Reorganisation Proposal: Increase focus on Reserve Management by adding regionally located, "dual-citizen" (both corporate and regional) full-time position to proactively work between the Group HRC and local Resource Coordinators

<u>Benchmark</u> XOM has a corporate staff of 13 for auditing, consulting & corporate data base management on reserves.

Shell's Reserves Philosophy

Prior Years — Reserve/Resource Reporting

- Central HRC and OU RC annually collect/report data in ARPR
- Proved reserves from probabilistic method (uses P85)
- SFR categories to track immature volumes

1998 - 2002 — Incremental change

- Expro shows deterministic method better for mature assets; suggested Group-wide
- Monthly/quarterly reporting of reserve changes and LE
- Increased information on and attention to SEC guidance
- No organisational changes

⇨

2003 - 2004 — Reserve Management (Step-function change)

- Pro-active push of Reserve Knowledge and Processes to OU RC and staff by regionally located Reserve Mgrs
- Includes training, booked volume challenges, "hit-list" opportunity tracking, developing RC "community" to work issues & share knowledge; ie, manage reserve processes
- Active in Industry forums to collect intelligence and work common issues on proved reserves

⇨

Future Opportunity — Resource Management

- More SFR impact: eg, track UDSFR maturation by split into leads, plays, prospects
- Industry work to recognise (report?) unproved reserves, SFR: eg, use ongoing IASB work to harmonise financial reporting rules (FASB/SEC, IASB, etc.)
- Replace ARPR with Group-wide resource volume database with "as occurs" changes and real-time reserve/SFR status

Unknown

From:	Barendregt, Anton AA SIEP-EPB-P
Sent:	22 June 2003 15:38
To:	Pay, John JR SIEP-EPS-P; Sidle, Rod RE SEPCO
Cc:	Coopman, Frank F SIEP-EPF; Van Poppel, Johannes JC SIEP-EPF-CT
Subject:	Comparison SEC vs Group guidelines
Sensitivity:	Confidential
Contacts:	Produced By Microsoft Exchange V6.0.6375.0

John, Rod,

In view of the recent excitements I thought it would be a good idea if we had a look at a comparison between SEC and Group guidelines for proved reserves. For this purpose I dusted off an old table which I had prepared some time ago. I have re-grouped the successive subjects in a somewhat revised sequence which, I believe, makes more sense than the quence in the FASB/SEC definitions. In the table I set side by side the original FASB/SEC definitions, a summary of the SEC 'guidance' and interpretations of 31 March 2001 and a transcript of our own (intended) guidelines.

You will probably agree with me that the SEC 'guidance' of their March 2001 website is not particularly clear. The text is rumbling (partly caused by the somehwat illogical text sequence of the original definitions, which the SEC adhere to), and the wording is sometimes (deliberately?) obscure or ambiguous. In my summary of their guidance I have tried to stick to SEC's choice of words as much as possible. Where I find the text ambiguous I have highlighted this in blue.

I have highlighted in red where it would seem that our Group guidelines may perhaps not be in full alignment with the SEC interpretations. As expected, the possible non-alignment relates to four subjects: Production Testing, LKH, Lateral Continuity of Production and Improved Recovery pilots. On all of these subjects I understand that we are (more or less) in alignment with the rest of the Industry. They all concern areas where strict adherence to the SEC interpretations would lead to unrealistically low reserves. These low reserves would bear no relation to the significant development capex that the industry, through improved technology, is prepared to put at risk.

The first objective of my preparing the table would be to give us focus. However, I would like to think that it might also be a tool with which to re-engage the SEC (e.g. in the October SPEE workshop) with the objective of ultimately arriving at a sensible and realistic (and hopefully better written) set of guidance and interpretations that would make sense in the current technical environment. The original definitions can remain as they are, they aren't so bad, after all.

One final remark: It would seem that correction of produced gas volumes for fuel and flare is <u>not</u> a FASB/SEC requirement. I know it has been in our guidelines for at least 20 years, probably because we needed to match the Finance Sales (now Gpafs) volumes with future reserves. If we'd want to include fuel and flare back into reserves we would need to change the definition for annual sales/production volumes in FIRST and in external reporting.

Regards,

Anton

SECvsShell-2003.ZIP

EXHIBIT
Sidle
13
10.31.06

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

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

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PROVED RESERVES DEFINITIONS - SEC AND SHELL INTERPRETATIONS CONFIDENTIAL

	FASB / SEC Definition	Current SEC Interpretations (Ref. 1)	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. A conservative approach is required until data is supported by field evidence. Performance based projections may be the median, not necessarily the low estimate.	Future revisions to proved reserves must be more likely to be upward than downward. 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. 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 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. Prices and costs should be as of the date the estimate is made, i.e. at the last day of the year.	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. Abandonment costs should be included in economics. Price and cost projections should be as per Group PSV screening values.
3.	*Producibility* **Reservoirs are considered proved if economic producibility is supported by either actual production or [a] conclusive formation test.** **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).**	Producibility must be demonstrated through a full formation test or through production at economic rates. Cannot be a wireline formation test. 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 and core data (which should be favourable to the unproduced reservoir). Note: This allowed analogy seems much more strict (log and core data; in same field) than that allowed for Improved Recovery.	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. A fluid sample must be available.
4.	*Proved Area – Fluid Levels* **The area of a reservoir considered proved includes that portion (...) defined by gas-oil and/or oil-water**	Reserves down to a known fluid contact or the Lowest Known Hydrocarbons (LKH) may be considered as proved. In the	Proved reserves shall fulfill 'Proved Area' conditions (see definition below).

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	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.	absence of a fluid contact (in the well, or from pressures or seismic?), no reservoir volume below the LKH shall be considered as proved. Note: The recent (5 June 03) SEC letter suggests no proved reserves below LKH under any circumstances	definition below). Water levels (and volumes below LKH) may be considered proved from pressures in the reservoir. Volumes below LKH can also be considered proved if
		Proved oil reserves can be carried above Highest Known Oil only if there is compelling evidence of the oil being undersaturated (Ref.2).	good quality seismic amplitudes can be considered proof of hydrocarbons and if these are continuous over the area (Ref. 3). 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 proved if continuity of production is certain. Continuity of production means more than just continuity of 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 (dynamic or static?) pressure tests. Seismic data alone is not seen as a sufficient condition to prove communication over areas outside the eight 'offset' drainage areas. The above conditions can be waived only by conclusive reservoir production evidence or performance.	Proved reserves shall fulfill '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 proven 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.3). 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 proven reservoir (of same or poorer properties) in the area. The above conditions can be waived by conclusive reservoir production evidence or performance.
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 additional development capital expenditure to become produced. 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.** **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.**	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 developed reserves can be claimed only for those wells that have shown production increases associated with the improved recovery technique.	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. Improved Recovery proved developed reserves should be based on performance extrapolations as soon as feasible.
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**	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.	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

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	because of uncertainty as to geology, reservoir characteristics, or economic factors;	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.	show stoppers. Commercial maturity implies that evacuation routes will be available and that a market is reasonably certain for gas volumes (e.g. through a LOI or Sales Agreement). FID must have been taken for major projects. Smaller projects should have passed VAR4 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.	Volumes in undrilled prospects or unappraised fields are carried as SFR. Oil shales etc: are booked as mining reserves, not Petroleum reserves.
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. A straightforward reconciliation is required for financial reporting purposes if probabilistic addition is used.	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 with 'Proved Area' conditions. 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 FASB**	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

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	with para 30 of FASB **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.)**	may not be used. End-year prices mean physical prices on the last day of the year. The same requirement applies to (future) costs.	discount rate of 10% is used.
13.	***Production Sharing Agreements***	Proved reserves must be based on the "economic interest method" (future cost+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+profit oil revenue divided by a reference oil price as per Group PSV screening values. 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.

