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IN THE UNITED STATES DISTRICT COURT
DISTRICT OF NEW JERSEY
Civ. No. 04-3749 (JAP)
Hon. Joel A. Pisano

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)
IN RE ROYAL DUTCH/SHELL)
TRANSPORT SECURITIES)
LITIGATION)
______________________________)

VIDEOTAPED DEPOSITION UPON
ORAL EXAMINATION
OF
ANTON BARENDREGT
VOLUME I
Taken on:
Monday, 19 February, 2007
Commencing at 10:52 a.m.

Taken at:

The Hague Zurich Tower
Muzenstraat 89
2511 WB The Hague
The Netherlands

REPORTED BY: FREDERICK WEISS, CSR, CM

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Deponent: Anton Barendregt
The Videographer: Richard Bly
Court Reporter: Frederick Weiss

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I N D E X

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ANTON BARENDREGT

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Barendregt Exhibit 2 - Draft Note dated 5 May, 2002 authored by Anton A. Barendregt, bearing Bates Nos. RJW01001167 through RJW01001170	97
Barendregt Exhibit 3 - Note dated 31 May, 2002 authored by Anton Barendregt regarding SEC Proved Reserves Audit, with Attachments 1, 2, 3 and 4 Bearing Bates Nos. RJW00061605 - RJW00061620	107

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"2002 SEC RESERVES AUDIT BRUNEI - CONCLUSIONS" dated February 15, 2004 consisting Of seven slides bearing Bates Nos. RJW01001171 - RJW01001177

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PROCEEDINGS --

THE VIDEOGRAPHER: This is the Video Operator speaking, Richard Bley, of LegalLink Action Video located at 420 Lexington Avenue, New York, New York.

Today's date is February 19th, 2007. The time on the record is 10:52 a.m.

We are in a conference room in The Hague, Netherlands to take the videotape deposition of Anton Barendregt in the matter of In Re: Royal Dutch/Shell Transport Securities litigation in the United States District Court for the District of New Jersey, Civil Action Number 04-3749 (JAP), consolidated cases before Honorable Joel A. Pisano.

Will counsel please introduce themselves?

MR. HABER: Jeffrey Haber, Bernstein, Liebhard & Lifshitz on behalf of lead Plaintiff, Peter M. Wood and The Class.

MS. COHEN: Rebecca Cohen,

Bernstein Liebhard & Lifshitz on behalf of lead

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Plaintiff, Peter M. Wood and The Class.

MR. ADLER: Derek Adler, Hughes Hubbard and Reed on behalf of PriceWaterhouseCoopers.

MS. MARIA: Leslie Maria, LeBoeuf Lamb, on behalf of the witness.

MR. CORSON: Nicholas Corson on behalf of KPMG Accountants NV, and I am accompanied today by Leen Groen and Alastair Hunter, both from KPMG.

MR. DAVIS: Sidney Davis on behalf of KPMG.

MS. WICKHEM: Rebecca Wickhem, Foley & Lardner LLP on behalf of Judith Boynton.

MR. GOLDSTEIN: Joseph Goldstein of Mayer, Brown, Rowe & Maw on behalf of Sir Philip Watts.

MR. MORSE: Adriaen Morse, Mayer, Brown for Phil Watts.

MR. WARE: David Ware, Debevoise & Plimpton, LLP on behalf of Royal Dutch/Shell Transport and Anton Barendregt.

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MR. EADIE: James Eadie of Blackstone Chambers, UK counsel for Mr. Barendregt.

MR. WEED: Earl Weed, in-house for Shell.

MR. TUTTLE: Jonathan Tuttle, Debevoise & Plimpton LLP on behalf of Shell Defendants and the witness here today.

MR. BEST: Stephen Best, LeBoeuf, Lamb, Greene & McRae LLP, Washington D.C. on behalf of Mr. Barendregt in his individual capacity.

THE VIDEOGRAPHER: Can we swear the witness?

ANTON BARENDREGT,

Called as a Witness by counsel for the Plaintiffs, after being duly sworn, testified as follows:

EXAMINATION BY MR. HABER

Q. Good morning, Mr. Barendregt.

A. Good morning.

Q. As you probably have been advised, I am going to be asking you a series of questions

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over the next few days, several days. I am looking for your best recollection and your knowledge of the events and circumstances that concern the recategorization of reserves at Shell.

If I ask you a question and you do not understand the question, will you let me know?

A. (Nodding) Yes.

Q. And just as I am going through, a lot of these sort of ground rules, if you will, are just an understanding between us so that the record is clear and we get all of your answers.

It's important for you to articulate your answers with a yes or a no. Head nods and Mm-Hmms, while they get picked up at the video operator, they don't get picked up with the stenographer.

So it's important for you to always articulate and answer.

A. I understand.

Q. Thank you.

If at any time there is a question that I ask that you would like me to rephrase or

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reask, will you let me know?

A. I will.

Q. And if you don't hear a question, will you tell me?

A. I will.

Q. If you don't know the answer to a question, will you let me know that as well?

A. Yes.

Q. Another occurrence, common occurrence -- always unintentional, but it happens anyway -- during question and answer, I will sometimes speak over you or you will sometimes speak over me.

I will do my best to make sure that I don't do that and let you finish your answer before I follow with a question, and I would just ask that you wait for me to finish my question before you answer. Is that okay with you?

A. I understand, yes.

Q. Good. And finally, if you need a break, please let me know. I will accommodate any requests for a break. The only exception will be

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if there is a question pending, in which case I will ask for an answer and then we will break.

Okay?

A. I understand, yes.

Q. For the record, can you tell us where you currently reside?

A. I reside in a place called Wassenaar, not far from The Hague, in an address Iepenlaan number 7.

Q. I take it you went to a university?

A. Yes, I did.

Q. And where did you attend university?

A. In Delft, here in Holland.

Q. In what year did you graduate?

A. In 1968.

Q. Did you graduate with a degree?

A. An engineering degree in physics, yes.

Q. Is this degree what we would have in the United States as an undergraduate degree, or would that include a higher degree such as a

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masters?

A. It would be at the level of a Masters Degree.

Q. When you graduated, where did you first get a job?

A. I got a job with Shell in Amsterdam, the Amsterdam laboratory, where I was employed as a mathematician/physicist.

Q. And how long were you in this position?

A. For about a year.

Q. What did you do next?

A. Next I was transferred to The Hague, to work with a group who had been developing a software database administration system for group exploration and production companies.

Q. And how long were you in that position?

A. That was approximately a year and-a-half, beginning of 1969 to 1971 so it would have been more than that. It was in fact two

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and-a-half years. It was originally for just one year but then it got extend.

Q. So this takes us to around 1971?

A. Yes. Yes.

Q. And your role in this position was to develop software?

A. To help develop software and to help it being implemented and actually installed on the computers of various exploration and production companies.

Q. What was the purpose for the software?

A. It was a database, a new database administration system. It was felt in exploration and production that there was a lack of tools to store the large amount of data that was coming in from various parts of the operation, from well logs and all the way to production data.

Q. Where did you go after this position?

A. I was transferred to Brunei for about a year and-a-half until the end of 1972,

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where I was made in charge of the conversion of all computer programs from the 19 -- from the previous ICL computer to the new IBM 360 computer that they had just purchased.

Q. Did you have a title while you were in Brunei?

A. I believe it was Team Leader, computer conversion.

Q. So you were there from around 1971

to the middle of 1972?

A. No. The end of 1972.

Q. The end of '72.

Did you have any responsibilities with regard to any field work that was being performed in Brunei?

A. No. Not at that time.

Q. Did there come a time when you had responsibilities for field work?

A. Yes. Much later.

Q. So you had another stint in Brunei?

A. Yes.

Q. So when you finished with this

position in Brunei in 1972, where did you go next?

A. I went back to The Hague, to the central office in The Hague, where I joined the group who were developing new kinds of software, not specifically for exploration production purposes, but for more general purposes.

And that assignment lasted until the end of 1973.

Q. Where did you go after that?

A. I went to Shell International Chemicals in London as a computer systems designer and analyst.

Q. And how long were you in that position?

A. It was until September of 1975.

Q. And where did you go after Shell International Chemicals?

A. At that time I decided to make a career change, and I applied for joining the exploration and production function.

Before that time, I had been working in the information and computing function.

That career move was agreed and I was transferred to the NAM, N-A-M for short, in Assen, who are the Dutch exploration and production operating arm for Shell.

Q. And what made you decide on this career change?

A. I found that in my previous assignments in the information and computer section, I was getting more and more away from my technical background; and also in my periods in Brunei and in visits to other EP operating companies in the years before, I had developed an interest in exploration production activity.

So these two factors combined led me to a request for a career move.

Q. When you got assigned to NAM, how long were you in the position that you were given?

A. I was given the position of Reservoir Engineer, and that position I kept until June 1978.

Q. Had you been given any training to serve as a Reservoir Engineer?

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A. Absolutely. Yes. I had numerous training assignments in The Hague during those first years while I was in Assen.

Q. So when you got assigned to NAM, that's when you had -- in the initial period you were given the training?

A. Yes. I had to join classes and of course I had to fit the schedule of these classes. There wasn't an individual training scheme set up. I had to join these classes, but they started almost within the first week that I joined NAM in Assen.

Q. In total, how long was the training courses that you had taken?

A. Difficult to say. All I can say is that the standard set of training courses that new graduates take typically take about three months. So I guess since mine was prepared at fairly late notice, I had to join the classes that still had time available.

So I didn't get them as one bunch, but I got them with intervals. But all in all,

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they must have added up to those three months.

Q. Did any of this training course work include reserves reporting requirements?

A. Reserves calculation requirements, there was a training course on reservoir engineering and that included reserves and reporting requirements, yes.

Q. Do you recall how long that course work was?

A. I believe it was a two-week course.

Q. Do you recall if there was any -- any lecture or discussion within this course work of SEC requirements for reporting Proved Reserves?

A. No. Because this was 1975 and this was before the SEC came out with that requirement for their requirement of Proved Reserves.

Q. Did you take any subsequent training in reserves reporting?

A. Yes. That was during my next assignment.

Q. And what was your next assignment?

A. My next assignment was as a

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Reservoir Engineer in Sarawak in Malaysia, and that lasted from June 1978 until late 1981.

Q. What were your responsibilities in your assignment in Malasia?

A. I was Reservoir Engineer for the new gas province that had been discovered and that was being prepared for development in Central Luconia Gas Province.

And later on, I was made -- I became in charge of the -- of a group of reservoir engineers consisting of three reservoir engineers responsible for oil and gas fields in the southern South China Sea offshore fields. And that included the Central Luconia fields but also some smaller oil fields nearby.

Q. Did you have any responsibility for the estimation of Proved Reserves in this position?

A. Yes, I did.

Q. Can you discuss a little bit what that entailed?

A. The gas fields were, like I said,

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they were new gas fields, they had been discovered in the previous five to ten years, and they were going to be developed by means of cluster development running, because they were pretty large fields and quite prolific.

We didn't really have sophisticated -- the sophisticated simulation tools available in those days that we would have available now, but some crude simulation work was done at that time.

In fact, four gas fields, it was found that it wasn't so much the subsurface for these particular fields because that was relatively easy, but it was the integration with the surface facilities that turned out to be a problem.

A problem that needed technical evaluation for which at that time in Sarawak there were no tools available. As it happened, in one of my last few months in the NAM in Assen, I had developed such a tool integrating surface with subsurface facilities and thereby getting more reliable forecasts of gas concentrate rates. I

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had taken this program with me to Sarawak and I applied it there with quite some success.

Q. Now, when I asked the question about the SEC reporting requirements, I did stand -- I was stood corrected, if you will. I stand corrected in a sense that the SEC did not promulgate its rule until 1978.

And in your answer, you said that you had some training with regard to the SEC rule in your subsequent position.

Is this the position you are referring to, or that you referred to?

MR. TUTTLE: Objection. Mischaracterization of the testimony. You can answer.

THE WITNESS:

A. The way I interpreted your question was did we report Proved Reserves in those days in the days in Assen? And the answer is yes, we did.

Shell had developed in the early

70s -- which is before I joined the exploration production function, Shell had developed a method

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which at that time was unique in the industry, of determining not only what we call the expectation or best estimate reserves, but also determining a more conservative and therefore a more robust estimate of proven -- what they called proven reserves.

This was done on the basis of probabilistic reserves, and that was adequately -- that was extensively dealt with in the reservoir engineering courses that I followed.

So I was used to reporting Proved Reserves already straight from my first month in my assignment in Assen.

Q. When you got to Malaysia, were you given any course work with regard to the SEC rule on reporting Proved Reserves?

A. Not course work as such. But when the new guidance was introduced, I believe I am reaching back into the early recesses of my brain now. But I believe that it took sometime, a few months if not a year, before it actually was filtered down from The Hague.

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The first dealings, when the request by the SEC, the first dealings were done in The Hague. And they were then ultimately translated into instructions, coming down from The Hague to the operating companies, how to report Proved Reserves.

Q. Were these instructions embodied in guidelines that were created in The Hague and disseminated to the various operating units?

A. There must have been some sort of document, but I honestly can't remember in what form that took.

Q. Other than the instructions that came down from The Hague, did you have any training or course work concerning the SEC requirements?

A. No. I think at this stage, it's

useful to remind you that when the SEC came forward with their request for Proved Reserves, within Shell that wasn't seen as a major new request. It was just a request for some additional data, yes.

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But it was data that we were already in the process of preparing internally. And therefore, it was a matter of picking up the data and putting it together in the report and reporting it to the SEC.

I understand, but I wasn't there, but I understand that at that time, there was contact between Shell, The Hague, the central office in The Hague and the SEC describing the position that Shell was in, i.e., that they were already having their own procedures for developing Proved Reserves.

And they obtained an agreement with the SEC, not a formal signed agreement, but at least some form of acceptance by the SEC that Shell would continue to use their own internal methods, which the way it was seen by Shell were fully in line to the new SEC definitions.

Q. What was the basis of your understanding that there was this contact between The Hague central office and the SEC?

A. Statements made by central office.

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There must have been some remarks made in the announcing Telexes that were sent out to the operating companies along the lines, and you found this repeated, because since -- and I had some various assignments in the central office and you found these understandings repeated to you.

So it was just, if you like, general accepted wisdom within Shell and within the professional E&P community that this agreement had been reached with the SEC and that Shell was essentially following their own previous guideline.

Q. And this, for purposes of timeframe, is sometime after 1978 --

A. Yes. Yes.

Q. -- not too far from when the rule was promulgated?

MR. TUTTLE: Objection to form. You can answer your best recollection at that timeframe.

THE WITNESS:

A. I believe it was the '79 reserves

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reporting that we first applied it throughout the group.

BY MR. HABER:

Q. So all of the Telexes and the communications would have occurred prior to the 1979 reporting?

A. If there were any between the central office and the SEC, then they would have, yes.

Q. Now, in your earlier answer, you also said that regarding the SEC communications, you said, "And they obtained an agreement with the SEC, not a formal signed agreement, but at least some form of acceptance by the SEC that Shell would continue to use their own internal methods, which the way it was seen by Shell were fully in line to the new SEC definitions."

A. Yes.

Q. It's the last part of that answer that I want to ask you a couple of questions. Who had determined that Shell's guidelines were fully in line with the new SEC rule?

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A. If you are asking for a specific person, I can only speculate. I don't know. I wasn't there in the center at the time, and that is where of course in the center in The Hague, and that is where all the discussions took place.

Q. Over time, during your tenure at Shell, did that -- did that position ever change?

A. Not really, no.

Q. And I know I am jumping ahead now in terms of your CV, but you became the Group Reserves Auditor.

Correct?
A. (Nodding)
Q. And when did you become the Group Reserves Auditor?
A. That was January/February 1999.
Q. And during that period, how long did you hold that position?
A. I held that position 5 years.
Q. So sometime early in 2004?
A. Yes. Sometime early in January 2004.

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Q. During your tenure as Group Reserves Auditor, did the view that you just testified about that Shell's guidelines were fully in line with the SEC rule, did that change?
MR. BEST: Objection. Mischaracterization of his testimony.
MR. TUTTLE: Same objection.
BY MR. HABER:
Q. You can answer.
A. My view did change. I think you can find it in various reports that no doubt you have access to.
Not initially, but gradually, the view did change to the extent that I felt that the group guidelines needed corrections, needed adjustments in order to become more closely aligned with the then new SEC guidance as it had been published in 2001.
Q. And that guidance, you are referring to the staff interpretive guidance that was released in March of 2001?
A. Correct, yes.

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Q. And when I say "staff interpretive guidance", you understand that I am referring to the staff of the SEC?
A. Yes.
Q. Now, up until this point, was it the view within Shell that Shell's guidelines were compliant with the SEC rule?
A. Absolutely, yes. And in fact,

there was some evidence to support that view. And in 1997, a comparison was made between the reserves bookings for some North Sea fields, both on the UK side and on the Netherlands side. A comparison was made with the Shell -- between the Shell Proved Reserves bookings and those booked by Exxon, who were the 50/50 partner in both of these ventures.

And it turned out that Exxon's Proved Reserves figures were higher and some of them quite a lot higher than the Shell figures.

So that strengthened Shell in their belief that their reserves estimation methods were, if anything, more conservative than perhaps

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the SEC definitions would require.

Q. Do you know if, as a consequence of this analysis that you just described, Shell revised its guidelines?

A. Yes.

Q. And were those guidelines changed in 1998?

A. They were.

Q. Do you have an understanding of the circumstances as to how the guidelines came to be revised?

MR. TUTTLE: Objection to form.

THE WITNESS: After this comparison, it was felt that the group guidelines could do with a sharpening and a change where required of the method in which reserves were calculated.

As I said before, since 1972, the methods in which reserves and particularly Proved Reserves were calculated was done on the basis of probabilistics, which is a very appropriate method for particularly new fields where uncertainties

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are large.

But what one tended to see in practice is that a proved and expectation reserves estimate was made for a field, a field would be taken into production.

So over the years, the proved and expectation reserves estimates of the field would be reduced by the amount of production that was taking place in that field.

But in some cases, what was not done. What should have been done was that the original proved and expectation reserve estimates were changed, and particularly the proved estimate, should grow with the amount of cumulative production that was taken from the field.

The net result was that remaining Proved Reserves, which is total Proved Reserves minus the cumulative production, in those fields tended to be quite a lot smaller in comparison to remaining expectation reserves.

And therefore the proved volumes

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in -- and we are dealing with mature fields here, the Proved Reserves of mature fields tended to be quite a lot more conservative.

Therefore the recommendation was made that in those mature fields, we could move towards what was called a deterministic determination, deterministic evaluation of the reserves, which was in fact more in line with the practice still prevailing in the industry.

I mention the word deterministic as opposed to probabilistic, which was the method that Shell had introduced in 1972.

The industry, the rest of the industry, the other major oil companies did follow what Shell had done in the early '70s and they had stuck with the deterministic method.

And that, like I said, led to higher reserve estimates in more mature fields.

Q. Now, at or about this time in 1988, do you know what method the SEC preferred, the deterministic as opposed to probabilistic?

MR. TUTTLE: Objection to form.

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Foundation.

MR. BEST: Same objection.

BY MR. HABER:

Q. I will rephrase. Do you know if the SEC had a preference for a methodology of determining reserves?

A. The short answer is no. But did I know whether the SEC had a preference.

All I can say is that the SEC had a statement which certainly was published in their additional guidance in 2001.

But even before, I think, they had made their view public, that yes, they were aware of the method of probabilistics reserve estimation.

And in fact, and I am just paraphrasing it now, but in fact they couldn't care whether people use it or not as long as they stuck or remained within the original guidelines.

And that, as I recollect from those days, was the attitude of the SEC.

Q. When you say stick with the

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original guidelines, are you referring to rule --

A. The original SEC definition.

Q. So that would be Rule 4-10 of regulation SX?

A. That's the one, yes.

Q. Now, a moment ago you mentioned expectation reserves.

For the record, what do you mean by expectation reserves?

A. Another way to describe them is your best estimate, middle of the road estimate. Taking all uncertainties into account, what would be the most likely estimate of reserves that you can come up with.

Q. Now, I have heard the term P50, P85.

Does that relate to expectation reserves?

A. Not strictly speaking, but in practice, yes. P50 is in fact the point at which the value is as likely to be exceeded or to be -- to be turning out to be less than that particular

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value.

And for a symmetrical distribution -- we are talking technicalities now, before the symmetrical distribution, they are one and the same. But if they are not a symmetrical distribution, they are different, but not a lot.

Q. Now, in your earlier answer, you referred to a recommendation regarding mature fields.

And what you said was, "therefore the recommendation was made that those mature fields, we can move towards what is called a deterministic determination."

A. Yes.

Q. Who made the recommendation?

A. It was done by a value assurance team, I believe was the name. I am not 100 percent sure whether that was the name. But anyway, there was a team setup in 1997 after the comparison with the Exxon fields to try and see whether they could -- whether Shell should come up with new reserves, guidelines in this respect.

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And that team made the recommendation in 1998, and it was then implemented in the Shell reserves guidelines at the end of 1998.

Q. Now, this team, have you heard a team referred to as a Value Creation Team?

A. That's the one, yes. Yes.

Q. And do you recall there being a Value Creation Team whose purpose was to review hydrocarbon resource maturation?

A. Yes.

Q. Were you a member of that team?

A. No, I was not. I was at that time development manager in Lowestoft in charge of the southern North Sea UK gas fields.

Q. That would be part of Shell Expro?

A. Yes.

Q. At the time the Value Creation Team was created, were you aware of its creation?

A. Yes, I was, yes.

Q. And how is it you became aware of its creation?

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A. In formal context, I think, with people still in the central office; its first creation. There was a formal announcement of a workshop made by that team once it had been set up, and that I took part in. That was a workshop intended for reserves estimators and reservoir engineers of the major E&P companies.

And that was held in The Hague and I was attending that.

Q. And what --

A. But before that, I had heard about the team being installed and I can't recollect precisely how, but it must have been through word of mouth.

Q. When was this workshop --

A. Held?

Q. Yes. Thank you. We get tongue tied.

A. I believe it must have been somewhat early in 1998.

Q. This workshop was conducted prior to the guideline changes --

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A. Yes.

Q. -- the official changes?

A. Yes.

Q. How long was the workshop?

A. A few days, three days, maybe. I can't be sure.

Q. Do you recall the sum and substance of what was discussed during the workshop, at least as to what you attended?

A. Again, it's a long time ago --

Q. I understand.

A. -- so I can't be too sure. But what I remember is that at that time -- at that time the group had already formed its opinion that seeing the comparison with Exxon, and they were thinking of, say, introducing a new way of calculating reserves in mature fields.

And they held the workshop to see whether they had perhaps overlooked something, whether this introduction of this new way of estimating reserves would lead to problems in the various operating companies, and that's why they

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held the workshop to hear the views of the people with the coal face, people in the field.

MR. TUTTLE: Coal or cold?

THE WITNESS: Coal face. It's a UK expression.

MR. TUTTLE: Yes.

THE WITNESS: People who are actually working at the point where it all happened.

MR. TUTTLE: Right.

BY MR. HABER:

Q. Do you know if there was a sponsor of the Value Creation Team?

A. There may have been. I can't remember.

Q. Do you know a Hank Dijkgraf, Dijkgraf?

A. Yes, I know.

Q. Who is Mr. Dijkgraf?

A. I expect you want me to answer the question who was Mr. Dijkgraf at the time?

Q. Correct.

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A. I believe he was at that time in charge of Shell International E&P new ventures. I believe it was called SIPV, something like that. And one of his responsibilities was to have reporting to him a section that was in charge of what was called group reporting, which included reserves reporting externally and internally, as a matter of fact.

Q. Do you know if Mr. Dijkgraf had any involvement in the creation of the guideline concerning resource maturation?

A. The short answer is I don't know. I wasn't there. I don't know precisely how it was instituted.

Q. Do you know who Philip Watts is and what his role was at the time?

A. Yes. He was the chief executive of E&P at the time.

Q. Do you know if Mr. Watts sponsored the VCT, the Value Creation Team?

A. I can't tell you that. I don't know it.

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Q. Do you know if there were any recommendations made by the Value Creation Team concerning hydrocarbon resource maturations?

MR. TUTTLE: Objection. Asked and answered.

THE WITNESS: Yes. They made recommendations. Like I said earlier, they made recommendations regarding the determination of reserves to the group that was responsible for issuing the Shell guidelines.

(Barendregt Exhibit No. 1 was marked for identification).

BY MR. HABER:

Q. We have just handed what we have just marked as Barendregt Exhibit 1. It's a multipage document that says as a subject, if you will, at the top of the page it says, "Creating Value Through Entrepreneurial Management of Hydrocarbon Resource Volumes."

And then underneath it, there is a Shell logo, and it says, "Volumes to Value."

There are two Bates ranges, the

0043

first is V00101293 through V00101317, and the second range is GUI 000398 to GUI 000422.

Mr. Barendregt, have you seen this document before today?

A. I must have, although I don't specifically remember.

Q. Do you recognize this document as -- well, withdrawn.

What do you recognize this document to be?

A. I see the title, and I -- it seems to be the report that was produced by the Value Creation Team that was looking into resource reporting.

Q. Do you know who the members were that were responsible for this document?

A. Only the Chairman, who was Stuart Evans.

Q. Who was Stuart Evans at the time?

A. He was the head of group, and the name of that group escapes me. The group that was set up in 1996 consisting of a group of senior E&P

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consultants and a group of IT -- IT specialists.

Q. Did you ever work with Mr. Evans?

A. Yes, I did, for a year before I went to Lowestoft in end of 1996.

Q. Do you know if Exhibit 1 was reviewed by Shell's external auditors?

A. No, I don't.

Q. Do you know who Shell's external auditors are or who they were at the time?

A. I was aware of KPMG at that time sitting where I was in Lowestoft, and I may have been aware of PriceWaterhouseCoopers, but I don't remember that.

Q. And are you aware of a process called the ARPR?

A. Yes.

Q. What is the ARPR?

A. Annual review of petroleum resources.

Q. And what's the purpose of this process?

A. It's a name that is given to the

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process at the end of the year when every company has to put together its estimates of produceable reserves and report these to the center. It's an activity that peaks or it used to peak, at least, in those days in the month of January.

Q. When you say produceable reserves, are you referring to Proved Reserves for external reporting purposes?

A. Yes, and internal purposes as well.

Q. Now, when you were at Shell Expro, did KPMG have any involvement in the ARPR process that was engaged in by Shell Expro?

A. In order for you to understand my answer to that question, you must understand that our office in Lowestoft was a subsidiary office to the main office of Shell Expro in Aberdeen.

And the way it was that we essentially -- or not essentially. We reported our reserve estimate to Aberdeen, and Aberdeen then put all the estimates together also from staff in Aberdeen themselves and reported that to The Hague.

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So the answer to your question is no, I do not remember having seen any personally or my staff having seen any staff from KPMG or any of the external auditors in Lowestoft.

And I wouldn't have expected that to have been the case. I would have expected that any contact would have been up in Aberdeen.

Q. I was just referring to your prior answer where you said, "I was aware of KPMG at that time sitting where I was in Lowestoft."

And I was just inquiring, and what I wanted to know is whether or not you were aware of it?

A. Well, yes. I mean, it's not as if we talked to each other and we have heard of KPMG.

Q. No. No. I just wanted to explain to you what I was following from that inquiring whether or not your knowledge came from working with KPMG while you were in Lowestoft?

A. The short answer is no.

Q. Okay. Now, again, with regard to Exhibit 1, do you know if PriceWaterhouseCoopers,

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anyone from that organization, had reviewed this document?

A. I don't.

MR. ADLER: Objection. Asked and

answered.

BY MR. HABER:

Q. During the time that you served as Group Reserves Auditor, do you recall any communications with KPMG concerning the guideline changes in 1998?

A. In passing through and during discussions that we had with them from time to time.

Q. When do you recall having such discussions?

A. I can't be sure. They must have happened. We saw KPMG staff typically three to four times a year, and the subject must have come up, but I can't recall precisely when.

Q. Do you recall the sum and substance of what was discussed?

A. Again, the short answer must be no.

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I know that these issues must at some stage have led to either a question or a remark from their side. But I cannot remember it being a -- an item for say prolonged discussion. There might have been a clarifying question from the side of KPMG that I would have answered. But it doesn't stand out in my memory as an issue that we debated at length, far from it.

Q. When the guidelines were changed to implement the recommendations, did it have any impact on the amount of reserves that Shell reported in the following year?

A. Yes, it did.

MR. TUTTLE: Objection to form. Foundation.

MR. BEST: Same objection.

BY MR. HABER:

Q. And how -- how did the changes to the guidelines impact on reported reserves?

A. They tended to increase the reserves in the mature fields pretty much as had been the expectation when the new guidelines were

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issued.

And following, of course, the comparison between the Exxon and the Shell reserves that I mentioned earlier.

But the increase in reserves was almost exclusively in what we call the mature fields, which were the fields that were in production, and fields therefore that had already been developed and the large contingent of their wells already drilled with all the ensuing information.

Q. With regard to this increase, do you recall having any discussions with KPMG about the increase?

A. Not specifically. But like I said, we talked with KPMG three to four times through the year, and more intensively at the end of the year during the ARPR exercise that we talked about.

So yes, the subject will have come up, but it doesn't stand out as a specific subject that we discussed.

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Q. What about with regard to PWC, PriceWaterhouseCoopers, do you recall having any discussions with them about the increase?

A. Not during the year, but at the end of the year, they were there in those discussions. I think at this point it's useful to bear in mind -- to remember that my role -- one of my roles was to report to E&P management and to external auditors at the end of the year just before the external reserves were going to be published.

I would prepare a report on my view and the reasonableness to the extent that I could -- that I had this position of the relevant details on the reasonableness of these reserve estimates.

I would prepare a report which KPMG and PriceWaterhouseCoopers did receive, and I would prepare a presentation that they attended to and at which they could ask as many questions as they liked.

Q. In the report that you prepared, is

this the annual report?

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A. Yes, indeed, yes. My annual report, yes.

Q. When you first started as Group Reserves Auditor, looking back at the changes in '98 to the guidelines, do you recall any discussion as to whether the changes complied with SEC Rule 4-10?

MR. BEST: Discussions with whom?

MR. HABER: With the auditors.

THE WITNESS:

A. Not specifically.

BY MR. HABER:

Q. How about generally?

A. Generally, the discussion is likely to have come up. And I am only -- I don't remember it specifically, but I can tell you that I would have expected them to have come up.

And our explanation at the time, which was abundantly documented, is that these changes were in mature fields. And that there was good evidence that we were conservative there for the reason that I have already highlighted here,

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and therefore that there was full justification for implementing them.

Q. Did you ever perform an analysis of whether the guideline changes in 1998 complied with Rule 4-10 when you first started as the Group Reserves Auditor?

MR. TUTTLE: Did he ever, but limited to when he first started in, so you got two timeframes.

MR. HABER: When he first started.

MR. TUTTLE: Okay.

MR. HABER: Let me rephrase it so it's clear.

Q. When you first started as Group Reserves Auditor in 1999, did you perform an analysis of the guideline changes in 1998 to determine whether those changes complied with Rule 4-10?

A. Not formally as you put it, and I will tell you why I saw no reason to do that. As I said, the changes were introduced in reaction to -- in reaction to a comparison between Shell and

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Exxon reserves where Shell was found to be conservative for reasons that had been identified.

And the changes related to developed and mature developed fields.

The changes that were proposed were to move away from probabilistic reserves estimates which had been yielding too conservative -- had been proven to yield too conservative figures to a more deterministic way of determining those reserves, which was the practice in the industry at large.

So we knew that we were aligning ourselves more closely with the industry at large. That itself did not raise the suspicion that we would have been falling foul from the SEC definitions; far from it, in fact.

Q. Did anyone -- withdrawn.

Did you undertake an analysis to determine whether the industry at large was compliant with the Rule 4-10?

A. No.

Q. I asked you if you had any

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discussions with compliance with the -- compliance with Rule 4-10 with the auditors.

Did you have discussions with anyone at EP concerning the guideline changes, again in '98, and their compliance with Rule 4-10?

A. No, certainly not at that time.

Let me remind you here that the reserves changes were in the mature fields. Now, during the coming days, we will no doubt reach the point in 2002/2003 when Shell came to its reserves restatement.

I think it is as well to bear in mind now that the reserves changes or the method changes that were introduced in 1998 related to those mature fields. Of those mature fields and of those reserves, very, very few in fact got restated in 2003.

The large majority of the reserves restated in 2003 related to new fields.

So the changes that were introduced in 1998 were, and I still believe that and everybody believes that, that they were reasonable

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and certainly in compliance to a very large extent with the SEC definitions as they were known at that time.

Q. You said a few were restated. Do you recall the fields where the reserves that were booked as a consequence of the guideline changes were then restated as part of the recategorization?

A. Not individually, no. No. I don't have those.

Q. Do you remember the operating units for which those fields were restated?

A. Yes. We all know those. SPDC was a big one, Oman, and various others.

MR. TUTTLE: His question was those fields that he said where the reserves that were booked as a consequence of the guideline changes were then restated. Do you know if, and then he picked up on those fields.

MR. HABER: I want to make sure that.

MR. TUTTLE: I want to make sure

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that your response is to the question and not if you know if field reserves in general were restated.

THE WITNESS: The short answer is no. When the restatement was made, it was made on the basis of studies largely done in the operating units themselves.

And I didn't overlook the individual studies that were carried out, and I certainly didn't look at details of fields.

I am thinking now of a company like SPDC where of course a large volume of restatement was made.

What I understand is that a lot of these changes related to -- in fact, I know that a lot of these changes related to new fields or possibly new areas in existing fields where development was not imminent.

Q. Just taking the timing a little bit forward, my original questions with regard to any analysis or comparison was restricted to when you first became Group Reserves Auditor.

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A. Mm-Hmm.

Q. Now, I want to know once you were firmly in that position from the middle of 1999 until the conclusion, do you recall having any discussions with anyone at EP concerning the guideline changes and their compliance with Rule 4-10?

A. Not these particular guideline changes, no. No.

Q. The same question with regard to the external auditors.

Do you recall having any discussions with them?

A. Not specifically, no.

Q. Did the issue come up -- withdrawn.

Were you involved in a project called "Project Rockford?"

A. Yes.

Q. What was Project Rockford?

A. Project Rockford was set up in the end of 2003 when it became clear that we were heading towards a -- what was amounting to a

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crisis situation regarding our reserves reporting.

It was set up, I believe, at the end of September, maybe early October in 2003 after we saw first evidence, first real evidence emanating from Nigeria that large amounts of reserves were likely to be in need of restatement.

Q. Did you have any involvement in Project Rockford?

A. Yes, I was. The name Project

Rockford or the project was set up to ensure confidentiality, because this was sensitive information obviously, and people only needed to take part on a need-to-know basis.

And that therefore the taking part in this project meant that you had to sign a specific confidentiality agreement, more specific and certainly more binding than the general one that any Shell staff would sign, including myself as a consultant.

So the reason why this was put together, the way I perceived it, as a means of controlling confidentiality of information.

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Q. My question was: Did you have any involvement in the project?

A. Yes.

Q. And what was your involvement?

A. My involvement was that as Group Reserves Auditor who of course had a shall we say a very direct participation in any reserves reporting or in any restatement of reserve.

Q. During your involvement in Project Rockford, did the guideline changes in 1998 come up as a topic of discussion?

A. They must have been. I don't specifically recall any discussions. If there had been, then my answer would have been pretty much on the lines of what I just told you, that the short answer to your question would have been no.

MR. TUTTLE: Jeff, we have been going a little over an hour. Do you want to take a couple of minutes?

BY MR. HABER:

Q. I just want to be clear in the record with regard to the record. Is your answer

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no, you have no recollection of the guideline changes being discussed during Rockford? Or no, they were not discussed?

A. When I said "no" just now, my final no, what I meant is that if anybody had asked me a question: Do you see the 1998 reserves changes as having any impact on these restatements? My answer to that question would have been no.

MR. HABER: All right. Why don't we go off.

THE VIDEOGRAPHER: Going off the record at 12:00 noon.

(Recess taken)

THE VIDEOGRAPHER: Returning to the record at 12:14 from 12:00 noon.

BY MR. HABER:

Q. Mr. Barendregt, a few moments ago, you had testified that you met with the external auditors three to four times a year?

MR. TUTTLE: Objection. Mischaracterization.

BY MR. HABER:

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Q. Let me go back and make it clear. Was it KPMG?

A. KPMG, yes.

Q. Did you meet with PriceWaterhouseCoopers during that same three to four times a year?

A. No.

Q. What were the reasons for meeting with KPMG three to four times a year?

A. It was mostly at their request. They usually took the initiative of asking for a meeting. And just -- let me rephrase that.

The main reason, as I saw it, you'd really have to ask KPMG of course to get the correct answer to that question, but the main reason as I saw it was for them to be able to ask me for any clarification of any audit reports, of any company audit reports that I sent them throughout the year as these audits occurred.

So typically, I would take anything between six and ten audits a year, and they appeared, as I wrote them, as they were published,

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and copies were directly sent to KPMG and PriceWaterhouseCoopers, and KPMG felt that it would be useful for them to ask for any clarifications from these reports, if they had any questions.

And in addition, they wanted to touch base with myself, Remco Aalbers, and his successors, to talk about any new developments, any major reserves changes that might be coming about, that sort of thing.

Q. Were these meetings scheduled?

A. In a sense that they were noted in our diaries, yes.

Q. I guess what I am asking: Were they scheduled for certain days throughout the year? For instance, one during the ARPR, one say during the summer, one in the fall?

A. No, not in that sense. Only that in the end of the year, during the January period, would be and particularly the final one on that which was end January or early February, that was really the only one that was scheduled in advance.

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Q. So the other three or so, those would be more impromptu during the year?

A. Yes. We would get an E-mail and we would fix the date, sort of a weekend, something like that.

Q. Is it your recollection that they initiated, KPMG that is, initiated these meetings?

A. By and large, yes. They took the first initiative in getting a date together. It wasn't because we didn't want them. It just so happened that they initiated at a time that it suited them.

Q. Now, what other type of communications did you have with KPMG?

A. Other than the two types of meetings that I mentioned to you, none.

Q. Do you recall having any E-mail communications with KPMG during the year?

A. Oh, I am sure I must have. Again, from what I remember and I don't remember specific instances, clarifications of questions.

Q. What type of questions would you

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see clarification from KPMG?

MR. TUTTLE: Objection to form. Mischaracterization of the testimony.

MR. BEST: Same objection.

THE WITNESS: It's difficult to say. I can't remember any specific questions that they had asked. And that indicates that none of these questions led to any major discussions about the results of my report.

Q. Did you ever initiate any communication with KPMG during the years?

A. I probably did, but I can't remember any specific instance.

Q. Do you have any recollection as to the reasons why you initiated communications with KPMG?

A. Like I said, no.

Q. I'd like to go back to your CV. I believe -- I think we were -- the last position that we were talking about was your position as a Reservoir Engineer in Malaysia which I believe you said concluded in late 1981.

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A. Yes.

Q. Where did you go after Malaysia?

A. I went to central office, Shell central office in The Hague.

Q. And what did you do there?

A. I was -- by that time, I was senior Reservoir Engineer attached to the senior area Reservoir Engineer in The Hague overlooking the operations in the Middle East.

Q. What were your responsibilities in this position?

A. Specific responsibilities were coordinate and minute regular meetings, quarterly meetings that we used to have with staff from petroleum development Oman, where at that time a sizeable program of various studies in relation to improved oil recovery were being done by at that time the Shell laboratory in Rijswijk that needed regular liaison.

And one of the ways that liaison

was being maintained was through central office, but more specifically through these quarterly

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meeting as that we had with them. Another important player in that meeting was the Oman government.

Now, these meetings needed to be set up, minutes needed to be written, and that was my responsibility.

I wasn't chairing the meeting obviously. There was a senior Reservoir Engineer in The Hague that was doing that.

Q. Why was the Omani government important?

A. Because the Oman government are a major shareholder -- not shareholder, but a major stakeholder in the Oman fields. And yeah, they have an interest, and they are paying -- they were paying a large amount of the costs of the research program and they felt that they needed to be made more aware of precisely what the program was about and what the results were.

Q. Now, during your tenure as Group Reserves Auditor, do you recall if there were oil recovery efforts being conducted in Oman?

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A. I am not quite sure what you mean by "oil recovery efforts." If you mean efforts at recovering oil, then that's essentially what petroleum development Oman was doing all the time. So...

Q. That's a fair point. I was referring to the studies similar to the ones that you just testified about that you said were being conducted out of Rijswijk?

A. There were always some studies, some of them small, some of them slightly bigger, but one specific one that stood out was a study that was initiated I believe late 2002, early 2003.

Q. Who was principally responsible for that study?

A. The Shell laboratory in Rijswijk.

The leader of that team was Stein Christiansen.

Q. And what was the purpose of that study?

A. As I remember it, it was instigated at perhaps not the request, but certainly after

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some concern had been expressed by the Oman government, about the recent, sudden decline in production in the Oman fields.

And I must say that the unexpected and sudden decline that had occurred I believe in the course of 2001, 2002.

Q. Do you know who was paying the costs for this study?

A. No is the short answer. I can guess, but I do not know.

Q. Do you have an understanding?

A. Well, like I said earlier on, the Oman government was to pay a significant amount of all costs relating to studies and the like.

So extrapolating from that, it would be reasonable to expect the Oman government to pay for the study as well.

However, it may well be seeing the sensitivities of the case vis-a-vis the Oman government for whom also this sudden decline was also a disappointment, it may well have been that Shell may have offered to carry out a study at

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their cost, but I don't know. I have no indications, nor have I ever asked questions in that direction.

Q. Now, going back to your position at The Hague, how long were you there?

MR. TUTTLE: Why don't you start in 1981.

MR. HABER: That's right. I was just going to make that clear. Thank you.

THE WITNESS: That was until May 1985 when I was transferred to become head Reservoir Engineer with Maersk Oil and Gas in Denmark.

Q. And what was your position in

Denmark?

A. Like I said, it was the senior -- the senior, the lead Reservoir Engineer, so the most senior Reservoir Engineer in that organization with a staff of -- on the order of I believe it was 10 to 12 people, reservoir engineers and assistants.

And we were in charge of the Danish

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chalk, offshore oil fields, mostly oil fields, one gas field, in which Shell had a 40 percent interest, as I remember it.

Q. Did you -- I am sorry. Go ahead?

A. Maersk Oil and Gas were the operator, and they had an agreement with the other major industry shareholders, one of them was Shell and the other one was Chevron and Texaco, the other two at the time, and each of these three major oil companies had secondees working in the Maersk oil and gas operation.

Q. Did you have any responsibility for reserve reporting in this position?

A. No. Well, sorry. I am jumping ahead. By your asking the question, I assumed external reserves reporting, and there the answer is no. But certainly we were responsible for reporting reserves for the center.

Q. As part of the ARPR?

A. Yes.

Q. Now, how long did you remain in this position?

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A. Until end December 1987.

Q. Where did you go next?

A. I went to Brunei to be the head of the department at reservoir engineering.

Q. What were your responsibilities as head of reservoir engineering?

A. Responsibilities was to carry out studies in the Brunei fields and reservoirs, to produce forecasts, and to contribute or to develop development plans -- to produce development plans specifically about proposals for the Brunei offshore fields.

Q. How long were you in this position?

A. I was in that position for four and-a-half years, so that would lead me to '92, somewhere the second half of '92.

Q. Now, during your time in Brunei, do you recall there being any concerns about -- expressed about legacy reserves?

A. Yes.

Q. And what do you recall?

A. In fact, it was a very big item in

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our relations with the Brunei government.

Before my arrival in the end of 1996 --

MR. TUTTLE: '96 or '86?

THE WITNESS: '86, beg your pardon. In 1986, there had been a major change introduced in Brunei Shell's expectation and also proven reserves.

The reason why this was introduced is because it came about that there were an increasingly large number of reservoirs, and particularly -- but even fields in some cases, where we had negative reserves, and in particular negative Proved Reserves.

Now, that may sound strange to somebody who is not closely involved in the business. But what it means is that the way the reserves were and still are calculated is that you have an estimate of what they call an ultimate recovery, and that can be both on an expectation basis or on a proven basis.

You have an estimation of the

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ultimate recovery in the fields, and from that you deduct the cumulative production that has been taken away out of that particular part of the field.

And it was found that if the books weren't maintained -- weren't maintained or were kept in line with continuing production, that in quite a large number of reservoirs, cumulative production in fact will overtake even the expectation reserves estimates, and that of course is wrong.

It's clear that you have produced more on those fields than what you carry on the books, which is clear an indication that the books are wrong.

Now, the handicap that we had in those days is that there were about 3,000 reservoirs, some of them small but some of them big, but particularly the large amount of small reservoirs were very difficult to study for a number of reasons. And I will have to make it technical now, for a number of reasons.

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These reservoirs you would have to think of as stratified. Oil reservoirs tend to be in stratified, essentially sealed from each other. These reservoirs are then caught through in a phenomenon called fault, which is a major shift in the earth structure and therefore they are also laterally, not only vertically, but laterally they are also sealed from other reservoirs.

In some cases they are sealed, in other cases they are not sealed. You don't know. In fact you don't know until you actually start putting wells on either side of the fault. And you are lucky if you see the fault in seismic, and there is either pressure communication or there isn't. That's fine if you have five reservoirs; but if you have 3,000, it's a major task, believe me.

Particularly because in those days, the tools that we had in simulating and trying to understand the reservoir performance were fairly crude still. They were improving but they were still fairly crude, particularly the setting up of

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what we later called the geological model of the model describing the precise 3D dimensions of the reservoirs, and the possible relation with each other, the possible pressure communication with each other. The tools there were primitive.

And it is only in the last ten years or so, counting back from now, from where we are now, that these tools have improved enormously. So we had a big problem. We had reservoirs that we knew where the wells that had been completed on it, that significant amounts of oil had been produced but we had no way of explaining that.

Okay. The easiest would have been perhaps to just set all of these reserves to set a value so that each year you end up with zero proven reserves, remaining reserves in those fields.

But that meant that you just updated your books each year with cumulative production without actually showing any foresight about what reserves might ultimately be produced.

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That was the situation that Brunei Shell was in at the end of 1986.

So together with advice from central office, the decision was made to apply a large correction to all of these fields essentially based on an estimate of what would be a realistic recovery factor in each of these reservoirs.

What is the recovery factor? It is the quotient between recoverable reserves, ultimate recoverable reserves and the in-place volume in those reservoirs.

So what was said is that these are clean reservoirs, light oil, that means that you have a recovery factor -- you can expect a recovery factor, 35, 40, 45 percent.

And the recovery factor that was postulated was adapted to the type of reservoir that was seen. Larger reservoirs probably got a higher recovery factor because you have more room to play with additional wells.

So on that basis, a reasonably

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sound estimate was made of those -- of those reserves on a bottom line basis, lastly on a bottom line basis without looking in detail to each of the individual reservoirs. And what do I mean by "in detail"? I mean actually carrying out a simulation study.

That increasing reserve was made without consulting the government.

Now, as it happened just before that, the government had imposed on Shell, on Brunei Shell, a production ceiling. They said you shall not produce more than 200,000 barrels a day, 200,000 barrels a day.

And in the eyes of the government, Shell had introduced this large reserve change in reaction to this -- to this imposition of a production ceiling. And they were not happy with it, and that is putting it mildly.

So that was the start of a very lengthy and at times acrimonious debate between Brunei Shell and the government. And it was right at the start of that period that I entered on the

scene.

So here I was needing to field the questions and accusations from the government, not personally, not myself, by myself alone but with my staff, obviously.

I think I am happy to say that we managed to -- to provide some structure in the discussions that we had with the government. We set up a -- or I set up with the government a schedule of which fields we will go through, detail by detail, and to describe to them why the new estimate was at least a reasonable estimate given the amount of information that we had available.

And that series of discussions continued throughout the years that I was there, and it hadn't even finished when I left in 1992.

What had become clear by that time is that of those reserves -- which by that time we started to call legacy reserves, because they were a legacy from a previous period -- about two-thirds were justified or had in fact already

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been in those years, because production of course continued, had in fact been taken or overtaken by production.

About two-thirds of those originally booked volumes were reasonable, and about one-third had to be debooked, and they were debooked after we had done the proper studies.

Q. Do you recall when the reserves were debooked?

A. As when the studies of when those particular reservoirs had occurred. So you could see a gradual reduction in ultimate recovery for these reservoirs over the years starting in 1987/88, over the years. And it continued, but at a slower pace, because obviously what we addressed first were the larger fields and the larger reservoirs, so the corrections were larger initially, and they were gradually getting smaller in the later years after I had left.

Q. Do you recall how much volume that one-third reserves that you just spoke about represented?

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A. Not off-hand. The only figure that sticks in my mind was a figure of 600 million barrels reserves being added to expectation reserves. Now, how much is translated to proven reserves, I don't remember.

I can expect that it would be something on the order of 400 million barrels or something. So that was the total figure that we started with.

Q. When this calculation that you just talked about was performed, 600 million barrels were added to expectation?

A. To proven.

Q. To proven?

MR. TUTTLE: Wait, you said 600 million were added to expectation or proven.

THE WITNESS: 600 million barrels were added to expectation, as I remember it. And I can't remember the exact figure, but I would guess 400 million barrels proven.

BY MR. HABER:

Q. And the two-thirds that you

testified were justified, that would be two-thirds of the 600 million?

A. Expectation.

Q. And then of course the balance being the one that were the legacy that needed to be addressed over time?

A. Yes.

Q. I think that since we are on Brunei, when you became Group Reserves Auditor, did you have an opportunity to audit the Brunei operating unit for Shell?

A. Yes, I did.

Q. Do you recall when you conducted the audit?

A. As I remember, it was in 2002.

Q. Do you recall what you had found?

A. I had found that considerable progress had been made. This was of course ten years after I had left from my previous assignment there in Brunei.

Considerable progress had been made, in particular the issue of the legacy

reserves, and particularly caused by the use of a new tool that took care of much more realistic geological modelling, and that as a result, most of these legacy reserves had been either matured in actual supported reserves or have been taken off the books. There was only a very small fraction of that left.

Q. When you say a small fraction, do you recall the volume?

A. Not off-hand. Ten, 20,000,000 barrels, something like that, I honestly can't remember the precise figure.

Q. Do you recall when you conducted the audit?

A. It was combined with a similar audit in Sarawak across the border, and I believe it was late April or early May that I was there.

Q. Do you recall how long the audit took?

A. A week.

Q. When you conducted the audit, did you have anyone assisting you?

0083

A. No. I never did on any of these audits anyway.

Q. So throughout your entire tenure as Group Reserves Auditor, you never had assistance in conducting the audits?

A. Correct.

Q. Did you ever ask for help?

A. No. No.

Q. Did you ever consider it appropriate to have additional people to assist you in performing the audits?

MR. TUTTLE: Objection to form.

THE WITNESS: Not until --

BY MR. HABER:

Q. You can answer.

A. Not until the very end of my tenure in late 2003 when it -- well, when the imminent reserves changes, reserves recategorizations became clear.

Q. And what was it about these reserve changes that caused you to re-think seeking assistance?

0084

A. Well, we are jumping ahead, you know, and I am sure that we are going to cover a lot of ground between those two events with my earlier stay in Brunei and later.

But in essence, what has happened during the last two, three years of my tenure as Group Reserves Auditor was that the SEC had come up with additional guidance, which in turn led us to a gradual tightening of reserves and to additional introduction of criteria which hitherto hadn't been included in the reserves guidelines and therefore hitherto hadn't been included in my estimates -- in my audits.

That meant that my audits initially -- while my audits initially were, to a large extent, process audits in the sense that I would sit together with selected groups of staff, and I would make the selection.

We would sit together with groups of staff and we would talk about specific fields, particularly starting with larger fields. And in a session of an hour or so, they would tell me --

0085

they would explain to me what the -- they say the dimensions of the field were, what the problems were, and what the current production performance of this field is.

With my experience and with the trust that I know I had and the trust that I placed also with the staff, that allowed me a pretty good idea about the way in which the reserves were calculated in that field.

And therefore, the soundness of the basis of those fields. Typically in my audits I would cover in this way anything between half, maybe three-quarters of the total reserves portfolio of that company.

So that's how I used to work. You take a few examples, representative examples and I would select them carefully beforehand, and on that basis, you would form an opinion about the soundness of the reserves basis.

Back to 2003. With the gradual tightening of the group reserves, it became clear that there were a lot more aspects that we needed

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to take into account for each of the smaller units, smaller fields, and that therefore are more comprehensive review of the company's portfolio was going to be required.

And that therefore, my efforts would have been taken over by at least two, if not more people. And that's what I made in the recommendation in my final report at the end of 2003.

And of course, since then, my

auditorship has been taken over by in fact not just a couple of people, but by teams consisting of up to six, seven people.

Q. Prior to 2003 -- withdrawn.

So it's your understanding that your recommendation was accepted by senior management?

A. Which recommendation?

MR. BEST: Which recommendation?

BY MR. HABER:

Q. The recommendation to have additional staff perform audits?

0087

A. Yeah. In fact, they had already made up their minds that a much larger effort was going to be required. At that time in particular, it was felt that a detailed field by field review of the entire group portfolio was going to be required as part of the recategorization of reserves. And that is what happened.

Q. Prior to 2003 when you made the recommendation for more staff, had you inquired of any of Shell's competitors of how they staffed their audit -- their internal audit program?

A. Not inquired, no.

Q. Were you aware of, let's say, how Exxon was staffing their internal audit group?

A. By word of mouth, by hearsay, yes.

Q. And what had you heard?

A. That Exxon had a team of 10, 12 people that were overseeing the process of reserves reporting in Exxon.

Q. And when had you heard this?

A. I cannot remember. It must have been 2001, something like that, 2002, I don't

0088

know.

Q. But it was between the time you started in your position in 2003?

A. It was certainly after my starting in the position, yes.

Q. Had you heard anything with regard to staffing of an internal audit team at other of

Shell's competitors, such as Chevron, Texaco Chevron?

A. No. No.

Q. Was Exxon the only one that you had heard about?

A. The only one that I can remember right now, yes.

Q. Was -- to your knowledge, was Exxon the company that people within Shell looked to with regard to how things were being done in the industry?

MR. TUTTLE: Objection to form. Calls for speculation.

THE WITNESS:

A. As I explained earlier on, Shell

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had their own way of reporting Proved Reserves right from the start when the SEC came about with the request of proof of that.

And that led to -- and that with the agreement that or the understanding at the very least that was reached with the SEC, led to Shell staff throughout the organization being aware that yes, there was this need to report reserves to the SEC.

But Shell had their own method, and they relied on the center in The Hague coming forward with detailed instructions on how to prepare Proved Reserves.

So in other words, Shell staff, throughout the organization in the operating companies, were not directly concerned with things like the SEC definitions. They were aware of them, they aware at the end of the guidelines that were issued, but they saw the reporting of external Proved Reserves as the responsibility of The Hague. They prepared the estimates, but that's as far as it went.

0090

Now, as far as comparing ourselves with Exxon, we didn't see any reason for it, any comparison of numbers that may have been heard, and the 10, 12 people that I mentioned to you, it wasn't clear at all whether those were in fact ten, 12 senior engineers or two senior engineers and a lot of clerical staff.

I mean, and anyway the subject didn't interest us, because we saw and we were aware that Shell had their own method, which by all accounts was in conformance with the original SEC definition and that therefore any comparison with staffing levels would be irrelevant.

On top of that, it wasn't just me going around from the center checking reserves. There was a whole system in place of what, by that time in the -- say in the early 2000s, what was called Value Assurance Reviews.

Now, those would typically consist of a number of senior experienced individuals in the organization. It would go around two operating companies and review projects, status of

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projects, status of uncertainties, status of development, and they would also look at project reserves.

In other words, there was also a very tight level of control through that system of Value Assurance Reviews.

And that was another reason why it was felt that there was no point in comparing Exxon's organization against ours. It was felt throughout the organization that the controls that we had in place, both through myself and through the VAR reviews, were adequate.

Q. We will talk about the VAR reviews sometime later.

In your answer, you had mentioned a couple of things: One, you mentioned conducting process audits. Were there any other type of audits that you conducted?

MR. TUTTLE: Objection to form. Characterization of the testimony.

THE WITNESS:

A. There was only one audit that I can

0092

remember that was specifically called a process audit, and that was the one carried out for Nigeria, for SPDC Nigeria in 2003. All the others were regular audits.

I use the word process audit, just now in describing them, in the sense that -- and what I meant by that is that I didn't actually go and check with the team.

With the field teams that I would gather around the table, I didn't actually go and check, okay, which wells did you drill, what sort of porosities did you see there, and how did you translate those porosities into your assumptions for your reservoir simulation models.

That is the sort of detail that I would expect the supervisor of those engineers would do. Mine would be at a higher level, saying okay, how many wells have you got, show me a typical cross-section of the reservoir simulation, how you applied it, how did you calculate the average porosities from your averages in the wells. Do you take any -- say any preference to

any particular well, that sort of thing.

So my review would be on a higher level than the detailed review that I would expect the supervisor to carry out.

Q. Now --

A. And that's what I mean by process. I looked at the process in which they came up with the reserves estimates. And from that space, if I like the process, then I had no reason to doubt the validity of the reserves estimate that came out of that work.

Q. And the staff and engineers that you just mentioned, these are staff and engineers who are working in the operating unit?

A. Correct, yes.

Q. And earlier, you had said that -- you had said, "with my experience and with the trust that I know I had and the trust that I placed also with the staff," in conducting your audits. Did you ever come to, after the fact, question whether that trust was properly placed?

MR. TUTTLE: Objection to form.
0094
Calls for speculation.

MR. HABER: It calls for his determinations after the fact.

THE WITNESS:

A. The short answer is no, certainly not for the Shell operated companies, for the Shell-staffed companies. There were one or two question marks that I had for non-Shell staffed companies. BEB stands particularly to mind, where later on I found that not all of my questions had been answered.

I forget what particular instances, so if you ask me for examples, I can't give them to you. But other than that, those were definitely exceptions within the Shell companies.

No. I have never had reason to doubt say the straightforwardness of the staff and the openness of the staff that they displayed in front of me.

Q. Did you ever have questions about the experience of the staff?

A. Not really, no. No. Don't forget
0095
that I knew many of these companies either because I had been working there myself, or because I had been visiting them there during a previous assignment in the early '90s when I was senior consultant in the organization in The Hague.

MR. HABER: Okay. I think we are running out of tape and this is probably a good time to break for lunch.

THE VIDEOGRAPHER: Going off the record at 12:59. This is the end of tape number 1.

(Lunch recess taken)

THE VIDEOGRAPHER: This is the beginning of tape number 2 returning to the record at 1:40 from 12:59. Go ahead.

BY MR. HABER:

Q. Good afternoon, Mr. Barendregt.

A. Good afternoon.

Q. Before we broke, we were talking about audits generally and reliance on operating staff and engineers.

I just want to ask you one

0096

follow-up question on that topic. During the audits that you conducted, did you ever find that the rotation of positions within the operating units caused you some concern about the reliability of the information that you were receiving?

A. Not as a structural complaint. I mean, sometimes you might be aware of some engineer around the table being fairly new on the subject and therefore he or she would be a bit more quiet than the others.

But the thing is that with these teams, with these field teams, it would be very, very rare indeed if all of them were new and hardly knew what they were talking about, so to speak.

So between them, you would always have a number of people that would actually remember things as they had been done the year before or something like that.

Even then, people that were new were, I always found, were certainly sufficiently

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knowledgeable about their subject to be able to contribute to the conversation if it came their way.

Q. Now, going back to the Brunei audit that you had conducted, I am going to ask you a couple of questions about the audit report that you had prepared. Actually, first on, I am going to ask you about a draft report.

(Barendregt Exhibit No. 2 was marked for identification)

We are marking as Barendregt Exhibit 2 a draft note which is dated May 5, 2002. It's a report, and the title of the report is "SEC Proved Reserves Audit, Brunei Shell Petroleum SDN BHD 29 April-3 May, 2002".

The Bates number is RJW01001167 through RJW01001170.

Mr. Barendregt, have you seen this document before today?

A. Obviously, yes. It looks like the draft report that I left with or shortly after my departure and sent over to Brunei Shell.

0098

Q. Now, do you recall -- in that answer, do you have any recollection if you prepared this draft while you were in Brunei Shell or immediately thereafter?

A. Before I answer that question, I think it's useful if I explain my procedures when carrying out with audits like these.

Q. Sure.

A. I liked to strive before leaving, on the last day of my audit, a complete draft of the report that I was going to issue on the auditing question. That didn't always happen. For obvious reasons I was very busy right until the very last day.

But usually, we then a few days after the end of the audit, I managed to get out a draft report to the company in question for their comments.

With that report, I always left instructions to the extent that I said, "Look, this is my draft report. I want you to go through it and check it on facts -- on matters of factual

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detail; in other words, "Did I get any of the facts wrong? Then please let me know".

"Secondly, you can give me your opinion about opinions that I have expressed and I will certainly read them. But what I will ultimately do is issue a report that expresses my opinion and my opinion alone."

So these reports would typically receive small corrections here and there, mostly of facts that I had got wrong. And ones that had been done and they would be typically between two and three weeks after the end of my audit, depending whether I was available in fact, because I might have another audit immediately afterwards.

And then I would issue it as a final note.

Q. Do you recall any instances where an operating unit did challenge an opinion that you had formed?

A. Not any specific instances. But I am sure on once or two occasions that it happened, yes.

0100

Q. On those occasions where it happened, do you recall if you changed your opinion, in light of what was being communicated to you?

A. I am just really trying to think of any particular examples here, which I can't.

Sometimes I might slightly change the wording on the facts leading to my conclusion, but I do not recollect any instances whereby I basically reviewed my opinion.

The only example that might be an exemption that I can think of, and I am thinking of while I am going through it, that an audit in Norway, where due to a very poor contribution by one of the contributors and the absence of his supervisor at the time, I ended up, without my knowledge, with a totally wrong set of facts, data, on which I based an opinion which later on was found to be unfounded.

The absence of the supervisor in question was sorely missed, and in the end on that particular audit, I had to come back at some later

0101

stage and redo the audit or parts of that audit again, this time with the supervisor present.

But that's an exception. That's the one exception that I can think of. But by and large in general, no, I would rarely find cause for changing my opinion.

Q. With regard to Shell Norway, do you recall when this event occurred?

A. 2000. The year 2000.

Q. Now, if you could look at Exhibit 2 for a minute.

(Witness complying)

I am sorry. I just want to check one thing here.

(Pause)

Looking at Exhibit 2, I just want to go back to my question that resulted in the last exchange. I had asked you if you prepared this draft while you were in Brunei Shell or immediately thereafter, and you answered it by giving me what your general practice was.

And I just want to know now, having

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said that, what's your recollection with regard to when you prepared Exhibit 2?

A. Well, I look at the date, which is a couple of days after the final day of my audit. I know that that particular -- those particular dates were a Monday through Friday. So this note was prepared on a Sunday.

I suppose that the major part of the text was prepared after my departure from Brunei.

Q. Now, if you look at the fourth paragraph, the one that begins "the audit found"?

A. Yes.

Q. There is a change that says, "although the volume of 'legacy' reserves have decreased substantially in the past few years, the continued presence of 'legacy reserves' remains an area of concern."

Is this a change that you made or is this a change that you made in response to information --

A. A change from what? I can only --

0103

Q. I am sorry. I just have to finish the question.

A. Sorry. Sorry.

Q. Is this a change that you made or is it a change that you made in response to information learned during the audit?

MR. BEST: Objection to form.

MR. TUTTLE: Objection to form.

THE WITNESS:

A. When you say change, I do not understand what you mean, a change -- I see only one text and I do not remember what has changed. This must be the preliminary report, and there must be a final version obviously that you have compared it against.

BY MR. HABER:

Q. Well, I am just looking at the part that's underscored, and there appears to be an addition.

This text appears to have been added from an earlier draft?

A. An earlier draft?

0104

Q. Let me ask you so I can head off an objection.

Do you recall preparing a draft prior to May 5 --

A. No.

Q. -- 2002?

A. No, I don't. That doesn't mean that I didn't do it, but I don't recall it.

Q. Now, looking at the text that we just focused on, do you recall which fields were -- that you were referring to in this text?

A. They would have been in the major fields Southwest Ampa, A-M-P-A, and Champion.

Q. Now, if you look at the paragraph above it, it says "the last previous SEC proved reserves audit for BSP was carried out in 1998."

Do you know if that was carried out prior to the changes in the guidelines that we talked about earlier today?

A. Probably. Probably. The guidelines were at the -- issued towards the end of 1998. I would imagine that these were being

0105

ahead of that, but I don't know.

Q. And the audit was carried out by your predecessor?

A. Yes.

Q. Who was your predecessor?

A. Ad de la Mar. A-D D-E L-A M-A-R.

Q. Now, if you look at the third sentence in this paragraph, and it I believe refers to the current audit. It says, "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 reserve submission."

A. Yes.

Q. How did you verify these items that you had written in this Exhibit?

0106

A. Before I answer that, I think it's useful to bear in mind that this is a pretty much a standard sentence that I included in all of my -- all of the summaries of my sentence.

Now, when it comes to --

MR. TUTTLE: So you want for each of the items that you read? So --

MR. HABER: Well, if there is something that he can talk about in a summary; if not, then in each, yes.

THE WITNESS:

A. Essentially, as you will have seen in my report, the method that I used in checking each of these items, is by means of a spreadsheet that I included in my -- in full in my report which gives the various criteria that were dependent -- that were important for assessing the quality of the reserves estimates in that particular company.

And that would allow me then to add in comments to each of these criteria where they had not be good. I also allowed it to score the

0107

company on that particular item.

Yeah. If you want to know how I did it, then I can only refer to the -- to the list, to the checklist that I included in each and every report.

(Barendregt Exhibit No. 3 was marked for identification)

BY MR. HABER:

Q. We are marking as Barendregt Exhibit 3 a note dated May 31, 2002. In the subject the title line reads "SEC Proved Reserves Audit, Brunei Shell petroleum, SDN BHD, 29 April - 3 May 2002." The Bates range is RJW00061605 through RJW00061620.

(Witness reading document)

Mr. Barendregt, have you seen Exhibit 3 before today?

A. Yes. It looks like my final report of the Brunei audit.

Q. And if you look at the lower left-hand corner, there is a signature. Is that your signature?

0108

A. Yes, it is.

Q. Now, if you look at the attachments, a moment ago you mentioned a spreadsheet.

And I think you might be referring to one of the attachments in this document?

A. Yes. Attachment 3.

Q. Now, in terms of verifying, let's say for argument's sake, technical maturity, and in answering the questions that are listed in the left-hand column, did you make your comments which are in the right column based on information that was provided to you by staff, in this case, Brunei staff?

A. Yes.

Q. Did you do anything independent of what was communicated to you to verify the information that was being communicated to you?

MR. TUTTLE: Object to form.

BY MR. HABER:

Q. You can answer.

A. I am not sure what you are meaning

0109

there. I was independent when I made the new review. I listened to the staff giving the explanation of what the field was like.

But as I made clear before, what I did not do was to check and see whether, on a very detailed level, staff had transferred the correct values from wells and well data and what not into the models.

Q. And so when you say in the -- we could look at Exhibit 2, that your audit included a verification of all those various pieces of information, that verification then is based upon the information that was provided to you from the operating unit staff.

Correct?

MR. TUTTLE: Objection to form. Characterization of the testimony.

BY MR. HABER:

Q. You can answer.

A. It -- my opinions were based on the information that I was given, together with interpretations and opinions by myself.

0110

Q. You can put these aside for the moment.

Actually, I am sorry. I apologize. I am sorry. Can you pick up Exhibit 2 again for a moment?

A. Okay.

Q. If you can turn to page two of attachment 1?

MR. BEST: Bates number?

MR. HABER: I am sorry. This is 1169.

(Witness complying)

THE WITNESS: Okay.

BY MR. HABER:

Q. I am looking at the second sentence of number 6. It says, "Any incomplete hydrocarbon column penetrations are thus also addressed probabilistically, i.e." and then it's underscored "proved areas", and it's also in quotes, "(ref. SEC definitions) are not adhered to rigidly."

Do you recall what the issue was that was reflected in what I just read?

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A. This seems to refer to what we later referred to as the LKH issue, lowest known hydrocarbons.

A reservoir is rarely a flat pancake. And particularly in the case of Brunei, you would always found that the reservoir would be tilting, would be running at the slope. That meant that across that reservoir, you could see various what we called fluid levels.

Typically in Brunei you would have a gas cap, i.e. the top of the reservoir would be filled with gas. You would get a layer of oil, and then underneath that water.

When you first drill a well through that reservoir, you might see early gas if you were really high up in the reservoir. You might see gas and oil if you were halfway. You might see pure oil, you might see oil and water, or you might in fact see nothing but water, depending on where you were, and in some cases it was difficult to determine beforehand where you were.

Typically this is the case in

0112

exploration and appraisal wells. Appraisal well is a well that you drill in a stage where you are still exploring and trying to define the actual content of the reservoir.

One of the instances where the original SEC definition of Proved Reserves is specific is about this issue of fluid levels. They say that if you drill, for instance, gas and oil, then you can only assume for Proved Reserves that the oil that you find as its deepest penetration is where you saw it deepest in the well.

That may still mean that there is some oil underneath that all the way down to the oil water contact as we call it, that is therefore not seen by the drill bit.

And that oil, even though you can interpret it perhaps by other means, either from seismic or from pressure measurements or whatever, there are various means of having at least a very good cast of that, that oil could not go into the SEC definition, be included in the Proved Reserves

0113

estimate.

Q. And the SEC definitions that you reference here, these are now with regard -- with reference to the staff interpretive guidance or --

A. No. The other ones.

Q. SX, regulation SX Rule 4-10?

A. Yes. Correct.

Q. So it's Rule 4-10?

A. Correct.

MR. WEED: Counsel, if I might make a quick note just for the clarity of the record, sometimes the Shell engineers from Europe refer to S-E-C as SEC, and that will occasionally come up.

I think the court reporter got it right this time. I just want to make it clear that because we usually in the States refer to it as strictly S-E-C. If you hear SEC, that's the same thing.

MR. HABER: Okay. Thank you.

MR. WEED: Thank you.

BY MR. HABER:

Q. Now, the next sentence says,

0114

"Although accepted Group practice in the past, this is no longer in line with Group guidelines."

Had the group guidelines been revised to address this proved area issue or the LKH issue that you mentioned?

A. Yes. I remember that in 2001, I had a fairly strong hand in revising the guidelines.

And this is one of the areas that I addressed more specifically in the guidelines. That was in the reaction to a similar instance that they found in an earlier -- in an earlier audit in 1999 with SNEPCO in Nigeria.

Q. Now, the next sentence says, "This should be addressed."

Did you provide BSP with advice on how to address the issue?

A. No. Because it was abundantly clear what they needed to do.

The fact that this doesn't feature prominently in, for instance, the summary on the first page, is that the effect of this in the BSP

0115

context was small. In most of these cases, the reservoirs have been penetrated by many, many wells because most of these fields are very mature.

And that therefore there are very few areas where we have the situation where we haven't actually seen all of what we call the oil column, and therefore very few areas where we haven't actually seen an oil water contact and the gas oil contact.

Q. Now, if you look at number 7 on Exhibit 2, which is also on 1169, same page. The recommendation, it says, "The auditor's opinion is that probabilistic addition of reservoirs to field level is not to be recommended."

What was the basis for that recommendation?

A. Can I read it first? Because the explanation is in the following paragraph obviously as you can see.

Q. Please go ahead.

(Pause)

0116

MR. FERRARA: Excuse me. What paragraph are you on again, Jeffery?

MR. HABER: This is paragraph number 7.

THE WITNESS:

A. There I give three reasons for my opinion, as you well have seen: First, these are mature fields. I already made that point on several occasions.

And in mature fields in 1998, we had the recommendation that rather than do a probabilistic reserves estimate, we would do a deterministic estimate, i.e. based on a specific realization, as we called it, of the reservoir model and determine that against the performance of that reservoir, i.e., at the fluid level -- the fluid production, the gas production, the oil production, and water production; and thereby compose a picture, a historical picture trying to match the performance against the model results.

And this is entirely different from the probabilistic reserves estimating that had

0117

been used before '98 in mature fields.

And what I am saying is just simply repeating that particular -- that particular premise.

Then the other two points: They are rather technical. What it says is that if you have various reservoirs in one field, and you add these up probabilistically, then it is very important whether you assume the individual reservoirs and the assessment of the recovery in the individual reservoirs is independent of that of the other reservoirs.

Now, if it's independent, that means that the total reserves estimate becomes narrower, i.e. the Proved Reserves, and the high estimate of reserves become closer and therefore closer to the expectation reserves.

That is -- yeah. You will have to take it from me, but that's a technical fact.

BY MR. HABER:

Q. That's one of the reasons that I asked if you could sort of put the technical into

0118

layman's terms so I can understand it.

A. Well, in order to do that, I would have to explain to you, and I am more than happy to explain to you a method what the Monte Carlo analysis is.

You have a situation -- you have a situation where you have a distribution describing the various outcomes of a reserve in a particular reservoir, say.

And typically, we tend to describe it by some sort of a bell-shaped curve. I am sure you have seen these bell-shaped curves elsewhere, and the bell-shape curve has its peaks somewhere around the expectation, as we call it.

And somewhere on the left, you have a lower value, and that depending on whether you take 90 percent or 95 percent is then your proven estimate. And then on the other side is a high estimate which we are not concerned with. You have a bell shape like this for each and every reservoir.

Now, there is one technique called

0119

the Monte Carlo analysis, which tries to establish a probabilistic sum of all these reservoirs together.

And you do that effectively by throwing a set of dice and deciding on that basis whether you take for a reservoir a low value or a medium value or a high value or any value in between.

You set it aside and take the next reservoir and you do a similar thing, and the next reservoir and the next reservoir.

And you do that through all of the reservoirs in succession, then you add up all these various estimates. And as you well have seen, some of the reserves in some of the reservoirs will have come out in the low side, some of them will have come out on the high side.

It's a matter of, what is called in the UK, swings or roundabout. You come up with a result that is fairly narrow, some low estimates chances of estimates will be compensated by chances of estimates on the high side.

0120

That is the case where you assume that these reservoirs are independent of each other.

Now, there is also a possibility and a fairly strong possibility that the reserves estimate in these reservoirs are in fact dependent.

What do we mean by that? It's that if you have a low outcome in one reservoir, then it's likely that your misguess, your -- say your estimate has been caused by a particular assumption that is -- may not be clear at that time, but that also affected all of the other reservoirs because you have applied the same method of calculation to each of these bell-shaped curves.

Now, that means that you really have to be more careful that if you go through the process again of taking one realization, one value out of the bell-shaped curve for each reservoir and you come out with a low one, then you must also take a low one from the other reservoirs

because there is some dependence, yeah?

And that means -- as I hope you can see, means that the total bell shape of all the reservoirs together will be wider, because you will more get a situation of low values being added to low values and et cetera, and on the high side the same.

And therefore, if your reservoirs are dependent, and to some extent that will always be the case if it's in the same field, and they are say modeled by the same method, you have to be careful, because the effects might be that your total range is too narrow, therefore your proved is too close to your expectation and effectively is too high. And that's what I am saying.

Q. Okay. I appreciate it. Thank you. If you turn to the final note which is Exhibit 3, I would like you to take a look at number 6 in attachment -- I believe it's attachment 1, on page 61607?

MR. BEST: I am sorry. Did you say a paragraph?

0122

MR. HABER: Yes. Paragraph 6. I am sorry.

(Pause)

My question, you will see there, the words "economically robust" are underscored there.

Q. What did you mean by that?

A. Shell did and still do screen their projects. And by "their projects," I mean activities which generate a certain amount of oil or gas activities like drilling a well or developing a whole field, such projects will be screened economically.

And one of the parameters that would be used would be what the Shell called a screening value oil price, which around this period was something in the order of 14 or 16 dollars a barrel, so conservative even for those days.

"Economically robust" meant that the result was economical for a range of parameters, for a range, for instance, for the

0123

typically for the proven reserves, the expectation reserves, et cetera.

Economically robust was one of the conditions that was introduced in -- back in 1993 in the reserve guidelines in 1993. The other one was technically robust.

And okay. That's meant -- that is what was meant with economically robust.

Q. And why was it that undeveloped reserves in a number of fields and reservoirs needed to be economically robust in order to be certain of their future development?

A. This is five years ago and I don't remember the individual field instances in -- on which this remark was based.

But I can only speculate that a number of these activities may have been associated with the legacy reserves, legacy reserves which were identified as reserves but not

really associated with identified -- identified activities like drilling a well.
But further on that, I'm afraid I

0124

can't tell you.
Q. Okay. Is there a difference between commercial maturity and economic robustness?
A. For all practical purposes, no. No.
Q. Now, when you concluded the audit, I believe you said earlier that you met with the staff of the operating unit.
Is that correct?
A. During the audit, yes. Yes.
Q. Just take me generally speaking, not necessarily with Brunei, but generally speaking.
When you finished the audit, did you have a meeting with people or staff, engineers at the operating unit to discuss your findings?
A. Yes. Yes.
Q. And was that a standard practice you had during your tenure as Group Reserves Auditor?
A. Yes. Yes.

0125

Q. Now with regard to Brunei, do you recall conducting such a meeting at the conclusion of your audit?
A. Not specifically, but I must have done, yes. Yes.
Q. Let me take this to the general again. When you met with the staff and engineers at the conclusion of the audit, did you make a presentation?
A. Mostly, yes. Not always, but mostly. It depended on the time squeeze that I was in. Sometimes I was in more of a time squeeze than other times.
Q. When you did have the time to make the presentations, did you prepare Powerpoints or view graphs for the staff to review?

A. I am sure you know the answer to that, yes.

Q. I have to ask them.

So okay. Do you recall preparing such a Powerpoint presentation for Brunei at the conclusion of your audit?

0126

A. Short answer is no, I don't specifically view it. Your question was did you view it? I cannot tell you. I would have to look through my files.

Q. At the meeting that you had in Brunei, do you recall having any discussions about a clean sweep of the legacy reserves?

MR. TUTTLE: Objection to form. Characterization of the testimony.

MR. HABER: I am just asking him a new one.

MR. TUTTLE: You said at the meeting do you recall, and he testified he doesn't recall, but he must have had one.

BY MR. HABER:

Q. Do you recall at any time during your -- I will rephrase.

Do you recall at any time during your audit discussing a clean sweep of the legacy reserves with BSP staff or engineers?

A. Not specifically, no. No.

I think just further on that, I

0127

think it's useful to that in mind that the legacy reserves by that time were a very small portion of the Brunei reserves, so therefore they didn't feature very highly or very prominently in my report.

(Barendregt Exhibit No. 4 was marked for identification)

Q. Let me show you what we have just marked as Barendregt Exhibit 4.

(Witness reviewing document)

And in particular, I am going to be asking you questions about slide six, which is 1176. And let me identify this document for the record.

This is a Powerpoint. It's dated -- it's hard to say. There is a date on the bottom which is February 15, 2004. In the upper right-hand corner it says, "SEC reserves Audit BSP, 27 April - 3 May, 2002."

The title of the document is "2002 SEC Reserves Audit Brunei - conclusions."

The Bates number is RJW01001171

0128

through RJW01001177.

A. Just a remark there, you mentioned the date of February 15, what it is in my Powerpoint I have got an automatic feature or I had an automatic feature which could take the current date as the date of printing.

Q. Okay.

A. Somebody must have printed it off in February 15, 2004, so it says that date.

Q. So do you recall preparing this document in or about May of 2002?

A. Like I say, not specifically. But obviously I have prepared it, and I will accept that this is what I prepared.

(Witness reviewing document)

Q. Does this refresh your recollection about discussing a clean sweep of the legacy reserves in Brunei?

A. Not totally, but I am getting there.

Q. Do you need a little more time to get there?

0129

A. No. No. Fire off the questions.

Q. Well, I am interested in the last bullet point on slide 6, which is Bates numbered 1176. You say, "Recommend to make the 'clean sweep' when we upgrade proved developed reserves."

Do you recall why you were making that recommendation?

A. As far as I recall, no. I would have to reconstruct it from what it is that I have said here.

But I would have -- I would guess that the reason why I made it is that this was a suggested way of getting rid of the final small percentage of proved legacy reserves.

Q. And by "clean sweep," what did you mean?

A. Making sure that anything that wasn't fulfilling the guidelines, as we had it then, was taken off the books.

Q. So that would be a complete debooking --

A. Yeah.

0130

Q. -- of whatever reserves fell into that category.

Correct?

A. Yes.

MR. TUTTLE: Objection. Characterization of the testimony.

THE WITNESS: If I refer to the same expression clean sweep in point 2 of that paragraph, what was -- and this is the historical situation, what was meant with the clean sweep there is that all of the reserves, the 600 million barrels that I talked to you about earlier, the 600 million barrels Expectation Reserves that were added in 1986 -- as I have already explained to you before that there has been some pressure, particularly from the government, to take away all of those 600 million barrels except the reservoirs, that meanwhile we had been making studies in, to just strike those off the books.

And we had always resisted to make such a clean sweep because we felt that certainly a sizeable portion of those reserves were in the

0131

end justified, except we just didn't know yet how.

So the clean sweep that we made there is sweep it all off the board, take it all out.

This is the same sort of clean sweep that we -- that I may have been referring to there.

Q. Okay.

A. Yes.

Q. Okay. You can put this aside.

A. Okay.

(Witness complying)

MR. TUTTLE: Are we on a new topic? Want to take a couple of minutes?

MR. HABER: Just a couple of follow-up and then we can break.

Q. Do you know if BSP in fact engaged in a clean sweep and debooked the reserves that were not in compliance with the guidelines?

A. The only one that I am aware of is the one that was done at the end of 2003 where the companies, the major companies, including BSP,

were instructed to take out all those Proved Reserves that weren't in fact covered by a firm plan yet, either FID, or in the case of Brunei where they could be small activities, typically an additional well or a sidetrack of a well, all of the Proved Reserves that were not covered by these confirmed activities were taken off the books.

So there was a lot more than just as any legacy reserves that we were talking about here.

Q. So you were -- I will spit this out. I am sorry. You are referring to Project Rockford?

A. Yes. Yes.

Q. Now, prior to Rockford, do you know if your recommendation about a clean sweep was in fact taken up by BSP and implemented?

A. No, I do not. And it would be too small to see me appearing at the end of the year for the total reserves submissions, from what I remember.

Q. One other question: In one of your

earlier answers, you had said that you were involved in the 2001 revision to Shell's guidelines?

A. Yes.

Q. What was your involvement?

A. A pretty strong one. The preparation of the updates of the guidelines was the responsibility of the group reserve's coordinator, which until the end of 2000, was Remco Aalbers. Remco was replaced by Leigh Yaxley who was an ex Shell employee and who had reapplied for a job again and was nominated to be the group reserves coordinator.

Lee -- I knew Lee from earlier years from his previous assignment, we had both served in The Hague together. Lee wasn't very happy mostly for family reasons, yet meanwhile married a second wife from Indonesia, who brought her mother-in-law with her, and they had a child in between.

And the mother had to go back to Indonesia because she couldn't get a residence

0134

permit, which made his wife particularly unhappy, which put him under a lot of domestic stress.

Therefore, Lee was by no means as effective as Remco was. And towards the end of the year, he quit before the end of the year ultimately.

But even before then, he didn't really take an active role in the things that, in my view, he should have done. And one of them was the preparation of the updated guidelines, which would typically happen over the middle of the year, to be issued September/October timeframe.

Since there were a number of issues that I felt had to be included or at least to be put in to make the guidelines more precise, I took it upon myself after checking with Lee, that shall I have a first go at updating the guidelines? And he agreed, so I did.

Q. When you had made -- withdrawn.

Did anyone in EP question whether it was appropriate for you to be revising the guidelines?

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MR. TUTTLE: Objection. Calls for

speculation.

MR. HABER: I will rephrase that.

Q. Did anyone communicate from EP to you whether it was appropriate for the Group Reserves Auditor to be revising the guidelines?

A. Nobody present in The Hague at the time that I remember. The one who was very vocal about it was Remco Aalbers, who I occasionally got in touch with. He was by that time in his new job up in Assen, and he made it clear to me that that would have never happened under his reign, and I agreed with him.

But there it was. I felt that new guidelines, new good quality guidelines needed to be issued. And if there was nobody else around who could do them, then I would be prepared to do them. And unless somebody actually stopped me doing it, I just went ahead and did it.

Q. Did you consider at the time whether it was a conflict for the Group Reserves Auditor to be revising Shell's guidelines?

0136

A. Not really, no. No.

MR. HABER: All right. This is a good time to break.

THE WITNESS: Okay.

THE VIDEOGRAPHER: Going off the record at 2:37.

(Short recess taken)

THE VIDEOGRAPHER: Returning to the record at 2:52 from 2:37.

BY MR. HABER:

Q. Mr. Barendregt, I am going to jump back to your CV again. I believe we were in Brunei, which sort of led us through this whole discussion.

I believe you said that you were the head Reservoir Engineer from '87 to sometime in the latter half of 1992 --

A. Correct.

Q. -- is that correct?

A. Correct. Yes. That's correct.

Q. Where did you go after Brunei?

A. After Brunei, I went to The Hague

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where I became one of the reservoir engineering consultants, and this particular area of responsibility being Southeast Asia and Africa, below the sub Sahara Africa as it was called.

Q. And what were you responsible for doing as a reservoir engineering consultant?

A. I was responsible for reviewing plans by the various operating companies, for reviewing particular projects.

And that would often mean me going out together with a number of colleagues from the other petroleum engineering disciplines like production, geology, petrophysics, et cetera, to operating companies if they had a particularly difficult project on their books.

And we would go out and review those plans, make recommendations regarding any changes to those plans as appropriate, and also advise Shell central office management about the soundness of the projects that would come out of the operating companies.

Q. Which operating units fell within

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this category of sub Sahara Africa?

A. That would be Southeast Asia, so Malaysia, Brunei, Philippines, Australia, New Zealand, and then Africa, sub Sahara Africa would be Nigeria, Gabon, and a very, very high tiny holding of Congo in Zaire.

I am not sure whether that's a comprehensive list, but those are the major players.

Q. How long were you a consultant in this capacity?

A. That was until the end of 1996 when I was transferred to Lowestoft, that we mentioned earlier.

Q. And what were your responsibilities at Lowestoft?

A. I was a development manager there. And that effectively equates to being the head of petroleum engineering, petroleum engineering manager in charge of a group of approximately 40 people, engineers and staff, and responsible for preparing development plans for the southern gas

0139

fields, making our proposals and the like, and also for maintaining liaison with Shell Gas Marketing in London, who would make the sales gas nominations with the gas customers.

We would prepare the forecast and say this is for the next year or for the next quarter, this is how much gas you can make available because we think or we see that this is the gas that we can make available in the next -- in the next month, in the next few months.

Q. What is a development plan?

A. Development plan is a plan describing the activities that are needed in order to bring a field or a reservoir into production. It consists of a number of -- of a number of things: First, very importantly, it consists of a description of the surface facilities, how many platforms, how many wells.

Also targets of these wells, whether they were just simple wells or whether they were wells with what we call sidetracks.

You go in through one whole in the

0140

surface, and then somewhere in the subsurface it splits into 2, 3, 4, 5, 6, 7, different bore holes, each penetrating different parts of reservoir, so it would describe that.

So it would describe the setting up of a model which invariably at that time we would set up in order to assess the future performance of that field. It would describe the assumptions that went into that model. It would include a comparison with original data, particularly log data from the wells.

And it would finally include an economic evaluation of the project or the set of activities that was being proposed.

Q. What did the economic evaluation

entail?

A. It would be based on a forecast which was going to be generated by people in my jurisdiction, under my -- in my group. And it would -- that forecast would be translated with certain assumptions regarding future oil price or gas price that would be related to a cash flow.

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And that cash flow would be set against the cash flow, the initial development cash flow, i.e., the costs of building the platform and installing the platform, drilling the wells.

And that will give a certain monetary forecast. And that forecast will be evaluated to see whether it fulfilled the economic criteria that Shell was hitting against.

Q. Now, the development plan that you just described, is that different from a field development plan or is that one and the same?

A. No. It's one and the same, yes.

Q. Now, is it necessary to have field development plans in place before an operating unit can book reserves, Proved Reserves that is?

A. Not before 2003, according to our guidelines.

Q. And when you say not before 2003, are you referring to guideline revisions in 2003 or after Project Rockford?

A. They appeared both at the same

0142

time.

Q. When were the guidelines revised and disseminated in 2003?

A. I can't remember off-hand, but it must have been again in the period October November, thereabouts.

Q. Now, any of the information that you just mentioned that goes into development plan, are these items considered in determining technical and commercial maturity?

MR. TUTTLE: Objection to form. Foundation.

THE WITNESS:

A. Ultimately, yes.

BY MR. HABER:

Q. So is it fair to say that in determining whether a particular project is technically mature or commercially mature, it would be a good practice to have a development plan in place?

A. Yes.

MR. TUTTLE: Objection to form.

0143

BY MR. HABER:

Q. I am sorry. The answer is yes?

A. The answer is yes.

Q. Now, you were -- withdrawn.

How long were you in that position?

A. This is the consultant position?

Q. Yes. The Lowestoft?

A. The Lowestoft. That was December '96 through January '99, so just over two years.

Q. And after this position, you became the Group Reserves Auditor?

A. Yes.

Q. How did you come to become the Group Reserves Auditor?

A. In the late -- in the period late 1998, Lowestoft was going through a reorganization where it became clear to me that because of, say, lack of compatibility between myself and my boss, who was the head of Lowestoft, it was clear that there was not going to be a position for me in the new organization, which was vertically different; rather than by discipline, which is what it was in

0144

my time, it would be by area unit, with the disciplines sort of integrated into each of these three area units.

It was clear that there wasn't going to be a position for me there. So I went back to The Hague and said, "This is the situation. What -- is there anything you have for me? And if not, then I'll be willing to take early retirement."

Because by that time, I had clocked up something like 32, 33 years of service, and that would give me a comfortable pension that I could live on.

Q. Now, who did you speak to at The Hague with regard to getting this whole works in process to move on from Lowestoft?

A. Primarily, Hans Bouman.

Q. And who is -- I am sorry. Hans Bouman?

A. Bouman, spelled B-O-U-M-A-N. He was in charge of career planning of petroleum engineers at the time.

Q. And when you went to Mr. Bouman, did he say that he was going to try to find something for you, a position for you?

A. No. It didn't quite go that way. In fact, I had heard on the grapevine that Ad de la Mar was poorly.

THE REPORTER: Can you repeat that, please?

THE WITNESS: He was ill. Sorry. English expression. He was just.

MR. BEST: Let me just state while he is talking that this, as we all understand, is hearsay.

So I am going to object to the form that's requiring him to answer this in double -- in single and double and if not triple hearsay. But you can continue to answer.

BY MR. HABER:

Q. You can answer.

A. What I knew was that Ad de la Mar was having health problems and it was likely that he was going to retire from the job around the end

of the year.

I was interested in the job, so I specifically inquired about me taking that job. And if that wasn't an option, then what else did he have available for me?

Q. And what did Mr. Bouman say to you?

MR. BEST: Same objection. Go ahead. You can answer.

THE WITNESS:

A. That he saw me as an excellent candidate for the job and that he was going to propose that I take the job.

BY MR. HABER:

Q. And how did you -- did you apply for the position?

A. In those days, a new system had been set up whereby everybody, upon a transfer, had to apply specifically themselves. In the old days, before 1998, transfers was essentially arranged by Senior Personnel Planners in the center.

But from 1998 onwards, each of us

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had to make specific applications for jobs with the new company that we sought as an employer.

Now, this job was somewhat different, because this job wasn't a regular career job. This job meant -- and I knew that beforehand, meant that one had to take early retirement in order to return as an independent consultant doing the reserves auditor job.

So when you say: Did you make a formal application? No. I didn't fill in any of these computerized sheets. But I did make clear to Hans Bouman that yes, I was interested in the job.

Q. How did you learn that you had the position?

A. Early December, there was a meeting of the BusCom, I think it was called, that was the meeting of the top level of managers of Shell International E&P, and the proposal of Hans Bouman to make me Group Reserves Auditor was discussed and accepted.

So after that meeting I was

0148

informed that I could indeed have the job.

Q. This was in early December of 1999?

A. Yes. Yes. 1998, I beg your

pardon.

Q. I am sorry. 1998?

A. Yes.

Q. I was just jumping ahead to when you started.

And you said you started in January of or early February of 1999?

A. Yes. In fact, my assignment in Lowestoft ended formally on the last day of February in '99, but most of the months of January and February I already spent in The Hague still formally being on the payroll in Lowestoft.

But I was effectively lent out by Lowestoft to The Hague. And then on the 1st of March, I formally took my leave from Shell and reentered my service as effectively a consultant contractor in doing the audit job.

That meant that from then on, my pension was fixed, my pension had been built up

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over the previous 32, 33 years, and it was by all accounts a good pension that I could expect to live on without any problem.

Q. Now, when you became the Group Reserves Auditor, was this a full-time position or?

A. No, it was not.

Q. It was a part time position?

A. Yes.

Q. How many hours were you expected to put into the position on a yearly basis?

A. In the order of 40 to 50 percent of my time.

MR. BEST: And when you say your time?

THE WITNESS: Oh, the normal office time that one would have available, which is 40 hours a week times 52 weeks minus the amount of holiday. It was something in the order of 1800 -- yeah. 1800 hours in a year, something like that.

So divide that by the percentage that I told you.

0150

BY MR. HABER:

Q. Now, a moment ago you said that the Group Reserves Auditor position was not a regular career job.

Do you have an understanding as to why?

A. In order to maintain independence. The position in principle could make recommendations that would not have been to the liking to management in the company or management of the central office.

And humans being what they are, that could then be feared to be having an effect on my future career, which incidentally is precisely what is happening to the auditors that are working for Shell now.

But leave that aside.

So that was a very sound basis on which to set a candidate up as a independent reserves auditor.

Q. Now, was there a transition period between you and Mr. De la Mar?

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A. No, effectively not, no. He was too ill.

Q. Did you have any communication with him before you began concerning what the job entailed, what the responsibilities were?

A. I had a telephone conversation with him. And he sent me -- as a result of that telephone conversation, he sent me an E-mail with some hints and tips.

Q. Do you recall the general sum and substance of what that E-mail said?

A. No is the short answer. What I do recall that particular E-mail didn't really contain information that was totally new to me.

Because I think it's also useful to bear in mind that this job of Group Reserves Auditor wasn't new to me in the sense that I knew what it was about.

I had experience in my successive positions as Senior Reservoir Engineer and reservoir engineering manager, I had been the subject of a group reserves audit both in my time

0152

in Sarawak and Brunei. So Sarawak in the late '70s and in Brunei in around 1990.

My two different then group auditing incumbents, one of them was Ad de la Mar, when I was in Brunei, and the previous one was Jaan Nesselaar who was the predecessor -- predecessor of Ad de la Mar.

Q. And were both predecessors to you reservoir engineers?

A. Yes.

Q. Now, other than the E-mail that you had with -- E-mail communication that you had with Mr. De la Mar, did you receive any training from Shell on how to perform the duties and responsibilities of the Group Reserves Auditor?

A. No. And I must say I didn't expect that, nor indeed did I feel in any way uncomfortable with that.

Because you must be reminded, by that time I had clocked up something like 25 years as a Reservoir Engineer. I had seen many, many Shell operations. I had built up a lot of

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expertise myself.

I had in fact in 1993 actively participated in issuing the set of reserves guidelines that were put up then. There was a major new release so to speak of the guidelines, which I had factored after.

So I felt fully qualified to take on this particular job, as held also by my predecessors who were of similar qualifications when they took up that particular job.

Q. When you had started the position or just prior to starting that position, had you received any training on the requirements under Rule 4-10, regulation SX?

A. I think in answering that, I must refer you again to the background of the understanding that Shell had reached with the SEC when Rule 4-10 was first published, and that is that Shell essentially made their own interpretation of Rule 4-10 to a large extent based on probabilistic reserves estimating, which was a method that had been used in Shell for quite

0154

some considerable time.

That doesn't mean of course that we weren't and that I wasn't -- was not aware of the SEC Rule 4-10.

We were, because they were included as an appendix in the successive reserve guidelines that were issued by Shell to operating companies and to staff in the operating companies.

Q. When you started as Group Reserves Auditor, were you a member of any professional organization, such as the SPE?

A. I was a member of SPE, yes.

Q. Do you recall at or about the time you started as Group Reserves Auditor, attending any meetings of the SPE?

A. Yes. I attended a -- in the course of '99, a workshop on probabilistic reserves estimates organized by the SPE in Houston.

Q. Do you recall if there were any representatives from the SEC at that workshop?

A. I am fairly certain there were, but I can't be sure.

0155

Q. Do you recall at the time you started as Group Reserves Auditor, reviewing any articles in journals that were published by the SPE concerning SEC reserves reporting requirements?

A. No. Short answer, no. By this, I mean no, I can't remember. I may have done, but it doesn't stand out in my memory.

Q. Do you recall reviewing any publication that was published by the SPE during your membership?

A. Again there, no. I can't remember.

Q. Do you recall when you became a member of the SPE?

A. Yes. That was way back in Sarawak. That was in 1978.

Q. And did you maintain your membership through your tenure as Group Reserves Auditor?

A. Yes. I am still a member.

Q. Now, again, going back to the beginning of your tenure as Group Reserves

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Auditor, did you review Shell's guidelines when you first started?

A. I certainly read through them.

Q. Do you recall having any discussions with anyone about the requirements that were in the guidelines for Proved Reserves reporting?

MR. BEST: I am sorry. Can you repeat the question?

MR. HABER: Sure.

BY MR. HABER:

Q. Do you recall having any discussions with anyone about the requirements that were in the guidelines for Proved Reserves reporting?

MR. BEST: Inside or outside of Shell or anyone?

MR. HABER: Inside or outside of Shell.

MR. TUTTLE: Limiting to that time?

MR. HABER: Yes. This is at the time he started.

0157

THE WITNESS:

A. I can't remember specifically. But I am sure I must have -- Remco and I.

Remco, who was the reserves coordinator at the time when I started the job, must have had from time to time had some discussions about specific points in the -- in the guidelines.

BY MR. HABER:

Q. Do you recall at any time, when you first started as Group Reserves Auditor, comparing

Shell's guidelines against Rule 4-10 to see if Shell's guidelines were compliant with Rule 4-10?

A. Yeah. In fact, this had already been done before me as I am sure you are aware, that there was at that time, and there still is, a comparison, or there still was at my time, a comparison between the SEC guidelines and the SEC definition and the interpretations by Shell.

So yes.

Q. Had you done that?

A. No. It was already there

0158

beforehand.

Q. Did you ever review that analysis to determine if that analysis was correct?

A. Not immediately. I mean, I read through it and I didn't see anything that struck me as being inappropriate.

But in the course of the year 2000, and particularly as a result of an audit in SNEPCO in Nigeria, I began to realize that these guidelines could be improved.

Q. And this realization, did this involve an analysis of SEC definitions?

A. Yes is the short answer. Now, I would submit that an analysis of SEC definitions sounds a rather grandiose term of what is in all fairness a fairly oblique, fairly vague set of rules.

The most important word in the original SEC definitions, the original Rule 4-10 definitions is the word "reasonable certainty." And it gives one or two specific examples, one of them is this LKH issue that we touched on earlier.

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And there are one or two other examples of as it happened for the portfolio of Shell of relatively minor importance.

But the rest of the rule was vague such that it was felt -- already as early as 1978, that it was felt that it was insufficient to just send out to the troops.

It had to be accompanied by a more

clearly and a more extensive write-up by Shell or by Shell office, Shell central office in order to disseminate this definition to the operating companies. That was what was done.

Q. Other than -- withdrawn.

Separate and apart from any Shell training, did you on your own, seek any coursework on the SEC's requirements for reports Proved Reserves?

A. No. No.

MR. HABER: This is probably a good time for us to break for the day.

THE WITNESS: Okay.

THE VIDEOGRAPHER: Mr. Haber, do

0160

you want to go off the record?

MR. HABER: Yes. Go off the record.

THE VIDEOGRAPHER: Going off the record. The time is 3:24. This is the end of tape number 2.

(Whereupon the deposition recessed at 3:24 p.m.)

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ERRATA

CORRECTION PAGE

_____________________ ____________
Signature Date

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I, Anton Barendregt, am a deponent in the foregoing video deposition, Volume I. 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 Monday, February 19, 2007.

Signed___________________________
ANTON BARENDREGT

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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

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IN THE UNITED STATES DISTRICT COURT
DISTRICT OF NEW JERSEY
Civ. No. 04-3749 (JAP)
Hon. Joel A. Pisano

IN RE ROYAL DUTCH/SHELL)
TRANSPORT SECURITIES)
LITIGATION)

VIDEOTAPED DEPOSITION UPON
ORAL EXAMINATION
OF
ANTON BARENDREGT
VOLUME II
Taken on:
Tuesday, 20 February, 2007
Commencing at 10:02 a.m.

Taken at:

The Hague Zurich Tower
Muzenstraat 89
2511 WB The Hague
The Netherlands

REPORTED BY: FREDERICK WEISS, CSR, CM

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The Videographer: Richard Bly
Court Reporter: Frederick Weiss

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I N D E X

DEPONENT

ANTON BARENDREGT

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Barendregt Exhibit 8 -	220

Document marked "Shell Confidential" entitled "Petroleum Resource Volume Guidelines Resource Classification and Value Realisation" dated April 2002 bearing Bates Nos. LON01470137 - LON01470175

Barendregt Exhibit 9 - 220

Document marked "Restricted to Shell Personnel Only" entitled "Petroleum Resource Volume Guidelines Resource Classification and Value Realisation" dated September 2003 bearing Bates Nos. RJW00762369 - RJW000762415

Barendregt Exhibit 10 - 220

Document marked "Shell Confidential" entitled "Guide for the Administration of Proved Reserves and Production for External Disclosure" bearing Bates Nos. RJW00122185 - RJW00122208

Barendregt Exhibit 11 - 287

"Draft Note" dated 19 Oct 2000 including Attachments 1, 2, 3 authored by Anton Barendregt bearing Bates Nos. PER00070670 - PER00070689

Barendregt Exhibit 12 - 296

"Draft Note" dated 21 Nov 2000 authored by Anton Barendregt with Attachment 1 bearing Bates Nos. PER00020307 - PER00020309

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EXHIBIT Page No:

Barendregt Exhibit 13 - 299

"Note" dated 5 Dec 2000 authored by Anton Barendregt with Attachments 1, 2 and 3 Bearing Bates Nos. RJW00060528 -

RJW00060538

Barendregt Exhibit 14 - 302
E-mail string from Anton Barendregt to David Christie regarding Draft Audit Note, and attached "Draft Note" Dated 21 Nov 2000 authored by Anton Barendregt with Attachments 1, 2, 3 Bearing Bates Nos. PER00081987 - PER00081997

Barendregt Exhibit 15 - 316
"Note" dated 8 Feb 2000 authored by Anton Barendregt with Attachments 1 - 7 bearing Bates Nos. V00280131 - V00280144

Barendregt Exhibit 16 - 329
"Note" dated 31 Jan 2003 authored by Anton Barendregt with Attachments 1 - 7 bearing Bates Nos. V00010650 - V00010666

Barendregt Exhibit 17 - 331
Document previously marked as Darley Exhibit 25, the front page of which being an E-mail From Jeroen Regtien to John Darley Subject Gorgon Reserves bearing Bates Nos. V00321087 - V00321104

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PROCEEDINGS --

THE VIDEOGRAPHER: This is the beginning of Volume II, videotape number 3 in the deposition of Anton Barendregt. Today's date is February 20, 2007. The time on the record is 10:02 a.m.

Please proceed.

EXAMINATION BY MR. HABER - continued

BY MR. HABER:

Q. Good morning, Mr. Barendregt.

A. Good morning.

Q. I am going to continue with the questioning that we left off with yesterday on your audits and when you first began in the position as Group Reserves Auditor.

So I just want to give you an idea of where we are going to start.

Now, when you started, in that period right before you started as Group Reserves

Auditor, did you review any documents to help acclimate yourself to the position?

A. No, because I had no time for it.

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I had another job to do.

But of course, in the time that I was in The Hague so to speak on loan from Lowestoft to SEIP in January, I did read through various documents, most notably the reserve guidelines as they were available at that time, the Shell reserve guidelines.

Q. In those guidelines, were they 1998 guidelines?

A. They would be, yes.

Q. Now, at any point when you first got into the position, did you receive any training on how to perform an audit?

A. Short answer is no, no. Not as such, no.

Q. Did you meet with anyone from KPMG when you first started in your position as Group Reserves Auditor?

A. Yes. I met Egbert Eeftink, E-G-B-E-R-T, E-E-F-T-I-N-K.

Q. And who is Mr. Eeftink?

A. He was at that time one of the

0173

partners of KPMG in the Netherlands.

Q. Do you recall when you met with Mr. Eeftink?

A. Not the precise period, but it would have been during that period in January.

Q. Do you recall the sum and substance of what was discussed during that meeting?

A. There were several meetings, and most notably of course the one at the end of January or early February where I would make my report on the process of getting together all these -- all these reserves data.

But before that, I cannot remember precisely when that was or what the subject was. It must have been just general introduction and getting to know each other, those sort of things.

Q. Do you recall Mr. Eeftink providing you with any guidelines on how to perform an audit?

A. No.

Q. Just so the record is clear, I just want to make sure there is an understanding; when

0174

you say that there was several meetings, there was an initial meeting, sort of get-to-know-you meeting, and then there were other meetings in connection with the ARPR process?

A. Yes.

Q. When you became the Group Reserves Auditor, did you have to sign a contract with Shell?

A. Yes.

Q. Do you recall how long a period of time you were -- you would be contracted to perform the duties as Group Reserves Auditor?

A. The contract was a contract that Shell had with a number of people, typically ex-employees or pensioned employees.

It would be best be described as a call-off contract of their services at that time, essentially providing for a daily rate or an hourly rate and a duration which typically would be one year, extendable by mutual consent.

Q. And so when you signed the contract, it was for one year?

0175

A. It was initially for one year, yes.

Q. Was that contract extended?

A. Obviously, of course. Yes.

Q. Who did you negotiate the contract with?

A. There wasn't any negotiation at the time. At the time, those contracts were very tightly controlled by the personnel function.

And in particular, what they didn't want to see is that people who were laid off later on came back being at what they feel was extortionist rates. So they were very strictly in control of these contracts. In fact they would hold the contract so to speak.

And in particular, the rate was tightly controlled as by its being a calculation of my previous Netherlands salary divided by the number of days that I would normally have worked in the Netherlands at that time.

Q. Now, you say at the time those contracts were tightly controlled.

Did that subsequently change over

0176

time?

A. I don't know what it is now. I do know that in the last year, when I -- in my last year which was in 2003, my pension had already started. I initially or originally had said to Remco and his boss, Wouter van Dorp -- I think his name has come up before.

Q. I think it's W-O-U-T-E-R?

A. W-O-U-T-E-R.

-- that I was intending, I was expecting to do this job for about four years, and then my pension would start, and then we would review the situation then.

So after these four years, I said to Frank Coopman, who was by that time in charge of reserves reporting, "I am ready to quit."

Frank Coopman was in finance. He was the head of EP Finance. There had been a change in the reporting relationships when he arrived on the scene.

Instead of me reporting to the head of the department that was doing the internal and

0177

external reporting of reserves and other matters, I was now reporting to the head of finance, head of EP Finance and that was Frank Coopman.

In that year, I said that I wanted to continue one year, but at a higher rate, to negotiate at a higher rate. I looked around me and saw indeed the rates, the going rates in the industry, and I negotiated the higher rate with Frank Coopman for one more year.

But I made it clear then, this was

at the beginning of 2003, that this was going to be my last year and they better start seeking a replacement for me by the end of the year. So that's what was happening.

And then so for that rate, which was then clearly in excess of what personnel would have liked me to take, they were overruled. I would imagine I don't know what sort of discussion took place.

Q. And the conversation that you had with Mr. Coopman, that was in late 2002, early 2003?

0178

A. Correct, yes.

Q. Do you know who succeeded you in your position as GRA, Group Reserves Auditor?

A. A whole group of people. The way I understand it is now set up is that reserves auditing is brought under the control of Group Audit. And there are two teams of approximately five or six people, so something like ten to 12 altogether, who go around and do a complete and a comprehensive annual check of all the reserves in the group.

They have external participation but also internal -- mostly internal participation.

Q. Is there a person who is in charge or heads the Group Audit function?

A. Yes. I don't know -- don't remember the name, no. You are talking now?

Q. Well, actually, my question really is with regard to 2004 when you left?

A. Yes. There was a person in charge. I forget his name.

0179

Q. Did you have any input into who this person who would head the Group Audit function would be?

A. No. No.

Q. Do you know if this person is a full-time employee of Shell?

A. The head of Group Audit certainly

was a full-time employee, yes. Yes.

Q. Do you know who that person reported to?

A. No. No.

Q. And --

A. It was an organization. I think it was -- bear in mind it was an organization that I had relatively little to do with.

Although, at the instigation of Frank Coopman, I did start to send my reports to Group Audit, somewhere during I believe it was either late 2001 or in the course -- I am sorry, late 2002 or in the course of 2003.

I am sorry. I would have to look up from my reports who that person was, but he is

0180

clearly listed as one of the addressees in my reports.

But other than that, I had very little to do with them. So precisely how they organized themselves, I honestly don't know.

Q. Have you heard of a Reserves Committee?

A. Yes. Yes. That was set up by Frank Coopman in the course of late 2002, early 2003, I think.

Q. And did you serve on the committee?

A. Yes.

Q. You were a full member or an advisory member?

MR. TUTTLE: Objection to form.

MR HABER: I am sorry. Let me rephrase.

Q. Were you a full member?

A. As far as I remember, yes. Yes.

Q. Did you serve as a member of a committee in an advisory capacity?

A. Yes. Yes. I had no executive

0181

powers, so yes. Yes.

Q. Is there a difference between the Reserve Committee function and the Group Audit function that you just described?

A. No. I sat there as Group Reserves Auditor, so in my capacity as Group Reserves Auditor.

Q. No. My question is: Was the committee, the Reserves Committee --

A. Yes.

Q. -- was that the same as the Group Audit function?

A. Oh, beg your pardon. No. No.

Q. Was there any interaction between the Reserves Committee and the Group Audit function?

A. I am not really the person to ask. You would have to ask the head of the Reserves Committee, who was Frank Coopman, and he was taking care of the dealings as far as I knew with the group auditors committee.

Q. For the record, who was Frank

0182

Coopman and what was his position at the time?

A. Frank Coopman was the head of EP Finance. He arrived, he took over from his predecessor in somewhere in the middle of 2002, I believe.

Q. Now, in terms of reporting, when you first started as Group Reserves Auditor, who did you report to?

A. To start with, I reported to Wouter van Dorp, the name that we mentioned, who was in charge of reserves and business reporting, particularly in the reporting of the amalgamation of financial and production forecasts and the like. Remco Aalbers was reporting to the same person at that time.

Q. Now, Mr. Aalbers was the Group Reserves Coordinator?

A. Correct, yes.

Q. And Mr. Van Dorp, he was in EPB, which I believe was EP Business Planning?

A. I forget what the reference indicators were, but it could well be as you said.

0183

Q. Did your reporting change over

time?

A. Yeah. After a not too long period, Wouter van Dorp left the company and he was succeeded by Aidan McKay.

Q. And do you recall when you began reporting to Mr. McKay?

A. Not precisely the dates, but it must have been somewhere in either late '99 or early 2000, something like that.

Q. And how long did you report to Mr. McKay?

A. Until he left for the US and he was taken over by -- he was succeeded by Jaap Nauta, I believe.

Q. And how long did you report to Mr. Nauta?

A. A year, year and-a-half, something like that. I don't know the precise dates in my head. The neatest trail is just to go and look through my audit reports and then you can pretty well see when one took over the year.

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Q. And do you know who succeeded Mr. Nauta?

A. Yes. But I forgot his name.

Q. Is it Malcolm Harper?

A. No. No. It was a Dutch man. I would have to look in my reports, sorry.

Q. Now, did you have -- I understand in Shell, it's called a dotted-line report.

Was there someone who you also reported to who wasn't a straight-line person above you?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. Not really, no. These were the persons I had to deal with on a day-to-day basis.

BY MR. HABER:

Q. Other than your annual reports, did people in the position that you just identified for the record, did they require to you file any other reports to them identifying the activities and conduct of what you had performed throughout the year?

0185

MR. TUTTLE: Objection to form.

THE WITNESS:

A. The reports that I issued were the reports of the actual company audits, which are well known and which all have full access to, and the reports at the end of the year, which again you have all seen.

Those were the two types of reports. And then of course there were my monthly statements regarding the number of hours worked and et cetera. But that was separate.

BY MR. HABER:

Q. How would you describe the level of supervision that these people that you reported to gave to you during your tenure?

MR. TUTTLE: Objection to form.

MR. BEST: Objection to form.

MR. WARE: Objection. Foundation.

THE WITNESS:

A. I would more call it -- my relationship with, say, the Group Reserves Coordinator's supervisor was hands off. I would

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meet him irregularly and not too frequently, mostly in the end of year period in January, then we would have a number of meetings.

But my day-to-day contacts were with the Group Reserves Coordinator.

Q. How would you describe your interaction with the Group Reserves Coordinator?

A. I would more describe it as cooperation. If I had for instance any concerns, any questions, I would go and see him and he would either share my concerns or give me an answer or whatever.

Anyway, we had an effective and I think even very cooperative way of working with each other.

Q. Now, you have mentioned Remco Aalbers and I believe yesterday you mentioned that there was a gap after Mr. Aalbers.

A. Mm-Hmm.

Q. Do you recall who were the people that filled that gap until a more permanent person was placed in that position?

0187

A. Yes. Remco Aalbers was first, succeeded by Leigh Yaxley. He did not last very long. He came on the scene, I believe, on the 1st of April, 2001. And he left somewhere in November 2001.

Q. Who --

A. As I mentioned yesterday, it was because of personal and home problems that he felt he could not continue his job with Shell.

Q. And who filled that space, that void, after Mr. Yaxley left?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. It was Jan Willem Roosch who was helping out over the period of the end of 2001 reserves reporting, because at that time there was no reserves coordinator; and the end of year period is obviously a very busy period and they needed someone, so it was Jan Willem Roosch.

Q. What was the level of interaction you had with Mr. Roosch?

A. Slightly more at the distance than

0188

with Remco Aalbers, I would say. We knew each other. We had met. In fact, we had even shared an office at one stage in the distant past.

Let's just say that Jan Willem is more of a people -- more of a man that keeps people at the distance than Remco Aalbers is.

Q. Who succeeded Mr. Roosch? I am sorry. Who succeeded him?

A. Oh, who succeeded him? There was, after another interval, it was John Pay, who as it happens, also started on the 1st of April, I believe, in 2003 -- 2002, beg your pardon.

Q. And what was the level of interaction you had with Mr. Pay?

A. Excellent, yes. Pretty much like I

had it with Remco Aalbers.

Q. Did you have to report -- withdrawn.

Did you report to KPMG during your tenure?

MR. TUTTLE: Objection to form.

THE WITNESS:

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A. I sent all my reports to KPMG, so yeah. In the strictest sense, yes, I did report to KPMG.

BY MR. HABER:

Q. Other than through your reports, was there any reporting that you had done with KPMG?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. No.

BY MR. HABER:

Q. Now, during your tenure as Group Reserves Auditor, who paid your compensation?

A. The way I interpret that question is on whose budget were my costs allocated. That was distributed. The costs of my visits to the operating companies were borne by the operating companies. And I had set up a system whereby I would keep tabs of how many hours I would have worked for each of the successive audits.

The overhead activities during the year and certainly the end-of-year activities

0190

would be charged to Remco Aalbers, his unit, i.e. to his supervisor.

Q. What do you mean by "overhead activities"?

A. Well, for instance, my involvement with issuing the new guidelines, all the activities that couldn't clearly be attributed to a specific company audit would be what I called overhead activities.

Q. So when you bill an operating unit, that bill or that invoice would cover your hourly rate and out-of-pocket expenses.

Is that correct?

A. Correct, yes.

Q. I believe yesterday you had said that as Group Reserves Auditor, you were a part-time employee.

Correct?

A. Yes.

MR. TUTTLE: Objection to form. Characterization of the testimony.

BY MR. HABER:

0191

Q. Did you believe during your tenure that you could devote sufficient time to performing the duties and responsibilities of a Group Reserves Auditor on a part-time basis?

A. I think we must realize that the system of a part-time Group Reserves Auditor had been in operation for Shell for 25 years at the time. And there never had been any reason for Shell to have second thoughts about a system.

And therefore, I hadn't come across any instances where I felt that, say, a larger amount of effort had to be spent on these audits.

As I explained earlier, my audits were of a form where I would sit around the table with a group of engineers describing a certain field; and with my experience and with the knowledge and the experience of the people around the table, it would be very quickly possible for me to get a good technical picture of the field in question and of the way in which the reserves estimate for that field was put together.

As I said, I didn't go checking

0192

individual details, like did they use the right values of porosity or permeability or any of the other parameters that you need in a simulation model.

But I did ask them how, for instance, they put together the various data that had come in from, for instance, drilling wells, how that had been put together into the simulation model.

MR. FERRARA: I am sorry. Had he finished his answer?

THE WITNESS: Effectively, yes. I am just describing this process yet again, to say that I felt a very effective transfer of knowledge and data did take place during those audits, and that I didn't need -- I didn't feel the need to have a much more thorough detailed investigation of those simulation models and whatever else the company was doing.

BY MR. HABER:

Q. Over the course of your tenure, did you come to have second thoughts about having

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sufficient time to perform your duties as a Group Reserves Auditor?

MR. BEST: Objection. Asked and answered.

MR. TUTTLE: Objection to the form. Asked and answered.

BY MR. HABER:

Q. You can answer.

A. This question sounds very much like a question you already asked me yesterday. Towards the end of my tenure, towards the end of 2003 when it became clear that there was a large proportion of our reserves that didn't fulfill the requirements of having, say, a firm development plan or even FID, it became clear to me that there was certainly a whole area in the portfolio of our reserves that needed a lot closer look.

So on that basis, I recommended that we would have need at least a doubling of manpower in the Group Reserves Auditor. That recommendation was taken up -- more than taken up, because now as I explained to you, they have two 5

0194

to 6 man teams, and they still have those.

Q. During the year, how many audits did you perform of Shell operating units?

A. Everything between seven and ten.

Q. How did you determine which operating units to audit?

A. There was a fixed schedule. The principle was that every operating unit was visited once every four years. There was an exception to that when I started, when a large backlog of these audits had been built up because of the illness of my predecessor.

And it was felt that we had to gradually catch up on that audit, on that backlog. So initially, we had a system whereby the larger operating companies would continue on their four year schedule. I would just continue that with the -- from the previous, the previous schedules, and the smaller operating companies would be delayed slightly by either once in five years or once in six years.

But after a few years, that backlog

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had been cleared. I reported on those -- on that schedule every year in my end of year report. So you can see the details there.

Q. Now, you say that this was based on a fixed schedule. Who created the schedule?

A. I maintained it and reported it or proposed it rather for the coming year. So each year, at the end of the year, I proposed a schedule for the coming year and agreed that with the external auditors and with the Group Reserves Coordinator.

Q. So the proposal was made to the Group Reserves Coordinator and the external auditors?

A. Primarily to the external auditors.

Q. And was it KPMG that you made the proposal to?

A. Both, KPMG and PriceWaterhouseCoopers.

Q. Who at PriceWaterhouseCoopers did you communicate with?

A. I am sorry. What?

0196

Q. I am sorry. Who at PriceWaterhouseCoopers did you communicate with?

A. Steve Johnson.

Q. Was he the primary contact?

A. Yes. Bearing in mind that the contact with PriceWaterhouseCoopers was mostly concentrated -- in fact, was concentrated at the end of the year. So at the end of January, a meeting that we had with the external auditors was in fact the only time in the year that I would see Steve Johnson.

Q. Do you know a Brian Puffer?

A. He was Steve Johnson's predecessor I believe.

Q. And he was also at PriceWaterhouseCoopers?

A. As far as I remember, yes.

Q. And when you made the proposal for the upcoming year schedule of audits, you sent it to Mr. Johnson?

A. Yes.

Q. And before him, Mr. Puffer?

0197

A. I hope that's right. Brian Puffer was before Steve Jones. I am sure somebody around the room can tell me.

MR. TUTTLE : Just your best recollection, that's all we're after.

MR HABER: That's all we're after.

Q. Now, did you ever make exceptions to the schedule?

A. Exceptions to the rule of once every four years --

Q. Yes.

A. -- you probably mean?

Q. That's correct.

A. Yes. There was one instance during the end of 2002, I believe, when there was a remark in one of the E-mails that we received from SNEPCO in Nigeria, where there was a discussion whether they could book a newly-discovered field, a newly-discovered field for reserves, for proved reserves.

And we, the Group Reserves Coordinator and myself, effectively told them no,

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you can't do this, because the maturity is just simply not sufficient to allow us to do that.

And they came back with the remark saying, Oh, but we booked -- I believe it was Erha, one of the other fields -- "We booked Erha in this manner last year".

And indeed, they had. It had just slipped through, or slipped through in the sense that they had made a booking.

It was made clear that it was a new field, but there was no reason for us to have any opinion about that booking, not until I would come and visit SNEPCO, which would be a couple of years later.

So when he made this remark, that really made us sit upright. We said: Clearly there is something funny.

Now, I was due to visit SNEPCO in 2003. But because of this remark, I proposed that we move the audit forward to 2002, and that is what has happened.

Q. Other than the SNEPCO situation,

0199

can you recall any other instances where you made an exception to the schedule of once every four years for an audit?

A. Not off-hand, except perhaps for Nigeria, my first visit to Nigeria as PDC was in 1999. And my predecessor had visited Nigeria in 1997 and had made the recommendation that Nigeria be visited again in 1999.

So that in itself was a change from the four-year rule.

Q. But once you got into the position, did you audit SPDC sooner than four years?

A. Apart from my first audit, no. No.

Q. Did you do any follow-up with operating units after you conducted an audit?

A. No. No. I considered that to be the responsibility of the operating unit concerned and of the reserves coordinator, and the general reporting relationship that that company had with the central office.

Q. If you made -- when you made recommendations in your operating unit reports,

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did you follow up to see if those recommendations were implemented?

A. Like I said, no. My responsibility was to go out, find, and report. But I had no executive powers directing companies to do this, that or the other.

Q. During your tenure as Group Reserves Auditor, did you ever come to question the propriety of conducting audits of the operating units on a four-year cycle?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. Again, there, we must bear in mind that this had been a system that had been in operation with Shell without any complaints from anywhere for 25 years.

Having said that, when in 2003, which was my fifth year in the position of Group Reserves Auditor, I went and visit some companies that I had also visited in my first year, because the four-year cycle.

And that's when I found that in

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cases where the reserves coordinator of that particular company was still the same position, was still held by the same person, there were very few complaints or changes.

But in quite a number of companies, you would find that that position had changed, and that -- or the person holding the position had changed.

And I was surprised by the amount of change that a new person sometimes could and would have introduced in the reporting procedures in that company.

So that's when I began to -- that's also when I began to realize that perhaps once every four years is not enough, but it wasn't until the fifth year.

BY MR. HABER:

Q. In preparing the schedule, did the efforts of the operating unit reserves coordinator factor into how you scheduled the audit for that particular operating unit?

A. I am sorry. Can you rephrase the

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question?

Q. Yes. When you prepared your schedule each year --

A. Yes.

Q. -- did the person who served as the operating unit reserves coordinator factor into how you scheduled the audits?

MR. TUTTLE: The identity of the person?

MR HABER: Yes. Who the person was.

THE WITNESS:

A. Yes. Typically, once I had agreed the schedule with the external auditors and the Group Reserves Coordinator at the end of January, I would approach the operating companies and tell them that they were due for an audit in the course of the year, and I would explain to them -- pretty much along standard text, I would explain to them what the audit entailed, and what sort of measures I would expect to be present, what sort of information I would need; and first and foremost,

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of course what would be a suitable date for them.

Q. Did you have this communication with them before the schedule was finalized with the external auditors?

A. No. Usually it was the other way around, usually. Sometimes I may have approached a company beforehand.

Q. A moment ago I asked you about recommendations that you would make after an audit. Whose responsibility was it to implement those recommendations?

A. The operating company.

Q. Now, as the Group Reserves Auditor, were your duties and responsibilities written down in any particular place in Shell?

A. Yes. There were two documents, one of them was Terms of Reference for my audit.

They were published each year in the Group Reserves Guidelines.

And there was a separate set of Terms of Reference for the group reserve auditor position.

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Q. And where was that separate set of Terms of Reference?

A. It wasn't -- it was residing on my computer for one, but it wasn't a set of formally enshrined in any particular document, but it certainly was available to all the persons concerned, Group Reserves Coordinator, et cetera et cetera.

Q. This document that you are referring to that was on your computer, was this something that you had created?

A. I would have put up the first draft of it. It started with a similar Terms of Reference that had already been in existence with my predecessor, and I changed it.

There have been over the years a number of changes, always agreed obviously with the Group Reserves Coordinator and his supervisor, and when Frank Coopman who came on the scene agreed with head of EP Finance.

One particular change for instance that came in was that when the group Reserves

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Committee was set up, and I had to take part in that committee or I was asked to take part in that committee as well, and then he added it to another paragraph in my Terms of Reference.

Q. The Terms of Reference that were attached to the group guidelines, did you draft that Terms of Reference each year?

A. Yes. I drafted it and received comments where applicable. It was finally an agreed document that would go into the Reserves Guidelines, yes.

Q. Now, when you say it was agreed, it was agreed upon with the Group Reserves Coordinator?

A. And his reporting relationship. Ultimately the Group Reserves Guidelines had to be agreed with and sponsored by the group reserves coordinator's supervisor and his two managers above that.

Q. When you first began as the Group Reserves Auditor, did you create an audit program that you followed with regard to conducting the

0206

audits of the various operating units?

A. Yes. I found that when looking at the reports of my predecessor, that there seemed to be an absence of a sort of a framework along which he would generate or conduct these audits.

And even though, of course, I was fully aware that reserves estimating is in the last instance is a matter of opinion taking the Reserves Guidelines as a guiding principle, I still felt that some more structure could be applied.

So what I did is I set up a checklist spreadsheet along the -- along the various points in the Reserves Guidelines which would allow me to A, make sure that I had covered all the subjects, all the relevant points in the reserves estimates; but also to have an attempt at scoring the company against that, and thereby get some sore of an aggregate score.

I found that a very useful method to be A, consistent, and B, comprehensive in doing my audits.

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Q. Did anyone assist you in preparing this checklist?

A. No.

Q. Did you pass the checklist over to KPMG for their review before?

A. It was a part of my -- a full part of my report that was sent out, so they received the completed checklists.

Q. My question is before --

MR. TUTTLE: His question was before you started using.

THE WITNESS:

A. Oh, I can't remember. Certainly if -- I think in 1999, which was my first year, I set up this checklist somewhere around February/March, before I went out on my first visit.

I think the answer is no. I am not 100 percent sure, but I think the answer is no. They didn't see my checklist until they saw my first report, which would have been at the end of April.

Q. Do you recall anyone at KPMG

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commenting on the checklist?

A. In any other sense than just favorable and a good idea, no.

Q. Did anyone from KPMG ever pass comment that the checklist was or was not comprehensive enough?

A. No.

Q. Did anyone from KPMG ever make a comment about whether the checklist captured all of the elements of commercial maturity?

A. I don't recall that.

Q. Same question with regard to technical maturity?

A. I don't recall that either.

Q. Do you recall anyone from KPMG commenting on whether the checklist captured the factors that go into a determination of reasonable certainty?

A. I don't specifically recall that.

Q. Now, this checklist that you created, did it vary from operating unit to operating unit when you conducted an audit?

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A. It developed over the years. So if you were to take my first report and compare it against the last report, you will see that it has indeed changed quite a bit over the year -- over the years.

This was basically as a result of instances -- no, first as a result of the changes guidelines over the years, but also as a result of specific instances, specific cases that came up during my audits where I felt that yeah, this would probably be another item that I would need to check.

So yes, it did change, yes.

MR. BEST: I think the question was did it vary from operating unit to operating unit?

THE WITNESS: Well, effectively, yes, because it gradually grew.

MR. BEST: All right. But --

THE WITNESS: The operating units in 2001 would have seen a different list than the ones in 1999 and in 2003, not grossly different, but yes, different, more extensive.

0210

BY MR. HABER:

Q. When you audited an operating unit, did you review the audit reports from the prior audits of that operating unit?

A. If I had them available, then yes. And I say that because I did not have a complete set of the audit reports of my predecessor. I had -- I think I had the most recent audit reports, but not a full set.

I didn't -- I didn't pay a lot of attention to it. I would glance through it and see whether there was any particular items that would be relevant to those companies, and that was for a number of reasons: A, I wanted to make my own assessment of the company, my independent judgment; but B, a lot of these companies I already knew, either because I worked there myself or because I had been visiting them on my previous assignment as consultant.

Q. Now, in terms of items that would be relevant to the companies, what sort of items are you referring to?

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A. I am not sure I understand your question.

Q. Well, let me go back to your answer. You said, "I would glance through it and see whether there was any particular items that would be relevant to those companies."

A. Oh, I see. If there was any particular finding in one of the previous reports about something that wasn't entirely as it should have been, then I would -- I would take that up. I would register that and say, okay, this is obviously something that I needed to check on.

But like I said, I didn't really feature it very much, because as I mentioned earlier, I didn't find the reports from my predecessor to contain a lot of structure. I didn't find them overly useful.

Q. Now, when you conducted audits, were these audits performed in the field, that is, in the operating unit itself?

A. Yes.

Q. Did you ever perform an audit of

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the operating company from The Hague?

A. Only when the effective working unit of the working company was in fact located in The Hague.

Q. And which operating unit or units fall into that category?

A. Oh, I don't remember. Pakistan, there was an exploration venture; Kazakhstan in 2003, I believe, yes. Those are the two that spring to mind.

Q. When you conducted an audit of the operating unit, did you ever send requests for information in advance of the audit?

A. Yes, quite often I would. Typically what I would ask is: Can you give me an up-to-date list of all the field names and their field reserves, like proven expectation reserves of oil gas -- oil and gas.

And with that, I would prepare the bubble plots that you will have seen appear in my reports.

And I found this to be an excellent

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way of picking out the exceptional fields, either fields with high proven reserves or the large fields because the size of the bubbles would indicate whether it was a large field or a small field.

Anyway, I found it an extremely useful method of picking out the fields on which I might want to ask some questions.

So on that -- on that basis, I would come back and say, okay, I want to talk with these and these and these fields. Typically the larger ones of course would be there. You would always go for the larger ones, but some of the smaller ones when they looked exceptional I would pick out as well.

Q. Now, is the information that you requested in advance of the audit, was this information that would also be found in the latest estimates that the operating unit sent to The Hague?

A. Yes. Yeah. I would expect those to be the same, yes.

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Q. Prior to conducting an audit, did you ever request the latest estimates to review for that operating unit?

A. I am not sure what you mean when you say "the latest estimates." As far as I remember, the latest estimates that came in during the year once every quarter were in fact the estimates on a company basis only, so the aggregate volume for the company.

It was only at the end of the year and during my audits that we would ask them to prepare a list of individual field value, of course then expecting that to add up to the aggregate company value.

Q. Did you ever compare the aggregate value in the latest estimates to the individual field?

A. Oh, yes. Definitely. That was part of my reports. It was a separate table in my reports which makes that comparison.

Q. Did you ever request information from the operating units to give you a picture of

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the reserves position at the beginning of the year and the end of the year so that you can do a comparison of changes?

MR. TUTTLE: Objection to form.

THE WITNESS: Yes. That was -- that was certainly done by me at the end of the year, in the end-year statement.

In my reports, there is a table that expresses that as well, that gives that -- that gives the reasons for changes, a separate set of tables, one for gas, one for oil. It gives those changes as well with my comments.

Q. I am sorry. And when you said end-year statements, you are referring to the year-end report?

A. Yes.

Q. Now, at the operating unit level, who is responsible for signing off on the reserves that are reported to the center?

A. In my days, it was the chief petroleum engineer, the head petroleum engineer, the petroleum engineering manager, so typically

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the same position as I was holding in Lowestoft.

Q. When you conducted your audits, did you have interaction with this person in that -- who was the chief petroleum engineer?

MR. TUTTLE: Do you want to ask for each one? I mean --

MR HABER: I am speaking generally.

THE WITNESS:

A. Yes. Definitely. Absolutely. I would -- during these audits, I would of course have a close working relationship with the reserves coordinator because he would be the one to answer all my questions, other than the questions that I would direct to the field teams and his supervisor, so the head reservoir engineer or the head petroleum engineering.

I would also, as a matter of fact, always make a point of visiting the Managing Director of that company when he was available, and sometimes a technical director as well.

But those would be just courtesy calls. And he would always -- he or she -- it's

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always a he as far as -- no. No. There only was one she. They would always receive a copy of my report at the very end.

BY MR. HABER:

Q. Who was the one woman that you are referring to?

A. Canada. I am sorry. I forget the name of the woman, I am sorry, for the moment.

Q. Do you know a Sheila Graham?

A. Yes, I know her.

Q. And who is she?

A. She was I believe the reserves coordinator in Shell Development Australia.

Q. And was she someone that you had interaction with when you audited --

A. Yes.

Q. -- SDA individual?

MR HABER: We can break now. This is fine.

THE VIDEOGRAPHER: Going off the record at 10:58.

(Short recess taken)

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THE VIDEOGRAPHER: Returning to the record at 11:18 from 10:58.

BY MR. HABER:

Q. Mr. Barendregt, we are about to mark a number of documents, six documents, I believe. Five of them are the Petroleum Resource Volume Guidelines from Shell. And they are from 1999 through 2003.

The last document is the guide for administration of Proved Reserves and production for external disclosure.

So we are going to mark these for the record. We have handed these documents out.

So when you start getting these, if you could just take a look at them, my questions are primarily going to be devoted to the Terms of Reference.

(Barendregt Exhibit No. 5 marked for identification)

The first document that we are marking as Barendregt Exhibit 5 is the Petroleum Resource Volume Guidelines Resource Classification and Value Realization. It is a multipage

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document. Bates range is PER00070810 through PER00070880, and this document is for the year 1999.

The next Exhibit, which we'll mark as Barendregt Exhibit 6, is a Petroleum Resource Volume Guidelines Resource Classification and Value Realization for the year 2000.

It's Bates range is PER00081330 through PER00081360.

(Barendregt Exhibit No. 6 marked for identification)

The next Exhibit, which will be Barendregt Exhibit 7, is the Petroleum Resource Volume Guidelines Resource Classification and Value Realization for the year 2001, and this is a multipage document. Its Bates range is RJW01000924 through RJW01000971.

(Barendregt Exhibit No. 7 marked for identification)

The next Exhibit, which will be Barendregt Exhibit 8, is the Petroleum Resource Volume Guidelines Resource Classification and

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Value Realization for the year 2002. And it's Bates range is LON01470136 through LON01470175.

(Barendregt Exhibit No. 8 marked for identification)

The next Exhibit, which will be Barendregt Exhibit 9, is a Petroleum Resource Guidelines Resource Classification and Value Realization for the year 2003. The Bates range is RJW00762369 through RJW00762415.

(Barendregt Exhibit No. 9 marked

for identification)

And finally Exhibit 10 will be the Guide for the Administration of Proved Reserves and Production for External Disclosure. The date of issue is July 2003. It's Bates range is RJW00122185 through RJW00122208.

(Barendregt Exhibit No. 10 marked for identification)

MR. TUTTLE: Mr. Haber, I just note for the record in Exhibit 5, that appears to be actually two documents. Starting at PER00070842 is the "Petroleum Resource Volumes Submission

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Requirements for Internal and external reporting (for Operating Units and New Venture Operations)."

MR HABER: Okay.

BY MR. HABER:

Q. Mr. Barendregt?

A. Okay.

Q. Have you seen each one of the documents that we've marked as Exhibits 5 through 10?

A. Yes. And they appear to be the documents that I have been working with, yes.

Q. Now, your counsel has noted on Exhibit 5, if you turn to page 70843, there is a document that says, "Petroleum Resource Volumes Submission Requirements for Internal and external reporting (for Operating Units and New Venture Operations)."

Do you see that?

A. Yes.

Q. Do you know if this document is a part of the resource volume guidelines that we have marked as Exhibit 5?

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A. Yes. It is part of it. It's a complement to it. The top document in Exhibit 5 are the actual guidelines, which is that -- which are the guidelines that I for one, as a reserves auditor, was using as my reference, and it was intended to be used as a reference by all the operating units in determining the actual volumes of the fields in question.

The second part is the -- is instructions for use of the tables that operating units had to submit to the center at the end of the year. So it's more of a how to input the figures type of explanation rather than the method used previous in determining the volumes of the actual volumes of the reserves.

So that's the difference between the two.

Q. When you conducted your audits, did you use the guidelines that we've marked today as Exhibits 5 through 9 as your reference?

A. Yes.

Q. When you conducted your audits, did

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you use SEC rule 4-10 as a reference to your audits?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. SEC rule 4-10 is included as an Appendix, and is, say, an unremovable part of and has been the resource volume guidelines that we've used.

So that goes also for this document.

BY MR. HABER:

Q. When you conducted your audits, did you refer to rule 4-10, which is an Appendix, and I believe if you look at Exhibit 5, that would be Appendix 3, which is on page 22 of the document, or Bates range 836?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. As I explained yesterday, the original rule 4-10 wasn't really useable in the form in which the SEC issued it in 1978.

And during discussions between

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central office at Shell and the SEC, it was determined that Shell would continue to use their own methods and would continue to use internal guidelines that, by all concerns, were deemed to yield the same if not actually more conservative results than rule 4-10.

In my audits, I therefore referred primarily, only by way of exception and now specifically -- sorry. I referred primarily to the internal Shell guidelines, to this document (indicating) and only on occasion specifically to rule 4-10, as you will see in my reports.

BY MR. HABER:

Q. Can you think of any specific audit report where you made that specific reference to rule 4-10?

A. Not off-hand. Let me think. Kazakhstan, maybe. That's the only one that springs to me at the moment, but I am sure that there were more, there were occasional remarks in the text.

Q. Now, if you can look at the Terms

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of Reference, which is on -- and I am looking at Exhibit 5 now, page 24 of the document, the Bates range ends 838.

And I believe earlier in your testimony, you said that you had drafted the Terms of Reference.

Is that correct?

A. Drafted and then agreed with the reserves coordinator and his supervisors, yes.

Q. So with regard to Exhibit 5, the Terms of Reference that we're looking at, you drafted this document?

A. That particular page, yes. Yes. And agreed after discussion, like I said. Which meant that they might have come up with slight changes of wording or additional comments.

Q. Did you --

A. So it was an agreed document.

Q. No. I understand that. And actually that's my next question.

Do you recall any comments that were given to you by the Group Reserves

0226

Coordinator and whoever they had reported to, such as let's say Mr. McKay?

A. Not specifically, but I know that there were. But like I said, I can't remember specifically what those comments were.

Q. Do you recall if the comments were substantive in nature?

A. From my recollection, which is vague -- after all, it's seven, eight years ago.

From my recollection, they came up with perhaps additional points that were relevant during those -- during those audits. So they felt that my original draft was maybe a little bit on the brief side and they felt that it could be expanded with one or two additional ones.

But if you ask me which ones are these, I cannot tell you.

Q. Now, do you know if KPMG had approved of this Terms of Reference?

A. They certainly had seen the draft of it, of the whole document.

Q. Right.

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A. And it was discussed between ourselves, so between myself and the Group Reserves Coordinator and KPMG.

Q. Do you recall if PWC participated in those discussions?

A. No. Not in that discussion.

Q. Do you recall if KPMG provided any comments to the Terms of Reference?

A. Yes, they did. But again, I cannot remember specifically which comment that would have been. But yes, that they would have asked questions and then on the basis of that, they may or may not have had comments.

Q. Do you recall if the comments or questions were substantive?

A. There is one comment that I can remember, specifically on this one, on this year.

In the previous year, there was a comment saying that KPMG -- or no, external auditors had approved of the -- of the guidelines. And we got a comment, or the Group Reserves

Coordinator got a comment or a question from KPMG

0228

saying, "Did we approve that? How did we approve that? Can you tell us how that went?" And ultimately that particular sentence in a successive guidelines was taken out.

Q. So did KPMG approve of the guidelines that are -- that have been marked as Exhibit 5, for 1999?

A. They saw it and they had no further comments to it.

Q. Do you recall any written document that evidenced their approval of the guidelines?

MR. TUTTLE: Object to the form. Foundation.

MR. BEST: Object.

MR. ADLER: Object to the form.

THE WITNESS:

A. No, I do not remember that.

BY MR. HABER:

Q. Now, I would like you to take a look at Exhibit 7. And also have handy Exhibit 6.

I am sorry, please turn to -- forgive me, Exhibit 8. If you can look at Exhibit

0229

6 and Exhibit 8.

And what I would like you to do is turn to page 28 of Exhibit 6, which ends 357 the Bates range. This is the Terms of Reference for the year 2000 and if you can now turn to Exhibit 8, page 27 of the document which ends 167 in the Bates number, which is the Terms of Reference for the guidelines which were issued in April of 2002.

Now, if you take a look at the -- looking at Exhibit 6, if you look at the first paragraph of the document, there is a reference to FASB Statement of Financial Accounting Standards no. 69; however, in Exhibit 8, which is 2002, the reference to FASB FAS 69 has been removed.

Do you have an understanding as to why in 2002 the reference to FAS 69 was omitted?

A. Yes. We took out the explicit reference to FASB statement number 69 which is the same as 4-10, which I am sure you are aware, because that particular document was included in the internal Group Reserves Guidelines.

It was referred to it, and as I

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have explained to you, the way the reserves estimation process in Shell went is that in the first instance, reference was made to the internal group guidelines, which in turn were made to conform with requirements, external requirements like rule 4-10.

So my reference in these audits I found had to be the internal guidelines.

The statement as it was in the year 2000 was a statement that had been carried over from previous versions. And I felt that since reference was primarily made to the Group Reserves Guidelines, there was no point in explicitly referring to the FASB statement of accounting standards.

So that was the reason why that was taken, just to align with the then prevailing practice.

Q. Now, again if you look at Exhibit 6, number 1, which begins to verify the technical maturity --

MR. BEST: Can you give a Bates

0231

number?

MR HABER: I am sorry. This is still 357.

MR. BEST: Thank you.

BY MR HABER:

Q. And if you compare that to Exhibit 8, which is 167, you will notice that the language which appears on page 1357, which is Exhibit 6, "and by verifying that undeveloped reserves are based on identifiable projects that can be considered technically mature" has been omitted in the 2002 guidelines, which is Exhibit 8.

What is your understanding of the omission of that portion of number 1?

MR. MORSE: Objection to form and

characterization of the document.

MR. TUTTLE: Same objection.

THE WITNESS:

A. I cannot remember what the reason was that that particular sentence was removed. All I can say is that in my reports and in my audits, I continued to specifically look at

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undeveloped reserves and ask the question whether they were based on identifiable projects.

So even though that particular sentence or part of the sentence has been taken out of the Terms of Reference, there was absolutely no change in my practice, as you will see from my checklist in all my successive reports.

BY MR. HABER:

Q. I would like you again to do a comparison now. If you look again at the 2000 guidelines, and the Bates number is 357, number 2, and compare that with the 2002 guidelines, which ends Bates number 167?

A. So comparing the number 2s of both of these pages?

Q. Correct.

A. Yes.

(Pause)

What had happened in between those two volumes is that in the year 2000/2001, under the direction of Aidan McKay, the group had

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instituted a much more formalized way of operating companies having to submit their proposals for future projects, whereas before it would be largely as a written document.

It now had to be formalized pretty much like the reserve system had been formalized through spreadsheets that had to be submitted to the center, which were then amalgamated in spreadsheet fashion, and which then provided a much more thorough and consistent manner of comparing various operating companies' plans.

Those submissions regarding their

plans -- and these were separate from the submissions of the NT reserves. Those submissions would be production forecasts where necessary by individual wells if they were to be drilled in the coming years, and otherwise they would be of specific projects like field developments or field extension developments with additional platforms with new wells.

And so it would be broken down to the lowest level of detail that was realistic.

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And all of that data would be submitted centrally so that Shell could then carry out its evaluation, its economic evaluation of these projects and thereby rank them and thereby assign available capital to each and every one or none of these projects.

Now, with that in place, people felt that it was important for me to check the consistency of those forecasts and those used for reserves estimating.

In other words, in cases where a production forecast is important, like in the case of an end-of-license situation, it was felt that I needed to look into the forecasts that were used and to ensure that they were the same as the ones that were submitted to the center.

And that is indeed what I did. There was a specific question added in my spreadsheet, and that explains the difference, the more extensive reference to production and sales forecasting. And that is included in that particular point.

0235

Q. Why was the words on Exhibit 6 "economic robustness" removed in the guidelines in 2002?

MR. TUTTLE: Objection. Characterization of the document.

BY MR HABER:

Q. If you look at number 2, it says that, "by assessing the robustness of project economics".

Why was that portion of the guidelines in 2000 not included in the 2002 version of the guidelines?

MR. TUTTLE: Same objection.

THE WITNESS:

A. By -- commercial maturity is a notion or is -- yeah, is a notion that is explained in the text of the document. And I cannot remember specifically why those words were taken out at the time.

But I would not consider -- and in fact, in my audits I did not consider that to be a material change of process. I continued to assess

0236

the commercial maturity of projects in exactly the same way as you saw before.

BY MR HABER:

Q. What I would like to you do now is to keep Exhibit 8 open to again the same page, 167?

A. Yes.

Q. And turn to Exhibit 9, which is the guidelines that were issued on September 2003.

(Witness complying)

And if you will turn to page 36 of the document, under Bates number that ends 408?

A. Mm-Hmm.

Q. I would like you to take a look at number 3 of Exhibit 9 and number 3 of Exhibit 8.

And what I would like you to focus on is the last sentence of Exhibit 9 in number 3, which reads, "The audit also verifies that applied future development is indeed likely to go ahead".

And you will see that that sentence is not included in number 3 --

A. Yes.

0237

Q. -- on Exhibit 8.

And if you could explain why that sentence was added?

A. As we discussed previously, the Group Reserves Guidelines over the years, particularly the years after 2001, gradually became more precise about the hurdles, the economic hurdles and, say, the business hurdles that needed to be taken by new projects before they could be booked as reserves.

In other words, there was a gradual tightening over the years. And this sentence is a very brief way of describing that gradual tightening.

The tightening was such that it was inspired by the additional guidance that was issued by the SEC in 2001, although even beforehand it became clear to me that some tightening in this respect was necessary.

But anyway, the tightening happened during these successive years. And like I said, that particular sentence is a brief way of

0238

representing that particular tightening.

Q. When you refer to the additional guidance that was issued by the SEC in 2001, you are referring to the interpretive guidance by the staff of the SEC?

A. Indeed the one that was published on the 1st of March, yes.

Q. Now, this tightening that's reflected by this language, from the audits of the operating units that you had conducted, did you have a sense that the people in the field in the operating units understood what was being referred to in this sentence?

MR. TUTTLE: Object to form. Calls for speculation.

THE WITNESS:

A. In this particular sentence?

BY MR. HABER:

Q. Yes.

A. I can't comment on the perception of this particular sentence, but I do know that staff in the operating units each year did receive

0239

their own copies of the Reserves Guidelines. And I do know that even in my introduction, while I was out on audits, I made sure that they realized what the latest additions to the guidelines were.

Q. When you visited the operating units for the audits, did you get a sense that the operating unit staff understood the information that was set forth in the guidelines?

A. Yes. Yes.

Q. Did you ever, throughout your tenure as Group Reserves Auditor, did you ever come to a conclusion that the operating units and the staff working at the operating units needed education with regard to the Shell guidelines?

A. Staff that I spoke to I think understood the changes in the guidelines.

And I didn't feel -- at that time, I didn't see any evidence that led me to the conclusion that the staff at the working level needed further education in the guidelines at that time.

Q. Now, you say "at that time".

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First of all, when are you referring to?

A. Generally to the period, say, from 2001 onwards.

Q. And prior to --

A. And I am dealing here with the staff whose responsibility it was to prepare the reserves estimates, or the staff that I would meet and work closely with during my audits.

Q. Prior to 2001, did you see any evidence that led you to believe that the staff did need education with regard to the guidelines?

A. No is the short answer to that. No.

Q. Now, if you can turn to Exhibit 10 for a moment, and in particular --

MR. BEST: Before you go on, do you want him to compare with --

MR HABER: No. No. No. We are done.

MR. BEST: Okay.

MR HABER: Just look at Exhibit 10.

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Q. I would like to direct your attention to Appendix F, the Bates number that ends 206.

A. Yes.

Q. This is titled "Group Reserves Auditor: Terms of Reference."

Did you prepare this document?

A. Yes. Similar to the previous Terms of Reference for the audit that we looked at, this one was drafted by myself and commented on and discussed with at that time Frank Coopman and John Pay, who was the Group Reserves Coordinator.

Q. Do you recall receiving any comments from Mr. Coopman?

A. Yes, he did. But if you ask me specifically which comments, maybe. Can I read through it --

Q. Yes, please. Please do.

A. -- and see whether the memory is jogged.

Yes. I believe and again I have to point to the fact that this is by now four years

ago.

I believe that he added or he suggested that I add the third point, i.e. the first two points being that I carry out audits and I do the end of year review of the reserves accumulation process.

And thirdly, he was making use more and more of my advice and views during the year, most importantly in setting up the group Reserves Committee, but also in other respects.

He would talk with me quite regularly, so that's why this third point was added.

Q. Was this Terms of Reference meant to supplant the Terms of Reference that we looked at in the various guidelines?

A. No. They are separate. These are the Terms of Reference for the Group Reserves Auditor. These are the things that he is expected to do.

The SEC audit guidelines are Terms of Reference. There is a distinct difference

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between these two guidelines. The ones you are having me to look at are the Group Reserves Auditor Terms of Reference.

There are three activities that the Group Reserves Auditor carries out, and these three are enumerated here. The first one is carry out group reserves audits in the operating companies.

The second one is to witness and audit the process of accumulating reserves at the end of the year, and that is taking place in the center.

And the third one is providing general advice to management of SIEP.

Now if you go back to the Terms of Reference in the guidelines, those are Terms of Reference of the reserves audits that are carried out in operating companies only, and they describe the methods that are used in carrying out those audits.

Therefore, they relate only to point 1 of the general Group Reserves Auditor

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Terms of Reference.

Q. Now, with regard to number 2, it says, "Witnessing and verifying the accumulation of the Group's Proved Reserves at the end of the year for inclusion into the Group Annual Reports and the SEC Form 20-F report on the basis of information supplied by Regions/Asset Holders."

Were you performing those duties prior to this document being drafted?

A. Yes, I was present during the month of January when these reserves would be coming in.

Q. Other than being present and witnessing the information coming in, did you verify the information that came in?

A. Yes. I would look at them, because the spreadsheet gave a lot of detail about where the specific changes came from; and I would pick out the -- I would pick out some projects where I had a question mark where I wanted to know more about why that particular change had been made, and I would pose those questions to the Group Reserves Coordinator: Okay, can you please

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provide me with some more background data here.

Q. Did you do anything other than that to get behind the numbers to check for their accuracy?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. The activity that I carried out at the end of the year in January, looking at all the groups' reserves changes, of course could not compare itself with actually going out into an operating company and carrying out at the end of the year.

So it was never the idea that I checked the validity of those reserves changes to the extent and to the detail that I would do in an actual operating company visit.

Having said that, if a company would come and propose a new reserves booking for a new field, a field that had been discovered by that company, it would be relatively easy to ask that company to give us reasons for that reserves booking, and in particular to give us a

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description of the maturity of that particular project.

Quite often, if it was indeed a project on which field development plans had been prepared, then those field development plans would have been available already in The Hague, and so it would be possible to refer to that.

But in some cases, that information would not have reached The Hague yet. And in that case, we would -- we would ask for some more data and pass our judgment on the maturity of those projects.

Q. In the instances where the development plans were prepared and available, did you do anything to check the validity of those plans?

MR. TUTTLE: Object to form.

THE WITNESS:

A. Yes. Where necessary, I would talk also to or with the Group Reserves Coordinator, and in some instances, with the Regional Business Directorate as it was called, who would be the

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group in SIEP overlooking the activities of a particular area that the operating company was in.

That didn't happen too often, but it did happen.

Q. When you say "where necessary," what circumstances would make it necessary for you to?

A. If the Group Reserves Coordinator couldn't provide me with the answers that I needed.

Q. Can you think of any instances where that occurred?

A. It started to occur on Angola. That's one specific instance that I remember. The other one was in Sakhalin, which would have been in 2003. No. There are no others that I can think of just right at this moment.

Q. With regard to Angola, what year are you thinking of?

A. That would have been the end of 2000.

Q. Now, you mentioned a comment that

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you received from Mr. Coopman, which you say is reflected in number 3 of Exhibit 10.

Do you recall any comments that you received from Mr. Pay to the draft, which is now reflected in final form in Exhibit 10?

A. Not specifically, no. No.

Q. Do you remember if Mr. Pay had any substantive comments to the draft?

A. He certainly had a close interest, and I am sure he would have given me some comments. But whether they were such that they turned the whole document around, I am certain that they weren't of that sort.

Q. Okay. You can put this document aside.

MR. TUTTLE: Is this a good time to take a break?

MR HABER: Yes.

MR. TUTTLE: If you are going to start a new section, then.

MR HABER: That's fine.

THE VIDEOGRAPHER: Going off the

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record at 12:04.

(Short recess taken)

THE VIDEOGRAPHER: Beginning tape number 4 and returning to the record at 12:18 from 12:04.

BY MR. HABER:

Q. Mr. Barendregt, just one follow-up question with regard to Exhibit 10. Prior to drafting the Terms of Reference that we were just talking about, was there a Terms of Reference that existed previously?

A. Yes, there were. Like I mentioned, I had on my computer, as I said, Terms of Reference ever since the early, the beginning period of my group auditorship, reserves auditorship back in 1999.

Q. Do you know if those versions of the Terms of Reference for the Group Reserves Auditor were ever printed and then disseminated to the Group Reserves Coordinator?

A. I know that whenever I changed, I came up with changes to the Terms of Reference.

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Or whenever somebody else, like for instance Frank Coopman instituted changes in Terms of Reference, they were certainly discussed with them, with the Group Reserves Coordinator and his supervisor or Frank Coopman.

But they weren't, as far as I remember, formally enshrined in some maintained document, not until the issue of Exhibit 10.

Q. So then the 2003 document, which is Exhibit 10, is the first time that they were included in a formal document, to your knowledge?

MR. TUTTLE: Objection to form. Characterization of the testimony.

THE WITNESS:

A. As far as I remember, yes.

BY MR. HABER:

Q. Now, just going back to your audits of the various operating units, generally speaking, how much time did you spend on an audit?

A. Typically two or three to five or six days, depending on the size of the company. The largest one was six days and that was Shell

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Expro. The smallest one would have been small ventures like Shell at the Port of Brunei, where I was for two days.

Q. Now, during your audits, what type of materials data did you review?

A. I would start -- as I mentioned, I would start about beforehand actually requesting a list of reserves, Proved Reserves and expectation reserves of oil and gas on the basis of which I would select the fields on which I wanted to have a closer discussion with -- on.

In those discussions, I would typically ask for maps, geological maps, any log data, any panels of log data, which would mean that you put the log data in graphical form next to each other.

And as far as those were relevant, I would definitely ask for the mature projects, the producing projects, I would ask for the production performance data, either by field or by reservoir. And normally they would have those available by any -- by any unit that I would

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request.

So it's those sort of data that I would ask for detailed data; and then I would ask them to explain the field to me, to give a description of the field, tell me where the challenges of the fields lay, was it low porosity permeability, or was it wells watering out or gassing out, any of those things.

And what was being done to combat these challenges, and what then ultimately was the way in which they had evaluated the reserves.

Q. When you made the request for information, did your request -- withdrawn.

When you made the request for information, was your request made directly to the operating unit?

A. Yes.

Q. Did you ever memorialize these requests in writing?

A. They were E-mails. They were in E-mail form, yes.

Q. Were these E-mails copied to the

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Group Reserves Coordinator?

A. Not normally, no. They would be just my dealings with the operating company, yes.

Q. As the Group Reserves Auditor, how did you view yourself in the reserves reporting process?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. Pretty much as implied by the word "auditor," I would review the procedures and methods in which the reserves estimates have been -- would have been prepared, and compared those against the group guidelines, specifically through the spreadsheet that I used in my reports, as you well have seen.

And on the basis of that, come to a composite judgment on the company in question.

BY MR. HABER:

Q. Did you ever tell anyone that you had formed a view that senior management viewed the role of the Group Reserves Auditor as a ceremonial position?

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A. I think I know where your question is coming from. I may have used that word in the first interview for the Davis Polk study, and that interview was carried out in February 2004.

I think it's important for us all to realize that the period of December 2003 to -- through January/February 2004 was an emotional period for all those concerned with the Group Shell Reserves, and I don't need to expand on that.

But that means that when I was first interviewed by the Davis Polk staff, and I must hasten to add that I was interviewed without any preparation, without any briefing by legal representative, it was just straight off the cuff.

And given the still rather emotional circumstances of that period, I may have used expressions that are fine in colloquial parlance, but that when written down are very easy to be taken out of context and out of meaning.

And I believe that that's -- that is what happened here.

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What I was referring to when I made comments like that was that indeed there had been very little -- I got very little reaction to my reports from senior management in Shell, in fact, so little that I never saw Philip Watts, for instance.

The last time I saw Philip Watts was when he was in that totally different and more junior position overseeing the operations in Denmark and when I was in Denmark myself. That was back in 1987.

But I never saw Philip Watts, I never got any reaction, and the same must be said of Walter van de Vijver when he arrived on the scene.

So I wasn't particularly perturbed by it. I was surprised, particularly because when I went out on my audits to the operating companies, I always made a point myself and admittedly I took the initiative there, I made a point myself of seeing the M.D. or at least the technical director.

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But that contact I did not have in The Hague.

Also, I found that other -- that as far as the external auditors was concerned, I found that yes, of course there was a good cooperation with particularly KPMG and at the end here meeting with PriceWaterhouseCoopers.

But it was -- certainly initially, it was completely oblivious to me -- I was completely oblivious about the process that would follow after that and, in particularly, about the external auditors taking the conclusions of my report to, for instance, the Group Auditors Committee.

To put it even more bluntly, when I started the job and during the first few years of my job, I wasn't even aware of what the Group Audit Committee was about.

Thinking back on it, I think it would have been better if the reserves matter had been reported more directly, particularly by players by myself in the Group Audit Committee.

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And that is precisely what is happening now, but of course that is after the event.

So it's these two factors combined that sometimes tended to create a situation where I felt completely separate from the totally cooperative manner in which I worked with the Group Reserves Coordinator.

I felt like working a bit in a vacuum. I never got any response back from senior circles within -- within SIEP. That was the basis of that particular remark expressed a bit more emotionally than I normally would have done it.

Q. Other than Philip Watts and Walter van de Vijver, were there other members of senior management that you would have expected you would have received feedback from?

MR. TUTTLE: Objection to form. Characterization of the testimony.

THE WITNESS:

A. Yes. At the end-of-year meeting that we had with the external auditors, I remember that initially at the end of '98, at the end of

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'99, in fact there would be very few people present from Shell themselves. There would be of course the Group Reserves Coordinator. There would be his supervisor, although at one particular meeting, even then he wouldn't be there.

And that would be just about it. There would be no senior management present. There would be a short briefing I remember with EPB, the head of the EPB.

That's the new business -- the director of the new business venture unit in SIEP, or not part of SIEP, it was in fact a separate company, SEPIV, S-E-P-I-V. But that was the extent of the interest that was expressed by senior Shell management in those days.

Q. Did the members of senior management who attended these meetings change over time?

A. Yeah. The organization changed. EPB became something else. It changed from being SEPIV, S-E-P-I-V, that's Shell E&P International

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Ventures, which back in 1998, it would be set up as a separate company.

That was phased out and that organization became part of SIEP, and I forget when that was. And yes, the organization and the organogram would change, and that would be --

Q. But the number of people who attended, did that change?

A. That increased over the years. Gradually over the years, there was more and more interest shown; I say the supervisors of group reserve coordinator and their managers.

And of course at the end of 2003, everybody was there.

Q. But other than 2003, when do you recall the shift from less to more?

A. It was gradual, it was gradual. Each year a few more people would turn up.

Q. Now, a moment ago you mentioned a Group Audit Committee. Did you make any presentation to the Group Audit Committee as the Group Reserves Auditor?

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A. Never.

Q. Were you ever invited by the group reserve -- the Group Audit Committee to make a presentation?

A. No.

Q. And again, this is during your tenure as Group Reserves Auditor?

A. Yes.

Q. Did you ever inquire as to the reasons why the Group Audit Committee had not invited you to make a presentation to them?

A. Not in so many words, no. No. Like I said, I didn't really become aware of the role of the Group Audit Committee effect -- until after the arrival of Frank Coopman.

And I believe that he -- from time to time, he would make suggestions that perhaps I would come along to one of his presentations. He would be called upon now and again to make presentations, and then they would be put off again at the very last minute.

But he suggested at one stage that

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I might come along, but then I believe the word came from above that that wouldn't be necessary.

Q. Do you know if your annual reports were presented to the Group Audit Committee?

A. The short answer is no, I don't. I don't know precisely in what form, if they ever were.

Q. Did anyone from EP ever report to you one way or the other with regard to the presentation of your annual report?

A. Sometimes we would receive some comment back, mostly from the external auditors, as a matter of fact, who would have been present in that presentation.

Initially, I believe, but I may have got it wrong there, but I believe that initially it was only the external auditors who would attend that Group Audit Committee meeting, and that changed again, I believe, only after Frank Coopman took over a more directing role in the reserves reporting process. And he certainly -- he would be attending those sort of meetings.

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Q. I take it from what you've just testified to, you believed at the time that you could add value to the process by being in attendance at these meetings?

MR. TUTTLE: Object to form. Characterization of the testimony.

THE WITNESS:

A. Certainly not initially. And in fact, it wasn't until very, very late in the process towards the end of 2003 when I -- when it became clear to me precisely what the various roles and responsibilities had been that I thought by myself: It would have been useful if I had been given an opportunity to report back to this committee.

I don't think we would have been able to avoid the recategorization of reserves. I mean, that was something that as soon as the additional guidance of the SEC came about in 2001, that was just waiting to happen; even when we didn't know it until 2003.

Q. Why do you say that it was just

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"waiting to happen"?

A. Well, the successive events that led up to the end of 2003, could it have been avoided? Even though we didn't know it, but it was unavoidable with hindsight, that the recategorization was what was necessary.

Most specifically, we discussed earlier, I described to you earlier, that one specific comment that was introduced at the end of 2003 in the reserve guidelines that were going to be used for the end 2003 reserves estimate was that FID was going to be required for major projects and certainly full field development plans for anything even slightly smaller than that.

That in itself turned out -- and we found out in 2000, end of November 2003, that in itself removed at least 700,000,000 from the Nigerian portfolio at a stroke, which turned out to be even more than that afterwards.

So that in itself set in train a number of changes to the reserves that were

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unavoidable. So in other words, we changed the guidelines and we made them so tight that ultimately, we had to debook this large amount of reserves, even though at the time when we were using them so in 2000, 2001, 2002, we weren't aware that there was so much reserves potentially exposed.

That realization became vaguely known in the course of 2000 -- end of 2002, 2003, and the full magnitude did not become clear until the end of 2000 -- November of 2003. And the rest we know.

Q. Now, when you say that awareness of exposures became known in the course of 2002, 2003, what caused that awareness?

MR. BEST: Objection to form and characterization.

MR. TUTTLE: Objection to form and characterization.

MR. BEST: That's not what he said.

MR HABER: I'll rephrase.

Q. You said that realization became

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vaguely known in the course of 2000, end of 2002 and 2003?

MR. TUTTLE: I am sorry. The sentence above it says, "We weren't aware that there was so much reserves potentially exposed. That realization became vaguely known in the course of 2000 -- end of 2002, 2003". So...

BY MR HABER:

Q. I still want to know what is the basis of that realization, what caused that realization.

A. We have to go back to the original SEC definition. As I think I have explained before, the original SEC definition was vague in many material respects. It was specific in one or two respects, but it was vague in many material respects.

And the only notion that was firm from that was the statement that reserves needed to be reasonably certain to be produced.

Now, reasonably certain can mean a lot of different things to different people.

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Some of the them interpret that there is 100 percent certainty, although to me that would be absolute certainty; some of them interpret it as 98 percent certainty, 85 percent certainty. Various levels of certainty can be mooted if you can quantify certainty, which in itself is a chance.

Now the situation changed and improved somewhat, somewhat, with the additional SEC guidance in 2001.

And the most important change that was introduced was the notion of commitment. The SEC expected to see a commitment by the company concerned to go and develop the reserves before they could be booked. And they gave similar examples like it could be signed contracts or whatever.

But the word commitment is really the operative word there. In addition, the SEC -- but those are side issues -- the SEC changed surreptitiously -- I find one of the wordings on the LKH issue that we touched upon earlier.

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But those were not significant in the context of the restatement of reserves. The restatement of reserves was ultimately emanating from the use of the word commitment and the way we interpret that in our successive guidelines.

MR HABER: This is probably a good place for us to stop for lunch.

THE VIDEOGRAPHER: Going off the record at 12:43.

(Lunch recess taken)

THE VIDEOGRAPHER: Returning to the record at 1:27.

BY MR. HABER:

Q. Good afternoon Mr. Barendregt.

A. Good afternoon.

Q. I am going to start my questioning around your audit of SDA. And in particular, my questions are going to be focused on the Gorgon booking.

Okay?

A. Yes.

Q. Did you perform an audit of SDA

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during your tenure as group reserve auditor?

A. Yes, I did. That was in the year 2000.

Q. Do you recall when?

A. I believe it was October.

Q. Do you recall how long the audit took?

A. I think it was four days.

Q. And when you performed the audit, was reference made to Shell's guidelines?

A. Yes. Yes.

Q. Do you recall making any specific reference to rule 4-10?

MR. TUTTLE: In the report or just at any time during the audit?

MR HABER: At any time during the audit.

THE WITNESS:

A. In answer to your question do I recall, no I do not.

BY MR. HABER:

Q. Just so the record is clear, is it

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do you recall? Or no, you do not?

A. I may have done it, but I do not recall specifically.

Q. Did you -- in particular with regard to the Gorgon booking, did you review any audit trail that supported the booking?

A. Not really. There -- the booking and the history behind it were verbally explained to me, but I did not dig into the files or ask people to dig into the files to tell me precisely where the documents were that they had shown me.

The predominant reason for that is that I tend to go on my audits in the frame of mind that I want to make my own opinion, I want to express my own opinion, I want to make my own judgment against the validity of that booking as against the Group Reserves Guidelines.

Q. Who was the person who verbally explained the history behind the Gorgon booking?

A. I expect that would have been Jeroen Regtien.

Q. What was Mr. Regtien's position at

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the time, if you recall?

A. I believe he was senior reservoir engineer of SDA at the time.

Q. Do you recall the sum and substance of what he had told you?

A. In respect of Gorgon or in general?

Q. Yes.

A. In respect of Gorgon, I do not recollect the conversation as such. But he will have told me that Gorgon was booked whenever it was first booked, I think a couple of years earlier, even three years earlier.

And that it was based on the evaluations as they were made at that time, the details of which just simply escape me.

Q. Do you recall if Mr. Regtien said anything about a market for the Gorgon gas?

A. We certainly discussed it. I think it is useful to bear in mind that Gorgon wasn't new to me when I was there. It wasn't as if I was faced with a totally new field to me. I knew

Gorgon quite well. I had been attending work

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shops organized by the operator who was Robert, a branch of Chevron, back in the early '90s when I was the representative of -- or one of the representatives of SEIP on partner workshops, as they were to be called then, discussing the development opportunities for the large field of Gorgon.

Even then in those early days in 199 -- in the early 1990s, Gorgon had already received a considerable amount of appraisal and a large number of wells, something in the order of ten to 15 wells, I seem to remember, had been drilled in the greater Gorgon area.

And from an appraisal point of view, it seemed like the field was getting more and more mature, and this is what I was expecting when I came back in 2000, which was something like five or six years after my previous visit there, my last previous visit.

And indeed, it turned out exactly like I expected. Meanwhile, a lot more work had been done on making and preparing a development

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plan for Gorgon by Chevron.

And meanwhile, a lot more work had been done by Shell on the, as we called it, downstream facilities that were required to bring the gas to market.

Gas that was found like Gorgon on the Northwest shelf, which is the Northwestern shore and against the Timor Sea in Australia, that gas did have no sizeable market in its near vicinity, and that meant that in order to bring that gas to a market, that gas had to be liquified, with which there was nothing wrong. That was quite an established method in the Southeast Asia area in bringing gas to market.

The market for that gas was most likely to be what we call the Pacific Rim. In principle, the western Pacific Rim, i.e., Japan, Korea, Taiwan.

But at the instigation of Chevron in particular, or Chevron/Texaco as they became to be known in early 2000, that Pacific Rim extended itself also to the US West Coast.

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So the market -- it was clear that the market was there, there was plenty of opportunities. Various marketing studies had been done and indeed were shown to me on my audit visit in the year 2000, showing up that from the second half of the first decade of the second Millennium, third Millennium, it was clear that market opportunities would open up.

But precisely when it was in that stage, not certain. But nobody that I spoke to and knowing the area and the background myself, there was no evidence to suggest that Gorgon would not become developed in the future.

Q. But at the time you conducted your audit, were there existing market opportunities for the sale of Gorgon gas?

A. I am not sure what you mean by existing. There certainly wasn't a gas contract in place or anything like that.

Q. That's certainly one aspect?

MR. TUTTLE: Objection to form.

THE WITNESS:

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A. It's an aspect but not a relevant one for reserves, because the reserves definition and also the SEC guidance does not talk about contracts or the requirement that you must have a sales contract. It requires a market to be available. The market was there, there was no doubt about it.

What was uncertain at that stage was the -- say the opening of the market for the Gorgon area. But the market was there, and it was definitely continued to be there, and it still is there.

BY MR. HABER:

Q. So within the rule 4-10, if I understand your answer, the market you say is

there, but it wasn't open.
Is that correct?
MR. TUTTLE: Objection.
Characterization of the testimony.
MR. BEST: Same objection.
THE WITNESS:
A. I don't know what you mean by

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"open." You don't develop a gas field from one day to the other when suddenly there is an opening in the gas market. It doesn't work that way.

You achieve an opening in a gas market by negotiating a contract with some buyers, certainly in those days.

Even in that nowadays is less formal, because more and more of LNG gas gets sold on the spot market, just like oil does.

You don't get that opportunity until you have actually built an LNG plant and put the field on stream through a development with platforms and wells and like that.

So you need to have a clear idea about how and where it is that you are going to sell the gas and who you are going to sell the gas to before you start actually developing a field.

BY MR. HABER:
Q. At the time that Gorgon was booked, did Gorgon have the facilities to sell the gas from the Gorgon fields?
A. No. No. The field was

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undeveloped.
Q. And at the time you conducted your audit, was the facility developed for the sale of the Gorgon gas?
A. No, it wasn't.
Q. Where was this facility supposed to be built?
A. The development plan that was considered at the time would be an off-shore construction consisting of several platforms and a pipeline to an onshore location where the LNG plant would be, and that would be on the Barrow

Island.

I must add that one of the other developments would be of the other occurrences that had happened over the years when I hadn't looked at Gorgon was that the LNG -- the LNG costs, the costs of constructing an LNG plant had come down quite significantly, thanks to work done, among others, by a Shell group, a group in Shell called Global Solutions.

The costs of building an LNG plant

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and in bringing gas in liquified form to market had come down considerably.

And that meant that the economic prospects for a field like Gorgon had improved enormously and there was absolutely no doubt that the field was economic to produce.

Q. Where was Global Solutions headquartered?

A. In The Hague.

Q. What did Global Solutions do?

MR. TUTTLE: Just generally?

MR HABER: Yes. Just generally.

THE WITNESS:

A. I don't know. I know that this is one of the things that they did, but I don't know what else that they did. It's part of exploration and production.

BY MR. HABER:

Q. Now, with regard to Barrow Island, did Shell -- withdrawn.

Were regulatory approvals required in order to build the facilities on Barrow Island?

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A. Undoubtedly, yes. Yes. They would have been.

Q. And at the time that the reserves were booked in Gorgon, do you know if the regulatory approvals had been obtained?

A. I believe not, but they were not believed to be any serious hindrance at that time.

Q. At the time you conducted your audit, had required approvals from the government been obtained for Barrow Island?

A. No. But there were certain rights, development rights enshrined in Australian law. And again, it was a matter of the Australian government not being able to withhold on unreasonable grounds any development.

Q. Do you know if Barrow Island was an environmentally protected area?

A. Yes it was. Yes it was. But it wasn't -- this LNG plant wouldn't be the first facility that was going to be built on Barrow Island. There were already facilities for an oil field in fact called Barrow Island that had

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already been in existence.

Q. Whose facility was that facility that you were referring to?

A. It would have been an oil production facility and an oil export facility of some sort. I cannot remember the precise detail, but it certainly was an oil facility together with oil wells.

Q. When -- withdrawn.

Do you know if the regulatory approvals had been obtained past the time that you had conducted your audit, so that is, from 2000 forward?

A. I am sorry. Can you rephrase the question?

Q. I will rephrase. Do you know if after the time you conduct your audit in 2000, the regulatory approvals had been obtained?

MR. TUTTLE: To the present?

MR HABER: To the present.

THE WITNESS:

A. No, I don't. I haven't -- I

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haven't followed that. But not a lot of change had happened since I -- when I was auditor, and I have stopped taking interest when I quit the auditor job.

BY MR. HABER:

Q. At the time that you left the

position, do you know if the required approvals from the government had been obtained?

A. That had --

MR. TUTTLE: Objection. Asked and answered.

BY MR. HABER:

Q. I am sorry. You can answer.

A. That particular detail I cannot remember.

Q. Now, earlier, you mentioned that there was not a gas contract at the time of the booking.

At the time that you conducted your audit, was there any gas contract through the sale of the Gorgon gas?

A. No, I don't --

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MR. TUTTLE: Objection. Form, speculation, characterization of the testimony.

THE WITNESS:

A. No. There was not. There was no contract in place.

BY MR. HABER:

Q. At the time that you conducted the audit, had anyone presented a signed contract for the sale of the Gorgon gas?

A. No.

Q. Between the time that you conducted your audit and project Rockford in late 2003, do you know if there was a signed contract for the sale of the Gorgon gas?

A. I know that there wasn't. But again, I think I want to clarify here that since you are continuing to refer to a signed contract, the signed contract was a sufficient condition for the booking reserves, but it was not a necessary condition for booking reserves.

That was made clear in, for example, the SEC additional guidance in 2001, even

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though that was after the period of this particular audit. But it was also clear in the guidelines as they were issued by Shell before that time.

MR. FERRARA: I am sorry. As a point of clarification for the reporter, for the past several answers this witness has been referring to a signed, S-I-G-N-E-D, contract and it's appearing in the transcript as side, S-I-D-E.

THE REPORTER: Thank you.

MR HABER: Thank you.

BY MR. HABER:

Q. Was obtaining all required governmental approvals a necessary condition for the booking of gas reserves?

A. It was not explicitly mentioned for contracts -- for projects of this type, as far as I recollect in the Group Reserves Guidelines.

The Group Reserves Guidelines, which was the only reference of importance at the time of the audit, insisted on a clear way visible towards obtaining a market entry, i.e., having a

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market already in existence, plus a clear way of obtaining a path into that market.

And that, in this particular case, meant having an undoubtedly economic way of making the gas into liquified gas and transporting it to market, which was a method that had been -- as I explained, had been well established over the previous 20 years in that area.

And the third one is: Is there any doubt that the field in question is not going to be developed for reasons of economic viability, whatever; and that doubt was simply not there.

Whoever I talked to made it very clear to me there was in nobody's mind was there any doubt that Gorgon at one stage was going to be developed, or indeed that any of the partners, Shell, Chevron, would walk away from Gorgon and decide not to develop the field.

In fact, later on when the requirement of commitment was mentioned in the additional SEC guidance, I could see evidence of that commitment.

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In particular, the attitude by Chevron/Texaco that came to pursue the project, to go ahead with the project, they had set up a dedicated team with a senior manager that it had to pursue the development of Gorgon.

Now, that to me is a serious commitment. You don't spend money on setting up a team, paying all the salaries, et cetera, et cetera, doing all the data gathering, that is required to start a project of this size.

Q. Well, going back to my question, which was: "Was obtaining all required governmental approvals a necessary condition for the booking of gas reserves?" In your answer, you said, "it was not explicitly mentioned for contracts."

So was it an understanding that such approval was needed before?

A. Yes, indeed. Yes. Yes.

MR. TUTTLE: Objection to form. Characterization of the testimony.

BY MR. HABER:

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Q. Now, you mentioned just a moment ago Chevron/Texaco.

Were they the operator of the project?

A. Yes, they were.

Q. And this commitment that you talked about, do you recall when this came to light?

A. It was after the -- after the audit, one, maybe two years later.

Q. So that would be some time in 2001, 2002?

A. 2002 more likely I think, yes.

Q. Do you recall who the partners were with Shell and the project? And again, I am referring to Gorgon?

A. Chevron/Texaco obviously. I am hesitating because there was BHP at one stage, but I am not sure whether they were still in, or whether they had in fact sold out, so that I don't know. I don't know.

Q. Well, at the time that Shell initially booked the reserves in Gorgon, do you

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know if any of Shell's partners booked Proved Reserves in the Gorgon project?

A. I didn't pursue that information. So the direct answer is I don't know. I certainly hadn't seen that any of its partners did, but...

Q. From the time that you conducted your audit to Rockford, did you ever become aware of whether Shell's partners booked or did not book reserves at the Gorgon?

A. No, I did not -- I did not become aware.

MR. TUTTLE: Plus let him finish getting his question out before you start your answer.

THE WITNESS: Yes. Yes. Yes. Yes. I am too eager.

BY MR. HABER:

Q. Now, when you conducted your audit, did you meet with the staff at SDA?

A. Yes.

Q. Other than other than Mr. Regtien, was there anyone else that you recall meeting?

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A. Well, yes. We mentioned her name before, Sheila Graham, but there were others, the regular acting supervisor. The name escapes me, but it can be found on the addressees of my audit report.

Q. Do you recall if that was Mark Chittleborough?

A. That name does not ring a bell.

Q. Does Sarah Bell come to mind as something that you may have met with?

A. No. I think that was after my time. I met Sarah Bell for the first time in Bangladesh.

Q. And when was that?

A. Around the same period, 2001 maybe. I would have to look it up.

(Barendregt Exhibit No. 11 marked

for identification)

Q. For the record, we are marking as Barendregt Exhibit 11 a draft note dated October 19, 2000. The title of the document is "SEC Proved Reserves Audit, Shell Development

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Australia, 9-13" October "2000."

The Bates range is PER00070679 through PER00070689.

(Handing)

Now, Mr. Barendregt, have you seen this document Exhibit 11 before today?

A. It would appear to be a draft version of my audit report.

Q. Do you recall preparing the draft note?

A. Well, I always did ahead of finalizing the report, yes.

Q. Now, you'll notice that a number of people are copied on this note. Is Alan Parsley the person that you were thinking of a few moments ago?

A. No, it was Robert Blaauw; that was the name I was trying to remember. I see now also that Jeroen Regtien, but he was in fact development manager of the SDA.

Q. Now, did you provide a copy of this draft to all of the people identified on this

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list?

A. No, I never did. I sent my draft report to the primary auditee, who in this case would have been Jeroen Regtien, expecting him to take care of appropriate distribution of this report in their organization.

Q. Do you recall providing a draft to anyone else?

A. I usually gave a draft copy also to the reserves coordinator.

Q. At this time, was that Remco Aalbers?

A. Yes, it would have been. Yes.

Q. Now, if you could just look to the

paragraph on page 1. That begins, "The audit commended the high quality technical work that had been carried out by Woodside"?

A. Mm-Hmm.

Q. If you go in a little bit further, the sentence that begins "Maintaining the preliminary booked volume of Gorgon gas." It would be the second sentence of that paragraph.

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A. Yes. Okay. What was the question?

Q. There is a reference in that sentence to a 5-year retention lease.

What does that refer to?

A. I am sorry. I must have been looking at the wrong paragraph. Which paragraph are you reading?

Q. I will reread it. It's the same paragraph that begins once the audit?

A. The second audit.

MR. TUTTLE: The fourth paragraph.

MR HABER: The fourth paragraph.

THE WITNESS: Oh, I am sorry. I missed that.

BY MR. HABER:

Q. And it would be the second sentence that begins "Maintaining the preliminary booked."

A. Can I read that, because I was in the second paragraph still?

Q. Yes.

(Pause)

A. Yes.

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Q. There is a reference in that sentence to a 5-year retention lease?

A. Yes.

Q. What does that refer to?

A. Fields under Australian law, as I remember it -- and of course I am far from an expert and also my memory to that day is getting dim.

But as I remember it, a field that was in its predevelopment stage, in other words, that was still in a stage of being studied by its operator and shareholders, was the subject of a retention lease, which would allow the operator to continue to do studies on the fields, to carry out additional appraisal drilling if necessary, and to further mature the fields towards the stage of development.

And from what I seem to remember, is that such a lease would be granted on a 5-year basis.

And it would be renewable effectively as a matter of course, provided that

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the operator could show that it was working the project, that it was spending effort and money on further maturing that -- of the project.

And in the case of the Australian government, there had never been any incidence in the past where such a retention lease was unreasonably withheld.

Q. And do you know if the retention lease was -- the extension was granted?

A. I don't remember off-hand. But if it wasn't, then the field would no longer be in Shell's position, so it must have been.

Q. Now, if you could look at the Attachments for a moment to this document, earlier you testified about a spreadsheet and also a checklist.

The attachment 3 appears to be a checklist?

A. Yes.

Q. Is this the -- I realize that it's relating to SDA. But was this the checklist the type of checklist that you were referring to

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earlier --

A. Yes.

Q. -- this morning?

A. Yes, it was. Yes, it is.

Q. Now, were the questions that are identified in the left-hand column of the attachment, were these form questions that you used for each audit that you performed throughout the year?

Or were they specific to a particular operating unit?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. No. This was part of a standard list that I would take with me with blank answers, obviously. And I wouldn't in fact take a checklist and sit around the table with the people concerned.

I would first instance sit around with the people concerned and gather all the data that was necessary and then later on typically at the evening of the first day, I would take out and

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tick these boxes myself.

Invariably, I would find that there was one particular question that hadn't come to be discussed during the day, and I would then take that up and come up with follow-up questions the following day, the second day or whatever.

And that is precisely what I did here.

BY MR. HABER:

Q. So did you ever add or subtract from the standard questions that were included in the checklist?

A. It would sometimes occur that there were questions which, for whatever reason, were not available. And I think there is one here, for instance, 118, then I would just simply say that it was not applicable.

It talks here about improved recovery estimates. Well, neither Gorgon initially, nor the Woodside fields had any improved recovery project installed in it.

By improved recovery in this sense,

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I meant either water injection or a gas injection project.

So since that wasn't in operation, that particular sentence was not applicable.

Q. I am not sure that you've addressed

the question I asked, which is: Well, if these questions were standard, did you ever add additional questions throughout the year as you were conducting your audits?

A. Yes. I think I explained that to you earlier, that each audit provided me an opportunity to check also and see whether I -- the range of questions that I had here was indeed a comprehensive one or whether I couldn't add to it.

Q. I see.

A. And more likely than not, over the years, more questions were asked or questions were rephrased as a result of these audits.

Q. Now, the previous attachment two appears to be a spreadsheet, or at least spreadsheet form.

I believe you addressed this a

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little earlier today.

A. Correct.

Q. And is this representative of what you were referring to earlier today?

A. Yes, it is.

MR. TUTTLE: Objection to form.

BY MR. HABER:

Q. So this spreadsheet would be filled in by the operating unit during the course of the audit?

A. No. I would fill it in myself.

(Barendregt Exhibit No. 12 marked for identification)

(Handing.)

Q. Mr. Barendregt, I am marking as Barendregt Exhibit 12 a draft note dated November 21, 2000.

And the title is "SEC Proved Reserves Audit, Shell Development Australia, 9-13" October "2000."

The Bates range is PER00020307 through PER00020309.

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Have you seen this document before today?

A. Again, it would appear to be a draft note, and I am somewhat surprised to see that this appears to be a second draft note that I prepared.

Q. Why are you surprised?

A. Well, I wasn't normally in the habit of issuing more than one version of a draft note. Now, there could be two explanations here. One of them is that this was in fact my final note where I omitted to take out the word draft. It happened once or twice.

Or indeed it was another draft note --

Q. Do you --

A. -- for reasons that I do not remember.

MR. TUTTLE: Mr. Barendregt, let me note for the record that the PER indicated that this document was produced from Perth from a collection of documents in Australia.

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So I don't want the witness to be misled in terms of the source of the document in speculating here on the origin of it.

So if you want to pursue that line, Mr. Haber, that's fine. But I just want to make sure that he understands what the production code suggests.

MR. HABER: It may be what the production code suggests, but the issue is whether he prepared a second draft note?

MR. TUTTLE: Then you can ask him if he recalls doing so.

BY MR. HABER:

Q. And that's the question. Do you recall preparing a second draft of a note?

A. The answer to the question is no, I do not.

Q. Now, do you recall with regard to the draft note? And since you recall Exhibit 11, do you recall receiving any comments to the draft from Mr. Regtien?

A. Not specifically. But I am sure I

0299

must have received some comments.

(Barendregt Exhibit No. 13 marked for identification)

Q. I am going to hand you what we have just marked as Barendregt Exhibit 13. And this is what I believe to be the final note?

A. Yes.

Q. It's dated 5 December, 2000. The title line reads "SEC Proved Reserves Audit, Shell Development Australia, 9-13" October "2000."

The Bates range is RJW00060528 through RJW00060538.

Do you recognize this document?

A. It would appear to be my final note, yes.

Q. Do you recall preparing this document?

A. Yes.

Q. And if you look at the bottom left-hand corner, there is a signature.

Do you recognize that signature?

A. My signature.

0300

Q. Do you recall if the final note was distributed to the people who were identified at the top of page 1 of the Exhibit?

A. Separate copies were put together in an envelope with each of these names highlighted and sent in the mail to SDA.

So I don't know whether they actually received it, but certainly they each were sent their own individual copy.

Q. Now, if you look in the copy portion in parenthesis on the left-hand side, it says "circulation"?

A. Mm-Hmm.

Q. At the right it says "SIEP - EPF: Gardy, van Nues," is it?

A. Van Nues.

Q. Van Nues.

Other than those two people, was there anyone else that you had intended within EPF for the note to be circulated to?

A. There was the business advisor in SIEP who received his separate copy.

0301

Q. Who is Mr. Van Nues?

A. Gardy was the -- say the predecessor of Frank Coopman, so the head of EP Finance. And van Nues was, as I remember it -- but I am certainly not 100 percent certain, was in charge of financial reporting, external financial reporting.

And by financial, I mean the financial results of E&P, so not say Group reporting, but E&P reporting as far as the financial results were concerned.

For instance, he was not responsible for reserves reporting. That was in the stream of Bell, McKay, and Aalbers.

Q. Do you recall if any of the people who are identified as recipients, either direct or as copied recipients, had commented on the report?

A. Not specifically, no.

Q. How about generally?

A. I would expect that Remco Aalbers would have given a number of comments, but the character of that I just do not know. I do not

0302

remember.

Q. And in terms of timing, do you have a recollection if you had received comments from Mr. Aalbers after this note was circulated?

A. I would have been surprised if he did, because he certainly had an opportunity to look at it beforehand.

Q. So he was one of the people that you distributed your draft note to?

A. Normally, yes. Yes.

Q. Now, is there anything in the final note -- withdrawn.

Do you recall receiving any comments from Mr. Regtien that were incorporated into the final note?

A. Do I recall a specific instance

where he did? No, I do not. I am not saying that he didn't.

(Barendregt Exhibit No. 14 marked for identification)

Q. Mr. Barendregt, I am going to hand you what we are marking as Barendregt Exhibit 14.

0303

It's two E-mails with attachments, and I will note that the attachment is a draft note which is dated November 21, 2000, which we marked as Exhibit 12.

The last E-mail which appears on the top of the page is from you. It's dated November 22, 2000 to David Christie, Jeroen Regtien, with a CC to Shiela Graham and Robert Blaauw. The subject line reads "DRAFT AUDIT NOTE."

And the Bates range is PER00081987 through PER00081997.

Have you seen this E-mail before today?

A. Well, since I sent it, I must have, yes.

Q. And looking at this E-mail, does it refresh your recollection sending out a second draft of this note of your audit?

A. Not a lot, but it's clear that there were some issues that gave reason for a second -- for a second draft.

Q. In looking at your E-mail to Mr.

0304

Christie and Mr. Regtien, I'd like to direct your attention to the middle bottom of the E-mail, the one that -- the sentence that begins "Gorgon losses."

Do you see that?

A. Yes.

Q. What did you mean by "again, a victim of the hurry to get the report out?"

A. I don't know what it refers to, what Gorgon losses refers to. Can I look back at my final report --

Q. Yes.

A. And see whether I can seek to

unearth what I meant? I simply do not know what I meant by "Gorgon losses." It obviously refer to say a particular item in the report.

MR. FERRARA: Perhaps you would consider directing the witness's attention to the second page of Exhibit 14, the second page of Exhibit 14, and then you may wish to look at that and then consult the audit report.

MR HABER: That's fine.

0305

THE WITNESS: Oh, there we are, okay. "A 2% correction was made for Gorgon losses", 6.03.

Oh, yes. This is this matter of own use fuel and losses.

In reporting gas volumes and particularly gas volumes as reserves, Shell had adopted the method of correcting the actual produced gas volumes as they came from the field for own use and losses, as I recall.

Various parts of the facilities, for bringing the oil and gas to surface and to shore, required fuel. And most of the time, this fuel used was taken -- or is taken from the gas stream, for instance to drive compressors, gas compressors and other facilities.

As a matter of fact, as an aside issue, the SEC guidelines we have later established do not actually require this deduction to be made. The reason why Shell adopted it is because the finance function reported gas sales, which effectively would have

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been gas produced minus gas lost in operation or used as fuel; fuel flared and losses is what that was called.

And in order to arrive at a situation whereby the annual production -- and this is all in existing fields, where the annual production was comparable between the submissions of the reserves and the submissions of the finance function, this deduction was made.

In order to be consistent with this

practice for existing fields, a similar projection needed to be made for future fields.

So in other words, the calculation of future recoveries in the Gorgon field, future gas recoveries, needed to be corrected for anticipated use for fuel, flare, and other losses, and that is what this is about.

Q. The next paragraph says the un -- and this is in paren -- I am sorry. In quotes, "The 'unsatisfactory' rating for the mismatch in 1999 gas production/sales figures: I hope you can understand that I can hardly rate this as 'good'.

0307

Trust that" quote, "'satisfactory'", close quote, "is a good compromise. I did check with EPF here and it seems that the old Ceres guidelines left an integrated OU like SDA with no option but reporting the way you did."

And it appears you are responding to a comment that Ms. Graham had made, again on the second page of the E-mail which is I believe referencing a new checklist 6.07.

My question is: Can you explain what this issue is about?

MR. TUTTLE: Just object to the characterization of the document, the comments from Ms. Graham.

You can answer.

THE WITNESS:

A. Yes. One of the activities that I carried out at the end of the year was to check the consistency of the reported oil and gas production figures as reported by the reserves reporting stream, on the one hand, which would be organized by the Group Reserves Coordinator, and

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the finance function on the other hand.

Finance would report separately sales of gas and oil during the year.

As a check, it was introduced I believe somewhere in the '80s, early '80s, that these two reported volumes, annual production and sales volumes, needed to be consistent between the two, and that meant that they needed to be the same; and if they weren't the same, then we needed to find out why it was that they were different, and that was one of the things that I did.

And invariably, you would find that one or two companies that had differences between these two streams, and it was sometimes easy, sometimes more difficult to find the reason for that.

Now, as I remember it, one of the problems that we had with SDA is that the fuel that was spent for running the Woodside LNG plant -- so this had nothing to do with Gorgon -- the Woodside LNG plant, because Woodside were producing gas as well, that that fuel was deducted

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as fuel and flare.

And our Reserves Guidelines make sure that only the fuel and flare that is used in the upstream operation, so in the pure physical act of bringing the gas to surface and bringing it to shore to the nearest -- to the nearest point of collection, only that fuel would be accounted for.

Now, the way the administration worked in Woodside was that that was an integrated operation as far as they were concerned. Therefore, the gas reserves by Woodside had to be reduced by a larger amount than there really should have been.

And that was part of the reporting by SDA. And as I said here, originally I proved that I -- I showed it to be unsatisfactory, and indeed it was not in line with the regulations.

But I gathered from my discussion with SP, in fact SDA had no option, they had no means of accessing data to correct that.

So they did what they had to do, what they couldn't avoid doing. So therefore I

0310

said: Well, it still isn't what it should be, but we will make it a middle of the road opinion.

Q. So if you look at Exhibit 11, your checklist, on the last page, which is 689, I believe at 6.07, that's where it is noted as an unsatisfactory grade?

A. Yes. I believe the cross was an unsatisfactory, yes.

Q. And in your draft note of November 21, which is Exhibit 12 or which is attached to the E-mail we were just talking about, it's now reflected as a satisfactory grade?

A. The November 21?

MR. FERRARA: I am sorry. This is Exhibit 12?

MR HABER: No. I am sorry, Exhibit --

THE WITNESS: The final copy.

MR HABER: Or just let's look at the Exhibit 14.

MR. FERRARA: I think we are in a jumble.

0311

MR HABER: Yes. No, I am going to correct it. Exhibit 14, which has November 21 note attached to it.

THE WITNESS: Oh, I see.

BY MR. HABER:

Q. And if you look at the last page of the document, that reflects now a satisfactory grade.

Correct?

MR. FERRARA: I am sorry. What page are you referring to?

MR HABER: 1997.

THE WITNESS:

A. Yes. Item 6.07 in Exhibit 14, it's an "O", which stands for satisfactory, yes.

BY MR. HABER:

Q. In terms of your grading system, in terms of which one is better, is good better than satisfactory?

A. (Nodding)

Q. I am sorry. You have to verbalize the answer?

0312

A. Yes.

Q. And I see in the final note, the final report, you graded SDA, the audit, satisfactory.

If you look on Exhibit 13, the bottom of the page?

A. Yes. Yes.

Q. Do you recall any instance when you performed an audit during your tenure as Group Reserves Auditor where you did not give a satisfactory or good grade to an operating unit?

A. There was one where it was for Abu Dhabi. And that was I believe somewhere in 2000, where in my draft report, I came up with an unsatisfactory answer.

And this was the situation where there was one person in Rijswijk, which is the research laboratory of Shell, there was one person made responsible for coordinating the reserve submission for Shell Abu Dhabi.

Shell Abu Dhabi -- Shell Abu Dhabi had themselves a very small office with hardly any

staff in Abu Dhabi, obviously, and the operation there would be run by ADCO, Abu Dhabi -- Abu Dhabi Company. I forget what it stands for.

Anyway, it was referred to as ADCO, who would be a joint venture company between ADNOC, who are the government oil company, and Shell. They would be the actual operators.

Now, because they were the actual operators but because there was a mixture there between Abu Dhabi government staff and Shell petroleum staff, petroleum engineering staff, it was deemed not necessary for me -- for me to visit that company in Abu Dhabi. But in fact it was deemed that it was sufficient for me to visit the person in Rijswijk who was responsible for putting their reserves together.

And I found that there were serious flaws in their -- in his submission, basically because he didn't get the data, and the ADCO company wouldn't make it available to him, so it wasn't his fault. But nevertheless, as an audit trail it was unsatisfactory.

0314

What we agreed then was that he would yet again go back to ADCO and seek the additional information that I was looking for, which I allowed him to do, and then a few months later we did the audit again and it came out at just satisfactory, but it always remained the lowest score as far as the audit that we had.

Now, as far as your question as to were there any audits that we gave that were unsatisfactory rating, the short answer is no. It wasn't until the year 2003 that the two audits of SPDC and of Oman were given an unsatisfactory rate.

Q. We will probably discuss those two tomorrow.

MR. FERRARA: We have gone for a little over an hour.

MR HABER: Yes. I was just going to say this is a good breaking point.

THE WITNESS: Okay.

MR. HABER: So we will take five minutes.

0315

THE VIDEOGRAPHER: Going off the record at 2:31.

(Short recess taken)

THE VIDEOGRAPHER: Beginning tape number 5 and returning to the record at 2:45 from 2:31.

BY MR. HABER:

Q. Mr. Barendregt, in 2000, do you recall there being an effort by SDA to book reserves additions in Gorgon?

A. Yes.

Q. When do you recall that occurring?

A. I don't know the precise date, but it was sometime before the -- before the audit, as I remember it.

Q. Do you recall how much SDA was -- how much volume SDA was trying to book as reserves?

A. No, I do not. But it was small.

Q. Do you recall discussing the issue with Remco Aalbers?

A. Not specifically. But it must have

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come up in discussions that we had at that time, yes.

Q. Do you recall what position Mr. Aalbers was advocating with regard to the booking of additional reserves in Gorgon?

A. I do not remember that, but I know that my position was that whatever they propose, we'll see when I get there.

In other words, people would give me perhaps opinions on this or not, but whether or not, they didn't in any way influence me. I had always made quite clear to Remco and to others that I would go out there, I would come to an opinion, and I would express that.

Q. Do you know if the ExCom considered the issue of whether it was appropriate to book reserves addition in SDA for Gorgon?

MR. TUTTLE: Objection to form. Foundation.

THE WITNESS:

A. I do not remember that.

(Barendregt Exhibit No. 15 marked

0317

for identification.)

BY MR. HABER:

Q. We are marking as Exhibit 15, Barendregt Exhibit 15, the "Review of Group End-1999 Proved Oil and Gas Reserves Summary Preparation."

It's a note dated 8 February, 2000. The document is multipaged. It bears two Bates ranges, the first one is V00280131 through V00280144, and the other range is DB 25123 through DB 25136.

Now, Mr. Barendregt?

