. Group guidelines clearly state that in such cases a number of simulator scenarios should be run, with a reasonable P85 scenario picked as the Proved case at first, which can gradually become updated by a scenario that grows closer to or equal to expectation values with increasing field maturity.

6. BSP have historically been one of the strongest proponents of probabilistic reserves estimation and initial volumetric estimates are still done probabilistically. Any incomplete hydrocarbon column penetrations are thus also addressed probabilistically, i.e. 'proved areas' (ref. SEC definitions) are not adhered to rigidly. Although accepted Group practice in the past, this is no longer in line with Group guidelines. This should be addressed.

7. Asset depreciation is done at a field level. Hence, guidelines would in principle allow probabilistic addition of reservoirs within a field. This is not done at present but is being considered by BSP as a possible method of bringing field Proved reserves closer to Expectation volumes.

The auditor's opinion is that probabilistic addition of ~~reservoir~~ reservoirs to field level is not to be recommended. The reasons for this ~~recommendation~~ are as follows:

- Probabilistic volumetric estimates become irrelevant for mature fields. Probabilistic parameter ranges (bulk volume, porosity etc) can often not realistically be changed to capture the effects of field performance data and any change in volumetrics could therefore become arbitrary and not auditable.
- Reservoir dependency will become a critical issue in proper probabilistic addition of reservoir volumes. This will also be susceptible to subjective judgment and will also present audit trail problems.
- The need for probabilistic addition should diminish significantly if the calculation methods of Proved developed and undeveloped reserves are brought closer in line with Group guidelines, thereby bringing Proved reserves much closer to Expectation volumes.

8. It is noted that there is no complete correspondence between reserves volumes and production forecasts in the Business Plan. This is largely due to the 'legacy' reserves, for which no forecasts are available. However, there are also other discrepancies (eg in Land / Darat BU where the BP contains forecasts for which there are no reserves (only SFR) in the books. The impression is that some of this SFR is sufficiently mature to warrant inclusion as reserves. This should be rectified.

9. Fairley Baram undeveloped oil reserves appear to be positive at Proved level, but the Expectatio undeveloped volume is zero. This is inconsistent and should be rectified.

10. Current production licences expire as follows:
Onshore and 'first offshore' (eg SWA): 22 Dec 2003,
Second offshore area (eg FA): 31 Dec 2007,
Third offshore area (rest): 31 Dec 2026.
There is a right to extend these licences by two successive periods of 15 years, at terms and conditions to be agreed upon. Discussions on the terms and conditions for the onshore and first offshore licences are

currently in progress. There are no indications that an acceptable set of new terms and conditions cannot be agreed with the Government and BSP management are fully confident that a licence extension will be obtained.

11. Various documents describing the reserves determination process are in place (eg a DUR review procedure guide). The annual reserves review process is kicked off by a note by the reserves coordinator, setting out the requirements, target dates and responsibilities. All reserves changes are documented in reports or notes, depending on their complexity. Full field (or part-field) reviews and FDPs are documented comprehensively. An annual report 'End-year Resource Volumes for External and Internal reporting' is issued, together with a summary of results. This provides for an excellent audit trail and is fully commended.

12. Consistency with field reserves and changes *(yet to be reviewed)*

13. Very good consistency with Finance reporting has been observed in the matters of annual production volumes and Unit of Production factors (UPF) for asset depreciation. This is seen to be the result of close cooperation between Finance Accounts and Reserves Coordination and is fully commended.

Recommendations

1. Replace the present method of deriving proved developed reserves from Expectation developed reserves (triangular distribution starting at Cum.prod + 0.5 * [Exp'n dev'd – Cum.prod]) by multiplying Expectation reserves by a factor which gradually approaches or equals 1 with increasing reservoir maturity (defined as Cum.prod / Exp'n UR)

2. Adhere better to Group guidelines for Proved undeveloped reserves by selecting a realistic P85 scenario of future activities, which scenario should be updated as more field performance is obtained and which should therefore grow closer to the Expectation scenario. This approach should be adopted in all new or revisit reservoir studies

3. Complete the recently started study into 'legacy' reserves and the appropriate level of Proved vs Expectation reserves in line with the present plan per end 2002.

4. Address the issue of 'proved areas', in particular in relation to the non-allowed booking of volumes below 'lowest known hydrocarbons' (LKH, see guidelines), unless supported by strong evidence (eg seismic amplitudes). This approach should be adopted in all new or revisit reservoir studies

5. R~~Seriously r~~econsider the justification for probabilistic addition of reservoir reserves to field level.

6. Review the appropriateness of booking some BP forecast volumes in Land/Darat BU as reserves and not as SFR as at present.

7. Rectify Fairley Baram Proved (>0) vs Expectation (=0) undeveloped reserves.

NOTE – 31 May 2002 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPB - GRA
To:	Lorin L. Brass	Director, Business Development, SIEP – EPB
	Chris G. Finlayson	Managing Director, BSP
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	Rosmawatty R. Abd-Mumin	Manager, Land (Darat) Business Unit, BSP
	Salleh-Bostaman b Zainal-Abidin	Manager, Western Business Unit, BSP
	Martin G. Graham	Manager, Eastern Business Unit, BSP
	Thomas T. Prudence	Technical Services Manager, BSP
	Peter J. Worby	Chief Accountant, BSP
	Ben B.R. van den Berg	Head Internal Audit, BSP
	Chris C. Kennett	Discipline Head, Reservoir Engineering (PE Mgr West), BSP
	(circulation)	SIEP – EPF: Dominique Gardy, Rahim Khan
	(circulation)	SIEP - EPB-P: Malcolm Harper, Jaap Nauta, John Pay
	Paul G. Tauecchio	Business Advisor, SIEP – EPA
	Han van Delden	Senior Manager, KPMG Accountants NV
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The audit finding is that the BSP statements fairly represent the Group entitlements to Proved Reserves at the end of 2001. There is a possibility of a small (3 %?) understatement of entitlement reserves due to the conservatism in particularly the Proved developed reserves. The changes in the Proved Reserves during 2001 can be reconciled from the documents at hand. The overall opinion from the audit regarding the state of BSP's 2001 Proved Reserves submission, taking account of the scoring in Attachment 3, is therefore satisfactory.

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

A.A. Barendregt

DEPOSITION EXHIBIT
Barendregt
#3 2/14/07

Attachments 1, 2, 3, 4

FOIA Confidential
Treatment Requested

RJW00061605

Attachment 1

SEC PROVED RESERVES AUDIT - BRUNEI SHELL PETROLEUM SDN BHD, 29 Apr - 3 May 2002

MAIN OBSERVATIONS

1. Brunei Shell Petroleum Sdn Bhd are a 50% Group company with their established head office in Seria, Brunei Darussalam. The remaining 50% of the company is held by the State of Brunei. The company operates a large number of offshore fields and some onshore fields. The three largest fields are the onshore Seria field, with first production in 1929 and the offshore SW Ampa and Champion fields where first production started in 1964 and 1972 respectively. Although the area is largely mature, there are still some smaller, recently discovered fields awaiting development.

   Reserves are approximately evenly divided between oil+NGI and gas. Gas has been produced to the Brunei LNG plant since 1972. The 20-year gas contract with Japanese buyers was extended for another 20 years in 1992 on the basis of then available proved gas reserves. This basis, being somewhat conservative, has since then grown and there is now a surplus of some 1.5 Tcf proved gas and some 5 Tcf of expectation volumes.

2. The Brunei fields consist of stacked near-shore reservoir sequences, broken up by clay diapir induced or tectonically induced faulting, resulting in numerous small reservoirs that show variable but generally poor communication. Initial fluid levels are therefore largely individual to reservoirs and each needs separate evaluation, although often in conjunction with its neighbours. A total of some 4000 reservoirs is currently recognized (of which some 1000 with Proved reserves), presenting a challenging task for reserves evaluation and development planning.

   All of the fields are in relatively shallow offshore areas (up to 100 m water depth). Exploration focus is shifting towards deep offshore turbidite sequences, in which one field (Merpati) is carrying proved undeveloped reserves at this stage.

   With the largest reservoirs developed first, BSP have faced several cycles of active development. Development tended to become temporarily reduced when the then available technology slowed down the maturation of new economically viable well targets. A recent upturn in development has been seen in the late 1990's when a number of factors contributed to an enhanced capability of reservoir performance modeling and development planning. These factors included enhanced 3D seismic acquisition (with Ocean Bottom Cable) and seismic processing (PSDM), more recently followed by geological modeling through the Petrel package, yielding greatly improved speed and accuracy of reservoir definition. Automatic downloading into MoReS dynamic simulation models allows this improved accuracy yield its benefits in dynamic modeling too. Through-tubing C-O logs allowed a much more widespread monitoring of dynamic fluid levels, greatly improving the accuracy of simulation models and predictions. Significant progress has been made in reducing drilling costs and improving drilling flexibility in well targeting, eg through short-radius horizontal drilling and multi-target sub-horizontal wells.

   The result of these successful technological developments is that new reserves developed per well show a steady trend, with no signs of any levelling off as yet.

3. Expectation developed ultimate recoveries (DURs) are determined from performance decline extrapolations in those cases where there is no active history matched simulation model. The standard method of determining <u>Proved DURs</u> is through fitting a symmetrical triangular distribution around the Expectation estimates with the lower end point halfway between cumulative production and expectation UR. This tends to result in a Proved developed reserves volume that is invariably some 75% of Expectation (see Att. 4.1). This is highly artificial and not in accordance with current Group guidelines (which in turn follow SEC guidelines).

   It is strongly recommended that proved developed reserves are derived from expectation developed reserves by multiplying the latter by a factor that is dependent on reservoir maturity and which approaches or equals 1 for the more mature reservoirs, where in-place volumes are well known.

4. In line with general Group practice in the 1970's and 1980's, BSP have tended to determine total reservoir recoveries from volumetrics with recovery factors either assumed or derived from analogues, obtained from analytical reservoir studies or obtained from assumed well numbers and notional recoveries per well. After the start of field development, the developed reserves became based on production performance extrapolations but undeveloped reserves remained poorly defined as they were maintained as the difference between total URs (which were kept largely unchanged) and DURs.