References:

1. SEC Website: "Issues in the Extractive Industries": www.sec.gov/divisions/corpfin/guidance/cfactfaq.htm#p279_57537
2. "Understanding US SEC guidelines minimizes reserves reporting problems", T.L.Gardner, D.R.Harrell, Oil&Gas Journal, Sept 24, 2001.
3. "Estimating Pay Probability Downdip from Well Control Using Seismic Amplitudes", by AK Jackson, SJ Saleh and PH Doe, SIEP (BTC Houston) EP 2000-9119

From: Sidle, Rod RE SEPCO
To: Pay, John JR SIEP-EPS-P; Barendregt, Anton AA SIEP-EPF-DIR
CC:
BCC:
Sent Date: 2003-12-20 05:22:58.000
Received Date: 2003-12-20 05:23:10.000
Subject: Rockford thoughts while flying
Attachments:

EXHIBIT
Sidle
14
10-31-06

John and Anton,

Although my best thinking was done with my eyes closed, before I nodded off these occurred to me:
* Might be good to have 10 yr plot (to cover before and after the jump to p50 for mature fields) for Shell and competitor on % of proved in undeveloped
* The 1998-2001 EP 1100 doc contains the interesting comment "Where Group guidelines interpret SEC definitions, as listed in Appendix 4, these interpretations have been accepted by external auditors as fulfilling SEC requirements." We have not discussed the role -- actual and what it should have been -- of our external auditors in validating our procedures. Do we have letters on file where they have reviewed these interpretations and agree with them? I do have similar documents from PwC for SEPCo (shout if you want a copy) but of course only for SEPCo practices.
* In the 2002-2003 EP 1100 documents, we state "This approach [p85 as proved] 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 [color added]. 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)." As I have now seen mature parts of SPDC and PDO still using probabilistics (they don't even have a place in their Risres db for a deterministic value), how do we respond to this situation? Perhaps this is one of the "unsatisfactory" elements in their recent GRA report. Or perhaps we don't really mean we expect all OUs with mature field to switch to a deterministic (and more like strict SEC) methods? This question may arise so we need be ready with an answer. (with question part 2 being - do you have other OUs with many mature fields who do not use the deterministic method?) and (interesting we waited to 2002 to note a change in Group practice that occurred in 1998.)
* After filing our 20F (and for SOC 10K), the SEC in some (all?) years sent a list of questions about the filing. Do we have a database of such questions (and any other enquiries precedeing the most recent ones) to see how we have answered questions related to reserve determination? It would be most embarassing to answer a soon coming fact question on historic practices as we now describe things only to find we already answered that same fact question some years ago with a very different perspective of the facts. Again we have to say what is true but good to know where such potential embarassments lie waiting for us.
All for nowwwwwwwwwww....zzzzzzzzzzzz, Rod

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Darley, John J SIEP-EPT

From: Sidle, Rod RE SEPCO
Sent: 31 December 2003 21:47
To: Barendregt, Anton AA SIEP-EPF-DIR
Cc: Pay, John JR SIEP-EPS-P; Coopman, Frank F SIEP-EPF; Bell, John J SIEP-EPS; Darley, John J SIEP-EPT
Subject: RE: Response to Walter's questions

Sensitivity: Private

Anton,

Certainly most happy to discuss next week. I will arrive at Rijswijk early afternoon on Tuesday and plan to stay until Friday noon. As early thoughts on your points:

- LKH - fully agree; their position on LKH is as foolish as their initial position on production testing. We seem likely to get them to concede on production testing but it will take some work and time to see if we can ever move them back to reality on LKH. (A place where the SPE Reserves Committee may be able to help.)
- Project commitment - Generally agree SEC 2001 guidance was a defining moment and that SOC/SEPCo circumstances may have helped us develop and use a more auditable practice for first booking of project reserves. It will be good to discuss other events that drove SEPCo to our practices before the 2001 guidance. As one example, the attached summary that I prepared circa 2000 to help incoming expats and non-subsurface-backgrounded new asset managers understand key elements of reserves and resource volumes.
- FID/VAR3/FDP - I would very much like to discuss this. Initial thoughts are we need a clearer definition but also perhaps some test metrics to assure we do not become overly aggressive on proved undeveloped reserves -- perhaps some like a limiting percentage of PUD of total proved by OU? Also I really don't consider VAR 3 as a commitment as much as a demonstration of technical maturity. Here we could add some language on "track record" to better define this element. Also we could consider changes in our business planning process to provide clearer corporate commitment to longer term, robust economic projects that will not see FID in the coming year.

Again just some initial thoughts to prime our discussion.

Beware the artillery barrage (fireworks) that I understand is a typical Netherlands New Years Eve. (We have some here too.)

Regards,
Rod

Final Summary of SEPCo OG Resv...

EXHIBIT
Sidle
15
10.31.06

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NOTE: Advice provided under applicable service agreements

-----Original Message-----
From: Barendregt, Anton AA SIEP-EPF-DIR
Sent: Wednesday, December 31, 2003 10:27 AM
To: Sidle, Rod RE SEPCO
Cc: Pay, John JR SIEP-EPS-P; Coopman, Frank F SIEP-EPF; Bell, John J SIEP-EPS; Darley, John J SIEP-EPT
Subject: RE: Response to Walter's questions
Sensitivity: Private

Rod,

Please allow me to make some comments here:

On question 1:

You're right on the issues of PSC and lateral size of proved area, of course. The 2001 SEC guidance did not, or hardly, change our perception on these issues and we knew that Group reserves were possibly exposed in this respect (PSCs only, that is, the lateral proved area issue became only relevant for Kashagan, booked in 2002).

On LKH we felt (and you felt) that we were compliant until the exchange of letters with the SEC during 2003, where they went (arguably) against their own 2001 guidance. The original FASB definition says: " In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limits of the reservoir". This clearly leaves room for pressure information (and even seismic information) to be used for assessing proved fluid levels and that's what the industry did. The 2001 SEC guidance said: "In the absence of a fluid contact, no offsetting reservoir volume below the LKH from a well penetration shall be classified as proved". Nobody really paid much attention to the SEC's omission of the words "information on" from their text, until the said exchange of letters in 2003. Editing a 'guidance' text such that its meaning is crisp and clear is not one of the SEC's strongest traits!