A. I am sorry.

Q. That's okay. Have you seen this document before today?

A. Yes. It would appear to be my end 1999 report.

Q. And if you look in the bottom left-hand corner, there is a signature there. Do you recognize that signature?

A. Yes. That's mine.

Q. That's yours? I would like you to

0318

turn to the attachment 1, which is 133 or the DB range 125. Under number 3, "In Australia", if you just take a look at that for a moment.

A. Yes.

Q. Now, do you recall when, having looked at this, when SDA was proposing to add the reserves?

A. Well, obviously from the date of this report, it would have been somewhere in the course of 1999.

Q. Now, in your report, it says, "The most likely market for this gas would be LNG. However, customers for this additional gas cannot at this stage be readily identified and the incremental volumes, (some 20 10^9 Nm3 Group share) have not been included in externally reported Proved Reserves at this stage. This is in line with Group guidelines and is therefore supported."

What is your understanding as to why these reserves were not included in the externally reported Proved Reserves at that time?

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A. As I remember it, my understanding at that time, not having been to visit SDA yet, was that Gorgon had been the subject of an update of the field development study, presumably by the operator, and that that had yielded a slight increase in the amount of reserves proved and expectation that were identified in the field.

So that is the nature -- as far as I remember it now, that was the nature of the slight increment, slight meaning in comparison with what was -- what -- the total size of Gorgon at that stage.

Q. Now, my question, thought, was what was your understanding as to why the reserves were not included in externally reported Proved Reserves at that time?

A. I cannot remember that. I cannot remember that precisely what the reason was, and I regret that I didn't specifically report that here. Normally I do that, but I didn't do that.

Q. Well, if you notice there is a reference to "customers", not, I am quoting,

0320

"mere, readily identified."

Was that an issue that you considered?

A. Yes. This comes back to the earlier subject that I mentioned that in order for gas to be carried as reserves a market -- a path to markets needs to be identified. In other words, there needs to be an existing market, and there needs to be a path identified to that market.

And in this case, that was an LNG plant and LNG shipment to the western Pacific Rim.

Q. Did you consider at the time whether those conditions which caused you to agree with not booking these reserves addition required you to consider whether to debook the reserves at Gorgon that had already been on the books?

MR. TUTTLE: Object to form. Characterization of the document, characterization of the testimony.

BY MR. HABER:

Q. You can answer.

0321

A. First, I regret that this particular paragraph hasn't been more extensive. That normally I try to write my reports in a lucid fashion such that people first, foremost people understand what it is I mean there, but also that I later on remember myself what I have written here.

And I regret to say that I cannot remember precisely what went through my head here.

When I say that "approved gas volumes are economic to develop and a market is readily available and the license duration is"... (Reading) I am sorry. Still reading, too.

(To the Reporter) Strike what I would have said because I was reading from the wrong paragraph.

"The most likely market for this gas would be LNG, although customers for this additional gas cannot be readily identified."

As I said, that in fact is not, say, a necessary condition for booking reserves, if you haven't additional customers.

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And linking it as I did with the incremental volumes has not really any substance. I should have written that much clearer than I did have.

Q. Well, when you say "it's not a condition," is it a factor that's considered?

A. It's a factor that I must have considered at the time.

Q. Do you recall considering whether it was appropriate to debook the Gorgon gas in light of this condition, this factor?

A. What I knew about Gorgon when I compared it against what the guidelines said, it fulfilled the guidelines. The Shell guidelines said that a market needs to be in existence, and this is in fact what I believe rule 4-10 said.

But that I am not 100 percent sure of. But anyway, a market needs to be in existence, and a robust way of developing that gas and bringing it to market must be identified and it must be economic to do so.

Now, all of these conditions, as I

0323

understood it, were present in Gorgon. Not having, and I repeat, not having been there yet myself, I couldn't assure the validity of each of these arguments, certain arguments as they were presented to me seem to be sufficient to book that gas.

Q. Now, in that last sentence of number 3, you say, "This is in line with Group guidelines", this being referenced to not booking the additional reserves.

Is that correct?

A. Yes. That's what obviously the text refers to.

Q. So my question is, then, the guidelines did not support the booking of the reserves additions.

Correct?

MR. TUTTLE: Objection to form. Characterization of the document, characterization of his testimony.

MR. MORSE: Same objection.

BY MR. HABER:

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Q. You can answer.

A. Again there, this is not clear. As I think back of it now, I think it was wrong for me to say it as I did.

What you must bear in mind is that it's always possible to agree with something not being booked. If you look at the SEC definitions and through 4-10, at the additional guidance at their own general guidelines, any of these guidelines never force you to book reserves. It effectively sets a limit to what you can book as reserves.

And that is very important, and that meant that whenever a proposal is made not to do -- not to book a certain volume, it's very easy to, as an auditor or as a regulatory body, to agree with that.

If you go to the SEC, and you say we propose not booking this, then they are bound to say okay, because their concern is reserves being overstated, not being understated.

And that is where I was coming from

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when I was saying that I supported it. And I regret that I didn't write it -- write it down right. This is one of the very -- I think very few instances where I could have been a lot clearer in my -- in writing down my considerations.

That's about as far as it goes.

Q. Okay. Did there come a time during your tenure as Group Reserves Auditor that you started to think about whether Gorgon should be debooked?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. Yes. I can think of a particular instance or particular instances after -- particularly after Frank Coopman came on the scene and took over from his predecessor.

And when Frank Coopman instructed the Group Reserves Coordinator, John Pay, to put up what we framed or what we called a group reserves exposure register -- I am sure we are going to be talking about it in the next couple of

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days -- and Gorgon featured on there. And the times when we discussed the exposure register, of course the question did come up, do we continue booking Gorgon?

The issue became -- and I maintained the attitude that the reasons why I supported the booking of Gorgon at the time of the audit had not changed.

And therefore in my opinion -- and I repeat that in my annual report. In my opinion, Gorgon can continue to be maintained on the books.

Now, in the course of 2003, of course, we were introducing in the guidelines the requirement for FID for a major -- for a major project like Gorgon.

And that meant that at the end of 2003, it was becoming inevitable to take Gorgon off the books. But then so many other reserves corrections were becoming apparent from November onwards that there were -- there was plenty of -- there were plenty of reserves corrections that were asking for our attention.

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But it was clear from then on that Gorgon was going to be debooked and together with a lot of other reserves.

Q. Did you reflect this thinking in any of your written annual reports?

A. Well, in 2000, the end of 2002 -- so before this letter of occurrence that I described to you -- I gave reasons why I still supported a booking of Gorgon.

Q. And into 2003 opinion for year-end 2002, is there anything that you recall you said in your report that questioned the Gorgon booking?

A. Well, the end of 2003, it had been taken out. Gorgon had been taken out.

Q. Gorgon was debooked as a consequence of Rockford?

A. As a consequence of Rockford, yes.

Q. I am saying prior to Rockford, when you prepared your report for year-end 2002, which comes out I believe in January or February 2003, is there anything in that report that reflects your thinking that Gorgon may no longer be

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supportable?

MR. TUTTLE: Objection, form. Characterization of his prior testimony. He just testified what was in his year-end 2002 report. So I maybe even misunderstood that.

MR. BEST: I join in the objection.

MR HABER: Maybe I didn't understand; maybe if you can just repeat your answer.

THE WITNESS:

A. In my report at the end of 2002, I did discuss Gorgon, as a whole paragraph devoted to Gorgon, and I gave my reasons there of maintaining Gorgon on the books.

And the reasons were essentially the same as the reasons I put forward in my audit in the year 2000.

MR. BEST: We had a gentleman's agreement in the generic sense to cut this off at 3:00 clock. And this was done specifically

because of considerations for Mr. Barendregt.
So how much longer do you think you

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need?
MR HABER: Absolutely. And I did, just so you know, did inquire at the break --
MR. BEST: Oh, you did.
MR HABER: -- to find out how long. I think I will probably be about another ten minutes --
MR. BEST: Great.
MR HABER: -- if that's acceptable to you and Mr. Barendregt.
MR. BEST: That's fine.
THE WITNESS: Thank you.
(Barendregt Exhibit No. 16 marked for identification)
BY MR. HABER:
Q. Mr. Barendregt, I am showing you what we have just marked as Barendregt Exhibit 16. It's a note dated January 31, 2003. It's "Review of Group End-2002 Proved Oil and Gas Reserves Summation Preparation." The Bates range is V00010650 through V0001066.
Mr. Barendregt, if I can direct

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your attention to item 7, your main observations, which is on page 654. Halfway down the page, there is a reference to Gorgon.
Is this what you were just referring to, this?
A. Yes, indeed it was. Yes.
Q. And this document, do you recognize this document as your annual report for year-end 2002?
A. It would appear to be that document, yes.
Q. And you drafted this document?
A. Yes.
Q. And if you look in the bottom left-hand corner, it bears the signature.
Do you recognize the signature as your own?

A. Yes, I do.

Q. Now, prior to the time of Rockford, do you recall anyone from SDA advising you that they were prepared to recommend a debooking of the Gorgon reserves?

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A. I remember that the issue was debated between SDA and Remco Aalbers, the Group Reserves Coordinator at the time.

When I heard about it -- and I don't remember precisely who told me, whether it was Jeroen Regtien in an E-mail or Remco verbally.

But when I heard about it anyway, I discussed it obviously with Remco. And I made clear to him that okay, all very interesting, but I am going to go out there, do my audit, and I will make up my own opinion.

I hear what the various plans are, but I will make -- I will express an opinion when I go out for the audit.

(Barendregt Exhibit No. 17 marked for identification)

Q. I have marked as Barendregt Exhibit 17?

A. We are done with 16?

Q. Yes.

An E-mail with attachments. It's multipaged, this was previously marked as Darley

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Exhibit 25.

The last -- the E-mail that appears on the first page of the Exhibit is from you to Jeroen Regtien. It's dated January 9, 2004. It's to John Darley. And as I said, there are a number of attachments.

The Bates range is V00321097 through V00321104.

And Darley 1097 through Darley 1104 and I would like to direct your attention to the second and third page of this document, which is an E-mail from Jeroen Regtien dated May 25, 2000 -- I am sorry, to you, with a CC to Robert Blaauw and Sheila Graham, the subject line reads, "SEC reserves audit - Australia".

And in particular, I would like you to look at the last page of this E-mail, the top of the page, the second bullet point. And this will be the last series of questions for the day.

A. So it's the bullet point with respect to Chevron-operated assets?

Q. Correct.

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(Witness reviewing document)

A. Yes.

Q. Do you recall receiving this E-mail?

A. Not specifically. But it's clear that I did receive it.

Q. Do you recall having direct communications with Mr. Regtien about possibly debooking the Gorgon gas?

MR. TUTTLE: Objection to form. Characterization of the document.

THE WITNESS:

A. Again, not specifically. As I said earlier, I did discuss the subject with Remco, and -- well, it's obvious from this, I must have sent him a reply. I sent Jeroen a reply that I discussed the issue with him as well. I don't know whether in the reply, in fact, I did mention Gorgon. I can't remember that.

BY MR. HABER:

Q. Just for the record, if you look at what Mr. Regtien says, he says, "With respect to

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Chevron operated assets, the giant Gorgon field is classified as proved undeveloped and we intend to downgrade that to SFR".

What is your understanding of what that means?

A. Precisely what it says there, that they wanted to reclassify it as SFR, Scope For Recovery, which is the Shell term for volumes that are identified, are known to be there, but cannot yet be booked as Proved Reserves.

Q. So then by moving it from proved

undeveloped to SFR, that would effectively debook the Gorgon --

A. Yes.

Q. -- gas reserves as proved.

Correct?

A. A Shell preferred term, that is recategorize it.

MR HABER: Thank you very much, Mr. Barendregt. I appreciate your indulgence for the extended time.

THE WITNESS: Okay.

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MR HABER: That concludes today.

THE VIDEOGRAPHER: Going off the record for the day at 3:14. This is the end of tape number 5.

(Whereupon, the deposition recessed at 3:14 p.m.)

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ERRATA

CORRECTION PAGE

____________________ ____________
Signature Date

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I, Anton Barendregt, am a deponent in the foregoing video deposition, Volume II. 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 Tuesday, 20 February, 2007.

Signed__________________________
ANTON BARENDREGT

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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

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IN THE UNITED STATES DISTRICT COURT
DISTRICT OF NEW JERSEY
Civ. No. 04-3749 (JAP)
Hon. Joel A. Pisano

____
)
IN RE ROYAL DUTCH/SHELL)
TRANSPORT SECURITIES)
LITIGATION)
____________________________)

VIDEOTAPED DEPOSITION UPON
ORAL EXAMINATION
OF
ANTON BARENDREGT
VOLUME III
Taken on:
Wednesday, 21 February, 2007
Commencing at 10:08 a.m.

Taken at:

The Hague Zurich Tower
Muzenstraat 89
2511 WB The Hague
The Netherlands

REPORTED BY: FREDERICK WEISS, CSR, CM

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Deponent: Anton Barendregt
The Videographer: Richard Bly
Court Reporter: Frederick Weiss

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I N D E X

DEPONENT

ANTON BARENDREGT

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Barendregt Exhibit 18 - Document entitled "NOTE - 31 Aug, 1999" Authored and signed by Anton Barendregt Bearing Bates Nos. LON00820516 - LON00820527	345
Barendregt Exhibit 19 - Document entitled "DRAFT NOTE - 23 Sept 2003" Authored by Anton A. Barendregt bearing Bates Nos. RJW00890491 - RJW00890500	345
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I N D E X - continued

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Barendregt Exhibit 21 - 359

Document entitled "NOTE - 30 January 2001" Authored and signed by A.A. Barendregt Bearing Bates Nos. LON01260652 - LON01260652

Barendregt Exhibit 22 - 435

Document entitled "NOTE - 30 January 2002" Authored and signed by A.A. Barendregt Bearing Bates Nos. V00300308 - V00300320

Barendregt Exhibit 23 - 450

Copy of handwritten notes with the title "SPDC Resvs Discussion" bearing Bates Nos. RJW00112775 - RJW00112786

Barendregt Exhibit 24 - 487

Copy of three pages of E-mail string from John Pay/Anton Barendregt, and copy of document entitled "Oil & Gas Reserves in Nigeria" bearing Bates Nos. RJW0092077 - RJW00920787

PROCEEDINGS --

(Whereupon, Barendregt Exhibit No. 18 was marked for identification)

(Whereupon, Barendregt Exhibit No. 19 was marked for identification)

(Whereupon, Barendregt Exhibit No. 20 was marked for identification)

THE VIDEOGRAPHER: This is the video operator speaking. We are beginning volume III, videotape number 6 of the continuing deposition of Anton Barendregt. Today's date is

February 21, 2007. The time on the record is 10:08 a.m.

Please proceed.

EXAMINATION BY MR. HABER - CONTINUED

BY MR. HABER:

Q. Good morning, Mr. Barendregt.

A. Good morning.

Q. Today, as I mentioned yesterday, we were going to start talking about SPDC in Oman. And just again as a marker so you know what we are going to start with, I am going to start asking

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you about SPDC.

A. Okay.

Q. Where is SPDC located?

A. In Nigeria, Western Africa.

Q. What is the ownership structure of SPDC?

MR. BEST: If you know.

THE WITNESS:

A. The precise ownership structure I am not aware of, but I know it's effectively a 50/50 deal with the government.

BY MR. HABER:

Q. With the Nigerian government?

A. With the Nigerian government, yes, indeed.

Q. Now, are you aware of any arrangement with regard to the payment of costs that the Nigerian government had committed itself to provide?

A. I am not quite sure that I understand the question.

Q. Well, if there were costs for

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investment in SPDC, who was to bear those costs?

A. The costs of development of the SPDC fields would be shared 50/50 between Shell and the government; and by most costs of development, I mean the costs of installing the facilities, drilling the wells, et cetera.

Q. Have you heard of a reserves addition bonus?

A. Yes, I have.

Q. What is that?

A. It was an agreement that was made with the Nigerian government who, at one stage, wanted Shell to increase the portfolio of reserves regarding the areas in their -- in their concession, regarding the fields in their concession.

It was aimed both at inducing or encouraging SPDC to carry out more exploration and, therefore, come to a more complete inventory of what was available in the Nigeria subsurface, but also to look at existing fields, or known fields at least, and try and come up with

development schemes that would maximize the recovery there as well.

Q. Now, was there a formula that was set up to calculate what that reserve addition would be?

A. I don't remember the details of the deal. I know what direction it went in, but I don't remember the details.

Q. And the direction it went in would be a payment to the Nigerian government?

A. Yes indeed. For every million barrels, they would receive a certain sum of money.

MR. TUTTLE: I am sorry. Did you say a payment to the Nigerian government?

MR. HABER: Yes.

THE WITNESS:

A. I am sorry. I misunderstood that. In actual fact, SPDC would come up with additional reserves, be it either through exploration or through additional developments, and those reserves additions would be discussed and

ultimately agreed with the Nigerian government.

And as a result of that, SPDC would receive from the Nigerian government a sum of money. I am sorry. I misunderstood your question.

BY MR. HABER:

Q. Thank you. And with regard to the development that you just referred to, as the group reserves auditor, did you ever reach a conclusion that the reserve -- excuse me, addition bonus influenced SPDC in the booking of reserves or the attempted booking of reserves?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. I think before I answer that question, I think it's important to say that the reserves addition bonus in the first instance was directed at expectation reserves, not at proven reserves.

You find and Shell finds that in dealings with the government, they are not really interested in improved reserves and in external

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reporting. They see that as a matter for Shell because they see that they themselves don't have that responsibility and -- for instance, the Nigerian state and the Oman state.

They are not interested in proven reserves, they are only interested in what Shell phrases expectation reserves. So the reserves expectation bonus was primarily awards based on expectation reserves. That's one.

The -- I am sorry. This explanation, I forgot the question again. What was it?

Q. Well, the question was whether the reserves addition bonus, if you had reached a conclusion with regard to the bonus of whether the bonus influenced the booking approved reserves at SPDC?

MR. BEST: I am going to object to the form. It's a compound question.

MR. TUTTLE: Object to the form.

THE WITNESS:

A. A lot -- when I arrived on the

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scene when I went to Nigeria on my first audit, the reserves addition bonus had already been in place for ten years. I believe it was started in the early 90s.

And it was beginning -- the discussions were beginning to fizzle out. The reason being that even though reserves addition bonus had been agreed in the early 90s, the Nigerian government was very slow in paying, and so it was beginning to be realized that the whole effort wasn't reallyworth while because the Nigerian government weren't paying anyway, or very, very slow indeed.

But certainly initially it had the result that fields were studied, because a field development study was made, fields were studied, which were not yet due for development.

Those fields might -- without the reserves addition bonus as I understand it, those fields might otherwise have lain on the shelf until they were due to be developed without carrying any reserves with them.

0352

But since those fields were studied and since defendable and agreed reserves estimates had been prepared for these fields, SPDC quite naturally decided that since they had expectation reserves and since there was a good development plan and it was economic and past all the hurdles, there was no reason why they shouldn't book proved reserves as well.

Q. And those bookings, were they done pursuant to the changes in the guidelines in 1998?

MR. TUTTLE: Object to form.

THE WITNESS:

A. No, they were not, because as I tried to explain, most of these reserves were in immature fields. They were either exploration discoveries, or they were in fields that were discovered but weren't due for development for a very long time.

So in other words, they were totally at the beginning end of the spectrum; whereas the '98 reserves changes, as I've explained to you, primarily dealt with the fields

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at the end of the maturity spectrum, fields that were in production.

BY MR. HABER:

Q. Under Shell's guidelines, was a mature field a defined term?

A. A mature field -- I am trying to think whether there was actually a definition of a mature field. Everybody knew at least what a mature field was.

A mature field was a field that had been developed, that had been in production for sometime, but there wasn't a, say, a hard definition saying that it must have produced at least 30 percent, or whatever, a certain percentage, a fixed percentage of the ultimate recovery in that field.

I don't believe that that was laid down.

Q. So in essence, it was subject to subjective determination of engineers and geologists?

MR. TUTTLE: Objection to form.

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Characterization of the testimony.

MR. BEST: Same objection.

BY MR. HABER:

Q. You can answer it.

A. If there was a difference in the interpretation, it certainly wasn't instrumental. It wasn't as if somebody would judge a field that had been in production for a half of a year and had been producing -- three percent of their ultimate recovery was regarded or defined or viewed upon as a mature field.

I mean, that sort of thing never happened. Everybody knew pretty well what a mature field was.

Q. Now, did SPDC have a scorecard?

A. I don't know for certain, but I expect there must have been, together with the rest of the organization, yes.

Q. And what are Score Cards, for the

record?

A. Score Cards were introduced somewhere in the late 90s. I forget which

particular year. They would set a number of targets to, for instance, a company or a division within a company.

They would set a number of quantified targets for annual production at the end of the year, reserves additions, specific targets like coming to certain agreements or -- with the government or producing field development plans.

And these targets would then be reviewed, and the performance against these targets were reviewed at the end of the year.

Meaning that for each, resulting in an assessment on each of these points, typically there would be something like anything between five and ten of these points, whether the targets had been met or not met or exceeded.

And for each of these scorings, one would get a number of points and the average of these -- or they would be totalled up to a certain weighting. And that meant that there was an overall score on the targets, on the scorecard

that determined, for instance, the bonus of individuals concerned, starting from the Managing Director of a company down to individual people.

Q. Did you ever review SPDC's scorecard?

A. No, I did not.

Q. Now, in your answer, you said that the targets would be reviewed.

Who reviewed the targets?

A. It depended on the level. If it was a scorecard for a company, then the targets will be reviewed in The Hague.

Q. Who at the Hague?

A. The Regional Business Director for that particular company; for SPDC, it would be the business director for Africa.

Q. Do you recall who the Regional Business Director was in SPDC during your tenure as group reserves auditor?

A. I know that it changed. But if you ask me for names, no, I would have to dig back in the file.

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Q. Is Brian Ward someone that rings a bell?

A. Brian Ward was certainly a business director at one stage. He may have been for Africa. I honestly don't know. I can't remember.

Q. How about Tim Warren?

A. Could have been.

Q. Were you a proponent of the scorecard system?

MR. TUTTLE: Object to form.

THE WITNESS:

A. Initially, I was neutral about it. But later on, and most notably because of the year 2000, I began to see possible effects on a particular reserves bookings that I considered undesirable.

And from then on, I wasn't in favor of Score Cards where it related to setting reserves addition targets.

BY MR. HABER:

Q. What happened in the year 2000 that caused you to change your position?

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A. It was particularly the booking for Shell Angola.

Q. And what was it about the booking of Shell Angola that raised your awareness about Score Cards?

A. The -- when Shell Angola wanted to propose a reserves addition for their Block 18 fields, there was some doubt expressed, in the first instance by Remco Aalbers, who was the group reserves coordinator, as you know, supported by myself. I had my doubts too.

And we were both taken aback by the aggressive reaction that we received from the organization, particularly from staff in Shell Development Angola, even more so in the regions, in the regional business directorate in The Hague.

Q. Who at SDAN are you referring to?

A. Mm-Hmm.

Q. I am sorry. Who?

A. Oh, who. My memory of names -- I have always been able to rely on my reports to look up names, but Grigoire Simon was one of them,

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but he wasn't the most vocal.

I think on balance, the most vocal were probably the people in the regional business directorate.

Q. And who were they?

A. There we go.

MR. TUTTLE: If you remember.

THE WITNESS:

A. The names appeared on, say, the notes that I made or that were made during the discussions at the end of the year. If I could have a look at those, then I could point out whose names they were.

BY MR. HABER:

Q. We are getting a little out of order in what we are marking, but this is going to be Barendregt Exhibit 21.

MR. TUTTLE: 21.

(Whereupon, Barendregt Exhibit No. 21 was marked for identification)

MR. TUTTLE: Jeff, do you just want to put on the record 18, 19, and 20 so we don't

0360

confuse every further, future reader of the transcript?

MR. HABER: Yes. That's fine. Let me identify Exhibit 21, and then I will note, as counsel has just noted, that we premarked some exhibits.

Exhibit 21 is a note dated January 30, 2001. Its title is, "Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation."

Its Bates number is LON01260652

through LON01260666.

(Handing)

And while the witness is looking at that, I will note for the record that we premarked three documents. The first one, Exhibit 18, is a note dated 31 August, 1999. Its title is, "Shell Proved Reserves Audit - Shell Petroleum Development Co (SPDC) Nigeria, 18-26 Aug 1999". Its Bates number is LON00820516 through LON00820527.

Barendregt Exhibit 19 is "Draft Note - 23 Sept 2003". The title reads, "Proved

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Reserves Process Audit - SPDC (NIGERIA), 18-19 Sept 2003". Its Bates range is RJW00890491 through RJW00890500.

And the third document that was premarked was Barendregt Exhibit 20. It's "NOTE" dated 30 September, 2003. The title is, "Proved Reserves Process Audit - SPDC (NIGERIA), 18-19 Sept 2003". Its Bates range is V00010772 through V00010781.

(Handing Exhibits to witness)

Q. Mr. Barendregt, if you could take a look at Exhibit 21.

Do you recognize this document?

A. Yes. It would seem to be my end 2000 report.

Q. And if you look in the bottom left-hand corner, there is a signature there.

Do you recognize that as your own?

A. Yes, I do.

Q. And do you recall preparing this note?

A. Yes, I do.

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Q. Now, if you would turn to Attachment 6, which ends 664.

(Witness complying)

Do you recognize Attachment 6?

A. Yes, I do.

Q. And what is Attachment 6?

A. Attachment 6 is a note reflecting

my findings regarding the Angola Block 18 attempted reserves bookings and ultimate reserve booking as it had developed over the last -- over the last months of year 2000 and the beginning of 2001.

Q. Now, you see in the second paragraph -- or yes, in the second paragraph and in the first paragraph as well, there is a reference to Shell Deepwater Services?

A. Yes.

Q. What is Shell Deepwater Services?

A. Shell Deepwater Services was a group of experts that had been set up in Houston to carry out studies effectively as some sort of a contractor for operating companies with deep

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water, with fields in deep off-shore water.

The group was set up as a center of expertise, particularly Deepwater Services that didn't therefore relate so much to the subsurface as well as the surface or subwater facilities, which were and had been a frontier area of development, where Shell had made quite some progress.

Since most of the progress in developing that technology had been in the Gulf of Mexico, Houston was the logical place to have locate this center of expertise.

I say that the emphasis was on surface and subsea facilities. In addition to that, the type of fields that one tends to find in the deep off-shore are called -- what geologists call turbidites, which are sand slumps off the continental shelf, so from the shallow inshore sea to the real deep water.

And these fields have specific qualities that, again, the American operation had quite some experience in.

0364

So that was felt to be another reason to bring that together in this Shell Deepwater Services Group in Houston.

Q. Now, if you look at -- if you look

at the third paragraph that begins "prior to preparation of the present Stage 1 development plan."

A. Yes.

Q. It says, "Two meetings were held late in 2000 between SDS/SDAN and SIEP/SEPCo advisors, including myself."

Do you recall where the first meeting was held that's referenced here?

A. I believe that the first meeting was held in The Hague. I am just recalling from recollection. Let me read the paragraph.

Q. Sure.

(Pause)

A. As I read it here, I am not too sure which two meetings specifically referred to; certainly, at least, one meeting at which Remco Aalbers and myself attended, which was held in

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Houston. And I believe that was early in December.

Prior to that, I happened to be in Houston for an audit of the Shell oil reserves bookings, so nothing to do with Angola or SDS in early move, and I believe I had an early pre-meeting with one or two staff of SDS, because at that time it was beginning to be clear that Shell Angola were wanting to book some reserves.

And Remco even at that stage was beginning to express concern that this might be too early.

So I had a brief preliminary discussion with one or two staff there. And in addition, Remco and I had discussions with Shell Development Angola staff in Rijswijk somewhere in the course of late November, early December, together with the Regional Business Director, whose names I forget, except that I believe one of the names was called Barry. He's not listed in one of the names here, but Barry is a name that comes to mind.

0366

Q. And there is a reference to a

SIEP/SEPCo advisor.

Who were you referring to there?

A. That would be Gordon Barry.

Q. Do you recall meeting with Rod Sidle at that time in December of 2000?

A. Oh, SEPCo advisor, yes. Rod Sidle was -- I cannot remember whether Rod Sidle was present in the big meeting that Remco and I had in December.

Somehow, I seem to remember that he wasn't there, but I cannot be sure.

Q. Now, if you look at the next sentence, it says, "In the face of prevailing uncertainties, marginal to poor economics, plus a failed VAR2 review in October 2000, SDS were advised to look for a 'creaming' development plan."

Under the VAR system, was it permissible to book Proved Reserves if a project did not pass VAR2?

MR. TUTTLE: Objection to form,

foundation, time period.

BY MR. HABER:

Q. At the time of the booking.

A. The short answer is yes.

Q. And why is that?

A. I believe that at the end of 2000 -- remember that the reserves guidelines gradually tightened over the years. And I believe at the end of 2000, that the requirement was preferably for our review to have been passed. I forget precisely what the requirements were.

Q. Do you recall if it was a VAR3?

MR. TUTTLE: Objection to form. Foundation.

THE WITNESS:

A. No, I do not.

BY MR. HABER:

Q. The reference to "marginal to poor economics," what were you referring to there?

A. Yes. Let me -- I think at this stage, it's useful to describe the project in more detail to you.

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There were six small fields discovered in the two years preceding this point in time. There were small fields that were typically something like ten -- no, 30 to 50 kilometers apart from each other.

BP were the operator; in other words, BP was doing the drilling and was making the development plan.

Shell decided to have their own shadow study being done, and in this case by SDS.

BP were quite keen on the project. They had been pushed along by their chairman, and they were committed to go and develop the fields as soon as possible.

Now, of these six small fields, small accumulations, invariably there were a couple that were larger and the rest of them were smaller.

But each of them need their own individual platform because they were too far apart from each other to even reach with long-reach wells.

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So each of them needed their own separate facilities, and that meant a separate facility already in deep water, and that with distances of 40, 50, 60 kilometers, and that meant expensive development.

Some of these smaller fields were in fact not big enough to really make that an effective proposition. And indeed, with Shell's screening criteria, and I stress Shell's screening criteria, which were done against a conservative oil price of in the order of 14 to 16 barrels -- I am sorry, 14 to 16 dollars per barrel, particularly the outlying fields, these smaller outlying fields did not seem attractive.

That was against Shell's own internal conservative estimates. However, it would appear that if you were to look at a smaller scale development of only the largest two, maybe three fields, then you might get a project that would yield less oil but certainly oil that was more economical to produce than the larger amount of oil, when you take the development as a whole.

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The Shell guidelines in those days quite clearly stated that in order to book reserves, one needed to demonstrate technical maturity and commercial maturity.

And the minimum requirement for that was at least a plan, a field development plan that could, if that was the case, it could be based on a notional development.

In other words, the prime purpose of that plan would be to demonstrate that this field could be produced economically, that the reserves that were quoted could be produced economically.

And that seemed to be the only way of booking reserves for Angola Block 18 rather than going for the full development that Shell development Angola were pushing for.

Q. Was it permissible to use notional development plans under SEC Rule 4-10?

A. Rule 4-10 never mentions anything like development plans. Rule 4-10 in this respect only talks about reasonable certainty and nothing

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else.

Like I mentioned on several occasions before, there are one or two other more specific items that Rule 4-10 addresses.

But as far as the concept of development plans is concerned, all it refers to is reasonable certainty. Shell had interpreted that along the lines as has been described in our guidelines.

Therefore, the accepted reserves bookings were fully in line with those internal Shell guidelines, which had been put up because Rule 4-10 wasn't specific enough.

Q. Did anyone -- withdrawn.

Did Rod Sidle ever express a view

that was contrary to the booking of approved reserves in Block 18 Angola?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. Rod Sidle did express concern about the bookings, and his concern focused primarily on the proved areas that were used in the development

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plan.

Now, what do I mean by "proved areas"? Proved areas are a notion in -- in Rule 4-10 that determines which areas around a well you can use for basing Proved Reserves on.

The most significant parts where it related to Angola Block 18 was this LKH issue, lowest known hydrocarbons, where the question was: Could we book oil that was seen below the penetration by the -- by the drill bit?

I think on the first day I explained to you that you may have a situation whereby you drill and you find oil in the reservoir, but you don't see any water, so you don't know where actually the transition between oil and water is.

And there are various tools that you can use to infer where that oil/water contact is, as we call it.

But Rule 4-10 says that in principle, you should stick -- in determining the proven volume of oil, you should stick to what

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you've seen in the drill bit.

And the precise words are "in the absence of information on a fluid contact, you will stick to this proven oil."

Now, Shell, and in particular Rod, had interpreted this as follows: Seismic -- seismic techniques had improved enormously in the previous ten, 15 years, and it was now possible to detect in fact the outline of the oil/water contact from seismic.

You could follow the outline of the oil/water contact. And together with the known depth of those structures and of those outlines that you could see on seismic, it was therefore possible to infer where the oil/water contact was even though you hadn't seen it with the drill bit.

That was seen to be a sufficient basis, and it was seen as a sufficient basis to qualify it as information on a contact.

So Rule 4-10 said that in the absence of information on a fluid contact you cannot do it, but the inference is if that there

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is information on the fluid contact and its arrival information, then you can use it. And that's what Shell Oil had developed as a method.

And Rod, who was quite instrumental in developing this -- this technique, this method, was concerned that we should stick to that in determining the proved areas in these Angola fields.

Q. Now, was this method implemented through appraisal wells?

A. It was based or it was coupled with results from appraisal wells, yes. But the prime source of the information was from seismic studies, seismic -- seismic surveys having been taken and interpreted.

Q. Now, do you know if Shell had drilled appraisal wells in Block 18?

A. Oh, yeah. Definitely. Yes.

Yeah. All the blocks were approved areas were delineated were all blocks that actually -- that had been penetrated by an appraisal well. So that was the primary example.

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If there was a particular block that we could see on seismic, a fault block, you can see those, you can see the faults run, if it was a block that hadn't been penetrated, then it couldn't be classified as proved.

Q. At this meeting, had you seen that data to show that wells had been drilled and that the block had been penetrated?

MR. TUTTLE: Objection to form.

Just a reference to "this meeting."

BY MR. HABER:

Q. I am sorry. The reference is to the December 2000 meeting.

A. Yes. We had all the maps out on the table and all the locations of the wells. So yes, we were shown that.

Q. Now, is there a difference between an exploration well and appraisal well?

A. Not really. The function is the same, except the exploration well is typically the first well that you drill on a structure, and therefore you are less certain of what the outcome

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is going to be.

Quite often, you always begin with shooting seismic, trying to see what is happening in the subsurface. But what you cannot see with seismic without well data, what you cannot see there is whether we actually have a structure that is oil or gas filled; or at least it's very difficult. You are very lucky if you can actually see it.

Q. Now, are there wells that are drilled after the exploration appraisal wells?

A. Yes. Those are called appraisal wells.

Q. And after the appraisal well, is there a well that's drilled -- let me ask that again. I am sorry.

After you drill an appraisal well, is there another type of well that's drilled?

A. Yes, development well. That's what you have when you start drilling wells for targets for producing oil, which you then plan to or will hook up to facilities and therefore produce the

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oil.

Q. So is a development well a well that one would create a development plan around?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. No. It would be the other way

around. You create a development plan that determines where development wells are going to be drilled.

BY MR. HABER:

Q. I see. Okay. Now, in the next part of this sentence, it says, "SDS were advised to look for" quote -- I am sorry -- "a 'creaming' development plan."

What is a creaming development plan?

A. A creaming development plan would be a descriptive term for the plan that I just described to you; i.e., even though it was clear that BP was going ahead with their development of all the structures, this creaming development would only address part of the structures and

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thereby allow only a portion of the ultimate project reserves to be booked as reserves.

So it would be a creaming of the more juicy bits in the development plan and put together -- and put those together as a plan.

The effect of this is that if you only book the reserves of such a creaming development, that in fact what you are doing is you are taking the best part of the total reserves and only book those, rather than the total reserves, which would contain a portion that were less attractive.

Q. Now is a creaming development compliant with Rule 4-10?

A. Rule 4-10 doesn't say anything about creaming development. All Rule 4-10 says is that it must be reasonably certain that it will get developed. One of the conditions for that is that it must be economical.

Q. When you say it will get developed, are you talking about the entire field?

MR. TUTTLE: Object to form.

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THE WITNESS:

A. Fields.

BY MR. HABER:

Q. You can answer.

A. Fields. I remember we were talking about five or six fields.

Q. And so a creaming plan only addresses a certain portion of the fields?

A. Yes.

Q. Now, we got on to Angola in response to a question I asked about Score Cards.

Do you recall any discussion at this December 2000 meeting concerning Score Cards?

A. No. No.

Q. Then what is it about the booking of Block 18 that raised your awareness about the effect of Score Cards?

MR. TUTTLE: Objection to form. Characterization of the testimony.

MR. BEST: Object to form.

THE WITNESS:

A. I mentioned strongly challenging

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the reaction, shall we say, of Shell Development Angola staff and of the Regional Business Director in The Hague when Remco, supported by myself, was beginning to make noises that he considered it too early to book reserves here.

And we saw a similar reaction with SDS staff. My interpretation of that is that Shell Development Angola and Regional Business Directorate staff in the Hague were on scorecard with reserves additions, but SDS staff seem to have been on Score Cards as well.

Q. Did anyone from Shell Angola express to you that booking Angola would favorably impact the scorecard?

A. I cannot remember that, whether anybody did.

Q. Was it --

A. I mean the subject was discussed between Remco and myself. Nobody -- I don't think anybody actually mentioned it in my face. It was just in a discussion with Remco. But having said that, it was quite clear that people were pushing

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it.

Q. Pushing?

A. For the original proposal of reserves, for the whole field, for the whole project to be -- to be booked.

Q. And that was because it would have a favorable impact on their scorecard?

A. Yes.

MR. TUTTLE: Object to form. Foundation.

BY MR. HABER:

Q. Now, when did you have this conversation or conversations with Mr. Aalbers?

A. Late November.

Q. Of 2000?

A. Of 2000, yes.

Q. And do you know if the reserves in Angola were recategorized as a consequence of project Rockford?

A. I believe ultimately that they were not. Because at the time of project Rockford, the FID had been taken and the field had been -- the

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fields had been moved in the maturation cycle in Shell.

And BP had put up a development plan which had been discussed, and Shell had agreed to go ahead with the development, and the money had been made available.

And that meant that the reserves were going to be produced and that the project was going to go ahead. So there was no reason to debook that, as far as I remember.

Q. Now, at the time that Shell booked the reserves in Block 18, had BP booked any Proved Reserves?

A. Not 100 percent sure, but I believe they hadn't. Not at that time, no.

Q. Do you recall how much volume was originally planned to be booked in Block 18?

MR. TUTTLE: Object to form. Foundation.

THE WITNESS:

A. Not specifically. I believe it was about three times the volume that was ultimately

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booked at that time.

BY MR. HABER:

Q. And how much was ultimately booked?

A. It's here in the notes, I am sure. Two figures, 11017 come to mind. Something like 11,000,000 cubic meters.

Q. Is that approximately 74,000,000 BOE? And I am referring to Shell's share.

A. Yes. 12,000,000 cubic meters Shell share, so times six, roughly that's 70 something or other, yes.

Q. Now, going back to what I told you we were going to talk about, which was SPDC?

A. Are we done with this?

Q. Yes. We are done with the document.

I think you mentioned yesterday that your predecessor, Ad de la Mar, had audited SPDC before you took over the position.

Correct?

A. Yes.

Q. And when was that audit?

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A. In 1997.

Q. Do you recall what Mr. De la Mar had found when he had audited SPDC?

A. Short answer is no, I do not recall specifically. I believe it was something to do with the audit trail, which indeed is -- I found to be a problem as well.

Q. And why did you find that to be a problem?

A. SPDC are in charge of a large number of fields, altogether an enormous amount of oil, far more than is required for their immediate needs for production, because Nigeria was a part of OPEC, still is a part of OPEC.

They were therefore on a self-imposed country off-take constraint, and that meant that the SPDC part of Nigerian production couldn't exceed a certain -- a certain threshhold, around the level of I believe nine -- at the time, 900,000,000 barrels a day --

Q. How did --

A. -- 900,000 barrels a day. Beg your

0385

pardon.

Q. So in effect, the OPEC constraint was a cap on how much SPDC could produce.

Is that correct?

A. Yes. On a daily basis, indeed. Yes.

Q. I think my original question was: What was it about the audit trail that you found to be a problem?

A. As I said, SPDC had a large amount of fields in their portfolio, more than they needed for their, say, immediate needs.

The total number of fields was in the order of 100. I found that a built up -- what you would require in a case like this, you would require a reconciliation between the total amount booked built up from individual field estimates.

And in most of the companies, that estimate was no problem -- no problem. And you would expect that both for the expectation and for the Proved Reserves level.

In Nigeria, there was the

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complication that Proved Reserves declared needed to be produced before the end of license, which was at that time perceived to be in 2019.

And therefore, it wasn't just simply a matter of totaling up what you see as Proved Reserves in each and every individual field. You needed to process it, put it together, and then a combined forecast which you would then cut off at 2019.

All of that work hadn't been done or at least wasn't available. But I am sure it hadn't been done either.

One of the reasons was that SPDC is located in three different areas. There is the head office where the persons responsible for SPDC reserves reporting to the center were located. And there are the two operating areas, one in a place called Warri, W-A-R-R-I, and Port Harcourt, P-O-R-T, H-A-R-C-O-U-R-T.

And the coordination between these two, particularly in the 90s, was not good.

Nigeria is a country that's

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struggling with its infrastructure, and it certainly has taken longer in that country to get things like E-mail, et cetera, off the ground; and that therefore, historically, communication between the head office in Lagos Warri and Port Harcourt had been difficult.

And Ad de la Mar could still see effects of that, and I also could, coupled I think with a lack of interest by the reserves coordinator that had been preparing the last reserves estimate at the end of 1998.

Q. And who was the reserves coordinator at the end of 1998?

A. Again, I would have to verify. He is not even mentioned on my note.

Q. Which note are you looking at?

A. On the -- on Exhibit No. 18, which is my Proved Reserves audit report of August 1999.

Q. And this is the note that you drafted?

A. No. It seems like this is the final note. It has my signature on it, Exhibit

0388

18.

Q. All right. And just for the record, did you prepare this note?

A. Yes, I did, and it's my signature.

Q. Thank you.

A. So no, I cannot tell you what the name was. He was Nigerian. End of 1998 was his first submission by himself. He had been the assistant of an expatriate, a reservoir engineer in previous years.

I think he had been left to his own

devices for too long.

SPDC had acknowledged that, even before my doing the audit, and had already decided that a dedicated unit for reserves reporting, internal reserves reporting -- and as a matter of fact, I believe also for general business reporting to the Hague -- would be set up, and that would be set up in Port Harcourt under the direction of Bram Sieders.

Therefore for all practicalities, I sent my report to Bram Sieders because he was the

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one who was going to do something with my report.

Q. And again, just for the record, I want to make sure when we were talking about the reserves coordinator, you were referring to a local reserves coordinator?

A. Correct.

Q. You were not talking about the reserves coordinator in The Hague.

Is that correct?

A. No, indeed. I was talking about the local reserves coordinator.

MR. HABER: We have been going at it for about an hour. Why don't we take a break.

MR. TUTTLE: Yes. Take a break.

THE VIDEOGRAPHER: Going off the record at 11:06.

(Short recess taken)

THE VIDEOGRAPHER: Returning to the record at 11:25 from 11:06.

BY MR. HABER:

Q. Mr. Barendregt, before I continue with SPDC, there is a couple of follow-up

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questions from our prior discussion that I'd like to ask you.

You mentioned SDS having some expertise with turbidite fields?

A. Yes.

Q. Are turbidite fields located in deep water only?

A. Not always, but it is the, say, the

geological setting under in which they originate. In other words, turbidites are always generated at the time that they were beginning to exist by sand slumps rolling off the continental shelf into the deep sea many, many millions of years ago.

So yes, typically you would find those on the edges of continental shelves, and that by definition almost means that they are in deep water.

Q. Were there any turbidite fields in SPDC?

A. Onshore, not. Most of the field settings that were there were fields of the type -- with sands of the type that are deposited in

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deltaic -- what the geologists call deltaic environments, which again is similar in the setting where you see now where the Niger river has a large Delta depositing sands that are eroded from upstream from that river and deposited downstream in the near shore area.

Q. Did Shell have any fields or projects in SPDC in the Delta water area?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. I am not sure whether I understand the question.

BY MR. HABER:

Q. Well, the Delta region that you just referred to?

A. Yes.

Q. Did Shell have any projects?

A. Oh, yeah. Yeah. Virtually 100 percent of their fields are in that environment.

MR. FERRARA: I am sorry. That's not what he asked. You mean projects with turbidite fields? Is that what your question was?

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MR. HABER: No. He said turbidite -- let's go back.

Q. These fields in the Niger Delta?

A. Yes.

Q. Do they include turbidite fields?

A. No, they do not.

Q. Okay.

A. In fact, the way Shell split up their business was that SNEPCo would be the off -- would be looking at the off-shore fields, which was a different concession, a different terms, and those fields would contain some turbidite fields.

But the onshore fields or near-shore fields, which would be operated by SPDC, would all be of a different type.

Q. Now, the technology that's used with regard to turbidite fields, does that have any application in nonturbidite fields?

MR. TUTTLE: Objection to form. Foundation.

MR. BEST: If you know.

THE WITNESS:

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A. It depends on the type of technology that you are referring to you. If you are referring to subsea and surface technology, the answer is no, they are not. These fields are not all located on deep sea but they are located on land, and that means an entirely different type of surface facilities.

The -- as far as the subsurface is concerned, i.e., the geological setting of these fields, no. Any knowledge specific to turbidites is not knowledge that you require -- other than general petroleum engineering knowledge that you always need, is not knowledge that you require for developing the typical fields in relation with SPDC.

BY MR. HABER:

Q. You have heard of the EA field in SPDC?

A. Yes. It's one of the shallow off-shore fields.

Q. Do you know if SDS provided any technical support at the EA field?

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A. I do not know. I would be surprised if they had.

Q. But you have no knowledge of it?

A. I have no knowledge of it.

Q. Now, just one other question about Angola. After the booking was made in December of 2000, did you have any discussions about the booking with the external auditors?

A. Yes. They saw all my reports. We must have discussed it, and they must have asked some questions about it.

Q. Do you recall when you had these discussions?

A. That would be in the latter half of January.

Q. As part of the closeout?

A. The January as part of the closeout of the year, yes.

Q. And do you recall who was present during the year closeout?

A. The actual closeout, which is say the important year-end meeting, would see presence

from both KPMG and PriceWaterhouseCoopers.

And the persons present from PriceWaterhouse would be for example Bert Eeftink, initially, until he had been taken over by Han van Delden and one or two of the KPMG engineers, whose names escape me at the moment.

They were engineers that we used to -- not engineers, but accountants that we used to see in those meetings.

Q. Do you recall either KPMG or PWC representatives challenging the Angola booking during the closeout meeting?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. Not challenging in the sense of expressing disbelief; seeking clarification, I think would be more the -- would be better description of the sort of discussion that we had.

BY MR. HABER:

Q. Do you recall what clarification they were seeking?

A. No. No.

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Q. Going back now to SPDC and your audit, you had mentioned before the break some concern that you had about the audit documentation, the audit trail for SPDC.

Did you include that in your audit note for SPDC?

MR. TUTTLE: Objection to form. Characterization of the testimony.

BY MR. HABER:

Q. And you can --

A. I believe I did. I believe I did. But with questions like these, I always refer back to my note to see precisely what I have written. It is, after all, seven years ago.

Q. And you can feel free to look at Exhibit 18, if it will help you.

And if I can help you even further, I note that there is a recommendation on the last page of Attachment 1 which is 518, where this is addressed in number 6.

(Witness examining document)

MR. BEST: Jeff, I want to note for

0397

the record that while he is looking at this document, that on Exhibit 18, as well as many of the exhibits that I have seen in the course of Mr. Barendregt's interview, there are handwritten notations on these documents which do not appear to be Mr. Barendregt's handwriting.

Certainly we haven't talked about that. But indeed, if ever these Exhibits are introduced into evidence, there has been no foundation laid for these handwritten notations.

And particularly on 18, there is more handwritten notations than on other documents I have seen.

MR. HABER: I will ask him after this pending question.

THE WITNESS: Okay. I have somewhat refreshed my memory. So would you --

BY MR. HABER:

Q. Is the recommendation portion of

Exhibit 18 the only place where you reference the audit trail situation that you've just testified about?

A. No. I also refer to audit trails in the previous findings, specifically in number 14 and 15.

Q. And what you have written in 14 and 15, do these reflect the issue that you just testified about concerning the audit trail?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. They provide the basis for my recommendation to improve their procedures for a comprehensive and consistent audit trail, for the corporate submission.

They had the audit trail notes for the two separate divisions, but now I would like to see it being brought together for the corporate. And that was particularly important for the end year -- for the end license situation where you -- where they needed to show a basis for their proved reserves estimate.

All in all, I had no -- my concern here was primarily a concern about making sure that I could follow the reserves estimate building

up from the individual field estimates.

I would typically, when I would do my own building up, taking individual field estimates that had been given to me separately, I would come up typically just say one or two percent below or sometimes higher than the figure that they had submitted.

I couldn't reconstruct the exact figure. I wanted to see an exact match between what you built up and what you -- and what they reported.

I had severe difficulty doing that. And that is what the point that I am trying to make here, that it's -- if you do your job properly, then it's very easy -- I mean, spreadsheets are very easy and comprehensive tools to achieve exactly that.

And they saw that point and they promised to improve.

Q. Now, at the time that you had conducted the audit, did you think about whether to give a grade to SPDC less than satisfactory,

0400

that is, unsatisfactory?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. I did. In the end, I decided against that -- can I just look further through the notes --

BY MR. HABER:

Q. Please.

A. -- and see precisely? As I explained before, my scoring of an audit would be also based on the scoring that I did in the checklist.

(Pause)

Okay. It's not printed here, no. So I don't have access to that. On my computer you can see what the actual scoring numerically comes out.

I know or I remember that SPDC was quite close to getting an unsatisfactory, but they were just above the cutoff level that I normally maintained for unsatisfactory audits.

But in response to your question

0401

did I consider it, yes, I did. In the end, I was happy to leave it as just satisfactory, even though it was on the lower range of the satisfactory basically, because I could see that there was a new team in place. They were eager to get on with it.

And like I said, I knew the person in charge of that unit, and I knew that he was more than capable of putting it together.

And on that basis, I decided to leave it -- to leave it as a satisfactory -- just satisfactory audit.

Q. Now, was the absence of this audit

trail an issue that recurred following your audit in 1999?

MR. TUTTLE: Objection to form. Foundation.

THE WITNESS:

A. The next audit that I carried out was in 2003, by which time the guidelines had changed considerably.

So the set of criteria that were

0402

used in looking at those fields was vastly different than the method of putting together a proved reserves estimate, was vastly different. So there really was no comparison.

So as far as my involvement as an auditor was concerned, the focus was no longer on or less so on audit trail. The focus over the coming years, as you will no doubt come and see, has been on the relevance of the end of license in 2019.

That's where much of the focus lay in the coming years, not so much the audit trail.

BY MR. HABER:

Q. We will get to the end of license in a moment.

A. But the point that I really made is that the effect of, say, an absolutely spotless audit trail has been small.

Like I said, I did my own audit trail if you like, and I always came up with an answer that was just off it, from what I remember typically, on the order of one or two percent.

0403

But it wasn't significant.

Q. Now, do you know if the absence of an audit trail was an issue that was considered during Project Rockford with regard to SPDC?

MR. TUTTLE: Objection to form. Foundation.

THE WITNESS:

A. Not as such. The input of SPDC in Project Rockford was -- entailed a major screening review of all of the portfolio against all of the portfolio of SPDC, all of the field portfolio of SPDC, a major screening review of say the maturity of the fields in that portfolio and the maturity requirements that by that time we had in the -- in the Shell guidelines.

Like I mentioned before, SPDC had built up a large portfolio of reserves in fields which were not due to be developed shortly as a result of the reserves addition bonus discussions with the government.

So in other words, they had accelerated their activities in relation to

0404

exploration drilling and subsequent appraisal drilling, and thereby got a large number of fields and significant volumes of oil on the shelf and, therefore, also on the books.

And there was nothing in Rule 4-10 that forbade that, that did not allow the well volumes to be there. They were proved, they were demonstrated by wells, and they were certain to be developed in due course because they were all attractive as well, economically attractive.

But the screening that was carried out in 2003, towards the end of 2003, was much more critical on the issue of how likely is this field going to be developed and, ultimately, is there a field development plan or at least an area development plan with a timetable.

And in many of these fields naturally, for the reasons I've explained to you, there wasn't.

And therefore, ultimately, there was something like a thousand million barrels that had to be taken off the SPDC portfolio as a result

0405

of Project Rockford.

But I am painting to you the picture that Rockford was four years later than this here, and there had been a significant shift in the conditions in our reserves guidelines.

Q. I understand that. And what I guess I am asking is a follow-up to what you just testified to.

During this screening that was carried out in 2003, did those that conducted that screening ever communicate to you that their work was difficult to perform because of the absence of the type of audit trail information that you were discussing?

MR. BEST: Objection. Form.

MR. TUTTLE: Objection to form. Characterization of the document. Characterization of the testimony.

BY MR. HABER:

Q. You can answer.

A. Yes. I am trying to think how to phrase it. A lot of these fields had reserves

0406

estimates forward in the books. When I was expressing concern about the audit trail here, I was simply expressing concern about the lack of a simple table saying, okay, this is what we have for this particular field in the books, and these are the volumes for all the other fields.

And if you put them together and add them all up, then this is what you get. That simple sum ultimately was just a simple addition and was difficult to reconstruct for me.

And that probably meant that in some cases, people in the past had been doing an addition from a different sum for some of these fields. And it was impossible for me to ascertain how or when or what, resulting in a different volume.

And all I was saying that look, go and look at these fields, take the volume that you carry, and put those in the table.

Now, before that, you can ask the question: Are the volumes that we carry for these fields, are those volumes representative for what

0407

we now think we can actually develop in those fields? Some of those fields hadn't been looked at for a long, long time because they had been literally on the shelf and the books had been in somebody's cupboard and yes, the fields weren't needed for development so they just sat there.

And by the end of 2003, SPDC undertook to carry out a comprehensive review of not the simple addition building up from the individual fields, but also trying to reconcile the field data with the reserves estimate that they had in place, trying to find documents on which those reserve estimates are based.

And that is what took them a lot of effort.

Q. Now, this review that was conducted in the end of 2003, who, if you know, led that review?

A. Names are beginning to fade in my memory very quickly, but it's also because of a lack of discipline at trying to remember them. I always go back to my notes and say who it was.

0408

Is there --

Q. Well, let me ask you, does David Kluesner sound familiar to you?

A. Yes. David Kluesner was somebody from Rijswijk.

Q. Does John Hoppe sound familiar?

A. John Hoppe, that was the man that I was referring to. He was the one that was in charge in Nigeria. He was based in Nigeria. Dave Kluesner was a consultant in Rijswijk helping him with that study.

Q. Now, do you know if they were able to find the documentation on which those reserves estimates were based?

A. I don't know. I don't remember. They certainly didn't give us a full review of which fields they found documentation and what not, although there was a large spreadsheet made highlighting -- no. Let me start again.

What SPDC did is that for all their fields, they made a huge spreadsheet showing precisely where they had problems in finding a

0409

reconciliation between the well data and the --

and any field development plan and a reserves estimate.

And it would highlight for instance whether there was any uncertainty regarding a field development plan, uncertainty regarding well data that had been use, whether there had been in fact sufficient appraisal wells drilled.

So it was an enormous patch sheet showing checkpoints against checklists against various criteria and hurdles that you need to pass in order to come up with a field development plan.

So yes, there had been information given to us that showed where they struggled or not with getting really together the entire audit trail.

Q. I just want to go back for a moment and then we are going to come back to this review. If you could look at Exhibit 18 for a moment, your counsel did mention there is handwriting and other type of notations, markings on the document.

Do you recognize those, on Exhibit

0410

18?

A. Well, the top right-hand corner, it says "spare," that's my handwriting. Somebody noted a "new Ind. Auditor", independent, "since '97." That's wrong.

MR. BEST: But more importantly, is that your handwriting?

THE WITNESS: No, it isn't.

MR. BEST: Okay.

THE WITNESS: And the "1999 audit satisfactory" wasn't my handwriting either.

BY MR. HABER:

Q. How about the line markings next to the text?

A. No. No. They are certainly not mine, no.

Q. So the only handwritten note that you recognize as your own is the word "spare" in the upper right-hand corner?

A. Yes, correct. And my signature.

MR. BEST: And so for the purposes

of at least putting the objection on the record,

0411

if any documents are ever going to be used in any foreseeable trial, I am going to object to them to the extent that Mr. Barendregt cannot authenticate the document that is being shown to him as regards these independent and unknown handwritten drawings.

If you want to redact them for the trial, so be it, but I have a standing objection for this and every other document that we haven't authenticated his handwriting on a document.

MR. HABER: As a matter of order, of course, these type of issues are reserved, and we certainly believe that the document itself has been authenticated. And certainly where he has identified his handwriting is authenticated for purposes of trial.

Q. Mr. Barendregt, if you could turn to Exhibit 16. This is the group end-2002 annual report, which is dated January 31, 2003.

Now, I'd like to direct your attention to page 3 and 4 of the document, and it's Bates number 654 to 655.

0412

In particular, under number 8, which is the heading "Production licence duration constraints."

A. Yes. Can I read it first before you ask any questions?

Q. Please.

A. Okay.

(Witness reading document)

Q. With regard to SPDC, what message were you trying to convey to the recipients of Exhibit 16?

MR. BEST: Objection to the form.

MR. TUTTLE: Objection to the form. Foundation.

BY MR. HABER:

Q. With regard to number 8, the production license constraints?

MR. TUTTLE: Same objection.

MR. BEST: Same objection.

THE WITNESS:

A. I was indicating that it was difficult to reconcile the proved oil volumes that

0413

were carried by SPDC with, on the one hand, the end of license in 2019 and the current off-take rates.

And for all that we could see, constrained off-take rates which, if assumed to continue until 2019, would not leave enough production to cover the current -- the carried proved reserved.

Now, SPDC had been aware of it, and they had been assuming a significant upturn in future off-take rates such that before 2019, they would have produced all of the currently carried Proved Reserves.

I had already hinted that this was the case or that this might pose a challenge to increase the production rate in 1999, in my audit report.

And when it was clear that for several years, SPDC had not been able to increase that off-take rate, it was also becoming clear that they would have a problem in making those proved reserves by the end of 2019.

0414

The situation now was different to that in 1999. In 1999, there had been a period when the Nigerian government found themselves incapable of putting forward their share of the capital expenditure required for installing new facilities.

And because of that, Shell had refused to put in any significant amount of money in developing new field facilities.

And that meant that with time, the off-take rates would gradually be declining.

However, in or around 1999, I don't remember the precise date, an agreement had been struck with the government whereby they would now make more money available for development.

So that meant that, in principle, SPDC could look forward to a gradual increase in off-takes, because there was also the implied promise by the Nigerian government that OPEC constraints would be gradually lifted for as far as it related to the SPDC off-take.

BY MR. HABER:

0415

Q. But -- I am sorry. Go ahead.

A. So in 1999, there was an outlook that the future off-take rates might well increase.

There was a promise by the government, and it seemed not unreasonable to assume an upturn in the off-take, particularly because SPDC management committed themselves to that promise in the implied promise that they made to the central office by putting that off-take rate in their development plan, in their business plan for the years '99.

Q. And had you reviewed SPDC's business plan at the time that this document was written?

A. "Reviewed" is too grand a word. I had somebody show me the relevant pages in the business plan.

MR. TUTTLE: By "this document," you are talking about the --

MR. HABER: Exhibit 16.

MR. TUTTLE: -- Exhibit 16, to the

0416

January 2003 note on the year end-2002 period?

MR. HABER: Correct.

MR. TUTTLE: I want to make sure -- you looked at the '99 business plan before you did your year-end 2002.

THE WITNESS:

A. What I was referring to was the SPDC business plan, which is a document that companies were required to submit to the Center describing a forecast in principle for five years but also with a long-term forecast included, describing their foreseen costs and productions and providing a general state of the union, so to speak, type of information from the operating company to the center.

Now, that is a document that is nowhere here contained, and that I don't -- I wouldn't normally receive. But if I ask for it, then I could have a look at it.

BY MR. HABER:

Q. Do you recall looking at it, so the record is clear, another business plan from SPDC

0417

when you conducted your audit in 1999?

A. Briefly, yes. Yes.

Q. Again, as you said before, relevant portions were shown to you?

A. Yes, particularly graphs. I mean, I want to see graphs.

Q. After 1999, did you look at SPDC's business plan as it was revised?

MR. TUTTLE: Objection. Form.

MR. HABER: I will withdraw the question.

Q. Did you, after 1999, did you look at SPDC's business plan?

A. Not in the year 2000.

At the end of 2001, I tried to get hold of a copy. In the end, I didn't get it. I tried to get hold of the information, particularly in relation to the long-term forecasts. I didn't get it. In 2002, I finally did get something, and I didn't like what I saw.

Q. And why didn't you like what you had seen?

0418

A. Because there was still, in spite of disappointments in the off-take rate, the off-take rate in fact from 1999 had gone down rather than up. And yet there was in the business plan still this assumption of an upturn.

And I felt at that time in a position to say: Well, look, there is an inconsistency. How the hell can you make us believe that you are going to do that?

And that is precisely the message that I put in -- put in here. My message in 1999 was still: Look, realize that your future -- your reserves that you carry are critically dependent on the future upturn of reserves. Make sure you realize that, to which effectively the answer was, Yes, of course we realize that, and we are confident that we are going to make it.

Okay. Fine. But after these three years when it became clear that they hadn't, for all sorts of reasons, community disturbances, governments not fulfilling their -- government not fulfilling their promise, but it was clear that

0419

they were struggling to maintain even the rate, let alone even increase it.

I said that it's very difficult for me and for many others to believe that you are actually going to make that upturn. And therefore, your Proved Reserves to the end of 2019 are under serious question.

Q. When did -- when did you start forming this view?

A. It was beginning at the end of 2001, so in the end-of-year process.

And I asked the stand-in reserves coordinator, who at that time as I mentioned earlier was Jan Willem Roosch, I asked him for information for a comparison of the production forecast assumed for the -- for the reserves estimate with the latest business plan.

I asked him, I said, because that's what he preferred me to do. He didn't want me to either go directly to the company or indeed go anywhere else. He wanted all my requests to go via him. Fine. That was the way he wanted to

0420

play it.

And I asked for that information somewhere early in January fairly shortly after the first submission of the reserves came in from the operating companies, which would have been the second week of -- the end of the first week of

January.

And I didn't get a reply until two weeks later. I was running out of patience. So I told him that look, if you are not going to give me that information, I am going to go out to SPDC in E-mail and ask him then directly for that information, to which he sort of shrugged his shoulder.

I did, and there was a panic reaction coming out of SPDC where they wanted to suddenly change all of their reserve submissions because of my question, which presented a great problem for Jan Willem Roosch who at that time had closed his books.

So he became rather cross with me, and I decided not to pursue the issue any further,

0421

but list it as a possible concern for me.

I didn't have access to -- so in the end, I hadn't access to any concrete evidence, and that would support my concern that I had this concern, and that's what I reported at my end 2001 report.

Come the end of 2002, my concerns of course hadn't gone away, and that led to the discussion that I have now got in front of me.

Q. When you say that SPDC wanted to change their reserve submission, in what way?

A. I don't remember the details. I honestly don't remember. He wanted to reduce it, but he didn't say by -- well, he did say implicitly by how much, but he didn't say what the reason for it was. It was just, okay, we will reduce it by whatever volume.

And he didn't give -- that was at that time, that was I believe Ojo Sanni who, in my view, was really getting out of his depth as far as his ability to stand on top of the reserves submission.

0422

Q. Who is Ojo Sanni?

A. He was the reservoir engineer in charge. He had taken over in that by that time from Bram Sieders as being in charge of reporting reserves to central office. He was based I believe in Port Harcourt.

Q. Now, in your prior answers, you were referring to an off-take rate. And for the record, can you explain what that is?

A. Yes. It's the production rate of the Shell share part of production from the fields that were operated by Shell.

Q. Is it fair to say then the documentation that you were seeing was showing that SPDC was not going to reach the forecasted production for the year?

MR. TUTTLE: Objection to form. Characterization of the testimony.

THE WITNESS: The forecasts that SPDC showed in the document that I saw the end of 2002, i.e., their business plan, did not show the upturn even on the five-year cycle that I deemed

0423

was necessary to cover all of the proved reserves.

I had made a plot, a graph giving a pictorial presentation of my argument, which isn't included in my end-year report but which was included in the view graph presentation that I made to external auditors at that time.

I am sure you have got access to that.

Q. Now, the documentation that you looked at in 2002, did this documentation show historical production against forecasts in the business plan?

A. I don't think so. That wasn't what was normally done. What you would see would be historical production and current projection of the future.

Q. Did you ask for a comparison of historical production against prior forecasts?

MR. TUTTLE: Time period?

MR. HABER: 2002.

THE WITNESS:

A. I can't be sure, but I don't

0424

believe I did. And the reason was that I was aware of a gradual reduction in the off-take because of various reasons, community disturbances, and being certainly one of them that I knew couldn't have been foreseen in previous -- in previous business plans.

So it was clear -- in other words, that it was clear to me that the actual off-take lagged behind whatever had been promised in the past.

Q. In light of what you had seen by the end of 2001, going into 2002, did you begin to form an opinion of whether reserves should be debooked in SPDC?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. You should remember that at the end of 2001, I didn't see anything. That was precisely the point and the bone of contention. So all the evidence -- the only evidence that I saw was at the end of 2002.

BY MR. HABER:

0425

Q. And by 2002, did you begin to form a view that the issue of a possible debooking should be raised?

A. Strange the way it may sound, no. I came to the view that certainly in the past, the reserves had been overstated on the basis that the implied forecasts, to be able to produce those reserves by 2019, had been unrealistic. And that point I made quite clearly.

But there was -- in the meantime, there was another development and, as it turned out, quite a significant development.

And the development was that partly I think as a result of my pushing against this. Since 2001, SPDC went and looked at the legal basis of the assumption that the license would expire by the end of 2019.

In 1999, I had spoken with the legal advisor, the SPDC legal advisor in Lagos, and he described to me that indeed the license was going to expire in 2019.

And I asked him how likely is it

0426

going to be extended? And could you already conclude an agreement with the government now to extend it?

And his answer was no, there is no point in doing that now. The government wouldn't be interested in pursuing something which at that time was 20 years in the future.

But anyway he, being the legal representative, informed me that yes indeed the license was expiring by the end of 2019.

I didn't review those documents, I am not a lawyer, and I was happy to accept his statement.

Now, back to 2002. After my initial rattling of the cage, so to speak, that there was something to be considered to the end of license, lawyers in SPDC looked again at the precise conditions of the license extension, and they came to the conclusion that in fact, there was a right to extend provided that SPDC fulfilled certain conditions which were by no means onerous, but just the sort of conditions that one would

0427

have expected any responsible operating company to fulfill.

In other words, it was clear and it was concluded from that review, from that legal review that, in fact, there was a right to extend the license.

Now with that conclusion, the whole issue of whether the assumed forecast was realistic dissolved into thin air.

So we -- the situation at the end of 2002 was that on the one hand, we had seen that something had been grossly amiss in the past, but on the other hand the whole issue had suddenly been dissolved and there was now no requirement anymore to insist on any type of forecast in order to defend the position that all the reserves were going to be defended before the end of license, which I believe was in 2029. I believe it was a 20-year extension.

Q. Who were the lawyers at SPDC that looked at the issue?

A. I do not remember. I have seen the

0428

notes, but I do not remember.

MR. TUTTLE: You are talking about 2002?

MR. HABER: Yes.

Q. And do you know if any attorneys at Shell EP looked at the issue in 2002? And again, I am referring to license extension issue?

A. I do not remember that specifically. But I am sure that an important conclusion like this would not have been taken by SPDC lawyers themselves, but they certainly would have sought legal advice both with E&P in The Hague and with Shell in London.

Q. And do you know if any legal advice was sought by outside counsel to Shell?

A. Who do you mean by outside counsel?

Q. A law firm that was retained by Shell to perform various services?

A. I do not remember that.

Q. Have you heard of a law firm by the name of Cravath, Swaine, and Moore?

A. Yes, I have heard of them.

0429

Q. Do you know if Cravath, Swaine, and Moore provided any legal services in connection with the license expiry issue?

A. I don't.

MR. BEST: Objection. Asked and answered.

THE WITNESS:

A. I do not remember that.

MR. HABER: I am told we have five minutes on the video, and this is probably a good time to break for lunch.

MR. TUTTLE: Okay.

THE VIDEOGRAPHER: Going off the record at 12:20. This is the end of tape number

6.

(Lunch recess taken)

THE VIDEOGRAPHER: Beginning tape number 7 and returning to the record at 1:10 from 12:20.

BY MR. HABER:

Q. Good afternoon, Mr. Barendregt.

A. Good afternoon.

0430

Q. If you could turn to Exhibit 18 for a moment, I would like you to look at the recipients of the note. In particular, I am looking at two people. The first one is Linda Cook.

Who is Linda Cook?

A. Linda Cook was the Director, i.e., the most senior person in the company called Shell E&P International Ventures. This company was set up as part of the reorganization that took part in Shell in the late 1990s.

And this company was primarily in charge of new business ventures which included exploration activities throughout the world, and included divestment and acquisition activities of other oil companies or assets.

In addition, for reasons that I have not been -- I have not been appraised of that I am not aware of, the group that was responsible for group reports of reserves and E&P financial activities internally and externally was also made part of that organization, of that SEPIV company.

0431

Q. Was Ms. Cook a member of the ExCom at that time?

A. Yes. She was part of ExCom, yes.

Q. Do you know if she was a member of the Committee of Managing Directors?

A. No, she was not at that time.

Q. Did there come a time when she did become a member of the Committee of Managing Directors or CMD?

A. I believe she is one of the directors now.

Q. Now, underneath her name is a gentleman by the name of Ron van den Berg.

Who is Mr. Van den Berg?

A. Mr. Van den Berg was at that stage Managing Director of -- i.e. the most senior person of SPDC in Lagos.

Q. And at this time, that is in 1999, was Mr. Van den Berg a member of the CMD?

A. Certainly not, no.

Q. Was he a member of the ExCom?

A. I believe he was a member of the

0432

what was called the extended ExCom. I believe that was the situation at that time; i.e., the ExCom would consist of the most senior persons in Shell E&P in The Hague consisting both of SEPIV, Shell E&P International Ventures, and Shell International E&P, SIEP. But in addition -- and they would meet regularly.

In addition, there was a circle of senior managers from large companies, SPDC being one of them, that would partake in ExCom meetings once a quarter, I believe, and in those meetings they would formally be part of the ExCom circle.

Q. Was it your understanding at this time that Mr. Van den Berg was a part of that circle?

A. As far as I understood it, yes.

Q. Now, in terms of your dissemination to the people identified on this document as the direct recipients and the copied recipient, how did you distribute your note to them?

A. Quite simply by putting the notes in an envelope and putting it in the out tray.

0433

That in particular was the case for the internal distribution, for distribution within SIEP and SEPIV. As for the external distribution and in this particular case, it would be for SPDC, all the SPDC persons.

And also for the external accountants, I would put all the SPDC in the schedule. I would put all the SPDC copies and each would have an identified copy to them, which is highlighted. All the copies I would put in a large envelope and just put it in the out-tray as well, and then the Shell system would take care of it being sent to Nigeria.

Q. Now, is this a practice that you employed throughout your tenure as group reserves auditor with respect to your operating unit audits?

A. Pretty much so, yes. It was only towards the very end of my tenure that I started sending out copies by E-mail, because by that time E-mail had been established as a reliable enough means of communication that made it practical to

0434

send these documents through that medium rather than the physical paper hard copy.

Q. Do you recall when, at the end of your tenure, you started using E-mail as a means of distribution?

A. Not precisely, but it must have been somewhere early in 2003.

Q. So with regard to your practice prior to the use of E-mail, did you use the same means of distribution for your annual reports as you did with the operating unit audit reports?

A. Yes.

Q. And then once you began using E-mail, did you distribute the annual reports via E-mail to the recipients of those reports?

A. Yes. If it -- if I did start doing that during the course of 2003, then it would in fact be the end of 2003 report that I sent out in this way. But as I said before, I am not sure whether I did start doing that early in 2003 or even earlier than that, late in 2002. It was somewhere around that period.

0435

Q. During your tenure as group reserves auditor, did anyone ever communicate to you that they had not received a report when they were expecting one?

A. Not that I can recollect, no.

(Barendregt Exhibit No. 22 marked for identification)

We are marking as Barendregt Exhibit 22 a note dated January 30, 2002. It's titled, "Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation." There are two Bates ranges. The first is V00300308 through V00300320, and the second range is DB29057 through DB29069.

(Handing)

Now, Mr. Barendregt, do you recognize this document?

A. Yes. It would seem to be my end-2001 report.

Q. Did you prepare this document?

A. Yes.

Q. And if you look in the bottom

0436

left-hand corner, there is a signature.

Do you recognize that signature?

A. Yes, I do, yes.

Q. Do you recognize it as your own?

A. Yes, I do.

Q. Now, before our lunch break, you had testified that you had hinted in the 2001 report about the license expiry issue.

And I would like you to direct me where that hint was located?

MR. TUTTLE: Objection to form. Characterization of the testimony.

THE WITNESS:

A. Okay. I will have to scan through it now, so bear with me.

BY MR. HABER:

Q. That's okay. If I can, I can perhaps make it easier. I believe it's number 6 on page 311. But again, you tell me where it is.

A. Yes.

(Pause.)

Yes, indeed. That is the point. I

0437

don't think it is mentioned in subsequent points.

Let me just scan through those.

(Pause)

Yes. That is the -- point 6 is the one that this particular issue is addressed in.

Q. Do you recall if there was any reaction from any person who was identified as a recipient, on the first page, to what's discussed in number 6 on page 311 of Exhibit 22?

MR. BEST: Any reaction?

MR. HABER: To that point.

THE WITNESS:

A. I am fairly certain that of the people copied there or addressed there, like Lorin Brass, Dominique Gardy, ExCom members -- I am sorry. Let me rephrase that.

I believe at that time, when I made my end-year presentation to -- in particular to KPMG and PriceWaterhouseCoopers, I had a session with Lorin Brass together with the group reserves coordinator who at that time was -- I certainly did with Remco Aalbers, but I am not sure whether

0438

I did -- I am sorry. I am thinking aloud now. I am trying to think back precisely how it went.

The previous year I definitely had a session with the director of EPB, who I seem to remember was Lorin Brass.

But on this particular one, when Jan Willem Roosch was in charge, I am not sure whether I had in fact a session with Lorin Brass; certainly with the others, Walter van de Vijver, Dominique Gardy, and all the others.

I am certain that none of them came back with any comments or questions. John Bell may have been present during some of the questions that I gave to external auditors.

But again there, my memory doesn't serve me in reminding me whether anybody actually made any specific comments. If they did, and they must have done, then I cannot remember precisely what they were about.

BY MR. HABER:

Q. Now, you have mentioned people within Shell. How about from the external

0439

auditors?

Do you recall any comments from them?

A. We had an extensive discussion, which I seem to remember did increase their appreciation of the report and their understanding of it. But I do not understand whether, on the issue of SPDC, they made any specific comments.

They may have done, but I do not remember that.

Q. This was at the closeout section?

A. Indeed, yes.

Q. And when you say that you recall extensive discussion which increased their appreciation of the report, is there anything in particular that you recall?

A. Like I said, no. No. The details are lost over those years.

Q. Now, if you turn the page for a moment to page 312 under number 9, the discussion of "Reserves Addition Targets in Score Cards".

Do you recall if anyone had a

0440

specific reaction to what you had written in number 9 concerning Reserves Addition Targets in Score Cards?

A. I do not recall any specific reaction, at the time at least, at the time -- at the -- say at the end of January.

I know that in the course of the year, after John Pay had arrived, the issue was discussed -- not in my presence, was discussed among EP management, maybe in ExCom, but I am not sure, but that was already much later.

Q. And how do you know that the issue was discussed?

A. John Pay told me.

Q. When did you have this conversation with Mr. Pay?

A. After his arrival, which was at the 1st of April, and it must have been sometime during the summer of 2002.

Q. Was this -- was this communication in The Hague?

A. Yes. Yeah.

0441

Q. When you were not conducting field audits, where were your offices located?

A. I didn't have an office as such. I shared a desk with -- well, in fact I had a hot seat so to speak. I had a desk that most of the time I could call my own, but not always.

I would, in the weeks that I would not be traveling, I would generally tend to come in one day a week on Tuesday, either to finalize my reports, to have it properly prepared, because at home I really didn't have proper print facilities that could do that, and pick up on any ongoing business and have a quick chat with the Group Reserves Coordinator to see what's new if there is anything we need to discuss.

And if there wasn't, after a half a day, I would probably be home again.

Q. And this desk, this hot desk, was it located on the same floor as EPB personnel?

A. It changed over various locations.

But at the time that John arrived, it was located on one floor above.

0442

Q. One floor above Mr. Pay?

A. Yes. More or less directly above him, but you had to walk around via the stair well.

Q. And this was in the center?

A. Yes. Yes.

Q. Now, before our lunch break, we were talking about a study that was -- a review of a study that was conducted by Mr. Kluesner, Mr. Hoppe.

Do you recall that?

A. Yes.

Q. Do you recall when that study commenced?

A. Not precisely. The study was committed by SPDC, sometime I guess around the middle of the year, the year 2003.

Q. And do you recall if that study commenced before or after your audit of SPDC?

A. Before.

Q. And just so the record is clear, we are talking about 2003.

0443

Correct?

A. Absolutely, yes.

Q. And that audit in 2003 would be reflected in Exhibits 19 and 20.

Is that correct?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. Accepting for the moment that these are indeed my reports, one of them is a draft report and the other one is a final version or what would seem to be the final version report, yes.

BY MR. HABER:

Q. Well, for the record, let's identify Exhibit 19.

You will see it says, "DRAFT NOTE" September 23, 2003.

Did you prepare this note?

A. It would seem to be a draft copy of my report, yes.

Q. Do you recall if you had prepared another version or an earlier draft of the note?

0444

A. No. I do not recall that, no.

Q. And if you look at Exhibit 20, the note is dated September 30, 2003.

Do you recognize this note?

A. Yes. It seems to be my final report, except that I note that there is no signature of mine on the top.

But I note that the draft has been taken away from the heading, which would make it seem to be the final version of the report.

Like I said, there is no signature of mine, so I cannot really say that this is the final version.

MR. TUTTLE: Can you ask him about the underlining?

MR. HABER: I am going to get to that, don't worry.

MR. TUTTLE: I just don't want him testifying about a final report that has handwriting on it.

MR. HABER: I understand. I will get to it.

0445

Q. Do you recall preparing a final note that was distributed to a number of people such as those identified on this document, Exhibit 20?

A. Yes, I do.

Q. Now, if you look at Exhibit 20, you will notice that there is underlining and some markings on the margins of the document; and on the third page of the document, text that's circled.

When you look through the Exhibit, can you tell me if you recognize any of these markings as yours?

A. No, they are not mine.

Q. Just so the record is clear, on the first page, 772, is that your hand markings?

A. No, they are not.

Q. And 774, are those your hand markings?

A. No, they are not.

Q. 775, are those your hand markings?

A. No.

0446

Q. Now, at the time that you had conducted your audit, which if you look at Exhibit 19 or Exhibit 20, it says, 18th and 19th of September, were you aware that Mr. Hoppe and Mr. Kluesner were conducting their study of SPDC?

A. Oh, yeah. Certainly. That's precisely what they came -- this audit was held in The Hague, so not in Nigeria. And Kluesner was of course already based in The Hague, near Rijswijk. And John Hoppe came specially to the Hague for the purpose of this study.

Incidentally, can I make a remark about the status of this note?

Q. Sure.

A. I see that in the enclosure there is a date on the bottom, I think, which I mentioned earlier I used to put in my reports, and the date reflecting automatically the date that it was printed. And this date seems to be the 5th of December.

So somebody took my electronic report and printed it out, which would explain why

0447

I haven't signed it and why this seems to be a copy that is not formally endorsed by me.

Q. Do you have an understanding that you disseminated or distributed this document to the recipients electronically?

A. Oh, yes. Of course. That's what it must have been, yes. Yes. I must have originally -- in those days I wasn't as tight enough to be able to use all the tools that we have nowadays. Nowadays, if you print a copy, you can make sure that people can't change it any more.

At that time, in fact, there was a utility which allows you to put it out in PDF format. That utility was not available to us throughout the group. It is now, but anyway -- so I had to do with just the electronic copy, and with a right to protect on it, and password write-protect and people could read it. So that was reasonably secure and free from possibilities of dabbling.

But there were fairly easy means of

0448

copying it and then issuing it as an original report after it had been doctored. It wasn't foolproof, but it worked at the time.

Q. When did you become aware that Mr. Hoppe and Kluesner were conducting their study?

A. It must have been sometime before the actual date of this -- of this audit. I cannot tell you when. I don't remember.

Q. During the study, were you consulted at any time?

A. This audit was in fact a consulting session at the same time. So indeed, I made some recommendations, as you will have seen, in that audit report.

And that indeed was the consulting about the way forward.

Q. Can you explain why the audit took place over a two-day period?

A. Yes. I think what you need to understand is that an audit was due in SPDC Nigeria because it was four years after the previous one.

0449

And one was due to be held in August of that year, which was going to be at least a full week just like the previous one had been.

And regrettably, I had to withdraw from the audit on the very -- at the very last moment because of -- because of cardiac problems.

So I had to apologize and say, I am sorry, I can't come.

And my preference would have been to tied over the audit to next year, but SPDC themselves and I believe Frank Coopman said, "No, we need to have at least some partial audit or at least some type of consulting with you before the year is out."

So that's why this visit was organized of John Hoppe and Dave Kluesner.

Q. Now, do you recall --

A. And that's the reason why it was only two days rather than a full week.

Q. Do you recall participating in any meeting with Mr. Kluesner and others concerning

0450

the review that was being conducted?

A. Yes. Yeah. He was there.

Q. Do you recall taking any notes of meetings that you participated in with Mr. Hoppe and Kluesner?

A. Certainly.

MR. TUTTLE: Other than the audit?

MR. HABER: Other than the audit concerning the review that they were conducting.

THE WITNESS:

A. I took notes of the discussions during those two days. I always do that, because that's what I use as a basis for my subsequent reports.

(Barendregt Exhibit No. 23 marked for identification)

(Handing.)

BY MR. HABER:

Q. We have just marked as Barendregt Exhibit 23 a multipage document of handwritten notes. The first page the title reads "SPDC RESVS" which I take to be reserves discussion. The

0451

Bates range is RJW00112775 through RJW00112786.

Mr. Barendregt, do you recognize the handwriting on this Exhibit 23?

A. Yes, I do.

Q. And do you recognize this handwriting as your own?

A. Indeed, yes.

Q. And do you recall when this document was prepared?

A. That will be the 18th and the 19th of September.

Q. And how is it that from this document, you know that it was on those two dates?

A. I am sorry?

Q. I said how is it that you know from looking at this document that the meeting that these notes were taken from occurred on the 18th and 19th of September?

A. I am not sure whether I understand your question correct.

MR. TUTTLE: How do you know that those are the dates.

0452

MR. HABER: Right.

THE WITNESS:

A. Oh, okay. Because I recognized the people that were coming, it was the subject of SPDC. If you asked me was this on the 18th or the 19th, then I would say probably the 18th, but there is no way of telling.

BY MR. HABER:

Q. Now, if you look at the first page, the middle of the document, I believe -- and again, you can tell me if I am not reading your handwriting correctly, it says, "Ssome volumes not sufficiently mature for proved reserves."

Did I read that correctly?

A. Yes. That's what it says there.

Q. Do you recall what was discussed around -- I am sorry -- what was discussed during this meeting on this issue?

A. No, is the short answer. But I think you must bear in mind that the study was started with the express purpose of finding out what the exact status of maturity was of the

portfolio.

And you don't do that if you do not have at least a question whether all the volumes are sufficiently mature for proved reserves, bearing in mind that the guidelines, as we prescribed them to the operating companies, were gradually getting more tight and requiring more firmness in the development machine.

Q. Did you begin to question whether the volumes in SPDC were sufficiently mature prior to this study?

MR. TUTTLE: Objection to form.

THE WITNESS:

A. Let's put it this way: I found it extremely useful when I heard that SPDC were going to -- were going to do this, because I was aware that the guidelines were tighter, and I would very much like to know what sort of effect these tightened guidelines would have upon the portfolio of SPDC.

As to the result, I had an

absolutely open mind. I didn't claim that the

0454

SPDC portfolio was overstated in this respect, nor did I discard the possibility that some of these proved reserves might not be sufficiently matured.

So when I heard about the study, I was quite happy to hear it.

BY MR. HABER:

Q. When you conducted your audit in 1999, did you find anything that raised any concerns about the maturity of the volumes in SPDC?

A. In answering that, we must remember that the group guidelines, against which I carried out the audit, were of course quite a bit different from the ones that we were beginning to be working with at this point in time.

Like I mentioned on several occasions before, project maturity, other than the requirements for technical maturity and commercial maturity that were in the Shell guidelines -- but project maturity in the sense of commitment to develop, was not an issue in either Rule 4-10 and for that matter in Shell guidelines at that time.

0455

Q. Could you have project maturity without having technical maturity?

MR. TUTTLE: Objection to form. Argumentative.

BY MR. HABER:

Q. You can answer.

A. The answer is yes, because by "project maturity," I mean state of advancement in the project development cycle, i.e., is it getting close to development, has FID been taken, for instance.

That is what I refer to as project maturity, and it is a notion that's completely different from what you mentioned, commercial maturity and technical maturity.

You can have a field or a project that is both commercially mature and technically mature, and yet have very little in the way of project maturity.

That is typically a field that had been studied, for which a development plan would have been developed, and that was shown to be

economical to undertake. But that for any particular reason, was chosen not to be undertaken at that particular point in time.

And it was clear and it was known that there were many of those fields in the SPDC portfolio, but none of these were at that time of any particular concern.

Q. Well, let me ask you this: Do you have reasonable certainty if there was no technical maturity?

A. I didn't say.

MR. TUTTLE: Objection to form.

MR. HABER: No. I know you didn't say. I am asking you a different question.

THE WITNESS:

A. These fields, as I had explained before, had been the subject of discussions with the Nigerian government as part of the reserves addition bonus cycle of events.

And that required that a field development plan would have been drawn up for them showing the economic viability of the project and

showing the technical maturity of the project.

That field development plan, which would have been documented because otherwise there is no basis upon which to discuss this with the government, was at that time a sufficient condition to carry Proved Reserves and expectation reserves.

BY MR. HABER:

Q. I guess my question was a little bit more general. Independent of SPDC, could you find a project to be reasonably certain if there was no technical maturity?

MR. TUTTLE: Objection to form. Vague. Characterization of the testimony.

MR. FERRARA: Sorry. It might help

if you sort between project and, you know, individual fields, because you are kind of confusing those issues, because he has made a distinction.

Do you know what I mean?

MR. HABER: Is counsel's distinction helpful to you?

THE WITNESS: Umm --

MR. FERRARA: He has testified about project maturity versus technical maturity for particular fields. He has made that distinction in his testimony.

MR. HABER: Okay.

MR. FERRARA: And if your questions make that distinction, it may help him.

MR. HABER: And that's fair.

Q. In terms of the field, can you have reasonable certainty with regard to booking Proved Reserves if there is no technical maturity?

MR. TUTTLE: Same objection.

THE WITNESS:

A. I will go ahead and answer it in my way, if I may.

The short answer is no, because the guidelines state quite clearly that in order to book expectation reserves or proved reserves in the Shell system, you need commercial maturity and you need technical maturity, and that I think is a sufficient answer to your question.

BY MR. HABER:

Q. Now, if you can turn to page 2 of the document, 776, and you will notice in the upper right-hand corner, you have the page 2 circled there.

Six lines from the bottom, and again if I am not reading correctly your handwriting, please correct me, it says, in quotes, "Project is highest area of immaturity."

Do you recall to what this refers?

A. I think you must bear in mind that these are, of course, handwritten notes which aren't of the quality that I like to think my final reports are in; in the sense that when you read it, then it's immediately clear what is meant.

So you must accept that in these notes, there are things that even I have difficulty understanding.

Okay. Having said that, how I interpret this now, knowing what was broadly discussed, is that the study that SPDC were

0460

carrying out was reviewing each of the fields in their portfolio against successive stages of maturity.

In other words, they would start by asking, "Have we appraised a field sufficiently? And if we have, have we drilled sufficient wells to come up with a reasonable delineation of the proved area? Has the proved area been able to be defined on the basis of lowest known hydrocarbons?" Et cetera, et cetera. "And if that had been the case, has sufficient proved area been identified to be able to come up with a development plan for that field?"

And so it went on.

So there were checklists of questions that described a successive stages in coming to a development for that field against which a field would be either ticked off or struck off and say, No, this is how far as it went, but this particular stage hasn't been reached.

So when you look at projects or at fields, you first look at the subsurface -- you

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first look at the subsurface description of the field, and then you go on and see whether there is a description of the number of wells that are required and whether in fact you are already in the process of preparing what is called a project.

By "project" I meant a description of the surface facilities and of course of the wells to be drilled, and a description of the activities that needed to be undertaken to actually get all of this development in place.

Now, the project is therefore the last stage. Defining a project is the last stage in these successive checkpoints in order to assess the maturity. And that I think is what is said by this "project is" the "highest area of immaturity."

You can imagine that when you have the whole portfolio, that many of the fields will have sufficient drilling, will have a proved area defined, et cetera, and some of them may be as far as having a field development plan.

But by no means all of them will

0462

have actually a project ready to be executed, and that I think is what is meant here.

Q. If you can turn the page to page 3, and the Bates number is 777. It's about a third of the way down from the top.

And what I am looking at is the portion of that top that reads in quotes, "'sloppy housekeeping'" close quote.

And again, please correct me if I am not correctly reading your note.

A. I am sorry. Which page are we on, 3?

Q. It's on page 3, 777?

A. Yes.

Q. It's the line that begins I think "Reservoir Categories."

A. Oh, yes. Yes.

Q. And if you look down from that one, two, three lines?

A. Yes. Okay. Sloppy housekeeping, yes.

Q. And then it goes further and says s "concern is large, volumes is, quote, "'marginal.'"

0463

A. In marginal.

Q. I am sorry. "In 'marginal'".

A. Yes.

Q. Oh, okay. In paren, is that less

than 2,000,000 barrels, close paren, and I think the rest says approximately 30 - 50%.

Is that correct?

A. Yes. I am not too sure about the 30, whether it's 20 or 30, but it's either of the two for sure, yes.

Q. Can you tell me what is meant by what I just read?

A. Remember my earlier remarks, yes? These are -- this is a document that of course I have not seen since the final issue of my note.

(Pause)

Yes. What I seem to be referring to here is that the reservoirs and fields were going to be categorized by SPDC in the study. First, there was going to be a category of

0464

projects that were deemed to be marginal, then there were fields that were apparently developed and closed in for whatever reason.

So the facilities had been installed, the wells had been drilled that had been closed in, then there was a category that was producing, then there was a category partly appraised, and there was a category unappraised, of which I say these are mutually exclusive.

And my assignment would be made by individual reservoir block, and then it says, "Not available as well, 'sloppy housekeeping'".

I do not know what that was referring to. Yeah. I am sorry. I can't say that. I don't understand that.

Q. Do you recall if this reference has anything to do with the audit trail issue that you testified about earlier?

A. No. My impression --

MR. TUTTLE: Objection to form.

THE WITNESS:

A. My impression is that we are

0465

referring here to fields that have been in some form or another developed or that are either producing or not producing. And if they are not producing, then there may be various reasons why they haven't been producing.

And one of them could be that their production facilities are not available or -- and that could have all sorts of meanings. One of them may be sloppy housekeeping, i.e., if a well wasn't maintained properly, they had left the sliding side door opened which couldn't be closed any more because they left it open for too long, anything of that order.

My impression is that I am referring to sloppy housekeeping in the fields, but I cannot tell for sure whether that is the case.

BY MR. HABER:

Q. Do you recall during this meeting if there was discussion of how much volume was exposed to debooking?

MR. TUTTLE: Objection to form.

0466

Foundation.

MR. HABER: Withdrawn.

Q. Was there a discussion concerning whether there were volumes exposed?

A. Yes. There certainly was a discussion, because there was -- in fact that was what the whole of the discussion was about. We in SPDC were trying to inventorize and see precisely whether there were volumes exposed; and if so, to what extent.

That was what the entire study that they were undertaking was about. So yes, certainly we were talking about the principle of volumes becoming exposed.

Q. Do you recall how much volume was exposed?

MR. TUTTLE: Objection to form.

BY MR. HABER:

Q. At the time of this meeting?

MR. TUTTLE: Objection to form. Foundation.

THE WITNESS:

0467

A. I am looking now at Exhibit 22 and I am trying to see if I can find an answer in there.

I am sorry. I am looking at the wrong -- I am looking at Exhibit 20. I beg your pardon.

(Pause)

There is a table in that note of this discussion, of this audit, process audit, that is page V00010777, and that gives a very preliminary estimates of the various categories in which the fields would eventually be classed.

And that was as per the database of September 2003.

BY MR. HABER:

Q. You are referring now to the table at the bottom of 777?

A. Yes. I am, yes. I am trying to see what we had there.

Q. And in total, how much was exposed as represented in this table?

MR. TUTTLE: Objection to the form.

0468

Characterization of the document.

MR. BEST: Same objection.

THE WITNESS:

A. I am trying to see whether that estimate is there because, if it was anywhere, then it would be in this table.

(Long pause)

MR. FERRARA: Do you want to withdraw this question?

MR. HABER: I am thinking about it.

MR. TUTTLE: Why don't you just withdraw the question.

THE WITNESS: I am sorry about it.

MR. FERRARA: If you just withdraw the question.

MR. HABER: Let me ask you a different question. I will withdraw the question. Let me ask you a different question.

MR. TUTTLE: Listen to the question.

THE WITNESS: Okay.

BY MR. HABER:

0469

Q. The table -- at the time that you participated in this meeting, had there been a preliminary calculation of what -- of the amount of volume that was exposed to debooking?

MR. TUTTLE: Objection to form. It calls for speculation.

THE WITNESS:

A. From what I remember, and I regret that even reading through those, my memory cannot be sufficiently jogged of anything more precise, there was at that time the large spreadsheet that they are filling.

At that time there were only certain criteria which fields had been checked against. In other words, the spreadsheet table was by no means complete.

And that seemed to suggest that the category that was beyond any doubt as being qualified for Proved Reserves was relatively small in comparison with the total portfolio.

That meant -- by relatively small, I mean out of the 1600 or so that was actually

0470

booked, less than half was completely beyond any doubt clear proved reserves.

That left to something -- and I am quoting from memory now, something more than half of what was carried on the books had at least one question mark against it.

And what was now needed to be done was that SPDC would go ahead and refine the scoring of all of these fields against the successive stages that I've described to you, and therefore come to an assessment of how many of these would actually be in a stage whereby you say, "Yes, with reasonable certainty and checking against the conditions that we have in our reserves guidelines, these can also be classified as proved reserves".

BY MR. HABER:

Q. Now, when you are referring to total portfolio, you are referring to the total portfolio within SPDC.
Is that correct?
A. That's correct, yes.

0471

Q. And the table that you've pointed us to, which is Attachment 2 on page 777 of Exhibit 20, does that table convey --
A. Well, that's what I was struggling with trying to understand. As you can see, that in the database, they had quite a significant number of fields with total volumes, proved volumes of 2238, which was well in excess of what was actually booked.
So that meant that in some stage in the past, some stage of these fields were clearly not -- were considered not worthy of booking.
And what this exercise was about was trying to reconstruct or actually looking with a fresh -- with a fresh eye into what out of this total portfolio, which fields would indeed not be worth or not fulfill the conditions of booking as Proved Reserves.
Now, the top line would seem to be fulfilling proved reserves requirements; in other words, at first glance, immediately fulfilling the requirements.

0472

You can see that there is two columns here, three as a matter of fact, the third one being the sum of the previous two.
First, there is proved developed reserves. These are reserves which are developed and in production, and there a portion of fields fulfilling at superficial inspection all the requirements is 377, which is somewhat less than the 850 that were actually booked. That's the figure then that sticks in my mind.
On the undeveloped reserves, the picture is -- well, reflects a lot more uncertainty. There only a relatively small portion, less than ten percent of what is carried

in the portfolio, is at first glance is fulfilling Proved Reserves.

And there are large reserves in some of the other categories, and these were going to be the subject of a further field study.

Q. Now, in the left column, there is abbreviation, CA/BP.

What does that refer to?

0473

A. I don't know what the CA stands for -- I don't remember. BP is business plan.

Q. Do you think CA -- or do you recall CA referring to capital allocation?

A. Yes. Yes.

Q. And so what the middle box of this chart on the left-hand column, what do these convey?

A. That there are 319 reservoirs that are not fulfilling, it would seem, requirements; that there are unknown reservoirs. I am not too sure what we meant by that. I guess because it's not clear whether these reservoirs have been sufficiently appraised, and that on the developed reserves there were in fact -- no.

What it is, last two lines, one of them, the first line of the -- sorry -- the second line in that box is where it says in capital allocation business plan, unknown reservoirs is where they have an entry in the capital allocation business plan.

An entry which in principle needed

0474

to be by field, but it wasn't clear where that entry would be coming from.

Typically there would be a line in the capital allocation saying Forcados-Yokri area. I am just quoting an example, but Forcados-Yokri is a name of a field, but then it wouldn't say which particular field or even reservoirs in that area would this be referring to.

But they were in the business plan, and then there was a category that was not in the business plan but where we were sure that they were known reservoirs.

Okay. On the developed reservoirs, there wasn't any identified. But certainly on the undeveloped, there was a sizeable proportion there.

Some of these would be -- could become as in a state where they could be carrying Proved Reserves, but they just needed further study.

Q. Now, at the time you conducted your audit in 1999, were you aware of this last

0475

category that is not in capital allocation/business plan known reservoirs unplanned?

MR. TUTTLE: Objection to form. Foundation.

THE WITNESS:

A. Well, I was aware of it. I mean, it's partly taken it up in my report.

MR. TUTTLE: In 1999.

MR. HABER: In 1999.

THE WITNESS: Oh, beg your pardon. Sorry.

MR. HABER: It's okay.

THE WITNESS:

A. No. Because like I said, project maturity at that stage was not a requirement in the Shell guidelines nor in the Rule 4-10.

It was an issue that was part of the lack of audit trail that I referred to in my report then, where I said show me a list of individual field volumes and show it to be built up to the volume that you carry as proved

0476

reserves.

I think we must bear in mind that in 1999, SPDC had and still have a significant number of fields, well over a hundred. And some of those fields would be big and those fields I would review.

By that time, my selection mechanism of fields wasn't as sophisticated as I developed over the successive years, so I took a random selection of fields that I discussed with the engineers in the way that I described to you earlier.

But certainly of the smaller fields, hardly any in the timeframe allocated to the audit, hardly any of those were presented to me.

So a lot of these fields that would be in these categories with question marks, they would simply not be addressed during my 1999 audit.

Q. Okay. I think this is probably a good place for us to take a break.

0477

THE VIDEOGRAPHER: Going off the record at 2:18.

(Short recess taken)

THE VIDEOGRAPHER: Returning to the record at 2:30 from 2:18.

BY MR. HABER:

Q. Mr. Barendregt, before we broke, we were talking about the volume that was exposed.

Did there come a time where that study that was being conducted by Mr. Hoppe and Mr. Kluesner reached a conclusion on how much volume was exposed?

A. Yes. The first time that reasonably definitive answers were coming out of that study was in November 2003. I forget the precise date, but it must have been before the 23rd of November, because that's when I returned from holiday. And by that time, the results have come in.

Q. Do you recall having any discussions with anyone on that maturation study team before the definitive answers were given?

0478

MR. TUTTLE: Objection to form. Other than what he has already testified?

MR. HABER: Yes.

THE WITNESS:

A. No. The study was carried out in

Nigeria, and I personally haven't had any contact with John Hoppe or anybody else during that period. Like I said, during part of it, I was also on leave myself.

MR. HABER:

Q. Do you know how much volume was exposed as found by that maturation team?

A. As I remember it, the volume that was being talked about when I came back at the end of November was in something in the order of 700,000,000 barrels, Shell share.

Q. Do you know what percentage that represented of SPDC's total portfolio?

A. Well, I am sure we can find it out by comparing it. Not off the top of my head. Something approaching half, thereabouts.

Q. Do you know if that was the amount

0479

of volume that was recategorized as a consequence of project Rockford?

A. I'm confident that virtually all of that 700,000,000 barrels that was talked about at that time was related to fields in the immature end of the spectrum.

As we discussed on the first day, the '98 reserves guideline changes related to the mature end of the reserves spectrum, i.e., related to fields that had already been taken into development, that had already been developed, and that had already been showing production performance sufficient for -- sufficient to yield a production trend that could be extrapolated into the future.

These volumes in Nigeria, virtually all of them came from a category that I described earlier as laying on the shelf, not ready for development.

Q. My question was: Do you know if the amount, the 700,000,000, changed as a consequence of the work that was done in project

0480

Rockford?

A. Ultimately, it became more. It was

something in the order of over a thousand. I forget what the precise volume was.

Q. That would be a billion?

A. A billion, sorry. A thousand million, yes.

Q. Now, if we can look at Exhibit 19 for a moment, which is your draft note of September 23, 2003, did you circulate a draft of this Draft Note to anyone?

A. Yes. Otherwise, there wasn't any point in having a Draft Note.

Q. Who did you distribute the draft to?

A. To -- certainly to Frank Coopman; and in The Hague to John Pay; and to SPDC; and I would have copied in first instance to John Hoppe, relying on him to circulate it within SPDC as he saw fit; and Dave Kluesner probably would have received a copy as well, although he is not mentioned here.

Q. Of the people that you just mentioned, do you recall receiving any comments to the draft from them?

A. Not specifically, no.

Q. I see in your note you gave SPDC an unsatisfactory grade.

Correct?

A. Yes.

Q. Did Mr. Coopman say anything in response to the Draft Note? And in particular, with regard to the unsatisfactory rating?

A. Not that I recall, nothing specific.

Q. Do you recall having any discussions with Mr. Pay concerning the Draft Note?

A. I don't recall them as such, but I must have done.

Q. Do you recall if Mr. Pay expressed any concern about the unsatisfactory rating?

A. No, I do not recall that.

Q. Now, do you know if a draft of this

0482

report was provided to any member of the ExCom?

A. As I said, to Frank Coopman. Other than that, I wouldn't know. It's possible, but I don't know.

Q. Do you know if a copy of this draft note was distributed to Walter van der Vijver?

A. I do not know. I certainly didn't do that myself. It's possible that Frank Coopman may have given him a copy.

Q. Did you ever speak to Mr. Van deVijver with regard to the final note, which is Exhibit 20?

A. No. Never.

Q. Did anyone communicate to you any reaction that Mr. Van der Vijver had to the note?

A. I don't remember, sorry.

Q. Do you recall having any discussions about the note with Han van Delden?

MR. TUTTLE: You are on the final note now or the draft?

MR. HABER: The final note.

THE WITNESS:

0483

A. No. I do not remember, no. Sorry.

BY MR. HABER:

Q. Do you recall having any communication with Brian Puffer about the final note?

A. No. Highly unlikely, I would have thought.

Q. Now, with regard to the final note, Exhibit 20, of the people who are identified as recipients, either direct or who are copied, did you receive any reaction from any of these individuals?

MR. BEST: In a comment?

MR. HABER: A comment to the note.

THE WITNESS: Nothing stands out in my memory, and I wouldn't be surprised if there wasn't any reaction.

BY MR. HABER:

Q. And is why wouldn't you be

surprised?

A. Because I very rarely did get reactions to my notes.

0484

Q. Something that we haven't discussed about SPDC has to do with a moratorium.

Have you heard about a moratorium being placed on reserves addition in SPDC during your tenure as GRA?

MR. TUTTLE: Objection to form. Foundation.

THE WITNESS:

A. Yes, I have.

BY MR. HABER:

Q. And when did you first hear about it?

A. I guess it must have been in the course of the year 2000, particularly towards the end of the year 2000. I may be a year out, but I think it was at the end of the year 2000.

Q. And how did you hear about it?

A. SPDC wanted to book a small additional slice of I believe it was oil reserves, and the figure of something on the order of 50,000,000 barrels sticks to mind.

And Remco Aalbers had told Nigeria

0485

that -- or had at least questioned with Nigeria the wisdom of doing it, taking into account the fact that they had this license extension or this lack of license extension, the end of license in 2019, and the fact that a rather significant upturn in production was required to produce these reserves.

Remco questioned the wisdom of booking those additional volumes, even though for the pro forma itself there was a specific study that was done that would justify it on the basis that, "Look, you are already capped by whatever your possibilities seem to be, for producing reserves." What is the point, or what is the justification even for getting those reserves? And I totally agreed with that.

Since then, SPDC have put a termed as moratorium on increases in reserves; i.e., whatever they did in the way of additional studies, it wouldn't yield additional bottom line Proved Reserves on their books.

Q. How long did the moratorium remain

0486

in effect?

A. Until 2002 when it became clear that the license extension was indeed a matter of right, and that therefore the whole issue of being boxed in by the end of license and the production forecast was no longer relevant.

Q. Do you know if SPDC booked reserves additions after the license expiry issue had been resolved?

A. We can very quickly verify by going to my end year-2002 report. Off-hand, nothing stands out significantly in my memory.

Q. Now, just going back to Exhibit 20 for a moment, can I ask you if you had received any reaction from the recipients of Exhibit 20, had you received any reaction from Judith Boynton?

A. No.

Q. Do you know who Judith Boynton was at the time?

A. Yes, I did.

Q. And who was she?

A. She was Director of Group Finance.

0487

Q. Had you heard any reaction from Tim Morrison?

A. No.

Q. Who was Tim Morrison at that time?

A. I believe he was just new in the position of Group Controller.

(Barendregt Exhibit No. 24 marked for identification)

Q. We are marking, for the record, Barendregt Exhibit 24, which is a series of E-mails with an Attachment. The last E-mail is from John Pay that's dated May 30, 2003, and it's to Mr. Barendregt.

The subject line reads, "SPDC Proved Reserves Booking Guidelines." The Bates range is RJW0092077 through RJW00920787.

Mr. Barendregt, do you recognize the E-mails and the Attachment?

A. I do not recognize the E-mails, simply because I do not specifically remember them. But on this particular sheet, I do remember the -- or do recognize the handwriting, which is

0488

mine.

Q. Okay.

A. So I must have seen it, obviously.

Q. Now, the handwriting that you say you recognize, just again so the record is clear, the first page 777, do you recognize that as your handwriting?

A. Mm-Hmm. Yes, I do.

Q. Do you recognize the markings on 778 as your handwriting?

A. Well, the tick marks could be anybody's of course, but in the context, they are likely to be mine, yes. And the text is mine.

Q. On page 779, do you recognize the text as yours?

A. Yes, I do.

Q. And do you recognize the other markings on this page as yours?

A. I recognize my exclamation mark, yes.

Q. And on the next page, 780, do you recognize this handwriting as your own?

0489

A. It must be.

Q. And again on page 781, do you recognize the markings and text as your own?

A. The text, certainly, and the rest must also be mine, yes.

Q. On page 782, do you recognize the markings and the text which includes the numbers?

A. Yes. The same comment.

Q. So you recognize them as your own?

A. They are text and the writing, and

the rest must be mine, too.

Q. And on page 783, do you recognize the text and writing as your own?

A. Yes, I do.

Q. And 784, do you recognize the text and writing as your own?

A. Yes, I do.

Q. 785, do you recognize the text and writing as your own?

A. It's only a few tick marks and some underlinings, so...

Q. I am sorry. I apologize. Do you

recognize those tick marks as your own?

A. I mean, in all likelihood, they must be mine because the rest of the document was mine.

Q. And the following page, page 786, do you recognize the text as your own?

A. Yes, I do.

Q. And the underscore at the top of the page?

A. Impossible to say. Likely.

Q. The handwriting is your own. Do you recognize that?

A. Yes indeed.

Q. If you can turn back to the first page of the document.

Actually, let me ask even a more general question: Do you recall the context in which this E-mail exchange occurred between you and Mr. Pay?

A. No, I do not. I would have to read the document before I could make any comments on them.

Q. Well, before we do that, let me ask you if you can look at the last E-mail, which is the first E-mail you see at the top of the page?

A. Mm-Hmm.

Q. It's from Mr. Pay to you dated May 30. He says in the second paragraph, "The minimum objective" paren "(from my point of view)" close paren "for the rest of the year is to ensure that the base case is safeguarded:" Colon, "namely that oil debookings are limited to an extent by which they offset gas bookings, so that net reserves changes for SPDC in 2003 are close to zero."

Do you see that?

A. Yes, I do.

Q. Do you have a recollection of having a discussion with Mr. Pay surrounding what he had written here in Exhibit 24?

A. To be honest, I do not specifically remember this discussion. I remember me having given John at some stage a fairly extensive note with my comments scribbled on them, which is obviously this note, but I would not have

0492

remembered before today what the subject of the note was nor the subject of any discussions that John and I may or may not have had.

I remember that I left this on his desk, and we didn't discuss it for quite sometime, not until several weeks later, and it was either because John was away or I was away. That is as much as I remember about this particular note.

Q. Do you recall any discussions with Mr. Pay about offsetting gas bookings with -- I am sorry -- offsetting oil debookings with gas bookings with regard to SPDC?

MR. TUTTLE: Objection to form. Characterization of the document.

THE WITNESS:

A. No is the -- I don't specifically remember that. I can add to that, the comment that any discussion like this, I would -- my attitude to them would be that I would listen to them, but it was not my job to ensure that at the end of the year, SPDC -- SPDC reserves submission would in any way be such that they would be

0493

offsetting any convenient targets.

That was just simply not my task in life, so to speak.

It was at the specific request of

Frank Coopman that I would take a more active role in these type of discussions. But I think that even -- that John Pay would have agreed with me that these sort of considerations would not be mine to act on.

I could listen to them, but I would not do anything with them until the end of the year, and then I would see what the situation was at that time and make a recommendation or a comment.

Q. Who did you believe was responsible for such considerations?

A. Well, it would seem that these are -- this is an E-mail from John Pay, and I read from this that these are his intentions or targets or aspirations.

Q. Okay. One last question, or mini series of questions: If you turn to page 779, the

0494

handwriting at the bottom, I am not sure I get all of that.

So if you could, could you read that for us, please?

A. "What about SIEP's" reserves replacement ratio "management process (to avoid" -- in between brackets -- "(to avoid major swings from year to year?"

Q. Do you recall what you meant by that?

A. In previous years, and I am going back to end '98, end '99, as a result of the introduction of the new guidelines, there were significant reserves additions.

These significant reserves additions led to additions that were in excess of what was actually produced.

Now, one way of describing that particular metric was to issue or to calculate a ratio that was called the reserves replacement ratio, which is in essence the increase in proved reserves divided by the amount of production

0495

occurring during that year.

And the target, the aspired target would always be 100 percent or more, in order that there would be more than replacement of production by additional reserves.

And if you looked at the profile, as for instance Exxon would publish from year on year, you would find that the reserves replacement ratio was hovering just above 100 percent; one year, 105, the next year 115, but just above 100 percent, very neat and tidy.

And we knew and everybody in the industry would have known that that is partly artificial, that that is the process of what I have no other way of describing as the reserves replacement ratio management.

It's probably done in such a way that any new projects are added to reserves, and then out of existing projects, existing production fields, reserves are matured into -- into Proved Reserves to such an extent that they end up with replacement ratio just above 100 percent.

It's crafty, it's good public relations. Shell were at that time, I can only say, more naive in the sense that they booked what they got.

What we could have got, could have done is spread out those reserves additions over the years, saved some of them up for next -- for following years, and achieve a reserves replacement ratio of 100 percent.

As it was, we didn't. I believe the reserves replacement ratio at the end of 1998 was close to 150 percent, and the following year it was something similar. And then in the year after, we were getting close to 100, and then we were dropping below.

John Pay had recognized this, and we had discussed it from time to time. And his idea was that if we had any reserves additions that would exceed the 100 percent, that we would store those up and save those for a rainy year, for the following year.

And that was an approach that I

0497

didn't object to and that I know that if, for instance, somebody like the SEC had been asked this, "Can we book something that, even though it is justified as being Proved Reserves, can we decide not to book that this year and keep it for a later year?" They would have shrugged their shoulders.

Their role in life -- and I think I mentioned this an earlier day -- their role in life was to ensure that reserves weren't overbooked, but underbooking was of no concern of theirs.

And I pretty much took that same attitude. I would report it, and I would say to management, "Look, you could have booked this, but if you chose not to, then I will not further comment."

That's what I was referring to the reserves replacement ratio management.

Why I have this particular question here with this, I cannot tell you without actually going through the note and reading that.

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MR. HABER: Okay. I think this is time for break for the day.

THE VIDEOGRAPHER: Going off the record for the day at 3:00 p.m.. This is the end of tape number 7.

(Whereupon the deposition was recessed at 3:00 p.m.)

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ERRATA

CORRECTION PAGE

____________________ ____________

Signature Date

0500

I, Anton Barendregt, am a deponent in the foregoing video deposition, Volume III. 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 Wednesday, 21 February, 2007.

Signed_________________________
ANTON BARENDREGT

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

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IN THE UNITED STATES DISTRICT COURT
DISTRICT OF NEW JERSEY
Civ. No. 04-3749 (JAP)
Hon. Joel A. Pisano

____
)
IN RE ROYAL DUTCH/SHELL)
TRANSPORT SECURITIES)
LITIGATION)
____________________________)

VIDEOTAPED DEPOSITION UPON
ORAL EXAMINATION
OF
ANTON BARENDREGT
VOLUME IV
Taken on:
Thursday, 22 February, 2007
Commencing at 10:10 a.m.

Taken at:

The Hague Zurich Tower
Muzenstraat 89
2511 WB The Hague
The Netherlands

REPORTED BY: FREDERICK WEISS, CSR, CM

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The Videographer: Richard Bly
Court Reporter: Frederick Weiss

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I N D E X

DEPONENT

ANTON BARENDREGT

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EXHIBIT	Page No:
Barendregt Exhibit 25 - Document entitled "NOTE - 18 Nov, 1999" Authored and signed by Anton Barendregt Bearing Bates Nos. LON00010729 - LON00010741	509
Barendregt Exhibit 26 - Document entitled "Draft Note - 3 Nov 2003" Authored by Anton A. Barendregt bearing Bates Nos. V00240172 - V00240180	509
Barendregt Exhibit 27 - Document entitled "NOTE - 29 Nov 2003" Authored by Anton A. Barendregt bearing Bates Nos. V00300014 - V00300028	509

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I N D E X - continued

EXHIBIT INDEX

EXHIBIT Page No:

Barendregt Exhibit 28 - 520

Shell Exploration & Production document Entitled "Petroleum Resource Volume Guidelines Resource Classification and Value Realisation" bearing Bates Nos. RJW00770633 - RJW00770663

Barendregt Exhibit 29 - 555

Document previously marked as Aalbers Exhibit D containing E-Mail string between Thomas Meijssen and Anton Barendregt with handwritten notes bearing Bates Nos. RJW00151703 - RJW00151705

Barendregt Exhibit 30 - 555

Document previously marked as Aalbers Exhibit E containing an E-Mail string bearing Bates Nos. V00102056 - V00102059

Barendregt Exhibit 31 - 610

Copy of E-Mail String from Frank Coopman to Frasier, Darley and Barendregt bearing Bates Nos. V00101693 - V00101694

Barendregt Exhibit 32 - 615

Copy of E-Mail from Anton Barendregt to Frank Coopman and John Pay, with attached document Entitled "Rockford - A historical perspective" Containing a total of ten pages

I N D E X - continued

EXHIBIT INDEX

EXHIBIT Page No:

Barendregt Exhibit 33 - 616

Document entitled "NOTE - 1 February 2004" Authored by Anton Barendregt including Attachments 1 - 8 bearing Bates Nos. RJW01021058 - RJW01021076

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PROCEEDINGS --

(Barendregt Exhibit Nos. 25, 26, and 27 were marked for identification)

THE VIDEOGRAPHER: This is the beginning of Volume IV, videotape number 8 in the deposition of Anton Barendregt. Today's date is February 22, 2007. The time on the record is 10:10 a.m.

Please proceed.

EXAMINATION BY MR. HABER - CONTINUED

BY MR. HABER:

Q. Good morning, Mr. Barendregt.

A. Good morning.

Q. Today I hope to be able to cover the reserve situation in PDO Oman as well as discuss a couple of documents with you concerning Project Rockford.

And then if there is any miscellaneous issues to tie up, we will finish with that. But that's what I plan to cover today.

Before we went on the record, I had premarked three exhibits which I will hand to you

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now, because these will be useful in our discussion. I will identify them for the record and then I will hand them off to you.

The first Exhibit, which is Exhibit 25, is a Note dated 18 November, 1999. The title reads, "SEC Proved Reserves Audit - Petroleum Development (Oman) and GISCO 23-27 October 1999." The Bates range is LON00010729 through LON00010741.

(Handing)

The second exhibit we premarked as Barendregt Exhibit 26 is a Draft Note dated 3 November, 2003. "SEC Proved Reserves Audit - PDO (Oman), 25-28 Oct 2003" is the title line. It has two Bates ranges. The first one is V00240172 through V00240180. And the second one is VIJVER, that's V-I-J-V-E-R, 2233 through VIJVER 2240.

(Handing)

The third document we premarked is a Note dated 29 November, 2003. Its title line reads, "SEC Proved Reserves Audit - PDO (Oman) 25-28 Oct 2003." Its Bates range is V0030014

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through V00300028, and that's Exhibit 27.

(Handing)

Now, Mr. Van de Vijver, before we start --

A. Beg your pardon?

Q. I am sorry, Mr. Barendregt. I apologize. As an aside, I tend to do that a lot.

A. I know we do look all alike.

(Laughter in the room)

Q. Not at all. My apologies, sir.

Before we get started into the audit, prior to 1999, when you went to Oman to perform the audit, had you reviewed any prior audit notes from your predecessor Ad de la Mar?

A. I cannot remember. I can expect I would have done.

Q. Do you recall any issues of note being raised by your predecessor with regard to Oman?

A. No.

Q. In 1999, what was your understanding of how Oman was reporting its
0512
reserves?

A. The -- as I have explained on various previous occasions, in Oman, the subject of reserves and future forecasts was a continuous subject of discussion with the government. The government expressed a keen interest in reserves carried. All of these discussions were at the level of expectation reserves.

That being so had led to a good system of expectation reserves and forecasts being maintained by PDO.

In other words, there was a good correspondence between individual field reservoir estimates and the build-up to expectation reserves.

Proved Reserves were not of any interest to the government of Oman, nor indeed were Proved Reserves of relevance to PDO themselves.

Normally an operating company would find that Proved Reserves need to be used for items like depreciation, et cetera, in the books.
0513
Now, in the case of PD Oman, the financial systems and the financial procedures were different from those of many other Shell companies. And the bottom line result was that Proved Reserves had no influence on the financial statements that PDO issued.

So that meant that we had a company here that -- whose functional interest in Proved Reserves were limited. The only reason why they maintained something that looked like Proved Reserves was for external reporting to the Center.

Q. Did -- oh, I am sorry. Go ahead.

A. And that was the situation that I found in 1999.

Q. Now, did PDO report expectation reserves to the Omani government?

A. Yes.

Q. How frequently did PDO make those reports?

A. I don't know. I would imagine at least annually. But I know that the subject was discussed with representatives from the Oman

Ministry of Petroleum at regular intervals. So...

Q. Do you recall anyone ever saying that the intervals were on a four-year cycle?

A. A four-year cycle? No. That would be highly surprising to me.

Q. Now, we talked, I believe it was two days ago or maybe three days ago, about the guideline changes in 1998.

A. Mm-Hmm.

Q. And by guidelines, I am referring to Shell's internal guidelines.

A. Correct, yes.

Q. Do you recall if there was any impact of the guidelines on the way in which PDO was reporting its reserves thereafter; that is, in the '98 ARPR which, as you know, was in '99 and then forward?

A. I am sorry. Can you rephrase the question?

Q. Sure. Do you recall if there was any impact of the guideline changes on the way in which PDO was reporting its reserves to the

Center?

A. Not immediately, no. Not in 1998 or 1999.

Q. When -- if it was in '98 and '99, when did the guideline changes in '98 impact the way in which PDO was reporting Proved Reserves to the Center?

A. That was at the end of 2000.

Q. And how did the guideline changes impact the way in which PDO was reporting its Proved Reserves?

A. I think we have to get a representative answer to that question. We have to go back to the situation that I found in 1999 with respect to Proved Reserves. So what I found was a good deal of discipline and order in the way reserves were built up and in the way, for instance, field development plans were maintained, et cetera.

And that in itself was good. The only element that was lacking was a proper representation of the bottom line Proved Reserves

0516

as they were built up from individual Proved Reserves.

To start with, Proved Reserves had been -- not been as diligently maintained as expectation reserves for a number of fields.

Some fields even carried negative Proved Reserves. This is what happens. If you make an initial estimate when the field is put on production, of proved and expectation reserves, and then leave these to estimates unchanged after production is started.

And from year on year, both the proved and expectation reserves would be reduced by the amount of production taking place in that year.

And in some cases, the cumulative amount of production had already overtaken the Proved Reserves estimates, which of course is unrealistic and should have been corrected.

In many cases also the Proved Reserves, remaining reserves estimates, i.e. the proved ultimate recovery for the field minus the

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cumulative production to date, the proved remaining reserves would be unrealistically low in comparison with the proved expectation reserves.

And this is what you get if you have a proved initial estimate and initial expectation estimates and you continue subtracting from both of these estimates, then the remaining reserves in the proved, of course, dwindle more rapidly than the expectation reserves.

And therefore, the ratio between the two is in fact going down; whereas, in practice it should be going up with increasing knowledge and certainty in the field.

So that was the situation that we found; then came rule -- the reserves guideline changes in 1998 pertaining in particular to the -- to mature fields, so fields that had been in production.

And we found that Oman were slow in coming up with the expected increase in reserves, in Proved Reserves in the mature fields.

One of the problems that Oman had

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in doing that is that in order -- since Oman had an end-of-license situation in 2012, and that meant that in order to make a proper assessment of the total company Proved Reserves, they needed to have a forecast, a proven forecast based on Proved Reserves stretching out into the future.

And that forecast would then be added -- would then be accumulated for each and every individual field and that combined forecasts would then be cut off -- would then need to be cut off at 2012 in order to assess the total Proved Reserves for the company.

That was necessary. It wasn't just simply a matter of totaling up and adding up the individual Proved Reserves in the fields. It was absolutely relevant to know along what profile, what forecast, what production forecast those Proved Reserves of the individual fields would be produced.

And PDO did not have that sort of situation in place. In my mind, it would have been relatively easy with an experienced engineer,

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who would have been able to resolve that within a few days.

And I left instructions appended to my 1999 audit report to suggest how they might have a -- or set up a convenient and accurate way of arriving at a representative total Proved Reserves estimates.

Now, I would have expected PDO

maybe not to have done that at the end of '99, but I certainly would have expected them to have done that at the end of 2000. And towards the end, it became clear that they hadn't done that.

So then after a visit by Remco Aalbers to PDO at the end of 2000, Remco, together with staff in PDO, had set up a method of increasing the Proved Reserves in the -- or making more realistic the Proved Reserves in the mature fields in Oman and bringing them more in line with the expectation value that was carried for those fields.

I overlooked that process and I supported it, as I've documented in my end of 2000

0520

report.

Q. Before we follow up on a number of questions, I just would like to mark another document as Barendregt Exhibit 27 -- I am sorry. 28.

(Whereupon, Barendregt Exhibit No. 28 was marked for identification)

And Barendregt Exhibit 28 is titled "Petroleum Resource Volume Guidelines Resource Classification Value Realisation." Its date of issue is August 1998. Its Bates range is RJW00770633 through RJW00770663.

Mr. Barendregt, do you recognize this document?

A. Yes. It would seem to be the end '98 resource for Petroleum Resource Volume Guidelines; in other words, the Shell internal guidelines for reserves estimates.

Q. And throughout the last few days, we have been talking about the '98 guidelines.

Are these the guidelines that you have been talking about?

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A. They would be, yes.

Q. For the moment, you can put that aside.

A. Okay.

Q. Now, earlier in your answer, you

had mentioned with regard to PDO that Proved Reserves were not diligently maintained as expected.

What did you mean by that?

A. Like I said, Proved Reserves weren't a primary concern of PDO in -- both in their dealings with the government and in their day-to-day business and, in particular, their financial reporting.

Yes. I think that's a complete answer, that it wasn't a primary concern and it didn't receive as much attention as expectation reserves.

Q. Did you discuss this issue with the people at PDO when you did your audit in 1999?

A. Yes, I did. And I am fairly certain I commented on it in my audit report.

0522

Q. Okay. Why don't we take a look at your audit report which we marked as Exhibit 25.

Do you recognize this report?

A. Yes. It would appear to be my audit reports.

Q. Do you recall preparing this report?

A. Yes, I do.

Q. If you look at the bottom left-hand corner, there is a signature.

Do you recognize that signature?

A. Indeed I do.

Q. Is it yours?

A. Yes.

Q. Now, you say that this issue about maintaining the proved reserve records is reflected in your report.

Can you show us where in the report?

A. Well, the first page on the summary page, fourth paragraph, I say, "The most significant comment concerns the generally

0523

conservative nature of the individual fields' proved and proved developed reserves estimates."

Q. And it's that sentence that captures the issue of Proved Reserves information?

A. Yes.

Q. Now, just so I am clear, when we are talking about maintaining this information, is this in the nature of an audit trail such as what we talked about yesterday with SPDC?

A. Not quite, not quite. In SPDC, it was, in the first instance, a matter of adding up individual fields' Proved Reserves. And it would appear that the register of individual field Proved Reserves was somehow not complete.

In other words, when I added up a register that was given to me during the audit in SPDC, a register with all the Proved Reserves and PDO Proved Reserves, I would add them up, and they did not add up to what was actually reported. It was close, but it did not add up precisely.

Here, when I did add up the Proved Reserves, they certainly didn't add up to the

declared Proved Reserves in the submission.

But that was entirely understandable, because there was this issue about the license expiring in 2012. In other words, some measure of cutoff had to be applied, and Oman knew that it had to be applied to each of the individual -- each individual fields.

But they couldn't show me how the end of 2000 -- the end of license in 2012 had been reflected in the sum of the reserves estimate that they had submitted.

The difference between Oman and SPDC was that the end of license was quite considerably closer than it was in the case of SPDC. In SPDC, it was 20 years away, and in Oman, it was just over ten years away.

Q. And if I understand correctly what you just said in your answer, so with regard to PDO, then you were not able to ascertain how much volume would be exposed due to license expiry.

Am I correct?

MR. TUTTLE: Objection to the

0525

characterization of the testimony. Sorry.

MR. MORSE: Same objection.

THE WITNESS: Would you mind repeating the question?

BY MR. HABER:

Q. I guess what I am trying to understand is what was the effect of not having that information given to you during your audit?

A. The effect is -- was that the Proved Reserves estimate that was given to me, that was submitted had been submitted at the end of 1998, because that was the one that I was due to audit in '99, had not been put together or at least there was no evidence put before me that it had been put together according to the proper procedures.

The reason being that on the one hand, the individual field estimates were too low and, secondly, that the way of adding up these reserves was not done in a proper fashion.

I suddenly realized that there was one further mention why PDO was different from

0526

SPDC, and that has been well documented in my reports, is that in addition that Oman had a target overall uptake, overall production level of 850,000 barrels a day, that was the Oman government imposed target.

And that meant that the at any day at the time that I was there, Oman could in fact -- the PDO operation could in fact produce more than that 850,000 barrels a day, but didn't.

And that meant that they had to do some sort of prioritizing, giving priority to certain fields and that other fields had to be held up.

Now, if you have a situation like that, then it becomes even more complicated to actually come up with a combined production forecast.

It is not just sufficient to have a proved production forecast for each and every individual field and then add it up, because then you would probably come up with a forecast that would touch 900, 950,000 barrels a day initially

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at least.

And that of course was not realistic. Some of these fields would have be deferred.

And that procedure could have been introduced fairly easy, and yet sufficiently accurately, but it wasn't.

I left some instructions with my audit report to deal with this particular problem, but as it turned out later on, that it -- these instructions weren't heeded. They weren't taken up.

Q. Now, you are referring to instructions to be taken up. Are those reflected in Attachment 3 of Exhibit 25, which is page 736?

A. Yes. Under the heading "taking account of production licence" -- "production licence expiry."

Q. Just going back to my question about the effect of not having the evidence before you, that you said that, "there was no evidence put before me that it had been put together

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according to the proper procedures."

As a consequence, were you able to determine how much volume fell outside -- that is, production fell outside the license, the end of license period?

A. My conclusion was that the bottom line Proved Reserves estimates submitted by PDO for the end year amalgamation in SIEP had been too conservative.

So I was expecting that a proper calculation of A, both the individual fields proved volumes, that I also leave some instructions in my report as you have seen, and taking account of the production license expiry together with the fixed off-take of 850,000 barrels a day, those two factors combined would have yielded a larger volume of Proved Reserves to be produced within license.

So it wasn't the matter of me suspecting that some of the Proved Reserves booked would in fact become produced after the license. It was the other way around. I was suspecting and

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in fact I was quite sure that the booked Proved Reserves were too low.

Q. Now, looking at Attachment 3 for a moment, under "Raising individual fields' proven volumes" , you identified four suggestions for reserves bookings.

Who asked -- withdrawn.

Did anyone ask you to provide these suggestions on how to book reserves of PDO?

A. I cannot remember, sorry. This is eight years ago.

Q. Do you recall if you had considered at the time whether it was appropriate for the group reserves auditor to provide guidance on how to book reserves?

A. The short answer is no. The way I carried out my audits was pretty much the same as the way in which I went about my business when I was a consultant for the group in my area of responsibility in the early 1990s.

That meant that I would make comment, I would be free to make comment, and I

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would also, as when necessary, make suggestions on how they could improve estimates and improve their procedures.

So I saw no conflict there with my role as group reserves auditor, nor did anybody else, as a matter of fact.

Q. When you say "nor did anybody else," did anyone approach you and communicate that to you?

A. The opposite. Nobody communicated to me that it wasn't appropriate for me to do that.

Q. Did you ever ask, for instance, the

external auditors if it was appropriate for the group reserves auditor to be providing guidance on --

A. Not as explicitly as you say, but they saw my report.

Q. And you don't recall any comment from them after reviewing the report?

A. No, I don't.

Q. Was there anyone at Shell's legal

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department that you liaised with?

A. No.

Q. Did you ever ask anyone at Shell's legal department if it was appropriate for the group reserves auditor to be providing guidance on the estimation of Proved Reserves?

MR. BEST: I am going to object to that question.

BY MR. HABER:

Q. You can just answer yes --

A. No.

Q. If you can look at Attachment 3. And if you could just explain number 2, and in particular, I am looking at the last sentence of number 2.

It says, "in Oman" -- I'm sorry. "In the Oman environment, where reservoirs tend to be generally" quote "'proven'," comma, "but more complex than in many other areas," comma, "a suitable criterion for" in quotes "'maturity' could be NP" greater than symbol "> 0.4*" -- I think that's an asterisk, "expn" capital "UR."

0532

Can you explain what that means?

A. Yes. It's reservoir engineers' jargon for expressing that cumulative production, and that's what the NP stands for, is greater than 40% of expectation ultimate recovery in the field; so in other words, if the field had produced, physically produced in excess of 40% of what the field was ultimately expected to yield in the way of recoverable oil or gas.

But in the case of PDO, it was

purely oil. PDO didn't try to get gas.

Q. Now, do you recall if your recommendations for, and I am just going to quote the document here, raising individual fields' proven volumes --

A. Mm-Hmm.

Q. -- was implemented by PDO?

A. No, it wasn't.

Q. How did you find out that it was not implemented?

A. Well, I would have expected an exercise or these two exercises to yield

0533

significantly higher Proved Reserves from PDO. And when they came out at the end of 2000, so the following year, they -- their first draft submission did not appear to have this significant increase that I was expecting.

So when we questioned that with them, it became quick -- quickly clear that they hadn't implemented either of these recommendations.

Q. Yesterday, you testified with regard to SPDC that your annual audit, which came out in January 2000, hinted at the license expiry issue.

Can the same be said for the license expiry issue in PDO?

A. I am sorry. Would you repeat the question?

Q. Well, do you recall if your annual report for year 1999, which comes out I believe in January --

A. Yes.

Q. -- of 2000 reflected your concerns

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about license expiry in PDO?

MR. MORSE: Objection to form.

THE WITNESS:

A. Okay. As I explained, my concern wasn't so much that the license expiry was having an effect on a particular -- a curtailing effect on Proved Reserves.

In fact, my concern was going the other way, that Proved Reserves were too conservative.

However, I was making the point -- making the point here in my report that in order to come up with a more realistic Proved Reserves estimate, one needs to take into account the license expiry.

So coming back to your question, at the end of 1999, I have given a brief summary of my conclusions of all the audits that the two -- in 1999 in my end-year report, and I am pretty certain that this particular issue, although brief, was mentioned in my end '99 report.

Q. If you take a look at Exhibit 15,

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that would be in this pile. (Indicating)

(Witness complying)

Is the reference that you just described found on the first page of the Exhibit?

A. I am sorry.

Q. I am sorry. If you look at Exhibit 15?

A. Yes.

Q. The reference that you just made to the conservativism and license expiry, is that found on the first page which ends 131?

A. No. It wouldn't be, because this is a total end-year report. And the conclusions of the individual audits would be in an appendix which in this note would be Attachment 6 on page V00280143.

Q. And that would be under the heading Oman?

A. Yes.

(Pause)

MR. TUTTLE: Is there a question pending?

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MR. HABER: I don't believe there is.

MR. FERRARA: Good.

MR. HABER: Let me ask one.

MR. TUTTLE: I think that's your job.

MR. HABER: Let me ask one.

Q. Under the heading Oman in Attachment 6, it says, "The generally conservative nature of individual fields' proved and proved developed reserves estimates was noted. However, any scope for increase in Proved Reserves was offset by the fact that the expiration of the production licence in 2012 had not been properly accounted for. The net result was that reported Proved Developed entitlements were likely to be some 15% overstated, whilst the total Proved entitlement reserves were probably of the right magnitude."

A. You will note that that is almost literally the same text as I have at the front of my -- of my audit report, which is Exhibit No. 25.

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Q. Do you recall how that 15% overstatement was arrived at?

A. I think we have some embarrassment here. I was -- one of the answers that I was giving you previously were answers quoting off my memory, not having read these particular documents for a long, long time.

Clearly there were -- my impression was that -- or my memory of that audit was that the Proved Reserves were on the conservative side.

Yet I come to the conclusion that at the end of my audit, and have documented my conclusion, that proved development entitlements were likely to be some 15% overstated.

I cannot remember why that is. I am sure if I dig in my report, I would be able to find that out. But I cannot see why that is the case. I apologize. My memory just served me badly here.

Q. Now, do you recall receiving any reaction from any of the recipients of Exhibit 15 to this portion of the note that I just read into

0538

the record?

A. No, not specifically.

Q. Do you recall the reasons why the proved developed entitlements were likely to be some 15% overstated?

A. Not without reading the document, no. I don't.

MR. TUTTLE: By "this document," you mean Exhibit 25?

THE WITNESS: I am sorry. That's Exhibit 25, yes.

BY MR. HABER:

Q. At the time that the annual report, Exhibit 15, was issued, Remco Aalbers was the Group Reserves Coordinator.

Correct?

A. Yes, he was. Yes.

Q. Do you recall having any discussions with Mr. Aalbers about this overstatement in Oman?

MR. TUTTLE: Objection. Characterization of the testimony.

0539

THE WITNESS: No. Not specifically.

BY MR. HABER:

Q. Again, if you look at Exhibit 15, the statement that says, "The net result was that" proved -- I am sorry -- "that reported Proved Developed entitlements were likely to be some 15% overstated."

Do you recall having any discussion with Roelof Platenkamp about that?

MR. TUTTLE: Objection. Characterization of the document.

MR. HABER: Well, I read it verbatim.

MR. TUTTLE: You need to read both sentences.

MR. GOLDSTEIN: One sentence just for the record.

MR. HABER: One sentence.

MR. GOLDSTEIN: But you didn't finish the sentence.

MR. TUTTLE: "Whilst the Total

0540

Proved entitlement reserves were probably of the right magnitude."

So you can ask him about proved developed, but I am going to object as long as you call it a blanket reserves overstatement.

MR. HABER: I believe I read directly in the record the net result was that "the reported Proved Developed entitlements were likely to be some 15% overstated."

MR. TUTTLE: We are not quibbling with your reading. We are quibbling with your question about this overstatement.

BY MR. HABER:

Q. Do you recall having any communications with Mr. Platenkamp concerning the portion of the sentence that I just read?

A. No, I do not. I think it's unlikely that I had it.

Q. The same question with regard to Lorin Brass?

A. I do not recall.

Q. What was the level of interaction

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you had with Lorin Brass?

A. Once a year meeting just before the end-of-year meeting with the external auditors, I would present my draft report -- he would see my draft report which I would have circulated to or within SIEP, and there would be a brief discussion of me together with the Group Reserves Coordinator and probably his supervisor with Lorin Brass.

Q. I mentioned --

A. You mentioned Lorin Brass, but at the time at the end of 1999 it was Linda Cook still, not Lorin Brass. Lorin Brass came on the scene, if I remember right, was just shortly after that.

Q. What was your level of interaction with Linda Cook?

A. As it happened, nil. Linda wasn't around at the end '99 period. And as a result, I have never actually attended a meeting in her office or with her, for that matter.

Q. I mentioned Roelof Platenkamp, and he is identified on Exhibit 15.

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What was your level of interaction with Mr. Platenkamp?

MR. BEST: Generally?

MR. HABER: Yes.

THE WITNESS:

A. On the business level, extremely infrequent. There may have been one meeting in the end year, or one or two meetings perhaps at the end year cycle, i.e., during January. I doubt if it was more than one.

We greeted each other in the corridor when we met.

BY MR. HABER:

Q. Now, did you receive any comment to the discussion in Attachment 6 in Oman from Mr. Watts?

A. No, certainly not, no.

Q. During the closeout session, do you recall discussing the information that's set forth in Attachment 6 under Oman?

A. Not specifically, no.

Q. Do you recall if the external

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auditors from KPMG or PWC asked any questions concerning the information that's set forth in Attachment 6 under Oman?

A. No, not specifically. No.

Q. Do you recall if the discussion concerning the reported proved developed entitlements came up during the closeout session for year-end 1999?

A. They certainly would have come up, because I made my presentation. It was mentioned in my report and in my -- in my presentation. I am fairly certain that a comment along these lines would have been included. But I need to go back to my actual presentation to be absolutely certain.

Q. Now, earlier in your testimony, you mentioned production forecasts.

Had you, at the time you conducted your audit in 1999, reviewed PDO's production forecasts?

A. At the -- I am trying to think. No. I do not remember whether I had seen a

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forecast before I went there. If I did see one forecast, then it must have been the general one with just the 850,000 barrels a day flat plateau of the aggregate forecast, but certainly not an individual field-by-field forecast, no.

Q. When you conducted your audit, do you recall who you met with?

A. Not everyone, but there was Neil O'Neil (Phonetic) who was in charge of -- I think he was the head reservoir engineer there. He is the only name that springs to mind at the moment.

Q. Do you know a person by the name of Said al-Abri?

A. Yes. And I am looking at Exhibit 25 now, he is the -- he was the reserves reporting coordinator in PDO, so indeed he would have been my daily contact during the audit.

Q. Do you know who Stuart Evans is?

A. Yes, I do.

Q. And who is Stuart Evans?

A. Stuart Evans is a senior engineer, senior reservoir engineer in Shell. At that time,

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he was the area reservoir engineer, area reservoir engineer and consultant for the Middle East. What else do you want me to say?

Q. Do you recall meeting with him at the time of your audit in 1999?

A. I don't think I did.

Q. Do you know a Stuart Clayton?

A. Yes. He was in Oman. I am trying to remember whether he was there at the time of the first audit. He certainly was there during the second -- during the time of the second audit in 2003. I cannot remember whether he was there in the first audit.

Q. Do you recall providing a draft of Exhibit 25 to anyone at PDO prior to it being finalized?

A. Not specifically, but it was -- as I explained to you several times, that was my habit of doing so. I must have done it here as well.

Q. Do you recall receiving any comment from any of the people that you distributed the

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draft to?

A. Not specifically. There is likely to have been one or two, yes.

Q. At the time you conducted your audit, did you review PDO's business plans?

A. No. No. That wasn't my task. I may have used it, but to say that I reviewed it, no. That was beyond my task.

MR. HABER: This is probably a good time to take a quick break.

MR. TUTTLE: Great.

THE VIDEOGRAPHER: Going off the record at 11:03.

(Short recess taken)

THE VIDEOGRAPHER: Returning to the record at 11:33 from 11:03.

MR. FERRARA: Mr. Haber, over the course of the break --

THE VIDEOGRAPHER: I don't have a mic on you, do I? Who is talking.

MR. BEST: Mr. Ferrara. Just speak up.

0547

THE VIDEOGRAPHER: Go ahead.

MR. FERRARA: Over the course of the break, Mr. Barendregt had an opportunity to reflect further on what appears to be some confusion that's entered into our record with respect to his testimony, on the one hand indicating that on a field-by-field basis the Oman Proved Reserves were understated, and his testimony that with respect to as reported Proved

Reserves may have been as much as 15% overstated.

And what Mr. Barendregt has done during the course of the break is to more carefully study his reports of those audits, and would like to have the opportunity to clarify the confusion that's been introduced into the record on these two points before we begin and continue with his examination here today.

MR. HABER: That would be fine.

MR. FERRARA: Mr. Barendregt, could you address yourself to those two issues, please?

THE WITNESS: Yes. Like I already said earlier, I hadn't seen this particular

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document or read this particular document for quite a long time. And it is by another careful read of what I actually wrote down at the time that I am beginning to have again a better appreciation of what it was that -- of the points that I was meaning to make.

I think one of the causes for the confusion was that there were two issues in my audit in '99.

One of them was that on an individual field basis, Proved Reserves, in particular proved remaining reserves in each of the fields tended to be low to very low in relation to expectation reserves, bearing in mind the maturity of these fields, by which I mean the amount of cumulative production that had meanwhile been produced from these fields.

I comment on that, but I do not give that comment a very high profile. That is one point.

And the second point is that accepting the proved volumes for each of the

0549

individual fields as a fair representation of the volumes that are actually producible -- of the volume that are producible from these fields and taking the production forecasts that would be commensurate with these proved volumes, proved volumes which as I said earlier are in fact low.

But anyway, let's ignore that particular effect.

If you do that, then the method that they have applied in putting together these forecasts in order to assess the affect of the end of license has been improper for the proved developed reserves, by which is meant the forecast producible from existing wells, the no further activity case, as it is sometimes referred to.

So you take your existing wells, you don't drill any additional wells, and then you get a gradually declining forecast.

And in order for it to get a proper reflection, of course, it has to be cut off at to 2012, and the actual fact was that it hadn't been, and that of course is improper.

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And that led to my statement saying that these proved developed reserves are 15% too high, the 15% being the portion in detail and beyond 2012.

I think it is useful to bear in mind also I have checked back at the record that an appropriate correction has in fact been made by PDO at the end of '99, so a couple of months after my audit report in the proved developed estimate for PDO.

So the point was accepted and an appropriate reduction was made in a proved reduction estimate.

I also make the point that the proved total, by which we mean the proved developed and the proved undeveloped reserves, i.e. the reserves producible from future activities, was probably -- was probably all right, was of the right magnitude, and therefore could be accepted as a fair representation. And that is what appeared -- ultimately appeared in the report.

0551

I hope this gives a better -- or this gives you a better understanding of my description of the situation in Oman around 1999.

BY MR. HABER:

Q. Just so I am clear then, the 15% overstatement of proved developed entitlements, that refers to reserves that have been booked, but fall outside of the license period?

A. Correct, yes.

Q. Okay.

A. And like I said, these 15% of reserves, overstated reserves had been corrected a couple of months later at the end of '99.

Q. And was that reflected in the year-end ARPR?

A. Yes. Indeed they were, yes.

Q. Okay. Thank you.

A. Okay.

Q. Now, with regard to production, I believe you had mentioned a production forecast of 850,000 barrels a day.

Is that correct?

0552

A. Yes.

Q. And that forecast was seen by you during your 1999 audit?

A. Yes. I am fairly certain it was. I believe that I had access to the year Oman -- to the PDO business plan. A copy was made available to me during the audit. So in the end, that would have contained the 850,000 barrels a day forecast.

Q. Did there come a time when that forecast changed?

A. How do you mean?

Q. Well, after 1999, did there come a time when PDO was finding it difficult to reach production of 850,000 barrels a day?

A. Yes. It came as a shock to us all. But I believe in the course of 2001, PDO were having serious problems in maintaining the 850,000 barrels a day. One particular problem that occurred, and one particular problem that stands out in my memory is that in their largest field, the Yibal field, they had over the previous years been installing in-fill drilling, i.e. drilling

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wells in between existing wells in order to accelerate oil production through water injection.

And it turned out that that latest round of in-fill drilling was by no means as successful as it had been anticipated. It is a matter of fractures providing a direct -- fractures in the field, unrecognized fractures providing a direct path between injectors and producers.

And therefore, the water injector would come out within hours or a very short period to the producers and therefore not yield the effect that had been anticipated.

That was a big project and dealt a serious blow to PDO's ability to maintain the forecasts. But that wasn't the only one. In other fields, there were disappointments occurring at the same time.

Q. Was the Yibal field the largest field in PDO?

A. If not the largest, at least the three largest. There were Natil, Fahuud, and

Yibal. I believe Yibal had the highest volume of recoverable oil. The others had somewhat lower recovery factors. But the in-place volumes of the other two fields may have been larger, but that I am not too sure of.

Q. I am sorry. I just want to go back to one second to your explanation when you were talking about the 15%.

A. Mm-Hmm.

Q. Did that 15% exposure represent 15% of PDO's total portfolio of Proved Reserves?

A. Proved developed.

Q. Proved developed reserves?

A. Yes.

Q. Now, coming back now to the production issue, do you recall when in 2001 you became aware of this production problem?

A. Somebody must have mentioned it to me, probably Remco Aalbers, maybe Ian McKay at the time, who was his supervisor.

Q. I am sorry. Was that Aidan McKay?
A. I am sorry. Aidan McKay, yes. But

0555

in all likelihood it would have been Remco Aalbers.
Q. Now, you had mentioned that Mr. Aalbers had gone to Oman in late 2000.
Do you recall the purpose of his meeting?
A. One of the reasons for that visit -- I don't remember them all, but one of the reasons for the visit was to see to what extent the recommendations that I had made in my audit had been included in PDO's procedures. And by "recommendations," I mean specifically the recommendations that were made an Attachment to my report in 1999.
Q. I would like to show you what we marked as Exhibit Aalbers D and Aalbers E, and I think we probably will just remark these with Exhibits for this deposition as well.
(Barendregt Exhibit Nos. 29 and 30 marked for identification)
We are marking Aalbers Exhibit D also as Barendregt Exhibit 29. And again just for

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the record, this is a series of E-mails, the last of one is from Thomas Meijssen dated January 3rd, 2001 to Mr. Barendregt with a CC to Remco Aalbers, Said Abri, Marcus Antonini. The subject line reads "Proved Reserves Visit - Group Resource Co-ordinator."
The second Exhibit, which was previously marked as Aalbers Exhibit E, we are marking as Barendregt Exhibit 30, also a series of E-mails. The last of which is from Mr. Barendregt dated January 4, 2001 to Thomas Meijssen with a CC to Remco Aalbers, Said Abri, and Marcus Antonini. Again, the subject line reads, "Proved Reserves Visit - Group Resource Coordinator."
A. Yes.
Q. Now, with regard to Aalbers Exhibit D, which we marked as Exhibit 29 --

A. Mm-Hmm.

Q. -- I'd like to direct your attention to the second chart and the paragraph at the bottom of the page that begins "I would propose for external reserves reporting."

0557

So this is the E-mail from Mr. Meijssen to you?

A. Yes.

Q. And if you could also take a look at Exhibit 25 at the same time, and in particular, your Attachment 3, number 2 on Attachment 3, which ends 736.

A. Yes.

Q. Now, am I correct that what Mr. Meijssen is proposing, which is, quote, "using the 40% maturity criterion," -- and I believe that's referring to the chart -- consistent with what you were including in your guidance that's reflected in Attachment 3, number 2?

A. Yes. They are this same criteria, yes.

Q. And when we look at the chart, the second one?

A. Which chart are you on?

Q. I am on, I am sorry, Exhibit 29?

A. But which chart?

Q. On the first page?

0558

A. Oh, the table you mean.

Q. I am sorry. Yes. The table.

A. Oh, okay.

Q. If you look at the table, the second table, would the second item listed there, proven developed reserves 40%, that line, be consistent with what you were recommending in your audit report, which is Attachment 3, number 2 on Exhibit 25?

MR. TUTTLE: Objection to the characterization of the document to the extent that you are just directing him to one paragraph of his report.

MR. HABER: I am asking him, and he

can feel free to look at whatever he needs to answer the question.

MR. TUTTLE: You should look at the entirety of your recommendations before you answer that.

THE WITNESS:

A. Okay. First, let me say that the gist of my -- or a summary of my recommendation of

0559

how to deal with the apparent general conservativism in the Oman Proved Reserves, and that is the top half of Attachment 3 in Exhibit 25, is that I point to the '98 reserves guidelines, the Shell reserves guidelines.

And I say that the point is made there that for mature fields, proved developed reserves can effectively be made equal to expectation developed reserves in line with accepted industry practice. Okay. That was a point that was made in the reserves guidelines.

Then I add to say that in the Omani context, a reasonable criterion for determining which fields are mature, I said that you could consider the fields with cumulative production being in excess of 40% of expectation ultimate recovery in that field.

That's what I say there. And that is -- those are the -- that is the line of thinking that they follow in this particular table.

BY MR. HABER:

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Q. So in the table, which one of the items in the left column is consistent with what you were suggesting in Attachment 3 of Exhibit 25?

A. In order to do that, I would have to read the -- I remember the conversation, but I don't remember the details of the -- of the E-mail discussion. So you will have to bear with me.

Q. Okay.

A. And I will to have read it carefully. Somebody has some scribbling in it, which certainly aren't my scribbles.

Q. That's going to be one of my next questions.

A. Well, they are not.

MR. BEST: And just for the record, Mr. Barendregt, you are speaking about the document with Bates number RJW00151703?

THE WITNESS: Indeed, yes. Number 29, yes.

(Pause)

Yes. I believe your answer was that the second line, which is headed in that

0561

table in Exhibit 29 -- the second line is proven developed reserves, 40%, that that is the one that is in line with my recommendation.

And my answer to that would be yes.

BY MR. HABER:

Q. Now, in your recommendation on Attachment 3, Exhibit 25, did you make any recommendation with regard to reporting proved undeveloped reserves?

A. Yes, I did. That's point number 3 of the first half -- top half of Attachment 3 in that Exhibit, Exhibit 25, where I say, "For proved undeveloped recoverables, a multiple scenario modelling...should ideally be followed," so indeed I addressed the undeveloped reserves there.

Q. So again looking at Exhibit 29, the table, of the bottom two items listed in the left-hand column which is proven developed reserves 40%, undeveloped reserves 60%, and proven developed reserves 40%, undeveloped reserves 40%, which one of these items in the table is consistent with what you are recommending or

0562

suggesting in Attachment 3 of Exhibit 25?

A. Before I answer that, I think it is useful to bear in mind that my recommendation is, particularly in item number 3 that we just talked about for undeveloped reserves, that item requires or I recommend that a range of multiple scenario modelling is carried out.

And by that, I mean that the range

of different reservoir simulation models are set up and run in a future prediction mode to assess what the realistic assessment is for expectation and Proved Reserves in that field. And particularly, the Proved Reserves would be the result of somewhat more conservative assumptions in those models.

I put it there fairly lightly, but that is quite a major amount of effort, amount of effort that PDO did not get a chance to get around to.

And certainly by the end of 2000, it was clear that accepted approach, although certainly desirable, would not be physically

0563

possible before the end of 2000.

So coming to your question is either of the two lines named proven developed 40%, undeveloped 60% or the one below that, 40% and 40%, is that in concurrence with my recommendation? The answer is no, it isn't.

Q. Now, if you look at Exhibit 30, which was also marked as Aalbers Exhibit D, and in particular, I'd like you to take a look at item 5, which appears on the bottom of the page.

It says, "As for your proposed volumes to book as externally reported Proved Reserves," paren, "(before they are cut off by license expiry)", close paren, "your line" quote "'proven,'" comma "'DevRes 40%,'" comma "'UndevRes 60%'" close quote paren "(347 mln m3 Dev Res and 254 UndevRes)" close paren "seems to be the best one to aim for?"

Do you recall having any discussions with Mr. Aalbers concerning this suggestion?

A. Yes. I -- yes I had, yes.

0564

Q. And how did you come to -- in the context -- withdrawn.

What do you recall discussing with Mr. Aalbers?

A. We mustn't forget that this is

almost seven years ago now. So I don't specifically recall say sentence by sentence what we discussed. I do recall of course the discussion that we had on this issue. And I recall writing this particular E-mail, which I did after having a discussion with Remco Aalbers on this.

Q. Do you recall what you and Mr. Aalbers had discussed?

A. Yeah. The merits of the various cases that Thomas Meijssen was presenting here.

Q. And was it in this discussion that you and Mr. Aalbers arrived at what's reflected in number 5 that I read, that proposal?

MR. TUTTLE: Objection to the characterization of the testimony.

THE WITNESS:

0565

A. I do not remember it, but it's clear that this is an E-mail which I sent.

So I wouldn't have sent this E-mail if it would have been, say, disputed by Remco Aalbers.

Then if there was any dispute, and I still wanted to go at it, then I would have reflected this in some way.

BY MR. HABER:

Q. Do you recall how your position evolved from what is reflected in Attachment 6 of Exhibit 25 to the proposal in Exhibit 30?

MR. TUTTLE: Attachment 6?

MR. HABER: I am sorry, Attachment 3. Thank you. I am sorry.

Q. Do you recall how -- let me reask that so it's clear.

A. Mm-Hmm.

Q. Do you recall how your position had evolved from what's reflected in Attachment 3 of Exhibit 25 to what is proposed in Exhibit 30?

MR. MORSE: Objection to form.

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THE WITNESS:

A. We were faced with the reality that

my recommendation in item 3 of Attachment 3 of Exhibit No. 25, that that recommendation was describing the ideal case of what PDO should do.

As it happened, PDO never got around to doing it. And I explained that to you. So that was a fact. That was something that they couldn't do something about any more, because it would be a fairly sizeable task to carry out these reservoir simulation studies for each and every one of their fields.

That being the case, it was deemed desirable to come up with a method of recalculating Proved Reserves in such a manner that the recommendation that I made here would be better reflected than they were in the figures that PDO had been carrying up to that date.

So it was in response to the reality and to the unchangeable reality that PDO hadn't been able to carry out these studies, which is something that I personally only discovered at

the time that all this played, which was late -- late 2000, that Remco and I discussed the cases and Thomas Meijssen of PDO discussed the case that we see here reflected.

Q. When you said in your answer, "It was deemed desirable to come up with a method of recalculating Proved Reserves in such a manner that the recommendation that I made here would be better reflected than they were."

And then it actually -- it's a little difficult to read, but who deemed it desirable to come up with a method of calculating Proved Reserves?

MR. TUTTLE: Objection. Characterization.

THE WITNESS:

A. The drive for this came from Remco Aalbers.

BY MR. HABER:

Q. Did Mr. Aalbers say what was causing him to be so driven?

MR. BEST: Objection.

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MR. HABER: You can answer.

MR. BEST: The question requires an answer which is hearsay.

BY MR. HABER:

Q. You can answer.

A. I can't say of course precisely why Remco Aalbers came to this conclusion, but I know that he read my report. He saw my assessment that the individual field Proved Reserves were low, and obviously too low in comparison with expectation reserves. And this was particularly for mature fields.

And of course, Remco was fully aware of the guidelines in 1998, which gave instructions on how to approach reserves in mature fields.

And it was clear that the reserves by PDO -- put forward by PDO were not in line with those guidelines for these mature fields.

Q. During your discussions with Mr. Aalbers, did you discuss reserve replacement ratio target?

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MR. TUTTLE: At any time? Any discussion with Remco Aalbers?

MR. HABER: No. The discussions concerning Oman.

THE WITNESS:

A. We may have done, but I don't specifically recall them. But we may have done.

BY MR. HABER:

Q. Do you recall any conversation concern this booking of reserves in Oman with Mr. Aalbers where he said to you that he was under pressure to reach a certain percentage of the RRR?

A. I remember comments to that effect, yes. In that period, he was under pressure; he appeared to be under pressure.

Q. What was the basis for your observation?

A. Comments by himself, I think.

Q. Do you recall what he said to you?

A. He was saying --

MR. BEST: Object. The same objection, as calling for a hearsay response.

BY MR. HABER:

Q. And you can answer.

A. Not literally, of course. But it was along the lines that he was under pressure to come to a -- to a reserves replacement ratio of around 100 percent.

Q. And did he say from where the pressure was being exerted?

MR. BEST: Objection. Again, calls for a hearsay answer.

BY MR. HABER:

Q. You can answer.

A. All I can remember is that he said that Philip Watts was expressing a close interest in the end-of-year reserves reporting and the volumes that were about to be reported.

Q. Do you recall him saying anything else on the subject?

MR. BEST: Same objection. All of these questions are calling for responses which are hearsay objections and are not part of any known exception that I know of to the hearsay

rule.

But go ahead and answer.

MR. HABER: You can raise them at trial. Go ahead.

MR. BEST: Well, I am preserving the record right now.

MR. HABER: All objections are preserved for trial except as to form.

Q. Go ahead.

A. I am sorry. Can you ask the question again?

Q. Do you recall Mr. Aalbers saying anything else on the subject?

A. No. Not off-hand, no.

Q. Now, do you recall if the method as proposed in Exhibit 30 is the method that was implemented for booking reserves in PDO in the end of 2000?

A. Not specifically. But it may well have been.

Q. Do you recall how many -- how much volume PDO booked as Proved Reserves for year-end

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2000?

A. As a quantified figure, no, I do not. But I can easily look that up.

Q. Does approximately 355 or so million barrels sound familiar to you?

A. No is the short answer.

Q. Okay. Now, a moment ago, you testified that there did come a time when PDO's production had declined.

Correct?

A. Yes. That was after this period.

Q. And my question now relates: Did that decline have any effect on what had been booked at the end of 2000?

A. Yes. I think you should understand that my assessment in '99 was based on a comparison of Proved Reserves versus expectation reserves.

In my view, and in my knowledge, there was no cause for concern regarding the volumes that PDO carried as expectation reserves.

And I base that view on what I saw

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during the audit. I mean, we had discussions about the major fields, some of the more -- some of the smaller fields.

In all, PDO had something close to 100 fields in their portfolio, so we didn't discuss each and every one of them. But certainly the major ones, and some of those were major developments were imminent, we discussed in the way I described before. I sat together with the team and we would look at it.

And on that basis, I had no reason to have any serious doubts about the expectation volumes that were carried in the books.

There was a further consideration in the back of my head, and that was that all of these field estimates of course were discussed extensively with Oman ministry staff who had their own external experts to help them.

So I was satisfied that the expectation reserves were a realistic estimate for the Oman portfolio.

What I was concerned about was the

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ratio between Proved Reserves and expectation reserves in these fields. I make a comment about that in my '99 report.

And there is even a plot in my '99 report which reflect in a graphical manner what I was referring to.

And this particular item was taken up in 2000 in order to bring the booked volume for Oman into closer alignment with expectation volumes.

What we were not aware of and what was a surprise to everyone, certainly in the center and I understand also in PDO themselves, was the sudden production problems that began to appear in 2001, i.e. within six months of us trying to do what we are doing here.

That was a major surprise to all of us. It meant that in fact the expectation reserves, which we had been viewing as a standard against which to judge the proven reserves, were in themselves obviously too optimistic, and therefore they had to be brought down. By how

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much that was far from clear at that time.

But clearly, some measure of reduction had to be applied.

Q. Did there come a time where you reached this conclusion?

A. In the course of 2001 when we heard about the first of these production problems, yes.

Q. Did you begin to consider whether the reserves that had just been booked should be debooked?

MR. TUTTLE: Objection.
Foundation.

THE WITNESS:

A. I discussed it in my end-year 2001 report because that would be my first opportunity to comment on it.

I discussed it in that report, bringing the issue together with the issues that are reported on SPDC and I believe Abu Dhabi, saying that here we have companies that are boxed in by end of license and a limit to their production forecast, and that therefore the Proved

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Reserves that should be booked should be in conformance with those.

And I forget the precise words, but I am pretty certain that I did address Oman at that time.

Q. You can feel free to look at Exhibit 22. And if you can identify where you said that, that would be helpful?

MR. BEST: While he is looking at that, let me make the record clear, because I apologize in our conversation, my objections were all to form, in that your questions required a hearsay response.

MR. HABER: Okay.

THE WITNESS:

A. Yes. In Exhibit 22, if you go to page two of Attachment 1, item number 6, titled "Production licence duration constraints," second paragraph of which starts with, "For a proper estimation of Proved Reserves (which have to fulfill the criterion of 'reasonable certainty')", et cetera, et cetera.

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I say that, "It is noted that PDO still maintain an 850,000 kb/d plateau in their forecast, in spite of recent problems in maintaining that production level."

I go on to say in the following paragraph that, "At present, the Group reserve guidelines do not provide any guidance about what assumptions to take for future forecasts in these cases. This should be rectified. Following that, the assumed forecasts should be reviewed with the OU's concerned."

And that is a statement of fact, that indeed the guidelines, as we had them in the -- in place at that time, did not say anything about what assumptions to take, nor was this particular issue anywhere addressed in Rule 4-10.

BY MR. HABER:

Q. Had you made any recommendations as to what the guidelines should include?

A. I am making them here now.

Q. So that paragraph that you just read is --

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A. Is where I make the recommendation and say effectively what I am saying there is look, at this moment, I cannot say that this particular assumption is not in line with our guidelines.

I believe that the guidelines should be tightened and should be made more specific, and then we should review again the situation of PDO and, as it happens, SPDC and the others.

Q. I guess the question I am asking you is: Did you suggest to anyone how the guidelines should be tightened and be made more specific?

A. Yes, I did, in the following year. And that would have been in the year of 2002.

Q. And is that recommendation reflected in your annual report?

A. Yes. Number 2 of my recommendations on page 4 of the same Attachment. But it says, "In the Group reserves guidelines, include guidance on assumptions to use in future

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production profiles when these become important for OUs with constrained production licence durations. With such guidance, review the present assumptions used by e.g. SPDC and PDO."

Q. Did you have any involvement in providing the assumptions that were to be used in any tightening of the guidelines?

A. The guidelines in 2002, as I remember it, were put together by Jan Willem Roosch at the beginning of 2002, and indeed I had made recommendations for corrections in certain parts, including this particular issue.

Q. And do you know if your recommendations were implemented in the revised guidelines?

A. I believe they were not.

Q. Do you have an understanding as to why?

A. The short answer is no. Jan Willem Roosch is Jan Willem Roosch, and he did his own thing.

Q. With the guideline revisions in

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2003, did you raise this issue again for inclusion into the guideline revisions?

A. We would have to refer to my end-year document. I can't be precise. Certainly the issue itself was raised. That of course I am sure about. Whether the issue of the guidelines, I cannot tell off-hand. I would have to look at my report.

Q. Now, from -- other than the challenge session -- withdrawn.

Other than the ARPR process, did you have any follow-up with PDO concerning any of the issues that you identified in your report, the 1999 report, that is?

A. None that I can remember.

Q. And again, other than the ARPR process, did you have any follow-up with PDO concerning the production problems that PDO -- that you had learned PDO was experiencing?

A. The only follow-up that I can remember is the follow-up at the end of 2002 when the issue of the production license constraints,

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et cetera, was raised again by me in my report.

And when I asked PDO and SPDC for specific data regarding their assumed off-take profiles, and that led to a specific item that I raised in my end 2002 report where I said that clearly the Proved Reserves estimate carried by PDO is too high.

I made quite a specific assessment of the volume by which, in my opinion, on the basis of the limited data that I had available, it was obvious that something was not right.

Q. If you can just take a look at Exhibit 16 for a moment, and just identify where that discussion is included or contained, rather?

A. It would be on page 3 of Attachment 1 of Exhibit 16, item number 8, last paragraph at the bottom. First I introduced the issue again of companies being constrained both by the end of license and by their offtakes. And then I described that I asked Shell Abu Dhabi PDO and SPDC for additional information.

And where in the last paragraph, I

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say, "PDO did not provide a clear answer to the query."

And I go on to say, "Comparison of their stated Proved oil reserves volume against their latest Business Plan forecast showed that the Proved volume seems unrealistically high," and then I go on.

Q. Now, with regard to this portion of the year-end report, and the portion I am referring now to what you just read under item 8, do you recall having any comment -- receiving any comment from any of the recipients on the first page of Exhibit 16?

And that includes the direct recipients and the recipients who are copied.

A. No specific comments stand out. Walter van de Vijver and ExCom members certainly didn't come back to me, Malcolm Harper didn't. Frank Coopman and I had frequent contact with, so he may have given some comments or asked questions.

But I don't remember specifically

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which they were, and the same as we said for Han van Delden and Brian Puffer who of course I saw at the end of January 80.

Q. Other than specific conversations, do you recall any specific conversations that you had with Mr. Coopman concerning Oman?

A. Not specifically, no. No. I am not saying that we hadn't, but I cannot remember any specific points.

Q. And again, general discussion over Oman, do you recall having that with Mr. Van Delden?

A. Not specifically. But I made the point, this particular point and many other points, quite clear in my presentation.

I remember that I showed a view graph with the production forecasts, at which I drew various lines suggesting what the minimum amount was by which I needed to see the Proved Reserves estimate needed to be corrected.

Q. And was Mr. Puffer present during this presentation?

0584

A. Yes, he would have been, yes.

Q. Do you recall any reaction from Mr. Van Delden or Mr. Puffer to the presentation?

A. Not specifically. But I know that it wasn't received in stony silence. We certainly did get questions and comments. But if you ask me who made what comment, I honestly cannot remember.

Q. Other than the recipients identified on Exhibit 16, did Ms. Boynton provide any comment about the Oman item that we just talked about?

MS. WICKHEM: Object. Lack of foundation.

MR. TUTTLE: To Mr. Barendregt?

MR. HABER: To Mr. Barendregt.

THE WITNESS:

A. Well, Ms. Boynton was not copied on my note, nor do I think she received a copy, at least to my knowledge.

BY MR. HABER:

Q. Well, let me ask a different question. Did you have a different discussion

with Ms. Boynton concerning the note that has been marked as Exhibit 16?

A. No. I have never met Ms. Boynton.

Q. Same question with regard to Mr. Watts. Did you discuss the note with Mr. Watts?

A. No. I never met Mr. Watts.

MR. BEST: Objection to form. Asked and answered.

BY MR. HABER:

Q. Now, you did conduct another audit of Oman.

Correct?

A. In 2003, yes.

Q. Was that audit a part of the cycle, the four-year cycle that had been your practice?

A. As it happened, yes. Yeah. But I think following my recommendation or my remark at the end of 2002, even if it had been part of the cycle, then in order it would have been carried out in Oman in the following year.

MR. FERRARA: Excuse me, Mr. Haber. If you think you are going to be able to wrap up

with 2003 and conclude your examination the next ten minutes or so, I would like to continue.

But in the event that you think that you are going to go longer than that, we have been on for a little more than an hour and we may want to take a five-minute break.

MR. HABER: I think probably we will be on for about ten to 15 minutes on 2003, and then I just have, as I mentioned earlier, one small area that I do want to inquire into that I don't anticipate longer than a half-hour, and should take less.

MR. FERRARA: Well then, we should take a break.

MR. HABER: That's fine.

THE VIDEOGRAPHER: Going off the record at 12:30.

(Short recess taken)

THE VIDEOGRAPHER: Beginning tape number 9 and returning to the record at 12:41 from 1230.

BY MR. HABER:

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Q. Mr. Barendregt, I just want to go back to one answer that you gave previously, and that concerned that 15% of proved developed entitlements.

I believe your earlier testimony was that it was corrected a few months later?

A. Yes. Certainly a correction was made to the proved developed estimate at that time, yes.

Q. And do you recall the basis for that correction?

A. As I recall it, it would have been as a result of the recommendation that I made in -- or the observation that I made in my 1999 audit report.

Q. And that correction was reflected in the final ARPR submission for PDO?

A. Yes, indeed it was. There was a sizeable negative correction, yes.

Q. Do you know if PDO had ever withdrawn its business plan during your tenure as group reserves auditor?

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A. I cannot recall. I can't recall. It wouldn't -- I wouldn't normally be involved in the process of business plan and capital allocation submissions.

Q. Were you involved in PDO's capital allocation submissions?

A. No, I was not.

Q. Now, right before the break, we were starting -- we were about to get into your 2003 audit.

Do you recall generally what you had found in Oman when you audited PDO?

MR. TUTTLE: In 2003?

MR. HABER: In 2003.

THE WITNESS:

A. It was clear that the original expectation reserves estimates for some fields, some of the fields, were too high. It was also clear that the production forecast, and in particular proved production forecast, had been too optimistic and needed review.

In addition, of course, we had the

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issue that we discussed before of the reserves guidelines having been tightened and, in particular, requiring a more strict hurdle before undeveloped reserves could be produced. And that also affected some of the proved forecasts for undeveloped reserves on PDO's books.

And the net result was that proved -- developed and proved undeveloped forecasts for PDO were quite a lot less than what they were before and, more importantly for me, that a lot of work still needed to be done to mature reserves such that they could be booked as Proved Reserves.

Q. If you take a look at Exhibit 26?

A. 26, yes, I have got it.

Q. And if you could pull 27 aside as well, because we will get to it.

Do you recall preparing this Draft Note?

MR. BEST: Which one?

MR. HABER: I am sorry. Exhibit 26.

THE WITNESS:

0590

A. Yes. As I explained several times before, I was in the habit of preparing a Draft Note shortly before my completion of the audit.

BY MR. HABER:

Q. And do you recall who you distributed the Draft Note to?

A. Not specifically. But in this case, I would have expected it to be Stuart Clayton.

Q. Do you know who Said al-Harty is?

A. He was the -- and I am looking now at Exhibit 27. He was the reserves coordinator.

Q. Do you recall providing him with a draft?

A. Not specifically. I would expect that I had done that via E-mail, yes.

Q. Do you recall if you sent a draft to Stuart Evans?

A. Probably not. I do not recall. The reason is that I sent my Draft Note typically to one or two people in the organization that I had -- I had audited, and I would expect them to

0591

distribute it further within their organization, appropriate persons in their organization.

Q. Do you recall receiving any feedback from the people that you sent the draft to?

A. Again, not specifically. But I always got feedback, small or slightly less small. But no, I cannot recall in this instance.

Q. In this particular instance, do you recall any of the people you distributed a draft to challenging the facts and conclusions set forth in Exhibit 26?

A. Not challenging it, no. No. I do not recall.

Q. I'd like you just to take a look at the first page for a moment of Exhibit 26. And it's the paragraph that begins, "The audit found that PDO's Group share proved developed reserves are largely reasonable, but that the proved total reserves are currently overstated by some 40%."

Do you see that?

A. Yes.

0592

Q. Now, when you referred to proved total reserves, what are you referring to?

A. The sum of proved developed and proved undeveloped reserves.

Q. And do you recall, between proved developed and proved undeveloped, which made up a greater portion of the overstatement?

A. No, I do not remember that detail.

Q. Now, further in this paragraph, you write -- and it's the second to last sentence in this paragraph, "PDO have recognised this and have embarked on it on an aggressive study programme to address the maturation of these projects."

Do you know when this project or this study program commenced?

A. I wasn't there when it was commenced. But it must have been in the course of 2003.

Q. So your understanding is it was commenced prior to the time you conducted your audit?

A. Yes. There was, of course, and I

think I mentioned that earlier on, a study -- meanwhile a study was going on by staff in Rijswijk, Stein Christiansen. There was a study regarding the STOIIP and reserves review of all the PDO fields.

But that wasn't a development study. Meanwhile, PDO themselves were starting -- at that time were starting to set up a program of studies.

Q. And I am sorry. I just don't recall, when did the study that was conducted by Stein Christiansen commence?

A. As I remember it, it must have been somewhere around the middle of the year, May/June thereabouts would have been my estimate.

Q. Now, if you could just turn to page 175, number 5 on the page. The first sentence reads, "There is mis-alignment between individual field proved reserves and the corporate PDO submission."

Was this a problem that existed at PDO at the time you conducted your audit in 1999?

A. I'll have to read the entire paragraph.

Q. Okay. Please do.

(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.)

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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 whether 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)

DEPOSITION EXHIBIT
Barendregt # 1
2/19/07

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.

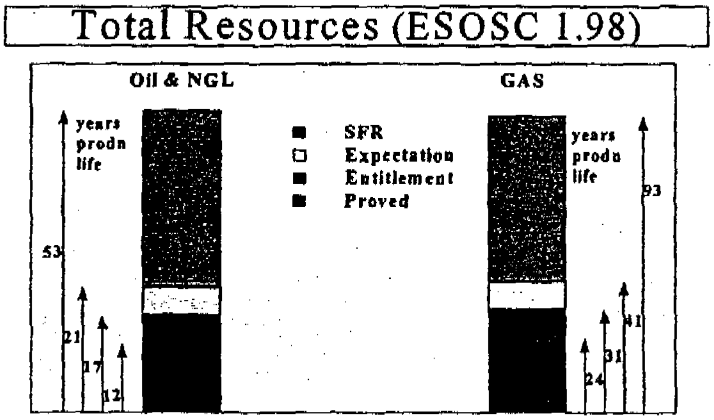
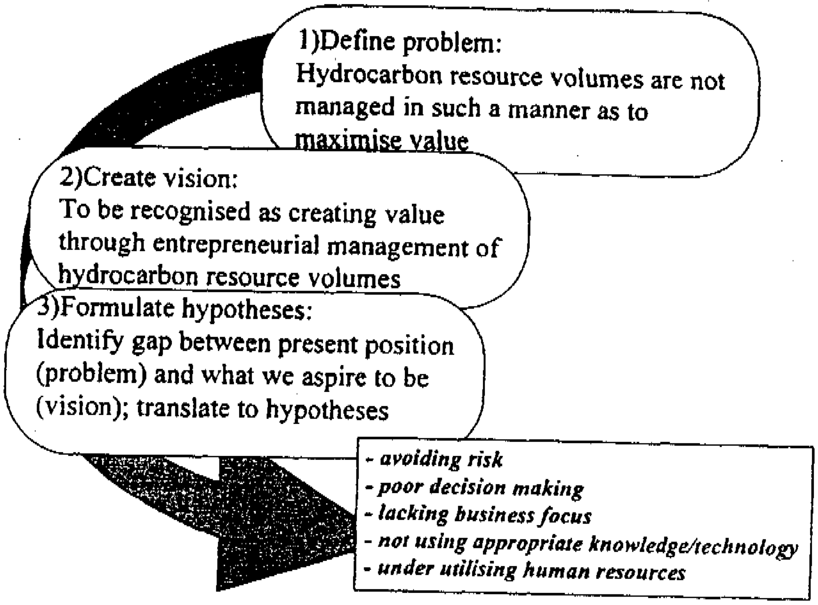


Figure 1: The Group's production future as function of resource volumes

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].



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*

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.

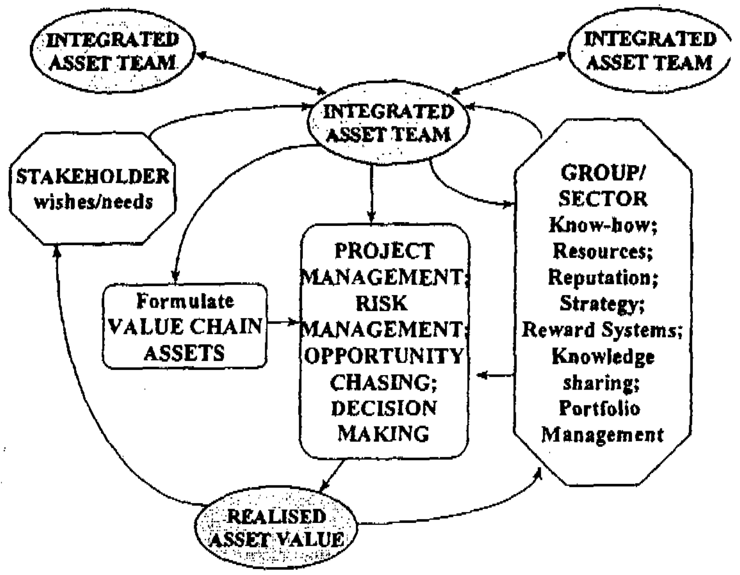


Figure 2: Entrepreneurial asset management

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.

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?)

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	Q3/98
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.	
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.

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.

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.

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

Attachment 1: The hydrocarbon resource volume value chain

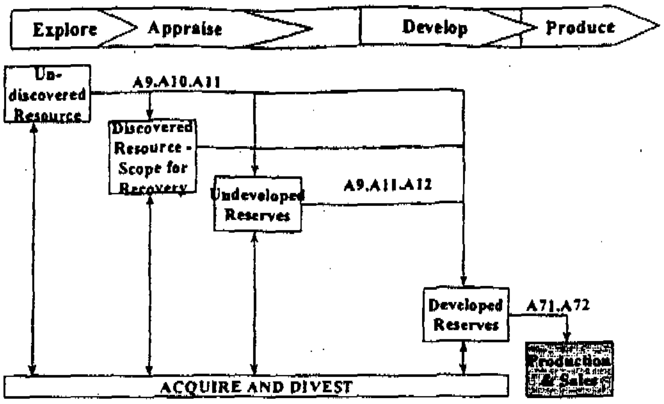


Figure 3: The resource volumes value chain as per classification in EP business model

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

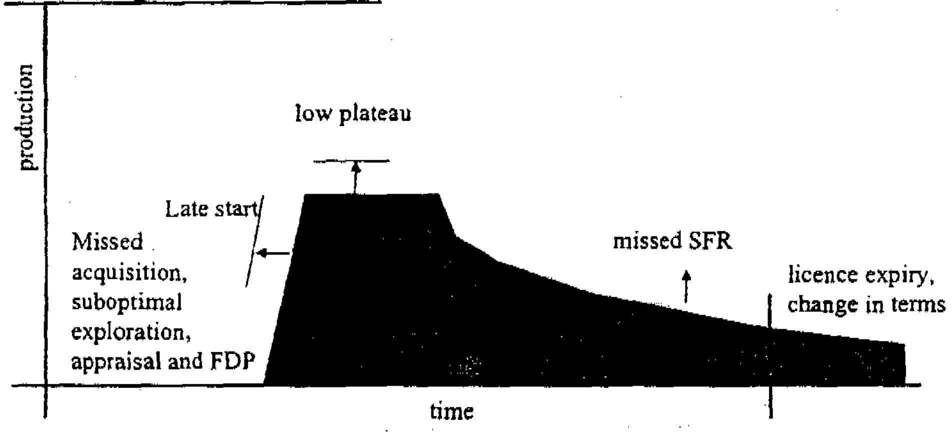


Figure 4: Value leakage during the asset life cycle an example

- 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.

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

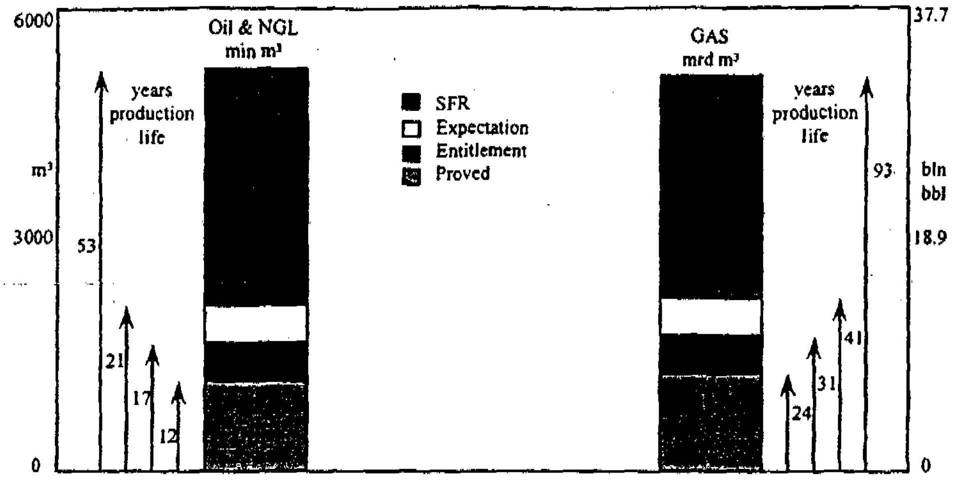
Attachment 3: Survey results (summary from Arthur Andersen report)

Hypotheses Matrix	E-mail Survey	Stakeholder Meetings	Best Practice Research
[illegible]	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
Poor Decision Making	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
Lack of Business Focus	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
[illegible]	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
[illegible]	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

External Reporting of our Resource Base

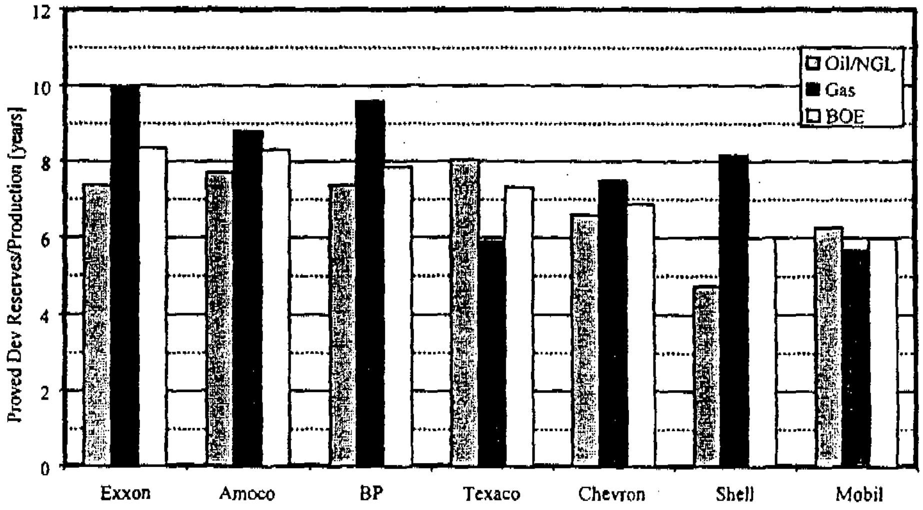
Total Resources (ESOSC 1.98)



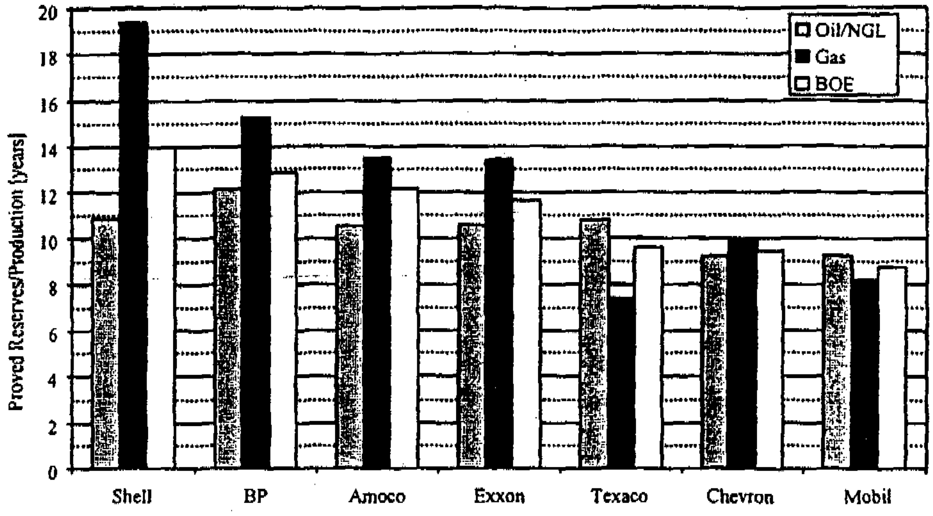
- Externally reported (Proved) reserves are only 25% of our Resource Volumes Base.
- Shell (ESOSC) stand out as having the lowest reported Proved Developed Reserves compared to other Oil Companies - 4.8 years of current production vs. approx 7 years.
- This has a significant impact on depreciation and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

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

Proved Developed Production Ratio (1.98)
(Group Companies Only)



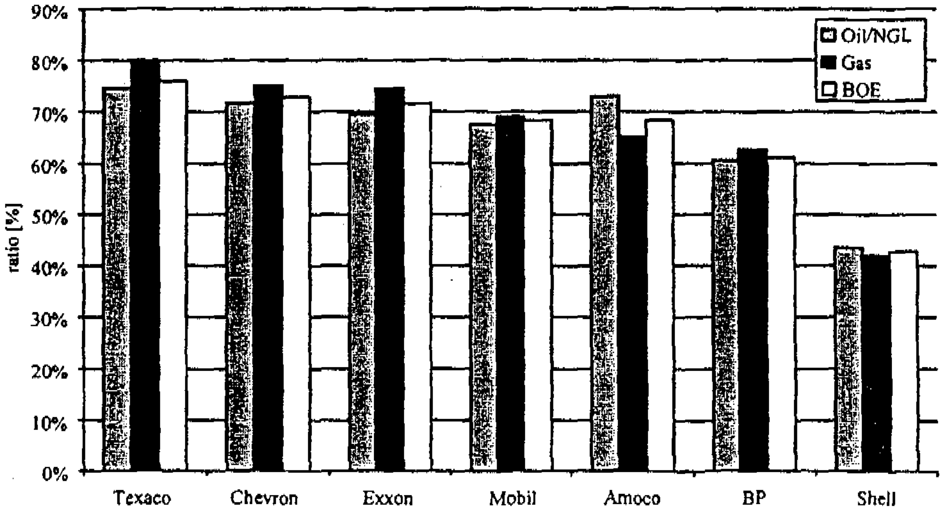
Externally Reported Reserves



Total Proved Production Ratio (1.98)
(Group Companies Only)

Benchmarking externally reported reserves

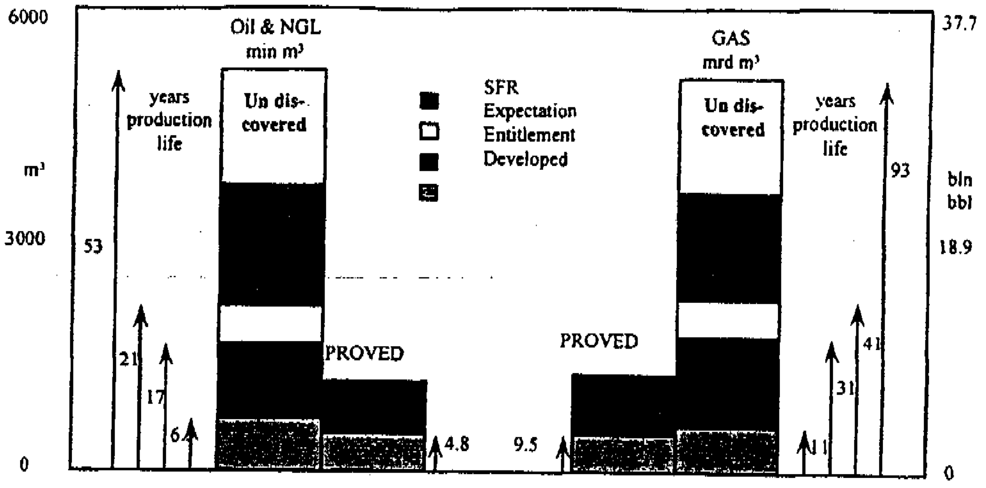
- Shell has the highest proved reserves when normalised by production. However, backing out gas, weare in line.
- Shell's proved developed oil reserves are low when compared to others. Proved developed to production is a measure of the rate at which we depreciate our assets.
- For both oil and gas, Shell's 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.



Ratio Proved Developed over Total Proved (1.98)
(Group Companies Only)

Maturing our Assets

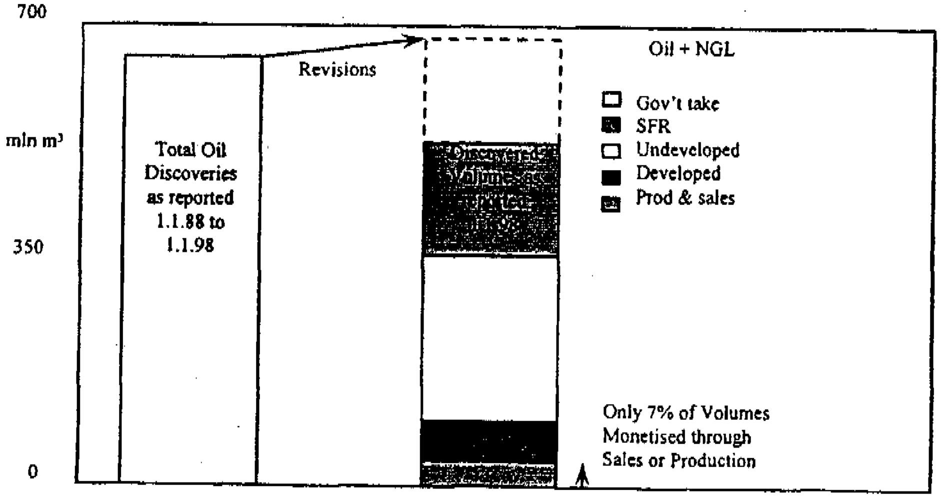
Total Resources (ESOSC 1.98)



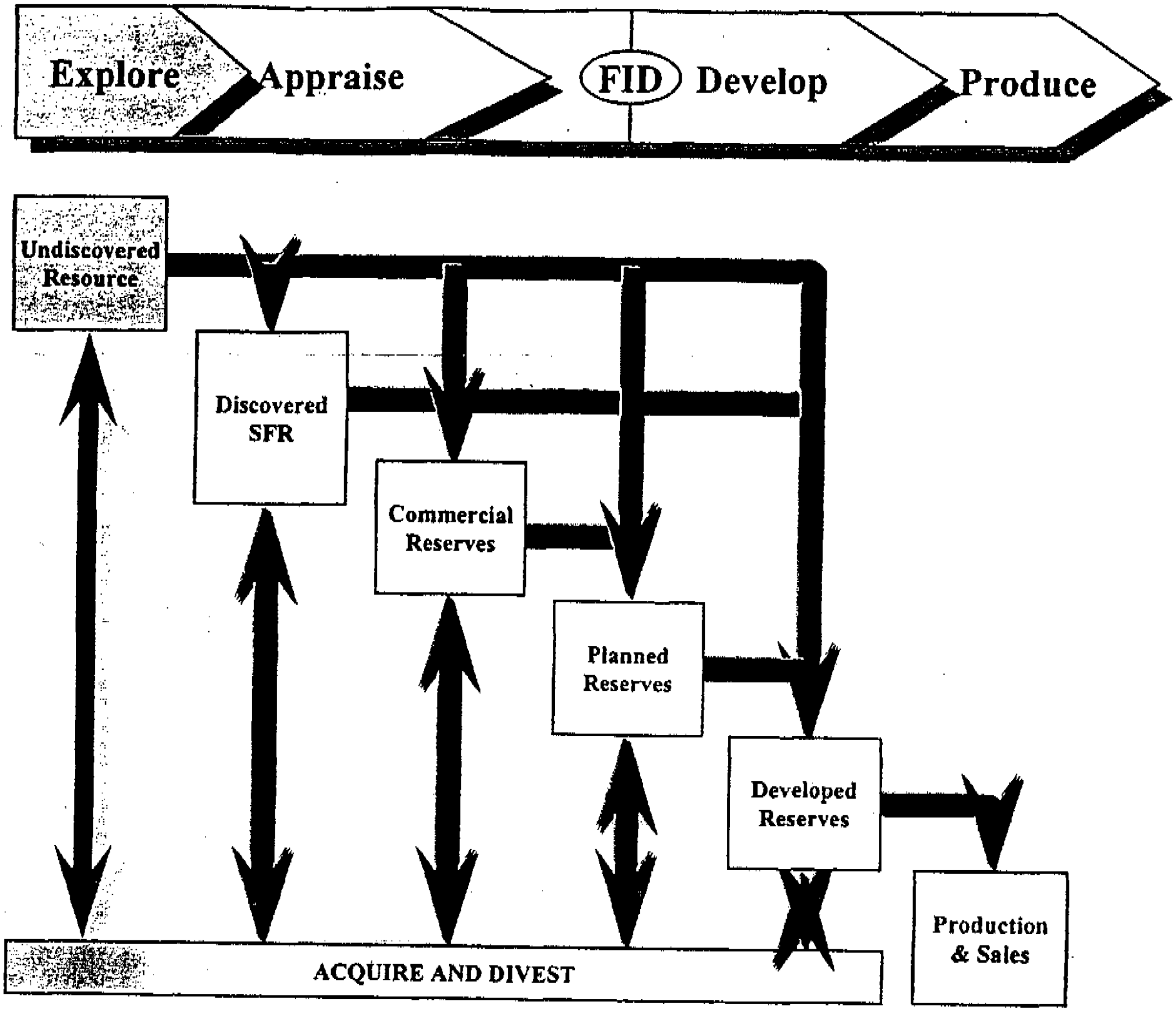
- Only 22% of the discovered resource base is developed.
- If we doubled the developed reserves, to 44%, we could support double the production without any increase in total volumes.
- Only 6% of the volumes discovered between 1988 and 1997 have been monetised - produced or sold - to date.

Are your Resource managers going after Value Realisation?

OU Resource Maturation Results 1988 to 1997



Resource Volumes Maturity Model the Value Chain



Explore
Appraise
FID
Develop
Produce

Undiscovered Resource
Discovered SFR
Commercial Reserves
Planned Reserves
Developed Reserves
Production & Sales
ACQUIRE AND DIVEST

- 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

Methodology

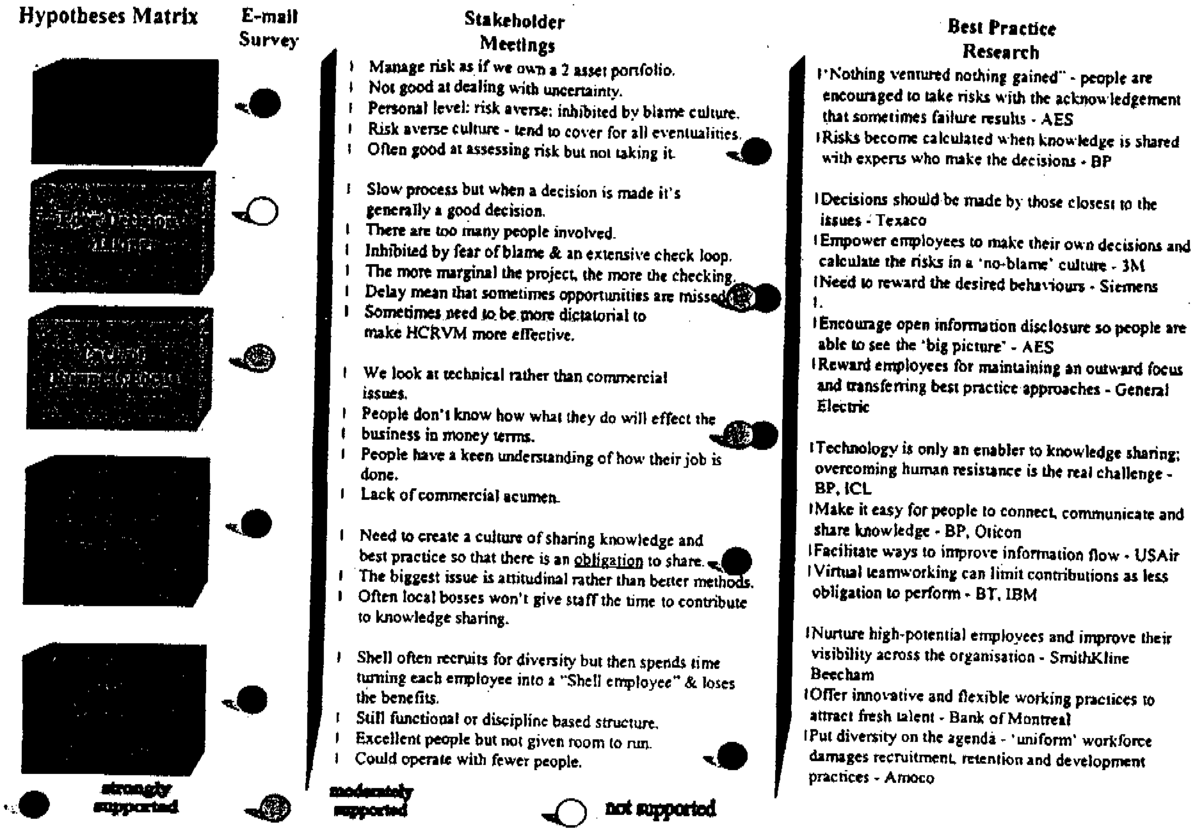
3) **Formulate hypotheses:**
Identify gap between present position (problem) and what we aspire to be (vision); translate to hypotheses

- 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

Hypothesis Testing - Results



Hypotheses Matrix	E-mail Survey	Stakeholder Meetings		Best Practice Research
[illegible]	●	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
[illegible]	○	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
[illegible]	◍	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
[illegible]	●	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
[illegible]	●	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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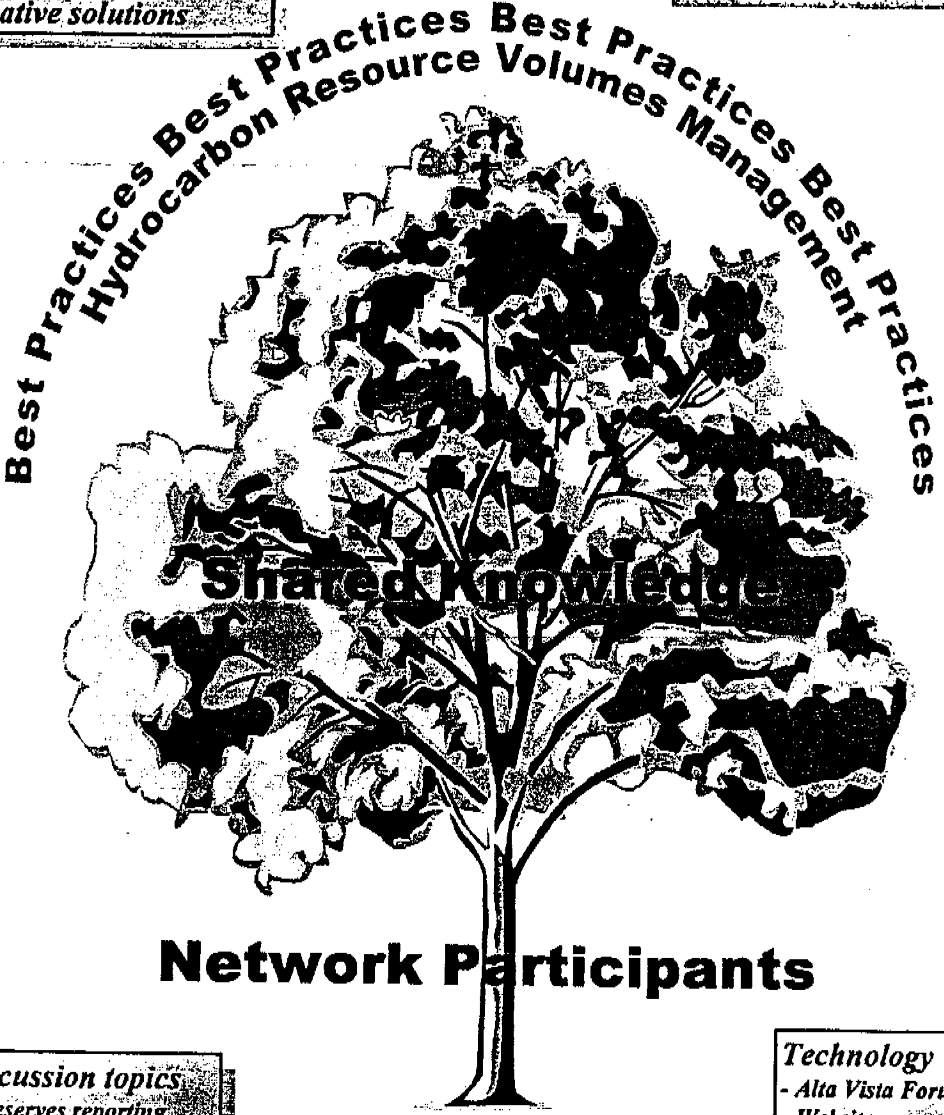
Slide 6

Knowledge Sharing in Hydrocarbons Resource Management

volumes to value

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 !