   With the introduction of new Group guidelines in 1993, requiring all reserves to be based on identified projects (i.e. well targets, numbers, costs and forecasts) the undeveloped reserves thus calculated became non-conformant with Group reserves guidelines. BSP have long recognized the non-conformance of these <u>'legacy' reserves</u>. However, any temptation to 'wipe the slate clean' (i.e. set all undefined undeveloped reserves to zero) was resisted because it was considered likely that in many reservoirs it would be possible to replace them by properly defined reserves, i.e with well targets, forecasts and robust economics. It was felt that major reserves swings needed to be avoided and the decision was therefore taken to keep these reserves in the books until the proper studies had been made. Significant progress has been made in this respect and the amount of reserves now covered by simulation models and studies is some 70% on average. As a result, the portion of 'legacy' reserves in undeveloped reserves (currently some 9% of Expectation, much less of Proved) is now considerably reduced.

A further reason why 'legacy' reserves have reduced in size was the conservatism in the original field in-place estimates (caused possibly by too rigorous petrophysical cut-offs?). As a result, developed URs continued to grow and in many cases they overtook the original total proved (and sometimes even expectation) UR estimates. Hesitation was observed in simply zeroising these negative reserves because reservoir crossflow was a common phenomenon and it was possible that the underestimate in one reservoir could be due to an overestimate in a neighbouring reservoir. A regional study was therefore required before proper updates could be made. Lack of resources and priority caused a continuous deferment of such studies in a number of areas. Negative reserves continued in many reservoirs (particularly in the Champion Main field), until concerted efforts in 2000/2001 brought back the total of such reserves to more reasonable, but still low proportions.

The continued existence of 'legacy' undeveloped reserves is still a cause for concern. BSP have therefore started and resourced a study that will address this issue and that of the too conservative Proved developed and undeveloped reserves that are not in accordance with Group guidelines. This study is fully supported. BSP are also strongly supported in their present drive for complete coverage of all developed and to-be-developed reservoirs by proper studies. One of the root causes for the present problems has been the practice of assessing total (developed + undeveloped) reservesas on estimate. Instead, developed and undeveloped reserves should both be defined separately and properly, preferably by a joint simulator model.

5. In the original approach followed by BSP, Proved undeveloped reserves were simply the difference between proved total and proved developed reserves. In the new approach, whereby undeveloped reserves are determined independently, the method of determining Proved volumes is less well defined. The impression is that in many cases, a conservative approach is still followed. Group guidelines clearly state that in such cases a number of simulator scenarios should be run, with a reasonable P85 scenario picked as the Proved case at first, which can gradually become updated by a scenario that grows closer to or equal to expectation values with increasing field maturity.

6. Undeveloped reserves in a number of fields and reservoirs do not yet fulfil the condition (to be introduced in Group guidelines at end 2002) that such identified reserves must be economically robust in order to be certain of their future development. Many of these reserves and associated forecasts are still notional and BSP are confident that, with proper study and with present technology (eg cheaper horizontal wellbores) they can be made economic. This is accepted.

7. BSP have historically been one of the strongest proponents of probabilistic reserves estimation and initial volumetric estimates are still done probabilistically. Any incomplete hydrocarbon column penetrations are thus also addressed probabilistically, i.e. 'proved areas' (ref. SEC definitions) are not adhered to rigidly. Although accepted Group practice in the past, this is no longer in line with Group guidelines. This should be addressed.

8. Asset depreciation is done at a field level. Hence, guidelines would in principle allow probabilistic addition of reservoirs within a field. This is not done at present but is being considered by BSP as a possible method of bringing field Proved reserves closer to Expectation volumes.

The auditor opinion is that probabilistic addition of reservoir reservoirs to field level is not to be recommended. The reasons for this recommendation are as follows:

- Probabilistic volumetric estimates become irrelevant for mature fields. Probabilistic parameter ranges (bulk volume, porosity etc) can often not realistically be changed to capture the effects of field performance data and any change in volumetrics could therefore become arbitrary and not auditable.
- Reservoir dependency will become a critical issue in proper probabilistic addition of reservoir volumes. This will also be susceptible to subjective judgment and will also present audit trail problems.
- The need for probabilistic addition should diminish significantly if the calculation methods of Proved developed and undeveloped reserves are brought closer in line with Group guidelines, thereby bringing Proved reserves much closer to Expectation volumes.

9. Somewhat exceptionally, BSP REs keep track of condensate production from oil wells in oil+associated gas reservoirs, even though these liquids are produced through the oil stream. This condensate production is added to the condensate balance in these reservoirs and reflected in individual field condensate volumes. Reported NGL reserves are however based on produced streams, i.e. reported NGLs are only those condensates produced and sold separately. Reported oil reserves similarly include condensate produced in the oil stream. The main justification for this extra accounting of condensate volumes (outside production and reserves reporting) is said to obtain a correct reflection of the condensate material balance in reservoirs with very large gas caps. However, it does not add to the clarity of the audit trail – no documents were sighted showing a clear connection between condensates and reported oil/NGL volumes. With the oil production of large gas cap reservoirs now coming to an end, thought should be given to either abandoning this complexity or at least provide a better audit trail on this aspect.

10. It is noted that there is no complete correspondence between reserves volumes and production forecasts in the Business Plan. This is largely due to the 'legacy' reserves, for which no forecasts are available. However, there are also other discrepancies (eg in Land ('Darat') Business Unit where the BP contains forecasts for which there are no reserves (only SFR) in the books. The impression is that some of this SFR is sufficiently mature to warrant inclusion as reserves. This should be rectified.

11. Fairley Baram undeveloped oil reserves appear to be positive at Proved level, but the Expectation undeveloped volume is zero. This is inconsistent and should be rectified.

12. Current BSP production licences expire as follows:
Onshore and 'first offshore' (eg SWA): 22 Dec 2003,
Second offshore area (eg FA): 31 Dec 2007,
Third offshore area: 31 Dec 2026.
There is a right to extend these licences by two successive periods of 15 years, at terms and conditions to be agreed upon. Any failure to agree such new terms would still lead to extension by one period of 15 years largely on existing terms. Discussions on the new terms and conditions for the onshore and first offshore licences are currently underway. The approach by both parties is said to be positive and there are no indications that an acceptable set of new terms and conditions cannot be agreed with the Government. Hence, BSP management are fully confident that a new licence extension (and an option for a further extension in the future) will be granted.

13. Various documents describing the reserves determination process are in place (eg a DUR review procedure guide). The annual reserves review process is kicked off by a note by the reserves coordinator, setting out the requirements, target dates and responsibilities. All reserves changes are documented in reports or notes, depending on their complexity. Full field (or part-field) reviews and FDPs are documented comprehensively. An annual report 'End-year Resource Volumes for External and Internal reporting' is issued, together with a summary of results. This provides for an excellent audit trail and is fully commended.

    In addition to these documents and in preparation for the audit, BSP had made a special effort to provide documents summarising the status of reserves in the three Asset Units (Land, East and West). Apart from a brief summary per field, these documents also contained overviews of proved, expectation reserves and SFR, historical reserves changes over the last few years etc. This was highly useful and is commended.

14. Consistency with field reserves and reserves changes was good. The one exception appeared to be the oil vs condensate issue (see 9 above).

15. Very good consistency with Finance reporting has been observed in the matters of annual production volumes and Unit of Production factors (UPF) for asset depreciation. This is seen to be the result of close cooperation between Finance Accounts and Reserves Coordination and is fully commended.

Recommendations

1. Replace the present method of deriving proved developed reserves from Expectation developed reserves (triangular distribution starting at Cum.prod + 0.5 * [Exp'n dev'd – Cum.prod]) by multiplying Expectation reserves by a factor which gradually approaches or equals 1 with increasing reservoir maturity (defined as Cum.prod / Exp'n UR). The initial value of this factor may reflect the uncertainties in the individual reservoirs.
2. Assess undeveloped reserves separately (and not as stopgap between developed and total reserves). Estimate Porved undeveloped reserves by selecting a realistic P85 scenario of future activities, which scenario should be updated as more field performance is obtained and which should therefore grow closer to the Expectation scenario.
3. Complete the recently started study into 'legacy' reserves and the appropriate level of Proved vs Expectation reserves in line with the present plan per end 2002.
4. Address the issue of 'proved areas', in particular in relation to the non-allowed booking of volumes below 'lowest known hydrocarbons' (LKH, see guidelines), unless supported by strong evidence (eg seismic amplitudes).
5. Review the need for maintaining the oil vs condensate split in reservoirs or improve the audit trail on this aspect
6. Critically evaluate the justification for probabilistic addition of reservoir reserves to field level.
7. Review the appropriateness of booking some BP forecast volumes in Land/Darat BU as reserves and not as SFR as at present.
8. Rectify Fairley Baram Proved (>0) vs Expectation (=0) undeveloped reserves.