Where the world did change (in my opinion) was the SEC's insistence on a 'commitment' before proved reserves could be booked. The original FASB definitions were vague on project commitment: "Estimates of proved reserves do not include [....] crude oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to [geology, reservoir charcteristics] or economic factors." The 2001 SEC guidance is of course much more outspoken on the issue, also on that of government permits (which are not covered by the FASB definitions, but I believe are dealt with somewhere else, not sure where). The practice in the US has mostly been that, once a project had been properly defined (i.e. an FDP had been prepared), it would progress to FID and implementation quickly, because there was generally little to stand in the way of rapid development (e.g. government approvals, infrastructure constraints etc). I would therefore submit that the US approach to wait for FDP/FID, sensible as it may have been, was not a result of direct SEC/FASB guidance but only from self-imposed conservatism. Grateful to discuss this with you next week.

On question 2:

The latest Group's guideline of FDP/VAR3/FID for small/medium/large projects does indeed rule out proved reserves for longer term medium-to-large projects, e.g. Groningen late-field compression. They may therefore be over-restrictive. Your practice seems to be that such projects can be included if there is a good track record of doing what we said. This is where judgement (and possibly argument) comes in. It would be better if we could capture this in some precise guidelines. Maybe we should expand the Business Plan to include long-term (>5 years) projects. Another subject for discussion next week?

Happy New Year!

Anton

-----Original Message-----
From: Sidle, Rod RE SEPCO
Sent: dinsdag 30 december 2003 19:07
To: Darley, John J SIEP-EPT
Cc: Pay, John JR SIEP-EPS-P; Coopman, Frank F SIEP-EPF; Bell, John J SIEP-EPS
Subject: Response to Walter's questions
Sensitivity: Private

John,

John Pay advised me that certain questions had been raised by Walter, my suggested response to which are as follows. I have restated the questions in line with our (John Pay and my) understanding of the issues Walter is concerned about.

1. Is it credible for Shell to claim "Only with the SEC Reserves guidance since 2001 were we able to first realise our internal reserve guidelines and practices did not comply with the SEC Proved Reserve definitions."?

RES - I do not believe this is a credible position. Not only did a major OU in our fold have different knowledge and considerable experience with interpreting the SEC rules but other outside USA indicators existed -- eg, external auditors expressing concern over PSC reserve evaluation oil price practices, current Shell staff who have worked for other companies (outside USA) that more diligently followed SEC rules who have noted our variance from such practices. We simply did not react to these warning signals nor did we proactively seek clearer understanding of the SEC rules from available industry sources.

2. What standards should proved undeveloped (PUD) reserves meet to be reasonably certain (with respect to corporate commitment -- eg, FID, VAR 3)?

RES - Requiring FID for all sizes and situations of PUD reserves is seemingly too conservative. Clearly the FID requirement for PUDs is proper in frontier settings, for major investments or where uncertainty over possible show-stoppers exist. But for routine, incremental projects where operations and infrastructure is already in place and a clear track record of execution of such smaller projects exists, reasonable certainty can come earlier -- as long as all other elements of the PUD definition are met. For example, SEPCo has not signed well drilling AFEs for each offsetting location to existing Pinedale producers but we have committed to the BLM (US regulatory party for this land) to execute a 40 acre development; we have this in our Business Plan; well profitability is robust against investment criteria; and, we have a quasi-FID in the overall project approval granted when Pinedale was purchased. The SEPCo track record of continuous development reinforces the reasonable certainty that these Pinedale PUD volumes will be developed and produced. This is consistent with how most US operators would treat this situation. Thus our current requirement of FID for only large, frontier projects is reasonable as long as, for all other projects, strong economics, existing operations/infrastructure and a clear positive track record of similar project execution exists (meaning we actually do what we put in our business plan -- a record of more than a few "dropped" projects once included but never done is difficult to accept as a clear positive track record).

Happy to explain further if needed.

Regards,
Rod

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A Summary of SEPCo O&G Reserve Reporting

SEPCo's Reserve Reporting guidelines are intended to provide one set of instructions that fully meets our governing legal requirements (e.g., SEC, National/Local governments – mostly through U.S. DOE, IRS and MMS), satisfies outside auditors (e.g., PWC), and is consistent with Group standards. Each group has its own description of reserve reporting – all of which are similar but none exactly the same. SEPCo's guide is our interpretation of how best to satisfy all using one set of rules and maintaining one set of volume data.

Specifically in the SEC regulation (and generally in all the others), the requirements that reserves must meet to be classified as proven can be summarized in three parts:

(1) technically recoverable (using "geologic and engineering data") criteria
(2) economic (judged "under existing economic conditions") criteria
(3) expectation of recovery criteria

All of these must meet a "likelihood test" of "reasonable certainty". So high risk or even "moderate risk but still expected" volumes cannot qualify as proved until the risk is low enough to be reasonably certain. On a probability of realization basis, this is equivalent to an 85% (Group EP Guide) to 90% (SPE and most industry) probability or better.

The specific details of SEPCo interpretations and practices are described in the guide document. However, a brief summary of the SEPCo approach to each of these three parts of the SEC standard is as follows:

- Reasonable certainty technically recoverable volumes – Using all available data and appropriate engineering/scientific methods (several if possible), a DETERMINISTIC, high confidence estimate should made. This does not mean a "absolute certainty" case constructed by using the lowest possible value of all factors (porosity, HC saturation, net thickness, recovery efficiency, etc.) but rather an expected value of each (within SEC limits on proved area as controlled by the lowest known HC) when available data provides a reasonable distribution. Where data is absent (say, recovery mechanism unknown), the more conservative outcome should be used to assure high confidence.

- Economic volumes – Within the reasonable certainty technically recoverable volumes, both developed (economics of continued production) and undeveloped (economics of development and production) volumes must satisfy defined hurdles when valued by discounted net cash flow analysis using both Shell premises (PSV) and SEC Standardized Measure (FAS 69) criteria. The Shell hurdle for undeveloped volumes is the minimum investment criteria (currently VIR $\geq$ 35%).

- Expectation of recovery – Reserves should be volumes that ultimately will be produced. Generally if volumes are technically recoverable and economic, one might assume they will be produced. However, other circumstances may intervene. For undeveloped volumes, there may be reasons why the needed investment would not be made – too large a capital requirement, does not fit desired portfolio, may cause image/reputation issues, etc. It is SEPCo's practice to book proved undeveloped reserves for major new projects at FID (or when a clear commitment to develop is evident) and to verify our current business plan includes development of all proved undeveloped volumes. This assures the "expectation" requirement is met. For developed volumes, such factors also exist. An example would be likely well failure before end of producing life. Such producing volumes at risk must show proper allowances to manage or account for this risk to be classified as proved. Here also the current business plan should include production volumes consistent with the stated developed reserves to confirm we expect these volumes will be recovered.

SEPCo guidelines for reserve/resource volumes other than "proved reserves" are not governed by SEC or other governmental rules so we can utilize Group guidelines. Here Group "Expectation Reserves" matches the definition of SEPCo "Proved + Unproved Reserves". Also SEPCo guidelines support calculating expectation reserves using probabilistic methods as is typically done for Group reserve reporting outside SEPCo. Further SEPCo uses the Group defined Scope for Recovery (SFR) categories to report expected volumes too immature (either technically or commercially) to be reserves.