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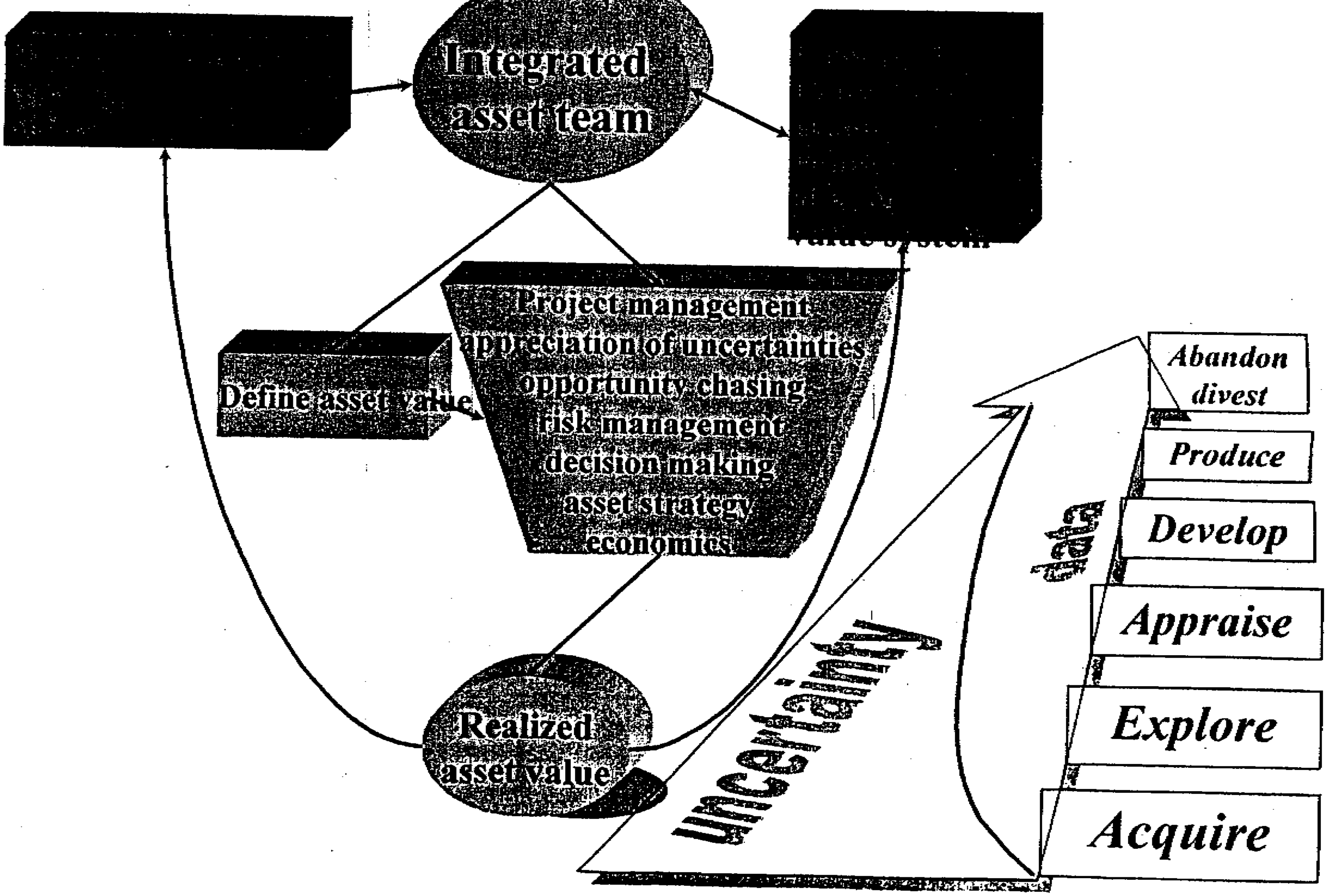
Slide 7

Volumes to Value - the Vision



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

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Slide 3

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
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		Exploration Manager, BSP
	Chris C. Kennett	Discipline Head, Reservoir Engineering, BSP
	(circulation)	SIEP – EPF: Dominique Gardy, Rahim Khan
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	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. Although the total volume of "legacy" reserves has decreased substantially in the past few years. ~~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 satisfactory.

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

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
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	Salleh-Bostaman b Zainal-Abidin	Manager, Western Business Unit, BSP
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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 related to the conservative nature of BSP's Proved reserves, in particular Proved developed reserves, many of which were not in accordance with current Group guidelines. Although decreased substantially in recent years, the continued presence of 'legacy reserves' remains an area of concern. These are undeveloped reserves which have historically been booked in reservoirs but for which no clear activies had been identified (in line with prevailing practice at the time). These reserves should be addressed at the first available opportunity, while striving to avoid major reserves swings.

The audit 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 2/19/07

Attachments 1, 2, 3, 4

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 Proved DURs 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 '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, 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

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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.

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Attachment 2.1

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 Totl 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	26.98	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	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
					121.30																
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%	89%	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	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
					23.17																
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	33.81	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	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
					217.586																

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-Att2, ResvsTotl

31-5-2002, 12:10

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SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Attachment 2.2

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						0.80	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															
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

Attachment 2.3

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

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

Proved Developed Reserves

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
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

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
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	60.00%		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	5.64	

Net Group Equity										
Proved Developed Reserves	0.00	-0.05					0.04	0.45	6.04	-0.46
Proved Total Reserves	0.00	-0.18	0.02	0.00	0.00	0.00		0.45	11.59	-0.61
10^6 m3										

2001 Submission										
Prov.Dev.Res	6.48	-0.05					0.03	0.42	6.04	6.04
Prov.Tot'l Res	12.14	-0.15	0.02					0.42	11.59	11.59
10^6 m3										

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

Conversion factors used by SIEP;	
1 slb =	0.159 m3
1 scf =	0.0283 sm3

Audit Trail: Fair match
1.1.2001 field volumes not available.

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Attachment 2.4

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

Field	Prov.Res. 1.1.2001	Revisons/ 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	27.819	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	8.217	46.65%	46.%	46.17%	0.000	4.256	1105	0.000	4.408	
Seria		0.957					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	13.832	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	

Net Group Equity										
Prov.Dev. Res	0.000	1.658					1.782	4.658	36.677	-1.217
Prov Tot'l Res	0.000	2.648	0.480	3.193	0.000	0.000		4.658	100.461	1.664
10^9 sm3										

2001 Submission										
Prov.Dev.Res	37.929	1.685					1.785	4.722	36.667	36.677
Prov.Tot'l Res	99.899	1.547	0.480	3.257				4.722	100.461	100.461
10^9 sm3										

Net Group Equity										
Prov.Dev. Res	0.000	1.721					1.906	4.974	39.218	-1.346
Prov Tot'l Res	0.000	2.785	0.501	3.441	0.000	0.000		4.974	107.351	1.754
10^9 Nm3 @ 9500 kCal/Nm3										

2001 Submission										
Prov.Dev.Res	39.374	2.240					1.923	5.110	38.427	38.427
Prov.Tot'l Res	106.230	2.730	0.517	3.509				5.110	107.876	107.876
10^9 Nm3 @ 9500 kCal/Nm3										

Conversion factors used by BSP			Conversion factors used by SIEP:		
1 m3 =	1	m3	1 stb =	0.159	m3
1 sm3 =	1	sm3	1 scf =	0.0283	sm3
1 sm3 =	0.948	Nm3	1 sm3 =	0.948	Nm3
and 1 sm3 =	1.0738097	Nm3@9500	and 1 sm3 =	0.948	Nm3 @ 9500
(i.e. avge GHV =	10761	kcal/Nm3	(if GHV =	9500	kcal/Nm3
or	10201	kcal/sm3	or	9006	kcal/sm3
or	45.05	MJ/Nm3	or	39.77	MJ/Nm3
or	42.71	MJ/sm3	or	37.71	MJ/sm3
or	1146	Btu/scf	or	1011	Btu/scf
of avg GHV of	1140	Btu/scf from above field data.			

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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Treatment Requested

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.

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

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.

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

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

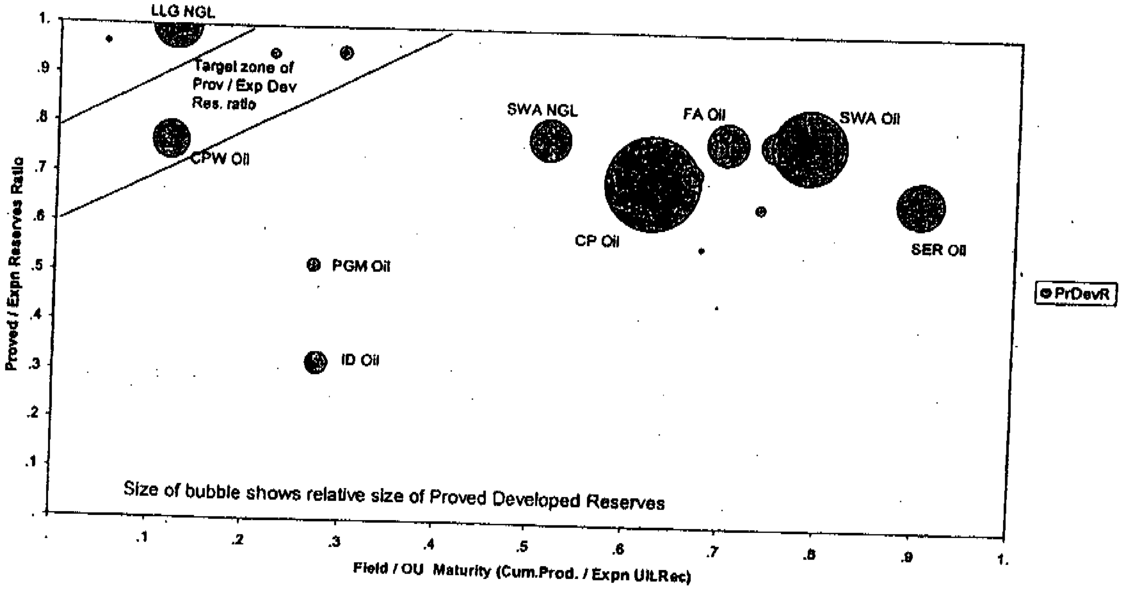
		Weight	Score (0-100%)
1	TECHNICAL MATURITY	25%	82%
2	COMMERCIAL MATURITY	16%	81%
3	REASONABLE CERTAINTY	14%	37%
4	GROUP SHARE CALCULATION	9%	100%
5	AUDIT TRAILS	16%	90%
6	CONSISTENCY WITH FINANCIAL REPORTING	11%	100%
7	OVERALL OPINION	8%	50%
	TOTAL SCORE	100%	78%

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

Attachment 4.1

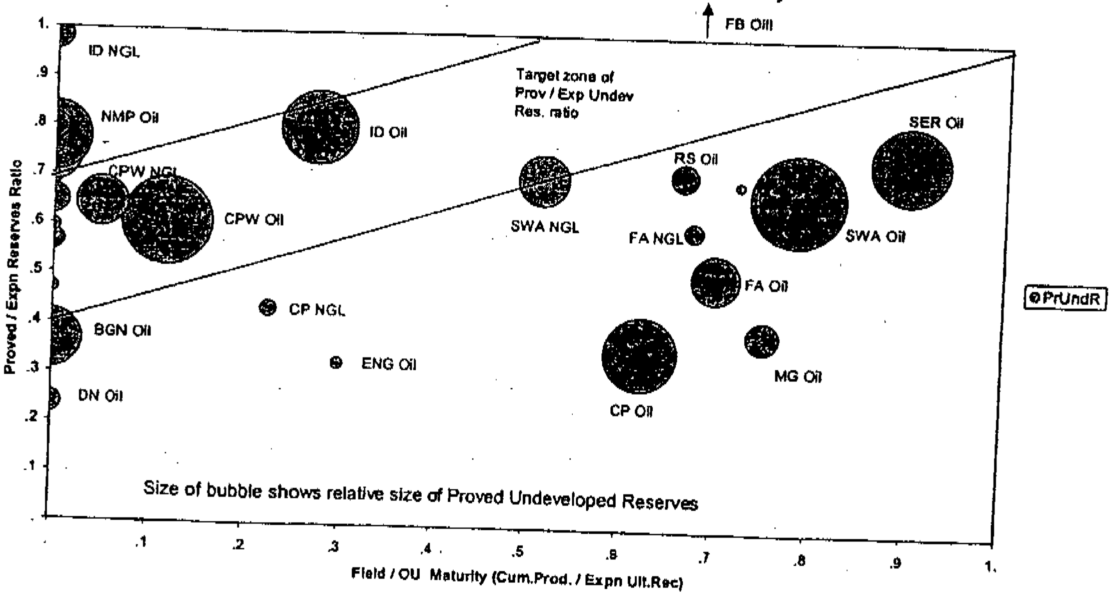
Proved / Expectation Oil+NGL Reserves versus field maturity

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



Size of bubble shows relative size of Proved Developed Reserves

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

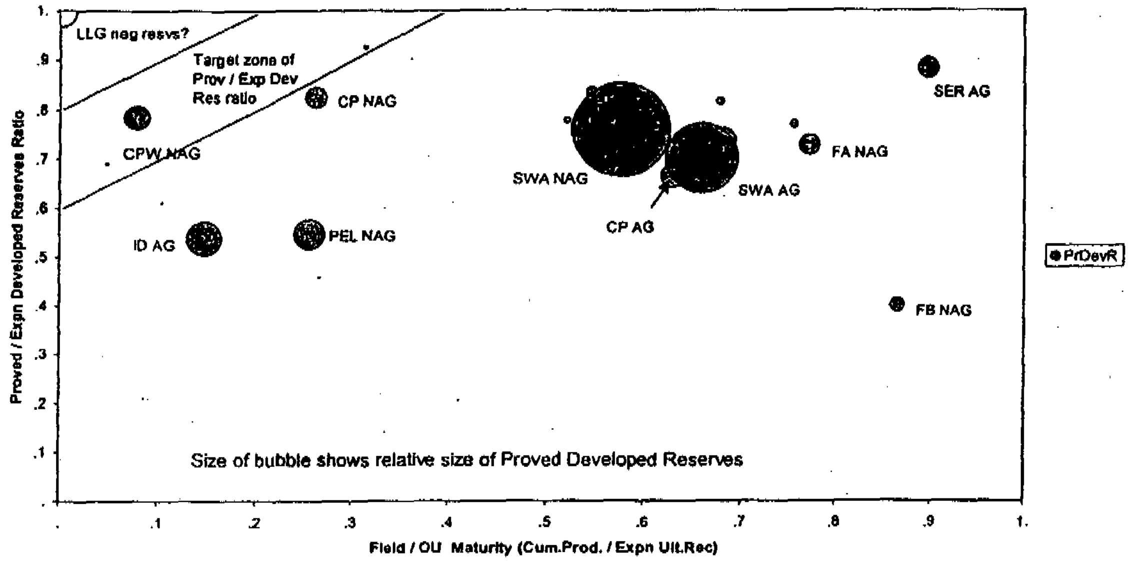


Size of bubble shows relative size of Proved Undeveloped Reserves

Attachment 4.2

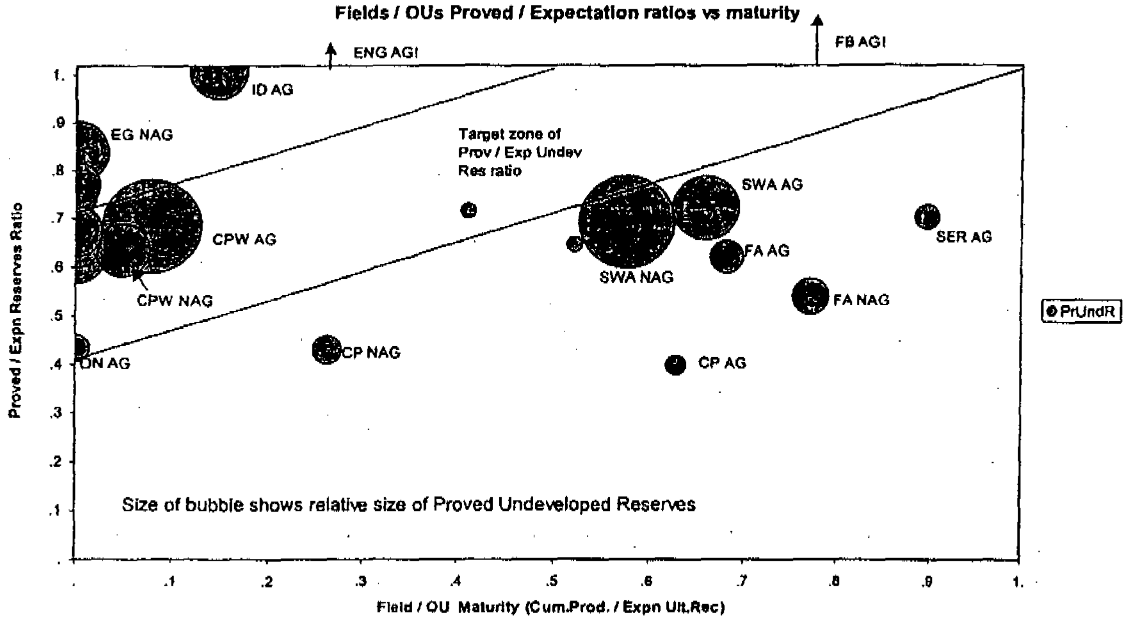
Proved / Expectation Gas Reserves versus field maturity

1.1.2002 BSP DEVELOPED GAS RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



Size of bubble shows relative size of Proved Developed Reserves

1.1.2002 BSP UNDEVELOPED GAS RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



Size of bubble shows relative size of Proved Undeveloped Reserves

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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**

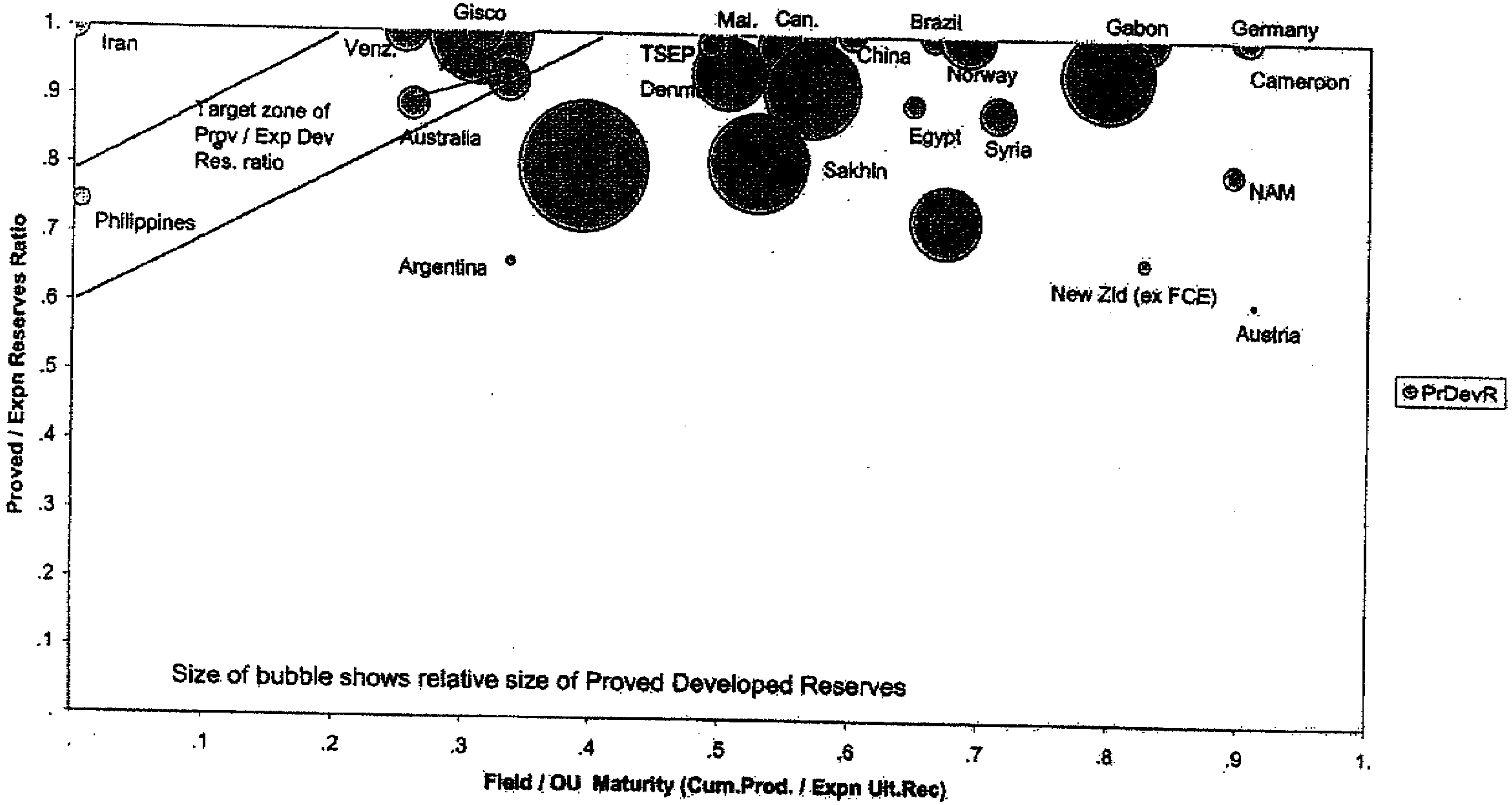
- **Established method of determining Proved developed reserves from Expectation volumes (P/E ~ 75%) is arbitrary, too conservative and not in line with Group guidelines**
  - **Need to move to a 'growth to Expectation' with growing field maturity**
  - **Target should be Proved ~ 90% of Expectation 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) not 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



Size of bubble shows relative size of Proved Developed Reserves

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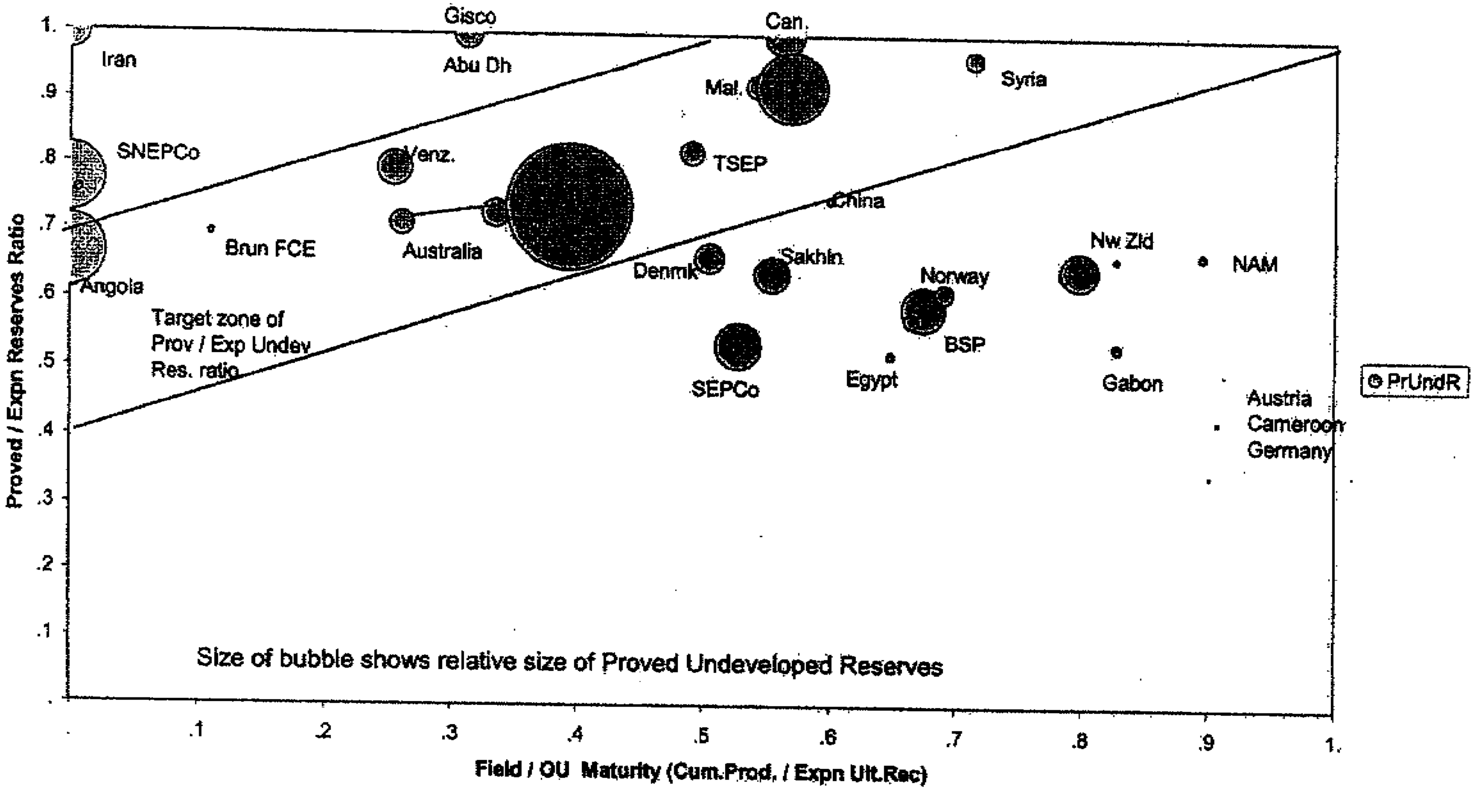
SEC Reserves Audit BSP, 27 Apr – 3 May 2002

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



Size of bubble shows relative size of Proved Undeveloped Reserves

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 2/28/07

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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SIEP 99-1100

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

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TABLE OF CONTENTS

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1. INTRODUCTION

Petroleum resources represent a significant part of the company's upstream assets and are the foundation of most of its current and future upstream activities. To aid in understanding, planning, and decision making about these petroleum resources, resource volumes are classified according to the maturity or status of its associated development project. The current status and changes in petroleum resources, and specifically the commercially recoverable portion (reserves), are a significant concern to management. The future of the company depends on our effectiveness in maturing resources to the point where maximum economic value is realised.

For the Shell Group as a whole, petroleum resources are reported annually to senior management and are essential information for the strategic planning process of the upstream sector. The current status and changes to the proved and proved developed reserves are also reported annually to the Securities and Exchange Commission (SEC).

Therefore the importance of these figures cannot be overemphasised. Reliability, uniformity, consistency, transparency and auditability are essential elements in the collation of petroleum resource reports by Operating Units (OUs) and New Venture Operations (NVOs). In 1998, the guidelines have been re-written, building on the foundation established by previous versions (References 1 to 5). These guidelines serve as a reference for OUs and NVOs and as the standard against which audits will be conducted.

The recommendations of the Hydrocarbon Resource Volume Value Creation Team have been incorporated in this update of the guidelines. The primary changes are increased attention to realise maximum value from volumes and the modification of the definition for proved developed reserves to be more consistent with industry practice. The value realisation theme is reflected in emphasising a) that reserves are project based and b) the importance of maturing resource volumes to developed reserves and hence sales. No major changes in the classification scheme are introduced.

This document contains only guidelines. The information on internal and external submission requirements and quantification methods that was contained in previous versions of this document will be included in other communications. Submission requirements will be communicated annually in a letter from EP Planning. Methods will be developed through the Hydrocarbon Resource Volume Common Interest Network (Reference 7).

The present, 1999 version contains a small number of corrections/modifications and clarifications compared to the 1998 edition, which are indicated by a line in the margin.

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2. PETROLEUM RESOURCES

2.1 Definition

A petroleum resource is any accumulation of hydrocarbons that is known or anticipated t exist in a sub-surface rock formation, located in the company's current exploration an production acreage. If the petroleum resource extends beyond the company's licence area th resource volumes must be divided according to the granted licence boundaries, to tak proper account of Group share.

Resource volumes are reported as the quantities of sales product for crude oil, natural ga and natural gas liquids. The corresponding quantities of field recovery should be maintaine by the OU (See Appendix 6). The reporting of petroleum resource volumes should furthe indicate the petroleum type, the reporting units and conditions, and the Group share.

Resource volumes are tied to the project that develops them and are generally reported b field. The term **reserves** is used for resource volumes associated with a project that technically and commercially mature. Resource volumes that do not meet these criteria ai called **scope for recovery** (SFR). **Proved reserves** are the portion of reserves that reasonably certain to be produced. These distinctions will be discussed in Sections 3 and 4.

2.2 Group Share

Only the Group share of resource volumes is reported. The Group share is determined b agreements with the resource holders. Resource volumes can be distinguished according t three different types of agreement, which are discussed below.

Equity

Equity resources are the Group share of resources in Concessions. Concession agreemen lay down the general terms and conditions of operation. These agreements with governmen define the applicable tax rules, the Group share of resources in Concessions and the duratic of the production licence.

Entitlement

Entitlement resources are the Group share of production in acreage governed by Production Sharing Contract (PSC). The Group share of production is the Group interest the sum of cost oil plus excess cost oil plus profit oil, in accordance with the PSC terms.

Innovative Production Contracts

In recent years, a number of resource holding countries have introduced innovati production contracts in order to attract investment by foreign oil companies while preservir the principle of national resource ownership. These agreements typically provide for tl contractor to recover costs and profits from hydrocarbon revenues while holding no title t or entitlement to receive petroleum resources.

US Financial Accounting Standards Board (FASB) regulations have lagged behind the developments and provide little explicit guidance on reserves disclosure when the risks ar rewards of ownership are carried without legal title to mineral rights.

However, volumes covered by such innovative contracts should be included in extern reports in an informative way to be consistent with the spirit of the SEC regulations. T volumes from which economic benefit is derived should be reported if all three of t following conditions are met:

1. The OU participates in the production operations as either operator or in partnersh with the operator, and so bears a share of the costs and risks of the producti operations.
2. The OU derives future economic value that is directly related to the volume hydrocarbons produced. For example, a fee expressed as a fixed or indexed amount p barrel of production would constitute a derivation of value from the produc hydrocarbons, but an operating fee that is largely independent of production would n The actual source of revenues used to pay the OU is not crucial to this point: F example, if the remuneration is determined by a produced gas volume but paid from revenues, the economic value to the OU is in effect derived from the produced gas, a this volume should be reported.

3. The OU is exposed to the normal risks and rewards associated with ownership of mineral rights, including the downside and upside from changes in the value of future production volumes. These include the risk that costs may not be recovered, due to either uncertainty as to the presence or magnitude of hydrocarbon volumes or to movements in petroleum prices.

OUs and NVOs working under such contracts should complete the standard resource volume submission for the Group/Company interest in these volumes, noting the nature of the interest. Reported volumes should be in line with the reporting of traditional reserves with regard to royalties and should therefore reflect the volumes from which pre-tax cash flow is derived. As elsewhere, cash royalties are regarded as a production cost.

If an OU has interests in several licence areas subject to different contract types (e.g. reward generating and PSC), a separate submission must be made with respect to the interest in the reward generating contract area.

When an OU is participating in a venture which grants neither title to, nor an entitlement to receive petroleum, and which does not satisfy the three criteria above the OU should not report reserves or production volumes. For example this might occur if the recovery of costs is guaranteed against adverse price movements or a shortfall in recovered volumes

Licence or Contract Extensions

For internal reporting purposes, Group share of the expectation estimate of reserves and scope for recovery are recorded for the total producing life, i.e. including the period beyond the relinquishment date, but not covered by a right to extend or by a letter of assurance (see below). The currently existing licence terms or other anticipated terms should be assumed for this extrapolation. In addition to full life cycle volumes, resource volumes limited to the current licence only are recorded for total expectation reserves, developed expectation reserves and total commercial scope for recovery.

For external reporting, Group share of reserves (proved, proved developed) is limited to production within the existing licence or contract period. However, production beyond the licence or contract period can be included if there is a legal right to extend a production licence or PSC, or if the government has formally indicated that it will favour substantiated requests for extensions in the future (letter of assurance). Then volumes recoverable during the extension period are included in the Group share, assuming currently existing or other anticipated terms. Such considerations should be documented in the annual submission.

In some countries, the issue or duration of production licences for gas fields is effectively coupled to the conclusion of gas sales contracts. In other areas, a realistic target date for initiation must be set for projects that are not yet firmly planned so that the production forecast and other screening assumptions can be used to estimate the volume produced before licence or contract expiry.

Long Term Supply Agreements

FASB regulations (69 par. 13) require that quantities of oil or gas subject to purchase under long term supply, purchase or similar agreements should be reported separately, if the OU participates in the operation of the properties in which the oil or gas is located or otherwise serves as the "producer" of those reserves, as opposed, for example, to being an independent purchaser, broker, dealer, or importer.

The "supply" agreement should be a consequence of the OU acting as producer. This would not be the case if, for example, others had similar agreements but did not participate in the production operations.

These net quantities, as well as the net quantities received under the agreement during the year, should be included in the end year estimate of reserve volumes for external disclosure form.

Royalty Royalty is a payment made to the host government for the production of mineral resources. It is usually calculated as a percentage of revenues (payable in cash) or production (payabl in kind).

Where in practice royalty obligations are met in kind (i.e. by delivering oil instead of cash) the Group share of production and reserves should be reported excluding these volumes.

Where royalty is payable in cash or is in principle payable in kind but the government ha formally elected to receive, or customarily receives, payment in cash, Group share o production and reserves should be reported without deduction of equivalent royalty volumes.

Fees in kind Third Parties may in some cases pay Fees in Kind or Tariff in Kind (TIK) for the use o infrastructure (e.g. pipeline tariff, processing fee). Such volumes received by the compan do not constitute a Group share in resources and should not be included in reported volumes Condensate volumes recovered from a pipeline system related to transportation of Thir Party gas volumes and sold by the company are equivalent to fees in kind received. All fee in kind received should be included as a purchased volume in the company accounts.

Where a company pays fees in kind (from its own fields/resources) to a Third Party, these d constitute a Group share in resources and should be included in the reported volumes Annual volumes produced and used as fees in kind should be included in sales volumes, wit associated revenues (at an agreed or fair market value) equivalent to booking of the incurre operating cost.

Open Acreage Group share of volumes is non-existent in open acreage and acreage for possible acquisitio or farm-in.

Under/Over Lift Group share should also allow for any historic under or over lift by partners or government.

Committed Gas Reserves Total volumes of expectation gas reserves within licence, which have been sold (committed under long and short term contractual agreements. In countries with a mature/deregulate gas market all gas reserves, which have a near certainty of market take-up can be classifie as 'committed'.

Committable Gas Reserves Volumes of gas reserves, which have not been sold, but could be sold (committable) unde contractual agreements. The sum of committed and committable gas reserves should equa expectation gas reserves within licence. Gas resource volumes, which are classified as scop for recovery due to lack market availability, should not be included.

Gas Re-injection Gas volumes re-injected in a reservoir, for pressure maintenance, gas conservatio underground storage (incl. cushion gas), or other reasons, remain part of a company' resource base and should be accounted for as such. These gas volumes should be classifie and reported as reserves or SFR, conform any other gas resource based on projec assumptions for re-development (taking into account expected re-saturation losses).

Gas volumes re-injected in an Under Ground Storage (UGS) project on behalf of a Thir Party (including any gas volumes previously sold by the company to this party) do n constitute a Group share in resources and should not be included in reported volumes.

Oil Sands Reporting of petroleum volumes (heavy oil, bitumen, syncrude, gas etc) recovered fro "oil sands" (tar sand, oil shales, coals etc.) as part of hydrocarbon resources (reserves c SFR) is principally governed by the method of recovery of such volumes. Volumes produce through wells, generally from thermal methods are reported as part of the hydrocarbo resource base. Volumes recovered though mining and subsequently recovered from th mined product are not part of the hydrocarbon resource base and should be reporte separately (see also Appendix 3 C4).

3. RESOURCE VOLUME CLASSIFICATION FOR INTERNAL REPORTING

3.1 Classification Scheme

The internal classification scheme shown in Figure 1 is intended to provide a consistent link between a field's resource volumes and the EP business model, identifying separately those resources that are the focus of the various stages in the development life cycle.

Cumulative Production	
Reserves:	Developed Reserves Undeveloped Reserves
Discovered Scope for Recovery:	Commercial Scope for Recovery by Proved Techniques Commercial Scope for Recovery by Unproved Techniques Non-Commercial Scope for Recovery
Undiscovered Scope for Recovery	Undiscovered Commercial Scope for Recovery
Discovered Initial In Place	

Figure 1: Resource Categories for Internal Reporting

A summary of the definitions for these categories is provided in Appendix 1. The cascade model (Figure 2) illustrates the migration of volumes between resource categories during the development life cycle.

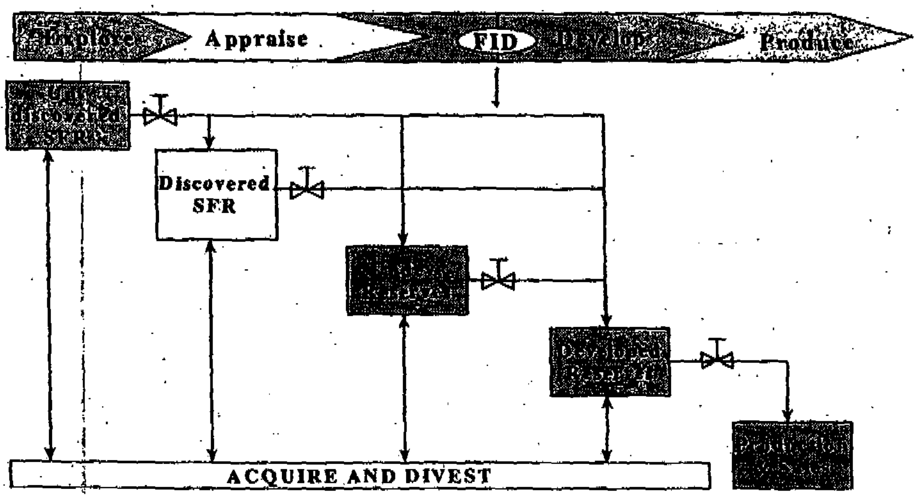

Figure 2: Cascade Model

A specific example of the migration of resource volumes between categories during a field's life cycle is shown in Appendix 2.

3.2 Value Realisation

The most important objective of resource volume management is the progression of th volumes to the point where maximum value is realised. The main purpose of the interna classification scheme tied to the development life cycle is to enable understanding of th potential value and the actions needed to mature volumes. In order to achieve busines growth and reserves replacement objectives, it is essential that OUs and NVOs have efficien systems to move volumes through the value chain from scope for recovery to production an sales as shown in the cascade model.

OUs and NVOs internal reserve management systems should;

a) set targets and monitor actual performance in maturing volumes towards valu realisation,

b) fully inventorise and have maturation plans for Scope for Recovery opportunities,

c) review ultimate recovery targets for existing fields and identify what activity - apprais study, new technology development, commercial agreement, etc. - is required to reac these targets,

d) and have Key Performance Indicators (KPI's) to measure performance (e.g. reserve replacement ratio, scope for recovery maturation ratio, time between discovery and fir production).

3.3 Technical and Commercial Maturity

The classification scheme uses a project's technical and commercial maturity as the primar criteria to distinguish between reserves and scope for recovery (SFR). Resource volumes ca be classified as reserves only if the associated project that will result in production of tho volumes is considered to be technically and commercially mature. If it cannot, the resour volumes should be classified as SFR. SFR needs an activity (e.g. exploration appraisal, fie trial, gas market development, etc) to achieve technical maturity and commercial viabili Secondary technical and commercial distinctions (between proved and unproved techniqu SFR and between commercial and non-commercial SFR) further identify resource volum at various stages in the life cycle.

Project Basis Technical and commercial maturity reflects the status of remaining uncertainties in t assessment of the optimal development project and its associated recovery. A project is a proposed or notional modification of the wells, the production facilities and/or t production policy, aimed at changing the company's sales product forecast. It can also be modification of the company's share in a venture (purchase/ sales-in-place, unitisation, new terms). The generic term 'project' is also used to describe a group of (sometim alternative) projects, each with a certain chance of realisation, depending on the results further data gathering. In that case, the project NPV is replaced by the Expected Moneta Value (or EMV, see Appendix 6).

Technically Mature For a project to be **technically mature**, information on the resource volume, including level of uncertainty, is such that an optimal project can be defined with an auditable proj development plan, based on a resource and development scenario description, w drilling/engineering cost estimates, a production forecast and economics. The plan may notional or it may be an analogy of other projects based on similar resources. However, th should be a reasonable expectation that a firm development plan can be matured with tin Projects do not have to have a completed development plan.

Commercially Mature A **commercially mature** project is commercially viable over a sufficiently large portion the range of possible scenarios that reflect the remaining resource uncertainties as well as remaining commercial uncertainties, including market availability. The definition of w constitutes "a sufficiently large portion" may vary from case to case and could for exam require the project NPV for the low reserves scenario to be positive for appropri commercial criteria. It is also likely to include an assessment of the capital exposure in c of project failure due to adverse resource realisations. The selected range of scenarios sho be documented and auditable.

Commercially Viable A scenario is **commercially viable** if the NPV is expected to be positive under the applicable (or expected) terms and conditions for the acreage and for the current advised Group reference criteria for commerciality (Reference 9).

Economically Viable A project is **economically viable** if the expected NPV under the applicable terms and conditions for the acreage exceeds the separately advised Group project screening criteria or if the project has already been approved by shareholders. Projects generally have to demonstrate economic viability in order to obtain investment approval. However, economic viability or formal project approval is not required for a project to be considered commercially mature. Reserves may be booked before project approval is sought.

3.4 Uncertainty Estimates

Uncertainty in resource volumes arises from using data and prediction techniques with varying degrees of uncertainty. The uncertainty in resource volume estimates can be assessed and represented using a variety of methods (see Reference 7). Probabilistic methods determine a range of estimates and the associated probability that they will occur. Scenario deterministic methods determine best estimates for specific cases such as a low side case or a base case.

The terms low, expectation or high estimates are used in this document to simplify the discussion and to define reported volumes where consistency is required. When using a probabilistic methodology, low, expectation and high estimates are defined as the P85, Mean and P15 values from the probability distribution function (see Appendix 7 for definitions). When using a scenario deterministic methodology, low, expectation and high estimates are the low side case, base case and high side cases, respectively.

Only the expectation estimate for each of the resource categories is required for Internal reporting. The low estimate is usually used to define externally reported proved reserves. It is up to the OU to decide whether there is a need to determine other estimates.

Uncertainty Reduction with Performance The uncertainty range of ultimate recovery generally decreases as a field is developed and produced. However, the uncertainty range as a percentage of remaining reserves may not always decrease with time. **As a field matures, initial in place volumes and recovery should shift from a volumetric to a performance-based estimate, incorporating the additional production data to reduce the uncertainty range.** Once the reservoir performance has been established with reasonable certainty, a fairly small difference between low, expectation and high estimates would be expected. Definition of the low and high estimates may no longer be of value in mature fields with relatively little uncertainty and use of a single expectation estimate should be considered in this situation.

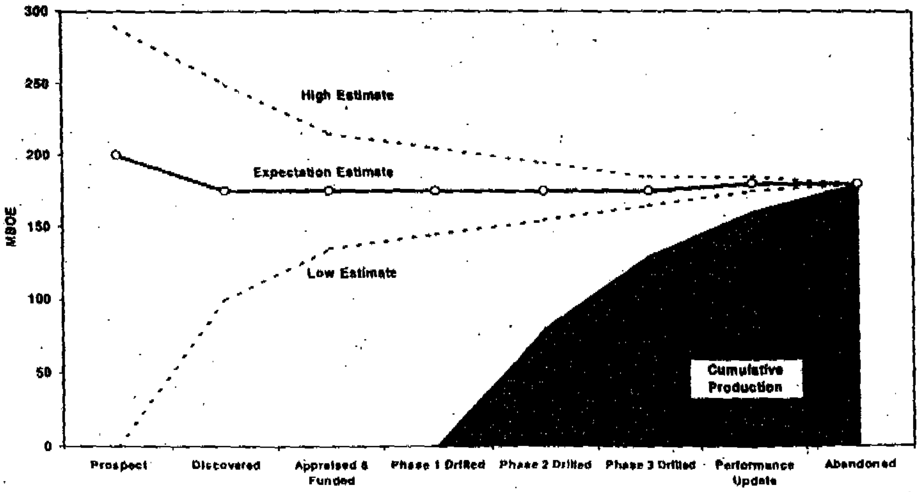

Figure 3: Uncertainty Reduction during the Field Life Cycle

Figure 3 illustrates the narrowing of the uncertainty with field appraisal and development This is a near ideal example where the expectation remains constant for most of the lif cycle. This example is also used in Appendix 2 to show the migration of resources betwee internal and external reporting categories during the field life cycle.

The reduction in uncertainty based on performance should be adequately reflected in th annual reserve and scope for recovery estimates for the field.

Addition of Resource Volumes

Resource volumes are added together at various levels during the resource assessment an reporting process. Addition of reserves at or above the level used for depreciatio calculations must be arithmetical for consistency with financial accounting. Below this level i.e. normally below the field level, addition should be done taking into account th dependency between the volumes to truly reflect the recoverable volumes associated with project. Arithmetical addition is appropriate for dependent volumes, but usually overstate the uncertainty range for the sum of partially independent volumes. Probabilistic additio should be used for partially independent volumes when the difference with arithmeti addition is significant.

North Rankin
depreciated
separately
Reserves only

Below are two examples where the method of addition is important to handle properly.

LNG phase
depreciated on total
reserves ... \
Think probabilistic
[illegible]

1) Field A is comprised of separate layers and the properties of these layers are independe of each other. In other words, a low result in one layer would not increase or decrea the chance of a low result in the other layers. Low, expectation and high estimates a calculated for each layer separately. Probabilistic addition should be used to account f the reduced uncertainty of adding together independent volumes. Arithmetical additio of these estimates would understate the low estimate and overstate the high estimate the total field.

2) A project develops three independent fields as sub-sea satellites connected to o platform. In this case, the investment in surface facilities may be totalled f depreciation[1] and consequently the reserves estimates should relate to the combin fields. Probabilistic addition should be used to calculate the total reserves associat with the platform.

P 5
NR 4
On 5
G 3

Careful consideration should be given to Commercial SFR by proved techniques whe eventual development is only incremental to an existing or planned development. The volumes may have a probability of success (POS) less than one, but with probabilist addition will contribute at all levels - low, expectation and high - of reserves estimate Examples of where this would apply are:

1) A fault block that is not yet tested and may be reasonably interpreted as an extension the delineated area of the field. The project itself is technically and commercial mature. The untested block would be developed through existing field facilities witho significant additional investment other than additional wells, which is recognised in t project scope. The uncertainty is geological and volumes are classed as reserves.

2) A phased development where there is uncertainty in the scope (e.g. number of wells) a project due to geological uncertainty. However, the nature of the project remai essentially unchanged and additional wells could be accommodated within the flexibil of the field facilities design, then the whole range of recoverable volumes should considered in deriving reserves. A scenario tree can be developed to represent the ran of outcomes, both in recovered volumes and optimised number of wells, dependent geological uncertainty. The uncertainty is resolved, with time, through planned d gathering eventually determining the number of wells. Hence the volumes can regarded as technically mature. If one branch of the scenario tree is not economic, th the volumes associated with that arm do not contribute to reserves.

If probabilistic addition is used, ensure the methodology and parameters used documented in the audit trail.

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[1] Group Accounts should be consulted when considering combining surface facilities for different fields depreciation purposes.

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3.5 Cumulative Production

The resource volume category "Cumulative Production" pertains to summation of sales quantities of production volumes up to the date of reporting. Consistency is required between sales and field quantities. Production Operations and Finance functions must reconcile their figures prior to any submission (annual oil/NGL production [0933] and gas sales [0323] as reported in CERES upstream sector must equal the volumes reported in the annual resource statement using the appropriate unit conversion factors).

3.6 Reserves

Reserves are the sales quantities anticipated to be produced and monetised from a discovered field associated with a project that is **technically and commercially mature** (see definition in Section 3.3). Petroleum volumes have been demonstrated to be producible through wells from the field. A market must reasonably be expected to be available.

The production forecast, and therefore the reserves, must be cut off at the point where cash generation becomes negative, i.e. when operating costs (with appropriate treatment of abandonment costs) exceeds sales revenues after royalties. If the remaining tail production is significant, it may be booked as Non-Commercial SFR (see below).

The production forecasts must be adjusted for any volumes flared/vented and 'own use' (fuel for production facilities, compressors etc) in the upstream operations prior to transfer of the volumes to the buyer (Third Party or 'Downstream').

The restriction of marketability is relevant to gas reserves and for the classification of those NGL products that are subject to go-ahead of a non-associated gas project. Apart from an assessment of the local market and identification of the type of export project (e.g. pipeline, LNG, methanol), this restriction implies earmarking the gas resources suitable to feed these outlets. The restriction applies to all confidence levels (low, expectation and high estimates) of reserves.

To minimise fluctuations over time, OUs and NVOs should exert caution in transferring volumes between the reserves and SFR categories. Demonstrable technical and commercial maturity will be required when new fields and reservoirs are added to the reserves base. The same requirement applies in principle when undeveloped reserves are retained. To retain developed reserves, their production should have a positive cash generation after subtraction of operating costs, tax and royalties.

Existing volumes classified as reserves, but which are no longer commercially mature, may be retained as reserves only in cases when there is an overriding strategic interest, or where a current small operating loss is expected to be reversed in the short term. In both cases support from shareholders must be obtained.

Developed Reserves

Developed reserves are the portion of reserves that is producible through currently existing completions, with installed facilities for treatment, compression, transportation and delivery, using existing operating methods. Outstanding project activities, such as initial completions, recompletions, hook-up and modifications to existing facilities, can be considered as existing or installed if the outstanding capital investment is minor (<10%) compared to the total project cost and if budget approval has been obtained. Volumes behind pipe are considered developed if additional activities (e.g. 'lower' zone abandonment, perforating, stimulating) do not require a full well entry/re-completion and if the future investment (normally opex) is minor (<10%) compared to a new well.

1.5 b

← [illegible]

Developed reserves are estimated by forecasting the production that will be contributed by the existing wells through the currently installed facilities assuming no future development activity. Future wells or facilities may be planned that add reserves and/or accelerate the reserves that would be produced by the existing investments. However, the portion of reserves expected to be accelerated by future investments are classified as developed with the existing investments and not after the future investments. If future investment accelerates production such that additional reserves are recovered within time limits (e.g. sales contract periods, field life), the additional reserves are classified as developed only after these investments are made.

Undeveloped Reserves

Undeveloped reserves are the complement of developed reserves in the total reserves requiring capital investment in new wells and/or production facilities in order to b produced.

For new development projects, developing additional reserves may defer field / platfor abandonment and may thereby also increase the reserves producible from existin completions. Such gains should be included in the economic evaluation of the ne development project and can only be classified as reserves if the project meets the technica and commercial criteria.

3.7 Scope for Recovery

Scope for Recovery is the recovery estimate of any notional project for whic implementation cannot yet be shown with sufficient confidence to be technically sound o commercially viable. However, there must be an expectation that this project could matur based on reasonable assumptions about the success of additional data gathering, a maturin technology from current research, relaxation in the market constraints and/or the terms an conditions for implementing such a project.

The economic evaluation should include any future pre-investment costs required to reduc technical uncertainty.

In the case of immature projects, the associated scope for recovery may be reported as single estimate for the undiscounted average recoveries in the case of success (mean succes volume, MSV) together with a probability of success (POS). For aggregation purposes th risked expectation volumes are used (POS*MSV).

Commercial SFR

SFR which is expected to be commercially viable should be reported in one of the followin three Commercial SFR categories.

Commercial SFR by Proved Techniques

SFR by proved techniques is the volume estimated to be recoverable from discovere resources, by a project utilising a recovery process or technique which has bee demonstrated to be technically feasible in the area or in the field. Implementation is expecte to be commercially viable, but a large range of technical uncertainty precludes t formulation of a technically sound project proposal.

Commercial SFR by Unproved Techniques

SFR by unproved techniques is the volume believed to be recoverable from discovere resources by a project utilising any recovery technique or process that has not yet bee demonstrated to be technically feasible in the field where its application is considered, b which through laboratory or trials elsewhere has a reasonable chance of being technical feasible in the future. If feasible, the process should be expected to be commercial.

Future data gathering may disprove the technique, and with it the possibility of developme and these SFR volumes must therefore be discounted for the risk that the consider technique will not prove to be feasible.

Undiscovered Commercial SFR

Undiscovered SFR is the volume believed to be recoverable from as yet undrilled potenti accumulations by any process that has been a technical success elsewhere, under simil conditions, and the development of which is expected to be commercial.

These SFR volumes must be discounted for the risk that petroleum is not present or is n commercial to develop (Probability of Success, see Appendix 6).

Future data gathering may result in a total write-off of these resources. Following drilli results, the resource volumes are revised and, in the case of a discovery, the economics assessed, whereupon the resource is either discarded or reclassified.

Non-Commercial SFR

SFR in discovered resources is considered non-commercial for development projects whic even if technically successful, would not be commercially viable. To avoid unrealis situations the reporting of Non-Commercial SFR is restricted to projects with a U Technical Cost below an annually advised ceiling.

Non-commercial SFR is reported in order to retain an indication of the discovered resour that could become commercial with a change of circumstances (e.g. an increase in oil pri a change in tax regime, development of a gas market, flared/vented/re-injected gas volumes if recoverable and significant enough to be marketed).

The volumes reported for the four SFR resource categories numbers are based on full life cycle. In addition, total Commercial SFR within licence should also be reported.

3.8 Initial In Place

The petroleum volume Initially In Place (IIP) are expressed in volumes of Stock Tank Oil Initially In Place (STOIIP), Condensate Initially In Place (CIIP) and Gas Initially In Place (GIIP) under standard conditions. For standard conditions the same PVT data must be used as adopted for the reporting of field recoveries.

4. RESOURCE VOLUME CLASSIFICATION FOR EXTERNAL REPORTING

4.1 Classification Scheme

Externally reported resource volumes have two primary purposes – financial calculation. and investor assessments. The reported figures are used to calculate the depreciation of El sector capital investments. The amount of depreciation affects the company's book earning that are also externally reported. Shareholders and the investment community use th reported volumes and earnings to assess the performance and value of the company. It i essential that externally reported proved reserves volumes are a true reflection of shareholde value. Externally reported proved reserves volumes should be equal to internally use proved reserves numbers.

The resource categories for external reporting are shown in Figure 4. Cumulative productioı total proved reserves and proved developed reserves are externally reported annually for oi gas and NGL sales quantities as of the 1st of January. The reported volumes must compl with SEC definitions, reproduced in Appendix 3. The Shell Group definitions contained i this section are in full compliance with these definitions. Where Group guidelines interpr SEC definitions, as listed in Appendix 4, these interpretations have been accepted b external auditors as fulfilling SEC requirements. A summary of the Group definitions for tl external categories is provided in Appendix 1.

Cumulative Production	
Proved Reserves:	Proved Developed Reserves Proved Undeveloped Reserves

Figure 4: Resource Categories for External Reporting

Cumulative production for external reporting has the same definition as used in the She internal classification scheme (see Section 3.5). An example of the migration of resour volumes between externally reported categories during a field's life cycle is shown Appendix 2.

4.2 Proved Reserves

Proved reserves are the portion of reserves, as defined for internal reporting, that **reasonably** certain to be produced and sold during the remaining period of existi production licences and agreements. Extension periods are only included if there is a leg right to extend, which may derive either from the initial concession agreement or from subsequent letter of assurance. Any applicable government restrictions on oil export a contractual or practical market limitations to gas delivery rates should be taken into accou Only the Group share of proved reserves is reported.

If probabilistic methods are used, reserves are reasonably certain when there is an 85 probability that the quantities actually recovered will equal or exceed the estimate. This the P85 value of the cumulative probability curve. If scenario deterministic methods used, the term reasonable certainty is intended to express a high degree of confidence tl the quantities will be recovered. This is the low side estimate. When the estimate assum significant volumes of hydrocarbons outside the defined fluid contacts, or when the recove mechanism is untested in the field or analogue fields, a lower estimate should be used tl reflects this uncertainty.

As discussed in Section 3.4, proved reserve estimates should be updated annually based development and performance data.

Proved Developed Reserves Proved developed reserves are the reasonably certain portion of internally reported developed reserves (i.e. produced from existing wells through installed facilities). Drilling and completing a well essentially proves the hydrocarbons that it develops and therefore proved developed reserves are based on the expectation estimate of developed reserves adjusted to take into account of undefined fluids contacts, untested recovery mechanisms, licence periods, government restrictions and market limitations, as discussed above. The expectation estimate is the mean value if probabilistic methods are used or the base case estimate if scenario deterministic methods are used and should tie-in with the expected No Further Activity (NFA) production forecast.

Proved Undeveloped Reserves Proved undeveloped reserves are the reasonably certain portion of internally reported undeveloped reserves (i.e. require additional capital investment for new wells or facilities). Reasonable certainty is met by using the P85 value or low side estimate of undeveloped reserves and taking into account undefined fluids contacts, untested recovery mechanisms, licence periods, government restrictions and market limitations, as discussed above.

Total proved reserves and proved developed reserves are often determined, and then proved undeveloped reserves is the difference between the two. In mature fields when most of the reserves have been developed, this approach can result in values for total proved reserves and proved undeveloped reserves that are no longer reasonable. Once a field is at this level of maturity, a deterministic approach should be used for both proved developed reserves and proved undeveloped reserves consistent with the SEC and SPE definitions (Appendix 3, Reference 8). Total proved reserves is then the sum of proved developed reserves and proved undeveloped reserves.

Estimates of proved reserves should be benchmarked against the "proved area" deterministic method consistent with the SEC and SPE definitions (Appendix 3, Reference 8). This method first defines the proved area[2] of the field and then estimates the volumes expected to be recovered from the proved area. If the proved and proved developed reserve estimates are significantly different using the proved area method (as generally used in the industry), a reconciliation should be made for the OU to assure itself that the reported reserves are a true reflection of shareholder value.

Asset holders should be aware of the differences between probabilistic and deterministic techniques since third parties, e.g. gas buyers and hence external reserves auditors for certification, may adopt different practices.

External Financing For projects which require some degree of external financing (e.g. LNG projects, major new venture start-ups), project financing must be expected to be available before proved reserves are disclosed externally. This could, by exception, be a reason why the reserves of some viable projects are excluded from external reporting.

Improved Recovery Projects in External Disclosures Advances in reservoir modelling techniques have greatly enhanced the systematic assessment of project recoveries across the full range of uncertainties, increasing confidence in the use of simulation results as the basis for investment decisions and reserves estimation. This improved quantification has in some cases shown that pilot testing is not necessary prior to project commitment (based on a Value of Information approach). Under these circumstances, recovery from improved recovery projects (e.g. fluid injection, reservoir blowdown) may be considered proved when the following three conditions are met:

1) A comprehensive assessment of uncertainties results in confidence that the actual volume will be greater than the low estimate.
2) The main features of the recovery process are supported by confirmed responses in analogous reservoirs.

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[2] The area of the reservoir considered as proved area includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data (Reference 8).

3) Project financing has been obtained or is expected to be available without a pilot testin phase.

In the case of improved gas recovery, the additional conditions in the following section als apply.

Proved Gas Reserves in External Disclosures

In addition to the foregoing conditions, proved reserves of natural gas should include onl quantities falling in the following categories:

1) that are contracted to sales; or
2) that can be considered as reasonably certain of being sold based on a reasonabl expectation of the availability of markets, along with transportation/ delivery facilitie that are in place; or
3) that, while not firmly planned, have been earmarked for future development and henc may reasonably be anticipated to be sold based upon expectation of availability c markets and project financing.

These restrictions also apply to the external disclosure of condensate/NGL products that ar subject to the go-ahead of a non-associated gas project.

Proved Reserves under Constrained Production

When operating under a combined production constraint (e.g. oil production quota) an production beyond the licence or agreement period is expected, the capability to accelerat the post licence production provides a safeguard against under-performance of the planne development programme during the licence period. This capability increases the confidenc level that can be assigned to the constrained production forecast during the licence period. I this circumstance, the proved reserves should be based on an accelerated developme programme that could be followed in the event that the base plan delivered less productio than expected.

Types of Agreements

Under US Financial Accounting Standards Board (FASB) regulations, separate disclosure required for oil and gas volumes applicable to different types of agreements. The requirements are illustrated in Figure 5.

Minority Interest

Reserves are reported on a 100% basis for companies in which the Group holds a controllir interest (in line with financial reporting) rather than on a Group share basis. Minori interest volumes included in the total proved reserves are disclosed separately.[3]

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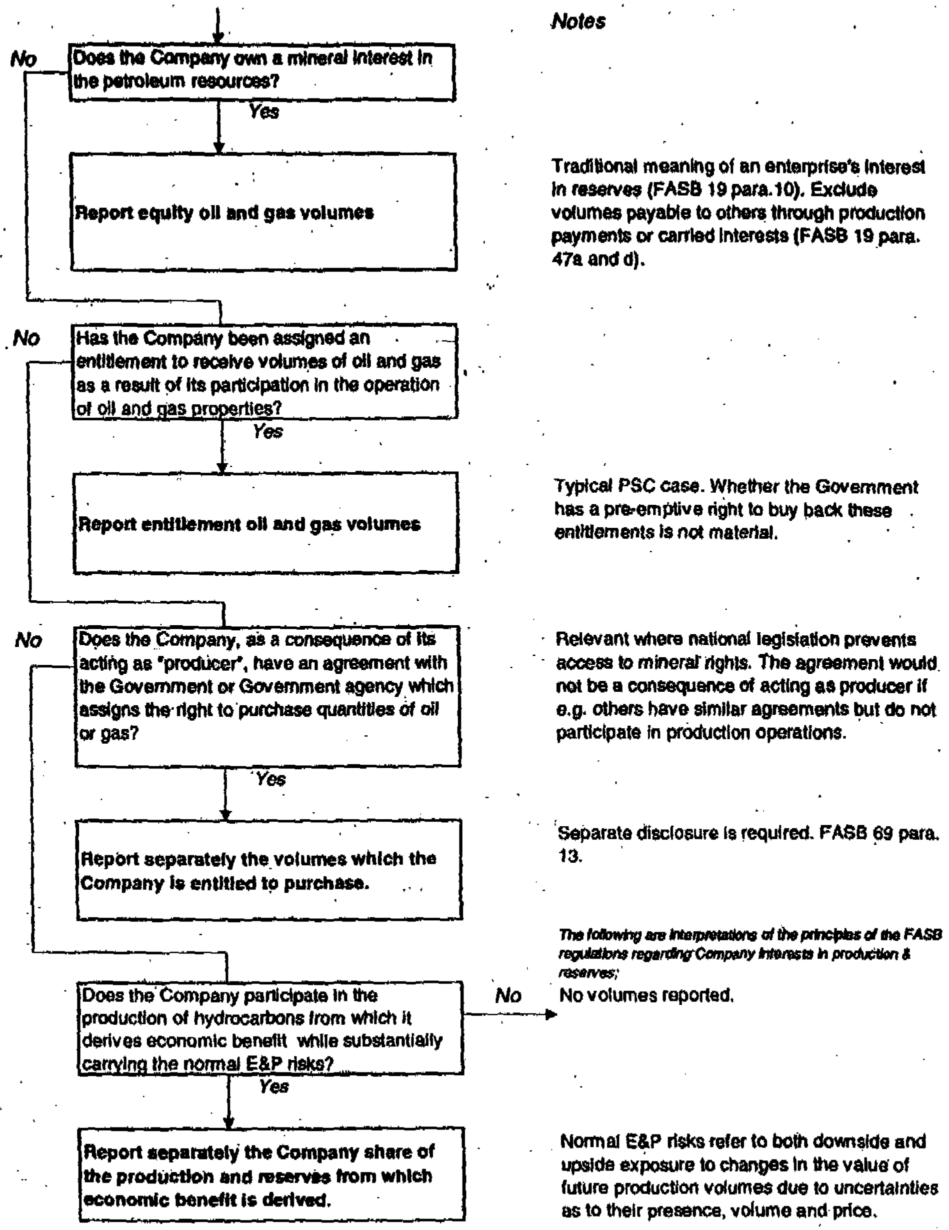
[3] Inclusion of minority interest requires prior agreement with the Group.



Traditional meaning of an enterprise's interest in reserves (FASB 19 para.10). Exclude volumes payable to others through production payments or carried interests (FASB 19 para. 47a and d).

Typical PSC case. Whether the Government has a pre-emptive right to buy back these entitlements is not material.

Relevant where national legislation prevents access to mineral rights. The agreement would not be a consequence of acting as producer if e.g. others have similar agreements but do not participate in production operations.

Separate disclosure is required. FASB 69 para. 13.

The following are interpretations of the principles of the FASB regulations regarding Company interests in production & reserves;

No volumes reported.

Normal E&P risks refer to both downside and upside exposure to changes in the value of future production volumes due to uncertainties as to their presence, volume and price.

Figure 5: Types of External Disclosures in Relation to FASB Regulations

5. RESOURCE VOLUME REPORTING, RESPONSIBILITIES AND AUDITS

5.1 Shareholder Requirements

EP Planning will communicate a timetable and the details about submission requirements t OUs and NVOs each year for both internal and external reporting.

Volumes will be reported based on the classification systems described in Sections 3 and 4 Additional information is reported for the calculation of the Standardized Measure require by the US Financial Accounting Standards Board (FASB).

5.2 Methods and Systems

OUs and NVOs are responsible for selecting the methods and systems that are technicall most appropriate for quantifying the resource volumes of their assets consistent with thes guidelines. The preferred methods and systems may vary depending on the type of resourc and with time as the resource matures and technology improves. Best practices will b developed, updated and shared in the Hydrocarbon Resource Volumes Managemer Common Interest Network (Reference 7). This network will replace the material previousl covered in Volume 2 of the 1988 guidelines (Reference 1).

A variety of commonly used Group and 3rd party systems are available to support resourc volume assessment. Group systems are tailored to these requirements and methods and wi generally provide an inherent level of quality assurance through input constraints, intern calibrations, and other "reality checks". Where more generalised 3rd party systems are use OU and RBD management should be aware of the greater burden of quality control that wi be required.

The Group Reserves Auditor will review decisions on methods and systems during t periodic audits. As far as these methods bear on the estimation of externally reporte resource volumes, the Group Reserves Auditor will ensure that recommended methods a acceptable to the external auditors.

In some cases, OUs and NVOs may be unable to follow Group guidelines and/ recommended practice, due to government requirements, hardware constraints or oth reasons. It is the responsibility of the OU Reserves Custodian to bring such cases to t attention of the Group Reserves Auditor, to enable him to obtain external auditors' approv of the OUs and NVOs specific methods and systems.

5.3 Responsibilities and Audit Requirements

EP Planning Responsibilities

EP Planning is responsible for compiling of the Group statistics of resource volumes, t analysis thereof and the communication to other functions. EP Planning also maintains t resource volume guidelines.

Reserves Auditor Responsibilities

The Group Reserves Auditor will carry out regular detailed reserves reviews in OUs a NVOs to ensure compliance with SEC requirements. The Terms of Reference of the SE Audit are included in Appendix 5. The external auditor will verify the data for exterr reporting.

Operating Unit Responsibilities

Within OUs and NVOs, a Management System should be established (see Reference clearly defining internal reporting requirements, tasks and responsibilities. Technical a Financial functions must co-ordinate and reconcile their figures (particularly producti volumes) prior to submission.

All levels in an OU, including Asset managers and the reservoir engineer preparing t individual field reserves estimates, should be aware of the importance of externally repor reserves (proved, proved developed) and their impact on financial indicators.

Asset and OU managers are responsible to ensure that the guidelines are implemented such a way as to best represent to the shareholders the true value of the asset.

Non-operated Reserves

Where Shell is not the operator, the local Shell EP representative should prepare the reserves submission. In this case the Shell representative has the responsibility of ensuring that resource volume assessments by the operator are aligned with Group guidelines before submission. This may include reclassification of volumes between reserves and SFR categories where the operator's criteria differ from Group criteria. As usual, an audit trail (Note for file) should be available to document the reserves estimate.

If there is no EP representative or if the necessary data are not available locally, then the submission is prepared by SEPI (responsible RBA).

Annual Review of Petroleum Resources

Until 1995, the Annual Review of Petroleum Resources (ARPR) was a constituent document of the annual EP Programme Documentation, providing an inventory of the status of petroleum resources. While OUs and NVOs no longer submit ARPR's to SEPIV/SEPI, the compilation of such an overview report will generally be necessary to satisfy the requirements of OU governance and as such will be a key element of the OU reserves Management System referred to above.

Audit Trail

For all the reported resource volumes an audit trail must be available of the assumptions made and process followed. This will allow any subsequent assessor to modify these estimates based on new information in a reconcilable manner. Thus, evaluation reports must be compiled (preferably on a field basis) giving the basic data, the way it has been interpreted and processed, the development options considered, and the resultant volumes with the assigned probabilities. In addition, a description should be given of the development strategy, including data gathering activities. These reports may be working files (if acceptable to local auditors), but it is recommended to make a duplicate 'for file' in order to ensure that the data are preserved in field reports.

Where subsequent small revisions are made, an update note must be compiled. Multiple changes may be combined in one overall update of the resource volumes if they all belong to the same change category. After several years of small changes or following a development study, a new evaluation report must be issued. When a proposed change has a significant impact on the Company's total reserves or financials, SEPIV/SEPI should be advised at the earliest opportunity.

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REFERENCES

1. EP 88-1140 Part 1, Classification, definitions and reporting requirements,

1a. EP 88-1145 Part 2, Methods and procedures for resource volume estimation, SIPM, April 1988

2. EP93-0075 Petroleum Resource Volume Guidelines, May 1993

3. Revision of Report EP93-0075, 12 August 1994

4. Revision of Report EP93-0075, 10 November 1995

5. Revision of Report SIEP97-1100, September 1997

5a. Revision of Report SIEP98-1100 & 1101, September 1998

6. EP92-0945 Business Process Management Guideline, SIPM, EPO/72, June 1992

7. Hydrocarbon Resource Volume Common Interest Network, http://sww1.epglobal.shell.com/value/index.htm

8. Petroleum Reserves Definitions, Society of Petroleum Engineers and World Petroleum Congresses, http://www.spe.org/technology2/reserves.html

9. Project Evaluation and Screening Criteria, SIEP 99-2030, June 1999

10. Handbook of SEC Accounting and Disclosure

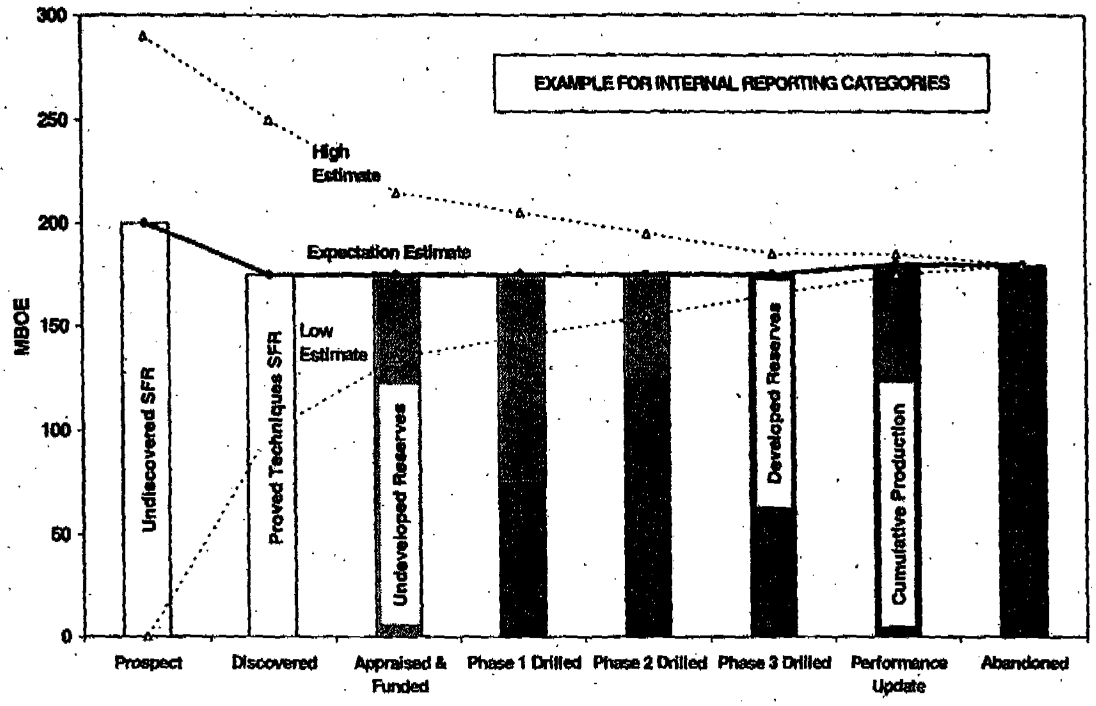
11. Financial Accounting Standards Board (FASB), e.g. Statements 19, 25 and 69.

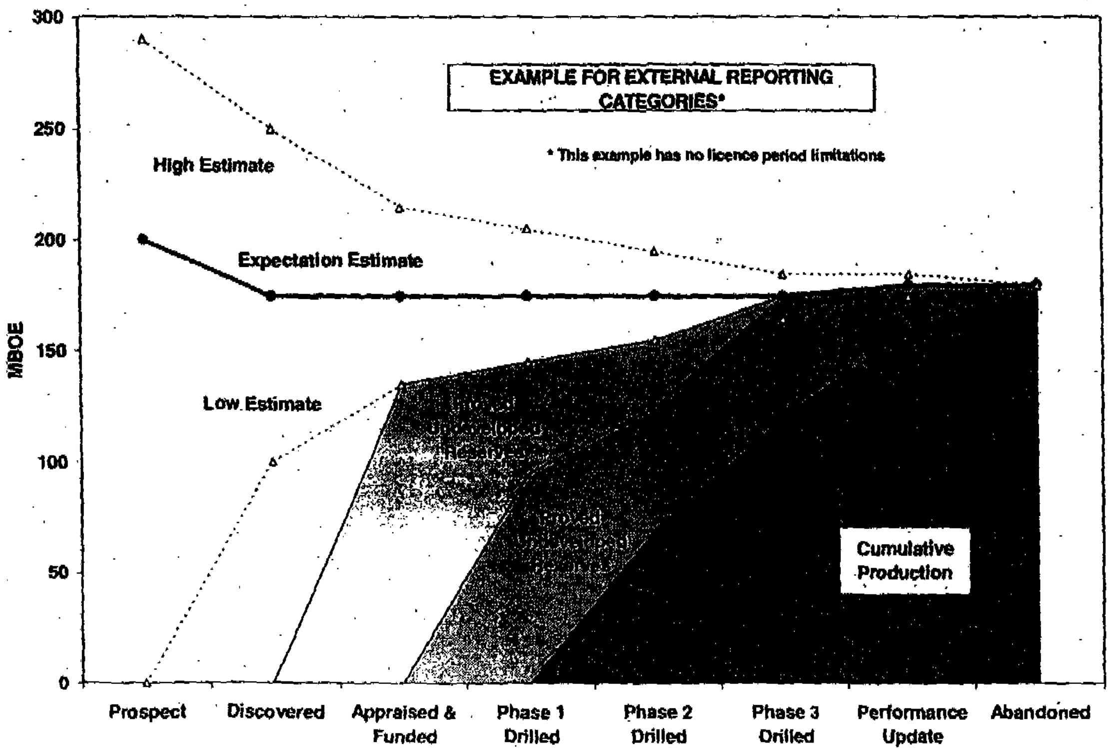
INDEX

APPENDIX 1: RESOURCE CATEGORY (QUICK REFERENCE)

External Reporting	Internal Reporting	Proved Reserves		• Portion of reserves, as defined for internal reporting, that are reasonably certain • Restricted by licence periods, government constraints and market limitations • External financing, when used, must be expected to be available • Deterministically estimated volumes should reflect undefined fluid contacts and untested recovery mechanisms
			Proved Developed Reserves	• Proved reserves producible through existing completions and installed facilities using existing operation methods • Outstanding project activities considered completed if remaining cost <10% of total
			Proved Undeveloped Reserves	• Proved reserves which require capital investment (wells and/or facilities)
	Internal Reporting	Reserves		• Project is "technically and commercially mature" Note: Formal project approval or economic viability is not required • Market is reasonably expected to be available • Includes only production with positive cash flow • Not restricted by licence period • Group share reported
			Developed Reserves	• Reserves producible through existing completions an installed facilities using existing operation methods • Outstanding project activities considered completed i remaining cost <10% of total
			Undeveloped Reserves	• Reserves which require capital investment (wells and/o facilities)
		Scope for Recovery		• Project is <u>not</u> technically and/or commercially mature • Not restricted by licence period • Group share reported
			Commercial SFR by Proved Techniques	• Discovered • Commercially viable • Techniques have been proved to be feasible in thi resource • A sound technical project proposal is not possible ye due to large range of technical uncertainty • Market not currently available
			Commercial SFR by Unproved Techniques	• Discovered • Commercially viable • Recoverable by techniques that have been successfu elsewhere, but cannot yet be demonstrated to be feasibl in this field • Laboratory work or trials elsewhere have a reasonabl chance of demonstrating feasibility in this field • Discounted for the risk that the considered techniqu will not prove to be feasible
			Non-Commercial SFR	• Discovered • Not commercially viable even if technically successful • Commercially viable with a change of commerci circumstances • Unit Technical cost below an annually advised ceiling • Remaining tail production if it is significant
			Undiscovered Commercial SFR	• Recovery from undrilled prospects • Commercially viable exploration and development • Techniques have been successful elsewhere und similar conditions • Discounted for the risk that commercial volumes are n present

APPENDIX 2: RESOURCE MIGRATION DURING FIELD LIFE





APPENDIX 3: SEC PROVED RESERVES DEFINITIONS

(Transcribed from the Handbook of SEC Accounting and Disclosure 1998, pages F3-63 t F3-64)

Proved Reserves

Proved reserves are the estimated quantities of crude oil, natural gas, and natural gas liquid which geological and engineering data demonstrate with reasonable certainty to b recoverable in future years from known reservoirs under existing economic and operatin conditions, i.e. prices and costs as of the date the estimate is made. Prices includ consideration of changes in existing prices provided only by contractual arrangements, bu not on escalations based upon future conditions.

A. Reservoirs are considered proved if economic productibility is supported by either actu production or conclusive formation test supports. The area of a reservoir considere proved includes:

1. that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, any, and
2. the immediately adjoining portions not yet drilled, but which can be reasonably judg as economically productive on the basis of available geological and engineering data. the absence of information on fluid contacts, the lowest known structural occurrence hydrocarbons controls the lower proved limit of the reservoir.

B. Reserves which can be produced economically through application of improv recovery techniques (such as fluid injection) are included in the "proved" classificati when successful testing by a pilot project, or the operation of an installed program in t reservoir, provides support for the engineering analysis on which the project or progra was based.

C. Estimates of proved reserves do not include the following:

1. oil that may become available from known reservoirs but is classified separately "indicated additional reserves";
2. crude oil, natural gas, and natural gas liquids, the recovery of which is subject reasonable doubt because of uncertainty as to geology, reservoir characteristics, economic factors;
3. crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; an
4. crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, c (excluding certain coalbed methane gas), gilsonite and other such sources.

Proved Developed Reserves

Proved developed reserves are reserves that can be expected to be recovered through existi wells with existing equipment and operating methods. Additional oil and gas expected to obtained through the application of fluid injection or other improved recovery techniques f supplementing the natural forces and mechanisms of primary recovery should be included "proved developed reserves" only after testing by a pilot project or after the operation of installed program has confirmed through production response that increased recovery will achieved.

Proved Undeveloped Reserves

Proved undeveloped reserves are reserves that are expected to be recovered from new we on undrilled acreage, or from existing wells where a relatively major expenditure is requi for recompletion. Reserves on undrilled acreage shall be limited to those drilling u offsetting productive units that are reasonably certain of production when drilled. Pro reserves for other undrilled units can be claimed only where it can be demonstrated w certainty that there is continuity of production from the existing productive formation. Un no circumstances should estimates for proved undeveloped reserves be attributable to a acreage for which an application of fluid injection or other improved recovery technique contemplated, unless such techniques have been proved effective by actual tests in the a and in the same reservoir.

APPENDIX 4: SHELL INTERPRETATION OF SEC RESERVE DEFINITIONS

SEC Definition	Shell Interpretation for External Reporting
Reasonable certainty; Proved area includes portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and the immediately adjoining portions not yet drilled...In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.	If probabilistic methods are used, reserves are reasonably certain when there is an 85% probability that the quantities actually recovered will equal or exceed the estimate. This is the P85 value of the cumulative probability curve. If scenario deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. This is the low side estimate. When the estimate assumes significant volumes of hydrocarbons outside the defined fluid contacts, or when the recovery mechanism is untested in the field or analogue fields, a lower estimate should be used that reflects this uncertainty. Drilling and completing a well essentially proves the hydrocarbons that it develops and therefore proved developed reserves are based on the expectation estimate of developed reserves adjusted to take into account of undefined fluids contacts and untested recovery mechanisms.
Fixed RT prices at level prevailing at date of estimate	Prices fixed by SIEP ca. 6 months prior to estimate date, but amended if there is a subsequent significant change.
Fixed RT costs at level prevailing at date of estimate.	Costs fixed by OUs and NVOs at date of estimate. Flat MOD costs must be supported by technology plans to show that implied cost reductions are viable.
Economic productibility	Technically and commercially mature (i.e. positive discounted real terms cash flow for sufficient range of scenarios).
Productibility supported by either actual production or conclusive formation test supports	Productibility should normally be demonstrated by a conclusive test, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.
Improved recovery processes included only after successful testing by a pilot project or the operation of an installed program	Reserves from improved recovery processes are normally included following an in-situ test; by analogy with the same process being used elsewhere under similar conditions, or occasionally as a result of lab tests or simulation studies.
No gas qualifier	Include only gas contracted or reasonably expected to be sold.
Developed reserves are from existing wells (including minor cost recompletions), existing facilities and operating methods	Existing wells, installed facilities and existing operating methods. Outstanding project activities can be considered existing or installed if outstanding costs are minor and approved. This includes volumes behind pipe if future costs are minor.

APPENDIX 5: SEC AUDIT - TERMS OF REFERENCE

The purpose of the SEC Reserves Audit is to verify that appropriate processes are in place in the OU to ensure that the proved and proved developed reserves estimates for external (SEC) reporting are prepared in accordance with the latest Group prescribed guidelines (SIEP 99-1100/1101) and the FASB Statement of Financial Accounting Standards no.69 (SFAS-69).

The Audit will be carried out by the Group Reserves Auditor. His specific tasks during the audit shall be:

1. To verify the technical maturity of the reported proved and proved developed reserves estimates by assessing the quality of the engineering data and study work supporting the estimates and by verifying that undeveloped reserves are based on identifiable projects that can be considered technically mature.
2. To verify the commercial maturity of the reported reserves volumes by assessing the robustness of project economics and by establishing that these volumes can reasonably be expected to be sold in present or future markets.
3. To verify the 'reasonable certainty' of the reserves estimates by assessing the validity of uncertainty ranges used for their constituent parameters, by verifying that estimates are realistic in comparison with expectation estimates, by verifying that appropriate methods are used for mature fields and by establishing that appropriate methods of reserves addition (probabilistic / arithmetic) have been applied.
4. To verify that the Group share of proved and proved developed volumes has been calculated properly and that these volumes are producible within prevailing licence periods.
5. To verify that reported volumes are up-to-date and consistent with previous estimates, that changes are reported in the appropriate categories and that appropriate audit trails are in place for the study work supporting the reported reserves estimates
6. To verify that reported reserves are net sales volumes and that the reported annual production (sales) volumes are consistent with those reported in submissions to Group Finance.

In case of deviations from the Group and FASB guidelines, the auditor shall establish whether and to what extent resulting estimates are likely to differ significantly from those that might be expected from the application of the standard guidelines.

The audit will be carried out by reviewing the reserves estimation and submission process through interviews of OU staff and by taking at random a number of fields for detailed analysis.

The audit will in principle be carried out on OU premises and will be based on documentation available in the OU. Assistance of OU staff may be called upon.

An audit report will be submitted to the Managing Director of the OU, to the EP CEO and EP RBA, to the OU's Hydrocarbon Resource Manager and to KPMG the external auditors. It will be prepared and discussed in draft form on site, after which a final report will be prepared in The Hague, once formal OU comments are received. The report will contain an overall judgement (Good, Satisfactory, or Unsatisfactory), with itemised conclusions and recommendations.

APPENDIX 6: TERMINOLOGY

A) *Petroleum Resources Terminology*

Reservoir A reservoir is a discovered petroleum resource where internal pressure communication is known to exist between all identified geological sub-units.

In case of doubt, reservoirs are restricted to fault blocks / sedimentary units until production performance proves communication to exist across faults/ barriers. PVT properties can vary within a reservoir.

Field A field is the collection of all petroleum resources within a closed areal boundary that belong to the same confining geological structure, and where the presence of petroleum has been demonstrated in at least one reservoir by a successful exploration well.

Field boundaries must be defined upon discovery and should encompass the unpenetrated petroleum resources in adjacent fault blocks and stratigraphic traps, if they are considered to be part of the same overall confining structure. Field boundaries may be re-defined on the basis of new geological information.

Potential Accumulations Potential petroleum resources beyond existing field boundaries, where the presence of petroleum has not yet been demonstrated, are collectively called potential accumulations.

Producibility Should normally be supported by a conclusive test in a drilled or immediately adjoining reservoir, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.

Production Facilities The production facilities consist of all hardware installed to recover petroleum from the sub-surface resources and to deliver a quality controlled end-product for sale. These comprise the production and injection wells and the surface facilities for treatment, conversion, compression/ pumping, transport and delivery.

Surface Facilities That part of the production facilities accessible at surface, connecting the wellheads ultimately to the delivery points.

Existing Development The collection of all completed projects or sub-projects is referred to as the existing development.

Field quantities Field quantities (also called "Wellhead" quantities) are those quantities routinely measured at surface for individual well strings and expressed in terms of the stabilised products oil, condensate and (wet) gas or in terms of the type of injected fluids. These quantities may subsequently be reconciled with fiscalised sales and other product outlets, see below.

Sales quantities The quantities sold after fiscal metering and delivered at the locations where the upstream company ceases to have an interest in the end-products. These can be expressed in terms of the general end-products oil, (dry) gas and natural gas liquids (NGL) or in terms of the actual product.

Field products and the subsequent sales products may be different and will be affected by own use and losses. The properties and volumes of end-products may be influenced by mixing and the petroleum type itself may be altered during surface processing. Since surface processing conditions may change during a project life, sales products may vary in specification and in relation to field products. To avoid ambiguity and double counting, a clear distinction must be made between recoveries in the field and the quantities estimated to be available for sale.

For general sales products, oil, gas and NGLs, only the quantities sold by the upstream E&P company can contribute to Group reserves. Condensates mixed with crude oil in the same stream and sold as such are reported under oil. Separator condensate from gas wells and light hydrocarbon liquid products, derived from surface processing, if collected in a separate stream and sold as such are reported under NGL. Bitumen may be reported under oil in summary reports (with an appropriate footnote). In line with SEC requirements, sales volumes for gas should be those committed or commitable to a gas contract. Committed Gas is covered by a gas contract. Commitable gas reasonably expected to be assigned to a contract in the future.

It is necessary to maintain a more detailed internal administration of the actually sold products by stream in two cases: 1) If the upstream E&P company has separate contracts for delivery of special converted sales products such as LNG, methanol, ethane, LPG, C5+, or 2) if there are special sales products like helium, sulphur or generated electricity.

Reconciliation	A monthly reconciliation is made between the fiscalised sales quantities and the quantities produced in the field. This is reported in the Monthly Report of Producing Wells (MRPW). The reconciliation process corrects for own use, flaring, losses and product conversion, and provides the end-product yield. For reserves estimating purposes an average future yield factor is to be estimated (e.g. LPG/ wet gas yield, dry gas/ wet gas yield).
Ultimate Recovery	The ultimate recovery (UR) of a petroleum type is the sum of cumulative production and the estimated volume of reserves.

B) Probabilistic Terminology

Probability Distribution Function	The probability distribution function of a stochastic variable indicates the probability that the actual variable value lies within a narrow interval around a particular value of the possible range, divided by the width of that interval.
P85	The value that has a 85% probability that it will be exceeded.
P15	The value that has a 15% probability that it will be exceeded.
Mean	The statistical mean of a stochastic variable is the weighted average over the entire probability range.
Mean Success Volume (MSV)	The probability weighted average of all realisations that equal or exceed the minimum reserves required for a commercial development of the resource.
Probability of Success (POS)	The probability that the minimum commercial volume will be exceeded and which therefore indicates the likelihood of any future development. The product of MSV and POS is the recovery expectation.

C) Commercial Terminology

Discount Rate	A rate at which future real terms costs or cash-flow are discounted over time to calculate their present value.
Net Present Value (NPV)	The net present value of a project is the sum of the discounted annual cash flow, expressed in real terms money, over the period from the first project expenditure to abandonment. The net present value is expressed in million US$ at the relevant discount rate.
Expected Monetary Value (EMV)	The expected monetary value is a probabilistic balance of investments and revenues, expected from a set of conditional operational activities, comprising data acquisition and one or more development projects, which are arranged in an ordered sequence with probabilities assigned to each action (decision tree). The EMV is the summation of the NPV's of projects, reduced by the costs of data acquisition activities, all expressed in discounted real term money and multiplied by their assigned probabilities. EMV is expressed in million US$ at the relevant discount rate. Projects with a negative NPV for certain resource model realisations should be excluded from the EMV calculation, if the assumption is valid that data gathering will prevent such projects being implemented.
Unit Technical Cost (UTC)	The unit technical cost of a development project is defined as the sum of capital plus operating costs, expressed in real terms money, divided by the total production over the period from start-up to abandonment. In addition, both the cost and the production must be discounted. The reference date for the discounting should be the same for denominator and numerator (e.g. the first year of expenditure) and should be stated. The unit technical costs is expressed in US$/bbl (oil equivalent) at the relevant discount rate.

D) *Exploration versus Development Wells*

The classification of a well as either an exploration well or as a development well is determined (in line with SEC rules) based on the proved area as follows:

Proved Area	The **proved area** is the part of a property to which proved reserves have been specifically attributed.
Exploration Well	An **exploration well** is a well that is not a development well, a service well, or a stratigraphic test well.
Development Well	A **development well** is a well drilled within the proved area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.
Service Well	A **service well** is basically any well which is either an injection well, a disposal well or a water supply well.
Appraisal Well	An **appraisal well, or stratigraphic test well** is a well drilled for geological information (not to test a prospect), either 'development-type' drilled in a proved area or 'exploratory-type' if not drilled in a proved area.

Shell International Exploration and Production B.V.

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SIEP 99-1101

Petroleum Resource Volumes

Submission requirements for internal and external reporting

(for Operating Units & New Venture Operations)

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Treatment Requested

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SIEP 99-1101

Petroleum Resource Volumes

Submission requirements for internal and external reporting

(for Operating Units & New Venture Operations)

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

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

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Contents

List of Appendices

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Purpose

This document provides the guidelines for the annual submission of internal and external resource volumes statements. These guidelines should be used in conjunction with the 'Petroleum Resource Volume Guidelines: Resource Classification and Value Realisation' (Reference 1). External reporting requirements comply with SEC rules and FASB statements (References 2 and 3).

The annual statement of Resource Volumes is submitted in the beginning of each year to EP Planning (SEPIV-EPB-P) by Operating Units (OUs), New Venture Organisations (NVOs) and Non Operated Ventures (NOVs).

EP Planning is responsible for aggregating the data at Group level and for the internal and external reporting. The Group Reserves Auditor will verify the data for external reporting.

Detailed information is provided in the appendices:

Appendix 1	Submission Requirements for Internal Reporting;
Appendix 2	Submission Requirements for External Reporting; and
Appendix 3	Guidance for the electronic spreadsheet 'Reserves Reporting Workbook'.

Schedule

The 1999 Resource Volume Statements should be with the Group Hydrocarbon Resource Coordinator in the Hague by the following dates:

Non-producing ventures	by **Wednesday 12 January 2000** (COB Local Time); and
Producing ventures	by **Wednesday 19 January 2000** (COB Local Time).

The data should be submitted in electronic format using the electronic (Excel) spreadsheet 'Reserves Reporting Workbook' as provided to each OU/NVO/NOV reserves focal point. The electronic workbook (password protected) can be submitted via Email or on diskette.

OU/NVO/NOVs should submit (by mail) signed copies of all internal and external resource reporting forms as approved at the appropriate level e.g. Technical Manager, General Manager or equivalent. The Standardized Measure submission should also be signed by the Finance Manager. Signed copies should be in the Hague offices no later than one week after the reporting deadlines given above.

Submissions by Email (password protected) should be addressed to Remco Aalbers SEPIV EPB-P (Remco.RD.Aalbers@sepivbv.shell.com).

Paper mail should be addressed to:

R.D. Aalbers (EPB-P)
Group Hydrocarbon Resource Coordinator
Shell EP International Ventures BV.
P.O. Box 663
2501 CR The Hague
The Netherlands

Tel. +31-70-377 2001
Fax. +31-70-377 2460

All submissions should be copied to the respective Regional Business Advisor (RBA).

Opening and Closing Statements

In view of the early reporting date, preliminary estimates of end year reserves and resources are accepted. Oil/NGL production and gas sales volumes should equal volumes reported as full year actual in CERES.

Opening reserves and resource statements should be equal to previous year's (preliminary) closing statements as submitted to the Group. The workbook received by each OU/NVO/NOV already includes their respective closing numbers from last year as a fixed input.

Units and Conversion Factors

Oil and NGL

Oil and NGL volumes are reported in m^3 sales volumes at standard conditions (15°C and 760 mm Hg).

1 bbl (15°C, 760 mm Hg) = 0.1590 m^3 (15°C, 760 mm Hg)

Gas

Gas volumes are reported in two different units:

1) Sales volumes "*tel quel*" (i.e. at its inherent heating value) in cubic meters at standard conditions (15°C and 760 mm Hg).

   Conversion factors between standard cubic meters (sm^3) and standard cubic feet (scf) are as follows:

   1 sm^3 (15°C, 760 mmHg) = 35.3147 scf (15°C, 760 mm Hg)
   = 35.2899 scf (60°F, 30 in Hg)

   1 scf (15°C, 760 mm Hg) = 0.02832 m^3 (15°C, 760 mm Hg)
   1 scf (60°F, 30 in Hg) = 0.02834 m^3 (15°C, 760 mm Hg)

2) Sales volumes at Normalised conditions (i.e. adjusted to an average heating value) in cubic meters at normal conditions (0°C, 760 mm Hg) and a gross heating value (GHV) of 9,500 kcal/nm3.

   Conversion between standard cubic meters (sm^3) and Normalised cubic meters (Nm^3) is carried out in two steps:

   a) Volume conversion reflecting the temperature change from standard cubic meter (sm^3) at 15°C to normal cubic meter (nm^3) at 0°C:

   1 sm^3 (15°C, 760 mm Hg) = 0.9480 nm^3 (0°C, 760 mm Hg)

   This conversion may - to some extent - depend on gas composition and slightly different values may apply.

   b) Volume conversion reflecting the gross heating value change from actual GHV ("tel quel") to a GHV of 9,500 kcal/Nm^3, for instance:

   1 nm^3 (GHV = 10,000 kcal/nm^3) = 10,000/9,500 = 1.0526 Nm^3 (GHV = 9,500 kcal/nm^3).

   Heating value conversion factors are:

   9,500 Kcal/nm^3 = 39.7480 MJ/nm^3
   1,000 btu/scf (15°C, 760 mm Hg) = 39.3027 MJ/nm^3
   1,000 btu/scf (60°F, 30 in Hg) = 39.2751 MJ/nm^3

e.g. for a gas with an average GHV of 1,000 btu/scf:

1 Nm^3 (9,500 kcal/nm^3) = 37.6738 scf (1,000 btu/scf)

See references 4 and 5 for other conversion factors if required.

Barrel of Oil Equivalent (boe)

Conversion of gas volumes to barrel of oil equivalent is (generally) defined as follows:

1 boe = 5.8 mln btu

As 'boe' is defined in terms of total energy, conversion of gas volumes to 'boe' depends on the average GHV of the gas as follows:

1 boe = 5,800 scf (GHV = 1,000 btu/scf)

1 boe = 153.95 Nm^3 (GHV = 9,500 kcal/nm^3)

e.g. for a gas with an average GHV of 1,100 btu/scf:

1 boe = 1,000/1,100 * 5,800 = 5,273 scf (GHV = 1,100 btu/scf)

References

1. Petroleum Resource Volume Guidelines: Resource Classification and Value Realisation; SIEP 99-1100, September 1999.
2. Financial Accounting Standards Board (FASB), e.g. Statements 19, 25 and 69.
3. Handbook of SEC Accounting and Disclosure, e.g. paragraph F3, Oil and Gas Entities.
4. Production Handbook, Volume 1; SIPM, 1991.
5. Natural Gas Terms and Measurements, SIG/69/1, SIG Ltd., 1992.

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A1 Internal Reporting

The following submissions are required for internal reporting:

1. **Expectation Estimate of Reserves Volumes Oil, NGL, and Gas**

   Group share of expectation estimate of reserves as at 31 December 1999 and reconciliation with the reserves reported in the previous year. A breakdown (by field) should be provided separately for significant changes in the expectation estimate of reserves. Expectation reserves are estimates of full life cycle future sales volumes.

2. **Expectation Estimate of Scope for Recovery Oil, NGL and Gas**

   Group share of expectation estimate of Scope for Recovery (SFR) as at 31 December 1999 and reconciliation with the SFR reported in the previous year. SFR volumes are reported as full life cycle numbers.

3. **Expectation Estimate of Exploration Discoveries Oil; NGL and Gas**

   Records the discoveries during the year 1999 with the expectation estimate of recoverable resources.

4. **Exploration Discoveries and Revisions Oil/ NGL and Gas**

   Provides a summary of exploration discoveries and revisions over the last ten years comparing initial estimates of discovered volumes (in the year of discovery) with current estimates of resources for the same fields.

   Combined with the exploration expenditure for each year provides an estimate of Unit Finding Costs.

5. **Summary of Resources by Field (new request)**

   Records a summary of resource volumes by field for each resource category. Input is split between oil and gas fields, with additional information on location (onshore, offshore or deepwater), on operated status (operated or non-operated), on oil and gas quality (API & GHV), group share in the field as well as area/contract information (free format per OU/NVO/NOv).

   Details should be provided for all the large and medium size fields within each venture, but small fields may be aggregated into one (or more) "other small fields" entries. Small fields (together less than 10% of the total reserves) should be grouped within the same 'subset' (e.g. offshore & operated, or onshore & non-operated). Equally exploration potential (Commercial SFR-undisc) may be aggregated from prospects/leads into concession block(s) etc as long as grouping is within an equivalent 'subset'.

A1.1 Licence and Contract period

For internal reporting purposes, Group share of the expectation estimate of reserves and scope for recovery are recorded for the total producing life, i.e. including the period beyond the licence period. The currently existing licence terms or other anticipated terms should be assumed for this extrapolation.

In the submission for Expectation Reserves (under 1 above), also the expectation estimate of both developed and total reserves that will be produced within the licence period is requested.

In the submission for Scope for Recovery (under 2 above), also total commercial SFR within Licence is recorded.

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A1.2 Change Categories

Reserves	Scope for Recovery (SFR)
New Fields	New Entries
Extensions	Discoveries
Terms and conditions	Terms and conditions
Purchases in place	Purchases in place
Sales in place	Sales in place
Improved recovery (to/from SFR)	Transfers to/from reserves
Economic Revisions	Economic Revisions
Technical Revisions	Technical Revisions
	Deletions
Production	

The change categories that apply to internal reporting are defined as follows:

New Fields	This category includes only Reserves volumes that are allocated for the first time to a discovered field. This could occur directly upon discovery by a successful exploration well but only if a technically mature and commercially viable development plan can already be formulated. This also includes first time allocation of reserves for discovered fields for which volumes were previously booked as SFR that are transferred to reserves following firming up of a technically mature and commercially viable development plan.
New Entries	Pertain to SFR estimates entered for the first time for a new identified petroleum resource and/or project. Transfers from reserves are thus not included in this category.
Extensions	Include only the Reserves allocated for the first time to a discovered accumulation (e.g. a new fault block or reservoir), located within the boundaries of a field that already carries Reserves.
Discoveries	Include only SFR volumes that are allocated for the first time to a discovered field as a result of a successful exploration well. It is noted that, immediately upon discovery of the presence of hydrocarbons in a field, it may not yet be possible to prepare a technically mature and commercially viable development plan.
Terms & Conditions	Describe Reserves/ SFR changes that are solely due to the allocation or retraction of a production or exploration licence/contracts, and/or to adjustments to the terms of existing licences/contracts, including licence/contract extensions.
Purchases in Place	Include Reserves/ SFR additions solely due to equity changes as a result of a financial or barter transaction.
Sales in Place	Include Reserves/ SFR reductions solely due to equity changes as a result of a financial or barter transaction.

Improved Recovery (to/from SFR)	Describes positive reserves changes allocated to a field where Reserves were already carried and consists only of transfers from SFR of volumes associated with new projects, that were hitherto not deemed technically mature or commercially viable to contribute to reserves. This excludes Extensions, which should be reported separately. In the audit trail, the reasons for such transfers should be given, as well as an indication whether the project pertains to an improvement in the sub-surface recovery technique or in surface processing. Negative reserves changes reflect the de-booking of volumes previously carried as reserves but no longer considered to be technically and commercially mature to SFR.
Transfers	Include those positive (negative) SFR changes that involve a reclassification of Reserves into (from) SFR. Negative Transfer volumes in SFR should be accompanied by positive volumes in the appropriate Reserves change category, and vice versa.
Revisions General	Include corrections to previous estimates of recovery for a project, or of previous IIP estimates for a resource, based on new information, re-evaluation and/or the conclusion of a unitisation agreement. Transfers of entire project resource volumes out of Reserves into SFR should be included in this category, with the reasons to be stated in the audit trail. Reserves revisions also include transfers from non-commercial SFR if the latter are due to changes in the economic abandonment rates for projects that already carry reserves.
Economic Revisions	Include those revisions that are solely due to a change in the advised Group reference criteria for commerciality.
Technical Revisions	Include all other revisions. If during a year, a project has been subject to technical revisions, whilst there has also been a change in reference criteria, the economic revisions should be calculated separately, where possible.
Production	Sales quantities sold during the year after fiscal metering and delivered at the location where the upstream sector ceases to have an interest in the end products.
Deletions	Pertain to SFR estimates for resources relinquished, projects withdrawn from the system and failed exploration/appraisal.

Please note that in the electronic workbook a number of logical links have been made to ensure consistent reporting of changes between SFR (transfer to/from reserves) and the equivalent changes to expectation reserves (new fields/discoveries, extensions and improved recovery). Data should be entered on the relevant SFR sheet and is automatically linked to the expectation sheet.

Similarly to ensure consistent reporting of production volumes these should be entered on the proved reserves sheet(s) for external reporting and are linked to the expectation sheet.

Further logical links are included between the volumes reported on the 'Discoveries 1999' sheet and volumes recorded as "discoveries" on the 'SFR' sheets and 10 year exploration overview sheets. The number of successful exploration wells reported in the statistics sheet are linked to the number of discoveries reported in the 'Discoveries 1999' sheet.

A1.3 Reconciliation of Changes

In principle, a reclassification should not alter the transferred quantity, nor the number of identified projects. Similarly, a revision should pertain to a change of the quantity estimated for a particular project, and should not affect the number of projects identified in the system. The latter can only be changed by new entries and deletions.

In practice, many resource volume changes will actually consist of a combination of constituent changes. For instance, a successful exploration well will cause a reclassification from undiscovered SFR to one of the discovered resource categories (Discovery or New Field), whilst at the same time it will provide new data that may modify the previously estimated resource volumes (Revision). Similarly, a development study may re-classify a resource from SFR to Reserves (Improved Recovery), whilst the new volumetrics will increase the Initially-in-Place estimate (Revision). Upon reclassification, the revision should be shown in the previous category and the new estimate will be transferred to the target category.

For reconciliation purposes, it is desirable for each composite change to be evaluated and stored as a number of constituent changes, each in its separate category.

Resource Volumes and Associated Change Categories

To \ From \	Cum Prod'n	Developed Reserves	Undev Reserves	Proved Tech SFR	Unprov. Tech SFR	Undisc'd SFR	Non-Comm SFR	Not carried
Cumulative Production	*TR*	-	-	-	-	-	-	-
Developed Reserves	Prod'n	TR/ER	-	-	-	-	ER/TC	SIP
Undeveloped Reserves	-	Develop't /TR	TR/ER	TR/ER	-	-	ER/TC	SIP
Proved Tech SFR	-	*IR/TS*	IR/TS	TR/ER	-	-	ER/TC	SIP /DEL
Unproved Tech SFR	-	*IR/TS*	IR/TS	TR	TR/ER	-	ER/TC	SIP /DEL
Undiscovered SFR	-	*NF/EX*	NF/EX	DIS	DIS	TR/ER	ER/TC	SIP /DEL
Non-comm SFR	-	ER/TC	ER/TC	ER/TC	ER/TC	*ER/TC*	TR/ER /TC	SIP /DEL
Not carried	-	PIP	PIP	PIP/NE	PIP/NE	PIP/NE	PIP/NE	-

DIS	Discovery	**IR**	Improved Recovery	**SIP**	Sale in Place
DEL	Deletion	**NE**	New Entry	**TC**	Term & Conditions
ER	Economic Revision	**NF**	New Field	**TR**	Technical Revisions
EX	Extension	**PIP**	Purchase in Place	**TS**	Transfer to/from SFR

Note; Italics indicate change categories which, although possible, are less common.

A1.4 Submission sheets

Internal reporting:	Expectation estimate of reserves volumes: Oil, NGL and Gas
Internal reporting:	Summary of Resources by Field
Internal reporting:	Expectation estimate of Scope for Recovery: Oil
Internal reporting:	Expectation estimate of Scope for Recovery: NGL
Internal reporting:	Expectation estimate of Scope for Recovery: Gas
Internal reporting:	Expectation estimate of Exploration Discoveries
Internal reporting:	Expectation estimate of Exploration Discoveries and Revisions 1990 - 1999: Oil/ NGL
Internal reporting:	Expectation estimate of Exploration Discoveries and Revisions 1990 - 1999: Gas

Internal reporting: Expectation Estimate of Reserves Volumes: Oil, NGL, Gas

Input sheet 1999

Country Name : Mycountry
Estimate for Company: My Company

Estimate for year ending: 31 December 1999
Group share of expectation sales volumes excluding royalty in kind.

Group interest in company is 100.00%

	Oil	*NGL*	*Gas sm3*	*Gas Nm3*
Minority interest %	0.00%	0.00%	0.00%	0.00%

	1999 - Input			
	Oil 10^6 m^3	NGL 10^9 m^3	Gas 10^9 std. m^3 (tel quel)	Gas 10^9 Nm^3 (9500 kcal /Nm^3)
Expectation estimate of reserves at 1.1.1999	0.00	0.00	0.000	0.000
New Fields/Discoveries	0.00	0.00	0.000	
Extensions	0.00	0.00	0.000	
Terms & Conditions				
Purchases in place				
Sales in place				
Improved recovery (to/from SFR)	0.00	0.00	0.000	
Economic revisions				
Technical revisions				
Production (sales) during 1999	0.00	0.00	0.000	0.000
Expectation estimate of reserves at 31.12.1999	0.00	0.00	0.000	0.000
Exp. est. of reserves within licence at 1.1.1999	0.00	0.00	0.000	0.000
Net changes in expectation	0.00	0.00	0.000	0.000
Transfer to post licence	0.00	0.00	0.000	0.000
Exp. est. of reserves within licence at 31.12.1999	0.00	0.00	0.000	0.000
Developed reserves within licence at 1.1.1999	0.00	0.00	0.000	0.000
Transfer Undeveloped Reserves to Developed				
Revisions				
Production (sales) during 1999	0.00	0.00	0.000	0.000
Developed reserves within licence at 31.12.1999	0.00	0.00	0.000	0.000
<check Dev Exp> Exp Res	OK	OK	OK	OK
<check Dev Exp> Dev Exp Res	OK	OK	OK	OK
Commited gas 31.12.1999				
Committable gas reserves at 31.12.1999			0.000	0.000
Minority Exp Res. Within Licence included 1.1.1999	0.00	0.00	0.000	0.000
Minority Exp Res. Within Licence included 31.12.1999	0.00	0.00	0.000	0.000

All figures input for Standardized Measure calculation.

Comments:

Expectation comments:

Date: 05-Nov-99

Signed by

Summary of Resources by Field

Annual Resource Reporting - Summary of Resources by Field
Input sheet (part 1) 1999
Country Name : Mycountry
Estimate for Company: My Company

Note : small fields can be rolled-up by area/contract (less 10% of total)

Estimate for year ending: 31 December 1999
Group share of resource volumes (excluding royalty in kind)

OIL

							[mln m3]	Proved Reserves		Exp Res wl Science		Expectation Reserves		Commercial SFR			
Field Name	Location	Area/ Contract	Operated	Group Share [% exp]	Oil Quality [Deg. API]	Check Input Loc, Oper & share	Cum Prod	Dev	Undev	Dev	Undev	Dev	Undev	Proved Tech.	Unproved Tech.	Undisc	SFR Non-Com
Other small fields						Error Error											
Total							0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Check Summary Oil	Missing Data	Missing Data	Missing Data	Missing Data	Missing Data			OK	OK	OK	OK total exp:		OK	OK	OK	OK	OK

NGL

							[mln m3]	Proved Reserves		Exp Res wl Science		Expectation Reserves		Commercial SFR			
Field Name	Location	Area/ Contract	Operated	Group Share [% exp]	Oil Quality [Deg. API]	Check Input Loc, Oper & share	Cum Prod	Dev	Undev	Dev	Undev	Dev	Undev	Proved Tech.	Unproved Tech.	Undisc	SFR Non-Com
Other small fields						Error Error											
Total							0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Check Summary NGL	Missing Data	Missing Data	Missing Data	Missing Data	Missing Data			OK	OK	OK	OK total exp:		OK	OK	OK	OK	OK
Total Oil/NGL							0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Annual Resource Reporting - Summary of Resources by Field
Input sheet (part 2) 1999
Country Name : Mycountry
Estimate for Company: My Company

Note : small fields can be rolled-up by area/contract (less 10% of total)

Estimate for year ending: 31 December 1999
Group share of resource volumes (excluding royalty in kind)

Gas - Associated

							[mrd sm3]	Proved Reserves		Exp Res wl Science		Expectation Reserves		Commercial SFR			
Field Name	Location	Area/ Contract	Operated	Group Share [% exp]	GHV [kcal/sm3]	Committed [%] exp res wl L.	Cum Prod	Dev	Undev	Dev	Undev	Dev	Undev	Proved Tech.	Unproved Tech.	Undisc	SFR Non-Com
Other small fields						0.0%				0.00	0.00						
Total					0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Check				Missing Data	Missing Data												

Gas - Non-Associated

							[mrd sm3]	Proved Reserves		Exp Res wl Science		Expectation Reserves		Commercial SFR			
Field Name	Location	Area/ Contract	Operated	Group Share [% exp]	GHV [kcal/sm3]	Committed [%] exp res wl L.	Cum Prod	Dev	Undev	Dev	Undev	Dev	Undev	Proved Tech.	Unproved Tech.	Undisc	SFR Non-Com
Other small fields																	
Total					0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Check				Missing Data	Missing Data												
Total Gas (Non Ass & Ass)					0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Check Summary Gas						OK		OK	OK	OK	OK total exp:		OK	OK	OK	OK	OK

Total of field resources by category should be equal to the total resources reported at company level for the specific resource category.

Note: for "Location" please enter/select: 'Onshore', 'Offshore' or 'Deepwater'.
for "Operated" please enter/select: 'Operated' or 'non-Operated'.

Internal reporting: Expectation Estimate of Scope for Recovery: Oil

Input sheet Oil **1999**

Country Name : Mycountry
Estimate for Company: My Company

Estimate for year ending: 31 December 1999
Group share of scope for recovery

	Including potential entitlement after licence expiry				Within licence
	Com. SFR Proved	Com. SFR Unproved	Com. SFR Undisc.	SFR Non Com.	SFR Tot Com.
	10^6m^3	10^6m^3	10^6m^3	10^6m^3	10^6m^3
Expectation estimate of SFR 1.1.1999	0.00	0.00	0.00	0.00	0.00
New Entries					
Discoveries			0.00		
Terms & Conditions					
Purchases in place					
Sales in place					
Transfer to/from reserves	0.00	0.00	0.00	0.00	0.00
Economic revisions					
Technical revisions					
Deletions					
Expectation estimate of SFR 31.12.1999	0.00	0.00	0.00	0.00	0.00

Check	OK	OK	OK	OK	OK

Transfer SFR to/from Reserves	0.00	0.00	0.00	0.00	0.00
New Fields/Discoveries			0.00		
Extensions					
Other to/from Reserves (Imp. Rec.)					

Comments:

SFR Oil comments:

Note:

For oil fields associated gas volumes should be included if oil SFR is carried (also for undiscovered SFR)

Date: 05-Nov-99
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Internal reporting: Expectation Estimate of Scope for Recovery: NGL

Input sheet NGL **1999**

Country Name : Mycountry
Estimate for Company: My Company

Estimate for year ending: 31 December 1999
Group share of scope for recovery

	Including potential entitlement after licence expiry				Within licence
	Com. SFR Proved	Com. SFR Unproved	Com. SFR Undisc.	SFR Non Com.	SFR Tot Com.
	$10^6 m^3$	$10^6 m^3$	$10^6 m^3$	$10^6 m^3$	$10^6 m^3$
Expectation estimate of SFR 1.1.1999	0.00	0.00	0.00	0.00	0.00
New Entries					
Discoveries.			0.00		
Terms & Conditions					
Purchases in place					
Sales in place					
Transfer to/from reserves	0.00	0.00	0.00	0.00	0.00
Economic revisions					
Technical revisions					
Deletions					
Expectation estimate of SFR 31.12.1999	0.00	0.00	0.00	0.00	0.00
Check	OK	OK	OK	OK	OK

Transfer SFR to/from Reserves	0.00	0.00	0.00	0.00	0.00
New Fields/Discoveries			0.00		
Extensions					
Other to/from Reserves (Imp. Rec.)					

Comments:

SFR NGL comments:

Note:

For Gas fields associated NGL volumes should be included if Gas SFR is carried (also for undiscovered SFR)

Date: 05-Nov-99
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Internal reporting: Expectation Estimate of Scope for Recovery: Gas

Input sheet Gas **1999**

Country Name : Mycountry
Estimate for Company: My Company

Estimate for year ending: 31 December 1999
Group share of scope for recovery

	Including potential entitlement after licence expiry				Within licence
	Com. SFR Proved	Com. SFR Unproved	Com. SFR Undisc.	SFR Non Com.	SFR Tot Com.
	10^9 std. m^3	10^9 std. m^3	10^9 std. m^3	10^9 std. m^3	10^9 std. m^3
Expectation estimate of SFR 1.1.1999	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
New Entries					
Discoveries			0.000		
Terms & Conditions					
Purchases in place					
Sales in place					
Transfer to/from reserves	0.000	0.000	0.000	0.000	0.000
Economic revisions					
Technical revisions					
Deletions					
Expectation estimate of SFR 31.12.1999	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

Check	OK	OK	OK	OK	OK

Transfer SFR to/from Reserves	0.000	0.000	0.000	0.000	0.000
New Fields/Discoveries			0.000		
Extensions					
Other to/from Reserves (Imp. Rec.)					

Comments

SFR Gas comments:

Note:

For Gas fields associated NGL volumes should be included if Gas SFR is carried (also for undiscovered SFR)

Date: 05-Nov-99
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Internal reporting: Expectation Estimate of Exploration Discoveries

Input sheet 1999

Country Name : Mycountry

Estimate for Company : My Company

Estimate for recoverable volumes (excl. flare/own use). Listing does not necessarily imply commerciality, but there should be a reasonable expectation that volumes will be developable at a UTC below the annually advised ceiling for non-commercial SFR.
Estimates should be given for all wells which the OU expects to record as discoveries for the year.

			Oil		NGL		GAS	
			10^6 m^3		10^6 m^3		10^9 std. m^3 (tel quel)	
Field Name (Well)	Type	Area	Total	Shell share	Total	Shell share	Total	Shell share
Total : 0 Wells			0.00	0.00	0.00	0.00	0.000	0.000
Government PSC take, Royalty in Kind or Exploration carry								
Total Discovered (excl. G'ment take etc)				0.00		0.00		0.000

Comments:

Discoveries comments:

Note:
1) For oil discoveries associated gas volumes should be included
2) For gas discoveries associated NGL volumes should be included.

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Internal reporting: Expectation Estimate of Exploration Discoveries and Revisions 1990 - 1999 Oil/NGL

Input sheet Oil/NGL 1999
Country Name : Mycountry
Estimate for Company : My Company
Estimate for year ending: 31 December 1999

Year of discovery	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Total
Discoveries as initially reported	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Sales in place to 31.12.1998											0.0
Revisions from discovery to 31.12.1998											0.0
Check	OK	OK	OK	OK	OK	OK	OK	OK	OK		
Total resources at 31.12.1998	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.0
Sales inplace during 1999											0.0
Revisions during 1999											0.0
Discoveries during 1999										0.00	0.0
Total resources at 31.12.1999	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0
of which											
Company share of expectation produced											0.0
developed reserves (P2)											0.0
undeveloped reserves (P3+E3)											0.0
commercial SFR(P4+E4 and P5+E5)										0.00	0.0
non-commercial SFR (P7+E7)										0.00	0.0
Government PSC take (& Royalty in Kind/Carry)										0.00	0.0
Check	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	

Oil/NGL & Gas Unit Finding Cost	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Total
Exploration Expenditure [mln US$]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.0
Discoveries as initially reported [mln boe]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Total resources at 31.12.1999 [mln boe]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Unit Finding Cost (initial) [US$/boe]											
Unit Finding Cost (resources 31.12.1999)											

Discovered volumes reported historically were estimates of recoverable volumes and did not imply commerciality. From 1998 onwards volumes reported as discoveries should as a minimum fall below the annually advised UTC ceiling for non commercial SFR.
After initial discovery, volumes down to end year total resources are Company equity share at 100% expectation volumes (including potential recovery after licence expiry), excluding royalty in kind. In PSC countries, these volumes therefore include government PSC take.

(Oil and NGL volumes in x.xx 10^6 std. m^3 at standard conditions.)

Comments:

DREV comments:

Date: 05-Nov-99
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Internal reporting: Expectation Estimate of Exploration Discoveries and Revisions 1990 - 1999 Gas

Input sheet Gas 1999
Country Name : Mycountry
Estimate for Company : My Company
Estimate for year ending: 31 December 1999

Year of discovery	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Total
Discoveries as initially reported	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Sales in place to 31.12.1998											0.000
Revisions from discovery to 31.12.1998											0.000
Check	OK	OK	OK	OK	OK	OK	OK	OK	OK		
Total resources at 31.12.1998	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000
Sales inplace during 1999											0.000
Revisions during 1999											0.000
Discoveries during 1999										0.000	0.000
Total resources at 31.12.1999	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
of which											
Company share of expectation produced											0.000
developed reserves (P2)											0.000
undeveloped reserves (P3+E3)											0.000
commercial SFR(P4+E4 and P5+E5)										0.000	0.000
non-commercial SFR (P7+E7)										0.000	0.000
Government PSC take (& Royalty in Kind/Carry)										0.000	0.000
Check	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	

Discovered volumes reported historically were estimates of recoverable volumes and did not imply commerciality. From 1998 onwards volumes reported as discoveries should as a minimum fall below the annually advised UTC ceiling for non commercial SFR.
After initial discovery, volumes down to end year total resources are Company equity share at 100% expectation volumes (including potential recovery after licence expiry), excluding royalty in kind. In PSC countries, these volumes therefore include government PSC take.

(Gas volumes "tel quel" in x.xxx 10^9 std. m^3 at standard conditions.)

Comments:

DREV comments:

Date: 05-Nov-99
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[redacted]

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A2 External Reporting

The following submissions are required for external reporting:

1. Proved and Proved Developed Reserves Volumes Oil, NGL and Gas

Group share of proved and proved developed reserves as at the 31 December 1999 and reconciliation with the reserves reported in the previous year. Reserves are expressed in sales products.

If an OU/ NVO has interests in several licence areas subject to different contract types (e.g. concession, PSC or else), a separate submission must be made for each contract type.

1a. Summary of Major Changes to Proved Reserves

A breakdown by field should be provided for significant changes in the proved and proved developed reserves. This is a new format for 1999.

2. Statistical Data

Records Group share in acreage and wells as at year-end with reconciliation to previous year's statement.

3. Standardized Measure

Records the 'Standardized Measure of Discounted Future Net Cash Flow Relating to Proved Oil and Gas Quantities' as per FASB Statement no. 69. Reporting of Standardized Measure (SM) and quantification of changes to the SM applies to all ventures reporting proved reserves at 31.12.99 (to estimate SM'99 and quantify changes from SM'98) or previously reported proved reserves at 31.12.98 but now report proved reserves equal to zero (to quantify the changes from SM'98 to SM'99=0).

This year for the first time the actual Standardized Measure calculation and results are part of the submission (in previous years only the input data was submitted).

A2.1 Licence and Contract period

For external reporting, Group share of reserves (proved, proved developed) is limited to production within the existing licence or contract period. However, production beyond the licence or contract period can be included if there is a legal right to extend a production licence or PSC, or if the government has <u>formally</u> indicated that it will favour substantiated requests for extensions in the future (letter of assurance). Then volumes recoverable during the extension period are included in the Group share, assuming currently existing or other anticipated terms. Such considerations should be documented in the annual submission.

In some countries, the issue or duration of production licences for gas fields is effectively coupled to the conclusion of gas sales contracts. In other areas, a realistic target date for initiation must be set for projects that are not yet firmly planned so that the production forecast and other screening assumptions can be used to estimate the volume produced before licence or contract expiry.

A2.2 Change Categories

The change categories that apply to external reporting are defined as follows:

Revisions and Reclassifications	Represents changes in previous estimates of proved reserves, either upward or downward, resulting from new information (except for extensions) normally obtained from development drilling and production history or resulting from a change in economic factors.
Improved Recovery	Describes positive reserves changes allocated to a field where Reserves were already carried resulting from application of improved recovery techniques if significant. If not significant, such changes shall be included in revisions and reclassifications.
Extensions and Discoveries	Include Reserves volumes that are allocated for the first time to a discovered field and Reserves allocated for the first time to a discovered accumulation (e.g. a new fault block or reservoir), located within the boundaries of a field that already carries Reserves. First time allocation of proved reserves is not necessarily linked to the year of actual discovery of the field.
Purchases in Place	Include Reserves additions solely due to equity changes as a result of a financial or barter transaction.
Sales in Place	Include Reserves reductions solely due to equity changes as a result of a financial or barter transaction.
Production	Sales quantities sold during the year after fiscal metering and delivered at the location where the upstream company ceases to have an interest in the end products.

A2.3 SEC Standardized Measure

The SEC requires disclosure of the "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities", which is effectively the present value of the Group's Proved Reserves based on end year prices and operating cost at a prescribed 10% discount rate. The input data and the method of calculation have been standardized by the US Financial Accounting Standards Board (FASB in statement No 69).

Three options are available for calculating and reporting Standardised Measure in USD:

1) Standard Input (General OU/NVO/NOVs)

Based on input parameters (production and capex forecast) the SM value of proved reserves is calculated using year end oil, NGL and gas prices (unit revenue averages for 4q99) and operating costs (unit lifting cost by product average for full year 1999) all derived from 1999 CERES returns.
If OUs have proved production profiles available, these should be submitted and all input data should be consistent with the proved profile (e.g. capex necessary to achieve this production, abandonment cost related to this production profile, etc.). If proved production profiles are not available, the expectation profile should be submitted and all input data should be consistent with the expectation profiles (capex, abandonment cost, etc.). In the latter case, the model will truncate the expectation production profile as soon as the proved reserve volumes are produced and will apply proved-to-expectation ratios to capex and abandonment costs.
The present value of the after tax cash flows relating to abandonment of the fields that feature in the production profile should be calculated using a discount rate of 10%.
OU/NVO/NOVs are requested to submit the effective tax rate appropriate to the annual income from production, which should be consistent with CERES

2) Direct Cash Flow (Innovative Contracts)

The SM value of proved reserves is calculated based on detailed cash flow and proved production forecast directly provided by the company. Cash flow should be consistent with data supplied in CERES return (end year prices and lifting costs).

3) Special (USA and Canada)

Explicit input of SM and record of changes in local currency (USD or CAD).

Input data for the SM can be selected in either USD or local currency. End year (31.12.99) exchange rates between USD and local currencies will be provided by EPB-P early January 2000.

A2.4 Submission sheets

External reporting:	Estimate of Proved and Proved Developed Reserves Volumes: Oil, NGL and Gas
External reporting:	Summary of Major Changes Proved Reserves
External reporting:	Statistical Data
External reporting:	Standardized Measure

External reporting: Estimate of Proved and Proved Developed Reserves
Volumes: Oil, NGL and Gas

Input sheet 1 1999

Country Name : Mycountry

Estimate for Company: My Company

Estimate for year ending: 31 December 1999

Volumes are Group entitlement to sales volumes, based on a Group interest of: 0.00%

A Company share of : 0.00%

Excluding royalty in kinds as follows:

Oil Royalty in kind % 0.00%

NGL Royalty in kind % 0.00%

Gas Royalty in kind % 0.00%

Minority interest % 0.00%

	1999 - Input GROUP EQUITY			
	Oil 10^6 m³	NGL 10^6 m³	Gas 10^9 std. m³ (tel quel)	Gas 10^9 Nm³ (9600 kcal/Nm³)
Proved reserves at 1.1.1999	0.00	0.00	0.000	0.000
Revisions and Reclassifications				
Improved recovery				
Extensions and Discoveries				
Purchases in place				
Sales in place				
Production (i.e. net sales) during 1999				
Proved reserves at 31.12.1999	0.00	0.00	0.000	0.000
Proved developed reserves at 1.1.1999	0.00	0.00	0.000	0.000
Transfer Undeveloped to Developed				
Revisions				
Production (i.e. net sales) during 1999	0.00	0.00	0.000	0.000
Proved developed reserves at 31.12.1999	0.00	0.00	0.000	0.000
Minority Reserves included 1.1.1999	0.00	0.00	0.000	0.000
Minority Reserves included 31.12.1999	0.00	0.00	0.000	0.000

Check Proved	OK	OK	OK	OK
Check Proved Developed	OK	OK	OK	OK

These estimates were prepared in accordance with the current Group interpretation of the SEC guidelines

NB. Separate forms by field may be requested if different fields are held in different proportions.

Comments:

Sec sheet 1 comments:

Date: 05-Nov-99

Signed by — —

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External Reporting: Statistical Data

Input Sheet

Country Name : Mycountry
Estimate for Company : **My Company**
Group Interest :
Estimate for year ending : **1999**

		Gross	Net
Acreage (in thousands of square kilometres)			
Developed (i.e. any licence, lease or concession area which contains a production field)		0.00	0.00
Undeveloped (i.e. total minus developed holdings)		0.00	0.00
Number of wells (as carried by Company records)			
New wells drilled during the year	**Exploration** (potential accumulations)		
	dry	0	0.0
	not dry	0	0.0
	Development (prospective plus productive fields)		
	dry	0	0.0
	not dry	0	0.0
New wells drilling at end year	Exploration	0	0.0
	Development	0	0.0
Producing or capable of production during December	oil	0	0.0
	gas	0	0.0

Location of Activities (at year end)
Exploration
Production
Shell Operated

These estimates were prepared in accordance with the current Group interpretation of the SEC guidelines.

Comments:

Statistics comments:

Date: 05-Nov-99

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Standard Input (General OU/NVO/NOV)

External reporting: Standardized Measure

Input sheet 1 1999

Country Name : Mycountry

Entity Number

Profile within licence

		Oil 10^6 m^3 Expectation	NGL 10^6 m^3 Expectation	Gas 10^6 Nm^3 Expectation
Is this profile Proved or Expectation within licence? Click to Toggle -->				
Forecast of production of reserves within licence period.	2000			
	2001			
	2002			
	2003			
	2004			
	2005			
	2006			
	2007			
	2008			
	2009			
	2010			
	2011			
	2012			
	2013			
	2014			
	2015			
	2016			
	2017			
	2018			
	2019			
Total production 2000 to 2019		0.00	0.00	0.00
Remaining unproduced at 31.12.2019				
Total reserves		0.00	0.00	0.00
		OK	OK	OK

	Currency	USD		Units:	mln
Total forecast development expenditure RT99				2000	
				2001	
				2002	
				2003	
				2004	
Total development expenditure 2000 to 2004					0.0
Total development expenditure 2005 to 2019					
Total development expenditure					0.0

Financial data - total upstream (to be completed with Finance Department)

Tax written-down value of property, plant and equipment at 31.12.1999	
Tax losses carry forward as at 31.12.1999	
Present value of after tax Abandonment cost discounted with factor (j,b) at 31.12.1999	
Statutory tax rate consistent with Sector 01, line item [3643]	0%
Exchange Rate USD/USD at 31.12.1999	1.0000
Actual Development expenditure 1999	

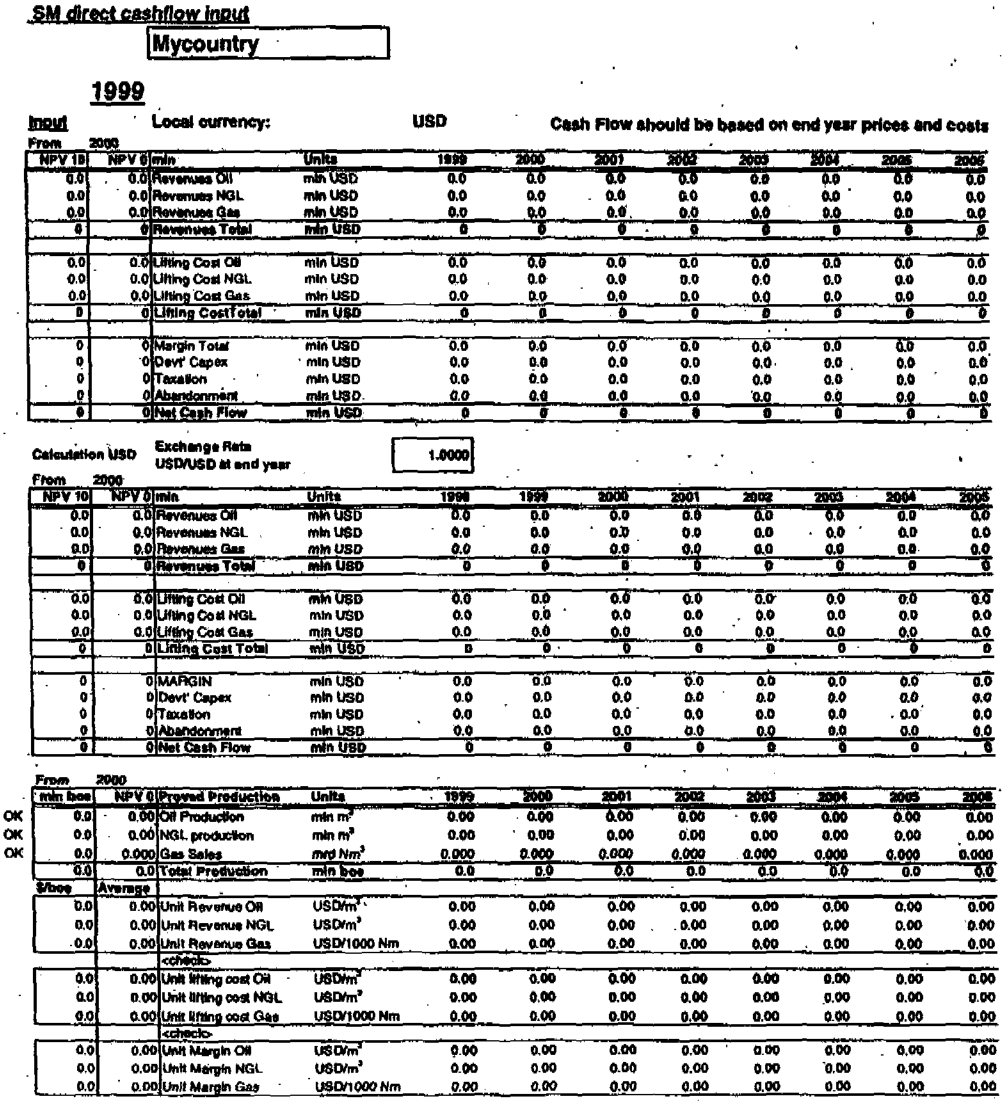
	A: revenues Q4	B: volume Q4	C: unit rev [A/ B]	CC:unit revenue net of roy [C-H]	unit margin [CC-G]
Use same Currency and units see above					
Oil:			0.00	0.00	0.00
NGL:			0.00	0.00	0.00
Gas:			0.00	0.00	0.00
	D: prod cost full year	*E: royalties full year*	*F: volume full year*	*G: unit prod cost [D / F]*	*H: unit royalty [E / F]*
Oil:			0.00	0.00	0.00
NGL:			0.00	0.00	0.00
Gas:			0.00	0.00	0.00

		total	developed	undeveloped
Proved Reserves, Oil	[mln m^3]	0.00	0.00	0.00
Proved Reserves, NGL	[mln m^3]	0.00	0.00	0.00
Proved Reserves, Gas	[mrd Nm^3]	0.000	0.000	0.000
Expectation Reserves within licence, Oil	[mln m^3]	0.00	0.00	0.00
Expectation Reserves within licence, NGL	[mln m^3]	0.00	0.00	0.00
Expectation Reserves within licence, Gas	[mrd Nm^3	0.000	0.000	0.000

Date: 05-Nov-99

Signed by — ...

Direct Cash Flow Input (Innovative Contracts).



SM direct cashflow input

Mycountry

1999

Input Local currency: USD Cash Flow should be based on end year prices and costs

From 2000

NPV 10	NPV 0	mln	Units	1999	2000	2001	2002	2003	2004	2005	2006
0.0	0.0	Revenues Oil	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	Revenues NGL	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	Revenues Gas	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Revenues Total	mln USD	0	0	0	0	0	0	0	0
0.0	0.0	Lifting Cost Oil	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	Lifting Cost NGL	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	Lifting Cost Gas	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Lifting CostTotal	mln USD	0	0	0	0	0	0	0	0
0	0	Margin Total	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Devt' Capex	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Taxation	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Abandonment	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Net Cash Flow	mln USD	0	0	0	0	0	0	0	0

Calculation USD Exchange Rate USD/USD at end year 1.0000

From 2000

NPV 10	NPV 0	mln	Units	1998	1999	2000	2001	2002	2003	2004	2005
0.0	0.0	Revenues Oil	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	Revenues NGL	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	Revenues Gas	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Revenues Total	mln USD	0	0	0	0	0	0	0	0
0.0	0.0	Lifting Cost Oil	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	Lifting Cost NGL	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	Lifting Cost Gas	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Lifting Cost Total	mln USD	0	0	0	0	0	0	0	0
0	0	MARGIN	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Devt' Capex	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Taxation	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Abandonment	mln USD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0	0	Net Cash Flow	mln USD	0	0	0	0	0	0	0	0

From 2000

	mln boe	NPV 0	Proved Production	Units	1999	2000	2001	2002	2003	2004	2005	2006
OK	0.0	0.00	Oil Production	mln m^3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OK	0.0	0.00	NGL production	mln m^3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OK	0.0	0.000	Gas Sales	mrd Nm^3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	0.0	0.0	Total Production	mln boe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	$/boe	Average										
	0.0	0.00	Unit Revenue Oil	USD/m^3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.0	0.00	Unit Revenue NGL	USD/m^3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.0	0.00	Unit Revenue Gas	USD/1000 Nm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
			<check>									
	0.0	0.00	Unit lifting cost Oil	USD/m^3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.0	0.00	Unit lifting cost NGL	USD/m^3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.0	0.00	Unit lifting cost Gas	USD/1000 Nm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
			<check>									
	0.0	0.00	Unit Margin Oil	USD/m^3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.0	0.00	Unit Margin NGL	USD/m^3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.0	0.00	Unit Margin Gas	USD/1000 Nm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Note: Only part of the sheet shown above.

Special (USA and Canada)

External reporting: Standardized Measure

Input sheet 2 1999

Country Name Mycountry
[redacted] Local Currency USD

	Local Currency				Currency USD		
$ millions	1999	1998	1997	1996	1999	1998	1997
Future cash inflows from sales of oil and gas	0	0	0		0	0	0
Future development costs (incl. Abandonment)	0	0	0		0	0	0
Future production costs	0	0	0		0	0	0
Future tax expenses	0	0	0		0	0	0
Future net cash flows	0	0	0		0	0	0
Effect of discounting net cash flows at 10%	0	0	0		0	0	0
Standardized measure of disc. future net cash flows	0	0	0	0	0	0	0

Analysis of Aggregate Change

	1999	1998	1997	1999	1998	1997
SM as at 1/1	0	0	0	0	0	0
a. changes in prices and lifting costs (net margin)	0	0	0	0	0	0
b. changes due to discoveries and improved recovery	0	0	0	0	0	0
c. changes due to purchases and sales of minerals	0	0	0	0	0	0
d. changes due to reserves revisions	0	0	0	0	0	0
e. changes in dev't costs related to future production	0	0	0	0	0	0
f. sales of Oil and Gas during the period	0	0	0	0	0	0
g. dev't cost incurred during the period	0	0	0	0	0	0
h. accretion of discount	0	0	0	0	0	0
i. net change in income tax	0	0	0	0	0	0
j. other (should be zero)	0	0	0	0	0	0
SM as at 31/12	0	0	0	0	0	0

	1999	1998	1997	1996	1999	1998	1997
Minority Share (%)	0.0000%	0.0000%	0.0000%				
Exchange rate USD/USD at end year	1.0000	1.0000	1.0000	1.0000			
Average Oil Price ($/bbl)	0.00	0.00	0.00		0.00	0.00	0.00
Average NGL Price ($/bbl)	0.00	0.00	0.00		0.00	0.00	0.00
Average Gas Price ($/boe)	0.00	0.00	0.00		0.00	0.00	0.00
Average Lifting Cost Oil ($/bbl)	0.00	0.00	0.00		0.00	0.00	0.00
Average Lifting Cost NGL ($/bbl)	0.00	0.00	0.00		0.00	0.00	0.00
Average Lifting Cost Gas ($/boe)	0.00	0.00	0.00		0.00	0.00	0.00
Average Margin Oil ($/bbl)	0.00	0.00	0.00		0.00	0.00	0.00
Average Margin NGL ($/bbl)	0.00	0.00	0.00		0.00	0.00	0.00
Average Margin Gas ($/boe)	0.00	0.00	0.00		0.00	0.00	0.00

Date: 05-Nov-99
Signed by --- --
Signed by Finance Mgr / Controller: ---
Original to SEPIV - EPB-P Portfolio and Economics FAX (+31) 70 377 2460

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A3 Guideline to the Reserves Reporting Workbook

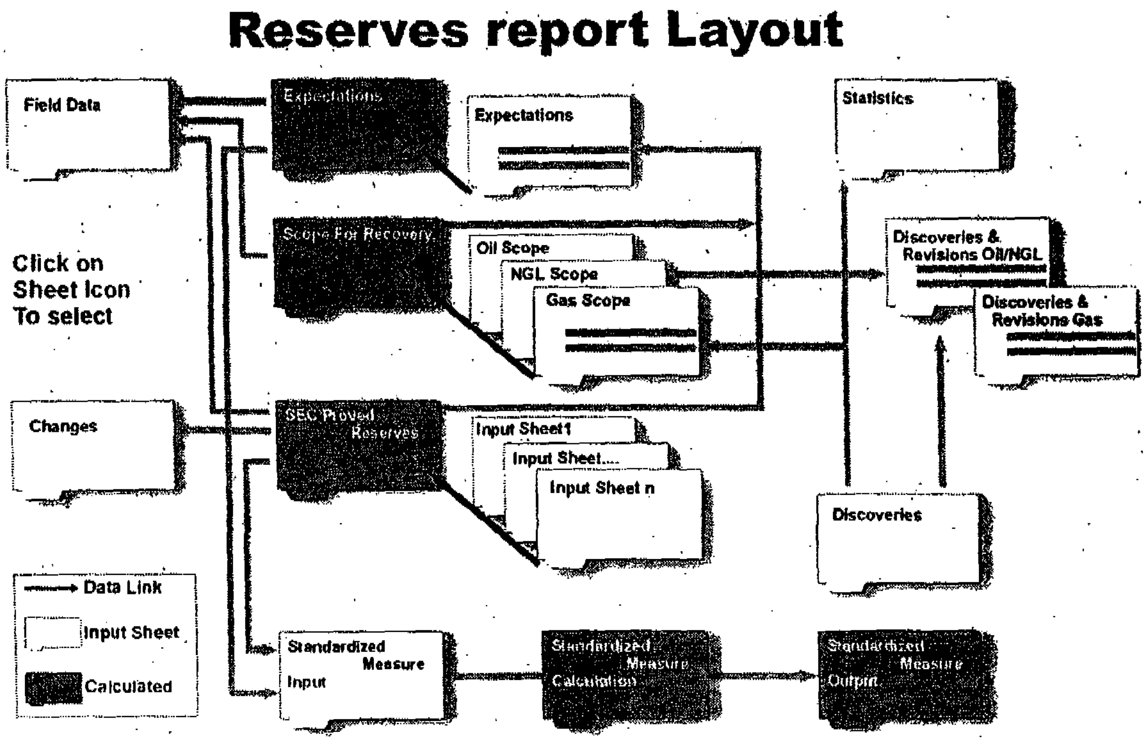
The Reserves Reporting Workbook is a Microsoft Excel workbook (Office'97 format) which contains all submission forms for the internal and external reporting of reserves volumes in spreadsheet format. The spreadsheets contain notes to assist the completing of the submission forms. Where possible, consistency checks are included.

Each year, each OU, NVO and NOV will receive its dedicated Reserves Reporting Workbook electronically, which already contains the relevant opening statements. The workbook is password protected. The password will be sent to OU and NVO reserves focal points separately.

EP Planning (EPB-P) is the custodian for the Reserves Reporting Workbook. Questions and suggestions regarding the workbook can be directed to the Group Hydrocarbon Resource Coordinator.

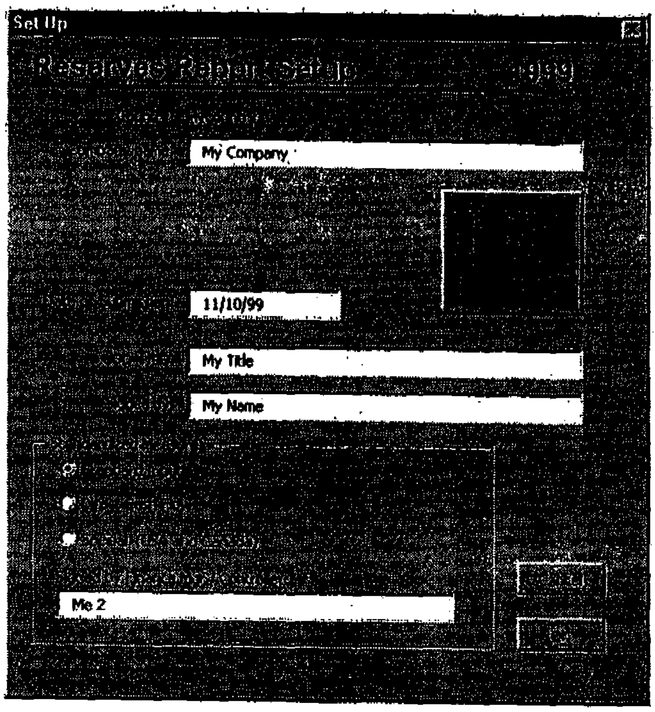
Road Map

When the model is opened the "Road Map" is shown as the default view. The Road Map gives an overview of the reserves workbook structure and can be used to navigate through the model. By clicking on the sheet icon, the sheet is selected.



Reserves Report Set-Up

When the workbook is opened for the first time, the set-up dialogue box will ask for general information, e.g. Company Name, Date, Job Title, and Name of the Manager responsible for signing. In the Standardized Measure box, the type of input and the Name of the Finance Manager/Controller who will sign the form are to be provided.



My Company

11/10/99

My Title

My Name

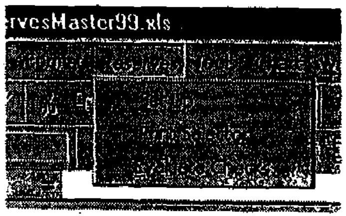
Me 2

The parameters can be changed at a later stage by using the "Set-Up" option in the main menu bar or from the 'road map'.

Utilities

The workbook will present a "Reserves" menu option in the main menu bar.

From this menu option three utilities can be pulled down which can be used to access the 'Set-Up' menu, the print selector menu and the 'evaluation log'.

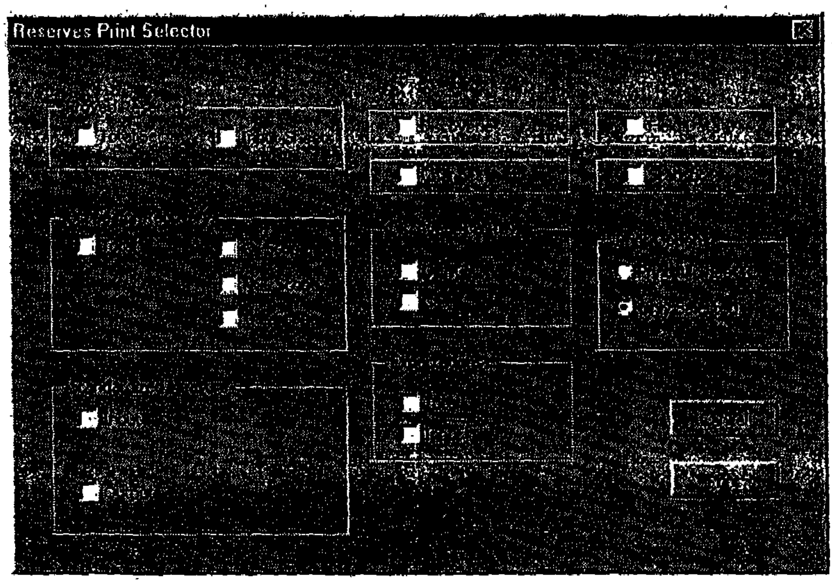


Set-Up

Allows changes to be made to the general data and Standardized Measure input selection as described under "Reserves Report Set-Up".

Print selector

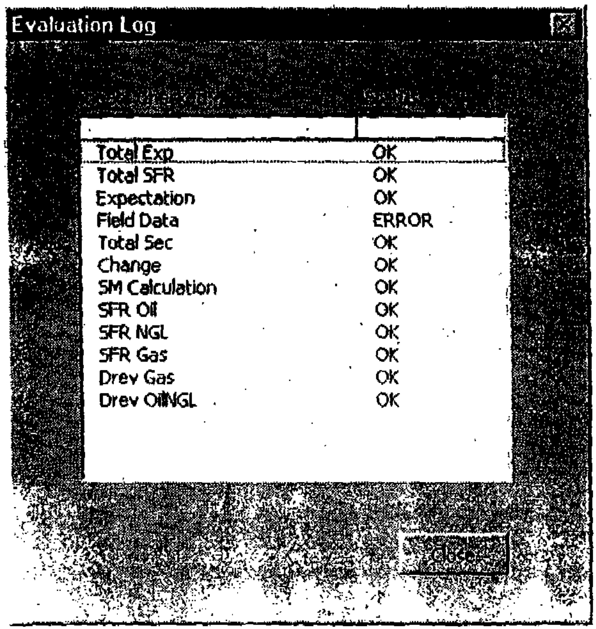
This menu allows printing of an individual selection of sheets from the workbook or all sheets in one go.



Evaluate Checks

Checks are built in on a number of sheets to ensure data consistency. These checks are automatically evaluated on closure of the workbook or when the 'Evaluate Checks' is selected from the pull down menu.

An evaluation log records the results of the checks. Please ensure that all checks are 'OK' prior to submitting the workbook to the Centre!



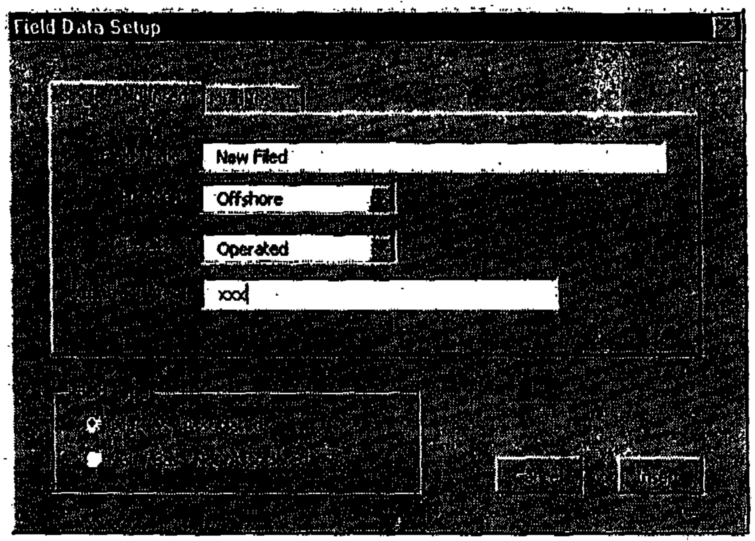
Total Exp	OK
Total SFR	OK
Expectation	OK
Field Data	ERROR
Total Sec	OK
Change	OK
SM Calculation	OK
SFR Oil	OK
SFR NGL	OK
SFR Gas	OK
Drev Gas	OK
Drev Oil/NGL	OK

Field Data

On the 'Field Data' sheet , additional lines to enter the resources volumes for individual fields can be dynamically added or deleted by using the 'red' or 'blue' buttons on the worksheet. The user has the choice to enter the additional lines field by field or to make a multiple entry.

Insert one field

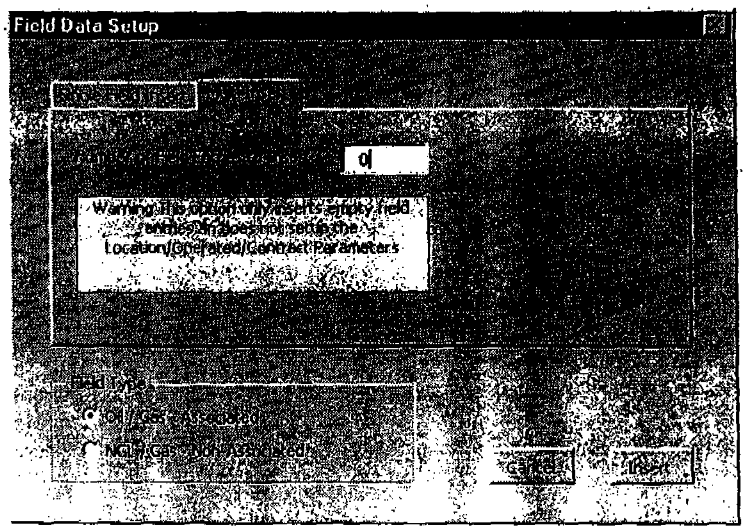
Entering data field by field can be done using the first 'tab' option in the menu which ensures a consistent set-up of the entered data,(i.e. Location/Operated and contract area)



New Filed
Offshore
Operated
xxx

Insert multiple field entries

This option can be used to insert a total number of blank lines equal to the total number of fields to be reported. Subsequently, the user can paste all field data, including field names and location/operated information directly from another electronic worksheet outside the model. Location and Operated information must be entered by the user. Note that these must be filled in as per the defined selection, as this is taken into account by the 'check' evaluation of the sheet.



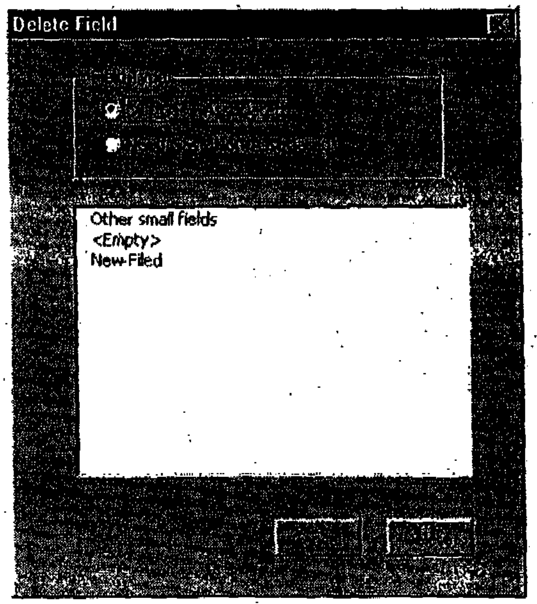
0

Warning: This option only inserts empty field entries. It does not set the Location/Operated/Contract Parameters

● Oil / Gas - Associated
○ NGL / Gas - Non Associated

Delete field entries

To remove a field entry from the sheet use the red button, this will bring up a dialogue from which the entry to be deleted can be selected, as shown below:



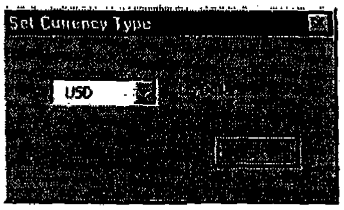
Other small fields
<Empty>
New-Filed

Standardized measure

The type of standardized measure input is defined in the "Set-up" menu.

Currency Selection

The local currency type has to be selected using a sheet button, this will show a dialogue containing the available currencies and will set the selected appropriate exchange rate.



USD

Exchange Rates

In January 2000 there will be a "plug in" distributed (via Email) which will update the internal Exchange Rates Table of the Reserves Report workbook. This plug-in is an Excel file, which will execute automatically on opening and only prompts for the Reserves Report workbook name.

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SIEP 2000-1100

Petroleum Resource Volume Guidelines

Resource Classification and Value Realisation

Custodian : SIEP-EPB-P
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TABLE OF CONTENTS

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1. INTRODUCTION

Petroleum resources represent a significant part of the company's upstream assets and are the foundation of most of its current and future upstream activities. Reserves replacement is the basis for a sustainable EP Business. To aid in understanding, planning, and decision making about these petroleum resources, resource volumes are classified according to the maturity or status of its associated development project. The current status and changes in petroleum resources, and specifically the commercially recoverable portion (reserves), are a significant concern to management. The future of the company depends on our effectiveness in maturing resources to the point where maximum economic value is realised.

For the Shell Group as a whole, petroleum resources are reported annually to ExCom and are essential information for the strategic planning process of the EP business. The current status and changes to the proved and proved developed reserves are also published in the Group's Annual Report and 20-F submitted to the Securities and Exchange Commission (SEC). Reserves also form a key component of analyst evaluation of company performance. Therefore the importance of these figures cannot be overemphasised. Reliability, uniformity, consistency, transparency and auditability are essential elements in the collation of petroleum resource reports by Operating Units (OUs) and New Venture Operations (NVOs).

Key issues are proved reserves replacement and realising maximum value from the total hydrocarbon resource portfolio, pursuing maturation of resource volumes to developed reserves and ultimately sales. Proved developed reserves though depreciation impact directly on the financial bottom line and therefore require special attention.

These guidelines serve as a reference for OUs and NVOs and as the standard against which audits will be conducted. The information on internal and external submission requirements and quantification methods are included in other communications. Submission requirements will be communicated annually in a letter from EP Planning.

The present, 2000 version contains a small number of corrections/modifications and clarifications compared to the 1999 edition, which are indicated by a line in the margin.

2. PETROLEUM RESOURCES

2.1 Definition

A petroleum resource is any accumulation of hydrocarbons that is known or anticipated to exist in a sub-surface rock formation, located in the company's current exploration and production acreage. If the petroleum resource extends beyond the company's licence area the resource volumes must be divided according to the granted licence boundaries, to take proper account of Group share.

Resource volumes are reported as the quantities of sales product for crude oil, natural gas and natural gas liquids. The corresponding quantities of field recovery should be maintained by the OU (See Appendix 6). The reporting of petroleum resource volumes should further indicate the petroleum type, the reporting units and conditions, and the Group share.

Resource volumes are tied to the project that develops them and are generally reported by field. The term **reserves** is used for resource volumes associated with a project that is technically and commercially mature. Resource volumes that do not meet these criteria are called **scope for recovery** (SFR). **Proved reserves** are the portion of reserves that is reasonably certain to be produced. These distinctions will be discussed in Sections 3 and 4.

2.2 Group Share

Only the Group share of resource volumes is reported. The Group share is determined by agreements with the resource holders. Resource volumes can be distinguished according to three different types of agreement, which are discussed below.

If an OU/NVO has interests in several licence areas subject to different contract types, a separate submission must be made with respect to proved reserves for each of the contract types.

Equity

Equity resources are the Group share of resources in Concessions. Concession agreements lay down the general terms and conditions of operation. These agreements with governments define the applicable tax rules, the Group share of resources in Concessions and the duration of the production licence.

Entitlement

Entitlement resources are the Group share of production in acreage governed by a Production Sharing Contract (PSC). The Group entitlement share of production is the Group interest in the sum of cost oil plus excess cost oil plus profit oil, in accordance with the PSC terms. The entitlement share is calculated from economic modelling reflecting current estimates of future costs.

Innovative Production Contracts

In recent years, a number of resource holding countries have introduced innovative production contracts in order to attract investment by foreign oil companies while preserving the principle of national resource ownership. These agreements typically provide for the contractor to recover costs and profits from hydrocarbon revenues while holding no title to, or entitlement to receive petroleum resources.

US Financial Accounting Standards Board (FASB) regulations have lagged behind these developments and provide little explicit guidance on reserves disclosure when the risks and rewards of ownership are carried without legal title to mineral rights.

However, volumes covered by such innovative contracts should be included in external reports in an informative way to be consistent with the spirit of the SEC regulations. The volumes from which economic benefit is derived should be reported if all three of the following conditions are met:

1. The OU participates in the production operations as either operator or in partnership with the operator, and so bears a share of the costs and risks of the production operations.

2. The OU derives future economic value that is directly related to the volume of hydrocarbons produced. For example, a fee expressed as a fixed or indexed amount per barrel of production would constitute a derivation of value from the produced hydrocarbons, but an operating fee that is largely independent of production would not. The actual source of revenues used to pay the OU is not crucial to this point. For example, if the remuneration is determined by a produced gas volume but paid from oil revenues, the economic value to the OU is in effect derived from the produced gas, and this volume should be reported.
3. The OU is exposed to the normal risks and rewards associated with ownership of mineral rights, including the downside and upside from changes in the value of future production volumes. These include the risk that costs may not be recovered, due to either uncertainty as to the presence or magnitude of hydrocarbon volumes or to movements in petroleum prices.

OUs and NVOs working under such contracts should complete the standard resource volume submission for the Group/Company interest in these volumes, noting the nature of the interest. Group share of production is calculated from economic modelling of total financial reward in line with contract terms versus total revenues. Reported volumes should be in line with the reporting of traditional reserves with regard to royalties and should therefore reflect the volumes from which pre-tax cash flow is derived. As elsewhere, cash royalties are regarded as a production cost.

When an OU is participating in a venture which grants neither title to, nor an entitlement to receive petroleum, and which does not satisfy the three criteria above the OU should not report reserves or production volumes. For example this might occur if the recovery of costs is guaranteed against adverse price movements or a shortfall in recovered volumes.

Licence or Contract Extensions

For internal reporting purposes, Group share of the expectation estimate of reserves and scope for recovery are recorded for the total producing life, i.e. including the period beyond the relinquishment date, but not covered by a right to extend or by a letter of assurance (see below). The currently existing licence terms or other anticipated terms should be assumed for this extrapolation. In addition to full life cycle volumes, resource volumes limited to the current licence only are recorded for total expectation reserves, developed expectation reserves and total commercial scope for recovery.

For external reporting, Group share of reserves (proved, proved developed) is limited to production within the existing licence or contract period. However, production beyond the licence or contract period can be included if there is a legal right to extend a production licence or PSC, or if the government has formally indicated that it will favour substantiated requests for extensions in the future (letter of assurance). Then volumes recoverable during the extension period are included in the Group share, assuming currently existing or other anticipated terms. Such considerations should be documented in the annual submission.

In some countries, the issue or duration of production licences for gas fields is effectively coupled to the conclusion of gas sales contracts. In other areas, a realistic target date for initiation must be set for projects that are not yet firmly planned so that the production forecast and other screening assumptions can be used to estimate the volume produced before licence or contract expiry.

Long Term Supply Agreements

FASB regulations (69 par. 13) require that quantities of oil or gas subject to purchase under long term supply, purchase or similar agreements should be reported separately, if the OU participates in the operation of the properties in which the oil or gas is located or otherwise serves as the "producer" of those reserves, as opposed, for example, to being an independent purchaser, broker, dealer, or importer.

The "supply" agreement should be a consequence of the OU acting as producer. This would not be the case if, for example, others had similar agreements but did not participate in the production operations.

These net quantities, as well as the net quantities received under the agreement during the year, should be included in the end year estimate of reserve volumes for external disclosure form.

Royalty Royalty is a payment made to the host government for the production of mineral resources. It is usually calculated as a percentage of revenues (payable in cash) or production (payable in kind).

Where in practice royalty obligations are met in kind (i.e. by delivering oil instead of cash), the Group share of production and reserves should be reported excluding these volumes.

Where royalty is payable in cash or is in principle payable in kind but the government has formally elected to receive, or customarily receives, payment in cash, Group share of production and reserves should be reported without deduction of equivalent royalty volumes.

Fees in kind Third Parties may in some cases pay Fees in Kind or Tariff in Kind (TIK) for the use of infrastructure (e.g. pipeline tariff, processing fee). Such volumes **received** by the company do <u>not</u> constitute a Group share in resources and should not be included in reported volumes. Condensate volumes recovered from a pipeline system related to transportation of Third Party gas volumes and sold by the company are equivalent to fees in kind received. All fees in kind received should be included as a purchased volume in the company accounts.

Where a company **pays** fees in kind (from its own fields/resources) to a Third Party, these do constitute a Group share in resources and should be included in the reported volumes. Annual volumes produced and used as fees in kind should be included in sales volumes, with associated revenues (at an agreed or fair market value) equivalent to booking of the incurred operating cost.

Open Acreage Group share of volumes is non-existent in open acreage and acreage for possible acquisition or farm-in.

Under/Over Lift Group share should also allow for any historic under or over lift by partners or government. A Group historic over lift should be reflected as an equivalent reduction of Group reserves, a Group historic under lift as an equivalent increase of Group reserves.

Group share should reflect impact of swap deals between fields where early production capacity in one is traded versus later production repayment by the other.

Treatment of take-or-pay volumes should be aligned with financial treatment of the cash received and booking of production volumes.

Committed Gas Reserves Total volumes of expectation gas reserves within licence, which have been sold (committed) under long and short term contractual agreements. In countries with a mature/deregulated gas market all gas reserves, which have a near certainty of market take-up can be classified as 'committed'.

Committable Gas Reserves Volumes of gas reserves, which have not been sold, but could be sold (committable) under contractual agreements. The sum of committed and committable gas reserves should equal expectation gas reserves within licence. Gas resource volumes, which are classified as scope for recovery due to lack market availability, should not be included.

Gas Re-injection Gas volumes re-injected in a reservoir, for pressure maintenance, gas conservation, Underground Gas Storage (UGS) incl. cushion gas, or other reasons, remain part of a company's resource base and should be accounted for as such. These gas volumes should be classified and reported as reserves or SFR, conform any other gas resource based on project assumptions for re-development (taking into account expected re-saturation losses).

Gas volumes re-injected in an Under Ground Storage (UGS) project on behalf of a Third Party (including any gas volumes previously sold by the company to this party) do <u>not</u> constitute a Group share in resources and should not be included in reported volumes.

Oil Sands Reporting of petroleum volumes (heavy oil, bitumen, syncrude, gas etc) recovered from "oil sands" (tar sand, oil shales, coals etc.) as part of hydrocarbon resources (reserves or SFR) is principally governed by the method of recovery of such volumes. Volumes produced through wells, generally from thermal methods are reported as part of the hydrocarbon resource base. Volumes recovered though mining and subsequently recovered from the mined product are not part of the hydrocarbon resource base and should be reported separately (see also Appendix 3 C4).

3. RESOURCE VOLUME CLASSIFICATION FOR INTERNAL REPORTING

3.1 Classification Scheme

The internal classification scheme shown in Figure 1 is intended to provide a consistent link between a field's resource volumes and the EP business model, identifying separately those resources that are the focus of the various stages in the development life cycle.

Cumulative Production	
Reserves:	Developed Reserves Undeveloped Reserves
Discovered Scope for Recovery:	Commercial Scope for Recovery by Proved Techniques Commercial Scope for Recovery by Unproved Techniques Non-Commercial Scope for Recovery
Undiscovered Scope for Recovery	Undiscovered Commercial Scope for Recovery
Discovered Initial In Place	

Figure 1: Resource Categories for Internal Reporting

A summary of the definitions for these categories is provided in Appendix 1. The cascade model (Figure 2) illustrates the migration of volumes between resource categories during the development life cycle.

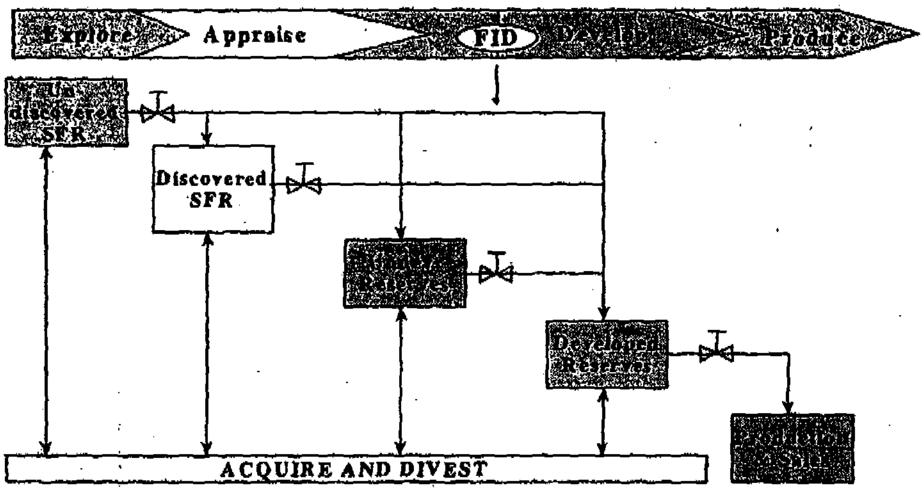

Figure 2: Cascade Model

A specific example of the migration of resource volumes between categories during a field's life cycle is shown in Appendix 2.

3.2 Value Realisation

The most important objective of resource volume management is the progression of the volumes to the point where maximum value is realised. The main purpose of the internal classification scheme tied to the development life cycle is to enable understanding of the potential value and the actions needed to mature volumes. In order to achieve business growth and reserves replacement objectives, it is essential that OUs and NVOs have efficient systems to move volumes through the value chain from scope for recovery to production and sales as shown in the cascade model.

OUs and NVOs internal reserve management systems should;

a) set targets and monitor actual performance in maturing volumes towards value realisation,

b) fully inventorise and have maturation plans for Scope for Recovery opportunities,

c) review ultimate recovery targets for existing fields and identify what activity - appraisal, study, new technology development, commercial agreement, etc. - is required to reach these targets,

d) and have Key Performance Indicators (KPI's) to measure performance (e.g. reserves replacement ratio, scope for recovery maturation ratio, time between discovery and first production).

3.3 Technical and Commercial Maturity

The classification scheme uses a project's technical and commercial maturity as the primary criteria to distinguish between reserves and scope for recovery (SFR). Resource volumes can be classified as reserves only if the associated project that will result in production of those volumes is considered to be technically and commercially mature. If it cannot, the resource volumes should be classified as SFR. SFR needs an activity (e.g. exploration appraisal, field trial, gas market development, etc) to achieve technical maturity and commercial viability. Secondary technical and commercial distinctions (between proved and unproved techniques SFR and between commercial and non-commercial SFR) further identify resource volumes at various stages in the life cycle.

Project Basis

Technical and commercial maturity reflects the status of remaining uncertainties in the assessment of the optimal development project and its associated recovery. A project is any proposed or notional modification of the wells, the production facilities and/or the production policy, aimed at changing the company's sales product forecast. It can also be a modification of the company's share in a venture (purchase/ sales-in-place, unitisation, or new terms). The generic term 'project' is also used to describe a group of (sometimes alternative) projects, each with a certain chance of realisation, depending on the results of further data gathering. In that case, the project NPV is replaced by the Expected Monetary Value (or EMV, see Appendix 6).

Technically Mature

For a project to be **technically mature**, information on the resource volume, including its level of uncertainty, is such that an optimal project can be defined with an auditable project development plan, based on a resource and development scenario description, with drilling/engineering cost estimates, a production forecast and economics. The plan may be notional or it may be an analogy of other projects based on similar resources. However, there should be a reasonable expectation that a firm development plan can be matured with time. Projects do not have to have a completed development plan. Successful completion of a Value Assurance Review (VAR) with sufficient definition supports technical maturity.

Commercially Mature

A **commercially mature** project is commercially viable over a sufficiently large portion of the range of possible scenarios that reflect the remaining resource uncertainties as well as the remaining commercial uncertainties, including market availability. The definition of what constitutes "a sufficiently large portion" may vary from case to case and could for example require the project NPV for the low reserves scenario to be positive for appropriate commercial criteria. It is also likely to include an assessment of the capital exposure in case of project failure due to adverse resource realisations. The selected range of scenarios should be documented and auditable.

Commercially Viable A scenario is **commercially viable** if the NPV is expected to be positive under the applicable (or expected) terms and conditions for the acreage and for the current advised Group reference criteria for commerciality (Reference 8).

Economically Viable A project is **economically viable** if the expected NPV under the applicable terms and conditions for the acreage exceeds the separately advised Group project screening criteria or if the project has already been approved by shareholders. Projects generally have to demonstrate economic viability in order to obtain investment approval. However, economic viability or formal project approval is not required for a project to be considered commercially mature. Reserves may be booked before project approval is sought.

3.4 Uncertainty Estimates

Uncertainty in resource volumes arises from using data and prediction techniques with varying degrees of uncertainty. The uncertainty in resource volume estimates can be assessed and represented using a variety of methods. Probabilistic methods determine a range of estimates and the associated probability that they will occur. Scenario deterministic methods determine best estimates for specific cases such as a low side case or a base case.

The terms low, expectation or high estimates are used in this document to simplify the discussion and to define reported volumes where consistency is required. When using a probabilistic methodology, low, expectation and high estimates are defined as the P85, Mean and P15 values from the probability distribution function (see Appendix 6 for definitions). When using a scenario deterministic methodology, low, expectation and high estimates are the low side case, base case and high side cases, respectively.

Only the expectation estimate for each of the resource categories is required for Internal reporting. The low estimate is usually used to define externally reported proved reserves. It is up to the OU to decide whether there is a need to determine other estimates.

Uncertainty Reduction with Performance The uncertainty range of ultimate recovery generally decreases as a field is developed and produced. However, the uncertainty range as a percentage of remaining reserves may not always decrease with time. **As a field matures, initial in place volumes and recovery should shift from a volumetric to a performance-based estimate, incorporating the additional production data to reduce the uncertainty range.** Once the reservoir performance has been established with reasonable certainty, a fairly small difference between low, expectation and high estimates would be expected. Definition of the low and high estimates may no longer be of value in mature fields with relatively little uncertainty and use of a single expectation estimate should be considered in this situation.

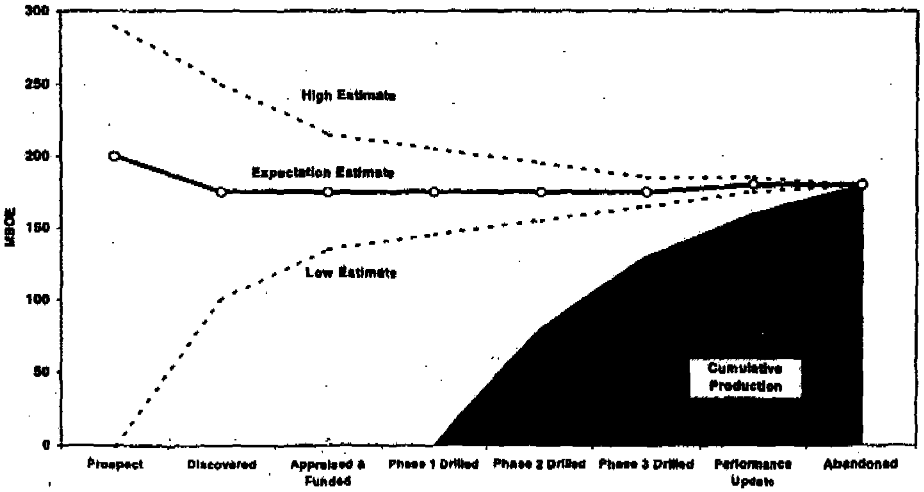

Figure 3: Uncertainty Reduction during the Field Life Cycle

Figure 3 illustrates the narrowing of the uncertainty with field appraisal and development. This is a near ideal example where the expectation remains constant for most of the life cycle. This example is also used in Appendix 2 to show the migration of resources between internal and external reporting categories during the field life cycle.

The reduction in uncertainty based on performance should be adequately reflected in the annual reserve and scope for recovery estimates for the field.

Addition of Resource Volumes

Resource volumes are added together at various levels during the resource assessment and reporting process. Addition of reserves at or above the level used for depreciation calculations must be arithmetical for consistency with financial accounting. Below this level, i.e. normally below the field level, addition should be done taking into account the dependency between the volumes to truly reflect the recoverable volumes associated with a project. Arithmetical addition is appropriate for dependent volumes, but usually overstates the uncertainty range for the sum of partially independent volumes. Probabilistic addition should be used for partially independent volumes when the difference with arithmetic addition is significant.

Below are two examples where the method of addition is important to handle properly.

1) Field A is comprised of separate layers and the properties of these layers are independent of each other. In other words, a low result in one layer would not increase or decrease the chance of a low result in the other layers. Low, expectation and high estimates are calculated for each layer separately. Probabilistic addition should be used to account for the reduced uncertainty of adding together independent volumes. Arithmetical addition of these estimates would understate the low estimate and overstate the high estimate of the total field.

2) A project develops three independent fields as sub-sea satellites connected to one platform. In this case, the investment in surface facilities may be totalled for depreciation[1] and consequently the reserves estimates should relate to the combined fields. Probabilistic addition should be used to calculate the total reserves associated with the platform.

Careful consideration should be given to Commercial SFR by proved techniques where eventual development is only incremental to an existing or planned development. These volumes may have a probability of success (POS) less than one, but with probabilistic addition will contribute at all levels - low, expectation and high - of reserves estimates. Examples of where this would apply are:

1) A fault block that is not yet tested and may be reasonably interpreted as an extension of the delineated area of the field. The project itself is technically and commercially mature. The untested block would be developed through existing field facilities without significant additional investment other than additional wells, which is recognised in the project scope. The uncertainty is geological and volumes are classed as reserves.

2) A phased development where there is uncertainty in the scope (e.g. number of wells) of a project due to geological uncertainty. However, the nature of the project remains essentially unchanged and additional wells could be accommodated within the flexibility of the field facilities design, then the whole range of recoverable volumes should be considered in deriving reserves. A scenario tree can be developed to represent the range of outcomes, both in recovered volumes and optimised number of wells, dependent on geological uncertainty. The uncertainty is resolved, with time, through planned data gathering eventually determining the number of wells. Hence the volumes can be regarded as technically mature. If one branch of the scenario tree is not economic, then the volumes associated with that arm do not contribute to reserves.

If probabilistic addition is used, ensure the methodology and parameters used are documented in the audit trail.

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[1] Group Accounts should be consulted when considering combining surface facilities for different fields for depreciation purposes.

3.5 Cumulative Production

The resource volume category "Cumulative Production" pertains to summation of sales quantities of production volumes up to the date of reporting. Consistency is required between sales and field quantities. Production Operations and Finance functions must reconcile their figures prior to any submission. Annual oil/NGL production [0933] and Gas Production available for Sales (from own reserves) (GPafS) [9130] as reported in CERES upstream sector **must equal** the volumes reported in the annual resource statement using the appropriate unit conversion factors.

3.6 Reserves

Reserves are the sales quantities anticipated to be produced and monetised from a discovered field associated with a project that is **technically and commercially mature** (see definition in Section 3.3). Petroleum volumes have been demonstrated to be producible through wells from the field. A market must reasonably be expected to be available.

The production forecast, and therefore the reserves, must be cut off at the point where cash generation becomes negative, i.e. when operating costs (with appropriate treatment of abandonment costs) exceeds sales revenues after royalties. If the remaining tail production is significant, it may be booked as Non-Commercial SFR (see below).

Production forecasts should reflect volumes available for sale taking into account all system constraints, abandonment timing, expected operational performance (planned and unplanned deferment), production quota restrictions, contractual sales volumes, market and other expected production limitations (community disturbance etc.).

The production forecasts must be adjusted for any volumes flared/vented and 'own use' (fuel for production facilities, compressors etc) in the upstream operations prior to transfer of the volumes to the buyer (Third Party or 'Downstream'). The definition for gas reserves and the definition for Gas Production available for Sale (GFIM) are fully aligned (both excluding flare/vent and own use).

The restriction of marketability is relevant to gas reserves and for the classification of those NGL products that are subject to go-ahead of a non-associated gas project. Apart from an assessment of the local market and identification of the type of export project (e.g. pipeline, LNG, methanol), this restriction implies earmarking the gas resources suitable to feed these outlets. The restriction applies to all confidence levels (low, expectation and high estimates) of reserves.

To minimise fluctuations over time, OUs and NVOs should exert caution in transferring volumes between the reserves and SFR categories. Demonstrable technical and commercial maturity will be required when new fields and reservoirs are added to the reserves base. The same requirement applies in principle when undeveloped reserves are retained. To retain developed reserves, their production should have a positive cash generation after subtraction of operating costs, tax and royalties.

Existing volumes classified as reserves, but which are no longer commercially mature, may be retained as reserves only in cases when there is an overriding strategic interest, or where a current small operating loss is expected to be reversed in the short term. In both cases support from shareholders must be obtained.

Developed Reserves

Developed reserves are the portion of reserves that is producible through currently existing completions, with installed facilities for treatment, compression, transportation and delivery, using existing operating methods. Outstanding project activities, such as initial completions, recompletions, hook-up and modifications to existing facilities, can be considered as existing or installed if the outstanding capital investment is minor (<10%) compared to the total project cost and if budget approval has been obtained. Volumes behind pipe are considered developed if additional activities (e.g. 'lower' zone abandonment, perforating, stimulating) do not require a full well entry/re-completion and if the future investment (normally opex) is minor (<10%) compared to a new well.

Developed reserves are estimated by forecasting the production that will be contributed by the existing wells through the currently installed facilities assuming no future development activity. Future wells or facilities may be planned that add reserves and/or accelerate the reserves that would be produced by the existing investments. However, the portion of reserves expected to be accelerated by future investments are classified as developed with the existing investments and not after the future investments. If future investment accelerates production such that additional reserves are recovered within time limits (e.g. sales contract periods, field life), the additional reserves are classified as developed only after these investments are made.

Undeveloped Reserves

Undeveloped reserves are the complement of developed reserves in the total reserves, requiring capital investment in new wells and/or production facilities in order to be produced.

For new development projects, developing additional reserves may defer field / platform abandonment and may thereby also increase the reserves producible from existing completions. Such gains should be included in the economic evaluation of the new development project and can only be classified as reserves if the project meets the technical and commercial criteria.

3.7 Scope for Recovery

Scope for Recovery is the recovery estimate of any notional project for which implementation cannot yet be shown with sufficient confidence to be technically sound or commercially viable. However, there must be an expectation that this project could mature based on reasonable assumptions about the success of additional data gathering, a maturing technology from current research, relaxation in the market constraints and/or the terms and conditions for implementing such a project.

The economic evaluation should include any future pre-investment costs required to reduce technical uncertainty.

In the case of immature projects, the associated scope for recovery may be reported as a single estimate for the undiscounted average recoveries in the case of success (mean success volume, MSV) together with a probability of success (POS). For aggregation purposes the risked expectation volumes are used (POS*MSV).

Commercial SFR

SFR which is expected to be commercially viable should be reported in one of the following three Commercial SFR categories.

Commercial SFR by Proved Techniques

SFR by proved techniques is the volume estimated to be recoverable from discovered resources, by a project utilising a recovery process or technique which has been demonstrated to be technically feasible in the area or in the field. Implementation is expected to be commercially viable, but a large range of technical uncertainty precludes the formulation of a technically sound project proposal.

Commercial SFR by Unproved Techniques

SFR by unproved techniques is the volume believed to be recoverable from discovered resources by a project utilising any recovery technique or process that has not yet been demonstrated to be technically feasible in the field where its application is considered, but which through laboratory or trials elsewhere has a reasonable chance of being technically feasible in the future. If feasible, the process should be expected to be commercial.

Future data gathering may disprove the technique, and with it the possibility of development, and these SFR volumes must therefore be discounted for the risk that the considered technique will not prove to be feasible.

Undiscovered Commercial SFR

Undiscovered SFR is the volume believed to be recoverable from as yet undrilled potential accumulations by any process that has been a technical success elsewhere, under similar conditions, and the development of which is expected to be commercial.

These SFR volumes must be discounted for the risk that petroleum is not present or is not commercial to develop (Probability of Success, see Appendix 6).

Future data gathering may result in a total write-off of these resources. Following drilling results, the resource volumes are revised and, in the case of a discovery, the economics re-assessed, whereupon the resource is either discarded or reclassified.

Non-Commercial SFR

SFR in discovered resources is considered non-commercial for development projects which, even if technically successful, would not be commercially viable. To avoid unrealistic situations the reporting of Non-Commercial SFR is restricted to projects with a Unit Technical Cost below an annually advised ceiling.

Non-commercial SFR is reported in order to retain an indication of the discovered resources that could become commercial with a change of circumstances (e.g. an increase in oil price, a change in tax regime, development of a gas market, flared/vented/re-injected gas volumes if recoverable and significant enough to be marketed).

The volumes reported for the four SFR resource categories numbers are based on full life cycle. In addition, total Commercial SFR within licence should also be reported.

3.8 Initial In Place

The petroleum volume Initially In Place (IIP) are expressed in volumes of Stock Tank Oil Initially In Place (STOIIP), Condensate Initially In Place (CIIP) and Gas Initially In Place (GIIP) under standard conditions. For standard conditions the same PVT data must be used as adopted for the reporting of field recoveries.

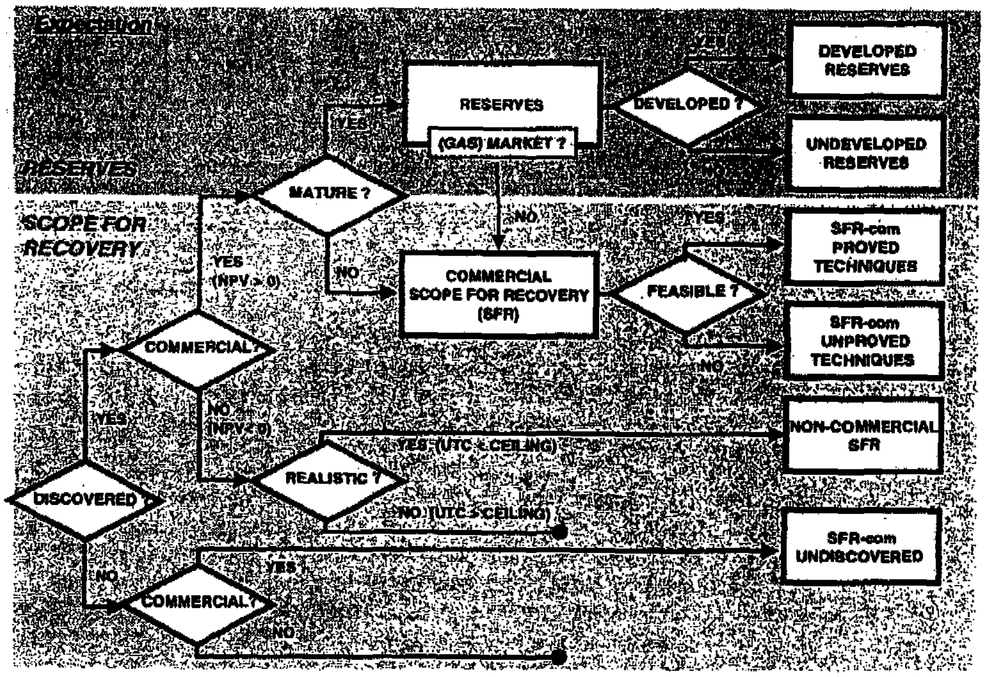

Figure 4: Internal resource classification flow diagram

4. RESOURCE VOLUME CLASSIFICATION FOR EXTERNAL REPORTING

4.1 Classification Scheme

Externally reported resource volumes have two primary purposes – financial calculations and investor assessments. The reported figures are used to calculate the depreciation of EP Business capital investments. The amount of depreciation affects the company's book earnings that are also externally reported. Shareholders and the investment community use the reported volumes and earnings to assess the performance and value of the company. It is essential that externally reported proved reserves volumes are a true reflection of shareholder value. Externally reported proved reserves volumes should be equal to internally used proved reserves numbers.

The resource categories for external reporting are shown in Figure 5. Cumulative production, total proved reserves and proved developed reserves are externally reported annually for oil, gas and NGL sales quantities as of the 1st of January. The reported volumes must comply with SEC definitions, reproduced in Appendix 3. The Shell Group definitions contained in this section are in full compliance with these definitions. Where Group guidelines interpret SEC definitions, as listed in Appendix 4, these interpretations have been accepted by external auditors as fulfilling SEC requirements. A summary of the Group definitions for the external categories is provided in Appendix 1.

Cumulative Production	
Proved Reserves:	Proved Developed Reserves Proved Undeveloped Reserves

Figure 5: Resource Categories for External Reporting

Cumulative production for external reporting has the same definition as used in the Shell internal classification scheme (see Section 3.5). An example of the migration of resource volumes between externally reported categories during a field's life cycle is shown in Appendix 2.

4.2 Proved Reserves

Proved reserves are those reserves that are reported externally[2] and are equal to the portion of reserves, as defined for internal reporting, that is **reasonably certain** to be produced and sold during the remaining period of existing production licences and agreements. Extension periods are only included if there is a legal right to extend, which may derive either from the initial concession agreement or from a subsequent letter of assurance. Any applicable government restrictions on oil export and contractual or practical market limitations to gas delivery rates should be taken into account. Only the Group share of proved reserves is reported.

If probabilistic methods are used, undeveloped reserves are reasonably certain when there is an 85% probability that the quantities actually recovered will equal or exceed the estimate. This is the P85 value of the cumulative probability curve. If scenario deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. This is the low side estimate. When the estimate assumes significant volumes of hydrocarbons outside the defined fluid contacts, or when the recovery mechanism is untested in the field or analogue fields, a lower estimate should be used that reflects this uncertainty. Reasonable certainty for developed reserves is the mean value or the base case for probabilistic or scenario deterministic methods respectively.

As discussed in Section 3.4, proved reserve estimates should be updated annually based on development and performance data.

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[2] Proved reserves are not by default equal to the P85 or low estimate!

Proved Developed Reserves

Proved developed reserves are the reasonably certain portion of internally reported developed reserves (i.e. produced from existing wells through installed facilities). Drilling and completing a well essentially proves the hydrocarbons that it develops and therefore proved developed reserves (as reported externally) are based on the expectation estimate of developed reserves adjusted to take into account of undefined fluids contacts, untested recovery mechanisms, licence periods, government restrictions and market limitations, as discussed above. The expectation estimate is the mean value if probabilistic methods are used or the base case estimate if scenario deterministic methods are used and should tie-in with the expected No Further Activity (NFA) production forecast.

Proved Undeveloped Reserves

Proved undeveloped reserves are the reasonably certain portion of internally reported undeveloped reserves (i.e. require additional capital investment for new wells or facilities). Reasonable certainty is met by using the P85 value or low side estimate of undeveloped reserves and taking into account undefined fluids contacts, untested recovery mechanisms, licence periods, government restrictions and market limitations, as discussed above.

Total proved reserves and proved developed reserves are often determined separately and though different methods, after which proved undeveloped reserves are calculated as the difference between the two. In mature fields, where a significant portion of the reserves has been developed, this approach can result in values for total proved reserves and proved undeveloped reserves that are no longer reasonable. Once a field is at this level of maturity, a deterministic approach should be used for both proved developed reserves and proved undeveloped reserves consistent with the SEC and SPE definitions (Appendix 3, Reference 7). Total proved reserves is then the sum of proved developed reserves and proved undeveloped reserves.

Estimates of proved reserves should be benchmarked against the "proved area" deterministic method consistent with the SEC and SPE definitions (Appendix 3, Reference 7). This method first defines the proved area[3] of the field and then estimates the volumes expected to be recovered from the proved area. If the proved and proved developed reserve estimates are significantly different using the proved area method (as generally used in the industry), a reconciliation should be made for the OU to assure itself that the reported reserves are a true reflection of shareholder value.

Asset holders should be aware of the differences between probabilistic and deterministic techniques since third parties, e.g. gas buyers and hence external reserves auditors for certification, may adopt different practices.

External Financing

For projects which require some degree of external financing (e.g. LNG projects, major new venture start-ups), project financing must be expected to be available before proved reserves are disclosed externally. This could, by exception, be a reason why the reserves of some viable projects are excluded from external reporting.

Improved Recovery Projects in External Disclosures

Advances in reservoir modelling techniques have greatly enhanced the systematic assessment of project recoveries across the full range of uncertainties, increasing confidence in the use of simulation results as the basis for investment decisions and reserves estimation. This improved quantification has in some cases shown that pilot testing is not necessary prior to project commitment (based on a Value of Information approach). Under these circumstances, recovery from improved recovery projects (e.g. fluid injection, reservoir blowdown) may be considered proved when the following three conditions are met:

1) A comprehensive assessment of uncertainties results in confidence that the actual volume will be greater than the low estimate.
2) The main features of the recovery process are supported by confirmed responses in analogous reservoirs.

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[3] The area of the reservoir considered as proved area includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data (Reference 7).

3) Project financing has been obtained or is expected to be available without a pilot testing phase.

In the case of improved gas recovery, the additional conditions in the following section also apply.

Proved Gas Reserves in External Disclosures

In addition to the foregoing conditions, proved reserves of natural gas should include only quantities falling in the following categories:

1) that are contracted to sales; or

2) that can be considered as reasonably certain of being sold based on a reasonable expectation of the availability of markets, along with transportation/ delivery facilities that are in place; or

3) that, while not firmly planned, have been earmarked for future development and hence may reasonably be anticipated to be sold based upon expectation of availability of markets and project financing.

These restrictions also apply to the external disclosure of condensate/NGL products that are subject to the go-ahead of a non-associated gas project.

Proved Reserves under Constrained Production

When operating under a combined production constraint (e.g. oil production quota) and production beyond the licence or agreement period is expected, the capability to accelerate the post licence production provides a safeguard against under-performance of the planned development programme during the licence period. This capability increases the confidence level that can be assigned to the constrained production forecast during the licence period. In this circumstance, the proved reserves should be based on an accelerated development programme that could be followed in the event that the base plan delivered less production than expected.

Types of Agreements

Under US Financial Accounting Standards Board (FASB) regulations, separate disclosure is required for oil and gas volumes applicable to different types of agreements. These requirements are illustrated in Figure 6.

Minority Interest

Reserves are reported on a 100% basis for companies in which the Group holds a controlling interest (in line with financial reporting) rather than on a Group share basis. Minority interest volumes included in the total proved reserves are disclosed separately.[4]

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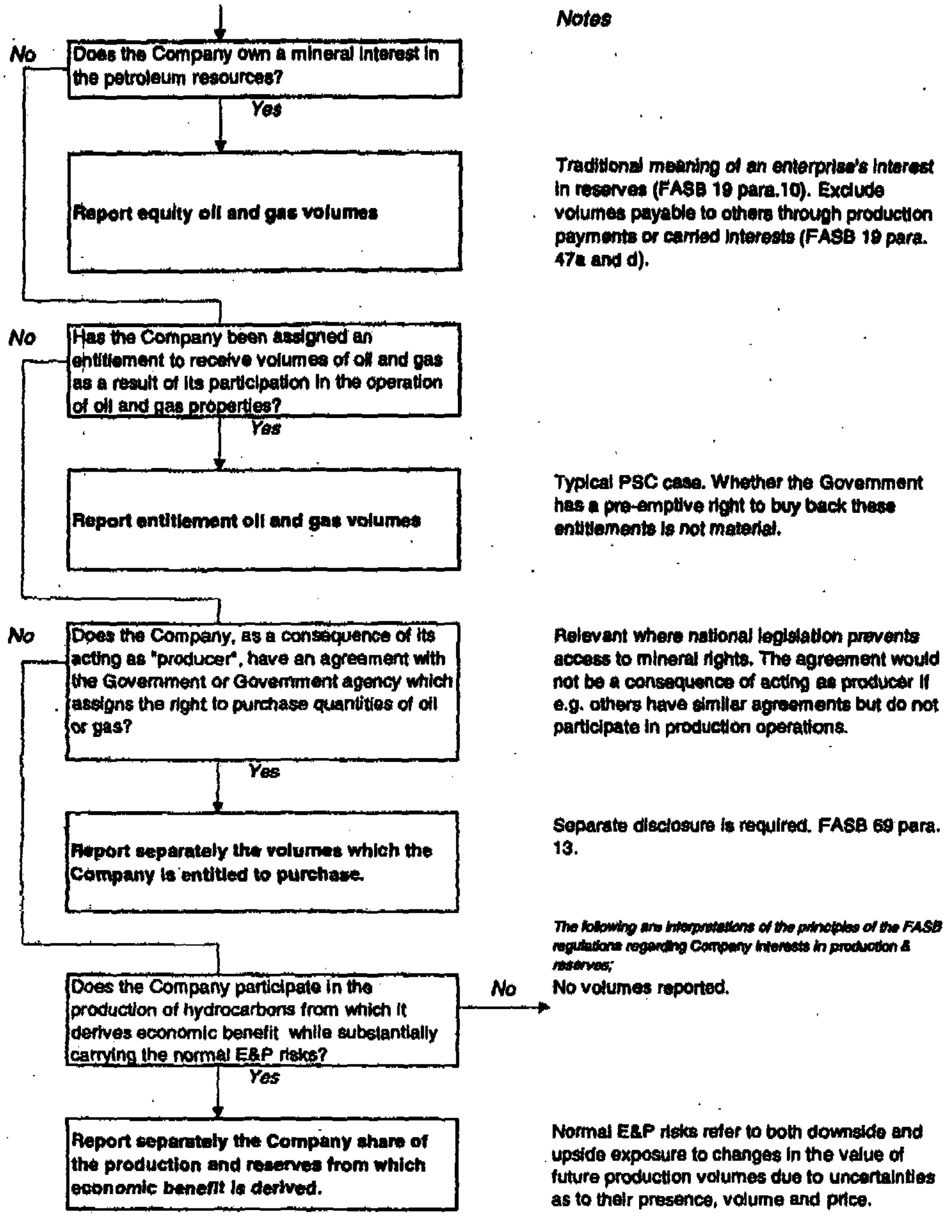
[4] Inclusion of minority interest requires prior agreement with the Group.