Attachment 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Proved Oil / NGL / Gas Reserves as at 1.1.2002

Area / field	Proven HIIP 10^6 m3 / 10^9 sm3	Exp'n HIIP 10^6 m3 / 10^9 sm3	Cum. Prod = Sales 31.12.01 10^6 m3 / 10^9 sm3	Proved Rem. Recov. Dev'd 10^6 m3 / 10^9 sm3	Proved Rem. Recov. Undev 10^6 m3 / 10^9 sm3	Exp'n Rem. Recov. Tot'l 10^6 m3 / 10^9 sm3	Maturity (Cum.pr / Exp'n UR) %	Dev. / Tot'l Proved UR. %	Proved RF Tot'l %	Exp'n RF Tot'l %	Excl ownuse & loss Pr.Dev. %	Excl ownuse & loss Pr.Undv %	Within Licence comtd Pr.Dev. 10^6 m3 / 10^9 sm3	Within Licence comtd Pr.Tot'l 10^6 m3 / 10^9 sm3	Shell share % %	Net Shell Equity Dev. 10^6 sm3/ 10^9 sm3	Net Shell Equity Tot'l 10^6 sm3/ 10^9 sm3	1.1.2002 Subm'n Dev 10^6 sm3/ 10^9 sm3	1.1.2002 Subm'n Tot'l 10^6 sm3/ 10^9 sm3	Prov. Res / Prod Dev. yrs	Prov. Res / Prod Tot'l yrs
Oil																					
SW Ampa	289.18	365.45	120.06	12.57	9.19	29.92	80%	94%	45%	41%	100.0%	100.0%	12.57	21.75	50.00%	6.28	10.88			5	9
Other main fields - West	94.54	126.07	28.33	5.35	5.79	16.07	64%	85%	36%	35%	100.0%	100.0%	5.35	11.13	50.00%	2.67	5.57			6	12
Champion	427.42	553.76	87.47	24.05	6.46	52.67	62%	95%	22%	25%	100.0%	100.0%	24.05	30.51	50.00%	12.02	15.25			7	9
Other main fields - East	164.13	240.68	26.96	7.50	25.82	55.86	33%	57%	32%	34%	100.0%	100.0%	7.50	33.31	50.00%	3.75	16.66			3	14
Seria	410.32	495.70	167.66	5.80	7.30	18.48	90%	96%	43%	38%	100.0%	100.0%	5.80	13.11	50.00%	2.90	6.55			7	17
Other main fields - Land	24.89	31.15	5.95	1.61	1.08	3.85	61%	67%	28%	31%	100.0%	100.0%	1.61	2.69	50.00%	0.81	1.35			20	8
Other small fields	14.96	35.78	0.10	0.00	1.71	4.30	2%	6%	12%	12%	100.0%	100.0%	0.00	1.71	50.00%	0.00	0.85				61
Condensate produced in oil stream				2.37	4.71		0	33%	0	0	100.0%	100.0%	2.37	7.08	50.00%	1.19	3.54				
Total Oil (MMstb)	1425.44	1848.59	436.53	59.24	62.06 121.30	181.14	71%	89%	35%	33%	100.0%	100.0%	59.24	121.30	50.00%	29.62	60.65	29.62	60.65	6	12
NGL																					
SW Ampa	62.51	79.06	15.75	6.46	4.59	14.79	52%	83%	33%	39%	100.0%	100.0%	6.46	11.05	50.00%	3.23	5.52			12	21
Other main fields - West	12.09	16.02	4.07	0.44	1.96	3.43	54%	70%	50%	47%	100.0%	100.0%	0.44	2.40	50.00%	0.22	1.20			6	34
Champion	3.54	5.38	0.40	0.32	0.45	1.37	22%	62%	24%	33%	100.0%	100.0%	0.32	0.77	50.00%	0.16	0.39			162	386
Champion-West	12.14	19.65	0.35	0.10	4.27	6.76	5%	10%	38%	36%	100.0%	100.0%	0.10	4.37	50.00%	0.05	2.19				
Other main fields - East	5.77	8.05	0.48	0.67	1.91	3.38	12%	37%	41%	48%	100.0%	100.0%	0.67	2.58	50.00%	0.34	1.29				
Seria	1.07	1.34	0.53	0.00	0.14	0.20	72%	79%	63%	55%	100.0%	100.0%	0.00	0.14	50.00%	0.00	0.07				
Other main fields - Land	0.28	0.40	0.13	0.01	0.02	0.06	69%	69%	54%	48%	100.0%	100.0%	0.01	0.03	50.00%	0.00	0.01				2
LLG	0.00	0.00	0.90	6.46	0.00	6.46	12%	100%	0	0	100.0%	100.0%	6.46	6.46	50.00%	3.23	3.23				14
Other small fields	11.43	17.60		0.00	2.46	3.95	0%	0%	21%	22%	100.0%	100.0%	0.00	2.46	50.00%	0.00	1.23				
Condensate produced in oil stream				-2.37	-4.71		0	33%	0	0	100.0%	100.0%	-2.37	-7.08	50.00%	-1.19	-3.54				
Total NGL (MMstb)	108.85	147.51	22.61	12.09	11.09 23.17	40.40	36%	76%	31%	43%	100.0%	100.0%	12.09	23.17	50.00%	6.04	11.59	6.04	11.59	13	26
Gas (Dry, sales gas volumes)																					
SW Ampa	347.664	402.402	200.792	60.252	32.747	128.327	61%	89%	67%	82%	92.3%	92.3%	55.64	85.88	50.00%	27.82	42.94			10	15
Other main fields - West	114.768	146.785	61.094	5.295	27.478	46.799	57%	71%	77%	74%	92.3%	92.3%	4.89	30.26	50.00%	2.44	15.13			4	24
Champion	34.257	49.269	12.308	4.085	3.014	12.791	49%	84%	45%	51%	92.3%	92.3%	3.77	6.56	50.00%	1.89	3.28			8	14
Champion-West	47.461	71.018	3.675	2.625	29.569	47.351	7%	18%	70%	72%	92.3%	92.3%	2.42	29.73	50.00%	1.21	14.86			5	57
Other main fields - East	62.622	88.222	6.676	9.217	27.392	52.707	11%	37%	54%	67%	92.3%	92.3%	8.51	33.61	50.00%	4.26	16.90			7	27
Seria	39.898	47.179	39.968	2.079	2.019	5.267	88%	95%	105%	96%	92.3%	92.3%	1.92	3.78	50.00%	0.96	1.89			11	22
Other main fields - Land	6.426	7.781	2.786	0.677	1.422	2.811	50%	71%	65%	72%	92.3%	92.3%	0.63	1.94	50.00%	0.31	0.97				12
LLG			-0.667	-4.792		-4.792	12%	100%	0	0	92.3%	92.3%	-4.42	-4.42	50.00%	-2.21	-2.21				
Other minor fields	30.685	48.916	0.017	0.000	14.507	23.001	0%	0%	47%	47%	92.3%	92.3%	0.00	13.40	50.00%	0.00	6.70				
Total Gas (10^9 sm3)	683.781	861.572	326.649	79.438	138.148 217.586	314.262	51%	75%	68%	74%	92.3%	92.3%	73.354	200.921	50.00%	36.677	100.461	36.667	100.461	8	21

Conversion factors used by BSP
1 stb = 1 m3
1scf = 1 sm3

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

Licence expiry dates:

Audit Trail: **100% volumes from 'Report no. 1.1' (Att.3) from CSS NFF 2002/001 (except condensate-as-oil volumes, for which no evidence was sighted)**
Overall, good match

BSP-All2, ResvsTotl

31-5-2002, 12:10

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Treatment Requested

RJW00061609

Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Proved Oil Reserves Changes 2001 (100%, 10^6 m3)

Field	Prov.Res. 1.1.2001	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Develd Reserves	Product'n 2001	Prov.Res 1.1.2002	Shell Equity Share % 1.1.2001	Shell Equity Share % 2001 Prod	Shell Equity Share % 1.1.2002	Net Shell Equity 1.1.2001 (10^6 m3)	Net Shell Equity 1.1.2002 (10^6 m3)	Comments
Proved Developed Reserves															
SW Ampa		-0.71					3.80	2.54	12.57	50.00%	50.00%	50.00%	0.00	6.28	
Other main fields - West		2.21						0.90	5.35	50.00%	50.00%	50.00%	0.00	2.67	
Champion		0.52					2.52	3.25	24.05	50.00%	50.00%	50.00%	0.00	12.02	
Other main fields - East		1.01						2.43	7.50	50.00%	50.00%	50.00%	0.00	3.75	
Seria		2.74					0.50	0.79	5.80	50.00%	50.00%	50.00%	0.00	2.90	
Other main fields - Land		-0.03					0.30	0.32	1.61	50.00%	50.00%	50.00%	0.00	0.81	
Other small fields									0.00	50.00%	50.00%	50.00%	0.00	0.00	
Condensate produced in oil stream								0.12	2.37	50.00%	50.00%	50.00%	0.00	1.19	
Prov.Dev.Resvs (10^6 m3)	0.00	62.47 5.74					7.11	10.34	59.24	0	50.00%	50.00%	0.00	29.62	
Proved Undeveloped Reserves															
SW Ampa		1.57	1.76						9.19	50.00%		50.00%	0.00	4.59	
Other main fields - West		-1.13	0.52						5.79	50.00%		50.00%	0.00	2.89	
Champion		2.16	0.18						6.46	50.00%		50.00%	0.00	3.23	
Other main fields - East		0.90		4.18					25.82	50.00%		50.00%	0.00	12.91	Bugan appr + discov.
Seria		0.37		1.29					7.30	50.00%		50.00%	0.00	3.65	SMR appraisal
Other main fields - Land		-0.22							1.08	50.00%		50.00%	0.00	0.54	
Other small fields									1.71	50.00%		50.00%	0.00	0.85	
Condensate produced in oil stream									4.71	50.00%		50.00%	0.00	2.36	
Prov.Undev.Res (10^6 m3)	0.00	54.12 3.65	2.47	5.48	0.00	0.00			62.08	0		50.00%	0.00	31.03	

Net Group Equity	Prov.Res. 1.1.2001	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Develd Reserves	Product'n 2001	Prov.Res 1.1.2002	
Proved Developed Reserves	0.00	2.87					3.55	5.17	29.62	1.25
Proved Total Reserves	0.00	4.69	1.23	2.74	0.00	0.00		5.17	60.65	3.49
10^6 m3										

2000 Submission										
Prov.Dev.Res	28.40	2.82					3.57	5.17	29.62	29.62
Prov.Tot'l Res	57.22	4.63	1.23	2.74				5.17	60.65	60.65
10^6 m3										

Conversion factors used by BSP
1 m3 = 1 m3
1 sm3 = 1 sm3

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

Audit Trail: **Overall, fair match.**
1.1.2001 field volumes not available

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Treatment Requested

RJW00061610

Attachment 2.3

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Proved NGL Reserves Changes 2001 (100%, 10^6 m3)