SEPCo and GDWS Strategic Contract Issues – Discussion Note

SEPCo wants to make GDWS a success. The following has been prepared by SOI staff with keen interest in the global DW arena as well as in the continued GOM success. The purpose of this note is to provide, from SEPCo's perspective as the major Deepwater operating company, summary observations towards a more cost effective and efficient system for managing our global deepwater resource while retaining the operational and regional excellence required to explore for, develop and produce oil and gas in the U.S. Gulf of Mexico. Key themes are

1) the importance of collocation of staff to enhance knowledge transfer, improve operational efficiency and ensure technical limit performance, particularly for an operating company with the full range of activity, from greenfield exploration to mature producing operations and
2) the need to focus on reduction of cost and overhead structure within GDWS to better align with our cost leadership objectives.

Summary of Observations:

1. Maintain status of development execution group. Reduce hourly charge to pre-GDWS rate. Evaluate urban planning and new product charges in 2000 relative to customer requirements.

2. Commit to a phased approach with milestones for the transfer of DW rigs and expertise to GDWS, giving careful consideration to critical business impact on GOM operations. SOI is somewhat unique in that the full range of deepwater well deliverability activities, from greenfield exploration, to appraisal and development drilling to subsea completions and interventions are required to execute the business plan. With immediate effect, share DW drilling knowledge through transfers and collocation, while retaining critical mass and expertise. Given demonstrated TLD performance and a validated drill string of DW greenfield activities, consider transfer of one rig in Q4 2000 to GDWS (see graphic attached). Further transfers to be considered for 2001.

WDU.ppt

3. Work closely with GDWS evaluation team staff to focus on critical plays and specified greenfield prospect work. Identify areas of focus, and agree upon deliverables and accountabilities to improve efficiency of exploration staff.

4. GDWS teams contracted for development follow-up work to greenfield discoveries in the GOM should preferably be collocated with SOI to maximize learnings from previous development experience and our 13 ongoing major development projects.

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Backgroud Discussion for Recommendations

Well Deliverability Unit

Drilling and completion activities are absolutely core to our Gulf of Mexico business. Designing and executing wells and completions to produce "the Limit" results is critical to our business success and requires fully integrated subsurface, development and drilling teams.

Benefits of Globalization of Well Delivery

This deepwater Well Delivery Unit is expected to add value to the Group by:

- Maintaining a core pool of staff recognised for their global expertise in deepwater
- Transferring deepwater experience from the GOM to the rest of the world
- Applying global resourcing to develop regional competencies
- Providing planning capability fully integrated with the rest of SDW
- Early and continuous involvement in field development planning
- Providing world class execution capability
- Applying the different well delivery VCT initiatives such as Deliver the Limit, Big Lever, and Deepwater Knowledge Sharing

Benefits of Centralized SOI Drilling Organization

Recently, SOI reorganized to focus on core work processes and make significant improvements in cost structure. All drilling, completion, workover, and subsea intervention engineering and operations are now handled by one group in SOI. This central organization enables SOI to:

- Easily move staff between various operations (e.g. TLP, platform and floating rig operations) to transfer learning and load level for maximum efficiency.
- Shift between asset based development projects (e.g.) Brutus), appraisal drilling and exploratory projects with a given rig.
- Use consistent techniques and operating procedures built on best practices.
- Direct accountability for organization and individuals.
- Align contracts across GOM to leverage buying power.
- Facilitate handling statistical interventions and workovers of subsea wells with floating rigs.
- Improve application of the Deliver the Limit Process across SOI.
- Effectively coordinate and manage Emergency Response Process, and Hurricane Evacuation Process with our Producing Assets.

SOI's performance to date with the new structure has been outstanding. Operational records in both drilling and completion times have recently been set and technological advances such as the suction pile mooring system are being progressed even further

Concerns with Globalization of Well Delivery

- Misalignment with subsurface teams in New Orleans.
- Additional interfaces to manage.
- Complex accountability
- Operational mistakes leading to increased costs due to inefficient knowledge transfer
- Potential lost discounts or problems with vendors if procurement strategies are not aligned
- Extra cost potential and exposure to develop and manage separate Emergency Response plans.

- Difficult budget management and possible lost opportunities if costs are not understood due to different tracking/finance systems.

Concerns Associated with Centralized SOI Drilling Organization
- Less global knowledge transfer
- Difficult process for global resourcing
- Global rig portfolio management less efficient.

Efforts by SOI to Support SDW-WDU
To help meet the expectations depicted in the relationship model regarding experience knowledge transfer, SOI has been working quite closely with the WDU to provide information and experienced personnel. In terms of staff and knowledge exchange, the following activities have been or will be effected:
- Two senior well engineers recently moved from SOI to WDU .
- An SOI experienced deepwater well engineer will be heading to Brasil to join the WDU execution team. Our plan is to back-fill this position with an expatriate.
- An experienced SOI deepwater drilling supervisor is being "loaned" to WDU to work on the Stena Tay during its first well in Trinidad. The incumbent drilling supervisor will come to SOI during this time period to gain insight to our operations.
- An experienced Group drilling supervisor from SNEPCO will come to SOI in Q4/99 for 6 to 8 months to become familiar with our development operations including subsea completions. He will then return to SNEPCO to begin supervising work on Bonga.
- SOI will provide opportunities for a number of First Assignees to work offshore GOM rigs as optimization/technical limit engineers.
- We are currently putting some learnings on the Wells Global Network. As we migrate to Livelink, WDU will have direct access to all of our well data and documentation.
- Drilling engineering and completion engineering network meetings are held on a weekly basis in OSS to provide forums for peer assists, lookback reviews, and technical presentations. These are routinely followed by technical "Lunch and Learns". WDU staff can attend these sessions when in New Orleans.
- Participation in Value Assurance Reviews for both organizations will be facilitated to share best practices in both directions.

SEPCo's WDU Recommendation
We recommend a phased approach:
- ❑ Initially, knowledge and expertise will be shared through transfer of select SOI drilling personnel to key Global deepwater drilling operations, while select staff in global deepwater services be collocated in New Orleans and assigned to SOI drilling operations.
- ❑ Implement Knowledge Sharing Systems such as Live Links
- ❑ Application of TLD to all well delivery operations by 4Q1999.
- ❑ Develop and validate inventory dedicated to SDS rig by end 3Q2000.
- ❑ Beginning October, 2000 (post capital allocation process) we will evaluate the transfer of one rig, with SOI deepwater trained staff, to Global Deepwater, for deployment in the Gulf of Mexico or elsewhere.
- ❑ We recommend collocation of Deepwater drilling and completion operations in SOI to accelerate the pace of knowledge transfer, increase confidence in performance and delivering targets, to facilitate emergency response coordination, and enhance logistics and procurement leverage.

Development Execution

The development execution group within GDWS continues to provide excellent service, including project timing, quality, innovation, project cost and HS&E performance. Cost reduction opportunities may exist in specified customer requests for "urban planning" and potentially through more focused systems selection and new project development activity.