Traditional meaning of an enterprise's interest in reserves (FASB 19 para.10). Exclude volumes payable to others through production payments or carried interests (FASB 19 para. 47a and d).

Typical PSC case. Whether the Government has a pre-emptive right to buy back these entitlements is not material.

Relevant where national legislation prevents access to mineral rights. The agreement would not be a consequence of acting as producer if e.g. others have similar agreements but do not participate in production operations.

Separate disclosure is required. FASB 69 para. 13.

The following are interpretations of the principles of the FASB regulations regarding Company interests in production & reserves;

No volumes reported.

Normal E&P risks refer to both downside and upside exposure to changes in the value of future production volumes due to uncertainties as to their presence, volume and price.

Figure 6: Types of External Disclosures in Relation to FASB Regulations

5. RESOURCE VOLUME REPORTING, RESPONSIBILITIES AND AUDITS

5.1 Shareholder Requirements

EP Planning will communicate a timetable and the details about submission requirements to OUs and NVOs each year for both internal and external reporting.

Volumes will be reported based on the classification systems described in Sections 3 and 4. Additional information is reported for the calculation of the Standardized Measure required by the US Financial Accounting Standards Board (FASB).

5.2 Methods and Systems

OUs and NVOs are responsible for selecting the methods and systems that are technically most appropriate for quantifying the resource volumes of their assets consistent with these guidelines. The preferred methods and systems may vary depending on the type of resource and with time as the resource matures and technology improves.

A variety of commonly used Group and 3rd party systems are available to support resource volume assessment. Group systems are tailored to these requirements and methods and will generally provide an inherent level of quality assurance through input constraints, internal calibrations, and other "reality checks". Where more generalised 3rd party systems are used, OU and RBD management should be aware of the greater burden of quality control that will be required.

The Group Reserves Auditor will review decisions on methods and systems during the periodic audits. As far as these methods bear on the estimation of externally reported resource volumes, the Group Reserves Auditor will ensure that recommended methods are acceptable to the external auditors.

In some cases, OUs and NVOs may be unable to follow Group guidelines and/or recommended practice, due to government requirements, hardware constraints or other reasons. It is the responsibility of the OU Reserves Custodian to bring such cases to the attention of the Group Reserves Auditor, to enable him to obtain external auditors' approval of the OUs and NVOs specific methods and systems.

5.3 Responsibilities and Audit Requirements

EP Planning Responsibilities

EP Planning is responsible for compiling of the Group statistics of resource volumes, the analysis thereof and the communication to other functions. EP Planning also maintains the resource volume guidelines.

Reserves Auditor Responsibilities

The Group Reserves Auditor will carry out regular detailed reserves reviews in OUs and NVOs to ensure compliance with SEC requirements. The Terms of Reference of the SEC Audit are included in Appendix 5. The external auditor will verify the data for external reporting.

Operating Unit Responsibilities

Within OUs and NVOs, a Management System should be established (see Reference 6), clearly defining internal reporting requirements, tasks and responsibilities. Technical and Financial functions must co-ordinate and reconcile their figures (particularly production volumes) prior to submission.

All levels in an OU, including Asset managers and the reservoir engineer preparing the individual field reserves estimates, should be aware of the importance of externally reported reserves (proved, proved developed) and their impact on financial indicators.

Asset and OU managers are responsible to ensure that the guidelines are implemented in such a way as to best represent to the shareholders the true value of the asset.

Non-operated Reserves

Where Shell is not the operator, the local Shell EP representative should prepare the reserves submission. In this case the Shell representative has the responsibility of ensuring that resource volume assessments by the operator are aligned with Group guidelines before submission. This may include reclassification of volumes between reserves and SFR categories where the operator's criteria differ from Group criteria. As usual, an audit trail (Note for file) should be available to document the reserves estimate.

If there is no EP representative or if the necessary data are not available locally, then the submission is prepared by SEPI (responsible RBA).

Annual Review of Petroleum Resources

Until 1995, the Annual Review of Petroleum Resources (ARPR) was a constituent document of the annual EP Programme Documentation, providing an inventory of the status of petroleum resources. While OUs and NVOs no longer submit ARPR's to SIEP/SEPI, the compilation of such an overview report will generally be necessary to satisfy the requirements of OU governance and as such will be a key element of the OU reserves Management System referred to above.

Audit Trail

Audit trails form an essential element in the reserves reporting process and are an indispensable tool for the Group Reserves Auditor to assess the quality of the reserves estimates. They should support and document the submitted figures and ensure that OU management understand and own the reserves submissions to SIEP. They also form an essential link in handing over resource estimates between field reservoir engineers and reserves coordinators and their successors.

For all the reported resource volumes an audit trail must be available of the assumptions made and process followed. This will allow any subsequent assessor to modify these estimates based on new information in a reconcilable manner. Thus, evaluation reports must be compiled (preferably on a field basis) giving the basic data, the way it has been interpreted and processed, the development options considered, and the resultant volumes with the assigned probabilities. In addition, a description should be given of the development strategy, including data gathering activities. These reports may be working files (if acceptable to local auditors), but it is recommended to make a duplicate 'for file' in order to ensure that the data are preserved in field reports.

Where subsequent small revisions are made, an update note must be compiled. Multiple changes may be combined in one overall update of the resource volumes if they all belong to the same change category. After several years of small changes or following a development study, a new evaluation report must be issued. When a proposed change has a significant impact on the Company's total reserves or financials, SIEP/SEPI should be advised at the earliest opportunity.

Guidelines on how to prepare a good audit trail, with suggested formats for tables etc. can be found on the Shell World Web (Reference 11).

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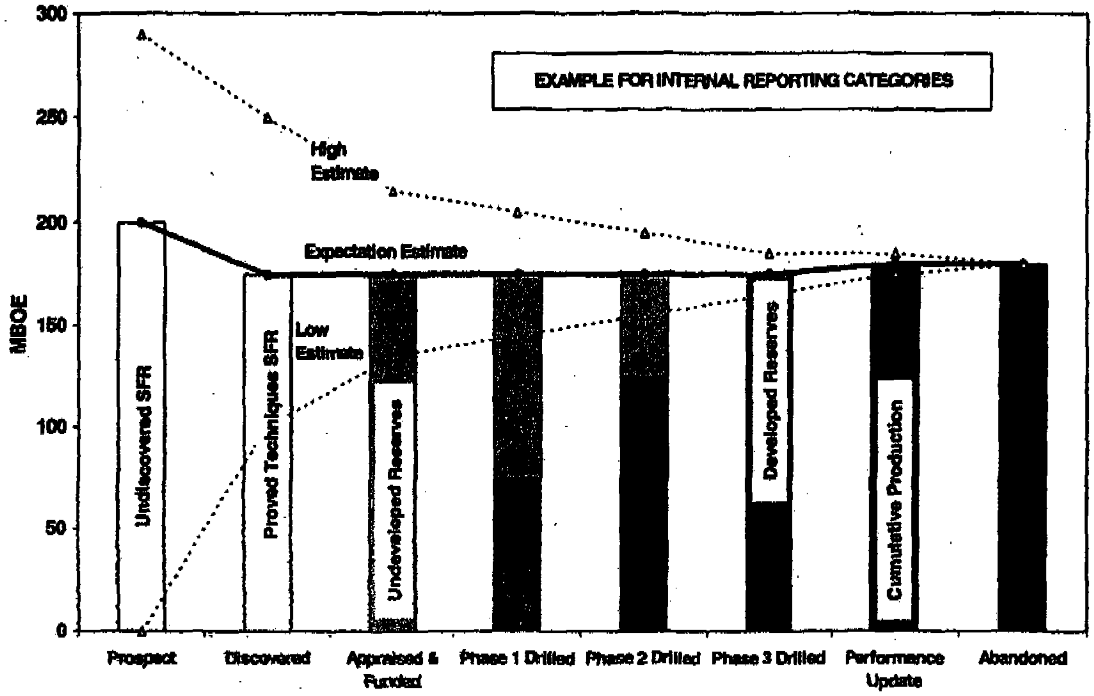
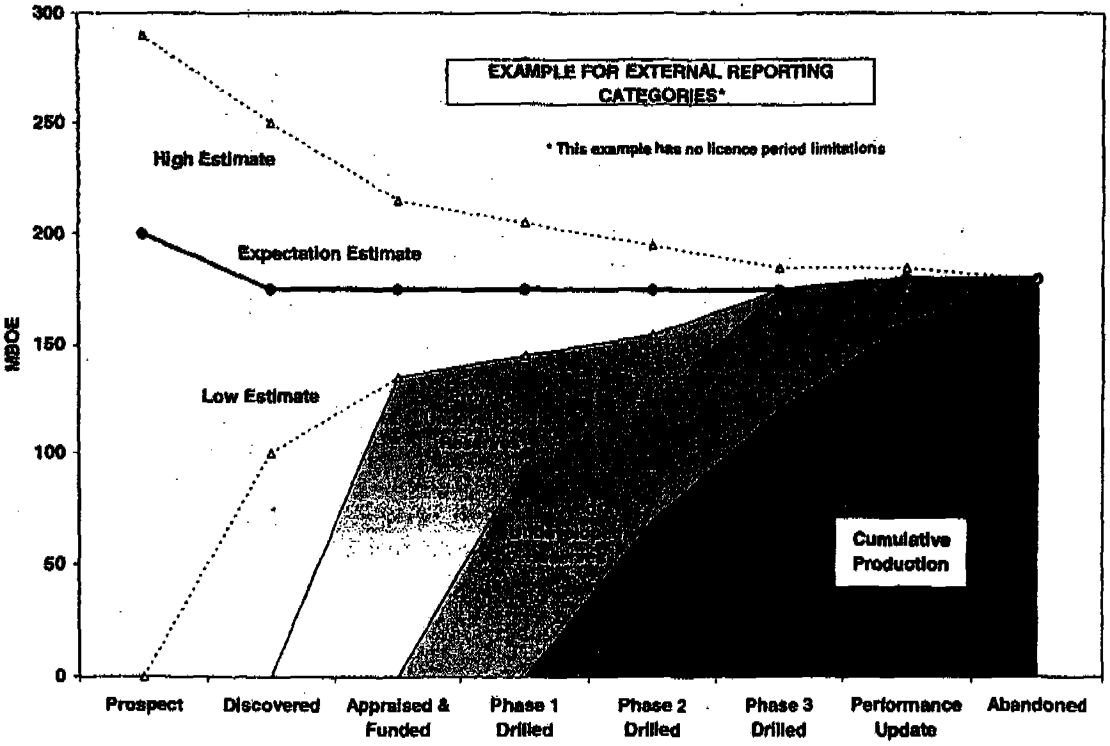
APPENDIX 1: RESOURCE CATEGORY (QUICK REFERENCE)

External Reporting	**Internal Reporting**	**Proved Reserves**		• Portion of reserves, as defined for internal reporting, that are reasonably certain • Restricted by licence periods, government constraints and market limitations • External financing, when used, must be expected to be available • Deterministically estimated volumes should reflect undefined fluid contacts and untested recovery mechanisms
			Proved Developed Reserves	• Proved reserves producible through existing completions and installed facilities using existing operation methods • Outstanding project activities considered completed if remaining cost <10% of total
			Proved Undeveloped Reserves	• Proved reserves which require capital investment (wells and/or facilities)
	Internal Reporting	**Reserves**		• Project is "technically and commercially mature" Note: Formal project approval or economic viability is not required • Market is reasonably expected to be available • Includes only production with positive cash flow • Not restricted by licence period • Group share reported
			Developed Reserves	• Reserves producible through existing completions and installed facilities using existing operation methods • Outstanding project activities considered completed if remaining cost <10% of total
			Undeveloped Reserves	• Reserves which require capital investment (wells and/or facilities)
		Scope for Recovery		• Project is not technically and/or commercially mature • Not restricted by licence period • Group share reported
			Commercial SFR by Proved Techniques	• Discovered • Commercially viable • Techniques have been proved to be feasible in this resource • A sound technical project proposal is not possible yet due to large range of technical uncertainty • Market not currently available
			Commercial SFR by Unproved Techniques	• Discovered • Commercially viable • Recoverable by techniques that have been successful elsewhere, but cannot yet be demonstrated to be feasible in this field • Laboratory work or trials elsewhere have a reasonable chance of demonstrating feasibility in this field • Discounted for the risk that the considered technique will not prove to be feasible
			Non-Commercial SFR	• Discovered • Not commercially viable even if technically successful • Commercially viable with a change of commercial circumstances • Unit Technical cost below an annually advised ceiling • Remaining tail production if it is significant
			Undiscovered Commercial SFR	• Recovery from undrilled prospects • Commercially viable exploration and development • Techniques have been successful elsewhere under similar conditions • Discounted for the risk that commercial volumes are not present

APPENDIX 2: RESOURCE MIGRATION DURING FIELD LIFE





APPENDIX 3: SEC PROVED RESERVES DEFINITIONS

(Transcribed from the Handbook of SEC Accounting and Disclosure 1998, pages F3-63 to F3-64)

Proved Reserves

Proved reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

A. Reservoirs are considered proved if economic productibility is supported by either actual production or conclusive formation test supports. The area of a reservoir considered proved includes:

1. that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and
2. the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

B. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

C. Estimates of proved reserves do not include the following:

1. oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";
2. crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
3. crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and
4. crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal (excluding certain coalbed methane gas), gilsonite and other such sources.

Proved Developed Reserves

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery techniques is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

APPENDIX 4: SHELL INTERPRETATION OF SEC RESERVE DEFINITIONS

SEC Definition	Shell Interpretation for External Reporting
Reasonable certainty; Proved area includes portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and the immediately adjoining portions not yet drilled. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.	If probabilistic methods are used, reserves are reasonably certain when there is an 85% probability that the quantities actually recovered will equal or exceed the estimate. This is the P85 value of the cumulative probability curve. If scenario deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. This is the low side estimate. When the estimate assumes significant volumes of hydrocarbons outside the defined fluid contacts, or when the recovery mechanism is untested in the field or analogue fields, a lower estimate should be used that reflects this uncertainty. Drilling and completing a well essentially proves the hydrocarbons that it develops and therefore proved developed reserves are based on the expectation estimate of developed reserves adjusted to take into account of undefined fluids contacts and untested recovery mechanisms.
Fixed RT prices at level prevailing at date of estimate	Prices fixed by SIEP ca. 6 months prior to estimate date, but amended if there is a subsequent significant change.
Fixed RT costs at level prevailing at date of estimate.	Costs fixed by OUs and NVOs at date of estimate. Flat MOD costs must be supported by technology plans to show that implied cost reductions are viable.
Economic productibility	Technically and commercially mature (i.e. positive discounted real terms cash flow for sufficient range of scenarios).
Productibility supported by either actual production or conclusive formation test supports	Productibility should normally be demonstrated by a conclusive test, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.
Improved recovery processes included only after successful testing by a pilot project or the operation of an installed program	Reserves from improved recovery processes are normally included following an in-situ test; by analogy with the same process being used elsewhere under similar conditions, or occasionally as a result of lab tests or simulation studies.
No gas qualifier	Include only gas contracted or reasonably expected to be sold.
Developed reserves are from existing wells (including minor cost recompletions), existing facilities and operating methods	Existing wells, installed facilities and existing operating methods. Outstanding project activities can be considered existing or installed if outstanding costs are minor and approved. This includes volumes behind pipe if future costs are minor.

APPENDIX 5: SEC AUDIT - TERMS OF REFERENCE

The purpose of the SEC Reserves Audit is to verify that appropriate processes are in place in the OU to ensure that the proved and proved developed reserves estimates for external (SEC) reporting are prepared in accordance with the latest Group prescribed guidelines (SIEP 2000-1100/1101) and the FASB Statement of Financial Accounting Standards no.69 (SFAS-69).

The Audit will be carried out by the Group Reserves Auditor. His specific tasks during the audit shall be:

1. To verify the technical maturity of the reported proved and proved developed reserves estimates by assessing the quality of the engineering data and study work supporting the estimates and by verifying that undeveloped reserves are based on identifiable projects that can be considered technically mature.
2. To verify the commercial maturity of the reported reserves volumes by assessing the robustness of project economics and by establishing that these volumes can reasonably be expected to be sold in present or future markets.
3. To verify the 'reasonable certainty' of the reserves estimates by assessing the validity of uncertainty ranges used for their constituent parameters, by verifying that estimates are realistic in comparison with expectation estimates, by verifying that appropriate methods are used for mature fields and by establishing that appropriate methods of reserves addition (probabilistic / arithmetic) have been applied.
4. To verify that the Group share of proved and proved developed volumes has been calculated properly and that these volumes are producible within prevailing licence periods.
5. To verify that reported volumes are up-to-date and consistent with previous estimates, that changes are reported in the appropriate categories and that appropriate audit trails are in place for the study work supporting the reported reserves estimates
6. To verify that reported reserves are net sales volumes and that the reported annual production (sales) volumes are consistent with those reported in submissions to Group Finance.

In case of deviations from the Group and FASB guidelines, the auditor shall establish whether and to what extent resulting estimates are likely to differ significantly from those that might be expected from the application of the standard guidelines.

The audit will be carried out by reviewing the reserves estimation and submission process through interviews of OU staff and by taking at random a number of fields for detailed analysis.

The frequency of the audit will in principle be once every four years for each OU, with possibility to extend this period to five years for medium sized OUs and six years for small OUs. Major reserves changes or concerns expressed during a previous audit may require an advancement of the next audit. For an OU reporting reserves for the first time, the first audit will in principle be within two years of this first submission.

The audit will in principle be carried out on OU premises and will be based on documentation available in the OU. Assistance of OU staff may be called upon.

An audit report will be submitted to the Managing Director of the OU, to the EP CEO and EP RBA, to the OU's Hydrocarbon Resource Manager and to KPMG the external auditors. It will be prepared and discussed in draft form on site, after which a final report will be prepared in The Hague, once formal OU comments are received. The report will contain an overall judgement (Good, Satisfactory, or Unsatisfactory), with itemised conclusions and recommendations.

APPENDIX 6: TERMINOLOGY

A) Petroleum Resources Terminology

Reservoir A reservoir is a discovered petroleum resource where internal pressure communication is known to exist between all identified geological sub-units.

In case of doubt, reservoirs are restricted to fault blocks / sedimentary units until production performance proves communication to exist across faults/ barriers. PVT properties can vary within a reservoir.

Field A field is the collection of all petroleum resources within a closed areal boundary that belong to the same confining geological structure, and where the presence of petroleum has been demonstrated in at least one reservoir by a successful exploration well.

Field boundaries must be defined upon discovery and should encompass the unpenetrated petroleum resources in adjacent fault blocks and stratigraphic traps, if they are considered to be part of the same overall confining structure. Field boundaries may be re-defined on the basis of new geological information.

Potential Accumulations Potential petroleum resources beyond existing field boundaries, where the presence of petroleum has not yet been demonstrated, are collectively called potential accumulations.

Producibility Should normally be supported by a conclusive test in a drilled or immediately adjoining reservoir, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.

Production Facilities The production facilities consist of all hardware installed to recover petroleum from the sub-surface resources and to deliver a quality controlled end-product for sale. These comprise the production and injection wells and the surface facilities for treatment, conversion, compression/ pumping, transport and delivery.

Surface Facilities That part of the production facilities accessible at surface, connecting the wellheads ultimately to the delivery points.

Existing Development The collection of all completed projects or sub-projects is referred to as the existing development.

Field quantities Field quantities (also called "Wellhead" quantities) are those quantities routinely measured at surface for individual well strings and expressed in terms of the stabilised products oil, condensate and (wet) gas or in terms of the type of injected fluids. These quantities may subsequently be reconciled with fiscalised sales and other product outlets, see below.

Sales quantities The quantities sold after fiscal metering and delivered at the locations where the upstream company ceases to have an interest in the end-products. These can be expressed in terms of the general end-products oil, (dry) gas and natural gas liquids (NGL) or in terms of the actual product.

Field products and the subsequent sales products may be different and will be affected by own use and losses. The properties and volumes of end-products may be influenced by mixing and the petroleum type itself may be altered during surface processing. Since surface processing conditions may change during a project life, sales products may vary in specification and in relation to field products. To avoid ambiguity and double counting, a clear distinction must be made between recoveries in the field and the quantities estimated to be available for sale.

For general sales products, oil, gas and NGL, only the quantities sold by the upstream E&P company can contribute to Group reserves. Condensates mixed with crude oil in the same stream and sold as such are reported under oil. Separator condensate from gas wells and light hydrocarbon liquid products, derived from surface processing, if collected in a separate stream and sold as such are reported under NGL. Bitumen may be reported under oil in summary reports (with an appropriate footnote). *In line with SEC requirements*, sales volumes for gas should be those committed or commitable to a gas contract. Committed Gas is covered by a gas contract. Commitable gas reasonably expected to be assigned to a contract in the future.

It is necessary to maintain a more detailed internal administration of the actually sold products by stream in two cases: 1) If the upstream E&P company has separate contracts for delivery of special converted sales products such as LNG, methanol, ethane, LPG, C5+, or 2) if there are special sales products like helium, sulphur or generated electricity.

Reconciliation A monthly reconciliation is made between the fiscalised sales quantities and the quantities produced in the field. This is reported in the Monthly Report of Producing Wells (MRPW). The reconciliation process corrects for own use, flaring, losses and product conversion, and provides the end-product yield.

For reserves estimating purposes an average future yield factor is to be estimated (e.g. LPG/ wet gas yield, dry gas/ wet gas yield).

Ultimate Recovery The ultimate recovery (UR) of a petroleum type is the sum of cumulative production and the estimated volume of reserves.

B) Probabilistic Terminology

Probability Distribution Function The probability distribution function of a stochastic variable indicates the probability that the actual variable value lies within a narrow interval around a particular value of the possible range, divided by the width of that interval.

P85 The value that has a 85% probability that it will be exceeded.

P15 The value that has a 15% probability that it will be exceeded.

Mean The statistical mean of a stochastic variable is the weighted average over the entire probability range.

Mean Success Volume (MSV) The probability weighted average of all realisations that equal or exceed the minimum reserves required for a commercial development of the resource.

Probability of Success (POS) The probability that the minimum commercial volume will be exceeded and which therefore indicates the likelihood of any future development. The product of MSV and POS is the recovery expectation.

C) Commercial Terminology

Discount Rate A rate at which future real terms costs or cash-flow are discounted over time to calculate their present value.

Net Present Value (NPV) The net present value of a project is the sum of the discounted annual cash flow, expressed in real terms money, over the period from the first project expenditure to abandonment. The net present value is expressed in million US$ at the relevant discount rate.

Expected Monetary Value (EMV) The expected monetary value is a probabilistic balance of investments and revenues, expected from a set of conditional operational activities, comprising data acquisition and one or more development projects, which are arranged in an ordered sequence with probabilities assigned to each action (decision tree).

The EMV is the summation of the NPV's of projects, reduced by the costs of data acquisition activities, all expressed in discounted real term money and multiplied by their assigned probabilities. EMV is expressed in million US$ at the relevant discount rate.

Projects with a negative NPV for certain resource model realisations should be excluded from the EMV calculation, if the assumption is valid that data gathering will prevent such projects being implemented.

Unit Technical Cost (UTC) The unit technical cost of a development project is defined as the sum of capital plus operating costs, expressed in real terms money, divided by the total production over the period from start-up to abandonment. In addition, both the cost and the production must be discounted. The reference date for the discounting should be the same for denominator and numerator (e.g. the first year of expenditure) and should be stated. The unit technical costs is expressed in US$/bbl (oil equivalent) at the relevant discount rate.

D) Exploration versus Development Wells

The classification of a well as either an exploration well or as a development well is determined (in line with SEC rules) based on the proved area as follows:

Proved Area	The **proved area** is the part of a property to which proved reserves have been specifically attributed.
Exploration Well	An **exploration well** is a well that is not a development well, a service well, or a stratigraphic test well.
Development Well	A **development well** is a well drilled within the proved area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.
Service Well	A **service well** is basically any well which is either an injection well, a disposal well or a water supply well.
Appraisal Well	An **appraisal well,** or **stratigraphic test well** is a well drilled for geological information (not to test a prospect), either 'development-type' drilled in a proved area or 'exploratory-type' if not drilled in a proved area.

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EP 2001-1100

Petroleum Resource Volume Guidelines
Resource Classification and Value Realisation

DEPOSITION
EXHIBIT
Barendregt
#7 2/20/07

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Petroleum Resource Volume Guidelines
Resource Classification and Value Realisation

Custodian:	SIEP EPB-P
Date of issue:	September 2001
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KEYWORDS

Resource Volumes, Guidelines, Reserves, FASB, SEC

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1. INTRODUCTION

Petroleum resources represent a significant part of the company's upstream assets and are the foundation of most of its current and future upstream activities. Reserves replacement is the basis for a sustainable EP Business. The current status and changes in petroleum resources, and specifically the commercially recoverable portion (reserves), are a significant concern to Group Management. The future of the Group depends on our effectiveness in maturing resources to the point where maximum economic value is realised. To aid in understanding, planning, and decision making about these petroleum resources, resource volumes are classified according to the maturity or status of their associated development activities.

Shell Group wide petroleum resource volumes are reported annually to ExCom and are essential information for the strategic planning process of the EP business. The current status and changes to the proved and proved developed reserves are also published in the Group's Annual Report and 20-F submitted to the Securities and Exchange Commission (SEC). Reserves also form a key component of evaluation of company performance by financial analysts. Therefore the importance of these figures cannot be overemphasised. Reliability, uniformity, consistency, transparency and auditability are essential elements in the collation of petroleum resource reports by Operating Units (OUs) and New Venture Operations (NVOs).

Key issues are proved reserves replacement and the realisation of maximum value from the total hydrocarbon resource portfolio, by pursuing maturation of resource volumes to developed reserves and ultimately sales. Proved developed reserves have, through depreciation, a direct impact on the financial bottom line and therefore require special attention.

These guidelines serve as a reference for OUs and NVOs in the reserves submission and reporting process and as the standard against which audits will be conducted. The information on the format requirements of internal and external submission is included in the second part of these guidelines (SIEP 2001-1101, Ref. 5d). Submission requirements will be communicated annually in a letter from EP Planning.

The present 2001 version contains a significant number of changes compared to the 2000 edition. These changes address an improvement of the report's readibility, the addition of a chapter on methods of quantifying uncertainty and an expanded text describing the new reserves guidelines introduced in 1998. The changes should be seen as editorial only. No change in the volume of reported reserves is intended or expected. Where text has been changed or added, this is indicated by a line in the margin.

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2. RESOURCE VOLUME CLASSIFICATION

2.1 Definition

A petroleum resource is any accumulation of hydrocarbons that is known or anticipated to exist in a sub-surface rock formation, located in the company's current exploration and production acreage. If the petroleum resource extends beyond the company's licence area the resource volumes must be divided according to the granted licence boundaries, to take proper account of Group share.

Resource volumes are reported as the quantities of sales product for crude oil, natural gas and natural gas liquids. The corresponding quantities of field recovery should be maintained by the OU (See Appendix 6). The reporting of petroleum resource volumes should further indicate the petroleum type, the reporting units and conditions, and the Group share.

2.2 Reserves and SFR

Resource volumes are tied to the project or activity that develops them and are generally reported by field. The term **reserves** is used for resource volumes associated with a project that is **technically and commercially mature**. Resource volumes that do not meet these criteria are called **Scope for Recovery** (SFR). **Proved reserves** are the portion of reserves that is reasonably certain to be produced and which will be reported externally. These distinctions will be discussed in Chapters 3, 5 and 6.

The classification scheme shown in Figure 1 is intended to provide a consistent link between a field's resource volumes and the EP business model, identifying separately those resources that are the focus of the various stages in the development life cycle.

Cumulative Production	Sum of successive Annual Production volumes
Reserves:	Developed Reserves (Proved and Expectation) Undeveloped Reserves (Proved and Expectation)
Discovered Scope for Recovery (SFR):	Commercial SFR by Proved Techniques Commercial SFR by Unproved Techniques Non-Commercial SFR
Undiscovered Scope for Recovery	Undiscovered Commercial SFR
Discovered Initial In Place	

Figure 1: Group Resource Categories

These categories are further explained in this Chapter and their definitions are summarised in Appendix 1.

The cascade model (Figure 2) illustrates the migration of volumes between resource categories during the development life cycle.

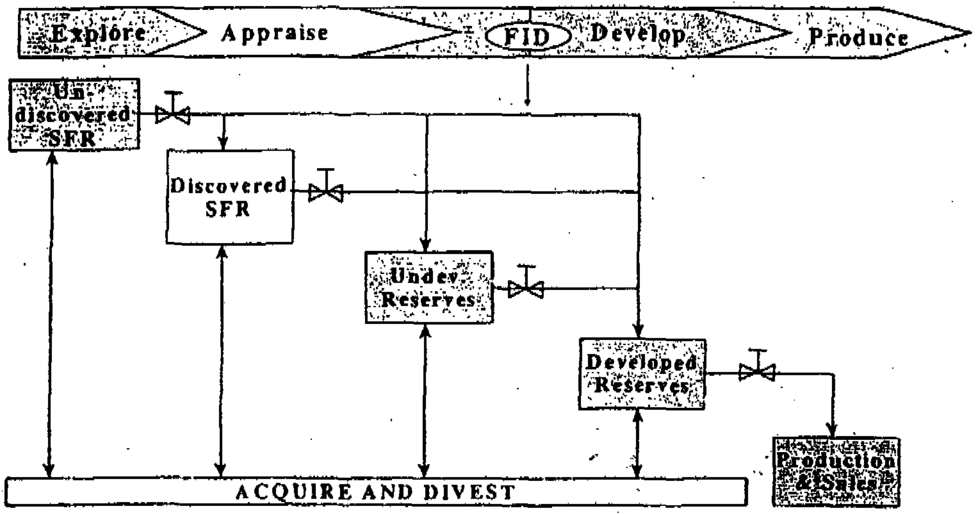

Figure 2: *Cascade Model*

A graphical example of the migration of resource volumes between categories during a field's life cycle is shown in Appendix 2.

2.3 Technical and Commercial Maturity

Resource volumes are realised as production through development projects and/or activities (see below). The classification scheme uses a project's **technical and commercial maturity** as the primary criterion to distinguish between reserves and scope for recovery (SFR). Resource volumes can be classified as reserves only if the associated project that will result in production of those volumes is considered to be technically and commercially mature. If this is not the case, the resource volumes should be classified as SFR. SFR needs a data gathering or other activity (e.g. exploration appraisal, field trial, gas market development, etc) to achieve technical maturity and commercial viability. Secondary technical and commercial distinctions (between proved and unproved techniques SFR and between commercial and non-commercial SFR) further identify resource volumes at various stages in the life cycle.

2.3.1 Project Basis

A project is any proposed or notional modification of the wells, the production facilities and/or the production policy, aimed at changing the company's sales product forecast. It can also be a modification of the company's share in a venture (purchase/ sales-in-place, unitisation, or new terms). The generic term 'project' is also used to describe a group of (sometimes alternative) projects, each with a certain chance of realisation, depending on the results of further data gathering. In that case, the project NPV is replaced by the Expected Monetary Value (or EMV, see Appendix 6).

2.3.2 Technically Mature

For a project to be **technically mature**, information on the resource volume, including its level of uncertainty, is such that a viable project can be defined with an auditable project development plan, based on resource and development scenario descriptions, with drilling/engineering cost estimates, a production forecast and economics. For small projects (e.g. infill drilling in an existing field, or a small satellite development) the plan may be notional or it may be an analogy of other projects based on similar resources. Large or frontier projects, whilst not needing a complete and optimised development plan, must have demonstrated technical and commercial maturity. Successful completion of a Value Assurance Review (VAR) with sufficient definition would support such maturity and robustness. This should preferably be a VAR3 (Concept Selection) review. In all cases, there should be a reasonable expectation that a firm optimal development plan can be matured with time.

2.3.3 Commercially Mature

A **commercially mature** project is commercially viable over a sufficiently large portion of the range of possible scenarios that reflect the remaining resource uncertainties as well as the remaining commercial uncertainties, including the availability of markets (see below). The definition of what constitutes 'a sufficiently large portion' may vary from case to case but it does require the project NPV for the proved reserves scenario to be positive for appropriate commercial criteria. It is also likely to include an assessment of the capital exposure in case of project failure due to adverse resource realisations. The selected range of scenarios should be documented and auditable.

2.3.4 Market availability

An essential requirement for commercial maturity is also that a market must be available or reasonably expected to be available for the hydrocarbon products. For oil and NGL this means at least the (expected) availability of a pipeline to a shipping terminal or other outlet (e.g. a refinery). For gas this means an expectation that access to a gas market will be available, i.e. the gas must be:

1) contracted to sales; or
2) considered as reasonably certain of being sold based on a reasonable expectation of the availability of markets, along with transportation/ delivery facilities that are in place; or
3) whilst not firmly planned, have been earmarked for future development and hence may reasonably be anticipated to be sold based upon expectation of availability of markets and project financing.

For major gas projects critically depending on new gas market capture, reserves booking should in principle be deferred until agreements have been signed, generally at or around project sanction (FID).

The condition of marketability to gas reserves also applies to the NGL products of a non-associated gas project. If the gas market is not matured (or likely to be matured) and the go-ahead of the project is still uncertain, neither the gas reserves nor the NGL reserves can be booked.

2.3.5 Commercially Viable

A scenario is **commercially viable** if the NPV is expected to be positive under the applicable (or expected) terms and conditions for the acreage and for the current advised Group reference criteria for commerciality.

2.3.6 Economically Viable

A project is economically viable if the expected NPV under the applicable terms and conditions for the acreage exceeds the separately advised Group project screening criteria or if the project has already been approved by shareholders. Projects generally have to demonstrate economic viability in order to obtain investment approval (See Ref. 13).

2.3.7 Important considerations

Full economic viability or formal project approval is not always required for a project to be considered commercially mature and hence for reserves to be booked. Commercially viable reserves may be booked before project approval is sought, but there must be identified activities to improve project economics, the expectation that economic viability will be achieved and a plan to seek approval at some time in the future. The project should also be included in the annual Business Plan. If that intention is not (yet) there (because the project is technically or commercially too immature), the project recoverables must either be booked as SFR or the project / field must be a candidate for divestment. Conversely, if a project is approved and it will go ahead, regardless of (re-evaluated) technical / commercial maturity, the reserves should be booked. An example of this may be a pilot waterflood.

To minimise fluctuations over time, OUs and NVOs should exert caution in transferring volumes between the reserves and SFR categories. Demonstrable technical and commercial maturity will be required when new fields and reservoirs are added to the reserves base. The same requirement applies in principle when undeveloped reserves are retained. To retain developed reserves, their production should have a positive cash generation after subtraction of operating costs, tax and royalties.

Existing volumes that have been classified as reserves, but which are no longer commercially mature, may be retained as reserves only in cases when there is an overriding strategic interest, or where a current small operating loss is expected to be reversed in the short term. In both cases support from shareholders must be obtained.

It is also important to realise that, if project recoverables for a resource are booked as reserves, these must contain both Expectation and Proved volumes, i.e. project volumes should be included in both the Internal and External Reporting submissions. It is not realistic to carry only Expectation and no Proved volumes since that implies that the project is immature and hence that the volumes must be booked as SFR.

Before first time booking of significant reserves in a new area (following exploration discovery, successful acquisition, new gas market capture, reaching project FID, agreeing new contractual terms etc.) it is recommended to review the project with the Centre (EPB-P) to ensure that volumes are supportable and that they would meet external audit requirements.

2.4 Developed, Undeveloped and Total Reserves

Reserves are subdivided in developed and undeveloped reserves. The sum of both is referred to as 'total' reserves.

2.4.1 Developed Reserves

Developed reserves must be producible through currently existing completions, with installed facilities, using existing operating methods. Facilities requiring minor outstanding activities in ongoing projects can be considered as existing if the outstanding capital investment is minor (<10%) compared to the total project cost and if budget approval has been obtained. Volumes behind pipe can only be considered developed if the additional activity (e.g. 'lower' zone abandonment, perforating, stimulating) does not require a full well entry/re-completion and if the cost of this activity (normally opex) does not exceed 10% of the cost of a new well.

Gas volumes in fields where compression is planned or anticipated in future, should only be classed as developed reserves to the extent that they can be produced through the currently existing facilities.

Developed reserves should in principle be estimated through extrapolation of existing well performance trends. This may be done either through plotting (e.g. rate vs. cumulative production, log oil rate vs. time) or through history matched simulation modelling. If no significant history is available to match, the developed reserves will be based on pre-development (simulation) model projections, updated for observed well geological and petrophysical data and well rates. The resulting forecast should represent the production that will be contributed by the existing wells through the currently installed facilities, assuming no future development activity (NFA forecast).

2.4.2 Undeveloped Reserves

Undeveloped reserves require capital investment through future projects (new wells and/or production facilities) in order to be produced. These projects must be technically and commercially mature (Section 2.3). In order to assess commercial viability of these reserves, the wells and activities must be clearly identified, together with their costs.

Gas volumes that require installation of planned or anticipated future compression should be classed as undeveloped until such compression has been installed.

New development projects, which add developed reserves, may defer field/platform abandonment and may thereby also increase the reserves producible from existing completions. Such gains should be included in the economic evaluation of the new development project and should be included in reserves when commercially viable.

Future wells or facilities may accelerate reserves that would otherwise be produced by existing investments. The portion of reserves expected to be accelerated by the new investments should be classified as developed with the existing investments. If future investment accelerates production such that additional reserves are recovered within time limits (e.g. sales contract periods, field life), the additional reserves should be classified as undeveloped until this investment has been made.

2.4.3 Total Reserves

Total reserves are the sum of Develop and Undeveloped reserves. As indicated in the preceding sections, developed and undeveloped reserves should be estimated separately. In particular undeveloped reserves should be based on an identified or identifiable project or projects. Historically, total reserves have sometimes been calculated through multiplication of the STOIIP/GIIP volumes by an assumed or estimated recovery factor, without specific reference to a project. Undeveloped reserves were then calculated as the difference between these total reserves and the separately estimated developed reserves. This practice is in conflict with the concept of project based reserves estimation and should be discontinued.

2.5 Scope for Recovery

Scope for Recovery is the recovery estimate of any notional project, which cannot yet be shown with sufficient confidence to be technically or commercially mature. However, there

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must be an expectation that this project could mature based on reasonable assumptions about the success of additional data gathering, a maturing technology from current research, relaxation in the market constraints and/or the terms and conditions for implementing such a project.

The economic evaluation should include any future pre-investment costs required to reduce technical uncertainty.

In the case of immature projects, the associated scope for recovery may be reported as a single estimate for the undiscounted average recoveries in the case of success (mean success volume, MSV) together with a probability of success (POS). For aggregation purposes the risked expectation volumes are used (POS*MSV).

2.5.1 Commercial SFR by Proved Techniques

SFR by proved techniques is the volume estimated to be recoverable from discovered resources, by a project utilising a recovery process or technique which has been demonstrated to be technically feasible in the area or in the field. Implementation is expected to be commercially viable, but a wide range of technical uncertainties in the recovery volumes precludes the formulation of a technically mature project proposal.

2.5.2 Commercial SFR by Unproved Techniques

SFR by unproved techniques is the volume believed to be recoverable from discovered resources by a project utilising any recovery technique or process that has been proven elsewhere, but that has not yet been demonstrated to be technically feasible in the area or in the field, and which requires future laboratory tests and field trials (pilot) in order to establish this feasibility. Once technically feasible, the process should be expected to be commercially viable.

Future data gathering may disprove the technique in the field, and with it the possibility of development, and these SFR volumes must therefore be discounted for the risk that the considered technique will not prove to be technically feasible.

2.5.3 Undiscovered Commercial SFR

Undiscovered SFR is the volume believed to be recoverable from as yet undrilled potential accumulations by any process that has been demonstrated to be technically feasible elsewhere, under similar conditions. Development of the accumulation should be expected to be commercially viable.

These SFR volumes must be discounted for the risk that petroleum is not present or is not commercial to develop (Probability of Success, see Appendix 6).

Future data gathering may result in a total write-off of these resources. Following drilling results, the resource volumes are revised and, in the case of a discovery, the economics re-assessed, whereupon the resource is either discarded or reclassified.

2.5.4 Non-Commercial SFR

SFR in discovered resources is considered non-commercial for development projects which, even if technically successful, would not be commercially viable. To avoid unrealistic situations the reporting of Non-Commercial SFR is restricted to projects with a Unit Technical Cost below an annually advised ceiling.

Non-commercial SFR is reported in order to retain an indication of the discovered resources that could become commercial with a change of circumstances (e.g. an increase in oil price, a change in tax regime, development of a gas market, flared/vented/re-injected gas volumes if recoverable and significant enough to be marketed).

2.6 Diagrammatic summary

A diagrammatic summary of the distinction between reserves and SFR is given in figure 3.

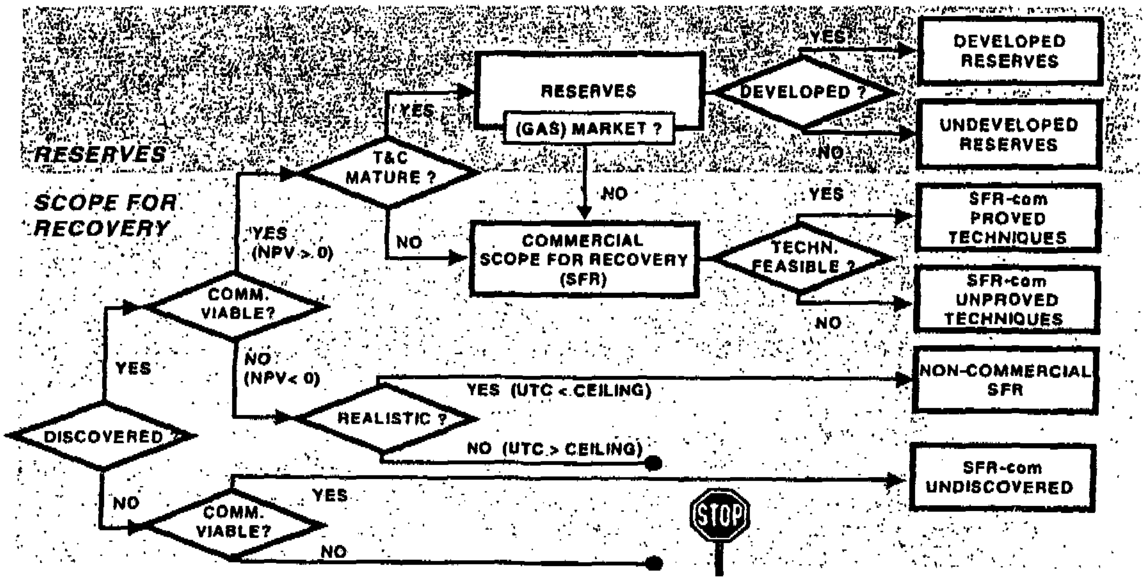

Figure 3: Internal resource classification flow diagram

3. QUANTIFICATION OF UNCERTAINTY

3.1 Quantification methods

Subsurface resource volume estimates are inherently subject to uncertainty, because they are based on data (from seismic and drilling) and interpretations that contain sometimes significant margins of error. These uncertainties in resource volume estimates can be assessed and represented using a variety of methods. The three most important are:

- The Probabilistic method (P85, Mean, P15)
- The Multi-scenario method (Low, Middle, High)
- The Deterministic method (Proved, Probable, Possible)

3.1.1 The probabilistic method

The probabilistic method has been in use by the Shell Group for more than 30 years. Whilst the Group was initially the only one in the industry applying this method, the method has, over the years, gradually gained wider acceptance, e.g. by the SPE (Ref. 7).

The method consists of assigning probability density functions (PDFs) to each of the constituent parameters that define a subsurface volume estimate (i.e. gross bulk volume, porosity, hydrocarbon fill and saturation, hydrocarbon volume factor, recovery factor). These PDFs are then combined (multiplied) either mathematically ('moment' method, see Ref. 1a - App. 7) or, more commonly, through Monte Carlo simulation. The latter method uses a random number generator which generates random selections from each of the parameter ranges, which are then combined into successive volume estimates, often numbering 1000 or more. Software tools using Monte Carlo simulation are e.g. @RISK, Crystal Ball and FASTRACK.

The resulting product from both the mathematical and the Monte Carlo methods is a PDF or its integral, the cumulative probability function (CPF), which defines the probabilities that the resource volume exceeds each of a range of values. The values associated with the 85% probability the 15% probability are called the 85% and 15% confidence levels or **P85** and **P15** for short. The probability-weighted average value is referred to as the **Mean**. The reason for the original selection of the 85% and 15% intervals by the Group was that they aligned most closely with the previously used distributions of three equi-probable values. More recently, the SPE and some operators and authorities have tended to favour 90% and 10% intervals (P90 and P10 respectively).

The probabilistic method is a good method for assessing the uncertainties of Exploration prospects and sparsely appraised discoveries. For fields that are approaching the development stage it is far inferior to the multi-scenario method and hence not recommended. The main reason for this is that the recovery factor is rarely an independently assessable parameter, but a direct consequence of the combination of static model realisation and development scenario chosen (see below). This can only be represented properly through multiple scenario realisations.

3.1.2 The multi-scenario method

This method is applied when the field has been modelled through a full set of static (geological) and dynamic (reservoir simulation) models. The static model is generally run for a range of possible subsurface realisations, yielding a range of hydrocarbon-in-place volumes. After assigning a probability to each of these realisations, the range of in-place volumes can be represented as a CPF (see above) from which 85%, mean and 15%

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confidence levels can be derived. Representative scenario cases close to these P85, mean and P15 values are then selected and defined as the Low, **Middle** and **High** cases respectively.

A representative selection of alternative geological model realisations is converted ('upscaled') into a discrete set of reservoir simulation models, which are then run each for a range of alternative development scenarios (e.g. different well numbers or positions). The alternative development scenarios are not necessarily identical for each geological realisation. The resulting set of model-scenario combinations (usually some 10-20 in number) can again be combined into a CPF, with identifiable P85, mean and P15 values, from which representative Low, Middle and High cases can be selected.

An important characteristic of the multi-scenario method is that it is project- or activity-based, i.e. the recoverable volumes are linked to a specific development plan or plans, with identified (or identifiable) costs, production forecasts and economics. The multiple scenario method is obviously more complex than the probabilistic method, but, with the present range of tools available (notably the GEOCAP – MoReS suite of linkable models) it is seen as a necessary requirement for any field development. It is therefore recommended that in principle all fields with booked reserves (proved and expectation) should use this method.

3.1.3 The deterministic method

The deterministic method has been the method most frequently used by the industry outside Shell. It derives from the original definitions of 'Proved Reserves' as issued by the American Financial Accounting Standards Board (FASB) and by the US Securities and Exchange Commission (SEC) (Refs. 8, 9, 10). These definitions describe the mandatory conditions for reserves that are reported annually through Company reports and public submissions to the SEC. Subsequent definitions for Probable and Possible reserves have been issued by the SPE in co-operation with the WPC (Ref. 7).

Proved reserves are defined as "...the estimated quantities of hydrocarbons which geological and engineering data demonstrate with **reasonable certainty** to be recoverable...". 'Reasonable certainty' is implied to mean that future reserves revisions are 'much more likely' to be positive than negative. Pivotal in the definition of Proved Reserves is the notion of a **'proved area'** of reservoir rock, outside of which no Proved Reserves can be declared. This proved area is constrained by:

- Economic **producibility** demonstrated by a production test (not a wireline test!),
- Delineated by GOC, OWC, GWC if seen by drilling,
- Oil volumes above OUT levels only if gas is seen updip and a GOC can be interpreted,
- No volumes below **'lowest known hydrocarbons'** (LKH), as seen by drilling,
- Laterally confined to one 'legal location' (US regulatory minimum well spacing) away from well control,
- **Certainty** (not just 'reasonable certainty'!) **of continuity of production** over the area (must be demonstrated by pressure interference data if beyond one 'legal location'!),
- **Improved recovery** volumes only with a successful **pilot** in that specific rock volume,
- The conservative restrictions regarding LKH and lateral well control may be lifted "...upon obtaining **sufficient performance history** to reasonably conclude that more reserves can be recovered..."

The significant information on reservoir structure and hydrocarbon fill available from modern seismic techniques (DHIs, flat spots etc) is acknowledged by the SEC (Refs. 8, 9), but they maintain insistence on the constraints as stated above.

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The practice in the industry outside Shell has been that Proved reserves estimates are generally 'best estimates', with the proved area constraint being the only conservative element that is strictly adhered to. The important consequence of this has been that Proved reserves as calculated by the deterministic method tended to be lower than probabilistic P85 (or multi-scenario Low) estimates for new discoveries and undeveloped fields. Similarly, they were generally higher for mature, fully appraised fields.

The SPE (Ref. 7) recommend that, if Proved reserves are determined probabilistically, a P90 value be selected. They generally align with the SEC guidance, except that they allow areas beyond the regulatory well spacing to be included if "...data from wells indicate with reasonable certainty (P90!) that the objective formation is laterally continuous and contains commercially recoverable hydrocarbons...".

The SPE/WPC definitions of Probable and Possible reserves (together called Unproved reserves) can be summarised as follows:

Probable reserves:
- 'More likely than not to be recoverable'; P50 if based on probabilistics,
- Probably productive from logs/cores,
- Likely volumes outside the 'proved area', e.g. updip behind interpreted faults,
- Volumes probably recoverable through unproved techniques (no successful pilot yet)

Possible reserves:
- 'Less likely than Probable', P10 if based on probabilistics,
- Hydrocarbon bearing from logs/cores, but possibly not productive
- Possible volumes outside the proved area, e.g. downdip behind interpreted faults,
- Volumes recoverable through unproved techniques, with success in 'reasonable doubt'.

Industry practice tends to be that Probable reserves contain not only volumes associated with areas in the field outside the volumetric confines of the 'proved area', but also volumes associated with projects that have not been fully matured or approved yet.

The sum of Proved and Probable reserves is sometimes regarded as equivalent to the Mean or Middle estimates from probabilistic or multi-scenario methods. Similarly, the sum of Proved, Probable and Possible has been equated to P10 or High reserves. However, the definition for Possible reserves clearly indicates that many of these volumes (and even some Probable reserves volumes) should be classified as SFR in the Shell system.

3.2 Shell Group practice

Shell Group practice has long been based on the probabilistic method as the Group standard for estimating Expectation reserves (for internal reporting) and Proved reserves (for external reporting). Expectation reserves were defined as equal to the mean expected volume and Proved reserves were set equal to the P85 estimate. As a result, the notions of Proved and P85 estimates have long been considered identical to many Group petroleum engineers.

With the increasing maturity of many of the Group's fields it was found that the externally reported Proved reserves were generally more conservative than those reported by the industry. This was confirmed by a Group task force set up in 1998 to compare Group guidelines with industry practice. The recommendation of the task force was to improve the practice of estimating externally reported Proved and Proved developed reserves, particularly for mature fields, in order to make Group estimates more in line with industry practice.

This has led to new Group guidelines setting the framework for annual submissions of internally and externally reported reserves.

The '**proved area**' is interpreted to be the area/volume that is defined by:

- Demonstrated producibility through a production test, or log/core data in a tested area,
- Delineated by GOC, OWC, GWC as seen/interpreted from pressures in the reservoir,
- In the absence of 'legal' well spacings, laterally defined by well control and surrounding areas with continuous and good quality seismic amplitudes, but not beyond potentially sealing barriers or faults. Evidence from well drainage limit tests may be used.
- Extended by production performance data, if conclusive,
- Improved recovery volumes supported by a pilot or a conclusive test (section 6.1.4)

The concept of this interpretation is that the drilling and completion of development wells will generally expand the 'proved area' such that its volumetric extent will cover much, if not all of the field. Even if still incomplete at first (i.e. after the first phase of development drilling), this coverage will increase to full coverage with growing field maturity and performance. In line with industry practice, Proved reserves should be based on 'best' or Expectation estimates of 'proved area' volumetrics.

Apart from the **volumetric** uncertainty, there is the uncertainty regarding reservoir **performance** (determined by sand development, reservoir continuity, injectant sweep efficiency, aquifer activity, etc.). The latter uncertainty will only be reduced after a sufficiently long period of reservoir production performance. Hence, a cautious, 'reasonably certain' approach should be followed for performance predictions in new fields, whilst for mature fields an estimate much closer to, or equal to the Expectation estimate can be taken, in line with industry practice. An example would be an initial assumption of oil recovery based on depletion only if aquifer influx is not yet certain.

The resulting description of scenario assumptions to be used for estimating Proved and Expectation reserves is given in Fig. 4 and Appendix 4. If reserves (particularly Proved reserves) are still based on probabilistic estimates, these should in principle be consistent with these scenario assumptions.

Expectation Developed and Undeveloped (internal reporting):	All fields	Mean probabilistic or Middle case scenario estimate (Proved+Probable if appropriate and if no Mean or Middle available)
Proved Developed reserves (external reporting):	New, recently developed fields:	'Reasonably certain' scenario (best estimate) of future performance, based on Expectation post-drill 'proved area' volumetrics.
	Mature fields:	Mean or Middle performance projection, based on Expectation fully post-drill + performance based 'proved area' volumetrics. The Proved estimate should in principle be equal to the Expectation estimate.
Proved Undeveloped reserves (external reporting):	Undeveloped fields	'Reasonably certain' scenario (best estimate) of future performance, consistent with pre-drill 'proved area' volumetrics
	New, recently developed fields:	'Reasonaly certain' scenario (best estimate) of future performance, based on Expectation post-drill 'proved area' volumetrics
	Mature fields:	Improved performance estimate, based on observed field performance and Expectation fully post-drill + performance based 'proved area' volumetrics. *The Proved estimate should be close to or equal to the* Expectation estimate. Lower Proved / Expectation ratios are possible if future activities are significantly different from existing development.

Figure 4: Group recommended practice for estimating Reserves

3.3 Further considerations

3.3.1 Uncertainty Reduction with Performance

The uncertainty range of ultimate recovery generally decreases as a field is developed and produced. However, the uncertainty range as a percentage of remaining reserves may not always decrease with time. **As a field matures, initial in-place volumes and recovery should shift from a volumetric to a performance-based estimate, incorporating the additional production data to reduce the uncertainty range.** Once the reservoir performance has been established with reasonable certainty, a fairly small difference between low, expectation and high estimates would be expected. Definition of the low and high estimates may no longer be of value in mature fields with relatively little uncertainty and use of a single expectation estimate should be considered in this situation (subject to 'proved area' conditions).

Figure 5 illustrates the narrowing of the uncertainty with field appraisal and development. This is a near ideal example where the expectation remains constant for most of the life cycle. This example is also used in Appendix 2 to show the migration of resources between internal and external reporting categories during the field life cycle.

The reduction in uncertainty based on performance should be adequately reflected in the annual reserve and scope for recovery estimates for the field.

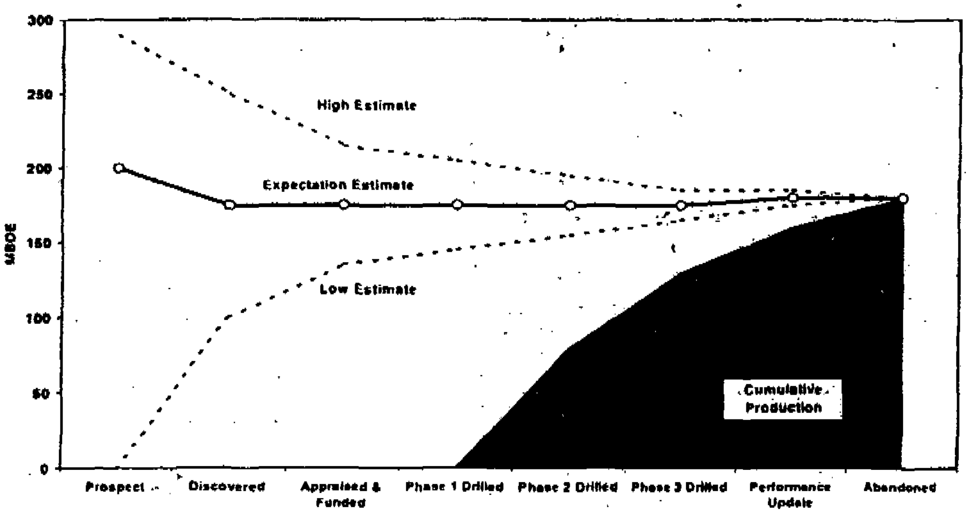

Figure 5: Uncertainty Reduction during the Field Life Cycle

3.3.2 Addition of Proved Reserves Volumes

Proved Reserves volumes are added together at various levels (reservoirs, fields, areas etc) during the resource assessment and reporting process. When Proved reserves are based on P85 or Low estimates, such addition could either be arithmetically or probabilistically. Arithmetical addition usually overstates the uncertainty range for the sum of partially independent volumes (i.e. the resulting sum of P85/Low values is too low), but is appropriate for dependent volumes. Probabilistic addition could be considered for partially

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independent volumes when the difference with arithmetic addition is significant. An important requirement is, however, that **addition of Proved reserves at or above the level used for financial depreciation calculations must be arithmetical for consistency with financial accounting** (see Section 6.1). Below this level, i.e. normally below the field level, an appropriate selection of the addition method must be made, such that account is taken of dependency between the volumes to truly reflect the aggregated P85/Low/Proved recoverable volume.

Below are two examples where the method of addition is important to handle addition properly.

a) Field A is comprised of separate layers and the properties of these layers are independent of each other. In other words, a low result in one layer would not increase or decrease the chance of a low result in the other layers. Low, expectation and high estimates are calculated for each layer separately. Probabilistic addition should be used to account for the reduced uncertainty of adding together independent volumes. Arithmetical addition of these estimates would understate the low estimate and overstate the high estimate of the total field.

b) A project develops three independent fields as sub-sea satellites connected to one platform. In this case, the investment in surface facilities may be totalled for depreciation[1] and consequently the reserves estimates should relate to the combined fields. Probabilistic addition should be used to calculate the total reserves associated with the platform.

Careful consideration should be given to Commercial SFR by proved techniques where eventual development is only incremental to an existing or planned development. These volumes may have a probability of success (POS) less than one, but with probabilistic addition will contribute at all levels - low, expectation and high - of reserves estimates. Examples of where this would apply are:

1) A fault block that is not yet tested and may be reasonably interpreted as an extension of the delineated area of the field. The project itself is technically and commercially mature. The untested block would be developed through existing field facilities without significant additional investment other than additional wells, which is recognised in the project scope. The uncertainty is geological and volumes are classed as reserves.

2) A phased development where there is uncertainty in the scope (e.g. number of wells) of a project due to geological uncertainty. However, the nature of the project remains essentially unchanged and additional wells could be accommodated within the flexibility of the field facilities design, then the whole range of recoverable volumes should be considered in deriving reserves. A scenario tree can be developed to represent the range of outcomes, both in recovered volumes and optimised number of wells, dependent on geological uncertainty. The uncertainty is resolved, with time, through planned data gathering eventually determining the number of wells. Hence the volumes can be regarded as technically mature. If one branch of the scenario tree is not economic, then the volumes associated with that arm do not contribute to reserves.

If probabilistic addition is used, it should be ensured that the used methodology and parameters are documented in the audit trail.

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[1] Group Accounts should be consulted when considering combining surface facilities for different fields for depreciation purposes.

4. GROUP SHARE

Only the Group share of resource volumes is reported, both in submissions for internal and for external reporting. The Group share is determined by three factors: (1) the contractual share of produced hydrocarbons, as agreed with the resource holders (usually the host government), (2) the Group share in the OU or venture that holds the contractual share, and (3) licence duration and other restrictions.

4.1 Contractual Share

Resource volumes can be distinguished according to three different types of agreement: Equity, PSC and 'New Contracts'. These are described below.

If an OU/NVO has interests in several licence areas subject to different contract types, a separate submission must be made with respect to proved reserves for each of the contract types. This applies in particular to submissions for external reporting, in line with FASB requirements (see Chapter 6).

4.1.1 Equity

Equity resources are the OU Company share of resources in Concessions. Concession agreements lay down the general terms and conditions of operation, define the applicable tax rules, the Company share of resources in Concessions and the duration of the production licence. These agreements are generally with the host government, but in the USA they may also be with the private owners of the mineral rights ("lease or fee" conveyance of rights to the operator).

4.1.2 PSC Entitlement

Entitlement resources are the OU Company share of production in acreage governed by a Production Sharing Contract (PSC). The Company entitlement share of production is the Company interest in the sum of cost oil plus excess cost oil plus profit oil, in accordance with the PSC terms. The entitlement share is calculated from economic modelling reflecting current estimates of future costs.

4.1.3 New Contracts

In recent years, a number of resource holding countries have introduced innovative production contracts in order to attract investment by foreign oil companies while preserving the principle of national resource ownership. These agreements typically provide for the contractor to recover costs and profits from hydrocarbon revenues while holding no title to, or entitlement to receive petroleum resources.

US Financial Accounting Standards Board (FASB) regulations have lagged behind these developments and provide little explicit guidance on reserves disclosure when the risks and rewards of ownership are carried without legal title to mineral rights.

However, volumes covered by such innovative contracts should be included in external reports in an informative way to be consistent with the spirit of the SEC regulations. The volumes from which economic benefit is derived should be reported if all three of the following conditions are met:

1. The OU Company participates in the production operations as either operator or in partnership with the operator, and so bears a share of the costs and risks of the production operations.

2. The OU Company derives future economic value that is directly related to the volume of hydrocarbons produced. For example, a fee expressed as a fixed or indexed amount per barrel of production would constitute a derivation of value from the produced hydrocarbons, but an operating fee that is largely independent of production would not. The actual source of revenues used to pay the OU is not crucial to this point. For example, if the remuneration is determined by a produced gas volume but paid from oil revenues, the economic value to the OU is in effect derived from the produced gas, and this volume should be reported.
3. The OU Company is exposed to the normal risks and rewards associated with ownership of mineral rights, including the downside and upside from changes in the value of future production volumes. These include the risk that costs may not be recovered, due to either uncertainty as to the presence or magnitude of hydrocarbon volumes or to movements in petroleum prices.

OUs and NVOs working under such contracts should complete the standard resource volume submission for the Group/Company interest in these volumes, noting the nature of the interest. Group share of production is calculated from economic modelling of total financial reward in line with contract terms versus total revenues. Reported volumes should be in line with the reporting of traditional reserves with regard to royalties and should therefore reflect the volumes from which pre-tax cash flow is derived. As elsewhere, cash royalties are regarded as a production cost (see below).

When an OU is participating in a venture which grants neither title to, nor an entitlement to receive petroleum, and which does not satisfy the three criteria above the OU should not report reserves or production volumes. For example this might occur if the recovery of costs is guaranteed against adverse price movements or a shortfall in recovered volumes.

4.2 Group Share in OU

If the Group holds only a partial share (i.e. less than a 100% share) in the company or entity that holds the concession or contractual share with the resource owners, this share must also be accounted for in the reserves submission.

As an exception to this, both Expectation and Proved reserves (internal and external reporting respectively) are reported on a 100% basis for companies in which the Group holds a controlling (>50%) interest, in line with financial reporting. Minority interest volumes included in these total reserves are then disclosed separately. Prior agreement must be obtained from Group Finance before such reporting is considered.

4.3 Licence duration and other restrictions

4.3.1 Licence or Contract Extensions

For internal reporting purposes, Group shares of the expectation estimates of reserves and scope for recovery are recorded for the total producing life, i.e. including the period beyond the relinquishment date, that is not (yet) covered by a right to extend or by a letter of assurance (see below). The currently existing licence terms or other anticipated terms should be assumed for this extrapolation. In addition to these full life cycle volumes, resource volumes are also recorded as limited to the current licence or its agreed extension only (total expectation reserves, developed expectation reserves and total commercial scope for recovery).

For external reporting, Group share of reserves (proved, proved developed) is limited to future production within the existing licence or contract period. However, production beyond the licence or contract period can be included if there is a legal right to extend a production licence or PSC, or if the government has formally indicated that it will favour substantiated requests for extensions in the future (letter of assurance). In that case, volumes recoverable during the extension period are included in the Group share, assuming currently existing or other anticipated terms. Such considerations should be documented in the annual submission.

In some countries, the issue or duration of production licences for gas fields is effectively coupled to the conclusion of gas sales contracts. In other areas, a realistic target date for initiation must be set for projects that are not yet firmly planned so that the production forecast and other screening assumptions can be used to estimate the volume produced before licence or contract expiry.

4.3.2 Long Term Supply Agreements

FASB regulations (Ref. 10, 69 par. 13) require that quantities of oil or gas subject to purchase under long term supply, purchase or similar agreements should be reported separately, if the OU participates in the operation of the properties in which the oil or gas is located or otherwise serves as the "producer" of those reserves, as opposed, for example, to being an independent purchaser, broker, dealer, or importer.

The "supply" agreement should be a consequence of the OU acting as producer. This would not be the case if, for example, others had similar agreements but did not participate in the production operations.

These net quantities, as well as the net quantities received under the agreement during the year, should be included in the end year estimate of reserve volumes for external disclosure form.

4.3.3 Royalty

Outside the USA, Royalty is a payment made to the host government for the production of mineral resources. It is usually calculated as a percentage of revenues (payable in cash) or production (payable in kind).

Where in practice royalty obligations are met in kind (i.e. by delivering oil instead of cash), the Group share of production and reserves should be reported **excluding** these volumes.

Where royalty is payable in cash or is in principle payable in kind but the government has formally elected to receive, or customarily receives, payment in cash, Group share of production and reserves should be reported **including** these equivalent royalty volumes.

Within the USA, Royalties are payable to the owner of the mineral rights, who can either be a private or a public entity (e.g. State government). In line with SEC regulations, these are always **excluded** from Group reserves whether paid in cash or in kind, for US properties.

4.3.4 Over-Riding Royalty

In the USA, there are often 'Overriding Royalties' payable to the owner of mineral rights or third parties. These shares of reserves are **excluded** from Group reserves. Third party overriding Royalties payable to Shell are **included** in Group reserves.

4.3.5 Volumes flared/vented and own use

Group share volumes must **exclude** any volumes flared/vented and 'own use' (fuel for production facilities, compressors etc) in the **upstream** operations prior to transfer of the volumes to the buyer (Third Party' or 'Downstream'). This is consistent with the definitions applied for e.g. Gas Production available for Sales from own reserves (GPafS), as applied in the Ceres production submissions through the Finance system (see GFIM ref. 11).

4.3.6 Fees in kind

Third Parties may in some cases pay Fees in Kind or Tariff in Kind (TIK) for the use of infrastructure (e.g. pipeline tariff, processing fee). Such volumes received by the company (to the extent that they originate from non-Group owned resources) do not constitute a Group share in resources and should be **excluded** from reported volumes. Condensate volumes recovered from a pipeline system related to transportation of Third Party gas volumes and sold by the company are equivalent to fees-in-kind received. All fees-in-kind received should be included as a purchased volume in the company accounts.

Where a company **pays** fees in kind (from its own fields/resources) to a Third Party, these do constitute a Group share in resources and should be **included** in the reported volumes. Annual volumes produced and used as fees in kind should be included in sales volumes, with associated revenues (at an agreed or fair market value) equivalent to booking of the incurred operating cost.

4.3.7 Under/Over Lift

Group share should also allow for any historic under or over lift by partners or government. A Group historic over lift should be reflected as an equivalent reduction of Group reserves, a Group historic under lift as an equivalent increase of Group reserves.

Group share should reflect impact of swap deals between fields where early production capacity in one is traded versus later production repayment by the other.

Treatment of take-or-pay volumes should be aligned with financial treatment of the cash received and booking of production volumes.

4.3.8 Open Acreage

Group share of volumes is non-existent in open acreage and acreage for possible acquisition or farm-in.

4.3.9 Committed Gas Reserves

Total volumes of expectation gas reserves within licence, which have been sold (committed) under long and short term contractual agreements. In countries with a mature/deregulated gas market all gas reserves, which have a near certainty of market take-up can be classified as 'committed'.

4.3.10 Committable Gas Reserves

Volumes of gas reserves, which have not been sold, but could be sold (committable) under contractual agreements. The sum of committed and committable gas reserves should equal expectation gas reserves within licence. Gas resource volumes, which are classified as scope for recovery due to lack market availability, should not be included.

4.3.11 Gas Re-injection

Gas volumes re-injected in a reservoir, for pressure maintenance, gas conservation, Underground Gas Storage (UGS, including cushion gas), or other reasons, without transfer of ownership, remain part of a company's resource base and should be included in the Group resource estimates. These gas volumes should be classified and reported as reserves or SFR, depending on the recovery anticipated through future developments (e.g. taking into account anticipated re-saturation losses).

Gas volumes re-injected in an UGS project on behalf of a **Third Party** (following transfer of ownership by the company to this party) do not constitute a Group share in resources and should be **excluded** from reported volumes.

4.3.12 Oil Sands

Petroleum volumes (heavy oil, bitumen, syncrude, gas, liquids, etc.) recovered from unconventional reservoirs (oil sands, tar sands, coals, oil shales) by a "manufacturing" process must be reported **separately** from the conventional resource base. This should also include conventional reservoirs where recovery occurs through a mining operation. However, conventional reserves or SFR can be claimed for otherwise unconventional reservoirs if the petroleum is recovered in its natural state and original location (i.e., has not been "manufactured" in situ by alteration from natural state) through the use of conventional methods (wells). Examples of this are coal bed methane produced from wells or heavy oil produced from wells using conventional thermal recovery methods. (Also see SEC definitions, Appendix 3 C4.)

5. RESOURCE VOLUMES FOR INTERNAL REPORTING (EXPECTATION RESERVES AND SFR)

The reported volumes must comply with the Shell Group guidelines contained in this report. Only the Group share of expectation reserves, SFR and production (sales volumes) is reported (Chapter 4).

5.1 Expectation Reserves

Reserves are the sales quantities anticipated to be produced and monetised from a discovered field associated through project(s) that is/are **technically and commercially mature** (see Section 2.3). Petroleum volumes must have been demonstrated to be producible through wells from the field.

A market must reasonably be expected to be available for the hydrocarbons, particularly for gas reserves (Section 2.3.4).

The production forecast, and therefore the reserves, must be cut off at the point where cash generation becomes negative, i.e. when operating costs (with appropriate treatment of abandonment costs) exceed sales revenues after royalties. If the remaining tail production is significant, it may be booked as Non-Commercial SFR (see below).

Production forecasts should reflect volumes available for sale taking into account all system constraints, abandonment timing, expected operational performance (planned and unplanned deferment), production quota restrictions, contractual sales volumes, market and other expected production limitations (community disturbance etc.).

The historical production and production forecasts (i.e. reserves) must be adjusted for any volumes flared/vented and 'own use' (see Section 4.3.5).

5.1.1 Expectation Developed Reserves

Developed reserves must be producible through existing completions and facilities, using existing operating methods. Volumes behind pipe can only be considered developed if the completion activities' cost does not exceed 10% of the cost of a new well. See section 2.4.1.

Developed reserves should in principle be estimated through extrapolation of existing well performance trends. The resulting forecast should represent the production that will be contributed by the existing wells through the currently installed facilities, assuming no future development activity (NFA forecast). For the full conditions, see Section 2.4.1.

5.1.2 Expectation Undeveloped Reserves

Undeveloped reserves require capital investment in future projects, which must be technically and commercially mature (Section 2.3). In order to assess commercial viability of these reserves, the wells and activities must be clearly identified, together with their costs.

For a more extensive description see Section 2.4.2.

5.2 Scope for Recovery

Scope for Recovery is the recovery estimate of any notional project, which cannot yet be shown with sufficient confidence to be technically or commercially mature (see section 2.5).

The economic evaluation should include any future pre-investment costs required to reduce technical uncertainty.

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In the case of immature projects, the associated scope for recovery may be reported as a single estimate for the undiscounted average recoveries in the case of success (mean success volume, MSV) together with a probability of success (POS). For aggregation purposes the risked expectation volumes are used (POS*MSV).

Scope for Recovery is subdivided into four distinct categories: Commercial SFR by proved techniques, Commercial SFR by unproved techniques, Undiscoverd commercial SFR and Non-commercial SFR. Details are given in section 2.5.

The volumes reported for the four SFR resource categories are based on **full life cycle**, i.e. without consideration of production licence expiry. In addition, total Commercial SFR within licence should also be reported.

5.3 Annual and Cumulative Production

Annual sales volumes are reported both through the annual reserves submissions and through the Finance system (Ceres). Both submissions find their separate ways into the Group Annual Report and consistency is of utmost importance. Production Operations and Finance functions must reconcile their figures prior to any submission. Annual oil/NGL production [Ceres line 0933] and Gas Production available for Sales from own reserves (GPafS) [Ceres line 9130] as reported in the upstream sector in Ceres **must equal** the volumes reported in the annual resource statement using the appropriate unit conversion factors. The definition for gas reserves and the definition for Gas Production available for Sale (see GFIM ref. 11) are fully aligned (both excluding flare/vent and own use).

The resource volume category 'Cumulative Production' pertains to summation of the annually reported yearly sales quantities of production volumes up to the date of reporting. Separate records must be kept of both annual Group share and full field produced volumes if the Group share percentage has changed over the years.

5.4 Volumes Initially In Place

The petroleum volume Initially In Place (IIP) is expressed in volumes of Stock Tank Oil Initially In Place (STOIIP), Condensate Initially In Place (CIIP) and Gas Initially In Place (GIIP) under standard conditions. For standard conditions the same PVT data must be used as adopted for the reporting of field recoveries.

It is necessary to maintain records of both the full field and the current Group share in-place volumes if ownership percentage of the properties has changed or is likely to change over the years.

6. RESOURCE VOLUMES FOR EXTERNAL REPORTING (PROVED RESERVES)

6.1 Proved Reserves

Proved Reserves are defined as those reserves that are reported externally in the Group Annual Report and through annual submissions to the SEC. A clear distinction is made between these externally reported Proved reserves and internally maintained P85 or Low volumes. This is explained in Chapter 3, in particular Section 3.2. Only the Group share of Proved reserves (sales volumes) is reported (Chapter 4).

Externally reported reserves volumes serve two important purposes – financial accounting and investor assessment. Financial accounting generally uses Proved developed reserves to calculate the depreciation of EP Business capital investments (GFIM, Ref. 11). The amount of depreciation affects the Group's book earnings, which are also externally reported. Shareholders and the investment community use the reported volumes and earnings to assess the performance and value of the company. It is therefore essential that externally reported proved reserves volumes are a true reflection of shareholder value.

Proved developed and Proved total (developed+undeveloped) reserves and annual production are reported for oil, gas and NGL sales quantities as at the 1st of January of each year. The reported volumes must comply with the Shell Group guidelines for reserves as contained in this report (summarised in Appendix 1). Group guidelines are based on SEC definitions, with some interpretations that have been accepted by external auditors (see section 3.2 and Appendix 4).

Reserves should be based on technically and commercially mature projects (Section 2.3). Only the Group share of proved reserves and production (sales volumes) is reported (Chapter 4). Proved reserves should be reasonably certain to be produced and sold during the remaining period of existing production licences and agreements (Section 4.3.1). Any applicable government restrictions on oil export and contractual or practical market limitations to gas delivery rates should be taken into account.

Proved reserves should be consistent with the 'proved area' as defined by SEC/FASB and interpreted by SIEP (Section 3.2). In cases where there is considerable uncertainty in fluid contacts, the P85 or Low estimate should be compared with the SEC proved area method, e.g. applying the criterion of lowest known hydrocarbon, if not disproved by performance. If the two reserve estimates should be significantly different from each other, a reconciliation should be made by the OU to assure itself that the reported reserves are a true reflection of shareholder value.

Asset holders should be aware of the differences between probabilistic and deterministic techniques (Section 3.1) since third parties, e.g. gas buyers and hence external reserves auditors for certification, may adopt different practices.

6.1.1 Proved Developed Reserves

Developed reserves must be producible through currently existing completions, with installed facilities, using existing operating methods. Volumes behind pipe can only be considered developed if additional activities require only minor future investment not exceeding 10% of the cost of a new well. See Section 2.4.1.

Proved developed reserves should in principle be estimated from extrapolations of existing well performance trends (Section 2.4.1). For recently developed fields, the original pre-development model projections (updated for observed well data and well rates) may be used.

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In line with recommended Group practice (Section 3.2), Proved developed reserves in new developed fields should be derived from a 'reasonably certain' scenario (best estimate) of anticipated field production, based on the Expectation (post-drill 'proved area') volumetrics. With increasing cumulative production, the Proved estimate should gradually grow until it equals the Expectation estimate when the field is mature. A mature field is broadly seen to be a field with a maturity ratio (cumulative production divided by expectation ultimate recovery) of 40% or more.

6.1.2 Proved Undeveloped Reserves

Undeveloped reserves require capital investment in future projects (new wells and/or production facilities) in order to be produced. These projects must be technically and commercially mature (Section 2.4.2).

Proved undeveloped reserves in undeveloped fields should be based on a 'reasonably certain' scenario of anticipated future performance, consistent with pre-development 'proved area' volumetrics. If probabilistic estimation is used, the P85 value should be consistent with this scenario and volumetrics.

Proved undeveloped reserves in new or recently developed fields should be derived from a 'reasonably certain' scenario (best estimate) of future wells' (and activities') performance, based on the Expectation (initial post-drill 'proved area') volumetrics. With increasing cumulative production through existing wells, the uncertainties regarding the performance of future wells should gradually diminish, such that Proved undeveloped reserves can be taken as equal to Expectation reserves for fully mature fields (broadly with a maturity ratio of 80% or more). However, there may still be uncertainties regarding the future wells that are not addressed by the current wells' performance (e.g. new horizontal wells in a field previously developed through conventional wells), which may require the Proved estimates still to be somewhat conservative.

6.1.3 External Financing

For projects which require some degree of external financing (e.g. LNG projects, major new venture start-ups), project financing must be expected to be available before proved reserves are disclosed externally. This could, by exception, be a reason why the reserves of some viable projects are excluded from external reporting.

6.1.4 Improved Recovery Projects in External Disclosures

Advances in reservoir modelling techniques have greatly enhanced the systematic assessment of project recoveries across the full range of uncertainties, increasing confidence in the use of simulation results as the basis for investment decisions and reserves estimation. This improved quantification has in some cases shown that pilot testing is not necessary prior to project commitment (based on a Value of Information approach). Under these circumstances, recovery from improved recovery projects (e.g. fluid injection, reservoir blowdown) may be considered Proved when the following three conditions are met:

1) A comprehensive assessment of uncertainties results in confidence that the actual volume will be greater than the low estimate.
2) The main features of the recovery process are supported by confirmed responses in analogous reservoirs.
3) Project financing has been obtained or is expected to be obtained without a pilot testing phase.

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In the case of improved gas recovery, the additional conditions in the following section also apply.

6.1.5 *Proved Gas Reserves and market availability*

In addition to the foregoing conditions, proved reserves of natural gas should include only quantities falling in the following categories:

1) that are contracted to sales; or
2) that can be considered as reasonably certain of being sold based on a reasonable expectation of the availability of markets, along with transportation/ delivery facilities that are in place; or
3) that, whilst not firmly planned, have been earmarked for future development and hence may reasonably be anticipated to be sold based upon expectation of availability of markets and project financing.

These restrictions also apply to the external disclosure of condensate/NGL products that are subject to the go-ahead of a non-associated gas project.

For major gas projects critically depending on new gas market capture, proved reserves booking should generally be postponed until agreements have been signed, generally at or around project sanction (FID).

6.1.6 *Proved Reserves vs Expectation Reserves Forecasts*

The development scenarios (in particular the timings of successive future field developments) for Proved and Expectation reserves do not need to be the same. It is reasonable to assume that whatever forecast has been assumed for the Expectation case can also be met by disappointing (i.e. Proved) reserves realisations in the fields, simply by accelerating their development. This is particularly important in cases where the Expectation forecast is capped by overall production rate constraints or production quota. The resulting Proved forecast will of course decline from plateau earlier than the Expectation forecast, but during initial years they should be the same. This will avoid losing too much proved reserves beyond licence expiry, when applicable.

6.1.7 *Types of Agreements*

Under US Financial Accounting Standards Board (FASB) regulations, separate disclosure is required for oil and gas volumes applicable to different types of licence or contract agreements, see also section 4.1. These requirements are illustrated in Figure 6.

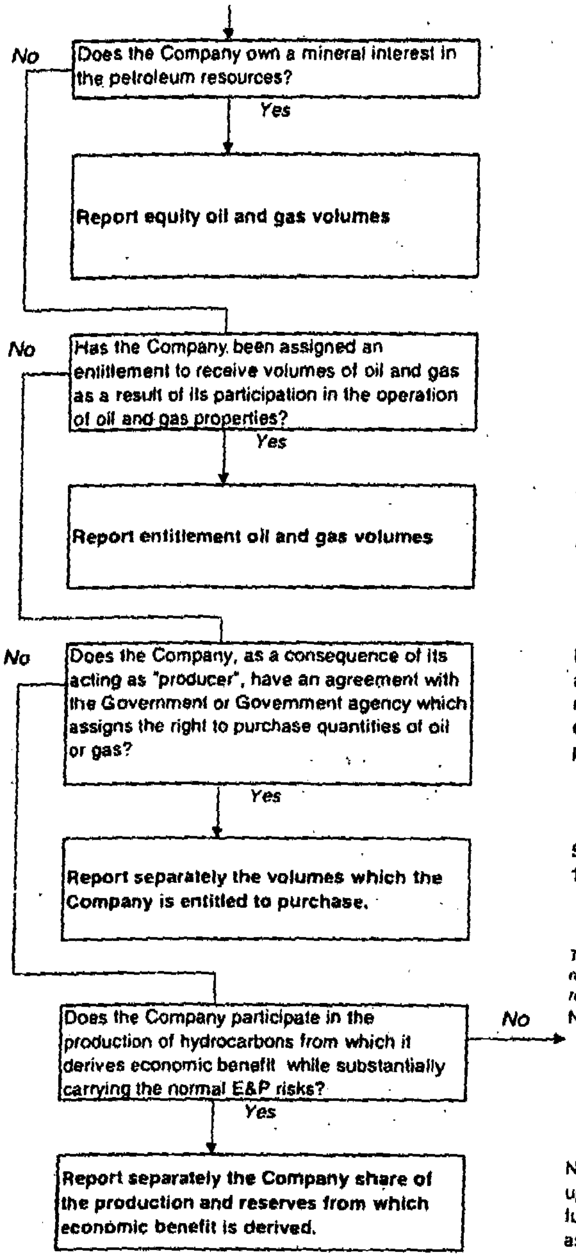
6.1.8 *Minority Interest*

Reserves are reported on a 100% basis for companies in which the Group holds a controlling interest (in line with financial reporting) rather than on a Group share basis. Minority interest volumes included in the total proved reserves are disclosed separately. Such inclusion of minority interest requires prior agreement with Group Finance. See also section 4.2.

6.2 Annual Production

Annual sales volumes are reported both through the annual reserves submissions and through the Finance system (Ceres). Both submissions find their separate ways into the Group Annual Report and consistency is of utmost importance. Production Operations and Finance functions must reconcile their figures prior to any submission. Annual oil/NGL production [Ceres line 0933] and Gas Production available for Sales from own reserves (GPafS) [Ceres line 9130] as reported in the upstream sector in Ceres must equal the volumes reported in the annual resource statement using the appropriate unit conversion factors. The definition for gas reserves and the definition for Gas Production available for Sale (see GFIM ref. 11) are fully aligned (both excluding flare/vent and own use).

Naturally, the annual sales volumes reported in the opening and closing balances for Proved and Expectation reserves should be identical in both submissions.



Notes

Traditional meaning of an enterprise's interest in reserves (FASB 19 para.10). Exclude volumes payable to others through production payments or carried interests (FASB 19 para. 47a and d).

Typical PSC case. Whether the Government has a pre-emptive right to buy back these entitlements is not material.

Relevant where national legislation prevents access to mineral rights. The agreement would not be a consequence of acting as producer if e.g. others have similar agreements but do not participate in production operations.

Separate disclosure is required. FASB 69 para. 13.

The following are interpretations of the principles of the FASB regulations regarding Company interests in production & reserves;

No volumes reported.

Normal E&P risks refer to both downside and upside exposure to changes in the value of future production volumes due to uncertainties as to their presence, volume and price.

Figure 6: Types of External Disclosures in Relation to FASB Regulations

7. RESOURCE VOLUME MANAGEMENT, REPORTING, RESPONSIBILITIES AND AUDITS

7.1 Value Realisation

The most important objective of resource volume management is the progression of the volumes to the point where maximum value is realised. The main purpose of the internal classification scheme tied to the development life cycle is to enable understanding of the potential value and the actions needed to mature volumes. In order to achieve business growth and reserves replacement objectives, it is essential that OUs and NVOs have efficient systems to move volumes through the value chain from scope for recovery to production and sales as shown in the cascade model.

OUs and NVOs internal reserve management systems should:

a) Set targets and monitor actual performance in maturing volumes towards value realisation,

b) Fully inventorise and have maturation plans for Scope for Recovery opportunities,

c) Regularly (annually) review ultimate recovery targets for existing fields and identify what activity - appraisal, study, new technology development, commercial agreement, etc. - is required to reach these targets,

d) Have Key Performance Indicators (KPI's) to measure performance (e.g. reserves replacement ratio, scope for recovery maturation ratio, time between discovery and first production).

7.2 Shareholder Requirements

EP Planning will communicate each year to OUs and NVOs a timetable and details about submission requirements for both internal and external reporting.

Volumes will be reported based on the classification systems described in this report. Additional information is reported for the calculation of the Standardized Measure required by the US Financial Accounting Standards Board (FASB).

7.3 Methods and Systems

OUs and NVOs are responsible for selecting the methods and systems that are technically most appropriate for quantifying the resource volumes of their assets consistent with these guidelines. The preferred methods and systems may vary depending on the type of resource and with time as the resource matures and technology improves.

A variety of commonly used Group and 3rd party systems are available to support resource volume assessment. Group systems are tailored to these requirements and methods and will generally provide an inherent level of quality assurance through input constraints, internal calibrations, and other 'reality checks'. Where more generalised 3rd party systems are used, OU and RBD management should be aware of the greater burden of quality control that will be required.

The Group Reserves Auditor will review decisions on methods and systems during the periodic audits. As far as these methods have an impact on the estimation of externally reported resource volumes, the Group Reserves Auditor will ensure that recommended methods are acceptable to the external auditors.

In some cases, OUs and NVOs may be unable to follow Group guidelines and/or recommended practice, due to government requirements, hardware constraints or other reasons. It is the responsibility of the OU Reserves Custodian to bring such cases to the attention of the Group Reserves Auditor, to enable him to obtain external auditors' approval of the OUs and NVOs specific methods and systems.

7.4 Responsibilities and Audit Requirements

7.4.1 EP Planning Responsibilities

EP Planning is responsible for compilation of the Group statistics of resource volumes, the analysis thereof and the communication to other functions. EP Planning also maintains the resource volume guidelines.

7.4.2 Reserves Auditor Responsibilities

The Group Reserves Auditor will carry out regular detailed reserves reviews in OUs and NVOs to ensure compliance with SEC requirements. The Terms of Reference for SEC Audits are included in Appendix 5. The external auditor will verify the Proved reserves data for external reporting.

7.4.3 Operating Unit Responsibilities

Within OUs and NVOs, a Management System should be established (see Reference 6), clearly defining internal reporting requirements, tasks and responsibilities. Technical and Financial functions must co-ordinate and reconcile their figures (particularly production volumes) prior to submission.

All levels in an OU, including Asset managers and the reservoir engineer preparing the individual field reserves estimates, should be aware of the importance of externally reported reserves (Proved, Proved developed) and their impact on financial indicators.

Asset and OU managers are responsible to ensure that the guidelines are implemented in such a way as to best represent to the shareholders the true value of the asset.

7.4.4 Non-operated Reserves

Where Shell is not the operator, the local Shell EP representative should prepare the reserves submission. In this case the Shell representative has the responsibility of ensuring that resource volume assessments by the operator are aligned with Group guidelines before submission. This may include reclassification of volumes between reserves and SFR categories where the operator's criteria differ from Group criteria. As usual, an audit trail (Note for file) should be available to document the reserves estimate.

If there is no EP representative or if the necessary data are not available locally, then the submission is prepared by SIEP (responsible RBA).

7.4.5 Annual Review of Petroleum Resources

Until 1995, the Annual Review of Petroleum Resources (ARPR) was a constituent document of the annual EP Programme Documentation, providing an inventory of the status of petroleum resources. While OUs and NVOs no longer submit ARPR's to SIEP, the compilation of such an overview report will generally be necessary to satisfy the requirements of OU governance and as such will be a key element of the OU reserves Management System referred to above.

7.4.6 Audit Trail

Audit trails form an essential element in the reserves reporting process and are an indispensable tool for the Group Reserves Auditor to assess the quality of the reserves estimates. They should support and document the submitted figures and ensure that OU management understand and own the reserves submissions to SIEP. They also form an essential link in handing over resource estimates between field reservoir engineers and reserves co-ordinators and their successors.

For all the reported resource volumes an audit trail must be available of the assumptions made and processes followed. This will allow any subsequent assessor to modify these estimates based on new information in a reconcilable manner. Thus, evaluation reports must be compiled (preferably on a field basis) giving the basic data, the way it has been interpreted and processed, the development options considered, and the resultant volumes with the assigned probabilities. In addition, a description should be given of the development strategy, including data gathering activities. These reports may be working files (if acceptable to local auditors), but it is recommended to make a duplicate 'for file' in order to ensure that the data are preserved in field reports.

Where subsequent small revisions are made, an update note must be compiled. Multiple changes may be combined in one overall update of the resource volumes if they all belong to the same change category. After several years of small changes or following a development study, a new evaluation report must be issued. When a proposed change has a significant impact on the Company's total reserves or financials, SIEP should be advised at the earliest opportunity.

Guidelines on how to prepare a good audit trail, with suggested formats for tables etc. can be found on the Shell World Web (Reference 12).

REFERENCES

1. EP 88-1140 Part 1, Classification, definitions and reporting requirements,
1a. EP 88-1145 Part 2, Methods and procedures for resource volume estimation, SIPM, April 1988
2. EP93-0075 Petroleum Resource Volume Guidelines, May 1993
3. Revision of Report EP93-0075, 12 August 1994
4. Revision of Report EP93-0075, 10 November 1995
5. Revision of Report SIEP97-1100, September 1997
5a. Revision of Report SIEP98-1100 & 1101, September 1998
5b. Revision of Report SIEP99-1100 & 1101, September 1999/October 1999
5c. Revision of Report SIEP2000-1100 & 1101, September 2000/October 2000
5d Revision of Report SIEP2001-1101, October 2001
6. EP92-0945 Business Process Management Guideline, SIPM, EPO/72, June 1992
7. Petroleum Reserves Definitions, Society of Petroleum Engineers and World Petroleum Congresses, http://www.spe.org/cda/content/0,1085,284,00.html
8. Handbook of SEC Accounting and Disclosure
9. SEC Clarifications to Proved Reserves Definitions, http:/www.sec.gov/divisions/corpfin/guidance/cfactfaq.htm#P279_57537
10. Financial Accounting Standards Board (FASB), e.g. Statements 19, 25 and 69.
11. Group Finance Information Manual - GFIM
12. Shell Wide Web – Resource Management web-page, http://sww.siep.shell.com/epb/epplan/arpr/resmgt.htm
13. Group Project Evaluation and Screening Criteria, June 2001.

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APPENDIX 1 RESOURCE CATEGORY (QUICK REFERENCE)

External Reporting	**Internal Reporting**	**Proved Reserves**		Portion of internally reported Expectation reserves (see conditions below), that is 'reasonably certain'. Additional conditions: Restricted by licence periods, government constraints and market limitations. External financing, when used, must be expected to be available. Deterministically estimated volumes should reflect undefined fluid contacts and untested recovery mechanisms ('proved area').
			Proved Developed Reserves	Proved reserves producible through existing completions and installed facilities using existing operation methods. Consistent with 'proved area'. Outstanding project activities considered completed if remaining cost <10% of total. 'Behind pipe' volumes only if cost <10% of well cost.
			Proved Undeveloped Reserves	Proved reserves which require future capital investment (wells and/or facilities). Consistent with 'proved area'. Recovery techniques must be proven 'in the rock volume'.
	Internal Reporting	**Expectation Reserves**		Project is 'technically and commercially mature'. Must be commercially viable; formal project approval or economic viability not required. Market is reasonably expected to be available. Includes only production with positive cash flow. Not restricted by licence period. Group share only reported.
			Developed Reserves	Reserves producible through existing completions and installed facilities using existing operation methods Outstanding project activities considered completed if remaining cost <10% of total. 'Behind pipe' volumes only if cost <10% of well cost.
			Undeveloped Reserves	Reserves which require capital investment (wells and/or facilities)
		Scope for Recovery		Project is technically or commercially <u>not</u> mature Not restricted by licence period. Group share only reported.
			Commercial SFR by Proved Techniques	Discovered. Commercially viable. Techniques have been proved to be feasible in this resource. A sound technical project proposal is not possible yet due to large range of technical uncertainty and/or due to market unavailability.
			Commercial SFR by Unproved Techniques	Discovered. Commercially viable. Recoverable by techniques that have been successful elsewhere, but cannot yet be demonstrated to be feasible in this field. Laboratory work or trials elsewhere have a reasonable chance of demonstrating feasibility in this field. Discounted for the risk that the considered technique will not prove to be feasible.
			Non-Commercial SFR	Discovered. Not commercially viable even if technically successful. Commercially viable with a change of commercial circumstances. Unit Technical Cost below an annually advised ceiling.
			Undiscovered Commercial SFR	Recovery from undrilled prospects. Commercially viable exploration and development. Techniques have been successful elsewhere under similar conditions. Discounted for the risk that commercial volumes are not present.

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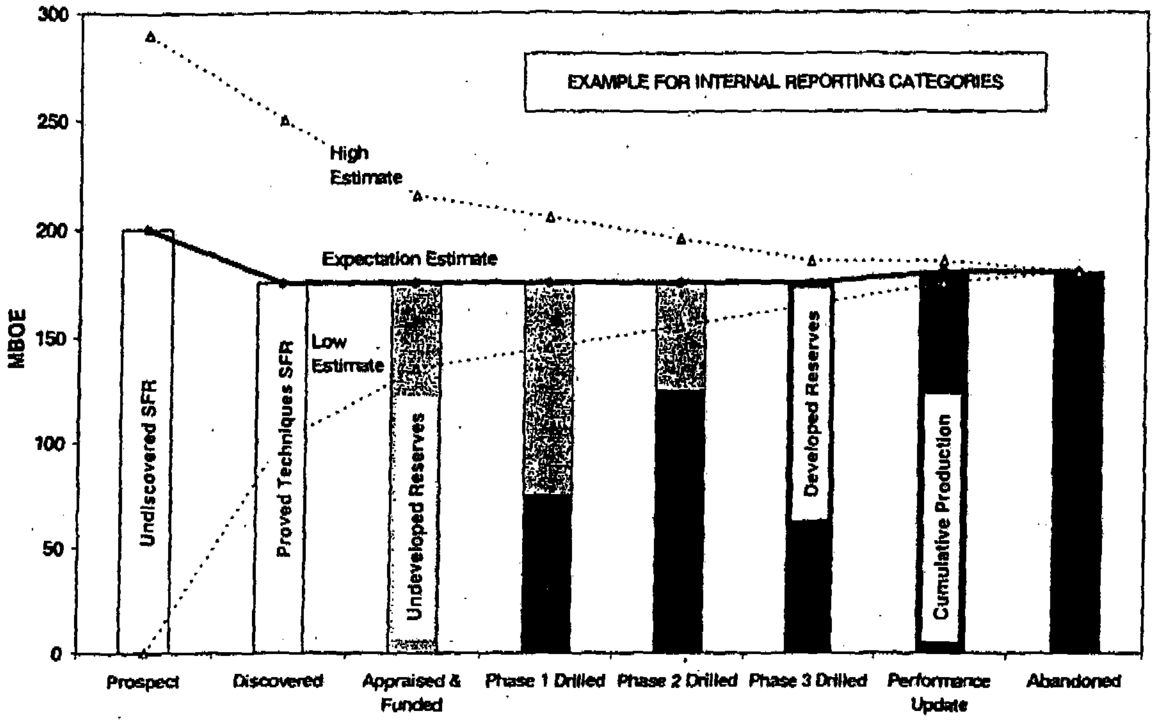
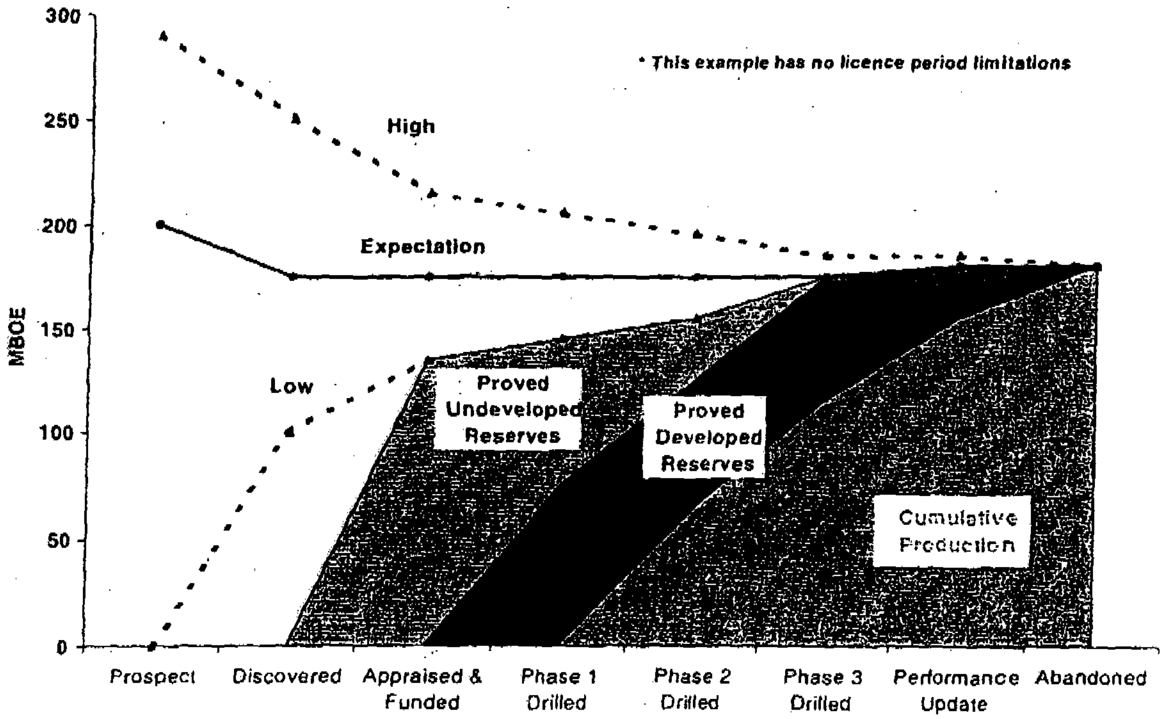
APPENDIX 2 RESOURCE MIGRATION DURING FIELD LIFE



EXAMPLE FOR EXTERNAL REPORTING CATEGORIES *



APPENDIX 3 SEC PROVED RESERVES DEFINITIONS

Transcribed from the Handbook of SEC Accounting and Disclosure 1998, pages F3-63 to F3-64 (Ref. 8). For a recent clarification by SEC, see Ref. 9.

Proved Reserves

Proved reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

A. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test supports. The area of a reservoir considered proved includes:

1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and

2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

B. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

C. Estimates of proved reserves do not include the following:

1) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";

2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

3) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal (excluding certain coal-bed methane gas), gilsonite and other such sources.

Proved Developed Reserves

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for re-completion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery techniques is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

APPENDIX 4 SHELL INTERPRETATION OF SEC RESERVES DEFINITIONS

SEC Definition	Shell Interpretation for External Reporting (section 3.2)
Reasonable certainty; Proved Area includes portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and the immediately adjoining portions not yet drilled (if supported by geological and engineering data). In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Extended by production evidence, if conclusive.	Proved area delineated by fluid levels as interpreted from pressures <u>in</u> the reservoir. Laterally confined to areas of good and continuous seismic amplitudes, not beyond potentially sealing barriers. Extended by production evidence if conclusive. Proved developed reserves in new developed fields derived from a 'reasonably certain' scenario (best estimate) of current wells' future production, based on the Expectation post-drill 'proved area' volumetrics. With increasing *cumulative production, the Proved estimate should grow* towards the Expectation estimate when the field is mature (maturity ratio, i.e. cumulative production divided by expectation ultimate recovery, of some 40% or more). Proved undeveloped reserves in new or recently developed fields derived from a 'reasonably certain' scenario (best estimate) of future wells' production, based on the Expectation initial post-drill 'proved area' volumetrics. With increasing cumulative production, proved reserves should grow towards Expectation reserves for fully mature fields (maturity ratio of some 80% or more). Some exceptions may justify lower Proved/Expectation ratios.
Fixed RT prices at level prevailing at date of estimate	Prices fixed by SIEP ca. 6 months prior to estimate date, but amended if there is a subsequent significant change.
Fixed RT costs at level prevailing at date of estimate.	Costs fixed by OUs and NVOs at date of estimate. Flat MOD costs must be supported by technology plans to show that implied cost reductions are viable.
Economic producibility	Technically and commercially mature (i.e. positive discounted real terms cash flow for sufficient range of scenarios).
Producibility supported by either actual production or conclusive formation test supports	Producibility should normally be demonstrated by a conclusive test, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.
Improved recovery processes included only after successful testing by a pilot project or the operation of an installed program	Reserves from improved recovery processes are normally included following an in-situ test; by analogy with the same process being used elsewhere under similar conditions, or occasionally as a result of lab tests or simulation studies. Reserves associated with a firmly planned pilot can be booked.
'A gas market must exist'	Include only gas contracted or reasonably expected to be sold.
Developed reserves are from existing wells (including minor cost re-completions), existing facilities and operating methods	Existing wells, installed facilities and existing operating methods. Outstanding project activities can be considered existing if outstanding costs are minor (<10% of project) and approved. Includes volumes behind pipe if future costs are minor (<10% of a new well).

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APPENDIX 5 SEC RESERVES AUDITS - TERMS OF REFERENCE

The purpose of the SEC Reserves Audit is to verify that appropriate processes are in place in the OU to ensure that the proved and proved developed reserves estimates for external (SEC) reporting are prepared in accordance with the latest Group prescribed guidelines (SIEP 2001-1100/1101) and the FASB Statement of Financial Accounting Standards no.69 (SFAS-69).

The Audit will be carried out by the Group Reserves Auditor. His specific tasks during the audit shall be:

1) To verify the technical maturity of the reported proved and proved developed reserves estimates by assessing the quality of the engineering data and study work supporting the estimates and by verifying that undeveloped reserves are based on identifiable projects that can be considered technically mature.
2) To verify the commercial maturity of the reported reserves volumes by assessing the robustness of project economics and by establishing that these volumes can reasonably be expected to be sold in present or future markets.
3) To verify the 'reasonable certainty' of the reserves estimates by assessing the validity of uncertainty ranges used for their constituent parameters, by verifying that estimates are realistic in comparison with expectation estimates, by verifying that appropriate methods are used for mature fields and by establishing that appropriate methods of reserves addition (probabilistic / arithmetic) have been applied.
4) To verify that the Group share of proved and proved developed volumes has been calculated properly and that these volumes are producible within prevailing licence periods.
5) To verify that reported volumes are up-to-date and consistent with previous estimates, that changes are reported in the appropriate categories and that appropriate audit trails are in place for the study work supporting the reported reserves estimates.
6) To verify that reported reserves are net sales volumes and that the reported annual production (sales) volumes are consistent with those reported in submissions to Group Finance.

In case of deviations from the Group and FASB guidelines, the auditor shall establish whether and to what extent resulting estimates are likely to differ significantly from those that might be expected from the application of the standard guidelines.

The audit will be carried out by reviewing the reserves estimation and submission process through interviews of OU staff and by taking at random a number of fields for detailed analysis.

The frequency of the audit will in principle be once every four years for each OU, with possibility to extend this period to five years for medium and small OUs. Major reserves changes or concerns expressed during a previous audit may require an advancement of the next audit. For an OU reporting reserves for the first time, the first audit will in principle be within two years of this first submission.

The audit will in principle be carried out on OU premises and will be based on documentation available in the OU. Assistance of OU staff may be called upon.

An audit report will be submitted to the Managing Director of the OU, to the EP CEO and EP RBA, to the OU's Hydrocarbon Resource Manager and to KPMG the external auditors. It will be prepared and discussed in draft form on site, after which a final report will be prepared in The Hague, once formal OU comments are received. The report will contain an overall judgement (Good, Satisfactory, or Unsatisfactory), with itemised conclusions and recommendations.

APPENDIX 6 TERMINOLOGY

A6.1 Petroleum Resources Terminology

Reservoir

A reservoir is a discovered petroleum resource where internal pressure communication is known to exist between all identified geological sub-units.

In case of doubt, reservoirs are restricted to fault blocks / sedimentary units until production performance proves communication to exist across faults/ barriers. PVT properties can vary within a reservoir.

Field

A field is the collection of all petroleum resources within a closed areal boundary that belong to the same confining geological structure, and where the presence of petroleum has been demonstrated in at least one reservoir by a successful exploration well.

Field boundaries must be defined upon discovery and should encompass the unpenetrated petroleum resources in adjacent fault blocks and stratigraphic traps, if they are considered to be part of the same overall confining structure. Field boundaries may be re-defined on the basis of new geological information.

Potential Accumulations

Potential petroleum resources beyond existing field boundaries, where the presence of petroleum has not yet been demonstrated, are collectively called potential accumulations.

Producibility

Should normally be supported by a conclusive test in a drilled or immediately adjoining reservoir, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.

Production Facilities

The production facilities consist of all hardware installed to recover petroleum from the sub-surface resources and to deliver a quality controlled end-product for sale. These comprise the production and injection wells and the surface facilities for treatment, conversion, compression/ pumping, transport and delivery.

Surface Facilities

That part of the production facilities accessible at surface, connecting the wellheads ultimately to the delivery points.

Existing Development

The collection of all completed projects or sub-projects is referred to as the existing development.

Field quantities

Field quantities (also called 'Wellhead' quantities) are those quantities routinely measured at surface for individual well strings and expressed in terms of the stabilised products oil, condensate and (wet) gas or in terms of the type of injected fluids. These quantities may subsequently be reconciled with fiscalised sales and other product outlets, see below.

Sales quantities

The quantities sold after fiscal metering and delivered at the locations where the upstream company ceases to have an interest in the end-products. These can be expressed in terms of the general end-products oil, (dry) gas and natural gas liquids (NGL) or in terms of the actual product.

Field products and the subsequent sales products may be different and will be affected by own use and losses. The properties and volumes of end-products may be influenced by mixing and the petroleum type itself may be altered during surface processing. Since surface processing conditions may change during a project life, sales products may vary in specification and in relation to field products. To avoid ambiguity and double counting, a clear distinction must be made between recoveries in the field and the quantities estimated to be available for sale.

For general sales products, oil, gas and NGL, only the quantities sold by the upstream E&P company can contribute to Group reserves. Condensates mixed with crude oil in the same stream and sold as such can be reported under oil. Separator condensate from gas wells and light hydrocarbon liquid products, derived from surface processing, if collected in a separate stream and sold as such are reported under NGL. Bitumen may be reported under oil in summary reports (with an appropriate footnote). In line with SEC requirements, sales volumes for gas should be those committed or committable to a gas contract. Committed Gas is covered by a gas contract. Committable gas reasonably expected to be assigned to a contract in the future.

It is necessary to maintain a more detailed internal administration of the actually sold products by stream in two cases: (1) If the upstream E&P company has separate contracts for delivery of special converted sales products such as LNG, methanol, ethane, LPG, C5+ etc., or (2) If there are special sales products like helium, sulphur or generated electricity.

Reconciliation

A monthly reconciliation is made between the fiscalised sales quantities and the quantities produced in the field. This is reported in the Monthly Report of Producing Wells (MRPW). The reconciliation process corrects for own use, flaring, losses and product conversion, and provides the end-product yield.

For reserves estimating purposes an average future yield factor is to be estimated (e.g. LPG/ wet gas yield, dry gas/ wet gas yield).

Ultimate Recovery

The ultimate recovery (UR) of a hydrocarbon field is the sum of cumulative production and the estimated volume of reserves (developed + undeveloped).

Total Resource Volume

The Total Resource Volume of a hydrocarbon field is the sum of cumulative production, the estimated volume of reserves (developed + undeveloped) and the Total Scope for Recovery.

A6.2 Probabilistic Terminology

Probability Density Function

The probability density function (PDF) of a stochastic variable indicates the probability that the actual variable value lies within a narrow interval around a particular value of the possible range, divided by the width of that interval.

Cumulative Probability Function

The cumulative probability function (CPF) of a stochastic variable describes the probability that the variable may exceed a certain value. The CPF is the mathematical integral of PDF.

P85

The value that has a 85% probability that it will be exceeded by the stochastic variable.

P15

The value that has a 15% probability that it will be exceeded by the stochastic variable.

Mean

The statistical mean of a stochastic variable is the probability weighted average of the variable over the entire variable range.

Mean Success Volume (MSV)

The probability weighted average of all realisations that equal or exceed the minimum reserves required for a commercial development of the resource.

Probability of Success (POS)

The probability that the minimum commercial volume will be exceeded and which therefore indicates the likelihood of any future development. The product of MSV and POS is the recovery expectation.

A6.3 Commercial Terminology

Discount Rate

A rate at which future real terms costs or cash-flow are discounted over time to calculate their present value.

Net Present Value (NPV)

The net present value of a project is the sum of the discounted annual cash flow, expressed in real terms money, over the period from the first project expenditure to abandonment. The net present value is expressed in million US$ at the relevant discount rate.

Expected Monetary Value (EMV)

The expected monetary value is a probabilistic balance of investments and revenues, expected from a set of conditional operational activities, comprising data acquisition and one or more development projects, which are arranged in an ordered sequence with probabilities assigned to each action (decision tree).

The EMV is the summation of the NPVs of projects, reduced by the costs of data acquisition activities, all expressed in discounted real term money and multiplied by their assigned probabilities. EMV is expressed in million US$ at the relevant discount rate.

Projects with a negative NPV for certain resource model realisations should be excluded from the EMV calculation, if the assumption is valid that data gathering will prevent such projects being implemented.

Unit Technical Cost (UTC)

The unit technical cost of a development project is defined as the sum of capital plus operating costs, expressed in real terms money, divided by the total production over the period from start-up to abandonment. In addition, both the cost and the production must be discounted. The reference date for the discounting should be the same for denominator and numerator (e.g. the first year of expenditure) and should be stated. The unit technical costs is expressed in US$/bbl (oil equivalent) at the relevant discount rate.

FID

Final investment decision, the decision (at CMD or senior executive level) to proceed with a project.

NFA forecast

No further (Capex) activity forecast, i.e. a forecast based on existing wells and facilities only.

A6.4 Exploration versus Development Wells

The classification of a well as either an exploration well or as a development well is determined (in line with SEC rules) based on the proved area as follows:

Proved Area

The proved area is the part of a property to which proved reserves have been specifically attributed (see also Section 3.1.3). It is delineated by the fluid levels seen / interpreted from drilled wells and by the area around those wells which geological / engineering data indicate to be producible.

Exploration Well

An **exploration well** is a well that is not a development well, a service well, or a stratigraphic test well.

Development Well

A **development well** is a well drilled within the **proved area** of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.

Service Well

A **service well** is either an injection well, a disposal well or a water supply well.

Appraisal Well

An **appraisal well,** or **stratigraphic test well** is a well drilled for geological information (not to test a prospect), either 'development-type' drilled in a proved area or 'exploratory-type' if not drilled in a proved area.

DEPOSITION
EXHIBIT
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Shell Confidential **EP 2002-1100**

Petroleum Resource Volume Guidelines
Resource Classification and Value Realisation

Custodian:	SIEP EPB-P
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KEYWORDS

Resource Volumes, Guidelines, Reserves, FASB, SEC

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1. INTRODUCTION

Petroleum resources represent a significant part of the company's upstream assets and are the foundation of most of its current and future upstream activities.

The Group's EP business depends on its effectiveness in finding and maturing petroleum resources to sustain itself and drive profitable production growth. To aid systematic resource management, the volumes concerned are classified according to the maturity or status of their associated development (project) and operational (production) activities.

Shell Group petroleum resource volumes and their anticipated changes are reported to Excom on a frequent basis. Proved reserves have a direct influence on net income, are disclosed externally and therefore subject to internal controls and external audit.

This document represents the petroleum resources accounting standard for Shell Group Operating Units (OU's) and New Venture Organizations (NVO's). It complies with rules set by the US Securities and Exchange Commission (SEC) and is to serve as a reference in the reserves submission, reporting and control processes.

Information on the format requirements of internal and external submission will be included in the second part of these guidelines (SIEP 2002-1101, Ref. 3). Detailed submission requirements are communicated annually in a letter from EP Planning.

The present (2002) version addresses recent clarifications of SEC definitions published by SEC staff. The text has also been shortened to promote clarity and readability. Where text has been changed or added, this is indicated by a line in the margin.

No material change in the volume of reserves reported by the Group is expected nor intended by these guidelines.

2. RESOURCE VOLUME CLASSIFICATION

2.1 Definition

A petroleum resource is any accumulation of hydrocarbons that is known or anticipated to exist in a sub-surface rock formation, located in the company's current exploration and production acreage.

Resource volumes are reported as the quantities of sales product for crude oil, natural gas and natural gas liquids. The corresponding quantities of field recovery should be maintained by the OU (See Appendix 6). The reporting of petroleum resource volumes should further indicate the petroleum type, the reporting units and conditions, and the Group share.

2.2 Reserves and SFR (Figure 1)

Resource volumes are tied to the project or activity that develops them and are generally reported by field. The term **reserves** is used for resource volumes associated with a project that is **technically and commercially mature** to the extent that funding is 'reasonably certain' to be secured. Resource volumes that do not meet these criteria are classified as **Scope for Recovery** (SFR). **Proved reserves** are the portion of reserves that is reasonably certain to be produced and which will be reported externally. If no Proved reserves can be assigned to a project, then the related resource volumes are to be retained as SFR.
The concept of 'reasonable certainty' requires 'hard' field data, contracts and thorough evaluation to underlie the numbers. The implication is that as more data becomes available, upward revision is much more likely than negative revision.

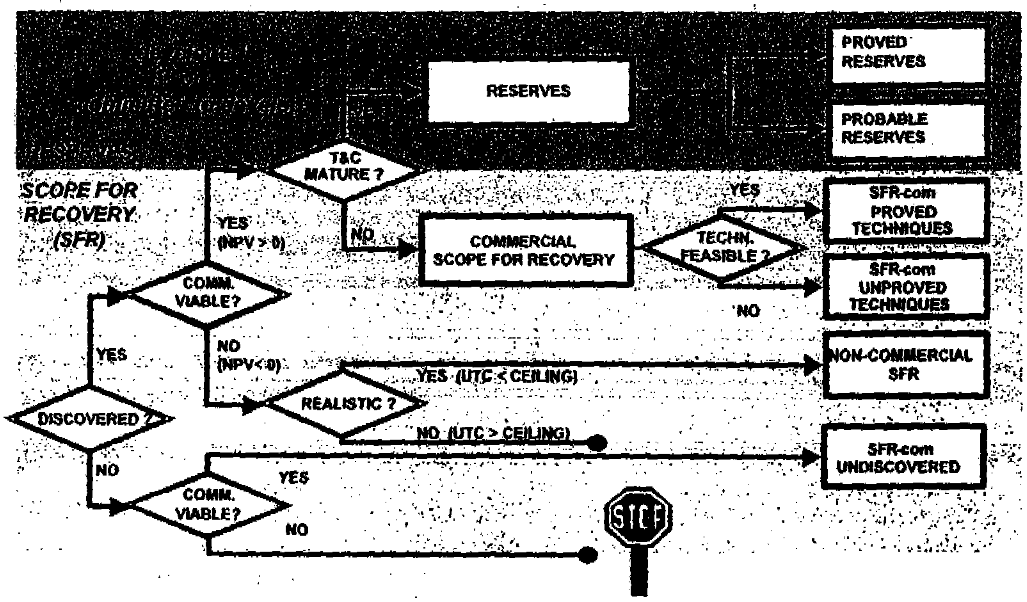

Figure 1: Resource classification flow diagram

These categories are further explained in this Chapter and their definitions are summarised in Appendix 1. A graphical example of the migration of resource volumes between categories during a field's life cycle is shown in Appendix 2.

2.3 Technical and Commercial Maturity

For a resource volume to pass from scope for recovery (SFR) to reserves (for internal as well as external reporting), the associated project(s) will have to reach both **technical** and **commercial maturity**. This is deemed to be the case when:

1. The Shell shareholder assurance processes have been satisfactorily passed both technically and commercially and no significant issues that could preclude proceeding with the project exist[i].
2. Support to fund the project is reasonably certain (e.g. the project survives the business planning processes of Capital Allocation) and the project forms (or is reasonably certain to form) part of the relevant business plan.

Major reserves volumes that are no longer judged to be commercially mature should only be de-booked after thorough (re-)evaluation.

2.3.1 *Project Basis*

Reserves being future hydrocarbon product available for sale are tied to projects (development) and activities (production operations). A project is any planned creation or modification of wells, surface production facilities and/or production policy, aimed at changing a company's sales product forecast. The aggregated production forecast of an OU must therefore be consistent with its reported reserves. This also holds for the 'proved forecast', as defined by the aggregated 'reasonably certain' amount of hydrocarbons forecast to be produced by the appropriate development/production scenario, duly respecting license duration and overall constraints (e.g. quota).

2.3.2 *Technical Maturity*

For a project to be **technically mature**, there should be a documented definition of a viable project that is anticipated to be implemented with 'reasonable certainty'. Such project definition should be based on resource and development scenario descriptions, with drilling/engineering cost estimates, a production forecast (including sensitivities) and economics.

For project reserves to enter into the Proved category, independent review and challenge is required (as a control) to preserve integrity of the external disclosures. For major projects such review is routinely executed through the Group's Value Assurance Review process. Note that concept selection (VAR3) must at least have been completed. In all cases, there should be 'reasonable certainty' that nothing is standing in the way of a firm development plan (i.e. there are no technical issues that could de-rail the project).

For smaller projects a documented development plan should suffice, which may be notional if a well established analogue is in place. The quality of such plan should be a sufficient basis on which to judge the likelihood of project funding (see below).

2.3.3 *Commercial Maturity*

A project is deemed **commercially mature**, when (1) its profitability meets the Group's criteria (as applied through Shell's corporate Capital Allocation process), (2) market availability is assured (see below) and (3) funding by the Group is 'reasonably certain'.

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[i] Examples: Gas sales contracts, major infrastructure needs, government approvals, un-tried technology

Assurance of market availability for oil (and/or NGL) means at least the 'reasonably certain' availability of a pipeline to a shipping terminal or other outlet (e.g. a refinery), whilst for gas this means that the product is:

1) contracted to sales; or
2) considered as reasonably certain of being sold based on an expectation of the availability of markets, along with transportation/ delivery facilities.

For major gas projects critically dependent on new gas market capture, reserves booking should in principle be deferred until agreements have been signed, which is generally at or around project sanction (FID).

The condition of marketability for gas reserves also applies to the NGL products of a non-associated gas project: If the gas market is not assured, neither the gas nor the NGL volumes can be reported externally.

2.4 Proved, Probable and Expectation Reserves

Total (Expectation) reserves are subdivided in Proved and Probable reserves. It should be emphasized that if no Proved reserves can be assigned to a project, then the related petroleum resource volume should be retained as SFR, i.e. there should be no Expectation reserves reported without Proved reserves.

2.4.1 Proved Reserves

Proved Reserves are the portion of Expectation reserves that is reasonably certain to be produced and which will be reported externally, as part of annual reports and (financial) accounts. The concept of 'reasonable certainty' requires 'hard' field data (incl. logs, pressures, (test) production, injection etc.), contracts and thorough evaluation to underlie the numbers. The implication is that as more data becomes available, upward revision is much more likely than negative revision. As fields mature, Proved reserves are expected to 'grow' towards (and in most cases become equal to) Expectation estimates. Quantification of uncertainty and estimation approaches are discussed in Appendix 4.

2.4.2 Probable Reserves

Probable reserves are the portion of **Expectation reserves** that is not (yet) Proved but is part of the production plan for existing fields and projects; alternatively defined as the difference between Expectation and Proved reserves.

2.5 Developed and Undeveloped Reserves

Developed and Undeveloped reserves should be evaluated separately. Assessment of undeveloped reserves on the basis of an assumed recovery factor is not acceptable.

2.5.1 Developed Reserves

Developed reserves must be producible through currently existing completions, with installed facilities, using existing operating methods. Facilities requiring minor outstanding activities in ongoing projects can be considered as existing if the outstanding capital investment is minor (< 10%) compared to the total project cost and if budget approval has been obtained. Volumes behind pipe can only be considered developed if the additional activity (e.g. 'lower' zone abandonment, perforating, stimulating) does not require a full well entry/re-completion and if the cost of this activity (normally Opex) does not exceed 10% of the cost of a new well.

Developed reserves should in principle be estimated through extrapolation of existing well performance trends. This may be done either through plotting (e.g. rate vs. cumulative production, log oil rate vs. time) or through history matched simulation modelling. If no significant history is available to match, the developed reserves will be based on pre-development (simulation) model projections, updated for observed well geological and petrophysical data and well rates. The resulting forecast should represent the production that will be contributed by the existing wells through the currently installed facilities, assuming no future development activity (NFA forecast).

2.5.2 Undeveloped Reserves

Undeveloped reserves require capital investment through future projects (new wells and/or production facilities) in order to be produced. These projects must be technically and commercially mature (Section 2.3).

Gas volumes that require installation of planned or anticipated future compression should be classed as undeveloped until such compression has been installed.

New development projects, which add developed reserves, may defer field/platform abandonment and may thereby also increase the reserves producible from existing completions. Such gains should be included in the economic evaluation of the new development project and should be included in reserves when commercially viable.

Future wells or facilities may accelerate reserves that would otherwise be produced by existing assets. The portion of reserves expected to be accelerated by the new investments should be classified as developed with the existing investments. If future investment accelerates production such that additional reserves are recovered within time limits (e.g. sales contract periods, field life), the additional reserves should be classified as undeveloped until this investment has been made.

2.6 Scope for Recovery

Scope for Recovery is the recovery estimate of any (notional) project, which has not reached technical as well as commercial maturity. However, there must be an expectation that this project could mature, based on reasonable assumptions about the success of further appraisal, emerging technology development, cost reduction strategies, marketing efforts, terms and conditions improvement and/or any other issue that may preclude the project's FID.

The economic evaluation should include any future pre-investment costs required to reduce technical uncertainty.

Scope for recovery is to be reported as a single best estimate (or a Mean Success Volume), discounted to take due account of the risk that the project will not materialise (for either technical or economic reasons).

2.6.1 Commercial SFR by Proved Techniques

The volume estimated to be recoverable from discovered resources by a project utilising a recovery process or technique which has been demonstrated to be technically feasible in the resource concerned or under analogue conditions and is expected to be economically viable.

2.6.2 Commercial SFR by Unproved Techniques

The volume estimated to be recoverable from discovered resources by a project utilising any recovery process or technique which has not been demonstrated to be technically feasible (under conditions applicable to the area or field) and which requires future laboratory tests and field trials (pilot) in order to establish this feasibility. Once technically feasible, the process should be expected to be commercially viable.

2.6.3 Undiscovered Commercial SFR

The volume believed to be recoverable from as yet undrilled potential accumulations by any process that has been demonstrated to be technically feasible elsewhere, under similar conditions. Development should be expected to be commercially viable.

These SFR volumes must be discounted for the risk that petroleum is not present or is not commercial to develop (Probability of Success, see Appendix 6).

Future data gathering may result in a total write-off of these resources. Following drilling results, the resource volumes are revised and, in the case of a discovery, the economics re-assessed, whereupon the resource is either discarded or reclassified.

2.6.4 Non-Commercial SFR

The volume that may be produced by development projects which, even if (technically) viable, would not be commercially viable. To avoid unrealistic situations the reporting of Non-Commercial SFR is restricted to projects with a Unit Technical Cost below a ceiling, advised annually by EP planning.

Non-commercial SFR is reported in order to retain an indication of the discovered resources that could become commercial with a change of circumstances (e.g. an increase in oil price, a change in tax regime, improvement of technology, development of a gas market for flared/vented/re-injected gas volumes).

3. GROUP SHARE

Only the Group share of resource volumes is reported, both in submissions for internal and for external reporting. The Group share is determined by three factors: (1) the contractual share of produced hydrocarbons, as agreed with the resource holders (usually the host government), (2) the Group share in the OU or venture that holds the contractual share, and (3) licence duration and other restrictions.

3.1 Contractual Share

Resource volumes can be distinguished according to three different types of agreement: Equity, PSC and 'New Contracts'. These are described below.

If an OU/NVO has interests in several licence areas subject to different contract types, a separate submission must be made with respect to Proved reserves for each of the contract types. This applies in particular to submissions for external reporting (see Figure 2).

3.1.1 Equity

Equity resources are the OU/NVOs share of resources in Concessions. Concession agreements lay down the general terms and conditions of operation, define the applicable tax rules, the Company share of resources in Concessions and the duration of the production licence. These agreements are generally with the host government, but in the USA they may also be with the private owners of the mineral rights ("lease or fee" conveyance of rights to the operator).

3.1.2 PSC Entitlement

Entitlement resources are the OU/NVOs share of production in acreage governed by a Production Sharing Contract (PSC). The Company entitlement share of production is the Company interest in the sum of cost oil plus excess cost oil plus profit oil, in accordance with the PSC terms. The entitlement share is calculated from economic modelling reflecting current estimates of future costs and sales value.

3.1.3 New Contracts

In recent years, a number of resource holding countries have introduced innovative production contracts in order to attract investment by foreign oil companies while preserving the principle of national resource ownership. These agreements typically provide for the contractor to recover costs and profits from hydrocarbon revenues while holding no title to, or entitlement to receive petroleum resources.

US Financial Accounting Standards Board (FASB) regulations have lagged behind these developments and provide little explicit guidance on reserves disclosure when the risks and rewards of ownership are carried without legal title to mineral rights.

However, volumes covered by such innovative contracts should be included in external reports in an informative way to be consistent with the spirit of the SEC regulations. The volumes from which economic benefit is derived should be reported if all three of the following conditions are met:

1. The reporting Company participates in the production operations as either operator or in partnership with the operator, and so bears a share of the costs and risks of the production operations.

2. The reporting Company derives future economic value that is directly related to the volume of hydrocarbons produced. For example, a fee expressed as a fixed or indexed amount per barrel of production would constitute a derivation of value from the produced hydrocarbons, but an operating fee that is largely independent of production would not. The actual source of revenues used to pay the OU is not crucial to this point. For example, if the remuneration is determined by a produced gas volume but paid from oil revenues, the economic value to the OU is in effect derived from the produced gas, and this volume should be reported.
3. The reporting Company is exposed to the normal risks and rewards associated with ownership of mineral rights, including the downside and upside from changes in the value of future production volumes. These include the risk that costs may not be recovered, due either to uncertainty as to the presence or magnitude of hydrocarbon volumes or to movements in petroleum prices.

OUs and NVOs working under such contracts should complete the standard resource volume submission for the Group/Company interest in these volumes, noting the nature of the interest. Group share of production is calculated from economic modelling of total financial reward in line with contract terms versus total revenues. Reported volumes should be in line with the reporting of traditional reserves with regard to royalties and should therefore reflect the volumes from which pre-tax cash flow is derived. As elsewhere, cash royalties are regarded as a production cost (see below).

When an OU is participating in a venture which grants neither title, nor an entitlement to receive petroleum, and which does not satisfy the three criteria above, the OU should not report reserves or production volumes. For example this might occur if the recovery of costs is guaranteed against adverse price movements or a shortfall in recovered volumes.

3.2 Group Share in OU

If the Group holds only a partial share (i.e. less than a 100% share) in the company or entity that holds the concession or contractual share with the resource owners, this share must also be accounted for in the reserves submission.

As an exception to this, both Expectation and Proved reserves (internal and external reporting respectively) are reported on a 100% basis for companies in which the Group holds a controlling (> 50%) interest, consistent with financial reporting. Minority interest volumes included in these total reserves are then disclosed separately. Prior agreement must be obtained from Group Finance before such reporting is considered.

3.3 Licence duration and other restrictions

3.3.1 Licence or Contract Extensions

For internal reporting purposes, Group shares of the Expectation estimates of reserves and scope for recovery are recorded for the total producing life, i.e. including the period beyond the relinquishment date, that is not (yet) covered by a right to extend or by a letter of assurance (see below). The currently existing licence terms or other anticipated terms should be assumed for this extrapolation. In addition to these full life cycle volumes, resource volumes are also recorded as limited to the current licence or its agreed extension only (Expectation developed reserves, total Expectation reserves and commercial SFR).

For external reporting, Group share of reserves (Proved, Proved Developed) is limited to future production within the existing licence or contract period, including any agreed extensions as may be covered by documented evidence.

volumes and sold by the company are equivalent to fees-in-kind received. All fees-in-kind received should be included as a purchased volume in the company accounts.

Where a company pays fees in kind (from its own fields/resources) to a Third Party, these do constitute a Group share in resources and should be included in the reported volumes. Annual volumes produced and used as fees in kind should be included in sales volumes, with associated revenues (at an agreed or fair market value) equivalent to booking of the incurred operating cost.

3.3.7 Under/Over Lift

Group share should also allow for any historic under or over lift by partners or government. A Group historic over lift should be reflected as an equivalent reduction of Group reserves, a Group historic under lift as an equivalent increase of Group reserves.

Group share should reflect impact of swap deals between fields where early production capacity in one is traded versus later production repayment by the other.

Treatment of take-or-pay volumes should be aligned with financial treatment of the cash received and booking of production volumes.

3.3.8 Open Acreage

Group share of volumes is non-existent in open acreage and acreage for possible acquisition or farm-in.

3.3.9 Committed Gas Reserves

Total volumes of expectation gas reserves within licence, which have been sold (committed) under long and short term contractual agreements. In countries with a mature/deregulated gas market all gas reserves which have a near certainty of market take-up can be classified as 'committed'.

3.3.10 Committable Gas Reserves

Volumes of gas reserves, which have not been sold, but could be sold (committable) under contractual agreements. The sum of committed and committable gas reserves should equal expectation gas reserves within licence.

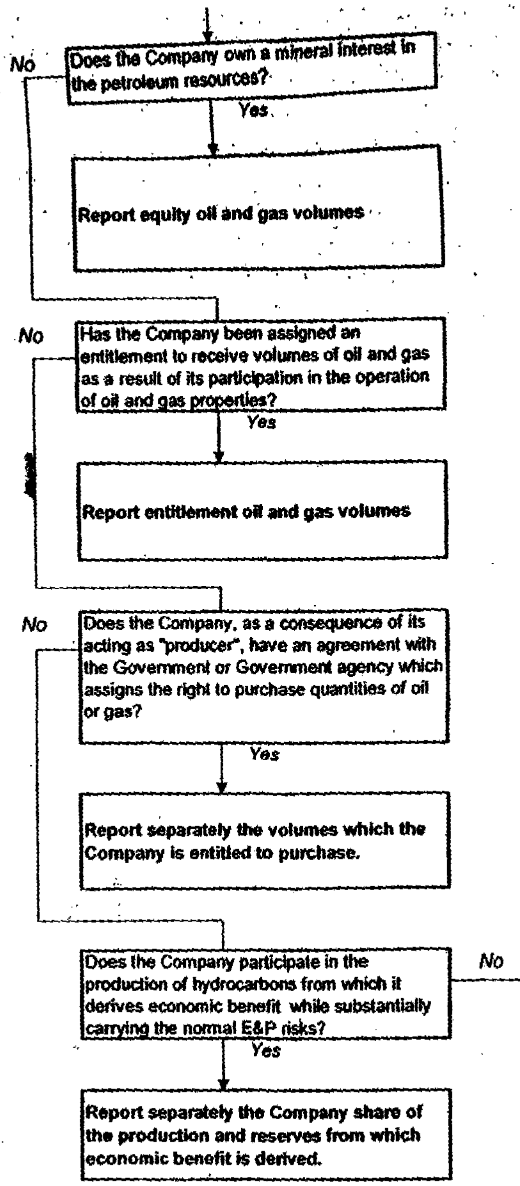
3.3.11 Gas Re-injection

Gas volumes re-injected in a reservoir, for pressure maintenance, gas conservation, Underground Gas Storage (UGS, including cushion gas), or other reasons, **without transfer of ownership**, remain part of a company's resource base and should be **included** in the Group resource estimates. These gas volumes should be classified and reported as reserves or SFR, depending on the recovery anticipated through future developments (e.g. taking into account anticipated re-saturation losses).

Gas volumes re-injected in an UGS project on behalf of a **Third Party** (either following transfer of ownership by the company to this party, or following production by the third party itself) do not constitute a Group share in resources and should be **excluded** from reported volumes.

3.3.12 Oil Sands

Petroleum volumes (heavy oil, bitumen, syncrude, gas, liquids, etc.) recovered from unconventional reservoirs (oil sands, tar sands, coals, oil shales) by a "manufacturing" process must be reported separately from the conventional resource base. This should also include conventional reservoirs where recovery occurs through a mining operation. However, conventional reserves or SFR can be claimed for otherwise unconventional reservoirs if the petroleum is recovered in its natural state and original location (i.e., has not been "manufactured" in situ by alteration from natural state) through the use of conventional methods (wells). Examples of this are coal bed methane produced from wells or heavy oil produced from wells using conventional thermal recovery methods.



Notes

Traditional meaning of an enterprise's interest in reserves (FASB 19 para.10). Exclude volumes payable to others through production payments or carried interests (FASB 19 para. 47a and d).

Typical PSC case. Whether the Government has a pre-emptive right to buy back these entitlements is not material.

Relevant where national legislation prevents access to mineral rights. The agreement would not be a consequence of acting as producer if e.g. others have similar agreements but do not participate in production operations.

Separate disclosure is required. FASB 69 para. 13.

The following are interpretations of the principles of the FASB regulations regarding Company interests in production & reserves;

No volumes reported.

Normal E&P risks refer to both downside and upside exposure to changes in the value of future production volumes due to uncertainties as to their presence, volume and price.

Figure 2: Types of External Disclosures in Relation to FASB Regulations

4. ASSESSMENT, REPORTING, RESPONSIBILITIES AND AUDITS

Resource classification and reporting is meant to support the company decision-making with respect to resource allocation and portfolio management in pursuit of profitable business growth and reserves replacement objectives. Efficient systems to monitor the annual changes in the various resource categories are therefore essential.

OUs or NVOs internal resource assessment and reporting systems should:

a) Record the maturation plans for all Scope for Recovery opportunities (projects),

b) Monitor performance in maturing volumes relative to target,

c) Provide for systematic controls to preserve integrity of reporting,

d) Support regular review of ultimate recovery targets for existing fields in pursuit of constant improvement,

e) Record Key Performance Indicators (KPI's) to measure performance, e.g. reserves replacement ratio, scope for recovery maturation ratio, time between discovery and first production.

4.1 Shareholder Requirements

EP Planning will communicate each year to OUs and NVOs a timetable and details about submission requirements for both internal and external reporting.

Volumes will be reported based on the classification systems described in this report. Additional information is reported for the calculation of the Standardized Measure required by the US Financial Accounting Standards Board (FASB).

4.2 Methods and Systems

OUs and NVOs are responsible for selecting the methods and systems that are technically the most appropriate for quantifying the resource volumes of their assets consistent with these guidelines. The preferred methods and systems may vary depending on the type of resource and with time as the resource matures and technology improves.

4.3 Responsibilities and Audit Requirements

4.3.1 EP Planning Responsibilities

EP Planning is responsible for compilation of the Group statistics of resource volumes, the analysis thereof and the communication to other functions. EP Planning also maintains the resource volume guidelines.

4.3.2 Reserves Auditor Responsibilities

The Group Reserves Auditor will carry out regular detailed reserves audits in OUs and NVOs to verify compliance with the Group's guidelines. The Terms of Reference for such audits are included in Appendix 5. In addition the Group external auditors will verify the Proved reserves data for external (annual corporate) reporting.

4.3.3 Operating Unit Responsibilities

Definition of internal reporting requirements, tasks and responsibilities should be as per the OUs/NVOs Management System (Ref. 5). Technical and Financial functions must co-ordinate and reconcile their figures (particularly production volumes) prior to submission.

All levels in an OU, including Asset managers and the reservoir engineer preparing the individual field reserves estimates, should be aware of the importance of externally reported reserves (Proved, Proved developed) and their impact on financial indicators.

Asset and OU managers are responsible to ensure that the guidelines are implemented in such a way as to best represent to the shareholders the true value of the asset.

4.3.4 Non-operated Reserves

Where Shell is not the operator, the Shell company that holds the interest/share in the venture is responsible for the preparation of the reserves submission. In this case the Shell company involved has the responsibility of ensuring that reporting is compliant with Group guidelines.

This may involve reclassification of volumes between reserves and SFR categories where the operator's criteria differ from Group criteria and re-evaluation of proved reserves.

4.3.5 Audit Trail

Audit trails form an essential element in the reserves reporting process and are an indispensable tool for the Group Reserves Auditor to assess the quality of the reserves estimates. They should support and document the submitted figures and ensure that OU management understand and own the reserves submissions to SIEP. They also form an essential link in handing over resource estimates between field reservoir engineers and reserves co-ordinators and their successors.

For all the reported resource volumes an audit trail must be available of the assumptions made and processes followed. This will allow any subsequent assessor to modify these estimates based on new information in a reconcilable manner. Thus, evaluation reports must be compiled (preferably on a field basis) giving the basic data, the way it has been interpreted and processed, the development options considered, and the resultant volumes with the assigned probabilities. In addition, a description should be given of the development strategy, including data gathering activities. These reports may be working files (if acceptable to local auditors), but it is recommended to make a duplicate 'for file' in order to ensure that the data are preserved in field reports.

Where subsequent small revisions are made, an update note must be compiled. Multiple changes may be combined in one overall update of the resource volumes if they all belong to the same change category. After several years of small changes or following a development study, a new evaluation report must be issued. When a proposed change has a significant impact on the Company's total reserves or financials, SIEP should be advised at the earliest opportunity.

Guidelines on how to prepare a good audit trail, with suggested formats for tables etc. can be found on the Shell Wide Web (Ref. 11).

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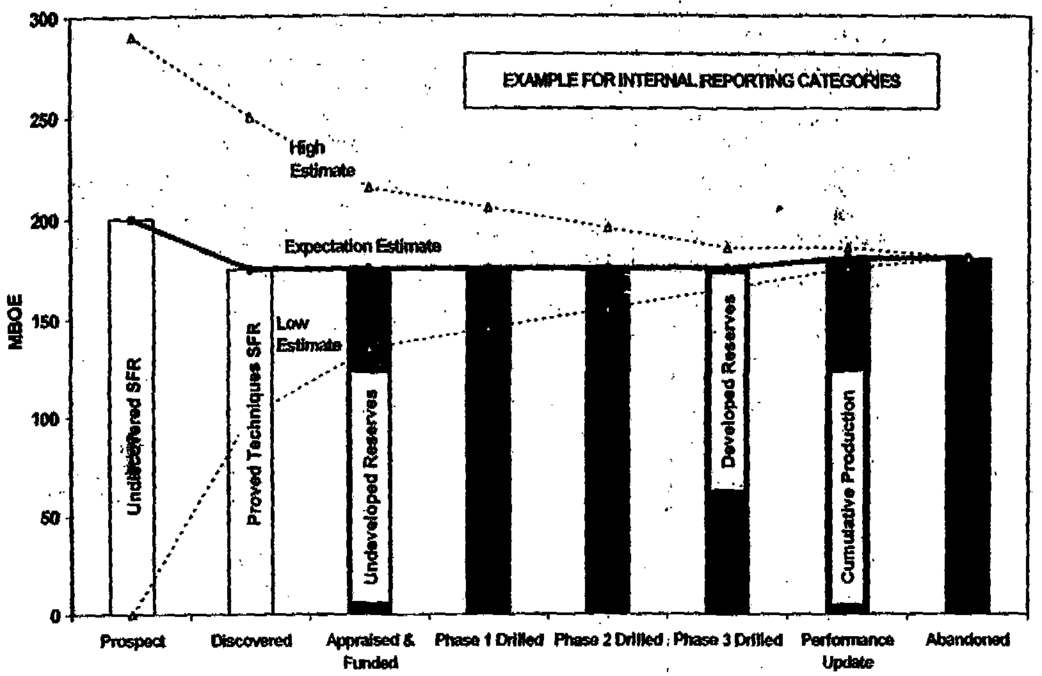
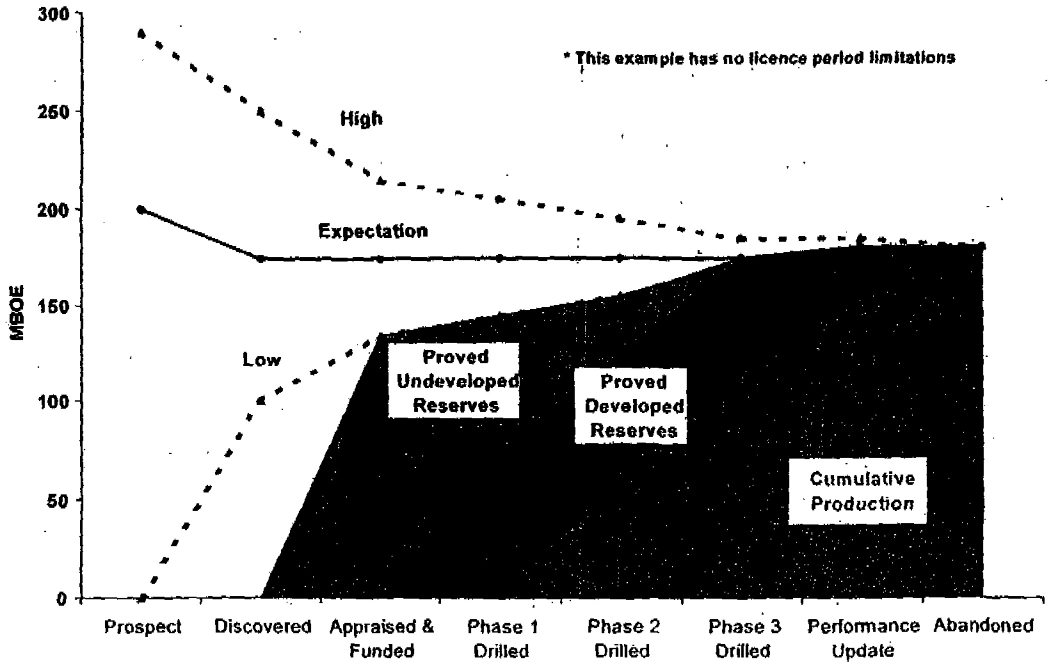
APPENDIX 1 RESOURCE CATEGORY (QUICK REFERENCE)

External Reporting	Internal Reporting	Proved Reserves	Portion of internally reported Expectation reserves (see conditions below), that is 'reasonably certain'. Additional conditions: Restricted by licence periods, government constraints and market limitations. Deterministically estimated volumes should reflect undefined fluid contacts and untested recovery mechanisms ('proved area').	
			Proved Developed Reserves	Proved reserves producible through existing completions and installed facilities using existing operation methods. Consistent with 'proved area'. Outstanding project activities considered completed if remaining cost < 10% of total. 'Behind pipe' volumes only if cost < 10% of well cost.
			Proved Undeveloped Reserves	Proved reserves which require future capital investment (wells and/or facilities). Consistent with 'proved area'. Recovery techniques to be proven in same or analogous reservoirs.
	Internal Reporting	Expectation Reserves	Project is 'technically and commercially mature' and funding 'reasonably certain'. Volumes to be consistent with business planning and production/sales forecast. Includes only production with positive cash flow. Not restricted by licence period. Group share only reported.	
			Developed Reserves	Reserves producible through existing completions and installed facilities using existing operation methods. Outstanding project activities considered completed if remaining cost < 10% of total. 'Behind pipe' volumes only if cost < 10% of well cost.
			Undeveloped Reserves	Reserves which require capital investment (wells and/or facilities)
		Scope for Recovery	Project is technically or commercially not mature Not restricted by licence period. Group share only reported.	
			Commercial SFR by Proved Techniques	Discovered. Commercially viable. Techniques have been proved to be feasible in this resource or analogous field. A sound technical project proposal is not possible yet due to large range of technical uncertainty and/or market constraints.
			Commercial SFR by Unproved Techniques	Discovered. Commercially viable. Recoverable by novel techniques or techniques that have been successful elsewhere, but cannot yet be demonstrated to be feasible in this field. R&D activities stand a reasonable chance of demonstrating feasibility in this field. Discounted for the risk that the considered technique will not prove to be feasible.
			Non-Commercial SFR	Discovered. Not commercially viable even if technically successful. Commercially viable with a change of commercial circumstances. Unit Technical Cost below an annually advised ceiling.
			Undiscovered Commercial SFR	Recovery from undrilled prospects. Commercially viable exploration and development. Techniques have been successful elsewhere under similar conditions. Discounted for the risk that commercial volumes are not present.

APPENDIX 2 RESOURCE MIGRATION DURING FIELD LIFE



EXAMPLE FOR EXTERNAL REPORTING CATEGORIES *



APPENDIX 3 PROVED RESERVES – SEC DEFINITIONS AND SHELL INTERPRETATIONS

	SEC Definition	Shell Group Interpretation
1.	**Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided by contractual arrangements, but not on escalations based upon future conditions.**	Reasonable certainty: Future revisions more likely to be upward than downward. Proved reserves to 'grow' towards Expectation estimates with increasing field maturity. Existing economic and operating conditions include identified future changes in these conditions (e.g. new developments, including abandonment), provided their costs are fully included in the project economics and planning basis. Prices and costs, see 8 below.
2.	**Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limits of the reservoir.**	Producibility: Either through a production test / production or through log / core / fluid data analogous with other produced reservoirs in the area. Proved Area: Areas with well control, confirmed producibility (in reservoir or analogue) and continuous good quality seismic amplitudes (Ref. 13), but within potentially sealing barriers or faults. Lowest Known Hydrocarbons: OWC, GWC, GOC may be interpreted from pressures in the reservoir unit. Continuity of production should preferably be demonstrated through pressure or fluid responses in the reservoir. However, demonstrated analogy with an analogous reservoir (of same or poorer properties) can be accepted. The above conditions can be waived by conclusive reservoir evidence or performance.
3.	**Improved Recovery Reserves which can be produced economically through applications of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.**	In cases where other information (core and fluid studies, coupled with analogue field experience) provides the necessary assurance, pilots may not be necessary. However, projects must be technically as well as commercially mature (see 4.), i.e. project funding must be reasonably certain.
4.	**Technical / commercial uncertainties Estimates of proved reserves do not include the following: - oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; - crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; - crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; - crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other sources.**	Must be technically and commercially mature, which is deemed to be the case when: (1) The Shell shareholder assurance processes have been satisfactorily passed both technically and commercially and no significant issues that could preclude proceeding with the project exist. AND (2) Support to fund the project is reasonably certain (e.g. the project survives the business planning processes of Capital Allocation) and the project forms (or is reasonably certain to form) part of the relevant business plan. Continuance of permits, or formal options to extend, are required. Heavy oil, bitumen, syncrude, gas, liquids, etc. recovered from unconventional reservoirs (oil sands, tar sands, coals, oil shales) by a

	SEC Definition	Shell Group Interpretation
		"manufacturing" process must be reported separately from the conventional resource base. However, reserves or SFR can be claimed for otherwise unconventional reservoirs if the petroleum is recovered in its natural state and original location (i.e., has not been "manufactured" in situ by alteration from natural state) through the use of conventional methods (wells).
5.	**Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.**	Proved developed reserves require existing facilities and completions, with existing operating methods. If outstanding activities in ongoing projects are only minor (< 10% of project Capex), the related volumes can be accounted as developed, as is the case for reserves requiring only minor well activities (< 10% of cost of new well). No special conditions for improved recovery reserves. Technical and commercial maturity must be demonstrated – see 4.
6.	**Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates of proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir (Emphasis added).**	Continuity of production: see under 2. Improved recovery reserves – see 4 and 5.
7.	**Analogous reservoirs (producibility)** **In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test.** **(Topic 12 of Accounting Series Release No. 257 of the Staff Accounting Bulletins).**	Producibility is shown either through a production test / production or through log / core / fluid data analogous with other produced reservoirs in the area (see also 2 above). This requires positive demonstration of the applicability of the analogy to the proposed reservoir.
8.	**Future cash inflows [should] be computed by applying year-end prices of oil and gas relating to the enterprise's proved reserves to the year-end quantities of those reserves. (Statement of Financial Accounting Standards 69, paragraph 30.a.)**	Standardized Measure submissions based on end-year prices as advised centrally.

	SEC Definition	Shell Group Interpretation
9.	Probabilistic methods of reserve estimating	If the method is used, proved reserves should conform to the "Proved Area" constraint (see 1 above). Probabilistic addition should only be used (subject to full 'independence' of the units) at levels below those used for financial depreciation accounting.
10.	Reservoir Simulation	Reservoir simulation is the preferred tool for determining reserves (Proved and Expectation). In the absence of production history to match, validation by other methods (i.e. analogy) required to assure 'reasonableness'. Proved reserves must always be consistent with the "Proved Area" principle. When doubt exists, conservative values should be used.
11.	Standardized measure of discounted future cash flows relating to oil and gas properties must comply with para 30 of FASB	As per FASB: Based on end-year prices, full-year average operating costs, Capex as per date of estimate, discount rate 10%.
12.	Production Sharing Agreements	Proved reserves must be based on the "economic interest method" (future cost+profit oil revenue divided by Group premises oil price). Producer must have the right to extract the hydrocarbons and must be exposed to exploration / development / production risk.

APPENDIX 4 UNCERTAINTY AND PROVED PART OF RESERVES

A4.1 Quantification methods

Subsurface resource volume estimates are inherently subject to uncertainty, because they are based on data (from seismic and drilling) and interpretations that contain sometimes significant margins of error. In-depth understanding is necessary to enable 'realistic' reporting of Proved reserves. The three most important methods to quantify and assess the range of uncertainty in resource volume estimates are:

- The Probabilistic method (P85, Mean, P15)
- The Multi-scenario method (Low, Middle, High)
- The Deterministic method (Proved, Probable, Possible)

A4.1.1 The probabilistic method

The probabilistic method has been in use by the Shell Group for more than 30 years. Whilst the Group was initially the only one in the industry applying this method, the method has, over the years, gradually gained wider acceptance, e.g. by the SPE (Ref. 6).

The method consists of assigning probability density functions (PDFs) to each of the constituent parameters that define a subsurface volume estimate (i.e. gross bulk volume, porosity, hydrocarbon fill and saturation, hydrocarbon volume factor, recovery factor). These PDFs are then combined (multiplied) either mathematically ('moment' method, see Ref. 4 - App. 7) or, more commonly, through Monte Carlo simulation. The latter method uses a random number generator which generates random selections from each of the parameter ranges, which are then combined into successive volume estimates, often numbering 1000 or more. Software tools using Monte Carlo simulation are e.g. @RISK, Crystal Ball and FASTRACK.

The resulting product from both the mathematical and the Monte Carlo methods is a PDF or its integral, the cumulative probability function (CPF), which defines the probabilities that the resource volume exceeds each of a range of values. The values associated with the 85% probability the 15% probability are called the 85% and 15% confidence levels or **P85** and **P15** for short. The probability-weighted average value is referred to as the **Mean**. The reason for the original selection of the 85% and 15% intervals by the Group was that they aligned most closely with the previously used distributions of three equi-probable values. More recently, the SPE and some operators and authorities have tended to favour 90% and 10% intervals (P90 and P10 respectively).

The probabilistic method is a good method for assessing the uncertainties of Exploration prospects, sparsely appraised discoveries and single development concepts in general. For (major) fields that are at concept selection stage the multi-scenario method is recommended, as described below.

A4.1.2 The multi-scenario method

This method is in principle applied before technical/commercial maturity is achieved and its application is predominantly in support of development concept selection. The method involves modelling through a full set of static (geological) and dynamic (reservoir simulation) models. The static model is generally run for a range of possible subsurface realisations, yielding a range of hydrocarbon-in-place volumes.

A representative selection of alternative geological model realisations is converted ('upscaled') into a discrete set of reservoir simulation models, which are then run each for a range of alternative development scenarios (e.g. different well numbers or positions). The alternative development scenarios are not necessarily identical for each geological realisation.

An important characteristic of the multi-scenario method is that it is project- or activity-based, i.e. the recoverable volumes are linked to a specific development plan or plans, with identified (or identifiable) costs, production forecasts and economics. These aspects make this approach well suited as a support to development concept selection.

A4.1.3 The deterministic method

The deterministic method has been the method most frequently used by the industry outside Shell. It derives from the original definitions of 'Proved Reserves' as issued by the American Financial Accounting Standards Board (FASB) and by the US Securities and Exchange Commission (SEC) (Refs. 7, 8 & 9). These definitions describe the mandatory conditions for reserves that are reported annually through Company reports and public submissions to the SEC. Subsequent definitions for Probable and Possible reserves have been issued by the SPE in co-operation with the WPC (Ref. 6).

Proved reserves are defined as "...the estimated quantities of hydrocarbons which geological and engineering data demonstrate with **reasonable certainty** to be recoverable...". 'Reasonable certainty' is implied to mean that future reserves revisions are 'much more likely' to be positive than negative. Pivotal in the definition of Proved Reserves is the notion of a **'proved area'** of reservoir rock, outside of which no Proved Reserves can be declared. This proved area is constrained by:

- Economic **producibility** demonstrated by a production test (not a wireline test!),
- Delineated by GOC, OWC, GWC if seen by drilling,
- Oil volumes above OUT levels only if gas is seen updip and a GOC can be interpreted,
- No volumes below **'lowest known hydrocarbons'** (LKH), as seen by drilling,
- Laterally confined to one 'legal location' (US regulatory minimum well spacing) away from well control,
- **Certainty** (not just 'reasonable certainty') of **continuity of production** over the area (must be demonstrated by conclusive data if beyond one 'legal location'),
- **Improved recovery** volumes only with a successful **pilot** in that specific rock volume,
- The conservative restrictions regarding LKH and lateral well control may be lifted "...upon obtaining **sufficient performance history** to reasonably conclude that more reserves can be recovered..."

The significant information on reservoir structure and hydrocarbon fill available from modern seismic techniques (DHIs, flat spots etc) is acknowledged by the SEC, but the staff emphasize the above constraints unless there is strong analogy with a nearby producing reservoir (Refs. 8 & 14).

The practice in the industry outside Shell has been that Proved reserves estimates are generally 'best estimates', with the proved area constraint being the only conservative element that is strictly adhered to. The important consequence of this has been that Proved reserves as calculated by the deterministic method tended to be lower than probabilistic P85 estimates for new discoveries and undeveloped fields. Similarly, they were generally higher for mature, fully appraised fields.

The SPE (Ref. 6) recommend that, if Proved reserves are determined probabilistically, a P90 value be selected. They generally align with the SEC guidance, except that they allow areas beyond the regulatory well spacing to be included if "…data from wells indicate with reasonable certainty (P90) that the objective formation is laterally continuous and contains commercially recoverable hydrocarbons…".

The SPE/WPC definitions of Probable and Possible reserves (together called Unproved reserves) can be summarised as follows:

Probable reserves:
- 'More likely than not to be recoverable'; P50 if based on probabilistics,
- Probably productive from logs/cores,
- Likely volumes outside the 'proved area', e.g. updip behind interpreted faults,
- Volumes probably recoverable through unproved techniques (no successful pilot yet)

Possible reserves:
- 'Less likely than Probable', P10 if based on probabilistics,
- Hydrocarbon bearing from logs/cores, but possibly not productive
- Possible volumes outside the proved area, e.g. downdip behind interpreted faults,
- Volumes recoverable through unproved techniques, with success in 'reasonable doubt'.

Industry practice tends to be that Probable reserves contain not only volumes associated with areas in the field outside the volumetric confines of the 'proved area', but also volumes associated with projects that have not been fully matured or approved yet.

The sum of Proved and Probable reserves is sometimes regarded as equivalent to the Mean or Middle estimates from probabilistic or multi-scenario methods. Similarly, the sum of Proved, Probable and Possible has been equated to P10 or High reserves. However, the definition for Possible reserves clearly indicates that many of these volumes (and even some Probable reserves volumes) should be classified as SFR in the Shell system.

A4.2 Shell Group Practice

Shell Group practice has long been based on the probabilistic method as the Group standard for estimating Expectation reserves (for internal reporting). Proved reserves (for external reporting) were set equal to the (volumetrically based) P85 estimates, which changed little as fields matured. This approach was found to lead to underreporting against major competitors and was replaced by a deterministic approach in 1998. In following the guidelines of the American Financial Accounting Standards Board (FASB) of the US Securities and Exchange Commission more strictly, the Group's reporting practice is now more in line with its major competitors (in particular with respect to mature fields).

Current practice still ascribes a portion of Expectation (internally reported) reserves to the (externally reported) Proved category. First "booking" therefore requires auditable evidence of technical and commercial maturity, to the extent that the project(s) are reasonably certain to attract corporate funding.

The preferred approach to development concept selection as it leads up to field development planning is based on the multi-scenario method. Reserves assessment is however to be based on the development concept as selected for execution. Proved reserves estimates should in principle be consistent with volumetrics in the 'proved area', which is defined by:

- Demonstrated producibility through a production test, or log/core data in a tested area,
- Delineated by GOC, OWC, GWC as seen/interpreted from pressures <u>in</u> the reservoir,
- In the absence of 'legal' well spacings, laterally defined by well control and surrounding areas with continuous and good quality seismic amplitudes (Ref 13), but not beyond

potentially sealing barriers or faults. Evidence from well drainage limit tests may be used.

- Extended by production performance data, if conclusive,
- Improved recovery volumes supported by a pilot or a robust analogy.

The thinking behind this interpretation is that the drilling and completion of development wells will generally expand the 'proved area' such that its volumetric extent will cover much, if not all of the field. Even if still incomplete at first (i.e. after the first phase of development drilling), this coverage will increase to full coverage with growing field maturity and performance. In line with industry practice, Proved reserves should be based on 'best' or Expectation estimates of 'proved area' volumetrics.

Apart from the volumetric uncertainty, there is the uncertainty regarding reservoir performance (determined by sand development, reservoir continuity, injectant sweep efficiency, aquifer activity, etc.). The latter uncertainty will be reduced as production progresses. Hence, a cautious, 'reasonably certain' approach should be followed for performance predictions in new fields (i.e. **the classic Shell approach adopting the Low natural outcome of the FDP as Proved reserves remains valid**). For mature fields the Proved reserves are expected to grow towards Expectation as field life progresses and the uncertainty range narrows. In some mature fields with well established production trends Proved developed reserves may become equal to Expectation estimates (see above).

The resulting description of assumptions to be used for estimating Proved and Expectation reserves is given in Fig. A4.1. To the extent that reserves (particularly Proved reserves) are based on probabilistic estimates, consistency with these assumptions is required.

Expectation Developed and Undeveloped (internal reporting):	All fields	Mean probabilistic or Middle case outcome of the development concept (FDP to be funded) selected for execution and based on Expectation volumetrics. (Proved+Probable if appropriate and if no Mean or Middle available)
Proved Developed reserves (external reporting):	New, recently developed fields:	'Reasonably certain' (Low case) outcome of the development concept (FDP to be funded) selected for execution based on Expectation 'proved area' volumetrics.
	Mature fields:	(Conservative) best estimate performance projection, based on Expectation post-drill + performance based on Expectation 'proved area' volumetrics. The Proved estimate should approach (and may become equal to) the Expectation estimate as field life progresses.
Proved Undeveloped reserves (external reporting):	Undeveloped fields	'Reasonably certain' (Low case, low activity scenario if applicable) outcome of the development concept (FDP to be funded) selected for execution based on Expectation 'proved area' volumetrics.
	New, recently developed fields:	'Reasonably certain' (Low case) outcome of the incremental development ahead, based on Expectation 'proved area' volumetrics.
	Mature fields:	'Reasonably certain' (Low case) outcome of the incremental development ahead, based on Expectation 'proved area' volumetrics. Expected to approach Expectation as field maturity progresses. Lower Proved / Expectation ratios should however apply if the reservoir mechanisms concerned differ from the current ones.

Figure A4.1: Group recommended practice for estimating Reserves

A4.3 Further considerations

A4.3.1 Uncertainty Reduction with Performance

The uncertainty range of ultimate recovery generally decreases as a field is developed and produced. However, the uncertainty range as a percentage of remaining reserves may not always decrease with time. **As a field matures, initial in-place volumes and recovery should shift from a volumetric to a performance-based estimate, incorporating the additional production data to reduce the uncertainty range.** Once the reservoir performance has been established with reasonable certainty, a fairly small difference between low, expectation and high estimates would be expected. Definition of the low and high estimates may no longer be of value in mature fields with relatively little uncertainty and use of a single expectation estimate should be considered in this situation (subject to 'proved area' conditions).

Figure A4.2 illustrates the narrowing of the uncertainty with field appraisal and development. This is a near ideal example where the expectation remains constant for most of the life cycle. This example is also used in Appendix 2 to show the migration of resources between internal and external reporting categories during the field life cycle.

The reduction in uncertainty based on performance should be adequately reflected in the annual reserve and scope for recovery estimates for the field.

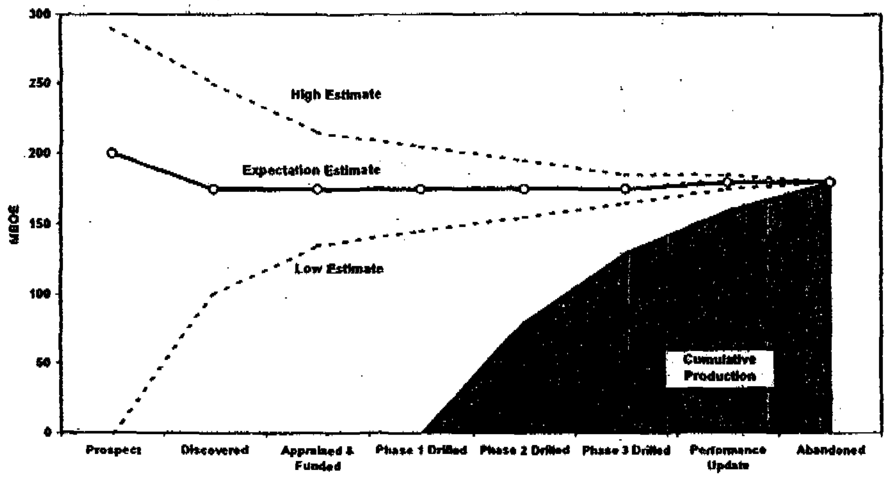


Figure A4.2: Uncertainty Reduction during the Field Life Cycle

A4.3.2 Addition of Proved Reserves Volumes

Proved Reserves volumes are added together at various levels (reservoirs, fields, areas etc) during the resource assessment and reporting process. When Proved reserves are based on P85 or Low estimates, such addition could either be arithmetic or probabilistic. Arithmetic addition usually overstates the uncertainty range for the sum of partially independent volumes (i.e. the resulting sum of P85/Low values is too low), but is appropriate for dependent volumes. Probabilistic addition could be considered for partially independent volumes when the difference with arithmetic addition is significant. An important requirement is, however, that **addition of Proved reserves at or above the level used for financial depreciation calculations must be arithmetical for consistency with financial accounting** (see Section 6.1). Below this level, i.e. normally below the field level, an appropriate selection of the addition method must be made, such that account is taken of dependency between the volumes to truly reflect the aggregated P85/Low/Proved recoverable volume.

Below are two examples where the method of addition is important to handle addition properly.

a) Field A is comprised of separate layers and the properties of these layers are independent of each other. In other words, a low result in one layer would not increase or decrease the chance of a low result in the other layers. Low, expectation and high estimates are calculated for each layer separately. Probabilistic addition should be used to account for the reduced uncertainty of adding together independent volumes. Arithmetical addition of these estimates would understate the low estimate and overstate the high estimate of the total field.

b) A project develops three independent fields as sub-sea satellites connected to one platform. In this case, the investment in surface facilities may be totalled for depreciation[1] and consequently the reserves estimates should relate to the combined fields. Probabilistic addition should be used to calculate the total reserves associated with the platform (assuming independence).

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[1] Group Accounts should be consulted when considering combining surface facilities for different fields for depreciation purposes.

APPENDIX 5 SEC RESERVES AUDITS - TERMS OF REFERENCE

The purpose of the Proved Reserves Audit is to verify that appropriate processes are in place in the OU to ensure that the Proved and Proved Developed reserves estimates for external (SEC) reporting are compliant with (these) Group guidelines.

The Audit will be carried out by the Group Reserves Auditor. His specific tasks during the audit shall be:

1) To verify the technical maturity of the projects and activities that underlie the reported proved and proved developed reserves estimates by assessing the quality of the engineering data and study work supporting the estimates.
2) To verify the commercial maturity of the reported reserves volumes by assessing consistency between the volumes reported and the company's business planning (production/sales forecasting), ensuring that these volumes can reasonably be expected to be (developed, produced and) sold in present or future markets.
3) To verify the 'reasonable certainty' of the reserves estimates by assessing the validity of uncertainty ranges used for their constituent parameters, by verifying that estimates are realistic in comparison with expectation estimates, by verifying that appropriate methods are used for mature fields and by establishing that appropriate methods of reserves addition (probabilistic / arithmetic) have been applied.
4) To verify that the Group share of proved and proved developed volumes has been calculated properly and are producible within prevailing licence periods.
5) To verify that reported volumes are up-to-date and consistent with previous estimates, that changes are reported in the appropriate categories and that appropriate audit trails are in place for the study work supporting the reported reserves estimates.
6) To verify that reported reserves are net sales volumes and that the reported annual production (sales) volumes are consistent with those reported in submissions to Group Finance.

In case of deviations from the Group guidelines the auditor shall establish whether and to what extent resulting estimates are likely to differ from those that might be expected from the 'proper' application of the guidelines.

The audit will be carried out by reviewing the reserves estimation and submission process through interviews of OU staff and by taking at random a number of fields for detailed analysis.

The frequency of the audit will in principle be once every four years for each OU, but should be adjusted as warranted by size of OU, past change volumes and complexity of the issues. Major reserves changes or concerns expressed during a previous audit may require an advancement of the next audit. For an OU/NVO reporting reserves for the first time, the first audit will in principle be within two years of this first submission.

The audit will in principle be carried out on OU premises and will be based on documentation available in the OU. Assistance of OU staff may be called upon.

An audit report will be submitted to the Managing Director of the OU, to the EP CEO and EP RBA, to the OUs Hydrocarbon Resource Manager and to KPMG the external auditors. It will be prepared and discussed in draft form on site, after which a final report will be prepared in The Hague, once formal OU comments are received. The report will contain an overall judgement (Good, Satisfactory, or Unsatisfactory), with itemised conclusions and recommendations.

APPENDIX 6 TERMINOLOGY

A6.1 Petroleum Resources Terminology

Reservoir

A reservoir is a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

In case of doubt, reservoirs are restricted to fault blocks / sedimentary units until production performance proves communication to exist across faults/ barriers. PVT properties can vary within a reservoir.

Field

A field is an area consisting of a single reservoir or multiple reservoirs within a closed areal boundary that belong to the same confining geological structure.

Field boundaries must be defined upon discovery and should encompass the unpenetrated petroleum resources in adjacent fault blocks and stratigraphic traps, if they are considered to be part of the same overall confining structure. Field boundaries may be re-defined on the basis of new geological information.

Potential Accumulations

Potential reservoirs beyond existing field boundaries, where the presence of petroleum has not yet been demonstrated, are collectively called potential accumulations.

Producibility

Should normally be supported by a conclusive test in a drilled or immediately adjoining reservoir, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.

Production Facilities

The production facilities consist of all hardware installed to recover petroleum from the sub-surface resources and to deliver a quality controlled end-product for sale. These comprise the production and injection wells and the surface facilities for treatment, conversion, compression/ pumping, transport and delivery.

Surface Facilities

That part of the production facilities accessible at surface, connecting the wellheads ultimately to the delivery points.

Existing Development

The collection of all completed projects or sub-projects is referred to as the existing development.

Field quantities

Field quantities (also called 'Wellhead' quantities) are those quantities routinely measured at surface for individual well strings and expressed in terms of the stabilised products oil, condensate and (wet) gas or in terms of the type of injected fluids. These quantities may subsequently be reconciled with fiscalised sales and other product outlets, see below.

Sales quantities

The quantities sold after fiscal metering and delivered at the locations where the upstream company ceases to have an interest in the end-products. These can be expressed in terms of the general end-products oil, (dry) gas and natural gas liquids (NGL) or in terms of the actual product.

Field products and the subsequent sales products may be different and will be affected by own use and losses. The properties and volumes of end-products may be influenced by mixing and the petroleum type itself may be altered during surface processing. Since surface processing conditions may change during a project life, sales products may vary in specification and in relation to field products. To avoid ambiguity and double counting, a clear distinction must be made between recoveries in the field and the quantities estimated to be available for sale.

For general sales products, oil, gas and NGL, only the quantities sold by the upstream E&P company can contribute to Group reserves. Condensates mixed with crude oil in the same stream and sold as such can be reported under oil. Separator condensate from gas wells and light hydrocarbon liquid products, derived from surface processing, if collected in a separate stream and sold as such are reported under NGL. In principle all non-oil hydrocarbons that are sold as separate streams in liquid state (pressurized or not) should be accounted as NGL. Bitumen may be reported under oil in summary reports (with an appropriate footnote). In line with SEC requirements, sales volumes for gas should be those committed or committable to a gas contract. Committed Gas is covered by a gas contract. Committable gas reasonably expected to be assigned to a contract in the future.

It is necessary to maintain a more detailed internal administration of the actually sold products by stream in two cases: (1) If the upstream E&P company has separate contracts for delivery of special converted sales products such as LNG, methanol, ethane, LPG, C5+ etc., or (2) If there are special sales products like helium, sulphur or generated electricity.

Reconciliation

A monthly reconciliation is made between the fiscalised sales quantities and the quantities produced in the field. This is reported in the Monthly Report of Producing Wells (MRPW). The reconciliation process corrects for own use, flaring, losses and product conversion, and provides the end-product yield.

For reserves estimating purposes an average future yield factor is to be estimated (e.g. LPG/ wet gas yield, dry gas/ wet gas yield).

Ultimate Recovery

The ultimate recovery (UR) of a hydrocarbon field is the sum of cumulative production and the estimated volume of reserves (developed + undeveloped).

Total Resource Volume

The Total Resource Volume of a hydrocarbon field is the sum of cumulative production, the estimated volume of reserves (developed + undeveloped) and the Total Scope for Recovery.

A6.2 Probabilistic Terminology

Probability Density Function

The probability density function (PDF) of a stochastic variable indicates the probability that the actual variable value lies within a narrow interval around a particular value of the possible range, divided by the width of that interval.

Cumulative Probability Function

The cumulative probability function (CPF) of a stochastic variable describes the probability that the variable may exceed a certain value. The CPF is the mathematical integral of PDF.

P85

The value that has a 85% probability that it will be exceeded by the stochastic variable.

P15

The value that has a 15% probability that it will be exceeded by the stochastic variable.

Mean

The statistical mean of a stochastic variable is the probability weighted average of the variable over the entire variable range.

Mean Success Volume (MSV)

The probability weighted average of all realisations that equal or exceed the minimum reserves required for a commercial development of the resource.

Probability of Success (POS)

The probability that the minimum commercial volume will be exceeded and which therefore indicates the likelihood of any future development. The product of MSV and POS is the recovery expectation.

A6.3 Commercial Terminology

Discount Rate

A rate at which future real terms costs or cash-flow are discounted over time to calculate their present value.

Net Present Value (NPV)

The net present value of a project is the sum of the discounted annual cash flow, expressed in real terms money, over the period from the first project expenditure to abandonment. The net present value is expressed in million US$ at the relevant discount rate.

Expected Monetary Value (EMV)

The expected monetary value is a probabilistic balance of investments and revenues, expected from a set of conditional operational activities, comprising data acquisition and one or more development projects, which are arranged in an ordered sequence with probabilities assigned to each action (decision tree).

The EMV is the summation of the NPVs of projects, reduced by the costs of data acquisition activities, all expressed in discounted real term money and multiplied by their assigned probabilities. EMV is expressed in million US$ at the relevant discount rate.

Projects with a negative NPV for certain resource model realisations should be excluded from the EMV calculation, if the assumption is valid that data gathering will prevent such projects being implemented.

Unit Technical Cost (UTC)

The unit technical cost of a development project is defined as the sum of capital plus operating costs, expressed in real terms money, divided by the total production over the period from start-up to abandonment. In addition, both the cost and the production must be discounted. The reference date for the discounting should be the same for denominator and numerator (e.g. the first year of expenditure) and should be stated. The unit technical costs is expressed in US$/bbl (oil equivalent) at the relevant discount rate.

FID

Final investment decision, the decision (at CMD or senior executive level) to proceed with a project.

NFA forecast

No further (Capex) activity forecast, i.e. a forecast based on existing wells and facilities only.

A6.4 Exploration versus Development Wells

The classification of a well as either an exploration well or as a development well is determined (in line with SEC rules) based on the proved area as follows:

Proved Area

The proved area is the part of a property to which proved reserves have been specifically attributed (see also Appendix 4). It is delineated by the fluid levels seen / interpreted from drilled wells and by the area around those wells which geological / engineering data indicate to be producible.

Development Well

A **development well** is a well drilled within the proved area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.

Service Well

A **service well** is either an injection well, a disposal well or a water supply well.

Appraisal Well

An **appraisal well**, or **stratigraphic test well** is a well drilled for geological information (not to test a prospect), either 'development-type' drilled in a proved area or 'exploratory-type' if not drilled in a proved area.

Exploration Well

An **exploration well** is a well that is not a development well, a service well, or a stratigraphic test well.

4

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Petroleum Resource Volume Guidelines
Resource Classification and Value Realisation

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KEYWORDS

Petroleum Resource Volumes, Guidelines, Reserves, Scope For Recovery, SFR, FASB, SEC

1. INTRODUCTION

Petroleum Resources represent a significant part of the Group's upstream assets and are the foundation of most of its current and future upstream activities.

The Group's EP business depends on its effectiveness in finding and maturing Petroleum Resources to sustain itself and drive profitable production growth. To aid systematic resource management, the volumes concerned are classified according to the maturity or status of their associated development (project) and operational (production) activities.

The Group's Petroleum Resource Volumes and changes to them, both actual and planned, are reported to the EP Executive regularly. Proved Reserves have a direct influence on net income, since they are used directly in the calculation of capital depreciation. Under the financial accounting rules of the United States Securities and Exchange Commission (SEC), Proved Reserves must be disclosed externally and therefore they are subject to internal controls and external review procedures. These external disclosures represent the only information on Petroleum Resource Volumes that is reported consistently by all major international oil and gas companies. Consequently, disclosed Proved Reserves figures are subjected to intense scrutiny by external analysts. Actual and projected performance in the replacement of Proved Reserves is one of the key factors taken into account by analysts when issuing advice to investors. This advice can directly influence the share price.

This document describes the Group's Petroleum Resource Volume classification system. In relation to Proved Reserves, it is intended to comply with rules set by the SEC and it serves as a reference in the reserves reporting and control processes, as applied by the asset holders. Additional controls that apply at the Group level are documented elsewhere (SIEP 2003-1102, Reference 3).

Information on the requirements for the collection of data for internal reporting and external disclosure will be addressed by the second part of these guidelines (SIEP 2003-1101, Reference 2). Detailed reporting requirements are communicated annually in a letter from EP Planning.

The present (2003) version of this document has been reformatted compared with previous versions, with the intention of improving clarity. It is stressed that, with the exception of the items summarized below, no changes to the internal rules for Petroleum Resource Volume accounting have been made.

Material changes to the volume of Proved Reserves reported by the Group are neither expected nor intended as the result of issuing these revised guidelines.

Substantial changes compared with previous guidelines:

1. The trigger for booking reserves for major projects has been refined from VAR3 to FID, or other public demonstration of commitment to proceed with the project. Refer to section 2.4.3
2. It is clarified that binding Heads of Agreement ("HOA") for sales contracts are a (minimum) necessary condition for booking major gas reserves that rely on the creation of access to market (e.g. those reliant on negotiation of LNG sales contracts). Refer to section 2.4.3.

2. PETROLEUM RESOURCE VOLUME CLASSIFICATION SYSTEM

2.1 Introduction

In general, all companies, authorities and other organizations that are involved in oil and gas exploration and production activities use a system for tracking Petroleum Resource Volumes as they mature from undiscovered prospects through to producing assets. All such systems aim to achieve similar objectives, but each is unique in terms of the nomenclature that is used and in the definition of certain terms. Often, the most fundamental differences stem from the differing areas of focus of the organizations that developed the systems: governmental organizations tend to address all aspects of technically recoverable resources, however notional, whereas commercial enterprises tend to concentrate on those elements that can most readily be monetized.

Thus, across the industry, a range of classification systems exists, each being tailored to the needs of the specific organizations that use it. This may introduce confusion and misunderstanding when different organizations discuss aspects of petroleum resource management, particularly when similar terms have different definitions under different systems (for example, the precise meaning of the term "reserves" can vary substantially between systems).

To help the industry avoid such confusion, several independent bodies have proposed the use of uniform classification systems. Probably the most widely known is that proposed jointly by the Society of Petroleum Engineers and the World Petroleum Congress and subsequently adopted by the American Association of Petroleum Geologists (SPE / WPC / AAPG, Reference 6).

The Group continues to use its own classification system, developed over a number of years and tailored specifically to the needs of the Group's business. The system will continue to evolve over time as the needs of the business change.

It is important for all individuals involved in the classification and management of the Group's Petroleum Resource inventory to realize that the system is unique to the Group, but also that it can be translated readily into the SPE system (and most other systems) should the need arise.

It is also important for all individuals involved in the preparation of Proved Reserves estimates to ensure compliance with the definitions and rules set by the United States Securities and Exchange Commission (SEC) and Financial Accounting Standards Board (FASB), as expressed and interpreted in these guidelines.

2.2 Overview

The Shell Petroleum Resource Volume classification system is summarized in Figure 1. It provides a framework for classifying the Petroleum Resource Volumes that are associated with a project as it matures from an undiscovered prospect through to a producing asset. Petroleum Resource Volume estimates are subject to uncertainty, reflected in the diagram through the use of columns expressing the Low, Expectation and High values of the estimate. A link to the SPE reserves classification (Proved, Probable, Possible) is also provided for the purpose of illustration.

Shell Notation	**Low**	**Expectation**	**High**
SEC Notation (reserves only)	**Proved**	n.a.	n.a.
SPE Notation	Proved	Proved plus Probable	Proved plus Probable plus Possible
Shorthand notation	1P	2P	3P

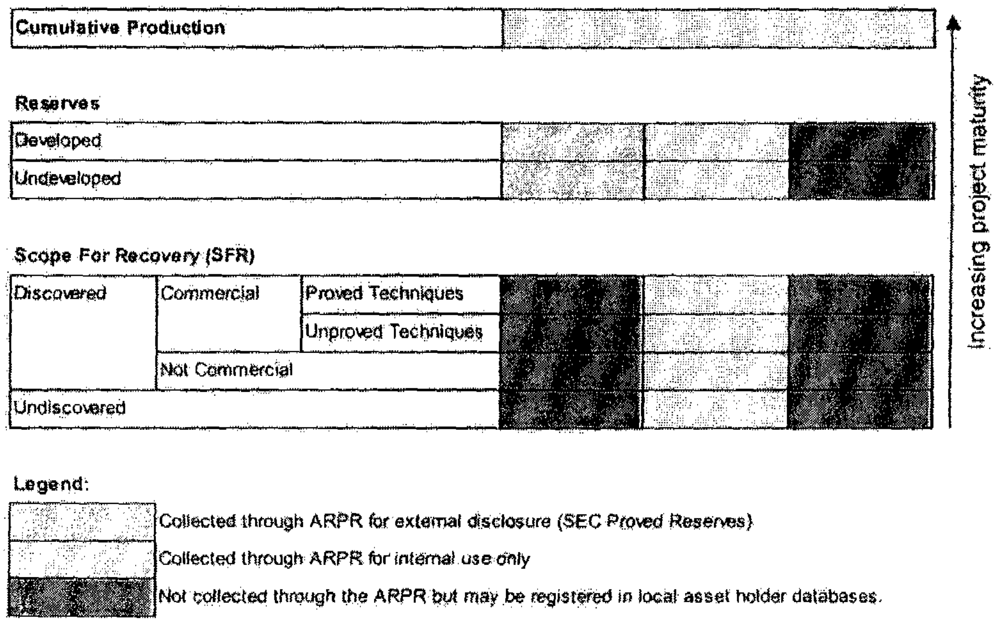

Figure 1: Overview of Shell Petroleum Resource Classification System

For internal Group purposes, Expectation estimates of Petroleum Resource Volumes must be reported to EP Planning through the annual Resource Volume data submission. Proved Reserves are required in addition to this for external disclosure.

In the following sections, a definition is provided of each category in the classification system (section 2.3), together with factors to be taken into account when Resource Volumes mature from one category into another (section 2.4).

A revised Petroleum Resource Volume classification system will take effect from 31.12.2003. This is described in Appendix 5. Whilst changes to Resource Volumes during 2003 will be reported according to the existing classification system, Resource Volume balances at 31.12.2003 will need to be subdivided into the revised classification system. These will then form the opening balances for the reporting of changes that occur during 2004.

2.3 Petroleum Resource Volume Definitions

In this section definitions are provided for each Petroleum Resource Volume category. Several ancillary and related terms are also defined in Appendix 4.

2.3.1 Petroleum Resource

A Petroleum Resource is any accumulation of hydrocarbons that is known or anticipated to exist in a sub-surface rock formation, located within the company's current exploration and production acreage.

Petroleum Resource Volumes are reported as the quantities of crude oil, natural gas and natural gas liquids that will be available for sale upon production. The volumes are reported on the basis of Group share. It is recommended that asset holders also maintain data on a 100% field basis.

Petroleum Resources are subdivided into two broad categories: Scope For Recovery (SFR) and Reserves.

2.3.2 Scope For Recovery (SFR)

SFR is any Petroleum Resource Volume associated with a project that is not yet sufficiently technically and commercially mature to qualify as reserves.

There must be an expectation that the project could mature, based on reasonable assumptions about the success of further appraisal, emerging technology development, cost reduction strategies, marketing efforts, improvement of terms and conditions and/or any other issue that might prevent the project progressing to development sanction (i.e. Final Investment Decision, "FID").

SFR is reported as a single best technical estimate, multiplied where necessary by the probability that the project will materialize. The objective at all times is to reflect as accurately as possible the Resource Volumes that eventually will be available to the Group in the expectation case.

The economic evaluation should take into full account any future pre-investment costs that are required to reduce technical uncertainty.

The further breakdown of SFR as "Undiscovered" or "Discovered" is as follows:

SFR Undiscovered

Resources that could be contained in an undrilled potential accumulation and which would be recoverable by any process that has been demonstrated to be technically feasible elsewhere, under similar conditions. Development should be expected to be commercially viable.

The expectation value of SFR Undiscovered should be reported as the product of the Mean Success Volume (MSV) at commercial cut-off and the corresponding Probability of Success at commercial cut-off (POS) (see Appendix 4.2).

Following drilling, the pre-drill estimate of Undiscovered SFR should be updated to take account of the drilling results and, in the case of a discovery, the economics of development should be re-assessed. At this point the resource is either discarded or reclassified to one of the SFR Discovered categories.

SFR Discovered

Resources that are contained in an accumulation in which the presence of movable hydrocarbons that are potentially of interest for development has been established through drilling and, where necessary, through associated data gathering activities.

Please refer to the definition of "discovery", section 2.4.2 below.

SFR Discovered may be held in one of three sub-categories: Non-Commercial SFR, Commercial SFR by Proved Techniques or Commercial SFR by Unproved Techniques.

Non-Commercial SFR

Resources that are associated with a discovered accumulation and with a project that is evaluated as having a negative Net Present Value (NPV) of development at the prevailing Group premises or for which there are clear commercial obstacles to development that appear to be insurmountable in the 5-year plan period.

To avoid retaining unrealistic volumes in the classification, the reporting of Non-Commercial SFR is restricted to projects with a Unit Technical Cost below a ceiling that is advised annually by EP Planning.

Non-Commercial SFR is reported in order to retain an indication of the discovered resources that could become commercial with a change of circumstances (e.g. an increase in oil price, a change in tax regime, improvement of technology, development of a gas market, discovery of additional volumes in the area that could form a critical mass for development).

SFR Discovered should be categorized as Commercial unless there is clear demonstration to the contrary. In other words, when commerciality is uncertain, the Resource Volumes should be allocated to a Commercial category pending further evaluation (which may result in the volumes being reclassified as Non-Commercial).

Commercial SFR by Proved Techniques

Resources that are associated with a discovered accumulation and with a project that (a) uses a recovery process or technique which has been demonstrated to be technically feasible in the resource concerned or under analogous conditions and (b) is expected to be Commercial.

Commercial SFR by Unproved Techniques

Resources that are associated with a discovered accumulation and with a project that uses any recovery process or technique which has not been demonstrated to be technically feasible (under conditions applicable to the area or field) and which requires future laboratory tests and field trials (pilot) in order to establish this feasibility. There must exist the reasonable expectation that, once the necessary work has been completed to demonstrate the technical feasibility of the project, it will be Commercial.

2.3.3 Reserves

The term "Reserves" describes any Petroleum Resource Volume that is associated with a producing asset or with a project that is technically and commercially mature to the extent that funding for the project is reasonably certain to be secured.

Two estimates of Reserves are captured in the annual reporting of Petroleum Resource Volumes: Proved Reserves and Expectation Reserves. Estimates of Reserves (both Proved and Expectation) are subdivided into quantities that have been developed to date (Developed Reserves) and those that will be addressed by planned or ongoing development activities (Undeveloped Reserves). Each of these categories is described below.

Expectation Reserves

The most likely estimate of the Resource Volume remaining to be recovered from a project that is technically and commercially mature, or from a producing asset.

If probabilistic techniques are used in reserves estimation, the Expectation Reserves are the probability-weighted average of all possible outcomes.

If deterministic techniques are used in reserves estimation, the Expectation Reserves correspond to the most likely estimate of future recovery.

In general, a field should not have Expectation Reserves allocated to it unless and until the necessary criteria for booking (at least some) Proved Reserves have been met: the criteria for categorizing resource volumes as "Reserves", rather than "SFR", apply in principle to all categories of Reserves and generally a field should not be allocated Expectation Reserves but no Proved Reserves. After first booking of reserves, it is possible for an additional development project in the field to have Expectation Reserves but no Proved Reserves, for example when it will be wholly executed on parts of the field that do not fall into the currently defined Proved Area, or when it will install an improved recovery scheme that is not supported by pilot test or local analogy.

Expectation Reserves are subdivided into Proved and Probable Reserves.

Proved Reserves

Proved Reserves are the portion of Expectation Reserves that is reasonably certain to be produced. Proved Reserves volumes are disclosed externally.

Please refer to Appendices 1 and 2 for the full SEC / FASB definition of Proved Reserves and notes on the interpretation of this definition as it is to be applied in Group operations. Note also the conditions that are required with respect to project technical and commercial maturity, section 2.4.3.

In all respects, and particularly when in doubt, the most important concept applicable to Proved Reserves is that of "reasonable certainty". The "reasonable certainty" criterion applies both to the booking of *any* Proved Reserves and to the *volume* of Proved Reserves that is booked. It must be certain, beyond reasonable doubt, that a project for which Proved Reserves are booked will actually be executed. Furthermore it must be certain, beyond reasonable doubt, that the volume booked will actually be produced.

The SEC / FASB rules on Proved Reserves imply that as more data becomes available, upward revision of the estimate is much more likely than negative revision. As fields mature, Proved Reserves are expected to increase towards, and eventually to become equal to, Expectation Reserves (see also Appendix 2.3.1)

Probable Reserves

Probable Reserves are the portion of Expectation Reserves that is not (yet) Proved; alternatively defined as the difference between Expectation and Proved Reserves.

Developed Reserves

Developed Reserves are that part of reserves (whether Proved or Expectation) that is producible through currently existing completions, with installed facilities, using existing operating methods. Facilities requiring minor outstanding activities in ongoing projects can be considered as existing if the outstanding capital investment is minor (< 10%) compared with the total project cost and if budget approval has been obtained. Volumes behind pipe can only be considered Developed if the additional activity (e.g. lower zone abandonment, perforating, stimulating) does not require a full well entry/re-completion and if the cost of this activity (normally Opex) does not exceed 10% of the cost of a new well.

Developed Reserves should in principle be estimated through extrapolation of existing well performance trends. This may be done either through plotting (e.g. rate vs. cumulative production, log oil rate vs. time) or through history matched simulation modelling. If no significant history is available to match, Developed Reserves will be based on pre-development (simulation) model projections, updated for observed well geological and petrophysical data and well rates. In all cases, Developed Reserves should represent the production that will be contributed by the existing wells through the currently installed facilities, assuming no future development activity (the No Further Activity or "NFA" forecast), other than any minor amounts as indicated above.

In general, the NFA forecast for mature assets may include volumes that will require a relatively modest (and clearly economic) level of future Capital Expenditure in order to safeguard existing facilities and equipment (excluding wells, which are discussed separately above). It should be certain, beyond reasonable doubt, that this expenditure will be incurred. Where substantial new investment is (found to be) required in order to safeguard or, in the worst case, replace ageing facilities, consideration should be given to reclassifying the reserves associated with these activities to Undeveloped Reserves.

Please refer to Appendices 1 and 2 for the full FASB / SEC definition of Proved Developed Reserves and notes on the interpretation of this definition as it is to be applied in Group operations.

Undeveloped Reserves

Undeveloped Reserves are that part of reserves (whether Proved or Expectation) that cannot be considered Developed Reserves, as defined above. They require capital investment through future projects (new wells and/or production facilities) in order to be produced. These projects must be technically and commercially mature (Section 2.4.3).

Gas reserves that require the installation of planned or anticipated future compression should be classed as Undeveloped Reserves until the compression equipment has been installed.

Incremental field development projects, which add reserves in their own right, may defer field/platform abandonment and may thereby also increase the reserves producible from existing completions. Such gains should be included in the economic evaluation of the incremental development project and should be included in reserves when the incremental development project concerned reaches technical and commercial maturity (i.e. when its Resource Volumes become classified as reserves).

Future wells or facilities may accelerate reserves that would otherwise be produced by existing assets. The portion of reserves expected to be accelerated by the new investments should be classified as Developed with the existing investments. If future investment accelerates production such that additional reserves are recovered within time limits (e.g. sales contract periods, licence duration), the additional reserves should be classified as Undeveloped until this investment has been made.

The Undeveloped Reserves attributed to a field should be evaluated for each of the specific identified future development activities with which they are associated. The preferred method is through detailed static and dynamic reservoir modelling. Deriving Undeveloped Reserves simply by subtracting Developed Reserves from an assumed total recovery estimate (e.g. from recovery factor correlations) is NOT acceptable.

Please refer to Appendices 1 and 2 for the full FASB / SEC definition of Proved Undeveloped Reserves and notes on the interpretation of this definition as it is to be applied in Group operations.

2.3.4 Guide to the correct allocation of resources to a category

Based on the forgoing, the following diagram summarizes the factors to be taken into account when assigning a Petroleum Resource Volume to its correct category:

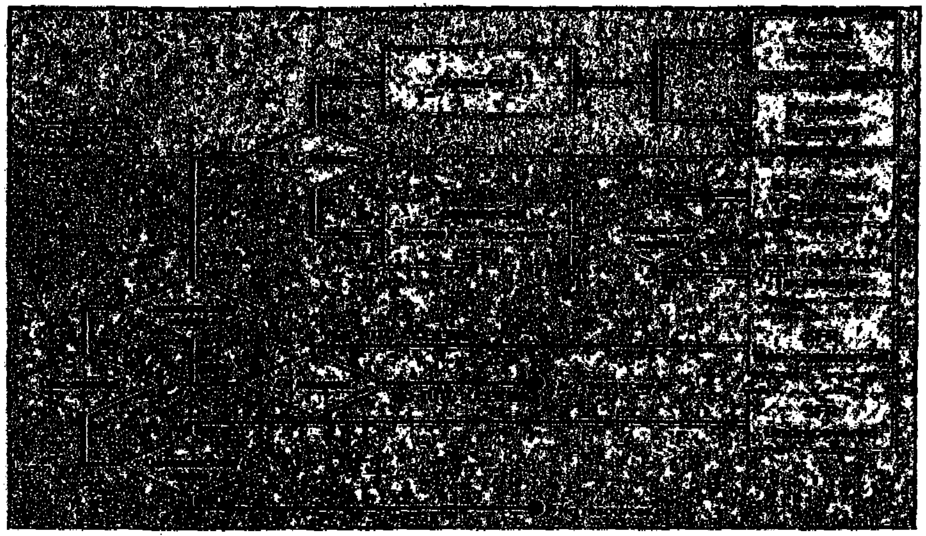

Figure 2: Resource classification guide

A graphical example of the migration of resource volumes between categories during a field's life cycle is shown in Appendix 2.3.1.

2.4 Petroleum Resource Volume Maturation

2.4.1 The maturation process

As a projects matures, the corresponding Resource Volume "cascades" through the classification system (Figure 3). It is recommended that a Petroleum Resource Volume Maturation Plan be maintained for all projects that have material Resource Volumes associated with them, documenting the work activities that are required for a project to pass through each stage of maturation. The project should also have associated with it: a plan of the actions required to mature the resources to the production phase; the associated costs of exploration, development and production; the scheduling of those costs; forecasts of crude oil, natural gas liquids and natural gas sales volumes and, together with associated pricing and fiscal terms, a quantification of the economic performance of the project.

Note that strict criteria apply in relation to technical and commercial maturity before a project can migrate from SFR to Reserves (see 2.4.3 below).

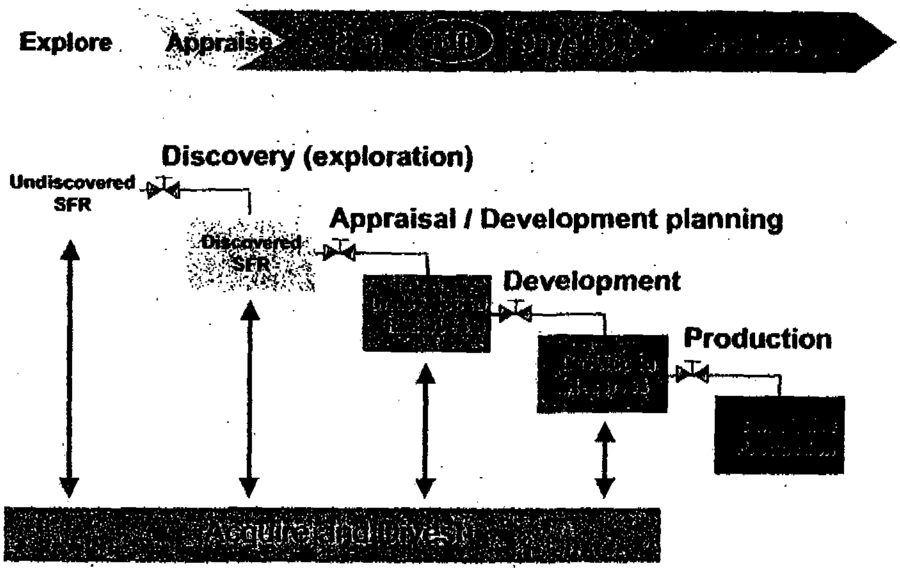

Figure 3: Resource classification flow diagram

2.4.2 Maturation from Undiscovered SFR: Discovery

Discovery occurs when the presence of an accumulation of movable hydrocarbons is proved through drilling and associated data gathering.

The concept of discovery applies to the entire accumulation that has been penetrated by the well, even if the penetration is only partial or the precise vertical and lateral extent of the accumulation has yet to be established or confirmed (through appraisal). All the Resource Volumes that are expected to be contained in the accumulation are deemed to have been discovered. These Resource Volumes mature upon discovery to one or more of the Discovered SFR or Reserves categories, after revisions have been applied to take account of information provided by the discovery well. The estimate of discovered Resource Volumes may have a wide range of uncertainty at this stage, reflecting the uncertainties pertaining to parts of the accumulation that are remote from the discovery well location.

The concept of discovery automatically extends to any areas of the accumulation for which there is a reasonable expectation that hydraulic continuity exists through the hydrocarbon phase with the discovery well location[1]. For "regional accumulations" which lack structural definition of their limits (such as oil shales, regionally pervasive tight gas sands and coal measures), the discovery volume may be limited according to a reasoned view of the area that can be expected to be productive on the evidence obtained from the discovery well, supported by local experience and analogy.

2.4.3 Maturation from SFR to Reserves

For a Resource Volume to pass from SFR to Reserves, the associated development project(s) must reach a minimum level of both **technical** and **commercial maturity** in order to satisfy the SEC requirement for "reasonable certainty" that the associated Proved Reserves will be produced.

Reserves that already have been booked but which potentially no longer satisfy the criteria for technical and commercial maturity should only be de-booked after thorough (re-)evaluation. This (re-)evaluation must be completed as soon as is reasonably practicable: generally it is not acceptable to retain reserves that cannot be justified. All reserves that are potentially exposed in this manner should be notified to the EP Hydrocarbon Resource Co-ordinator, who maintains an inventory of such volumes.

Project Basis

Reserves are associated either with a project (a development that is planned or in execution) or with an existing producing asset (i.e. a project that has been executed). A project is any planned creation or modification of wells, surface production facilities or production policy, aimed at changing an asset's sales product forecast.

For Reserves to enter into the Proved category, independent review and challenge is required (as a control) to preserve the integrity of external disclosures. For major projects such reviews are routinely executed through the Group's Value Assurance Review (VAR) process, or by locally defined analogous processes in the case of minor projects.