Field	Prov.Res. 1.1.2001	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves (Transf. Und. to Dev)	Product'n 2001	Prov.Res 1.1.2002	Shell Equity Share % 1.1.2001	Shell Equity Share % 2001 Prod	Shell Equity Share % 1.1.2002	Net Shell Equity 1.1.2001 (10^6 m3)	Net Shell Equity 1.1.2002 (10^6 m3)	Comments
Proved Developed Reserves															
SW Ampa		-0.04					0.08	0.52	6.46	50.00%	50.00%	50.00%	0.00	3.23	
Other main fields - West		-0.13						0.07	0.44	50.00%	50.00%	50.00%	0.00	0.22	
Champion								0.00	0.32	50.00%	50.00%	50.00%	0.00	0.16	
Champion-West		-0.02						-0.03	0.10	50.00%	50.00%	50.00%	0.00	0.05	
Other main fields - East		0.08						0.00	0.67	50.00%	50.00%	50.00%	0.00	0.34	
Seria		0.00						0.00	0.00	50.00%	50.00%	50.00%	0.00	0.00	
Other main fields - Land								0.01	0.01	50.00%	50.00%	50.00%	0.00	0.00	
LLG								0.45	6.46	50.00%	50.00%	50.00%	0.00	3.23	
Other small fields									0.00	50.00%	50.00%	50.00%	0.00	0.00	
Condensate produced in oil stream								-0.12	-2.37	50.00%	50.00%	50.00%	0.00	-1.19	
Prov.Dev.Resvs (10^6 m3)	0.00	12.91 -0.11					0.08	0.91	12.09	0	50.00%	50.00%	0.00	6.04	
Proved Undeveloped Reserves															
SW Ampa		-0.21	0.05						4.59	50.00%		50.00%	0.00	2.30	
Other main fields - West		0.08							1.96	50.00%		50.00%	0.00	0.98	
Champion		-0.07							0.45	50.00%		50.00%	0.00	0.22	
Champion-West		-0.20							4.27	50.00%		50.00%	0.00	2.13	
Other main fields - East		0.06							1.91	50.00%		50.00%	0.00	0.96	
Seria		0.00							0.14	50.00%		50.00%	0.00	0.07	
Other main fields - Land		0.07							0.02	50.00%		50.00%	0.00	0.01	
LLG									0.00	50.00%		50.00%	0.00	0.00	
Other small fields									2.46	50.00%		50.00%	0.00	1.23	
Condensate produced in oil stream									-4.71	50.00%		50.00%	0.00	-2.36	
Prov.Undev.Res (10^6 m3)	0.00	11.04 -0.26	0.05	0.00	0.00	0.00			11.09	0		50.00%	0.00	5.54	

Net Group Equity	Prov.Res. 1.1.2001	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Product'n 2001	Prov.Res 1.1.2002	
Proved Developed Reserves	0.00	-0.05					0.04	0.45	6.04	-0.46
Proved Total Reserves 10^6 m3	0.00	-0.18	0.02	0.00	0.00	0.00		0.45	11.59	-0.61
2001 Submission										
Prov.Dev.Res	6.48	-0.05					0.03	0.42	6.04	6.04
Prov.Tot'l Res 10^6 m3	12.14	-0.15	0.02					0.42	11.59	11.59

Conversion factors used by BSP
1 m3 = 1 m3
1 sm3 = 1 sm3

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

Audit Trail: Fair match
1.1.2001 field volumes not available.

BSP-Att2, NGLResvChg

31-5-2002, 11:36

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RJW00061611

Attachment 2.4

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Gas Reserves Changes 2001 (100%, 10^9 sm3) - Dry sales gas volumes

Field	Prov.Res. 1.1.2001	Revisions/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves (Transf.	Product'n 2001	Prov.Res 1.1.2002	Shell Equity Share % 1.1.2001	Shell Equity Share % 2001 Prod	Shell Equity Share % 1.1.2002	Net Shell Equity 1.1.2001 (10^9 sm3)	Net Shell Equity 1.1.2002 (10^9 sm3)	GHV (Btu/scf)	Net Shell Equity 1.1.2001 (10^9 Nm3	Net Shell Equity 1.1.2002 (10^9 Nm3	Comments
Proved Developed Reserves																		
SW Ampa		-2.473					3.172	6.340	60.252	46 65%	46.%	46 17%	0.000	27.818	1150	0.000	29.986	
Other main fields - West		0.395						1.352	5.295	46.65%	46.%	46.17%	0.000	2.445	1147	0.000	2.628	
Champion		0 654					0 376	0 504	4.085	46 65%	46.%	46 17%	0 000	1 886	1050	0.000	1.656	
Champion-West		1.569						0.561	2.625	46.65%	46.%	46.17%	0.000	1.212	1150	0.000	1.306	
Other main fields - East		2.583						1.344	9.217	46.65%	46.%	46.17%	0.000	4.256	1105	0.000	4.408	
Seria		0.857					0 179	0.163	2.079	46.65%	46.%	46.17%	0.000	0.960	1180	0.000	1.082	
Other main fields - Land		-0.093					0.133	0.178	0.677	46.65%	46.%	46.17%	0.000	0.313	1139	0.000	0.334	
LLG								-0.337	-4.792	46.65%	46.%	46.17%	0.000	-2.212	1139	0.000	-2.362	
Other minor fields									0.000	46.65%	46.%	46.17%	0.000	0.000	1139	0.000	0.000	
Prov.Dev.Resvs (10^9 sm3)	0.000	85.703 3.592					3 880	10.125	79 438	.%	46 %	46 17%	0 000	36 677	1141	0.000	39.218	
Proved Undeveloped Reserves																		
SW Ampa		1.545	0.665						32.747	46.65%		46.17%	0.000	15.119	1150	0.000	16.297	
Other main fields - West		-1.143							27.478	46.65%		46.17%	0.000	12.687	1113	0.000	13.235	
Champion		0 488	0.375						3 014	46 65%		46.17%	0 000	1 392	1050	0 000	1.370	
Champion-West		2.279							29.569	46.65%		46.17%	0.000	13.652	1150	0.000	14.716	
Other main fields - East		-2.096		6.915					27.392	46.65%		46.17%	0.000	12.647	1150	0.000	13.632	Bugan appr + discov
Seria		0.234							2.019	46.65%		46.17%	0.000	0.932	1180	0.000	1.031	
Other main fields - Land		0.837							1.422	46.65%		46.17%	0.000	0.657	1139	0.000	0.701	
LLG									0.000	46.65%		46.17%	0.000	0.000	1139	0.000	0.000	
Other minor fields									14.507	46.65%		46.17%	0.000	6.698	1139	0.000	7.151	
Tot'l Prov.Res (10^9 sm3)	0.000	130.193 2.144	1.040	6.915	0.000	0.000			138.148	.%		46.17%	0.000	63.784	1140	0.000	68.133	

	Prov.Res. 1.1.2001	Revisions/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves (Transf.	Product'n 2001	Prov.Res 1.1.2002	
Net Group Equity										
Prov.Dev. Res	0.000	1.658					1.782	4.658	36.677	-1.217
Prov Tot'l Res 10^9 sm3	0.000	2.648	0.480	3.193	0.000	0.000		4.658	100.461	1.664
2001 Submission										
Prov.Dev.Res	37.929	1.685					1.785	4.722	36.667	36.677
Prov.Tot'l Res 10^9 sm3	99.899	1.547	0.480	3.257				4.722	100.461	100.461
Net Group Equity										
Prov.Dev. Res	0.000	1.721					1.906	4.974	39.218	-1.346
Prov Tot'l Res 10^9 Nm3 @ 9500 kCal/Nm3	0.000	2.785	0.501	3.441	0.000	0.000		4.974	107.351	1.754
2001 Submission										
Prov.Dev.Res	39.374	2.240					1.923	5.110	38.427	38.427
Prov.Tot'l Res 10^9 Nm3 @ 9500 kCal/Nm3	106.230	2.730	0.517	3.509				5.110	107.876	107.876

Conversion factors used by BSP
1 m3 = 1 m3
1 sm3 = 1 sm3
1 sm3 = 0.948 Nm3
and 1 sm3 = 1.0738097 Nm3@9500
(i.e. avge GHV = 10761 kcal/Nm3
or 10201 kcal/sm3
or 45.05 MJ/Nm3
or 42.71 MJ/sm3
or 1146 Btu/scf
cf avg GHV of 1140 Btu/scf from above field data.

Conversion factors used by SIEP:
1 stb = 0.159 m3
1 scf = 0.0283 sm3
1 sm3 = 0.948 Nm3
and 1 sm3 = 0.948 Nm3 @ 9500
(if GHV = 9500 kcal/Nm3
or 9006 kcal/sm3
or 39.77 MJ/Nm3
or 37.71 MJ/sm3
or 1011 Btu/scf

Audit Trail:

Slight mis-match in production and end-year Nm3 volumes.
Mis-match in revisions probably due to different method of calculation.