Evaluation and Development Planning

Core Competencies

The technical support provided by core competencies is of high quality but the cost for delivery is high. Technical redundancy exists between some groups in core competencies and SEPTAR and should be examined for cost and deliverability of products to customers.

Evaluation Teams:

The strategic contract relative to the evaluation teams will need to address two primary issues:

- Since SOI shifted its exploratory strategy to a play focus, the geographic basis for the strategic contract has been diminished. We will recommend that we contract the evaluation teams for specified regional work in support of our exploration efforts, for continued evaluation of the Perdido Fold Belt. Bathyal play and the BAHA prospect and drillsite, and for specified prospect evaluation work. We will also recommend that the water depth delineation for work be reevaluated in the context of our play focus.

- The geographic isolation of the Houston SDS evaluation team from SOI has the potential to diminish knowledge sharing and increase SOI costs. The issue may be especially acute in future years for development projects.

From:	Varner, Marc MA SEPCO
To:	Balzarini, Maria MA SEPCO; Morell, Jose JI SEPCO; Kornacki, Alan AS SEPCO; Sidle, Rod RE SEPCO; Lanson, Tony AP SEPCO; Sims, Eldon WE SEPCO; Zhu, Hua H SEPCO; Sieler, Jeffery JJ SEPCO; Jones, Charles TC SEPCO; Koinis, Rena RL SEPCO
CC:	
BCC:	
Sent Date:	1999-07-28 15:55:06.000
Received Date:	1999-07-28 15:55:06.000
Subject:	FW: Meeting with Nigerian visitors - July 29 & 30 - 1154 BTC
Attachments:	DPRvisit.doc , UNTITLED.BIN , Shell Houston Visit Agenda.doc

In case you didn't receive this the first time.

-----Original Message-----
From: Koinis, Rena RL SEPCO
Sent: Wednesday, July 28, 1999 8:54 AM
To: Balzarini, Maria MA SEPCO; Morell, Jose JI SEPCO; Kornacki, Alan AS SEPCO; Sidle, Rod RE SEPCO; Lanson, Tony AP SEPCO; Sims, Eldon WE SEPCO; Zhu, Hua H SEPCO; Sieler, Jeffery JJ SEPCO; Varner, Marc MA SEPCO; Jones, Charles TC SEPCO
Cc: Henderson, Lyle LE SEPCO
Subject: Meeting with Nigerian visitors - July 29 & 30 - 1154 BTC

Thank you all for agreeing to participate in the subject meeting. The agenda is attached. Let me know ASAP if you have any problem with your time slot.

The following notes provide the background for the visit. We will be hosting three visitors: John Ikhanoba and Chinenye Okereke (Shell Nigeria) and Segun Ogunjana (Department of Petroleum Resources). The primary purpose is to familiarize the representative from the Department of Petroleum Resources with the Shell E&P companies and to "show case" the technology that we use to support our reserve bookings.

Rena Koinis
Shell E&P Technology Company
Room 1184B BTC
713-245-7451 (phone)
713-245-7147 (fax)
rlkoinis@shellus.com

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Note: 20 July 1999

Shell Visit Programme – DPR Staff

Visiting Team

P.O (Segun). Ogunjana	DPR, Head Resources Evaluation
John Ikhanoba	SPDC, Commercial (New Business)
Chinenye Okereke	SPDC, Reserves Coordinator

Purpose of Visit

- To familiarise the DPR with the Shell Group and the (scale of) the E&P Sector, in particular.
- To "show case" the Shell technologies that are relevant to hydrocarbon resource management
- To provide a clear picture of Shell Group reserves management practices and demonstrate that SPDC's current practices are in line with Group guidelines.

Visit Themes

- Shell Group Reserves assessment practices
- The role of technology in the transfer of scope to reserves (and the huge capital investment required to mature technology)
- The booking of reserves is not dependent on the state of implementation of the associated project.
- The Shell Group is not more optimistic than the competition on reserves assessment (we appear to be more conservative than the competition)
- The Shell Group is a leader in E&P technology, particularly in Deepwater.

Visit Outline

20 – 23/7, SIEP Rijswijk
Focal points: Rosmawatty and Annemarie Bourdrez

26 – 27/7, Shell Expro, Aberdeen
Focal point: John Gallagher, UEDN/7

29 – 30/7, SEPCO, Houston
Focal point: Maria Balzarini

2 – 3/7, SDDI, New Orleans
Focal point: TBA

Outline Travel Schedule

19/7/99	Arrive Holland by SwissAir
20 - 23/7/99	Technical discussions in SEPTAR, Rijswijk
24/7/99	Free day in Holland
25/7/99	Amsterdam/Aberdeen, KL 2065, dep: 14.25, arr: 15.00
26 - 27/7/99	Technical discussions in Expro
28/7/99	Aberdeen, BA 1301, dep: 06.40/London/Zurich/Atlanta/Houston, DL 823, arr: 21.14
29 -30/7/99	Technical discussions in SEPCO
31/7/99	Houston/New Orleans, CO 1625, dep: 11.50, arr: 12.49
01/8/99	Free day in New Orleans
02 -03/8/99	Technical discussions in Shell Deep Water.
03/8/99	New Orleans, SN 8143, dep: 13.50/Atlanta/Brussels/Lagos, SN 527, arr: 16.25 (04/8/99)

DPR Staff: Technical Visit to Shell

Background

The current fiscal arrangement under which SPDC operates includes a bonus for increases in oil and condensate reserves - Reserves Additions Bonus (RAB). Government approval of the bonus is contingent on DPR's concurrence with the increase reported by the company. DPR (Department of Petroleum Resources) is the government agency regulating the oil and gas industry.

While DPR has certified a significant portion of our claims, a lot more remain under negotiations. These negotiations have proved difficult partly because the large majority of the members of the DPR negotiating team are not very familiar with Shell Group guidelines/philosophy/methodology for reserve estimation. In particular, their Team Leader has never visited any Shell company (including SPDC) for any form of technical orientation/attachment. Consequently, major technical misunderstanding remain between SPDC and DPR.

The Problem

The problem is how to reduce the areas of misunderstanding to an acceptable level. The prize is very significant and has direct bottom line effect, a few hundred million US dollars for the SPDC-JV (Shell share is 30%).

Our plan

We would like to arrange a tour for this Team Leader to "show case" the Shell technology that are directly relevant to hydrocarbon (HC) resource management. **The deliverable** from this visit is: the visitor gains a clear impression that current practices in SPDC with respect to reserves assessment and reporting are (i) in line with Shell Group standards, guidelines, philosophy, and practices, (ii) not SPDC (or Shell Group) concoctions designed purely to maximize RAB. We have secured DPR approval in principle for such a tour.