In compliance with the spirit and intent of the SEC rules for Proved Reserves, and also to match reserves additions with external expectations, reserves in principle should not be reported until a project has been sanctioned (Final Investment Decision: FID). This requirement is mandatory for major projects with Proved Reserves exceeding 50 million boe Group share at FID or which require more than US$100 million Group share capital expenditure. In exceptional cases, reserves for major projects may be registered in advance of FID provided that there is a clear public demonstration of the Group's intention to proceed with executing the project, or other mitigating circumstances. Such cases should be raised well in advance of year-end reporting with the SIEP EPS-P.

For intermediate development projects (for which between 10 and 50 million boe Proved Reserves would be booked), concept selection (VAR3) must at least have been completed.

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[1] This should not be confused with the much more stringent requirement of "certainty that there is continuity of production" that is required when determining the extent of the "Proved Area" for the attribution of Proved Reserves according to the SEC rules – for example, see Appendix 1.

For small projects (less than 10 million boe Proved Reserves Group share) a documented development plan should suffice, which may be notional if a well established analogy is in place. The quality of such a plan should be a sufficient basis on which to judge the likelihood of project funding.

~~The distinction between major and smaller projects is drawn above because "intermediate" and "small" projects may not be subject to dedicated FID decisions by the EP Executive. However, if any intermediate or small projects are subject to a dedicated FID by the EP Executive it is unlikely that any reserves booking could be made before then.~~

"Major" projects must not be split into several smaller projects in order to avoid the requirement to await FID before booking reserves. Similarly, estimates of Proved Reserves should not be played down for the same reason. The cut-off volumes described above serve as a guide: if there are compelling reasons for accelerating the booking of Proved Reserves for "major" projects ahead of FID, or for delaying the booking of smaller project reserves until FID, these should be discussed with SIEP EPS-P on a case-by-case basis.

It is emphasized that all Proved Reserves require full Group, Region and Asset Holder commitment that the associated projects will indeed be executed. This should be demonstrated by, for example, inclusion of the projects concerned in the current Business Plan, or by a clear demonstration that the projects are certain, beyond reasonable doubt, to be executed.

echnical Maturity

For a project to be **technically mature**, there must be a documented definition of a technically feasible project that is expected to be implemented with 'reasonable certainty'. The project definition must include: a description of the development concept (including the planned recovery process); specification of the engineering works required (number and type of wells, production facilities and associated support facilities, evacuation infrastructure); drilling/engineering cost estimates; a production forecast (including sensitivities) and economics. There should be no technical issues identified that could prevent the project from proceeding. Please refer also to the general criteria described in "Project Basis" above.

Commercial Maturity

A project is deemed commercially mature, when (1) its profitability meets the Group's investment criteria (as specified in EP's Project Evaluation and Screening Criteria, Reference 12), (2) market availability is assured and (3) funding by the Group is 'reasonably certain' to be provided (i.e. certain, beyond reasonable doubt). There should be no commercial issues identified that could prevent the project from proceeding. Please refer also to the general criteria described in "Project Basis" above.

Assurance of market availability for oil (and/or NGL) means at least the 'reasonably certain' availability of a pipeline to a shipping terminal or other outlet (e.g. a refinery), whilst for existing gas provinces this means that the product is:

1) contracted to sales; or
2) considered reasonably certain of being sold into existing markets, through existing or firmly planned transportation and delivery facilities.

For major gas reserves that rely on the creation of access to market (e.g. those reliant on negotiation of LNG sales contracts), reserves booking should in principle be deferred until certainty exists concerning sales agreements. A Letter of Intent generally will not provide sufficient assurance that a Sale and Purchase Agreement will be concluded. Consequently Proved Reserves cannot be booked on the basis of a Letter of Intent except with the express approval of the EP Executive (such approval should be sought via the EP Hydrocarbon Resource Coordinator). Binding Heads of Agreements are a sufficient basis for the booking of Proved Reserves, provided that such documents are phrased in a way that commits both parties (buyer and seller) to proceed to the conclusion of a Sale and Purchase Agreement. In the event that Heads of Agreement do not provide a binding commitment, Proved Reserves bookings should be deferred until the signature of the Sale and Purchase Agreement.

In all cases, Proved Reserves should only be booked to the extent that they are supported by firm tranches of the sales agreement. Optional tranches – especially those executable at buyer's discretion – should not be used as the basis for booking Proved Reserves unless and until commitments are made for the volumes in question or precedence exists in support of a claim that it is 'reasonably certain' that said volumes will be produced and sold.

Similar conditions apply to planned "spot market" sales of, for example, LNG cargoes. Generally there should be precedence in support of a claim that it is 'reasonably certain' that said volumes will be produced and sold.

The condition of marketability for gas reserves also applies to any associated NGL products. If the gas market is not assured, neither the gas nor the associated NGL volumes can be reported externally.

In some situations, potential buyers of gas or financiers of the associated development projects require evidence of "Proved Reserves" as part of their own assurance processes. Since the assurance of market or finance availability is often a pre-requisite for booking Proved Reserves via the Annual Report to the SEC, marketing and financing requirements may need to be satisfied not with reference to the "SEC" Proved Reserves, but instead to "technical" Proved Reserves, i.e. the Proved Reserves volume that would qualify for disclosure via the SEC assuming that all commercial issues had been resolved.

Projects in Support of Long- erm Commitments

Special consideration may be given to projects that support long-term supply contracts (e.g. LNG sales), for which a commitment has effectively been made to execute the project, but for which the due process of verifying maturity might not yet be fully in place. Such situations can arise when the project will not be executed until far into the future and, consequently, detailed value assurance work has yet to be carried out (VAR3 or higher).

Generally, commitment to the supply contract represents a clear public demonstration of intent to execute the development projects that are necessary in support of it. Also, value assurance work usually will have been undertaken prior to signing the contract or taking FID on any infrastructure in support of it. In such cases, it may be appropriate to register reserves for the projects that are expected to feed the long-term contract. Proved Reserves so registered must adhere to the SEC definition of Proved Reserves (Appendix 1) and must be constrained where necessary by a reasonably conservative estimate of the volumes that will be lifted under the contract (i.e. limited to the duration of existing contracts, unless extension is certain, limited to the Take or Pay volume where applicable, or excluding optional tranches that cannot be considered reasonably certain to be lifted).

3. GROUP SHARE

All Resource Volume estimates reported to EP Planning must be on the basis of Group share. Group share is determined by three factors: (1) the contractual share of produced hydrocarbons, as agreed with the resource holders (usually the host government), (2) the Group share in the assets or the venture that holds the contractual share, and (3) licence duration and other restrictions.

3.1 Contractual Share

Resource Volumes can be distinguished according to three different types of agreement: Equity, PSC and 'New Contracts'. These are described below.

If a company has interests in several licence areas subject to different types of agreement, a separate report must be made with respect to Proved Reserves for each of the contract types.

3.1.1 Equity

Equity resources are the Group share of Resource Volumes in Concessions. Concession agreements lay down the general terms and conditions of operation, define the applicable tax rules, the Group share of Resource Volumes in the Concession and the duration of the production licence. These agreements are generally with the host government, but in the USA they may also be with the private owners of the mineral rights ("lease or fee" conveyance of rights to the operator). Such agreements may also be referred to as "Tax / Royalty" agreements.

3.1.2 PSC Entitlement

PSC Entitlement resources are the Group share of production in acreage governed by a Production Sharing Contract (PSC). The Group entitlement share of production is the Group interest in the sum of cost oil plus excess cost oil plus profit oil, in accordance with the PSC terms. The entitlement share is calculated from economic modelling reflecting current estimates of future costs and sales value. The entitlement calculation should be based on the Group's middle PSV of oil or gas (see 3.3.14 below).

To help adhere to the SEC's requirement that Proved Reserves estimates should be much more likely to be revised upwards than downwards in future, the model should be based on a "reasonably certain" production forecast, consistent with the requirements of the SEC Proved Reserves definition (Appendix 1). Similarly, since cost uncertainties can assume a significant role in the overall uncertainty associated with entitlement reserves for mature assets, the PSC entitlement share of Proved Reserves should be calculated using a reasonably conservative estimate of future costs, such that actual costs are more likely than not to be higher than assumed and consequently the Proved Reserves entitlement as estimated today is more likely than not to err on the side of conservatism.

3.1.3 New Contracts

A number of resource-holding countries have introduced innovative production contracts in order to attract investment by foreign oil companies while preserving the principle of national resource ownership. These agreements typically provide for the contractor to recover costs and profits from hydrocarbon revenues while holding no title to, or entitlement to receive, petroleum resources.

US Financial Accounting Standards Board (FASB) regulations have lagged behind these developments and provide little explicit guidance on reserves disclosure when the risks and rewards of ownership are carried without legal title to mineral rights.

However, volumes covered by such innovative contracts should be included in external reports in an informative way to be consistent with the spirit of the SEC regulations. The volumes from which economic benefit is derived should be reported, in principle, if all three of the following conditions are met:

1. A physical reservoir of minerals which meet the SEC definition of Proved Reserves must underlie the transaction.
2. The Group must legally own the minerals or be the recipient of an in-substance conveyance of ownership.

   Note: An in-substance conveyance of ownership of (part of the) mineral rights can be deemed to occur if the Group has capital at risk, if the repayment of the capital is dependent on the success of the project and if the Group is, or has been, critically involved in bringing the project to a successful conclusion.
3. The funding must not be a loan with little or no reservoir risk. In other words, the level of risk should be commensurate with the higher levels of risk that are normally associated with oil and gas reserves development, rather than the lower levels of risk that apply typically to loans.

Any new contract that is under consideration must be assessed for the right to disclose reserves on its own merits. This requires early engagement of the EP Hydrocarbon Resource Coordinator, who will be able to provide more specific guidance and engage the Group Reserves Auditor and other experts (including external legal opinion and Group External Auditor opinion) as required.

Asset holders working under such contracts should complete the annual Resource Volume report for the Group interest in these volumes, noting the nature of the interest. Group share of production is calculated from economic modelling of total financial reward in line with contract terms versus total revenues (see also 3.1.2 above). Reported volumes should be in line with the reporting of traditional reserves with regard to royalties and should therefore reflect the volumes from which pre-tax cash flow is derived. As elsewhere, cash royalties are regarded as a production cost (see 3.3.2).

When participating in a venture which grants neither title nor an entitlement to receive petroleum, and which does not satisfy the three criteria above, no reserves or production volumes should be reported. For example this might occur if the recovery of costs is guaranteed against adverse price movements or a shortfall in recovered volumes.

3.2 Group Share in EP Legal Entity

If the Group holds only a partial share (i.e. less than a 100% share) in the company or entity that holds the concession or contractual share with the resource owners, this share must be taken into account in the reserves submission.

FASB rules stipulate that when the Group share of such entities exceeds 50%, Proved Reserves are reported on a 100% basis, with the contribution that the minority interest shareholding makes to the total being noted in external disclosures. Prior agreement must be obtained from Group Finance before such reporting is considered. When the Group share of such entities is 50% or less, reserves are reported on the basis of the share holding.

3.3 Licence duration and other restrictions

3.3.1 Licence or Contract Extensions

For internal reporting, Group share of Expectation Reserves and SFR are recorded for the economic producing life of the asset, regardless of the expiry date of current licences. Current licence terms should be assumed to apply to any licence extension or renewal unless it is known or expected that different terms would apply. In addition, Resource Volumes are also recorded as limited to the current licence period (including any extension or renewals that are certain to be granted, see below) for Expectation Developed Reserves, Expectation Reserves and SFR.

For external reporting, Group share of Proved Reserves and Proved Developed Reserves is limited to future production within the existing licence or contract period, including any extensions or renewals that are covered by documented agreement, by legally enforceable rights or where precedence supports the view that extension or renewal is granted "as a matter of course" by the applicable authorities. Estimates of "post-licence" Proved Reserves are also collected, so that the reward associated with licence extension can be judged, but these volumes cannot be included in external disclosures.

3.3.2 Royalty

Outside the USA, royalty is a payment made to the host government for the production of mineral resources. It is usually calculated as a percentage of revenues (payable in cash) or production (payable in kind).

Where in practice royalty obligations are met in kind (i.e. by delivering oil instead of cash), the Group share of production and reserves should be reported **excluding** these volumes.

Where royalty is payable in cash or is in principle payable in kind but the government has formally elected to receive, or customarily receives, payment in cash, Group share of production and reserves should be reported **including** these equivalent royalty volumes.

Within the USA, royalties are payable to the owner of the mineral rights, who can either be a private or a public entity (e.g. State government). In line with SEC regulations, these are always **excluded** from Group reserves whether paid in cash or in kind, for US properties.

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3.3.3 Overriding Royalty

In the USA, there are often Overriding Royalties payable to the owner of mineral rights or third parties. These shares of reserves are **excluded** from Group reserves. Third party Overriding Royalties payable to Shell are **included** in Group reserves.

3.3.4 Own Use and Losses

Group share Resource Volumes must **exclude** any volumes consumed as "own use" (fuel for production facilities, compressors etc) or lost (flared or vented) in the upstream operations prior to transfer of the product to the buyer (Third Party' or 'Downstream'). This is consistent with the definitions applied for e.g. Gas Production available for Sales from own reserves (GPafS), as applied in financial reporting (Ref. 10).

3.3.5 Fees in kind

Third Parties may in some cases pay Fees in Kind or Tariff in Kind for the use of infrastructure (e.g. pipeline tariff, processing fee). Such volumes received by the company (to the extent that they originate from non-Group owned resources) do not constitute a Group share in resources and should be **excluded** from reported volumes. Condensate volumes recovered from a pipeline system related to transportation of Third Party gas volumes and sold by the company are equivalent to Fees in Kind received. All Fees in Kind received should be included as a purchased volume in the company accounts.

Where a company pays Fees in Kind (from its own fields/resources) to a Third Party, these do constitute a Group share in resources and should be **included** in the reported volumes. Annual volumes produced and used as Fees in Kind should be included in sales volumes, with associated revenues (at an agreed or fair market value) equivalent to booking of the incurred operating cost.

3.3.6 Under-lift and Over-lift

Group share should allow for any historic under-lift or over-lift by partners or government. A Group historic over-lift should be reflected as an equivalent reduction of Group reserves, a Group historic under-lift as an equivalent increase of Group reserves.

Group share should reflect the effect of swap deals, for example in gas fields in which early production capacity in one field is traded against later production repayment by the other. In principle, reserves booked for each field should reflect the volumes actually produced (and sold) from the field in question.

Treatment of take-or-pay volumes should be aligned with financial treatment of the cash received and booking of production volumes. This generally means that volumes paid for but not yet taken (produced) should be included in reserves.

It is essential that the treatment of reserves and production in the above cases are consistent with the corresponding treatment of Group income in financial reporting, see also 3.3.13.

3.3.7 Open Acreage

Group share of Resource Volumes is non-existent in open acreage and acreage for possible future acquisition or farm-in.

3.3.8 Committed Gas Reserves

This is the total volume of Expectation Gas Reserves Within Licence that has been committed for sale under long and short-term contractual agreements. In countries with a mature or deregulated gas market, all gas reserves which have a near certainty of market take-up can be classified as Committed.

3.3.9 Committable Gas Reserves

This is the total volume of expectation gas reserves that has not been sold, but which could be sold under contractual agreements yet to be negotiated. The sum of committed and committable gas reserves is equal to the Expectation Gas Reserves Within Licence.

3.3.10 Gas Re-injection

Gas volumes re-injected in a reservoir, for pressure maintenance, gas conservation, Underground Gas Storage (UGS, including cushion gas), or other reasons, **without transfer of ownership**, remain part of a company's resource base and should be **included** in the Group Resource Volume estimates. These gas volumes should be classified and reported as reserves or SFR, depending on the recovery anticipated through future developments (also taking into account anticipated re-saturation losses).

Gas volumes re-injected in a UGS project on behalf of a **Third Party** (either following transfer of ownership by the company to this party, or following production by the third party itself) do not constitute a Group share in resources and should be **excluded** from reported volumes.

3.3.11 Oil Sands

Petroleum volumes (heavy oil, bitumen, syncrude, gas, liquids, etc.) recovered from unconventional reservoirs (oil sands, tar sands, coals, oil shales) by a "manufacturing" process must be reported **separately** from the conventional resource base. This includes conventional reservoirs where recovery occurs through a mining operation. However, conventional Reserves or SFR can be claimed for otherwise unconventional reservoirs if the petroleum is recovered in its natural state and original location (i.e. has not been "manufactured"" *in situ* by alteration from natural state) through the use of conventional methods (wells). Examples of this are coal bed methane produced from wells or heavy oil produced from wells using conventional thermal recovery methods.

3.3.12 Aggregated production forecast

The aggregated production forecast of an entity must be consistent with its reported reserves. This also holds for the 'proved forecast', as defined by the aggregated 'reasonably certain' amount of petroleum forecast to be produced by the appropriate development/production scenario, duly respecting license duration and overall constraints (e.g. quota).

The total Proved Reserves disclosed by an Asset Holder should be underpinned by a corresponding production forecast that at no point in time exceeds the Asset Holder's aggregated Business Plan forecast. In general it is expected that the production forecast for Proved Reserves will start at the same level as the Business Plan forecast and that it will gradually fall below it over time, reflecting the decreasing level of certainty that is normally associated with longer term elements of the Business Plan. The Proved production forecast should contain only the current Proved Reserves and the corresponding projects. In principle project scheduling should be the same as that of the Business Plan forecast, or somewhat accelerated if this can be justified. Refer also to Appendix A2.3.3.

3.3.13 Consistency with financial reporting

Proved Reserves and production must be reported consistently with procedures adopted by the Asset Holder's finance department, guided ultimately with reference to the Group Financial Information Manual (GFIM, Ref. 10). Close co-operation is therefore required between the finance and technical functions to ensure that alignment exists. Areas for attention include, but are not limited to, the reporting of: Total Oil Sales; Total Net Gas Production Available for Sale; quantities used in the calculation of depreciation through the Unit Of Production method; gas volumes paid for but not lifted; volumes reported in relation to Group consolidated companies; etc.

3.3.14 Oil and Gas Price

Resource Volumes should be evaluated at the Group Mid PSV of oil and gas price: that is, the economic limit for production operations in which Resource Volumes are reported using the equity method (see 3.1.1 above) should be established based on the Mid PSV. Similarly, when estimating Resource Volumes using the entitlement method (PSCs and "novel" contracts – see 3.1.2 and 3.1.3 above), the Mid PSV should be used as the basis of the calculation.

This approach could be deemed contrary to the letter of the SEC rules for Proved Reserves, which imply that the prices extant on the date of the estimate (31st December) should be used. The Group retains the Mid PSV as the basis for reporting since (1) changes in product price have either neutral or opposing effects on the reserves estimates for the equity and entitlement methods, so that overall the Group's Proved Reserves are relatively insensitive to changes in product price; (2) the adoption of year-end pricing could lead to excessive annual revisions to the Proved Reserves estimates for individual assets, and; (3) it is generally not feasible to await observation of the year-end price before completing, auditing and discussing with other stakeholders the estimate of Proved Reserves.

The Group's disclosure of the Standardized Measure of Discounted Cash Flows is calculated at the actual year-end price.

4. ASSESSMENT, REPORTING, RESPONSIBILITIES AND AUDITS

Resource classification and reporting is designed to support the Group's decision-making process with respect to resource allocation and portfolio management in pursuit of profitable business growth and reserves replacement objectives. Efficient systems to monitor the annual changes in the various resource categories are therefore essential.

An asset holder's internal resource assessment and reporting systems should:

a) Record the maturation plans for all Scope For Recovery opportunities (projects),

b) Monitor performance in maturing volumes relative to target,

c) Provide for systematic controls to assure the integrity of volumes that are reported,

d) Provide for regular review of ultimate recovery targets for existing fields in pursuit of constant improvement,

e) Record Key Performance Indicators (KPIs) to measure performance, e.g. reserves replacement ratio, Scope For Recovery maturation ratio, time between discovery and first production.

4.1 Shareholder Requirements

EP Planning will communicate each year a timetable and details of data submission requirements for both internal and external reporting.

Volumes will be reported based on the classification system described in this report. Additional information is reported for the calculation of the Standardized Measure, external disclosure of which is required by the US Financial Accounting Standards Board (FASB).

4.2 Methods and Systems

Asset holders are responsible for selecting the methods and systems that are technically the most appropriate for quantifying the Resource Volumes of their assets consistent with these guidelines. The preferred methods and systems may vary depending on the type of resource and with time as the resource matures and technology improves.

4.3 Responsibilities and Audit Requirements

4.3.1 EP Planning Responsibilities

EP Planning is responsible for compilation of the Group statistics of Resource Volumes, the analysis thereof and the communication to other functions. EP Planning also maintains the Petroleum Resource Volume guidelines.

4.3.2 Reserves Auditor Responsibilities

The Group Reserves Auditor carries out regular detailed reserves audits in asset holders to verify compliance with the Group's guidelines. The Terms of Reference for such audits are included in Appendix 3. In addition the Group External Auditors verify the Proved Reserves data for external disclosure.

4.3.3 Region and Asset Holder Responsibilities

Definition of internal reporting requirements, tasks and responsibilities should be as per the Region's (or Asset Holder's) Management System (Ref. 5). Technical and Financial functions must co-ordinate and reconcile their figures (particularly production volumes) prior to submission.

All levels in a Regional organization, including asset managers and the reservoir engineer preparing the individual field reserves estimates, must be aware of the importance of externally reported reserves (Proved, Proved Developed) and their impact on financial indicators.

Region and asset holder management is responsible for ensuring that the guidelines are implemented in such a way as to best represent to shareholders and potential investors the true value of the asset, subject to the rules and regulations of the SEC and FASB, as stated and interpreted herein (Appendices 1 and 2).

4.3.4 Reserves Operated by Others

Where Shell is not the operator, the Group company that holds the interest/share in the venture is responsible for the preparation of the reserves submission. In this case the Group company involved is responsible for ensuring that reporting is compliant with Group guidelines.

This may involve reclassification of volumes between Reserves and SFR categories where the operator's criteria differ from Group criteria concerning the evaluation of Proved Reserves.

4.3.5 Audit Trail

Audit trails are essential in the Resource Volume reporting process. They are indispensable tools for the Group Reserves Auditor to assess the quality of the Proved Reserves estimates and when handing over Resource Volume estimates between field reservoir engineers and reserves co-ordinators and their successors. They should support and document the reported figures and ensure that the Region and Asset Holder management understand and "own" the reported volumes.

For all Resource Volumes an audit trail must be available of the assumptions made and processes followed. This will allow any subsequent assessor to modify these estimates based on new information in a reconcilable manner. Thus, evaluation reports must be compiled (preferably on a field basis) giving the basic data, the way it has been interpreted and processed, the development options considered, and the resultant volumes with the assigned probabilities. In addition, a description should be given of the development strategy, including data gathering activities. These reports may be working files (if acceptable to local auditors), but it is recommended to make a duplicate 'for file' to ensure that the data are preserved in field reports.

Where subsequent small revisions are made, an update note must be compiled. Multiple changes may be combined in one overall update of the resource volumes if they all belong to the same change category. After several years of small changes or following a development study, a new evaluation report must be issued. When a proposed change has a significant impact on the Company's total reserves or financials, EP Planning should be advised at the earliest opportunity.

Guidelines on how to prepare a good audit trail, with suggested formats for tables etc. can be found on the Shell Wide Web (Ref. 11).

4.3.6 Data Management

The reporting of Resource Volume data to EP Planning is achieved using a standard Excel template workbook (the "Resource Volume Workbook"). This is described in a separate document (Ref. 2).

Each asset holder must adopt a system for storing Resource Volume data that both delivers data in the required format for the Resource Volume Workbook and meets the needs of the asset holder for planning and monitoring performance in petroleum resource maturation. Typically the latter requirement means that data must be stored at a finer level of resolution than is required for the Resource Volume Workbook. The detail and sophistication of the data storage and management system is dictated largely by the nature and complexity of the portfolio of assets in question.

Whatever system is used, it must store data in such a way that changes to Resource Volumes can be tracked over time. Systems must provide for the aggregation and reporting of year-end Resource Volumes in each classification system category. They must also provide for the aggregation of changes in Resources Volumes that occur in each year, enabling changes to be further subdivided by each of the "reasons for change" that are prescribed in the Resource Volume Workbook (Ref. 2).

Asset holders are advised to record all Resource Volumes in such a way that they can be aggregated and expressed on a per-field basis (in the event that a field may be the subject of several different projects) or a per-project basis (in the event that a single project addresses several different fields) when required.

At present there is no single Group-supported system for the storage of Resource Volume data. Each asset holder typically makes use of a system that has been tailored to the complexity of its portfolio of assets. These systems include RISRES (for the more complex portfolios), FASTRACK, commercially available software and Excel spreadsheets. All such systems must be accompanied by a documented audit trail that summarizes the source and location of the relevant information.

Consideration is currently being given to introducing a Group-standard system, with links to the systems used for business planning and capital allocation.

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3. EP 2003-1102, "*Guide for the Administration of Proved Reserves and Production for External Disclosure*", July 2003
4. EP 88-1145 Part 2, "*Methods and procedures for resource volume estimation*", SIPM, April 1988.
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13. EP 2000–9119, "*Estimating pay probability downdip from well control using seismic amplitudes*", A.K. Jackson, S.J. Saleh, P.J. Doe, STEP (Houston)

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APPENDIX 1 PROVED RESERVES – DEFINITION

United States Securities and Exchange Commission (SEC), Rule 4-10(a) of Regulation S-X, produced pursuant to the United States Securities Exchange Act of 1934:

Proved oil and gas reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";

(B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates, for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Shell's interpretation of the SEC definitions, supplemented by guidance published by SEC staff, is as follows:

	FASB / SEC Definition	SEC Interpretations (Ref. 8)	Shell Group Interpretation
1	**Reasonable Certainty** Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs ...	Future revisions should be more likely to be upward than downward.	Future revisions should be more likely to be upward than downward.
		A conservative approach is required until data is supported by field evidence.	Reserves estimates for new and recently developed fields should be based on a Low case (conservative) projection of future production and should be consistent with 'Proved Area' volumetrics.
		Performance-based projections may be the median, not necessarily the low estimate.	Reserves estimates for mature fields should be based on 'best estimate' performance extrapolations and projections. Proved reserves should grow towards Expectation reserves with increasing field maturity.
2	**Existing Conditions, Prices and Costs** [Proved reserves should be estimated] ... under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.	Existing economic and operating conditions may include future changes in these conditions. Such future changes must be known and determinable, must have a reasonable certainty of occurring and must be included in the economic feasibility. The latter must also include abandonment.	Existing economic and operating conditions may include identified future changes in these conditions (e.g. new developments), provided their costs are fully included in the project economics. Projects must be economically viable (in the Expectation case). Abandonment costs should be included in economics.
		Prices and costs should be as of the date the estimate is made, i.e. at the last day of the year.	Prices should be as per Group Mid Project Screening Value (PSV) of oil and / or gas price, this reflecting the Group's long-term estimate of product prices based on currently existing conditions.
3	**Producibility** Reservoirs are considered proved if economic producibility is supported by either actual production or [a] conclusive formation test.	Producibility must be demonstrated through a full formation test or through production at economic rates. Cannot be a wireline formation test.	Producibility is demonstrated either through production or a production test, through a wireline test, or through log and/or core data that give positive demonstration of analogy with other produced reservoirs in the area (NB – not necessarily in the same field). A fluid sample must be available.
	In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate [that] the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test. (Topic 12 of Accounting Series Release No. 257 of the Staff Accounting Bulletins).	Proved reserves in unproduced reservoirs can be claimed only if an analogy can be demonstrated with other produced reservoirs in the same field. This analogy requires the 'overwhelming' support of log <u>and</u> core data (which should be favourable to the unproduced reservoir). Note: This allowed analogy seems much more strict (log <u>and</u> core data; in same field) than that allowed for Improved Recovery.	

	FASB / SEC Definition	SEC Interpretations (Ref. 8)	Shell Group Interpretation
4	**Proved Area – Fluid Levels** The area of a reservoir considered proved includes that portion (…) defined by gas-oil and/or oil-water contacts, if any. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limits of the reservoir.	Reserves down to a known fluid contact or the Lowest Known Hydrocarbons (LKH) may be considered as proved. In the absence of a fluid contact, no reservoir volume below the LKH shall be considered as proved. Note: Recent statements by the SEC imply that no proved reserves can be attributed below the lowest logged hydrocarbon under any circumstances until performance data is available that clearly demonstrates their presence. The Shell Group is currently seeking clarification of this matter from the SEC.	Proved reserves shall fulfil 'Proved Area' conditions (see definition below). Water levels (and volumes below LKH) may be considered proved based on indirect evidence obtained from pressure measurements made in the reservoir concerned. Volumes below LKH can also be considered proved if good quality seismic amplitudes can be considered proof of hydrocarbons and if these are continuous over the area (Ref. 13).
		Proved oil reserves can be carried above Highest Known Oil only if there is compelling evidence of the oil being undersaturated (Ref. 14).	Proved oil reserves can be carried above Highest Known Oil if there is convincing evidence of the oil being undersaturated.
5	**Proved Area – Lateral Extent** The area of a reservoir considered proved includes that portion delineated by drilling (...), and the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.	The Proved Area should consist of one 'legal' (USA) or technically justified (non-USA) drainage area around the wellbore, plus up to eight surrounding ('offset') legal or technical drainage areas. Areas outside these 'offset' locations can only be considered proved if continuity of production is certain. Continuity of production means more than just continuity of the producing formation. Hydraulic continuity of the hydrocarbon fluid and producibility of the reservoir must be demonstrated with certainty. This requires conclusive evidence of communication from production or (interference) pressure measurements. Seismic data alone is not seen as a sufficient condition to prove communication over areas outside the eight 'offset' drainage areas.	Proved Reserves shall fulfil 'Proved Area' conditions. The 'Proved Area' is defined as an area of the reservoir with at least one well penetration and with confirmed producibility either in the reservoir itself or in an analogous reservoir. The Proved Area is delineated by water levels proved either by logs/cores or by pressure interpolations in the reservoir. Continuous good quality seismic amplitudes, giving positive indication of hydrocarbons may further delineate the area (conditions in Ref. 13). The area should not extend beyond potentially sealing barriers or faults. Areas extending beyond nine well drainage areas can be accepted as a basis for proved reserves if there is a demonstrated analogy with a proved reservoir (of same or poorer properties) in the area, or (preferably) through observed pressure or fluid responses in the reservoir.
		The above conditions can be waived only by conclusive reservoir production evidence or performance.	The above conditions can be waived by conclusive reservoir production evidence or performance.

	FASB / SEC Definition	SEC Interpretations (Ref. 8)	Shell Group Interpretation
6	**Proved Developed Reserves** Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.	Proved developed reserves can also be booked if only minor expenditure is outstanding before production can be started (e.g. sales connection, re-completion, additional perforation, bore hole stimulation).	Proved developed reserves require existing facilities and completions, with existing operating methods. If outstanding activities in ongoing projects are only minor (<10% of project Capex), the project can be booked as developed. Similarly, reserves requiring only minor well activities (<10% of cost of new well) may be booked as developed. Proved developed reserves should be derived from production trend extrapolations or through No Further Activity (NFA) forecasts from simulation models. These models must be properly history matched when production history is available.
7	**Proved Undeveloped Reserves** Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.	Proved reserves must be booked as undeveloped if major expenditure is required to produce the volumes.	Proved undeveloped reserves are reserves that require significant additional development capital expenditure to enable production (see above). Reservoir simulation is the preferred tool for determining undeveloped reserves. Undeveloped reserves must be based on specifically identified future activities (new wells or facilities).
8	**Improved Recovery** Reserves which can be produced economically through applications of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.	To carry Improved Recovery proved reserves, the improved recovery method must either: - Be verified by routine commercial use in the area, or - Have a technically and commercially successful pilot test or an installed program in that specific rock volume in the field, or - Have a successful pilot test in an analogous reservoir in the same geologic formation in the immediate area. An analogous reservoir is one having the same or poorer reservoir properties (porosity, permeability, thickness, hydrocarbon saturations, continuity). Note: This allowed analogy is much more lenient than that allowed for producibility.	Improved Recovery proved reserves in frontier areas can be booked without a pilot if the latter is not justified and if other information (core and fluid studies, analogue field experience) provides the necessary assurance (Value of Information approach). This implies that the project must be technically and commercially mature and project financing must be reasonably certain without the pilot. FID must have been taken for major projects.
	Under no circumstances should estimates of proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.	Improved Recovery proved developed reserves can be claimed only for those wells that have shown production increases associated with the improved recovery technique.	Improved Recovery proved developed reserves should be based on performance extrapolations as soon as feasible.

	FASB / SEC Definition	SEC Interpretations (Ref. 8)	Shell Group Interpretation
9	**Reasonable certainty of development** Estimates of proved reserves do not include the following: - crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;	Proved reserves require a serious commitment to pursue the project, e.g. AFE, FID, MOU, signed contracts, firm plans and timetables. This implies economic viability. Project financing must be reasonably certain. An inordinately long delay in the schedule of development may introduce doubt, sufficient to preclude the attribution of proved reserves. Proved reserves must have a reasonable certainty that a market exists, e.g. existing or firmly planned evacuation infrastructure, sales contracts or commitments. Proved reserves require continuance of permits, concessions and commerciality agreements to pursue the project. If the regulatory body has the right to end the agreement upon expiry, automatic renewal can only be assumed if there is a long and clear track record of renewals and if there is no reason to expect that this renewal may not occur.	Projects must be Technically and Commercially Mature and funding under the Group Capital Allocation scheme must be likely. Technical Maturity implies that there are no potential show stoppers. Commercial maturity implies that evacuation routes will be available and that a market is reasonably certain for gas volumes (e.g. through binding Heads of Agreement or and actual Sales Agreement). FID must have been taken for major projects. Smaller projects should have passed VAR3 or similar peer reviews. Proved volumes must be produced within existing production licences or their extension if there is provision for the latter in the licence permit.
10	**Unproved reserves and non-reserves** Estimates of proved reserves do not include the following: - oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; - crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; - crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other sources.	Tar sands, Oil sands, Oil shales etc: must be booked as mining reserves, not petroleum reserves, if recovery is not through the drilling of wells.	Heavy oil, bitumen, syncrude, gas, liquids, etc. recovered from unconventional reservoirs (oil sands, tar sands, coals, oil shales) by a "manufacturing" process must be reported separately from the conventional resource base. However, reserves can be claimed for otherwise unconventional reservoirs if the petroleum is recovered in its natural state and original location (i.e., has not been "manufactured" in situ by alteration from natural state) through the use of conventional methods (wells). An example would be coal bed methane. Volumes in undrilled prospects or unappraised fields are carried as SFR.

	FASB / SEC Definition	SEC Interpretations (Ref. 8)	Shell Group Interpretation
11	**Probabilistic methods of reserve estimating**	Probabilistic methods are recognised to have become more useful. The issuing of confidence criteria (e.g. 90%) is at this stage too premature. Past and current practices utilize a median or best estimate, which may imply that future revisions are not more likely to be positive than negative. This inconsistency should be resolved. Limiting criteria, e.g. LKH, shall still be honored.	Deterministic Low case scenario modelling (based on 'Proved Area' volumetrics in immature fields) is the preferred method for estimating proved reserves. Probabilistic methods are recommended mainly for calculating volumes in exploration prospects and unappraised discoveries. If probabilistic volumetric calculations are used for estimating proved reserves they must conform to 'Proved Area' conditions.
		A straightforward reconciliation is required for financial reporting purposes if probabilistic addition is used.	Probabilistic addition should only be used at levels below those used for financial asset accounting.
12	**Standardized Measure** Standardized measure of discounted future cash flows relating to oil and gas properties must comply with para 30 of FAS 69*.	All elements, including income tax, must be discounted at the standard rate of 10%. "Short cut" as per SAB topic12:D:1-Qu.2 may not be used.	Standardized Measure submissions are based on end-year prices and full-year average operating costs. Capex costs are as per date of estimate. The prescribed discount rate of 10% is used.
	Future cash inflows [should] be computed by applying year-end prices of oil and gas relating to the enterprise's proved reserves to the year-end quantities of those reserves. (*Statement of Financial Accounting Standards 69, paragraph 30.a.)	End-year prices mean physical prices on the last day of the year. The same requirement applies to (future) costs.	
13	**Production Sharing Agreements**	Proved reserves must be based on the "economic interest method" (future cost and profit oil revenue divided by year-end oil price) and not the "working interest method" (working interest in contractor venture, minus royalty), as the sum of all entitlements must not exceed 100%. Reserves volumes determined by various owners should add up to 100% of field volumes. Producer must have the right to extract the hydrocarbons and must be exposed to exploration / development risk.	Reserves are based on cost and profit oil revenue divided by a reference oil price as per Group PSV screening values. PSC entitlement share should be calculated using a reasonably conservative estimate of future costs. For PSCs and other novel contracts: The company should have provided / contributed technical upstream expertise to the project and it should have funded development capital that is subject to upstream risk.

APPENDIX 2 RESOURCE VOLUME ESTIMATION

A2.1 Quantification methods

Resource Volume estimates are inherently subject to uncertainty because they are based on sparse data (from seismic and drilling) and interpretations that contain sometimes significant margins of error. In-depth understanding is necessary to enable 'realistic' reporting of Proved Reserves. The most important methods to quantify and assess the range of uncertainty in Resource Volume estimates are:

- The Probabilistic method (p85, Mean, p15)
- The Deterministic method:
    - Multi-scenario
    - SEC / SPE (Proved, Probable, Possible)

The SEC Proved Reserves definition is strictly deterministic and all Proved Reserves disclosed externally by Shell should adhere to the SEC definition. Group practice in this respect is summarized in section A2.2.

A2.1.1 The probabilistic method

The probabilistic method is good for assessing the uncertainties of exploration prospects, partially appraised discoveries and single development concepts in general. For (major) fields that are at the "concept selection" stage the multi-scenario method is preferred, as described below.

The probabilistic method has been in use by the Group since the 1970s. Whilst the Group was initially alone in the industry in applying it, the method has gradually gained wider acceptance, e.g. by the SPE (Ref. 6).

The method consists of assigning probability density functions (PDFs) to each of the parameters that define a Resource Volume estimate (e.g. gross bulk volume, porosity, hydrocarbon fill and saturation, hydrocarbon volume factor, recovery factor). The PDFs are then combined either mathematically ('moment' method, see Appendix 7 of Ref. 4) or, more commonly, through Monte Carlo simulation. The Monte Carlo method selects a value at random from each of the parameter PDFs, combines them to yield a Resource Volume estimate, and repeats this process many times over to yield a PDF for the Resource Volume itself. Software tools that use Monte Carlo simulation include @RISK, Crystal Ball and FASTRACK.

The PDF of the Resource Volume may be integrated to yield a cumulative probability function (CPF), which defines the probability that the Resource Volume exceeds each value in the range of possible outcomes. The Resource Volumes associated with the 85% and 15% confidence levels are referred to as the Low and High estimates (or **p85** and **p15**). The probability-weighted average value of the entire distribution is referred to as the **Expectation** value. The reason for the original selection of the 85% and 15% intervals by the Group was that they aligned most closely with the previously used distributions of three equi-probable values. More recently, the SPE and some operators and authorities have tended to favour 90% and 10% intervals (p90 and p10 respectively).

A2.1.2 The deterministic multi-scenario method

This method is applied in principle before technical/commercial maturity is achieved and its application is predominantly in support of development concept selection. The method involves modelling through a full set of static (geological) and dynamic (reservoir simulation) models, all of which are internally consistent and honour the available data. The static model is generally run for a range of possible subsurface realisations, yielding a range of hydrocarbon-in-place volumes.

A representative selection of alternative geological model realisations is converted ('upscaled') into a discrete set of reservoir simulation models, which are then run each for a range of alternative development scenarios (e.g. different well numbers or positions). The alternative development scenarios are not necessarily identical for each geological realisation.

An important characteristic of the multi-scenario method is that it is project- or activity-based, i.e. the recoverable volumes are linked to a specific development plan or plans, with identified (or identifiable) costs, production forecasts and economics. These aspects make this approach well suited to supporting development concept selection.

In its simplest form, the method may yield Low, Middle and High estimates of Resource Volumes. However, it is increasingly common to apply the method to far more possible realizations, yielding, in effect, a PDF for the Resource Volume, with each discrete point on the PDF being defined by a unique deterministic scenario. Although it may be tempting to equate the p85 of the corresponding CPF to "Proved Reserves", it is important to bear in mind that the externally disclosed Proved Reserves must still conform to the Group guidelines (i.e. the SEC rules) on the definition of Proved Reserves (see A2.1.3 and A2.2 below).

A2.1.3 The SEC / SPE deterministic methods

The deterministic method has been the method most frequently used by the industry at large. It derives from the original definitions of 'Proved Reserves' as issued by the US Financial Accounting Standards Board (FASB) and by the US Securities and Exchange Commission (SEC) (Refs. 7, 8 & 9). These definitions describe the mandatory conditions for reserves that are reported annually through company reports and public submissions to the SEC.

Proved Reserves are defined by the SEC as "…the estimated quantities of hydrocarbons which geological and engineering data demonstrate with **reasonable certainty** to be recoverable…". 'Reasonable certainty' is implied to mean that future reserves revisions are 'much more likely' to be positive than negative. Pivotal in the definition of Proved Reserves is the notion of a **'Proved Area'** of reservoir rock, outside of which no Proved Reserves can be attributed. Similarly, only recovery from techniques that have been proved effective can be included. Please refer to Appendix 1 and to Reference 8 for further information on the constraints applicable to the definition of the Proved Area and Proved Reserves estimates, but take note also of the current Shell guidelines on interpretation, also included in Appendix 1 and summarized in A2.2 below.

The practice in the industry at large has been that Proved Reserves estimates are generally 'best estimates', with the Proved Area constraint being the only conservative element that is strictly adhered to. An important consequence of this in relation to the Group's histroical practice is that Proved Reserves as calculated by the deterministic method tended to be lower than probabilistic p85 estimate for new discoveries and undeveloped fields. Similarly, they were generally higher for mature, fully appraised fields.

The SPE (Ref. 6) extended the definition of "Reserves" to include Probable and Possible Reserves. Whilst the latter two are commonly referred to by the industry at large, they do not qualify for disclosure according to the SEC rules. The SPE definition of Proved Reserves is somewhat more relaxed than the SEC's, for example by allowing probabilistic techniques (with Proved Reserves equating to the p90 confidence level). This theme is extended through the Probable and Possible definitions, for which some of the key features are:

Probable reserves:

- 'More likely than not to be recoverable'; p50 if based on probabilistics,
- Probably productive from logs/cores,
- Likely volumes outside the 'Proved Area', e.g. updip behind interpreted faults,
- Volumes probably recoverable through unproved techniques (no successful pilot yet)

Possible reserves:

- 'Less likely than Probable', p10 if based on probabilistics,
- Hydrocarbon bearing from logs/cores, but possibly not productive,
- Possible volumes outside the Proved Area, e.g. downdip behind interpreted faults,
- Volumes recoverable through unproved techniques, with success in 'reasonable doubt'.

Industry practice tends to be that Probable Reserves sometimes contain not only volumes associated with areas in the field outside the volumetric confines of the 'Proved Area', but also volumes associated with projects that have not been fully matured or approved yet.

The sum of Proved and Probable reserves is sometimes regarded as equivalent to the Mean or Middle estimates from probabilistic or multi-scenario methods. Similarly, the sum of Proved, Probable and Possible has been equated to p10 or High reserves. However, the definition for Possible Reserves clearly indicates that many of these volumes (and even some Probable Reserves volumes) would be classified as SFR in the Shell system.

A2.2 Shell Group Practice

Group practice has long been based on the probabilistic method for estimating Expectation Resource Volume estimates (for internal reporting). Proved Reserves (for external reporting) were for many years set equal to the probabilistic p85 estimates, which tended to change little as fields matured. This approach was found to lead to under-reporting of reserves in mature fields compared with major competitors and consequently it was replaced by a deterministic approach in 1998. In following the guidelines of the US Financial Accounting Standards Board (FASB) and the US Securities and Exchange Commission more strictly, the Group's reporting practice is now more in line with its major competitors (in particular with respect to mature fields).

First "booking" requires auditable evidence of technical and commercial maturity, to the extent that the project(s) are reasonably certain to attract corporate funding.

The preferred approach to development concept selection as it leads up to field development planning is based on the multi-scenario method. Reserves assessment is, however, to be based on the development concept that is actually selected for execution. Proved Reserves estimates should in principle be consistent with volumetrics in the 'Proved Area', which is defined by (see also Appendix 1):

- Demonstrated producibility through a production test, or log/core data in a tested area,
- Delineated by GOC, OWC, GWC as seen/interpreted from pressures in the reservoir or by good quality seismic amplitude data (Ref. 13); if neither is available, by LKH,
- In the absence of 'legal' well spacings, laterally defined by well control and surrounding areas with continuous and good quality seismic amplitudes (Ref. 13), but not beyond potentially sealing barriers or faults. Evidence from well drainage limit tests may be used.
- Extended by production performance data, if conclusive,
- Improved recovery volumes supported by a pilot or a robust analogy.

Underpinning this approach is the concept that the drilling and completion of development wells will generally expand the 'Proved Area' until it covers much, if not all, of the field. Even if still incomplete at first (i.e. after the first phase of development drilling), this coverage will increase to full coverage with growing field maturity and performance. In line with industry practice, Proved Reserves should be based on 'best' or Expectation estimates of 'Proved Area' volumetrics (in-place volumes).

Apart from the volumetric uncertainty, there is the uncertainty regarding reservoir **performance** (determined by sand development, reservoir continuity, injectant sweep efficiency, aquifer activity, etc.). The latter uncertainty will be reduced as production progresses. Hence, a cautious, 'reasonably certain' approach should be followed for performance predictions in new fields **(i.e. the classic Shell approach adopting the Low natural outcome of the FDP as Proved Reserves remains valid).** For mature fields the Proved Reserves are expected to grow towards Expectation as field life progresses and the uncertainty range narrows. In some mature fields with well established production trends Proved Developed Reserves may become equal to Expectation estimate.

The resulting assumptions to be used for estimating Proved and Expectation Reserves is given in Fig. A2.1 (below). To the extent that reserves (particularly Proved Reserves) are still based on probabilistic estimates, consistency with these assumptions is required.

Expectation Developed and Undeveloped Reserves (internal reporting):	All fields	Mean probabilistic or Middle case outcome of the development concept selected and approved for execution, based on Expectation volumetrics. (Proved+Probable if appropriate and if no Mean or Middle available)
Proved Developed Reserves (external reporting):	New, recently developed fields:	'Reasonably certain' (Low case) outcome of the development concept selected and approved for execution based on Expectation 'Proved Area' volumetrics.
	Mature fields:	Best estimate performance projection, based on Expectation "Proved Area" volumetrics. Err on the side of conservatism when in doubt. The Proved Developed Reserves estimate should approach (and may become equal to) the Expectation estimate as field life progresses.
Proved Undeveloped Reserves (external reporting):	Undeveloped fields	'Reasonably certain' (Low case, low activity scenario if applicable) outcome of the development concept selected and approved for execution based on Expectation 'Proved Area' volumetrics.
	New, recently developed fields:	'Reasonably certain' (Low case) outcome of the incremental development ahead, based on Expectation 'Proved Area' volumetrics.
	Mature fields:	'Reasonably certain' (Low case) outcome of the incremental development ahead, based on Expectation 'Proved Area' volumetrics. The Proved Undeveloped Reserves estimate may approach the Expectation estimate in highly mature and well-understood reservoirs. However, lower Proved : Expectation ratios should apply if the development project involves changing the recovery mechanism from that currently employed.

Figure A2.1: Group recommended practice for estimating Reserves

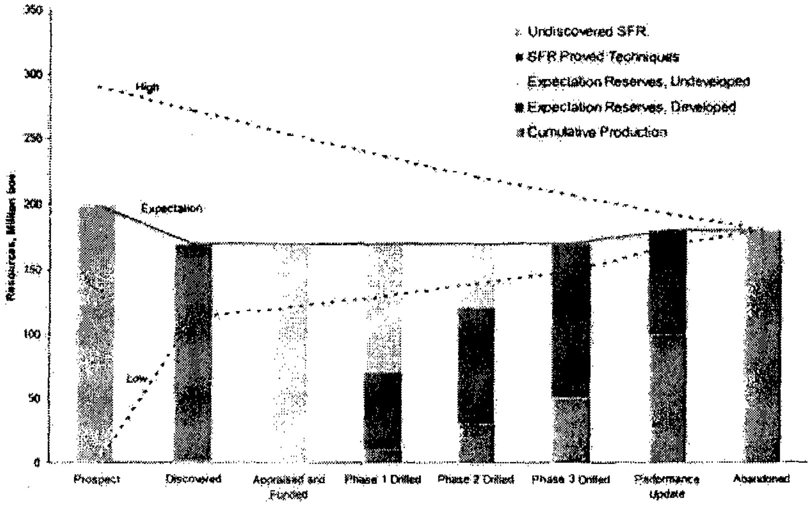
For most reservoirs it will be possible to make a robust case for reporting Proved Developed Reserves as being equal (or close to) Expectation Developed Reserves when cumulative production has exceeded some 40% of the Expectation Developed Ultimate Recovery. Lower thresholds may be appropriate for very well understood reservoirs, with copious local, direct analogue data. Similarly, higher thresholds may be appropriate for reservoirs in which relatively novel (but still "proved") recovery techniques are being employed, or when circumstances dictate that a more cautious approach be taken to Proved Reserves estimation.

A2.3 Further Considerations

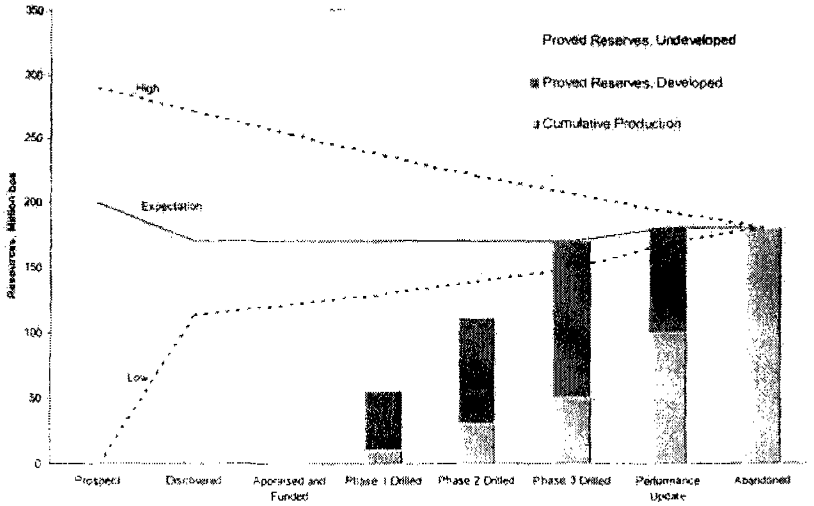
A2.3.1 Uncertainty Reduction with Performance

The uncertainty range of Ultimate Recovery generally decreases as a field is developed and produced. However, the uncertainty range as a percentage of remaining reserves may not always decrease with time. **As a field matures, initial in-place volumes and recovery should shift from a volumetric to a performance-based estimate, incorporating the additional production data to reduce the uncertainty range.** Once reservoir performance has been established with reasonable certainty, a fairly small difference between low, expectation and high estimates would be expected. Definition of the low and high estimates may no longer be of value in mature fields with relatively little uncertainty and use of a single expectation estimate should be considered in this situation (subject to 'Proved Area' conditions).

The following diagram illustrates the reduction in uncertainty for Resource Volume estimates (including cumulative production) over the lifetime of an asset:



For the above example, the Proved Reserves (taking account of cumulative production) profile as disclosed externally might be as follows:



A2.3.2 Addition of Proved Reserves Volumes

Proved Reserves are aggregated at various levels (reservoirs, fields, areas, etc) during the Resource Volume assessment and reporting process. When Proved Reserves are based on p85 or Low estimates, such addition could in principle either be arithmetic or probabilistic.

Arithmetic addition usually overstates the uncertainty range for the sum of (partially) independent volumes (i.e. the resulting sum of p85/Low values is too low), but it is appropriate for dependent volumes.

Probabilistic addition could be considered for partially independent volumes when the difference with arithmetic addition is significant. An important requirement is, however, that **addition of Proved Reserves at or above the level used for financial depreciation calculations must be arithmetical for consistency with financial accounting.** Below this level, i.e. normally below the field level, an appropriate selection of the addition method must be made, such that account is taken of dependency between the volumes to truly reflect the aggregated p85/Low/Proved recoverable volume.

Below are two examples where the method of addition is important to handle addition properly.

a) Field A consists of separate layers and the properties of these layers are independent of each other. In other words, a low result in one layer would not increase or decrease the chance of a low result in the other layers. Low, expectation and high estimates are calculated for each layer separately. Probabilistic addition should be used to account for the reduced uncertainty of adding together independent volumes. Arithmetical addition of these estimates would understate the low estimate and overstate the high estimate of the total field.

b) A project develops three independent fields as sub-sea satellites connected to one platform. In this case, the investment in surface facilities may be totalled for depreciation[1] and consequently the reserves estimates should relate to the combined fields. Probabilistic addition should be used to calculate the total reserves associated with the platform (assuming independence).

Please refer also to Appendix 1.

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[1] Group Accounts should be consulted when considering combining surface facilities for different fields for depreciation purposes.

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A2.3.3 Production Forecasts

The following notes are intended to guide the preparation of production forecasts in support of Resource Volume reporting and in particular in support of Proved and Expectation Reserves reporting.

The basis for all Resource Volume reporting is either an existing producing asset or a "project", however notionally defined.

Resource Volume estimates should preferably be supported in all cases by a production forecast for the corresponding reservoir development scenario, linked to a specification of the recovery process, the number and type of wells necessary, facilities requirements and the costs of installing and operating the required wells and facilities.

The production forecasts should be defined at a level of resolution that is appropriate for the needs of the business and the maturity of the assets concerned: for example reservoir unit, reservoir or field.

Account should be taken, where necessary, of overriding constraints, such as evacuation system capacity, (likely) OPEC quota levels or funding levels, particularly if these affect the timing of development activities and the Resource Volume for the project concerned is dependent on the timing of execution.

The aggregation of all production forecasts for Expectation Resource Volumes should reflect the overall business plan for the collection of assets in question.

It is recommended to construct Proved production forecasts for each asset, not least because in principle this is required to create the Standardized Measure of Discounted Cash Flow for external disclosure and to reliably estimate volumes producible within the licence period (external Proved Reserves disclosures must be constrained by licence expiry – see section 3.3.1 of main text).

Where Proved Reserves are based on reservoir modelling, the Proved production forecast should be based on a specific modelled Proved Reserves scenario.

The Proved production forecast for Developed Reserves should equal the Expectation production forecast at its starting point and thereafter it should gradually fall further and further below the Expectation production forecast (in cases where Proved Developed Reserves do not equal the Expectation estimate). The Proved production forecast for Undeveloped Reserves may commence at a lower level than the Expectation production forecast to reflect uncertainty in the initial production rate.

When expressed in terms of rate versus cumulative production, the Proved production forecast should never exceed the Expectation production forecast.

The aggregated Proved production forecast for a business or collection of assets should at no point in time exceed the aggregated Expectation production forecast (i.e. the business planning forecast), unless there are clearly defined circumstances that would make it possible for this to happen.

APPENDIX 3 SEC RESERVES AUDITS - TERMS OF REFERENCE

The purpose of the Proved Reserves Audit is to verify that appropriate processes are in place in the asset holder to ensure that the Proved and Proved Developed Reserves estimates for external (SEC) reporting are compliant with the Group guidelines.

The Audit will be carried out by the Group Reserves Auditor. His specific tasks during the audit shall be:

1) To verify the technical maturity of the projects and activities that underlie the reported proved and proved developed reserves estimates by assessing the quality of the engineering data and study work supporting the estimates.

2) To verify the commercial maturity of the reported reserves volumes by assessing consistency between the volumes reported and the company's business planning (production/sales forecasting), ensuring that these volumes can reasonably be expected to be (developed, produced and) sold in present or future markets.

3) To verify the 'reasonable certainty' of the reserves estimates by assessing the validity of uncertainty ranges used for their constituent parameters, by verifying that estimates are realistic in comparison with expectation estimates, by verifying that appropriate methods are used for mature fields and by establishing that appropriate methods of reserves addition (probabilistic / arithmetic) have been applied. The audit also verifies that implied future development is indeed likely to go ahead.

4) To verify that the Group share of proved and proved developed volumes has been calculated properly and are producible within prevailing licence periods.

5) To verify that reported volumes are up-to-date and consistent with previous estimates, that changes are reported in the appropriate categories and that appropriate audit trails are in place for the study work supporting the reported reserves estimates.

6) To verify that reported reserves are net sales volumes and that the reported annual production (sales) volumes are consistent with those reported in submissions to Group Finance.

In case of deviations from the Group guidelines the auditor shall establish whether and to what extent resulting estimates are likely to differ from those that might be expected from the 'proper' application of the guidelines.

The frequency of the audit will in principle be once every four years for each asset holder, but should be adjusted as warranted by size of asset holder, past change volumes and complexity of the issues. Major reserves changes or concerns expressed during a previous audit may require an advancement of the next audit. For an asset holder reporting reserves for the first time, the first audit will in principle be within two years of this first submission.

The audit will in principle be carried out on asset holder premises and will be based on documentation available in the asset holder. The audit will be carried out by reviewing the reserves estimation and submission process through interviews of asset holder staff and by taking a number of selected fields for more detailed technical analysis.

An audit report will be submitted to the Managing Director and Petroleum Resource Manager of the asset holder (where appropriate), to the EP CEO and Regional Technical and Finance management and to KPMG the external auditors. It will be prepared and discussed in draft form on site, after which a final report will be prepared in The Hague, once formal asset holder comments are received. The report will contain an overall judgement (Good, Satisfactory, or Unsatisfactory), with itemised conclusions and recommendations.

APPENDIX 4 TERMINOLOGY

A4.1 Petroleum Resources Terminology

Reservoir

A reservoir is a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

In case of doubt, reservoirs are restricted to fault blocks or sedimentary units that have been proved to be productive until production performance proves communication to exist across faults or other barriers.

PVT properties can vary within a reservoir.

Field

A field is an area consisting of a single reservoir or multiple reservoirs within a closed areal boundary that belong to the same confining geological structure.

Field boundaries must be defined upon discovery and should encompass the unpenetrated petroleum resources in adjacent fault blocks and stratigraphic traps, if they are considered to be part of the same overall confining structure. Field boundaries may be re-defined on the basis of new geological information.

Potential Accumulations

Potential reservoirs beyond existing field boundaries, where the presence of petroleum has not yet been demonstrated, are collectively called potential accumulations.

Hydrocarbons Initially in Place

The volume of hydrocarbon which is estimated to exist (or have existed) originally in a naturally occurring accumulation at the time of its discovery. The volume is usually expressed at standard conditions of temperature and pressure (or, sometimes for gas, "normal" conditions of temperature and pressure) taking account of volume and phase changes that would occur were the entire hydrocarbon content of the accumulation to be brought to those conditions. It is also usual to specify the volume separately for each hydrocarbon product at the reference conditions, usually oil, natural gas liquids and gas (which may be further subdivided into gas occurring in the gas phase at original reservoir conditions – "non-associated gas" or "free gas" – and gas that forms a part of the liquid phase at original reservoir conditions – "associated gas" or "solution gas"). It is also usual to quantify the range of uncertainty associated with the estimate (see A4.2).

Ultimate Recovery

The sum of cumulative production and the estimated reserves. The definition may be qualified to indicate the use of Proved Reserves, Expectation Reserves or Expectation Reserves Within Licence as required. It may be further qualified to include either developed reserves or total reserves (developed + undeveloped). It may also be defined as including (and, for immature reservoirs, may consist entirely of) SFR volumes. From the foregoing it should be clear that whenever Ultimate Recovery figures are quoted, they should be defined and qualified with the same rigour as resource volumes.

Recovery Factor

The Recovery Factor is the ratio of Ultimate Recovery to Hydrocarbon Initially in Place, expressed as a fraction or percentage.

Natural Gas Liquids

Natural Gas Liquids (NGLs) are hydrocarbons existing in the liquid phase at standard conditions of temperature and pressure ("stock tank" conditions), but which formed a part of the gas phase at original reservoir conditions, and which are recovered from the production facilities.

In some cases, NGLs are spiked into oil for export and sales purposes: in these cases it is recommended that the NGLs are still accounted for separately.

Liquefied Petroleum Gas (LPG) products, which exist in the liquid phase at the point of sale but which would evaporate if flashed to standard conditions of temperature and pressure, should be accounted for as ***gas***.

Economic Producibility

Economic producibility should normally be supported by a conclusive test in a drilled or immediately adjoining reservoir, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.

Production Facilities

Production facilities consist of all hardware installed to recover petroleum from the sub-surface resources and to deliver a quality controlled end product for sale. These comprise the production and injection wells and the surface facilities for treatment, conversion, compression/ pumping, transport and delivery.

Surface Facilities

That part of the production facilities accessible at surface, connecting the wellheads ultimately to the delivery points.

Existing Development

The collection of all completed projects or sub-projects is referred to as the existing development.

Field quantities

Field quantities (also called 'Wellhead' quantities) are those quantities routinely measured at surface for individual well strings and expressed in terms of the stabilised products oil, condensate and (wet) gas or in terms of the type of injected fluids. These quantities may subsequently be reconciled with fiscalized sales and other product outlets, see below.

Sales quantities

The quantities sold after fiscal metering and delivered at the locations where the upstream company ceases to have an interest in the end products. These can be expressed in terms of the general end-products oil, (dry) gas and natural gas liquids (NGL) or in terms of the actual product.

Field products and the subsequent sales products may be different and will be affected by own use and losses. The properties and volumes of end products may be influenced by mixing and the petroleum type itself may be altered during surface processing. Since surface processing conditions may change during a project life, sales products may vary in specification and in relation to field products. To avoid ambiguity and double counting, a clear distinction must be made between recoveries in the field and the quantities estimated to be available for sale.

For general sales products, oil, gas and NGL, only the quantities sold by the upstream E&P company can contribute to Group reserves. Condensates mixed with crude oil in the same stream and sold as such can be reported under oil. Separator condensate from gas wells and light hydrocarbon liquid products, derived from surface processing, if collected in a separate stream and sold as such are reported under NGL. In principle all non-oil hydrocarbons that are sold as separate streams in liquid state (pressurized or not) should be accounted as NGL. Bitumen may be reported under oil in summary reports (with an appropriate footnote). In line with SEC requirements, sales volumes for gas should be those committed or committable to a gas contract. Committed Gas is covered by a gas contract. Committable gas reasonably expected to be assigned to a contract in the future.

It is necessary to maintain a more detailed internal administration of the actually sold products by stream in two cases: (1) If the upstream E&P company has separate contracts for delivery of special converted sales products such as LNG, methanol, ethane, LPG, C5+ etc., or (2) If there are special sales products like helium, sulphur or generated electricity.

Reconciliation

A monthly reconciliation is made between the fiscalized sales quantities and the quantities produced in the field. This is reported in the Monthly Report of Producing Wells (MRPW). The reconciliation process corrects for own use, flaring, losses and product conversion, and provides the end-product yield.

For reserves estimating purposes an average future yield factor is to be estimated (e.g. LPG/ wet gas yield, dry gas/ wet gas yield).

A4.2 Probabilistic Terminology

Probability Density Function

The probability density function (PDF) of a stochastic variable indicates the probability that the actual variable value lies within a narrow interval around a particular value of the possible range.

Cumulative Probability Function

The cumulative probability function (CPF) of a stochastic variable describes the probability that the variable may exceed a certain value. The CPF is the mathematical integral of PDF.

p85

The value that has a 85% probability of being exceeded by any randomly selected value in a range.

p15

The value that has a 15% probability of being exceeded by any randomly selected value in a range.

Mean (Expectation)

The statistical mean of a random variable is the probability-weighted average of the variable over its entire range.

Commercial Cut-off Volume

The commercial cut-off volume is that resource volume for which the development NPV (Net Present Value) is equal to zero at the Mid PSV of oil or gas price.

Probability of Success (POS)

When applied to an undrilled potential accumulation (Undiscovered SFR), POS expresses the probability that the accumulation will contain resource volumes exceeding a certain volume ("cut-off"):

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POS at zero cut-off: The probability of finding hydrocarbons.

POS at commercial cut-off: The probability of finding a the minimum resource volume required for commercial development. The POS at commercial cut-off can never exceed the POS at zero cut-off. Please refer also to the definition of "Commercial", A4.3 below.

Mean Success Volume (MSV)

The Mean Success Volume (MSV) is the mean of all success-case volumetric outcomes. The MSV of a prospect depends on the (volumetric) cut-off that has been applied and therefore should always be quoted with reference to that cut-off.

See also Probability of Success (POS).

The expectation resource volume (Undiscovered SFR) associated with an undrilled potential accumulation is the product of MSV and POS at commercial cut-off.

A4.3 Commercial Terminology

Commercial

When applied to SFR, *Commercial* denotes SFR that is associated with a project that is evaluated as having a positive Net Present Value (NPV) of development (i.e. excluding exploration and appraisal costs) at the prevailing Group Mid PSV of oil and gas price and for which there is the reasonable expectation that any remaining obstacles to development can be overcome (e.g. securing gas sales contracts, provision of major infrastructure, government approvals, unproven technology).

Non-Commercial

When applied to SFR, *Non-Commercial* denotes SFR that is associated with a project that is evaluated as having a negative Net Present Value (NPV) at the prevailing Group premises assumptions or for which there are clear obstacles to development that at present appear to be insurmountable (see definition of "Commercial").

Discount Rate

A rate at which future real terms costs or cash flow are discounted over time to calculate their present value.

Net Present Value (NPV)

The net present value of a project is the sum of the discounted cash flow, expressed in real terms money, over the period from the first project expenditure to abandonment. The net present value is expressed in million US$ at the relevant discount rate.

Expected Monetary Value (EMV)

The expected monetary value is a probabilistic balance of investments and revenues, expected from a set of conditional operational activities, comprising data acquisition and one or more development projects, which are arranged in an ordered sequence with probabilities assigned to each action (decision tree).

The EMV is the summation of the NPVs of projects, reduced by the costs of data acquisition activities, all expressed in discounted real term money and multiplied by their assigned probabilities. EMV is expressed in million US$ at the relevant discount rate.

Projects with a negative NPV for certain resource model realisations should be excluded from the EMV calculation, if the assumption is valid that data gathering will prevent such projects being implemented.

Unit Technical Cost (UTC)

The unit technical cost of a development project is defined as the sum of capital plus operating costs, expressed in real terms money, divided by the total production over the period from start-up to abandonment. In addition, both the cost and the production must be discounted. The reference date for the discounting should be the same for denominator and numerator (e.g. the first year of expenditure) and should be stated. The unit technical costs is expressed in US$/bbl (oil equivalent) at the relevant discount rate.

FID

Final investment decision, the decision (at CMD or senior executive level) to proceed with a project.

NFA forecast

No further (Capex) activity forecast, i.e. a forecast based on existing wells and facilities only.

A4.4 Exploration and Development Wells

The classification of a well as either an exploration well or as a development well is determined (in line with SEC rules) based on the proved area as follows:

Proved Area

The proved area is the part of a property to which Proved Reserves have been specifically attributed (see also Appendix 1). It is delineated by the fluid levels seen / interpreted from drilled wells and by the area around those wells which geological / engineering data indicate to be producible.

Development Well

A development well is a well drilled within the proved area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.

Service Well

A service well is either an injection well, a disposal well or a water supply well.

Appraisal Well

An appraisal well, or stratigraphic test well is a well drilled for geological information (not to test a prospect), either 'development-type' drilled in a proved area or 'exploratory-type' if not drilled in a proved area.

Exploration Well

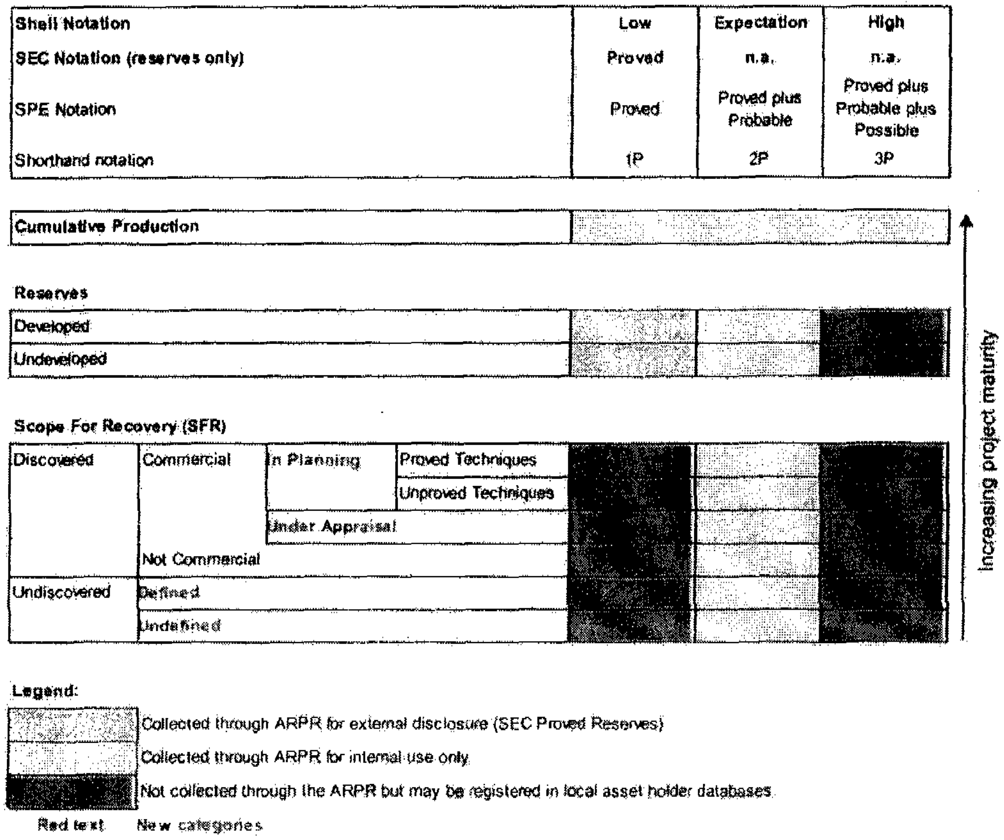
An exploration well is a well that is not a development well, a service well, or a stratigraphic test well.

Exploration Expenditure and Capital Expenditure

For details of the allocation of costs between Exploration Expenditure and Capital Expenditure, please refer to the Group Financial Information Manual (GFIM, Ref. 10). In simple terms, Exploration Expenditure includes all costs incurred in drilling wells to locations that fall outside the Proved Area.

APPENDIX 5 NEW CLASSIFICATION SYSTEM

With effect from 31.12.2004 the Petroleum Resource Volume Classification System will be revised as indicated below (see section 2.2 of main text for comparison). The changes relate to an expansion of the SFR categories, so as to provide more useful information on the maturity of the Resource Volumes concerned. At 31.12.2003, year-end Resource Volume balances should be sub-divided into the new categories to form opening balances for the reporting of changes in 2004.



Shell Notation	**Low**	**Expectation**	**High**
SEC Notation (reserves only)	**Proved**	**n.a.**	**n.a.**
SPE Notation	Proved	Proved plus Probable	Proved plus Probable plus Possible
Shorthand notation	1P	2P	3P

Cumulative Production	▒	▒	▒

Reserves

Developed	▒	░	▓
Undeveloped	▒	░	▓

Scope For Recovery (SFR)

Discovered	Commercial	In Planning	Proved Techniques	▓	░	▓
			Unproved Techniques	▓	░	▓
		Under Appraisal		▓	░	▓
	Not Commercial			▓	░	▓
Undiscovered	Defined			▓	░	▓
	Undefined			▓	░	▓

Legend:

▒	Collected through ARPR for external disclosure (SEC Proved Reserves)
░	Collected through ARPR for internal use only
▓	Not collected through the ARPR but may be registered in local asset holder databases
Red text	New categories

Figure A5.1: Overview of proposed new Shell Petroleum Resource Classification System

The purpose of introducing further resolution into the SFR Undiscovered category is to highlight the more mature elements of the exploration portfolio. The changes to the SFR Discovered category are intended to give greater insight into the maturity of projects for discovered resources *en route* to development FID.

Definitions of New SFR Categories

SFR Undiscovered: Undefined

SFR Undiscovered resource volumes that are not specifically attributable to a potential accumulation that has been mapped.

This category describes notional volumes that are anticipated to be present based on, for example, play maturity modelling (for example, inferences based on existing discovered field size distributions), but which cannot yet be assigned to any identified prospect or lead. There should be a reasonable likelihood that any such resource volumes would be commercial to develop.

SFR Undiscovered: Defined

SFR Undiscovered resource volumes that are identified with mapped potential accumulations (prospects and leads).

SFR Commercial

Within this category, project maturity can vary considerably and the new sub-divisions are designed to provide greater transparency on the distribution of Resource Volumes on the "maturity" scale.

The pre-existing SFR Proved Techniques and SFR Unproved Techniques will now be reserved for projects that are at a relatively late stage of Field Development Planning: these will be grouped and referred to as "In Planning". Typically these will be projects that are being actively worked through concept selection towards VAR3 (they will generally have already passed VAR2) or for which Field Development Plans are being prepared for FID.

For projects that are not sufficiently mature to qualify under these (revised) pre-existing categories, a new category will be created:

SFR Discovered: Under Appraisal

SFR Discovered resource volumes that are associated with a field or project that is subject to ongoing appraisal or the evaluation of exploration or appraisal results.

This category describes new (or recent) discoveries: partially appraised fields or unappraised discoveries. This category generally covers projects up to VAR2. Upon completion of further appraisal and / or evaluation studies, the project would either be declared Non-Commercial or it would pass to the "In Planning" category and from there to Reserves.

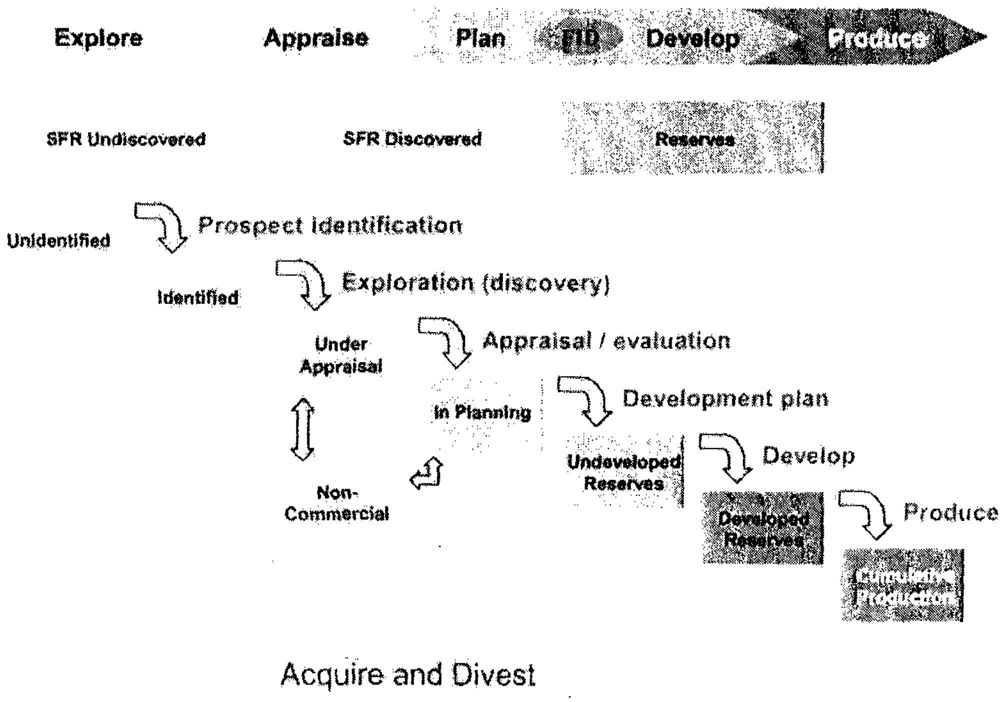


Figure A5.2: New resource volume classification flow diagram

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Guide for the Administration of Proved Reserves and Production for External Disclosure

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Guide for the Administration of Proved Reserves and Production for External Disclosure

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SHELL INTERNATIONAL EXPLORATION AND PRODUCTION B.V., RIJSWIJK

Further copies can be obtained from the Global EP Library, Rijswijk with permission from the author.

KEYWORDS

PROVED OIL AND GAS RESERVES, RESERVES COMMITTEE, GROUP COMPANIES, ASSOCIATED COMPANIES, SEC, FASB

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1. INTRODUCTION

The status of the Group's oil and gas proved reserves position and the changes in the figures from year to year are reviewed regularly by the EP Executive and by the Committee of Managing Directors. The proved reserves status and changes over time are reported in the Parent Company Annual Reports and the United States Securities and Exchange Commission (SEC) "Form 20-F" annual report submission. Production volumes are also disclosed in these reports and in the Quarterly Results Announcement. Further explanation of all figures is also provided in presentations made in meetings with financial analysts.

The accuracy and consistency of the production and reserves figures reported are therefore of significant management concern, not only in their technical evaluation but also in their conformance with applicable regulations and in respect of Group interest under the various corporate arrangements with the EP Operating Companies ("Asset Holders").

The EP Hydrocarbon Resource Coordinator has the responsibility to ensure that reserves reporting guidelines, approval processes and data gathering systems are in place for the collection and disclosure of accurate proved reserves information in a timely manner.

The Group Reserves Auditor has the responsibility to verify that reserves evaluations made for Group annual financial reporting purposes are in conformance with the approved procedures and definitions, and he or she acts independently to provide this assurance to the Reserves Committee and, hence, the EP Executive.

The Reserves Committee takes responsibility for ensuring that the business controls pertaining to proved reserves disclosures are adequate and are being adhered to.

This guide provides a summary of responsibilities and authorities as applied during the administration of returns of hydrocarbon reserves and production, which are subsequently used as the basis for Group reporting. It refers to the relevant statutory rules and to internal Shell documents which guide the application of said rules by Shell EP Asset Holders and in which the procedure for compiling the required figures is described. Taken in total, this documentation, and execution of work activities in conformance with it, is intended to promote consistency in the application of definitions and in the preparation of reports or returns by all parts of the Shell EP organization.

Since information, in particular concerning production, is collected both through the Annual Report of Petroleum Resources (to EPS) and through financial reporting systems (FIRST: to Group Reporting, SI-FCGB, and EPF), it is essential that the technical and finance functions in the regions and Asset Holders fully coordinate and reconcile their figures prior to submission.

Proved reserves disclosures must conform to the rules and regulations set by the SEC. It is therefore important at all stages leading to the disclosure of these figures that roles and responsibilities are agreed and adhered to. This guide is designed to help meet these objectives and to provide a summary of the controls that are in place to assure the accuracy of the Group's proved reserves disclosures.

2. DEFINITIONS AND THEIR APPLICATION

Proved reserves are a constituent part of the total hydrocarbon resources in the Group's portfolio: other categories, which are not yet sufficiently mature as to qualify for disclosure under the SEC rules, are probable reserves, discovered scope for recovery and undiscovered scope for recovery. Definitions of terms relating to all hydrocarbon resource volume categories, including proved reserves, can be found in:

EP yyyy-1100[a]: Petroleum Resource Volume Guidelines
Resource Classification and Value Realisation

The Petroleum Resource Volume Guidelines provide a framework for describing the maturation of hydrocarbon resource volumes with reference to EP business activities such as exploration, appraisal, field development planning, field development and production operations. The guidelines are updated annually, or less frequently when updates are deemed not to be necessary in a particular year. Revisions are required for several reasons, including: to take into account evolving guidance from the SEC on the manner in which its rules should be interpreted; to revise or (more usually) clarify Shell's further interpretation of the SEC rules, and; to reflect changes and clarifications to resource volume category definitions other than proved reserves. Such changes are made only after consultation with senior specialists in the Group. In the case of any changes affecting the Group's proved reserves disclosure, the approval of the Reserves Committee and the EP Chief Executive Officer is required and the matter may be referred further to Group Reporting (SI-FCGB) and/or the Committee of Managing Directors either for information or approval depending on the circumstances of each case.

The Petroleum Resource Volume Guidelines are the standard reference for all Shell EP professionals engaged in the estimation of proved reserves. They are also the standard against which the Group Reserves Auditor conducts (1) periodic audits of the reserves reported by Asset Holders and (2) reviews of the Group's overall annual proved reserves disclosure (see 5 below).

Given the foregoing, only those definitions that are directly applicable to the external disclosure of proved reserves are listed below:

(a) **Proved oil and gas reserves**, and

(b) **Proved developed oil and gas reserves**, and

(c) **Proved undeveloped reserves**

External disclosures of proved reserves must comply with the rules set by the United States Securities and Exchange Commission (SEC), Rule 4-10(a) of Regulation S-X, produced pursuant to the United States Securities Exchange Act of 1934. This is reproduced in Appendix A and it defines all three terms listed above. As mentioned previously, the Petroleum Resource Volume Guidelines (EP yyyy-1100) provides guidance on how the SEC rules are to be interpreted and implemented in estimating the Group's proved reserves.

Note: The SEC rules are based on several Statements of Financial Accounting Standards (FAS) produced by the United States Financial Accounting Standards Board (FASB), notably: FAS19 (1977), FAS25 (1979) and FAS69 (1982).

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[a] All versions retain the same EP reference number ("1100"), prefixed by the year of issue ("yyyy")

(d) Parent companies

There are two Parent Companies: Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company plc. For further information on Parent Companies and other entities described below, please refer to the Manual of Group Financial Accounting Policies, section A.30.

(e) Group (Shell)

The Group is the collection of all companies in which the Parent Companies hold interests, either directly or indirectly. The Group is also referred to as "Shell" herein.

(f) Group companies

For the purposes of external disclosures, Group Companies are companies in which the Parent Companies together have direct or indirect control through a majority of the voting rights, the power to exercise control or the ability to appoint the majority of the management or supervisory boards. Some companies in which the equity interest is greater than 50% are treated, by exception, as Associated Companies.

Where any of the remaining, minority equity share capital is not held by the Shell Parent Companies, this interest is referred to as a "minority interest shareholding". Any significant contribution that minority interest shareholdings make to the total proved reserves of Group Companies must be disclosed in Form 20-F.

(g) Associated companies

For the purposes of external disclosures, Associated Companies are companies in which the Group companies do not have control but in which they have an interest (normally this means up to and including 50% of the voting rights) in the operating and financial decisions of the company. Some companies in which the equity interest is greater than 50% are treated, by exception, as Associated Companies.

(h) Service companies

The main business of Service Companies is to provide advice and services to other Group and associated companies.

(g) Operating companies (Asset Holders)

Operating Companies are engaged in various activities related to oil and natural gas, chemicals, power generation, renewable resources and other businesses throughout the world. Under the EP global organization and for the purposes of this document, EP Operating Companies are referred to as Asset Holders.

(h) Group interest

Group Interest is used to indicate the direct and / or indirect proportionate equity interest held by the Parent Companies in a venture or partnership or company (i.e., after exclusion of minority interest shareholdings in Group Companies and third party interests in Associated Companies).

(i) Group share

Group Share is used to indicate the volumes to which Group and Associated Companies are entitled for proved oil and natural gas reserves and production. Group Share of production is also referred to as "net equity production". Further information on factors to be taken into consideration when calculating the Group Share of proved reserves can be found in the Petroleum Resource Volume Guidelines.

3. PROCEDURES FOR COLLECTING AND REPORTING DATA

3.1 Specific guides

The two key documents to be used by those responsible for estimating and reporting proved reserves data (as well as data on other petroleum resource volume categories) are:

a) **"Petroleum Resource Volume Guidelines: Resource Classification and Value Realisation"** – issued by SIEP-EPS annually, standard reference code EP yyyy-1100, in which "yyyy" denotes the year of issue (e.g. "2002").

This describes the Shell petroleum resource volume classification system and the rules and guidelines that are to be followed in the estimation of all such volumes, including proved reserves.

b) **"Petroleum resource volumes submission requirements for internal and external reporting"** – issued by SIEP-EPS annually, standard reference code EP yyyy-1101, in which "yyyy" denotes the year of issue (e.g. "2002").

This describes the manner and format in which petroleum resource volumes, and in particular changes to said volumes, are to be reported annually by all Asset Holders.

3.2 Main reports in which oil and gas reserves figures are used

a) **EP Reserves and Scope For Recovery**

This is an annual internal publication in which the status of petroleum resource volumes in all categories is summarized at the Asset Holder, region and EP level, with commentaries being provided on reasons for change, trends and comparison of the Group's performance over time with that of its main competitors (in the case of proved reserves).

b) **Annual Report submission to the US Securities and Exchange Commission (SEC, Form 20-F)**

The Group results included in SEC Form 20-F include supplemental information on proved oil and gas reserves. This includes details of proved reserves and proved developed reserves at the start and end of the year, together with an analysis of the changes that occurred during the year. The data are grouped by geographical area and subdivided into Group Companies and Associated Companies (in line with the reporting of certain financial information under these categories elsewhere in the Form 20-F report). Data from the previous two years are also reproduced. These data are prepared by the EP Hydrocarbon Resource Coordinator, are reviewed and verified by the Group Reserves Auditor and the external Group Auditors and are then submitted to Group Reporting (see 5 below).

Form 20-F also includes a report of the **Standardized Measure of Discounted Cash Flow** applicable to the Group's proved reserves, referred to commonly as the "Standardized Measure". This is required under FAS69, in which certain conditions for the calculation are stipulated.

In addition a geographical analysis of net equity production of oil, natural gas liquids and natural gas per annum for the reporting year and in previous years is included. These production data are prepared by Group Reporting from information provided through the Group Financial Information system ("FIRST"). The Group Reserves Auditor verifies the consistency between the production data so reported and that reported separately by the Asset Holders as part of the submission of reserves data.

The supplemental information on proved oil and gas reserves is not audited but is subjected to review procedures to assure compliance with the Petroleum Resource Volume Guidelines and hence the applicable SEC regulations (see 5 below).

c) **Parent Company Annual Report(s)**

The Parent Company Annual Report(s) contains similar information for oil and gas reserves to that provided for SEC Form 20-F.

d) **Quarterly Results Announcement**

Net equity production, analysed by geographical region by quarter, is submitted to Group Reporting by Asset Holders through the Group Financial Information system ("FIRST"). These data are not verified by the Group Reserves Auditor except in the case of the fourth quarter, in which production for the entire year is verified as mentioned in (b) above. Reserves are not disclosed externally except at the end of the year with, or at about the same time as, the fourth quarter results.

e) **Financial and Operating Information**

This report includes similar information to that published in SEC Form 20-F.

3.3 Preparation of reports

Appendix B illustrates schematically the steps leading to the preparation of net equity production figures for inclusion in the various Quarterly and Annual reports listed in section 3.2 above.

Appendix C illustrates schematically the steps leading to the preparation of proved reserves figures for inclusion in the various reports listed in section 3.2 above. The schematic indicates the activity to be carried out, the action parties and comments to aid clarity.

Part 1 of the schematic concerns activities that take place during the course of the reporting year and which focus primarily on the flow of information to the EP Executive on progress with proved reserves changes that are likely to be reflected in disclosures made at the end of the year. During this period there is provision for a challenge session on proved reserves changes that are to be disclosed at each regional level, at which senior technical professionals within each region will review the proposed changes for compliance with the Petroleum Resource Volume Guidelines and, hence, with the SEC rules. There is also provision for two reviews of status by the Reserves Committee – the first taking place in July and the second in October after, and hence benefitting from the recommendations of, the regional challenge sessions. The objective of these reviews is to enable the Reserves Committee (and, where necessary, the EP Executive) to determine or otherwise approve actions to be taken in relation to proved reserves bookings or debookings that are to be reflected in the year-end reports.

Part 2 of the schematic concerns activities that take place after the close of the reporting year. This includes all aspects relating to the collection, quality checking and summarizing of information submitted by the Asset Holders to the EP Hydrocarbon Resource Coordinator. It also includes the review and verification of the proved reserves data by the Group Reserves Auditor and the provision of information to the external Group Auditors. Finally it summarizes the procedures by which Reserves Committee members approve the proved reserves figures for publication.

An approximate timetable for all activities is indicated in Appendix C, a more detailed version of which is produced annually by the EP Hydrocarbon Resource Coordinator in consultation with SIEP-EPF, SI-FCGB (Group Reporting) and SI-PXXC (External Affairs: Annual Report and Form 20-F production).

In support of the preparation of proved reserves disclosures, three additional documents are used purely for internal administrative purposes and they are referred to in Appendix C:

(a) Reserves Reporting Workbook

This is a Microsoft Excel workbook, configured in a standard format for all Asset Holders and designed to capture information on all movements and changes in petroleum resource volumes during each reporting year (calendar year). The workbook is also used to collect Standardized Measure of Discounted Cash Flow data, again on a consistent basis across the whole Group. A workbook, pre-populated with opening balances, is distributed to each Asset Holder by the EP Hydrocarbon Resource Coordinator in Q4 of each year, with returns required by mid-January of the following year. The aggregation of information supplied in this manner constitutes the Group's global database of petroleum resource volumes and forms the basis for, among other things, its external disclosure of proved reserves.

(b) Opportunities Catalogue

A summary of opportunities that have the potential to add significant proved reserves to the inventory is maintained by the EP Hydrocarbon Resource Coordinator and is used as the basis for prioritizing work programmes where appropriate.

(c) Potential Exposure Catalogue

An inventory is maintained by the EP Hydrocarbon Resource Coordinator of proved reserves in the current portfolio that could potentially be at risk. This generally consists of volumes which were booked previously but which may not fulfil the present guidelines (which may have been revised since the bookings were made). Debooking of these volumes is held pending while the results of imminent actions or decisions are awaited, for example appraisal drilling or FID. The catalogue is considered by the Reserves Committee at least twice annually (at the two reviews referred to above), with direction being given as to the continued booking or debooking of reserves as appropriate (also with reference to the views of the Group Reserves Auditor).

4. ANNUAL PRODUCTION VOLUMES

Both reserves and production volumes must be quantified at the same reference conditions for ease of comparison.

For reservoir engineering purposes the measurement of the total physical production withdrawn from the reservoir is required to help estimate the remaining oil and gas reserves. However, in external disclosures and in accordance with Shell's general accounting principles, both reserves and production are specified as products that are available for sale.

Generally, for liquids (oil and natural gas liquids), these two volumes (i.e. those physically produced and those available for sale) are the same. However, frequently for gas (and occasionally for liquids) a portion of the physical production is consumed as fuel ("Own Use"), or is otherwise "lost" through flaring or venting to the environment ("Losses"). Disclosures of production and reserves must take into account volumes consumed in this manner, requiring Asset Holders to maintain parallel data records of the products physically extracted from the reservoir (for use in reservoir engineering analysis) and those either actually sold (production) or expected to be sold (reserves) after making due allowance for Own Use and Losses.

This approach is consistent with the definitions applied for, for example, **Gas Production available for Sales from own reserves (GPafS)**, as applied to Finance reporting and documented in the Group Financial Information Manual (GFIM).

In the past it was standard practice for the Group to report natural gas sales volumes in SEC Form 20-F (and other external disclosures) on a different basis to the production figures listed in the supplemental information concerning proved reserves. The former was quoted at "normal" conditions of temperature and pressure and normalized to a reference calorific value, while the latter was quoted at "standard" conditions and was not normalized for calorific value.

Since 2001, this potentially confusing difference has been removed and all volumes are now quoted as follows:

> Not normalized for calorific value, the volume being expressed either in standard cubic metres (i.e. at 1013 mbar and 15°C) or standard cubic feet (i.e. at 14.65 lbf/in^2 and 60°F/15.6°C).

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5. RESPONSIBILITIES AND AUTHORITIES

5.1 Disclosure of Proved Reserves and Standardized Measure

The estimate of proved reserves and Standardized Measure at year-end is prepared by the Asset Holders in accordance with the Petroleum Resource Volume Guidelines and submitted to the EP Hydrocarbon Resource Coordinator in January of each year. The EP Hydrocarbon Resource Coordinator checks the submissions for quality and consistency with reference to the Petroleum Resource Volume Guidelines before passing the data, plus summaries in the format of the eventual disclosure, to the Group Reserves Auditor for verification.

Disclosures for Shell Canada are finalized by them independently and aggregated with the rest of the Group data by the EP Hydrocarbon Resource Coordinator.

The aggregate SEC Form 20-F oil and gas reserves volume summaries are discussed with the external Group Auditors by the Group Reserves Auditor and the EP Hydrocarbon Resource Coordinator on behalf of the Reserves Committee. The external Group Auditors are KPMG and PriceWaterhouseCoopers.

5.2 Internal Responsibilities and Authorities

Responsibilities for the accurate estimation of proved reserves and production data in line with the Petroleum Resource Volume Guidelines exist at the following generic levels in the EP organization and are described in said guidelines:

- Asset teams
- Region / Asset Holder Hydrocarbon Resource Coordination function
- Region / Asset Holder Technical and Financial Management
- EP Planning (EP Hydrocarbon Resource Coordinator)

The role and responsibility of the EP Hydrocarbon Resource Coordinator in relation to proved reserves disclosures are further elaborated in Appendix D.

Authorities for the approval of the proved reserves and production figures exist at the following generic levels in the EP organization (for simplicity, authorization of production data submitted separately to Group Reporting is omitted):

- Region / Asset Holder Technical and Financial Management
- EP Executive (Chief Financial Officer and Corporate Support Director).

Asset Holder and / or Regional Technical and Financial Managers are required to sign and submit to the EP Hydrocarbon Resource Coordinator paper copies of those parts of the Reserves Reporting Workbook that include information that will be disclosed externally. In so doing, they provide assurance that the information has been prepared in compliance with the Petroleum Reserves Volume Guidelines (EP yyyy-1100 and EP yyyy-1101) and the Group Financial Information Manual (GFIM).

Accountability within EP for the external proved reserves disclosures rests with the EP Executive and specifically with the Chief Financial Officer (EPF) and the Corporate Support Director (EPS). They co-sign "Letters of Comfort" to the external Group Auditors concerning each annual disclosure of proved reserves and the Standardized Measure, examples of which are given in Appendix E.

Disclosure by the Group follows the Group's Disclosure Control Procedures (beyond the scope of this document).

5.3 Reserves Committee

The Reserves Committee consists of the following permanent members:

- EP Chief Financial Officer (EPF)
- EP Corporate Support Director (EPS)
- EP Director Shell Technology (EPT)
- EP Hydrocarbon Resource Coordinator (EPS-P)
- SI Deputy Group Controller (FCG)

In addition, the Group Reserves Auditor attends the Reserves Committee in an advisory role.

The Reserves Committee reports to the EP Chief Executive Officer and the other members of the EP Executive on all procedural matters concerning the disclosure of proved reserves. In this context, its duties include, but are not limited to:

- To understand, challenge and ultimately to authorize on behalf of the EP Chief Executive Officer the proved reserves figures that are disclosed externally, together with any explanation thereof that is to be published.
- At least annually, to review internal procedures (as described herein) and the Petroleum Resource Volume Guidelines with a view to determining the need for revision and to direct such revisions where necessary.
- To coordinate relevant correspondence with the United States Securities and Exchange Commission on behalf of the Group Controller.
- To maintain an interface with the external Group Auditors.
- To monitor action taken by Regions/Asset Holders or by the EP organization as a whole in response to Group Reserves Auditor recommendations and to inform the external Group Auditors accordingly.
- To assist in the resolution of disagreements between authorizers of proved reserves at different levels in the EP organization.

5.4 Audit of Disclosures of SEC Proved Reserves and Standardized Measure

By their nature, all estimates of proved reserves cannot be subjected to audit in the conventional sense that is applied to financial information. However, the annual proved oil and gas reserves and the standardized measure disclosures are subjected to limited review procedures. The review of the Standardized Measure disclosure is conducted by the external Group Auditors. The external Group Auditors also review the proved reserves volume disclosure but rely heavily on a more detailed review that is conducted by the Group Reserves Auditor.

The Group Reserves Auditor also conducts audits of the principal Asset Holders once every three to five years, or more frequently if warranted. This regular cycle is designed to assure that reserves calculations and procedures are being carried out in accordance with the procedures and standards described in the Group Petroleum Resource Volume Guidelines, which also contain Terms of Reference for the audits.

The more general Terms of Reference of the Group Reserves Auditor are elaborated in Appendix F.

5.5 Schedule of Authorities

A Schedule of Authorities is included as Appendix G. This indicates responsibility for the preparation and approval of all the formal documents concerned, plus their main recipients.

No change to the Schedule of Authorities or to the procedures that underpin it may be made without at least the approval of the Reserves Committee, which may refer matters to other EP Executive members, the Group Reserves Auditor, Group Reporting, the Committee of Managing Directors, external Group Auditors or external legal counsel as appropriate.

SEC Rules Concerning Proved Reserves

United States Securities and Exchange Commission (SEC), Rule 4-10(a) of Regulation S-X, produced pursuant to the United States Securities Exchange Act of 1934:

Proved oil and gas reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";

(B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates, for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Schematic of Reporting Procedure: Net Equity Production

Action party	Activity	Comments
1) Quarterly		
Region / Asset Holder Finance Department	Reporting of quarterly net equity production	Provided through FIRST to SI-FCGB (and EPF)
Group Reporting, SI-FCGB	Prepares Summary	Prepares data for Quarterly Results Announcement
EPF	Prepares Summary	Prepares production summary for quarterly EP highlights
Group Investor Relations SI-FI	Quarterly Results Announcement	This announcement includes, by geographical region: a) Quarterly production b) Year-to-date production

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2) Annually

GRA, SI-FCGB, EPF	Reconcile net equity production reported in FIRST with that reported in the annual reserves data submission
Group Reporting, SI-FCGB	Net equity production by country for 'SEC Form 20-F' and 'Financial and Operating Information'

GRA: Group Reserves Auditor

Schematic of Reporting Procedure: Proved Reserves

Part 1: Prior to the end of the Reporting Year

Action party	Activity	Comments
EP Executive December, previous year	Establish target Proved Reserves Additions and target range for the reporting year	
Reserves Committee February	Review of previous year's disclosure process	Determine need for changes to process and / or guidelines. To include consideration of GRA recommendations.
Regions/Asset Holders, HRC Monthly	Maintain Latest Estimate (LE) of Proved Reserves Additions during the reporting year	Via EPMIS. Report to EP Executive monthly.
Reserves Committee, HRC July	Mid-year review: Review LE, Opportunities Catalogue and Potential Exposure Catalogue.	Reserves Committee to specify actions required for year-end reporting. To include GRA comments.
HRC, GRA September, October	Update Petroleum Resource Volume Guidelines (reports EP yyyy-1100 and EP yyyy-1101)	Distributed to all Regions/Asset Holders and made available on the EPS Planning internal website
Regions, HRC, GRA September	Regional Reserves Challenge sessions	Scrutinize proposed new bookings and existing balances for (continued) compliance with guidelines on proved reserves.
HRC October	Distribute pre-populated Reserves Reporting Workbooks to Regions/Asset Holders	
Reserves Committee, HRC October	Q4 Review: Review LE, Opportunities Catalogue, Potential Exposure Catalogue and outcome of Regional Reserves Challenge sessions	Reserves Committee to specify actions required for year-end reporting. To include GRA comments.
HRC October	Advise Regions/Asset Holders of Reserves Committee decisions on proved reserves bookings	
HRC, Regions/Asset Holders December	Agree detailed procedures for implementing Reserves Committee decisions on reserves bookings	

Continued on the following page

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

HRC: EP Hydrocarbon Resource Coordinator GRA: Group Reserves Auditor

Part 2: After the end of the Reporting Year

Continued from the previous page		
Regional management January, weeks 1 & 2	Notification of reserves	Reserves Reporting Workbooks placed on EPS global server or e-mailed to HRC.
HRC, GRA January weeks 2 & 3	Clarify and challenge Region/Asset Holder submissions as required	Verify that changes reported for the year can be supported.
HRC, Regions/Asset Holders January week 3	Resubmissions	If required.
HRC January weeks 3 & 4	Provide summary data to external Group Auditors for review	
HRC, GRA, SI-FCGB January week 4	Agree final production data	Production reported in the Reserves Reporting Workbook must be consistent with FIRST reporting.
HRC, Reserves Committee January week 4	Preliminary report and presentation to EP Executive	Note for Discussion plus presentation. NB: preliminary figures
GRA, external Group Auditors End of January	Agree final proved reserves for external disclosure	
GRA, HRC End of January	Present final reserves to Reserves Committee (and EP Executive if necessary)	Declaration of satisfaction with the figures to be reported at year-end for proved and proved developed reserves. EPS & EPF sign "Letter of Comfort" to external auditors, sent via SI-FCG
HRC on behalf of Reserves Committee, GRA End of January	Reserves Meeting	Report and Presentation of proved reserves information to external Group Auditors and Deputy Group Controller.
HRC, EPS Early February	Final report to EP Executive and CMD on year-end proved reserves	Note for Information plus presentation if required.
HRC, external Group Auditors Early February	Agree final Standardized Measure data for external disclosure	EPS & EPF sign "Letter of Comfort" to external auditors, sent via SI-FCG
HRC Early February	Parent Company Annual Report	Reserves figures passed to SI-FCGB. Including copy of initialled schedules from external Group Auditors.
HRC, EPS End of May	EP Reserves and Scope For Recovery	Reference report describing changes in Group Hydrocarbon Resources during the reporting year.

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

HRC: EP Hydrocarbon Resource Coordinator GRA: Group Reserves Auditor

EP Hydrocarbon Resource Coordinator: Accountabilities

The EP Hydrocarbon Resource Coordinator reports (indirectly) to the Corporate Support Director, EPS. He or she ensures that hydrocarbon resource volume assessment and reporting practices are aligned with the Petroleum Resource Volume Guidelines (EP yyyy-1100) and related documentation (EP yyyy-1101 and EP yyyy-1102), that proved reserves estimates comply with the relevant accounting standards and regulations (i.e. as defined by the SEC), and that future changes in the hydrocarbon resource volumes in each category are estimated commensurate with the requirements of business planning within EP.

Accountabilities (in relation to proved reserves):

(a) Deliver a realistic view of proved reserves additions that can be expected to result from the overall hydrocarbon maturation process as part of, and consistent with, the optimized EP business plan.

(b) Deliver accurate progress reports (based on data supplied via EPMIS) of short-term reserves maturation (proved reserves additions) in close cooperation with regional management and Asset Holder reserves focal points.

(c) Maintain inventories of proved reserves bookings that are potentially under threat (Potential Reserves Exposure Catalogue) and opportunities to add to the proved reserves base (Opportunities Catalogue).

(d) Provide systems that ensure the timely and accurate collection of information on petroleum resource volumes from the Asset Holders.

(e) Compile and submit quality-assured internal and external reserves reports.

(f) Maintain Petroleum Resource Volume Guidelines (EP yyyy-1100) and Submission Requirements (EP yyyy-1101) that are to be used within the Group and which aim to ensure that Shell's practices are aligned with statutory standards, internal needs and industry practice.

(g) Analyse hydrocarbon maturation performance versus target and (perceived) potential, the latter in close cooperation with appropriate technical specialists in the Group.

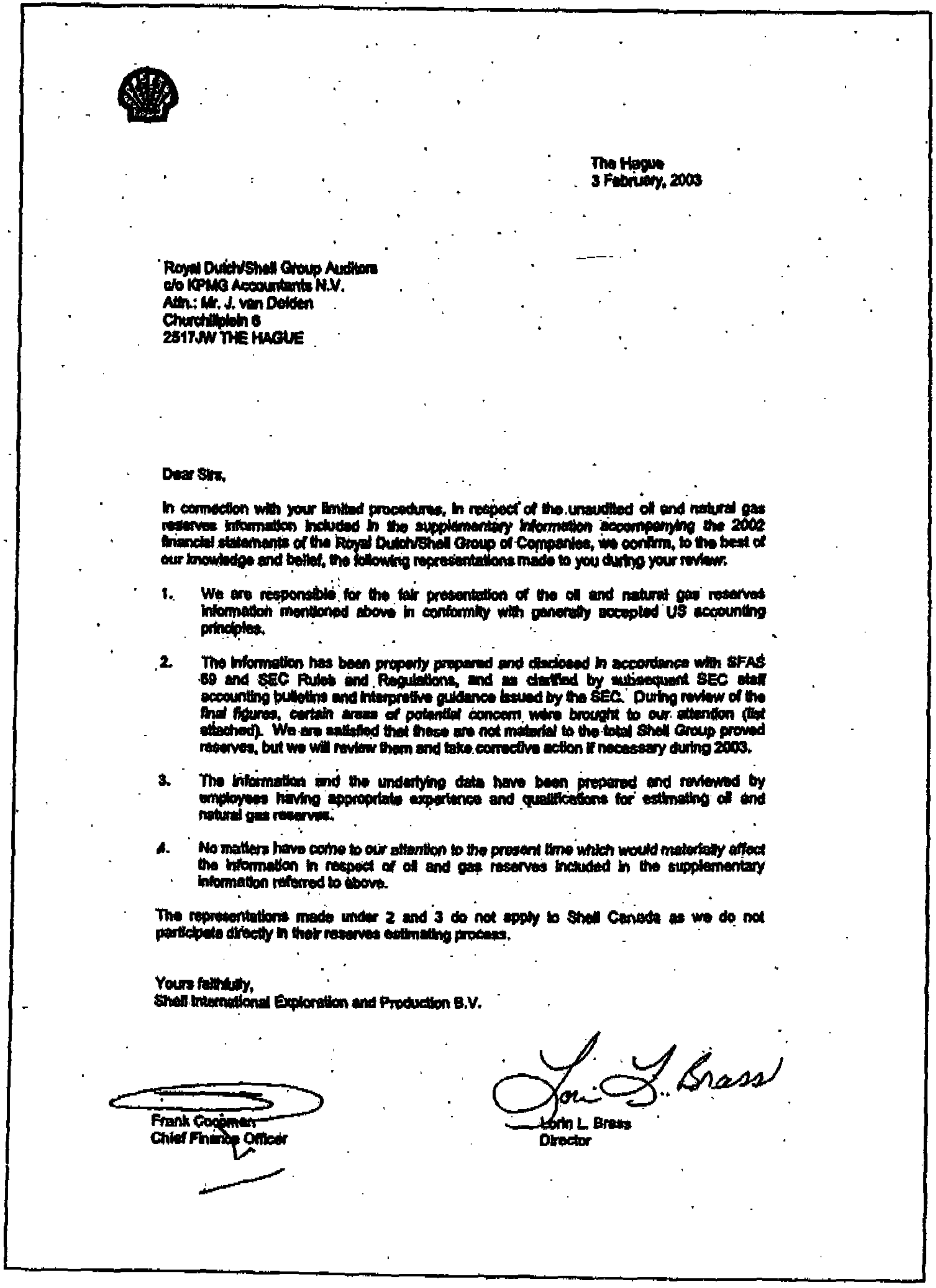
(h) Maintain interfaces with the Group Reserves Auditor, EP management, regional organizations, Asset Holders and Finance. In particular to act as a first point of reference for any topic related to proved reserves that requires consideration, clarification or approval of the appropriate course of action to be taken. This includes the approach to be taken in the reporting of significant proved reserves changes and points of clarification on the interpretation and implementation of the appropriate rules.

(i) Maintain external interfaces with external Group Auditors and the SEC.

(j) Provide *ad hoc* input to Group Control, Investor Relations, Group General Financial Accounting Policies (GFAP) or other internal interfaces as may be required from time to time.

(k) Monitor developments on resource reporting in the industry (SEC, SPE, etc).

Letter of Comfort: Proved Reserves



The Hague
3 February, 2003

Royal Dutch/Shell Group Auditors
c/o KPMG Accountants N.V.
Attn.: Mr. J. van Delden
Churchillplein 6
2517JW THE HAGUE

Dear Sirs,

In connection with your limited procedures, in respect of the unaudited oil and natural gas reserves information included in the *supplementary information* accompanying the 2002 financial statements of the Royal Dutch/Shell Group of Companies, we confirm, to the best of our knowledge and belief, the following representations made to you during your review:

1. We are responsible for the fair presentation of the oil and natural gas reserves information mentioned above in conformity with generally accepted US accounting principles.
2. The information has been *properly prepared* and disclosed in accordance with SFAS 69 and SEC Rules and Regulations, and as clarified by subsequent SEC staff accounting bulletins and interpretive guidance issued by the SEC. During review of the *final figures, certain areas of potential concern* were brought to our attention (list attached). We are satisfied that these are *not material* to the total *Shell Group* proved reserves, but we will review them and take corrective action if necessary during 2003.
3. The information and the underlying data have been prepared and reviewed by employees having appropriate experience and qualifications for estimating oil and natural gas reserves.
4. No matters have come to our *attention* to the *present time which would materially affect* the information in respect of oil and gas reserves included in the supplementary information referred to above.

The representations made under 2 and 3 do not apply to Shell Canada as we do not participate directly in their reserves estimating process.

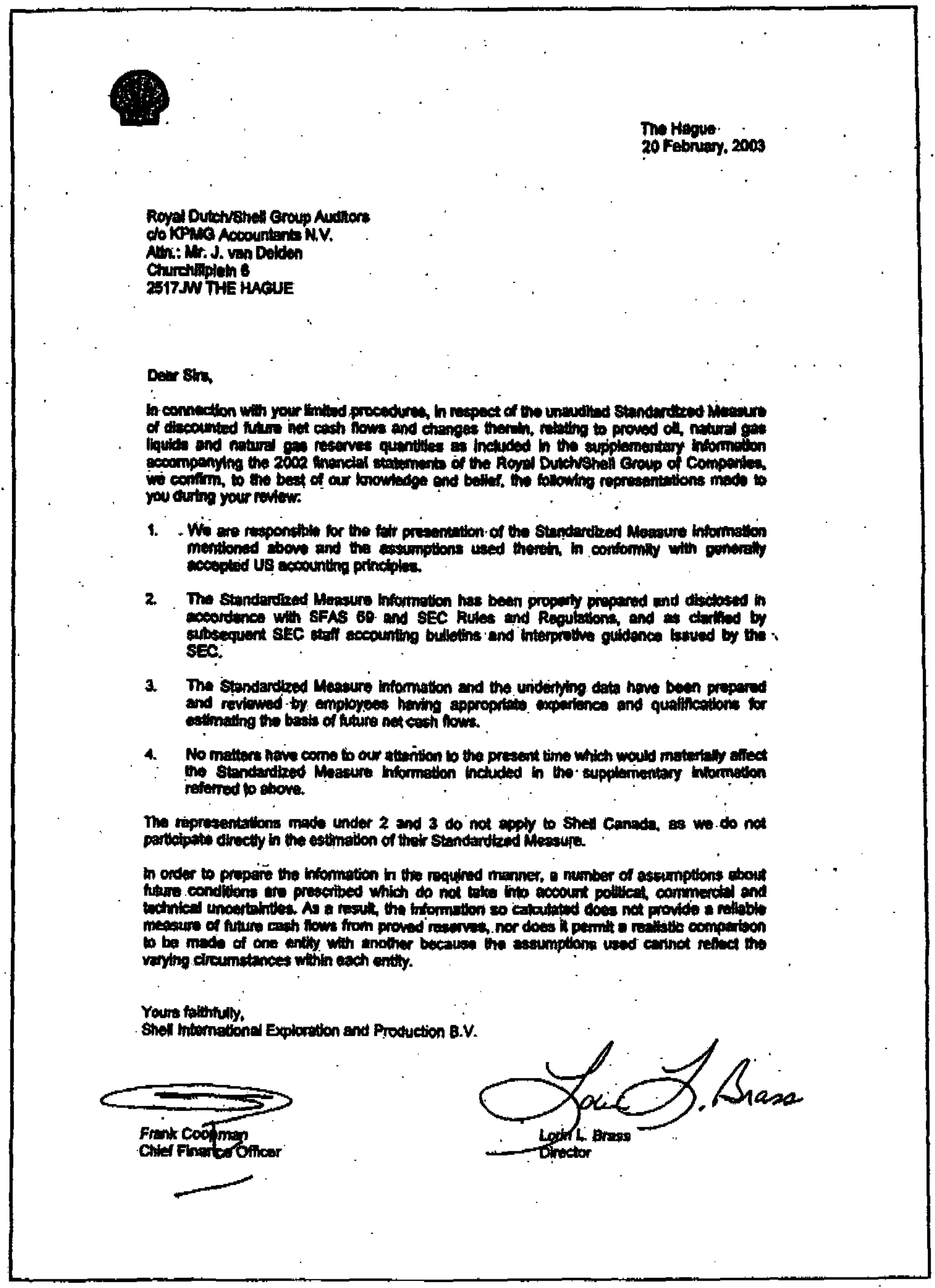
Yours faithfully,
Shell International Exploration and Production B.V.

Frank Coopman
Chief Finance Officer

Lori L. Brass

Lorin L. Brass
Director

Letter of Comfort: Standardized Measure



The Hague
20 February, 2003

Royal Dutch/Shell Group Auditors
c/o KPMG Accountants N.V.
Attn.: Mr. J. van Delden
Churchillplein 6
2517JW THE HAGUE

Dear Sirs,

In connection with your limited procedures, in respect of the unaudited Standardized Measure of discounted future net cash flows and changes therein, relating to proved oil, natural gas liquids and natural gas reserves quantities as included in the supplementary information accompanying the 2002 financial statements of the Royal Dutch/Shell Group of Companies, we confirm, to the best of our knowledge and belief, the following representations made to you during your review:

1. We are responsible for the fair presentation of the Standardized Measure information mentioned above and the assumptions used therein, in conformity with generally accepted US accounting principles.
2. The Standardized Measure information has been properly prepared and disclosed in accordance with SFAS 69 and SEC Rules and Regulations, and as clarified by subsequent SEC staff accounting bulletins and interpretive guidance issued by the SEC.
3. The Standardized Measure information and the underlying data have been prepared and reviewed by employees having appropriate experience and qualifications for estimating the basis of future net cash flows.
4. No matters have come to our attention to the present time which would materially affect the Standardized Measure information included in the supplementary information referred to above.

The representations made under 2 and 3 do not apply to Shell Canada, as we do not participate directly in the estimation of their Standardized Measure.

In order to prepare the information in the required manner, a number of assumptions about future conditions are prescribed which do not take into account political, commercial and technical uncertainties. As a result, the information so calculated does not provide a reliable measure of future cash flows from proved reserves, nor does it permit a realistic comparison to be made of one entity with another because the assumptions used cannot reflect the varying circumstances within each entity.

Yours faithfully,
Shell International Exploration and Production B.V.

Frank Coopman
Chief Financial Officer

Lorin L. Brass
Director

Group Reserves Auditor: Terms of Reference

The Group Reserves Auditor reports directly to the EP Chief Financial Officer (EPF) but acts independently in:

1. The auditing of submitted Proved Reserves of Regions/Asset Holders by visits to those units.

   The Reserve Audits verify that all the required processes are in place and adhered to which ensure that the reported Group share Proved Reserves are estimated in accordance with the most recent version of the Group Petroleum Resource Volume Guidelines. The audits address the Technical Maturity, the Commercial Maturity and the 'Reasonable Certainty' of the reported reserves and also verify that the Group share calculation and the consistency with Finance reporting are in order and that appropriate audit trails are in place.

   A report is prepared for each Reserves Audit that is addressed to the Chief Executive of the Region/Asset Holder concerned, to the EP Chief Financial Officer (EPF), to the EP Corporate Support Director (EPS) and to the external Group Auditors. Copies are sent to selected individuals in the Region/Asset Holder, the EP Internal Audit function, and the Hydrocarbon Resource Coordination function in EPS and to the external Group Auditors. A summary of the year's audit findings is included in the end-year Group Reserves Auditor report.

   The Reserve Audits form part of an annually agreed plan, aiming at an audit frequency of one audit every four years for each Asset Holder. Terms of Reference for these audits are to be found in the Group Petroleum Resource Volume Guidelines (EP *yyyy*-1100).

   Due to local restrictions, the Group Reserves Auditor does not audit the resources reported by Shell Canada.

2. Witnessing and verifying the accumulation of the Group's Proved Reserves at the end of each year for inclusion into the Group Annual Reports and the SEC Form 20-F report on the basis of information supplied by Regions/Asset Holders.

   In this task the assembled data as received are audited in cooperation with representatives of KPMG Accountants (as external Group Auditors). Changes compared with the previous year are reviewed and their reasonableness is assessed on the basis of the information available. Where necessary, additional information is requested from the Region/Asset Holder concerned.

   Production volumes for the reporting year are compared for consistency with data supplied via the Group financial information system (FIRST) to Group Reporting.

   At the end of this process a Reserves Auditor Report with Auditor findings is written to the external Group Auditors, the EP Chief Financial Officer (EPF) and the EP Corporate Support Director (EPS). It is copied to the EP Chief Executive. The Chief Financial Officer and Corporate Support Director thereupon release the 'The Letter of Comfort', addressed to the external Group Auditors (KPMG and PWC). In addition KPMG Accountants issue a note with Supplementary Information to the Group Auditors (PWC).

   The Reserves Auditor Report is also presented and discussed in a meeting between Group Auditors (KPMG, PWC), The Deputy Group Controller (SI-FCG), representatives from SIEP Corporate Support / Hydrocarbon Resource Coordination and the Group Reserves Auditor at the end of January.

3. The provision of general advice with respect to Petroleum Resource Volume Guidelines and Procedures.

   Petroleum Resource Volume Guidelines are in principle reviewed and, where necessary, updated annually by the EP Hydrocarbon Resource Coordination function. The Group Reserves Auditor will provide advice regarding the changes proposed. He or she may also be called upon to provide other advice regarding issues that may arise from time to time with respect to Reserves reporting methods and procedures.

Schedule of Authorities: Proved Reserves and Standardized Measure

Based on EP 86-0725 (1986), updated 1996, 2002 and 2003

	Title of document or activity	Responsible for Preparation	Responsible for Approval	Final submission for use to
1	Proved Reserves Replacement Target Setting	HRC	EP Executive	EP Regions /Asset Holders
2	Reserves Audit Reports (Region / Asset Holder audits)	GRA		EPS, EPF, Regions, Asset Holders
3	Resource Management and Reporting Guidelines			
	a) Process, responsibilities, definitions, requirements	HRC, GRA	Reserves Committee	Asset Holders
	b) Technical methodologies	EPT/T&OE	EPT/T&OE	Asset Holders
	c) Matters relating to proved and proved developed reserves estimating procedures	GRA, HRC	Reserves Committee	SI-FCGB and Asset Holders
4	Annual reserves return from Regions/Asset Holders	Region/AH Technical &Finance functions	Region Technical and Financial Management	GRA, HRC
5	Audit trail in support of annual reserves return from Asset Holder.	Asset Holder Senior RE	Region / Asset Holder PE Manager (or equiv't)	Region /AH Technical Management
6	Preliminary report on year-end proved reserves to EP Executive	HRC	Reserves Committee	EP Executive
7	Reserves Auditor Report	GRA		Reserves Committee
8	Standardized Measure Report			
	- Region / Asset Holder annual submission (together with proved reserves – see (4) above)	Region/AH Technical &Finance functions	Region Technical and Financial Management	HRC
	- Group submission to SEC Form 20-F	HRC	EPS, EPF	SI-FCGB
9	Proved reserves & Standardized Measure "Letters of Comfort" to external Group Auditors.	GRA	EPS, EPF	Group Auditors
10	Statement of crude oil and natural gas reserves for inclusion in Annual Report submission to the US Securities and Exchange Commission (Form 20-F) and other Parent Company publicly disclosed reports.	HRC	Reserves Committee	SI-FCGB

HRC: EP Hydrocarbon Resource Coordinator GRA: Group Reserves Auditor AH: Asset Holder

O. Christie

DRAFT NOTE – 19 Oct 2000 COPY **CONFIDENTIAL**

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

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

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

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 99-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The last previous SEC proved reserves audit for SDA was carried out in 1996. The audit took the form of technical discussions with staff from Woodside Energy Ltd (the operator for a large part of the assets with SDA interest) and detailed discussions about the reserves reporting process with SDA staff.

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

The audit commended the high quality technical work that had been carried out by Woodside, particularly in assessing the subsurface uncertainties and in evaluating the ranges of in-place and reserves estimates. Intensive SIEP assistance through VAR- and other reviews was noted. Maintaining the preliminarily booked volume of Gorgon gas reserves (first done at 1.1.1999) was supported on the grounds that a gas market was highly likely to be established in due course and that it must be considered likely that an extension of the current 5-year Retention Lease will be granted in 2002. Proved reserves in some mature fields (N-Rankin, Goodwyn and the four oil fields) should be increased to expectation levels, in line with the guidelines. This could increase Group entitlement by some 12 mln m3oe. Concern was expressed about the lack of a concisely documented audit trail, which hampered a proper assessment of the reasons for the end-1999 reserves changes.

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

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

A.A. Barendregt

DEPOSITION EXHIBIT
Barendregt
#11 2/20/07

Attachments 1, 2, 3

Attachment 1

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

MAIN OBSERVATIONS

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

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

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

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

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

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

5. One of the requirements of a reserve audit is that OU Group share submissions can be reconciled with reserves volumes and changes in individual fields. The audit should also establish that Group share reserves changes have been reported in the correct category (revisions, field extensions and discoveries, purchases / sales in place etc.). This process was greatly hampered by the lack of a concise audit note, with full detail at field level and by the lack of a proper record of 1999 produced volumes by individual fields. As a result, only a very partial match could be obtained with individual field volumes and changes as reported by Woodside and Chevron, see Attachments 2.1-2.4. In particular, no explanation could be found for the sizeable reduction in proved total gas reserves during 1999 (causing an alarming reserves replacement ratio of –340%!).

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

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

submission with average Gorgon and NWS GHVs, but no match could be obtained (Att. 2.4). This problem will disappear in the end-2000 cycle when reporting in Nm3 will no longer be required.

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

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

Electronic transmission [illegible] directly into the [illegible]

Recommendations

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

Attachment 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved Oil / NGL / Gas Reserves as at 31.12.99

Area / field	Proven HIP MMstb / Bscf	Exp'n HIP MMstb / Bscf	Cum. Prod = Sales 31.12.99 MMstb / Bscf	Proved Rem. Recov. Dev. MMstb / Bscf	Proved Rem. Recov. Tot'l MMstb / Bscf	Exp'n Rem. Recov. Tot'l MMstb / Bscf	Maturity (Cum.pr / Exp'n UR) %	Dev. / Tot'l Proved UR. %	Proved RF Tot'l %	Exp'n RF Tot'l %	Fract'n wi lic. & comtd Pr.Dev. %	Fract'n wi lic. & comtd Pr.Tot'l %	Within Licence & comtd Pr.Dev. MMstb / Bscf	Within Licence & comtd Pr.Tot'l MMstb / Bscf	Venture Shell share % %	Shell Equity Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Tot'l 10^6 sm3/ 10^9 sm3	1999 Subm'n Dev 10^6 sm3/ 10^9 sm3	1999 Subm'n Tot'l 10^6 sm3/ 10^9 sm3
Oil																			
Wanaea	283.30	340.30	43.80	96.20	104.80	141.10	23.7%	94.2%	52.5%	54.3%	100.0%	100.0%	97.20	104.80	16.67%	2.58	2.78		
Cossack	76.60	120.10	34.20	14.20	14.20	37.60	47.6%	100.0%	63.2%	59.8%	100.0%	100.0%	14.20	14.20	16.67%	0.38	0.38		
Lambert	55.60	74.50	1.10	14.50	22.30	32.10	3.3%	65.7%	42.1%	44.6%	100.0%	100.0%	14.50	22.30	16.67%	0.38	0.59		
Hermes	22.10	28.10	7.70	1.80	3.00	5.60	57.9%	88.8%	48.4%	47.3%	100.0%	100.0%	1.80	3.00	16.67%	0.05	0.08		
Egret	18.60	37.60			6.00	13.10	0.0%	0.0%	32.3%	34.8%	100.0%	100.0%	0.00	6.00	16.67%	0.00	0.16		
Laminaria	162.30	204.00	3.00	85.60	95.60	126.90	2.3%	89.9%	60.8%	63.7%	100.0%	100.0%	85.60	95.60	25.00%	3.40	3.80		
Coralina	71.50	97.00	0.70	37.60	38.40	55.20	1.3%	98.0%	54.7%	57.6%	100.0%	100.0%	37.60	38.40	25.00%	1.49	1.53		
Barrow Island (WAPET)	1353.61	1353.61	284.85	51.70	51.70	77.70	78.6%	100.0%	24.9%	26.8%	55.8%	55.8%	28.86	28.86	28.57%	1.31	1.31		
Thevenard Island (WAPET)	282.91	282.91	134.45	23.97	23.97	33.95	79.8%	100.0%	56.0%	59.5%	100.0%	100.0%	23.97	23.97	35.71%	1.36	1.36		
NWS + WAPET Oil - SDA 'direct' share																10.95	11.98	11.64	12.63
Wan., Coss., Lamb., Herm., Egret (W=16.67%)													127.70	150.30	5.71%	1.16	1.36		
Lamainaria, Coralina (Woods = 50%)													123.20	134.00	17.14%	3.36	3.65		
SDA 'indirect' 34.27% share in Woodside																4.52	5.02	4.28	5.44
Total Oil (MMstb)	2326.52	2538.12	509.80	325.57	359.97	523.25							303.73	337.13	31.7%	15.47	17.00	15.92	18.07
NGL																			
North Rankin	313.50	347.30	127.80	15.00	68.20	89.40	58.8%	72.9%	62.5%	62.5%	100.0%	100.0%	15.00	68.20	15.66%	0.37	1.70		
Perseus	308.30	377.80	18.20	22.10	164.70	215.40	7.8%	22.0%	59.3%	61.8%	100.0%	100.0%	22.10	164.70	15.66%	0.58	4.10		
Goodwyn	530.76	629.70	117.10	84.50	194.00	251.10	31.8%	84.8%	58.6%	58.5%	100.0%	100.0%	84.50	194.00	15.66%	2.10	4.83		
Angel	129.90	165.30			65.80	87.00	0.0%	0.0%	50.7%	52.6%	100.0%	100.0%	0.00	65.80	15.66%	0.00	1.64		
Other NWS gas + oil fields	261.00	396.30	2.10	3.70	103.20	152.90	1.4%	5.5%	40.3%	39.1%	100.0%	100.0%	3.70	103.20	15.66%	0.09	2.57		
Gorgon field (WAPET)	170.00	210.40			110.69	131.30	0.0%	0.0%	65.1%	52.4%	100.0%	100.0%	0.00	110.69	28.57%	0.00	5.03		
Chrysaor, W-Trial Rocks (WAPET)	69.00	90.00				53.00	0.0%	0	0.0%	58.9%	100.0%	100.0%	0.00	0.00	28.57%	0.00	0.00		
Total SDA 'direct' share																3.12	19.87	3.12	19.86
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)													125.30	595.90	6.76%	1.35	6.41	1.35	6.41
Total NGL (MMstb)	1762.40	2216.80	265.20	125.30	706.59	980.10							125.30	706.59	23.39%	4.47	26.28	4.47	26.27
Gas (Dry, sales gas volumes)																			
North Rankin	11620.00	12190.00	4200.00	1730.00	6180.00	6810.00	38.1%	57.1%	89.3%	90.3%	96.3%	96.3%	1665.99	5951.34	15.64%	7.374	28.341		
Perseus	8770.00	10680.00	500.00	930.00	7010.00	8830.00	5.4%	19.0%	85.6%	87.4%	96.3%	96.3%	895.69	6750.63	15.64%	3.964	29.879		
Goodwyn	7040.00	8390.00	660.00	1610.00	4330.00	5420.00	10.9%	45.5%	70.9%	72.5%	96.3%	96.3%	1550.43	4169.79	15.64%	6.862	18.456		
Angel	2270.00	2790.00			1390.00	1770.00	0.0%	0.0%	61.2%	63.4%	96.3%	96.3%	0.00	1338.57	15.64%	0.000	5.925		
Other NWS gas + oil fields	4440.00	6360.00	40.00	130.00	2360.00	3410.00	1.2%	7.1%	54.1%	54.2%	96.3%	96.3%	125.19	2272.68	15.64%	0.554	10.059		
Gorgon field (WAPET)	20936.86	24828.94			10650.00	15200.00	0.0%	0.0%	50.9%	61.2%	100.0%	100.0%	0.00	10650.00	28.57%	0.000	86.113		
Chrysaor, W-Trial Rocks (WAPET)	4550.98	7343.34				3300.00	0.0%	0	0.0%	44.9%	100.0%	100.0%	0.00	0.00	28.57%	0.000	0.000		
Thevenard Island	163.00	163.00	70.00	33.00	39.00	55.00	56.0%	94.5%	65.9%	76.7%	100.0%	100.0%	33.00	39.00	35.71%	0.333	0.394		
Total SDA 'direct' share																19.088	177.167	18.583	178.638
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)													4237.20	20483.01	6.98%	8.371	40.466	8.147	40.205
Total Gas (Bscf)	59790.85	72745.28	5470.00	4433.00	31959.00	44795.00	10.9%	28.5%	62.6%	69.1%			4270.20	31172.01	24.7%	27.459	217.633	26.730	218.843

Conversion factors used by SDA.
1 stb = 0.158 m3
1scf = 0.0283 sm3

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

Licence expiry dates:

Audit Trail:

Oil: SDA submission not corrected for beyond-licence oil from Barrow Island;. Minor error in Woodside share % in Laminaria (double correction for unitisation share)
NGL: Good match
Gas: Fractions 'wi licence & comtd' reflect 3.7% correction for future upstream fuel and flare.

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Attachment 2.2

Proved Oil Reserves Changes 1999 (100%, MMstb)

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Dev'd Reserves	Product'n = Sales 1999	Prov.Res 31.12.99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^6 m3)	Net Shell Equity 1.1.2000 (10^6 m3)	Comments
Proved Developed Reserves															
Wanaea									97.20	16.67%	16.67%	16.67%	0.00	2.58	
Cossack									14.20	16.67%	16.67%	16.67%	0.00	0.38	
Lambert									14.50	16.67%	16.67%	16.67%	0.00	0.38	
Hermes									1.80	16.67%	16.67%	16.67%	0.00	0.05	
Egret									0.00	16.67%	16.67%	16.67%	0.00	0.00	
Laminaria							85.60		85.60	25.00%	25.00%	25.00%	0.00	3.40	Laminaria ?coralina new developed
Corallina							37.80		37.80	25.00%	25.00%	25.00%	0.00	1.49	
Legendre sold to Woodside						25.90				19.00%	19.00%	19.00%	0.00	0.00	Legendre sold to Woodside
Barrow Island (WAPET)									28.86	28.57%	28.57%	28.57%	0.00	1.31	
Thevenard Island (WAPET)									23.97	35.71%	35.71%	35.71%	0.00	1.36	
NWS + WAPET Oil - SDA 'direct' share															
Legendre sold to Woodside					25.90					9.22%	9.22%	9.22%	0.00	0.00	Legendre sold to Woodside
Wan., Coss., Lamb., Herm., Egret (W=16.67%)									127.70	5.71%	5.71%	5.71%	0.00	1.16	
Lamainaria, Coralline (Woods = 50%)							123.40		123.20	17.14%	17.14%	17.14%	0.00	.3.36	
SDA 'indirect' 34.27% share in Woodside															
Prov.Dev.Resvs (MMstb)	0.00	0.00 307.83	0.00	0.00	25.90	25.90	248.80	0.00	554.63				0.00	15.47	
Proved Total Reserves															
Wanaea									104.60	16.67%	16.67%	16.67%	0.00	2.78	
Cossack									14.20	16.67%	16.67%	16.67%	0.00	0.38	
Lambert									22.30	16.67%	16.67%	16.67%	0.00	0.59	
Hermes									3.00	16.67%	16.67%	16.67%	0.00	0.08	
Egret				6.00					6.00	16.67%	16.67%	16.67%	0.00	0.16	Egret booked first time
Laminaria									95.60	25.00%	25.00%	25.00%	0.00	3.80	
Corallina									38.40	25.00%	25.00%	25.00%	0.00	1.53	
Legendre sold to Woodside						25.90				19.00%	19.00%	19.00%	0.00	0.00	Legendre sold to Woodside
Barrow Island (WAPET)									28.88	28.57%	28.57%	28.57%	0.00	1.31	
Thevenard Island (WAPET)									23.97	35.71%	35.71%	35.71%	0.00	1.38	
NWS + WAPET Oil - SDA 'direct' share															
Legendre sold to Woodside					25.90					9.22%	9.22%	9.22%	0.00	0.00	
Wan., Coss., Lamb., Herm., Egret (W=16.67%)				6.00					150.30	5.71%	5.71%	5.71%	0.00	1.38	Egret booked for first time
Lamainaria, Coralline (Woods = 50%)									134.00	17.14%	17.14%	17.14%	0.00	3.85	
SDA 'indirect' 34.27% share in Woodside															
Tot'l Prov.Res (MMstb)	0.00	0.00 609.43	0.00	12.00	25.90	25.90		0.00	621.43				0.00	17.00	
Net Group Equity															
Prov.Dev. Res	0.00	7.60	0.00	0.00	0.38	0.78	8.27	0.00	15.47						
Prov Tot'l Res	0.00	17.19	0.00	0.21	0.38	0.78		0.00	17.00						
10^6 m3															
1999 Submission															
Prov.Dev.Res	7.83	:1.45					8.03	1.38	15.92	15.92					
Prov.Tot'l Res	18.73	:0.92		:0.21	0.38	0.78		1.39	18.07	18.07					
10^6 m3															

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

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

Audit Trail:

Main changes:
Legendre sold to Woodside (resulting in change of SDA share % from 'direct' to 'indirect')
Laminaria/Corallina new developed during 1999
Egret booked for first time

General: 1.1.1999 field data and individual 1999 field productions not available.
Laminaria/Corallina new developed reserves do not fully match submission

FOIA Confidential Treatment Requested

Attachment 2.3

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved NGL Reserves Changes 1999 (100%, MMstb)

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Product'n = Sales 1999	Prov.Res 31.12.99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^6 m3)	Net Shell Equity 1.1.2000 (10^6 m3)	Comments
Proved Developed Reserves															
North Rankin									15.00	15.66%	15.66%	15.66%	0.00	0.37	
Perseus									22.10	15.66%	15.66%	15.66%	0.00	0.55	
Goodwyn									84.50	15.66%	15.66%	15.66%	0.00	2.10	
Angel									0.00	15.66%	15.66%	15.66%	0.00	0.00	
Other NWS gas + oil fields									3.70	15.66%	15.66%	15.66%	0.00	0.09	
Gorgon field (WAPET)									0.00	28.57%	28.57%	28.57%	0.00	0.00	
Chrysaor, W-Trial Rocks (WAPET)									0.00	28.57%	28.57%	28.57%	0.00	0.00	
Total SDA 'direct' share															
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)									125.30	6.76%	6.76%	6.76%	0.00	1.35	
Prov.Dev.Resvs (MMstb)	0.00	0.00 - 250.60	0.00	0.00	0.00	0.00	0.00	0.00	250.60	0	0	11.21%	0.00	4.47	
Proved Total Reserves															
North Rankin									66.20	15.66%	15.66%	15.66%	0.00	1.70	
Perseus									164.70	15.66%	15.66%	15.66%	0.00	4.10	
Goodwyn									194.00	15.66%	15.66%	15.66%	0.00	4.83	
Angel									65.60	15.66%	15.66%	15.66%	0.00	1.64	
Other NWS gas + oil fields									103.20	15.66%	15.66%	15.66%	0.00	2.57	
Gorgon field (WAPET)									110.69	28.57%	28.57%	28.57%	0.00	5.03	
Chrysacr, W-Trial Rocks (WAPET)									0.00	28.57%	28.57%	28.57%	0.00	0.00	
Total SDA 'direct' share															
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)									595.90	6.76%	6.76%	6.76%	0.00	6.41	
Tot'l Prov.Res (MMstb)	0.00	0:00 1302.49	0.00	0.00	0.00	0.00		0.00	1302.49	0	0	12.69%	0.00	26.28	

Net Group Equity										
Prov.Dev. Res	0.00	4.47	0.00	0.00	0.00	0.00	0.00	0.00	4.47	
Prov Tot'l Res	0,00	26.28	0.00	0.00	0.00	0.00		0.00	26.28	
10^6 m3										
1999 Submission										
Prov.Dev.Res	9.64	-3.79						1.38	4.47	4.47
Prov.Tot'l Res	24.75	2.90						1.38	26.27	28.27
10^6 m3										

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

Audit Trail: **General: 1.1.1999 field data and individual 1999 field productions not available. Match incomplete; Overall auditability of changes poor.**

Attachment 2.4

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Gas Reserves Changes 1999 (100%, Bscf) - Dry sales gas volumes

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Develd Reserves	Productn = Sales 1999	Prov.Res 31.12.98	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^9 sm3)	Net Shell Equity 1.1.2000 (10^9 sm3)	GHV (Btu/scf)	Net Shell Equity 1.1.1999 (10^9 Nm3)	Net Shell Equity 1.1.2000 (10^9 Nm3)	Comments
Proved Developed Reserves																		
North Rankin									1665.990	15.64%	15.64%	15.64%	0.000	7.374	1055	0.000	7.287	
Perseus									895.590	15.64%	15.64%	15.64%	0.000	3.964	1055	0.000	3.918	
Goodwyn									1560.430	15.64%	15.64%	15.64%	0.000	6.862	1055	0.000	6.782	
Angel									0.000	15.64%	15.64%	15.64%	0.000	0.000	1055	0.000	0.000	
Other NWS gas + oil fields									125.190	15.64%	15.64%	15.64%	0.000	0.554	1055	0.000	0.548	
Gorgon field (WAPET)									0.000	28.57%	28.57%	28.57%	0.000	0.000	1073	0.000	0.000	
Chrysaor, W-Trial Rocks (WAPET)									0.000	28.57%	28.57%	28.57%	0.000	0.000	1073	0.000	0.000	
Thevenard Island									33.000	35.71%	35.71%	35.71%	0.000	0.333	1124	0.000	0.351	
Total SDA 'direct' share																		
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)									4237.200	6.98%	6.98%	6.98%	0.000	8.371	1055	0.000	8.273	
Prov.Dev.Resvs (Bscf)	0.000	0.000 8507.400	0.000	0.000	0.000	0.000	0.000	0.000	8507.400	0	0	0.00%	0.000	27.459	1056	0.000	27.158	
Proved Total Reserves																		
North Rankin									5951.340	15.64%	15.64%	15.64%	0.000	26.341	1055	0.000	26.032	
Perseus									6750.630	15.64%	15.64%	15.64%	0.000	29.879	1055	0.000	29.529	
Goodwyn									4169.790	15.64%	15.64%	15.64%	0.000	18.456	1055	0.000	18.240	
Angel									1338.570	15.64%	15.64%	15.64%	0.000	5.925	1055	0.000	5.855	
Other NWS gas + oil fields									2272.680	15.64%	15.64%	15.64%	0.000	10.059	1055	0.000	9.941	
Gorgon field (WAPET)									10650.000	28.57%	28.57%	28.57%	0.000	86.113	1073	0.000	86.555	
Chrysaor, W-Trial Rocks (WAPET)									0.000	28.57%	28.57%	28.57%	0.000	0.000	1073	0.000	0.000	
Thevenard Island									39.000	35.71%	35.71%	35.71%	0.000	0.394	1124	0.000	0.415	
Total SDA 'direct' share																		
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)									20483.010	6.98%	6.98%	6.98%	0.000	40.466	1055	0.000	39.991	
Tot'l Prov.Res (Bscf)	0.000	0.000 51655.020	0.000	0.000	0.000	0.000		0.000	51655.020	0	0	0.00%	0.000	217.633	1062	0.000	216.558	

Net Group Equity										
Prov.Dev. Res	27.459	27.459	0.000	0.000	0.000	0.000	0.000	0.000	27.459	
Prov Tot'l Res	217.633	217.633	0.000	0.000	0.000	0.000		0.000	217.633	
10^9 sm3										
1999 Submission										
Prov.Dev.Res	81.599	-31.136						3.733	26.730	26.730
Prov.Tot'l Res	229.560	-8.984						3.733	216.843	216.843
10^9 sm3										
Net Group Equity										
Prov.Dev. Res	27.158	27.158	0.000	0.000	0.000	0.000	0.000	0.000	27.158	
Prov Tot'l Res	216.558	216.558	0.000	0.000	0.000	0.000		0.000	216.558	
10^9 Nm3 @ 9500 kCal/Nm3										
1999 Submission										
Prov.Dev.Res	63.444	-29.874						4.064	29.406	29.406
Prov.Tot'l Res	233.887	-1.374						4.064	228.249	228.249
10^9 Nm3 @ 9500 kCal/Nm3										

Conversion factors used by SDA
1 stb = 0.159 m3
1 scf = 0.0283 sm3
1 sm3 = 0.948 Nm3
and 1 sm3 = 1.0526 Nm3@9500
(i.e. avge GHV = 10546 kcal/Nm3
or 1123.7 Btu/scf
or 44.16 MJ/Nm3
cf avg GHV of 1062.2 kcal/Nm3 from above columns

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.02834 sm3
1 sm3 = 0.948 Nm3
and 1 sm3 = 0.948 Nm3 @ 9500
(if GHV = 9500 kcal/Nm3
or 1012.0 Btu/scf
or 39.77 MJ/Nm3

Audit Trail:
1.1.1999 field data and individual 1999 field productions not available.
Match incomplete;
Reduction in developed reserves due to correction for
(as yet undeveloped) reserves attributable to compression
No individual field GHV data available, hence Nm3 volumes not verifiable.
Overall auditability of changes poor

SDA, Oct 2000 **CHECKLIST SEC RESERVES AUDITS** **Attachment 3**

COMPANY: SHELL DEVELOPMENT AUSTRALIA LTD **AREA / FIELD: ALL**

Dimensions (100% field figures as at 1.1.2000): **Average Group share: 25 - 37%**

1.1.2000 Proved Oil Reserves	45	10^6 m3	(Group share 18 10^6 m3)
1.1.2000 Proved Developed Oil Reserves	40	10^6 m3	(Group share 16 10^6 m3)
1999 Oil Production	6	10^6 m3	(Group share 1.4 10^6 m3)
	16	10^3 m3/d	(Group share 3.8 10^3 m3/d)
1.1.2000 Proved Gas Reserves	900	10^9 sm3	(Group share 216 10^9 sm3)
1.1.2000 Proved Developed Gas Reserves	124	10^9 sm3	(Group share 27 10^9 sm3)
1999 Gas Production	16	10^9 sm3	(Group share 4.1 10^9 sm3)
	45	10^6 sm3/d	(Group share 11 10^6 sm3/d)
Number of fields in area	20		
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 has been shot and interpreted over all the fields
1.02	Are seismic processing and interpretation state-of-the-art?	+	Although much of the seismic vintage is from the early 1990's, re-processing and re-interpretation using the latest techniques is gradually being introduced (eg Lambert/Hermes, Laminaria)
1.03	Is well log data quantity and quality adequate?	+	Extensive log and core data have been gathered in appraisal wells and in development wells as appropriate.
1.04	Is well data coverage adequate?	+	Certainly in developed fields; Subsurface uncertainties are properly accounted for in undeveloped fields and proved reserves are in principle not booked until data coverage is adequate.
1.05	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Proved reserves are not booked until well data coverage is adequate.
1.06	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Yes, most notably in Gorgon
1.07	Is there a proper volumetric estimate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.08	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	Yes, extensive PVT analyses are standard practice and these are properly reflected in static and dynamic models.
1.09	Is a static model available / adequate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.10	Is a dynamic model available / adequate?	+	Yes, detailed dynamic models (downloaded from static models) are available for all fields with proved reserves.
1.11	Is a history match available / adequate?	+	History matches, to the extent that there is sufficient production history, are good and are kept up-to-date on a regular basis.
1.12	Is the recovery factor for proved reserves realistic?	+	Yes, the RFs fully reflect the range of possible subsurface realisations and possible development scenarios.
1.13	Are developed reserves based on proper NFA (No Further Activity) forecasts?	+	Yes; dedicated NFA dynamic model runs are made, incorporating existing facilities' constraints, as relevant.
1.14	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. A proper correction was made at 1.1.2000 to reflect the as yet undeveloped state of gas reserves obtainable through compression.
1.15	Has/have (a) development project(s) been defined for undeveloped reserves or can it/they be defined?	+	Yes
1.16	Is/are the project(s) technically mature or is further data gathering necessary?	+	Those projects pertaining to proved reserves are mature, with the possible exception of Egret, where the low reserves estimate does not appear to pass screening criteria. In the large Gorgon gas field, there is also a technically (and economically) robust development plan.
1.17	Is/are there (an) auditable development project plan(s) with costs, benefits and economics?	+	Yes
1.18	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	N.A.	Apart from ongoing gas recycling in Goodwyn and some LPG/gas injection in Laminaria/Corallina, there are no improved recovery projects planned.
1.19	Has the project been subjected to a VAR review or other external review and if so, what have been the main conclusions?	+	All projects in which SDA have an interest are subjected to regular peer reviews and VAR reviews with SIEP-EPT assistance. In particular the SIEP assistance to Woodside can be classified as intensive.
2	**COMMERCIAL MATURITY**		
2.01	Is/are the project(s) commercially mature (positive NPV for Group Ref. Crit. over a range of possible future scenarios / low case reserves)?	+	Yes; those that are not are classified as SFR

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2.02	Is/are the project(s) economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	+	Yes, with the possible (minor) exception of Egret, see 1.16 above.
2.03	Have forecasts been cut off when rates become uneconomic?	+	Yes; those that are not are classified as SFR
2.04	Have the latest Group Screening / Reference Criteria been used?	+	Yes (standard Group practice)
2.05	Are assumed prices and costs RT (or justified if not)?	+	Yes (standard Group practice)
2.06	Has/have the project(s) been approved by Shareholders?	O	Shareholder approval is usually not sought until start of project activity.
2.07	Is project financing available or can it reasonably be expected to be available?	+	Yes, no foreseeable problems in this respect.
2.08	Are developed reserves actually in production?	+	Yes
2.09	Have all proved gas reserves been contracted to sales?	O	Not all of these. There is still uncontracted gas in the NWS fields, whilst Gorgon gas is as yet wholly uncommitted.
2.10	If not, can they reasonably be expected to be sold in existing markets and through existing facilities?	+	Existing NWS gas buyers are likely to be quite willing to extend current contracts; Existing facilities' life span is not seen as a constraint.
2.11	If neither, can they reasonably be expected to be developed and sold in a future market?	+	There are likely to be ample opportunities for expansion of the LNG market in South and East Asia (Japan and Korea, but also Taiwan, China, India), particularly post-2005. Although there is competition on the supply side, there can be little doubt that buyers can eventually be found for all economically producible gas on the Australian shelf.
3	**REASONABLE CERTAINTY**		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	+	The established procedure of fully probabilistic volumetrics and multi-realisation static modelling ensures that proper ranges are taken for each of the volumetric parameters.
3.02	Is the uncertainty range of developed recovery adequate?	+	Yes, it takes account of the maturity of the field
3.03	Is the uncertainty range of undeveloped recovery adequate?	+	Yes, reflected through the multi-scenario dynamic modelling
3.04	Have market / production constraint uncertainties been taken into account?	N.A.	Since there are no end-of -licence issues for the NWS fields, market/facilities constraints have essentially no effect on reserves estimates. For a discussion on Gorgon, see 4.01.
3.05	What is ratio of field(s) cum.prod. / proved total recovery?		Ranges from 0 to 40% (excluding Barrow island and Thevenard, see also Att 2.1)
3.06	Can the field(s) be considered mature?		Some (N-Rankin, Wanaea, Cossack), yes. The very mature fields Barrow Island and Thevenard have been sold during 2000.
3.07	Are proved (developed and total) reserves benchmarked against expectation reserves for 'proved areas' when field(s) are mature (deterministic approach)?	X	No; Guidelines allow externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) to be taken as equal to expectation reserves.
3.08	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Proved reserves for fields are added together arithmetically. Depreciation for e.g. the NWS gas fileds is done on a combined asset basis and probabilistic addition within those assets would in principle be allowed.
3.09	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	+	Probabilistic estimates for entities (areas, reservoir sands) within fields are added together probabilistically.
3.10	Is any assumed dependency in probabilistic addition appropriate?		
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?	O	Licences start with an exploration permit for up to 6 years, renewable for up to 5 years, to be followed by a Production Licence if commercial production is undertaken. Production Licences last for 21 years, with one extension option of another 21 years, followed by a further extension option of indefinite duration. The Production Licence lapses only if there has been no production for 5 successive years. Hence there is no end-of-licence cut-off in effect for any of the NWS or Laminaria/Corallina fields.

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			Fields for which the exploration licence has ended and for which no production licence has been applied for can be granted a Retention Lease for a period of 5 years. This can be followed by an indefinite number of successive 5-year extension options, which carry the conditions that the field can be considered likely to become commercially viable within the next 15 years and that the lessee is actively pursuing the evaluation of commercial viability, including the conclusion of long term sales contracts. Currently, the fields in the Gorgon area are held under a Retention Lease, of which the current extension ends in 2002. Although it is considered likely that the interest holders can convince the authorities that commercial viability on these fields is actively being pursued, it is not clear whether this can be seen as a 'right to extend'.
4.02	Are the forecasts required to demonstrate the above condition consistent with those presented in the latest Business Plan?	N.A.	
4.03	Is the company's hydrocarbons Equity share calculated properly?	+	Yes, total Shell equity is calculated as the sum of 'direct' Shell (SDA) participation share in the respective ventures, plus the 'indirect' Shell share (34.27%) in Woodside Petroleum Ltd, which has separate holdings in the respective ventures.
4.04	Is the net Shell share calculated properly (100% for consolidated Shell companies, with minority reserves reported separately, or actual percentage if less than 50%)?	+	Yes, actual percentage is reported.
4.05	Is the hydrocarbons PSC entitlement share (net cost oil + profit oil only) calculated properly?	N.A.	
4.06	Is the hydrocarbons Purchase Right share (to the extent that economic benefit is derived from production while still bearing share of risks and rewards) calculated properly?	N.A.	
4.07	Are royalties in cash (legally or customarily) counted as reserves?	+	All royalties are paid in cash and corresponding volumes are included in reserves.
4.08	Are royalties in kind excluded from reserves?	N.A.	
4.09	Are volumes given away or received as fees in kind (e.g. for infrastructure use by third parties) excluded from reserves?	N.A.	
4.10	Has historic Group under-or overlift (compared with other co-venturers) been accounted for?	N.A.	
4.11	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?	N.A.	
4.12	Have separate submissions been made for Equity, Entitlement and Purchase Right volumes?	N.A.	Separate submissons have been made for 'Direct' and 'Indirect' Shell share volumes.
5	**AUDIT TRAILS**		
5.01	Are proved and proved developed reserves estimates up-to date?	+	Reserves for the Woodside operated fields (NWS and Laminaria/Corallina) are being kept up-to-date annually and revised as necessary.
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	O	Largely, yes. A good match (or reconciliation of minor errors) was obtained for Oil and NGL figures, but gas volumes appeared to show discrepancies of 1-3%, see Att. 2.1.
5.03	Can reported net Group equity reserves be reconciled with other relevant data (e.g. production constraints, gas markets, etc.)?	N.A.	Not really relevant
5.04	Can reserve changes be reconciled with individual field changes?	X	No individual field reserves (100%) from last year's submission were available, neither were individual field production data for 1999 (see also 6.06-07). Specific categories for oil (purchases/sales in place, new discoveries, new developed reserves) could be broadly reconciled to individual fields. A significant reduction in developed gas reserves was due to a correction for (as yet undeveloped) reserves attributable to future compression. The cause for the reduction of total gas reserves could not be established.
5.05	Are reserve changes reported in the appropriate categories?	+	Yes, see above.
5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	O	Most field reserves are in line with estimates in the latest FDP reports, with remarkably little change being required in e.g. Wanaea / Cossack and Laminaria / Corallina. However, the latest correction in developed gas reserves (correcting for compression) was not found to have been documented anywhere.

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

SDA, Oct 2000 **CHECKLIST SEC RESERVES AUDITS** **Attachment 3**

5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	X	FDP reports are indexed and identified properly and full sets of copies are kept by the operators. It was found however, that a number of SDA copies of Woodside documents were unavailable following the office move from Melbourne to Perth.
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?	X	A brief summary note (text only) was produced but this was insufficient to provide a comprehensive audit trail (e.g. only expectation volumes mentioned, no tabulated details by field, etc).
5.09	Are data bases containing historic submissions' data and current reserves status (e.g. RISRES) in place and accessible?	O	In view of the limited number of fields, data are kept in spreadsheets only.
5.10	Do these data bases also contain references to detailed reports?	X	No.
6	**CONSISTENCY WITH FINANCIAL REPORTING**		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes, in particular LPGs are reported correctly as gas
6.03	Are own use, fuel, losses etc excluded?	O	Upstream own use, fuel and losses (estimated at 3.7% in the Woodside 'Version-7' submission to SDA, although 2.9% was shown in a later submission) are excluded from the NWS gas volumes. No such correction is made for the Gorgon volumes, which is acceptable in view of the as yet preliminary nature of these volumes. Downstream fuel and losses (i.e. in the LNG plant) are correctly included in reserves.
6.04	Are gas GHVs properly measured for sales gas conditions and accounted for in reserves submissions?	O	GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes. An attempt was made at reconciling the SDA Nm3 submission with average Gorgon and NWS GHVs, but no match could be obtained (Att. 2.4).
6.05	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	O	Yes, although the audit trail was poor: a copy of the original note by SDA Petroleum Engineers advising SDA Finance about the reserves to be used could not be found. Upon advice from SIEP early in 2000, asset depreciation for North Rankin facilities is done on total North Rankin reserves, whilst those for the other fields are done on proved developed reserves.
6.06	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. 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?	+	The end-1999 submissions for 1999 oil+NGL production through Ceres and through SIEP were, after some corrections, identical.
6.07	Are annual gas production (sales) volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0323 = 0934 (Group Cy net NG sales) + 3598 (Assoc.Cy NG sales), corrected for 1404+4796 (Gas purchases) and 4100+4510+4575+0873 (Trade, other Sales and Transfers)?	X	The end-1999 submissions for 1999 gas sales through Ceres and through the reserves reporting line (SIEP) were inconsistent with each other (some 9% different). This was due to LNG plant fuel and flare being excluded from the Ceres figures, in line with theri prevailing definitions. The new 1.1.2000 definitions in Ceres should remove this inconsistency. [illegible] already adopted [illegible]
7	**OVERALL**		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Group guidelines were not completely followed with respect to proved and proved developed reserves in mature fields (see 3.07). The potential understatement in total proved reserves could be some 12 mln m3oe Group share, or some 4% of SDA booked reserves. Gorgon gas reserves (some 86 bln sm3 or 30% of SDA's m3oe Group share volume) can be maintained at their present level in the reserves portfolio and should only be changed if definitive new information regarding the project and/or the retention lease extension becomes available.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	O	Bearing in mind the above remarks, the SDA statement of proved and proved developed reserves at end 1999 can be considered to give a reasonably accurate reflection of shareholder value.

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DRAFT NOTE – 21 Nov 2000 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPB - GRA
To:	Lorin Brass	Director, Business Development, SIEP - EPB
	Alan Parsley	CEO, Shell Development Australia (SDA)
Copy:	Robert Blaauw	E&P Manager, SDA
	David Christie	Finance Manager, SDA
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	Rob Jager	Business Advisor, SIEP (EPA)
	Egbert Eeftink	Director, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

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

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

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 99-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The last previous SEC proved reserves audit for SDA was carried out in 1996. The audit took the form of technical discussions with staff from Woodside Energy Ltd (the operator for a large part of the assets with SDA interest) and detailed discussions about the reserves reporting process with SDA staff.

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

The audit commended the high quality technical work that had been carried out by Woodside, particularly in assessing the subsurface uncertainties and in evaluating the ranges of in-place and reserves estimates. Intensive SIEP assistance through VAR- and other reviews was noted. Maintaining the preliminarily booked volume of Gorgon gas reserves (first done at 1.1.1999) was supported on the grounds that a gas market was highly likely to be established in due course and that it must be considered likely that an extension of the current 5-year Retention Lease will be granted in 2002. Proved reserves in some mature fields (N-Rankin, Goodwyn and the four oil fields) should be increased to expectation levels, in line with the guidelines. This could increase Group entitlement by some 12 mln m3oe. Concern was expressed about the lack of a concisely documented audit trail, which hampered a proper assessment of the reasons for the end-1999 reserves changes.

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

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

DEPOSITION
EXHIBIT
Barendregt
#12 2/20/07

A.A. Barendregt

Attachments 1, 2, 3

0024_a01 (SDA-Covn.doc)

19/02/04

Attachment 1

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

MAIN OBSERVATIONS

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

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

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

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

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

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

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

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

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

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

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

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

Recommendations

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

R. Aalbers

NOTE – 5 Dec 2000 **CONFIDENTIAL**

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

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

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

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 99-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The last previous SEC proved reserves audit for SDA was carried out in 1996. The audit took the form of technical discussions with staff from Woodside Energy Ltd (the operator for a large part of the assets with SDA interest) and detailed discussions about the reserves reporting process with SDA staff.

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

The audit commended the high quality technical work that had been carried out by Woodside, particularly in assessing the subsurface uncertainties and in evaluating the ranges of in-place and reserves estimates. Intensive SIEP assistance through VAR- and other reviews was noted. Maintaining the preliminarily booked volume of Gorgon gas reserves (first done at 1.1.1999) was supported on the grounds that a gas market was highly likely to be established in due course and that it must be considered likely that an extension of the current 5-year Retention Lease will be granted in 2002. Proved reserves in some mature fields (N-Rankin, Goodwyn and the four oil fields) should be increased to expectation levels, in line with the guidelines. This could increase Group entitlement by some 12 mln m3oe. Concern was expressed about the lack of a concisely documented audit trail, which hampered a proper assessment of the reasons for the end-1999 reserves changes.

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

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

DEPOSITION EXHIBIT rcw
Barendregt
#13 2/20/07

A.A. Barendregt

Attachments 1, 2, 3

Attachment 1

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

MAIN OBSERVATIONS

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

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

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

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

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

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

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

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

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

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

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

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

Recommendations

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

Attachm...... 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved Oil / NGL / Gas Reserves as at 31.12.99

Area / field	Proven HIP MMstb / Bscf	Exp'n HIP MMstb / Bscf	Cum. Prod = Sales 31.12.99 MMstb / Bscf	Proved Rem. Recov. Dev. MMstb / Bscf	Proved Rem. Recov. Tot'l MMstb / Bscf	Exp'n Rem. Recov. Tot'l MMstb / Bscf	Maturity (Cum.pr / Exp'n UR) %	Dev. / Tot'l Proved UR. %	Proved RF Tot'l %	Exp'n RF Tot'l %	Fract'n w/i lic. & comtd Pr.Dev. %	Fract'n w/i lic. & comtd Pr.Tot'l %	Within Licence & comtd Pr.Dev. MMstb / Bscf	Within Licence & comtd Pr.Tot'l MMstb / Bscf	Venture Shell share % %	Shell Equity Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Tot'l 10^6 sm3/ 10^9 sm3	1999 Subm'n Dev 10^6 sm3/ 10^9 sm3	1999 Subm'n Tot'l 10^6 sm3/ 10^9 sm3
Oil																			
Wanaea	283.30	340.30	43.80	96.20	104.80	141.10	23.7%	94.2%	52.5%	54.3%	100.0%	100.0%	97.20	104.80	16.67%	2.58	2.78		
Cossack	76.60	120.10	34.20	14.20	14.20	37.60	47.6%	100.0%	63.2%	59.8%	100.0%	100.0%	14.20	14.20	16.67%	0.38	0.38		
Lambert	55.60	74.50	1.10	14.50	22.30	32.10	3.3%	66.7%	42.1%	44.6%	100.0%	100.0%	14.50	22.30	16.67%	0.38	0.59		
Hermes	22.10	28.10	7.70	1.80	3.00	5.60	57.9%	88.8%	48.4%	47.3%	100.0%	100.0%	1.80	3.00	16.67%	0.05	0.06		
Egret	18.60	37.60			6.00	13.10	0.0%	0.0%	32.3%	34.8%	100.0%	100.0%	0.00	6.00	16.67%	0.00	0.16		
Laminaria	162.30	204.00	3.00	85.60	95.60	128.90	2.3%	89.9%	60.8%	63.7%	100.0%	100.0%	85.60	95.60	25.00%	3.40	3.60		
Coralina	71.50	97.00	0.70	37.60	38.40	56.20	1.3%	98.0%	54.7%	57.6%	100.0%	100.0%	37.60	38.40	25.00%	1.49	1.53		
Barrow Island (WAPET)	1353.61	1353.61	284.85	51.70	51.70	77.70	78.6%	100.0%	24.9%	26.8%	55.8%	55.8%	28.88	28.86	28.57%	1.31	1.31		
Thevenard Island (WAPET)	282.91	282.91	134.45	23.97	23.97	33.95	79.8%	100.0%	56.0%	59.5%	100.0%	100.0%	23.97	23.97	35.71%	1.36	1.36		
NWS + WAPET Oil - SDA 'direct' share																10.85	11.88	11.64	12.83
Wan., Coss., Lamb., Herm., Egret (W= 16.67%)													127.70	150.30	5.71%	1.16	1.36		
Lamainaria, Coralina (Woods = 50%)													123.20	134.00	17.14%	3.36	3.65		
SDA 'indirect' 34.27% share in Woodside																4.82	5.02	4.28	5.44
Total Oil (MMstb)	2326.52	2538.12	509.80	325.57	359.97	523.25							303.73	337.13	31.7%	15.47	17.00	15.82	18.07
NGL																			
North Rankin	313.50	347.30	127.80	15.00	58.20	89.40	58.8%	72.9%	62.5%	62.5%	100.0%	100.0%	15.00	58.20	15.66%	0.37	1.70		
Perseus	308.30	377.80	18.20	22.10	164.70	215.40	7.8%	22.0%	59.3%	61.6%	100.0%	100.0%	22.10	164.70	15.66%	0.55	4.10		
Goodwyn	530.70	629.70	117.10	84.50	194.00	251.10	31.8%	64.8%	58.6%	58.5%	100.0%	100.0%	84.50	194.00	15.66%	2.10	4.83		
Angel	129.90	165.30			65.80	87.00	0.0%	0.0%	50.7%	52.6%	100.0%	100.0%	0.00	65.80	15.66%	0.00	1.64		
Other NWS gas + oil fields	261.00	396.30	2.10	3.70	103.20	152.90	1.4%	5.5%	40.3%	39.1%	100.0%	100.0%	3.70	103.20	15.66%	0.09	2.57		
Gorgon field (WAPET)	170.00	210.40			110.69	131.30	0.0%	0.0%	65.1%	62.4%	100.0%	100.0%	0.00	110.69	28.57%	0.00	5.03		
Chrysaor, W-Trial Rocks (WAPET)	69.00	90.00				53.00	0.0%	0	0.0%	58.9%	100.0%	100.0%	0.00	0.00	28.57%	0.00	0.00		
Total SDA 'direct' share																3.12	18.87	3.12	18.88
SDA 'indirect' 34.27% share in Woodside cond. (18.74% of NWS cond.)													125.30	595.90	6.76%	1.35	6.41	1.35	6.41
Total NGL (MMstb)	1782.40	2216.80	265.20	125.30	706.59	980.10							125.30	706.59	23.38%	4.47	28.28	4.47	28.27
Gas (Dry, sales gas volumes)																			
North Rankin	11620.00	12190.00	4200.00	1730.00	6180.00	6810.00	38.1%	57.1%	89.3%	90.3%	96.3%	96.3%	1685.99	5951.34	15.64%	7.374	28.341		
Perseus	8770.00	10580.00	500.00	930.00	7010.00	8830.00	5.4%	19.0%	85.6%	87.4%	96.3%	96.3%	895.59	6750.83	15.64%	3.964	29.679		
Goodwyn	7040.00	8390.00	660.00	1610.00	4330.00	5420.00	10.9%	45.5%	70.9%	72.5%	96.3%	96.3%	1550.43	4169.79	15.64%	6.862	18.456		
Angel	2270.00	2790.00			1390.00	1770.00	0.0%	0.0%	61.2%	63.4%	96.3%	96.3%	0.00	1338.57	15.64%	0.000	5.925		
Other NWS gas + oil fields	4440.00	6360.00	40.00	130.00	2360.00	3410.00	1.2%	7.1%	54.1%	54.2%	96.3%	96.3%	125.19	2272.68	15.64%	0.554	10.059		
Gorgon field (WAPET)	20936.86	24828.94			10650.00	15200.00	0.0%	0.0%	50.9%	61.2%	98.0%	98.0%	0.00	10437.00	28.57%	0.000	84.391		
Chrysaor, W-Trial Rocks (WAPET)	4550.98	7343.34				3300.00	0.0%	0	0.0%	44.9%	98.0%	98.0%	0.00	0.00	28.57%	0.000	0.000		
Thevenard Island	163.00	163.00	70.00	33.00	39.00	55.00	56.0%	94.5%	66.9%	76.7%	100.0%	100.0%	33.00	39.00	35.71%	0.333	0.394		
Total SDA 'direct' share																18.088	175.445	18.583	176.638
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)													4237.20	20483.01	6.98%	8.371	40.466	8.147	40.206
Total Gas (Bscf)	59790.85	72745.28	5470.00	4433.00	31959.00	44795.00	10.9%	26.5%	62.6%	69.1%			4270.20	30959.01	24.6%	27.459	215.911	26.730	216.843

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

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

Licence expiry dates:

Audit Trail:

Oil: SDA submission not corrected for beyond-licence oil from Barrow Island; Minor error in Woodside share % in Laminaria (double correction for unitisation share)
Gas: Fractions 'w/i licence & comtd' reflect 3.7% correction for future upstream fuel and flare.
Good match for NGL, but matches for oil and gas are poor.

Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved Oil Reserves Changes 1999 (100%, MMstb)

Proved Developed Reserves

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase In-place	Sales in-place	New Deve'd Reserves	Product'n = Sales 1999	Prov.Res 31.12.99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^6 m3)	Net Shell Equity 1.1.2000 (10^6 m3)	Comments
Wanaea									97.20	16.67%	16.67%	16.67%	0.00	2.58	
Cossack									14.20	16.67%	16.67%	16.67%	0.00	0.38	
Lambert									14.50	16.67%	16.67%	16.67%	0.00	0.38	
Hermes									1.60	16.67%	16.67%	16.67%	0.00	0.05	
Egret									0.00	16.67%	16.67%	16.67%	0.00	0.00	
Laminaria							85.60		85.60	25.00%	25.00%	25.00%	0.00	3.40	Laminaria ?Corallina new developed
Corallina							37.80		37.80	25.00%	25.00%	25.00%	0.00	1.49	
Legendre sold to Woodside						25.90				19.00%	19.00%	19.00%	0.00	0.00	Legendre sold to Woodside
Barrow Island (WAPET)									28.86	28.57%	28.57%	28.57%	0.00	1.31	
Thevenard Island (WAPET)									23.87	35.71%	35.71%	35.71%	0.00	1.38	
NWS + WAPET Oil - SDA 'direct' share															
Legendre sold to Woodside					25.90					9.22%	9.22%	9.22%	0.00	0.00	Legendre sold to Woodside
Wan., Coss., Lamb., Herm., Egret (W=16.67%)									127.70	5.71%	5.71%	5.71%	0.00	1.16	
Lamainaria, Corallina (Woods = 50%)							123.40		123.20	17.14%	17.14%	17.14%	0.00	3.36	
SDA 'indirect' 34.27% share in Woodside															
Prov.Dev.Resvs (MMstb)	0.00	0.00 307.83	0.00	0.00	25.90	25.90	246.60	0.00	554.63				0.00	15.47	

Proved Total Reserves

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase In-place	Sales in-place	New Deve'd Reserves	Product'n = Sales 1999	Prov.Res 31.12.99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^6 m3)	Net Shell Equity 1.1.2000 (10^6 m3)	Comments
Wanaea									104.80	16.67%	16.67%	16.67%	0.00	2.78	
Cossack									14.20	16.67%	16.67%	16.67%	0.00	0.38	
Lambert									22.30	16.67%	16.67%	16.67%	0.00	0.59	
Hermes									3.00	16.67%	16.67%	16.67%	0.00	0.08	
Egret				6.00					8.00	16.67%	16.67%	16.67%	0.00	0.16	Egret booked first time
Laminaria									95.60	25.00%	25.00%	25.00%	0.00	3.80	
Corallina									38.40	25.00%	25.00%	25.00%	0.00	1.53	
Legendre sold to Woodside						25.90				19.00%	19.00%	19.00%	0.00	0.00	Legendre sold to Woodside
Barrow Island (WAPET)									28.86	28.57%	28.57%	28.57%	0.00	1.31	
Thevenard Island (WAPET)									23.97	35.71%	35.71%	35.71%	0.00	1.36	
NWS + WAPET Oil - SDA 'direct' share															
Legendre sold to Woodside					25.90					9.22%	9.22%	9.22%	0.00	0.00	
Wan., Coss., Lamb., Herm., Egret (W=16.67%)				6.00					150.30	5.71%	5.71%	5.71%	0.00	1.38	Egret booked for first time
Lamainaria, Corallina (Woods = 50%)									134.00	17.14%	17.14%	17.14%	0.00	3.65	
SDA 'indirect' 34.27% share in Woodside															
Tot'l Prov.Res (MMstb)	0.00	0.00 609.43	0.00	12.00	25.90	25.90		0.00	821.43				0.00	17.00	

Net Group Equity 10^6 m3	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase In-place	Sales in-place	New Deve'd Reserves	Product'n = Sales 1999	Prov.Res 31.12.99
Prov.Dev. Res	0.00	7.60	0.00	0.00	0.38	0.78	8.27	0.00	15.47
Prov Tot'l Res	0.00	17.19	0.00	0.21	0.38	0.78		0.00	17.00

1999 Submission 10^6 m3	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase In-place	Sales in-place	New Deve'd Reserves	Product'n = Sales 1999	Prov.Res 31.12.99	
Prov.Dev.Res	7.83	1.45					8.03	1.39	15.92	15.92
Prov.Tot'l Res	18.73	0.92		0.21	0.39	0.78		1.39	18.07	18.07

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

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

Audit Trail:

Main changes:
Legendre sold to Woodside (resulting in change of SDA share % from 'direct' to 'indirect')
Laminaria/Corallina new developed during 1999
Egret booked for first time

General: 1.1.1999 field data and individual 1999 field productions not available.
Laminaria/Corallina new developed reserves do not fully match submission

FOIA Confidential Treatment Requested

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved NGL Reserves Changes 1999 (100%, MMstb)

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Product'n = Sales 1999	Prov.Res 31.12.99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^6 m3)	Net Shell Equity 1.1.2000 (10^6 m3)	Comments
Proved Developed Reserves															
North Rankin									15.00	15.66%	15.66%	15.66%	0.00	0.37	
Perseus									22.10	15.66%	15.66%	15.66%	0.00	0.55	
Goodwyn									84.50	15.66%	15.66%	15.66%	0.00	2.10	
Angel									0.00	15.66%	15.66%	15.66%	0.00	0.00	
Other NWS gas + oil fields									3.70	15.66%	15.66%	15.66%	0.00	0.09	
Gorgon field (WAPET)									0.00	28.57%	28.57%	28.57%	0.00	0.00	
Chrysaor, W-Trial Rocks (WAPET)									0.00	28.57%	28.57%	28.57%	0.00	0.00	
Total SDA 'direct' share															
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)									125.30	6.76%	6.76%	6.76%	0.00	1.35	
Prov.Dev.Resvs (MMstb)	0.00	0.00 250.60	0.00	0.00	0.00	0.00	0.00	0.00	250.60	0	0	11.21%	0.00	4.47	
Proved Total Reserves															
North Rankin									68.20	15.66%	15.66%	15.66%	0.00	1.70	
Perseus									164.70	15.66%	15.66%	15.66%	0.00	4.10	
Goodwyn									194.00	15.66%	15.66%	15.66%	0.00	4.83	
Angel									65.80	15.66%	15.66%	15.66%	0.00	1.64	
Other NWS gas + oil fields									103.20	15.66%	15.66%	15.66%	0.00	2.57	
Gorgon field (WAPET)									110.69	28.57%	28.57%	28.57%	0.00	5.03	
Chrysaor, W-Trial Rocks (WAPET)									0.00	28.57%	28.57%	28.57%	0.00	0.00	
Total SDA 'direct' share															
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)									595.90	6.76%	6.76%	6.76%	0.00	6.41	
Tot'l Prov.Res (MMstb)	0.00	0.00 1302.49	0.00	0.00	0.00	0.00		0.00	1302.49	0	0	12.69%	0.00	28.28	

Net Group Equity									
Prov.Dev. Res	0.00	4.47	0.00	0.00	0.00	0.00	0.00	0.00	4.47
Prov Tot'l Res	0.00	28.28	0.00	0.00	0.00	0.00		0.00	28.26
10^6 m3									

1999 Submission										
Prov.Dev.Res	9.64	-3.79						1.38	4.47	4.47
Prov.Tot'l Res	24.75	2.90						1.38	26.27	26.27
10^6 m3										

Conversion factors used by SDA			Conversion factors used by SEPIV		
1 stb =	0.159	m3	1 stb =	0.159	m3
1scf =	0.0283	sm3	1 scf =	0.0283	sm3

Audit Trail: **General: 1.1.1999 field data and individual 1999 field productions not available. Match incomplete; Overall auditability of changes poor.**

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SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Attachment 2.4

Gas Reserves Changes 1999 (100%, Bscf) - Dry sales gas volumes

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Develd Reserves	Productn = Sales 1999	Prov.Res 31.12 99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^9 sm3)	Net Shell Equity 1.1.2000 (10^9 sm3)	GHV (Btu/scf)	Net Shell Equity 1.1.1999 (10^9 Nm3)	Net Shell Equity 1.1.2000 (10^9 Nm3)	Comments
Proved Developed Reserves																		
North Rankin									1665.990	15.64%	15.64%	15 64%	0 000	7.374	1118	0.000	7 723	
Perseus									895 590	15.64%	15 64%	15 64%	0 000	3.964	1157	0.000	4 296	
Goodwyn									1550 430	15.64%	15 64%	15 64%	0 000	6.882	1121	0.000	7 206	
Angel									0 000	15.64%	15 64%	15 64%	0 000	0 000	1228	0.000	0 000	
Other NWS gas + oil fields									125 190	15 64%	15 64%	15 64%	0 000	0.554	1187	0 000	0 616	
Gorgon field (WAPET)									0 000	28.57%	28 57%	28 57%	0 000	0.000	1044	0.000	0 000	
Chrysaor, W-Trial Rocks (WAPET)									0 000	28.57%	28 57%	28 57%	0 000	0.000	1044	0.000	0 000	
Thevenard Island									33 000	35.71%	35 71%	35 71%	0 000	0.333	1191	0.000	0 372	
Total SDA 'direct' share																		
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)									4237 200	6.98%	6 98%	6 98%	0 000	8.371	1144	0.000	8 971	
Prov.Dev.Resvs (Bscf)	0.000	0.000 8507.400	0.000	0.000	0.000	0.000	0.000	0.000	8507.400	0	0	0 00%	0 000	27.459	1135	0.000	29.184	
Proved Total Reserves																		
North Rankin									5951 340	15.64%	15 64%	15 64%	0 000	26.341	1118	0.000	27 587	
Perseus									6750 630	15.64%	15 64%	15 64%	0 000	29.879	1157	0.000	32 384	
Goodwyn									4169 790	15.64%	15 64%	15 64%	0 000	18 456	1121	0.000	19 381	
Angel									1338 570	15.64%	15 64%	15 64%	0 000	5.925	1228	0.000	6 815	
Other NWS gas + oil fields									2272 680	15.64%	15 64%	15 64%	0 000	10.059	1187	0.000	11 185	
Gorgon field (WAPET)									10437 000	28.57%	28 57%	28 57%	0 000	84.391	1044	0.000	82 531	
Chrysaor, W-Trial Rocks (WAPET)									0 000	28.57%	28 57%	28 57%	0 000	0 000	1044	0.000	0 000	
Thevenard Island									39 000	35.71%	35 71%	35.71%	0 000	0 394	1191	0 000	0 440	
Total SDA 'direct' share															0			
															0			
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)									20483 010	6.98%	6.98%	6.98%	0.000	40.466	1144	0.000	43 365	
Tot'l Prov.Res (Bscf)	0.000	0.000 51442.020	0.000	0.000	0.000	0.000		0.000	51442 020	0	0	0.00%	0.000	215.911	1106	0.000	223.688	

Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^9 sm3	27.459 215.911	27.459 215.911	0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	0 000	0.000 0.000	27.459 215.911	
1999 Submission **Prov.Dev.Res** **Prov.Tot'l Res** **10^9 sm3**	61.599 229.560	-31.136 -8.184						3.733 3.733	28.730 218.843	28.730 216.843
Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^9 Nm3 @ 9500 kCal/Nm3	29.184 223.688	29.184 223.688	0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	0 000	0.000 0.000	29.184 223.688	
1999 Submission **Prov.Dev.Res** **Prov.Tot'l Res** **10^9 Nm3 @ 9500 kCal/Nm3**	63.444 233.687	-29.974 -1.374						4.064 4.064	29.408 228.249	29.406 228.249

Conversion factors used by SDA

1 stb = 0.158 m3
1 scf = 0.0283 sm3
1 sm3 = 0.948 Nm3
and 1 sm3 = 1.0528 Nm3@9500
(i.e. avge GHV = 10548 kcal/Nm3
or 1123.7 Btu/scf
or 44.18 MJ/Nm3
cf avg GHV of 1106.0 kcal/Nm3 from above columns

Conversion factors used by SEPIV:

1 stb = 0.159 m3
1 scf = 0.02834 sm3
1 sm3 = 0.948 Nm3
and 1 sm3 = 0.948 Nm3 @ 9500
(if GHV = 9500 kcal/Nm3
or 1012.0 Btu/scf
or 39.77 MJ/Nm3

Audit Trail:

1.1.1999 field data and individual 1999 field productions not available.
Match incomplete;
Reduction in developed reserves due to correction for
(as yet undeveloped) reserves attributable to compression
individual field GHV data do not seem to match with overall GHV average from submission
Overall auditability of changes poor

SDA, Oct 2000 **CHECKLIST SEC RESERVES AUDITS** **Attachment 3**

COMPANY: SHELL DEVELOPMENT AUSTRALIA LTD AREA / FIELD: ALL

Dimensions (100% field figures as at 1.1.2000): **Average Group share: 25 - 37%**

1.1.2000 Proved Oil Reserves	45	10^6 m3	(Group share 18 10^6 m3)
1.1.2000 Proved Developed Oil Reserves	40	10^6 m3	(Group share 16 10^6 m3)
1999 Oil Production	6	10^6 m3	(Group share 1.4 10^6 m3)
	16	10^3 m3/d	(Group share 3.8 10^3 m3/d)
1.1.2000 Proved Gas Reserves	900	10^9 sm3	(Group share 216 10^9 sm3)
1.1.2000 Proved Developed Gas Reserves	124	10^9 sm3	(Group share 27 10^9 sm3)
1999 Gas Production	16	10^9 sm3	(Group share 4.1 10^9 sm3)
	45	10^6 sm3/d	(Group share 11 10^6 sm3/d)
Number of fields in area	20		
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 has been shot and interpreted over all the fields
1.02	Are seismic processing and interpretation state-of-the-art?	+	Although much of the seismic vintage is from the early 1990's, re-processing and re-interpretation using the latest techniques is gradually being introduced (eg Lambert/Hermes, Laminaria)
1.03	Is well log data quantity and quality adequate?	+	Extensive log and core data have been gathered in appraisal wells and in development wells as appropriate.
1.04	Is well data coverage adequate?	+	Certainly in developed fields; Subsurface uncertainties are properly accounted for in undeveloped fields and proved reserves are in principle not booked until data coverage is adequate.
1.05	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Proved reserves are not booked until well data coverage is adequate.
1.06	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Yes, most notably in Gorgon
1.07	Is there a proper volumetric estimate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.08	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	Yes, extensive PVT analyses are standard practice and these are properly reflected in static and dynamic models.
1.09	Is a static model available / adequate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.10	Is a dynamic model available / adequate?	+	Yes, detailed dynamic models (downloaded from static models) are available for all fields with proved reserves.
1.11	Is a history match available / adequate?	+	History matches, to the extent that there is sufficient production history, are good and are kept up-to-date on a regular basis.
1.12	Is the recovery factor for proved reserves realistic?	+	Yes, the RFs fully reflect the range of possible subsurface realisations and possible development scenarios.
1.13	Are developed reserves based on proper NFA (No Further Activity) forecasts?	+	Yes; dedicated NFA dynamic model runs are made, incorporating existing facilities' constraints, as relevant.
1.14	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. A proper correction was made at 1.1.2000 to reflect the as yet undeveloped state of gas reserves obtainable through compression.
1.15	Has/have (a) development project(s) been defined for undeveloped reserves or can it/they be defined?	+	Yes
1.16	Is/are the project(s) technically mature or is further data gathering necessary?	+	Those projects pertaining to proved reserves are mature, with the possible exception of Egret, where the low reserves estimate does not appear to pass screening criteria. In the large Gorgon gas field, there is also a technically (and economically) robust development plan.
1.17	Is/are there (an) auditable development project plan(s) with costs, benefits and economics?	+	Yes
1.18	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	N.A.	Apart from ongoing gas recycling in Goodwyn and some LPG/gas injection in Laminaria/Corallina, there are no improved recovery projects planned.
1.19	Has the project been subjected to a VAR review or other external review and if so, what have been the main conclusions?	+	All projects in which SDA have an interest are subjected to regular peer reviews and VAR reviews with SIEP-EPT assistance. In particular the SIEP assistance to Woodside can be classified as intensive.
2	**COMMERCIAL MATURITY**		
2.01	Is/are the project(s) commercially mature (positive NPV for Group Ref. Crit. over a range of possible future scenarios / low case reserves)?	+	Yes; those that are not are classified as SFR

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

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2.02	Is/are the project(s) economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	+	Yes, with the possible (minor) exception of Egret, see 1.16 above.
2.03	Have forecasts been cut off when rates become uneconomic?	+	Yes; those that are not are classified as SFR
2.04	Have the latest Group Screening / Reference Criteria been used?	+	Yes (standard Group practice)
2.05	Are assumed prices and costs RT (or justified if not)?	+	Yes (standard Group practice)
2.06	Has/have the project(s) been approved by Shareholders?	O	Shareholder approval has been obtained for imminent projects and projects in progress. For projects further into the future it will be soughtin die course.
2.07	Is project financing available or can it reasonably be expected to be available?	+	Yes, no foreseeable problems in this respect.
2.08	Are developed reserves actually in production?	+	Yes
2.09	Have all proved gas reserves been contracted to sales?	O	Not all of these. There is still uncontracted gas in the NWS fields, whilst Gorgon gas is as yet wholly uncommitted.
2.10	If not, can they reasonably be expected to be sold in existing markets and through existing facilities?	+	Existing NWS gas buyers are likely to be quite willing to extend current contracts; Existing facilities' life span is not seen as a constraint.
2.11	If neither, can they reasonably be expected to be developed and sold in a future market?	+	There are likely to be ample opportunities for expansion of the LNG market in South and East Asia (Japan and Korea, but also Taiwan, China, India), particularly post-2005. Although there is competition on the supply side, there can be little doubt that buyers can eventually be found for all economically producible gas on the Australian shelf.
3	REASONABLE CERTAINTY		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	+	The established procedure of fully probabilistic volumetrics and multi-realisation static modelling ensures that proper ranges are taken for each of the volumetric parameters.
3.02	Is the uncertainty range of developed recovery adequate?	+	Yes, it takes account of the maturity of the field
3.03	Is the uncertainty range of undeveloped recovery adequate?	+	Yes, reflected through the multi-scenario dynamic modelling
3.04	Have market / production constraint uncertainties been taken into account?	N.A.	Since there are no end-of -licence issues for the NWS fields, market/facilities constraints have essentially no effect on reserves estimates. For a discussion on Gorgon, see 4.01.
3.05	What is ratio of field(s) cum.prod. / proved total recovery?		Ranges from 0 to 40% (excluding Barrow island and Thevenard, see also Att 2.1)
3.06	Can the field(s) be considered mature?		Some (N-Rankin, Wanaea, Cossack), yes. The very mature fields Barrow Island and Thevenard have been sold during 2000.
3.07	Are proved (developed and total) reserves benchmarked against expectation reserves for 'proved areas' when field(s) are mature (deterministic approach)?	X	No; Guidelines allow externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) to be taken as equal to expectation reserves.
3.08	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Proved reserves for all individual fields are added together arithmetically. Depreciation for e.g. the NWS gas fields is done on a combined asset basis and probabilistic addition within those assets would in principle be allowed.
3.09	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	+	Probabilistic estimates for entities (areas, reservoir sands) within fields are added together arithmetically, with the exception of the reservoirs in Goodwyn, which are added together probabilistically.
3.10	Is any assumed dependency in probabilistic addition appropriate?	O	The probabilistic ranges for the reservoirs in Goodwyn are assumed to be independent. This is probably too optimistic, since dependencies in the estimates must be present. However, the issue will disappear if expectation reserves are used (see 3.07)
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?	O	Licences start with an exploration permit for up to 6 years, renewable for up to 5 years, to be followed by a Production Licence if commercial production is undertaken. Production Licences last for 21 years, with one extension option of another 21 years, followed by a further extension option of indefinite duration. The Production Licence lapses only if there has been no production for 5 successive years. Hence there is no end-of-licence cut-off in effect for any of the NWS or Laminaria/Corallina fields.

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			Fields for which the exploration licence has ended and for which no production licence has been applied for can be granted a Retention Lease for a period of 5 years. This can be followed by an indefinite number of successive 5-year extension options, which carry the conditions that the field can be considered likely to become commercially viable within the next 15 years and that the lessee is actively pursuing the evaluation of commercial viability, including the conclusion of long term sales contracts. Currently, the fields in the Gorgon area are held under a Retention Lease, of which the current extension ends in 2002. Although it is considered likely that the interest holders can convince the authorities that commercial viability on these fields is actively being pursued, it is not clear whether this can be seen as a 'right to extend'.
4.02	Are the forecasts required to demonstrate the above condition consistent with those presented in the latest Business Plan?	N.A.	
4.03	Is the company's hydrocarbons Equity share calculated properly?	+	Yes, total Shell equity is calculated as the sum of 'direct' Shell (SDA) participation share in the respective ventures, plus the 'indirect' Shell share (34.27%) in Woodside Petroleum Ltd, which has separate holdings in the respective ventures.
4.04	Is the net Shell share calculated properly (100% for consolidated Shell companies, with minority reserves reported separately, or actual percentage if less than 50%)?	+	Yes, actual percentage is reported.
4.05	Is the hydrocarbons PSC entitlement share (net cost oil + profit oil only) calculated properly?	N.A.	
4.06	Is the hydrocarbons Purchase Right share (to the extent that economic benefit is derived from production while still bearing share of risks and rewards) calculated properly?	N.A.	
4.07	Are royalties in cash (legally or customarily) counted as reserves?	+	All royalties are paid in cash and corresponding volumes are included in reserves.
4.08	Are royalties in kind excluded from reserves?	N.A.	
4.09	Are volumes given away or received as fees in kind (e.g. for infrastructure use by third parties) excluded from reserves?	N.A.	
4.10	Has historic Group under-or overlift (compared with other co-venturers) been accounted for?	N.A.	
4.11	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?	N.A.	
4.12	Have separate submissions been made for Equity, Entitlement and Purchase Right volumes?	N.A.	Separate submissons have been made for 'Direct' and 'Indirect' Shell share volumes.
5	**AUDIT TRAILS**		
5.01	Are proved and proved developed reserves estimates up-to date?	+	Reserves for the Woodside operated fields (NWS and Laminaria/Corallina) are being kept up-to-date annually and revised as necessary.
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	O	Largely, yes. A good match (or reconciliation of minor errors) was obtained for Oil and NGL figures, but gas volumes appeared to show discrepancies of 1-3%, see Att. 2.1.
5.03	Can reported net Group equity reserves be reconciled with other relevant data (e.g. production constraints, gas markets, etc.)?	N.A.	Not really relevant
5.04	Can reserve changes be reconciled with individual field changes?	X	No individual field reserves (100%) from last year's submission were available, neither were individual field production data for 1999 (see also 6.06-07). Specific categories for oil (purchases/sales in place, new discoveries, new developed reserves) could be broadly reconciled to individual fields. A significant reduction in developed gas reserves was due to a correction for (as yet undeveloped) reserves attributable to future compression. Both developed and total reserves had to be reduced to account for the larger share that Woodside will take in future Domgas sales.
5.05	Are reserve changes reported in the appropriate categories?	+	Yes, see above.
5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	O	Most field reserves are in line with estimates in the latest FDP reports, with remarkably little change being required in e.g. Wanaea / Cossack and Laminaria / Corallina. However, the latest correction in developed gas reserves (correcting for compression) was not found to have been documented anywhere.

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

5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	X	FDP reports are indexed and identified properly and full sets of copies are kept by the operators. It was found however, that a number of SDA copies of Woodside documents were unavailable following the office move from Melbourne to Perth.
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?	X	A brief summary note (text only) was produced but this was insufficient to provide a comprehensive audit trail (e.g. only expectation volumes mentioned, no tabulated details by field, etc).
5.09	Are data bases containing historic submissions' data and current reserves status (e.g. RISRES) in place and accessible?	O	In view of the limited number of fields, data are kept in spreadsheets only.
5.10	Do these data bases also contain references to detailed reports?	X	No.
6	CONSISTENCY WITH FINANCIAL REPORTING		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes, in particular LPGs are reported correctly as gas
6.03	Are own use, fuel, losses etc excluded?	O	Upstream own use, fuel and losses (estimated at 3.7% in the Woodside 'Version-7' submission to SDA, although 2.9% was shown in a later submission) are excluded from the NWS gas volumes. A similar 2% correction was made for the Gorgon volumes. Downstream fuel and losses (i.e. in the LNG plant) are correctly included in reserves.
6.04	Are gas GHVs properly measured for sales gas conditions and accounted for in reserves submissions?	O	GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes for NWS fields. An attempt was made at reconciling the SDA Nm3 submission with individual field's and Gorgon GHVs, but the resulting average GHV did not seem to match with the average GHV implied by the submission (Att. 2.4).
6.05	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	O	Yes, although the audit trail was poor: a copy of the original note by SDA Petroleum Engineers advising SDA Finance about the reserves to be used could not be found. Upon advice from SIEP early in 2000, asset depreciation for North Rankin facilities is done on total North Rankin reserves, whilst those for the other fields are done on proved developed reserves.
6.06	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. 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?	+	The end-1999 submissions for 1999 oil+NGL production through Ceres and through SIEP were, after some corrections, identical.
6.07	Are annual gas production (sales) volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0323 = 0934 (Group Cy net NG sales) + 3598 (Assoc.Cy NG sales), corrected for 1404+4796 (Gas purchases) and 4100+4510+4575+0873 (Trade, other Sales and Transfers)?	O	The end-1999 submissions for 1999 gas sales through Ceres and through the reserves reporting line (SIEP) were inconsistent with each other (some 9% different). This was due to LNG plant fuel and flare being excluded from the Ceres figures, thus effectively reporting the downstream sales, not the upstream production. The new 1.1.2000 definitions in Ceres should remove this inconsistency.
7	OVERALL		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Group guidelines were not completely followed with respect to proved and proved developed reserves in mature fields (see 3.07). The potential understatement in total proved reserves could be some 12 mln m3oe Group share, or some 4% of SDA booked reserves. Gorgon gas reserves (some 86 bln sm3 or 30% of SDA's m3oe Group share volume) can be maintained at their present level in the reserves portfolio and should only be changed if definitive new information regarding the project and/or the retention lease extension becomes available.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	O	Bearing in mind the above remarks, the SDA statement of proved and proved developed reserves at end 1999 can be considered to give a reasonably accurate reflection of shareholder value.

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

Regtien, Jeroen SDA-EP/2

From:	Barendregt, Anton AA SIEP-EPB-GRA
Sent:	Wednesday, November 22, 2000 12:47 AM
To:	Christie, David DA SDA-FP; Regtien, Jeroen JMM SDA-EP/2
Cc:	Graham, Sheila S SDA-FP/421; Blaauw, Robert R SDA-EP
Subject:	RE: DRAFT AUDIT NOTE

David, Jeroen,

Many thanks for yor comments and apologies for my lateness in replying - the US audit took longer than I anticipated.

As for your comments:

GHV reconciliation - I did indeed manage to extract the individual field GHVs from the various sheets that Sheila gave to me - they were not immediately obvious at the time and I missed them in the rush to get the report finalised. Yet, even with these individual GHVs (see extra sheet added to Att.2) I do not seem to get a match with your overall average GHV, see Att.2.4.

I changed the wording on shareholder approval somewhat (2.06 in Att.3). Trust the present version is OK.

Gorgon losses - again a victim of the hurry to get the report out. I meant to check with Sheila, but forgot. Apologies.

The 'unsatisfactory' rating for the mismatch in 1999 gas production/sales figures: I hope you can understand that I can hardly rate this as 'good'. Trust that 'satisfactory' is a good compromise. I did check with EPF here and it seems that the old Ceres guidelines left an integrated OU like SDA with no option but reporting the way you did.

As for the issue of expectation reserves to be used for externally reported Proved Reserves, I trust that we're all aligned now. I will admit that the wording 'Proved' is confusing. I prefer to use 'P85' if I refer to low case reserves.

Finally, one small issue regarding point 3.10 in Att.3: Do we use partial or full independency in the in-field probabilistic addition in Perseus and Goodwyn?. Grateful your reply and comment about the appropriateness of the choice.

I'll issue the report as soon as I receive your reply.

Best regards,

Anton

SDA-Covn.doc SDA-Att2.xls SDA-Att3.xls

DEPOSITION
EXHIBIT
Barendregt
#14 2/20/07

-----Original Message-----

From:	**Christie, David SDA-FP**
Sent:	24 October 2000 05:42
To:	Barendregt, Anton SIEP-EPB-GRA
Cc:	Graham, Sheila SDA-FP/421; Blaauw, Robert SDA-EP; Parsley, Alan SDA-CEO; Grasso, Wim Hein SDA-DC
Subject:	DRAFT AUDIT NOTE

Anton,
My comments and incorporating Sheila Graham's:

MAIN OBSERVATIONS:

ITEM 4: See comment against 6.08 below.

ITEM 6: Incorrect observation. This reconciliation was performed and a spreadsheet was given to the auditor which included the reconciliation referred to.

ITEM 8. Finance in fact receive the sales and production data as part of a monthly fax (not telex) containing financial data which is also sent to the other JVPs. Finance feel that electronic transmission of this data from Woodside is feasible and would save approximately 2 manhours of work per month.

CHECKLIST:

2.06 Not strictly speaking correct.

6.03 Incorrect. A 2% correction was made for Gorgon losses.

6.04 Incorrect. A reconciliation sheet was given by Sheila Graham to the auditor.

6.07 How can this finding be graded as "Unsatisfactory" when SDA complied strictly with CERES guidelines and have already implemented the new definitions from 1/1/2000?

6.08 This matter has been discussed with Group Finance who support SDA's current treatment. Initial further enquiries have indicated a divergence of views between the reserves auditor and Group Finance on the acceptability of using Expectation reserves for depreciation purposes. SDA will attempt to resolve this difference by year end, but we are puzzled why this divergence should exist on such a fundamental issue.

Many thanks again for your useful review.

regards,

David

David A Christie
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Shell Development Australia
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DRAFT NOTE – 21 Nov 2000 **CONFIDENTIAL**

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

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

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

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 99-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The last previous SEC proved reserves audit for SDA was carried out in 1996. The audit took the form of technical discussions with staff from Woodside Energy Ltd (the operator for a large part of the assets with SDA interest) and detailed discussions about the reserves reporting process with SDA staff.

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

The audit commended the high quality technical work that had been carried out by Woodside, particularly in assessing the subsurface uncertainties and in evaluating the ranges of in-place and reserves estimates. Intensive SIEP assistance through VAR- and other reviews was noted. Maintaining the preliminarily booked volume of Gorgon gas reserves (first done at 1.1.1999) was supported on the grounds that a gas market was highly likely to be established in due course and that it must be considered likely that an extension of the current 5-year Retention Lease will be granted in 2002. Proved reserves in some mature fields (N-Rankin, Goodwyn and the four oil fields) should be increased to expectation levels, in line with the guidelines. This could increase Group entitlement by some 12 mln m3oe. Concern was expressed about the lack of a concisely documented audit trail, which hampered a proper assessment of the reasons for the end-1999 reserves changes.

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

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

A.A. Barendregt

Attachments 1, 2, 3

Attachment 1

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

MAIN OBSERVATIONS

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

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

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

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

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

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

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

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

6. GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes for NWS fields. An attempt was made at reconciling the SDA Nm3 submission with individual field's and Gorgon GHVs, but the resulting average GHV did not seem to match with the average GHV implied by the submission (Att. 2.4).

7. Asset depreciation for Group accounts is done correctly through proved developed reserves depletion (proved total reserves for the full North Rankin facilities, which act as a hub for the entire NWS offshore gas system). Correct reserves values are being used, but no copy could be found of the formal end-1999 note of advice to Finance with the proper new reserves volumes to be used.
8. Full monthly production and sales statistics (100% field volumes) are received by fax from Woodside, who are the only operator at present with fields in production in SDA-held acreage. A selection of these figures (e.g. totals by assets only, not fields) is manually transcribed into the Finance system for monthly /. quarterly reporting. A parallel system (also with manual input) is maintained by the Development Manager for e.g. KPI and MIS reporting. There would appear to be opportunities for synergy and rationalisation, also through electronic transfer of data. Incorporation of data at field level could help the end-year audit trail.