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RJW00061612

COMPANY: BRUNEI SHELL PETROLEUM Sdn Bhd **AREA / FIELD: ALL FIELDS**

Dimensions (100% field figures as at 1.1.2002): **Average Group share: ..%**

1.1.2002 Proved Oil Reserves		10^6 m3	(Group share 10^6 m3)
1.1.2002 Proved Developed Oil Reserves		10^6 m3	(Group share 10^6 m3)
2000 Oil Production		10^6 m3	(Group share 10^6 m3)
	0	10^3 m3/d	(Group share 10^3 m3/d)
1.1.2002 Proved Gas Reserves		10^9 sm3	(Group share 10^9 sm3)
1.1.2002 Proved Developed Gas Reserves		10^9 sm3	(Group share 10^9 sm3)
2000 Gas Production		10^9 sm3	(Group share 10^9 sm3)
	0	10^6 sm3/d	(Group share 10^6 sm3/d)
Number of fields in area			
Number of wells drilled / in production			

	Audit criteria	Result	Comments
1	**TECHNICAL MATURITY**		
1.01	Is 3D seismic available and used for the field(s) in question?	+	3D Seismic coverage is almost universal over the main producing area in the shallow offshore. For new seismic surveys the OBC (seabottom cables) technique is used, particularly to avoid acquisition problems around the densely spaced platforms. An important area where such new 3D acquisition is now planned is the Champion Main field, where the poor quality seismic mapping todate (caused by seabottom reefs) has hindered advancement of reservoir simulation and performance definition.
1.02	Are seismic processing and interpretation state-of-the-art?	+	PSDM is applied (where the data are available) to obtain better definition of fault planes. A major advance in interpretation quality has been obtained by the introduction of the Petrel geological modelling package which allows a rapid and complete integration of the seismic data with the dense well data and with structural interpretations.
1.03	Is well data coverage adequate?	+	Most of the fields are mature and well data is more than adequate. Adequate appraisal well data is available in undeveloped fields.
1.04	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	O	BSP have historically been one of the strongest proponents of probabilistic reserves estimation and volumetric estimates are still done probabilistically. Any incomplete hydrocarbon column penetrations are therefore addressed probabilistically.
1.05	Is this 'proved area' supported by seismic amplitude studies and/or reservoir analogues in the area?	N.A.	Good DHI amplitude data are available in some cases, eg the deeper offshore.
1.06	Are petrophysical well data quality and quantity adequate?	+	Log selection in new wells is state-of-the-art and fully adequate. Log interpretation seems historically to have been somewhat conservative (too severe cut-offs?), resulting in STOIIPs that are too low in comparison with present performance. A major breakthrough has been the availability of through-tubing C-O tools (RST Schlumberger, RPM Becker-Atlas) by which moving fluid levels in reservoirs can be traced much more accurately and on a much wider scale than before.
1.07	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Appraisal wells in undeveloped fields are rarely production tested. Fully adequate data are obtained from sampling tools (MDT). Very good data are also obtained through modern NMR logs. Finally, there is ample analogue data in the area.
1.08	Are there proper volumetric estimates?	+	Static reservoir models (CPS-3, now being replaced by Petrel) are generally used as the method of making volumetric estimates upon first discovery. Petrel geological models are prepared following well drilling (if not already before) and volumetric estimates are obtained from these. Refined features like porosity maps, saturation-height curves etc can thus be included in an early stage. Historical HIIP estimates tend in some cases to be too conservative, probably caused by too conservative petrophysical interpretations (cut-offs).
1.09	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	PVT samples are obtained and interpreted through the proper tools
1.10	Are static models available / adequate?	+	Historically, GEOCAP models were often used to replace the initial CPS-3 models prior to major field studies. More recently, Petrel models have become the standard. Coverage is not complete yet - areas with higher development priority are being addressed first.

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

1.11	Are dynamic models available / adequate?	O	Dynamic model coverage is not complete (some 70%) over reservoirs with proved and expectation reserves. Coverage is complete for areas under study, i.e. those areas where further development is seen as likely and as having priority. Models are almost invariably downloaded from geological models.
1.12	Are history matches available / adequate?	+	History matches are complicated by both water and gas breakthrough in these fields (many primary gas caps) and by pressure communication with neighbouring reservoirs through partially sealing faults. Improved geological modelling has improved the quality of these matches.
1.13	Are the recovery factors for proved reserves realistic?	+	Recovery factors are generally based on simulation studies or on production performance data. Gas recoveries take account of installed and future compression.
1.14	Are developed reserves based on proper NFA (No Further Activity) forecasts?	+	Yes
1.15	Are developed reserves based on existing wells, completions and facilities, or do they require only minor costs (<10% project cost) to be hooked up?	+	Yes; Most behind-pipe volumes are not counted as developed until they are properly completed.
1.16	Have development projects been defined for undeveloped reserves or can they be defined?	O	The large majority of undeveloped reserves are covered by well targets (some notional or even undetermined and in need of further study) and forecasts. A small amount (around 9% of expectation undeveloped, much less of proved), sometimes referred to as 'legacy reserves') is not covered by targets and/or forecasts yet.
1.17	Are there auditable development project plans with costs, benefits and economics?	+	Projects with forecasts are included in the BSP Business Plan and have project costs (some preliminary) and economics associated with them.
1.18	Are the projects technically mature or is further data gathering necessary?	O	Projects are ranked and their development sequence is set accordingly. Those with later target dates tend to require further study work before they can be matured. Their associated recoveries tend to be based on earlier, preliminary study work or on analogues.
1.19	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	+	A successful gas injection project (within-well, from deeper gas horizons) is in operation in SW Ampa. Water injection is in operation on some areas in Champion and expansion of this into neighbouring areas is being considered. For any undeveloped reserves, no pilots are deemed necessary.
1.20	Have the projects successfully passed a VAR3 review or are they otherwise ready for application for funding?	O	New field developments are subjected to VAR reviews, but in-field projects are generally too small for these. The projects with lower priority tend to require more study work before they can be matured.
1.21	Are the projects firmly planned to go ahead - are there any potential show stoppers?	O	In principle there are no show stoppers. Projects will go ahead in due course as and when they can be made technically and economically robust.
2	**COMMERCIAL MATURITY**		
2.01	Are the projects economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	O	Most projects pass economic screening criteria. Those that at this stage do not, are felt to become economically viable with further work and updated cost estimating
2.02	Have forecasts been cut off when rates become uneconomic?	+	Yes; minimum economic rates are determined by field.
2.03	Have the latest Group Screening / Reference Criteria been used?	+	Yes
2.04	Are assumed prices and costs RT (or justified if not)?	+	Yes
2.05	Is export infrastructure (pipelines, terminals etc) available or, if not, is it firmly planned and fully included in the economics?	+	Yes, any new infrastructure required (flow lines, well jackets etc) are included in the cost estimates and economics
2.06	Is project financing available or can it reasonably be expected to be available?	+	Yes
2.07	Are developed reserves actually in production?	+	Yes; A regular review is held of 'shut-in potential' and it is rare for wells with developed reserves to remain shut in for a long time.
2.08	Have all proved gas reserves been contracted to sales?	O	The BLNG plant is the main customer for BSP gas. Additional, smaller gas sales streams are for local domestic use and for power generation. The BLNG contract was extended in 1992 on the basis of then available proved gas reserves. This base, being somewhat conservative, has since then grown and there is now a surplus of some 1.5 Tcf proved gas and some 5 Tcf of expectation volumes.

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2.09	If not, can they reasonably be expected to be sold in existing markets and through existing / firmly planned facilities?	+	There is no doubt that any surplus gas will be able to be contracted to the existing supply outlets. Additional local outlet possibilities are being pursued.
2.10	If neither, is there a firm commitment (eg FID) that supports the assumption and maturing of a future market?	N.A.	
3	**REASONABLE CERTAINTY**		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	O	Probabilistic volumetric estimates tend to become irrelevant for mature fields since they cannot capture reservoir performance data properly. Volumetric Proved HIIPs therefore tend to become too low.
3.02	Is the uncertainty range of developed recovery adequate?	X	Expectation developed recoveries are determined from performance decline extrapolations in those cases where there is no active history matched simulation model. The standard method of determining proved developed volumes is through fitting a symmetrical triangular distribution around the expectation estimates with the lower end point halfway between cumulative production and expectation value. This invariably results in a 'proved' developed reserves volume that is some 70-78% of expectation. This is highly artificial and not in accordance with current Group guidelines.
3.03	Is the uncertainty range of undeveloped recovery adequate?	X	Historically, total reservoir recoveries were determined from volumetrics with recovery factors derived from analogues or from preliminary simulation studies. A significant portion of total recoveries in BSP are still based on these estimates. Developed reserves were based on performance extrapolations and undeveloped reserves were the difference between total and developed reserves. With time, developed reserves grew and in many cases overtook the original total proved (sometimes even expectation) estimates. Hesitation was applied in updating these negative reserves because reservoir crossflow was a common phenomenon and any such updates required a regional study. Lack of resources and priority caused a continuous deferment of such studies in many cases. Negative reserves continued in many reservoirs (particularly in the Champion Main field), until concerted efforts in 2000/2001 brought back the total of such reserves to more reasonable, but still low proportions. The proper way of determining undeveloped reserves is through a simulation study whereby these reserves are calculated from identified activities, with well targets. Developed reserves can be determined from the same (history matched) simulation model or from well performance extrapolations. With progressing field development, both developed and undeveloped reserves are updated in the light of reservoir performance, new drilled wells, changed future well targets etc. Total reserves are always the sum of both developed and undeveloped reserves and are therefore no longer fixed 'target' recoveries that do not (or only poorly) become updated with progressing field life. This is now the norm in the large majority of Group OUs and in BSP this is also the approach in the field areas with simulation models. In the original approach followed by BSP, proved undeveloped reserves were simply the difference between proved total and proved developed reserves. In the new approach, whereby undeveloped reserves are determined independently, the method of determining proved volumes is less well defined. The impression is that in many cases, a conservative approach is still followed. Group guidelines clearly state that in such cases a number of simulator scenarios should be run, with a reasonable P85 scenario picked at first, which can gradually become updated by a scenario that grows closer to or equal to expectation values with increasing field maturity.
3.04	Have market / production constraint uncertainties been taken into account?	N.A.	There are production constraints but these are taken account of in field planning and present no uncertainties.
3.05	What is ratio of field(s) cum.prod. / expectation total recovery?		Quite variable, from 0 (undeveloped fields) to 92% (Seria field). BSP average is 70% for oil and 50% for gas.
3.06	Can the field(s) be considered mature?		Approximately half is mature to very mature.
3.07	Are proved (developed and total) reserves consistent with 'proved areas'?	O	Proved areas are not adhered to rigidly, although partial penetrations etc are taken account of in the probabilistic estimates, see also 1.04.