Timing and Program

Due to other DPR commitments, the visit has to take place within the time window: 19/07 – 06/08/99. We are planing the tour to start on 20/7/99. Our suggested program is as follows:

Period	Host	Subjects
20-21/07/99	EPT-IF	Nigerian Study items
22-23/07/99	EPT-AM/others	HCRVM issues - General V- to-V issues - Thin Oil Rims - Difficult fields (e.g. Rabi) - Major Project Realization VCT
26-27/07/99	Shell Expro Aberdeen (London?)	- Development of satellite assets - Brent: Locate remaining oil - Reporting to authorities: Challenges - Other developments in Shell Expro
28/07/99	Depart to Houston/New Orleans	
29-30/07/99	Shell Oil	- Mature/end-game assets - Reporting to regulators: Challenges.
02-03/08/99	Shell Deep Offshore	- Deep offshore: State of the art.
04/08/99	Depart US for Nigeria	

Shell Houston Visit Agenda – DPR Staff

Visiting Team

P.O (Segun). Ogunjana	DPR, Head Resources Evaluation
John Ikhanoba	SPDC, Commercial (New Business)
Chinenye Okereke	SPDC, Reserves Coordinator

Thursday July 29, 1999 Room 1154 BTC

9:00 – 9:15	Welcome and Introduction Overview of BTC Services	Rena Koinis
9:15 – 9:30	Field Studies Overview	Maria Balzarini
9:30 – 10:00	Demo of Reservoir Engineering Tools (Spider)	Jose Morell
10:00 – 10:30	Mars waterflood studies	Jeff Sieler
10:30 – 11:00	Ursa studies	Jeff Sieler
11:00 – 1:00	Lunch	
1:00 – 2:15	Welcome and Introduction to SOC Reserve Management and Reporting Practices	Rod Sidle
2:30 – 3:00	Yemen Studies	Tony Lanson
3:00 – 3:30	China oil rim study	Tony Lanson
3:30 – 4:00	Review of the days issues	All

Friday July 30, 1999 Room 1154 BTC

9:00 – 9:30	Ram Powell Studies	Eldon Sims
9:30 – 10:00	Integrated Reservoir Studies	Hua Zhu
10:00 – 11:00	Reservoir Properties Services	Alan Kornacki
11:00 – 1:00	Lunch	
1:00 – 1:30	Columbia Studies	Marc Varner
1:30 – 2:00	4D Seismic Study	Charles Jones
2:00 – 2:30	Value Assurance Reviews	Rod Sidle
2:30 – 3:00	Review of the days issues	All

From:	Lockwood, Alan AF SIEP-EPT-DE
To:	Hines, Ian IM SIEP-EPT-DE; Newberry, Derek D SIEP-EPT-DE; Coggins, Jerome J SIEP
CC:	
BCC:	
Sent Date:	2000-11-03 18:30:14.000
Received Date:	2000-11-03 18:30:14.000
Subject:	Reserve Booking Meeting With Anton Barendregt
Attachments:	

Ian/Derek/Jerry,

See my meeting summary below. Please make any additions or changes based on what you've heard. I can coordinate the responses and put together the final version of this note and circulate back to you before we pass this on to wider circles.

This morning (11/3/00) a group from the Angola Block 18 SDS team had a meeting with Anton Barendregt, the group's reserve auditor. In attendance were:

Ian Hines
Derek Newberry
Rod Sidle
Jerry Coggins
Alan Lockwood
Anton Barendregt
Barry Knight (by phone at the end of the meeting)

Ian gave Anton an overview of the Block 18 exploration history and the proposed hub development. Derek proceeded with a history of the reserve estimates associated with each of the fields, and how they have changed historically with further evaluation. Derek's presentation also included discussion of the analog work prepared by Dave Powell, which is the basis for the team's range in recovey efficiency and ultimate recovery per well. In addition, Jerry Coggins showed amplitude maps for Paladio and Galio, and round-table discussion took place regarding the maturity of the technical work and the work needed for booking reserves. The following is a list of highlights from this discussion:

* The project is not at a technically mature stage at present; normally a much

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higher degree of technical work is necessary to book reserves. Booking of reserves based on a full field development is not feasible this year.
* One option for booking reserves would be to identify a minimum development option which could be brought forward based on our existing data and level of technical maturity. This option must be one which would warrant an investment in 2001 if it was deemed necessary (for example if we would have to sacrifice the block if we didn't invest). This means that the reserves we evaluate are only the ones that can have a high degree of certainty associated with them at the present time. This would include areas of high N/G - presumably in high amplitude areas with DHI's, and would exclude low amplitude areas away from well control. This is basically a "cherry picked" development.
* Even for the cherry-picked development, the project needs to be robust for the full range of possibilities (oil in place within the cherry-picked areas, recovery efficiency, EUR/well, and cost). This can be interpreted to mean that the P85 VIR (which encompasses all of the previously mentioned uncertainties, not just reserves) is greater than 0 under $14 Brent price premise.
* Anton highly recommended that we consult Remco Albers (reserve booking coordinator) ASAP regarding our plans so that we do not have any last-minute suprises.
* January 10 is the final date for booking reserves.

Alan Lockwood
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SIEP - Shell Deepwater Services
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RD/S

ANGOLA

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Aalbers, Remco RD SIEP-EPB-P

'rom: Barendregt, Anton AA SIEP-EPB-GRA
Sent: Tuesday, November 21, 2000 17:57
To: Aalbers, Remco RD SIEP-EPB-P
Subject: Angola

Remco,

Seems our friends are struggling...

Anton

-----Original Message-----
From: **Sidle, Rod RE SEPCO**
Sent: 21 November 2000 17:54
To: Barendregt, Anton AA SIEP-EPB-GRA
Subject: RE: Comments on Draft Report and Att3

Anton,

' have continued to talk with the Angola team and provide guidance on the approach you outlined for them for booking roved reserves. It appears their situation is that they need all expected volumes just to meet economic hurdles for even a minimal development scheme. By pulling back to only those "high confidence" volumes (meaning not counting all the way to seismic OWC and across major observed faults), they seem challenged to imagine a reasonable but lower capex development that would produce the reserves at 0 NPV. We agreed to get back together in December after they had worked this more to review the results (which sounds like when you would be attending).

I will advise if I hear more from the Angola team.

Regards,
Rod

Rod Sidle
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Email: residle@shellus.com
Secretary: Barbara Schletzbaum 281-544-2052

-----Original Message-----
From: Barendregt, Anton AA SIEP-EPB-GRA
ent: Tuesday, November 21, 2000 10:42 AM
): Sidle, Rod RE SEPCO
ubject: RE: Comments on Draft Report and Att3

Rod,

A quick 'Thank you' for the comments received so far. Haven't gone through them in detail yet (working on my SDA report at present), but I'll hold sending any updates of the report until I've got the final word on Marjorie's and Phil Spaniol's efforts. Many thanks again so far, it was an audit that leaves me with pleasant memories!

Chances are, we may see each other sooner than we thought. Remco's muttering about a reserves review on Angola somewhere in December in Houston and wants me to join him. Seems they're under pressure from high up to book something...