Recommendations

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

Attachment 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved Oil / NGL / Gas Reserves as at 31.12.99

Area / Field	Proven HIP MMstb / Bscf	Exp'n HIIP MMstb / Bscf	Cum. Prod = Sales 31.12.99 MMstb / Bscf	Proved Rem. Recov. Dev. MMstb / Bscf	Proved Rem. Recov. Tot'l MMstb / Bscf	Exp'n Rem. Recov. Tot'l MMstb / Bscf	Maturity (Cum.pr / Exp'n UR) %	Dev. / Tot'l Proved UR. %	Proved RF Tot'l %	Exp'n RF Tot'l %	Fract'n w/i lic. & comtd Pr.Dev. %	Fract'n w/i lic. & comtd Pr.Tot'l %	Within Licence & comtd Pr.Dev. MMstb / Bscf	Within Licence & comtd Pr.Tot'l MMstb / Bscf	Venture Shell share % %	Shell Equity Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Tot'l 10^6 sm3/ 10^9 sm3	1999 Subm'n Dev 10^6 sm3/ 10^9 sm3	1999 Subm'n Tot'l 10^6 sm3/ 10^9 sm3
Oil																			
Wanaea	283.30	340.30	43.60	96.20	104.80	141.10	23.7%	94.2%	52.5%	54.3%	100.0%	100.0%	97.20	104.80	16.67%	2.58	2.78		
Cossack	78.80	120.10	34.20	14.20	14.20	37.60	47.6%	100.0%	83.2%	59.8%	100.0%	100.0%	14.20	14.20	16.67%	0.38	0.38		
Lambert	55.60	74.50	1.10	14.60	22.30	32.10	3.3%	66.7%	42.1%	44.6%	100.0%	100.0%	14.50	22.30	16.67%	0.38	0.59		
Hermes	22.10	28.10	7.70	1.80	3.00	5.60	57.9%	88.6%	46.4%	47.3%	100.0%	100.0%	1.80	3.00	16.67%	0.05	0.08		
Egret	18.60	37.60			6.00	13.10	0.0%	0.0%	32.3%	34.8%	100.0%	100.0%	0.00	6.00	16.67%	0.00	0.16		
Laminaria	162.30	204.00	3.00	85.60	95.60	126.90	2.3%	89.9%	60.5%	63.7%	100.0%	100.0%	85.60	95.60	25.00%	3.40	3.80		
Corallina	71.50	97.00	0.70	37.60	38.40	55.20	1.3%	98.0%	54.7%	57.6%	100.0%	100.0%	37.60	38.40	25.00%	1.49	1.53		
Barrow Island (WAPET)	1353.61	1353.61	284.65	51.70	51.70	77.70	78.6%	100.0%	24.9%	26.8%	55.8%	55.8%	28.86	28.86	28.57%	1.31	1.31		
Thevenard Island (WAPET)	282.91	282.91	134.45	23.97	23.97	33.95	79.8%	100.0%	56.0%	59.5%	100.0%	100.0%	23.97	23.97	35.71%	1.36	1.36		
NWS + WAPET Oil - SDA 'direct' share																10.95	11.98	11.64	12.63
Wan., Coss., Lamb., Herm., Egret (W=16.67%)													127.70	150.30	5.71%	1.16	1.36		
Lamainaria, Coralina (Woods = 50%)													123.20	134.00	17.14%	3.36	3.66		
SDA 'indirect' 34.27% share in Woodside																4.52	5.02	4.28	5.44
Total Oil (MMstb)	2328.52	2538.12	509.60	325.67	359.97	523.25							303.73	337.13	31.7%	15.47	17.00	15.92	18.07
NGL																			
North Rankin	313.50	347.30	127.80	15.00	68.20	89.40	58.8%	72.8%	62.5%	62.6%	100.0%	100.0%	15.00	68.20	15.66%	0.37	1.70		
Perseus	308.30	377.60	18.20	22.10	164.70	215.40	7.8%	22.0%	59.3%	61.8%	100.0%	100.0%	22.10	164.70	15.66%	0.55	4.10		
Goodwyn	530.70	629.70	117.10	84.50	194.00	251.10	31.8%	64.8%	58.6%	58.5%	100.0%	100.0%	84.60	194.00	15.66%	2.10	4.83		
Angel	129.90	165.30			65.80	87.00	0.0%	0.0%	50.7%	52.6%	100.0%	100.0%	0.00	65.80	15.66%	0.00	1.84		
Other NWS gas + oil fields	261.00	398.30	2.10	3.70	103.20	152.90	1.4%	5.5%	40.3%	39.1%	100.0%	100.0%	3.70	103.20	15.66%	0.09	2.57		
Gordon field (WAPET)	170.00	210.40			110.69	131.30	0.0%	0.0%	65.1%	62.4%	100.0%	100.0%	0.00	110.69	28.57%	0.00	5.03		
Chrysaor, W-Trial Rocks (WAPET)	69.00	90.00				53.00	0.0%	0	0.0%	58.9%	100.0%	100.0%	0.00	0.00	28.57%	0.00	0.00		
Total SDA 'direct' share																3.12	19.87	3.12	19.86
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)													125.30	595.90	6.76%	1.35	6.41	1.35	6.41
Total NGL (MMstb)	1782.40	2218.80	265.20	125.30	708.59	980.10							125.30	708.59	23.39%	4.47	26.28	4.47	26.27
Gas (Dry, sales gas volumes)																			
North Rankin	11620.00	12180.00	4200.00	1730.00	8160.00	8810.00	38.1%	57.1%	89.3%	80.3%	96.3%	96.3%	1665.99	5951.34	15.64%	7.374	26.341		
Perseus	8770.00	10680.00	500.00	930.00	7010.00	8830.00	5.4%	19.0%	85.6%	87.4%	96.3%	96.3%	895.59	6750.63	15.64%	3.964	29.879		
Goodwyn	7040.00	8390.00	660.00	1610.00	4330.00	5420.00	10.9%	45.5%	70.9%	72.5%	96.3%	96.3%	1550.43	4169.79	15.64%	6.862	18.456		
Angel	2270.00	2790.00			1390.00	1770.00	0.0%	0.0%	61.2%	63.4%	96.3%	96.3%	0.00	1338.57	15.64%	0.000	5.925		
Other NWS gas + oil fields	4440.00	6360.00	40.00	130.00	2360.00	3410.00	1.2%	7.1%	54.1%	54.2%	96.3%	96.3%	125.19	2272.68	15.64%	0.554	10.059		
Gordon field (WAPET)	20936.66	24826.94			10650.00	15200.00	0.0%	0.0%	50.9%	61.2%	98.0%	98.0%	0.00	10437.00	28.57%	0.000	64.391		
Chrysaor, W-Trial Rocks (WAPET)	4550.96	7343.34				3300.00	0.0%	0	0.0%	44.9%	98.0%	98.0%	0.00	0.00	28.57%	0.000	0.000		
Thevenard Island	163.00	163.00	70.00	33.00	39.00	55.00	56.0%	94.5%	66.9%	76.7%	100.0%	100.0%	33.00	39.00	35.71%	0.333	0.394		
Total SDA 'direct' share																19.088	175.445	18.583	176.638
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)													4237.20	20483.01	6.98%	8.371	40.466	8.147	40.205
Total Gas (Bscf)	59790.65	72745.28	5470.00	4433.00	31969.00	44795.00	10.9%	26.5%	62.6%	69.1%			4270.20	30959.01	24.8%	27.459	215.911	26.730	216.843

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

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

Licence expiry dates:

Audit Trail:
Oil: SDA submission not corrected for beyond-licence oil from Barrow Island; Minor error in Woodside share % in Laminaria (double correction for unitisation share)
Gas: Fractions 'w/i licence & comtd' reflect 3.7% correction for future upstream fuel and flare.
Good match for NGL, but matches for oil and gas are poor,

SDA, Oct 2000

CHECKLIST SEC RESERVES AUDITS

Attachment 3

COMPANY: SHELL DEVELOPMENT AUSTRALIA LTD AREA / FIELD: ALL

Dimensions (100% field figures as at 1.1.2000): **Average Group share: 25 - 37%**

1.1.2000 Proved Oil Reserves	45	10^6 m3	(Group share 18 10^6 m3)
1.1.2000 Proved Developed Oil Reserves	40	10^6 m3	(Group share 16 10^6 m3)
1999 Oil Production	6	10^6 m3	(Group share 1.4 10^6 m3)
	16	10^3 m3/d	(Group share 3.8 10^3 m3/d)
1.1.2000 Proved Gas Reserves	900	10^9 sm3	(Group share 216 10^9 sm3)
1.1.2000 Proved Developed Gas Reserves	124	10^9 sm3	(Group share 27 10^9 sm3)
1999 Gas Production	16	10^9 sm3	(Group share 4.1 10^9 sm3)
	45	10^6 sm3/d	(Group share 11 10^6 sm3/d)
Number of fields in area	20		
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 has been shot and interpreted over all the fields
1.02	Are seismic processing and interpretation state-of-the-art?	+	Although much of the seismic vintage is from the early 1990's, re-processing and re-interpretation using the latest techniques is gradually being introduced (eg Lambert/Hermes, Laminaria)
1.03	Is well log data quantity and quality adequate?	+	Extensive log and core data have been gathered in appraisal wells and in development wells as appropriate.
1.04	Is well data coverage adequate?	+	Certainly in developed fields; Subsurface uncertainties are properly accounted for in undeveloped fields and proved reserves are in principle not booked until data coverage is adequate.
1.05	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Proved reserves are not booked until well data coverage is adequate.
1.06	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Yes, most notably in Gorgon
1.07	Is there a proper volumetric estimate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.08	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	Yes, extensive PVT analyses are standard practice and these are properly reflected in static and dynamic models.
1.09	Is a static model available / adequate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.10	Is a dynamic model available / adequate?	+	Yes, detailed dynamic models (downloaded from static models) are available for all fields with proved reserves.
1.11	Is a history match available / adequate?	+	History matches, to the extent that there is sufficient production history, are good and are kept up-to-date on a regular basis.
1.12	Is the recovery factor for proved reserves realistic?	+	Yes, the RFs fully reflect the range of possible subsurface realisations and possible development scenarios.
1.13	Are developed reserves based on proper NFA (No Further Activity) forecasts?	+	Yes; dedicated NFA dynamic model runs are made, incorporating existing facilities' constraints, as relevant.
1.14	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. A proper correction was made at 1.1.2000 to reflect the as yet undeveloped state of gas reserves obtainable through compression.
1.15	Has/have (a) development project(s) been defined for undeveloped reserves or can it/they be defined?	+	Yes
1.16	Is/are the project(s) technically mature or is further data gathering necessary?	+	Those projects pertaining to proved reserves are mature, with the possible exception of Egret, where the low reserves estimate does not appear to pass screening criteria. In the large Gorgon gas field, there is also a technically (and economically) robust development plan.
1.17	Is/are there (an) auditable development project plan(s) with costs, benefits and economics?	+	Yes
1.18	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	N.A.	Apart from ongoing gas recycling in Goodwyn and some LPG/gas injection in Laminaria/Corallina, there are no improved recovery projects planned.

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

1.19	Has the project been subjected to a VAR review or other external review and if so, what have been the main conclusions?	+	All projects in which SDA have an interest are subjected to regular peer reviews and VAR reviews with SIEP-EPT assistance. In particular the SIEP assistance to Woodside can be classified as intensive.
2	COMMERCIAL MATURITY		
2.01	Is/are the project(s) commercially mature (positive NPV for Group Ref. Crit. over a range of possible future scenarios / low case reserves)?	+	Yes; those that are not are classified as SFR
2.02	Is/are the project(s) economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	+	Yes, with the possible (minor) exception of Egret, see 1.16 above.
2.03	Have forecasts been cut off when rates become uneconomic?	+	Yes; those that are not are classified as SFR
2.04	Have the latest Group Screening / Reference Criteria been used?	+	Yes (standard Group practice)
2.05	Are assumed prices and costs RT (or justified if not)?	+	Yes (standard Group practice)
2.06	Has/have the project(s) been approved by Shareholders?	O	Shareholder approval has been obtained for imminent projects and projects in progress. For projects further into the future it will be soughtin die course.
2.07	Is project financing available or can it reasonably be expected to be available?	+	Yes, no foreseeable problems in this respect.
2.08	Are developed reserves actually in production?	+	Yes
2.09	Have all proved gas reserves been contracted to sales?	O	Not all of these. There is still uncontracted gas in the NWS fields, whilst Gorgon gas is as yet wholly uncommitted.
2.10	If not, can they reasonably be expected to be sold in existing markets and through existing facilities?	+	Existing NWS gas buyers are likely to be quite willing to extend current contracts; Existing facilities' life span is not seen as a constraint.
2.11	If neither, can they reasonably be expected to be developed and sold in a future market?	+	There are likely to be ample opportunities for expansion of the LNG market in South and East Asia (Japan and Korea, but also Taiwan, China, India), particularly post-2005. Although there is competition on the supply side, there can be little doubt that buyers can eventually be found for all economically producible gas on the Australian shelf.
3	REASONABLE CERTAINTY		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	+	The established procedure of fully probabilistic volumetrics and multi-realisation static modelling ensures that proper ranges are taken for each of the volumetric parameters.
3.02	Is the uncertainty range of developed recovery adequate?	+	Yes, it takes account of the maturity of the field
3.03	Is the uncertainty range of undeveloped recovery adequate?	+	Yes, reflected through the multi-scenario dynamic modelling
3.04	Have market / production constraint uncertainties been taken into account?	N.A.	Since there are no end-of -icence issues for the NWS fields, market/facilities constraints have essentially no effect on reserves estimates. For a discussion on Gorgon, see 4.01.
3.05	What is ratio of field(s) cum.prod. / proved total recovery?		Ranges from 0 to 40% (excluding Barrow island and Thevenard, see also Att 2.1)
3.06	Can the field(s) be considered mature?		Some (N-Rankin, Wanaea, Cossack), yes. The very mature fields Barrow Island and Thevenard have been sold during 2000.
3.07	Are proved (developed and total) reserves benchmarked against expectation reserves for 'proved areas' when field(s) are mature (deterministic approach)?	X	No; Guidelines allow externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) to be taken as equal to expectation reserves.
3.08	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Proved reserves for fields are added together arithmetically. Depreciation for e.g. the NWS gas fileds is done on a combined asset basis and probabilistic addition within those assets would in principle be allowed.
3.09	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	+	Probabilistic estimates for entities (areas, reservoir sands) within fields are added together probabilistically. Examples are Main, Perseus-West and Capella (added probabilistically to form greater Perseus and the individual reservoirs in Goodwyn).
3.10	Is any assumed dependency in probabilistic addition appropriate?		??
4	GROUP SHARE CALCULATION		

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

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?	O	Licences start with an exploration permit for up to 6 years, renewable for up to 5 years, to be followed by a Production Licence if commercial production is undertaken. Production Licences last for 21 years, with one extension option of another 21 years, followed by a further extension option of indefinite duration. The Production Licence lapses only if there has been no production for 5 successive years. Hence there is no end-of-licence cut-off in effect for any of the NWS or Laminaria/Corallina fields.
			Fields for which the exploration licence has ended and for which no production licence has been applied for can be granted a Retention Lease for a period of 5 years. This can be followed by an indefinite number of successive 5-year extension options, which carry the conditions that the field can be considered likely to become commercially viable within the next 15 years and that the lessee is actively pursuing the evaluation of commercial viability, including the conclusion of long term sales contracts. Currently, the fields in the Gorgon area are held under a Retention Lease, of which the current extension ends in 2002. Although it is considered likely that the interest holders can convince the authorities that commercial viability on these fields is actively being pursued, it is not clear whether this can be seen as a 'right to extend'.
4.02	Are the forecasts required to demonstrate the above condition consistent with those presented in the latest Business Plan?	N.A.	
4.03	Is the company's hydrocarbons Equity share calculated properly?	+	Yes, total Shell equity is calculated as the sum of 'direct' Shell (SDA) participation share in the respective ventures, plus the 'indirect' Shell share (34.27%) in Woodside Petroleum Ltd, which has separate holdings in the respective ventures.
4.04	Is the net Shell share calculated properly (100% for consolidated Shell companies, with minority reserves reported separately, or actual percentage if less than 50%)?	+	Yes, actual percentage is reported.
4.05	Is the hydrocarbons PSC entitlement share (net cost oil + profit oil only) calculated properly?	N.A.	
4.06	Is the hydrocarbons Purchase Right share (to the extent that economic benefit is derived from production while still bearing share of risks and rewards) calculated properly?	N.A.	
4.07	Are royalties in cash (legally or customarily) counted as reserves?	+	All royalties are paid in cash and corresponding volumes are included in reserves.
4.08	Are royalties in kind excluded from reserves?	N.A.	
4.09	Are volumes given away or received as fees in kind (e.g. for infrastructure use by third parties) excluded from reserves?	N.A.	
4.10	Has historic Group under-or overlift (compared with other co-venturers) been accounted for?	N.A.	
4.11	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?	N.A.	
4.12	Have separate submissions been made for Equity, Entitlement and Purchase Right volumes?	N.A.	Separate submissons have been made for 'Direct' and 'Indirect' Shell share volumes.
5	AUDIT TRAILS		
5.01	Are proved and proved developed reserves estimates up-to date?	+	Reserves for the Woodside operated fields (NWS and Laminaria/Corallina) are being kept up-to-date annually and revised as necessary.
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	O	Largely, yes. A good match (or reconciliation of minor errors) was obtained for Oil and NGL figures, but gas volumes appeared to show discrepancies of 1-3%, see Att. 2.1.
5.03	Can reported net Group equity reserves be reconciled with other relevant data (e.g. production constraints, gas markets, etc.)?	N.A.	Not really relevant

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5.04	Can reserve changes be reconciled with individual field changes?	X	No individual field reserves (100%) from last year's submission were available, neither were individual field production data for 1999 (see also 6.06-07). Specific categories for oil (purchases/sales in place, new discoveries, new developed reserves) could be broadly reconciled to individual fields. A significant reduction in developed gas reserves was due to a correction for (as yet undeveloped) reserves attributable to future compression. Both developed and total reserves had to be reduced to account for the larger share that Woodside will take in future Domgas sales.
5.05	Are reserve changes reported in the appropriate categories?	+	Yes, see above.
5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	O	Most field reserves are in line with estimates in the latest FDP reports, with remarkably little change being required in e.g. Wanaea / Cossack and Laminaria / Corallina. However, the latest correction in developed gas reserves (correcting for compression) was not found to have been documented anywhere.
5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	X	FDP reports are indexed and identified properly and full sets of copies are kept by the operators. It was found however, that a number of SDA copies of Woodside documents were unavailable following the office move from Melbourne to Perth.
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?	X	A brief summary note (text only) was produced but this was insufficient to provide a comprehensive audit trail (e.g. only expectation volumes mentioned, no tabulated details by field, etc).
5.09	Are data bases containing historic submissions' data and current reserves status (e.g. RISRES) in place and accessible?	O	In view of the limited number of fields, data are kept in spreadsheets only.
5.10	Do these data bases also contain references to detailed reports?	X	No.
6	**CONSISTENCY WITH FINANCIAL REPORTING**		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes, in particular LPGs are reported correctly as gas
6.03	Are own use, fuel, losses etc excluded?	O	Upstream own use, fuel and losses (estimated at 3.7% in the Woodside 'Version-7' submission to SDA, although 2.9% was shown in a later submission) are excluded from the NWS gas volumes. A similar 2% correction was made for the Gorgon volumes. Downstream fuel and losses (i.e. in the LNG plant) are correctly included in reserves.
6.04	Are gas GHVs properly measured for sales gas conditions and accounted for in reserves submissions?	O	GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes for NWS fields. An attempt was made at reconciling the SDA Nm3 submission with individual field's and Gorgon GHVs, but the resulting average GHV did not seem to match with the average GHV implied by the submission (Att. 2.4).
6.05	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	O	Yes, although the audit trail was poor: a copy of the original note by SDA Petroleum Engineers advising SDA Finance about the reserves to be used could not be found. Upon advice from SIEP early in 2000, asset depreciation for North Rankin facilities is done on total North Rankin reserves, whilst those for the other fields are done on proved developed reserves.
5.06	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. 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?	+	The end-1999 submissions for 1999 oil+NGL production through Ceres and through SIEP were, after some corrections, identical.

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6.07	Are annual gas production (sales) volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0323 = 0934 (Group Cy net NG sales) + 3598 (Assoc.Cy NG sales), corrected for 1404+4796 (Gas purchases) and 4100+4510+4575+0873 (Trade, other Sales and Transfers)?	O	The end-1999 submissions for 1999 gas sales through Ceres and through the reserves reporting line (SIEP) were inconsistent with each other (some 9% different). This was due to LNG plant fuel and flare being excluded from the Ceres figures, thus effectively reporting the downstream sales, not the upstream production. The new 1.1.2000 definitions in Ceres should remove this inconsistency.
7	**OVERALL**		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Group guidelines were not completely followed with respect to proved and proved developed reserves in mature fields (see 3.07). The potential understatement in total proved reserves could be some 12 mln m3oe Group share, or some 4% of SDA booked reserves. Gorgon gas reserves (some 86 bln sm3 or 30% of SDA's m3oe Group share volume) can be maintained at their present level in the reserves portfolio and should only be changed if definitive new information regarding the project and/or the retention lease extension becomes available.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	O	Bearing in mind the above remarks, the SDA statement of proved and proved developed reserves at end 1999 can be considered to give a reasonably accurate reflection of shareholder value.

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NOTE – 8 Feb 2000 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP
To:	Linda Z Cook	(Previous) Director, EP Business Development, SIEP
	Lorin Brass	Director, EP Business Development, SIEP
Copy:	Phil B. Watts	EP Chief Executive Officer, SIEP
	Roelof J. Platenkamp	Vice Pres. Strategy, Planning, Portfolio and Economics, SIEP
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	Egbert Eeftink	Director, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

REVIEW OF GROUP END-1999 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

In accordance with prescribed US Generally Accepted Accounting Principles (SFAS69), SIEP staff have prepared a summary of Group equity proved and proved developed oil and gas reserves for the year 1999. The summary (Att. 3) forms part of the supplementary information that will be presented in the 1999 Group Annual Reports and has been prepared on the basis of information provided by Group and Associated companies. The submissions by these companies (excluding those by Shell Canada) are based on the procedures laid down in the "Petroleum Resource Volumes Guidelines" (EP 99-1100/1101) which in turn are based on the requirements of SFAS 69. Shell Canada's submissions are subject to their own procedures and reviews.

I have reviewed the process of preparing the above summary of proved and proved developed oil and gas reserves in as far as these relate to companies outside Canada. This review included a verification of the reasonableness of major reserves changes and any omissions of such changes, as appropriate. The review also included a comparison between 1999 production (i.e. sales) volumes as reported in the OU reserves submissions and those reported separately through the Finance system in Ceres.

Two significant additions to the Group's proved hydrocarbon portfolio have not been included in SEC externally reported reserves this year. These are the heavy oil volumes recoverable from oil sands in Canada and the proved oil entitlements under the new Iran contract. The first is a mining project and as such cannot be reported under oil&gas reserves, in line with SEC and Group guidelines. As for the Iran entitlements, SEC and Group guidelines prescribe that these should be classified as reserves. On host government insistence, this has not been done.

The challenge by SIEP to constrain Group entitlement reserves increases in companies facing production ceilings and impending production licence expirations (this year primarily in Nigeria) is supported.

There appears to be significant scope for further increasing proved reserves in some areas (Brunei, Oman, and others), where estimates tend to be conservative in comparison with expectation volumes and thereby not fully in line with latest Group guidelines.

It was disappointing to see that, in spite of some progress through SIEP efforts, the persistent problem of inconsistencies between the annual sales volumes reported through the Finance system (Ceres) and those in the reserves submissions had not yet been resolved during 1999. The matter is of importance, because both submissions find their separate ways into the Group annual report and discrepancies are in principle detectible.

SIEP staff is commended for the effective system of electronic spreadsheets and controls governing the OU submissions. This has greatly improved auditability of the results.

During 1999 I made reserves audit visits to a total of nine Group OUs. Audit opinions on six of these were 'satisfactory', whilst three of them were classed as 'good'. A summary of these audit findings is attached (Att. 6). It was found that most recommendations had already been followed up in the 1999 submissions. Similar audits are planned in six OUs in the course of 2000. An updated Audit Plan is attached (Att. 7).

The finding from the audit visits and the end-year review in SIEP is that the SIEP statements fairly represent the Group entitlements to Proved Reserves at the end of 1999. The 1999 changes in the Proved Reserves can be fully reconciled from the individual OU submissions.

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

A.A. Barendregt

Attachments 1 - 7

DEPOSITION EXHIBIT
Barendregt
#15 2/20/07

Attachment 1	Main Observations end-year process
Attachment 2	Major Reserves Changes
Attachment 3	Group Proved Reserves Summaries
Attachment 4	Proved/Expn reserves vs field maturity
Attachment 5	Production Reconciliation Ceres vs Reserves Submissions
Attachment 6	Main observations 1999 Reserves Audits
Attachment 7	Reserves Audit Plan 2000

Attachment 1

REVIEW OF GROUP END-1999 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

MAIN OBSERVATIONS

1. Significant reserves changes are listed in Attachment 2.

   In **Nigeria**, Exxon have discovered and appraised the **Ehra** field (Shell share 44%) and are close to producing a field development plan. On the basis of work done to date and with the analogue of SNEPCO's Bonga field, economic viability of the project is not under doubt The proved volumes (24 10^6 m3 oil) have therefore been included in the externally reported reserves. This is supported.

   Field studies have led to sizable proved field volume increases in **Nigeria** and **Oman**, but these have been partially capped to reflect the requirement that proved reserves must be producible before end-of-licence (see below).

   An **equity increase** was booked for the Troll field in **Norway**. **Equity decreases** had to be booked in **Australia** (corrected gas share in line with contract) and **Oman-Gisco** (lower funding and reward gas).

   Add-back of volumes previously (and wrongly) excluded as **royalties in kind** has led to reserves increases in **Canada**.

   Project start-ups (Oman-Gisco, Sable Island, F23 compression, Obaiyed) and development drilling have helped to maintain developed reserves.

   Dilution or divestment of equity has led to reserves reductions in the **USA, Philippines and Canada.**

2. Two significant additions to the Group's proved hydrocarbon portfolio have not been included in externally reported reserves this year. These are the **Muskeg oil sands** in Athabasca, Canada (95 10^6 m3heavy oil), following project FID in 1999 and the proved reserves under the new **Iran contract** (Soroosh/Nowrooz, 24 10^6 m3 oil). The first is a mining project and as such cannot be reported under oil&gas reserves, in line with SEC and Group guidelines. The Iran contract and associated oil volume entitlements are similar in nature to those for the Venezuelan and Oman-Gisco contracts. The SEC and Group guidelines therefore prescribe that these entitlements be classified as reserves. However, host government insistence has led to the decision not to include these in the externally reported volumes for 1.1.2000.

3. In **Australia**, WAPET have re-evaluated the gas reserves in their large, undeveloped **Gorgon** field, indicating that some 20% more reserves would be economically recoverable. The most likely market for this gas would be LNG. However, customers for this additional gas cannot at this stage be readily identified and the incremental volumes (some 20 10^9 Nm3 Group share) have not been included in externally reported proved reserves at this stage. This is in line with Group guidelines and is therefore supported.

4. In the **Netherlands**, NAM have written down exploration costs related to the **Waddenzee** finds, because no development was likely to occur within the next five years, following the new Government moratorium (for an indefinite period, but not permanent) on drilling in that area. However, the proved gas volumes are economic to develop, a market is readily available and the licence duration is indefinite. Hence, the proved volumes have been maintained in externally reported reserves. This is supported.

5. SEC and Group guidelines prescribe that proved and proved developed reserves can be demonstrated to be producible before the **expiry of current production licences** (or their extension if a right to extend is formally agreed). Whilst not a severe constraint in many cases, it is becoming a serious issue for large resource holders that are facing production or export level constraints, i.e. **SPDC Nigeria** and **ADCO Abu Dhabi** and **PDO Oman.** The first two companies carry significant aspirational upturns in future offtake levels in order to justify their proved reserves levels. In view of the need for reasonable certainty of these levels, total proved reserves for SPDC Nigeria have been capped this year by not booking a bottom line increase of 49 10^6 m3, arising from recovery improvements in a series of fields. This is supported. Abu Dhabi reserves had already been capped in previous submissions. Vigilance will be required to ensure that forecasts in future submissions remain realistic.

6. A review of the margin between proved an expectation reserves for major OU fields has shown a tendency for **conservative estimating**, in particular in some mature fields (see Att. 4). Potential increases in proved reserves could be up to 100 10^6 m3 oil equivalent. Field proved reserves are in principle expected to grow closer to expectation reserves with increasing field maturity. Group guidelines also recommend that proved developed reserves are made equal to expectation developed reserves for mature fields (e.g. where cumulative production exceeds some 30-40% of expectation ultimate recovery).

   From Attachment 4 it is clear that many fields do not fulfill these requirements. Main exceptions for undeveloped reserves are in **Norway, UK and Oman**, whilst **Brunei** and **Denmark** tend to be too conservative for both total and developed proved reserves. It is noted that Denmark have compensated for this by introducing, justifiably but somewhat unconventionally, probabilistic addition of their field volumes. For Oman, this conservatism has already been flagged during the October 1999 audit and PDO have undertaken to address this conservatism in their future field reviews. Norway will be audited in 2000.

It may be observed that there are a number of fields that show proved reserves close to or equal to expectation reserves, even for low maturity levels. Whilst a number of these fields are from Shell Canada (with only 'proved', no 'probable' reserves carried), most of these tend to be exceptions of some sort, e.g. small fields in a larger cluster (UK, Netherlands), or reserves constrained by licence expiry (Abu Dhabi).

7. Until this year, **Shell Oil** made their separate reserves submission to SEC, following their own internal and SEC guidelines. In line with the Group's efforts at globalisation, Shell Oil's separate status was discontinued in 1999 and they were expected to adhere to Group guidelines in their reserves submission. It was noted that Shell Oil include **own use gas** in their reserves on the premise that this gas is in principle available for sale into a market and SEC guidelines do not forbid (nor prescribe) their inclusion. Group guidelines specifically forbid inclusion of own use, fuel and flare volumes. The volume affected is some 6.5 10^9 Nm3, mainly in the Area and Altura ventures. Although in contravention of current Group guidelines, Excom advice has been received that Shell Oil reserves submission should not be changed in this respect, pending an analysis of EP industry practice. The issue should be resolved, if necessary through an update of the Group guidelines.

8. In **Venezuela**, it was noted during the 1999 reserves audit that reserves booked by SVSA were **100%** of their operated field **reserves**, even when the net fee received for the oil amounted to only half the prevailing oil price. The Oman Gisco contract and all PSC contract entitlements booked for other OUs take account of the net effective volumes or prices received. Current Group reserves guidelines are not clear on the issue. For Venezuela, it was subsequently decided that, with fees in the near future likely to rise to levels very close to full oil price, the booking of 100% of field volumes was justified. To facilitate booking of future contracts, a more structural solution, through Group guidelines, is recommended.

9. Part of the requirements made in the Group guidelines is that **1999 production**, to be deducted from 1.1.1999 reserves in the reserves submission, should be equal to sales volumes reported under the Finance system through **Ceres**, since both volumes are reported externally. Comparison between the two submissions is made for Oil+NGL (in m3) and gas (in Nm3 at 9500 kCal/Nm3). Results of the comparison are shown in Attachment 5.

   From the comparison, it is clear that the final correspondence between the two submissions is good for **Oil+NGL**, with the main exception being **Shell Canada**, who erroneously exclude royalties in cash from their Ceres submission. The reserves submission has been corrected for this, in line with Group and SEC guidelines.

   For **gas**, the comparison is far less favourable. An outstanding discrepancy of 2.5 10^9 Nm3 (or 3% of 1999 sales) remains, which, because of ingrained procedures, cannot be corrected readily. Main reasons for the discrepancy are:

   - Ceres submissions for **integrated companies (Australia, Germany, Shell Oil, Canada, UK)** report sales as ex-downstream, not upstream sales. Hence, downstream effects like LNG plant fuel, gas storage movement, take-or-pay gas not taken etc cause a variety of distortions.
   - Although both submissions should be in Nm3 at 9500 kCal/Nm3 equivalent, the **unit conversions** from scf or sm3 volumes is often done inconsistently within OUs and between OUs. Conversions in the reserves submissions appear to be correct more often than in the Ceres submissions. It was noted that OU staff, particularly on the Finance side, tend to be reluctant to change their established procedures.
   - **Kingfisher** gas in the **UK** is delivered free of payment as tariff in kind for oil processing services by a third party (Marathon). Kingfisher volumes and production are correctly included in the reserves submission, but are still excluded from the Ceres submission. Shell UK Expro have undertaken to correct this for the 2000 Ceres submission.

   It is disappointing to see that these problems, most of which have been present for several years, have not yet been resolved, in spite of strenuous SIEP efforts. The matter is of importance, because **both submissions** find their separate ways into the **Group annual report** and any discrepancies are in principle detectible. I note that steps are now underway to re-define the externally reported gas volumes under Ceres as sales ex-upstream only and that gas volumes in both reports should from 2000 onwards be in sm3 tel quel, i.e. not normalised for GHV content. These changes should help to bring consistency in the gas volumes to the same level as that for oil+NGL and they are therefore fully supported.

10. Similar to last year, reserves submissions from OUs were made in strictly unified format through SIEP-designed **electronic workbooks**, with strict controls embedded. The ample use of consistency validation in these workbooks has greatly improved the quality of the submissions and the auditability of the accumulation process. Further improvements this year included the tables for individual field data and

volume changes for major fields, plus the request for new developed proved reserves volumes (i.e. transfers from undeveloped to developed reserves). These improvements have enhanced the review process and SIEP staff are to be commended for this. A further refinement, by including an entry for purchases/sales-in-place for proved developed reserves changes by field would be welcomed.

Recommendations:

1. Encourage OUs with low proved reserves in comparison with their expectation levels, to review and upgrade these on an urgent basis.
2. Ensure that OU forecasts to calculate proved within-licence recoverable volumes remain realistic.
3. Implement current plans to unify submission requirements for annual (upstream) sales volumes in both Ceres and the reserves submissions, addressing volume units (sm3 for all) and strict upstream sector delineation.
4. Address the issue of own use gas in the Shell Oil / Pecten reserves submissions, if necessary by adapting the definitions in the Group reserves (and Ceres!) guidelines.
5. For the benefit of future reserves bookings, amend the guidelines to address the issue of the appropriate Shell share to be used in the new type of incentive contracts as in force in Oman-Gisco and Venezuela.
6. Include an entry for sales/purchases-in-place in the proved developed reserves field changes in the reserves submission spreadsheet.

Attachment 2

MOST SIGNIFICANT 1999 PROVED AND PROVED DEVELOPED RECOVERY CHANGES

(Shell Group share)

MAJOR TECHNICAL REVISIONS					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Nigeria - SPDC	-	+39	-	+12	Field reviews.
Nigeria - SPDC	+7	+27	-	-	Late implementation of new (1998) guidelines in a number of reservoirs.
Nigeria - SNEPCO	-	+24	-	-	Ehra discovery (no market yet, hence no gas reserves)
Oman - PDO	+9	+19	-	-	Field reviews, incl. +7 10^6 m3 improved recovery (undev'd) in Marmul
USA – Shell Oil	-	+10	-	+9	Field extensions/discoveries?
Norway	-1	+1	-8	+15	Equity re-determination Troll.
Norway	-	+1	-	+12	Field extension in Ormen Lange (undev'd)
Nigeria – SPDC	-	+5	-	+6	Discoveries/extensions in K1, K1 South, Uzuaku
Oman - Gisco	+27	-	+59	-	Project start-up June '99
USA – Shell Oil	+18	-	+11	-	Development activities
Canada	+5	-	+22		Sable Island start-up Dec '99
UK	+18	-	+8	-	Development activities
Nigeria - SPDC	+15	-	-	-	Development activities
Malaysia	+1	-	+11	-	F23-KA compression installed
Egypt	+4	-	+7	-	Obaiyed on stream Aug '99
Oman	+9	-	-	-	Development activities
Abu Dhabi	+8	-	-	-	More detailed analysis per field
Australia	-3	-	-34		Correction for N-Rankin developed reserves requiring (not yet installed) compression

OTHER MAJOR CHANGES					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Canada	+4	+5	+10	+14	Add-back of cash royalties, previously not included.
Nigeria - SPDC	-	+11	-	-	Effective Shell share increased from 30% to 77% in EA/EJA offshore fields following new funding agreement.
Australia	-0	-0	-0	-7	Re-calculation of NWS net Shell share (direct share up, indirect share down), to bring in line with contract provisions.
Oman - Gisco	+1	+2	-12	-12	Increased NGL due to allocation of early production to GISCO for tax payments. Overall reduction in GISCO cashflow due to lower funding agreed in September 1999.
Canada	-7	-11	-2	-3	Plains BU divested Nov '99
Oman	-17	-	-	-	Correction to reflect proper no-activity forecast to end-of-licence.
Philippines	-	- 4	-	-19	Divestment of 45% of Malampaya to Texaco
Nigeria SPDC	-	-49	-	-	Correction for field increases to reflect total bookable SPDC proved reserves being constrained by an already ambitious forecast and end of licence in 2019.
USA – Shell Oil	-25	-44	-5	-15	Divestments to Apache, Enterprise, plus dilution of three Gulf of Mexico fields

OTHER MINOR CHANGES					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Chad, Khazakstan	-	+2	-	-	Divestment in Chad (-0.4), First discovery in Khazakstan (+2)
Other	+57	+30	+24	+17	

TOTAL CHANGES					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
	+130	+68	+91	+29	

DB 25128

1999 GROUP RESERVES SUBMISSIONS

Attachment 3.1

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

FOIA Confidential Treatment Requested

Country Name	Proved reserves 1.1.1999	Revisions and Reclassifications	Improved recovery	Extensions and Discoveries	Purchases in place	Sales in place	Production (i.e. net sales) during 1999	Proved reserves at 31.12.1999	Proved developed reserves at 1.1.1999	Transfer Undeveloped to Developed	Revisions	Production (i.e. net sales) during 1999	Proved developed reserves at 31.12.1999	Minority Reserves included 1.1.1999	Minority Reserves included 31.12.1999		Replacement Ratio (%) DevRes	Replacement Ratio (%) TotRes
Argentine	3.88	-.19	.	.	.	.	.26	3.43	1.97	.01	.31	.26	2.03	.	.		123%	-73%
Bangladesh	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Denmark	35.57	4.1	.32	6.02	.	.	6.86	39.15	28.22	2.77	3.49	6.85	27.63	.	.		91%	152%
Egypt	9.15	-.03	.	.31	.	.	.37	9.06	2.31	3.83	-.04	.37	5.73	.	.		1024%	78%
Kazakhstan - Temir	.	.	.	2.	.	.	.	2.	.	.	.	.	.	.	.			
Nigeria (SNEPCO)	50.4	-2.97	.	23.98	.	.	.	71.41	.	.	.	.	.	.	.			
Nigeria (SPDC)	429.82	25.79	.	4.78	.	.	12.29	448.1	103.25	14.99	7.24	12.29	113.19	.	.		181%	249%
Oman Gisco	32.34	1.72	.	.	.	.	.88	33.18	.	26.75	1.45	.88	27.32	4.85	4.98		3205%	195%
Pakistan	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Philippines	7.4	.	.	.	.	3.58	.	3.82	.	.	.	.	.	.	.			
Russia Sakhalin	8.71	-4.75	3.78	.	.	.	.05	7.69	.	2.65	.	.04	2.61	.	.		8625%	-1940%
Chad	.42	-.42	.	.	.	.	.	.	.	.	.	.	.	.	.			
Venezuela	25.27	-1.47	.	.	.	.	2.37	21.43	9.6	4.9	-.52	2.37	11.61	.	.		185%	-62%
Congo (DR)	4.34	-.96	.	.	.	.	.16	3.22	1.27	.94	.25	.16	2.3	.	.		744%	-600%
Abu Dhabi	108.78	-.72	.	.	.	.	4.8	103.26	81.	.	7.51	4.8	83.71	.	.		158%	-15%
Austria	.25	,01	.	.	.	.	.03	.23	.2	.	.02	.03	.19	.	.		67%	33%
Australia (Direct)	31.03	4.05	.	.18	.	.76	1.97	32.49	12.95	4.78	-.98	1.97	14.76	.	.		192%	174%
Australia (Indirect)	12.45	-.24	.	.05	.38	.	.79	11.85	4.52	3.27	-1.37	.79	5.63	.	.		241%	24%
Brunei	55.23	4.19	3.	1.86	.	.	5.	59.28	23.72	5.87	3.61	5.	28.19	.	.		190%	181%
Canada	56.13	5.72	.	.01	.	10.54	4.16	47.16	30.68	5.1	-2.49	4.16	29.13	12.33	10.36		63%	-116%
China	2.79	1.03	.	.	.	.	.58	3.24	2.38	.52	.51	.58	2.83	.	.		178%	178%
Gabon	20.2	4.89	.	.	.	.	5.18	19.91	15.86	1.17	5.61	5.19	17.45	5.08	4.97		131%	94%
Germany	4.04	-.34	.	.	.	.	.33	3.37	3.67	.	-.27	.33	3.07	.	.		-82%	-103%
Malaysia	27.12	2.02	.09	.13	.	.	3.81	25.55	13.41	3.23	1.13	3.81	13.95	.	.		114%	59%
Netherlands	6.09	.43	.	.01	.	.	.76	5.77	3.36	.97	.37	.76	3.93	.	.		176%	58%
Norway	38.75	-1.45	.	.78	.	.	4.82	33.26	23.48	3.84	-1.83	4.82	20.65	.	.		42%	-14%
New Zealand	3.59	-.01	.	1.46	.	.	.44	4.6	2.95	.	.1	.45	2.6	.	.		22%	330%
Oman	134.09	11.73	8.46	1.68	.	.	16.46	139.5	100.22	8.8	-7.56	16.46	85.	.	.		8%	133%
Shell Oil (Aera)	83.38	5.64	.	.	.05	2.15	7.66	79.26	63.85	1.02	1.8	7.66	59.01	.	.		37%	46%
Shell Oil (Altura)	42.03	5.74	2.63	.	.17	.06	2.64	47.87	39.13	.	3.75	2.64	40.24	.	.		142%	321%
Shell Oil (MCC)	4.91	-2.11	.	.1	.01	.5	.55	1.86	3.55	.35	-1.79	.55	1.56	.	.		-262%	-455%
Shell Oil (TMR)	.87	.27	.	.17	.	.	.18	.93	.45	.	.29	.18	.56	.	.		161%	244%
Shell Oil (EH) - China	3.84	.04	.	.	.	.	.59	3.29	3.2	.26	.	.59	2.87	.	.		44%	7%
Shell Oil (EH) - Cameroon	9.04	.02	.	.	.	.	1.31	7.75	8.31	.11	.18	1.3	7.28	.	.		21%	2%
Shell Oil (EH) - New Zeala	.77	.14	.	.	.	.	.11	.8	.64	.	.14	.11	.67	.	.		127%	127%
Shell Oil (USA) cons	149.43	-4.87	.	10.02	.	44.37	18.21	92.	79.79	18.04	-25.5	18.21	54.12	.	.		-41%	-215%
Shell Oil (USA) - Oil Shale	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Shell Oil (WH) cons	.93	.	.	.	.	.	.12	.81	.93	.	.	.12	.81	.	.		0%	0%
Syria	22.78	1.14	.	.	.	.	4.11	19.81	14.63	.93	.84	4.11	12.29	.	.		43%	28%
Thailand	12.73	1.74	.37	.35	.	.	1.02	14.17	5.57	.28	-1.05	1.02	3.78	.	.		-75%	241%
UK	156.4	-2.54	.	.	.	.6	23.34	129.82	94.35	18.2	1.13	23.33	90.35	.	.		83%	-13%
Totl Oil+NGL	1,594.76	57.34	18.66	53.87	.61	62.58	132.21	1,530.43	779.4	133.56	-3.69	132.19	777.05	22.24	20.31		98%	61%
							Check	1530.43				Check	777.06					

1999 GROUP RESERVES SUBMISSIONS

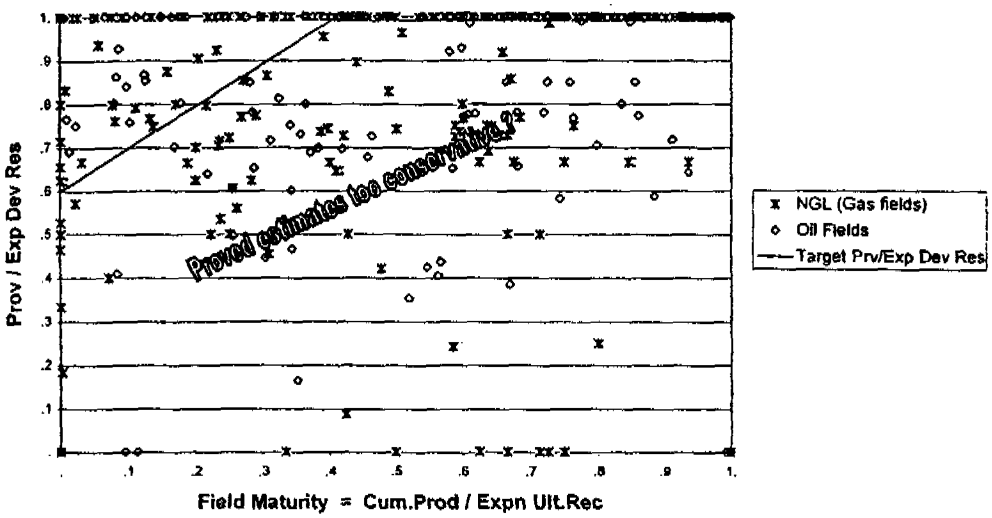
Attachment 3.2

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

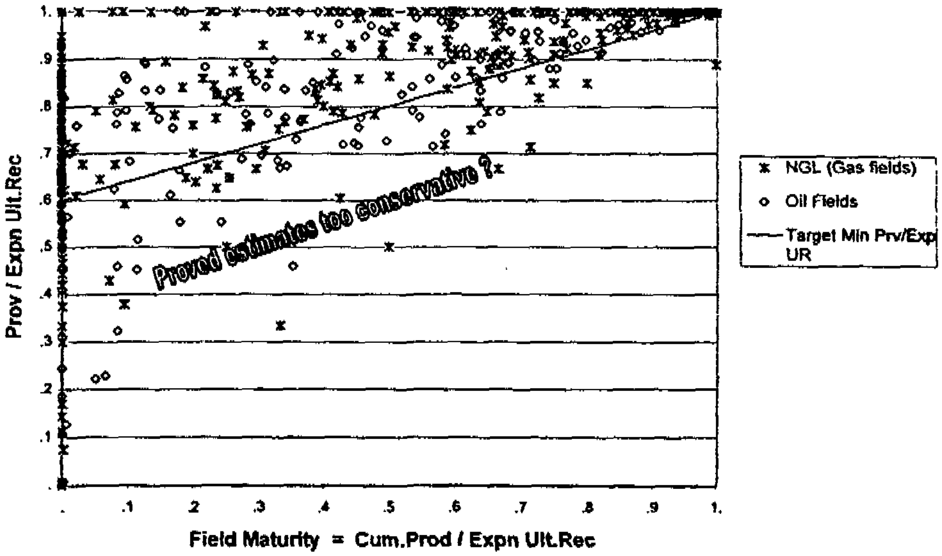
FOIA Confidential Treatment Requested

Country Name	Proved reserves 1.1.1999	Revisions and Reclassifications	Improved recovery	Extensions and Discoveries	Purchases in place	Sales in place	Production (i.e. net sales) during 1999	Proved reserves at 31.12.1999	Proved developed reserves at 1.1.1999	Transfer Undeveloped to Developed	Revisions	Production (i.e. net sales) during 1999	Proved developed reserves at 31.12.1999	Minority Reserves included 1.1.1999	Minority Reserves included 31.12.1999		Replacement Ratio (%) DevRes	Replacement Ratio (%) TotRes
Argentina	6.22	1.09	.	.	.	.	.02	7.28	.05	.07	.45	.02	.55	.	.		2486%	5176%
Bangladesh	6.74	-1.7	.	.	.	.	.33	4.71	2.81	.	.37	.33	2.85	.	.		110%	-512%
Denmark	32.81	-1.63	.06	2.42	.	.	3.22	30.44	20.93	.25	.77	3.22	18.73	.	.		32%	26%
Egypt	29.48	.71	.	2.16	.	.	1.08	31.27	7.92	6.52	.69	1.08	14.06	.	.		669%	266%
Kazakhstan - Temir	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Nigeria (SNEPCO)	7.31	-1.61	.	.	.	.	.	5.7	.	.	.	.	.	.	.			
Nigeria (SPDC)	92.06	-.98	.	5.66	.	.	.81	95.93	39.14	.	-.49	.81	37.84	.	.		-61%	579%
Oman Gisco	59.32	-12.4	.	.	.	.	1.23	45.69	.	59.32	-12.4	1.23	45.69	8.9	6.85		3606%	-1005%
Pakistan	10.17	-.29	.	1.61	.	.	.16	11.34	2.13	.	1.37	.16	3.35	.	.		868%	839%
Philippines	39.2	-.7	.	.	.	19.06	.	19.44	.	.	.	.	.	.	.			
Russia Sakhalin	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Chad	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Venezuela	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Congo (DR)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Abu Dhabi	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Austria	1.24	-.01	.	.42	.	.	.17	1.48	1.2	.	.41	.17	1.44	.	.		243%	243%
Australia (Direct)	174.51	4.4	.	.	.	.	2.27	176.64	37.96	.	-17.11	2.27	18.56	.	.		-755%	194%
Australia (Indirect)	55.05	-13.38	.	.	.	.	1.47	40.21	23.64	.	-14.02	1.47	8.15	.	.		-957%	-913%
Brunei	103.56	2.16	.	1.59	.	.	4.7	102.61	40.29	2.65	2.5	4.7	40.74	.	.		110%	80%
Canada	78.42	19.	.	.03	.	3.34	5.81	88.31	43.41	21.9	12.69	5.81	72.2	17.23	19.4		596%	270%
China	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Gabon	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Germany	62.34	.66	.31	1.11	.	.	5.	59.42	50.69	1.32	-.59	5.	46.42	.	.		15%	42%
Malaysia	183.03	3.98	1.75	1.61	.	.	6.55	183.82	35.93	11.2	-2.84	6.55	37.75	.	.		128%	112%
Netherlands	424.81	4.38	.	.15	.	.	15.71	413.43	221.34	3.46	2.12	15.71	211.22	.	.		36%	29%
Norway	67.01	13.41	.	11.85	.	.	2.38	89.9	53.22	.	-8.65	2.38	42.19	.	.		-364%	1062%
New Zealand	11.97	1.86	.	.	.07	.	1.26	12.65	11.03	.	1.94	1.26	11.7	.	.		154%	153%
Oman	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Shell Oil (Aera)	4.42	1.58	.	.	.	.	.47	5.53	3.05	.25	.32	.47	3.15	.	.		121%	336%
Shell Oil (Altura)	5.88	2.71	.	.	.	.09	.43	8.07	5.51	.	1.91	.43	6.99	.	.		444%	609%
Shell Oil (MCC)	2.	.09	.	.02	.	.01	.55	1.55	1.73	.06	.26	.55	1.5	.	.		58%	18%
Shell Oil (TMR)	1.28	-.09	.	.69	.	.02	.17	1.69	.99	.	.37	.17	1.19	.	.		218%	341%
Shell Oil (EH) - China	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Shell Oil (EH) - Cameroon	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Shell Oil (EH) - New Zeala	2.58	.	.	.	.	.	.27	2.31	2.28	.	.	.27	2.01	.	.		0%	0%
Shell Oil (USA) cons	118.44	1.35	.	9.3	.01	14.78	18.09	96.23	88.2	11.42	-4.74	18.09	76.79	.	.		37%	-23%
Shell Oil (USA) - Oil Shale	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			
Shell Oil (WH) cons	4.82	.01	.	.	.	.	.45	4.38	4.82	.	.01	.45	4.38	.	.		2%	2%
Syria	3.46	-2.16	.	.	.	.	.28	1.01	2.56	.01	-1.7	.28	.6	.	.		-600%	-769%
Thailand	6.69	-.22	.09	.06	.	.	.39	6.23	3.74	.02	-.6	.39	2.77	.	.		-148%	-18%
UK	116.44	2.88	.	.	.12	.01	9.98	109.45	67.92	7.96	1.83	9.98	67.73	.	.		98%	30%
Total Gas	1,711.07	26.11	2.2	38.68	.2	37.31	83.24	1,656.72	772.51	126.43	-36.14	83.24	780.57	26.13	26.26		110%	36%
							Check	1656.72				Check	780.57					

Attachment 4.1



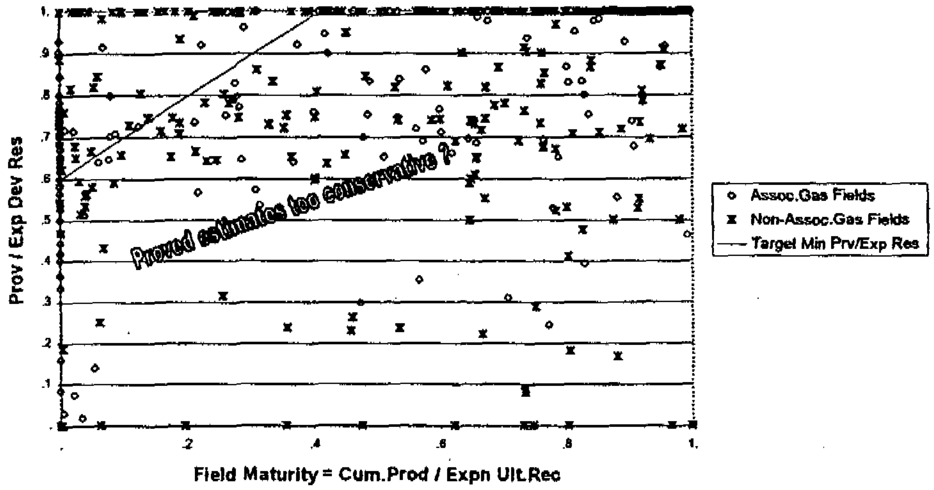
RATIO OF PROVED / EXPN RESERVES vs FIELD MATURITY
Developed - Oil+NGL



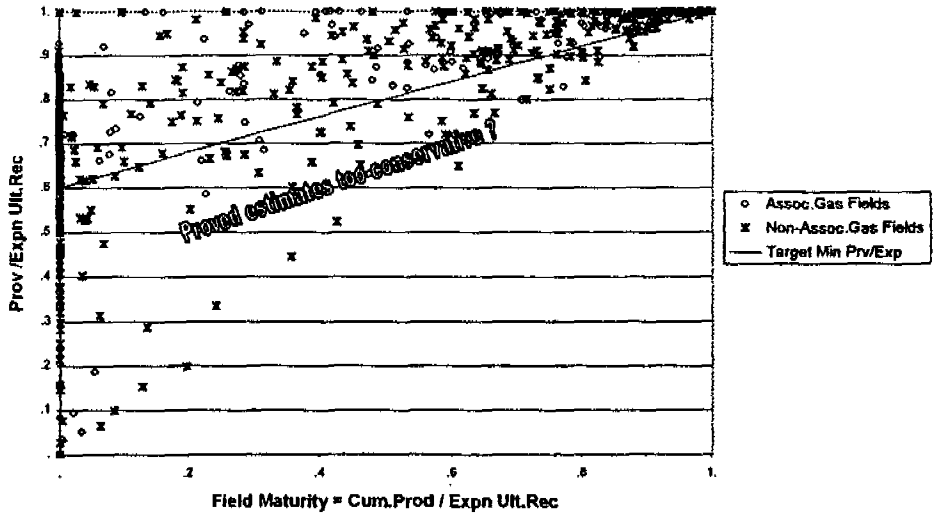
RATIO OF PROVED / EXP'N RESERVES vs FIELD MATURITY
Total Ultimate Recovery - Oil+NGL

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

Attachment 4.2



RATIO OF PROVED / EXP'N RESERVES vs FIELD MATURITY
Developed - Gas



RATIO OF PROVED / EXP'N RECOVERY vs FIELD MATURITY
Total Ultimate Recovery - Gas

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

1999 PRODUCTION RECONCILIATION - OIL+ NGL

Attachment 5.1

FOIA Confidential Treatment Requested

Country	Org'l CERES			Org'l Reserves		Org'l diff'ce	Final CERES		Final Resvs		Difference		Comment
	mln bbl		10^6m3		10^6m3		mln bbl	10^6m3		10^6m3	10^6m3		
Argentina	1.614		0.26		0.26	.	1.614	0.26		0.26	.		OK
Denmark	43.128		6.86		6.85	-.01	43.128	6.86		6.86	.		Accept Ceres (SIEP will correct res. submission)
Egypt	2.353		0.37		0.37	.	2.353	0.37		0.37	.		OK
Nigeria (SPDC)	77.294		12.29		11.15	-1.14	77.294	12.29		12.29	.		SPDC claim Ceres figures are final. Reserves submission corrected.
Oman Gisco		0.90		0.88					0.90				Gisco claim that 0.88 is correct. Ceres not corrected; reserves submission updated.
Oman		16.46		16.37					16.46				PDO 16.37 volume excludes minor NGL production (produced in black oil stream) prior to start of Gisco contract. Reserves submission corrected.
Oman Total	109.176		17.36		17.25	-.11	109.176	17.36		17.36	.		
Russia Sakhalin	0.306		0.05		0.04	-.01	0.306	0.05		0.05	.		Accept Ceres (SIEP will correct res. submission)
Venezuela	14.932		2.37		2.37	.	14.932	2.37		2.37	.		OK
Congo (DR) Zaire	1.004		0.16		0.16	.	1.004	0.16		0.16	.		OK
Abu Dhabi	30.173		4.80		4.80	.	30.173	4.80		4.80	.		OK
Austria	0.161		0.03		0.03	.	0.161	0.03		0.03	.		OK
Australia (SDA direct)		1.98		2.68					1.97				
Australia (indirect)		0.71		1.21					0.79				
Australia Total	16.937		2.69		3.89	1.2	17.381	2.76		2.76	.		SDA reserves submission corrected, plus minor Ceres corrections.
Brunei	31.421		5.00		5.00	.	31.421	5.00		5.00	.		OK
Canada	22.398		3.56		4.16	.6	22.423	3.57		4.16	.59	I	Ceres updated, but still not matching. Ceres volumes exclude all royalties (cash and in kind), whilst reserves volumes include royalties in cash.
China				0.58					0.58				
Shell Oil (EH) - China				0.59					0.59				
China Total	7.329		1.17		1.17	.	7.329	1.17		1.17	.		OK
Gabon	32.571		5.18		5.19	.01	32.571	5.18		5.18	.		Accept Ceres (SIEP will correct res. submission)
Germany	2.066		0.33		0.33	.	2.066	0.33		0.33	.		OK
Malaysia	23.983		3.81		3.81	.	23.983	3.81		3.81	.		OK
Netherlands	4.809		0.76		0.77	.01	4.809	0.76		0.76	.		Accept Ceres (NAM to re-submit, together wih Gas)
Norway	30.280		4.81		4.82	.01	30.280	4.81		4.81	.		Accept Ceres (SIEP will correct res. submission)
Syria	25.878		4.11		4.11	.	25.878	4.11		4.11	.		OK
Thailand	6.401		1.02		1.01	-.01	6.401	1.02		1.02	.		Accept Ceres (SIEP will correct res. submission)
UK	146.770		23.34		23.33	-.01	146.770	23.34		23.34	.		Accept Ceres (SIEP will correct res. submission)
New Zealand				0.45		.			0.44				
Shell Oil (EH) - New Zealand				0.11		.			0.11				
New Zealand Total	3.482		0.55		0.56	.01	3.482	0.55		0.55	.		Accept Ceres (SIEP will correct res. submission)
Shell Oil (Aera)		7.66		7.66					7.66				
Shell Oil (Altura)		2.64		2.64					2.64				
Shell Oil (MCC)		0.55		0.55					0.55				
Shell Oil (TMR)		0.18		0.18					0.18				
Shell Oil (USA) cons		18.32		18.20					18.21				USA cons prod'n submissions brought in line.
Shell Oil USA Total	184.682		29.36		29.23	-.13	183.911	29.24		29.24	.		Manually corrected
Shell Oil (WH) cons (Brazil)	0.766		0.12		0.12	.	0.766	0.12		0.12	.		OK
Shell Oil (EH) - Cameroon	8.208		1.31		1.30	-.01	8.208	1.31		1.31	.		Accept Ceres (SIEP will correct res. submission)
Total	828.120		131.67		132.08	0.41	827.820	131.62		132.22	0.60		

I Not reconciled or not yet closed out.

1999 PRODUCTION RECONCILIATION - GAS

Attachment 5.2

FOIA Confidential Treatment Requested

Country	Org'l CERES 10^9Nm3	Org'l Resvs 10^9Nm3	Org'l diff'ce	Final CERES 10^9Nm3	Final Resvs 10^9Nm3	Difference 10^9Nm3		Comment
Argentina	0.077	0.030	-.047	0.077	0.025	-0.052	!	Erroneous Ceres submission (figure of .077 is boe of 0.01178 mcm oil)? Reserves submission is production, not sales. Left unchanged due to lateness and immateriality.
Bangladesh	0.340	0.326	-.014	0.326	0.326			Bangladesh claim correction to Ceres needed; done.
Denmark	3.417	3.395	-.022	3.394	3.394			Denmark claim correct figure is 3.394 - Ceres updated.
Egypt	1.101	1.101	.	1.101	1.101			OK
Nigeria (SPDC)	0.844	0.959	.115	0.824	0.928	0.104	!	SPDC use 1.02 sm3/Nm3(9500) in Ceres and, correctly, 1.148 sm3/Nm3(9500) in reserves. Too late to change Ceres.
Oman Gisco	1.256	1.272	.016	1.272	1.272			Gisco claim that 1.272 is correct. Ceres updated.
Pakistan		0.136	.136	0.136	0.136			No Ceres submission by Pakistan. Now corrected.
Austria	0.164	0.161	-.003	0.164	0.164			Accept Ceres (SIEP will correct res. submission)
Australia (Direct)		2.497			2.497			
Australia (Indirect)		1.587			1.587			
Australia Total	3.617	4.084	.447	3.716	4.064	0.348	!	Difference between Ceres and Reserves due to Ceres reporting sales ex-LNG plant, i.e. excluding LNG plant fuel and losses. Correctly maintained in Reserves. Apart from minor correction, Ceres submission also unchanged.
Brunei	5.064	5.064	.	5.064	5.064			OK
Canada	5.714	5.626	-.088	5.714	5.604	-0.110	!	Ceres volumes are in sm3 tel quel and include all royalties (both incorrect), whilst reserves volumes are claimed to have been converted to Nm3(9500) correctly.
Germany	4.101	4.298	.197	4.101	4.298	0.197	!	Sales reported under reserves is net sales to downstream; Ceres figure is downstream sales, including storage movements etc. Both submissions maintained.
Malaysia	8.702	6.711	.009	6.702	6.702			Malaysia say that 6.711 is production, 8.702 is sales. Reserves submission corrected.
Netherlands	14.040	14.068	.028	14.040	14.040			Diference due to different GHV corrections in the two submissions. NAM has brought reserves in line with Ceres.
Norway	2.296	2.348	.052	2.348	2.348			Norway claim 2.348 is correct. Ceres updated.
New Zealand	1.130	1.130		1.130	1.130			
Shell Oil (EH) - New Zealand	0.266	0.250		0.266	0.250		!	SOC claim Ceres submission for Pecten NZ is 0.254, not 0.266. Difference claimed to be due to erroneous conversion factor (0.028738 vs 0.0283) used in SOC Finance.
Total New Zealand	1.396	1.380	-.016	1.396	1.380	-0.016		
Shell Oil (Aera)		0.450			0.446			Not corrected for 75% own use gas
Shell Oil (Altura)		0.410			0.408			Not corrected for 8% own use gas
Shell Oil (MCC)		0.520			0.520			
Shell Oil (TMR)		0.160			0.160			
Shell Oil (USA) cons		17.090			19.550		!	USA reserves submission taken as sm3 (not corrected for 1.9% own use), then converted by SIEP to Nm3 (*0.948), then GHV corrected (*1.14) to Nm3(9500).
Shell Oil Total	20.017	18.630	-1.387	20.017	21.084	1.067	!	Ceres submission includes re-purchased royalties-in-kind; off-set by reserves submission correction.
Shell Oil other WH (Brazil+7)	0.274	0.420	.146	0.274	0.420	0.146	!	Coral (Canada) 4Q correction of -0.157 made in Ceres. Should have been entered correctly under 'Canada' in Ceres?
Syria	0.286	0.284	-.002	0.286	0.286			Accept Ceres (SIEP will correct res. submission)
Thailand	0.419	0.416	-.003	0.419	0.419			Accept Ceres (SIEP will correct res. submission)
UK	8.816	9.622	.806	8.827	9.622	0.795	!	Difference (after small Ceres correction) mainly due to Kingfisher gas (produced and given as payment in kind for third party processing, hence not classed as sales in Ceres). In addition, Reserves submission has been correctly normalised to Nm3 (9500kCal/Nm3), while the Ceres submission has been (wrongly) maintained at un-normalised Nm3 (i.e. not corrected for GHV).
Total	79.941	80.311	0.370	80.198	82.677	2.479		

! Not reconciled or not yet closed out.

Attachment 6

1999 RESERVES AUDITS - MAIN OBSERVATIONS

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

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

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

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

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

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

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

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

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

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TIME TABLE SEC RESERVES AUDITS

Attachment 7

COUNTRY	Size*	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	Comments
ABU DHABI	L			X				X				In The Hague (EPT-AM)
NIGERIA -SPDC	L	X				X		X				Combined with SNEPCO
OMAN	L			X				X				
VENEZUELA	M				$			X				Combined with Argentina
EGYPT	M		X					X				
NIGERIA - SNEPCO	M					$		X				Combined with SPDC
PHILIPPINES	M					$		X				Combined with Thailand
THAILAND	M		X					X				Combined with Philippines
ARGENTINA	S			X				X				Combined with Venezuela
AUSTRALIA	L				X				P			
NORWAY	L				X				P			
USA	L								P			
GABON	M			X					P			
BANGLADESH	S					$			P1			
RUSSIA - SAKHALIN	S					$			P1			In The Hague
NETH. NAM	L	X				X				P		
UK	L			X		X				P		
SYRIA	M	X			X					P		
AUSTRIA	S			X						P		
CHINA	S		$							P1		
BRUNEI	L		X				X				P	
MALAYSIA	L		X				X				P	
DENMARK	M	X				X					P	
GERMANY	M	X				X					P	
NEW ZEALAND	S				X						P	
NAMIBIA	M										P1?	
RUSSIA - SALYM	M										P1?	
KAZAKHSTAN-TEMIR	S							$			P1?	
KAZAKHSTAN-OKIOC	S										P1?	
CHAD	S			X								No proved reserves since 1999
COLOMBIA	-		X									Hocol/Homcol interest sold 1997
PERU	M											Camisea venture abandoned 1999
CANADA	L											No direct involvement
PAKISTAN	S					$						To be divested?
ZAIRE	S		X									To be sold during 2000
total nr. of audits		5	6	7	4	5	2	9	7	6	8	

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

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

2000 Programme

Date	Country
March 27-30	Gabon
April 17-20	Bangladesh
June 5/13	Norway
Aug	Russia-Sakhalin
Sept 16/25	Australia
Nov	USA

Consideration:

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

Audit frequency;

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

unless recommended otherwise
in auditor reports etc,

or when combinable with other audits.

AudSch99Note.xls

08/02/00

NOTE – 31 January 2003

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A.A. Barendregt

DEPOSITION
EXHIBIT
Barendregt
#16 2/20/07

Attachments 1-7

Attachment 1 Main Observations End-2002 Reserves

Attachment 2 Significant Reserves Changes

Attachment 3 Group Proved Reserves Summaries

Attachment 4 Production Reconciliation Ceres vs. Reserves Submissions

Attachment 5 Proved Reserves Maturity – by OU

Attachment 6 Main Observations 2002 Reserves Audits

Attachment 7 Reserves Audit Plan 2003

Attachment 1

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

MAIN OBSERVATIONS

1. **Reserves Summary**

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

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

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

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

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

2. **Significant reserves changes**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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TREATMENT REQUESTED

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

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

4. **Enterprise Oil assets**

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

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

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

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

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

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

5. **Kazakhstan – Kashagan field**

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

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

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

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

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

6. **SNEPCO fields**

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

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

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

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

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

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

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

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

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

8. **Production licence duration constraints**

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

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

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

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

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

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

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

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

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

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

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

9. PSC Reserves

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

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

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

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

10. **Group Guidelines – mature fields**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

14. **SEC Reserves Audits**

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

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

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

15. **Electronic Workbooks**

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

Recommendations to SIEP Reserves Coordination:

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

References

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

Attachment 2

SIGNIFICANT 2002 PROVED AND PROVED DEVELOPED RECOVERY CHANGES

(Shell Group share)

MAJOR TECHNICAL REVISIONS

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

OTHER MAJOR CHANGES

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

OTHER MINOR CHANGES
AND TOTAL

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

GROUP RESERVES SUBMISSIONS

Attachment 3

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

Country Name	Proved Resvs 1.1.2002	Rev'ns and Reclassific'ns	Improved Recovery	Ext'ns and Discoveries	Purchases in Place	Sales in Place	Prod'n (avail. for sales) 2002	Proved Resvs 1.1.2003	Beyond end of licence	Proved Dev'd Resvs 1.1.2002	Transf Under to Dev'd	Revisions	Prod'n (avail. for sales) 2002	Proved Dev'd Resvs 1.1.2003	Minority Resvs incl 1.1.2002	Minority Resvs incl 1.1.2003	R/P Tot (yr)	Replmt Ratio TotRes (%)	Replmt Ratio DevRes (%)
Australia (Algeria)				.71				.71											
Australia (Direct)	26.7	1.69					3.31	25.08		12.29		1.7	3.31	10.68			8	51%	51%
Australia (WPL)	18.07	.32					2.06	16.33		6.85		.54	2.06	5.33			8	16%	28%
Bangladesh																			
Brunei (BSP)	72.74	6.49	.98	.47			5.83	74.85		35.66	2.6	7.72	5.83	40.15			13	136%	177%
Brunei (SDB)	.95	.09					.05	.99		.31	.33		.05	.59			20	180%	660%
China	6.05	.44					1.38	5.11		4.82	.83	-.2	1.38	4.07			4	32%	46%
Malaysia	25.36	-2.86	.62				3.45	19.67	1.1	13.6	1.54	-1.58	3.45	10.11	17	17	6	-65%	-1%
New Zealand	9.96	-.83	.37			1.67	1.61	6.22		5.62	.02	-.53	1.61	3.5			4	-132%	-32%
New Zealand (SPWes-FCE)	1.63					1.58	.05			1.06		-1.01	.05				0	-3160%	-2020%
Pakistan																			
Philippines	3.54	.61					.24	3.91		2.15		.41	.24	2.32			16	254%	171%
Thailand	15.14	-5.48					.9	8.76		4.37	.38	-.28	.9	3.57			10	-609%	11%
Angola	11.85		7.34					19.19											
Austria	.23	.01		.03			.03	.24		.21		.03	.03	.21			8	133%	100%
Cameroon (Pecten))	4.33						.98	3.35		4.12	.17	-.36	.98	2.95	.87	.67	3	0%	-19%
Congo (DR)	3.05					3.01	.04			1.98		-1.94	.04				0	-7525%	-4850%
Denmark	52	4.51	1.35				8.14	49.72	10.69	36.15	6.48	4.22	8.14	38.71			6	72%	131%
Ireland (ex-EO)																			
Italy (ex-EO)		1.12			19.28		.67	19.73				8.08	.67	7.41			29	3045%	1206%
Gabon	16.23	.39					2.69	13.93	3.29	14.68	.38	.56	2.69	12.93	4.06	3.49	5	14%	35%
Germany	2.97	.06	.04			.06	.3	2.71		2.87	.01	.04	.3	2.62			9	13%	17%
Netherlands	4.04	.17	.22				.54	3.89		3.01	.07	.2	.54	2.74			7	72%	50%
Nigeria (SNEPCO)	89.97	-16.14						73.83											
Nigeria (SPDC)	417.66	-.73					12.47	404.46	13.63	116.74	26.66	7.93	12.47	138.86			32	-6%	277%
Norway	29.09	-3.86			42.61		8.49	59.35		22.21	1.48	30.15	8.49	45.35			7	456%	373%
UK	87.59	14.2	.78	.06	44.16	.02	22.09	124.68		60.89	11.49	32.45	22.09	82.74			6	268%	199%
Abu Dhabi	93.29	-1.09					5.81	86.39	149.9	77.58	.91	.66	5.81	73.34			15	-19%	27%
Egypt	4.08	.17					.65	3.6		2.98	.03	.29	.65	2.65			6	26%	49%
Russia (KMOC)					19.31	.16	.33	18.82			.33	2.41	.33	2.41			57	5803%	830%
Iran	33.45	-7.86	.17			9.87	.74	15.41		5.64	1.33	-2.58	.74	3.65			21	-2339%	-189%
Kazakhstan				60.41				60.41											
Oman (PDO)	162.3	-4.74	.34	1.49			15.22	144.17		65.8	7.27	4.92	15.22	62.77			9	-19%	60%
Oman (Gisco)	12.65	-2.07					3.28	7.3		10.48		-1.94	3.28	5.26	1.9	1.09	7	-63%	-59%
Russia (Sakhalin Holding)	30.94	10.43					1.71	39.66		8.45		.99	1.71	7.73	13.92	17.85	23	610%	58%
Syria	14.82	.82	2.07				2.87	14.84	1.46	9.01	1.8	2.1	2.87	10.04			5	101%	135%
Argentina	1.39		.03				.03	1.39		.46	.09	-.01	.03	.51			46	100%	267%
Brazil (ex-EO)		1.69			16.31			18.											
Brazil (Shell Oil WH)	.83	-.08					.09	.66		.83		-.11	.09	.63			7	-89%	-122%
Canada	53.17	-.9		.08			3.27	49.08		24.52	1.61	-2.29	3.27	20.57	11.79	10.94	15	-25%	-21%
Canada (AOSP)	95.4							95.4			95.4			95.4	21.15	21.26			
USA (SEPCo)	107.34	12.34	8.1	5.19	1.08	.55	19.07	114.43		68.26	3.36	6.75	19.07	59.3			6	137%	53%
USA (Aera)	56.56	10.43		5.23			6.58	65.63		52.32	6.4	5.78	6.58	57.92			10	238%	185%
Venezuela	36.17	1.81					2.66	35.32	8.4	12.75	3.76		2.66	13.85			13	88%	141%
Grand Total	1,601.04	21.35	22.41	73.67	142.75	16.87	137.63	1,706.72	188.67	688.67	174.73	105.1	137.63	830.87	53.86	55.47	12	177%	203%
Total excl Can. AOSP	1,505.64	21.35	22.41	73.67	142.75	16.87	137.63	1,611.32	188.67	688.67	79.33	105.1	137.63	735.47	32.71	34.21	12	177%	134%
Tot.excl.AOSP-Min.Resvs	1,472.93							1,577.11											

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

Country Name	Proved Resvs 1.1.2002	Rev'ns and Reclassific'ns	Improved Recovery	Ext'ns and Discoveries	Purchases in Place	Sales in Place	Prod'n (avail. for sales) 2002	Proved Resvs 1.1.2003	Beyond end of licence	Proved Dev'd Resvs 1.1.2002	Transf Under to Dev'd	Revisions	Prod'n (avail. for sales) 2002	Proved Dev'd Resvs 1.1.2003	Minority Resvs incl 1.1.2002	Minority Resvs incl 1.1.2003	R/P Tot (yr)	Replmt Ratio TotRes (%)	Replmt Ratio DevRes (%)
Australia (Algeria)				.175				.175											
Australia (Direct)	175.41	1.815					2.366	174.86		29.644		1.174	2.366	28.452			74	77%	50%
Australia (WPL)	39.049	.765					1.494	38.32		12.971		.829	1.494	12.306			26	51%	55%
Bangladesh	4.745	-.345					.435	3.965		1.973		.001	.435	1.539			9	-79%	0%
Brunei (BSP)	100.461	4.891	.213	.886			4.806	101.645		35.677	1.295	7.776	4.806	40.942			21	125%	189%
Brunei (SDB)	5.646	.81					.442	6.014		3.124	1.124	.095	.442	3.901			14	183%	276%
China																			
Malaysia	164.31	-17.27	2.962				6.855	143.147	12.772	44.903	10.715	-1.938	6.855	45.925	2.629	2.388	21	-209%	121%
New Zealand	33.682	-6.12	1.29			2.041	4.627	22.184		20.251	.155	-1.173	4.627	14.606			5	-148%	-72%
New Zealand (SPWes-FCE)	4.771					4.641	.13			2.855		-2.725	.13				0	-3570%	-2096%
Pakistan	6.323	-1.204						5.119			3.839			3.839					
Philippines	17.716	.156					.369	17.505		10.711		.121	.369	10.463			47	42%	33%
Thailand	7.334	-1.277					.423	5.634		2.788	.073	-.07	.423	2.368			13	-307%	1%
Angola																			
Austria	1.345	.017		.097			.22	1.239		1.152		.151	.22	1.083			6	52%	69%
Cameroon (Pecten))																			
Congo (DR)																			
Denmark	28.173	.039	.25				3.238	25.224	5.647	20.059	2.972	-2.168	3.238	18.405			8	9%	74%
Ireland (ex-EO)		-.089			7.857			7.768											
Italy (ex-EO)		.153			2.58		.095	2.638				1.17	.095	1.075			28	2877%	1179%
Gabon																			
Germany	54.899	.909	.312				4.216	51.904		41.479	.204	.577	4.216	38.044			12	29%	19%
Netherlands	408.1	1.049	.33	.246			15.777	394.548		190.769	11.03	.786	15.777	186.818			25	14%	75%
Nigeria (SNEPCO)	7.02	-4.467						2.553											
Nigeria (SPDC)	88.173	-1.391					2.524	85.258		42.039	11.689	-2.861	2.524	48.353			34	-55%	350%
Norway	86.897	-1.971			6.577		2.588	90.915		35.045	.018	4.186	2.588	36.66			35	178%	162%
UK	91.261	1.37	.634	.569	13.378	.149	11.726	95.338		61.801	4.052	7.508	11.726	61.635			8	135%	99%
Abu Dhabi																			
Egypt	22.772	1.926					2.392	22.306		11.089		1.323	2.392	10.02			9	81%	55%
Russia (KMOC)																			
Iran																			
Kazakhstan																			
Oman (PDO)																			
Oman (Gisco)	35.364	-4.218					8.119	23.027		24.937		-3.796	8.119	13.022	5.305	3.454	3	-52%	-47%
Russia (Sakhalin Holding)																			
Syria	.337	.26					.172	.42	.05	.211		.361	.172	.4			2	161%	210%
Argentina	12.631		.003				.255	12.379		5.907	.477	-1.606	.255	4.523			49	1%	-443%
Brazil (ex-EO)		.082			1.666			1.748											
Brazil (Shell Oil WH)	4.798	-.427					.394	3.977		4.798		-1.276	.394	3.128			10	-108%	-324%
Canada	70.771	-2.583		.35			6.306	62.232		55.776	1.361	-8.054	6.306	42.777	15.89	13.865	10	-35%	-108%
Canada (AOSP)																			
USA (SEPCo)	104.552	4.58	.564	11.604	5.896	.274	17.292	109.63		68.875	11.666	4.295	17.292	65.533			6	129%	92%
USA (Aera)	.411	.206		.025			.054	.588		.318	.081	.126	.054	.471			11	470%	303%
Venezuela																			
Grand Total	1,579.948	22.324	7.158	13.952	37.954	7.104	97.314	1,512.27	18.469	778.552	68.25	4.751	97.314	694.239	23.824	19.717	16	30%	67%
Total excl Can. AOSP	1,579.948	22.324	7.158	13.952	37.954	7.104	97.314	1,512.27	18.469	778.552	68.25	4.731	97.314	694.239	23.824	19.717	16	30%	67%
Tot.excl.AOSP-Min.Resvs	1,556.124							1,492.553											

2002 PRODUCTION RECONCILIATION - CERES/FIRST vs. RESERVES SUBMISSIONS

Attachment 4

OIL+NGL

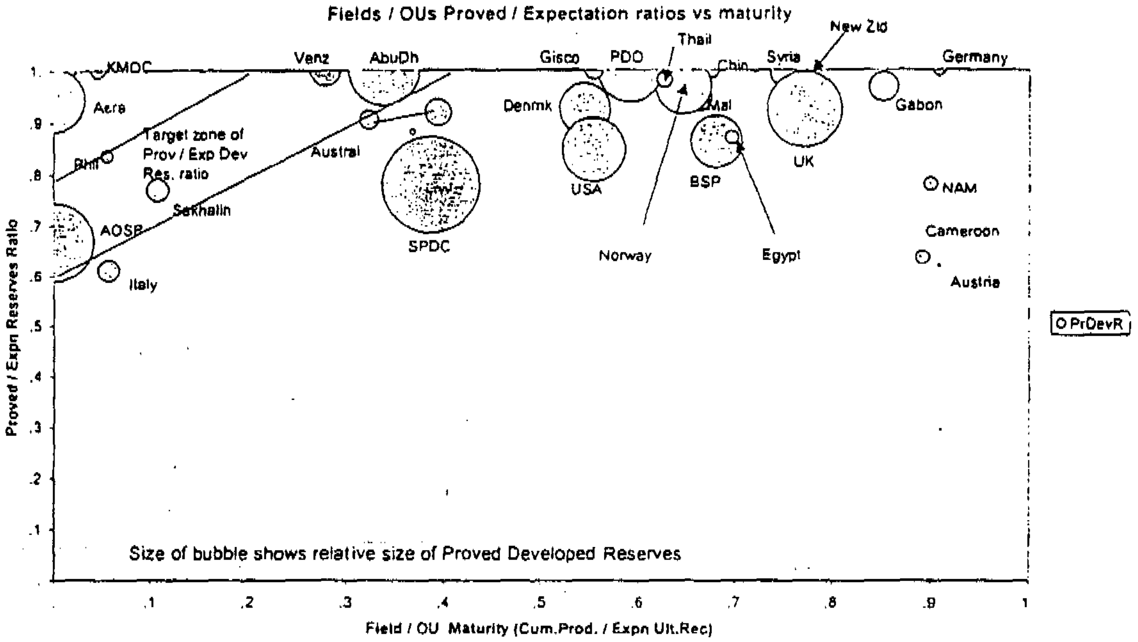
Country	Original FIRST		Org'l Resvs Subm'n		Difference	Final FIRST		Final Resvs Subm	Difference	Comment
.159	mln bbl	10^6m3		10^6m3	10^6m3	mln bbl	10^6m3	10^6m3	10^6m3	
Australia (SDA)			3.31							
Australia (WPL)			2.06							
Australia Total	33.72	5.36		5.37	.01	33.72	5.36	5.37	.01	OK (Accept rounding error)
Brunei (BSP)	36.646	5.83		5.83		36.646	5.83	5.83		OK
Brunei (FCE)	.336	.05		.05		.336	.05	.05		OK
China	8.672	1.38		1.38		8.672	1.38	1.38		OK
Malaysia	21.664	3.44		3.45	.01	21.664	3.44	3.45	.01	OK (Accept rounding error)
New Zealand			1.61							
New Zealand (SPM/ex-FCE)			.05							
New Zealand Total	10.456	1.66		1.66		10.456	1.66	1.66		OK
Philippines	1.534	.24		.24		1.534	.24	.24		OK
Thailand	5.639	.9		.9		5.639	.9	.9		OK
Austria	.154	.02		.03	.01	.154	.02	.03	.01	OK (Accept rounding error)
Denmark	51.211	8.14		8.14		51.211	8.14	8.14		OK
Germany	1.857	.3		.3		1.857	.3	.3		OK
Italy	2.871	.46		.67	.21	2.871	.46	.67	.21	FIRST subm'n excludes 0.21 m3 Q2 ex-EO production
Netherlands	3.411	.54		.54		3.411	.54	.54		OK
Norway NSEP (incl ex-EO)	48.614	7.73		8.49	.76	47.867	7.61	8.49	.88	FIRST subm'n excludes 0.88 m3 Q2 ex-EO production. Error in FIRST - corrected
UK Expro (incl ex-EO)	127.657	20.3		22.09	1.79	127.657	20.3	22.09	1.79	FIRST subm'n excludes 1.79 m3 Q2 ex-O production
Cameroon (PPC)	6.153	.98		.98		6.153	.98	.98		OK
Congo (OR)	.273	.04		.04		.273	.04	.04		OK
Gabon	16.898	2.69		2.72	.03	16.898	2.69	2.69		Reserves submission was based on Working Interest, not PSC entitlement share - corrected
Nigeria (SPDC)	78.546	12.49		12.47	-.02	78.546	12.49	12.47	-.02	Ceres/FIRST submission in error (should be 78,405 MMstb), but too late to change. Resvs submission OK
Abu Dhabi	36.56	5.81		5.81		36.56	5.81	5.81		OK
Egypt	4.07	.65		.65		4.07	.65	.65		OK
Iran	4.677	.74		.74		4.677	.74	.74		OK
Oman PDO	95.718	15.22		15.22		95.718	15.22	15.22		OK
Oman Gisco	20.625	3.28		3.28		20.625	3.28	3.28		OK
Russia (Sakhalin Holding)	10.771	1.71		1.71		10.771	1.71	1.71		OK
Russia (KMOC)	.708	.11		.33	.22	1.33	.21	.33	.12	FIRST subm'n excludes 0.12 m3 Q2 ex-EO production - corrected (+0.622 MMstb)
Syria	18.022	2.87		2.87		18.022	2.87	2.87		OK
Argentina	.171	.03		.03		.171	.03	.03		OK
Brazil (SOC - Meruza)	.585	.09		.09		.585	.09	.09		OK
Canada	20.6	3.28		3.27	-.01	20.6	3.28	3.27	-.01	OK (Accept rounding error)
USA (SEPCo)			19.07							
USA (Aera)			6.58							
USA Total	161.312	25.65		25.65		161.312	25.65	25.65		OK
Venezuela	16.735	2.66		2.66		16.735	2.66	2.66		OK
Q2 Prodn Ex-EO UK, Norway, Italy, Russia	19.073	3.03			-3.03	19.073	3.03		-3.03	OUs claim Q2 prod'n is 3.00, FIRST submission of 3.03 originated from EO HO - difference of 0.03 left unresolved
Total	865.839	137.684		137.66	-.02 -.02	865.814	137.66	137.63	-.03 -.03	

GAS

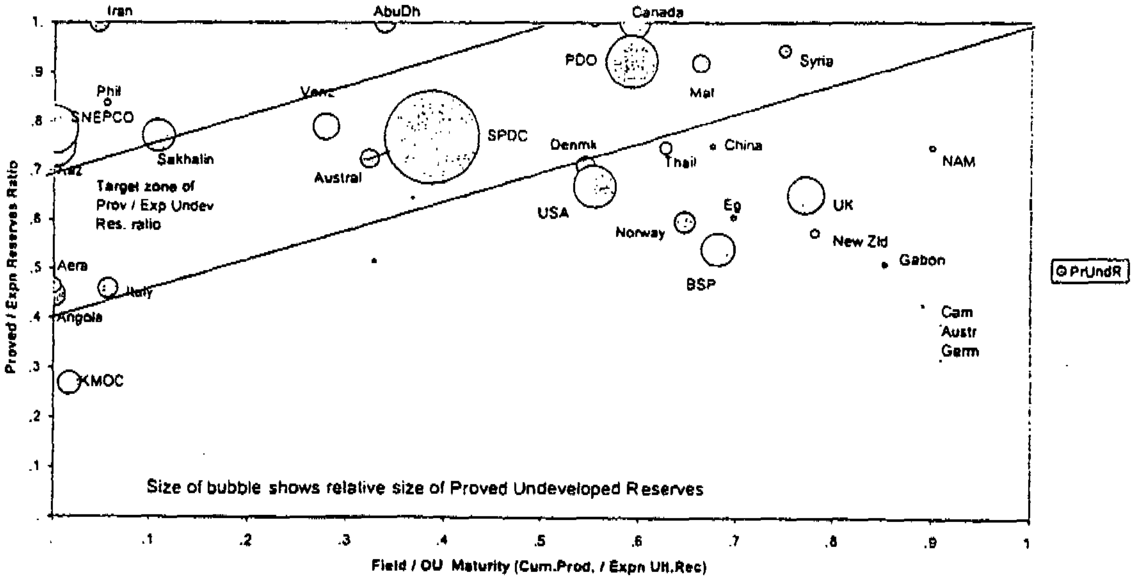
Country	Org'l FIRST	Org'l Resvs Subm'n		Difference	Final FIRST	Final Resvs Subm'n	Difference	Comment
	10^9sm3		10^9sm3		10^9sm3	10^9sm3		
Australia (SDA)		2.365						
Australia (WPL)		1.494						
Australia Total	3.858		3.859	.001	3.858	3.859	.001	OK (accept rounding error)
Bangladesh	.435		.435		.435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

MATURITY OF PROVED OIL+NGL RESERVES - BY OU

Attachment 5.1



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



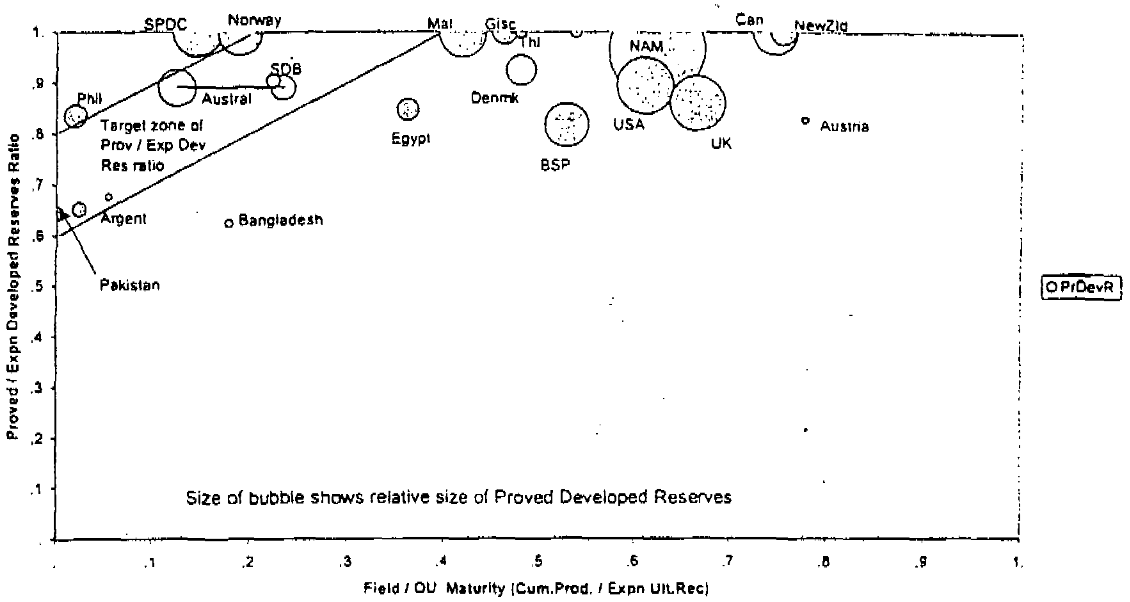
1.1.2003 UNDEVELOPED OIL+NGL RESERVES
Fields / OUs Proved / Expectation ratios vs maturity

MATURITY OF GAS RESERVES - BY OU

Attachment 5.2

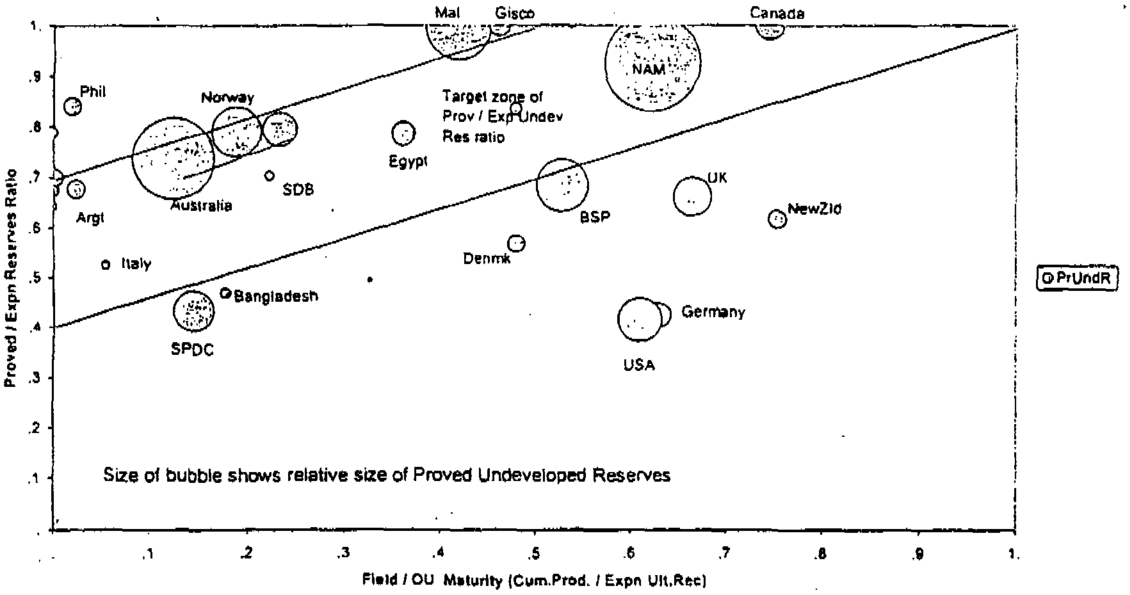
1.1.2003 DEVELOPED GAS RESERVES

Fields / OUs Proved / Expectation ratios vs maturity



1.1.2003 UNDEVELOPED GAS RESERVES

Fields / OUs Proved / Expectation ratios vs maturity



Attachment 6

2002 SEC RESERVES AUDITS - MAIN OBSERVATIONS

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

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

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

The audit opinion was satisfactory.

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

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

The audit opinion was satisfactory.

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

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

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

The audit opinion was satisfactory.

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

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

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

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

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

The audit opinion was satisfactory.

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

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

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

The audit opinion was good.

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

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

The audit opinion was good.

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

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

The audit opinion was good.

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

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

The audit opinion was satisfactory.

Badhra reserves have been de-booked at end 2002.

EX-ENTERPRISE OIL OU AUDITS:

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

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

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

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

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

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

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

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

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

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

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

SEC RESERVES AUDIT PLAN - 2003

Attachment 7

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

Audit Status:

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

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

Audit frequency:

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

Unknown

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

John,

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

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

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

Regards,

Jeroen

✉
RE: SEC Reserves Audit - Austr...

✉
RE: Gorgon Reserves vs SFR

SDA - Reserves Audit.ZIP

Jeroen Regtien
Manager TLT Support Team

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DEPOSITION EXHIBIT
Barendregt
#17 2/20/07

EXHIBIT
Darley 25
11/17/06

Unknown

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

Jeroen,

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

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

Anton

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

resend due to size limitation error.

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

Anton,

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

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

Some basic information on SDA:

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

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

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

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

Looking forward to your response,

Jeroen Regtien

Unknown

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

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

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

Sheila,

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

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

- We have booked the Gorgon volumes as reserves in 1998(7) following the certification by NSAI and whilst very close to signing an LOI with Korean LNG customers. The Asian crisis has evaporated the market and we do currently not have an outlook to signed LOIs or SPAs. Recent Domgas options fell through, we are now restarting a greenfield LNG effort
- We have a Gorgon case in our BP which meets screening criteria
- The Sunrise project is further in its commercialisation process (LOIs, VAR) and has no proved reserves in the books
- None of the JV partners has booked the Gorgon volumes as proved reserves.

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

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

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

Looking forward to your response,

Jeroen

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

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

Sheila

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

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

Wim, Sheila,

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

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

Met vriendelijke groeten / With kind regards.

Remco D. Aalbers
Group Hydrocarbon Resource Coordinator
& Senior Economist

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

DRAFT NOTE – 21 Nov 2000 **CONFIDENTIAL**

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

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

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

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 99-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The last previous SEC proved reserves audit for SDA was carried out in 1996. The audit took the form of technical discussions with staff from Woodside Energy Ltd (the operator for a large part of the assets with SDA interest) and detailed discussions about the reserves reporting process with SDA staff.

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

The audit commended the high quality technical work that had been carried out by Woodside, particularly in assessing the subsurface uncertainties and in evaluating the ranges of in-place and reserves estimates. Intensive SIEP assistance through VAR- and other reviews was noted. Maintaining the preliminarily booked volume of Gorgon gas reserves (first done at 1.1.1999) was supported on the grounds that a gas market was highly likely to be established in due course and that it must be considered likely that an extension of the current 5-year Retention Lease will be granted in 2002. Proved reserves in some mature fields (N-Rankin, Goodwyn and the four oil fields) should be increased to expectation levels, in line with the guidelines. This could increase Group entitlement by some 12 mln m3oe. Concern was expressed about the lack of a concisely documented audit trail, which hampered a proper assessment of the reasons for the end-1999 reserves changes.

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

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

DARLEY 1102

A.A. Barendregt

Attachments 1, 2, 3

Attachment 1

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

MAIN OBSERVATIONS

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

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

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

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

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

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

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

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

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

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

7. Asset depreciation for Group accounts is done correctly through proved developed reserves depletion (proved total reserves for the full North Rankin facilities, which act as a hub for the entire NWS offshore gas system). Correct reserves values are being used, but no copy could be found of the formal end-1999 note of advice to Finance with the proper new reserves volumes to be used.
8. Full monthly production and sales statistics (100% field volumes) are received by fax from Woodside, who are the only operator at present with fields in production in SDA-held acreage. A selection of these figures (e.g. totals by assets only, not fields) is manually transcribed into the Finance system for monthly / quarterly reporting. A parallel system (also with manual input) is maintained by the Development Manager for e.g. KPI and MIS reporting. There would appear to be opportunities for synergy and rationalisation, also through electronic transfer of data. Incorporation of data at field level could help the end-year audit trail.

Recommendations

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

Spare

NOTE – 31 Aug, 1999

New Ind. Auditor
since 197

CONFIDENTIAL

1999 AUDIT
"Satisfactory"

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

DEPOSITION EXHIBIT
Barendregt
#18 2/21/07

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

18-26 Aug 1999

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

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, EP 98-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The audit took the form of detailed discussions about the reserves reporting process with SPDC staff and technical discussions with some SPDC engineers regarding some major 1998 reserves increases in the SPDC portfolio.

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

Most significant comments from this present audit are as follows:

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

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

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

A.A. Barendregt

Attachments 1, 2, 3

SPDCovnt.doc

31/08/99

Attachment 1

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

MAIN OBSERVATIONS

1. As part of the drive to implement the 1998 SIEP guidelines, a concerted effort has been made by SPDC during 1998 to identify 'proven fault blocks', based on criteria of known fluid contacts, sufficient number of well penetrations, and cumulative production in excess of 40% of UR. This has led to a significant increase (926 MMstb) in proved oil reserves during 1998. Further extension of the 'proven blocks' set to blocks with production greater than 25% of UR is planned. This is commended.
2. Experience has shown that older volumetric estimates based on 2D seismic tend to be conservative. This is being addressed by the (almost complete) 3D seismic coverage, of which the results are incorporated into the programme of field studies.
3. Present oil recovery factors are in the range of 30-60%. There is ample evidence that more favourable recoveries (in excess of 60%) are possible in many good quality reservoirs, where light oil is displaced at low rates by active aquifers. Evidence for this is the large amount of negative reserves (production exceeding booked recoveries), which had to be corrected in 1998. This is gradually being addressed through the field studies programme. However, even reserves based on relatively recent field studies show signs of being overtaken by production, e.g. Forcados-Yokri.
4. New wells and projects have to pass economic screening, in accordance with standard Group practice. The portfolio of long term life cycle projects is gradually being subjected to economic screening and adjusted if necessary. It is noted that development and infill drilling costs are low to moderate, resulting in UTCs of 1-2 $/boe.
5. On average, proved remaining reserves per field tended to be some 60-70% of expectation. This was a wider range than would be expected from a mature area as that operated by SPDC. This has been addressed by SPDC's application of the 1998 SIEP guidelines, bringing the average proved oil recovery to some 72% of expectation, with further additions planned.
6. Proved developed oil reserves are based on best estimate extrapolations of existing drainage points. It is noted that expectation developed oil reserves do also include effects of the short term remedial (rig-less) activities plan (stimulations, new perforations etc.). There seems to be no reason why these effects should not also be included in the proved forecast.
7. Reservoir blocks within fields are added arithmetically. It is recommended that probabilistic addition, assuming appropriate (in-)dependencies, be considered, in line with SIEP guidelines. This will mitigate the conservative effect of the SEC-required arithmetic addition of many individual fields' proven reserves in SPDC's acreage.
8. Forecasts have been made for all hydrocarbon streams and these have in principle been cut off at the end of the licence periods (30/11/2008 for offshore and 30/6/2019 for onshore). Minor errors have occurred in some instances in the precise date of the cut-off, by taking e.g. end 2019 and not mid-2019 as the date of cut-off (see also Att. 2.1).
9. The proved corporate total oil forecast used for the reserves submission has been based on the 5-year activity forecast, but beyond that it is notional and aimed at (just) producing all technical reserves by 2019. A proper life-cycle projects based forecast would have been preferable and this is intended for next year's submission.
10. There is no legal right to an extension in the present production licences and hence, no reserves can be booked that are produced beyond that period. The considered legal opinion within SPDC is that an extension is likely to be granted, at least for the fields still in production.
11. Present gas sales contracts are in volumes only. Energy accounting of gas sales is not done, although this will change for NLNG. Current sales contracts generally stipulate a minimum GHV of 8920 kcal/Nm3 (950 BTU/scf). Although gas streams are regularly sampled and analysed, no authoritative data base of GHV data seemed to be available. The average SPDC gas GHV was said to be around 9700 kcal/Nm3, a historically maintained figure, for which the basis is not clear. The 1998 submission implies a GHV of 10230 kcal/Nm3, apparently in error. The quarterly Ceres submissions, possibly based on the same conversion calculation, should also be checked.
12. The onset of NLNG sales and SPDC's ambitious plans to stop flaring of all associated gas by 2008 will require a stronger emphasis on close integration of gas supply and gas demand forecasts and on gas/NGL reserves in the reserves submissions and audit trail.

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

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

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

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

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

Recommendations:

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

Attachment 2.1

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

Oil / NGL / Gas Proved Reserves as at 31.12.98

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

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

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

AUDIT TRAIL:

Oil:
STOIIPs from RISRES print
Cum.oil from MRPW (Audit Pack)
Prov.Dev. oil from NFA FC (W), audit tr.note (E)
Prov. Tot'l oil from RISRES
Within Lic. Dev. oil from dev.oil (NFA) FC
(discrepancy between A/B/C NFA and NFA total in East - 1176 resp 1376)
Within Lic. Tot'l oil = Rem.Recov - 66.8 (H&K) - 91.1 (EA)
Prov.tot'l oil FC based on 5-yr act.plan and made to fit in licence

NGL:
CIIPs from RISRES print
Cum.NGLs from MRPW (Audit Pack)
Prov.Dev. NGL not available
Prov. Tot'l oil from RISRES
Within Lic. Dev. NGL not available
Within Lic. Tot'l NGL not available
Within Lic. Comtd Dev. NGL from Div. Gas FC (W only)
Within Lic. Comtd Tot'l NGL from Div. Gas FC

Gas:
GIIPs from RISRES print
Cum.gas from MRPW (Audit Pack)
Prov.Dev. gas not available
Prov. Tot'l gas from RISRES
Within Lic. Dev. gas from dev.AG (NFA) FC + expn.dev. NAG from Risres
Within Lic. Tot'l gas (comtd.+ uncomtd.) from NFA FC (AG only avail.)
Within Lic.Com.Dev. gas from Div.gas FC (E) and dev.gas (W)
Within Lic. Comtd Tot'l gas from Div. Gas FC

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

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

Incomplete match in gas totals
due to full 2019 assumed
in submission (East and West).

Dev.gas volumes do not match

Apparent error in sm3/Nm3/GHV calculation

FOIA Confidential
Treatment Requested

Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION

SPDC, 18-26 Aug 99

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

Field	Prov.Res. 1.1.98	Revisons/ Reclasins Guidelines	Revisons/ Reclasins Licence	Revisons/ Reclasins Studies etc	Revisons/ Reclasins Total	Improved Recovery	Extens./ Discov's	Purchase In-place	Sales in-place	New Devel'd Reserves	Product'n 1998	Prov.Res 31.12.98	Shell Equity Share % 1997	Shell Equity Share % 1998	Net Shell Equity 1.1.98 (MMstb)	Net Shell Equity 31.12.98 (MMstb)	Comments
Proved Total Reserves																	
East	4459.90	470.40	-66.80	288.70	692.30					▨	148.70	5039.40	30.00%	30.00%	1337.97	1511.82	
West	2651.10	456.10	-91.10	738.50	1103.50		53.50			▨	130.70	3779.40	30.00%	30.00%	795.33	1133.82	Discovery Aluo - 33.0 MMstb Extension Seibu - 11.5 MMstb Extension Tunu - 9.0 MMstb
Tot'l Prov.Res (MMstb)	7111.00 7178.90				1795.80 1865.60		53.50			▨	279.40	8818.80	186.89%	30.00%	2133.30	2645.64	
Proved Developed Reserves																	
East	797.30	469.70		117.40	587.10						148.70	1176.32	30.00%	30.00%	239.19	352.90	Reserves and reported field changes do not match.
West											130.70	980.62	30.00%	30.00%	0.00	294.19	
Prov.Dev.Resvs (MMstb)	1335.64				1100.70						279.40	2156.94	112.83%	30.00%	239.19	647.08	
Net Group Equity																	
Prov.Dev. Res	63.71				52.50						13.33	102.89					
Prov Tot'l Res 10^6 m3	342.41				88.99		2.55				13.33	420.63					
1998 Submission																	
Prov.Dev.Res	63.71											102.88					
Prov.Tot'l Res 10^6 m3	342.41				88.99		2.55				13.33	420.62					

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

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

Audit trail: **Reasonable match between RISRES and submitted volumes.**

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

Attachment 2.3

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

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

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

Conversion factors used by SPDC:	Conversion factors used by SEPIV:
1 stb = 0.15899 m3	1 stb = 0.159 m3
1scf = 0.02834 sm3	1 scf = 0.02834 sm3
1sm3 = 0.948 Nm3 (if GHV=9500kcal/Nm3)	1sm3 = 0.948 Nm3 (if GHV=9500kcal/Nm3)

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

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

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

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

Attachment 2.4

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

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

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

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

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

Audit trail:

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

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

Mismatch in proved developed gas reserves

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

CHECKLIST SEC RESERVES AUDITS

Attachment 3

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

Dimensions:

		Volumes are 100% sales, within licence period
1.1.99 Proved Oil Reserves	8818	MMstb
1.1.99 Proved Developed Oil Reserves	2157	MMstb
1998 Oil Production	279	MMstb
	764	Mstb/d
1.1.99 Proved Gas Reserves	10662	Bscf
1.1.99 Proved Developed Gas Reserves	1607	Bscf
1998 Gas Production	305	Bscf
	836	MMscf/d
Number of fields in area	206	More than 5000 reservoirs!
Number of wells drilled / in production	>1000/ 858	

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

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

CHECKLIST SEC RESERVES AUDITS

Attachment 3

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

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

CHECKLIST SEC RESERVES AUDITS

Attachment 3

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

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

CHECKLIST SEC RESERVES AUDITS

Attachment 3

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

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

CHECKLIST SEC RESERVES AUDITS

Attachment 3

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

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

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

DRAFT NOTE – 23 Sept 2003 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPF - GRA
To:	Frank Coopman	Chief Financial Officer, SIEP – EPF
	John Bell	Corporate Support Director, SIEP – EPS
	Chris Finlayson	Managing Director, SPDC
Copy:	Mark Comer	Development Director, SPDC
	Steve Ratcliffe	Business Director, SPDC
	Cees Uijlenhoed	Finance Director, SPDC
	John Hoppe	Head, Reservoir Engineering, SPDC
	(circulation)	SIEP – EPS-P: Hans Bakker, John Pay
	Ton van Leenen	Technical Director, Europe & Africa Region, SEPI – EPG
		Finance Director, Europe & Africa Region, SEPI – EPG
	Ken Marnoch	Internal Auditor EP, SI-FSAR, The Hague
	Han van Delden	Partner, KPMG Accountants NV (2x)
	Brian Puffer	PriceWaterhouseCoopers

PROVED RESERVES PROCESS AUDIT - SPDC (NIGERIA), 18-19 Sept 2003

I have audited the processes underlying the Proved Reserves submissions of SPDC for the year 2002 and the current measures undertaken by SPDC to introduce improvements in these processes. The reserves submissions present the SPDC contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 2002.

Total Group share Proved Reserves booked by SPDC at the end of 2002 were 404 mln m3 of Oil+NGL and 85 bln sm3 of gas. This represents some 16% of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratios for SPDC over 2002 were -6% for oil+NGL and -55% for gas.

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

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

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

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

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

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

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A.A. Barendregt

DEPOSITION
EXHIBIT
Barendregt
#19 2/21/07

Attachments 1, 2, 3

Attachment 1

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

MAIN OBSERVATIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Recommendations

1. Verify and complete all entries in the SPDC reserves/ projects spreadsheet such that a proper scan of the maturity of the reserves portfolio can be made.
2. Add (and complete) two additional maturity criteria to the spreadsheet:
    - Confirmation that proved reserves are consistent with 'known' fluid levels (logs and/or pressures)
    - The intended year of start of development.
3. Use should be made of data redundancies to verify and enhance the quality and robustness of the spreadsheet entries.
4. The proved and expectation oil reserves volumes for each of the seven suggested (or slightly modified) reserves categories (representing varying degrees of maturity) should be reported in a table format similar to that presented in the lower half of Attachment 2.
5. SPDC condensate reserves should be based on foreseen (and committed) NAG field gas sales and should be administered fully separately from the oil reserves.
6. Proved oil reserves per 1.1.2004 should, in first instance, be set at a level whereby the sum of proved oil and condensate reserves does not exceed the 1.1.2003 sum of these volumes, minus the combined 2003 production. Further reductions may be necessary, i.e. all volumes in category G (fully immature, see 6 above) and possibly those in category F (long term projects).
7. Plots as presented in Att. 3 should be used to verify the appropriateness of proved vs. expectation estimates.

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

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

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

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ATTACHMENT 2 - SPDC – SPREADSHEET CRITERIA FOR PROVED OIL RESERVES

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

In italics *Criteria not yet in spreadsheet!*

+: Necessary criterion (must be 'Yes')
blank: Not needed
X: Not allowed (must be 'No')

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

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

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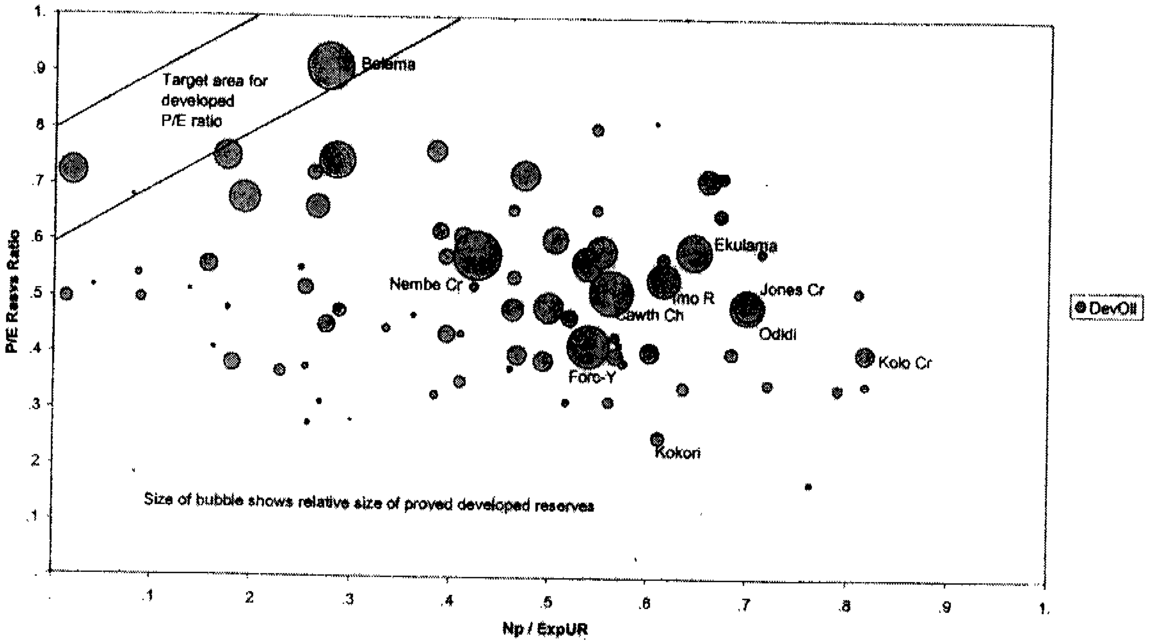
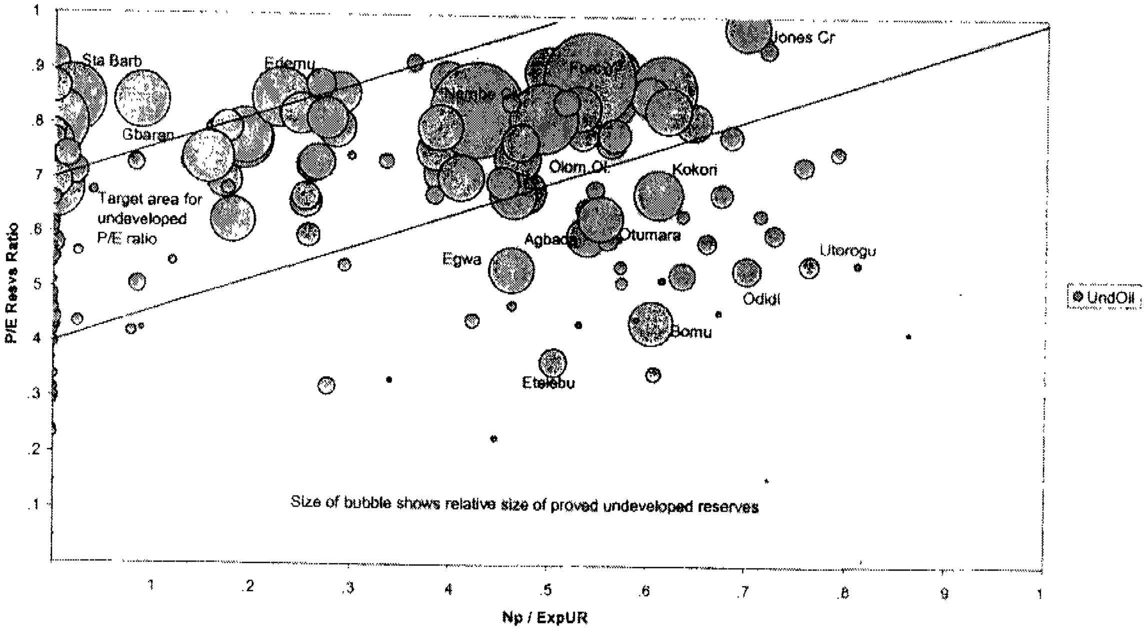
Attachment 3.1

SPDC - OIL DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - OIL UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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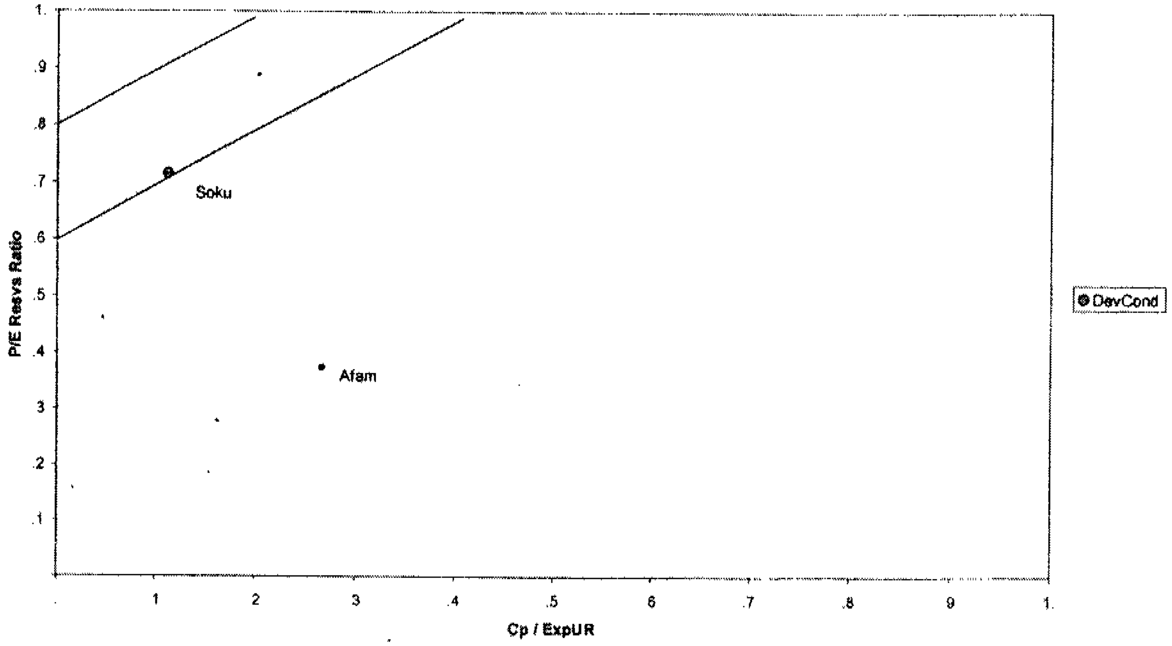
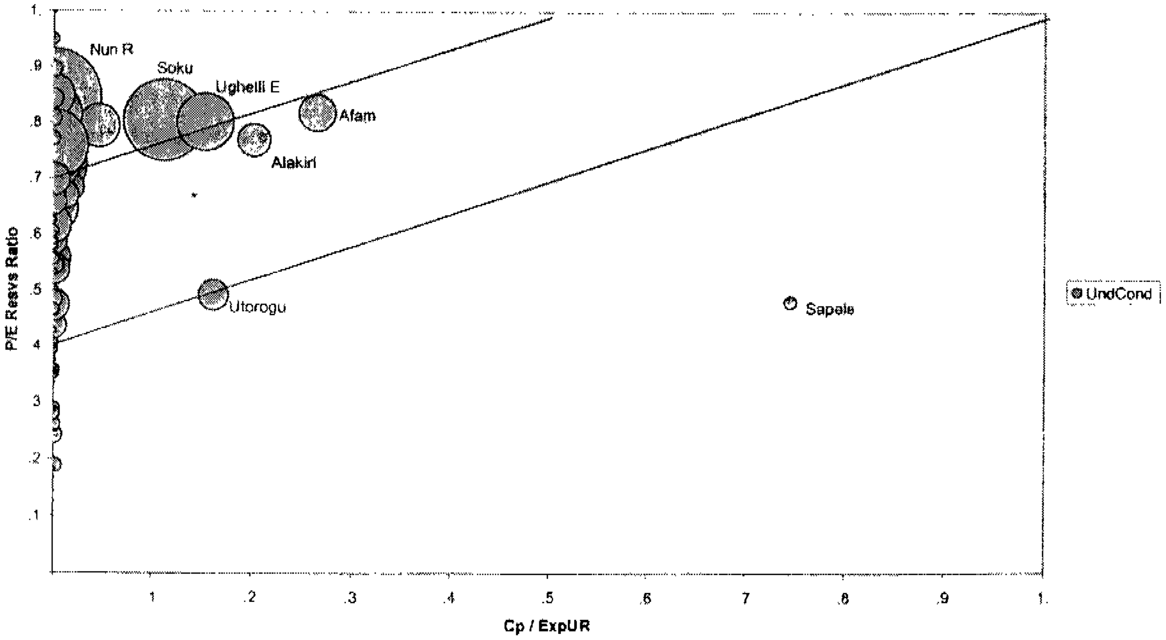
Attachment 3.2

SPDC - CONDENSATE DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - CONDENSATE UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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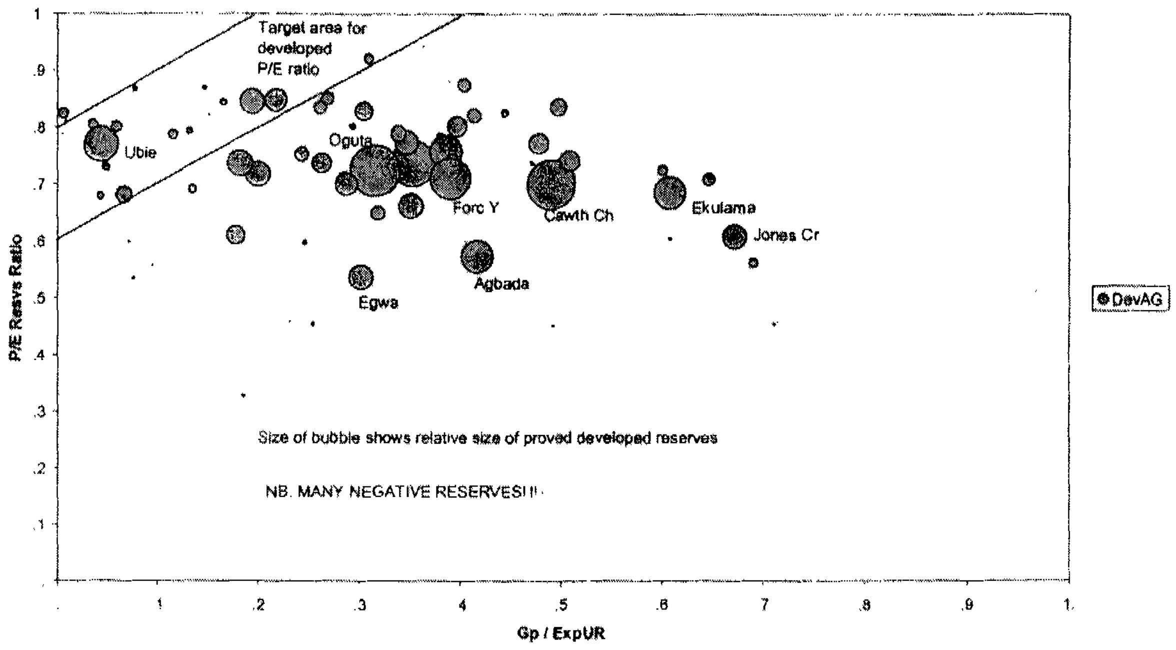
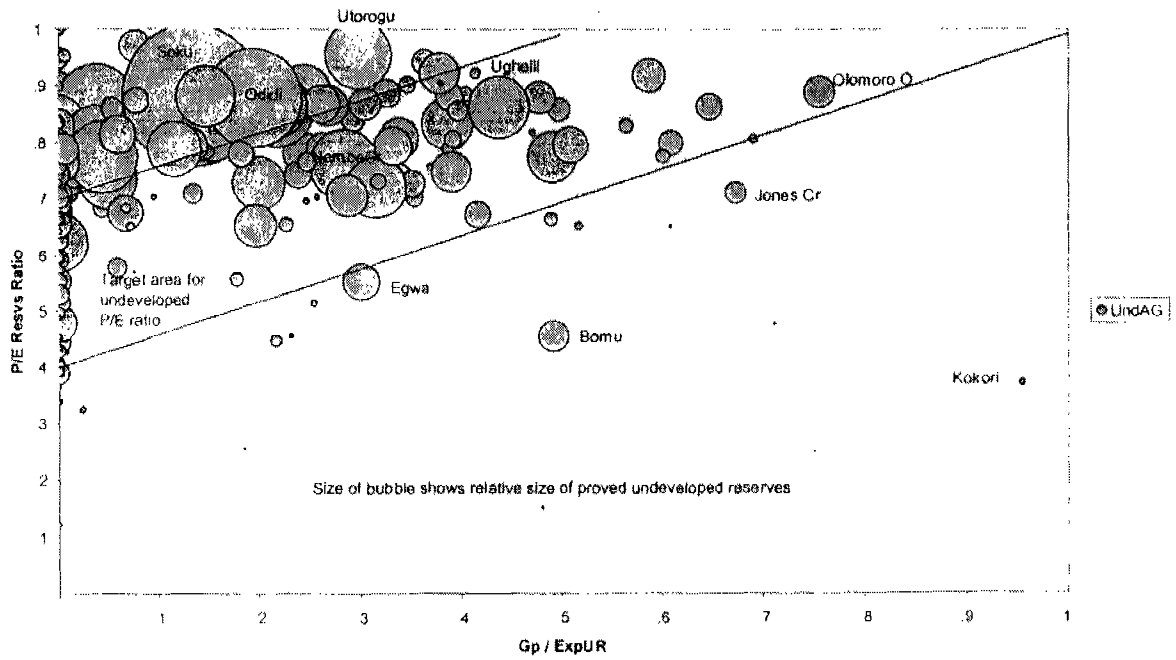
Attachment 3.3

SPDC - ASSOCGAS DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

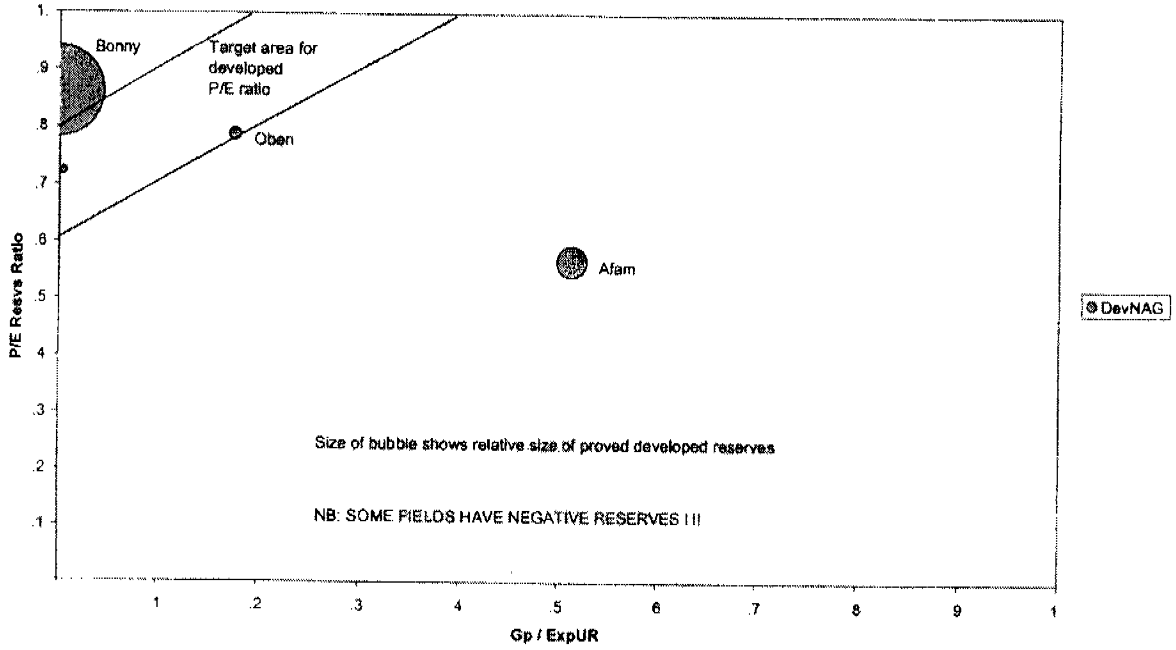


SPDC - ASSOCGAS UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

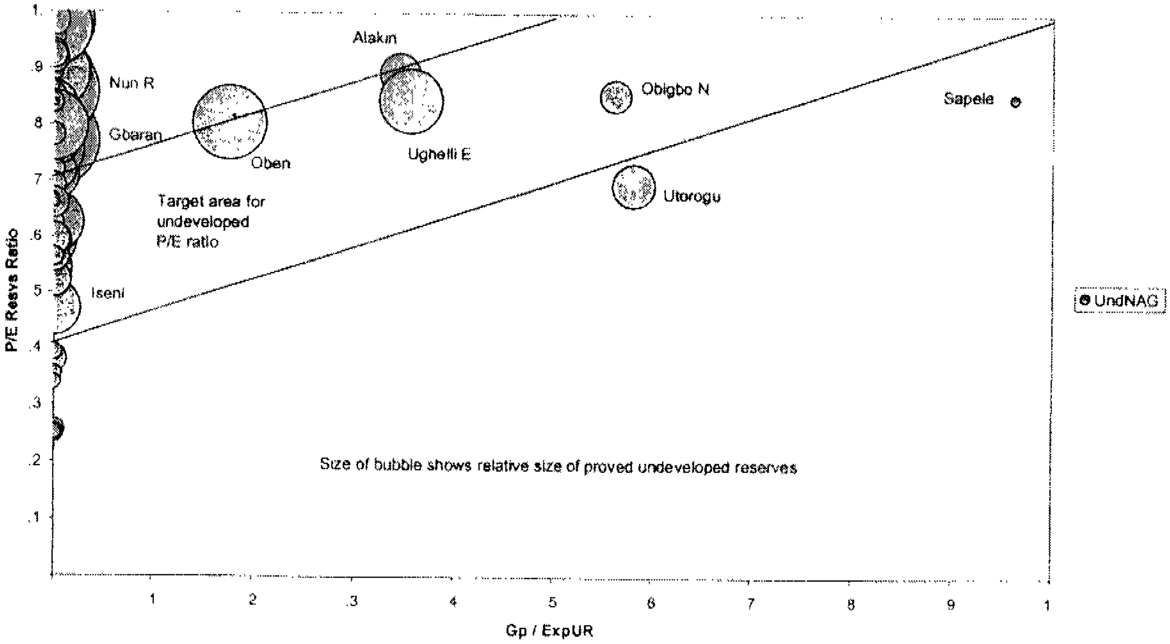


Attachment 3.4

SPDC - NAG DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - NAG UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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NOTE – 30 Sept 2003 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP & EPF - GRA
To:	Frank Coopman	Chief Financial Officer, SIEP – EPF
	John Bell	Corporate Support Director, SIEP – EPS
	Chris Finlayson	Managing Director, SPDC
Copy:	Mark Comer	Development Director, SPDC
	Steve Ratcliffe	Business Director, SPDC
	Cees Uijlenhoed	Finance Director, SPDC
	Promise Egele	Petroleum Engineering Manager, SPDC
	John Hoppe	Head, Reservoir Engineering, SPDC
	(circulation)	SIEP – EPS-P: Hans Bakker, John Pay
	Tom van Leenen	Technical Director, Europe & Africa Region, SEPI – EPG
	Martin ten Brink	Finance Director, Europe & Africa Region, SEPI – EPG
	Ken Marnoch	Internal Auditor EP, SI-FSAR, The Hague
	Han van Delden	Partner, KPMG Accountants NV (2x)
	Brian Puffer	PriceWaterhouseCoopers

PROVED RESERVES PROCESS AUDIT - SPDC (NIGERIA), 18-19 Sept 2003

I have audited the processes underlying the Proved Reserves submissions of SPDC for the year 2002 and the current measures undertaken by SPDC to introduce improvements in these processes. The reserves submissions present the SPDC contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 2002.

Total Group share Proved Reserves booked by SPDC at the end of 2002 were 404 mln m3 of Oil+NGL and 85 bln sm3 of gas. This represents some 16% of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratios for SPDC over 2002 were -6% for oil+NGL and -55% for gas.

The last previous SEC proved reserves audit for SPDC was carried out in 1999. This current audit is a partial audit of reserves reporting processes only (in The Hague), replacing a full audit, which has been deferred to 2004. The audit took the form of presentations and detailed discussions about the reserves reporting process with a small selection of SPDC staff.

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

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

The audit finding is therefore that the present status of SPDC's proved oil reserves is unsatisfactory. Efforts are underway to address this situation. Proved gas reserves at 1.1.2003 appeared insufficiently founded on firm contracts but this will now be corrected with the commitment to a fourth and a fifth LNG train.

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

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

A.A. Barendregt

Attachments 1, 2, 3

DEPOSITION EXHIBIT
Barendregt
#20 2/21/07

Attachment 1

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

MAIN OBSERVATIONS

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

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

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

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

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

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

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

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

A number of the criteria checks coincide with necessary conditions for booking proved reserves, in accordance with the most recent (2003) Reserves guidelines. These are highlighted in Att. 2 A first pass run through the spreadsheet data seemed to indicate that only 44% of proved developed reserves and not more than 7% of proved undeveloped reserves fulfil the criteria for proved reserves. It is likely that these percentages are too low There are still a considerable number of 'empty' entries in the spreadsheet and these should be completed before end year. However, there is a strong indication that in particular the undeveloped proved reserves estimates have not kept pace with the increased requirements for booking such reserves as defined in the recent Group guidelines. The most significant of these is that the associated development projects must have passed either VAR3 (for small brownfield projects) or FID (for new field and major projects).

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

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

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

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

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

6. To provide better insight into the maturity of SPDC's proved oil reserves portfolio it is suggested that, following completion and validation of all spreadsheet entries, a distinction is made into **seven categories of proved oil reserves:**
   A Proper proved developed reserves
   B Proved developed reserves in reservoirs without properly defined 'proved areas'
   C Proper proved undeveloped reserves
   D Reservoirs / projects that are likely to pass VAR3/FID in the next 2 years
   E Reservoirs / projects that are likely to pass VAR3/FID between 2 and 5 years from now,
   F Reservoirs / projects that are likely to pass VAR3/FID more than 5 years from now,
   G Reservoirs / projects that fall into none of the above and hence are completely immature.

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

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

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

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

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

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

the next (Sept 2003) guidelines should be revised in such a manner that 'existing markets' are defined more precisely and may include mature LNG markets.

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

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

13. In summary, the way forward for SPDC's oil, condensate and gas reserves booking per 1.1.2004 is suggested to be as follows:
    - Proved gas reserves can be booked as per plan, i.e. for NLNG trains 1-5 and appropriate, committed volumes for domestic gas,
    - Proved condensate reserves should be evaluated in line with foreseen NAG sales and should be administered to their full (proved!) extent, independently from oil reserves,
    - Proved oil reserves are at present overstated and a reduction in 1.1.2004 proved oil reserves will probably be necessary. The precise value of the reduction cannot be assessed at this stage as it will depend on SPDC's evaluation of the maturity spectrum of their portfolio by early December. At the least, all volumes in category G (fully immature or undefined, see 6 above) and probably those in category F (long term projects) will need to be removed from the proved reserves portfolio.

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

Recommendations

1. Verify and complete all entries in the SPDC reserves/ projects spreadsheet such that a proper scan of the maturity of the reserves portfolio can be made.
2. Add (and complete) two additional maturity criteria to the spreadsheet:
    - Confirmation that proved reserves are consistent with 'known' fluid levels (logs and/or pressures)
    - The intended year of start of development.
3. Use should be made of data redundancies to verify and enhance the quality and robustness of the spreadsheet entries.
4. The proved and expectation oil reserves volumes for each of the seven suggested (or somewhat modified) reserves categories should be reported in a table format similar to that presented in the lower half of Attachment 2.
5. SPDC condensate reserves should be based on foreseen (and committed) NAG field gas sales and should be administered fully separately from the oil reserves.
6. Proved oil reserves per 1.1.2004 should exclude all volumes in category G (fully immature or undefined, see 6 above) and probably those in category F (long term projects). This should be reviewed jointly with SIEP EPS-P.
7. Plots as presented in Att. 3 should be used to verify the appropriateness of proved vs. expectation estimates.

8. The 2004 audit should specifically look at:
- The status of the maturity of future projects in SPDC's portfolio and the effect that this will have on bookable proved reserves,
- The reason why small (<2 MMbl) reservoir reserves volumes occur in a large majority of cases,
- The precise status of gas contractual sales commitments,
- The reasons for the low Proved/Expectation reserves ratios in many fields (Att. 3).
These issues are already covered by the general Reserves Audit Terms of Reference, but in the case of SPDC reserves they require particular attention.

9 The (Sept 2003) Group reserves guidelines should be revised in such a manner that 'existing markets' are defined more precisely and may include mature LNG markets (action: SIEP EPS-P).

ATTACHMENT 2 - SPDC – SPREADSHEET CRITERIA FOR PROVED OIL RESERVES

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

In Italics *Criteria not yet in spreadsheet!*

+:	Necessary criterion (must be 'Yes')
blank:	Not needed
X:	Not allowed (must be 'No')

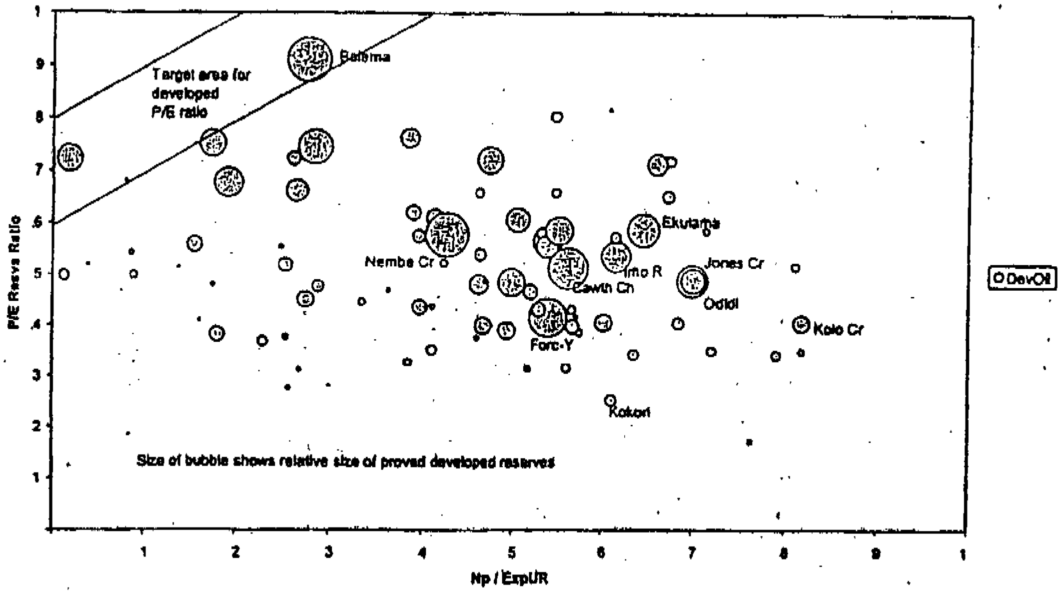
SPDC Group share oil reserves volumes (MMstb) as per data base Sept 2003

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

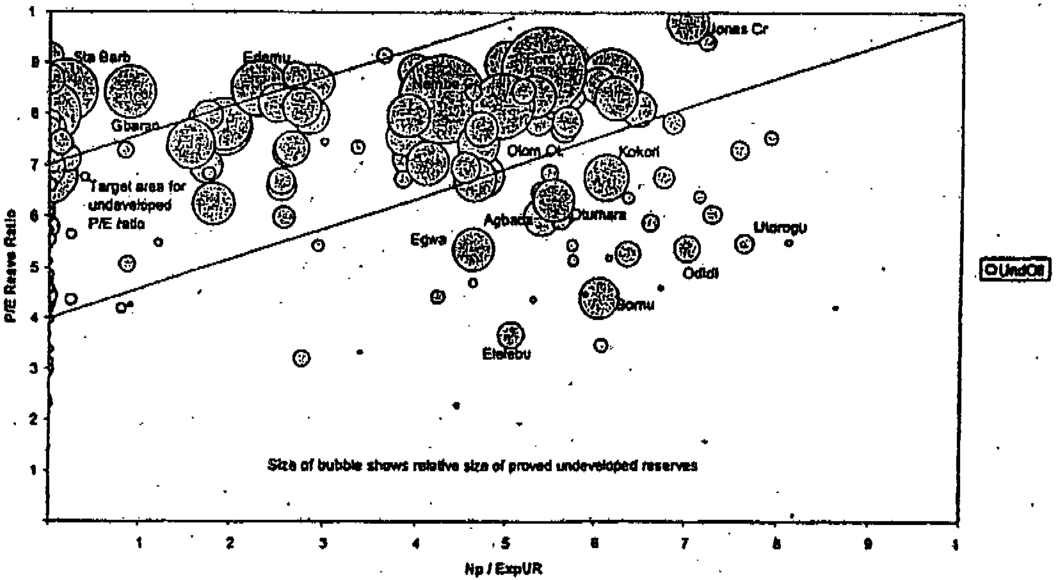
Note: 'Unknown' and 'Unplanned' volumes may overlap – addition is not strictly valid!

Attachment 3.1

SPDC - OIL DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - OIL UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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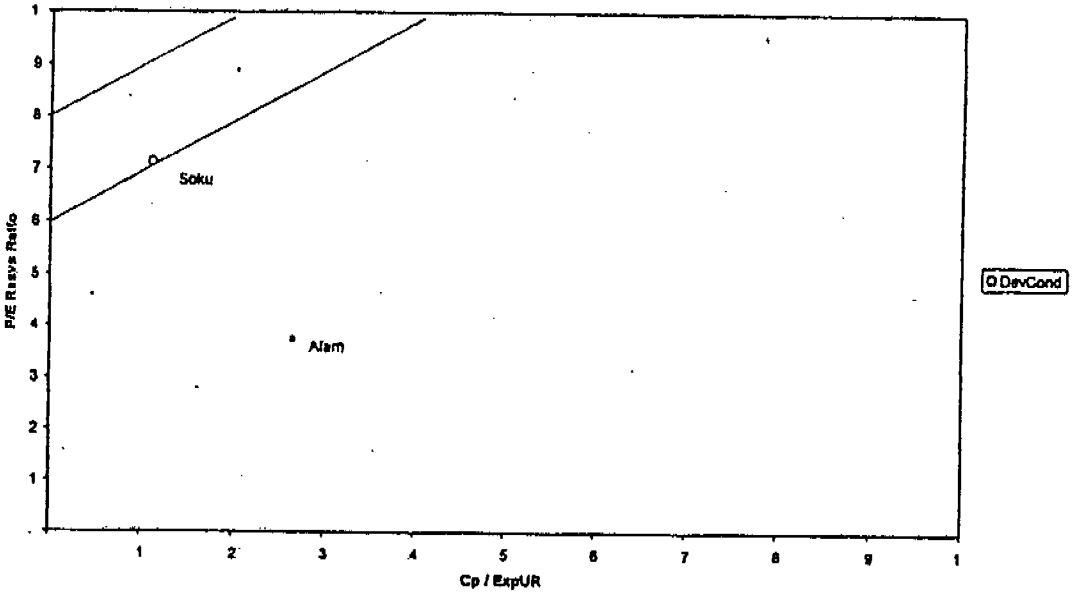
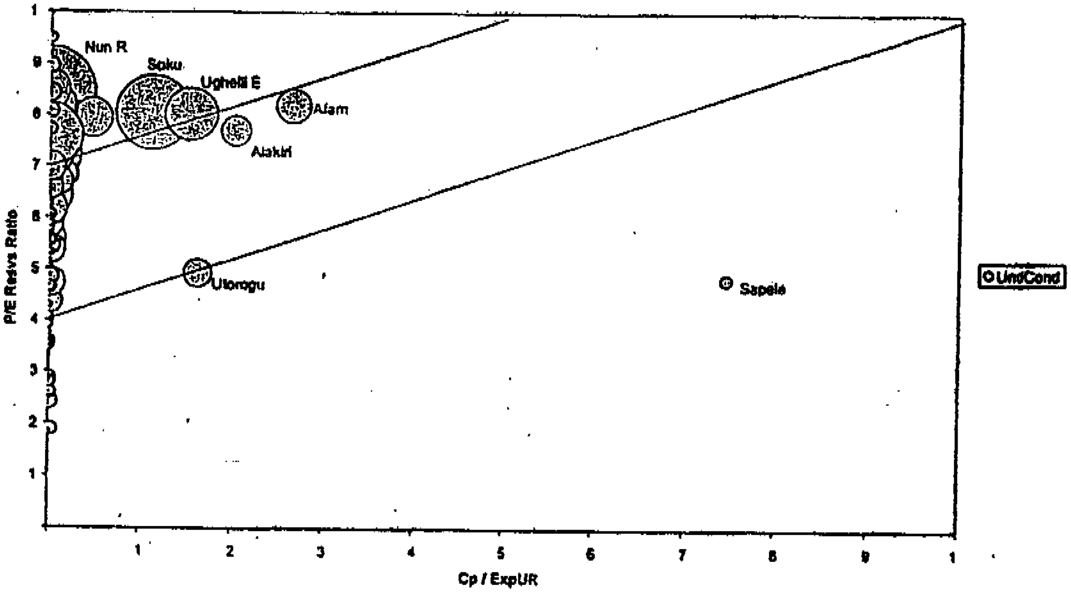
Attachment 3.2

SPDC - CONDENSATE DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - CONDENSATE UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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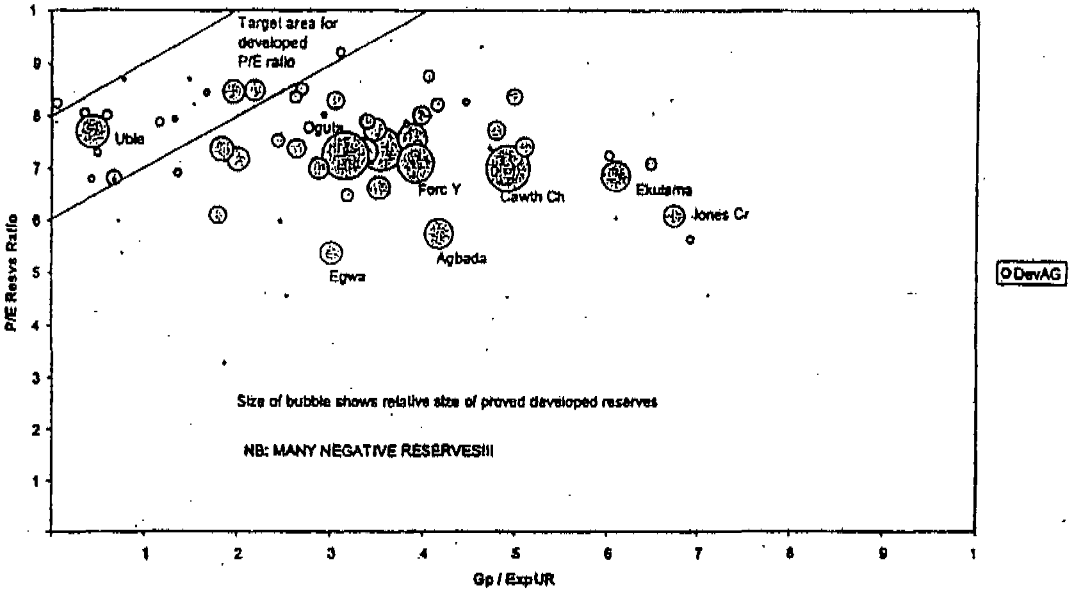
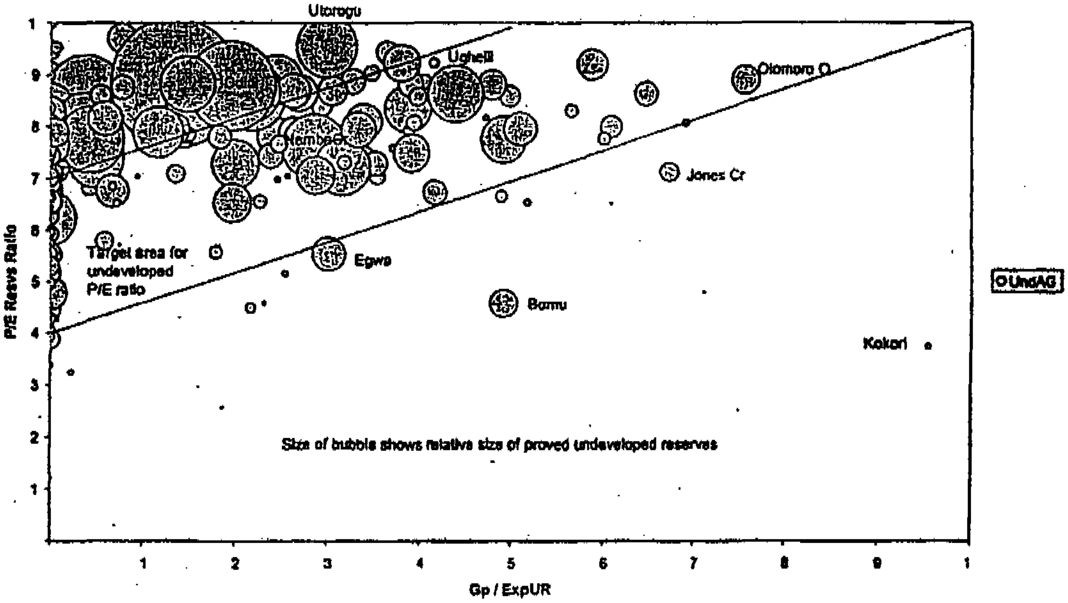
Attachment 3.3

SPDC - ASSOCGAS DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

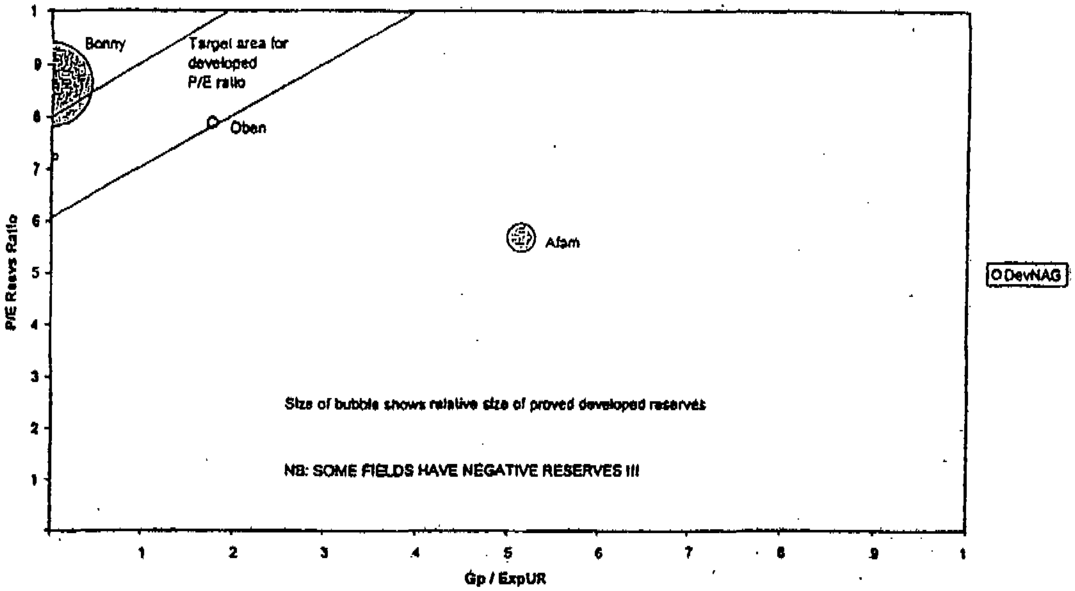


SPDC - ASSOCGAS UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

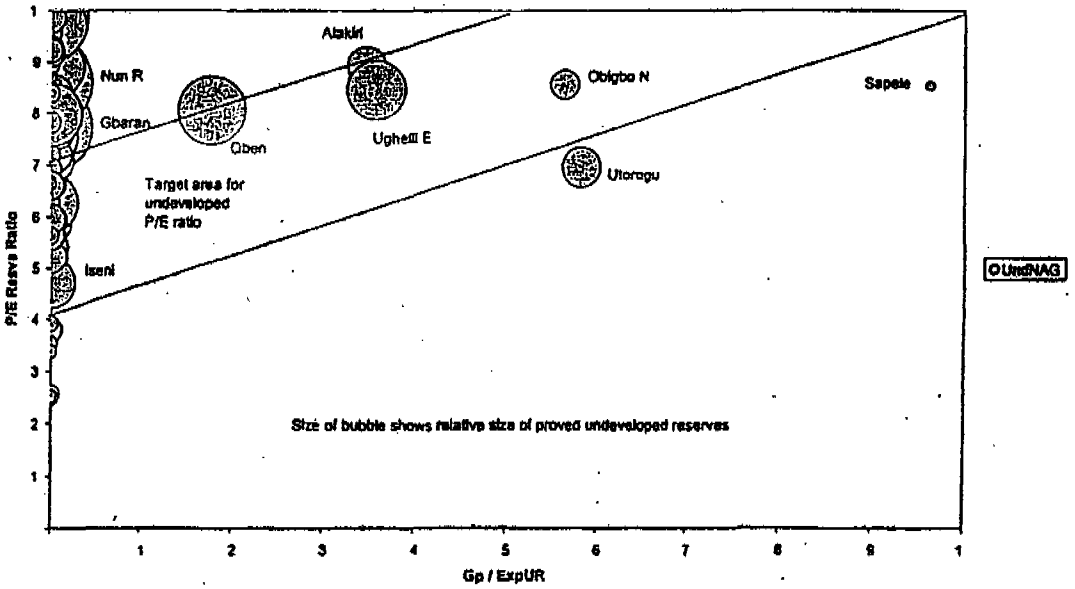


Attachment 3.4

SPDC - NAG DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - NAG UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



NOTE – 30 January 2001 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP EPB-GRA
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REVIEW OF GROUP END-2000 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

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

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

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

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

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

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

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

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

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

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

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

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

30/1/01

A.A. Barendregt

Attachments 1 - 8

DEPOSITION EXHIBIT
Barendregt
#21 2/21/07

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

Attachment 1

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

MAIN OBSERVATIONS

1. Significant reserves changes during 2000 were as follows:

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

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

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

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

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

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

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

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

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

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

A tabulation of these changes is given in Attachment 2.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Recommendations to SIEP Reserves Coordination:

1. Vigilance should continue to be applied by the SIEP Reserves Coordinator to ensure that all future Proved Reserves changes will be fully in accordance with Group Reserves Guidelines.
2. Confirm the viability of the 78% Proved Reserves increase booked by SVSA by a review of the planned VAR report and associated SVSA documentation during 2001.
3. Include the volume of Proved and Proved Developed Reserves not producible within current production licences in annual OU reserves submissions.
4. Strengthen the message that externally reported Proved and Proved Developed Reserves should be brought close to (made equal to) expectation reserves in mature fields in the Group Reserves Guidelines to be updated during 2001 and in the cover letter.

Attachment 2

SIGNIFICANT 2000 PROVED AND PROVED DEVELOPED RECOVERY CHANGES

(Shell Group share)

MAJOR TECHNICAL REVISIONS

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

OTHER MAJOR CHANGES

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

OTHER MINOR CHANGES AND TOTAL

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

2000 GROUP RESERVES SUBMISSIONS

Attachm 3.1

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Treatment Requested

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

Country Name	Proved Resvs 1.1.2000	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2000	Proved Resvs 1.1.2001	Proved Dev'd Resvs 1.1.2000	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2000	Proved Dev'd Resvs 1.1.2001	Minority Resvs incl. 1.1.2000	Minority Resvs incl. 1.1.2001	R / P Tot (yr)	Repl'mt Ratio TotlRes (%)	Repl.R. TotlRes (%) Excl Pur/ Sales /P	Repl'mt Ratio DevRes (%)
Australia (SDA)	32.49	4.18	.	.07	.	3.5	4.2	29.04	14.76	.	.52	4.2	11.08	.	.	7	18%	101%	12%
Australia (WPL)	11.85	2.64	.	4.83	.	.	2.28	17.04	5.63	.	2.26	2.28	5.61	.	.	7	328%	328%	99%
Brunei	59.28	8.92	2.8	3.9	.	.	5.54	69.36	28.19	6.04	6.19	5.54	34.88	.	.	13	282%	282%	221%
China	3.24	4.16	.	.	.	.	1.43	5.97	2.83	.7	3.18	1.43	5.27	.	.	4	291%	291%	271%
China (Shell Oil EH)	3.29	-3.29	.	.	.	.		.	2.87	.	-2.87	.	.	.	.				
Malaysia	25.55	-.94	2.84	2.68	.	.	3.28	26.85	13.95	3.	.09	3.28	13.76	.	.	8	140%	140%	94%
New Zealand	4.6	-.17	.	.98	.	.	.41	5.	2.6	.11	-.04	.41	2.26	.	.	12	198%	198%	17%
New Zealand (Shell Oil EH)	.8	.05	.	.	.	.	.11	.74	.67	.	.06	.11	.62	.	.	7	45%	45%	55%
Philippines	3.82	.38	.	.	.	.7	.	3.5	.	.	.	.	.	.	.				
Thailand	14.17	.89	1.34	.	.	.	1.04	15.35	3.78	.95	.33	1.04	4.02	.	.	15	214%	214%	123%
Angola	.	.	.	11.85	.	.	.	11.85	.	.	.	.	.	.	.				
Argentina	3.43	.26	.	.07	.	.	.22	3.54	2.03	.06	-.03	.22	1.84	.	.	16	150%	150%	14%
Brazil (Shell Oil WH)	.81	.2	.	.	.	.	.09	.92	.81	.	.2	.09	.92	.	.	10	222%	222%	222%
Cameroon (Shell Oil EH)	7.75	-1.68	.2	.11	.	.	1.21	5.17	7.28	.29	-1.36	1.21	5.	.	1.03	4	-113%	-113%	-88%
Congo (DR)	3.22	-.01	.	.	.	.	.17	3.04	2.3	.	-.02	.17	2.11	.	.	18	-6%	-6%	-12%
Gabon	19.91	3.83	.	.	.	.81	3.99	18.94	17.45	1.12	2.5	3.99	17.08	4.97	4.74	5	76%	96%	91%
Nigeria (SNEPCO)	71.41	7.15	.	10.98	.	.	.	89.54	.	.	.	.	.	.	.				
Nigeria (SPDC)	448.1	.	.	.	.	.	13.93	434.17	113.19	4.29	13.33	13.93	116.88	.	.	31	0%	0%	126%
Venezuela	21.43	16.66	.	.	.	.	2.54	35.55	11.61	1.03	1.19	2.54	11.29	.	.	14	656%	656%	87%
Abu Dhabi	103.26	.02	.	.	.	.	5.58	97.7	83.71	2.11	.94	5.58	81.18	.	.	18	0%	0%	55%
Bangladesh	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Egypt	9.06	-2.59	.	.	.	.	.58	5.89	5.73	.01	-1.69	.58	3.47	.	.	10	-447%	-447%	-290%
Iran	23.85	7.74	.	.	.	.	.	31.59	.	.	.	.	.	.	.				
Kazakhstan (Temir)	2.	.01	.	.	.	2.	.01	.	.	.01	.	.01	.	.	.	0	-19900%	100%	100%
Oman	139.5	34.88	18.43	3.21	.	.	16.62	179.4	85.	4.95	6.67	16.62	80.	.	.	11	340%	340%	70%
Oman Gisco	33.18	-12.34	.	.	.	.	2.36	18.48	27.32	.	-8.2	2.36	16.76	4.98	2.77	8	-523%	-523%	-347%
Pakistan	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Russia (Sakhalin Holding)	7.69	-.01	.	.	7.93	.	.51	15.1	2.81	1.19	2.59	.51	5.88	.	.	30	1553%	-2%	741%
Syria	19.81	-1.17	.	.	.	.	2.92	15.72	12.29	.98	1.	2.92	11.35	.	.	5	-40%	-40%	68%
Austria	.23	.02	.	.01	.	.	.03	.23	.19	.	.03	.03	.19	.	.	8	100%	100%	100%
Canada	47.16	-1.42	14.43	.07	.	.01	3.36	56.87	29.13	.	1.11	3.36	26.88	10.36	12.49	17	389%	389%	33%
Canada (AOSP)	95.4	.	.	.	.	.	.	95.4	.	.	.	.	.	21.2	21.08				
Denmark	39.15	7.17	4.34	.41	.	.	7.53	43.54	27.63	1.41	11.44	7.53	32.95	.	.	6	158%	158%	171%
Germany	3.37	-.01	.	.	.	.	.31	3.05	3.07	.17	-.02	.31	2.91	.	.	10	-3%	-3%	48%
Netherlands	5.77	-.06	.	.	.	.	.75	4.96	3.93	.41	.1	.75	3.69	.	.	7	-8%	-8%	68%
Norway	33.26	5.34	.	.	.	.77	5.07	32.76	20.65	4.56	3.44	5.07	23.58	.	.	6	90%	105%	158%
Shell Oil (MCC)	1.86	-1.86	.	.	.	.	.	.	1.56	.	-1.56	.	.	.	.				
Shell Oil (TMR)	.93	.16	.	.13	.	.08	.16	.98	.56	.07	.14	.16	.61	.	.	6	131%	181%	131%
UK	129.92	.49	2.89	1.42	.	10.49	21.98	102.25	90.35	14.56	-7.35	21.98	75.58	.	.	5	-26%	22%	33%
USA	92.	2.24	.	20.04	.01	.94	16.18	97.17	54.12	11.54	6.34	16.18	55.82	.	.	6	132%	138%	111%
USA (Aera)	79.26	-3.07	.26	.	.	.13	7.23	69.09	59.01	4.08	1.39	7.23	57.25	.	.	10	-41%	-39%	76%
USA (Altura)	47.87	.61	.	.	.	47.78	.7	.	40.24	.	-39.54	.7	.	.	.	0	-6739%	87%	-5649%
Total excl Can. AOSP	**1,554.28**	**79.38**	**47.53**	**60.76**	**7.94**	**67.21**	**132.32**	**1,550.36**	**777.05**	**63.64**	**2.36**	**132.32**	**710.72**	**20.31**	**21.03**	**12**	**97%**	**142%**	**50%**
Grand Total	**1,649.68**	**79.38**	**47.53**	**60.76**	**7.94**	**67.21**	**132.32**	**1,646.75**	**777.05**	**63.64**	**2.36**	**132.32**	**710.72**	**41.61**	**42.11**	**12**	**97%**	**142%**	**50%**

2000 GROUP RESERVES SUBMISSIONS

Attachment 3.2

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

Country Name	Proved Resvs 1.1.2000	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2000	Proved Resvs 1.1.2001	Proved Dev'd Resvs 1.1.2000	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2000	Proved Dev'd Resvs 1.1.2001	Minority Resvs incl. 1.1.2000	Minority Resvs incl. 1.1.2001	R / P Tot (yr)	Repl'mt Ratio TotlRes (%)	Repl.R. TotlRes (%) Excl Pur/ Sales iP	Repl'mt Ratio DevRes (%)
Australia (SDA)	176.638	2.576	.	.453	.	.394	2.356	176.917	18.583	.	1.824	2.356	18.051	.	.	75	112%	129%	77%
Australia (WPL)	40.205	1.274	.	.155	.	.	1.45	40.184	8.147	.	1.305	1.45	8.002	.	.	28	99%	99%	90%
Brunei	102.612	-2.08	.	4.023	.	.	4.656	99.899	40.744	5.442	-3.601	4.656	37.929	.	.	21	42%	42%	40%
China	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
China (Shell Oil EH)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Malaysia	183.819	-11.93	5.625	.	.	.	5.723	171.791	37.746	20.212	-1.27	5.723	50.965	.	.	30	-110%	-110%	331%
New Zealand	12.646	.031	.	3.361	.154	.	1.381	14.811	11.704	.016	.19	1.381	10.529	.	.	11	257%	246%	15%
New Zealand (Shell Oil EH)	2.314	-.312	.	.	.	.	.247	1.755	2.014	.	-.319	.247	1.448	.	.	7	-126%	-126%	-129%
Philippines	19.436	1.029	.	.	.	3.551	.	16.914	.	.	.	.	.	.	.				
Thailand	6.226	.338	.063	.	.	.	.437	6.189	2.769	.263	.238	.437	2.833	.	.	14	92%	92%	115%
Angola	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Argentina	7.284	1.522	.	.619	.	.	.036	9.389	.547	.056	-.501	.036	.066	.	.	261	5947%	5947%	-1236%
Brazil (Shell Oil WH)	4.384	1.083	.	.	.	.	.326	5.141	4.384	.	1.083	.326	5.141	.	.	16	332%	332%	332%
Cameroon (Shell Oil EH)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Congo (DR)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Gabon	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Nigeria (SNEPCO)	5.7	.57	.	.75	.	.	.	7.02	.	.	.	.	.	.	.				
Nigeria (SPDC)	95.93	-8.384	.	.	.	.	1.836	85.71	37.837	.	-1.987	1.836	34.014	.	.	47	-457%	-457%	-108%
Venezuela	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Abu Dhabi	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Bangladesh	4.713	.039	.	.457	.	.	.384	4.825	2.846	.	-.2	.384	2.262	.	.	13	129%	129%	-52%
Egypt	31.272	-2.326	.39	.	.	.	1.455	27.881	14.059	1.624	-.722	1.455	13.506	.	.	19	-133%	-133%	62%
Iran	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Kazakhstan (Temir)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Oman	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Oman Gisco	45.693	14.272	.	.	.	.	4.758	55.207	45.693	.	3.825	4.758	44.76	6.854	8.281	12	300%	300%	80%
Pakistan	11.339	-.752	.	.	.	.532	.189	9.866	3.347	.	.	.189	3.158	.	.	52	-679%	-398%	0%
Russia (Sakhalin Holding)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Syria	1.012	-.074	.	.	.	.	.234	.704	.596	.013	-.038	.234	.337	.	.	3	-32%	-32%	-11%
Austria	1.476	.191	.	.104	.	.	.175	1.596	1.441	.	.228	.175	1.494	.	.	9	169%	169%	130%
Canada	88.31	3.231	.	.206	.	.895	6.153	84.699	72.2	.	.688	6.153	66.735	19.402	18.608	14	41%	56%	-11%
Canada (AOSP)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Denmark	30.44	.941	.711	.365	.	.	3.105	29.352	18.73	.518	2.307	3.105	18.45	.	.	9	65%	65%	91%
Germany	59.422	1.225	.	.	.	.	4.659	55.988	46.423	1.565	1.023	4.659	44.352	.	.	12	26%	26%	56%
Netherlands	413.425	.132	.	1.122	.	.	14.828	399.851	211.215	3.23	.73	14.828	200.347	.	.	27	8%	8%	27%
Norway	89.897	2.15	.	.	.	.208	2.06	89.781	42.194	.224	-3.466	2.06	36.892	.	.	44	94%	104%	-157%
Shell Oil (MCC)	1.552	-1.552	.	.	.	.	.	.	1.504	.	-1.504	.	.	.	.				
Shell Oil (TMR)	1.693	-.364	.	.128	.	.113	.202	1.142	1.193	.062	-.16	.202	.893	.	.	6	-173%	-117%	-49%
UK	109.447	1.493	2.27	.075	.	3.096	11.583	98.606	67.734	11.532	-.223	11.583	67.46	.	.	9	6%	33%	98%
USA	96.232	-1.091	.	18.564	1.421	2.217	16.592	96.317	76.788	10.178	-3.968	16.592	68.406	.	.	6	101%	105%	37%
USA (Aera)	5.53	-4.036	.052	.	.	.142	.117	1.287	3.145	.761	-2.803	.117	.986	.	.	11	-3526%	-3405%	-1745%
USA (Altura)	8.068	.062	.	.	.	8.018	.112	.	6.985	.	-6.873	.112	.	.	.	0	-7104%	55%	-6137%
Total excl Can. AOSP	**1,656.715**	**-.742**	**9.111**	**30.382**	**1.576**	**19.164**	**85.054**	**1,592.822**	**780.568**	**55.696**	**-14.194**	**85.054**	**737.016**	**26.256**	**26.889**	**19**	**25%**	**46%**	**49%**
Grand Total	**1,656.715**	**-.742**	**9.111**	**30.382**	**1.576**	**19.164**	**85.054**	**1,592.822**	**780.568**	**55.696**	**-14.194**	**85.054**	**737.016**	**26.256**	**26.889**	**19**	**25%**	**46%**	**49%**

2 PRODUCTION RECONCILIATION - OIL+

Attachm 4.1

Country	Original CERES			Org'l Resvs Subm'n		Difference	Final CERES		Final Resvs Subm		Difference	Comment
	mln bbl		10^6m3		10^6m3		mln bbl	10^6m3	10^6m3		10^6m3	
Australia (SDA)				4.2								
Australia (WPL)				2.28								
Australia Total	40.749		6.48		6.48		40.749	6.48		6.48		OK
Brunei	34.84		5.54		5.54		34.84	5.54		5.54		OK
China				1.37								
China (Shell Oil EH)												
China Total	9.024		1.43		1.37	-.06	9.024	1.43		1.43		Errors in SEC submission - corrected.
Malaysia	20.618		3.28		3.27	-.01	20.618	3.28		3.28		Rounding error - SEC submission corrected
New Zealand				.42					.41			
New Zealand (Shell Oil EH)				.12					.11			
New Zealand Total	3.573		.57		.54	-.03	3.27	.52		.52		Correction to Ceres plus minor corr'n for gasolines (excluded) in SEC submission.
Thailand	6.548		1.04		1.04		6.548	1.04		1.04		OK
Argentina	1.397		.22		.22		1.397	.22		.22		OK
Brazil (Shell Oil WH)	.562		.09		.09		.562	.09		.09		OK
Cameroon (Shell Oil EH)	7.595		1.21		1.21		7.595	1.21		1.21		OK
Congo (DR)	1.064		.17		.17		1.064	.17		.17		OK
	25.117		3.99			-.08	25.117	3.99		3.99		SEC subm'n omitted production from Echira (sold) - corrected
Gabon					3.91							
Nigeria (SPDC)	87.585		13.93		13.93		87.585	13.93		13.93		OK
Venezuela	15.998		2.54		2.54		15.998	2.54		2.54		OK
Abu Dhabi	35.108		5.58		5.58		35.108	5.58		5.58		OK
Egypt	3.632		.58		.58		3.632	.58		.58		OK
Oman				16.61								
Oman Gisco				2.36								
Oman Total	119.34		18.98		18.97	-.01	119.34	18.98		18.98		Rounding error - SEC submission corrected
Russia (Sakhalin Holding)		3.12		.51		.01			.51			
Kazakhstan (Temir)		.016							.01			
Russia Total	3.136		.5		.51		3.248	.52		.52		Ceres based on unreconciled volumes - corrected; Rounding correction for Temir SEC submission
Syria	18.349		2.92		2.92		18.349	2.92		2.92		OK
Austria	.176		.03		.03		.176	.03		.03		OK
Canada	21.142		3.36		3.36		21.142	3.36		3.36		OK
Denmark	47.38		7.53		7.54	.01	47.38	7.53		7.53		Rounding error; SEC submission corrected
Germany	1.965		.31		.31		1.965	.31		.31		OK
Netherlands	4.701		.75		.75		4.701	.75		.75		OK
Norway	31.908		5.07		5.07		31.908	5.07		5.07		OK
UK	138.239		21.98		21.97	-.01	138.239	21.98		21.98		Rounding error - SEC submission corrected
USA				16.18								
USA (Aera)				7.23								
USA (Altura)	.6375	.1		.8								
Shell Oil (MCC)												
Shell Oil (TMR)				.16								
USA Total	152.638		24.27		24.37	.1	152.638	24.27		24.27		Ceres submission excluded Altura prodn - too late to correct, hence SEC submission corrected
Total	832.384		132.35		132.27	-.08	832.191	132.32		132.32		Not fully reconciled - match forced

Jan30Note-tbl.xls, OilNGLRecn-Att4.1

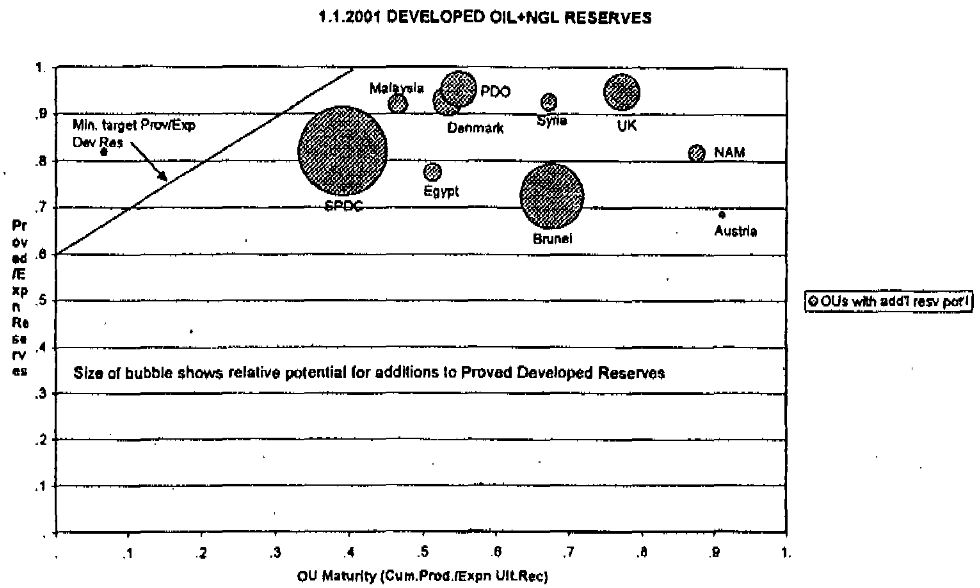
26/01/01, 10:05

2000 PRODUCTION RECONCILIATION - GAS

Attachment 4.2

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

Attachment 5.1


1.1.2001 DEVELOPED OIL+NGL RESERVES

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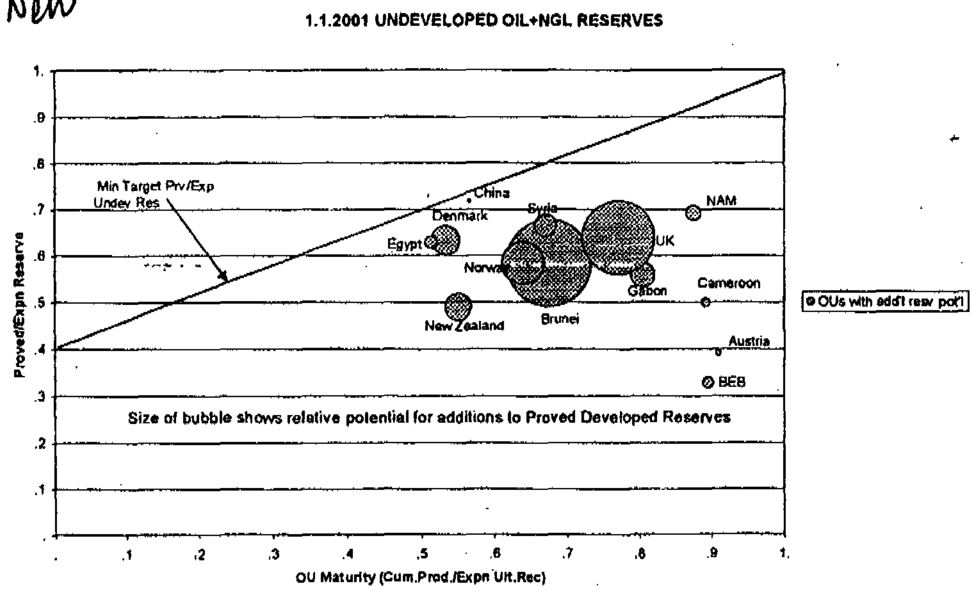
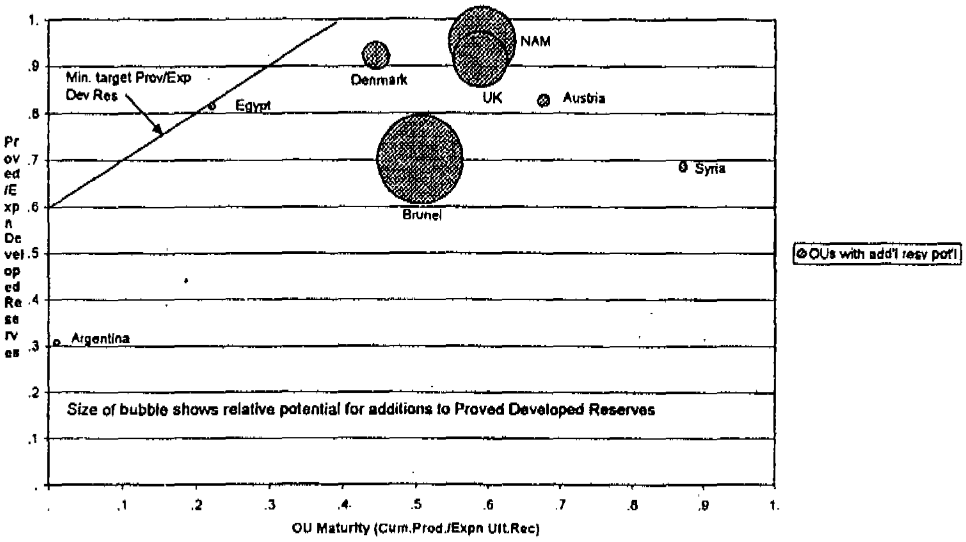
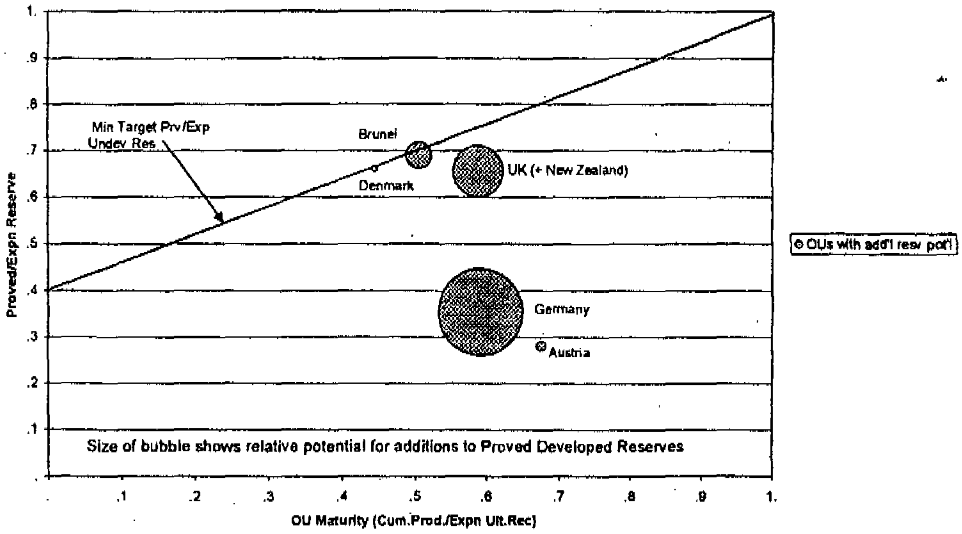

1.1.2001 UNDEVELOPED OIL+NGL RESERVES

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

Attachment 5.2


1.1.2001 DEVELOPED GAS RESERVES


1.1.2001 UNDEVELOPED GAS RESERVES

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

FOIA Confidential Treatment Requested

BP - operator

Attachment 6

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

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

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

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

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

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

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

A.A. Barendregt, 17 January 2001

References:

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

Attachment 7

2000 RESERVES AUDITS - MAIN OBSERVATIONS

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

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

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

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

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

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

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Attachment 8

TIME TABLE SEC RESERVES AUDITS

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

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

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

Audit frequency:

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

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

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Treatment Requested

Jan30Note-tbl.xls, AudSched-Att8

26/01/01

DEPOSITION
EXHIBIT
Barendregt
#22 2/21/07

NOTE – 30 January 2002 **CONFIDENTIAL**

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

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

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

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

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

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

I have reviewed the process of preparing the above summary of proved and proved developed oil and gas reserves in as far a these relate to companies outside Canada. This review included, where possible, a verification of the appropriateness of maj reserves changes. The most significant conclusions are as follows:

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

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

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

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

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

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

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

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

A.A. Barendregt

Attachments 1-7

Attachment 1 Main Observations End-2001 Reserves
Attachment 2 Significant Reserves Changes
Attachment 3 Group Proved Reserves Summaries
Attachment 4 Production Reconciliation Ceres vs. Reserves Submissions
Attachment 5 Proved Reserves Maturity – by OU
Attachment 6 Main Observations 2001 Reserves Audits
Attachment 7 Reserves Audit Plan 2002

Attachme

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

MAIN OBSERVATIONS

1. **Reserves Summary**

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

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

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

The Replacement Ratios mentioned above are with respect to total Group share reserves, i.e. including the Canadian sands and Minority reserves.

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

2. **Significant reserves changes**

Significant reserves changes during 2001 were as follows:

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

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

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

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

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

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

The 95 mln m3 oil volumes from Shell Canada's Athabasca Oil Sands Project (AOSP) are not strictly oil and gas reserves as defined by the US Securities and Exchange Commission (SEC). Hence, they will be excluded from the Group's submission of Proved oil and gas reserves to the SEC. They are also mentioned separately in the Group Annual Report.

4. **Angola block 18**

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

5. **SNEPCO fields**

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

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

6. **Production licence duration constraints**

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

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

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

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

7. **Group Guidelines – mature fields**

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

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

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

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

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

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

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

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

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

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

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

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

Group Proved Reserves receive increasingly close attention by Group Management. Reserves addition targets are se annually, both to OUs and to SIEP Directorates and these are reflected in individual and collective score cards affectin variable pay and bonuses of staff involved. This is leading to a noticeable increase in attempts to book reserves which are not technically or commercially mature and which do not fulfil Group reserves guidelines, cf. the new field bookings in Angola and Nigeria.

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

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

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

10. **Awareness of Group guidelines**

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

11. **Criterion for commerciality**

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

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

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

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

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

13. **SEC Reserves Audits**

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

14. **Electronic Workbooks**

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

Recommendations to SIEP Reserves Coordination:

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

References

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

Attachment 2

SIGNIFICANT 2001 PROVED AND PROVED DEVELOPED RECOVERY CHANGES

(Shell Group share)

MAJOR TECHNICAL REVISIONS

Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Netherlands				+23	Groningen review
Australia	+3		+18		Perseus devmt
Nigeria (SPDC)	+11		+6		Commissioning of gas plant
Nigeria (SPDC)		+15			Condensate devmt Soku + Nun River (offset by oil, see below
Philippines	+2		+11		Malampaya on stream
USA (SEPCo)		+9		+1	Holstein FID (first booking)
USA (SEPCo)	+7	+2	+2	+1	Brutus development
USA (SEPCo)	+5	+3	+2	+2	Mars field performance and drilling results
USA (SEPCo)	+4		+1		Crosby development
USA (SEPCo)	+4		+1		Oregano development
USA (SEPCo)		+9		+7	Various field reviews and drilling results
Denmark		+7		+0	Halfdan FDP approved (improved recovery)
Argentina	+0	+0	+6	+3	San Pedrito development
Netherlands			+6		Small fields development
Iran	+6				Soroosh on stream
Brunei (BSP)		+2		+3	Bugan discovery / appraisal
Malaysia		+0		+5	Lower abandonment pressure E11/F13W (offset by licence)
Denmark	+3	+3	+1	+1	Proved growth to Expectation (audit recommendation)
Russia Sakhalin		+3			Review (new reservoir model + external reserves audit)
Egypt		-1		-4	Obaiyed field performance
Canada	-0	-1	-6	-9	Sable review
New Zealand	-2	-2	-9	-9	Maui C sands revision
Nigeria (SPDC)		-17		+6	Field reviews and forecast review (backed out by NGL)
Total Major Techn'l	**+43**	**+32**	**+39**	**+30**	

OTHER MAJOR CHANGES

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

OTHER MINOR CHANGES AND TOTAL

	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Other Minor Chgs	**+60**	**+44**	**+43**	**+32**	
Grand Total Chgs	**+107**	**+84**	**+85**	**+80**	
Production	**-129**	**-129**	**-93**	**-93**	

Attachment 3

	OIL + NGL (10^6 m3)				All volumes net Shell Group Share														
Country Name	Proved Resvs 1.1.2001	Rev'ns and Reclass-ific'ns	Improved Recovery	Ext'ns and Discoveries	Purchases in Place	Sales in Place	Prod'n (avail. for sales) 2001	Proved Resvs 1.1.2002	Beyond end of licence	Proved Dev'd Resvs 1.1.2001	Transf. Undev to Dev'd	Revisions	Prod'n (avail. for sales) 2001	Proved Dev'd Resvs 1.1.2002	Minority Resvs incl. 1.1.2001	Minority Resvs incl. 1.1.2002	R / P Tot (yr)	Repl'mt Ratio Tot/Res (%)	Repl'mt Ratio Dev/Res (%)
Australia (SDA)	29.04	1.21					3.55	26.7		11.08	2.85	2.1	3.55	12.28			8	34%	134%
Australia (WPL)	17.04	2.41	.8				2.18	18.07		5.61	1.91	1.51	2.18	6.85			8	147%	157%
Brunei	69.36	4.48	1.25	2.74			5.99	72.24		34.88	3.8	2.77	6.89	35.66			13	152%	114%
Brunei (FCE)		.11			.88		.04	.95				.35	.04	.31			24	2475%	875%
China	5.97	1.44					1.36	6.05		5.37	.56	.35	1.36	4.82			4	106%	67%
Malaysia	28.85	-.28	1.27	.99			3.46	25.36	14.84	13.76	2.68	.72	3.46	13.8		.17	7	67%	95%
New Zealand	5.	-3.81	.23		10.		1.46	9.96		2.26		4.82	1.46	5.62			7	440%	330%
New Zealand (Pecten)	.74	-.74								.62		-.62							
New Zealand (SPM/ex-FCE)					1.9		.27	1.63				1.33	.27	1.06			6	704%	493%
Philippines	3.6	-.16	.23				.03	3.54			2.18		.03	2.15			118	233%	7267%
Thailand	15.35	.73					.94	15.14		4.02	1.15	.14	.94	4.37			16	78%	137%
Angola	11.85							11.85											
Argentina	3.54	.18		.07		2.25	.14	1.39		1.64	.47	-1.71	.14	.45			10	-1456%	-866%
Brazil (Pecten)	.92						.09	.83		.82			.09	.83			9	0%	0%
Cameroon (Pecten)	5.17	.04	.06	.16			1.1	4.33		5.	.27	-.05	1.1	4.12	1.03	.87	4	24%	20%
Congo (DR - Zaire)	3.04	.11		.08			.18	3.05		2.11		.05	.18	1.98			17	106%	28%
Gabon	18.94	.36	.17			.02	3.22	16.23		17.08	.98	.24	3.22	14.88	4.74	4.06	5	16%	25%
Nigeria (SNEPCO)	89.54	.43						89.97											
Nigeria (SPDC)	434.17	-1.87					14.54	417.66	83.86	116.88	14.89	-.39	14.64	116.74			29	-14%	99%
Venezuela	35.55	3.15					2.53	36.17	6.77	11.29	2.82	1.17	2.53	12.75			14	125%	158%
Abu Dhabi	97.7	1.04					5.45	93.29	69.37	81.18	1.71	.64	5.45	77.58			17	19%	34%
Bangladesh																			
Egypt	6.89	-1.03		.03			.81	4.08		3.47	.02	.3	.81	2.98			5	-123%	40%
Iran	31.59	1.87						33.46			5.64			5.64					
Oman (PDO)	179.4	-8.43	6.22	1.51			16.4	162.3	49.7	80.		2.2	16.4	65.8			10	-4%	13%
Oman Gisco	16.48	-3.27					2.56	12.65		16.76		-3.72	2.56	10.48	2.77	1.9	5	-128%	-145%
Pakistan																			
Russia (Sakhalin Assoc.)	16.1	-13.79					1.31			5.88		-4.57	1.31				0	-1053%	-349%
Russia (Sakhalin Consol.)		30.94						30.94				8.45		8.45		13.92			
Syria	15.72	1.91					2.81	14.82	1.7	11.35	1.82	-1.35	2.81	9.01			5	68%	17%
Austria	.23	.02		.01			.03	.23		.19	.02	.03	.03	.21			8	100%	167%
Canada	56.87	-.48		.01	.01	.01	3.23	53.17		26.88	.8	.08	3.23	24.52	12.49	11.26	16	-16%	27%
Canada (AOSP)	95.4							95.4							21.08	20.2			
Denmark	43.54	6.73	9.27				7.54	52.	10.89	32.85	4.78	5.96	7.54	36.15			7	212%	142%
Germany	3.05	.25					.33	2.97		2.91		.29	.33	2.87			9	76%	88%
Netherlands	4.96	-.33					.59	4.04		3.69		-.09	.59	3.01			7	-56%	-15%
Norway	32.76	1.52					5.19	29.08	.28	23.58	3.56	.26	5.19	22.21			6	29%	74%
UK	102.25	-.63	1.35	2.88			18.06	87.59		75.68	7.51	-4.13	18.06	60.89			5	19%	19%
USA (Aera)	69.09	-5.43	.08			.49	6.71	56.55		57.25	5.83	-4.05	6.71	52.32			8	-87%	27%
USA (SEPCo)	97.17	4.78		22.14	.47	.11	17.11	107.34		55.82	19.97	9.58	17.11	68.26			6	159%	175%
USA (TMR)	.98					.97	.01			.61		-.6	.01				0	-9700%	-6000%
Total excl Can. AOSP	1,550.35	23.36	20.93	30.42	13.26	3.85	128.82	1,505.64	227.46	710.72	84.62	22.14	128.82	688.67	21.03	32.18	12	65%	83%
Grand Total	1,645.75	23.36	20.93	30.42	13.26	3.85	128.82	1,601.04	227.46	710.72	84.62	22.14	128.82	688.67	42.11	52.38	12	65%	83%

	GAS (10^9 sm3)			All volumes net Shell Group Share															
Country Name	Proved Resvs 1.1.2001	Rev'ns and Reclass-ific'ns	Improved Recovery	Ext'ns and Discoveries	Purchases in Place	Sales in Place	Prod'n (avail. for sales) 2001	Proved Resvs 1.1.2002	Beyond end of licence	Proved Dev'd Resvs 1.1.2001	Transf. Undev to Dev'd	Revisions	Prod'n (avail. for sales) 2001	Proved Dev'd Resvs 1.1.2002	Minority Resvs incl. 1.1.2001	Minority Resvs incl. 1.1.2002	R / P Tot (yr)	Repl'mt Ratio Tot/Res (%)	Repl'mt Ratio Dev/Res (%)
Australia (SDA)	176.917	.901					2.408	175.41		18.051	13.548	.453	2.408	29.644			73	37%	591%
Australia (WPL)	41.184	.378					1.611	39.949		8.882	5.928	.552	1.511	12.871			25	25%	429%
Brunei	99.899	1.547	.48	3.257			4.722	100.461		37.329	1.785	1.866	4.722	36.677			21	112%	73%
Brunei (FCE)		1.303			4.801		.348	5.846			.8	2.873	.348	3.124			16	1728%	988%
China																			
Malaysia	171.781	-6.385	-4.876	.31			6.85	164.31	66.61	50.868	2.128	-3.486	6.85	44.689		2.828	27	-36%	-8%
New Zealand	14.811	-3.917	1.713		25.439		4.383	33.663		10.838		14.785	4.383	20.261			8	539%	325%
New Zealand (Pecten)	1.748	-1.748								1.448		-1.448							
New Zealand (SPM/ex-FCE)					6.25		.489	4.771				3.344	.489	2.855			10	1076%	684%
Philippines	16.914	-.303	1.161				.044	17.719			10.755		.044	10.711			403	1927%	24443%
Thailand	6.189	1.581	-.007				.429	7.334		2.633	.13	.254	.429	2.788			17	367%	90%
Angola																			
Argentina	9.389	.301	-.016	3.163		.08	.148	12.831		.096	6.043	-.098	.148	6.307			87	2321%	4101%
Brazil (Pecten)	6.141						.343	4.798		5.141			.343	4.798			14	0%	0%
Cameroon (Pecten)																			
Congo (DR - Zaire)																			
Gabon																			
Nigeria (SNEPCO)	7.02							7.02											
Nigeria (SPDC)	85.71	5.729					2.288	89.173		34.014	10.291		2.266	42.039			38	250%	454%
Venezuela																			
Abu Dhabi																			
Bangladesh	4.825	.344					.424	4.745		2.267		.136	.424	1.979			11	81%	32%
Egypt	27.881	-6.341		2.887			2.566	22.772		13.805	.388	.151	2.566	11.089			9	-89%	6%
Iran																			
Oman (PDO)																			
Oman Gisco	65.207	-14.136					5.707	45.364		44.76		-14.116	5.707	24.937	8.281	6.305	6	-248%	-247%
Pakistan	9.866	-.006			1.816	5.134	.219	6.323		3.159		-2.939	.219				29	-1518%	-1342%
Russia (Sakhalin Assoc.)																			
Russia (Sakhalin Consol.)																			
Syria	.704	-.185					.186	.332		.397		.081	.186	.211			2	-100%	32%
Austria	1.595	-.14		.093			.204	1.345		1.494	-.092	-.046	.204	1.152			7	-23%	-68%
Canada	84.699	-6.485		.779	.334	.334	6.341	70.771		66.736	.988	-6.188	6.341	55.776	16.508	14.882	11	-120%	-72%
Canada (AOSP)																			
Denmark	28.352	2.255	.347				3.187	28.173	2.288	18.45	3.464	2.132	3.187	20.859			9	83%	176%
Germany	55.988	3.336					4.425	54.899		44.357	.164	1.388	4.425	41.479			12	75%	35%
Netherlands	399.851	21.804	1.06	1.651			16.066	408.1		200.347	5.612	.878	16.066	190.769			25	151%	40%
Norway	89.781	.934					1.818	88.897	10.555	36.892	.005	-.034	1.818	35.045			49	51%	-2%
UK	98.606	.338	.288	4.408			12.351	91.281		67.48	7.194	-.922	12.351	61.801			7	41%	54%
USA (Aera)	1.287	-.814	.001			.009	.054	.411		.866	.056	-.37	.054	.518			8	-1522%	-1137%
USA (SEPCo)	86.317	3.993		10.877	10.066	.244	16.441	104.552		65.406	10.816	5.995	16.441	65.876			6	190%	103%
USA (TMR)	1.142					1.129	.013			.883		-.88	.013				0	-8685%	-6769%
Total excl Can. AOSP	1,592.822	3.278	9.069	27.15	47.459	6.81	93.06	1,579.348	71.356	737.016	79.588	5.008	93.06	728.552	26.889	23.116	17	85%	91%
Grand Total	1,592.822	3.278	9.069	27.15	47.459	6.81	93.06	1,579.348	71.356	737.016	79.588	5.008	93.06	728.552	26.889	23.116	17	85%	91%

Atachment 3 – 2001 Group Reserves Submissions

Attachment 4

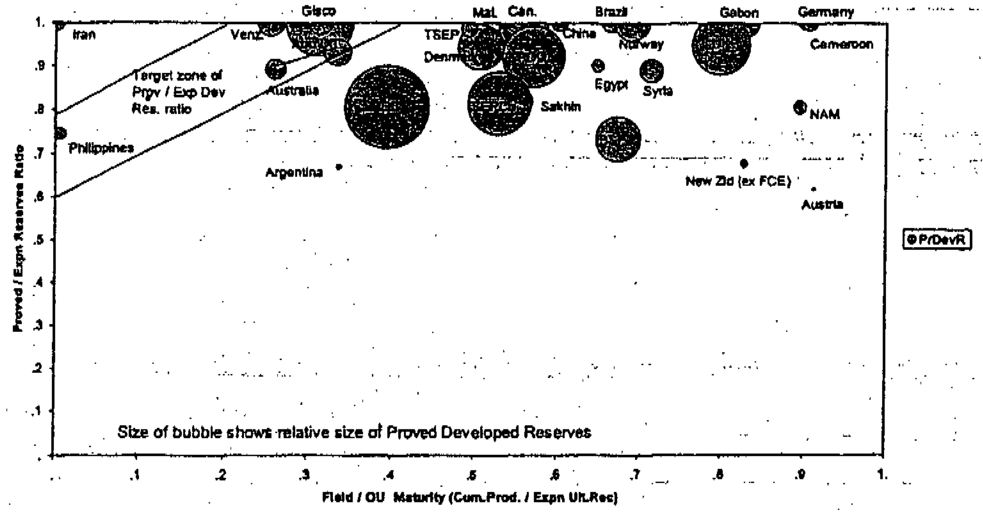
	OIL + NGL												
Country	Original CERES			Org'l Resvs Subm'n		Difference		Final CERES		Final Resvs Subm	Difference		Comment
	min bbl		10^6m3		10^6m3			min bbl	10^6m3	10^6m3	10^6m3		
Australia (SDA)				3.55						3.55			
Australia (WPL)				2.18						2.18			
Australia Total		36.078	5.74		5.73	.01		36.078	5.74	5.73	.01		Rounding error? - not corrected
Brunei (BSP)				5.59						5.59			
Brunei (FCE)				.04						.04			
Brunei Total		35.47	5.64		5.63	.01		35.47	5.64	5.63	.01		Rounding error? - not corrected
China		8.516	1.35		1.36	-.01		8.533	1.36	1.36			Q1 error in Ceres - corrected
Malaysia		21.78	3.46		3.46			21.78	3.46	3.46			OK
New Zealand				1.46						1.46			
New Zealand (SPM/ex-FCE)				.27						0.27			
New Zealand Total		10.875	1.73		1.73			10.875	1.73	1.73			OK
Philippines		.165	.03		.03			.165	.03	.03			OK
Thailand		5.91	.94		.94			5.91	.94	.94			OK
Argentina		.907	.14		.14			.907	.14	.14			OK
Brazil (Shell Oil WH)		.56	.09		.09			.56	.09	.09			OK
Cameroon (Shell Oil EH)		6.966	1.11		1.1	.01		6.956	1.11	1.1	.01		Ceres figure incorrect (Govt penalty in Dec) - not changed
Congo (OR)		1.123	.18		.18			1.123	.18	.18			OK
Gabon		20.105	3.2		3.22	-.02		20.299	3.22	3.22			Error in Ceres - corrected
Nigeria (SPDC)		91.42	14.54		14.55	-.01		91.42	14.54	14.54			Reserves submission corrected
Venezuela		15.888	2.53		2.53			15.888	2.53	2.53			OK
Abu Dhabi		34.306	5.45		5.45			34.306	5.45	5.45			OK
Egypt		6.126	.81		.81			6.125	.81	.81			OK
Oman	103.14			16.4						16.40			
Oman Gisco	16.091			2.56						2.56			
Oman Total		119.231	18.96		18.96			119.231	18.96	18.96			OK
Russia (Sakhalin Holding)	8.255			1.31						1.31			
Kazakhstan (Temir)													
Russia Total		8.255	1.31		1.31			8.255	1.31	1.31			OK
Syria		17.689	2.81		2.81			17.689	2.81	2.81			OK
Austria		.2	.03		.03			.2	.03	.03			OK
Canada		20.321	3.23		3.23			20.321	3.23	3.23			OK
Denmark		47.423	7.54		7.54			47.423	7.54	7.54			OK
Germany		2.003	.32		.33	-.01		2.003	.32	.33	-.01		Error in Ceres - not corrected
Netherlands		3.71	.59		.59			3.71	.59	.59			OK
Norway		32.641	5.19		5.19			32.641	5.19	5.19			OK
UK		113.574	18.06		18.06			113.574	18.06	18.06			OK
USA (SEPCo)				17.11						17.11			
USA (Aera)				6.71						6.71			
Shell Oil (TMR)				.01						0.1			
USA Total		149.891	23.83		23.83			149.891	23.83	23.83			OK
Total		810.102	128.81		128.83	.02		810.273	128.83	128.82	.01		

	GAS									
Country	Org'l CERES	Org'l Resvs Subm'n		Difference		Final CERES	Final Resvs Subm'n	Difference		Comment
	10^9sm3		10^9sm3			10^9sm3	10^9sm3			
Australia (SDA)		2.408								
Australia (WPL)		1.511								
Australia Total	3.919		3.919			3.919	3.919			OK
Brunei (BSP)	4.722	4.722				4.722				
Brunei (FCE)	0.231	.348				0.348				Error in FCE Ceres - corrected
Brunei Total	4.953		5.07	-.117		5.07	5.07			
Malaysia	5.99		5.99			5.99	6.99			OK
New Zealand		4.363				4.363				
New Zealand (SPM/exFCE)		.489				0.489				
New Zealand Total	4.852		4.852			4.852	4.852			OK
Philippines	.044		.044			.044	.044			OK
Thailand	.429		.429			.429	.429			OK
Argentina	.146		.146			.146	.146			OK
Brazil (Shell Oil WH)	.343		.343			.343	.343			OK
Nigeria (SPDC)	2.381		2.266	.115		2.266	2.266			Error in Ceres - corrected
Bangladesh	.424		.424			.424	.424			OK
Egypt	2.582		2.565	.017		2.565	2.565			Error in Ceres - corrected
Oman Gisco	5.707		5.707			5.707	5.707			OK
Pakistan	.219		.219			.219	.219			OK
Syria	.186		.186			.186	.186			OK
Austria	.204		.208	-.004		.204	.204			Error in Resvs submission - corrected
Canada	6.297		6.341	-.044		6.337	6.341	-.004		Delay error in Foothills prod; Resvs vol = SCL press release!
Denmark	3.187		3.187			3.187	3.187			OK
Germany	4.425		4.425			4.425	4.425			OK
Netherlands	16.066		16.066			16.066	16.066			OK
Norway	1.818		1.818			1.818	1.818			OK
UK	12.351		12.351			12.351	12.351			OK
USA (SEPCo)		16.441								
USA (Aera)		.054								
Shell Oil (TMR)		.013								
USA Total	16.514		16.508	.006		16.508	16.508			Error in Ceres - corrected
Total	93.037		93.064	-.027		93.056	93.06	-.004		

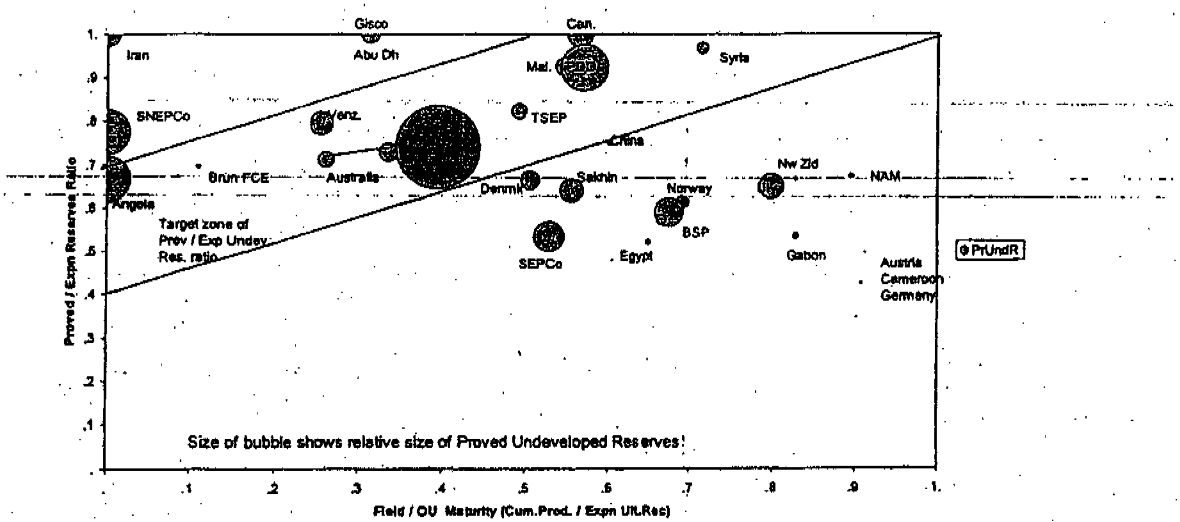
Attachment 4 - 2001 Production reconciliation – Ceres vs Reserves

Attachment 5.1

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



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

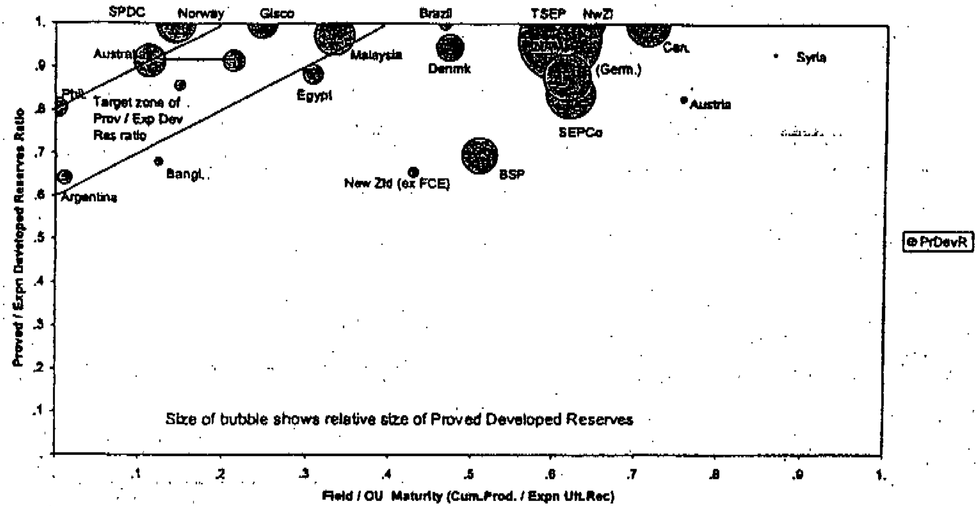


Maturity of Proved Oil+NGL Reserves - by OU

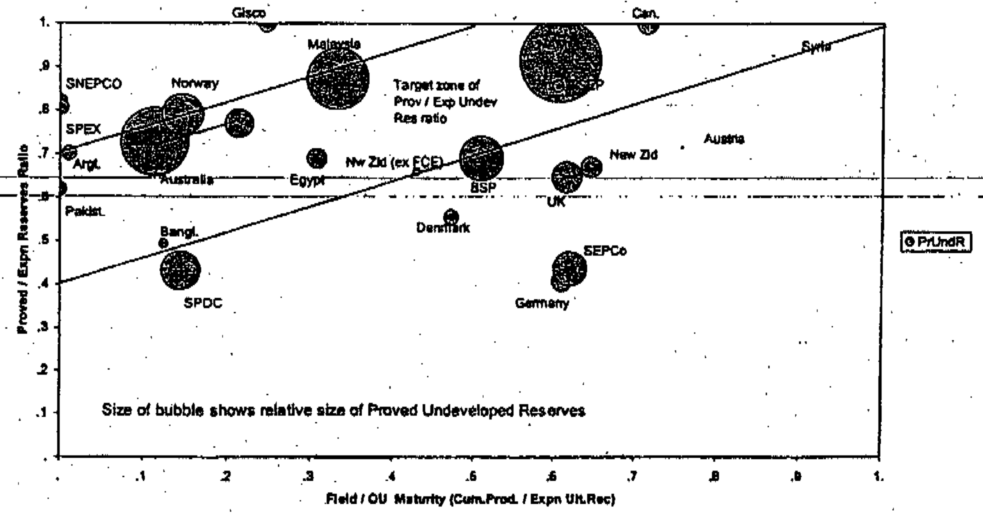
FOIA Confidential
Treatment Requested

Attachment 5.2

1.1.2002 DEVELOPED GAS RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



1.1.2002 UNDEVELOPED GAS RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



Maturity of Proved Gas Reserves - by OU

Attachment 6

2001 RESERVES AUDITS - MAIN OBSERVATIONS

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

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

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

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

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

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

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

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

Attachment 7

COUNTRY	Size**	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Comments
MALAYSIA	L		X				X				A				15-19 Apr 2002
BRUNEI	L		X				X				A				22-26 Apr 2002
BRAZIL (Pecten)	M/S						*				P1?				Not yet accepted
SYRIA	M/S	X			X						A				2-6 June 2002
PAKISTAN	M/S					$					A1				Sept 2002
IRAN	L							$			A1				Oct 2002
USA (AERA)	L					$					A1				11-15 Nov 2002
ANGOLA	M/S								$		A1?				Dependent on project progress
NIGERIA - SNEPCO	L					$		X			P?				To be considered
ABU DHABI	L			X				X				P			
NIGERIA -SPDC	L	X				X		X				P			
OMAN	L			X				X				P			
EGYPT	M/S		X					X				P			
VENEZUELA	L				$			X				P			
ARGENTINA	M/S			X				X				P			Combine with Venezuela
CAMEROON (Pecten)	M/S						*					P1			
AUSTRALIA	L				X				X				P		
NORWAY	L				X				X				P		
USA (SEPCo)	L						*		X				P		
PHILIPPINES	M/S					$		X					P		
THAILAND	M/S		X					X					P		
KAZAKHSTAN-OKIOC											$1?		P1?		
RUSSIA - SALYM												$?	P1?		
GABON	M/S			X					X					P	
BANGLADESH	M/S					$			X					P	
RUSSIA - SAKHALIN	M/S					$			X					P	
NAMIBIA												$?		P1?	
NETH. NAM	L	X				X				X				P	
GERMANY	L	X				X				X				P	
UK	L			X		X				X				P	
DENMARK	L	X				X				X				P	
CHINA	M/S		$							X					
AUSTRIA	M/S			X						X					
NEW ZEALAND	L				X					X					
CANADA	L														No direct involvement
CHAD	M/S			X											Divested 2000
KAZAKHSTAN-TEMIR	M/S							$							Divested 2000
USA (ALTURA)	L					$									Divested 2000
ZAIRE	M/S		X												To be divested?