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3.08	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Yes
3.09	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	+	Asset depreciation is done at a field level. Hence, guidelines would allow probabilistic addition of reservoirs within a field. This is not done at present. In view of the impractical aspects and intransparency of results (dependency!) this is supported.
3.10	Is any assumed dependency in probabilistic addition appropriate?	N.A.	
4	**GROUP SHARE CALCULATION**		
4.01	Are proved and proved developed reserves fully producible within the licence period (or its extension if there is a legal right) and within production ceilings/constraints?	+	Current production licences expire as follows: Onshore and 'first offshore' (eg SWA): 22 Dec 2003, Second offshore area (eg FA): 31 Dec 2007, Third offshore area (rest): 31 Dec 2026. There is a right to extend these licences by two successive periods of 15 years, at terms and conditions to be agreed upon. Discussions on the terms and conditions for the onshore and first offshore licences are currently in progress. There are no indications that an acceptable set of new terms and conditions cannot be agreed with the Government and BSP management are fully confident that a licence extension will be obtained.
4.02	Are the forecasts required to demonstrate the above condition consistent with the firm Base Case presented in the latest Business Plan?	+	Yes, all reserves for which forecasts are available are included in the Business Plan.
4.03	Is the hydrocarbon Equity share calculated properly (regular production contracts)?	+	BSP is a 50% owned Shell company, with the remainder being held by the Brunei government. All licences are 100% BSP owned, BSP has full title to the produced oil and gas and Group share is thus uniformly 50%
4.04	Is the hydrocarbon PSC entitlement share (net cost oil + profit oil only) calculated properly?	N.A.	
4.05	Is the hydrocarbon Purchase Right share (to the extent that economic benefit is derived from production while still bearing share of risks and rewards) calculated properly?	N.A.	
4.06	Are royalties that are (formally or customarily) paid in cash included in reserves?	+	Royalties (between 8 and 12.5%, dependent on area) are paid in cash and are thus not subtracted from reserves.
4.07	Are royalties paid in kind excluded from reserves?	N.A.	
4.08	Are volumes delivered free of charge as fees in kind (e.g. for infrastructure use by third parties) included in reserves? Similarly, are volumes received as fees in kind excluded from reserves?	N.A.	
4.09	Has historic Group under-or overlift (e.g. compared with other co-venturers) been accounted for?	N.A.	
4.10	Have gas volumes produced from the reservoir but not yet sold (e.g. through UGS, gas re-injection into another reservoir or a swap deal with another field) been properly maintained in reserves?	+	Gas production and re-injection volumes involved in the intra-well gas re-injection project in SW-Ampa are properly recorded , subtracted from the source reservoirs as production and added (as negative production) to the target reservoirs. Gas ultimate recoveries in the latter are from time to time re-evaluated, taking account of possible future losses due to residual gas saturations in gas flooded oil zones.
4.11	Have gas volumes paid for by the buyer but not yet produced and sold ('take-or-pay' gas) been properly maintained in reserves?	N.A.	
4.12	Have separate submissions been made for Equity , Entitlement and Purchase Right volumes?	N.A.	
5	**AUDIT TRAILS**		
5.01	Are proved and proved developed reserves estimates up-to date?	O	Developed reserves are reviewed annually in many, but not all reservoirs. Undeveloped reserves in the 70% (approx.) of reserves that are covered by 'active' simulation models are reviewed regularly as well. Undeveloped reserves in the remaining 30% are generally derived from older total recovery estimates and are thus less up-to-date.
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	O	Yes, with the exception of the condensate-produced as oil (see 6.02)
5.03	Can reserves changes be reconciled with individual field changes?	+	Largely, yes, with the exception of the condensate-produced as oil (see 6.02)
5.04	Are reserve changes reported in the appropriate categories?	+	Yes
5.05	Is there a document in place describing the OU's reserves reporting procedures?	+	Various documents are in place (eg a DUR review procedure guide). The annual reserves review process is kicked off by a note by the reserves coordinator, setting out the requirements, target dates and responsibilities.

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5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	+	All reserves changes are documented in reports or notes, depending on their complexity. Full field (or part-field) reviews and FDPs are documented comprehensively.
5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	+	Yes
5.08	Is the annual reserves submission supported by a sufficiently detailed summary note explaining the reserves changes (classified in revisions, extensions, sales-in-place etc) per field, with references to detailed reports as appropriate?	+	Yes, an annual report 'End-year Resource Volumes for External and Internal reporting' is issued, together with a summary of results.
5.09	Are electronic data bases containing both historic submissions' data and current reserves data in place and accessible?	+	Yes, a comprehensive RISRES data base is in place
5.10	Do these data bases also contain references to detailed reports?	+	Yes (a very rare feature among OUs)
6	**CONSISTENCY WITH FINANCIAL REPORTING**		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Oil, NGL and gas are reported by stream. The condensate stream (consisting of gas well liquids or 'CHPS' and slugcatcher liquids plus other liquids from the BLNG plant, called 'LLG') is sold and exported separately. Somewhat exceptionally, BSP REs keep track of condensate production from oil wells in oil+associated gas reservoirs, even though these liquids are produced through the oil stream. This condensate production is added to the condensate balance in these reservoirs and reflected in individual field condensate volumes. Reported NGL reserves are however based on produced streams, i.e. NGLs are only those condensates produced and sold separately. Reported oil reserves similarly include condensate produced in the oil stream. The main justification for this extra accounting (not in the EPPROMS system) is to obtain a correct reflection of the condensate in reservoirs with very large gas caps. The LLG stream has been included in the sales and reserves accounting since 2000. The reason for their inclusion was that BSP have effective title to these liquids (with the BLNG ga
6.03	Are own use, fuel, losses etc excluded?	+	Own use, fuel and losses are deducted as a bottom line correction from annual production and from reserves before the annual Group reserves submission. The percentage is calculated annually (around 8%).
6.04	Are gas GHVs measured properly for sales gas conditions and accounted for in reserves submissions?	+	Yes, gas samples are taken regularly and evaluated with the proper tools.
6.05	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system? (Ceres line 0933, which is the sum of line 7385 (Reward Oil/NGL) and line 0871 [= 8462-Oil + 8464-NGL for Consolidated Companies + line 3596 (= 0931-Oil + 0932-NGL) for Assoc. Companies).	+	Yes, close cooperation is observed between Finance accounts and the reserves coordinator.
6.06	Are annual gas production volumes in reserves submissions consistent with Upstream Gas production available for Sales (GpafS) volumes reported into the Finance (Ceres) system? (Ceres line 9130).	+	Yes, close cooperation is observed between Finance accounts and the reserves coordinator.
6.07	Are the Financial and Reserves accounting of production / sales fully consistent with each other also in cases like royalties, fees-in-kind, underlift/overlift, gas re-injection/UGS, take-or-pay gas?	+	Yes (only relevant for annual production)
6.08	Are the net Shell share reserves reported properly and consistently with Finance reporting (100% for consolidated Shell companies, with minority reserves reported separately, or actual percentage if less than 50%)?	N.A.	BSP is a 50%, i.e. an associate company and accounts and reserves are reported on a net Group share basis.
6.09	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	+	Yes, Proved developed reserves and Unit of Production Factors are advised annually by the reserves coordinator to Finance accounts.
7	**OVERALL**		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Proved reserves are likely to be somewhat understated due to the conservative procedures still in place
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	O	Whilst expectation estimates appear quite reasonable, the proved estimates are too conservative in comparison with Group guidelines

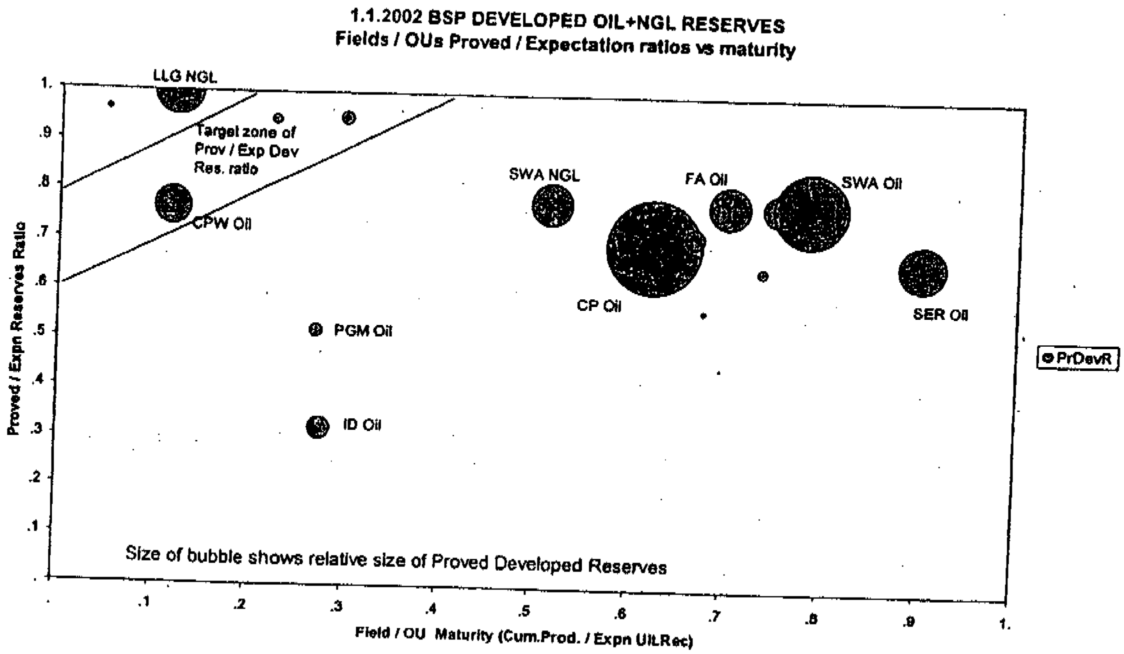
+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