Anton

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 be likely to 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 lateral 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 dat set). With the postulated well spacings this could expose this reservoir to a potential downside of a 10-30% lower recovery.
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 been minimal.
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. No studies have yet been done regarding any 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 futher 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, SIEP, Houston, January 2001.
2. "Estimating Pay Probability Downdip from Well Control Using Seismic amplitudes", A. Jackson, SEPTAR, Houston

Jespers, Bea BL SIEP-EPB-P

From: Aalbers, Remco RD SIEP-EPB-P
Sent: Monday, October 30, 2000 8:52 AM
To: McKay, Aidan A SIEP-EPB-P
Cc: Jespers, Bea BL SIEP-EPB-P
Subject: FW: Angola - Reserves LE 3Q00

fyi

-----Original Message-----
From: Rothermund, HC SEPI-EPG
Sent: Sunday, October 29, 2000 17:27
To: Bichsel, Matthias M SIEP-EPT-D
Cc: Aalbers, Remco RD SIEP-EPB-P; Lovelock, Susan S SEPI-EPG; Minderhoud, Martijn M SEPI-EPG; Parry, Gordon G SIEP-EPG; Simon, Grigore G SIEP-SDAN-AM; Warren, Tim TN SIEP-EPT
Subject: Angola - Reserves LE 3Q00

Matthias,

Below please find a good summary by Sue Lovelock and Remco Aalbers on the reserves situation in Amgola. As mentioned to you on earlier occasions, there is a critical need for EP to be in a position to book these reserves in 2000. SDS plays a key role in this. Grateful you keep very close to this.

Regards
Heinz

-----Original Message-----
From: Aalbers, Remco R.D.
Sent: 27 October 2000 17:27
To: ROTHERMUND, H.C.
Cc: LOVELOCK, S.; Simon, Grigore G.; PARRY, G.
Subject: Angola - Reserves LE 3Q00

Heinz,
Understand from Sue that you would like to get an update on the Angola reserves position. She had to leave before the numbers were finalised so she asked me to send this.
Regards,
Remco
============
Proved Reserves LE - 293 mln bbl
This number is LE Shell PSC entitlement for the first hub (Plutonio/Galio/Paladio/Cromio/Cobalto).
Plutonio estimates are under downward pressure as technical evaluation continues in Houston, in this case static modeling. Revision here may drop proved reserves to 265 mln bbl (being challenged). There is still some additional upside for Cobalto (if no gas is encountered) of 30 mln bbl, the well is currently being drilled, resulting in an upward range for proved reserves of 295 mln bbl. LE is still achievable.
Booking of any reserves is based on commerciality and here team is making progress. Positive NPV looks possible, (although peer review in Houston still in progress). Although current position does not meet screening VIR (which is being worked), this alone would not prevent reserves booking, which is based on commerciality test. Notional Development Plan is part of model, so in progress. Angola Team will maintain pressure on SDS in Houston.
We understand that BPA is not under any pressure to book further reserves this year, so will not book Block 18 reserves. Their target remains FID date (Sanction in BP's terminology), which overall is still good news for Shell. It would have been helpful if they also booked Blk

18, but understand we have deviated from partners before in our booking of proved reserves.

Another booking test is move from exploration licence to production licence. Team have reviewed PSC. View is that as long as venture declares commercial project within 24 months from formal notice of discovery there is automatic right to 25 year production licence. Formal Notices will no doubt be required, but there seems nothing legal to prevent reserves booking. Production term is long enough to support booking of reserves. Proved reserves booking will be visible externally and therefore available to Angolan Govt etc. We would not necessarily want to have this be seen as trigger FID for production licence and be committed to development expenditure. This is issue raised before, but not concluded - we really need to watch carefully. Will take up with team, Gordon and Martijn on return.

SFR Maturation to expectation reserves LE - 367 mln bbl

Expectation reserves of 367 mln bbl is for 1st hub and includes same fields as above. Similar to proved reserves there is pressure on the Plutonio expectation estimate which might drop to SFR maturation to 328 mln bbl, again possible upside for Cobalto of some 40 mln bbl to 368 mln bbl.

Given move within same year from SFR maturation to proved reserves we will get some bbls in both SFR maturation and proved reserves additions.

Good news.

Susan Lovelock

From: Read, Norman NS SIEP-EPT-AV
To: Bollich, Libby EB SIEP-EPT-AV; Freeman, Justin JJ SIEP-EPT-AE; Sevier, Bill B SIEP-EPB-S; Sidle, Rod RE SEPCO; Wilson, Thomas V SEPCO
CC: s=Jean-Marc.SEGUINEAU;ou1=mime;p=SHELL;a=400NET;c=NL;dda:HPMEXT1=Jear Marc.SEGUINEAU(a)totalfinaelf.com;
BCC:
Sent Date: 2001-09-06 16:03:12.000
Received Date: 2001-09-06 16:04:53.000
Subject: Bonga SW VAR 1-2, Houston, 10 to 13 Sept 2001
Attachments: Bonga SW VAR 1-2 ToR.doc

Lady and Gents,

Pls find attached the finalised ToR and a draft programme for the Bonga SW VAR 1/2. The VAR will take place in Houston, at Shell's Woodcreek building from 08.00 am on Monday 10th September to approx 18.30 on Thursday 13th Sept. When you reach reception, our contact is Jon Crane, whose office is room no 2120. Shell staff pls charge account A-004460-105.

For those staying in Houston into the evening of Thursday, I believe the project team is intending to invite us to dinner.

See you on Monday, those travelling have a safe journey,

regards,

Norman

From: Crane, Jonathan JE SIEP-EPT-DE
Sent: Wednesday, September 05, 2001 1:47 PM
To: Lauferts, Hermann H SIEP-EPT-DE; Li, Yan Y SIEP-EPT-DEC; Cambio, Mark MR SIEP-EPT-DD; Gunn, Neill NJ SIEP-EPT-DD; Allan, John D SNEPCO-SNIM
Cc: Stovall, Mike RM SIEP-EPT-DE; Goter, Edwin ER SIEP-EPT-DE
Subject: Draft Bonga SW VAR Agenda

EXHIBIT
Sidle
20
10-31-06

Timings are my first guess feel free to change. So far I see interviews following on Tuesday/Wednesday. Attached draft TOR for those who have not seen it.

Monday 10th September.

VAR Agenda Day 1

8:30 Introductions and SNEPCo Bonga SW Overview Charles Shotton
9:15 Bonga Context Chris Varley
10:00 Break
10:15 Bonga SW Prospect and Discovery Well Herman Lauferts
& FASTTRACK Volumetrics
11:15 Subsurface; Recovery Factors and Inflow Performance Yan Li
(MAPS + Post discovery reserves comparison)
12:00 Lunch
1:00 Sub Sea Layout / Surface Methodology and Studies Mark Cambio / David Adejumo
1:45 Economics of fast tracking John Allan
2:15 Break
2:30 Block Economics Jon Crane

Way Forward
3:00 Appraisal Plan Herman Lauferts
3:30 Subsurface Plan and Organisation Jon Crane
4:00 Subsea/Topsides Niell Gunn
4:30 Bonga West Impact Charles Shotton ?
5:00 Discusion wrap up Day 1 All.

Any thing else to add/delete ?

Rgds

Jon.