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

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

Audit frequency:

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

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

Attachment 7 - SEC Reserves Audit Plan 2002

SPDC Resvs Discussion

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

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

Dave K + Peter Stephenson in PH to kickoff Phase I

- Some volumes not sufficiently mature for proved resvs

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

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

Ph 1 only oil

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

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

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

X Copy of DK mesh

DEPOSITION EXHIBIT
Barendregt
#23 2/21/07

②

Short Tm Activities

Dev'd = NFA

Pr Undev = projects in CA (Cap Alloch) & BP
with firm funding; STA, LTA
- "mature" - no resvr/fld/proj exposure
- "immature"

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

Used for discounting exp'n to proved

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

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

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

Exposure tranches defined.

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

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

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③

Overlaps between exposure volumes?

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

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

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

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

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

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

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

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

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

(4)

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

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

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

Corporate forecast

BP forecast 0.8 → 1.4 MMb/d 2003 → 2009

LIO – ~~Light~~ Locked In Oil?

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

~700 MMb/yr reserves addition target.

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

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

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

Need to set criteria to decide when we book reserves.

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

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

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

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

GOR [illegible]

pushing back HG forecasts -> initially more NAG needed
Trains 6+ = all/mostly AG.

Combined HFPT model of 3 NAG fields

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

⑥

300 MMscf/d

Ea Dom Gas: only two fields (Alakiri NAG, Obigbo NAG + AG) at present, filling only ≈25% of presently ~~foreseen~~ anticipated demand. Rest would come from other fields in the area.

West Dom Gas ≈ 450 MMscf/d. Number of target fields, plus Utorogu NAG, Oben NAG (Egwa). No contract yet?
No long term ~~forecast~~ contracts, just short extensions

WAGP = West Africa Gas Pipeline, along shore to Ghana, Iv. Coast etc.

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

John Hoppe 0629 327 247

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

Peter's results 19/9/03

377 Prov Dev OK — (Base + Options) Devel Unknown (178)

125 Prov Undev OK — Un~~Planned~~ Unknown = (198)

1324 Prov Undev not OK

2185 = Dev + Base + Options

590 = "Unplanned" known

3112 = 178 / 198

Total data base

⑦

Questions / Remarks

1. SPDC has largest contribn to Group Proved Resvs:
487 vs 3000 or 16% $\overset{3}{\text{Mboe}}$.

2. Fully agree with approach:
– Complete portfolio of documented projects, mod. forecasts, economics
[illegible] per manage point

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

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

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

6. Many small / marginal projects?

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

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

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

Note: Proved resvs require all criteria to be met.

8

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

11. Correct criteria for setting P = E (~~[illegible]~~ Resvr mature + $N_p > 2$

~~12 What are PAFs, UAD?~~

12 Discounting

~~[illegible]~~ Exposure to 10 criteria – overlaps

Maturity – Marginal

– Closed in

– Prod – >10

– – 5-10

– – <5

– Unappraised – near

– far

13. Why couldn't the study differentiate Partially Apprd Fld into near and far? (Unapp discoveries could!)

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

Suggest:

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

2) But have SS figures available at all levels.

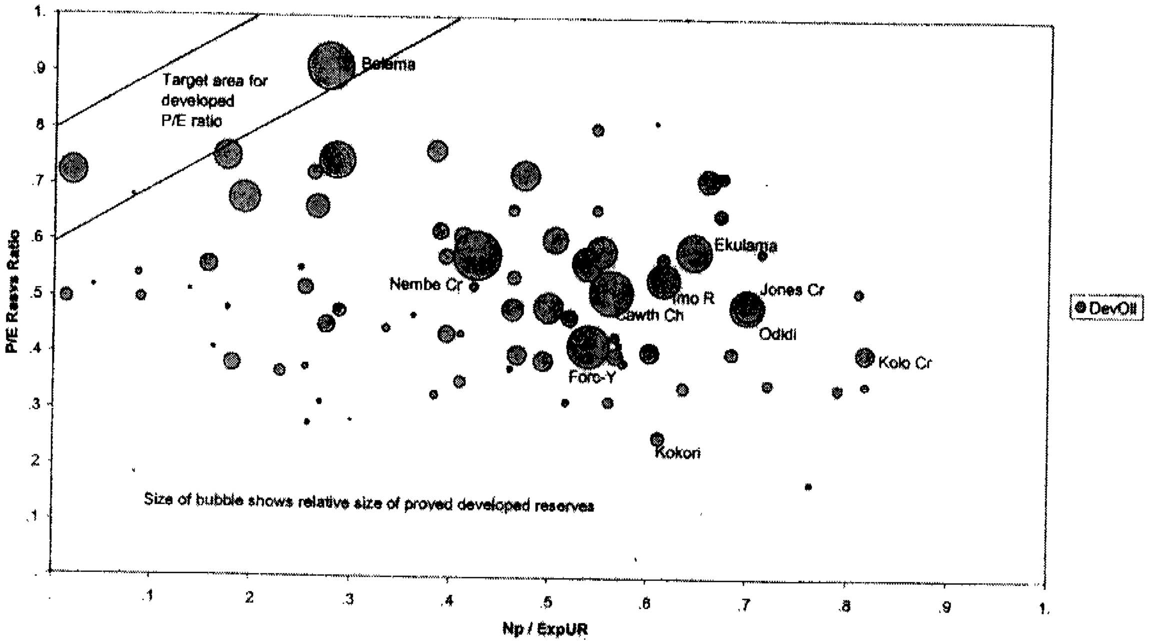
15 Not clear how maturity breakdown and Reservoir category interact,

Suggest:

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

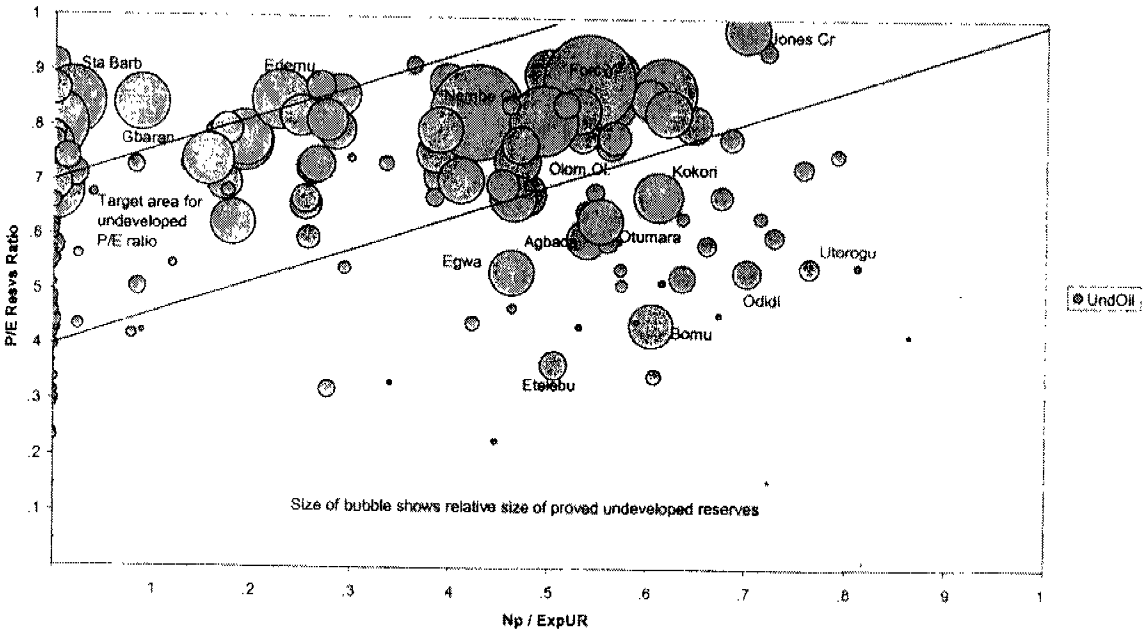
Attachment 3.1

SPDC - OIL DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



Size of bubble shows relative size of proved developed reserves

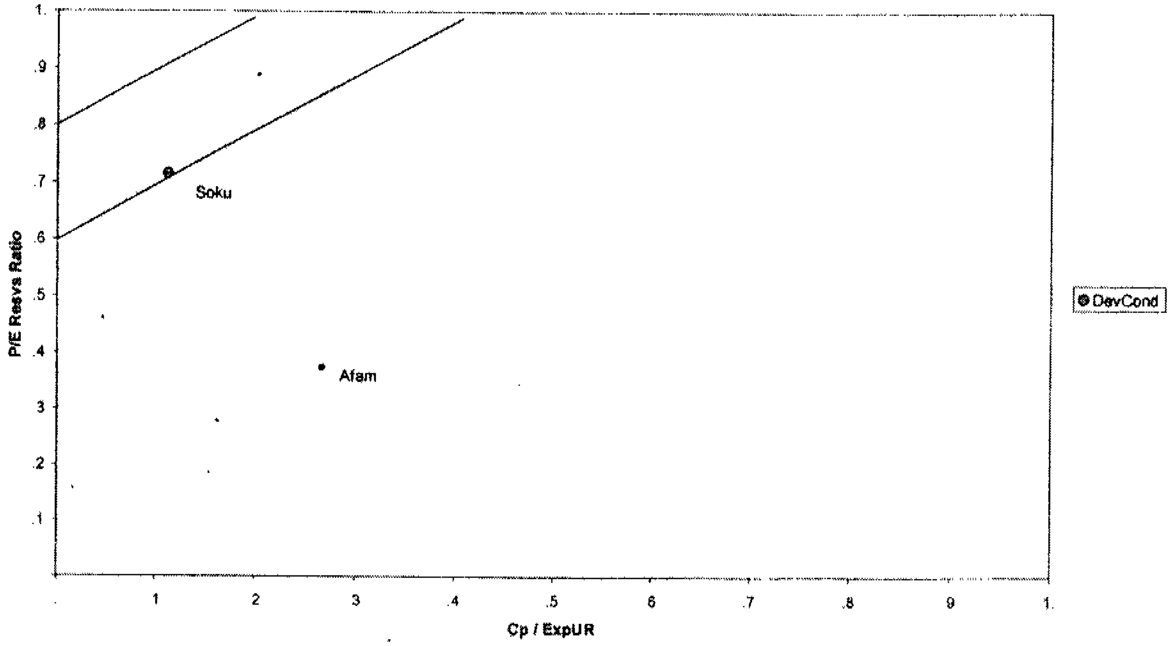
SPDC - OIL UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



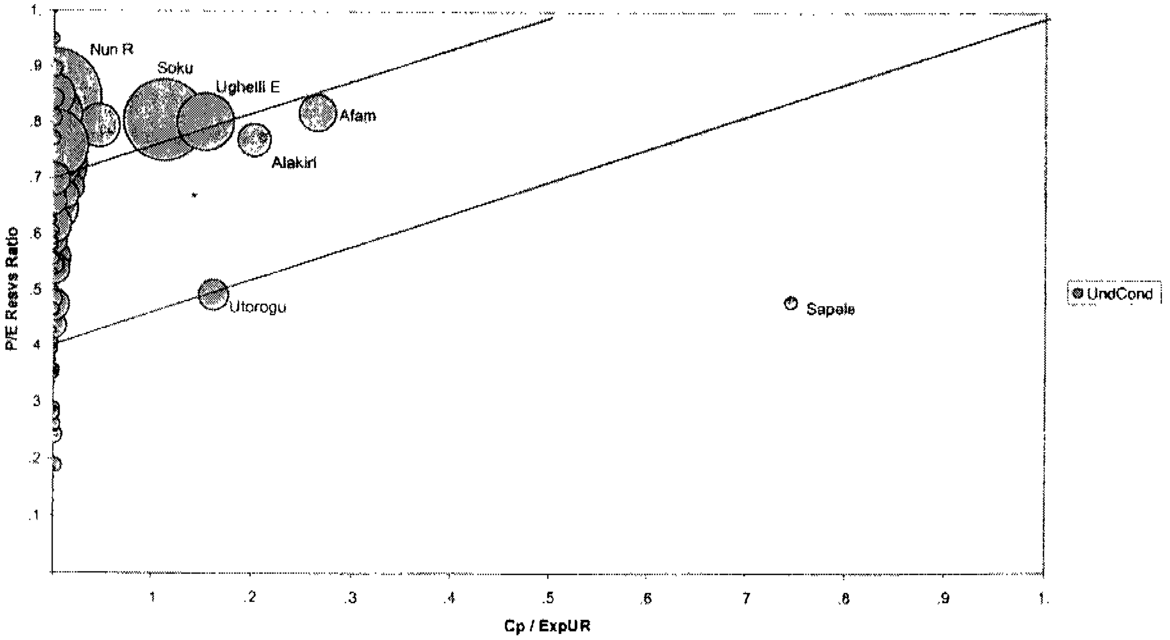
Size of bubble shows relative size of proved undeveloped reserves

Attachment 3.2

SPDC - CONDENSATE DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - CONDENSATE UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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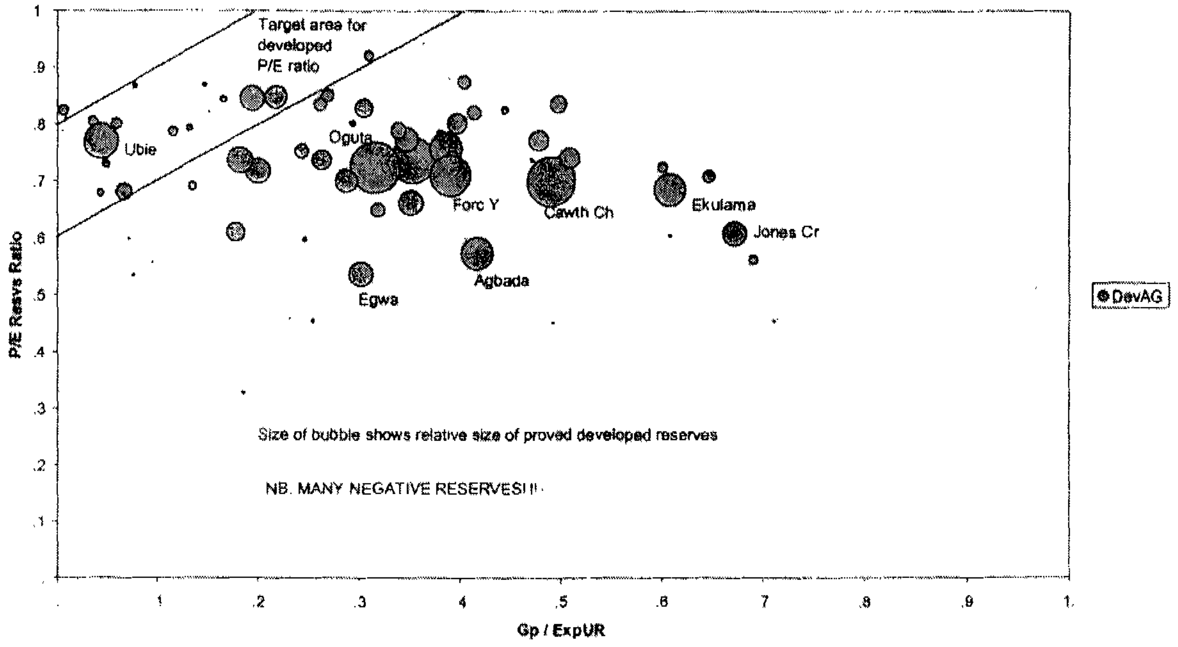
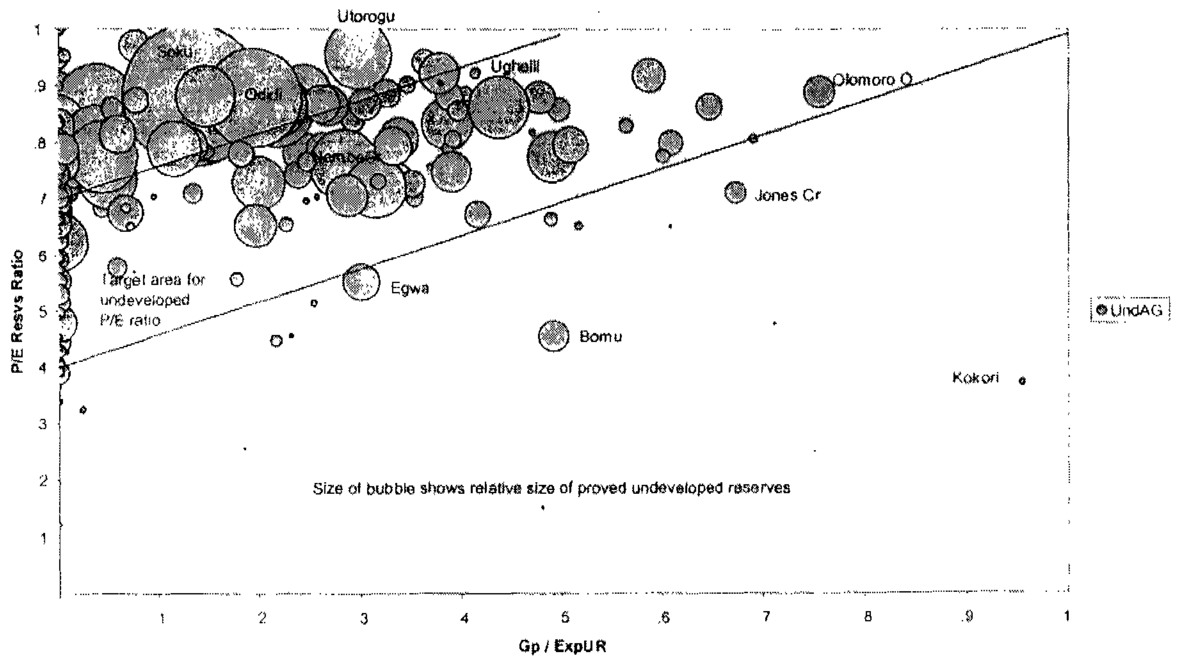
Attachment 3.3

SPDC - ASSOCGAS DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

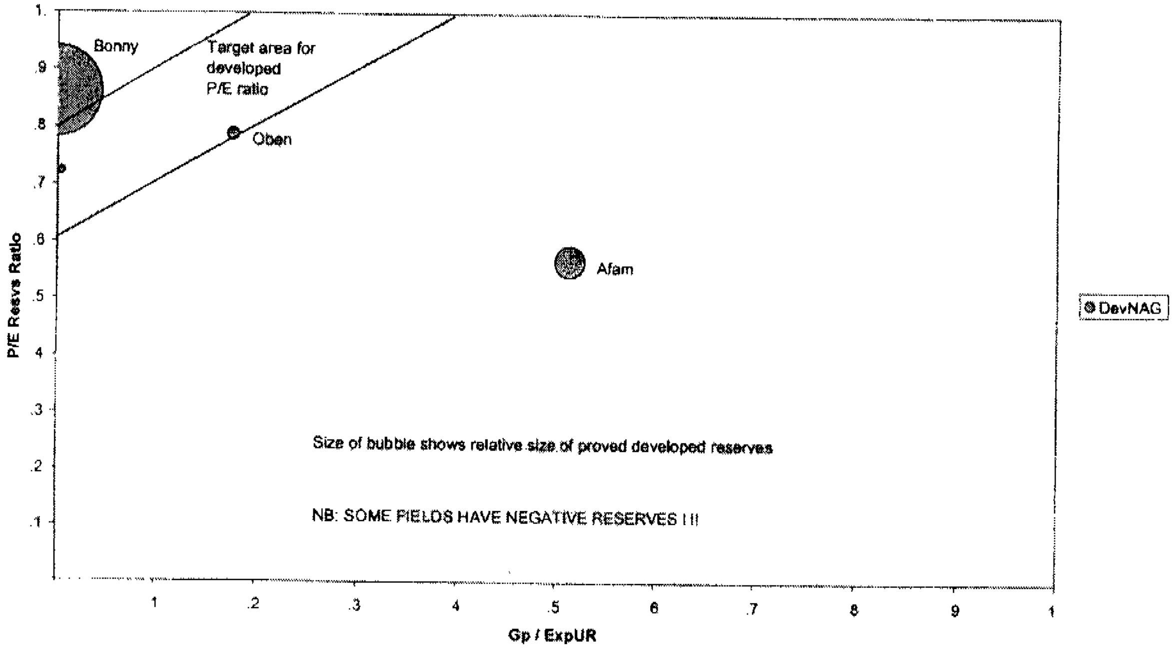


SPDC - ASSOCGAS UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



Attachment 3.4

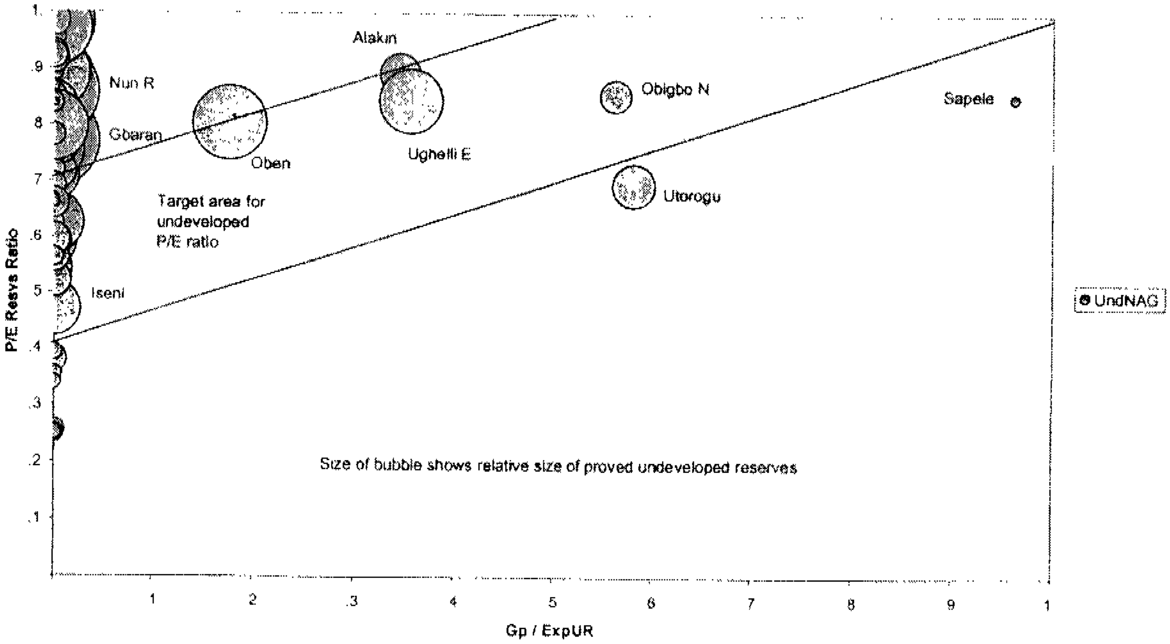
SPDC - NAG DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



Size of bubble shows relative size of proved developed reserves

NB: SOME FIELDS HAVE NEGATIVE RESERVES ! !!

SPDC - NAG UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



Size of bubble shows relative size of proved undeveloped reserves

NOTE – 30 Sept 2003 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP & EPF - GRA
To:	Frank Coopman	Chief Financial Officer, SIEP – EPF
	John Bell	Corporate Support Director, SIEP – EPS
	Chris Finlayson	Managing Director, SPDC
Copy:	Mark Comer	Development Director, SPDC
	Steve Ratcliffe	Business Director, SPDC
	Cees Uijlenhoed	Finance Director, SPDC
	Promise Egele	Petroleum Engineering Manager, SPDC
	John Hoppe	Head, Reservoir Engineering, SPDC
	(circulation)	SIEP – EPS-P: Hans Bakker, John Pay
	Tom van Leenen	Technical Director, Europe & Africa Region, SEPI – EPG
	Martin ten Brink	Finance Director, Europe & Africa Region, SEPI – EPG
	Ken Marnoch	Internal Auditor EP, SI-FSAR, The Hague
	Han van Delden	Partner, KPMG Accountants NV (2x)
	Brian Puffer	PriceWaterhouseCoopers

PROVED RESERVES PROCESS AUDIT - SPDC (NIGERIA), 18-19 Sept 2003

I have audited the processes underlying the Proved Reserves submissions of SPDC for the year 2002 and the current measures undertaken by SPDC to introduce improvements in these processes. The reserves submissions present the SPDC contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 2002.

Total Group share Proved Reserves booked by SPDC at the end of 2002 were 404 mln m3 of Oil+NGL and 85 bln sm3 of gas. This represents some 16% of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratios for SPDC over 2002 were -6% for oil+NGL and -55% for gas.

The last previous SEC proved reserves audit for SPDC was carried out in 1999. This current audit is a partial audit of reserves reporting processes only (in The Hague), replacing a full audit, which has been deferred to 2004. The audit took the form of presentations and detailed discussions about the reserves reporting process with a small selection of SPDC staff.

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

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

The audit finding is therefore that the present status of SPDC's proved oil reserves is unsatisfactory. Efforts are underway to address this situation. Proved gas reserves at 1.1.2003 appeared insufficiently founded on firm contracts but this will now be corrected with the commitment to a fourth and a fifth LNG train.

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

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

A.A. Barendregt

Attachments 1, 2, 3

DEPOSITION EXHIBIT
Barendregt
#20 2/21/07

Attachment 1

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

MAIN OBSERVATIONS

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

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

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

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

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

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

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

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

   A number of the criteria checks coincide with necessary conditions for booking proved reserves, in accordance with the most recent (2003) Reserves guidelines. These are highlighted in Att. 2 A first pass run through the spreadsheet data seemed to indicate that only 44% of proved developed reserves and not more than 7% of proved undeveloped reserves fulfil the criteria for proved reserves. It is likely that these percentages are too low There are still a considerable number of 'empty' entries in the spreadsheet and these should be completed before end year. However, there is a strong indication that in particular the undeveloped proved reserves estimates have not kept pace with the increased requirements for booking such reserves as defined in the recent Group guidelines. The most significant of these is that the associated development projects must have passed either VAR3 (for small brownfield projects) or FID (for new field and major projects).

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

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

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

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

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

6. To provide better insight into the maturity of SPDC's proved oil reserves portfolio it is suggested that, following completion and validation of all spreadsheet entries, a distinction is made into seven categories of proved oil reserves:
   A Proper proved developed reserves
   B Proved developed reserves in reservoirs without properly defined 'proved areas'
   C Proper proved undeveloped reserves
   D Reservoirs / projects that are likely to pass VAR3/FID in the next 2 years
   E Reservoirs / projects that are likely to pass VAR3/FID between 2 and 5 years from now,
   F Reservoirs / projects that are likely to pass VAR3/FID more than 5 years from now,
   G Reservoirs / projects that fall into none of the above and hence are completely immature.

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

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

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

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

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

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

the next (Sept 2003) guidelines should be revised in such a manner that 'existing markets' are defined more precisely and may include mature LNG markets.

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

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

13. In summary, the way forward for SPDC's oil, condensate and gas reserves booking per 1.1.2004 is suggested to be as follows:
- Proved gas reserves can be booked as per plan, i.e. for NLNG trains 1-5 and appropriate, committed volumes for domestic gas,
- Proved condensate reserves should be evaluated in line with foreseen NAG sales and should be administered to their full (proved!) extent, independently from oil reserves,
- Proved oil reserves are at present overstated and a reduction in 1.1.2004 proved oil reserves will probably be necessary. The precise value of the reduction cannot be assessed at this stage as it will depend on SPDC's evaluation of the maturity spectrum of their portfolio by early December. At the least, all volumes in category G (fully immature or undefined, see 6 above) and probably those in category F (long term projects) will need to be removed from the proved reserves portfolio.

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

Recommendations

1. Verify and complete all entries in the SPDC reserves/ projects spreadsheet such that a proper scan of the maturity of the reserves portfolio can be made.
2. Add (and complete) two additional maturity criteria to the spreadsheet:
   - Confirmation that proved reserves are consistent with 'known' fluid levels (logs and/or pressures)
   - The intended year of start of development.
3. Use should be made of data redundancies to verify and enhance the quality and robustness of the spreadsheet entries.
4. The proved and expectation oil reserves volumes for each of the seven suggested (or somewhat modified) reserves categories should be reported in a table format similar to that presented in the lower half of Attachment 2.
5. SPDC condensate reserves should be based on foreseen (and committed) NAG field gas sales and should be administered fully separately from the oil reserves.
6. Proved oil reserves per 1.1.2004 should exclude all volumes in category G (fully immature or undefined, see 6 above) and probably those in category F (long term projects). This should be reviewed jointly with SIEP EPS-P.
7. Plots as presented in Att. 3 should be used to verify the appropriateness of proved vs. expectation estimates.

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

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

9 The (Sept 2003) Group reserves guidelines should be revised in such a manner that 'existing markets' are defined more precisely and may include mature LNG markets (action: SIEP EPS-P).

ATTACHMENT 2 - SPDC – SPREADSHEET CRITERIA FOR PROVED OIL RESERVES

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

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

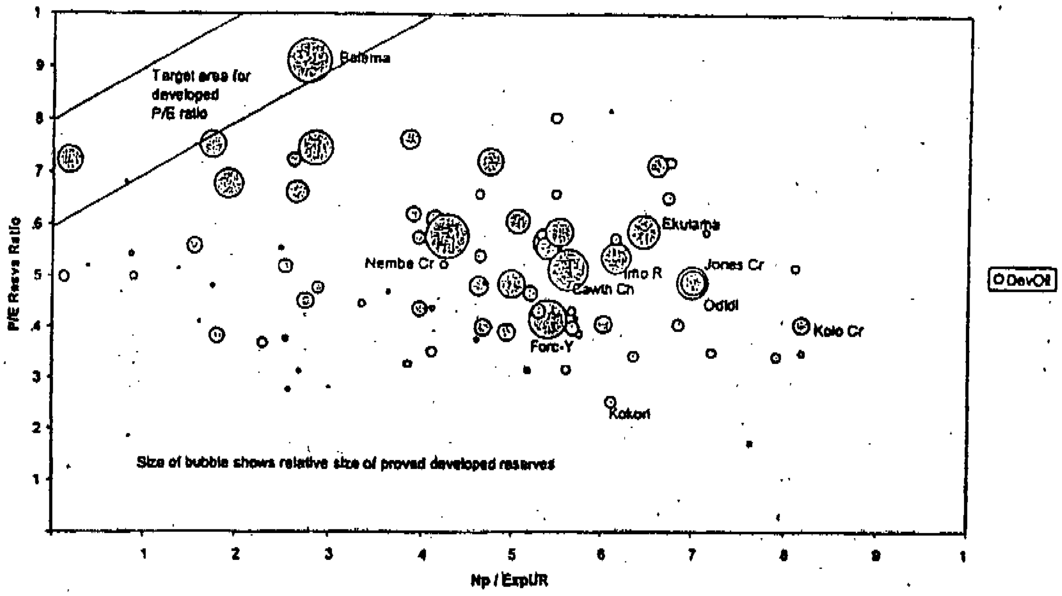
SPDC Group share oil reserves volumes (MMstb) as per data base Sept 2003

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

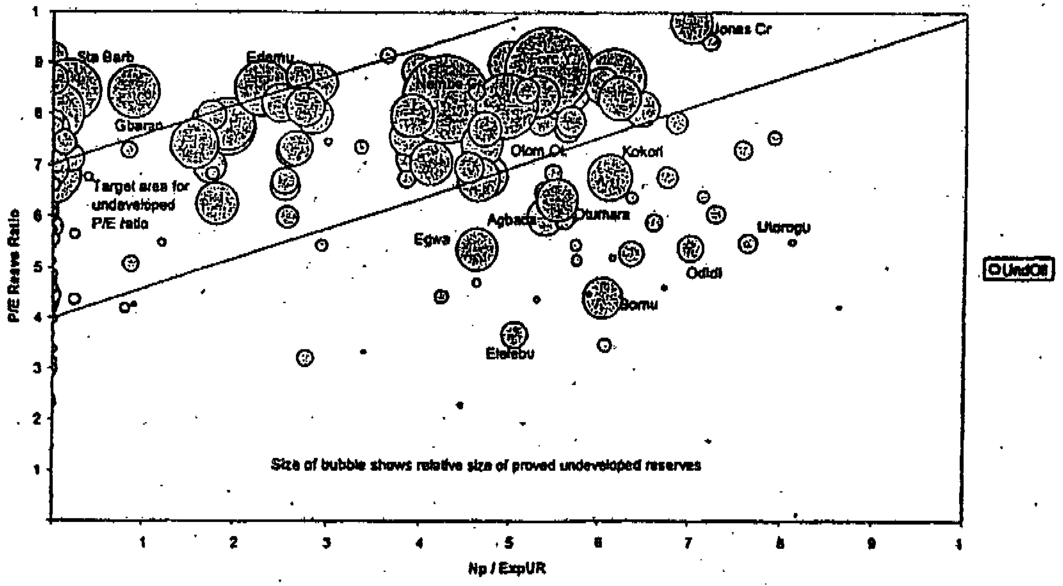
Note: 'Unknown' and 'Unplanned' volumes may overlap – addition is not strictly valid!

Attachment 3.1

SPDC - OIL DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

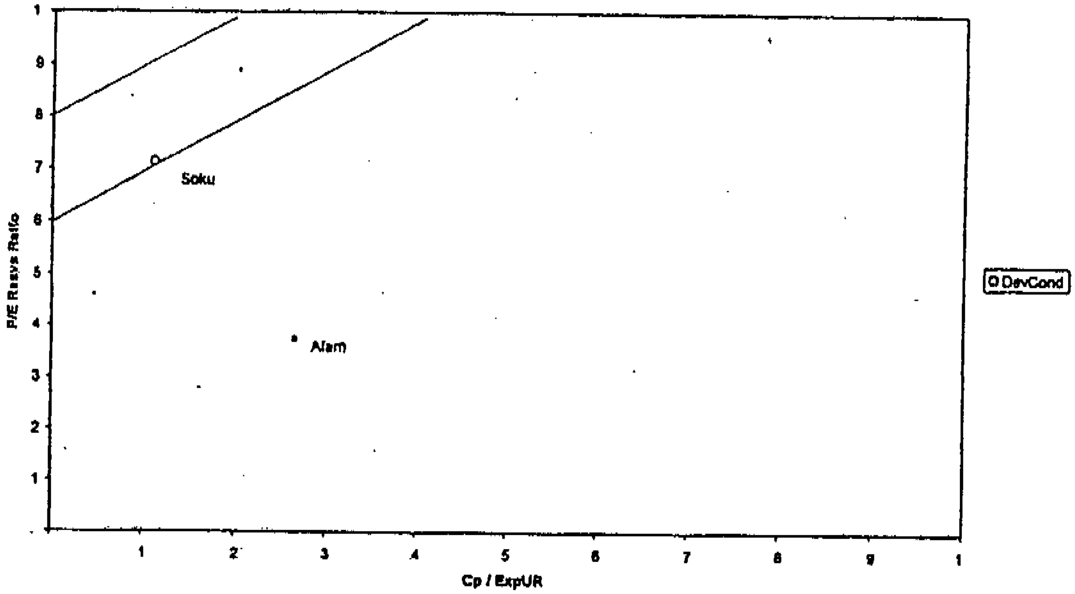


SPDC - OIL UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

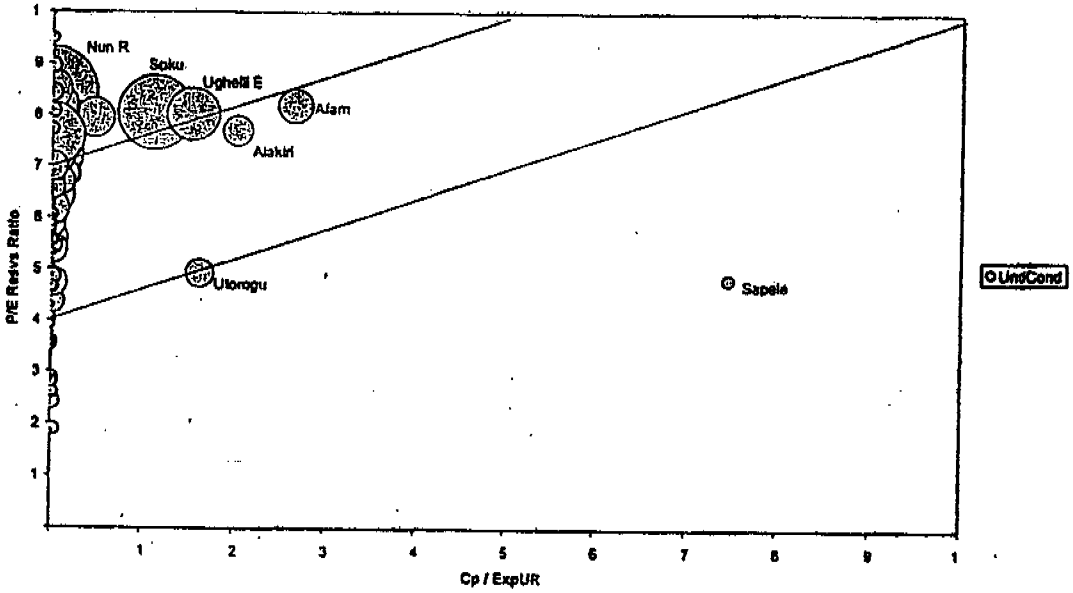


Attachment 3.2

SPDC - CONDENSATE DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

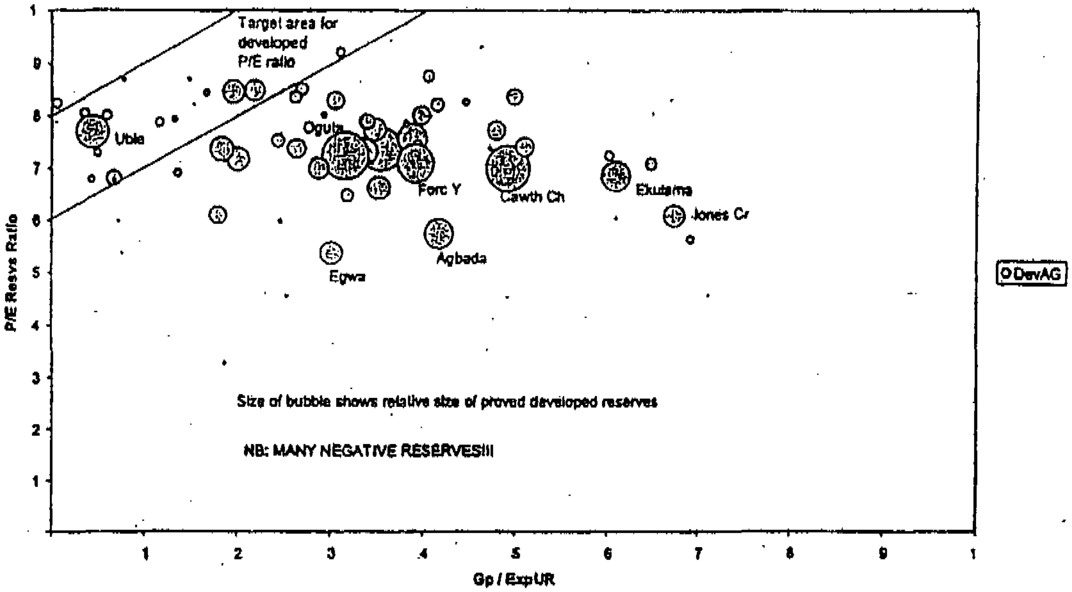


SPDC - CONDENSATE UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

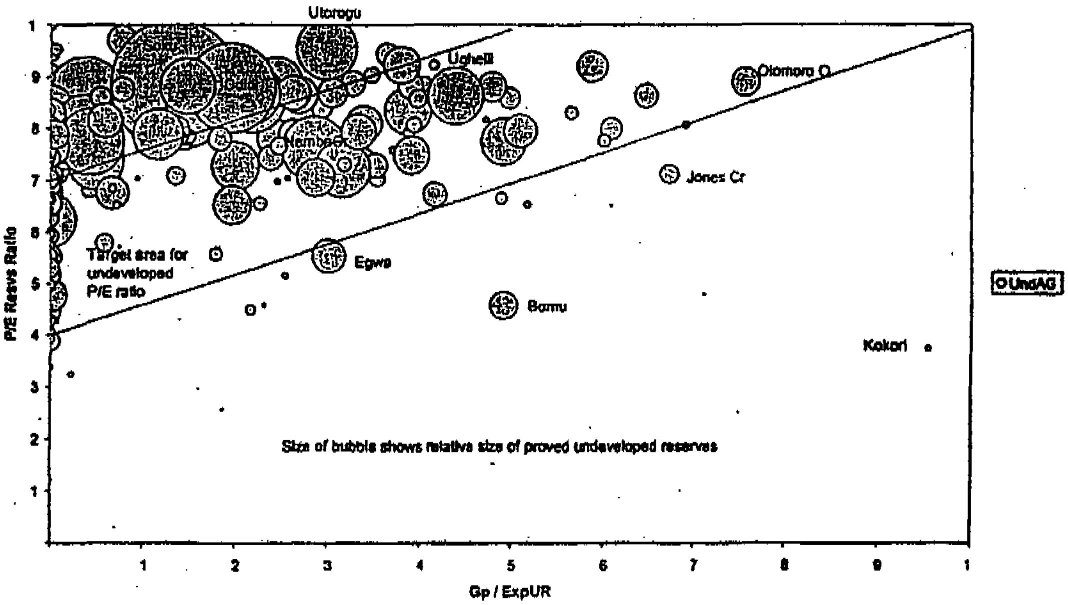


Attachment 3.3

SPDC - ASSOCGAS DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

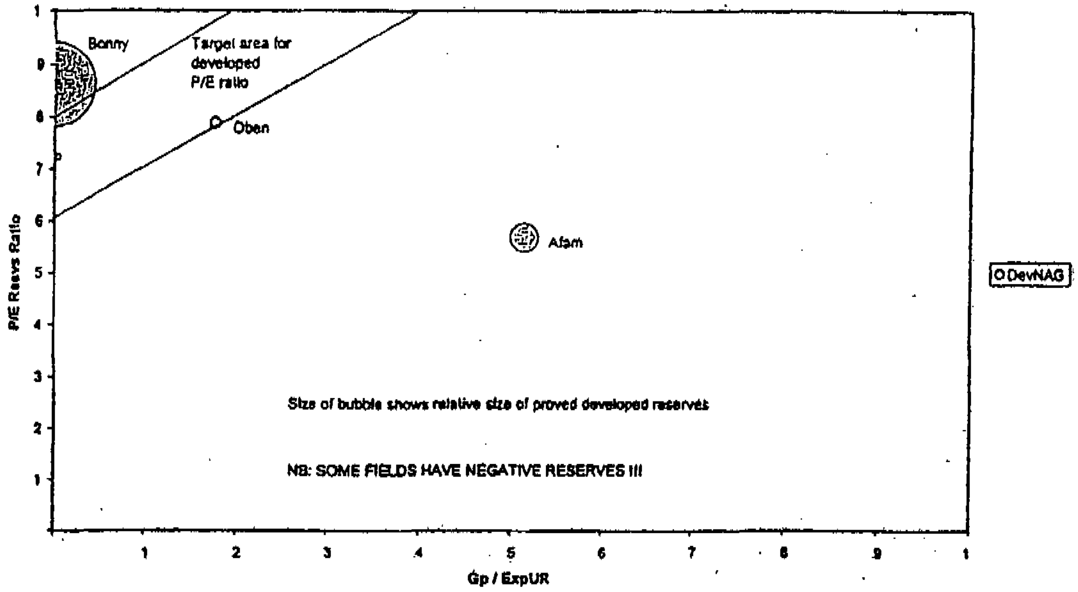


SPDC - ASSOCGAS UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

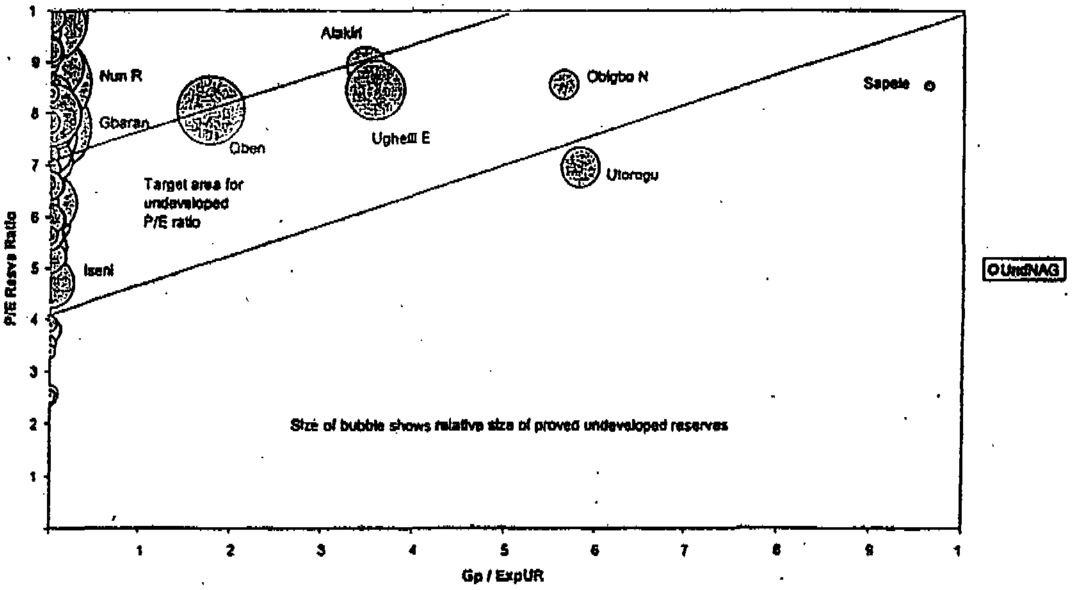


Attachment 3.4

SPDC - NAG DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



SPDC - NAG UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



NOTE – 30 January 2001 **CONFIDENTIAL**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

30/1/01

A.A. Barendregt

Attachments 1 - 8

DEPOSITION EXHIBIT
Barendregt
#21 2/21/07

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

Attachment 1

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

MAIN OBSERVATIONS

1. Significant reserves changes during 2000 were as follows:

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

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

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

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

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

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

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

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

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

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

A tabulation of these changes is given in Attachment 2.

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

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

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

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

[•] 1 mln m3oe = 1 mln m3 oil equivalent = 1.03 bln sm3 gas

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Recommendations to SIEP Reserves Coordination:

1. Vigilance should continue to be applied by the SIEP Reserves Coordinator to ensure that all future Proved Reserves changes will be fully in accordance with Group Reserves Guidelines.
2. Confirm the viability of the 78% Proved Reserves increase booked by SVSA by a review of the planned VAR report and associated SVSA documentation during 2001.
3. Include the volume of Proved and Proved Developed Reserves not producible within current production licences in annual OU reserves submissions.
4. Strengthen the message that externally reported Proved and Proved Developed Reserves should be brought close to (made equal to) expectation reserves in mature fields in the Group Reserves Guidelines to be updated during 2001 and in the cover letter.

Attachment 2

SIGNIFICANT 2000 PROVED AND PROVED DEVELOPED RECOVERY CHANGES

(Shell Group share)

MAJOR TECHNICAL REVISIONS

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

OTHER MAJOR CHANGES

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

OTHER MINOR CHANGES AND TOTAL

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

2000 GROUP RESERVES SUBMISSIONS

Attachm 3.1

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

Country Name	Proved Resvs 1.1.2000	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2000	Proved Resvs 1.1.2001	Proved Dev'd Resvs 1.1.2000	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2000	Proved Dev'd Resvs 1.1.2001	Minority Resvs incl. 1.1.2000	Minority Resvs incl. 1.1.2001	R / P Tot (yr)	Repl'mt Ratio TotlRes (%)	Repl.R. TotlRes (%) Excl Pur/ Sales iP	Repl'mt Ratio DevRes (%)
Australia (SDA)	32.49	4.18	.	.07	.	3.5	4.2	29.04	14.76	.	.52	4.2	11.08	.	.	7	18%	101%	12%
Australia (WPL)	11.85	2.64	.	4.83	.	.	2.28	17.04	5.63	.	2.26	2.28	5.61	.	.	7	328%	328%	99%
Brunei	59.28	8.92	2.8	3.9	.	.	5.54	69.36	28.19	6.04	6.19	5.54	34.88	.	.	13	282%	282%	221%
China	3.24	4.16	.	.	.	.	1.43	5.97	2.83	.7	3.18	1.43	5.27	.	.	4	291%	291%	271%
China (Shell Oil EH)	3.29	-3.29	.	.	.	.	.	.	2.87	.	-2.87	.	.	.	.				
Malaysia	25.55	-.94	2.84	2.68	.	.	3.28	26.85	13.95	3.	.09	3.28	13.76	.	.	8	140%	140%	94%
New Zealand	4.6	-.17	.	.98	.	.	.41	5.	2.6	.11	-.04	.41	2.26	.	.	12	198%	198%	17%
New Zealand (Shell Oil EH)	.8	.05	.	.	.	.	.11	.74	.67	.	.06	.11	.62	.	.	7	45%	45%	55%
Philippines	3.82	.38	.	.	.	.7	.	3.5	.	.	.	.	.	.	.				
Thailand	14.17	.89	1.34	.	.	.	1.04	15.35	3.78	.95	.33	1.04	4.02	.	.	15	214%	214%	123%
Angola	.	.	.	11.85	.	.	.	11.85	.	.	.	.	.	.	.				
Argentina	3.43	.26	.	.07	.	.	.22	3.54	2.03	.06	-.03	.22	1.84	.	.	16	150%	150%	14%
Brazil (Shell Oil WH)	.81	.2	.	.	.	.	.09	.92	.81	.	.2	.09	.92	.	.	10	222%	222%	222%
Cameroon (Shell Oil EH)	7.75	-1.68	.2	.11	.	.	1.21	5.17	7.28	.29	-1.36	1.21	5.	.	1.03	4	-113%	-113%	-88%
Congo (DR)	3.22	-.01	.	.	.	.	.17	3.04	2.3	.	-.02	.17	2.11	.	.	18	-6%	-6%	-12%
Gabon	19.91	3.83	.	.	.	.81	3.99	18.94	17.45	1.12	2.5	3.99	17.08	4.97	4.74	5	76%	96%	91%
Nigeria (SNEPCO)	71.41	7.15	.	10.98	.	.	.	89.54	.	.	.	.	.	.	.				
Nigeria (SPDC)	448.1	.	.	.	.	.	13.93	434.17	113.19	4.29	13.33	13.93	116.88	.	.	31	0%	0%	126%
Venezuela	21.43	16.66	.	.	.	.	2.54	35.55	11.61	1.03	1.19	2.54	11.29	.	.	14	656%	656%	87%
Abu Dhabi	103.26	.02	.	.	.	.	5.58	97.7	83.71	2.11	.94	5.58	81.18	.	.	18	0%	0%	55%
Bangladesh	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Egypt	9.06	-2.59	.	.	.	.	.58	5.89	5.73	.01	-1.69	.58	3.47	.	.	10	-447%	-447%	-290%
Iran	23.85	7.74	.	.	.	.	.	31.59	.	.	.	.	.	.	.				
Kazakhstan (Temir)	2.	.01	.	.	.	2.	.01	.	.	.01	.	.01	.	.	.	0	-19900%	100%	100%
Oman	139.5	34.88	18.43	3.21	.	.	16.62	179.4	85.	4.95	6.67	16.62	80.	.	.	11	340%	340%	70%
Oman Gisco	33.18	-12.34	.	.	.	.	2.36	18.48	27.32	.	-8.2	2.36	16.76	4.98	2.77	8	-523%	-523%	-347%
Pakistan	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Russia (Sakhalin Holding)	7.69	-.01	.	.	7.93	.	.51	15.1	2.81	1.19	2.59	.51	5.88	.	.	30	1553%	-2%	741%
Syria	19.81	-1.17	.	.	.	.	2.92	15.72	12.29	.98	1.	2.92	11.35	.	.	5	-40%	-40%	68%
Austria	.23	.02	.	.01	.	.	.03	.23	.19	.	.03	.03	.19	.	.	8	100%	100%	100%
Canada	47.16	-1.42	14.43	.07	.	.01	3.36	56.87	29.13	.	1.11	3.36	26.88	10.36	12.49	17	389%	389%	33%
Canada (AOSP)	95.4	.	.	.	.	.	.	95.4	.	.	.	.	.	21.2	21.08				
Denmark	39.15	7.17	4.34	.41	.	.	7.53	43.54	27.63	1.41	11.44	7.53	32.95	.	.	6	158%	158%	171%
Germany	3.37	-.01	.	.	.	.	.31	3.05	3.07	.17	-.02	.31	2.91	.	.	10	-3%	-3%	48%
Netherlands	5.77	-.06	.	.	.	.	.75	4.96	3.93	.41	.1	.75	3.69	.	.	7	-8%	-8%	68%
Norway	33.26	5.34	.	.	.	.77	5.07	32.76	20.65	4.56	3.44	5.07	23.58	.	.	6	90%	105%	158%
Shell Oil (MCC)	1.86	-1.86	.	.	.	.	.	.	1.56	.	-1.56	.	.	.	.				
Shell Oil (TMR)	.93	.16	.	.13	.	.08	.16	.98	.56	.07	.14	.16	.61	.	.	6	131%	181%	131%
UK	129.92	.49	2.89	1.42	.	10.49	21.98	102.25	90.35	14.56	-7.35	21.98	75.58	.	.	5	-26%	22%	33%
USA	92.	2.24	.	20.04	.01	.94	16.18	97.17	54.12	11.54	6.34	16.18	55.82	.	.	6	132%	138%	111%
USA (Aera)	79.26	-3.07	.26	.	.	.13	7.23	69.09	59.01	4.08	1.39	7.23	57.25	.	.	10	-41%	-39%	76%
USA (Altura)	47.87	.61	.	.	.	47.78	.7	.	40.24	.	-39.54	.7	.	.	.	0	-6739%	87%	-5649%
Total excl Can. AOSP	**1,554.28**	**79.38**	**47.53**	**60.76**	**7.94**	**67.21**	**132.32**	**1,550.36**	**777.05**	**63.64**	**2.36**	**132.32**	**710.72**	**20.31**	**21.03**	**12**	**97%**	**142%**	**50%**
Grand Total	**1,649.68**	**79.38**	**47.53**	**60.76**	**7.94**	**67.21**	**132.32**	**1,646.75**	**777.05**	**63.64**	**2.36**	**132.32**	**710.72**	**41.61**	**42.11**	**12**	**97%**	**142%**	**50%**

FOIA Confidential Treatment Requested

2000 GROUP RESERVES SUBMISSIONS

Attachment 3.2

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

Country Name	Proved Resvs 1.1.2000	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2000	Proved Resvs 1.1.2001	Proved Dev'd Resvs 1.1.2000	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2000	Proved Dev'd Resvs 1.1.2001	Minority Resvs incl. 1.1.2000	Minority Resvs incl. 1.1.2001	R / P Tot (yr)	Repl'mt Ratio TotlRes (%)	Repl.R. TotlRes (%) Excl Pur/ Sales iP	Repl'mt Ratio DevRes (%)
Australia (SDA)	176.638	2.576	.	.453	.	.394	2.356	176.917	18.583	.	1.824	2.356	18.051	.	.	75	112%	129%	77%
Australia (WPL)	40.205	1.274	.	.155	.	.	1.45	40.184	8.147	.	1.305	1.45	8.002	.	.	28	99%	99%	90%
Brunei	102.612	-2.08	.	4.023	.	.	4.656	99.899	40.744	5.442	-3.601	4.656	37.929	.	.	21	42%	42%	40%
China	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
China (Shell Oil EH)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Malaysia	183.819	-11.93	5.625	.	.	.	5.723	171.791	37.746	20.212	-1.27	5.723	50.965	.	.	30	-110%	-110%	331%
New Zealand	12.646	.031	.	3.361	.154	.	1.381	14.811	11.704	.016	.19	1.381	10.529	.	.	11	257%	246%	15%
New Zealand (Shell Oil EH)	2.314	-.312	.	.	.	.	.247	1.755	2.014	.	-.319	.247	1.448	.	.	7	-126%	-126%	-129%
Philippines	19.436	1.029	.	.	.	3.551	.	16.914	.	.	.	.	.	.	.				
Thailand	6.226	.338	.063	.	.	.	.437	6.189	2.769	.263	.238	.437	2.833	.	.	14	92%	92%	115%
Angola	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Argentina	7.284	1.522	.	.619	.	.	.036	9.389	.547	.056	-.501	.036	.066	.	.	261	5947%	5947%	-1236%
Brazil (Shell Oil WH)	4.384	1.083	.	.	.	.	.326	5.141	4.384	.	1.083	.326	5.141	.	.	16	332%	332%	332%
Cameroon (Shell Oil EH)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Congo (DR)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Gabon	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Nigeria (SNEPCO)	5.7	.57	.	.75	.	.	.	7.02	.	.	.	.	.	.	.				
Nigeria (SPDC)	95.93	-8.384	.	.	.	.	1.836	85.71	37.837	.	-1.987	1.836	34.014	.	.	47	-457%	-457%	-108%
Venezuela	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Abu Dhabi	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Bangladesh	4.713	.039	.	.457	.	.	.384	4.825	2.846	.	-.2	.384	2.262	.	.	13	129%	129%	-52%
Egypt	31.272	-2.326	.39	.	.	.	1.455	27.881	14.059	1.624	-.722	1.455	13.506	.	.	19	-133%	-133%	62%
Iran	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Kazakhstan (Temir)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Oman	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Oman Gisco	45.693	14.272	.	.	.	.	4.758	55.207	45.693	.	3.825	4.758	44.76	6.854	8.281	12	300%	300%	80%
Pakistan	11.339	-.752	.	.	.	.532	.189	9.866	3.347	.	.	.189	3.158	.	.	52	-679%	-398%	0%
Russia (Sakhalin Holding)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Syria	1.012	-.074	.	.	.	.	.234	.704	.596	.013	-.038	.234	.337	.	.	3	-32%	-32%	-11%
Austria	1.476	.191	.	.104	.	.	.175	1.596	1.441	.	.228	.175	1.494	.	.	9	169%	169%	130%
Canada	88.31	3.231	.	.206	.	.895	6.153	84.699	72.2	.	.688	6.153	66.735	19.402	18.608	14	41%	56%	-11%
Canada (AOSP)	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.				
Denmark	30.44	.941	.711	.365	.	.	3.105	29.352	18.73	.518	2.307	3.105	18.45	.	.	9	65%	65%	91%
Germany	59.422	1.225	.	.	.	.	4.659	55.988	46.423	1.565	1.023	4.659	44.352	.	.	12	26%	26%	56%
Netherlands	413.425	.132	.	1.122	.	.	14.828	399.851	211.215	3.23	.73	14.828	200.347	.	.	27	8%	8%	27%
Norway	89.897	2.15	.	.	.	.208	2.06	89.781	42.194	.224	-3.466	2.06	36.892	.	.	44	94%	104%	-157%
Shell Oil (MCC)	1.552	-1.552	.	.	.	.	.	.	1.504	.	-1.504	.	.	.	.				
Shell Oil (TMR)	1.693	-.364	.	.128	.	.113	.202	1.142	1.193	.062	-.16	.202	.893	.	.	6	-173%	-117%	-49%
UK	109.447	1.493	2.27	.075	.	3.096	11.583	98.606	67.734	11.532	-.223	11.583	67.46	.	.	9	6%	33%	98%
USA	96.232	-1.091	.	18.564	1.421	2.217	16.592	96.317	76.788	10.178	-3.968	16.592	66.406	.	.	6	101%	105%	37%
USA (Aera)	5.53	-4.036	.052	.	.	.142	.117	1.287	3.145	.761	-2.803	.117	.986	.	.	11	-3526%	-3405%	-1745%
USA (Altura)	8.068	.062	.	.	.	8.018	.112	.	6.985	.	-6.873	.112	.	.	.	0	-7104%	55%	-6137%
Total excl Can. AOSP	**1,656.715**	**-.742**	**9.111**	**30.382**	**1.576**	**19.164**	**85.054**	**1,592.822**	**780.568**	**55.696**	**-14.194**	**85.054**	**737.016**	**26.256**	**26.889**	19	25%	46%	49%
Grand Total	**1,656.715**	**-.742**	**9.111**	**30.382**	**1.576**	**19.164**	**85.054**	**1,592.822**	**780.568**	**55.696**	**-14.194**	**85.054**	**737.016**	**26.256**	**26.889**	19	25%	46%	49%

2 PRODUCTION RECONCILIATION - OIL+

Attachme 4.1

Country	Original CERES		Org'l Resvs Subm'n		Difference	Final CERES		Final Resvs Subm	Difference	Comment
	min bbl	10^6m3		10^6m3		min bbl	10^6m3	10^6m3	10^6m3	
Australia (SDA)			4.2							
Australia (WPL)			2.28							
Australia Total	40.749	6.48		6.48		40.749	6.48	6.48		OK
Brunei	34.84	5.54		5.54		34.84	5.54	5.54		OK
China			1.37							
China (Shell Oil EH)										
China Total	9.024	1.43		1.37	-.06	9.024	1.43	1.43		Errors in SEC submission - corrected.
Malaysia	20.618	3.28		3.27	-.01	20.618	3.28	3.28		Rounding error - SEC submission corrected
New Zealand			.42					.41		
New Zealand (Shell Oil EH)			.12					.11		
New Zealand Total	3.573	.57		.54	-.03	3.27	.52	.52		Correction to Ceres plus minor corr'n for gasolines (excluded) in SEC submission.
Thailand	6.548	1.04		1.04		6.548	1.04	1.04		OK
Argentina	1.397	.22		.22		1.397	.22	.22		OK
Brazil (Shell Oil WH)	.562	.09		.09		.562	.09	.09		OK
Cameroon (Shell Oil EH)	7.595	1.21		1.21		7.595	1.21	1.21		OK
Congo (DR)	1.064	.17		.17		1.064	.17	.17		OK
	25.117	3.99			-.08	25.117	3.99	3.99		SEC subm'n omitted production from Echira (sold) - corrected
Gabon				3.91						
Nigeria (SPDC)	87.585	13.93		13.93		87.585	13.93	13.93		OK
Venezuela	15.998	2.54		2.54		15.998	2.54	2.54		OK
Abu Dhabi	35.108	5.58		5.58		35.108	5.58	5.58		OK
Egypt	3.632	.58		.58		3.632	.58	.58		OK
Oman			16.61							
Oman Gisco			2.36							
Oman Total	119.34	18.98		18.97	-.01	119.34	18.98	18.98		Rounding error - SEC submission corrected
Russia (Sakhalin Holding)		3.12	.51		.01			.51		
Kazakhstan (Temir)		.016						.01		
Russia Total	3.136	.5		.51		3.248	.52	.52		Ceres based on unreconciled volumes - corrected; Rounding correction for Temir SEC submission
Syria	18.349	2.92		2.92		18.349	2.92	2.92		OK
Austria	.176	.03		.03		.176	.03	.03		OK
Canada	21.142	3.36		3.36		21.142	3.36	3.36		OK
Denmark	47.38	7.53		7.54	.01	47.38	7.53	7.53		Rounding error; SEC submission corrected
Germany	1.965	.31		.31		1.965	.31	.31		OK
Netherlands	4.701	.75		.75		4.701	.75	.75		OK
Norway	31.908	5.07		5.07		31.908	5.07	5.07		OK
UK	138.239	21.98		21.97	-.01	138.239	21.98	21.98		Rounding error - SEC submission corrected
USA			16.18							
USA (Aera)			7.23							
USA (Altura)	.6375	.1	.8							
Shell Oil (MCC)										
Shell Oil (TMR)			.16							
USA Total	152.638	24.27		24.37	.1	152.638	24.27	24.27		I Ceres submission excluded Altura prodn - too late to correct, hence SEC submission corrected
Total	832.384	132.35		132.27	-.08	832.191	132.32	132.32		! Not fully reconciled - match forced

Jan30Note-tbl.xls, OilNGLRecn-Att4.1

26/01/01, 10:05

2000 PRODUCTION RECONCILIATION - GAS

Attachment 4.2

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

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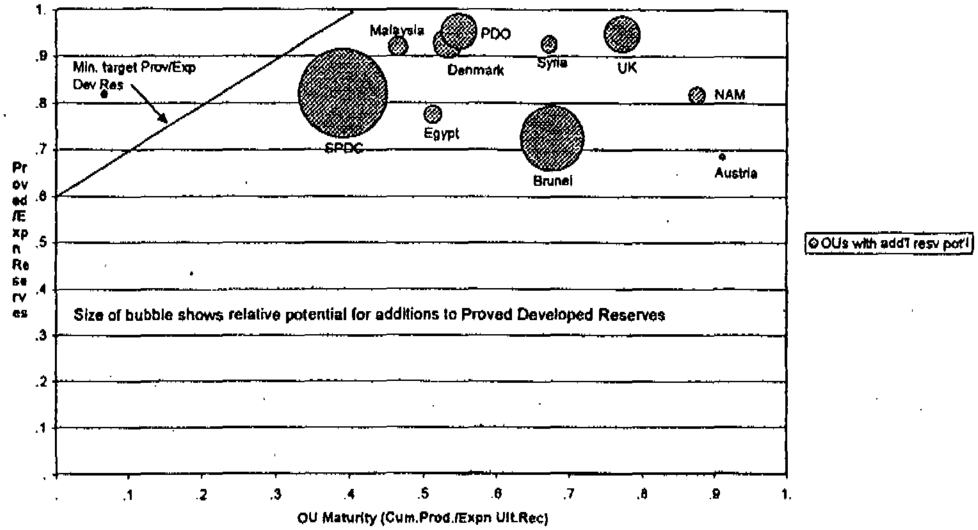
Attachment 5.1



1.1.2001 DEVELOPED OIL+NGL RESERVES

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NEW

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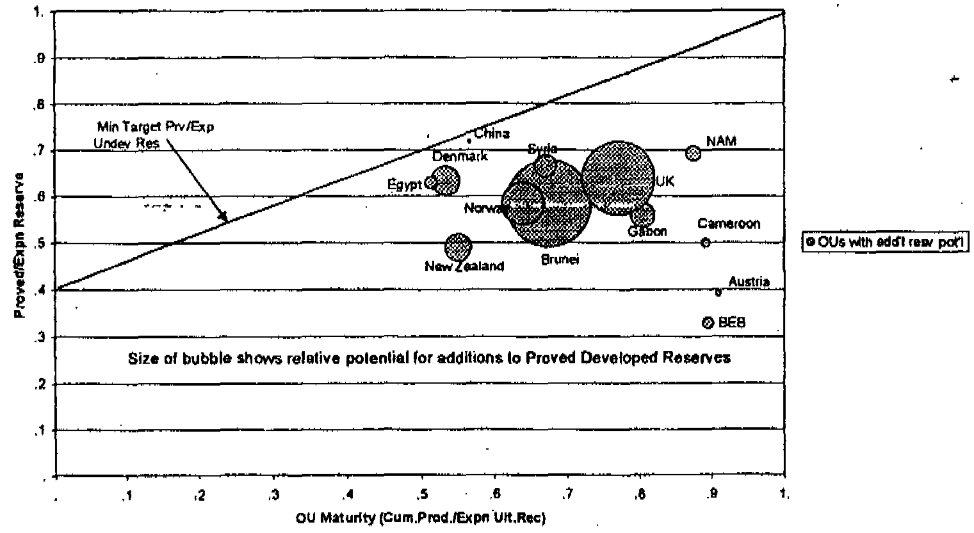

1.1.2001 UNDEVELOPED OIL+NGL RESERVES

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

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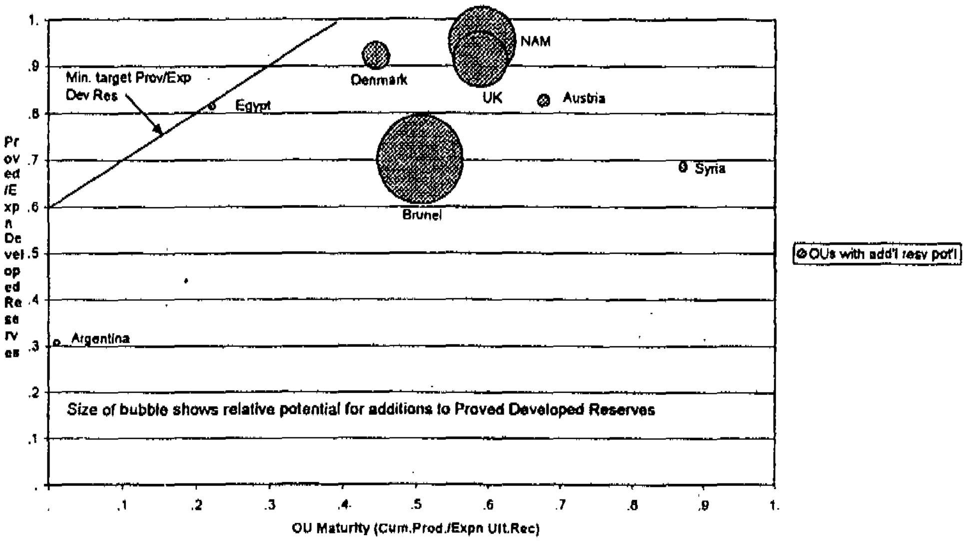
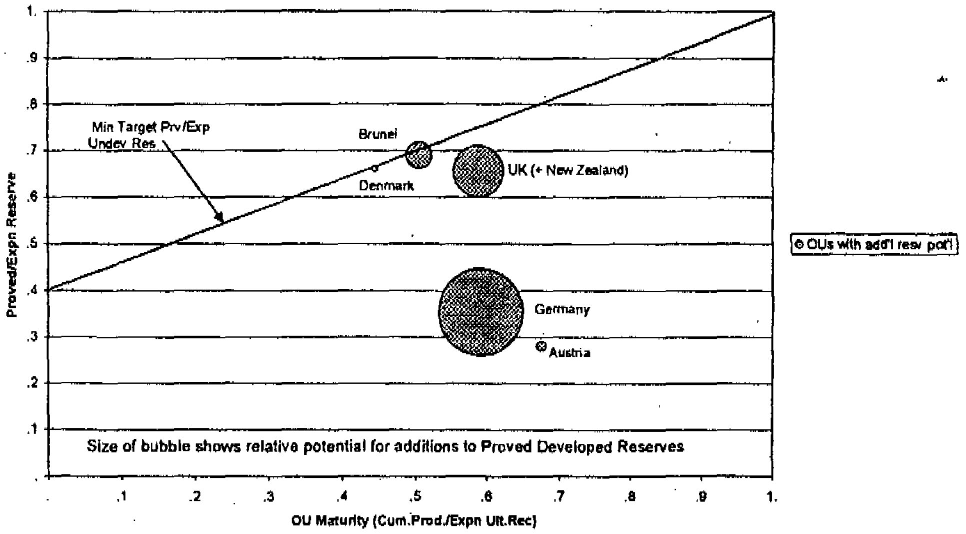
Attachment 5.2

1.1.2001 DEVELOPED GAS RESERVES



1.1.2001 UNDEVELOPED GAS RESERVES



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

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BP - operator

Attachment 6

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

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

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

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

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

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

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

A.A. Barendregt, 17 January 2001

References:

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

Attachment 7

2000 RESERVES AUDITS - MAIN OBSERVATIONS

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

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

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

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

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

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

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TIME TABLE SEC RESERVES AUDITS

Attachment 8

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

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

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

Audit frequency:

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

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

Jan30Note-tbl.xls, AudSched-Att8

26/01/01

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DEPOSITION
EXHIBIT
Barendregt
#22 2/21/07

NOTE – 30 January 2002 **CONFIDENTIAL**

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

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

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

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

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

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

I have reviewed the process of preparing the above summary of proved and proved developed oil and gas reserves in as far a these relate to companies outside Canada. This review included, where possible, a verification of the appropriateness of maj reserves changes. The most significant conclusions are as follows:

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

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

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

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

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

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

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

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

A.A. Barendregt

Attachments 1-7

Attachment 1 Main Observations End-2001 Reserves

Attachment 2 Significant Reserves Changes

Attachment 3 Group Proved Reserves Summaries

Attachment 4 Production Reconciliation Ceres vs. Reserves Submissions

Attachment 5 Proved Reserves Maturity – by OU

Attachment 6 Main Observations 2001 Reserves Audits

Attachment 7 Reserves Audit Plan 2002

Attachme

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

MAIN OBSERVATIONS

1. **Reserves Summary**

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

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

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

The Replacement Ratios mentioned above are with respect to total Group share reserves, i.e. including the Canadian sands and Minority reserves.

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

2. **Significant reserves changes**

Significant reserves changes during 2001 were as follows:

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

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

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

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

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

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

The 95 mln m3 oil volumes from Shell Canada's Athabasca Oil Sands Project (AOSP) are not strictly oil and gas reserves as defined by the US Securities and Exchange Commission (SEC). Hence, they will be excluded from the Group's submission of Proved oil and gas reserves to the SEC. They are also mentioned separately in the Group Annual Report.

4. **Angola block 18**

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

5. **SNEPCO fields**

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

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

6. **Production licence duration constraints**

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

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

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

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

7. **Group Guidelines – mature fields**

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

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

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

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

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

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

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

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

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

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

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

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

Group Proved Reserves receive increasingly close attention by Group Management. Reserves addition targets are se annually, both to OUs and to SIEP Directorates and these are reflected in individual and collective score cards affectin variable pay and bonuses of staff involved. This is leading to a noticeable increase in attempts to book reserves which are not technically or commercially mature and which do not fulfil Group reserves guidelines, cf. the new field bookings in Angola and Nigeria.

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

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

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

10. **Awareness of Group guidelines**

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

11. **Criterion for commerciality**

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

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

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

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

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

13. **SEC Reserves Audits**

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

14. **Electronic Workbooks**

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

Recommendations to SIEP Reserves Coordination:

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

References

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

Attachment 2

SIGNIFICANT 2001 PROVED AND PROVED DEVELOPED RECOVERY CHANGES

(Shell Group share)

MAJOR TECHNICAL REVISIONS

Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Netherlands				+23	Groningen review
Australia	+3		+18		Perseus devmt
Nigeria (SPDC)	+11		+6		Commissioning of gas plant
Nigeria (SPDC)		+15			Condensate devmt Soku + Nun River (offset by oil, see below
Philippines	+2		+11		Malampaya on stream
USA (SEPCo)		+9		+1	Holstein FID (first booking)
USA (SEPCo)	+7	+2	+2	+1	Brutus development
USA (SEPCo)	+5	+3	+2	+2	Mars field performance and drilling results
USA (SEPCo)	+4		+1		Crosby development
USA (SEPCo)	+4		+1		Oregano development
USA (SEPCo)		+9		+7	Various field reviews and drilling results
Denmark		+7		+0	Halfdan FDP approved (improved recovery)
Argentina	+0	+0	+6	+3	San Pedrito development
Netherlands			+6		Small fields development
Iran	+6				Soroosh on stream
Brunei (BSP)		+2		+3	Bugan discovery / appraisal
Malaysia		+0		+5	Lower abandonment pressure E11/F13W (offset by licence)
Denmark	+3	+3	+1	+1	Proved growth to Expectation (audit recommendation)
Russia Sakhalin		+3			Review (new reservoir model + external reserves audit)
Egypt		-1		-4	Obaiyed field performance
Canada	-0	-1	-6	-9	Sable review
New Zealand	-2	-2	-9	-9	Maui C sands revision
Nigeria (SPDC)		-17		+6	Field reviews and forecast review (backed out by NGL)
Total Major Techn'l	**+43**	**+32**	**+39**	**+30**	

OTHER MAJOR CHANGES

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

OTHER MINOR CHANGES AND TOTAL

	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Other Minor Chgs	**+60**	**+44**	**+43**	**+32**	
Grand Total Chgs	**+107**	**+84**	**+85**	**+80**	
Production	**-129**	**-129**	**-93**	**-93**	

Attachment 3

Country Name	OIL + NGL (10^6 m3) Proved Resvs 1.1.2001	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	All volumes net Shell Group Share Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2001	Proved Resvs 1.1.2002	Beyond end of licence	Proved Dev'd Resvs 1.1.2001	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2001	Proved Dev'd Resvs 1.1.2002	Minority Resvs incl. 1.1.2001	Minority Resvs incl. 1.1.2002	R / P Tot (yr)	Replmt Ratio Tot/Res (%)	Replmt Ratio Dev/Res (%)
Australia (SDA)	29.04	1.21					3.55	26.7		11.08	2.86	2.1	3.55	12.29			8	34%	134%
Australia (WPL)	17.04	2.41	.8				2.18	18.07		5.61	1.91	1.51	2.18	6.85			8	147%	157%
Brunei	69.36	4.48	1.25	2.74			6.89	72.24		34.88	3.8	2.77	6.89	35.66			13	152%	114%
Brunei (FCE)		.11			.88		.04	.95				.35	.04	.31			24	2475%	875%
China	5.97	1.44					1.36	6.05		5.27	.96	.35	1.36	4.62			4	106%	67%
Malaysia	28.85	-.28	1.27	.99			3.46	25.36	14.84	13.76	2.88	.72	3.46	13.8		.17	7	67%	95%
New Zealand	5.	-3.81	.23		10.		1.46	8.96		2.26		4.82	1.46	5.62			7	440%	330%
New Zealand (Pecten)	.74	-.74								.62		-.62							
New Zealand (SPM/ex-FCE)					1.9		.27	1.63				1.33	.27	1.06			6	704%	493%
Philippines	3.6	-.16	.23				.03	3.64			2.18		.03	2.15			118	233%	7267%
Thailand	15.35	.73					.94	15.14		4.02	1.15	.14	.94	4.37			16	78%	137%
Angola	11.85							11.85											
Argentina	3.54	.18		.07		2.25	.14	1.39		1.64	.47	-1.71	.14	.46			10	-1436%	-866%
Brazil (Pecten)	.92						.09	.83		.92			.09	.83			9	0%	0%
Cameroon (Pecten)	5.17	.04	.06	.16			1.1	4.33		5.	.27	-.05	1.1	4.12	1.03	.87	4	24%	20%
Congo (DR - Zaire)	3.04	.11		.08			.18	3.05		2.11		.05	.18	1.98			17	106%	28%
Gabon	18.94	.36	.17			.02	3.22	16.23		17.08	.98	.24	3.22	14.89	4.74	4.06	5	16%	25%
Nigeria (SNEPCO)	69.54	.43						69.97											
Nigeria (SPDC)	434.17	-1.87					14.64	417.66	83.86	116.88	14.89	-.39	14.64	116.74			29	-14%	99%
Venezuela	35.55	3.15					2.53	36.17	6.77	11.29	2.82	1.17	2.53	12.75			14	125%	158%
Abu Dhabi	97.7	1.04					5.45	93.29	69.37	81.18	1.71	.64	5.45	77.58			17	19%	34%
Bangladesh																			
Egypt	6.89	-1.03		.03			.81	4.08		3.47	.02	.3	.81	2.88			5	-127%	40%
Iran	31.59	1.87						33.46			5.64			5.64					
Oman (PDO)	179.4	-8.43	6.22	1.51			16.4	162.3	49.7	80.		2.2	16.4	65.8			10	-4%	13%
Oman Gisco	16.48	-3.27					2.56	12.65		16.76		-3.72	2.56	10.48	2.77	1.9	5	-128%	-145%
Pakistan																			
Russia (Sakhalin Assoc.)	16.1	-13.79					1.31			5.88		-4.57	1.31				0	-1053%	-349%
Russia (Sakhalin Consol.)		30.94						30.94				8.45		8.45		13.92			
Syria	15.72	1.91					2.81	14.82	1.7	11.35	1.82	-1.35	2.81	9.01			5	68%	17%
Austria	.23	.02		.01			.03	.23		.18	.02	.03	.03	.21			8	100%	167%
Canada	56.87	-.49		.01	.01	.01	3.23	53.17		26.88	.8	.08	3.23	24.52	12.49	11.26	16	-15%	27%
Canada (AOSP)	95.4							95.4							21.08	20.2			
Denmark	43.54	6.73	9.27				7.54	52.	10.89	32.85	4.78	5.96	7.54	36.15			7	212%	142%
Germany	3.05	.25					.33	2.97		2.91		.29	.33	2.87			9	76%	88%
Netherlands	4.96	-.33					.59	4.04		3.69		-.09	.59	3.01			7	-56%	-15%
Norway	32.76	1.52					5.19	29.08	.28	23.58	3.56	.26	6.19	22.21			6	29%	74%
UK	102.25	-.63	1.35	2.88			18.06	87.69		75.66	7.51	-4.13	18.06	60.89			5	19%	19%
USA (Aera)	69.09	-5.43	.08			.49	6.71	56.55		57.25	5.83	-4.05	6.71	52.32			8	-87%	27%
USA (SEPCo)	97.17	4.78		22.14	.47	.11	17.11	107.34		55.82	19.97	9.58	17.11	68.26			6	159%	175%
USA (TMR)	.98					.97	.01			.61		-.6	.01				0	-9700%	-6000%
Total excl Can. AOSP	1,550.35	23.36	20.93	30.42	13.26	3.85	128.82	1,505.64	227.46	710.72	84.62	22.14	128.82	688.67	21.03	32.18	12	65%	83%
Grand Total	1,645.75	23.36	20.93	30.42	13.26	3.85	128.82	1,601.04	227.46	710.72	84.62	22.14	128.82	688.67	42.11	52.38	12	65%	83%

Country Name	GAS (10^9 sm3) Proved Resvs 1.1.2001	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	All volumes net Shell Group Share Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2001	Proved Resvs 1.1.2002	Beyond end of licence	Proved Dev'd Resvs 1.1.2001	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2001	Proved Dev'd Resvs 1.1.2002	Minority Resvs incl. 1.1.2001	Minority Resvs incl. 1.1.2002	R / P Tot (yr)	Replmt Ratio Tot/Res (%)	Replmt Ratio Dev/Res (%)
Australia (SDA)	176.917	.901					2.408	175.41		18.051	13.548	.453	2.408	29.644			73	37%	691%
Australia (WPL)	40.184	.378					1.511	39.049		8.002	5.928	.552	1.511	12.971			26	25%	429%
Brunei	99.899	1.547	.48	3.257			4.722	100.461		37.529	1.765	1.866	4.722	36.677			21	112%	73%
Brunei (FCE)		1.303			4.891		.348	6.046			.8	2.873	.348	3.124			18	1723%	898%
China																			
Malaysia	171.781	-6.386	-4.675	.38			6.88	164.34	[illegible]	60.866	2.128	-3.486	6.88	44.680		2.626	27	-38%	-8%
New Zealand	14.811	-3.917	1.719		26.439		4.583	33.892		10.828		14.165	4.583	20.381			8	639%	325%
New Zealand (Pecten)	1.799	-1.799								1.449		-1.449							
New Zealand (SPM/ex-FCE)					5.26		.489	4.771				3.344	.489	2.855			10	1076%	684%
Philippines	16.914	-.309	1.161				.044	17.718			10.755		.044	10.711			403	1927%	24443%
Thailand	6.189	1.581	-.007				.429	7.334		2.633	.13	.354	.429	2.708			17	367%	90%
Angola																			
Argentina	9.389	.301	-.016	3.163		.08	.148	12.651		.098	6.043	-.098	.148	6.907			67	2321%	4101%
Brazil (Pecten)	6.141						.343	4.798		6.141			.343	4.798			14	0%	0%
Cameroon (Pecten)																			
Congo (DR - Zaire)																			
Gabon																			
Nigeria (SNEPCO)	7.02							7.02											
Nigeria (SPDC)	85.71	5.729					2.266	89.173		34.014	10.291		2.266	42.039			39	253%	454%
Venezuela																			
Abu Dhabi																			
Bangladesh	4.825	.344					.424	4.745		2.257		.136	.424	1.973			11	81%	32%
Egypt	27.881	-5.341		2.897			2.666	22.772		13.605	.389	-.151	2.666	11.089			9	-89%	6%
Iran																			
Oman (PDO)																			
Oman Gisco	65.207	-14.136					5.707	55.364		44.76		-14.116	5.707	24.937	8.281	6.305	6	-248%	-247%
Pakistan	9.866	-.006			1.816	5.134	.219	6.323		3.158		-2.939	.219				29	-1518%	-1342%
Russia (Sakhalin Assoc.)																			
Russia (Sakhalin Consol.)																			
Syria	.704	-.185					.186	.332		.327		.05	.166	.211			2	-100%	32%
Austria	1.586	-.14		.093			.204	1.346		1.494	-.082	-.046	.204	1.152			7	-23%	-68%
Canada	84.699	-8.486		.779	.394	.234	6.341	70.771		66.736	.588	-6.188	6.341	55.776	18.608	14.882	11	-120%	-73%
Canada (AOSP)																			
Denmark	29.352	2.256	-.247				3.187	28.173	2.288	18.45	3.464	2.132	3.187	20.859			9	63%	176%
Germany	55.988	3.536					4.425	54.699		44.357	.164	1.388	4.425	41.479			12	76%	35%
Netherlands	399.651	21.804	1.06	1.651			16.086	408.1		200.347	5.612	.876	16.086	190.769			25	151%	40%
Norway	89.781	.934					1.818	88.897	10.555	36.892	.005	-.034	1.818	35.045			49	51%	-2%
UK	98.606	.338	.288	4.408			12.351	91.281		67.48	7.194	-.502	12.351	61.801			7	41%	54%
USA (Aera)	1.287	-.814	.001			.009	.054	.411		.886	.056	-.37	.054	.518			8	-1522%	-1137%
USA (SEPCo)	95.317	3.893		10.877	10.066	.244	16.441	104.552		65.406	10.916	5.995	16.441	66.876			6	150%	103%
USA (TMR)	1.142					1.129	.013			.883		-.88	.013				0	-8685%	-6769%
Total excl Can. AOSP	1,592.822	3.278	9.069	27.15	47.499	6.81	93.86	1,579.948	71.356	737.016	79.588	5.008	93.86	728.552	26.889	23.116	17	85%	91%
Grand Total	1,592.822	3.278	9.069	27.15	47.499	6.81	93.86	1,579.948	71.356	737.016	79.588	5.008	93.86	728.552	26.889	23.116	17	85%	91%

Atachment 3 – 2001 Group Reserves Submissions

Attachment 4

OIL + NGL

Country	Original CERES			Org'l Resvs Subm'n		Difference		Final CERES		Final Resvs Subm	Difference		Comment
	mln bbl		10^6m3		10^6m3			mln bbl	10^6m3	10^6m3	10^6m3		
Australia (SDA)				3.55						3.55			
Australia (WPL)				2.18						2.18			
Australia Total		36.078	5.74		5.73	.01		36.078	5.74	5.73	.01		Rounding error? - not corrected
Brunei (BSP)				5.59						5.59			
Brunei (FCE)				.04						.04			
Brunei Total		35.47	5.64		5.63	.01		35.47	5.64	5.63	.01		Rounding error? - not corrected
China		8.516	1.35		1.36	-.01		8.533	1.36	1.36			Q1 error in Ceres - corrected
Malaysia		21.78	3.46		3.46			21.78	3.46	3.46			OK
New Zealand				1.46						1.46			
New Zealand (SPM/ex-FCE)				.27						0.27			
New Zealand Total		10.875	1.73		1.73			10.875	1.73	1.73			OK
Philippines		.165	.03		.03			.165	.03	.03			OK
Thailand		5.91	.94		.94			5.91	.94	.94			OK
Argentina		.907	.14		.14			.907	.14	.14			OK
Brazil (Shell Oil WH)		.58	.09		.09			.56	.09	.09			OK
Cameroon (Shell Oil EH)		6.966	1.11		1.1	.01		6.956	1.11	1.1	.01		Ceres figure incorrect (Govt penalty in Dec) - not changed
Congo (OR)		1.123	.18		.18			1.123	.18	.18			OK
Gabon		20.105	3.2		3.22	-.02		20.299	3.22	3.22			Error in Ceres - corrected
Nigeria (SPDC)		91.42	14.54		14.55	-.01		91.42	14.54	14.54			Reserves submission corrected
Venezuela		15.888	2.53		2.53			15.888	2.53	2.53			OK
Abu Dhabi		34.306	5.45		5.45			34.306	5.45	5.45			OK
Egypt		5.125	.81		.81			5.125	.81	.81			OK
Oman	103.14			16.4						16.40			
Oman Gisco	16.091			2.56						2.56			
Oman Total		119.231	18.96		18.96			119.231	18.96	18.96			OK
Russia (Sakhalin Holding)	8.255			1.31						1.31			
Kazakhstan (Temir)													
Russia Total		8.255	1.31		1.31			8.255	1.31	1.31			OK
Syria		17.689	2.81		2.81			17.689	2.81	2.81			OK
Austria		.2	.03		.03			.2	.03	.03			OK
Canada		20.321	3.23		3.23			20.321	3.23	3.23			OK
Denmark		47.423	7.54		7.54			47.423	7.54	7.54			OK
Germany		2.003	.32		.33	-.01		2.003	.32	.33	-.01		Error in Ceres - not corrected
Netherlands		3.71	.59		.59			3.71	.59	.59			OK
Norway		32.641	5.19		5.19			32.641	5.19	5.19			OK
UK		113.574	18.06		18.06			113.574	18.06	18.06			OK
USA (SEPCo)				17.11						17.11			
USA (Aera)				6.71						6.71			
Shell Oil (TMR)				.01						0.1			
USA Total		149.891	23.83		23.83			149.891	23.83	23.83			OK
Total		810.102	128.81		128.83	.02		810.273	128.83	128.82	.01		

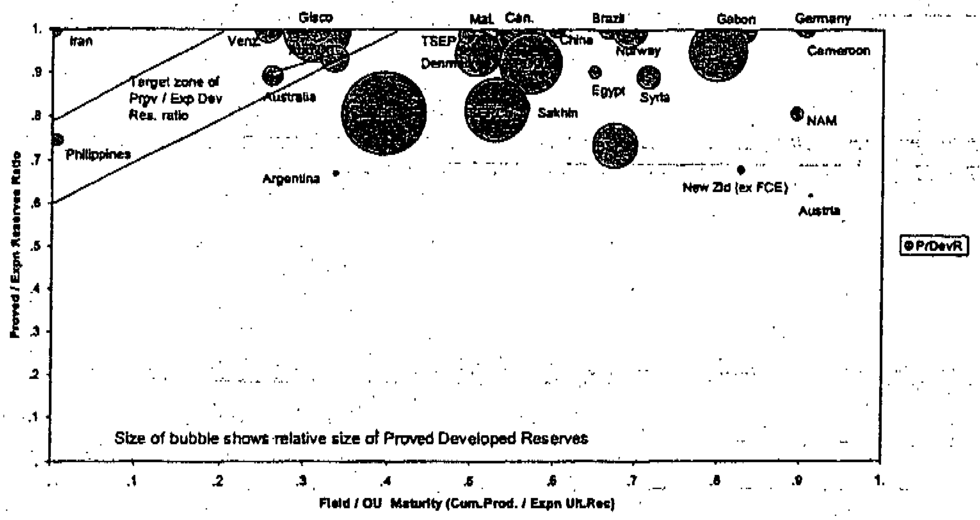
GAS

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

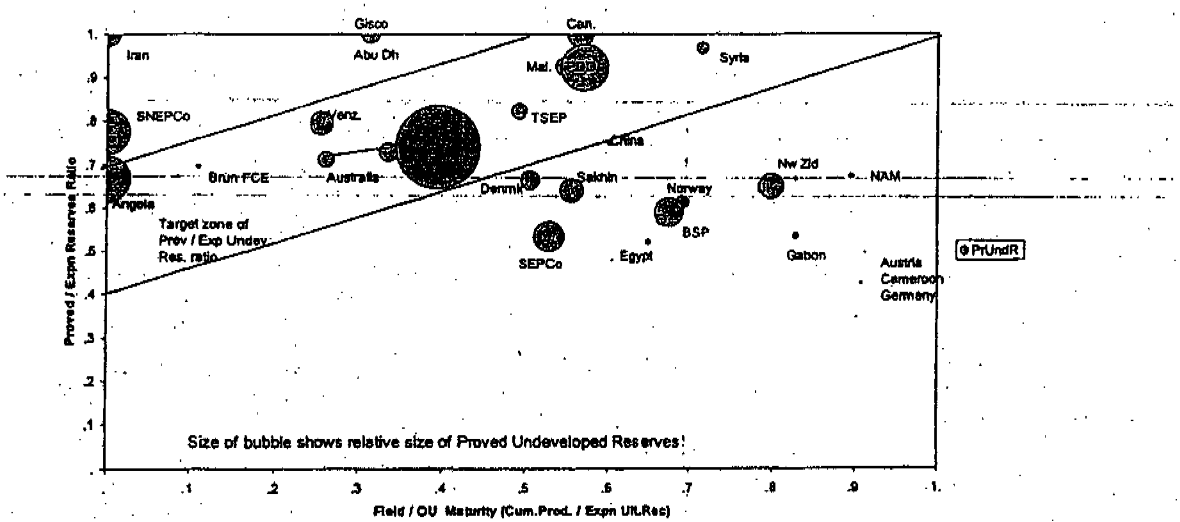
Attachment 4 - 2001 Production reconciliation – Ceres vs Reserves

Attachment 5.1

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



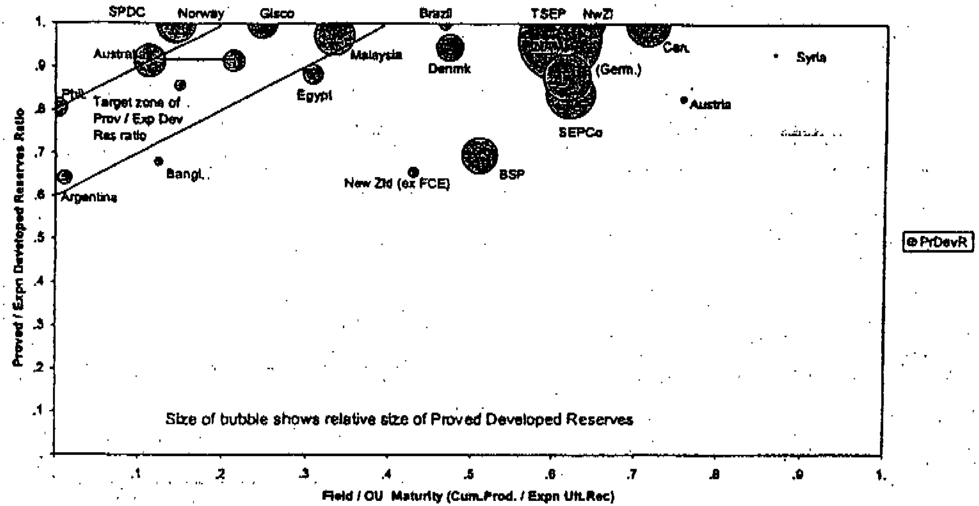
1.1.2002 UNDEVELOPED OIL+NGL RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



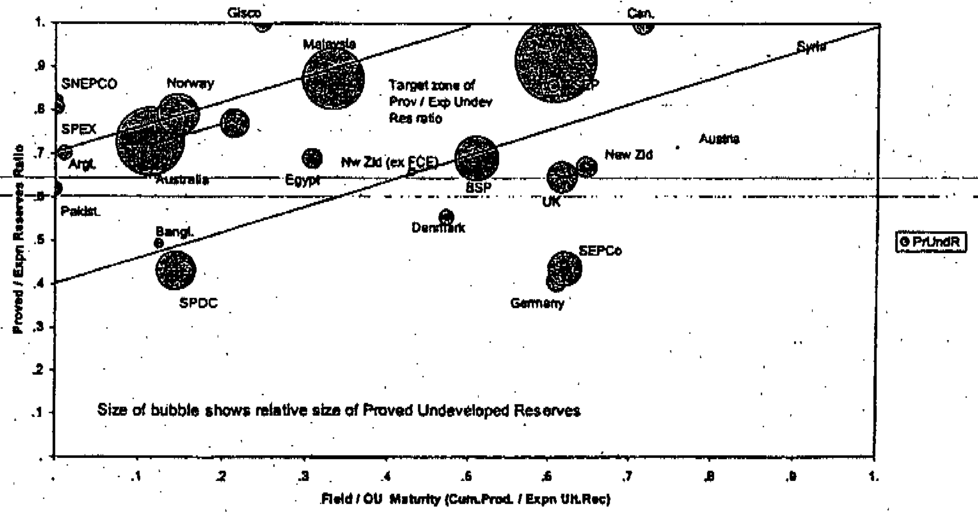
Maturity of Proved Oil+NGL Reserves - by OU

Attachment 5.2

1.1.2002 DEVELOPED GAS RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



1.1.2002 UNDEVELOPED GAS RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



Maturity of Proved Gas Reserves - by OU

V00300318

FOIA Confidential
Treatment Requested

Attachment 6

2001 RESERVES AUDITS - MAIN OBSERVATIONS

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

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

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

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

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

China (SECL): Undeveloped reserves should be based on a full (not a partial) set of future development activities and their uncertainties. This could lead to an increase in undeveloped reserves. A properly documented audit trail note should be prepared. Overall audit opinion is satisfactory.

Austria (RAG): RAG reserves still appear to show remnants from the previous Mobil reserves guidelines. Many undeveloped reserves volumes are not yet based on identified future well activities. There also appear to be some undocumented 'legacy' reserves, which may need to be de-booked after study. The quality of the audit trails should be improved by properly documenting critical stages of the reserves estimation process. Overall audit opinion is satisfactory.

In addition, a brief review was made of the reasons underlying the 17 mln m3 increase in Group share Proved reserves booked at end 2000 by **SVSA in Urdaneta West.** This represented a significant increase (+78%) of SVSA's reported Proved reserves and was deemed a subject for review by the Group reserves auditor. Documentation received during 2001 showed that these reserves additions were based on increasing the number of drainage points and lowering well inflow pressures through artificial lift in the tight Icotea/Misoa and Cogollo/Rio Negro reservoir, thus maximising oil recovery within the reservoir abandonment pressure window. Management commitment to this additional development was already given during 2000 and activities were started during 2001. Hence, these reserves additions could be supported.

Attachment 7

COUNTRY	Size**	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Comments
MALAYSIA	L		X				X				A				15-19 Apr 2002
BRUNEI	L		X				X				A				22-26 Apr 2002
BRAZIL (Pecten)	M/S						*				P1?				Not yet accepted
SYRIA	M/S	X			X						A				2-6 June 2002
PAKISTAN	M/S					$					A1				Sept 2002
IRAN	L							$			A1				Oct 2002
USA (AERA)	L					$					A1				11-15 Nov 2002
ANGOLA	M/S								$		A1?				Dependent on project progress
NIGERIA - SNEPCO	L					$		X			$?				To be considered
ABU DHABI	L			X				X				P			
NIGERIA -SPDC	L	X				X		X				P			
OMAN	L			X				X				P			
EGYPT	M/S		X					X				P			
VENEZUELA	L				$			X				P			
ARGENTINA	M/S			X				X				P			Combine with Venezuela
CAMEROON (Pecten)	M/S						*					P1			
AUSTRALIA	L				X				X				P		
NORWAY	L				X				X				P		
USA (SEPCo)	L						*		X				P		
PHILIPPINES	M/S					$		X					P		
THAILAND	M/S		X					X					P		
KAZAKHSTAN-OKIOC											$?		P1?		
RUSSIA - SALYM												$?	P1?		
GABON	M/S			X					X					P	
BANGLADESH	M/S					$			X					P	
RUSSIA - SAKHALIN	M/S					$			X					P	
NAMIBIA												$?		P1?	
NETH. NAM	L	X				X				X				P	
GERMANY	L	X				X				X				P	
UK	L			X		X				X				P	
DENMARK	L	X				X				X				P	
CHINA	M/S		$							X					
AUSTRIA	M/S			X						X					
NEW ZEALAND	L				X					X					
CANADA	L														No direct involvement
CHAD	M/S			X											Divested 2000
KAZAKHSTAN-TEMIR	M/S							$							Divested 2000
USA (ALTURA)	L					$									Divested 2000
ZAIRE	M/S		X												To be divested?

P = Proposed
A = Accepted
X = Completed
()1 = First audit
$ = First SEC resvs subm'n
* = First SEC subm'n via SIEP

** L : > 30 mln m3oe ss
M/S : < 30 mln m3oe ss

Audit frequency:

Large OUs once every 4 years,
Medium/Small OUs every 5 years,
First audit within 2 yrs after first submission.

Exceptions possible in case of:
- major reserves changes,
- critical audit reports etc,
- when combinable with other audits.

Attachment 7 - SEC Reserves Audit Plan 2002

SPDC Resvs Discussion

Dave Kluesner EPT-VAR
John Pay
~~Koni Kuaano (?)~~ Okon Ikono
Promise Eghele
~~Austin~~ Resvs Mgr Designate Oshin Olorunsola
John Hoppe
(Peter Stephenson)

Reserves Maturation Study { Phase I Aug 13 - Sept 5 '03

Dave K + Peter Stephenson in PTH to kickoff Phase I

- Some volumes not sufficiently mature for proved resvs

TOR defined - forecasts by drainage pt.
Maturity Plan to be defined.

Ph 2 Oct/Nov, Ph 3 Jan-Dec '04

Ph 1 only oil

2.5 MMbls (Shell share) Proved in ARPR, 1.8 only from projects
0.9 MMMbls potential projects.

42% of base plan is <2 MMbls per drainage pt

(Some to-and-fro between 100% and Shell share volumes)

X Copy of DK presn

DEPOSITION
EXHIBIT
Barendregt
#23 2/21/07

②

Short Tm Activities

Dev'd = NFA
Pr Undev = projects in CA (Cap Allocn) & BP
with firm funding; STA, LTA
- "mature" - no resvr/fld/proj exposure
- "immature"

Ten criteria developed for 'maturity'; eg community disturbance; facilities vandalised.
(Resvr/field/project maturity & exposure)

Used for discounting expl to proved

P85 vals vs Expn taken from whatever (volumetrics) is available

Three groups: Prov = Exp, Prov = P85, Prov = 0

"A lot of expectation volumes are likely to be SFR"

Exposure tranches defined.

70-90 dev wells/yr, 9 rigs (max 2 per team),
50-60% of staff on well proposals. "No panic"
9-12 mths duration per well proposal (18 mths is [illegible])

Project is highest area of immaturity.
Currently 8-10 VARs p year, ≈2 people from Rwken
(now being grouped into larger VARs).
? "Project" deficient fields = not clear where/which fields?
"Community" exposure is relatively small

Overlaps between exposure volumes?

Need to prioritise and weed out the multiple exposures? (not done yet)

Reservoir Categories: Marginal, Closed in, Producing, Part/Unappraised (mutually exclusive — by resv block)
"not available" as well — "sloppy housekeeping"
Concern is large vol's in "Marginal" (< 2MMbls) — appm ~~upto~~ 30 - 50%.

"Are getting mature on the creaming curve, need to look closer and closer".

In 'unplanned' there are some good projects, eg Sta Barbara which are not in BP eg because they need ullage that is not yet available — not addressed / captured.

Condensate is included in oil volume but not accounted for (300+ Mln bls).

"Unknown": used Prov = 0.87 × Expl
(0.87 is avge of ~~all~~ total Prov/Expl)

Unaccounted projects: in plan but not clear where from — probably coding errors.

Gas forecasts, three groups:
70% of total { — in AGG nodes: extensive modelling — quite good
— rough consistency check only
— not (yet) reviewed.
Overall, quality is better than 2 yrs ago
NAG: Soku, Gbaran, ~~[illegible]~~ Bonny mostly — extensively modelled

Soku - oil rims ~~at~~ being addressed and assessed, NAG mostly from non-oil rim fields.

/ Originally highly individual projects

How did we get here? Major funding problems 5-6 yrs ago - not worked through a reserves.
Ojo Sanni probably the only person keeping short & long term together.
Project ideas are mostly there but often not (yet) captured.

Dave K's work is 100% Shell - no reports to outsiders.

Corporate forecast

BP forecast 0.8 → 1.4 MMb/d 2003 → 2009

LIO - ~~Light~~ Locked In Oil?

Options = eg AGG fac's - assumes a flat funding profile extension from BP.

~700 MMb/yr reserves addition target.

Akri-Oguta: FID 2006, but unitised and Agip are determined to go ahead.

South Forcados: have funding but plan now changed, ie go through VAR3, 4, FID again.

Gbaran/Ubie: lots of pressure by EP to
accelerate FID.

Need to set criteria to decide when
we book reserves.

Overall forecast constraint determined
by Opec quota's
Stream of FDDs 2006/7/8, technically
minimum. But oil would only be
needed post 2015 (end plateau), ie
one would take FID only at eg 2011-13
ie reserves not until 2011?

"Flares-out" is now gov't imposed – 2008.
Consequence not fully carried through
in plan

NLNG trains
3 operating, 4 2005, 5 end 2005,
5 trains currently committed,
tr 6 FID next yr, 7+8 being discussed,
9, 10, 11 mooted.
Train 1-3 re-rating (upward) is another option.

All gas todate committed to US contracts
Remainder spot market? – Reserves issue
– improved metering, also of flared vol's.

GOR [illegible]

pushing back HG forecasts → initially more
NAG needed

Trains 6+ = all/mostly AG.

Combined HFPT model of 3 NAG fields

Three separate gas streams: NLNG, Eastern
DomGas, Western DomGas

(6)

300 MMscf/d

Ea Dom Gas: only two fields (Alakiri NAG, Obigbo NAG + AG) at present, filling only ≈25% of presently ~~foreseen~~ anticipated demand. Rest would come from other fields in the area.

West Dom Gas ≈ 450 MMscf/d. Number of target fields, plus Utorogu NAG, Oben NAG (Egwa). No contract yet?
No long term ~~forecast~~ contracts, just short extensions
WAGP = West Africa Gas Pipeline, along shore to Ghana, Iv. Coast etc.

(increase!)
1.1.2004 : Propose full 1-5 than volumes NA
AG: essentially developed gas only (reduction!)
Net increase + 30 mrd m3 Shell share.

John Hoppe 0629 327 247

Oil: Foresee to stay constant on oil usus for at least next 2 years.

~~Peter's results~~ 19/9/03

377 ProvDev OK — (Base+Options) Devel Unknow (178)

125 Prov Undev OK — Un~~planned~~ Unknown = (198)
1324 Prov Undev not OK

2185 = Dev + Base + Options
590 = "Unplanned" known
3112 = 178
198

Total data base

⑦

Questions / Remarks

1. SPDC has largest contribn to Group Proved Resvs:
487 vs 3000 or 16% m^3oe.

2. Fully agree with approach:
- Complete portfolio of documented projects, prod. forecasts, economics
- [illegible] per manage point

3. Previous audit noted that reserves kept going up, even in recently studied fields. Is this trend now broken?

4. How to discount from Exp'n to Proved f/cs / resvs?

5. Above still based on volumetric P85's - a weak link!
May be conservative!

6. Many small/marginal projects?

7. R/P Dev'd (oil) = 11 yrs - normal
R/P Undev (oil) = 22 yrs - High!

8. Dev'd, Base, Options: OK for Proved Resvs
Unknown - N/A, Unaccounted, Unplanned - not OK, should be removed.

9. Very good set of criteria:
X Reservoir (4) → VAR2, 3D, OWC, productivity ; other?
Area/field (3) → AGG, community, fac's intact ; other?
Project (3) - Executing, VAR3 or FID ; showstoppers?
not exclusive/independent!

Note: Proved resvs require all criteria to be met.

(8)

10 Why is SPDC P/E gas dev = 1, undev = 0.4?

11. Correct criteria for setting P = E (~~N_p/UR > 25~~ Resvr mature + N_p > 2

~~12 What are PAFs, UAD?~~

12. Discounting
~~Reservoir~~ Exposure to 10 criteria – overlaps
Maturity – Marginal
– Closed in
– Prod – >10
– – 5-10
– – <5
– Unappraised – near
– far

13. Why couldn't the study differentiate Partially Apprd Fld into near and far? (Unapp discoveries could!)

14 Multitude of sets of figures – consistency is there but not obvious.
Suggest:
1) Maintain 100% volumes only to gain easy acceptance by teams
2) But have SS figures available at all levels.

15 Not clear how maturity breakdown and Reservoir category interact,
Suggest:

16. Volumes without any exposures constitute only 22% of Proved Reserves!

⑰ Producing, Closed 0. What about not producing yet?

⑱ Copy of spreadsheet?

⑲ Conflict: rapid reserves maturation vs long-term FID need is an inherent discrepancy that needs to be resolved.

⑳ Check P85 Expl. vs Commn/UR

㉑ Introduce new criteria:
Proved/Expn Developed and P, E Undev resvs
Proved = LKH
CI = pre-production / post production
Economics OK?

㉒ Project executed/executing: relevant?

㉓ Criterion < 2 MMbls: could bring lower if we combine several reservoirs?

㉔ Give recommendations regarding 2004 audit?

10

Tentative Conclusions

① Portfolio is far less mature than originally thought / appeared in 1999 (but guidelines have changed also?) | LACK OF INTEGRATED PLAN?
Rem reserves kept largely unchanged (ie URs inflated?) without real justification by individual field estimates

② Very good start with inventorisation of reserves / reservoir blocks
Interesting insight into (lack of) maturity of portfolio

③ Only some 20% of Proved reserves portfolio passes all ~~reservoir~~ maturity criteria.
However, not all of these needed for Proved res (eg 3D seismic)
Need to re-screen with appropriate partial set of criteria.

④ Need to integrate all criteria: maturity (reservoir, field, project) with those of size and BP status.

⑤ [illegible]
for action; e.g. additional data gathering, study + FDP etc; weed out "unknown" projects etc

⑥ Dev'd R/P = 11 yrs - OK
Undev'd R/P = 22 yr - already large?
Seeking to increase latter may not be realistic: FIDs on many of these projects may not be until 2011+
"Are getting mature on the creaming curve"

11

(7) RFs (oil) generally look favourably.
What is reason for large amount of small (< 2 MMbl) reservoir blocks? RF?, depletion size?

(8) Condensate should be accounted for <u>separately</u> with increasing definition in gas reserves.

(9) Gas forecast/reserves approach seems largely sound.

(10) "Flares out 2008" seems most immediate problem to address — <u>No</u> oil or gas reserves post 2008 if not yet addressed?.

(11) Spot market gas is an issue — to be resolved by updated guidelines.
Approach as in US/ ~~Land~~ Europe Land market?, ie when we install facs (LNG plt) we can book?

(12) Proved Res seem overstated
- Can accept maintaining on the books if action to mature is clearly there
- Do <u>not</u> increase <u>UR</u> (ie <u>reduce</u> <u>reserves</u>) until portfolio mature. — depending on

Check previous points as well?

X Copy of spreadsheet?

Tom v Leenen		EPG
Mark Horner	DvDir ~~[illegible]~~	SPDC
Chris Finlayson		SPDC
Steve Ratcliffe	BusDir	SPDC
John Hoppe		SPDC
Cees van ~~[illegible]~~ ~~[illegible]~~ Vijlenhoed		CFD

John Pay

Barendregt, Anton AA SIEP-EPB-P

From: Pay, John JR SIEP-EPB-P
Sent: vrijdag 30 mei 2003 12:14
To: Barendregt, Anton AA SIEP-EPB-P
Subject: RE: SPDC Proved Reserves Booking Guidelines

John,
My (preliminary) scribbles/comments
Anton

Anton

this is still not the final draft (which I have not yet seen), but it is close to being final.

The minimum objective (from my point of view) for the rest of the year is to ensure that the base case is safeguarded: namely that oil debookings are limited to an extent by which they offset gas bookings, so that net reserves changes for SPDC in 2003 are close to zero.

My ideal objective would be that SPDC is able to conduct the necessary technical assurance work between now and the end of the year that will enable them to avoid any net debooking of oil reserves, so that there would be no change to oil, an addition to gas and an overall significant contribution in boe terms from SPDC. I have asked them to seriously consider what it would take to achieve this - if the reserves were booked in the past, surely it must be possible to find a way of underpinning them today so that they do not have to be written off... It would be a genuine shame if we were to write off reserves in the area that is the most rich resource base in our portfolio!

Oil Gas Reserves in Nigeria-m...

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-----Original Message-----
From: Barendregt, Anton AA SIEP-EPB-P
Sent: 30 May 2003 12:05
To: Pay, John JR SIEP-EPB-P
Subject: RE: SPDC Proved Reserves Booking Guidelines

John,

Happy to discuss next Tuesday (3rd June). In your message you refer to 'John Hoppe's proposal' - is there a mailable doument that I could have a look at? I agree with you that in setting new rules we should be as reasonable and as objective as possible, leaving no room for subjective interpretation.

Anton

DEPOSITION EXHIBIT
Barendregt
#24 2/21/07

-----Original Message-----
From: Pay, John JR SIEP-EPB-P
Sent: woensdag 28 mei 2003 18:51
To: Barendregt, Anton AA SIEP-EPB-P
Subject: FW: SPDC Proved Reserves Booking Guidelines

Anton

we are strugling to come up with practical guidelines for controlling the proved reserves additions process in Nigeria. I have just had (yet another) discussion with various people on this topic, which as usual seems to have resolved nothing. I would appreciate the opportunity to discuss this again with you next time you are in the office. Meanwhile, please find attached my latest plea for a pragmatic and defensible solution, on which your comments would be most welcome,

John Pay
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Shell International Exploration and Production B.V.
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-----Original Message-----
From: Pay, John JR SIEP-EPB-P
Sent: 28 May 2003 18:44
To: Davis, Phil P SEPI-EPG
Cc: Blaha, Michael FMJ SEPI-EPM; Ten Brink, Martin J SEPI-EPG
Subject: SPDC Proved Reserves Booking Guidelines

Phil

following our discussion, I think it helpful to put the following statements down on paper as a means of helping to shape the final guidelines:

1. There is not absolute certainty on how the SEC rules must be interpreted - we have to put our own rules in place and our managers have to be comfortable that they honour the spirit and intent of the SEC rules. ✓

2. The key test is "reasonable certainty" that our disclosed proved reserves will indeed be produced. We must be able to stand up in front of a third party and defend to them that the reserves we have booked reflect a scenario that is certain, within reason, to materialize. ✓

3. This requires that a minimum level of documentary evidence is in place to defend the assertion that reasonable certainty exists. We (in Shell) have translated this into the minimum requirement for technical and commercial project maturity, as documented in our guidelines. The only significant change to these criteria that is currently being contemplated is to link reserves booking for major projects and new field developments to FID, as opposed to VAR 3. ✓

4. In Nigeria, the situation is made more difficult by the fact that the available discovered resources are vastly more than can be accommodated within a reasonable time frame under current OPEC constraints. This is a very unusual situation, requiring some form of "reasonable certainty" test to be applied to the entire Nigeria portfolio. Here I find it difficult to be specific, and depending on one's attitude one can be more or less bullish while still claiming "reasonable certainty" to exist. I suggest that the current ExCom would be unwilling to over stretch proved reserves bookings (but we should test them on this) and therefore some form of blocker needs to be put in place to regulate the pace with which new reserves are added to the portfolio. ✓ ✓

5. John Hoppe's suggestion of distinguishing between (1) incremental developments on existing producing assets and (2) new developments requiring significant new infrastructure provides a sensible means of effecting control which maps relatively easily onto the existing guidelines for the rest of the Group. The former would require a relatively lower level of technical definition (VAR 3) than the latter (VAR 4 / FID). This in principle prevents a whole slug of new reserves being booked on the one hand, while allowing the study effort to be varied to bring new reserves in as and when required. ✓ if we do have a VAR3 at all?

6. Allied to this, we need sensible criteria for assessing the commercial maturity of individual projects* and of the portfolio as a whole. I think it reasonable to book proved gas reserves in relation to LNG contracts that we have in place and to cover a plausible outlook for domestic gas sales, as suggested by John Hoppe. For oil, there is a whole range of things we might consider. Certainyl individual projects need to be shown to be commercially attractive. However, in addition we need to show that entire portfolio reflects a plausible view of what can be considered certain, within reason, to materialize. I think it would be reasonable to assume that today's level of investment will continue indefinitely** and this might be one factor that is taken into consideration in scheduling new developments. Another factor is clearly a plausible outlook for SCIN's share of OPEC quota. However, I feel that we must be careful about how far we extend this into the future. Is it reasonable to book reserves today in relation to developments that will take FID in 2010? Yes, I think so. In 2020? Probably not. In 2030? Almost certainly not. However, I don't know where the cut-off should be and at the end of the day it will be up to our managers (who sign off on the reserves disclosure) to determine where their level of comfort is. Perhaps an approach would be as follows: ?? Hm

That's what worries me

Establish a reasonably certain (i.e relatively conservative) forecast for production and expenditure. Using this as a constraint, schedule each technically mature development and establish when FID would be. (as per BP?

* Provided we can demonstrate that the technical reserves are there?

** As per BP?

Allow bookings only for proved reserves where FID will occur within the lifetime of the existing licence.

Such an approach is arbitrary, but it has the advantages that:

But allow developed reserves to continue beyond that

a) genuine growth in production can be used as the justification for accelerating FIDs and bringing in more reserves
b) licence extension, when secured, would allow substantial additional reserves to be booked.
c) it would be difficult for a 3rd party to argue that we were being unreasonable.

Other approaches are possible: we could arbitrarily limit reserves to today's production rate times a fixed number of years. This allows us to add reserves every year, and throw more in when we get a genuine and sustainable increase in offtake rate.

Does not instill much discipline on details per field?

7. Whatever we do, it must be demonstrably plausible. I think John Hoppe's suggested approach provides enough flexibility at the individual project level that we can then use his suggested criteria as a means of restating reserves bookings, yet in a controlled and reasonable manner.

8. The limiting case, whatever we do, would be our base plan going forward: we should not book proved reserves that exceed what will be delivered by our documented base business plan. To do otherwise would be to clearly violate the principle of reasonable certainty.

Happy to discuss further, but let's try to land on an approach that we can all feel comfortable with. If that means we have to take two or more alternative suggestions to our managers and let them decide, so be it.

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What about SIEP's RRR management process (to avoid major swings from year to year?

Oil & Gas Reserves in Nigeria

Summary

1. Introduction

A moratorium on additional SPDC reserves bookings was introduced in 1999 given concerns that it may not be possible to deliver the ambitious growth programme and produce the current proven reserves volume prior to licence expiry in November 2019. The moratorium was extended to gas in 2001, as domestic gas sales were falling significantly below the forecasts upon which reserves were based. Consequently, it was decided not to book additional reserves when FID was taken on NLNG Trains 4/5 in March 2002, pending an overall review of gas reserves. ?

Reserves were one of the "Five Critical Issues" identified in November 2002, for which detailed action plans were developed and are now being implemented. This reflected concerns that reserves may be over booked if production and development activity continue to be constrained by factors such as OPEC quota, NNPC funding constraints or executive capacityor if growth in the domestic gas market failed to materialise. Considerable upside was also identified if the licence constraint could be removed, given SPDC's massive resource base and continuing technical success rate in exploration. This note details the main findings of the work carried out under the Critical Issue Plan.

The work concluded that SPDC could book reserves after licence renewal. This was unexpected and was therefore extensively tested, both internally and externally. The conclusions were confirmed and hence this constraint has been dropped in the reserves estimates presented in this note.

The principal remaining constraint on reserves was found to be the technical and commercial maturity of SPDC's underlying resource base. As the interpretation of SEC guidelines[2] has been tightened over the last few years, a detailed review of the resource base was undertaken to determine the volume that currently qualifies as proven reserves. A fundamental review of domestic gas demand was also undertaken as part of a wider EP/GP Gas Strategy Review in order to re-assess gas reserves.

2. Reserves Post Licence Renewal

For external reporting, Group share of reserves (Proved, Proved Developed) is limited to future production within the existing licence or contract period, including any agreed extensions as may be covered by documented evidence.

Recent work has confirmed that both SPDC and SNEPCO have a legal right to licence extensions. In the case of SPDC:

- ➢ The Government is obliged to grant a licence renewal under the Petroleum Act, so long as the lease holder has complied with their licence obligations. These obligations are in line with normal business practices and SPDC is therefore unlikely to be found in default.
- ➢ Licence renewals have been granted to all JV partners in the past. A relatively low fixed charge has also now been specified for licence renewal (in the past a payment was negotiated).
- ➢ Legal opinions were obtained from Group Legal, Nigerian Counsel and Cravaths Swain and Moore . All confirmed a solid legal basis for the lease holder's right to licence extensions.
- ➢ A "defence" letter outlining the position was approved by EPG, EPF, and LSEP and has been accepted by KPMG.

In the case of SNEPCO:

- ➢ Licence rights under the PSC are vested in NNPC as licence holder, who are obliged under the terms of the PSC to apply for renewals.
- ➢ The renewal conditions are as covered by the Petroleum Act, and so essentially identical to those for the SPDC licences.
- ➢ If the renewal is granted, either party to the PSC may exercise the option (provided for in the PSC) to extend the PSC term in line with the licence renewal.

3. Application of SEC Guidelines in Nigeria

The SEC Guidelines, as documented in the Group's Petroleum Resource Volume Guidelines, are applied fully in SPDC and SNEPCO. There are no "grey" areas allowing for interpretation. The key elements are as follows: ?

- ➢ Reserves, being future hydrocarbon product available for sale, are tied to **projects**. The aggregated production forecast must be consistent with the reported reserves. This also holds for the 'proved forecast', as defined by the aggregated **'reasonably certain'** amount of hydrocarbons forecast to be produced by the appropriate development/production scenario, duly respecting license duration and overall constraints (e.g. quota).
- ➢ For a resource volume to pass from scope for recovery (SFR) to reserves (for internal as well as external reporting) the associated project(s) have to reach both **technical** and **commercial maturity**. This is deemed to be the case when:
  - o The Shell shareholder assurance processes have been satisfactorily passed both technically and commercially and no significant issues that could preclude proceeding with the project exist.

  - Support to fund the project is reasonably certain (e.g. the project survives the business planning processes of Capital Allocation) and the project forms (or is reasonably certain to form) part of the relevant business plan.
  - It should be emphasized that if no Proved reserves can be assigned to a project, then the related petroleum resource volume should be retained as SFR, i.e. there should be no Expectation reserves reported without Proved reserves.
- Major reserves volumes that are no longer judged to be commercially mature should only be de-booked after thorough (re-)evaluation.
- For project reserves to enter into the Proved category, **Independent** review and challenge is required (as a control) to preserve integrity of the external disclosures. For major projects such review is routinely executed through the Group's Value Assurance Review process. Note that concept selection (VAR3) must at least have been completed. Applied to all SPDC projects? now FID

Historically, SPDC's reserves have been based on probabilistic estimates of volumes initially-in-place combined with ranges of recovery factors. Projects were only defined, as part of the Field Development Planning process, after many of the reserves volumes were already booked. In recent years Ultimate Recovery Change Reports (URCRs) used to document reserves bookings, have included a description of a "Notional Development Plan" that outlines how the volumes could be produced, but not how they will be produced. Consequently there is now a need to reconcile the booked reserves numbers with the volumes covered by projects in the Business Plan.

Strictly speaking, booked reserves that are not covered by a specific project should be reclassified as SFR. However, it is recognised that project recoveries may change as a project progresses to execution, and new projects may be defined as a result of ongoing work in the Asset Teams. Reclassification should only take place as the result of a thorough re-evaluation of the reserves volumes documented in a URCR. In between such revisions, any variances between the booked ARPR volumes and the Business Plan project volumes should be tracked and reported annually as part of the Hydrocarbon Master Plan. Each variance should be accompanied by a resource maturation plan explaining how and when it will be resolved, either by maturing new development activities, or by re-evaluation and reclassification.

Development projects within SPDC are defined to incorporate activities only from within a single field, but may deliver production from several reservoirs and blocks. Production forecasts associated with each project must be broken down into separate forecasts for each reservoir-block to enable accounting at a level where the correct physical reservoir behaviour can be shown to apply. Proved forecasts are derived from the expectation forecasts by discounting by the ratio between the low ultimate recovery (P85 estimate) and the expectation ultimate recovery of the respective reservoir-blocks. In recent years, all proved developed volumes (i.e. those related to the NFA forecasts) have been taken equal to the expectation forecasts (i.e. undiscounted). Clarification in the latest Group Guidelines recommends that this should only apply to "mature" reservoir-blocks This year, SPDC is re-introducing the concept of **proved blocks** to catalogue those reservoir-blocks that are sufficiently mature to require no discounting. Proved forecasts for all other blocks are discounted from the expectation. Proved blocks are defined to be those with:

- Volumetric estimates based on 3D seismic;
- Fluid contacts known to "reasonable certainty"; — based on seismic / pressures / logs?
- An adequate number and distribution of well penetrations;
- Cumulative production in excess of 25% of the estimated ultimate recovery.

The key documentation for a project in SPDC is the Project Proposal Sheet (PPS). This provides a description of a project and all of the information to carry out an economic evaluation. However, more is required to demonstrate a project is technically mature.

- For each reservoir-block addressed by a project there must be a demonstrable audit trail for the resource volumes carried in the current ARPR. For some of the older resource volumes reported before the introduction of the URCR reporting system, this may require additional review.
- Each PPS must be based on a current Field (re-)Development Plan (FDP), and any changes from the FDP must be documented.
- Smaller projects, for which the PPS is based on a "notional" development plan, must be based on a well-established analogue for which there is a current FDP. The basis for the analogy and any deviations must be documented.
- all of them? Projects in the "Base Plan" contribute to SPDC's proved reserves and therefore must have been subjected to independent review and challenge (as a control) to preserve integrity of the external disclosures.
  - For major projects (>US$100 million, 100%) such a review will be an externally led VAR3. now FID
  - For minor projects (<US$100 million, 100%) an internal SPDC Corporate Project Review (CPR) should be carried out.
  - Related minor projects producing through shared facilities such that they may mutually affect each others development decisions should be grouped for review purposes, e.g. an infill-drilling project, tie-in of a satellite field through the same facilities, and the installation of associated gas gathering facilities. In many cases the resulting integrated project will then require a full VAR.

- Resource volumes reported in the ARPR, for which there are no mature projects defined, must have a hydrocarbon resource maturation plan documenting how and when projects will be defined, or the resource volumes removed. These will include small volumes "left over" after reconciling project volumes ~~with the ARPR, many of the PAFs~~ and UADs and all of the SFR.
- Resource volumes "missing" from the ARPR, i.e. volumes carried in a PPS for which there are no corresponding volumes reported in the current ARPR must be documented in a URCR during the current year for reporting in the next ARPR at the end of the year.

All projects must be assessed against the Group's profitability criteria as set for the Capital Allocation process. This does not mean the projects must rank and be funded, but they must pass the screening levels to be considered mature. why not ?

Assurance of market availability, in addition to having a contract, requires the availability of the infrastructure to transport the product to market. This requires either:

- The project will deliver product into an existing pipeline system having sufficient ullage to handle the full volumes; or
- The project includes the development of the necessary transport infrastructure. FID

Where major new infrastructure is to be built, e.g. for a new offshore field such as in the H-Block, or for a remote onshore field such as Utapate, the project should pass VAR4 to ensure there are no significant issues that could preclude proceeding with the project. Moreover, where the infrastructure component of such a project is dedicated to the project, i.e. is not providing shared capacity for use by other developments, then the project is a true "option", and in order to be reasonably certain of funding by the Group it should take FID before being considered commercially mature.

Much of SPDC's gas reserves are associated gas volumes subject to the same concerns as the corresponding oil volumes. Little non-associated gas has been booked to date, and with the focus on oil, NAG reservoirs have received little attention until recently. Further areas of concern for gas are:

- The commercial maturity of the various projects. In particular the availability of evacuation routes to the designated customers, and contractually bound, realistic, gas demand forecasts to constrain the sales gas supply forecasts. Many of the domestic gas contracts are small GSPAs, effectively renewable indefinitely, and consequently do not provide a clear boundary for the reserves. In such cases the reserves are constrained from the supply side, ensuring only existing supplies and projects in the Base Plan are counted. Previously these forecasts tended to assume continuity of supply by drilling NAG wells as required.
- Data availability. In particular, gas properties from fluid samples, and the reliability of historical gas production volumes. This should be reflected in the range of volumetric uncertainty and the corresponding discount to proved reserves.
- Sufficient supply projects are defined in the Base Plan to cover the full contractual demand for NLNG trains 1-5, but the plan assumes full blow-down of the back-up/swing NAG supplies in Bonny and Soku in the later years [ISSUE BEING OIL RIMS?]. These volumes will be replaced in subsequent Business Plans (2004/2005) by further AG nodal projects that are not yet mature enough to carry in the Base Plan this year.

With the size of SPDC's portfolio, not all projects can be accommodated within a five-year programme period due to funding and other resource constraints. It is important to distinguish incremental projects in existing fields that are reasonably certain to be funded by the Group and Partners at some time, probably soon after the five-years, from new developments that can be truly said to be optional and therefore not reasonably certain to receive funding. The former category of projects are candidates to be included in the Base Plan.

4. Review of SPDC Resource Base

15.33?

SPDC currently carries 16.57 billion barrels (100%) of expectation oil reserves in the following categories:

MMbbl, 100%	Proved Blocks	Unproved Blocks	Total	
Developed	1,971	626	2,597	1.625 Proved
Undeveloped in Base Plan	1,931	3,132	5,063	9.018 Proved
Undeveloped, not in Base Plan	1,962	2,207	4,169	
Closed-in Fields (e.g. Ogoni Area, Utapate)	-	1,627	1,627	to be SFR
Partially-Appraised Fields/ Unappraised Discoveries (PAF/UAD)	-	3,113	3,113	
Total				

Here, "Base Plan" is defined to be those projects carried in last year's Business Plan plus the critical T4/5 gas supply projects being matured in Soku and Gbaran/Ubie this year.

Of these volumes, only the first two categories carry corresponding proved volumes. The other three categories do not, and therefore should be carried as SFR not reserves. A case could probably be made that the bulk of reserves in

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the third category, "Undeveloped, not in Base Plan", should be retained as expectation reserves on the basis that they represent incremental developments within existing developed fields. However, this will require further work to review their project definitions and maturity. Possibly part of the PAFs & UADs could be similarly justified as satellite developments tying in to existing fields. The remaining 4 to 5 billion barrels should really be down-graded to SFR, with little prospect of adequate studies in the near future to mature, or in many cases even define their development projects. i.e. need separate accounting of Proved and Expl

Besides the impact on the Group's internally reported volumes, it would be difficult not to reflect such a change in the volumes reported to Government. These are reported under the Nigerian National Standard (NNS) format based on the 1987 SPE definitions of Proved, Probable and Possible volumes. Moving expectation reserves to SFR would require a corresponding move from probable (P2) to possible (P3). This would undoubtedly have a knock-on effect on our position with regard to the Reserves Addition Bonus, particularly in the light of the ongoing legal dispute.

There would also be a consequence for Exploration, in that most newly discovered volumes could only be booked as discovered SFR. The only reserves would be for early hook-ups, and then not necessarily in the year of discovery. Moving SFR to reserves would require a Field Development Plan and commitment to development sometime later.

Projects in the Base Plan, which hence carry proved reserves, have been reviewed against the criteria for technical maturity (see section 3 above: audit trail for ARPR volumes; PPS clearly linked to a current FDP). All projects in the Base Plan have passed economic screening against the Capital Allocation criteria, and are being proposed for funding. They are therefore deemed commercially mature. Projects are either mature or not, there is no "in-between". Projects that are not mature [which ones are these; the options?]will have maturation plans prepared by the end of June 2003 leading to full maturity for next year's Business Plan (by 30th April 2004 at the latest).

✓ Projects have also been reviewed to establish whether or not they have been subject to independent review and challenge of the selected concepts (passed VAR3 or equivalent). Again there is no "grey" area, they have either passed or not. Where further independent review is required, this will be scheduled as part of the projects' maturation plans.

A comparison of the expectation Base Plan forecast using the criteria discussed above with that of last year's Business Plan is presented in figure 1. The NFA forecasts for drainage points producing from fields with no associated gas gathering or other gas solution in the Base Plan have been truncated from 1/1/2008 to comply with flares-out. A breakdown of the latest estimate of proved oil volumes compared with those as booked at 1.1.2003 is presented in Table 1, and the changes summarized in figure 2. Shell share?

of- sible!

The overall net reduction is 75 Million m3 (471 MMbbl?). An overall reduction of 150.34 million m^3 within the current licence period is partially offset by an additional 75.35 million m^3 post licence. The bulk of the reduction within the licence period, 132.78 million m^3, results from including only the Base Plan projects. Other changes are relatively small:

- -4.40 million m^3 for the reintroduction of discounting proved developed volumes in unproved blocks;
- -7.77 million m^3 for closing in NFA production from 2008 where there is no associated gas gathering or alternative solution to achieve flares out;
- -5.02 million m^3 for the postponement of EA phase 2.

Most of the volumes that are technically and commercially mature have been subject to external review, but roughly one third of LE volumes at 1.1.2004 require further work to either demonstrate they are sufficiently mature, or mature them further. Of these exposures, 28.38 million m^3 are mature, but have not been externally reviewed, while 81.55 million m^3 have not been demonstrated to be mature.

A number of projects currently excluded from the base plan are being matured and will achieve VAR3 by late 2003 or during 2004. These could be included in the base plan beyond the five year programme period on the grounds that they enable continued production from existing assets post-flares out in 2008 and develop incremental reserves in existing assets. They would be carried as exposures at 1.1.2004, but with clear plans in place to mature the volumes by 1.1.2005. Volumes are as follows:

Otumara	9.35 mln m^3	VAR3 October 2003
Akri-Oguta	11.38 mln m^3	VAR3 November 2003
Remaining Ubie	4.34 mln m^3	VAR3 July 2003
Land Area - West	6.63 mln m^3	AGG has VAR4 but project is currently on hold. Oroni-Uzere fields take VAR3 in June 2003; Aferolo fields take VAR3 in November 2003.
Nun River	8.94 mln m^3	VAR3 currently planned for July 2005.

why?

The combined volume of 40.64 million m^3 would reduce the shortfall to 34.35 million m^3 (216 MMbbl).

5. Review of Gas Forecasts

Volumes for NLNG are based on the various train DCQs and premised 338 stream days per year. Demand forecasts are run out to the expiry of the basic contract terms for each train:

- Trains 1 & 2 basic term expires 30/9/2021
- Train 3 basic term expires 30/9/2023
- Trains 4 & 5 basic term expires 30/9/2026

demonstrated?

No discounting from expectation to proved has been applied as supply plans include sufficient NAG swing capacity to guarantee meeting demand. Bonga gas production (9.28 milliard m^3, 100%) has been excluded from the demand volumes to determine SPDC supply volumes. No provision has been made for further volumes from Bonga. These should be offset from the train 6 bookings expected next year.

Domestic gas volumes are also based on the latest demand forecasts. These have been reduced from last year to include only those volumes for which there are firm contracts in place. Gas supplies to NEPA's power stations (Egbin, Delta, Sapele and Afam), Ewekoro/Shagamu cement factories and DSC Aladja are based on GSPAs between SPDC and NGC:

- Utorogu, ACQ 66 Bcf/yr end date 2008;
- Oben, ACQ 14.7 Bcf/yr end date 2012;
- Sapele, ACQ 24 Bcf/yr end date 2007;
- Afam/Obigbo North, ACQ 31.85 Bcf/yr end date 2016.

There is a direct GSPA between SPDC and NEPA for Ughelli East, ACQ 21.9 Bcf/yr expired but under re-negotiation.

A GSPA exists to supply gas from Alakiri to NGC for delivery to NAFCON's fertiliser plant (ACQ 17.5 Bscf/yr). This contract expires in 2008 but has similar extension provisions to the other GSPAs. NAFCON has been dormant since mid-1999 due to plant breakdown. Forecast gas sales to this customer are based on expected reactivation of the fertilizer plant to its existing capacity and extension of the GSPA beyond current contract life. However, for the purposes of proved reserves, reactivation of the plant has been excluded.

Although a GSPA has never been executed for gas supply to ALSCON, negotiation had been ongoing since the early 1990's and there is an interim agreement with NGC to supply gas from Alakiri and Obigbo. This allowed ALSCON to start commissioning their plant, build up consumption to 30 MMscf/d before the plant shut down in 2000 for lack of working capital. Current demand of about 10 MMscf/d is for utilities only. The forecast shows a restart of the plant 1n 2006, building up to 102 MMscf/d in 2008. However, for the purposes of proved reserves, restart of the plant has been excluded.

The smaller customers have direct GSPAs with SPDC with various end dates.

All above GSPAs are not tied to field depletion and all have provisions for extension on the basis of mutually acceptable terms. Extension of these GSPAs has been assumed based on historical connection to SPDC's gas sources and the limited scope for other suppliers to deliver gas more competitively to most of these customers than SPDC could. In the West, the forecast has made allowance for Chevron's share of the gas supplies.

Work is still in progress on the supply side, particularly the existing small NAG plants, to determine the technical lifetime of these supplies. At this stage all domestic gas volumes have been cut-off at the old licence boundary of 30th November 2019 as used for previous bookings. It may be possible to extend some volumes beyond that date once the work has been completed later this year.

The increase in gas supply to the Afam power station has been excluded for the purposes of proved reserves. Although the project is "committed" and being progressed on a fast-track, at this stage the upstream project definition is barely at the VAR2 stage. By the end of the year VAR3 will have been taken, and it may be possible to include the volumes. Similarly the increases in ALSCON and NAFCON demand may become bookable if we get firmer indications that they will indeed increase their take.

Where to?

Although a Letter of Intent has already been signed for the West African Gas Pipeline, there is currently no firm supply project identified to provide additional gas in the Western division. This may mature sufficiently during the year to allow booking at 1.1.2004.

A breakdown of the latest estimate of proved gas volumes compared with those as booked at 1.1.2003 is presented in Table 2.

Shell share

The overall net increase is 37.5 75 Milliard sm3 ~~(xx boe)~~. The changes are summarised in figure 3. The reductions in domestic gas volumes (14.478 mrd m^3, Shell share) and removal of WAGP volumes (4.180 mrd m^3, Shell share) are more than offset by the new NLNG bookings (56.202 mrd m^3, Shell share). Potential upsides from the reintroduction of WAGP, and the Afam power station, ALSCON and NAFCON increases could add a further 4.180, 6.708, 3.739 and 1.661 mrd m^3, Shell share respectively.

6. Current Reserves Position – SPDC

The overall position for SPDC is summarized in figure 4. The currently defined Base Plan includes a number of projects requiring further maturation to be fully compliant with the SEC and Group guidelines. However, studies are in progress to achieve compliance. Moreover, there are a number of projects currently excluded from the Base Plan, which are essentially no less mature and also being studied (Otumara, Akri-Oguta, Remainder of Ubie, Land Area

West, Nun River, Afam Power gas supply including ALSCON & NAFCON increase, WAGP gas supply). These should be moved within the Base Plan. Criteria for inclusion are:

- Project addresses further development within an existing field or fields, and supports continued production beyond flares-out in 2008.
- Studies are in progress leading to full maturity in time for next year's Business Plan and would result in re-booking next year if de-booked this year.
- Gas market availability is confirmed.

This results in a bottom line of **2930 MMboe**, Shell share, approximately the same as would result from continuing the moratorium for one more year (1.1.2003 volumes less 2003 production giving an LE of 2921 MMboe). There is an overall shift of about 320 MMboe from oil to gas, but this is all proved undeveloped.

[Indicate the equivalent numbers if we follow's Daljit's suggestion ref leaving the option projects out of the base plan]

With the upside projects included (otherwise some NFA production is lost from flares-out in 2008), proved developed oil volumes decrease only slightly by 8 MMbbl, Shell share. This reflects the relatively low drilling activity during 2003, which does not quite replace production. Movements between fields may have some impact on depreciation calculations, but these should be small.

A **proved reserves audit** is planned for early August 2003. This will provide the acid-test for SPDC's numbers.

7. Current Reserves Position - SNEPCO

SNEPCO's reserves were subjected to an external reserves auditor review last year (Houston, Sept. 2002). All evaluation techniques and resulting data for external disclosure strictly conform to the SEC Guidelines.

- Proven volumes for the SEC are booked only for those projects where FID has been awarded (OML118, OPL209 and OPL219). For each of the fields, Shell entitlement (i.e. not working interest) is given.
- Of the current proven volumes, none are foreseen to be produced beyond the licence period. The only volumes projected beyond the licence period are SFR. However, licence will become an issue in the future:
    - As producing assets are developed and produced, maturing further proved volumes towards the technical expectation;
    - For OPL219 where a conversion to an OML is being pursued, and first production is now possibly delayed.
- Apart from a fraction of the associated gas from Bonga where firm gathering plans are in place, all gas (and NGLs from the gas) are currently booked as SFR-un-commercial. No PSC terms are in place for the gas. There is likely to be more gas to come from Bonga, but as yet no firm plans are published for when and how much. This needs to be taken into account in SPDC's future gas bookings to ensure no double counting of the NLNG volumes. The gas volumes currently booked for Bonga are best left on the books rather than de-booked and then re-booked later; provided PSC terms are being negotiated before start-up.

SNEPCO as at 1.1.2003, Shell entitlement

	Oil million m^3	Gas milliard sm^3	
Bonga	48.27	2.553	(9.28, 100%)
Erha (operated by ExxonMobil)	21.35	-	Gas reinjected
Abo (operated by Agip)	4.21	-	Gas reinjected
Total	73.83	2.553	

Plans are in place to book a further 3.47 million m^3 for the ExxonMobil operated Bosi Field (oil only) for 1.1.2004. As with Abo and Ehra, all gas will be re-injected and no reserves are carried.

8. Recommendations [for issues within SPDC control, i.e. most, we should present these as action plans rather than recommendations]

For SPDC:

- Seek EXCOM acceptance of the level of exposures we will carry until volumes are fully matured.
- Prepare maturation plans for all exposed projects by the end of June 2003. These will include realistic timing and resource requirements to allow them to be ranked. A small "hit squad" working with each of the Asset Teams will tackle the top-ranked volumes, and there will be an education and awareness campaign at all levels to get things right up-front for new volumes.
- Establish a formal resource maturation process in line with the current T&OE efforts to address the wider issues of compliance with the Group Guidelines for internal reporting. The "what" and "how" is fairly well established, but we are lacking common tools and data systems, and need to more clearly define roles and responsibilities.
- Broaden our LE tracking (quarterly) to address a wider range of resource categories and resource volume maturity (only expectation volumes at the moment, and then without any measure of maturity).

- Further investigate the position with regard to booked expectation reserves not covered by any projects, and the implications of reclassification of volumes as SFR.

SNEPCO is in good compliance with the Group and SEC guidelines. The only exposure being the small volume of Bonga gas reserves. The only recommendation here is:

- Ensure that negotiation of PSC terms for the gas take place during this year or early next.

---

[1] SPDC Onshore Oil Reserves, EPG Note for Information, January 2000

[2] Petroleum Resource Volume Guidelines, Resource Classification and Value Realisation, EP 2002-1100, SIEP EPB-P, April 2002

- ~~We're likely to have oodles of reserves now - let's debook whatever is not according to guidelines and keep only what we can support.~~
- Accept that we shouldn't book any decreases (provisionally) this year
- BP ~~is~~ consistency paramount – extrapolations beyond that must be consistent with it, eg – same investment level, forecasts
- Capital allocation should in principle cover all of the portfolio.

Table 1 - SPDC Oil & Condensate, million m^3, Shell share

	Within current licence period	Post-licence	Total
Booked at 2003[1]			
Onshore (30% Shell share)	360.18	-	360.18
Shallow Offshore (30%)	1.56	-	1.56
Shallow Offshore (77.14%)	42.95	-	42.95
Total booked at 1.1.2003	**404.69**	-	**404.69**
Expected production during 2003[2]			
Onshore (30% Shell share)	15.15	-	15.15
Shallow Offshore (30%)	0.17	-	0.17
Shallow Offshore (77.14%)	2.13	-	2.13
Total expected production during 2003	17.45	-	17.45
Reference position at 1.1.2004			
Onshore (30% Shell share)	345.03	-	345.03
Shallow Offshore (30%)	1.39	-	1.39
Shallow Offshore (77.14%)	40.82	-	40.82
Total reference position at 1.1.2004	**387.24**	-	**387.24**
Base Plan 2003			
Developed	104.42	25.34	129.76
Fully mature	57.57	14.89	72.46
Exposures			
No external challenge	19.46	9.02	28.48
Technically immature	55.45	26.10	81.55
Total exposures	74.91	35.12	110.03
Total Base Plan 2003	**236.90**	**75.35**	**312.25**
Change w.r.t. reference position	-150.34	+75.35	-74.99
Upsides [3]			
Otumara			9.35
Akri-Oguta			11.38
Remaining Ubie			4.34
Land Area – West			6.63
Nun River			8.94
Total upsides			40.64

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1) *Minor revisions to production data compared with 17th January 2003 submission.*
2) *Based on 2002 Business Plan forecast.*
3) *Includes 7.77 mln m^3 restored to proved developed by providing AGG facilities for NFA production.*

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NOTE – 18 Nov, 1999

CONFIDENTIAL

From:	Anton Barendregt	Group Reserves Auditor, SEPIV
To:	Linda Cook	Director, SEPIV
	Steve Ollereamshaw	Managing Director, PDO / GISCO
Copy:	Abdulla Lamki	Deputy Managing Director, PDO
	Kees Ruitenbeek	Director Corporate Affairs, PDO
	Vince Holtham	Planning and Economics Manager, PDO
	Said al-Abri	Reserves Reporting Coordinator, PDO
	Niel O'Neill	Discipline Head, Reservoir Engineering, PDO
	(circulation)	EPS-FX: Gardy, Renard
	(circulation)	EPB-P: Platenkamp, van Dorp, Aalbers
	Charles Watson	Business Advisor, SIEP (EPM)
	Egbert Eeftink	Director, KPMG Accountants NV
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SEC PROVED RESERVES AUDIT - PETROLEUM DEVELOPMENT (OMAN) and GISCO

23-27 October 1999

I have audited the proved reserves statements of PDO / GISCO for the year 1998 and the processes that were followed in their preparation. These statements present the externally reported Proved and Proved Developed Reserves as at 31 December 1998 together with a summary of the changes in Proved Reserves during 1998.

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, EP 98-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The audit took the form of detailed discussions about the reserves reporting process with PDO / GISCO staff and brief technical reviews with PDO staff of some of the major oil and gas fields. Total booked reserves (Proved, Group share) were 134 10^6 m3, of which 100 10^6 m3 was reported as developed.

The audit found that PDO / GISCO follow well prescribed procedures in their annual reserves reporting process and that there were no deficiencies in these procedures or their application. Particular commendation was made of the well organised system of end-year reserves reporting, which ensures a sound technical basis and a rigorous consistency and auditability between reserves reported to SEPIV and those documented in the annual ARPR.

The most significant comment concerns the generally conservative nature of individual fields' proved and proved developed reserves estimates. However, any scope for increase in externally reported reserves is offset by the fact that the expiration of the production licence in 2012 (within which reported volumes have to be demonstrably producible) has not been properly accounted for. The net result is that reported Proved Developed entitlements are likely to be some 15% overstated, whilst the Total Proved entitlement reserves are probably of the right magnitude. As the 2012 date draws nearer, the cut-off effect will become more pronounced and it should therefore receive proper attention in future submissions.

The audit finding is that the PDO / GISCO statements fairly represent the Group entitlements to Proved Reserves at the end of 1998. The 1998 changes in the Proved Reserves during 1998 can be fully reconciled from the documents at hand. The overall opinion from the audit regarding the state of PDO / GISCO's 1998 Proved Reserves submission, taking account of the thorough technical work underlying the estimates, as reflected in Attachment 4, is therefore <u>good</u>.

A summary of the findings and observations is included in the Attachments.

A.A. Barendregt

Attachments 1, 2, 3

OmnCovnt.doc

18/11/99

DEPOSITION EXHIBIT
Barendregt
#25 2/22/07

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Attachment 1

SEC PROVED RESERVES AUDIT - PDO / GISCO, 23-27 Oct 1999

MAIN OBSERVATIONS

1. The audit covered the combined reserves submission by PDO and GISCO (Gas Investment and Services Co). The reserves submitted by PDO related exclusively to the oil fields in the PDO-held concession, in which the net Group interest is 85% of the private shareholders' share of 40%, or a net 34%. No Group entitlement exists to any gas or condensate reserves although PDO can apply any associated gas that it produces for its own use. The private shareholders (PSH) have no title to any gas or liquids from NAG gas reservoirs within the PDO licence, but there is an agreed (in principle, but not exercised) purchase right by the PSH under the new GISCO / Oman LNG contract. This allows NGL and NAG reserves to be assessed and booked by the PSH. Calculation is complex and is essentially determined by translating forecast PSH profits into gas/NGL volumes through agreed NGL/gas price formulae. Separate sheets (within the same submission) have been supplied for oil (PDO equity) and NGL/gas (GISCO Purchase Right) volumes. This is accepted because the three streams are mutually exclusive in the submissions and do not give rise to confusion.
2. The Omani Government are keen to see an expansion of the country's reserves base and have awarded PDO a reserves addition bonus for every barrel of additional reserves in existing fields agreed with the Government. Extensive study work is undertaken by PDO to justify reserves additions through further infill drilling (most of it through horizontal wells) and through a continuing effort of new technology solutions and cost reduction, in an attempt to keep infill drilling costs at their current low level of $2-3/bl. A well established process of reserves approval is in place, involving proper documentation of the basis for the reserves addition, followed by meetings with Ministry staff. Main focus of these efforts are the 30-year field reserves, but proved estimates are now also updated and recorded in the documentation. The latter was one of the recommendations of the previous reserves audit in 1995.
3. The audit found that PDO follow well prescribed procedures in their annual reserves reporting process and that there were no deficiencies in these procedures or their application. Particular commendation can be made of the well organised system of end-year reserves reporting, which ensures rigorous consistency and full auditability between reserves reported to SEPIV and those documented in the annual ARPR. The latter document contains exclusively 100% field figures and includes in-place and reserves estimates for the NAG gas fields. Whilst full audit trails are in place for all updates of any significance, it was noted that some minor updates, e.g. those adjusting too low proved estimates when the latter are being overtaken by production, are handled by brief notes for file, which are not always referenced in the text.
4. Many STOIIP probabilistic estimates tend to be based on static well data only. No account seems to be taken of available performance /material balance evidence. Total oil recovery estimates tend to be based on probabilistic combinations of RF ranges from simulation studies and static STOIIP estimates for each reservoir. No probabilistic addition of reservoirs within fields is made. The result is that many proved total recoveries are low in comparison with the field's maturity (see also Fig. 1).
5. Proved developed reserves for each field are calculated as the minimum of either expectation developed reserves or proved total reserves. Because of the conservative nature of the latter, that value tends to prevail. In line with Group guidelines, proved developed reserves should be made equal to expectation developed reserves for mature fields. Many fields have a ratio of Np/UR in excess of 40% (see Fig.1). The area can therefore be classed as mature.
6. The PDO production licence expires on 24th June 2012. There is at present no legal right to extension. Total proved reserves in the 1998 reserves submission have been postulated to be producible within that period. This was done through a forecast at current plateau level, cut off at the point where production exceeds total field proved reserves (in 2007). This forecast cannot be seen as realistic.
7. For the proved developed reserves no proper assessment has been made of the volumes actually producible within the licence period. It was noted that the expectation NFA (no further activity) forecast shows a licence producible volume (100% field) of only 255 10^6 m3, i.e. less than the 295 10^6 m3 currently carried for proved developed reserves.
8. It is noted that in the 1998 reserves submission for internal reporting a figure of 632 10^6 m3 (100%) is reported as the expectation volume producible within licence, together with a figure of 752 10^6 m3 for total fields' 30-year expectation reserves. The volume producible within licence cannot be correct as the forecast on which it is based contains a significant slice of volumes that are presently classified as SFR.
9. Gisco's NGL and gas entitlements have been properly derived from an extensive spreadsheet including anticipated sales, developments and operating costs and resulting cash flows and profits. NGL and gas entitlements are calculated from this through an agreed price formula.

10. Proper gas GHV measurements exist for the fields dedicated to the Omani government gas grid and the Gisco contract. The reserves-weighted average of all gas fields is calculated as 1064 Btu/scf (with individual fields varying between 956 and 1137 Btu/scf, see Fig.2). A different average may be appropriate, dependent on which fields can actually be considered as dedicated to the gas contract. Either way, the appropriate average seems to exceed the 1025 Btu/scf implied in the 1998 submission, see Att. 2.4.

Recommendations:

1. Investigate ways of adjusting the proved reserves estimates in mature fields where this can be justified by performance. Some suggestions are given in Attachment 3.
2. At a PDO corporate level, proper allowance should be made for the licence expiry in 2012 in the end-year submission of proved and proved developed reserves. This will probably need documentation in a separate note for file outside (or as an attachment to) the ARPR. Suggestions are also given in Attachment 3.
3. Ensure that the properly calculated average gas GHV is used in the conversion to normalised gas volumes (9500 kCal/m3) in the annual submission.
4. Ensure that minor reserves changes are also referenced in the ARPR text.

Attachment 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION

Oman, 23-27 Oct 99

Oil / NGL / Gas Reserves as at 31.12.98

Area / field	Exp'n HIIP 10^6 sm3/ 10^9 sm3	Proven HIIP 10^6 sm3/ 10^9 sm3	Cum. Prod 10^6 sm3/ 10^9 sm3	Proved Rem. Recov. Dev. 10^6 sm3/ 10^9 sm3	Proved Rem. Recov. Tot'l 10^6 sm3/ 10^9 sm3	RF Dev. %	RF Tot'l %	PSH share Dev. 10^6 sm3/ 10^9 sm3	PSH share Tot'l 10^6 sm3/ 10^9 sm3	Within Licence & comtd Dev. 10^6 sm3/ 10^9 sm3	Within Licence & comtd Tot'l 10^6 sm3/ 10^9 sm3	Venture Shell share % %	Shell Equity Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Tot'l 10^6 sm3/ 10^9 sm3	1998 Subm'n Dev 10^6 sm3/ 10^9 sm3	1998 Subm'n Tot'l 10^6 sm3/ 10^9 sm3
Oil																
PDO Fields GISCO contract (NAG fields)	7870.79	5925.52	878.18	294.77	394.36	19.8%	21.5%			294.77	394.36	34.0%	100.22	134.08		
Total Oil	7870.79	5925.52	878.18	294.77	394.36	19.8%	21.5%			294.77	394.36	34.0%	100.22	134.08	100.22	134.09
NGL																
PDO Fields GISCO contract (NAG fields)	283.40	191.17	0.62	0.00	70.50	0.3%	37.2%	0.00	32.34	0.00	32.34	100.0%	0.00	32.34		
Total NGL	283.40	191.17	0.62	0.00	70.50	0.3%	37.2%	0.00	32.34	0.00	32.34	100.0%	0.00	32.34	0.00	32.34
Gas																
PDO Fields GISCO contract (NAG fields)	1176.751	877.583	45.398	0.000	525.224	5.2%	65.0%	0.000	59.321	0.000	59.321	100.0%	1.000	59.321		
Total Gas (Bscf / 10^9 sm3) (10^9 Nm3)	1176.751	877.583	45.398	0.000	525.224	5.2%	65.0%	0.000	59.321	0.000	59.321	100.0%	1.000	59.321	0.000	59.321

Audit Trail:

Total HIIPs from ARPR/RISRES

Cum.Prod. from ARPR/RISRES

Oil Prov.Dev Res from spreadsheet

All field proved oil reserves are postulated to be producible within licence by cutting off exp'n forecast at proved volumes

Gas/NGL Priv.ShareHolders (PSH) share from economic model

Shell share in GISCO venture is 85%; Group accounting rules require 100% to be reported (consolidated Co.)

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Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
Oman, 23-27 Oct 99

Oil Reserves Changes 1998 (100%, 10^6m3)

Field	Prov.Res. 1.1.98	Revisons/ Reclassns Guidelines	Revisons/ Reclassns Economic	Revisons/ Reclassns Other	Revisons/ Reclassns Total	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Product'n 1998	Prov.Res 31.12.98	Shell Equity Share % 1997	Shell Equity Share % 1998	Net Shell Equity 1.1.98 (10^6 m3)	Net Shell Equity 31.12.98 (10^6 m3)	Comments
Proved Total Reserves																	
PDO Fields	391.84				35.00	9.49	8.52				48.46	394.36	34.00%	34.00%	133.23	134.08	Field reviews as per ARPR; 9.5 10^6 m3 improved recovery from Fahud (Natih-E NW)
GISCO contract (NAG fields)																	
Tot'l Prov.Res (10^6 m3)	391.84	0.00	0.00	0.00	35.00	9.49	8.52	0.00	0.00		48.48	394.36	34.00%	34.00%	133.23	134.08	
Proved Developed Reserves																	
PDO Fields GISCO contract (NAG fields)	227.38				115.87					?	48.48	294.77	34.00%	34.00%	77.31	100.22	
Prov.Dev.Resvs 10^6 m3	227.38	0.00	0.00	0.00	115.87	0.00	0.00	0.00	0.00	0.00	48.48	294.77	34.00%	34.00%	77.31	100.22	
Net Group Equity																	
Prov.Dev. Res	77.31				39.40						16.48	100.22					
Prov Tot'l Res	133.23				11.90	3.23	2.22				16.48	134.08					
10^6 m3																	
1998 Submission																	
Prov.Dev.Res	77.31											100.22					
Prov.Tot'l Res	133.22				11.82	3.23	2.22				16.50	134.08					
10^6 m3																	

Audit Trail:

1.1.98 ProvRes 391.84 10^6 m3 =
1221.76 (1.1.98 oil PUR) - 876.18 (1.1.98 oil cumprod) + 46.26 (1998 oil prod)
1998 Revisions (35.00 10^6 m3) includes 0.22 10^6 m3 allowance
for 1998 condensate prod'n from Saih Rawl and Barik (no entitlement reserves)

1998 Production includes 0.22 10^6 m3 condensate
from Saih Rawl / Barik pre-Gisco contract start.

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Attachment 2.3

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
Oman, 23-27 Oct 99

NGL Reserves Changes 1998 (100%, 10^6 m3)

Field	Prov.Res. 1.1.98	Revisons/ Reclassns Guidelines	Revisons/ Reclassns Economic	Revisons/ Reclassns Other	Revisons/ Reclassns Total	Improved Recovery	Extens./ Discov's	Purchase In-place	Sales In-place	New Devel'd Reserves	Product'n 1998	Prov.Res 31.12.98	Shell Equity Share % 1997	Shell Equity Share % 1998	Net Shell Equity 1.1.98 (10^6 m3)	Net Shell Equity 31.12.98 (10^6 m3)	Comments
Proved Total Reserves																	
PDO Fields GISCO contract (NAG fields)	32.12				0.22					▨	0.00	32.34	100.00%	100.00%	32.12	32.34	Minor revision due to changes in Gisco devml cost profile
Tot'l Prov.Res 10^6 m3	32.12	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	▨	0.00	32.34	100.00%	100.00%	32.12	32.34	
Proved Developed Reserves																	
PDO Fields GISCO contract (NAG fields)	0.00										0.00	0.00	100.00%	100.00%	0.00	0.00	
Prov.Dev.Resvs 10^6 m3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00%	100.00%	0.00	0.00	

Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^6 m3	0.00 32.12				0.00 0.22						0.00 0.00	0.00 32.34
1998 Submission Prov.Dev.Res Prov.Tot'l Res 10^6 m3	0.00 32.12				0.22						0.00	0.00 32.34

Audit Trail: Full match

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Attachment 2.4

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
Oman, 23-27 Oct 99

Gas Reserves Changes 1998 (100%, 10^9 sm3)

Field	Prov.Res. 1.1.98	Revisions/ Reclassns Guidelines	Revisions/ Reclassns Economic	Revisions/ Reclassns Other	Revisions/ Reclassns Total	Improved Recovery	Extens/ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Product'n 1998	Prov.Res 31.12.98	Shell Equity Share % 1997	Shell Equity Share % 1998	Net Shell Equity 1.1.98 (10^9sm3)	Net Shell Equity 31.12.98 (10^9sm3)	Comments
Proved Total Reserves																	
PDO Fields GISCO contract (NAG fields)	11.434				47.887						0.000	59.321	100.00%	100.00%	11.434	59.321	Revision due to changes in GISCO contract assumptions (gas price)
Tot'l Prov.Res 10^9 sm3	11.434	0.000	0.000	0.000	47.887	0.000	0.000	0.000	0.000		0.000	59.321	100.00%	100.00%	11.434	59.321	
Proved Developed Reserves																	
PDO Fields GISCO contract (NAG fields)	0.000										0.000	0.000	100.00%	100.00%	0.000	0.000	
Prov.Dev.Resrvs 10^9 sm3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000	100.00%	100.00%	0.000	0.000	
Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^9 sm3	0.000 11.434				0.000 47.887						0.000 0.000	0.000 59.321					
1998 Submission Prov.Dev.Res Prov.Tot'l Res 10^9 sm3	0.000 11.434				47.887						0.000	0.000 59.321					
Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^9 Nm3 @ 8500 kCal/Nm3	0.000 10.977				0.000 45.971						0.000 0.000	0.000 56.948					
1998 Submission Prov.Dev.Res Prov.Tot'l Res 10^9 Nm3 @ 8500 kCal/Nm3	0.000 10.977				45.971						0.000	0.000 56.948					

GHV used: 1024.80 Btu/scf

Conversion factors used by PDO/GISCO:
1 sm3 = 0.948 Nm3 (if GHV=8500 kcal/Nm3 or 1012 Btu/scf))
1 sm3 = 0.960 Nm3 (for GHV=9620 kcal/Nm3 or 1024.8 Btu/scf))

Audit Trail:
- Full match for sm3 volumes.
- GHV implied in conversion to Nm3 volumes seems too low (1028 iso 1064 Btu/scf)

Attachment 3

SEC PROVED RESERVES AUDIT - PDO / GISCO, 23-27 Oct 1999

SOME SUGGESTED PROCEDURES FOR RESERVES BOOKING

Raising individual fields' proven volumes:

1. For mature fields (e.g. with cumulative productions of 40% of expectation UR or more), separate deterministic assessment of developed and undeveloped recoverables through simulation modelling often becomes more appropriate than conventional probabilistic estimates of ultimate recovery. This is in line with the need for a gradual shift from volumetric to performance based reserves estimates as the fields mature, see Group guidelines SIEP 98-1100, p.15.
2. For proved developed reserves, Group guidelines (p.14) state that these can be made equal to expectation developed reserves 'for mature fields', provided the relevant portion of the field can be considered 'proven' with regard to fluid contacts and fault delineations. In the Oman environment, where reservoirs tend to be generally 'proven', but more complex than in many other areas, a suitable criterion for 'maturity' could be Np > 0.4*expnUR.
3. For proved undeveloped recoverables, a multiple scenario modelling approach should ideally be followed. To some extent this is already being applied for many fields in PDO. It is suggested that STOIIP uncertainties (if still present and significant) could be included in these scenarios. In any event, an attempt should be made to calibrate low (and high) STOIIP estimates against field performance.
4. Consider the appropriateness of probabilistic addition of reservoirs within fields. For reservoirs that cannot be seen as fully independent, some partial probabilistic dependency could be adopted, if its quantification can be properly assessed and justified.

Taking account of production licence expiry

1. For proved developed reserves it is suggested to take the <u>corporate</u> expectation NFA forecast, proportionally downgraded to take account of the ratio between proved developed reserves (compounded from individual field estimates as suggested above) and expectation developed reserves. The proper way to do this downgrading is to transform the forecast vs. time into a rate vs. cumulative production forecast, shrink the horizontal axis in proportion to the proved vs. expectation reserves and re-expand into a time-based forecast. This should leave the production rate in the initial year of the forecast more or less unchanged. The downgraded forecast can then be cut off at the appropriate date (24th June 2012).
2. For proved total reserves a similar approach is suggested by taking the corporate expectation forecast for developed and undeveloped reserves (but excluding volumes that are presently classed as SFRI) and by following a similar downgrading as above to reflect the ratio between proved and expectation total reserves. The expectation forecast itself should of course be used for assessing the expectation volumes producible within licence (see submission for internal reporting).
3. It can be argued that simply taking the corporate forecast after deduction of the SFR slice is somewhat conservative. In reality, if no SFR would be maturing to reserves in the coming years, it would be likely that development of the present undeveloped reserves portfolio would be accelerated. Allowance could be made manually for this, but the only rigorous way would be to revert to the individual project forecasts and re-schedule those. Care should be taken that the SFR forecast itself should be similarly adjusted, to reflect the fact that acceleration of reserves within licence (under a ceiling-constrained production scenario) should cause a backout of SFR volumes beyond licence expiry.

Figure 1 - Proved/Expn reserves ratio vs Field Maturity

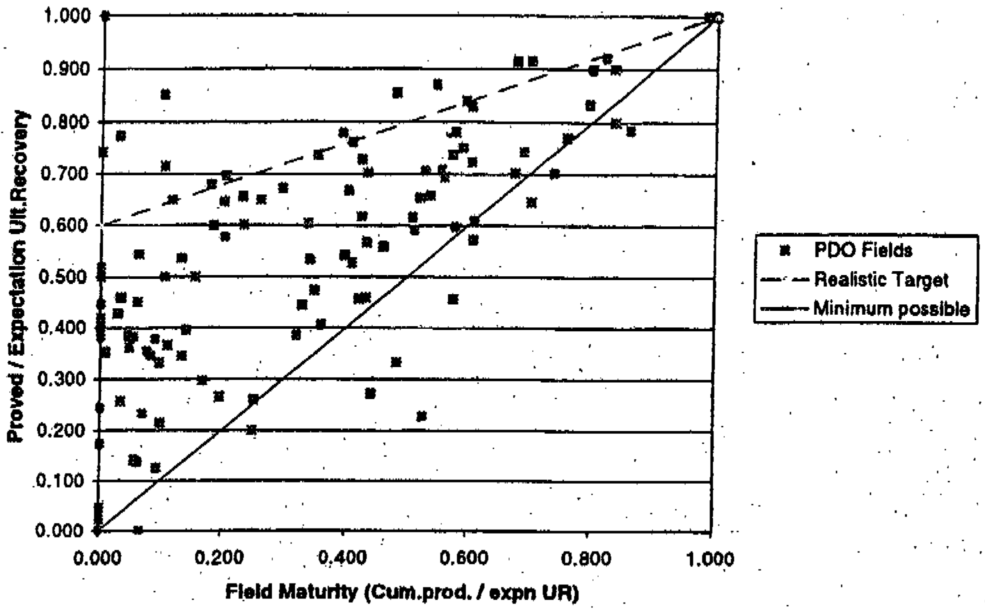

Figure 2 - PDO Expectation Gas Reserves, 1.1.99

Field	Expectation Reserves		HHV	HHV*Reserves		
	bcm	Tcf				
Barik-Bk	57.511	2.034923	1137	65390		
Saih Rawl-	228.195	8.074269	1102	251471		
Saih Nihay	37.571	1.329382	1083	40689		
Saih Rawl-	139.187	4.924881	1005	139883		
Saih Nihay	38.701	1.369365	1027	39746		
Saih Nihay	8.691	0.307515	1016	8830		
Central O	509.856	18.04034		546009	Average weighted heating val	1071 btu/scf
					Reserves equivalent	19320 10exp12 btu
Yibal Natl	75.846	2.683674	1061	80473		
SN-Shuaib	21.978	0.777652	998	21934		
Makarem	17.565	0.621506	956	16792		
Burhaan V	3.296	0.116623	1118	3685		
Burhaan V	8.336	0.294954	1050	8753		
Other	127.021	4.494409		131637	Average weighted heating val	1036 btu/scf
					Reserves equivalent	4658 10exp12 btu
Central +	636.877	22.53475		677646	Average weighted heating val	1064 btu/scf
					Reserves equivalent	23977 10exp12 btu
Total Oman		25.9				

OmnFig12.xls, Report-Fig1-2

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CHECKLIST SEC RESERVES AUDIT
Oman, 23-27 Oct 1999

Attachment 4

COMPANY: PDO and GISCO, Oman	**AREA / FIELD: Total area**

Dimensions:

	100% Field volumes	
1.1.99 Proved Oil Reserves	394	10^6 m3
1.1.99 Proved Developed Oil Reserves	295	10^6 m3
1998 Oil Production	48	10^6 m3
	132	10^3 m3/d
1.1.99 Proved Gas (NAG) Reserves	525	10^9 Sm3
1.1.99 Proved Developed Gas (NAG) Reserves	0	10^9 Sm3
1998 Gas (NAG) Production	0	10^9 Sm3
	0	10^6 Sm3/d
Number of fields in area	113	
Number of wells drilled / in production	2200 / 750	

Audit criteria		Result	Comments
1	TECHNICAL MATURITY		
1.01	Is 3D seismic available and used for the field(s) in question?	+	Coverage is virtually complete for the discovered fields.
1.02	Is pre-SDM available and used (when relevant)?	+	Pre-SDM is used in areas with high relief and/or salt domes. Other state-of-the-art techniques (amplitude mapping, buried geophones, cross-well seismic) are used as appropriate.
1.03	Is well log data quantity and quality adequate?	+	Full suites of logs and cores are taken in initial wells and development wells as appropriate.
1.04	Is well data coverage adequate?	+	Most fields require relatively dense well spacing patterns
1.05	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Fluid contacts tend to be well known in developed areas; unappraised areas are suitably discounted
1.06	Is reservoir producibility supported by production tests or other evidence?	+	Production tests are a standard part of data gathering in successful exploration / appraisal wells.
1.07	Is there a proper volumetric estimate?	+	All discovered fields have a proper volumetric estimate which is regularly updated as new data becomes available.
1.08	Is a static model available / adequate?	+	The larger fields / reservoirs, particularly those with more complex geology, have proper geological models.
1.09	Is a dynamic model available / adequate?	+	Proper simulation models (full field or often multiple sectors) are used for the larger reservoirs.
1.10	Is a history match available / adequate?	+	History matches are updated regularly, often annually.
1.11	Is the recovery factor for proved reserves realistic?	+	Proved reserves RF (as fraction of proved STOIIP) is equal to expn RF (some 21%). SFR volumes up to an RF of 29% are recognised and a continuous effort is made to improve recoveries through reduced well costs and new technology.
1.12	Are developed reserves based on existing wells, completions and facilities, or do they require only minor costs (<10% project cost) to be hooked up?	+	Expectation developed reserves are based on proper NFA (no further activity) forecasts and/or full well performance reviews. No specific forecast is made for proved reserves, which are derived somewaht conservatively from expectation developed reserves (see also 3.07).
1.13	Has/have (a) development project(s) been defined for undeveloped reserves or can it/they be defined?	+	All expectation reserves updates are discussed with the Omani Government who require them to be supported by proper reservoir modelling and forecasts.
1.14	Is/are the project(s) technically mature or is further data gathering necessary?	+	Projects generally consist of infill drilling of wells (many of them now horizontal). Water and/or gas injection projects are also well established.
1.15	Is/are there (an) auditable development project plan(s) with costs, benefits and economics?	+	New projects and/or wells are subjected to proper evaluation and screening.
1.16	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	+	Water- and gas injection are well established recovery methods in the PDO environment.
2	COMMERCIAL MATURITY		
2.01	Is/are the project(s) commercially mature (positive NPV for Group Ref. Crit. over a range of possible future scenarios / low case reserves)?	+	Yes; Most drilling activities in the next few years have UTCs of $2-3/bl. All new field developments are required to fulfill the appropriate screening criteria.
2.02	Is/are the project(s) economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	+	See above.
2.03	Has/have the project(s) been approved by Shareholders?	+	Development activities are approved on an annual basis by shareholders.
2.04	Have the latest Group Screening / Reference Criteria been used?	+	Yes.
2.05	Are assumed prices and costs RT (or justified if not)?	+	Yes
2.06	Is project financing available or can it reasonably be expected to be available?	+	Yes, although some projects may from time to time be deferred.
2.07	Are developed reserves actually in production?	+	Yes
2.08	Have all gas proved reserves been contracted to sales?	+	Yes (see also 4.05)
2.09	If not, can they reasonably be expected to be sold in existing markets and through existing facilities?	N.A.	

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

CHECKLIST SEC RESERVES AUDIT
Oman, 23-27 Oct 1999

Attachment 4

2.10	If neither, can they reasonably be expected to be developed and sold in a future market?	N.A.	
3	**REASONABLE CERTAINTY**		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	O	Many STOIIP probabilistic estimates tend to be based on static well data only. No account is taken of performance /material balance evidence.
3.02	Is the uncertainty range of total recovery adequate?	O	Total oil recovery estimates tend to be based on probabilistic combinations of RF ranges from simulation studies and static STOIIP estimates. The result is that many proved total recoveries are low in comparison with the field's maturity (see also Fig. 1).
3.03	Is the uncertainty range of developed recovery adequate?	O	Proved developed reserves for each field are calculated as the minimum of either expectation developed reserves or proved total reserves. Because of the conservative nature of the latter, that value tends to prevail. In line with Group guidelines, proved developed reserves should be made equal to expectation developed reserves for mature fields (see also 3.07). However, the impact of this apparent conservatism is nullified by the constraint that reserves must be producible within licence (see 4.01).
3.04	Have market / production constraint uncertainties been taken into account?	+	In line with Government directives, PDO oil offtake is constrained to 6.5% of expectation reserves per annum. The resulting ceiling of some 825 kb/d has been incorporated in all relevant production forecasts.
3.05	What is ratio of field(s) cum.prod. / proved total recovery?		Many fields (together some 85% of Ultimate Recovery) have a ratio of Np/UR in excess of 40% (see Fig.1). The area can therefore be classed as mature.
3.06	Can the field(s) be considered mature?		Yes, see above.
3.07	Are proved (developed and total) reserves benchmarked against expectation reserves for 'proved areas' when field(s) are mature (deterministic approach)?	O	No, a more conservative approach is taken (see 3.03, but also 4.01).
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?	O	No; This should be considered.
3.10	Is any assumed dependency in probabilistic addition appropriate?	N.A.	
4	**GROUP SHARE CALCULATION**		
4.01	Are proved and proved developed reserves producible within the licence period (or its extension if there is a legal right)?	X	The PDO production licence expires on 24th June 2012. There is at present no legal right to extension. Total proved reserves are postulated to be producible within that period through a forecast at current plateau level, cut off at the point where production exceeds total field proved reserves (in 2007). This forecast cannot be seen as realistic. No assessment is made of the proved developed reserves producible within the licence period. The expectation NFA forecast shows a licence producible volume of 255 10^6 m3, i.e. less than the 295 10^6 m3 currently carried for proved developed reserves. In the 1998 submission for internal reporting, 632 10^6 m3 (100%) is given as the expectation volume producible within licence, together with 752 10^6 m3 for total fields' 30-year expectation reserves. The first of these figures cannot be correct as the forecast on which it is based contains a significant slice of volumes that are presently classified as SFR.
4.02	Are proved and proved developed reserves producible within production ceilings / constraints etc.?	+	All relevant forecasts do take account of the 825 kb/d production ceiling (see 3.04).
4.03	Is the hydrocarbons Equity share calculated properly?	+	Yes. For oil, the Shell equity is 85% of the Private shareholders' 40% share of the venture. Net Group share for oil is thus 34%. For gas and NGL, see 4.04 below.
4.04	Is the hydrocarbons PSC entitlement share (net cost oil + profit oil only) calculated properly?	N.A.	

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

CHECKLIST SEC RESERVES AUDIT
Oman, 23-27 Oct 1999

Attachment 4

4.05	Is the hydrocarbons Purchase Right share (to the extent that economic benefit is derived from production while still bearing share of risks and rewards) calculated property?	+	Although the private shareholders (PSH) have no title to any gas or liquids from NAG gas reservoirs within the PDO licence, there is an agreed (in principle, but not exercised) purchase right by PSH under the new GISCO / Oman LNG contract. This allows NGL and NAG reserves to be booked by the PSH. Calculation is complex and is essentially determined by translating forecast PSH profits by agreed NGL/gas price formulae.
4.06	Are royalties in cash (legally or customarily) counted as reserves?	+	Royalties are paid in cash and are not deducted from reserves bookings.
4.07	Are royalties in kind excluded from reserves?	N.A.	
4.08	Are volumes received as fees in kind (e.g. for infrastructure use by third parties) excluded?	N.A.	A small third party stream (from Oxy) is handled and paid for in cash. Associated volumes are excluded reserves and production.
4.09	Has Group under-or overlift been accounted for?	N.A.	Partner liftings are administered downstream, i.e after fiscalisation of production
4.10	Have separate submissions been made for Equity , Entitlement and Purchase Right volumes?	O	Separate sheets (within the same submission) have been supplied for oil (equity) and NGL/gas (Purchase Right) volumes. This is accepted because the three streams are mutually exclusive in the submissions and do not give rise to confusion.
5	**AUDIT TRAILS**		
5.01	Are proved and proved developed reserves estimates up-to date?	+	A reserves addition bonus of $0.15/bl is awarded by the Omani Government. This is a strong incentive for PDO to keep reserves estimates up to date and to agree new values when justified, particularly where previous estimates have tended to be conservative.
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	+	Annual reserves submissions are prepared at the same time as PDO's annual ARPR document. Both are fully consistent (see Att. 2.1).
5.03	Can reported net Group equity reserves be reconciled with other relevant data (e.g. production constraints, gas markets, etc.)?	+	For oil: forecasts, where used, are appropriate (see 3.04, 4.02). For NGL/gas: reserves are based on current best estimates of gas markets demand.
5.04	Can reserve changes be reconciled with individual field changes and are they reported in the appropriate categories?	+	Yes, full reconciliation is possible, see Atts 2.2-2.4.
5.05	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	+	All reserves updates need discussion and agreement with the Omani Government. A detailed report (now also adressing proved reserves) is a standard requirement in this process. Trivial updates, e.g. upgrading too low proved estimates when these are being overtaken by production, are handled by a brief note for file.
5.06	Are reports numbered / indexed property and is there a central library where copies are kept?.	+	All reports are indexed property and master copies are kept in a central location.
5.07	Is the annual reserves submission supported by a sufficiently detailed summary note explaining the reserves changes (classified in revisons, extensions, sales-in-place etc) per field, with references to detailed reports as appropriate?	+	A concise summary ARPR document is issued annually, together with a detailed supplement giving individual field details.
5.08	Are data bases containing historic submissions' data and current reserves status (e.g. RISRES) in place and accessible?	+	A RISRES data base is kept up to date and frozen copies of previous ARPRs' data are archived.
5.09	Do these data bases also contain references to detailed reports?	+	Yes, references are included in RISRES as well as the ARPR document.
6	**CONSISTENCY WITH FINANCIAL REPORTING**		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes; Oil volumes are property fiscalised. NGL/gas volumes are based on currently anticipated net sales.
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes; NGLs from the Gisco contract are in fact spiked into the main PDO crude stream, but in view of their special status vav Group entitlement their separate booking is fully justified. A minor exception existed in the advance test production from two gas wells destined for the Gisco contract. PDO was allowed to keep the condensate during the 1-2 year test period (ended in June 1999 with the commencement of deliveries under the Gisco contract). Appropriate allowance has been made for this under the oil reserves, see Att 2.2.
6.03	Are own use, fuel, losses etc excluded?	+	Yes, see 6.01.

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Attachment 4

CHECKLIST SEC RESERVES AUDIT
Oman, 23-27 Oct 1999

6.04	Are gas GHVs properly measured for sales gas conditions and accounted for in reserves submissions?	O	Proper HHV measurements exist for the fields dedicated to the Oman government gas grid and the Gisco contract. Their reserves-weighted average is calculated as 1064 Btu/scf (with individual fields varying between 956 and 1137 Btu/scf). This does not seem to match with the 1025 Btu/scf implied in the 1998 submission, see Att. 2.4.
6.05	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	N.A.	Asset depreciation is done through a fixed percentage profile over 5 years, both for tax purposes and (by exception) for Group Accounts. Hence, no account is taken of proved developed reserves.
6.06	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream production volumes reported into the Finance (Ceres) system, i.e. Ceres line 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.
6.07	Are annual gas production (sales) volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0323 = 0934 (GroupCy net NG sales) + 3598 (Assoc.Cy NG sales), corrected for 1404+4796 (Gas purchases) and 4100+4510+4575+0873 (Trade, other Sales and Transfers)?	N.A.	Gisco's NGL and gas entitlements have been derived from profits via an agreed price formula. Hence, once contract deliveries have started (June 1999), produced and delivered volumes will not necessarily match those deemed to be 'sold' by Gisco (and deducted from future entitlements).
7	OVERALL		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Proved developed oil reserves for individual fields (30 yrs) are too conservative, but the SEC reported value is probably some 15% too high because no proper account has been taken of volumes realistically producible within licence. Total proved oil reserves are similarly conservative on an individual field basis. However, little account has been taken of the volumes actually producible within licence and the correct value may well be comparable to the value presently reported. NGL and gas reserves have been properly accounted for.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	+	On the basis of the above, PDO/Gisco's statement of proved and proved developed reserves can be considered to give a fair reflection of shareholder value. However, proper account must be taken of volumes producible within licence in future submissions, since this becomes more important as the 2012 date moves nearer.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

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DRAFT NOTE – 3 Nov 2003 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPF - GRA
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	John Bell	Corporate Support Director, SIEP – EPS
	John Malcolm	MD, PDO
	Andy Wood	General Manager, Shell Representative Office, Oman
Copy:	Abdulla Lamki	Deputy Managing Director, PDO
	Stuart Clayton	Head, Economics, Technology & Planning, PDO
	Stuart Evans	
	Fatima Kharusi	Finance Director, PDO
	Guy Jansens	Controller, PDO
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	Han van Delden	Partner, KPMG Accountants NV
	Brian Puffer	PriceWaterhouseCoopers

SEC PROVED RESERVES AUDIT - PDO (OMAN), 25-28 Oct 2003

I have audited the Proved Reserves submissions of Petroleum Development Oman (PDO) for the year 2002 and the processes that were followed in their preparation. These submissions present the PDO contribution to the Group's externally reported Proved and Proved Developed Reserves and their associated changes as at 31 December 2002.

Total Group share Proved Reserves booked by PDO at the end of 2002 were 144 mln m3 of oil. This represents some 5% of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratio for PDO over 2002 was –19%.

The last previous SEC proved reserves audit for PDO was carried out in 1999. This current audit verified the PDO procedures against those laid down in the "Petroleum Resource Volume Guidelines, SIEP 2002-1100/1101" (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 the reserves reporting process with PDO staff. Emphasis was placed on the procedures and methods followed and less on detailed individual field estimates.

The audit found that PDO's Group share proved developed reserves are largely reasonable, but that the proved total reserves are currently overstated by some 40%. The reason for this was partly the progressive tightening of Group reserves guidelines (following SEC guidance), but more fundamentally that proved reserves had not been reviewed and reduced in the light of recent downturns in oil production rates. The technical maturity of the projects associated with proved undeveloped reserves had also been eroded through lack of medium- to long-term field development planning work. PDO have recognised this and have embarked on an aggressive study programme to address the maturation of these projects. A foreseen extension to the current production licence agreement with the Government during 2004 may provide some relief from the necessary de-booking of the overstated volumes.

The audit recommendation is that the present erroneous volumes be continued unchanged per 1.1.2004 (reduced by 2004 production), but that a properly based portfolio of proved reserves should be submitted by 1.1.2005. The overall opinion on the state of PDO's 1.1.2003 Proved Reserves submission, taking account of the audit's findings (see Attachment 3), is unsatisfactory. Improvements have been set in motion.

A summary of the findings and observations is included in the Attachments.

DEPOSITION EXHIBIT
Barendregt
#26 2/22/07

Attachment 1

SEC PROVED RESERVES AUDIT - PDO and GISCO 25-28 Oct 2003

MAIN OBSERVATIONS

1. PDO are the operator in a land-based concession in the Oman Interior. Shareholders in PDO are the Oman Government (60%) and the 'private shareholders' (Shell, BP and Partex). Shell holds 85% of the private shareholders' share of 40% and has thus title to 34% of the PDO produced crude. PDO are free to use produced gas for own use and for re-injection where needed, but the Oman Government has exclusive title to the exported gas. Hence, no gas reserves are carried by PDO. The current production licence started in 1967 and ends on 24th June 2012.

   A separate agreement has been concluded between Shell, Total and Partex with the Oman Government regarding processing and further export of the associated and non-associated gas produced from PDO fields. This gas plant has been funded jointly between the co-venturers and the Oman Government and in recognition of this funding each of the co-venturers receives an annual fee, which is translated back into entitlement volumes for gas and NGL. This operation, administered by **GISCO**, is not addressed in this audit report.

   PDO projects are in principle approved by the PDO board. The Group Capital Allocation system has little influence on these decisions. The verbal statement was made that many of the latest projects might not have passed the stringent Group criteria. Previous UTC levels were at some $4/bl, but these have risen in recent years and the current outlook is that these may rise further to levels up to $10/bl.

2. **PDO production levels** have climbed gradually from 200 Mb/d in the early 1970's to a plateau of 850 Mb/d in the late 1990's. A relatively steep decline has set in since 2000 and current production is at some 700 Mb/d. The fundamental reason for the decline is the progressing maturity of the many producing fields, as evidenced by increasing water cuts and, to a lesser extent, increasing GORs. The first signs of field decline had been countered by an aggressive drilling campaign, including many horizontal wells, which has helped to maintain the earlier plateau production level. Decline, or at least production at lower levels, has now been accepted by PDO (and the shareholders) as inevitable, although further development options are still pursued vigorously.

   At the request of the Oman Government, PDO have committed a team from SIEP-EPT to carry out a comprehensive review of the STOIIPs and reserves of the PDO operated fields (the **STOIIP and Reserves Review Team**, or RSST). This review was in the final stages of completion during the audit. Preliminary conclusions by the RSST were that PDO's STOIIP estimates could largely be confirmed and that current reserves estimates were generally in line with field performance, with the exception of Yibal, Marmul and Qam Alam. Expectation reserves in these fields were concluded to be overstated by some 100 MMstb out of a total expectation reserves base of some 730 MMstb as at 1.1.2003. The RSST also noted that the great majority of the projects associated with the undeveloped reserves were not properly defined (i.e. passed VAR3) and that some were notional to very notional.

   The auditor is indebted to the RSST for sharing their preliminary conclusions with him. The review was found to be highly opportune and it provided a firm basis for the audit's findings.

3. **The characteristics of the PDO fields** tend to be complex in nature. The predominant reservoirs in the northern part of the concession are the Natih and Shuaiba carbonates, which are generally tight and which show varying degrees of fracturing. The predominant reservoirs in the South are the Haima and Al Khlata sandstones. The latter is of glacial origin and has been deposited onto the heavily scoured and eroded Haima sands. It tends to be highly heterogeneous, showing poor to excellent permeabilities.

   The oil in these reservoirs varies from medium-light to heavy quality, with generally low GORs. Coupled with generally poor aquifer activity, this means that reservoir energy tends to be low and that pressure maintenance methods of recovery have to be applied. Water injection is used most widely, but gas injection under gas-oil gravity drainage has been implemented successfully in the steeply dipping Fahud field. Steam and polymer injection have been tried with varying success in the Marmul field in the South. A steam injection pilot has been in progress for several years in the heavily fractured Qam Alam field and a field wide application is now planned. Injection of gas alternated by water (WAG) is seen as a possible further recovery mechanism. Horizontal wells have been used quite successfully and these have led to significantly improved field rates and, in many cases, improved recoveries.

   However, the heterogeneous nature of both the carbonates and the sandstones make good sweep efficiencies a challenging target. The current average recovery factor is some 23% and major fields like Fahud and Natih have recovery factors in this range. The best recoveries are in the 40-50% range (Yibal, Rima, Saih Nihalda). The aspiration by the Oman Government and by PDO is to raise the target recoveries to the latter level for all fields. This will require extraction of the oil from the less permeable portions of the reservoirs, which is counteracted by the many bypass routes (higher permeable 'thief zones' or fractures) that surround these tighter portions.

Many of the PDO fields started production before or during the 1970's and **production declines** are apparent in a number of them. As mentioned, these declines have been countered by an aggressive drilling campaign, and this has helped maintain the PDO plateau production through the 1990's. The many infill wells did not always yield the additional reserves that were aspired. A striking example is seen in the Yibal field, where a massive horizontal infill well campaign did raise production, but now shows a decline towards an ultimate recovery that is not much different from that seen before, see Fig.1. A possible mild arrest of the decline may be evident from recent measurements. The lesson seems to be that many fields will yield additional recoverable volumes, but that they need sufficient time. The prevailing reservoir heterogeneities make gas-oil gravity drainage or induced/spontaneous water imbibition the only realistice option for further recovery. The associated time frames can hardly be accelerated.