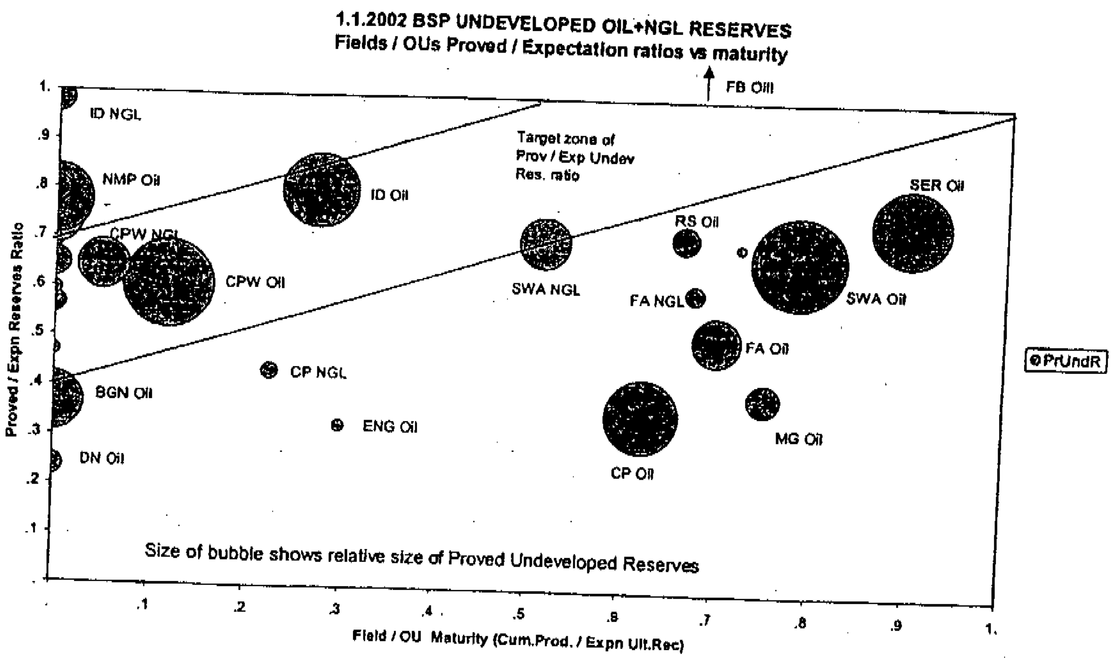
		Weight	Score (0-100%)
1	TECHNICAL MATURITY	25%	82%
2	COMMERCIAL MATURITY	16%	81%
3	REASONABLE CERTAINTY	14%	37%
4	GROUP SHARE CALCULATION	9%	100%
5	AUDIT TRAILS	16%	90%
6	CONSISTENCY WITH FINANCIAL REPORTING	11%	100%
7	OVERALL OPINION	8%	50%
	TOTAL SCORE	100%	78%

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

Attachment 4.1

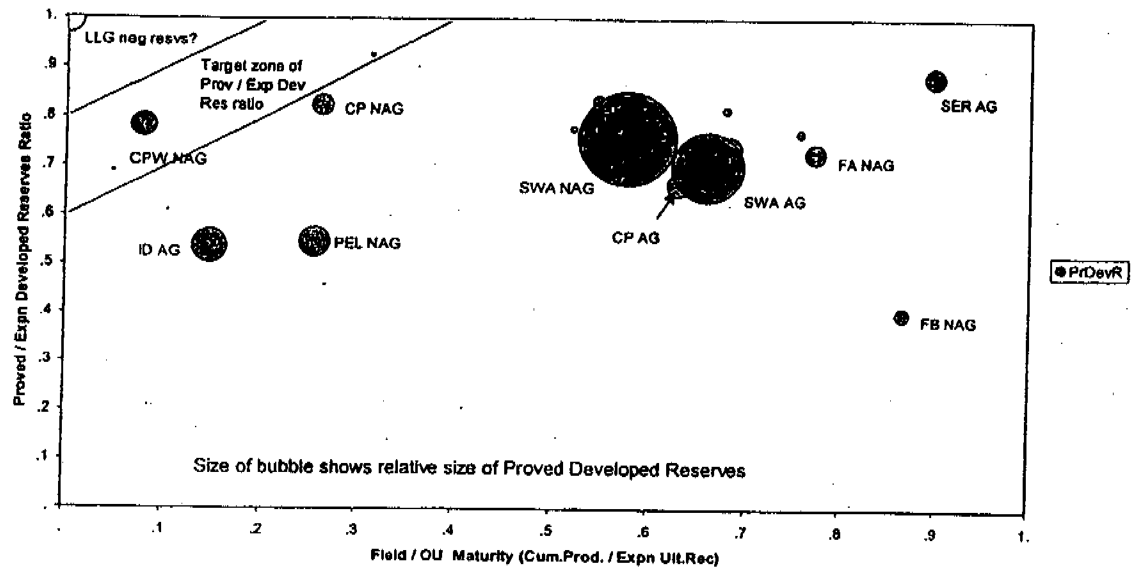
Proved / Expectation Oil+NGL Reserves versus field maturity

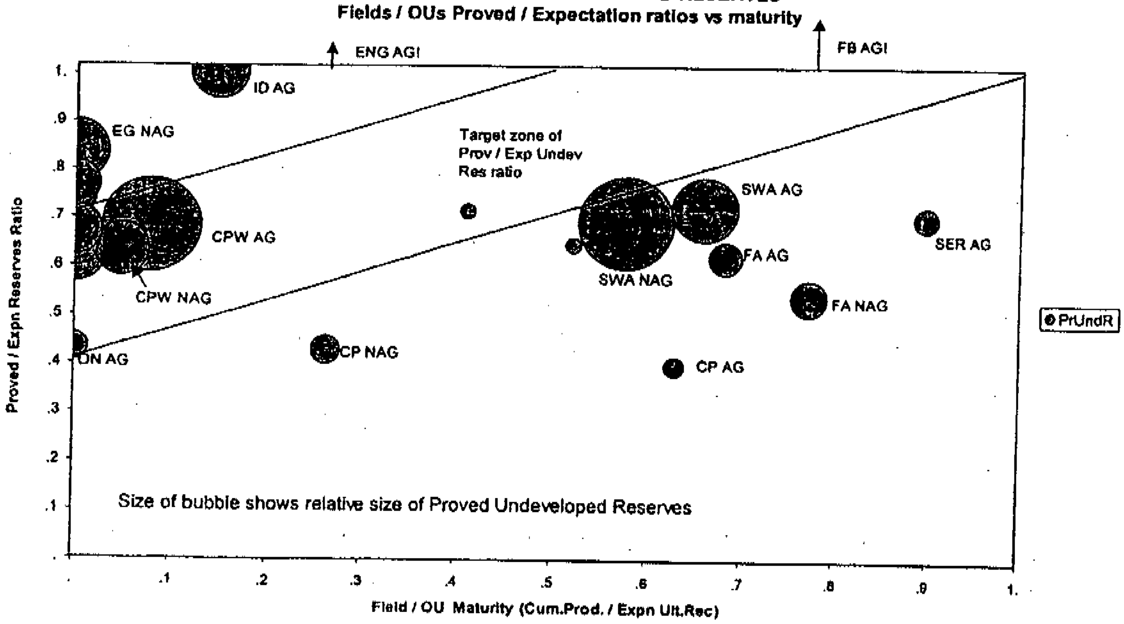




Attachment 4.2

Proved / Expectation Gas Reserves versus field maturity





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RJW00061620

2002 SEC RESERVES AUDIT BRUNEI - CONCLUSIONS

DEPOSITION EXHIBIT
Barendregt
#4 2/19/07

AUDIT CONCLUSIONS - INTRO

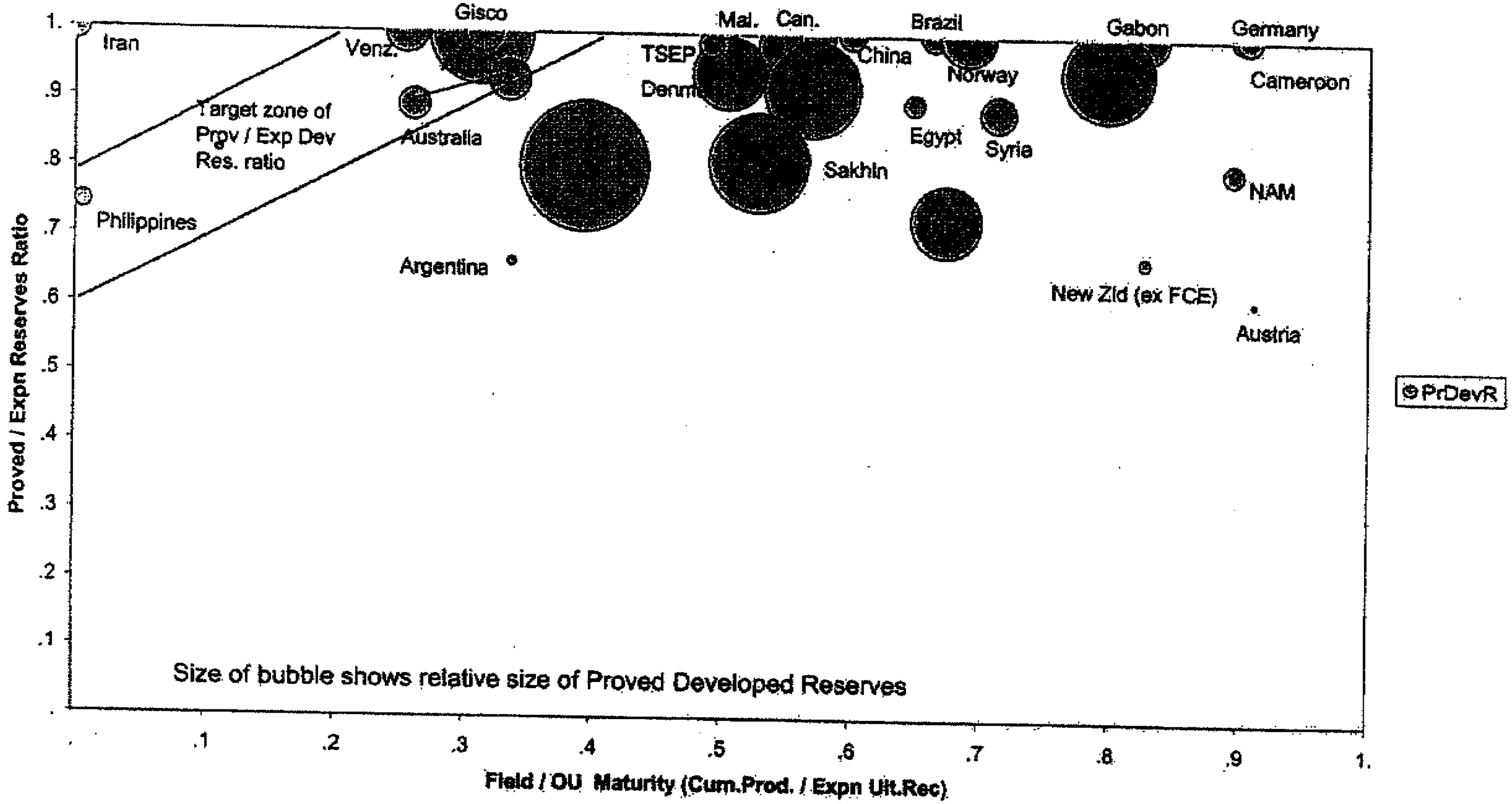
- Reminder:
  Audit is about reserves procedures, not a comprehensive (VAR) review!
  Audit opinion is based on comparison with Group guidelines and with practice in other OUs
- Excellent preparation for audit by RE staff – best seen to date
- Very good progress in studies and field maturation efforts over the last decade
  - Result of dedicated study effort, helped by new technology
- Significant breakthroughs in Technology and cost control:
  - Seismic acquisition: 3D, OBC
  - Petrel geological modeling: major advance in quality and speed of results
  - Widespread use of MoReS and GFPT reservoir / planning models
  - Through-tubing RST logs to track dynamic fluid levels
  - Major well drilling cost reductions and target/trajectory improvements
  - Reserves developed per well drilled do not show a decline yet

AUDIT CONCLUSIONS - PROVED vs EXP'N RESERVES

- BSP's historical leading role in probabilistic reserves estimation (from 1970's) now overtaken by events
  - Method is designed for new fields, too conservative for mature fields (difficult to reflect dynamic performance in static parameter distributions)
  - New Group guidelines recommend deterministic estimation - not followed by BSP
  - PU sensitivities re raising (Proved) reserves were an issue – now addressed
  - Increased tax payable by BSP if reserves are raised – resolve is needed
- Established method of determining Proved developed reserves from Expectation volumes (P/E ~ 75%) is arbitrary, too conservative and not in line with Group guidelines
  - Need to move to a 'growth to Expectation' with growing field maturity
  - Target should be Proved ~ 90% of Expectation at Company level (cf other OUs)
- Proved undeveloped reserves must be simulator-derived from (initially) realistic P85 performance scenario of Expectation volumetrics - later updated with field performance
- Probabilistic addition (from reservoir to field level) <u>not</u> recommended:
  - Effect of reservoir changes on field volumes becomes intransparent – audit trail issue!
  - Necessary dependency assumptions may become arbitrary – audit trail issue!
  - Becomes unnecessary if we follow Group guidelines at reservoir level (Proved ~ Exp'n)

SEC Reserves Audit BSP, 27 Apr – 3 May 2002

1.1.2002 DEVELOPED OIL+NGL RESERVES
Fields / OUs Proved / Expectation ratios vs maturity

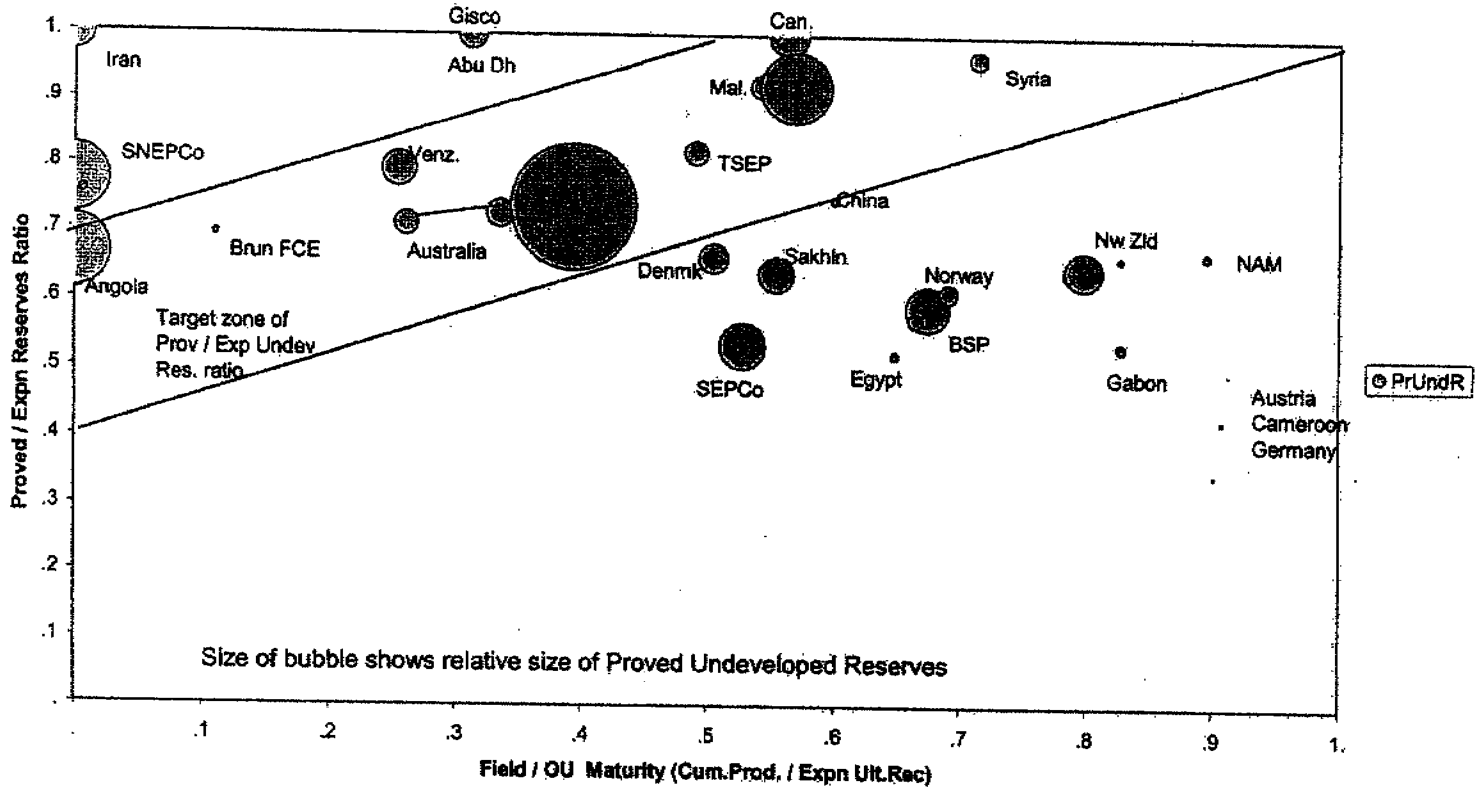


Slide 4

February 15, 2004, 16:59 PM

SEC Reserves Audit BSP, 27 Apr – 3 May 2002

1.1.2002 UNDEVELOPED OIL+NGL RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



Slide 5

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AUDIT CONCLUSIONS - 'LEGACY' RESERVES

- Originating from 'antiquated' method of determining reservoir ultimate recovery (UR) from recovery factor assumption, from an analogue or, at best, from a crude simulation study
  - Undev'd reserves (UDR) equated to difference between UR and dev'd reserves (DUR)
  - Undeveloped well targets / forecasts, economic evaluation rarely available
  - In some small undev'd fields economics are marginal, but now deemed out of date
  - In other cases (Champion!) UDRs became negative when UR was overtaken by DUR
  - Proved 'legacy' reserves are small (9% of Exp'n undev.reserves, ~ 3% of Proved?)
- Historical reluctance to make a 'clean sweep':
  - Avoid major reserves swings
  - Crossflow an issue, needing an area-wide, not individual reservoir resolution
  - With up to 4000 reservoirs, not an easy task in BSP
  - Effort made in 2000/2001 and proper project now started and resourced to address this
- Simulation study the <u>only</u> proper way of maintaining accuracy in both developed and undeveloped reserves - now the norm in the large majority of OUs
  - Reserves coverage of simulation models in BSP is progressing (now 70%)
- Recommend to make the 'clean sweep' when we upgrade proved developed reserves
  - Set URs equal to DURs, unless we have well targets and forecasts for UDRs
  - Maintain marginally economic UDRs if we are confident that they can be improved

AUDIT CONCLUSIONS - OTHER

- BSP has historically been strong on reserves audit trails – confirmed in the audit
- Very good consistency with Finance reporting (annual production, UPFs)
  - Good cooperation between FAC and reserves coordinator
- Licence extension (first in 2003) not seen as an issue
  - Full confidence that extension terms will be successfully agreed

- Overall audit conclusion: <u>Satisfactory</u>

DEPOSITION EXHIBIT
Barendregt (?)
#5 2/20/07

Shell International Exploration and Production B.V.

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SIEP 99-1100

Petroleum Resource Volume Guidelines

Resource Classification and Value Realisation

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Petroleum Resource Volume Guidelines

Resource Classification and Value Realisation

Custodian : SEPIV-EPB-P
Date of issue : September 1999
Keywords : Resource Volumes; Guidelines, Reserves, FASB, SEC

SHELL INTERNATIONAL EXPLORATION AND PRODUCTION B.V., THE HAGUE

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