4. The RSST have identified that lack of **reservoir understanding** is the single most important bottleneck to production increases and further oil development maturation. Good reservoir understanding requires a reliable and representative 3D reservoir model (first static, then dynamic) and the experience in many other operations in the Group is that the availability of **good 3D seismic** is key to such modelling. Spectacular results have been seen in a number of places making e.g. reservoir character or oil fill clearly visible. Many PDO teams claim that, due to the complex overburden (a number of strong reflective events) and due to the poor acoustic contrast at reservoir level, little use can be made of the available seismic in reservoir characterisation and 3D mapping. This opinion seems to be contradicted by experience in the Rima field, where it has been shown that dedicated re-processing (Cheats and van Gogh filtering) and close cooperation with Exploration Processing can yield much improved results. This should be pursued further to see whether similar results can be obtained in other fields.

5. There is **mis-alignment between individual field proved reserves and the corporate PDO submission.** The root cause for this has been that PDO have historically focused mainly on expectation reserves because these are the subject of intensive discussions with the Oman Government (and also the basis for reserves addition bonuses). Proved reserves estimates for individual fields were prepared but these have hardly been updated and they have now shrunk to unrealistic levels (see 6 below). Because of this, PDO have maintained corporate Group share proved total reserves as an independent entity, not linked to individual field volumes. This approach has not only caused problems with the audit trail but, more seriously, it allowed the Group proved reserves estimate to drift away from realistic levels, see 8 below.

6. **Probabilistic estimates** of STOIIP and ultimate recoveries have been prepared by PDO prior to and in early stages of field development. Recovery factor ranges were obtained from preliminary reservoir modelling. The probabilistic parameter ranges tend still to be based on early well data only, i.e. no adjustment has been made for subsequent dynamic STOIIP and recovery determination from production performance. Hence, the current **proved vs expectation recovery ranges** are too wide for the current stage of field development. The 1999 reserves audit made the same observation. It is therefore disappointing to see that no progress has been made in this respect.

   The conservative nature of the current field proved (P85) recoveries has been further exposed by progressing cumulative production from the fields. With proved and expectation ultimate recoveries fixed, the range between proved and expectation remaining reserves will widen with progressing production. This is clearly visible in Figure 2. Cumulative production has already overtaken proved ultimate recovery in some fields, with the result that these fields now carry negative proved remaining reserves, which is of course impossible. Examples are Rima, Sayyala, Wafra and Runib.

   Group reserves guidelines state clearly that field / reservoir reserves estimates should be made separately for developed (no further activity, or NFA) and undeveloped reserves. The latter must be project based, i.e. they must be associated with clearly identified future development activities (wells, facilities). Estimation of total recoveries based on (largely assumed) recovery factors is archaic and is considered indefensible with the current state of petroleum engineering technology.

   Proved developed reserves should be derived in a deterministic manner, using reservoir model simulations and production trend extrapolations. Proved undeveloped reserves should be evaluated in the same manner, using a low case model realisation. This practice should result in proved undeveloped reserves growing towards expectation levels with progressing field maturity, see Fig. 2.

7. Expectation **developed reserves** are generally, and correctly, derived from well and cluster decline analysis (through Oil Field Manager software) or from reservoir simulation models. The origin of the Group share proved developed estimate was not clear (poor audit trail, see below), but its volume seems broadly in line with the expectation NFA forecast, cut off at the end-of-licence in 2014. This is in accordance with Group guidelines. However, the link between Group share / corporate proved reserves and individual field estimates should be re-established.

8. There is a serious flaw in the corporate **total proved reserves** estimate (and, by implication, in the undeveloped reserves estimate) in that this estimate was not reviewed when the PDO oil production started to decline rapidly from 2000 onwards. Group share reserves should be producible within the current licence period (ending in 2014) and the achievement of production of the stated volumes in that time period has rapidly

become unlikely.

The majority of **undeveloped field reserves** are associated with identified projects. However, many of these are notional or highly notional, while others do not even have a forecast associated with them in the Business Plan. There are of course more mature projects, but many of these are recognised as needing further work or re-work in order to become matured towards the required VAR3 (or FID) level. Even some projects/volumes based on FDPs from the late 1990's, which did pass VAR3 earlier, are now seen as out of date because of subsequent well and field performance. The estimate made by PDO and the SRRT is that 80-90% of the presently identified undeveloped reserves are yet to pass through the VAR3 stage. This means that these volumes do not fulfil present Group and SEC guidelines. It is accepted that the latter have tightened over the last three years (from 'defined' projects to VAR3) and thus further increased the exposure.

The main reason for this regrettable situation is that proper modern static and dynamic modelling has received insufficient attention in PDO in recent years. Much attention was diverted towards short-term activities to provide new well proposals. The situation is now being addressed through an urgent and aggressive study programme.

The Group share total (i.e. undeveloped) reserves booked at 1.1.2003 have thus been seriously overstated. A preliminary estimate by PDO is that of the 907 MMstb (Group share) booked at 1.1.2003, some 400 MMstb are exposed as insufficiently mature according to present Group guidelines.

The impact of this overstatement of reserves is somewhat reduced by the fact that discussions between PDO and the Oman Government towards an extension of the current production licence are currently in progress and that a Heads of Agreement is expected before the end of 2003. A formal extension agreement could then be signed during the first half of 2004. This should bring some 300 MMstb (230 MMstb developed, 70 MMstb undeveloped) into the Group reserves portfolio.

9. It has been noted during the audit that PDO carry a number of projects with **positive expectation reserves but zero proved reserves.** These volumes relate to projects and exploration discoveries, whose development plan is not yet sufficiently mature to merit the booking of proved reserves. The expectation volumes have been agreed with the Oman Government and reserves addition- and exploration bonuses have been received for them. The Group guidelines state clearly that expectation reserves can only be booked if the associated projects fulfil the conditions for proved reserves. If the latter is not the case, the expectation volumes should be booked as SFR. This should be addressed in the forthcoming submission.

10. The **consistency between reserves and Finance** was good. There was full agreement between the 1.1.2003 submissions for reserves and for annual production through Ceres/FIRST, without any corrections being required.

The verification of the correctness of proved developed and proved total reserves used for UOP asset depletion calculations was not relevant in the case of PDO, because UOP asset depletion has not been applied in the past. The operating agreement stipulates a 40-30-10-10-10% depreciation profile for all capex and this is applied for calculation of the PDO profit margin and for PDO tax returns. Shell Group accounts returns are prepared by Shell Oman Trading (SOMANT) and they do not declare any share in the PDO assets.

PDO accounts are managed with depreciation through the abovementioned 5-year profile. This is not in accordance with International accounting practices, which require **UOP depletion**, based on proved total and proved developed reserves. This has led to qualifications in external auditor reports, which the Oman Government now want to see removed. Hence, PDO will need to start maintaining proper estimates of individual field proved developed and proved total (i.e. undeveloped) reserves. In view of the current state of PDO's proved reserves estimates (both corporate and by field), PDO have considered it not realistic to start with the new method of UOP accounting per 1.1.2004. A start per 1.1.2005 was seen to be the earliest possible as it would be desirable to avoid major swings in individual field reserves and asset values due to the necessary corrections to be applied during 2004. This view is fully supported.

Following the implementation of the new method of asset accounting, PDO will be required to re-state their accounts back to 2000. The intention was to do this on the basis of the 1.1.2005 volumes, correcting back only for annual production. The auditor recommendation is to include annual transfers from undeveloped to developed volumes (i.e. development activity) as well, since without this correction the earlier proved developed reserves would become too large.

11. By way of **audit trail**, PDO issue an annual ARPR report, which lists full life cycle (i.e. 30-years) recoverable volumes of oil+condensate (from PDO facilities) and associated gas. The format of the report seems somewhat cumbersome (duplicated data and unnecessary data, e.g. depletion rates, high estimates) and it could benefit from a simplification.

There is no note or report describing the basis or background for the Group share reserves submission. There is a spreadsheet, but this is not very accessible. Individual field proved reserves in the 1.1.2003 submission are clearly wrong (e.g. larger than expectation volumes and also larger than full-field-life proved reserves). The submission listed changes in the 'Improved Recovery', 'Extensions and Discoveries', and 'Transfers form Undeveloped to Developed' categories, but there was no audit trail to link this back in a quantitative manner to individual fields. The audit trail for PDO's shell share proved reserves is thus extremely poor. Guidelines for a proper audit trail are published on the EPB-P website ('Planning'/'Reserves', to be moved to a new EPS website in due course) and these should be followed. What is needed is a set of tables as presented in Att.2, with a brief note describing the source of the constituent data.

It was noted that there seems to be no effective central PDO library and field teams tend to keep project reports in personal filing cabinets. The RSST reported instances where documents had to be obtained from the Ministry because no copies could be found within PDO, following the temporary abandonment and re-assignment of the Fahud field team. This clearly an undesirable situation and corrective measures should be undertaken.

12. The auditor's suggestion for **the way forward** is as follows:

- In view of the short period left to end-2003, continue booking the present proved developed and proved total Group share reserves volumes in the 1.1.2004 submission, correcting only for 2003 production and for transfers from developed to undeveloped. Total proved reserves replacement ratio should thus be ~100%.
- Conclude the production licence extension agreement with the Oman Government during 2004
- Book the proper sum of full life cycle proved developed reserves for all fields and proved undeveloped reserves for all projects fulfilling Group reserves criteria per 1.1.2005. This would require the maturation of at least some 200 MMstb of proved project volumes, to obtain a 100% proved reserves replacement ratio over 2004, see Table 1 below. Group share reserves should be a straight 34% of PDO oil reserves.
- It is suggested to invite the Group Reserves Auditor for a consultation visit towards the end of 2004 to verify with him the status of the of the proved developed and proved undeveloped reserves portfolio.

Group share total proved reserves 1.1.2003 (MMstb)	907
2003 Production	-87
Group share total proved reserves 1.1.2004 (MMstb)	820
Group share total proved reserves 1.1.2004 (MMstb)	820
Overstatement 400 MMstb	-400
Transfer from beyond-licence	+287
New matured proved reserves	+200
2004 Production	-87
Group share total proved reserves 1.1.2005 (MMstb)	820

Table 1 – Progression of PDO Group share proved reserves during 2003 / 2004

Recommendations

1. Pursue the possible improvements in reservoir characterization and modelling that may be obtained from dedicated seismic re-processing (cf Rima).
2. Declare proved developed as equal to expectation developed reserves in fields where there is either a good simulation history match or where there is a well-defined decline rate extrapolation. New fields and reservoirs with neither of these should be assigned a conservative (low case) value for proved developed reserves.
3. Prepare proved and expectation estimates of undeveloped reserves by individual project and by field. Proved estimates should preferably be based on low case simulation model realisations and should be seen to be growing towards expectation levels with progressing field cumulative production. Projects should be ranked according to their maturity, e.g. 'firm' (VAR3/FID), 'mature' (documented FDP), 'possible' (VAR2) etc.
4. Invite the Group Reserves Auditor for a consultation visit towards the end of 2004 to verify the status of Group share proved developed and proved undeveloped reserves.
5. In the re-statement of PDO accounts for years back to 2000, correct the 1.1.2005 volumes back to earlier years by adding annual production and by subtracting annual transfers from undeveloped to developed reserves.
6. Classify projects with expectation reserves but zero proved reserves as SFR in the 1.1.2004 submission.
7. Improve the audit trail for the Group reserves submission by following the guidelines for on the EPB/Planning/Reserves website.
8. Consider the installation of a central library where properly indexed copies of reports and meeting notes (e.g. with the Ministry) can be stored and kept.

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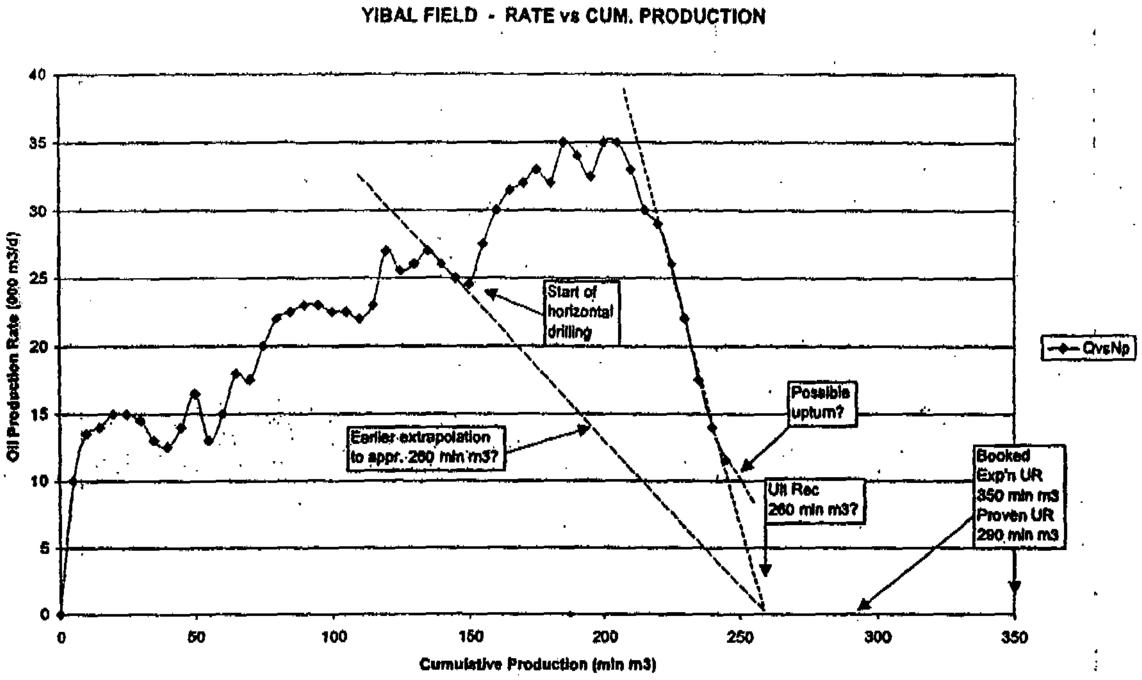

Figure 1 - Yibal field oil rate decline versus cumulative production

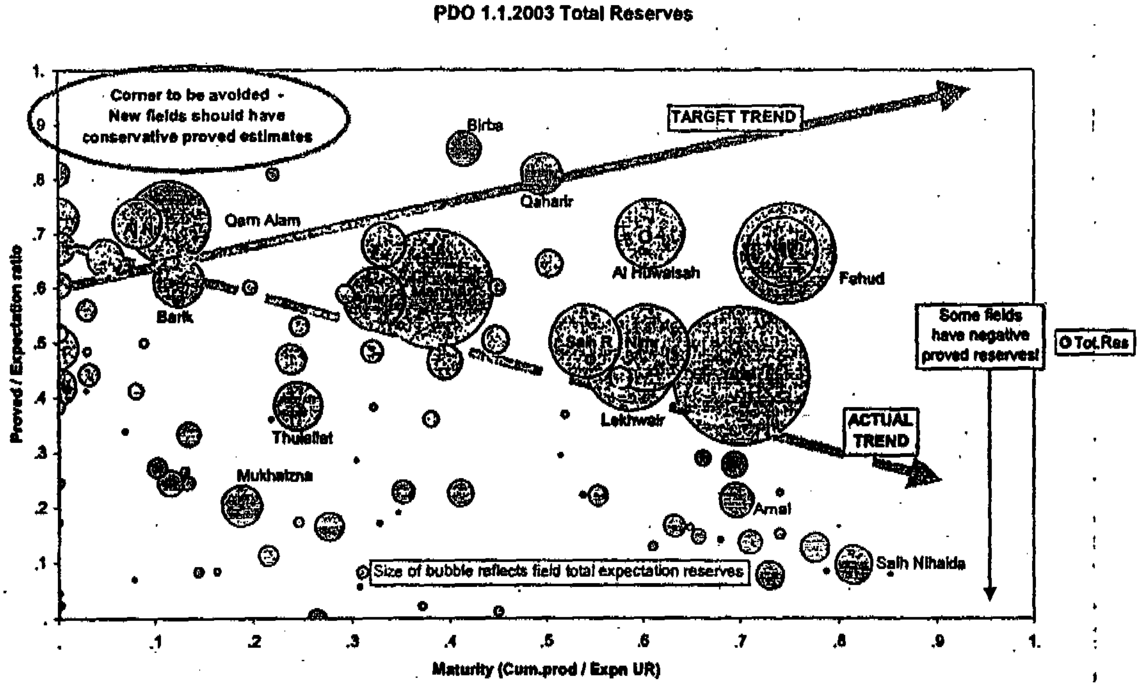

Figure 2 - Ratio of Proved / Expectation Reserves versus progressing field maturity

Attachment 2

PDO — **Proved Oil / NGL / Gas Reserves as at 1.1.2003**

Area / field	Proven HIIP MMstb / Bscf	Exp'n HIIP MMstb / Bscf	Cum. Prod + Sales 1.1.2003 MMstb / Bscf	Proved Rem. Recov. Dev'd mln m3	Proved Rem. Recov. Undev mln m3	Exp'n Rem. Recov. Tot'l mln m3	Maturity (Cum.pr / Exp'n UR) %	Dev. / Tot'l Proved UR %	Prov / Expn Rsvs %	Proved RF Tot'l %	Exp'n RF Tot'l %	Frac'n w/l lic. contd Pr.Dev. %	Frac'n w/l lic. contd Pr.Undv %	Within Licence contd Pr.Dev. mln m3	Within Licence contd Pr.Tot'l mln m3	Venture Shell share % %	Shell Equity Pr.Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Pr.Tot'l 10^6 sm3/ 10^9 sm3	1.1.2003 Subm'n Pr.Dev 10^6 sm3/ 10^9 sm3	1.1.2003 Subm'n Pr.Tot'l 10^6 sm3/ 10^9 sm3	Prov. Res / Prod Dev. yrs	Prov. Res / Prod Tot yrs
Oil																						
YIBAL	557.79	696.12	246.22	10.76	35.39	105.07	70%	69%	44%	61%	50%	400.65%	44.71%	43.12	98.94	34.00%	14.66	20.04			2	9
FAHUD	845.49	1016.77	165.40	36.59	0.79	56.44	75%	100%	66%	24%	22%	49.68%	659.52%	18.18	25.00	34.00%	6.18	8.50			10	11
MARMUL	463.11	666.37	49.21	10.91	35.97	78.46	39%	63%	60%	21%	23%	191.08%	79.16%	20.85	49.32	34.00%	7.09	16.77			6	22
LEKHWAIR	230.75	311.51	67.58	18.26	5.84	47.63	69%	84%	46%	39%	37%	133.17%	174.22%	21.85	31.47	34.00%	7.35	10.70			3	4
NATIH	414.24	458.39	77.98	16.11	1.78	26.87	74%	98%	67%	23%	23%	83.81%	125.24%	13.50	15.74	34.00%	4.59	5.35			9	10
HMR	368.61	426.13	62.93	7.66	12.56	41.08	61%	85%	49%	23%	24%	180.38%	108.34%	13.62	27.35	34.00%	4.63	9.30			2	4
RIMA	161.46	177.17	74.36	-1.39	0.03	6.64	92%	100%	-20%	46%	46%	286.66%	6382.72%	3.94	6.66	34.00%	1.34	1.82			-1	-1
AL HUWAISAH	187.70	249.02	42.26	6.52	12.61	27.73	61%	80%	70%	33%	28%	79.85%	108.19%	5.21	18.74	34.00%	1.77	6.37			4	11
SAIH RAWL	142.32	174.66	36.01	8.71	0.15	29.67	64%	84%	50%	36%	37%	143.74%	128.12%	9.66	20.09	34.00%	3.28	6.83			3	6
QARN ALAM	185.30	185.80	6.07	0.76	27.30	38.91	12%	10%	72%	20%	24%	94.15%	94.68%	0.71	26.63	34.00%	0.24	9.02			0	318
Other Fields	2508.29	3630.60	240.76	38.02	85.67	276.44	47%	76%	45%	15%	14%	89.97%	129.57%	34.21	146.21	34.00%	11.63	49.37			2	7
Total Oil (mln m3)	6058.04	7899.82	1068.17	149.80	225.80	734.86	69%	84%	61%	24%	23%	124.07%	105.03%	184.62	424.03	34.00%	62.77	144.17	62.77	144.17	3	8
NGL																						
(No NGL reserves carried)							0	0	0	0	0			0.00	0.00		0.00	0.00				
Total NGL (MMstb)	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0	0.00	0.00	0	0.00	0.00	0.00	0.00		
Gas (Dry, sales gas volumes)																						
(No gas reserves carried)							0	0	0	0	0			0.000	0.000		0.000	0.000				
Total Gas (Bscf)	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0	0.000	0.000	0	0.000	0.000	0.000	0.000		

Conversion factors used by PDO:		Conversion factors used by SIEP:		Licence expiry date: 24 June 2012
1 m3 =	1 m3	1 stb =	0.159 m3	
1scf =	0.0283 sm3	1 scf =	0.0283 sm3	

Audit Trail: Proved developed and undeveloped field volumes (100%) derived from exp' devs Wunder'd volumes, multiplied by proved/exp's total reserves ratio.
Disconnect between field volumes in submission and actual field volumes (e.g. within-licence volume exceeds 100% field volume in some cases)
Negative proved field reserves in Rima

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PDO	Proved Oil Reserves Changes 2002 (100%, mln m3)														
Field	Prov.Res. 1.1.2002	Revisons/ Reclassns	Improved Recovery	Extens / Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves (Transf. Und. to	Product'n 2002	Prov.Res 1.1.2003	Shell Equity Share % 1.1.2002	Shell Equity Share % 2002 Prod	Shell Equity Share % 1.1.2003	Net Shell Equity, 1.1.2002 (10^6 m3)	Net Shell Equity 1.1.2003 (10^6 m3)	Comments
Proved Developed Reserves															
YIBAL	16.76	0.00						6.00	10.76	136.22%	34.%	136.22%	21.47	14.66	
FAHUD	40.15	0.00						3.56	36.59	16.89%	34.%	16.89%	6.78	6.18	
MARMUL	13.09	0.00						2.18	10.91	64.97%	34.%	64.97%	8.50	7.09	
LEKHWAIR	21.17	0.00						4.91	16.26	45.28%	34.%	45.28%	9.59	7.36	
NATIH	17.90	0.00						1.79	16.11	28.5%	34.%	28.5%	5.10	4.59	
NIMR	12.05	0.00						4.50	7.55	61.33%	34.%	61.33%	7.39	4.63	
RIMA	0.21	0.00						1.59	-1.38	-97.19%	34.%	-97.19%	-0.20	1.34	
AL HUWAISAH	8.31	0.00						1.79	6.52	27.15%	34.%	27.15%	2.26	1.77	
SAIH RAWL	9.03	0.00						2.32	6.71	48.87%	34.%	48.87%	4.42	3.28	
QARN ALAM	0.84	0.00						0.09	0.75	32.01%	34.%	32.01%	0.27	0.24	
Other Fields	55.04	0.00						17.02	38.02	30.59%	34.%	30.59%	16.84	11.63	
Prov.Dev.Resvs (mln m3)	193.56	0.00 0.00	0.00	0.00	0.00	0.00	0.00	44.76	148.80	42.57%	34.%	42.18%	82.41	62.77	
Proved Undeveloped Reserves															
YIBAL	35.39	0.00							35.39	18.2%		18.2%	6.39	6.39	
FAHUD	0.79	0.00							0.79	291.3%		291.3%	2.32	2.32	
MARMUL	35.97	0.00							35.97	25.91%		25.91%	9.32	9.32	
LEKHWAIR	5.64	0.00							5.64	59.24%		59.24%	3.34	3.34	
NATIH	1.78	0.00							1.78	42.58%		42.58%	0.76	0.76	
NIMR	12.56	0.00							12.56	37.16%		37.16%	4.67	4.67	
RIMA	0.03	0.00							0.03	1930.13%		1930.13%	0.58	0.58	
AL HUWAISAH	12.51	0.00							12.51	35.79%		35.79%	4.48	4.48	
SAIH RAWL	8.15	0.00							8.15	43.56%		43.56%	3.55	3.55	
QARN ALAM	27.30	0.00							27.30	32.16%		32.16%	8.78	8.78	
Other Fields	85.67	0.00							85.67	44.05%		44.05%	37.74	37.74	
Prov.Under.Res (mln m3)	225.80	0.00 0.00	0.00	0.00	0.00	0.00			225.80	36.05%		36.05%	81.40	81.40	
Net Group Equity															
Proved Developed Reserves	82.41	-4.42					0.00	15.22	62.77	62.77					
Proved Total Reserves 10^6 m3	163.81	-4.42	0.00	0.00	0.00	0.00		15.22	144.17	144.17		Audit Trail:			
1.1.2003 Submission												No 1.1.2002 field data available!			
Prov.Dev.Res	65.80	4.92					7.27	15.22	62.77	62.77		No audit trail for Transfers undev'd-to-dev'd,			
Prov.Tot'l Res 10^6 m3	162.30	-4.71	0.34	1.49				15.22	144.17	144.17		Extensions/Discoveries and Improved Recovery!			

Conversion factors used by PDO:			Conversion factors used by SIEP:		
1 m3 =	1	m3	1 stb =	0.159	m3
1scf =	0.0283	sm3	1 scf =	0.0283	sm3

VIJVER 2241

NOTE – 29 Nov 2003 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPF - GRA
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	John Bell	Corporate Support Director, SIEP – EPS
	John Malcolm	Managing Director, PDO
Copy:	Abdulla Lamki	Deputy Managing Director, PDO
	Stuart Clayton	Head, Economics, Technology & Planning, PDO
	Stuart Evans	Petroleum Engineering Value Assurance Manager, PDO
	Fatma Kharusi	Finance Director, PDO
	Guy Janssens	Controller, PDO
	Lynda Armstrong	Exploration Director, PDO
	Dave Kemshell	Corporate Function Discipline Head Reservoir Engineering, PDO
	Said Al Harty	Reserves Coordinator, PDO
	(circulation)	SIEP – EPS-P: Hans Bakker, John Pay
	Andrew Vaughan	Technical Director, SEPI – EPM
	Maarten Wetselaar	Finance Director, SEPI – EPM
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	Han van Delden	Partner, KPMG Accountants NV
	Brian Puffer	PriceWaterhouseCoopers

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Barendregt
#27 2/22/07

SEC PROVED RESERVES AUDIT - PDO (OMAN), 25-28 Oct 2003

I have audited the Proved Reserves submissions of Petroleum Development Oman (PDO) for the year 2002 and the processes that were followed in their preparation. These submissions present the PDO contribution to the Group's externally reported Proved and Proved Developed Reserves and their associated changes as at 31 December 2002.

Total Group share Proved Reserves booked by PDO at the end of 2002 were 144 mln m3 of oil. This represents some 5% of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratio for PDO over 2002 was –19%.

The last previous SEC proved reserves audit for PDO was carried out in 1999. This current audit verified the PDO procedures against those laid down in the "Petroleum Resource Volume Guidelines, SIEP 2002-1100/1101" (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 the reserves reporting process with PDO staff. Emphasis was placed on the procedures and methods followed and less on detailed individual field estimates.

The audit found that PDO's Group share proved developed reserves are largely reasonable, but that some 40% of the submitted proved total reserves at 1.1.2003 do not fulfil present reserves guidelines. The reason for this is partly the progressive tightening of Group reserves guidelines (following SEC guidance), but more fundamentally that submitted proved reserves have not been reviewed and reduced in the light of recent downturns in oil production rates. The technical maturity of the projects associated with proved undeveloped reserves had also been eroded due to lack of medium- and long-term field development planning work. PDO have recognised this and have embarked on an aggressive study programme to address the maturation of the associated projects. An imminent agreement with the Government regarding an extension to the current production licence may provide further (partial) relief from the necessity to de-book the overstated volumes.

In view of the many positive changes foreseen during 2004, the audit suggestion is that the present volumes be continued unchanged per 1.1.2004 (reduced by 2003 production), but that a properly based portfolio of proved reserves should be submitted by 1.1.2005. The overall opinion on the state of PDO's 1.1.2003 Proved Reserves submission, taking account of the audit's findings (see Attachment 3), is <u>unsatisfactory</u>. However, improvements have been set in motion.

A summary of the findings and observations is included in the Attachments.

A.A. Barendregt

Attachments 1, 2, 3

Attachment 1

SEC PROVED RESERVES AUDIT - PDO and GISCO 25-28 Oct 2003

MAIN OBSERVATIONS

1. **PDO** are the operator in a land-based concession in the Oman interior. Shareholders in PDO are the Oman Government (60%) and the 'private shareholders' (Shell, TFE and Partex). Shell holds 85% of the private shareholders' share of 40% and has thus title to 34% of the PDO produced crude. PDO are free to use produced gas for own use and for re-injection where needed, but the Oman Government has exclusive title to the exported gas. Hence, no gas reserves are carried by PDO. The current production licence started in 1967 and ends on 24th June 2012.

   A separate agreement has been concluded between Shell, Total and Partex with the Oman Government regarding processing and further export of the associated and non-associated gas produced from PDO fields. This gas plant has been funded jointly between the co-venturers and the Oman Government and in recognition of this funding each of the co-venturers receives an annual fee, which is translated back into entitlement volumes for gas and NGL. This operation, administered by **GISCO**, is not addressed in this audit report.

   PDO projects are in principle approved by the PDO board. The Group Capital Allocation system has little influence on these decisions. The verbal statement was made that many of the latest projects might not have passed the stringent Group criteria. UTC levels (an important screening tool for the PDO board) have risen above $4/bl in recent years and the current outlook is that these may rise further, up to $10/bl for some projects.

2. **PDO production levels** had climbed gradually from 200 Mb/d in the early 1970's to a plateau of 850 Mb/d in the late 1990's. A relatively steep decline has set in since 2001 and current production is at some 700 Mb/d. The fundamental reason for the decline is the progressing maturity of the many producing fields, as evidenced by increasing water cuts and, to a lesser extent, increasing GORs. The first signs of field decline had been countered by an aggressive drilling campaign, including many horizontal wells, which has helped to maintain the earlier plateau production level. Decline, or at least production at lower levels, has now been accepted as inevitable by PDO (and the shareholders), although further development options are still pursued vigorously.

   Prior to and during Programme Build preparation in 2003, PDO staff recognised that some 900 MMstb (100% volumes) of expectation undeveloped reserves could not be supported by identifiable projects. These volumes were still based on assumed recovery factors, which should be seen as an outdated practice. After initial shareholder resistance, these 'unmatched' volumes have now been moved out of the 30-year Programme Build window. To address the resulting shortfall, Shell committed a team from SIEP-EPT and other sources to carry out a comprehensive review of the STOIIPs and reserves of the PDO operated fields (the **STOIIP and Reserves Review Team**, or SRRT). This review was in the final stages of completion during the audit. Preliminary conclusions by the SRRT were that PDO's STOIIP estimates could largely be confirmed and that the expectation project reserves estimates in the 2003 Programme Build could generally be supported. Some exceptions were still found in Marmul and Yibal, where expectation reserves in these fields were considered to be some 20 mln m3 too high. The SRRT also noted that the great majority of the projects associated with the undeveloped reserves were not properly defined (i.e. passed VAR3) and that some were notional to very notional.

   The auditor is indebted to the SRRT for sharing their preliminary conclusions with him. The review was found to be highly opportune and it provided a firm basis for the audit's findings.

3. **The characteristics of the PDO fields** tend to be complex in nature. The predominant reservoirs in the northern part of the concession are the Natih and Shuaiba carbonates, which are generally tight and which show varying degrees of fracturing. The predominant reservoirs in the South are the Haima and Al Khlata sandstones. The latter is of glacial origin and has been deposited onto the heavily scoured and eroded Haima sands. It tends to be highly heterogeneous, showing poor to excellent permeabilities.

   The oil in these reservoirs varies from medium-light to heavy quality, with generally low GORs. Coupled with generally poor aquifer activity, this means that reservoir energy tends to be low and that pressure maintenance methods of recovery have to be applied. Water injection is used most widely, but gas injection under gas-oil gravity drainage has been implemented successfully in the steeply dipping Fahud field. Steam and polymer injection have been tried with varying success in the Marmul field in the South. A steam injection pilot has been in progress for several years in the heavily fractured Qarn Alam field and a field wide application is now planned. Injection of gas alternated by water (WAG) is seen as a possible further recovery mechanism. Horizontal wells have been used quite successfully and these have led to significantly improved field rates and, in many cases, improved recoveries.

   The heterogeneous nature of both the carbonates and the sandstones make **good sweep efficiencies a challenging target**. The current average recovery factor is some 23% and major fields like Fahud and Natih have recovery factors in this range. The best recoveries are in the 40-50% range (Yibal, Rima, Saih Nihaida).

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The aspiration by the Oman Government and by PDO is to raise the target recoveries to the latter level for all fields. This will require extraction of the oil from the less permeable portions of the reservoirs, which is counteracted by the many bypass routes (higher permeable 'thief zones' or fractures) that surround these tighter portions.

Many of the PDO fields started production before or during the 1970's and production declines are apparent in a number of them. As mentioned, these declines have been countered by an aggressive drilling campaign, and this has helped maintain the PDO plateau production through the 1990's. The many infill wells did not always yield the additional reserves that were aspired. A striking example is seen in the Yibal field, where a massive horizontal infill well campaign did raise production, but where the subsequent much steeper decline seems to point towards an ultimate recovery that is not much different from that seen before, see Fig.1. A possible mild arrest of the decline may be evident from recent measurements. The lesson seems to be that many fields will yield additional recoverable volumes, but that they need sufficient time. The prevailing reservoir heterogeneities make gas-oil gravity drainage or induced/spontaneous water imbibition the only realistic option for further recovery. The associated time frames can hardly be accelerated.

4. The SRRT have identified that lack of **reservoir understanding** is the single most important bottleneck to production increases and further oil development maturation. Good reservoir understanding requires a reliable and representative 3D reservoir model (first static, then dynamic) and the experience in many other operations in the Group is that the availability of **good 3D seismic** is key to such modelling. Spectacular results have beer seen in a number of other Group operated areas making e.g. reservoir character or oil fill clearly visible. Many teams in the South Oman area to claim that, due to the complex overburden (a number of strong reflective events) and due to the poor acoustic contrast at reservoir level, little use can be made of existing seismic in reservoir characterisation and 3D mapping. This opinion seems to be contradicted by experience in the Rima field, where it has been shown that dedicated re-processing (Cheats and van Gogh filtering) and close cooperation with Exploration Processing can yield much improved results. Further pursuit of this, to see whether similar results can be obtained in other fields, is strongly encouraged and supported.

5. There is **mis-alignment between individual field proved reserves and the corporate PDO submission.** The root cause for this has been that PDO have historically focused mainly on expectation reserves because these are the basis for business planning. Expectation reserves are also the subject of intensive discussions with the Oman Government (and also the basis for reserves addition bonuses!). Proved reserves estimates for individual fields were prepared but these have hardly been updated and they have now shrunk to unrealistic levels (see 6 below). Because of this, PDO have maintained corporate Group share proved total reserves as an independent entity, not linked to individual field volumes. This approach has not only caused problems with the audit trail but, more seriously, it allowed the Group proved reserves estimate to drift away from realistic levels, see 8 below.

6. **Probabilistic estimates** of STOIIP and ultimate recoveries have been prepared by PDO prior to and in early stages of field development. Recovery factor ranges were obtained from preliminary reservoir modelling. Although new well results are incorporated, the probabilistic parameter <u>ranges</u> still seem to reflect early well data only, i.e. little adjustment seems to be made for subsequent dynamic STOIIP and recovery determination from production performance. Hence, the current **proved vs. expectation recovery ranges** in individual fields are too wide for the current stage of field development. The 1999 reserves audit made the same observation. It is therefore disappointing to see that no progress has been made in this respect.

   The conservative nature of the current field proved (P85) recoveries has been further exposed by progressing cumulative production from the fields. With proved and expectation ultimate recoveries fixed, the range between proved and expectation remaining reserves will widen with progressing production. This is clearly visible in Figure 2. Cumulative production has already overtaken proved ultimate recovery in some fields, with the result that these fields now carry negative proved remaining reserves, which is of course impossible. Examples are Rima, Sayyala, Wafra and Runib.

   Group reserves guidelines state clearly that field / reservoir reserves estimates should be made separately for developed (no further activity, or NFA) and undeveloped reserves. The latter must be project based, i.e. they must be associated with clearly identified future development activities (wells, facilities). Estimation of total recoveries based on (largely assumed) recovery factors is archaic and is considered indefensible with the current state of petroleum engineering technology.

   Proved developed reserves should be derived in a deterministic manner, using reservoir model simulations and production trend extrapolations. Proved undeveloped reserves should be evaluated through simulation, using either a low case model realisation or e.g. a specific assessment for infill wells whether they address 'proved areas'. This practice should result in proved undeveloped reserves growing towards expectation levels with progressing field maturity, see Fig. 2.

7. Expectation **developed reserves** are generally, and correctly, derived from well and cluster decline analysis (through Oil Field Manager software) or from reservoir simulation models. The Group share proved developed estimate was derived from the expectation NFA forecast, cut off at the end-of-licence in June 2012. This is in accordance with Group guidelines. However, the link between Group share / corporate proved reserves and individual field estimates should be re-established.

8. There is a serious flaw in the corporate **total proved reserves** estimate (and, by implication, in the undeveloped reserves estimate) in that this estimate was not reviewed when the PDO oil production started to decline rapidly from 2000 onwards. Group share reserves should be producible within the current licence period (ending in 2012) and the achievement of production of the stated volumes in that time period has rapidly become unlikely.

   The majority of the declared corporate **undeveloped field reserves** are associated with identified projects. However, many of these are notional or highly notional. There are of course more mature projects, but many of these are recognised as needing further work or re-work in order to become matured towards the required VAR3 (or FID) level. Even some projects/volumes based on FDPs from the late 1990's, which did pass VAR3 earlier, are now seen as out of date because of subsequent well and field performance. The estimate made by PDO and the SRRT is that 80-90% of the presently identified undeveloped reserves are yet to pass through the VAR3 stage. This means that these volumes do not fulfil present Group and SEC guidelines. It is accepted that the latter have tightened over the last three years (from 'defined' projects to VAR3) and thus further increased the exposure.

   The main reason for this regrettable situation is that proper modern static and dynamic modelling has received insufficient attention in PDO in recent years. Much attention was diverted towards short-term activities to provide new well proposals. The situation is now being addressed through an urgent and aggressive study programme.

   The Group share undeveloped reserves at 1.1.2003 (and hence the total proved reserves) contain therefore a large portion that does not fulfil current Group reserves guidelines. A preliminary estimate made by PDO during 2003 is that of the 907 MMstb (Group share) booked at 1.1.2003, some 400 MMstb are exposed in this manner.

   It is noted that the 907 MMstb submission at 1.1.2003 had been based on SIEP advice, reducing it from a higher value proposed by PDO. This advice was seen as a preliminary correction, pending results of further PDO investigations and the planned 2003 reserves audit. The approach was supported by the Group reserves auditor, but he did express concern in his end-2002 report that PDO's proved reserves were overstated.

   The impact of this effective overstatement of reserves is somewhat reduced by the fact that discussions between PDO and the Oman Government towards an extension of the current production licence are currently in progress and that a Heads of Agreement is expected before the end of 2003. A formal extension agreement could then be signed during the first half of 2004. This should bring some 300 MMstb of mature project reserves (230 MMstb developed, 70 MMstb undeveloped) into the Group reserves portfolio.

9. It was noted during the audit that PDO are proposing to carry a number of projects with **positive expectation reserves but zero proved reserves**. These volumes relate to projects and exploration discoveries, whose development plan is not yet sufficiently mature to merit the booking of proved reserves. The expectation volumes have been agreed with the Oman Government and reserves addition- and exploration bonuses will be received for them. The Group guidelines state clearly that expectation reserves can only be booked if the associated projects fulfil the conditions for proved reserves. If the latter is not the case, the expectation volumes should be booked as SFR.

10. The **consistency between reserves and Finance** was good. There was full agreement between the 1.1.2003 submissions for reserves and for annual production through Ceres/FIRST, without any corrections being required.

    The verification of the correctness of proved developed and proved total reserves used for UOP asset depletion calculations was not relevant in the case of PDO, because UOP asset depletion was not applied in the past. The operating agreement stipulates a 40-30-10-10-10% depreciation profile for all capex and this is applied for calculation of the PDO profit margin and for PDO tax returns. Shell Group accounts returns are prepared by Shell Oman Trading (SOMANT) and they do not declare any share in the PDO assets.

    PDO accounts are declared with asset depreciation through the abovementioned 5-year profile. This is not in accordance with international accounting practices, which require **UOP depletion**, based on proved total and proved developed reserves. This has led to continuing qualifications in external auditor reports (since 1967), which the Oman Government now want to see removed. Hence, PDO will need to start maintaining proper estimates of individual field proved developed and proved total (i.e. undeveloped) reserves. In view of the current state of PDO's proved reserves estimates (both corporate and by field), PDO have considered it not realistic to start with the new method of UOP accounting per 1.1.2004. A start per 1.1.2005 was seen to be the earliest possible as it would be desirable to avoid major swings in individual field reserves and asset values due to the necessary corrections to be applied during 2004. This view is fully supported.

    Following the implementation of the new method of asset accounting, PDO will be required to re-state their accounts back to 2000. The intention was to do this on the basis of the 1.1.2005 volumes, correcting back only for annual production. The auditor recommendation is to include annual transfers from undeveloped to developed volumes (i.e. development activity) as well, since without this correction the earlier proved developed reserves would become too large.

11. By way of **audit trail**, PDO issue an annual ARPR report, which lists full life cycle (i.e. 30-years) recoverable volumes of oil+condensate (from PDO facilities) and associated gas. The format of the report seems

somewhat cumbersome (duplicated data and unnecessary data, e.g. depletion rates, high estimates) and it could benefit from a simplification.

There is no note or report describing the basis or background for the Group share reserves submission. There is a spreadsheet, but this is not very accessible. Individual field proved reserves in the 1.1.2003 submission are clearly wrong (e.g. larger than expectation volumes and also larger than full-field-life proved reserves). The submission listed changes in the 'Improved Recovery, 'Extensions and Discoveries', and 'Transfers form Undeveloped to Developed' categories, but there was no audit trail to link this back in a quantitative manner to individual fields. The audit trail for PDO's Group share proved reserves is thus extremely poor. Guidelines for a proper audit trail are published on the EPB-P website ('Planning'/'Reserves', to be moved to a new EPS website in due course) and these should be followed. What is needed is a set of tables, at field level, with a format as presented in Att.2 and with a brief note describing the source of the constituent data.

It was noted that, whilst there is a central PDO library, field teams tend to keep project reports in personal filing cabinets. The SRRT reported instances where documents had to be obtained from the Ministry because no copies could be found within PDO, following the temporary abandonment and re-assignment of the Fahud field team. This is clearly an undesirable situation and corrective measures should be undertaken.

12. The auditor's suggestion for **the way forward** is as follows:

- In view of the short period left to end-2003, it will not be possible to arrive at a properly defined set of individual field proved reserves that could form a sound basis for the PDO corporate Group share proved reserves booking.

- Assuming that a Heads of Agreement can be obtained with the Oman Government before end 2003 regarding an extension of the PDO production licence, it is argued that the impact of the present reserves overstatement is reduced.

- 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 developed to undeveloped. Total proved reserves replacement ratio should thus be 0%.

- The proper sum of full life cycle proved developed reserves for all fields and proved undeveloped reserves for all projects fulfilling Group reserves criteria should then be booked per 1.1.2005. This would require the maturation of at least some 200 MMstb of proved project volumes, to obtain a 100% proved reserves replacement ratio over 2004, see Table 1 below. Group share reserves should be a straight 34% of PDO oil reserves.

- It is suggested to invite the Group Reserves Auditor for a consultation visit towards the end of 2004 to verify with him the status of the proved developed and proved undeveloped reserves portfolio.

Group share total proved reserves 1.1.2003 (MMstb)	907
2003 Production	-87
Group share total proved reserves 1.1.2004 (MMstb)	820
Group share total proved reserves 1.1.2004 (MMstb)	820
Overstatement 400 MMstb	-400
Transfer from beyond-licence	+287
New matured proved reserves	+200
2004 Production	-87
Group share total proved reserves 1.1.2005 (MMstb)	820

Table 1 – Possible progression of PDO proved reserves during 2003 / 2004

Recommendations

1. Continue pursuing the possible improvements in reservoir characterization and modelling that may be obtained from dedicated seismic re-processing (cf Rima).
2. Declare proved developed as equal to expectation developed reserves in fields where there is either a good simulation history match or where there is a well-defined decline rate extrapolation. New fields and reservoirs with neither of these should be assigned a conservative (low case) value for proved developed reserves.
3. Prepare proved and expectation estimates of undeveloped reserves by individual project and by field. Proved estimates should preferably be based on low case simulation model realisations and should be seen to be growing towards expectation levels with progressing field cumulative production. Projects should be ranked according to their maturity, e.g. 'firm' (VAR3/FID), 'mature' (documented FDP), 'possible' (VAR2) etc.
4. Invite the Group Reserves Auditor for a consultation visit towards the end of 2004 to verify the status of Group share proved developed and proved undeveloped reserves.

5. In the re-statement of PDO accounts for years back to 2000, correct the 1.1.2005 volumes back to earlier years by adding annual production and by subtracting annual transfers from undeveloped to developed reserves.
6. Classify projects with expectation reserves but zero proved reserves as SFR in the next appropriate submission.
7. Improve the audit trail for the Group reserves submission by following the guidelines for reserves audit trails on the EPB/Planning/Reserves website.
8. Ensure that the central library facilities are fully utilised by all teams, particularly where it relates to proper storing and indexing of copies of all reports and meeting notes (e.g. with the Ministry).

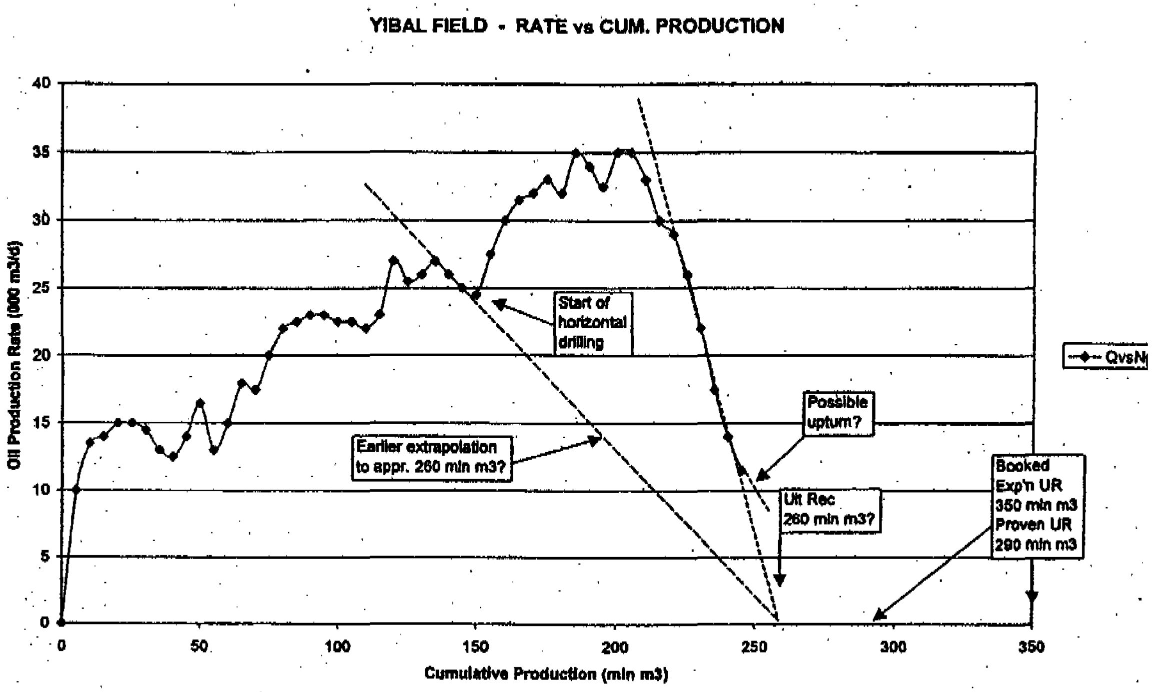

Figure 1 - Yibal field oil rate decline versus cumulative production

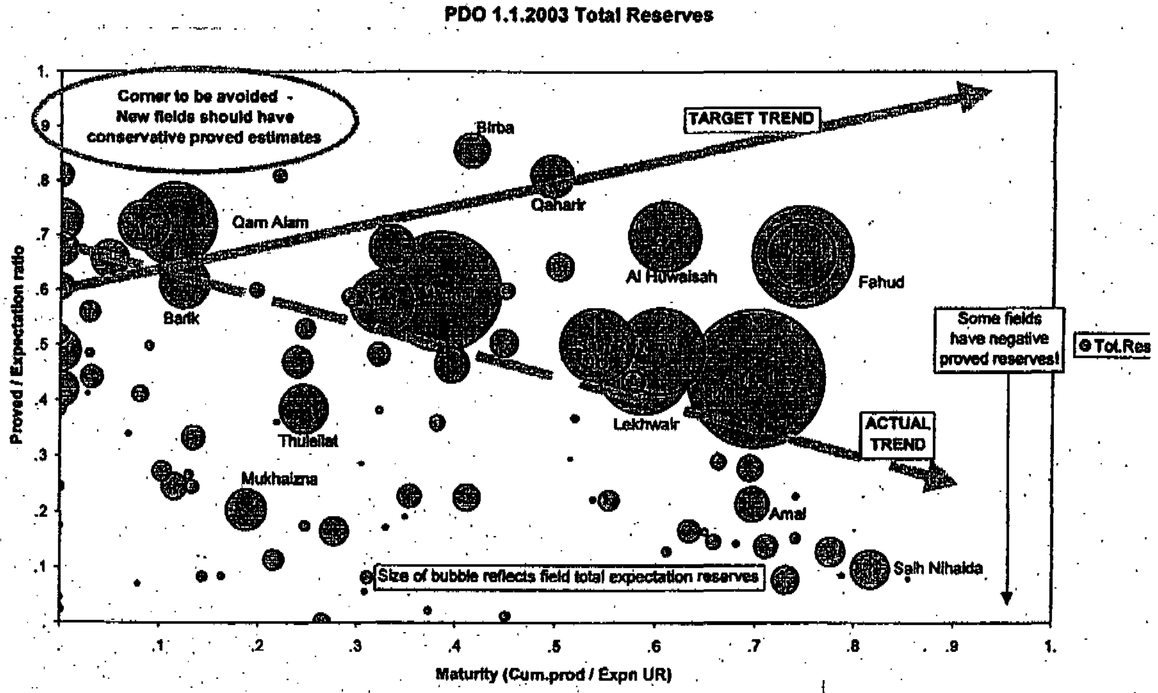

Figure 2 - Ratio of Proved / Expectation Reserves versus progressing field maturity

Attachment 2

PDO Proved Oil / NGL / Gas Reserves as at 1.1.2003

Area / field	Proven HIIP	Exp'n HIIP	Cum. Prod + Sales 1.1.2003	Proved Rem. Recov. Dev'd	Proved Rem. Recov. Undev	Exp'n Rem. Recov. Tot'l	Maturity (Cum.pr / Exp'n UR)	Dev. / Tot'l Proved UR	Prov / Expn Resvs	Proved RF Tot'l	Exp'n RF Tot'l	Fract'n wrt lic. commit Pr.Dev.	Fract'n wrt lic. commit Pr.Undv	Within Licence commit Pr.Dev.	Within Licence commit Pr.Tot'l	Venture Shell share %	Shell Equity Pr.Dev.	Shell Equity Pr.Tot'l	1.1.2003 Subm'n Pr.Dev	1.1.2003 Subm'n Pr.Tot'l		Prov. Res / Prod Dev.	P R P T
	MMstb / Bscf	MMstb / Bscf	MMstb / Bscf	mln m3	mln m3	mln m3	%	%	%	%	%	%	%	mln m3	mln m3	%	10^6 sm3/ 10^9 sm3	10^6 sm3/ 10^9 sm3	10^6 sm3/ 10^9 sm3	10^6 sm3/ 10^9 sm3		yrs	)
Oil																							
YIBAL	667.79	686.12	246.22	10.76	35.39	105.07	70%	68%	44%	51%	50%	400.65%	44.71%	43.12	69.94	34.00%	14.66	20.04				2	
FAHUD	645.49	1016.77	156.40	35.59	0.79	56.44	75%	100%	65%	24%	22%	49.69%	659.52%	16.10	26.00	34.00%	6.10	6.00				10	
MARMUL	463.11	588.37	48.21	10.91	35.97	78.48	39%	63%	60%	21%	23%	191.09%	79.16%	20.85	49.32	34.00%	7.08	16.77				5	
LEKHWAIR	230.75	311.61	67.99	16.26	5.64	47.53	69%	94%	45%	39%	37%	133.17%	174.22%	21.65	31.47	34.00%	7.36	10.70				3	
NATIH	414.24	458.39	77.99	16.11	1.79	26.67	74%	90%	67%	23%	23%	83.81%	125.24%	13.60	15.74	34.00%	4.69	5.35				9	
NIMR	369.81	426.13	67.93	7.55	12.96	41.06	81%	65%	49%	23%	24%	180.36%	105.34%	13.62	27.38	34.00%	4.63	9.30				2	
RIMA	161.46	177.17	74.36	-1.38	0.03	6.64	92%	100%	-30%	45%	45%	-285.65%	6392.72%	3.94	5.66	34.00%	1.34	1.92				-1	
AL HUWAISAH	187.70	249.02	42.25	6.52	12.51	27.23	61%	60%	70%	33%	28%	79.85%	103.19%	5.21	18.74	34.00%	1.77	6.37				4	
SAIH RAWL	142.32	174.65	38.01	6.71	8.16	29.87	54%	84%	60%	35%	37%	143.71%	128.17%	9.65	20.09	34.00%	3.28	6.83				3	
QARN ALAM	166.30	186.66	6.67	0.75	27.30	38.91	12%	16%	72%	20%	24%	94.15%	84.58%	0.71	26.53	34.00%	0.24	9.02				8	3
Other Fields	2509.29	3630.60	240.70	39.02	65.67	276.44	47%	75%	45%	15%	14%	89.97%	129.57%	34.21	145.21	34.00%	11.63	49.37				2	
Total Oil (mln m3)	6065.04	7699.67	1066.17	148.80	226.80	734.66	69%	84%	51%	24%	23%	124.07%	108.03%	184.52	424.03	34.00%	62.77	144.17	62.77	144.17		3	
NGL																							
(No NGL reserves carried)							0	0	0	0	0			0.00	0.00		0.00	0.00					
Total NGL (MMstb)	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0	0.00	0.00	0	0.00	0.00	0.00	0.00			
Gas (Dry, sales gas volumes)																							
(No gas reserves carried)							0	0	0	0	0			0.000	0.000		0.000	0.000					
Total Gas (Bscf)	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0	0.000	0.000	0	0.000	0.000	0.000	0.000			

Conversion factors used by PDO:
1 m3 = 1 m3
1 scf = 0.0283 sm3

Conversion factors used by SIEP:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Licence expiry date: 24 June 2012

Audit Trail:
Proved developed and undeveloped field volumes (100%) derived from exp' deve'd/undev'd volumes, multiplied by proved/exp'n total reserves ratio.
Disconnect between field volumes in submission and actual field volumes (e.g. within-licence volume exceeds 100% field volume in some cases)
Negative proved field reserves in Rima!

PDO Proved Oil Reserves Changes 2002 (100%, mln m3)

Field	Prov.Res. 1.1.2002	Revisions/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves (Transf. Und. to	Product'n 2002	Prov.Res 1.1.2003	Shell Equity Share % 1.1.2002	Shell Equity Share % 2002 Prod	Shell Equity Share % 1.1.2003	Net Shell Equity 1.1.2002 (10^6 m3)	Net Shell Equity 1.1.2003 (10^6 m3)	Comments
Proved Developed Reserves															
YIBAL	15.78	0.00						5.00	10.78	136.22%	34%	136.22%	21.47	14.66	
FAHUD	40.15	0.00						3.56	35.59	16.89%	34%	16.89%	6.78	6.10	
MARMUL	13.09	0.00						2.18	10.91	64.87%	34%	64.87%	8.50	7.08	
LEKHWAIR	21.17	0.00						4.91	16.26	45.26%	34%	45.26%	9.58	7.36	
NATIH	17.90	0.00						1.79	16.11	28.5%	34%	28.5%	5.10	4.69	
NIMR	12.05	0.00						4.50	7.55	61.33%	34%	61.33%	7.39	4.63	
RIMA	0.21	0.00						1.59	-1.38	-97.19%	34%	-97.19%	-0.20	1.34	
AL HUWAISAH	8.31	0.00						1.79	6.52	27.15%	34%	27.15%	2.26	1.77	
SAIH RAWL	9.03	0.00						2.32	6.71	48.87%	34%	48.87%	4.42	3.28	
QARN ALAM	0.84	0.00						0.09	0.75	32.01%	34%	32.01%	0.27	0.24	
Other Fields	56.04	0.00						17.02	39.02	30.69%	34%	30.69%	16.84	11.63	
		0.00													
Prov.Dev.Resvs (mln m3)	193.56	0.00	0.00	0.00	0.00	0.00	0.00	44.76	148.80	42.67%	34%	42.18%	82.41	62.77	
Proved Undeveloped Reserves															
YIBAL	35.39	0.00							35.39	18.2%		18.2%	6.38	6.38	
FAHUD	0.79	0.00							0.79	291.9%		291.9%	2.32	2.32	
MARMUL	35.97	0.00							35.97	26.81%		26.81%	9.68	9.68	
LEKHWAIR	5.64	0.00							5.64	60.24%		60.24%	3.34	3.34	
NATIH	1.79	0.00							1.79	42.56%		42.56%	0.76	0.76	
NIMR	12.96	0.00							12.96	37.18%		37.18%	4.82	4.82	
RIMA	0.03	0.00							0.03	1830.12%		1830.12%	0.59	0.59	
AL HUWAISAH	12.51	0.00							12.51	35.70%		35.70%	4.50	4.50	
SAIH RAWL	8.16	0.00							8.16	43.66%		43.66%	3.55	3.55	
QARN ALAM	27.30	0.00							27.30	32.16%		32.16%	8.78	8.78	
Other Fields	65.67	0.00							65.67	44.05%		44.05%	37.74	37.74	
		0.00													
Prov.Undev.Res (mln m3)	226.80	0.00	0.00	0.00	0.00	0.00			226.80	36.05%		36.05%	81.40	81.40	
Net Group Equity															
Proved Developed Reserves	62.41	-4.42					0.00	15.22	62.77	62.77					
Proved Total Reserves	163.81	-4.42	0.00	0.00	0.00	0.00		15.22	144.17	144.17					
10^6 m3												Audit Trail:			
1.1.2003 Submission												No 1.1.2002 field data available!			
Prov.Dev.Res	65.80	4.97					7.27	15.22	62.77	62.77		No audit trail for Transfers undev'd-to-dev'd,			
Prov.Tot'l Res	162.30	-4.74	0.34	1.43				15.22	144.17	144.17		Extensions/Discoveries and Improved Recovery!			
10^6 m3															

Conversion factors used by PDO:
1 m3 = 1 m3
1 scf = 0.0283 sm3

Conversion factors used by SIEP:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

FOIA Confidential Treatment Requested

C RESERVES AUDIT - VOLUMES RECONCILIATIO
PDO 1.1.2003

Attachment 2.1

FOIA Confidential Treatment Requested

PDO — Proved Oil / NGL / Gas Reserves as at 1.1.2003

Area / field	Proven HIIP MMstb / Bscf	Exp'n HIIP MMstb / Bscf	Cum. Prod = Sales 1.1.2003 MMstb / Bscf	Proved Rem. Recov. Dev'd mln m3	Proved Rem. Recov. Undev mln m3	Exp'n Rem. Recov. Tot'l mln m3	Maturity (Cum.pr / Exp'n URI %	Dev. / Tot'l Proved UR. %	Prov / Expn Revs %	Proved RF Tot'l %	Exp'n RF Tot'l %	Fract'n w/i lic. comtd Pr.Dev. %	Fract'n w/i lic. comtd Pr.Undv %	Within Licence comtd Pr.Dev. mln m3	Within Licence comtd Pr.Tot'l mln m3	Venture Shell share % %	Shell Equity Pr.Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Pr.Tot'l 10^6 sm3/ 10^9 sm3	1.1.2003 Subm'n Pr.Dev 10^6 sm3/ 10^9 sm3	1.1.2003 Subm'n Pr.Tot'l 10^6 sm3/ 10^9 sm3	Prov. Res / Prod Dev. yrs	Prov. Res / Prod Totl yrs
Oil																						
YIBAL	587.79	666.12	248.22	10.76	35.39	105.07	70%	88%	44%	51%	50%	400.65%	44.71%	43.12	58.94	34.00%	14.66	20.04			2	9
FAHUD	845.49	1016.77	166.40	36.59	0.79	66.44	75%	100%	86%	24%	22%	49.88%	858.52%	18.18	25.00	34.00%	6.16	8.50			10	11
MARMUL	463.11	566.37	49.21	10.91	35.97	78.48	39%	63%	60%	21%	23%	191.09%	79.16%	20.85	49.32	34.00%	7.09	16.77			5	22
LEKHWAIR	230.75	311.51	67.96	16.28	5.64	47.63	59%	94%	46%	39%	37%	133.17%	174.22%	21.65	31.47	34.00%	7.36	10.70			3	4
NATIH	414.24	456.39	77.98	16.11	1.78	26.87	74%	90%	67%	23%	23%	83.81%	125.24%	13.50	15.74	34.00%	4.59	5.35			9	10
NIMR	368.61	426.13	62.93	7.56	12.66	41.08	61%	85%	49%	23%	24%	180.38%	109.34%	13.62	27.35	34.00%	4.63	9.30			2	4
RIMA	161.45	177.17	74.36	-1.38	0.03	6.84	92%	100%	-20%	45%	46%	-285.86%	5382.72%	3.94	5.85	34.00%	1.34	1.92			-1	-1
AL HUWAISAH	187.70	248.02	42.25	6.52	12.51	27.23	61%	60%	70%	33%	28%	79.85%	108.19%	5.21	18.74	34.00%	1.77	6.37			4	11
SAIH RAWL	142.32	174.65	35.01	6.71	8.15	29.67	54%	84%	50%	35%	37%	143.74%	128.12%	9.65	20.09	34.00%	3.28	6.83			3	6
QARN ALAM	165.30	185.66	5.07	0.75	27.30	38.91	12%	18%	72%	20%	24%	94.15%	94.58%	0.71	26.63	34.00%	0.24	9.02			8	318
Other Fields	2509.29	3638.80	240.78	38.02	85.87	276.44	47%	76%	45%	15%	14%	89.97%	129.57%	34.21	145.21	34.00%	11.63	49.37			2	7
Total Oil (mln m3)	6056.04	7899.62	1068.17	148.80	225.80	734.66	59%	64%	51%	24%	23%	124.07%	106.03%	184.62	424.03	34.00%	62.77	144.17	62.77	144.17	3	8
NGL																						
(No NGL reserves carried)							0	0	0	0	0			0.00	0.00		0.00	0.00				
Total NGL (MMstb)	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0	0.00	0.00	0	0.00	0.00	0.00	0.00		
Gas (Dry, sales gas volumes)																						
(No gas reserves carried)							0	0	0	0	0			0.000	0.000		0.000	0.000				
Total Gas (Bscf)	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0	0.000	0.000	0	0.000	0.000	0.000	0.000		

Conversion factors used by PDO:
1 m3 = 1 m3
1scf = 0.0283 sm3

Conversion factors used by SIEP:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Licence expiry date: 24 June 2012

Audit Trail: **Proved developed and undeveloped field volumes (100%) derived from exp' deve'd/undev'd volumes, multiplied by proved/exp'n total reserves ratio.**
Disconnect between field volumes in submission and actual field volumes (e.g. within-licence volume exceeds 100% field volume in some cases!)
Negative proved field reserves in Rima!

DB 28772

Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
PDO 1.1.2003

PDO **Proved Oil Reserves Changes 2002 (100%, mln m3)**

Field	Prov.Res. 1.1.2002	Revisions/ Reclassns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves (Transf. Und. to Dev)	Productn 2002	Prov.Res 1.1.2003	Shell Equity Share % 1.1.2002	Shell Equity Share % 2002 Prod	Shell Equity Share % 1.1.2003	Net Shell Equity 1.1.2002 (10^6 m3)	Net Shell Equity 1.1.2003 (10^6 m3)	Comments
Proved Developed Reserves															
YIBAL	15.76	0.00						5.00	10.76	136.22%	34.%	136.22%	21.47	14.66	
FAHUD	40.15	0.00						3.56	36.59	16.89%	34.%	16.89%	6.78	6.18	
MARMUL	13.09	0.00						2.18	10.91	64.97%	34.%	64.97%	8.50	7.09	
LEKHWAIR	21.17	0.00						4.91	16.26	45.28%	34.%	45.28%	9.58	7.36	
NATIH	17.90	0.00						1.79	16.11	28.5%	34.%	28.5%	5.10	4.59	
NIMR	12.05	0.00						4.50	7.55	61.33%	34.%	61.33%	7.39	4.63	
RIMA	0.21	0.00						1.59	-1.38	-97.19%	34.%	-97.19%	-0.20	1.34	
AL HUWAISAH	8.31	0.00						1.79	6.52	27.15%	34.%	27.15%	2.26	1.77	
SAIH RAWL	9.03	0.00						2.32	6.71	48.87%	34.%	48.87%	4.42	3.28	
QARN ALAM	0.84	0.00						0.09	0.76	32.01%	34.%	32.01%	0.27	0.24	
Other Fields	55.04	0.00						17.02	38.02	30.59%	34.%	30.59%	16.84	11.63	
Prov.Dev.Resvs (mln m3)	193.56	0.00 0.00	0.00	0.00	0.00	0.00	0.00	44.76	148.80	42.57%	34.%	42.18%	82.41	62.77	
Proved Undeveloped Reserves															
YIBAL	35.39	0.00							35.39	15.2%		15.2%	5.38	5.38	
FAHUD	0.79	0.00							0.79	291.9%		291.9%	2.32	2.32	
MARMUL	35.97	0.00							35.97	26.91%		26.91%	9.68	9.68	
LEKHWAIR	5.64	0.00							5.64	59.24%		59.24%	3.34	3.34	
NATIH	1.78	0.00							1.78	42.58%		42.58%	0.76	0.76	
NIMR	12.56	0.00							12.56	37.18%		37.18%	4.67	4.67	
RIMA	0.03	0.00							0.03	1830.13%		1830.13%	0.58	0.58	
AL HUWAISAH	12.51	0.00							12.51	36.78%		36.78%	4.60	4.60	
SAIH RAWL	8.15	0.00							8.15	43.56%		43.56%	3.55	3.55	
QARN ALAM	27.30	0.00							27.30	32.16%		32.16%	8.78	8.78	
Other Fields	85.67	0.00							85.67	44.05%		44.05%	37.74	37.74	
Prov.Undev.Res (mln m3)	225.80	0.00 0.00	0.00	0.00	0.00	0.00			225.80	36.05%		36.05%	81.40	81.40	
Net Group Equity															
Proved Developed Reserves	82.41	-4.42					0.00	15.22	62.77	62.77					
Proved Total Reserves	163.81	-4.42	0.00	0.00	0.00	0.00		15.22	144.17	144.17					
10^6 m3															
1.1.2003 Submission															
Prov.Dev.Res	65.80	4.92					7.27	15.22	62.77	62.77					
Prov.Tot'l Res	162.30	-4.74	0.34	1.49				15.22	144.17	144.17					
10^6 m3															

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Audit Trail:

No 1.1.2002 field data available!
No audit trail for Transfers undev'd-to-dev'd,
Extensions/Discoveries and Improved Recovery!

Conversion factors used by PDO:
1 m3 = 1 m3
1scf = 0.0283 sm3

Conversion factors used by SIEP:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

PDO/Gisco, Oct 2003

CHECKLIST SEC RESERVES AUDITS

Attachment 3

COMPANY: PDO **AREA / FIELD: ALL FIELDS**

	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 universal over all discovered fields.
1.02	Are seismic processing and interpretation state-of-the-art?	O	Seismic tends to be of poor quality due to strong shallow multiples, surface rugosity and other irregularities, e.g. local sinkholes. Filtering (Cheats, van Gogh) has been applied with mixed success. Results are more promising in one area (Rima cluster) where it is anticipated that good information can be obtained on structure and small scale faulting, but, more importantly on reservoir stratification and perhaps characterisation.
1.03	Is seismic quality used / adequate for proving hydrocarbing bearing areas?	N.A.	Oils tend to be generally heavy and of low GOR. Acoustic contrast with water is small and oil bearing areas cannot be distinguished from seismic.
1.04	Is well data coverage adequate?	+	The majority of fields have been developed by numerous wells, both vertical and horizontal.
1.05	Are fluid levels known?	+	Since seismic and regional aquifer pressures are not reliable for predicting OWCs these tend to be specifically targeted by appraisal wells.
1.06	Are petrophysical well data quality and quantity adequate?	O	Not all wells had full suites of logs during major development drilling phases (GR and resistivity only, no porosity tools). This is a slight hindrance in reservoir characterisation.
1.07	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Most fields are now in production. Production tests are carried out in exploration / appraisal wells.
1.08	Are there proper volumetric estimates?	+	Volumetric estimates have been made for all fields. Most date back from the older generation of mapping packages (Zycor, CPS, Supervol). Most of these were coarse layered or coarse gridded. However, the recent (STEP staffed) STOIIP and Reserves Review Team has largely confirmed the validity of these estimates.
1.09	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	Proper sampling and analysis is done for new fields.
1.10	Are gas GHVs measured properly for sales gas conditions and accounted for in reserves submissions?	+	No gas reserves are carried
1.11	Are static models available / adequate?	X	Proper modern static and dynamic modelling has received insufficient attention in recent years. A large volume of booked reserves is based on older and outdated FDPs or on earlier volumetric estimates. This is now being addressed through an urgent study programme. Petrel models are the present standard.
1.12	Are dynamic models available / adequate?	X	See above. MoReS models are now downloaded from Petrel.
1.13	Are history matches available / adequate?	X	History matches are gradually becoming available as models are matured.
1.14	Are the recovery factors for proved reserves realistic?	X	PDO and the STOIIP and Reserves Review Team have concluded that a number of the older (FDP) expectation reserves estimates have been overstated (Yibal, Marmul, Qarn Alam). Individual field proved reserves are still based on old probabilistic volumetrics, in which the margins are much too wide in relation to the field's maturity. As for the booked proved corporate Shell share reserves, these cannot be tied back to realistic proved individual field estimates.
1.15	Are developed reserves based on proper NFA (No Further Activity) forecasts?	+	Expectation developed reserves are based on NFA forecasts - derived from well and cluster decline analysis (through Oil Field Manager software. The origin of the corporate proved developed estimate was not clear, but its volume seems broadly in line with the expectation NFA forecast, cut off at the end-of-licence in 2014.
1.16	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; No behind-pipe reserves are carried.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

1.17	Have development projects been defined for undeveloped reserves or can they be defined?	X	The majority of undeveloped field reserves are associated with identified projects. However, many of these are notional or highly notional, while others have no forecast associated with them in the Business Plan.
1.18	Are there auditable development project plans with costs, benefits and economics?	X	A large majority of the undeveloped reserves projects are notional, with at best only approximate forecasts and cost estimates.
1.19	Are the projects technically mature or is further data gathering necessary?	X	The majority of projects are recognised as needing further work or re-work in order to become matured. Even many projects/volumes based on FDPs from the late 1990's are now seen as out of date because of subsequent well and field performance.
1.20	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	O	There are ample water injection projects in the PDO operated area. This could normally count as a sufficient analogue base for proving further new water injection projects. However, the reservoirs concerned (notably the Al Khlata sandstone and some shallower fractured carbonates) present a high degree of variability and such analogues may not always be representative.
1.21	Have the projects successfully passed a VAR3/VAR4 review or are they otherwise ready for application for funding?	X	PDO and the STOIIP / Reserves Review Team have recognised that 80-90% of the undeveloped reserves are yet to pass through the VAR3 stage. This includes a number of projects that have gone through such a stage in the past but which are now seen to need updating.
1.22	Are the projects firmly planned to go ahead - are there any potential show stoppers?	O	The Oman Government, as the major shareholder, is firmly committed to maximise oil recovery in a manner that is beneficial to them. Only projects with very poor economics would be at risk of not being executed.
2	COMMERCIAL MATURITY		
2.01	Are the projects economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	O	PDO projects are in principle approved by the PDO board. The Group Capital Allocation system has little influence on these decisions. The verbal statement was made that many projects would not have passed the stringent Group criteria. Previous UTC levels were at some $4/bl, but these have risen in recent years and the current outlook is that these may rise to levels up to $10/bl.
2.02	Have forecasts been cut off when rates become uneconomic?	N.A.	Forecasts are cut off at the end of the current production licence (24th June 2012). This long before production levels have declined below economic production levels.
2.03	Have the latest Group Screening / Reference Criteria been used?	O	See 2.01 above
2.04	Are assumed prices and costs RT (or justified if not)?	O	See 2.01 above
2.05	Is export infrastructure (pipelines, terminals etc) available or, if not, is it firmly planned and fully included in the economics?	+	Most of the export infrastructure is already in place. Any extensions would be included in the relevant 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, see 1.15.
2.08	Have all major gas project reserves been committed or contracted to sales, e.g. through a HOA, GSA?	N.A.	PDO is free to use produced gas for own use and for re-injection where needed, but they have no title to exported gas. Hence, no gas reserves are carried.
2.09	Can smaller gas project reserves reasonably be expected to be sold in existing markets and through existing / firmly planned facilities?	N.A.	
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?	X	STOIIP ranges were evaluated probabilistically after the early static (deterministic) modelling. Parameter ranges tended to take into account well log data only, but no adjustment was made for dynamic STOIIP determination from production performance. Hence these ranges were perhaps defensible at the time of their preparation but they are too wide for the current stage of field development.
3.02	Have 'proved areas' been defined (lowest known fluid contact, 'continuity of production', no major/sealing faults) and are they realistic?	+	Water contact levels are well known and well control tends to be more than adequate.
3.03	Are proved (developed and total) reserves consistent with these 'proved areas'?	+	Yes

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+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

3.04	Is the uncertainty range of developed recovery adequate?	O	Although there is no clear audit trail for the composite proved developed recovery estimate, it appears to align with the expectation NFA forecast within the licence period. This is largely reasonable for a portfolio with the size and maturity of PDO's. Some downward corrections should be made for new developed fields. The composite proved forecast is not linked back to proved estimates for individual fields. The reason is that no such individual field estimates are made.
3.05	Is the uncertainty range of undeveloped recovery adequate?	X	The undeveloped forecast within licence contains a large number of projects that are far from mature and which can therefore not be regarded as proved (or, for that matter as true expectation). The composite proved undeveloped estimate includes a significant number of these immature projects. This is not in accordance with SEC and Group guidelines. As for the developed reserves, the composite proved undeveloped forecast is not linked back to proved estimates for individual fields because no such proved estimates are made.
3.06	Have market / production constraint uncertainties been taken into account?	N.A.	Offtake is at maximum field capacity.
3.07	Is the Group / Region / Asset Holder committed to proceed with development?	+	Yes, see also 1.22.
3.08	What is ratio of field(s) cum.prod. / expectation total recovery?		0.59
3.09	Can the field(s) be considered mature?		On average, yes, although there are numerous small new fields
3.10	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Yes
3.11	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	O	Field recovery estimates are now generally made in a deterministic manner. Probabilistic addition is no longer appropriate.
3.12	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?	X	The proved developed reserves align with the expectation NFA forecast, which is appropriate for mature fields. The proved undeveloped reserves are likely to be overstated because they are not fully supported by proved projects.
4.02	Are the forecasts required to demonstrate the above condition consistent with the firm Base Case presented in the latest Business Plan?	X	The proved total estimate is well in excess of the 'Tranche 1' projects forecast from the 2002 Business Plan and similar forecasts from the 2003 Business Plan.
4.03	Is the hydrocarbon Equity share calculated properly (regular production contracts)?	+	The Group share is 34%, which is 85% of the 'private shareholders' share of 40% in the PDO operated fields.
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 are paid in cash and are not deducted from liftings nor reserves bookings.
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 used by third parties) included in reserves? Similarly, are volumes received as fees in kind excluded from reserves?	N.A.	Minor streams of third party crude are exported through PDO pipelines. Fees are paid in cash.
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?	N.A.	No gas reserves are carried
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?	X	The composite total proved reserves within-licence estimate has largely been maintained from previous years, in spite of the growing immaturity of the constituent projects.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	X	No; The individual proved / expectation reserves ratios for individual fields are too low, particularly for the more mature fields (see Att.4).
5.03	Can reserves changes be reconciled with individual field changes?	X	Changes have been reported in the 'Improved Recovery, 'Extensions and Discoveries', Transfers form Undeveloped to Developed' categories and of course in 'Revisions'. There was no audit trail note to link this back in a quantitative manner to individual fields. The ARPR is in full 30-year life cycle volumes only.
5.04	Are reserves changes reported in the appropriate categories?	X	Since the source of the changes was not clear, it could not be established whether the categorisation of the changes was appropriate.
5.05	Is there a document in place describing the OU's reserves reporting procedures?	O	A document has been in circulation in draft form for some time. A final version is anticipated in November this year.
5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	O	FDP documents were prepared upon the conclusion of studies. Very few of these have been issued in recent years because of time pressure.
5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	X	Whilst there is a central library with search facilities, field teams tend to keep project reports in personal filing cabinets.
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?	X	An ARPR report is issued annually, which lists full life cycle (i.e. 30-years) recoverable volumes of oil+condensate (from PDO facilities) and associated gas. The format seems somewhat cumbersome (duplicated data and unnecessary data e.g. depletion rates, high estimates). It could benefit from a simplification. A note describing the basis for the Group estimates was not present, only a complex spreadsheet.
5.09	Are electronic data bases containing both historic submissions' data and current reserves data in place and accessible?	+	Yes, largely in the form of spreadsheets
5.10	Do these data bases also contain references to detailed reports?	O	No
6	CONSISTENCY WITH FINANCIAL REPORTING		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes; Oil (and any co-produced oil gas condensate) is reported by PDO, gas and ex-gas plant liquids entitlements are reported by Gisco.
6.03	Are own use, fuel, losses etc excluded?	+	Gas own fuel and losses are not relevant to the calculation of Group share oil entitlements
6.04	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
6.05	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).	N.A.	No gas reserves carried by PDO
6.06	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 royalties are applicable here)
6.07	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%)?	+	PDO prepares the submissions as an associated company with 34% Group share.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

6.08	Are reported proved total and proved developed reserves consistent with those used for asset depreciation in Group Accounts?	N.A.	PDO has not applied UOP asset depletion in the past. The operating agreement stipulates a 40-30-10-10-10% depreciation profile for all capex and this is applied for calculation of the Shell margin and for tax submissions. Shell Group returns are made by Somant who do not hold any share in the PDO assets, hence no asset depreciation is applicable for Group accounts. PDO accounts are managed with depreciation through the abovementioned 5-year profile. This is not in accordance with international accounting practices, which require UOP depletion, based on proved total and proved developed reserves. This has led to qualifications in external auditor reports, which the Oman Government now want to see removed. Hence, PDO will need to maintain proper estimates of individual field proved developed and proved total (i.e. undeveloped) reserves, probably starting at 1.1.2005.
7	OVERALL		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	X	Group share proved developed reserves at 1.1.2003 are largely acceptable. However, Group share total (i.e. undeveloped) reserves are not in accordance with SEC and Group guidelines and have thus been overstated significantly.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	+	In spite of the above comment, the currently reported volumes give a reasonable reflection of shareholder value if account is taken of the probable extension of the current production licence agreement beyond 2012.

		Weight	Score (0-100%)
1	TECHNICAL MATURITY	30%	47%
2	COMMERCIAL MATURITY	9%	72%
3	REASONABLE CERTAINTY	21%	67%
4	GROUP SHARE CALCULATION	8%	50%
5	AUDIT TRAILS	16%	23%
6	CONSISTENCY WITH FINANCIAL REPORTING	7%	100%
7	OVERALL OPINION	8%	50%
	TOTAL SCORE	100%	54%

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+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

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Petroleum Resource Volume Guidelines

Resource Classification and Value Realisation

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Petroleum Resource Volume Guidelines

Resource Classification and Value Realisation

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1. INTRODUCTION

Petroleum resources represent a significant part of the company's upstream assets and are the foundation of most of its current and future upstream activities. To aid in understanding, planning, and decision making about these petroleum resources, resource volumes are classified according to the maturity or status of its associated development project. The current status and changes in petroleum resources, and specifically the commercially recoverable portion (reserves), are a significant concern to management. The future of the company depends on our effectiveness in maturing resources to the point where maximum economic value is realised.

For the Shell Group as a whole, petroleum resources are reported annually to senior management and are essential information for the strategic planning process of the upstream sector. The current status and changes to the proved and proved developed reserves are also reported annually to the Securities and Exchange Commission (SEC).

Therefore the importance of these figures cannot be overemphasised. Reliability, uniformity, consistency, transparency and auditability are essential elements in the collation of petroleum resource reports by Operating Units (OUs) and New Venture Operations (NVOs). These guidelines, building on the foundation established by previous versions (References 1 to 5), aim to achieve these goals. They serve as a reference for OUs and NVOs and as the standard against which audits will be conducted.

The recommendations of the Hydrocarbon Resource Volume Value Creation Team have been incorporated in this update of the guidelines. The primary changes are increased attention to realise maximum value from volumes and the modification of the definition for proved developed reserves to be more consistent with industry practice. The value realisation theme is reflected in emphasising a) that reserves are project based and b) the importance of maturing resource volumes to developed reserves and hence sales. No major changes in the classification scheme are introduced.

This document contains only guidelines. The information on internal and external submission requirements and quantification methods that was contained in previous versions of this document will be included in other communications. Submission requirements will be communicated annually in a letter from EP Planning. Methods will be developed through the Hydrocarbon Resource Volume Common Interest Network (Reference 7).

2 PETROLEUM RESOURCES

2.1 Definition

A petroleum resource is any accumulation of hydrocarbons that is known or anticipated to exist in a sub-surface rock formation, located in the company's current exploration and production acreage. If the petroleum resource extends beyond the company's licence area the resource volumes must be divided according to the granted licence boundaries, to take proper account of Group share.

Resource volumes are reported as the quantities of sales product. The corresponding quantities of field recovery should be maintained by the OU (See Appendix 6). The reporting of petroleum resource volumes should further indicate the petroleum type, the reporting units and conditions, and the Group share.

Resource volumes are tied to the project that develops them and are generally reported by field. The term **reserves** is used for resource volumes associated with a project that is technically mature and commercially viable. Resource volumes that do not meet these criteria are called **scope for recovery** (SFR). **Proved reserves** are the portion of reserves that is reasonably certain to be produced. These distinctions will be discussed in Sections 3 and 4.

2.2 Group Share

Only the Group share of resource volumes is reported. The Group share is determined by agreements with the resource holders. Resource volumes can be distinguished according to three different types of agreement, which are discussed below.

Equity Equity resources are the Group share of resources in Concessions. Concession agreements lay down the general terms and conditions of operation. These agreements with governments define the applicable tax rules, the Group share of resources in Concessions and the duration of the production licence.

Entitlement Entitlement resources are the Group share of production in acreage governed by a Production Sharing Contract (PSC). The Group share of production is the Group interest in the sum of cost oil plus excess cost oil plus profit oil, in accordance with the PSC terms.

Innovative Production Contracts In recent years, a number of resource holding countries have introduced innovative production contracts in order to attract investment by foreign oil companies while preserving the principle of national resource ownership. These agreements typically provide for the contractor to recover costs and profits from hydrocarbon revenues while holding no title to, or entitlement to receive, petroleum resources.

US Financial Accounting Standards Board (FASB) regulations have lagged behind these developments and provide little explicit guidance on reserves disclosure when the risks and rewards of ownership are carried without legal title to mineral rights.

However, volumes covered by such innovative contracts should be included in external reports in an informative way to be consistent with the spirit of the SEC regulations. The volumes from which economic benefit is derived should be reported if all three of the following conditions are met:

1. The OU participates in the production operations as either operator or in partnership with the operator, and so bears a share of the costs and risks of the production operations.
2. The OU derives future economic value that is directly related to the volume of hydrocarbons produced. For example, a fee expressed as a fixed or indexed amount per barrel of production would constitute a derivation of value from the produced hydrocarbons, but an operating fee that is largely independent of production would not. The actual source of revenues used to pay the OU is not crucial to this point. For example, if the remuneration is determined by a produced gas

volume but paid from oil revenues, the economic value to the OU is in effect derived from the produced gas, and this volume should be reported.

3. The OU is exposed to the normal risks and rewards associated with ownership of mineral rights, including the downside and upside from changes in the value of future production volumes. These include the risk that costs may not be recovered, due to either uncertainty as to the presence or magnitude of hydrocarbon volumes or to movements in petroleum prices.

OUs and NVOs working under such contracts should complete the standard resource volume submission for the Group/Company interest in these volumes, noting the nature of the interest. Reported volumes should be in line with the reporting of traditional reserves with regard to royalties and should therefore reflect the volumes from which pre-tax cash flow is derived. As elsewhere, cash royalties are regarded as a production cost.

If an OU has interests in several licence areas subject to different contract types (e.g. reward generating and PSC), a separate submission must be made with respect to the interest in the reward generating contract area.

When an OU is participating in a venture which grants neither title to, nor an entitlement to receive petroleum, and which does not satisfy the three criteria above the OU should not report reserves or production volumes. For example this might occur if the recovery of costs is guaranteed against adverse price movements or a shortfall in recovered volumes

Licence or Contract Extensions

For internal reporting purposes, Group share of the expectation estimate of reserves and scope for recovery are recorded for the total producing life, i.e. including the period beyond the relinquishment date, but not covered by a right to extend or by a letter of assurance (see below). The currently existing licence terms or other anticipated terms should be assumed for this extrapolation.

For external reporting, Group share of reserves (proved, proved developed) is limited to production within the existing licence or contract period. However, production beyond the licence or contract period can be included if there is a legal right to extend a production licence or PSC, or if the government has formally indicated that it will favour substantiated requests for extensions in the future (letter of assurance). Then volumes recoverable during the extension period are included in the Group share, assuming currently existing or other anticipated terms. Such considerations should be documented in the annual submission.

In some countries, the issue or duration of production licences for gas fields is effectively coupled to the conclusion of gas sales contracts. In other areas, a realistic target date for initiation must be set for projects that are not yet firmly planned so that the production forecast and other screening assumptions can be used to estimate the volume produced before licence or contract expiry.

Long Term Supply Agreements

FASB regulations (69 para. 13) require that quantities of oil or gas subject to purchase under long term supply, purchase or similar agreements should be reported separately, if the OU participates in the operation of the properties in which the oil or gas is located or otherwise serves as the "producer" of those reserves, as opposed, for example, to being an independent purchaser, broker, dealer, or importer.

The "supply" agreement should be a consequence of the OU acting as producer. This would not be the case if, for example, others had similar agreements but did not participate in the production operations.

These net quantities, as well as the net quantities received under the agreement during the year, should be included in the end year estimate of reserve volumes for external disclosure form.

Royalty

Royalty is a payment made to the host government for the production of mineral resources. It is usually calculated as a percentage of revenues (payable in cash) or production (payable in kind).

Where in practice royalty obligations are met in kind (i.e. by delivering oil instead of cash), the Group share of production and reserves should be reported excluding these volumes.

Where royalty is payable in cash or is in principle payable in kind but the government has formally elected to receive, or customarily receives, payment in cash, Group share of production and reserves should be reported without deduction of equivalent royalty volumes.

Fees in kind Third parties may in some cases pay fees in kind for the use of infrastructure (e.g. pipeline tariff). Such payments do not constitute a Group share in resources and should not be included in reported volumes.

Open Acreage Group share of volumes is non-existent in open acreage and acreage for possible acquisition or farm-in.

Under/Over Lift Group share should also allow for any historic under or over lift by partners or government.

3. RESOURCE VOLUME CLASSIFICATION FOR INTERNAL REPORTING

3.1 Classification Scheme

The internal classification scheme shown in Figure 1 is intended to provide a consistent link between a field's resource volumes and the EP business model, identifying separately those resources that are the focus of the various stages in the development life cycle.

Cumulative Production	
Reserves:	Developed Reserves Undeveloped Reserves
Discovered Scope for Recovery:	Proved Techniques Scope for Recovery Unproved Techniques Scope for Recovery Non-Commercial Scope for Recovery
Undiscovered Scope for Recovery	
Discovered Initial In Place	

Figure 1: Resource Categories for Internal Reporting

A summary of the definitions for these categories is provided in Appendix 1. The cascade model (Figure 2) illustrates the migration of volumes between resource categories during the development life cycle.

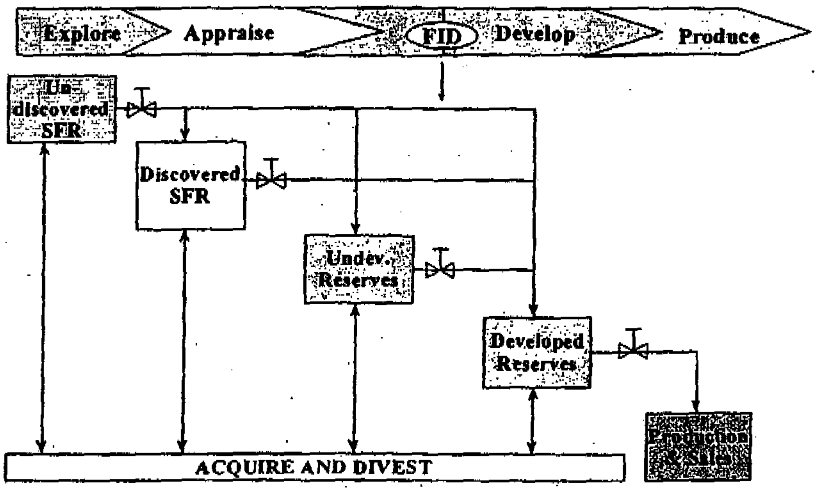

Figure 2: Cascade Model

A specific example of the migration of resource volumes between categories during a field's life cycle is shown in Appendix 2.

3.2 Value Realisation

The most important objective of resource volumes management is the progression of the volumes to the point where maximum value is realised. The main purpose of the internal classification scheme tied to the development life cycle is to enable understanding of the potential value and the actions needed to mature volumes. In order to achieve business growth and reserves replacement objectives, it is essential that OUs and NVOs have efficient systems to move volumes through the value chain from scope for recovery to production and sales as shown in the cascade model.

OUs and NVOs internal reserve management systems should;

a) set targets and monitor actual performance in maturing volumes towards value realisation,

b) fully inventorise and have maturation plans for Scope for Recovery opportunities,

c) review ultimate recovery targets for existing fields and identify what activity - appraisal, study, new technology development, commercial agreement, etc. - is required to reach these targets,

d) and have Key Performance Indicators (KPI's) to measure performance (e.g. replacement ratio, time between discovery and first production).

3.3 Technical and Commercial Maturity

The classification scheme uses a project's technical and commercial maturity as the primary criteria to distinguish between reserves and scope for recovery (SFR). Resource volumes can be classified as reserves only if the associated project that will result in production of those volumes is considered to be technically mature and commercially viable. If it cannot, the resource volumes should be classified as SFR. SFR needs an activity (e.g. exploration appraisal, field trial, gas market development, etc) to achieve technical maturity and commercial viability. Secondary technical and commercial distinctions (between proved and unproved techniques SFR and between commercial and non-commercial SFR) further identify resource volumes at various stages in the life cycle.

Project Basis

Technical and commercial maturity reflects the status of remaining uncertainties in the assessment of the optimal development project and its associated recovery. A project is any proposed or notional modification of the wells, the production facilities and/or the production policy, aimed at changing the company's sales product forecast. It can also be a modification of the company's share in a venture (purchase/ sales-in-place, unitisation, new terms). The generic term 'project' is also used to describe a group of (sometimes alternative) projects, each with a certain chance of realisation, depending on the results of further data gathering. In that case, the project NPV is replaced by the Expected Monetary Value (or EMV, see Appendix 6).

Technically Mature

For a project to be **technically mature**, information on the resource volume, including its level of uncertainty, is such that an optimal project can be defined with an auditable project development plan, based on a resource and development scenario description, with drilling/engineering cost estimates, a production forecast and economics. The plan may be notional or it may be an analogy of other projects based on similar resources. However, there should be a reasonable expectation that a firm development plan can be matured with time. Projects do not have to have a completed development plan.

Commercially Mature

A **commercially mature** project is commercially viable over a sufficiently large portion of the range of possible scenarios that reflect the remaining resource uncertainties. The definition of what constitutes "a sufficiently large portion" may vary from case to case and could for example require the project NPV for the low reserves scenario to be positive for appropriate commercial criteria. It is also likely to include an assessment of the capital exposure in case of project failure due to adverse resource realisations. The selected range of scenarios should be documented and auditable.

A scenario is **commercially viable** if the NPV is expected to be positive under the applicable terms and conditions for the acreage and for the current advised Group reference criteria for commerciality (Reference 9).

A project is **economically viable** if the expected NPV under the applicable terms and conditions for the acreage exceeds the separately advised Group project screening criteria or if the project has already been approved by shareholders. Projects generally have to demonstrate economic viability in order to obtain investment approval. However, economic viability or formal project approval is not required for a project to be considered commercially mature. Reserves may be booked before project approval is sought.

3.4 Uncertainty Estimates

Uncertainty in resource volumes arises from using data and prediction techniques with varying degrees of uncertainty. The uncertainty in resource volume estimates can be assessed and represented using a variety of methods (see Reference 7). Probabilistic methods determine a range of estimates and the associated probability that they will occur. Scenario deterministic methods determine best estimates for specific cases such as a low side case or a base case.

The terms low, expectation or high estimates are used in this document to simplify the discussion and to define reported volumes where consistency is required. When using a probabilistic methodology, low, expectation and high estimates are defined as the P85, Mean and P15 values from the probability distribution function (see Appendix 7 for definitions). When using a scenario deterministic methodology, low, expectation and high estimates are the low side case, base case and high side cases, respectively.

Only the expectation estimate for each of the resource categories is required for Internal reporting. The low estimate is usually used to define externally reported proved reserves. It is up to the OU to decide whether there is a need to determine other estimates.

Uncertainty Reduction with Performance

The uncertainty range of ultimate recovery generally decreases as a field is developed and produced. However, the uncertainty range as a percentage of remaining reserves may not always decrease with time. As **a field matures, initial in place volumes and recovery should shift from a volumetric to a performance-based estimate, incorporating the additional production data to reduce the uncertainty range.** Once the reservoir performance has been established with reasonable certainty, a fairly small difference between low, expectation and high estimates would be expected. Definition of the low and high estimates may no longer be of value in mature fields with relatively little uncertainty and use of a single expectation estimate should be considered in this situation.

Figure 3 illustrates the narrowing of the uncertainty with field appraisal and development. This is a near ideal example where the expectation remains constant for most of the life cycle. This example is also used in Appendix 2 to show the migration of resources between internal and external reporting categories during the field life cycle.

The reduction in uncertainty based on performance should be adequately reflected in the annual reserve and scope for recovery estimates for the field.

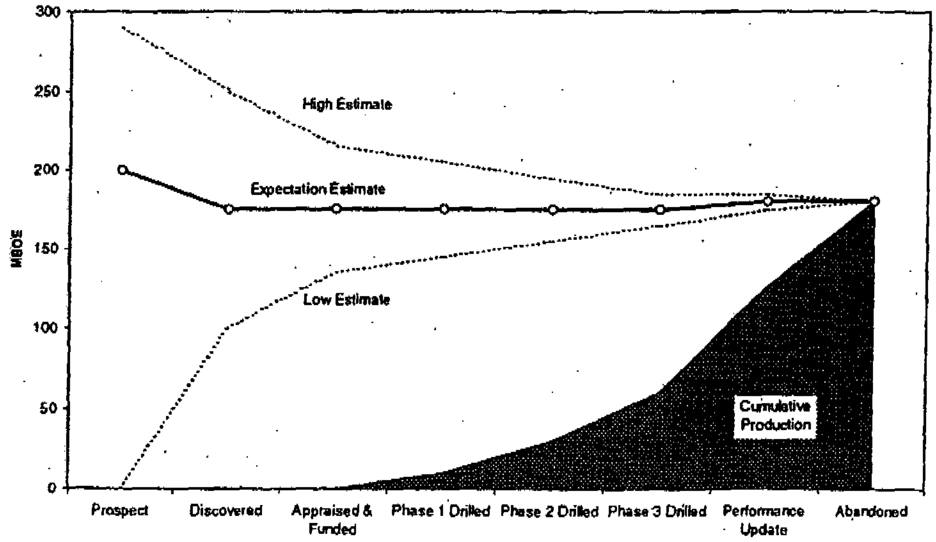

Figure 3: Uncertainty Reduction during the Field Life Cycle

Addition of Resource Volumes

Resource volumes are added together at various levels during the resource assessment and reporting process. Addition of reserves at or above the level used for depreciation calculations must be arithmetical for consistency with financial accounting. Below this level, i.e. normally below the field level, addition should be done taking into account the dependency between the volumes to truly reflect the recoverable volumes associated with a project. Arithmetical addition is appropriate for dependent volumes, but usually overstates the uncertainty range for the sum of partially independent volumes. Probabilistic addition should be used for partially independent volumes when the difference with arithmetic addition is significant.

Below are two examples where the method of addition is important to handle properly.

1) Field A is comprised of separate layers and the properties of these layers are independent of each other. In other words, a low result in one layer would not increase or decrease the chance of a low result in the other layers. Low, expectation and high estimates are calculated for each layer separately. Probabilistic addition should be used to account for the reduced uncertainty of adding together independent volumes. Arithmetical addition of these estimates would understate the low estimate and overstate the high estimate of the total field.

2) A project develops three independent fields as sub-sea satellites connected to one platform. In this case, the investment in surface facilities may be totalled for depreciation[1] and consequently the reserves estimates should relate to the combined fields. Probabilistic addition should be used to calculate the total reserves associated with the platform.

Careful consideration should be given to Commercial SFR by proved techniques where eventual development is only incremental to an existing or planned development. These volumes may have a probability of success (POS) less than one, but with probabilistic addition will contribute at all levels - low, expectation and high - of reserves estimates. Examples of where this would apply are:

1) A fault block that is not yet tested and may be reasonably interpreted as an extension of the delineated area of the field. The project itself is technically mature and commercially viable. The untested block would be developed through existing field facilities without significant additional investment other than additional wells, which is recognised in the project scope. The uncertainty is geological and volumes are classed as reserves.

2) A phased development where there is uncertainty in the scope (e.g. number of wells) of a project due to geological uncertainty. However, the nature of the project remains essentially unchanged and additional wells could be accommodated within the flexibility of the field facilities design, then the whole range of recoverable volumes should be considered in deriving reserves. A scenario tree can be developed to represent the range of outcomes, both in recovered volumes and optimised number of wells, dependent on geological uncertainty. The uncertainty is resolved, with time, through planned data gathering eventually determining the number of wells. Hence the volumes can be regarded as technically mature. If one branch of the scenario tree is not economic, then the volumes associated with that arm do not contribute to reserves.

If probabilistic addition is used, ensure the methodology and parameters used are documented in the audit trail.

3.5 Cumulative Production

The resource volume category "Cumulative Production" pertains to summation of sales quantities of production volumes up to the date of reporting. Consistency is required between sales and field quantities. Production Operations and Finance functions must reconcile their figures prior to any submission.

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[1] Group Accounts should be consulted when considering combining surface facilities for different fields for depreciation purposes.

3.6 Reserves

Reserves are the sales quantities anticipated to be produced from a discovered field due and associated with a project that is **technically and commercially mature** (see definition in Section 3.3). Petroleum volumes have been demonstrated to be producible from the field. A market must reasonably be expected to be available.

The production forecast, and therefore the reserves, must be cut off at the point where cash generation becomes negative, i.e. when operating costs (with appropriate treatment of abandonment costs) exceeds sales revenues after royalties. If the remaining tail production is significant, it may be booked as Non-Commercial SFR (see below).

The restriction of marketability is relevant to gas reserves and for the classification of those NGL products that are subject to go-ahead of a non-associated gas project. Apart from an assessment of the local market and identification of the type of export project (e.g. pipeline, LNG, methanol), this restriction implies earmarking the gas resources suitable to feed these outlets. The restriction applies to all confidence levels (low, expectation and high estimates) of reserves.

To minimise fluctuations over time, OUs and NVOs should exert caution in transferring volumes between the reserves and SFR categories. Demonstrable technical and commercial maturity will be required when new fields and reservoirs are added to the reserves base. The same requirement applies in principle when undeveloped reserves are retained. To retain developed reserves, their production should have a positive cash generation after subtraction of operating costs and royalties.

Existing volumes classified as reserves, but which are no longer commercially mature, may be retained as reserves only in cases when there is an overriding strategic interest, or where a current small operating loss is expected to be reversed in the short term. In both cases support from shareholders must be obtained.

Developed Reserves

Developed reserves are the portion of reserves that is producible through currently existing completions, with installed facilities for treatment, compression, transportation and delivery, using existing operating methods. Outstanding project activities, such as initial completions, recompletions, hook-up and modifications to existing facilities, can be considered as existing or installed if the outstanding capital investment is minor (<10%) compared to the total project cost and if budget approval has been obtained or is reasonably expected.

Developed reserves are estimated by forecasting the production that will be contributed by the existing wells through the currently installed facilities assuming no future development activity. Future wells or facilities may be planned that add reserves and/or accelerate the reserves that would be produced by the existing investments. However, the portion of reserves expected to be accelerated by future investments are classified as developed with the existing investments and not after the future investments. If future investment accelerates production such that additional reserves are recovered within time limits (e.g. sales contract periods, field life), the additional reserves are classified as developed only after these investments are made.

Undeveloped Reserves

Undeveloped reserves are the complement of developed reserves in the total reserves, requiring capital investment in new wells and/or production facilities in order to be produced.

For new development projects, developing additional reserves may defer field / platform abandonment and may thereby also increase the reserves producible from existing completions. Such gains should be included in the economic evaluation of the new development project and can only be classified as reserves if the project meets the technical and commercial criteria.

3.7 Scope for Recovery

Scope for Recovery is the recovery estimate of any notional project for which implementation cannot yet be shown with sufficient confidence to be technically sound or commercially viable. However, there must be an expectation that this project could mature based on reasonable assumptions about the success of additional data gathering, a maturing technology from current research, relaxation in the market constraints and/or the terms and conditions for implementing such a project.

The economic evaluation should include any future pre-investment costs required to reduce technical uncertainty.

In the case of immature projects, the associated scope for recovery may be reported as a single estimate for the undiscounted average recoveries in the case of success (mean success volume, MSV) together with a probability of success (POS). For aggregation purposes the risked expectation volumes are used (POS*MSV).

Non-Commercial SFR

SFR in discovered resources is considered non-commercial for development projects which, even if technically successful, would not be commercially viable. To avoid unrealistic situations the reporting of Non-Commercial SFR is restricted to projects with a Unit Technical cost below an annually advised ceiling.

Non-commercial SFR is reported in order to retain an indication of the discovered resources that could become commercial with a change of circumstances (e.g. an increase in oil price, a change in tax regime, development of a gas market, flared/vented/re-injected gas volumes if significant enough to be marketed).

SFR which is expected to be commercially viable should be reported in one of the following three SFR categories.

SFR by Proved Techniques

SFR by proved techniques is the volume estimated to be recoverable from discovered resources, by a project utilising a recovery process or technique which has been demonstrated to be technically feasible in the area or in the field. Implementation is expected to be commercially viable, but a large range of technical uncertainty precludes the formulation of a technically sound project proposal.

SFR by Unproved Techniques

SFR by unproved techniques is the volume believed to be recoverable from discovered resources by a project utilising any recovery technique or process that has not yet been demonstrated to be technically feasible in the field where its application is considered, but which through laboratory or trials elsewhere has a reasonable chance of being technically feasible in the future. If feasible, the process should be expected to be commercial.

Future data gathering may disprove the technique, and with it the possibility of development, and these SFR volumes must therefore be discounted for the risk that the considered technique will not prove to be feasible.

Undiscovered SFR

Undiscovered SFR is the volume believed to be recoverable from as yet undrilled potential accumulations by any process that has been a technical success elsewhere, under similar conditions, and the development of which is expected to be commercial.

These SFR volumes must be discounted for the risk that petroleum is not present or is not commercial to develop (Probability of Success, see Appendix 6).

Future data gathering may result in a total write-off of these resources. Following drilling results, the resource volumes are revised and, in the case of a discovery, the economics re-assessed, whereupon the resource is either discarded or reclassified.

3.8 Initial In Place

The petroleum volume Initially In Place (IIP) are expressed in volumes of Stock Tank Oil Initially In Place (STOIIP), Condensate Initially In Place (CIIP) and Gas Initially In Place (GIIP) under standard conditions. For standard conditions the same PVT data must be used as adopted for the reporting of field recoveries.

4. RESOURCE VOLUME CLASSIFICATION FOR EXTERNAL REPORTING

4.1 Classification Scheme

Externally reported resource volumes have two primary purposes – financial calculations and investor assessments. The reported figures are used to calculate the depreciation of EP sector capital investments. The amount of depreciation affects the company's book earnings that are also externally reported. Shareholders and the investment community use the reported volumes and earnings to assess the performance and value of the company. It is essential that externally reported volumes are a true reflection of shareholder value.

The resource categories for external reporting are shown in Figure 4. Cumulative production, total proved reserves and proved developed reserves are externally reported annually for oil, gas and NGL sales quantities as of the 1st of January. The reported volumes must comply with SEC definitions, reproduced in Appendix 3. The Shell Group definitions contained in this section are in full compliance with these definitions. Where Group guidelines interpret SEC definitions, as listed in Appendix 4, these interpretations have been accepted by external auditors as fulfilling SEC requirements. A summary of the Group definitions for the external categories is provided in Appendix 1.

Cumulative Production	
Proved Reserves:	Proved Developed Reserves Proved Undeveloped Reserves

Figure 4: Resource Categories for External Reporting

Cumulative production for external reporting has the same definition as used in the Shell internal classification scheme (see Section 3.5). An example of the migration of resource volumes between externally reported categories during a field's life cycle is shown in Appendix 2.

4.2 Proved Reserves

Proved reserves are the portion of reserves, as defined for internal reporting, that is **reasonably certain** to be produced and sold during the remaining period of existing production licences and agreements. Extension periods are only included if there is a legal right to extend, which may derive either from the initial concession agreement or from a subsequent letter of assurance. Any applicable government restrictions on oil export and contractual or practical market limitations to gas delivery rates should be taken into account. Only the Group share of proved reserves is reported.

If probabilistic methods are used, reserves are reasonably certain when there is an 85% probability that the quantities actually recovered will equal or exceed the estimate. This is the P85 value of the cumulative probability curve. If scenario deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. This is the low side estimate. When the estimate assumes significant volumes of hydrocarbons outside the defined fluid contacts, or when the recovery mechanism is untested in the field or analogue fields, a lower estimate should be used that reflects this uncertainty.

As discussed in Section 2.4, proved reserve estimates should be updated annually based on development and performance data.

Proved Developed Reserves

Proved developed reserves are the reasonably certain portion of internally reported developed reserves (i.e. produced from existing wells through installed facilities). Drilling and completing a well essentially proves the hydrocarbons that it develops and therefore proved developed reserves are based on the expectation estimate of developed reserves adjusted to take into account of undefined fluids contacts, untested recovery mechanisms, licence periods, government restrictions and market limitations, as discussed above. The expectation estimate is the mean value if probabilistic methods are used or the base case estimate if scenario deterministic methods are used.

Proved Undeveloped Reserves

Proved undeveloped reserves are the reasonably certain portion of internally reported undeveloped reserves (i.e. require additional capital investment for new wells or facilities). Reasonable certainty is met by using the P85 value or low side estimate of undeveloped reserves and taking into account undefined fluids contacts, untested recovery mechanisms, licence periods, government restrictions and market limitations, as discussed above.

Total proved reserves and proved developed reserves are often determined, and then proved undeveloped reserves is the difference between the two. In mature fields when most of the reserves have been developed, this approach can result in values for total proved reserves and proved undeveloped reserves that are no longer reasonable. Once a field is at this level of maturity, a deterministic approach should be used for both proved developed reserves and proved undeveloped reserves consistent with the SEC and SPE definitions (Appendix 3, Reference 8). Total proved reserves is then the sum of proved developed reserves and proved undeveloped reserves.

Estimates of proved reserves should be benchmarked against the "proved area" deterministic method consistent with the SEC and SPE definitions (Appendix 3, Reference 8). This method first defines the proved area[2] of the field and then estimates the volumes expected to be recovered from the proved area. If the proved and proved developed reserve estimates are significantly different using the proved area method (as generally used in the industry), a reconciliation should be made for the OU to assure itself that the reported reserves are a true reflection of shareholder value.

Asset holders should be aware of the differences between probabilistic and deterministic techniques since third parties, e.g. gas buyers and hence external reserves auditors for certification, may adopt different practices.

External Financing

For projects which require some degree of external financing (e.g. LNG projects, major new venture start-ups), project financing must be expected to be available before proved reserves are disclosed externally. This could, by exception, be a reason why the reserves of some viable projects are excluded from external reporting.

Improved Recovery Projects in External Disclosures

Advances in reservoir modelling techniques have greatly enhanced the systematic assessment of project recoveries across the full range of uncertainties, increasing confidence in the use of simulation results as the basis for investment decisions and reserves estimation. This improved quantification has in some cases shown that pilot testing is not necessary prior to project commitment (based on a Value of Information approach). Under these circumstances, recovery from improved recovery projects (e.g. fluid injection, reservoir blowdown) may be considered proved when the following three conditions are met:

1) A comprehensive assessment of uncertainties results in confidence that the actual volume will be greater than the low estimate.

2) The main features of the recovery process are supported by confirmed responses in analogous reservoirs.

3) Project financing has been obtained or is expected to be available without a pilot testing phase.

In the case of improved gas recovery, the additional conditions in the following section also apply.

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[2] The area of the reservoir considered as proved area includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data (Reference 8).

Proved Gas Reserves in External Disclosures

In addition to the foregoing conditions, proved reserves of natural gas should include only quantities falling in the following categories:

1) that are contracted to sales; or
2) that can be considered as reasonably certain of being sold based on a reasonable expectation of the availability of markets, along with transportation/ delivery facilities that are in place; or
3) that, while not firmly planned, have been earmarked for future development and hence may reasonably be anticipated to be sold based upon expectation of availability of markets and project financing.

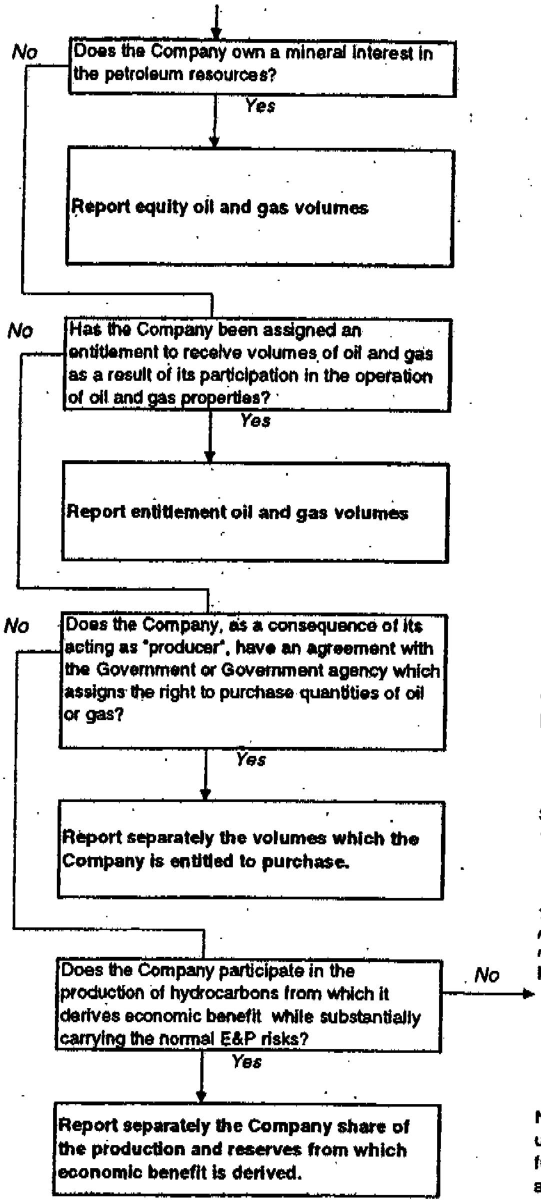
These restrictions also apply to the external disclosure of condensate/NGL products that are subject to the go-ahead of a non-associated gas project.

Proved Reserves under Constrained Production

When operating under a combined production constraint (e.g. oil production quota) and production beyond the licence or agreement period is expected, the capability to accelerate the post licence production provides a safeguard against under-performance of the planned development programme during the licence period. This capability increases the confidence level that can be assigned to the constrained production forecast during the licence period. In this circumstance, the proved reserves should be based on an accelerated development programme that could be followed in the event that the base plan delivered less production than expected.

Types of Agreements

Under US Financial Accounting Standards Board (FASB) regulations, separate disclosure is required for oil and gas volumes applicable to different types of agreements. These requirements are illustrated in Figure 5.



Does the Company own a mineral interest in the petroleum resources?

Report equity oil and gas volumes

Has the Company been assigned an entitlement to receive volumes of oil and gas as a result of its participation in the operation of oil and gas properties?

Report entitlement oil and gas volumes

Does the Company, as a consequence of its acting as "producer", have an agreement with the Government or Government agency which assigns the right to purchase quantities of oil or gas?

Report separately the volumes which the Company is entitled to purchase.

Does the Company participate in the production of hydrocarbons from which it derives economic benefit while substantially carrying the normal E&P risks?

Report separately the Company share of the production and reserves from which economic benefit is derived.

Notes

Traditional meaning of an enterprise's interest in reserves (FASB 19 para.10). Exclude volumes payable to others through production payments or carried interests (FASB 19 para. 47a and d).

Typical PSC case. Whether the Government has a pre-emptive right to buy back these entitlements is not material.

Relevant where national legislation prevents access to mineral rights. The agreement would not be a consequence of acting as producer if e.g. others have similar agreements but do not participate in production operations.

Separate disclosure is required. FASB 69 para. 13.

The following are interpretations of the principles of the FASB regulations regarding Company interests in production & reserves:

No volumes reported.

Normal E&P risks refer to both downside and upside exposure to changes in the value of future production volumes due to uncertainties as to their presence, volume and price.

Figure 5: Types of External Disclosures in Relation to FASB Regulations

5. RESOURCE VOLUME REPORTING, RESPONSIBILITIES AND AUDITS

5.1 Shareholder Requirements

EP Planning will communicate a timetable and the details about submission requirements to OUs and NVOs each year for both internal and external reporting.

Volumes will be reported based on the classification systems described in Sections 3 and 4. Additional information is reported for the calculation of the Standardized Measure required by the US Financial Accounting Standards Board (FASB).

5.2 Methods and Systems

OUs and NVOs are responsible for selecting the methods and systems that are technically most appropriate for quantifying the resource volumes of their assets consistent with these guidelines. The preferred methods and systems may vary depending on the type of resource and with time as the resource matures and technology improves. Best practices will be developed, updated and shared in the Hydrocarbon Resource Volumes Management Common Interest Network (Reference 7). This network will replace the material previously covered in Volume 2 of the 1988 guidelines (Reference 1).

A variety of commonly used Group and 3rd party systems are available to support resource volume assessment. Group systems are tailored to these requirements and methods and will generally provide an inherent level of quality assurance through input constraints, internal calibrations, and other "reality checks". Where more generalised 3rd party systems are used, OU and RBD management should be aware of the greater burden of quality control that will be required.

The Group Reserves Auditor will review decisions on methods and systems during the periodic audits. As far as these methods bear on the estimation of externally reported resource volumes, the Group Reserves Auditor will ensure that recommended methods are acceptable to the external auditors.

In some cases, OUs and NVOs may be unable to follow Group guidelines and/or recommended practice, due to government requirements, hardware constraints or other reasons. It is the responsibility of the OU Reserves Custodian to bring such cases to the attention of the Group Reserves Auditor, to enable him to obtain external auditors' approval of the OUs and NVOs specific methods and systems.

5.2 Responsibilities and Audit Requirements

EP Planning Responsibilities

EP Planning is responsible for compiling of the Group statistics of resource volumes, the analysis thereof and the communication to other functions. EP Planning also maintains the resource volume guidelines.

Reserves Auditor Responsibilities

The Group Reserves Auditor will carry out regular detailed reserves reviews in OUs and NVOs to ensure compliance with SEC requirements. The Terms of Reference of the SEC Audit are included in Appendix 5. The external auditor will verify the data for external reporting.

Operating Unit Responsibilities

Within OUs and NVOs, a Management System should be established (see Reference 6), clearly defining internal reporting requirements, tasks and responsibilities. Technical and Financial functions must co-ordinate and reconcile their figures (particularly production volumes) prior to submission.

All levels in an OU, including Asset managers and the reservoir engineer preparing the individual field reserves estimates, should be aware of the importance of externally reported reserves (proved, proved developed) and their impact on financial indicators.

Asset and OU managers are responsible to ensure that the guidelines are implemented in such a way as to best represent to the shareholders the true value of the asset.

Non-operated Reserves

Where Shell is not the operator, the local Shell EP representative should prepare the reserves submission. In this case the Shell representative has the responsibility of ensuring that resource volume assessments by the operator are aligned with Group guidelines before submission. This may include reclassification of volumes between reserves and SFR categories where the operator's criteria differ from Group criteria. As usual, an audit trail (Note for file) should be available to document the reserves estimate.

If there is no EP representative or if the necessary data are not available locally, then the submission is prepared by SIEP.

Annual Review of Petroleum Resources

Until 1995, the Annual Review of Petroleum Resources (ARPR) was a constituent document of the annual EP Programme Documentation, providing an inventory of the status of petroleum resources. While OUs and NVOs no longer submit ARPR's to SIEP, the compilation of such an overview report will generally be necessary to satisfy the requirements of OU governance and as such will be a key element of the OU reserves Management System referred to above.

Audit Trail

For all the reported resource volumes an audit trail must be available of the assumptions made and process followed. This will allow any subsequent assessor to modify these estimates based on new information in a reconcilable manner. Thus, evaluation reports must be compiled (preferably on a field basis) giving the basic data, the way it has been interpreted and processed, the development options considered, and the resultant volumes with the assigned probabilities. In addition, a description should be given of the development strategy, including data gathering activities. These reports may be working files (if acceptable to local auditors), but it is recommended to make a duplicate 'for file' in order to ensure that the data are preserved in field reports.

Where subsequent small revisions are made, an update note must be compiled. Multiple changes may be combined in one overall update of the resource volumes if they all belong to the same change category. After several years of small changes or following a development study, a new evaluation report must be issued. When a proposed change has a significant impact on the Company's total reserves or financials, SIEP should be advised at the earliest opportunity.

REFERENCES

1. EP 88-1140 Part 1, Classification, definitions and reporting requirements,
   EP 88-1145 Part 2, Methods and procedures for resource volume estimation,
   SIPM, April 1988
2. EP93-0075 Petroleum Resource Volume Guidelines, May 1993
3. Revision of Report EP93-0075, 12 August 1994
4. Revision of Report EP93-0075, 10 November 1995
5. Revision of Report SIEP97-1100, September 1997
6. EP92-0945 Business Process Management Guideline, SIPM, EPO/72, June 1992
7. Hydrocarbon Resource Volume Common Interest Network,
   http://sww1.epglobal.shell.com/forums/aca-2/dispatch.cgi
8. Petroleum Reserves Definitions, Society of Petroleum Engineers and World Petroleum Congresses, http://w.w.w.spe.org/ip/reserves
9. Project Evaluation and Screening Criteria, SIEP 97-2020, June 1997
10. Handbook of SEC Accounting and Disclosure
11. Financial Accounting Standards Board (FASB), e.g. Statements 19, 25 and 69.

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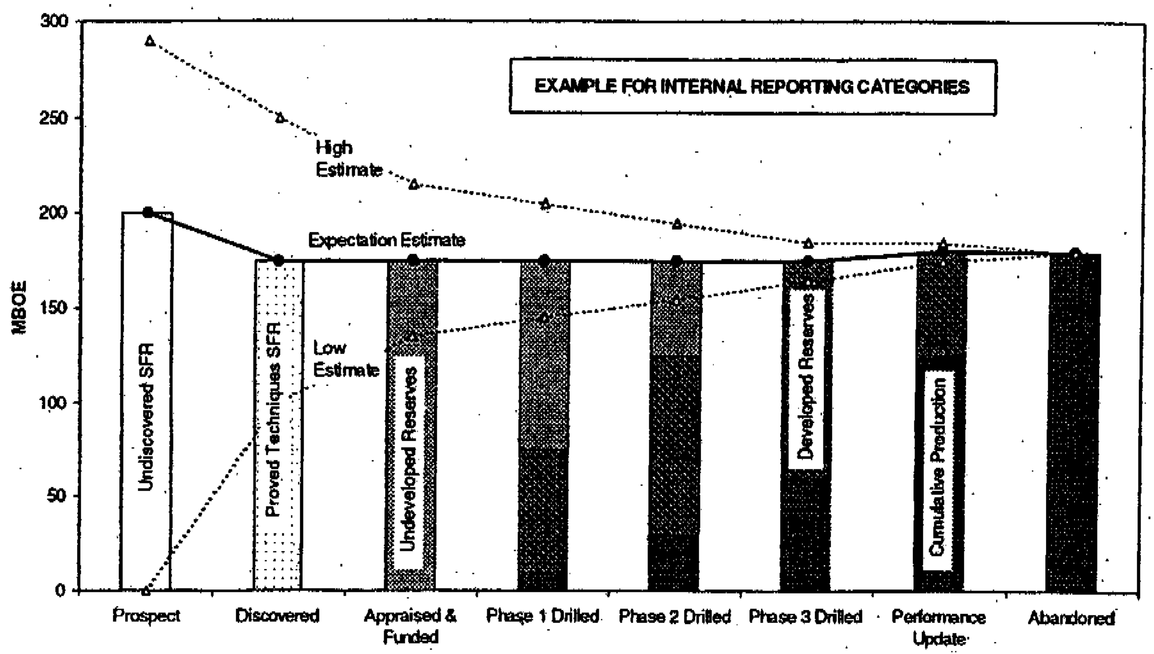
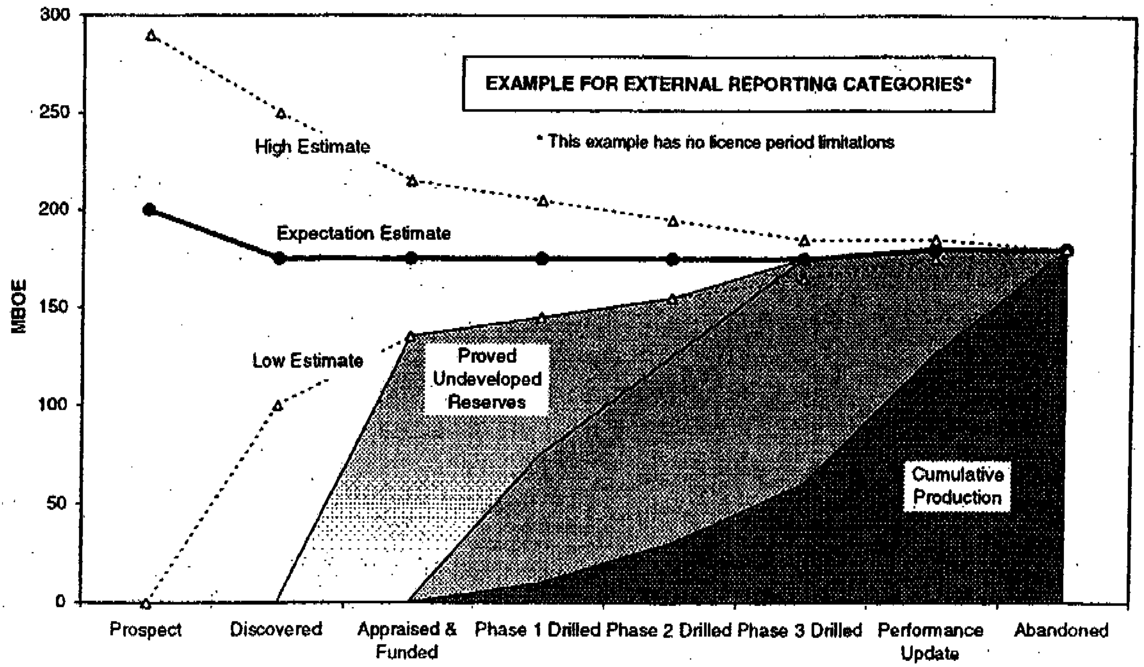
APPENDIX 1: RESOURCE CATEGORY DEFINITIONS SUMMARY

Internal Reporting	**Reserves**		• Project is "technically and commercially mature" (defined in section 3.3) • Formal project approval or economic viability is not required • Market is reasonably expected to be available • Includes only production with positive cash flow • Not restricted by licence period • Group share reported
		Developed Reserves	• Reserves producible through existing completions and installed facilities using existing operation methods • Outstanding project activities considered completed if <10% of total
		Undeveloped Reserves	• Reserves which require capital investment (wells and/or facilities)
	Scope for Recovery		• Project is <u>not</u> technically and commercially mature • Not restricted by licence period • Group share reported
		Proved Techniques SFR	• Discovered • Commercially viable • Techniques have been proved to be feasible in this resource • A sound technical project proposal is not possible yet due to large range of technical uncertainty
		Unproved Techniques SFR	• Discovered • Commercially viable • Recoverable by techniques that have been successful elsewhere, but cannot yet be demonstrated to be feasible in this field • Laboratory work or trials elsewhere have a reasonable chance of demonstrating technically feasibility in this field • Discounted for the risk that the considered technique will not prove to be feasible
		Non-commercial SFR	• Discovered • Not commercially viable even if technically successful • Commercially viable with a change of commercial circumstances • Unit Technical cost below an annually advised ceiling • Remaining tail production if it is significant
		Undiscovered SFR	• Recovery from undrilled prospects • Commercially viable • Techniques have been successful elsewhere under similar conditions • Discounted for the risk that commercial volumes are not present
External Reporting	**Proved Reserves**		• Portion of reserves as defined above that are reasonably certain • Discounted for undefined fluid contacts and untested recovery mechanisms • Restricted by licence periods, government constraints and market limitations • External financing, when used, must be expected to be available
		Proved Developed Reserves	• Reserves producible through existing completions and installed facilities using existing operation methods • Outstanding project activities considered completed if <10% of total
		Proved Undeveloped Reserves	• Reserves which require capital investment (wells and/or facilities)

APPENDIX 2: RESOURCE MIGRATION DURING FIELD LIFE





APPENDIX 3: SEC PROVED RESERVES DEFINITIONS

(Transcribed from the Handbook of SEC Accounting and Disclosure 1998, pages F3-63 to F3-64)

Proved Reserves

Proved reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

A. Reservoirs are considered proved if economic productibility is supported by either actual production or conclusive formation test supports. The area of a reservoir considered proved includes:

   1: that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and

   2. the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

B. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

C. Estimates of proved reserves do not include the following:

   1. oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";

   2. crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

   3. crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

   4. crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal (excluding certain coalbed methane gas), gilsonite and other such sources.

Proved Developed Reserves

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery techniques is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

APPENDIX 4: SHELL INTERPRETATION OF SEC RESERVE DEFINITIONS

SEC Definition	Shell Interpretation for External Reporting
Reasonable certainty; Proved area includes portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and the immediately adjoining portions not yet drilled...In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.	If probabilistic methods are used, reserves are reasonably certain when there is an 85% probability that the quantities actually recovered will equal or exceed the estimate. This is the P85 value of the cumulative probability curve. If scenario deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. This is the low side estimate. When the estimate assumes significant volumes of hydrocarbons outside the defined fluid contacts, or when the recovery mechanism is untested in the field or analogue fields, a lower estimate should be used that reflects this uncertainty. Drilling and completing a well essentially proves the hydrocarbons that it develops and therefore proved developed reserves are based on the expectation estimate of developed reserves adjusted to take into account of undefined fluids contacts and untested recovery mechanisms.
Fixed RT prices at level prevailing at date of estimate	Prices fixed by SIEP ca. 6 months prior to estimate date, but amended if there is a subsequent significant change.
Fixed RT costs at level prevailing at date of estimate.	Costs fixed by OUs and NVOs at date of estimate. Flat MOD costs must be supported by technology plans.
Economic productibility	Technically and commercially mature (i.e. positive discounted real terms cash flow for sufficient range of scenarios).
Productibility supported by either actual production or conclusive formation test supports	Productibility should normally be demonstrated by a conclusive test, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.
Improved recovery processes included only after successful testing by a pilot project or the operation of an installed program	Reserves from improved recovery processes are normally included following an in-situ test; by analogy with the same process being used elsewhere under similar conditions, or occasionally as a result of lab tests or simulation studies.
No gas qualifier	Include only gas contracted or reasonably expected to be sold.
Developed reserves are from existing wells (including minor cost recompletions), existing facilities and operating methods	Existing wells, installed facilities and existing operating methods. Outstanding project activities can be considered existing or installed if outstanding costs are minor and is reasonably expected.

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APPENDIX 5: SEC AUDIT - TERMS OF REFERENCE

The Auditor's task is the following:

1. Establish whether the reserves estimates for external reporting have been prepared in accordance with the established guidelines. If not, to establish that the procedures used are acceptable, and not likely to result in reserves estimates that differ from those that might be expected from the application of the standard guidelines.
2. Establish that the basis for estimating the reserves quantity information is consistent with the previous periods.
3. Check that the source data is adequately documented and that movements in proved reserves are supported by such data and are correctly classified.
4. Establish that the frequency and extent of the reserves estimates are sufficient to make the estimates continuously reliable.
5. Investigate any differences between volumes that are reported for external purposes and those that are reported to SIEP in annual financial reporting.
6. Check the calculation of proved developed reserves and investigate any differences between proved developed reserves used for external purposes and those used as a basis for asset depletion purposes.
7. Establish whether proved gas reserves agree with sales contracts concluded.
8. Ensure that all quoted proved reserves are expressed in sales quantities, e.g. own use has been excluded. In case of gas sales the production quantity should be given as measured at the point of transfer.
9. Ensure that sales quantities of hydrocarbons are in line with those reported to Finance.

The checks will be carried out by taking at random one or more fields for detailed analysis, and a judgement will be passed accordingly.

The audit will be carried out as a stand alone exercise based on documentation available in the company to be investigated. In case of queries assistance of company staff may be called upon.

An audit report will be prepared on site (draft) and discussed locally. The report will contain an Action List based on recommendations of the report.

APPENDIX 6: TERMINOLOGY

A) *Petroleum Resources Terminology*

Reservoir	A reservoir is a discovered petroleum resource where internal pressure communication is known to exist between all identified geological sub-units.
	In case of doubt, reservoirs are restricted to fault blocks / sedimentary units until production performance proves communication to exist across faults/ barriers. PVT properties can vary within a reservoir.
Field	A field is the collection of all petroleum resources within a closed areal boundary that belong to the same confining geological structure, and where the presence of petroleum has been demonstrated in at least one reservoir by a successful exploration well.
	Field boundaries must be defined upon discovery and should encompass the unpenetrated petroleum resources in adjacent fault blocks and stratigraphic traps, if they are considered to be part of the same overall confining structure. Field boundaries may be re-defined on the basis of new geological information.
Potential Accumulations	Potential petroleum resources beyond existing field boundaries, where the presence of petroleum has not yet been demonstrated, are collectively called potential accumulations.
Producibility	Should normally be supported by a conclusive test in a drilled or immediately adjoining reservoir, but may be based on log or core evaluation in an area where many similar reservoirs have been conclusively tested.
Production Facilities	The production facilities consist of all hardware installed to recover petroleum from the sub-surface resources and to deliver a quality controlled end-product for sale. These comprise the production and injection wells and the surface facilities for treatment, conversion, compression/ pumping, transport and delivery.
Surface Facilities	That part of the production facilities accessible at surface, connecting the wellheads ultimately to the delivery points.
Existing Development	The collection of all completed projects or sub-projects is referred to as the existing development.
Field quantities	Field quantities (also called "Wellhead" quantities) are those quantities routinely measured at surface for individual well strings and expressed in terms of the stabilised products oil, condensate and (wet) gas or in terms of the type of injected fluids. These quantities may subsequently be reconciled with fiscalised sales and other product outlets, see below.
Sales quantities	The quantities sold after fiscal metering and delivered at the locations where the upstream company ceases to have an interest in the end-products. These can be expressed in terms of the general end-products oil, (dry) gas and natural gas liquids (NGL) or in terms of the actual product.
	Field products and the subsequent sales products may be different and will be affected by own use and losses. The properties and volumes of end-products may be influenced by mixing and the petroleum type itself may be altered during surface processing. Since surface processing conditions may change during a project life, sales products may vary in specification and in relation to field products. To avoid ambiguity and double counting, a clear distinction must be made between recoveries in the field and the quantities estimated to be available for sale.
	For general sales products, oil, gas and NGLs, only the quantities sold by the upstream E&P company can contribute to Group reserves. Condensates mixed with crude oil in the same stream and sold as such are reported under oil. Separator condensate from gas wells and light hydrocarbon liquid products, derived from surface processing, if collected in a separate stream and sold as such are reported under NGL. Bitumen may be reported under oil in summary reports (with an appropriate footnote). In line with SEC requirements, sales volumes for gas should be those committed or

commitable to a gas contract. Committed Gas is covered by a gas contract. Commitable gas reasonably expected to be assigned to a contract in the future.

It is necessary to maintain a more detailed internal administration of the actually sold products by stream in two cases: 1) If the upstream E&P company has separate contracts for delivery of special converted sales products such as LNG, methanol, ethane, LPG, C5+, or 2) if there are special sales products like helium, sulphur or generated electricity.

Reconciliation A monthly reconciliation is made between the fiscalised sales quantities and the quantities produced in the field. This is reported in the Monthly Report of Producing Wells (MRPW). The reconciliation process corrects for own use, flaring, losses and product conversion, and provides the end-product yield.

For reserves estimating purposes an average future yield factor is to be estimated (e.g. LPG/ wet gas yield, dry gas/ wet gas yield).

Ultimate Recovery The ultimate recovery (UR) of a petroleum type is the sum of cumulative production and the estimated volume of reserves.

B) Probabilistic Terminology

Probability Distribution Function The probability distribution function of a stochastic variate indicates the probability that the actual variate value lies within a narrow interval around a particular value of the possible range, divided by the width of that interval.

P85 The value that has a 85% probability that it will be exceeded.

P15 The value that has a 15% probability that it will be exceeded.

Mean The statistical mean of a stochastic variate is the weighted average over the entire probability range.

Mean Success Volume (MSV) The probability weighted average of all realisations that equal or exceed the minimum reserves required for a commercial development of the resource.

Probability of Success (POS) The probability that the minimum commercial volume will be exceeded and which therefore indicates the likelihood of any future development. The product of MSV and POS is the recovery expectation.

C) Commercial Terminology

Discount Rate A rate at which future real terms costs or cash-flow are discounted over time to calculate their present value.

Net Present Value (NPV) The net present value of a project is the sum of the discounted annual cash flow, expressed in real terms money, over the period from the first project expenditure to abandonment. The net present value is expressed in million US$ at the relevant discount rate.

Expected Monetary Value (EMV) The expected monetary value is a probabilistic balance of investments and revenues, expected from a set of conditional operational activities, comprising data acquisition and one or more development projects, which are arranged in an ordered sequence with probabilities assigned to each action (decision tree).

The EMV is the summation of the NPV's of projects, reduced by the costs of data acquisition activities, all expressed in discounted real term money and multiplied by their assigned probabilities. EMV is expressed in million US$ at the relevant discount rate.

Projects with a negative NPV for certain resource model realisations should be excluded from the EMV calculation, if the assumption is valid that data gathering will prevent such projects being implemented.

Unit Technical Cost (UTC) The unit technical cost of a development project is defined as the sum of capital plus operating costs, expressed in real terms money, divided by the total production over the period from start-up to abandonment. In addition, both the cost and the production must be discounted. The reference date for the discounting should be the same for denominator and numerator (e.g. the first year of expenditure) and should be stated. The unit technical costs is expressed in US$/bbl (oil equivalent) at the relevant discount rate.

Aalbers, Remco RD SIEP-EPB-P

From: Meijssen, Thomas OQP
Sent: 03 January 2001 08:51
To: Barendregt, Anton SIEP-EPB-GRA
Cc: Aalbers, Remco SIEP-EPB-P; Abri, Said CEM3; Antonini, Marcus CEM5
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Anton, Remco,

Many thanks for your Email. Based on the guidelines given in your Email below, we have evaluated the impact on the proven reserves numbers to be used for external reporting using the notional ARPR 1/1/2001 data.

In the table below, a breakdown of the total expected reserves (developed and undeveloped) versus maturity (as expressed in cumulative production / expected recovery) has been given. As can be observed from the table, 61% of the total expected reserves can be classified as mature, using the 40% criterion.

Maturity	Tot Res	%
<40%	305	39%
40-60%	227	29%
>60%	255	32%
Total expectation	787	100%

All volumes 100% PDO, mln m3

MMT = 192.8 1/1/2001

An overview of the proven and expected reserves as carried by PDO and the impact of using the Shell Group guidelines on externally reported proven reserves has been indicated in the table below.

/144.5 ~ 78% ~~144.6~~ 137.3

	DevRes	UndevRes	TotRes	Incr	Incr %
~~Proven~~ P85	205	220	425		
Proved 1999 method	380	46	425	0	0%
Proven, DevRes 40%	347	220	567	141	33%
Proven, DevRes 40%, UndevRes 60%	347	254	601	176	41%
Proven, DevRes 40%, UndevRes 40%	347	304	651	225	53%
Expectation	380	408	787		
All volumes 100% PDO, mln m3	54%	54%	54%		

→ 192.8 55 @ 34%
90%
||
~~[illegible]~~ 1735

Some remarks: P85

- The ~~proven~~ and expectation reserves are as per the reserves bookings, the expected developed reserves are updated annually using the do-nothing production forecast. The proven developed reserves are calculated by pro-rating the proven/expectation reserves and expected developed reserves.
- ~~Proven~~ P85: ~~Proven~~ P85 reserves as carried by PDO at 1/1/2001
- Expecation: Expected reserves as carried by PDO at 1/1/2001
- Proven, 1999 method: Proven reserves, making proven developed reserves equal to expectated developed reserves for all fields ~~exceeding 40% maturity~~, but keeping the total proven reserves equal. As a result the proven undeveloped reserves reduces to 46 mln m3 which seems unrealistically low.
- Proven, DevRes 40%: Proven reserves, making proven developed reserves equal to expectated developed reserves for fields exceeding 40% maturity, keeping the proven undeveloped reserves equal.
- Proven, DevRes 40%, UndevRes 60%: As above, but in addition now making the proven undeveloped reserves equal to the expected undeveloped reserves for fields exceeding 60% maturity (more relaxed criterion, to reflect the additional uncertainty related to the undeveloped reserves).
- Proven, DevRes 40%, UndevRes 40%: As above, but using the 40% maturity criterion for undeveloped reserves.

I would propose for external reserves reporting to only adjust the proven developed reserves using the 40% maturity criterion and to keep the undeveloped reserves for internal and external reporting the same (case: Proven, DevRes 40%). As a result the total proven reserves increases by 141 mln m3 (100% PDO). Any further increase in total proven reserves becomes more difficult to argue in view of the additional uncertainty of the undeveloped reserves which is difficult to quantify.

Would you agree with the proposed method? Following your advise, I will inform PDO senior management on the proposed method for external reserves reporting to the Shell Group.

Best regards,

DEPOSITION EXHIBIT
Barendregt
#29 2/22/07

DEPOSITION EXHIBIT
Aalbers D
2/19/07 #

Thomas

-----Original Message-----
From: Barendregt, Anton AA SIEP-EPB-GRA
Sent: 02 January 2001 16:05
To: Meijssen, Thomas TEM PDO-OQP / UPR
Cc: Aalbers, Remco RD SIEP-EPB-P; Abri, Said SM PDO-CEM3; Antonini, Marcus MCJ PDO-CEM5
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Thomas,

In response to your query, I fully support the conclusions reached during Remco's visit, as reflected in your note of 24th October. In particular, I support the move towards using expectation estimates for the externally reported proved reserves for mature fields (i.e. for fields with cum.prod. greater than 40% of expectation ultimate recovery). I note that the 40% criterion is not necessarily rigorous: for simple clastic light oil waterdrive reservoirs it could easily be set lower, for heavy oil reservoirs or complex carbonate reservoirs like many of those in Oman, it seems a realistic proposition.

As mentioned in my 1999 audit report (Att. 3) we should move away from determining total proved reserves through probabilistic volumetrics, combined with probabilistic estimates of recovery factors. Instead we should make separate estimates of developed reserves (from decline analysis or history matched reservoir simulation) and undeveloped reserves (from reservoir simulation or other reliable predictions). Undeveloped reserves must always be based on a well defined set of future activities (new wells, infill drilling, re-completions etc.).

Each of the two volumes (i.e. developed and undeveloped reserves) can have a probability range (P85, P50, P15, Expectation) associated with it. Group guidelines prescribe that for developed reserves in mature fields we should take the Expectation estimate as the externally reported 'Proved Developed Reserves'. For those mature fields it is expected that the P85 estimate would be close to the P50/Expectation value anyway. For externally reported undeveloped reserves it will often be appropriate to take the expectation value as well, but in some of the more uncertain cases (e.g. different future well types) it may be more appropiate to take the P85 volume.

The externally reported total reserves should be the sum of the developed and the undeveloped reserves estimates.

Trust this clarifies. Good luck with your 2000 submission!

Last but no least, I wish yourself and the PDO PE community a successful, safe and healthy 2001!

Anton Barendregt

> -----Original Message-----
> **From:** **Meijssen, Thomas OQP**
> **Sent:** 22 December 2000 14:36
> **To:** Barendregt, Anton SIEP-EPB-GRA
> **Cc:** Aalbers, Remco SIEP-EPB-P; Abri, Said CEM3; Antonini, Marcus CEM5
> **Subject:** FW: Proved Reserves Visit - Group Resource Co-ordinator
>
> **Anton,**
>
> **With reference to the visit of Remco Aalbers to PDO from 23-24 October 2000, we would like to know your opinion with respect to external reporting of proven reserves. During the visit of Aalbers the following was suggested:**
>
> **External reporting of proved reserves in line with Group guidelines will be handled by PDO reserves co-ordinator and the CFDH reservoir engineering. It is recommended to use field maturity in excess of 40% (as expressed in cumulative production / expected recovery) as the criterion to use proved developed = expectation developed. As a result the total proved reserves will similarly increase. This procedure will be further clarified with Group Reserve Auditor Anton Barendregt. Action: CEM/3, UPR**
>
> **Looking forward to your reply,**
>
> **Best regards,**
>
> **Thomas Meijssen**
> **CFDH Reservoir Engineering**

DEPOSITION EXHIBIT
Aalbers # E
2/19/07 (7a)

-----Original Message-----
From: Barendregt, Anton AA SIEP-EPB-GRA
Sent: donderdag 4 januari 2001 13:51
To: Meijssen, Thomas TEM PDO-OQP / UPR
Cc: Aalbers, Remco RD SIEP-EPB-P; Abri, Said SM PDO-CEM3; Antonini, Marcus MCJ PDO-CEMS
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Thomas,

Remco and I have looked at your proposed figures and our comment is as follows:

1. The ratio between your total P85 and expectation reserves (425 and 787 mln m3 respectively) is 54%. This is far too low for a mature area like Oman and indicates that there are fundamental flaws in PDO's present process of calculating the probabilistic range of ultimate recovery in its fields. In essence, it seems that the ranges of volumetric and RF parameters are taken far too wide, as if they applied to virgin fields instead of fields with large numbers of wells and extensive production history. The result is that P85 UR volumes are not increased in line with production performance history. This flaw was highlighted during the 1999 SEC reserves audit and again during Remco's visit in October 2000.
2. Having said that, we appreciate that updating field P85 recoveries to more realistic levels requires discussion with the Ministry and hence may take time. We suggest that priorities are set if necessary, aiming at updating the P85 volumes first for the largest fields
3. We stress again that the issue of what reserves to report as 'Proved, externally reported' is, since the 1998 changes in the reserves guidelines, quite different from the issue of what reserves to carry as P85 or Low volumes for individual fields. The latter may be subject to discussion with the Ministry, but the first cannot be, if only because the total PDO Shell share volume has to be curtailed at licence expiry, an issue that does not interest the Ministry.
4. In order to avoid confusion, also internally within PDO, it may be opportune to reserve the term 'Proved' exclusively for the externally reported Proved reserves and use 'P85' or 'Low' (NOT 'Proven') for the high confidence reserves values. We'll consider whether this distinction can perhaps be made more clearly in future versions of the Guidelines.
5. As for your proposed volumes to book as externally reported Proved Reserves (before they are cut off by licence expiry), your line "Proven, DevRes 40%, UndevRes 60%" (347 mln m3 Dev Res and 254

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UndevRes) seems the best one to aim for. It is still conservative (because of the too low P85 values in the less mature fields), but it has the advantage that one can maintain this method of determining externally reported Proved reserves in future submissions. Any future over-reporting of undeveloped reserves (i.e. in fields where undeveloped reserves are still somewhat uncertain in spite of the field's maturity) is compensated by the fact that we take expectation only for fields in excess of 60% maturity (and not 40%) and P85 for those below 60%.

6. As mentioned, externally reported Proved reserves must be cut off at licence expiry through a realistic forecast. For the recommended case "Proven, DevRes 40%, UndevRes 60%" we estimate a 9-year plateau plus subsequent decline (@20%), leading to a Proved volume after licence expiry cut off (but before 34% Shell share) of some 87% of 347+254 mln m3, i.e some 523 mln m3. Shell share would then be 178 mln m3 1/1/2001, versus 139.5 mln m3 1/1/2000, an increase of some 55 mln m3 (assuming 2000 prod is some 16.5 mln sm3).
7. This method results in a proved/exp dev ratio of 347/380 = 91% and a proved/exp undev ratio for 254/408 = 62% (PDO), values that are much more in line with the maturity of the Oman fields, even if the undev ratio is still too low.

We hope the above clarifies. Please let us know if you have further queries.

Best regards,

Anton

-----Original Message-----
From: Meijssen, Thomas OQP
Sent: 03 January 2001 09:59
To: Barendregt, Anton SIEP-EPB-GRA
Cc: Aalbers, Remco SIEP-EPB-P; Abri, Said CEM3; Antonini, Marcus CEM5
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Anton, Remco,

Please note that the 1999 method used for external reporting made the proven developed reserves equal to expectated developed reserves for <u>all</u> fields (irrespective of their maturity) and kept the total proven reserves equal.

Best regards,

Thomas

-----Original Message-----
From: Meijssen, Thomas OQP
Sent: 03 January 2001 12:52
To: Barendregt, Anton SIEP-EPB-GRA
Cc: Aalbers, Remco SIEP-EPB-P; Abri, Said CEM3; Antonini, Marcus CEM5
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Anton, Remco,

Many thanks for your Email. Based on the guidelines given in your Email below, we have evaluated the impact on the proven reserves numbers to be used for external reporting using the notional ARPR 1/1/2001 data.

In the table below, a breakdown of the total expected reserves (developed and undeveloped) versus maturity (as expressed in cumulative production / expected recovery) has been given. As can be observed from the table, 61% of the total expected reserves can be classified as mature, using the 40% criterion.

<< OLE Object: Microsoft Excel Worksheet >>

An overview of the proven and expected reserves as carried by PDO and the impact of using the Shell Group guidelines on externally reported proven reserves has been indicated in the table below.

<< OLE Object: Microsoft Excel Worksheet >>

Some remarks:

- The proven and expectation reserves are as per the reserves bookings, the expected developed reserves are updated annually using the do-nothing production forecast. The proven developed reserves are calculated by pro-rating the proven/expectation reserves and expected developed reserves.
- Proven: Proven reserves as carried by PDO at 1/1/2001

- Expecation: Expected reserves as carried by PDO at 1/1/2001
- Proven, 1999 method: Proven reserves, making proven developed reserves equal to expectated developed reserves for fields exceeding 40% maturity, but keeping the total proven reserves equal. As a result the proven undeveloped reserves reduces to 48 mln m3 which seems unrealistically low.
- Proven, DevRes 40%: Proven reserves, making proven developed reserves equal to expectated developed reserves for fields exceeding 40% maturity, keeping the proven undeveloped reserves equal.
- Proven, DevRes 40%, UndevRes 60%: As above, but in addition now making the proven undeveloped reserves equal to the expected undeveloped reserves for fields exceeding 60% maturity (more relaxed criterion, to reflect the additional uncertainty related to the undeveloped reserves).
- Proven, DevRes 40%, UndevRes 40%: As above, but using the 40% maturity criterion for undeveloped reserves.

I would propose for external reserves reporting to only adjust the proven developed reserves using the 40% maturity criterion and to keep the undeveloped reserves for internal and external reporting the same (case: Proven, DevRes 40%). As a result the total proven reserves increases by 141 mln m3 (100% PDO). Any further increase in total proven reserves becomes more difficult to argue in view of the additional uncertainty of the undeveloped reserves which is difficult to quantify.

Would you agree with the proposed method? Following your advise, I will inform PDO senior management on the proposed method for external reserves reporting to the Shell Group.

Best regards,

Thomas

—–Original Message—–
From: Barendregt, Anton AA SIEP-EPB-GRA
Sent: 02 January 2001 16:05
To: Meijssen, Thomas TEM PDO-OQP / UPR
Cc: Aalbers, Remco RD SIEP-EPB-P; Abri, Said SM PDO-CEM3; Antonini, Marcus MCJ PDO-CEM5
Subject: RE: Proved Reserves Visit - Group Resource Co-ordinator

Thomas,

In response to your query, I fully support the conclusions reached during Remco's visit, as reflected in your note of 24th October. In particular, I support the move towards using expectation estimates for the externally reported proved reserves for mature fields (i.e. for fields with cum.prod. greater than 40% of expectation ultimate recovery). I note that the 40% criterion is not necessarily rigorous: for simple clastic light oil waterdrive reservoirs it could easily be set lower, for heavy oil reservoirs or complex carbonate reservoirs like many of those in Oman, it seems a realistic proposition.

As mentioned in my 1999 audit report (Att. 3) we should move away from determining total proved reserves through probabilistic volumetrics, combined with probabilistic estimates of recovery factors. Instead we should make separate estimates of developed reserves (from decline analysis or history matched reservoir simulation) and undeveloped reserves (from reservoir simulation or other reliable predictions). Undeveloped reserves must always be based on a well defined set of future activities (new wells, infill drilling, re-completions etc.).

Each of the two volumes (i.e. developed and undeveloped reserves) can have a probability range (P85, P50, P15, Expectation) associated with it. Group guidelines prescribe that for developed reserves in mature fields we should take the Expectation estimate as the externally reported 'Proved Developed Reserves'. For those mature fields it is expected that the P85 estimate would be close to the P50/Expectation value anyway. For externally reported undeveloped reserves it will often be appropriate to take the expectation value as well, but in some of the more uncertain cases (e.g. different future well types) it may be more appropiate to take the P85 volume.

The externally reported total reserves should be the sum of the developed and the undeveloped reserves estimates.

Trust this clarifies. Good luck with your 2000 submission!

Last but no least, I wish yourself and the PDO PE community a successful, safe and healthy 2001!

Anton Barendregt

—–Original Message—–
From: Meijssen, Thomas OQP
Sent: 22 December 2000 14:36

To: Barendregt, Anton SIEP-EPB-GRA
Cc: Aalbers, Remco SIEP-EPB-P; Abri, Said CEM3; Antonini, Marcus CEM5
Subject: FW: Proved Reserves Visit - Group Resource Co-ordinator

Anton,

With reference to the visit of Remco Aalbers to PDO from 23-24 October 2000, we would like to know your opinion with respect to external reporting of proven reserves. During the visit of Aalbers the following was suggested:

External reporting of proved reserves in line with Group guidelines will be handled by PDO reserves co-ordinator and the CFDH reservoir engineering. It is recommended to use field maturity in excess of 40% (as expressed in cumulative production / expected recovery) as the criterion to use proved developed = expectation developed. As a result the total proved reserves will similarly increase. This procedure will be further clarified with Group Reserve Auditor Anton Barendregt. **Action: CEM/3, UPR**

Looking forward to your reply,

Best regards,

Thomas Meijssen
CFDH Reservoir Engineering

Unknown

From: Barendregt, Anton AA SIEP-EPF-DIR
Sent: 03 January 2004 12:29
To: Coopman, Frank F SIEP-EPF
Cc: Pay, John JR SIEP-EPS-P; Darley, John J SIEP-EPT; Bell, John J SIEP-EPS
Subject: RE: internal control weaknesses

Frank,

I have added my suggestions to your text. As a further remark: are we sure we addressed some of the shortcomings already in 2002? As far as I can see, all of the corrective action was in (late) 2003.

I have added a reference to the internal guidelines. These were, after all, the 'bible' against which I had to carry out my audits in the OUs. On the few occasions in my early years where I signalled a conflict with SEC rules I was called back by Remco and by the OUs who argued, rightly, that the only rules they should be bound by were the Group guidelines. These are the backbone of our internal controls on reserves. The spear-point of the SEC reserves auditor's control should therefore have been on a correct formulation of the Group guidelines. With hindsight, I should have been more forceful in this respect. It would have been a clear break with all my predecessors and it would probably have cost me my job in those days, but I should have. My successors will have the same constraints, only to be made easier once our uidelines are fully compliant.

I realise that Curtis may not like my reference to the guidelines. I seem to remember him saying that we should not say externally that our internal guidelines were different from the SEC's. I do not see how we can maintain that pose in ernest. It would imply saying that either our guidelines were SEC compliant (which would be an easily refutable lie) or that we had no guidelines at all, which would be unbelievable and also clearly not true.

Glad to have a further debate about this, if desired.

nton

-----Original Message-----
From: Coopman, Frank F SIEP-EPF
Sent: 02 January 2004 16:23
To: Frasier, Curtis R SI-LSEP
Cc: Darley, John J SIEP-EPT
Subject: internal control weaknesses

Curtis,

Suggested text for the Note to CMD" , paragraph 3.2 Potential issues.

Control weaknesses.

With the benefit of hindsight it is obvious where there have been control weaknesses;

At local level ;
appliance of basic disciplines in proved reserves calculations were allowed to slip. Supervisory (Chief PE) controls must have been weak.
[Barendregt, Anton AA SIEP-EPB-GRA] **Due to resource constraints, compliance checking by the Group reserves auditor was typically once in every four years which allowed slackness in local controls to go undetected for quite some time.**

At central EP level ;
reliance on the year end Group reserves auditors report , which would only cover the areas audited during that year.
An "independent" Group reserves auditor ***[Barendregt, Anton AA SIEP-EPB-GRA]*** **whose assessments were bound by the internal reserves guidelines and who was therefore not completely independent.**
no comprehensive review of all the exposed areas at set interval.

At Group Level;
No assurance was demanded for proved reserves figures, yet the 20F requires certification.

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These control weaknesses were addressed during 2002 ***[Barendregt, Anton AA SIEP-EPB-GRA]*** ?? and 2003.
The recruitment of several (instead of one) reserves auditors ,set in train, will address the resource issue.
The change in reporting line will be implemented in 2004 to ensure the "independence". The 2004 assurance letter will be amended to include proved reserves.

end of text

I will ask John Pay and Anton Barendregt for comments.

Frank Coopman
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Shell International Exploration and Production B.V.
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From: Barendregt, Anton AA SIEP-EPF-DIR
To: Coopman, Frank F SIEP-EPF; Pay, John JR SIEP-EPS-P
CC:
BCC:
Sent Date: 2004-01-16 15:22:56.000
Received Date: 2004-01-16 15:22:59.000
Subject: Rockford - a historical prespective
Attachments: Rockford-HistPersp.doc

Frank, John,

Having had some time to think in the last few days I have written down my thoughts on why we ended up where we did.

I'm still not 100% happy with the text (it needs further honing), but it's in a state where I'm happy to take comments.

I'm not sure yet whether this should be part of (or an appendix to) my end-year report. At the least it is a 'witness statement' for when I've left.

Anton

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Email: Anton.Barendregt@shell.com
Internet: http://www.shell.com/eandp-en

DEPOSITION
EXHIBIT 7a
Barendregt
#32 2/22/07

PROJECT ROCKFORD - A HISTORICAL PERSPECTIVE

By A.A. Barendregt, Group Reserves Auditor

January 2004

Introduction

The impact of Project Rockford and the ensuing de-booking of 20% of the Group's proved reserves will lead to numerous questions as to why and how such an event could have arisen. This note attempts to inventorise the facts as seen from the perspective of someone who has been involved in reservoir engineering and reserves reporting since 1975 and who has been present at or closely involved in critical stages of the process of preparing and maintaining the Group reserves guidelines from the early 1990's onwards. The note aims to be objective and it does not seek to lay blaim to specific parties.

The note follows the successive historical events, as graphically presented in Fig. 2.

References to documented evidence are given where possible.

1972-2003: Group awareness of SEC rules

In 1972, the Group introduced a new method of reserves characterisation that was at that time unique in the industry (Ref. 1). The method was based on probabilistic assessment of in-place and recoverable hydrocarbon volumes, using probability density functions for each of the constituent volumetric and recovery parameters. The result would be a probability density function (or 'Expectation Curve') for recoverable reserves in each reservoir, describing the probability that reserves would exceed each of a range of values, starting with the 100% confidence (or minimum) value and ending with the 0% confidence (or maximum) value. 'Proved' reserves were postulated to be the value at which there was at least 85% confidence that reserves would be equal or larger than that value. The value was referred to as the Low or P85 estimate.

Industry practice at the time was based on the notions of 'proved', 'probable' and 'possible' reserves. 'Proved' was largely defined to mean 'more likely than not to be present', 'probable' meant 'equally likely to be present or not' and 'possible' would be 'less likely to be present than not'.

In 1978, the SEC issued specific definitions on proved reserves (Ref. 8) and requested that companies disclose these in their filings with the SEC. The definitions focused almost exclusively on the subsurface uncertainties regarding in-place and recoverable volumes. For more details see Table 1 and the Guidelines section below.

The Group (outside the US) adopted the SEC reporting requirement through the introduction of various reserves guidelines in the following years (Refs 2, 3, 4). These guidelines acknowledged (and even included copies of) the SEC guidelines, but in all cases they concluded that the Shell P85 probabilistic estimate was considered to be 'reasonably certain' and hence in compliance with the SEC definitions (Ref. 2, 3). One document (Ref. 4) stated that "Shell definitions are more rigorous [than SEC definitions]", and that the Group guidelines "generate reserves which are equivalent to those which would have been derived using the SEC definitions".

The confidence that the Group guidelines for proved reserves were compliant with SEC rules was maintained throughout the following series of guidelines (Refs 5, 6). Statements made were "The Shell Group definitions are in full compliance with [SEC] definitions and, in some instances, quantified in greater detail" (Ref. 5) and "Where Group guidelines interpret SEC definitions [...] these interpretations have been accepted by external auditors as fulfilling SEC requirements" (Ref. 6, 1996-2001)". From 1993 onwards, Group guidelines contained detailed lists of the SEC definitions and the Group's interpretations thereof. In some cases, these interpretations departed from the SEC text, e.g. by allowing probabilistic estimates of volumes below lowest known hydrocarbon (LKH) levels, by allowing PSC reserves based on Group PSV prices instead of end-year prices and by waiving the need for a pilot before booking of water injection reserves in certain cases (see Guidelines section below). This departure did not affect the confidence that Group proved reserves did fulfil SEC requirements.

The confidence in SEC compliance had two important consequences in the Group's petroleum engineering community:

- Group proved reserves guidelines became the only norm for evaluating proved reserves, also in proved reserves audits by the Group Reserves Auditor (see e.g. audit TORs in Refs.6),
- Education and awareness of SEC rules and their importance became neglected.

1996-2001: A strong drive to boost proved reserves

In the mid-1990s there was considerable internal and external pressure to boost proved reserves (Ref. 7). In particular it was found that Exxon booked higher proved reserves for their share of the (by now mature) fields in the North Sea. A LEAP value creation team was set up and this gave the recommendation that proved developed reserves should be made equal to expectation reserves. These recommendations were included into the 1998 Group guidelines, together with the recommendation that total proved reserves (i.e. developed plus undeveloped) should approach expectation reserves with increasing field production maturity. This recommendation was duly implemented and led to the booking of some additional 1000 MMbl Group share proved reserves over the period 1998-2000.

This major change in proved reserves reporting procedures was justified by the reporting practice in the industry, which was indeed less conservative than the probabilistic Group approach as far as it related to fields in mature production. However the change ignored the fact that SEC definitions tended to be more conservative than Group proved reserves for non-mature fields and reservoirs. The reasons were the rather strict SEC constraints to the 'proved area', which were interpreted more liberally by the Group's probabilistic approach. Guidelines at the time (e.g. Ref. 6, 1998) only mentioned that 'a reconciliation should be made' between proved area and the probabilistic reserves estimate, without specifying how this should be achieved.

The result was that, whilst there was a balance between over-reporting for immature fields and under-reporting for mature fields, this balance was effectively removed in 1998, see the schematic picture below. What remained was a potential overstatement of reserves on the immature end of the project spectrum. This was not sufficiently recognised at the time.

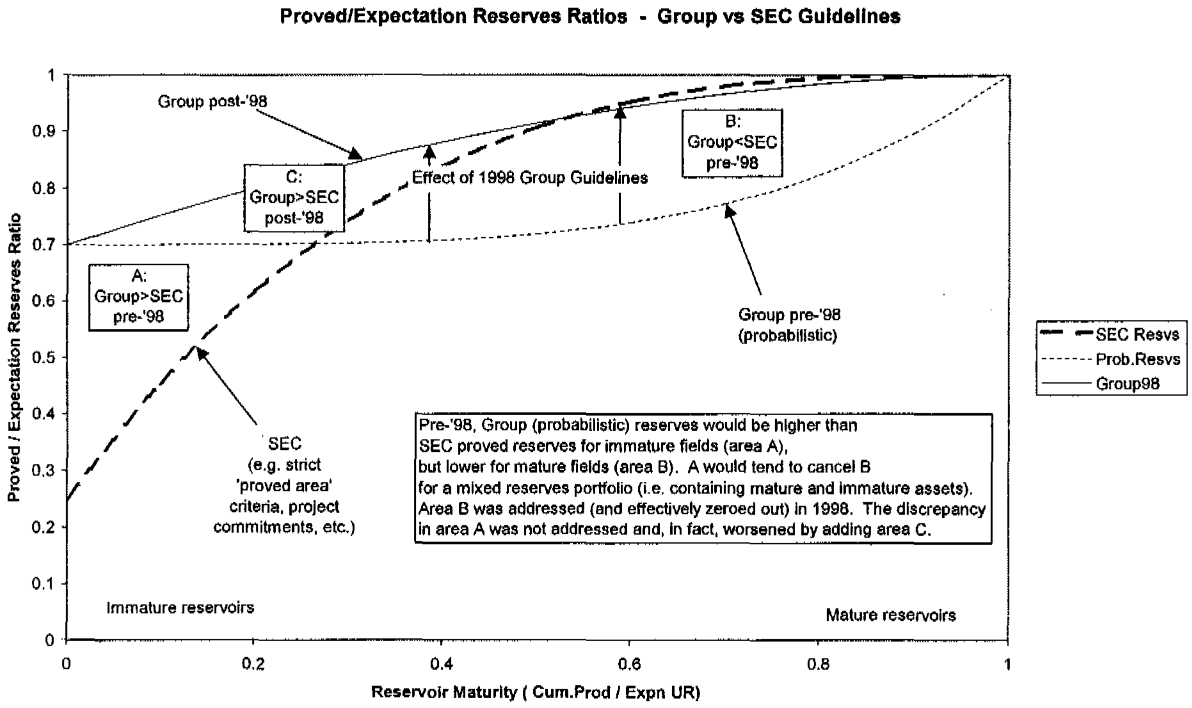

Figure 1 – Proved / Expectation reserves ratios – Group vs. SEC guidelines

1996-2001: Other aggressive reserves bookings

As mentioned, the new 1998 guidelines resulted in a significant volume of new reserves bookings in mature fields in most of the large OUs. Most of the OUs reported these additions in 1998, some in 1999. One of the OUs seen to be lagging behind was PDO. During a 1999 reserves audit it was noted that individual field proved reserves were too low in comparison with expectation reserves as many of these were still based on pre-development probabilistic estimates. Guidelines were left on how to build a proved reserves forecast portfolio with which to make a proper assessment of reserves producible within the duration of the production licence in 2012. However, by end 2000 no progress had been made in this respect. Following a visit by the SIEP

Reserves Coordinator, PDO were advised to amend their corporate proved reserves estimate, based on a continuation of the then current plateau of 850 Mb/d until 2008, followed by a relatively steep decline thereafter. This assumption of a continued plateau production was based on PDO's Business Plan, which foresaw a continuation of the 850 kb/d plateau at least until 2010. The implied lifetime proved reserves were some 75% of lifetime expectation reserves, which was not unreasonable. The implied assumption was also that PDO's drilling and development sequence would be accelerated if field reserves were to materialise at proved and not at expectation levels.

With hindsight, this advice has been unfortunate, not least because PDO's production levels declined sharply in the following years, implying that expectation forecasts were grossly optimistic. More fundamentally, the advice induced PDO to relinquish the audit trail to individual field proved reserves estimates. The understanding was that PDO would re-establish this link in 2001 by proper individual field proved forecasting, but this never happened. This regrettable situation was perpetuated and in fact worsened in 2001 and 2002 when PDO chose not to reduce proved reserves even when it was clear that stated proved reserves could not be produced before end-of-licence with the lower production levels.

SPDC had been booking significant increases in proved reserves since 1996, with major leaps in 1998 and 1999 following the implementation of new guidelines with respect to mature fields. The sum of the 1998 and 1999 reserves additions (Group share) was some 1000 MMbl of oil+NGL, of which some 460 MMbl was attributed to the new guidelines. The remainder was the result of field reviews, correction of negative reserves etc. A reserves audit in 1999 did not find any significant areas of non-compliance with Group guidelines, which at that time were not very strict on project definition and maturity (see below).

At end 1998, the proved reserves over annual production ratio (R/P) was 32 years. With 20.5 years still to go to the end of licence in 2019, this implied that the relatively steep production increase planned in those years would indeed be required in order to produce all of the stated proved reserves before end-of-licence. In subsequent years it became clear that, due to funding constraints, associated gas gathering delays ('flares out by 2008'!) and community disturbances it would be unlikely that the aspired production level increases would be realised. At end 2002 the R/P ratio stood still at 32 years, while the number of years to end-of-licence had shrunk to 16.5 years. This should have led SPDC to reduce their booked proved reserves accordingly, but it was decided to impose only a 'moratorium' (i.e. a freeze) on liquids reserves instead.

In the course of 2002 SPDC discovered that Nigerian law does in fact provide a right for production licence holders to have these licences extended upon expiry (subject to fulfilment of all licence obligations). SEC stipulations require an established 'track record' of the granting of such extensions and this is available in the Nigerian environment. These circumstances removed the potentially serious overstatement of proved reserves on licence duration grounds. However, by that time SEC had published the requirement for project maturity and commitment (see below) and this changed, but did not reduce the focus on SPDC reserves exposures. Many of the reserves increases booked on the late 1990s by SPDC had been based on reservoir reviews and long term development plans which were acceptable as a basis for proved reserves under previous Group guidelines but which could not pass the test of actual project commitment.

Significant proved reserves additions were also booked in other areas during the late 1990s. Many of these related to first-time bookings for new fields, some of them in frontier areas. Two important examples are the large Gorgon gas field offshore the Australian Northwest shelf and the more recently discovered Ormen Lange gas field in the Norwegian North Sea. The first field requires a major new opening in the Pacific Rim gas market, which seemed imminent at the time of booking, but which has been delayed significantly following the downturns in the Asian and worldwide economies in the late 1990s and in 2002. The Ormen Lange field faced a major technical challenge in perceived sea bottom stability, which has taken significant work to be relegated back to the 'negligible risk' category. FID on Ormen Lange will be taken shortly. Both proved reserves bookings were in accordance with Group reserves guidelines at the time.

Other proved reserves bookings on new field developments were made in Brunei, Venezuela, Nigeria (SNEPCO), New Zealand, the Netherlands and Norway (see Table 2). All of these were based on proper field development plans formulated at the time, which made them in accordance with Group guidelines. However, actual development was only foreseen in the longer term, either because of economic competition by other developments or, as in the case of the Waddenzee volumes in the Netherlands, because of a government moratorium on drilling.

Two undeveloped fields with apparently premature proved reserves were added to the portfolio in 2002 as part of the Enterprise Oil acquisition. One was in Italy (Tempa Rossa) where various licence and commercial uncertainties made the associated proved reserves exposed. The other was offshore Ireland (Corrib) where project development had already started but where an appeal had been lodged against the planning permission for the onshore gas processing plant. Both of these reserves bookings had already been made by Enterprise. Progress on the Tempa Rossa development has been disappointing during 2003 and the appeal against the planning permission in Ireland was sustained during 2003, making another application for planning permission necessary.

With the exception of the ex-Enterprise assets, most of the reserves additions discussed above appear to have been made in accordance with Group reserves guidelines prevailing at the time. They became only non-compliant when the guidelines were tightened in 2002-2003. The exceptions were the proved reserves moratoria in SPDC and PDO in 2001 and 2002, which, although not expressly forbidden by the guidelines, did go beyond the 'reasonable certainty' required of them. Production constraint criteria for licence-constrained operations were not introduced until 2002.

Reserves targets in Group score cards

Another consequence of the drive towards boosting proved reserves in the late 1990s was the introduction of proved reserves addition targets in scorecards for variable pay, both for individuals and for groups. This led to some aggressive attempts at booking of proved reserves at the immature end of the Group reserves spectrum. The prevailing mood at the time is best reflected by the often-posed question: "Tell me where it says in your guidelines that I can't do this". The consequent discussions about the appropriateness of such bookings led to immense pressure on e.g. reserves coordination staff in SIEP and on anyone suggesting a more moderate approach.

The SEC have not issued guidance on the appropriateness of individuals' pay being influenced by the amount of proved reserves booked by them. The SPE have issued such guidance and they clearly condemn such influence as unacceptable (Ref. 12). Concern was expressed about the proved reserves addition targets in a succession of Group Reserves Auditor reports identifying these as potential integrity threats to the Group's proved reserves filings (Ref. 11, 2000-2002), but the targets are still in effect.

The proponents of proved reserves addition targets will maintain that the controls in place (e.g. guidelines, reserves audits, end-year submission reviews and now end-year challenge sessions) should prevent inappropriate reserves being booked. However, these controls can only be effective if control resource levels are adequate. This has not been the case. Examples are the wholly inappropriate moratoria on proved reserves introduced by PDO and SPDC in 2001, which could have been detected by a higher frequency in reserves audits (see below). The more fundamental objection against the setting of reserves addition targets, i.e. that it affects the objectivity of the reserves estimator, stands unchallenged.

SEC definitions and Group Reserves Guidelines

Until 2001, there were only a few relatively small differences between the 1978 SEC reserves definitions and the Group proved reserves guidelines (see Table 2). The most significant difference in this period was the oil price assumption for PSCs and similar contracts, which the SEC required to be at end-year price levels and which Group guidelines set at mid-PSV levels. Because the latter were set conservatively, this implied an overstatement of Group PSC proved reserves, which has been maintained until 2003.

It is important to note that the SEC rules of 1978 made no reference to the (un)certainty that undeveloped reserves would actually become developed. The only general reference was to 'reasonable certainty' (see Table 1). The Group guidelines were, if anything, more specific about the issue. Since 1993 there was a requirement in the Group guidelines that undeveloped reserves should be based on identified projects, with associated well targets, costs and economics. However, these projects could be notional or simply based on analogies with similar fields or reservoirs.

During the period pre-2001, most US based companies seem to have settled on a practice whereby proved reserves would generally only be booked when projects were close to being committed. The explanation for this could be that, once evaluated and quantified (making reserves bookable), a property would be developed quickly because there were very few physical or bureaucratic hindrances standing in the way. Development costs also tended to be low initially and risks were small. SOC (later SEPCo) adopted this self-imposed practice (of waiting for full FDP or even FID) in 1986, following some embarrassment from a series of negative reserves revisions.

In 2001, following pre-announcement during the preceding year, the SEC published 'guidance' on their website, giving clarification about how they wished to see the original 1978 reserves definitions interpreted by the industry (Ref. 9). The most significant new item in the 2001 guidance was that the SEC wished to see a 'commitment' to those projects for which proved undeveloped reserves had been booked. This 'commitment' requirement was largely in line with reserves booking practice in the US. It was also seen as sensible and desirable, providing a clear criterion against which to assess the appropriateness of booking proved reserves. However, it presented an immediate threat to the SEC compliance of an (at that time unknown) volume of

Group proved reserves, because these had been booked under Group guidelines that were less strict, allowing e.g. notional projects as a basis.

In reaction to the new SEC guidance, the Group guidelines were changed gradually to the point where, at end 2003, they required either FID, a VAR3 or a full FDP for large, medium and small projects respectively before proved reserves could be booked (Ref. 6, 2003). These changes were introduced partly at the recommendation of end-year reserves auditor reports and also to prevent premature reserves bookings for new projects.

The 2001 SEC guidance was followed by an exchange of letters between the Group and the SEC during 2002 and 2003, in which the SEC expressed an even stricter interpretation regarding the LKH issue.

The remaining areas of divergence between the recent SEC guidance and the 2003 Group guidelines are thus the strict definition of the 'proved area' (producibility, LKH and continuity of production) and the price assumptions for PSCs (see Table 1). A stricter requirement for adherence to the 'proved area' concept had already been introduced in the Group guidelines in 2001. The divergence on the need for an improved recovery pilot is not material in the Group's portfolio, with only some exposure in Sakhalin, which will be addressed per end 2003. The FDP/VAR3/FID criterion may not be completely congruent with the SEC 'commitment' requirement, but it can be argued that, if there is a track record of the company to carry out its planned (FDP'd or VAR3'd) projects this can be seen as sufficient commitment.

In summary, the most significant change in the SEC definitions and guidance in 2001 was the introduction of the need for project commitment before proved reserves could be booked. This resulted in an immediate threat of non-compliance to a large (but unknown) volumes of the Group's proved reserves. Group guidelines have largely been brought in agreement with SEC guidance in 2002. Remaining, lesser discrepancies, will be removed in 2004.

Reasons for non-compliance

The new 2003 Group guidelines were applied in two proved reserves audits late in 2003, one in SPDC and one in PDO. Both companies had been challenged in the end-2002 reserves audit report regarding their continued moratorium on proved reserves when it was clear that stagnant production (in SPDC) or indeed production declines (in PDO) made their booked proved reserves questionable. Both companies had started extensive internal reviews to investigate the status of reservoir knowledge and the maturity of their project portfolios forming the basis for undeveloped reserves. When the potential magnitude of exposure in both companies became clear, a thorough scan was made through the Group-wide Business Plan portfolio to identify other areas with volumes that were based on longer term projects for which no VAR3 / FID had been taken yet. This resulted in the list of Table 2.

From this list it can be seen that the requirement of project commitment formed by far the largest reason for compliance failure in the list of exposed proved volumes.

The conclusion is therefore that it was the 2001 insistence on project commitment by the SEC that caused the compliance failure of the large majority of the reserves to be de-booked per end 2003. As demonstrated by Table 1, these reserves were in compliance with both Group and SEC guidelines before 2001, because the guidelines were either not very strict or non-existent on this issue.

Group Reserves Audits

Group reserves guidelines were the only technical control document distributed throughout the Group on the issue of estimating and booking proved reserves. Hence, these were also the only reference against which proved reserves audits in the OUs and at end-year in SIEP could be (and should have been) carried out.

The historically set frequency of OU reserves audits had been once every four years, or more frequently if indicated by e.g. unsatisfactory audit results. The experience, particularly in the last few years, has been that this frequency has been too low. Repeat audits in various OUs have shown that an OU's reserves reporting procedures can deteriorate quite quickly upon critical staff re-assignments or re-organisations. A more intensive programme of OU audits (at least once every two years) has now been agreed as desirable and this is being implemented. Such a higher frequency could have detected the inappropriateness of e.g. the SPDC and PDO proved reserves moratoria in a much earlier stage.

As the potential conflicts between SEC definitions and guidance and Group reserves guidelines became clearer, these were generally flagged in audit reports. Group reserves guidelines were then gradually adapted to ensure closer alignment with SEC requirements where possible and when deemed appropriate.

Other follow-up from the reserves audits included the setting up by SIEP of an 'Exposure Register' of volumes that were potentially non-compliant with either Group or SEC requirements. The total volume in this register was deemed to be less than material in relation to the total Group portfolio and any associated de-bookings were held pending until more data, positive or negative, would become available.

Conclusions

In summary, it is the writer's opinion that the following factors have played a role in the build-up towards project Rockford:

- The inappropriate notion that Group reserves guidelines were in full compliance with SEC definitions, perpetuated in the series of Group reserves guidelines since 1980
- The lack of awareness of the significance of SEC reporting requirements among the Group's petroleum engineering community,
- The significant drive for proved reserves additions in mature fields in the late 1990s, without paying heed to the requirements for constraining proved reserves in immature fields,
- The introduction of proved reserves addition targets in individuals' scorecards, which removed much of the objectivity required in proved reserves evaluations, and which prevented reserves de-bookings when these would have been appropriate,
- The historical lack of perception within the Group of the need for some form of project commitment before proved reserves should be booked, which left the Group vulnerable to new SEC guidance in 2001.

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3. "Upstream Disclosure Requirements - A Guide for the Preparation, Reporting and Review of Proved Reserves Quantities and Values and Other Statistical Data", SIPM, 1983
4. "Petroleum Resource Volume Guidelines", Part 1, EP 88-1140, SIPM, April 1988
5. "Petroleum Resource Volume Guidelines", EP 93-0075, SIPM – EPD/EPE, May 1993
6. "Petroleum Resource Volume Guidelines", SIEP nnnn-1100, issued annually 1996-2003
7. "Note for Discussion – Proved Reserves", J. Pay, 8 Dec 2003
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9. "*Issues in the Extractive Industries*", United States Securities and Exchange Commission (SEC), March 2001: (http://www.sec.gov/divisions/corpfin/guidance/cfactfaq.htm#P279_57537)
10. "Proved Reserves Definitions – SEC Guidance – 31 March 2001", AA Barendregt (2002-2003)
11. "Review of Group end-year proved oil and gas reserves summary preparation", Group Reserves Auditor (January 1999 – January 2003)
12. "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information", Society of Petroleum Engineers, 2001 (http://www.spe.org)
13.

Subject	1978 SEC Definition	Group guidelines pre-2001	2001-2003 SEC Guidance	Group guidelines end-2003
Reservoir 'Proved Area':				
Producibility	Producibility proven by production test or log and core based analogue	Producibility proven by production test or log or core based analogue	Producibility proven by production test or log and core based analogue	Producibility proven by production test or log or core based analogue
LKH	If no information on fluid levels: no proved reserves below LKH	Proved reserves below LKH if indicated by pressures or seismic amplitude mapping, or included in probabilistic estimate	No proved reserves below LKH under any circumstances	Proved reserves below LKH if indicated by pressures or seismic amplitude mapping
'Continuity of production'	Continuity of production must be certain (max. 9 well spacings around existing wells)	'Continuity of production' uncertainty included in probabilistic or multi-scenario estimate	Continuity of production must be certain (max. 9 well spacings around existing wells)	'Continuity of production' uncertainty included in probabilistic or multi-scenario estimate
'Improved Recovery'	Successful (pilot) test required, either in the reservoir itself or in the same reservoir in a different field in the area	Successful pilot test required unless the project can go ahead without it ('Value of Information' approach)	Successful (pilot) test required, either in the reservoir itself or in the same reservoir in a different field in the area	Successful pilot test required unless the project can go ahead without it ('Value of Information' approach)
'Existing Conditions'	Existing (year-end) prices and cost estimate assumptions required for confirming economic viability	Mid PSV prices and cost assumptions, also for PSCs	Existing (year-end) prices and cost estimate assumptions required for confirming economic viability	Mid PSV prices and cost assumptions, also for PSCs
'Reasonable Certainty'	'No 'reasonable doubt' about geology, reservoir or economic factors	Proved undeveloped reserves must be based on an identified project, which may be notional	Proved undeveloped reserves must have a commitment to the project	Proved undeveloped reserves must have an FDP / VAR3 / FID for small / medium / large projects

Table 1 - Main elements and differences of successive proved reserves definitions

UNITED STATES DISTRICT COURT
DISTRICT OF NEW JERSEY

IN RE ROYAL DUTCH/SHELL TRANSPORT SECURITIES LITIGATION	**Civ. No. 04-374 (JAP)** **(Consolidated Cases)** **Judge Joel A. Pisano**

DECLARATION OF ANTON A. BARENDREGT

I, ANTON A. BARENDREGT, declare and affirm as follows:

1. From January 1999 through January 2004, I served as the Group Reserves Auditor for the Exploration and Production ("E&P") business of the Royal Dutch/Shell Group of Companies ("Shell" or "the Group"). I am currently retired.

2. I hold a Master's degree in Technical Physics from Delft University in the Netherlands. I am a member of the Society of Petroleum Engineers.

3. I understand that an issue in this case involves the nature and extent of any United States conduct from April 8, 1999 to March 18, 2004 relating to the estimation or reporting of proved reserves that Shell later restated. I am making this declaration in connection with Shell's submissions on this issue. I previously was deposed in this matter on February 19-22, 2007. I understand that the Court and the parties have access to the transcript of that proceeding.

4. Unless otherwise stated, I make this declaration on personal knowledge and am competent to testify as to the matters set forth herein.

5. As Group Reserves Auditor, I was based at E&P headquarters, which were located for most of my tenure in The Hague, the Netherlands, and later moved to Rijswijk, the Netherlands.

6. As Group Reserves Auditor, I performed three principal tasks. First, I commented on and monitored the Petroleum Resource Volume Guidelines (the "Guidelines") that were edited each year by the Group Hydrocarbon Resources Coordinator, also known at the Group Reserves Coordinator ("GRC"). Second, I conducted audits of individual operating units to assess whether their estimation of their oil and gas resources conformed to the requirements of the then-extant Guidelines. Third, I evaluated whether, on an aggregate level, the Group's estimate of its total proved oil and gas reserves was fairly presented and whether the total estimate was properly derived from the estimates of the operating units.

Petroleum Resource Volume Guidelines

7. Other than in 2001, I reviewed the GRC's revisions to the Guidelines each year. Because the GRC had resigned his position in the fall of 2001, I took responsibility for revising the 2001 edition of the Guidelines.

8. The Guidelines contained instructions to the Group's individual operating units on the estimation and reporting of oil and gas resources. The principal purpose of the Guidelines was to ensure that E&P received proper estimates of each operating unit's "expectation reserves," the volumes of oil and gas resources that were likely to be produced in the future and on which E&P made its internal business-planning decisions.

9. The Guidelines also, however, instructed the operating units on the estimation of "proved reserves," the oil and gas volumes that were reasonably certain of being produced in the future based on existing economic and operating conditions.

10. The estimation of proved reserves by a publicly traded oil and gas company is governed by SEC Rule 4-10(a) of Regulation S-X, which defines what volumes of oil and gas can properly be designated as proved reserves, and by Statement of Financial Accounting Standards 69, which requires that publicly traded oil and gas companies report their estimates of proved reserves as supplementary information to their annual financial statements.

11. I reviewed the Guidelines that the GRC revised and E&P issued each year in order to confirm that the Guidelines would lead the operating units to estimate their proved reserves in a manner that would yield results consistent with the requirements of Rule 4-10(a).

12. Although I occasionally discussed the Guidelines and the requirements of Rule 4-10(a) with Rod Sidle, a reservoir engineer employed by Shell Exploration and Production Company ("SEPCO"), E&P's United States operating unit, the GRC was always responsible for revising and played the principal role in revising the Guidelines. Personnel from E&P would occasionally consult with Sidle concerning reserves-related matters, but the primary purpose of involving Sidle was to help him ensure that SEPCO's policies and practices for estimating and reporting proved reserves were consistent with Group practices. The final decisions concerning the

content of the Guidelines were always made by the GRC or other E&P personnel located in the Netherlands.

Operating-Unit Audits

13. My audits of the reported proved reserves of individual operating units were generally conducted in the country where the operating unit's oil and gas assets were located. For example, my 1999 audit of Shell Petroleum Development Company ("SPDC"), the Group's onshore and shallow-offshore Nigeria operating unit, took place at SPDC headquarters in Nigeria. My contacts for these audits would be personnel in the operating unit who were responsible for overseeing the estimation and reporting of oil and gas resources to E&P headquarters, usually the Chief Reservoir Engineer or Chief Petroleum Engineer. [A. Barendregt Dep. at 215-16.]

14. There were three circumstances in which I audited an operating unit somewhere other than in the country where the operating unit's oil and gas assets were located. One such circumstance resulted from personal health issues. In 2003, I was scheduled to perform my audit of SPDC in Nigeria, as I had in 1999. I was unable to make the trip, however, due to health reasons. The audit of SPDC was postponed for a short while until the SPDC personnel with whom I needed to meet had occasion to travel to the Netherlands to meet with personnel from Shell Exploration and Production Technology, Applications and Research ("SEPTAR"), an E&P technical service provider based in the Netherlands that performed technical

services for SPDC. The SPDC personnel extended their visit to the Netherlands so that I could conduct my SPDC audit there.

15. Another circumstance in which an audit took place in a country other than the one in which the operating unit's oil and gas assets were located involved small operating units that were based at E&P headquarters, rather than in the country where their assets were located. For example, the staff of Shell Kazakhstan Development ("SKD"), the Group's operating unit responsible for its oil and gas assets in Kazakhstan, was based at E&P headquarters in The Hague. As a result, I audited SKD in The Hague, rather than in Kazakhstan.

16. On February 20, 2007, I stated that I performed audits of operating units from The Hague "when the effective working unit of the working company was in fact located in The Hague." [A. Barendregt Dep. at 212.] I named the operating units in Kazakhstan and Pakistan as examples. [*Id.*] This statement pertained only to those audits of the small operating units based in The Hague as just discussed, and not to the operating unit audits discussed below.

17. The third category of audits that took place in a country other than the location of the operating unit were those audits that I conducted in a location where technical data pertaining to the operating unit's assets was stored. During my tenure as Group Reserves Auditor, I performed five audits—other than my 2000 audit of Shell Exploration and Production Company ("SEPCO"), the Group's United States-based operating unit—in the United States because technical data was located there: my 2001 audit of Shell Exploration (China) Ltd. ("SECL"), my 2002 audit of Shell

Nigeria Exploration and Production Company ("SNEPCO"), my 2002 audit of Shell Development Angola ("SDAN"), my 2002 audit of Shell Brazil Exploration and Production ("SBEP"), and my 2003 audit of Pecten Cameroon Company ("PCC").

18. **SECL**. My audit of SECL in 2001 was conducted in Houston, Texas, because SEPTAR's Houston office was providing technical services to SECL. At all times SECL, not SEPTAR, held the final responsibility for estimating its oil and gas resources and submitting those estimates to E&P. My understanding from my review of the year-end 2003 proved reserves and the recategorization recommendations from Project Rockford is that, although SECL later recategorized certain proved reserves in 2004, this recategorization related to SECL's use of the Group's internal project-screening values rather than year-end prices to calculate its proved reserves entitlements, not to any technical work performed by SEPTAR.

19. **SNEPCO**. My audit of SNEPCO in 2002 was conducted in Houston because Shell Deepwater Services ("SDS"), an E&P technical service provider based in Houston, was providing technical services to SNEPCO. At all times, SNEPCO, not SDS, held the final responsibility for estimating its oil and gas resources and submitting those estimates to E&P. Although SNEPCO later recategorized certain proved reserves in 2004, I do not believe that SDS's work was responsible for SNEPCO's reserves overstatement. First, most of the proved reserves that were recategorized by SNEPCO related to the Bonga field, proved reserves for which were first booked before the creation of SDS in 1999. Second, most of the reserves restatement for SNEPCO was due to: (*i*) E&P's decision to

report proved reserves for SNEPCO fields before having taken a final investment decision regarding those fields, a decision that was reversed in 2004, and (*ii*) E&P's decision to report proved reserves based on an internal project-screening price rather than the year-end price prescribed by Rule 4-10(a).

20. The document Bates-numbered V00330377-V00330392, an email string in which I discuss technical work performed by SDS on the Bonga SW field, does not change my conclusions stated above. No proved reserves were ever reported for the Bonga SW field, meaning that no technical work that SDS might have performed regarding that field led to an overstatement of proved reserves.

21. **SDAN**. My audit of SDAN in 2002 was conducted in Houston because SDS was providing technical services to SDAN. Although SDAN later recategorized certain proved reserves in 2004, I understand that SDS's work did not contribute to SDAN's initial reserves overstatement. First, the reserves restatement for SDAN was due to E&P's decision to report proved reserves for SDAN's Block 18 asset before having taken a final investment decision regarding that asset, a decision that was reversed in 2004. Second, SDS's technical work ultimately led to a decrease, rather than an increase, in the amount of reserves that SDAN reported as proved. Third, at all times SDAN had the responsibility for estimating its oil and gas resources and submitting those estimates to E&P. As discussed below, both the GRC and I attended meetings at which the reporting of proved reserves for SDAN was discussed. It was clear at all times that any proved reserves would have to be proposed by SDAN and approved by E&P and by me before being reported

externally. For example, it was the GRC and me who suggested to SDAN and SDS that a "creaming project" targeting only the highest-value resources for initial booking as proved reserves could be pursued and could, according to the Guidelines existing at the time, potentially support a booking of proved reserves.

22. **SBEP**. My audit of SBEP in 2002 was conducted in Houston because SEPCO personnel were providing technical services to SBEP. These technical services, however, related to the Merluza field. I understand that no proved reserves relating to Merluza were recategorized in 2004.

23. **PCC**. My audit of PCC in 2003 was conducted in Dallas because the Dallas office of Netherland Sewell & Associates had performed study work underlying the PCC ARPR submission. My understanding, however, is that no proved reserves were restated for PCC in 2004.

Consultations Regarding SDAN Proved Reserves

24. In addition to the five audits conducted in the United States described above, I briefly consulted with SDS staff in Houston on two other occasions concerning proved reserves for SDAN.

a. In early November 2000, I visited Houston to perform my audit of SEPCO, the United States-based operating company. While in Houston, I was presented with the current results of technical work that SDS had performed for SDAN, technical work that SDAN and E&P hoped could serve as the basis for a booking of proved reserves in 2000. I advised SDS that its technical work was not sufficient to support a booking of proved reserves and made recommendations concerning the further technical work that needed to be done.

b. On December 12, 2000, I attended a second meeting in Houston where SDS and SDAN personnel presented GRC and me with the results of its further technical work. I concluded after the December 12 meeting that, with additional technical work, a limited booking of proved reserves for SDAN in 2000 would be consistent with the Guidelines.

25. Like the technical work that SDS performed for SNEPCO, the work that SDS performed for SDAN led SDAN to estimate and report fewer proved reserves than it might have otherwise. SDS's work did not contribute to the initial overstatement of reserves. At all times, furthermore, SDAN, not SDS, held the responsibility for making the ultimate estimate of its oil and gas resources and submitting that estimate to E&P.

26. The document Bates-numbered SMJ00035943-SMJ00035946, a string of emails discussing the booking of proved reserves by SDAN in 2000, does not change my conclusions that (*i*) SDS did not have the authority to propose or book proved reserves, and (*ii*) SDS's technical work, rather than contributing to SDAN's overstatement of reserves, led SDAN to book fewer proved reserves than it might otherwise have booked. In the email string, Gordon Parry states that "the latest figures coming out of SDS are lower than the 293" million barrels that E&P

personnel had proposed to report as proved. E&P proposed that the GRC, E&P, and I meet to discuss the proper proved-reserves figure to be reported externally, because E&P made the final determination and Shell's external auditors and I had to approve that determination.

27. The document Bates-numbered SMJ00036352-SMJ00036354, an email string ending in an email from me to Aidan McKay, does not change my conclusion that SDS did not have the authority to estimate and report proved reserves. Although I stated in my email that SDS had asked me to "discuss Block 18 reserves with them and advise them what they needed to do to be able to book reserves," I did not mean that SDS itself was responsible for reporting proved reserves. SDS was asked by SDAN to develop technical scenarios that would allow SDAN to report proved reserves, but SDS's work was only preparatory to SDAN's decision to report proved reserves, and E&P, the external auditors, and I then had to agree that the reserves could be properly reported externally as proved.

28. The document Bates-numbered V00070311-V00070313, an email to me from McKay forwarding an email from McKay to John Bell concerning the circumstances surrounding SDS's involvement in SDAN's booking of proved reserves in 2000, does not change my conclusion that SDS acted primarily as a technical service provider to SDAN and that SDAN held the final responsibility for estimating and reporting its oil and gas resources. McKay explains in the email that SDS was performing technical work concerning the SDAN fields in Angola. Although one of the aims of the technical work was to support SDAN's ability to

report proved reserves, nothing in the email contradicts the fact that SDAN and E&P, not SDS, made the final decision concerning whether SDAN could properly report proved reserves for its assets. Furthermore, it is my understanding that the proved reserves that SDAN reported for 2000 were retroactively restated in 2004 because, in 2000, E&P had not taken a final investment decision on the Block 18 project, and the Group decided in 2004 to restate proved reserves that had been reported prior to a final investment decision. The recategorization did not occur because of any errors in SDS's technical work.

Year-End Review of Proved Reserves

29. Each year, I evaluated whether E&P's estimate of its proved reserves was consistent with the requirements of the Guidelines, and therefore with the requirements of applicable law. My evaluation, contained in a report called the Review of Group End-[Year] Proved Oil and Gas Reserves Summary Preparation ("Year-End Review"), was one of the many steps in the process by which the Group compiled and reported its proved-reserves estimates.

30. In January of each year, each operating unit submitted a form to the GRC at E&P headquarters containing the unit's estimate of its oil and gas resources as of the end of the previous year. This form, called an Annual Review of Petroleum Resources ("ARPR"), divided the resource estimates into various categories and sub-categories, including Proved Reserves, Proved Developed Reserves, and Expectation Reserves.

31. The operating units themselves were responsible for estimating, compiling and submitting their resource volumes. While some operating units received technical assistance from service providers such as SEPTAR and SDS, this assistance was designed either to allow the operating unit to estimate its subsurface oil and gas volumes and map the structures of subsurface reservoirs more accurately or to enable the unit to develop ways to improve its production of hydrocarbons in the subsurface. Once this technical work had been performed (either by a technical service provider or by the operating unit itself), the operating unit needed to conduct the necessary economic, legal, and contractual analysis to determine the appropriate volumes of resources to report to E&P for each category in the ARPR. Operating units often consulted with the GRC concerning whether a proposed categorization of oil and gas resources was consistent with the Guidelines.

32. After each operating unit submitted its ARPR to the GRC in the Netherlands, the GRC compiled that information into an aggregate estimate of the Group's oil and gas resources. The GRC also made a preliminary determination concerning whether the operating units' reported oil and gas resource numbers were appropriate.

33. I reviewed both the GRC's aggregate estimate of the Group's proved and proved developed reserves and the individual estimates from the operating units. My review was designed to confirm that: (*i*) the GRC had properly aggregated the proved reserves estimates of the individual operating units; (*ii*) the operating units whose reserves estimates I had audited during the previous year had properly taken

my observations and comments into account in making their submission; (*iii*) any significant changes in an operating unit's reported proved reserves were properly supported; and (*iv*) any other important questions concerning the propriety of an operating unit's proved reserves were addressed.

34. After reviewing the ARPR data submitted by the operating units, I composed the Year-End Review. The Year-End Review discussed (*i*) the results of the individual operating-unit audits that I had conducted during the previous year, (*ii*) other notable issues concerning the operating units' ARPRs, such as a significant change in an operating unit's proved reserves, and (*iii*) any observations that I had concerning changes that needed to be made to the Guidelines to ensure that operating units conformed to both the spirit and the letter of applicable law in estimating their proved reserves.

35. I submitted my Year-End Review to the E&P leadership and to the Group's external auditors, KPMG and PricewaterhouseCoopers ("PwC"). Around the same time, a meeting would be held in The Hague to discuss the proved reserves figures that the Group proposed to report externally. I attended the meeting, as did the GRC, one or more E&P personnel who supervised the GRC and representatives from KPMG, PwC, and the Group Controller's office. None of the attendees was based in the United States. At this meeting, the GRC would present the Group's proposed proved reserves figures, which the E&P leadership had approved, to KPMG and PwC. I would present the results of my review and my opinion concerning whether the proposed proved reserves figures fairly presented the

Group's entitlement to proved reserves. KPMG and PwC were able to, and did, ask clarifying questions concerning any issue about which they were uncertain.

36. After KPMG and PwC had reviewed the proved-reserves figures pursuant to the requirements of Statement on Auditing Standards No. 52, they were included in the Group's Annual Report on Form 20-F and in its other public disclosures to the market. Thus, disclosure did not occur until (*i*) the operating units had submitted their ARPRs to the GRC in the Netherlands; (*ii*) the GRC had compiled the aggregate proved reserves figures in the Netherlands; (*iii*) the E&P leadership in the Netherlands had approved the proved reserves figures that the GRC submitted; (*iv*) I had reviewed the proved reserves figures in the Netherlands; and (*v*) the GRC and I had presented our results and opinions to KPMG and PwC in the Netherlands.

37. During 2003, I became a part of the Reserves Committee, a committee within E&P that was established specifically to monitor the Group's oil and gas resource portfolio and to improve the process of estimating and reporting oil and gas resources. The Reserves Committee sat in the Netherlands.

I declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

ANTON A. BARENDREGT

Executed:

June 10, 2007

Wassenaar, Netherlands