Norman Stanley Read
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Bonga Southwest

Combined VAR 1 & 2 - Project Initiation, Identification & Feasibility Terms of Reference

Background:

The Bonga-Southwest accumulation is situated in the South Western corner of Oil Mining Licence (OML) 118, offshore Niger Delta. This block covers an area of around 2300 km2 and lies in water depths ranging from 200 m to 1500 m. The accumulation was discovered with the Bonga-SW-1 well that was drilled between January (tophole only) and May 2001 to a TD of 4160 m. With the Bonga-SW-1 well, the OML 118 partnership led by Shell Nigeria Exploration and Production Co. (SNEPCO), with partners Esso Exploration and Production Nigeria (Deepwater) Ltd, Elf Petroleum Nigeria Ltd., and Nigerian Agip Exploration Ltd., now have a second discovery following the Bonga Field that was found in 1996 some 15 km to the Northeast of Bonga-Southwest.

The exploration well Bonga-SW-1 well penetrated a total of seven stacked amplitude anomalies (685-3, 685-2, 692-1, 719-1, 719-3, 803, 812), all of which came in oil bearing as predicted. The deeper reservoirs 816 and 834 came in with residual hydrocarbon saturations and are likely to contain oil in an updip position. All the reservoirs are channelized turbidite deposits with a variable degree of vertical and lateral amalgamation. The most critical reservoir uncertainty that is presently addressed by the upcoming appraisal campaign is the areal net sand distribution within the individual reservoir bodies. From the well-to-seismic tie of the Bonga-SW-1 well it appears that bounding shale properties have a strong influence on the seismic expression of the reservoirs. In the shallow reservoirs (600 series) there is clear definition of hydrocarbon contacts visible on seismic amplitude maps. In the intermediate (700 series) and deep reservoirs (800 series) there is no clear identification of hydrocarbon fill possible. Here, interpretation relies on correlation with the Bonga Field. In the current outline the Bonga-Southwest accumulation comprises more, but individually smaller reservoirs than Bonga.

Objectives:

- Do we understand what we are starting?
- Has a full enough range of strategies and scenarios been identified?

Timing:

10th-13th September 2001, Woodcreek, Houston

Decision:

- Confirm that, based on the Bonga Main analogue, the Bonga Southwest discovery well data and the current reserves estimate for the field (P50, P85, and P15), Bonga Southwest represents a significant commercially and technically viable business opportunity for which a team should be set up to move the project forward to concept selection.
- Validate the basis to pursue Bonga South West as a fast-track development, FDP Q3 2002, FID 2002 and delivering first oil by end 2005, to maximise value to Stakeholders. The fast-track would be achieved by progressing an assumed base case of a Bonga FPSO hub look-alike through the contracting plan in parallel to the necessary design studies that will lead to single concept selection.

- Confirm that an appraisal plan (integrated activities and resources) has been developed that will ensure adequate definition of the Bonga South-West Field prior to this aspirational/target project schedule.

Opportunity Identification

Confirm that:

- Information has been gathered in a manner that ensures that the opportunity presented by Bonga South West is understood and that analogous projects, specifically Bonga main and Erha, have been screened for learning.
- The correct conclusions have been drawn from the information gathered.
- Key risks and costs associated with initiation of the project have been identified and can be appropriately managed.
- Bonga Southwest has a reasonable chance of success and its business value in terms of potential commercial rewards has been assessed. Critical success factors have been identified and are understood.
- Basis for establishing the project team and continuing with the appraisal drilling is sound.

Range of Scenarios and Strategies

- Scenarios have been developed to cover the full range of risks / uncertainties: surface, sub-surface, operational, infrastructure and business environment.
- Subsurface uncertainty quantification is robust over the entire range of possible outcomes.
- All available data have been used in subsurface outcome definition.
- The Value of Information associated with the key risks and opportunities has been analysed to define the key appraisal strategies.
- A framework for active monitoring of the assumptions underlying the expected value of the project is in place
- Opportunities for maximising value, including cost-leadership initiatives, application of technologies and alternative fiscal and financial constructions have been fully explored.

Business Environment

- The business environment is understood and the project has been framed within its context.
- Project is aligned with Sector and/or Company strategic direction and commitment to Sustainable Development.
- Potential options are aligned with the objectives, value drivers and key stakeholders' aspirations.
- Uncertainties related to schedule, commercial environment, competition, government and partnering aspects have been identified.
- All risks / opportunities have been identified and the key risks / opportunities prioritised. Key Social, Environmental and Economic impacts have been identified.
- Stakeholder controls and expectations will allow the project to take advantage of global contracts and synergies with other projects/ventures.

Forward Plan

- Project definition is unambiguous and realistic, with agreed and shared objectives.
- Value Assurance Review points are mapped and agreed with Stakeholders
- Key Sustainable Development, organisational, IT, HSE, issues management and PA aspects have been identified.
- The economics, (incl. costs), are modelled to an appropriate level and justify continuation
- The plans for the next stages are realistic and fit for purpose
- The necessary organisation, resources/skills, data and technology have been identified and staff continuity has been planned through the remaining phase(s).
- There is clarity on future decision points and commitments and the technical and data requirements to support these.
- Tollgates that link to significant fund releases have been adequately defined and exit options at various stages considered.

Learnings and Best Practices

- Integration of lessons learnt from other Nigeria Deepwater PSC projects, specifically Bonga and Erha, has taken place.

Outcome:

- Support for subsurface uncertainty range and outcomes.
- Support for ranges of in-place hydrocarbon resource volumes and technical reserves.
- Support for range of integrated field development concepts.
- Support for continuation into Concept Selection and Full Field Development Planning
- Support for parallel development approach, i.e. conceptual studies together with an assumed base case, to fast-track FID.
- Agreement on Terms of Reference for VAR 3 with identification of essential issues that must have been resolved at next VAR decision point.

VAR team:

Norman Read (lead, engineering and project management, SIEP)

Tom Wilson (Reservoir Geology, SEPCo)

Justin Freeman (Petrophysics, SEPTAR)

Rod Sidle (Reservoir Engineering)

Libby Bollich (Systems selection incl well engineering, SIEP)

Bill Sevier (Commercial, SIEP)

Attachments

- Notes from Meeting on Bonga-SW Development Plan Initial VAR discussions
- OML 118 Location Offshore Nigeria
- OML 118 prospect overview map.

Useful References

- SDS 00-10333 OPL 212 (OML118) IFO and Satellites Atlas and Conceptual Development Plan.
- EP2000-2826 Bonga SW-AX Exploration Well Proposal OPL 212 (OML118) - Nigeria

Notes from Meeting on Bonga-SW Development Plan Initial VAR discussions

The Hague, Friday 8th June, 2001

Attending:

Brad Kerr, RBA in EPA
Charles Shotton, SNEPCO
Chris Varley, SDS
Mark Cambio, SDS
Jon Crane, SDS
David Adejumo, SDS
Rudolf de Ruiter, SDS

Purpose of the Meeting:

To present SNEPCO's initial thoughts regarding a Bonga-SW Development Plan, and to receive early feedback on the Plan from an experienced VAR Consultant.

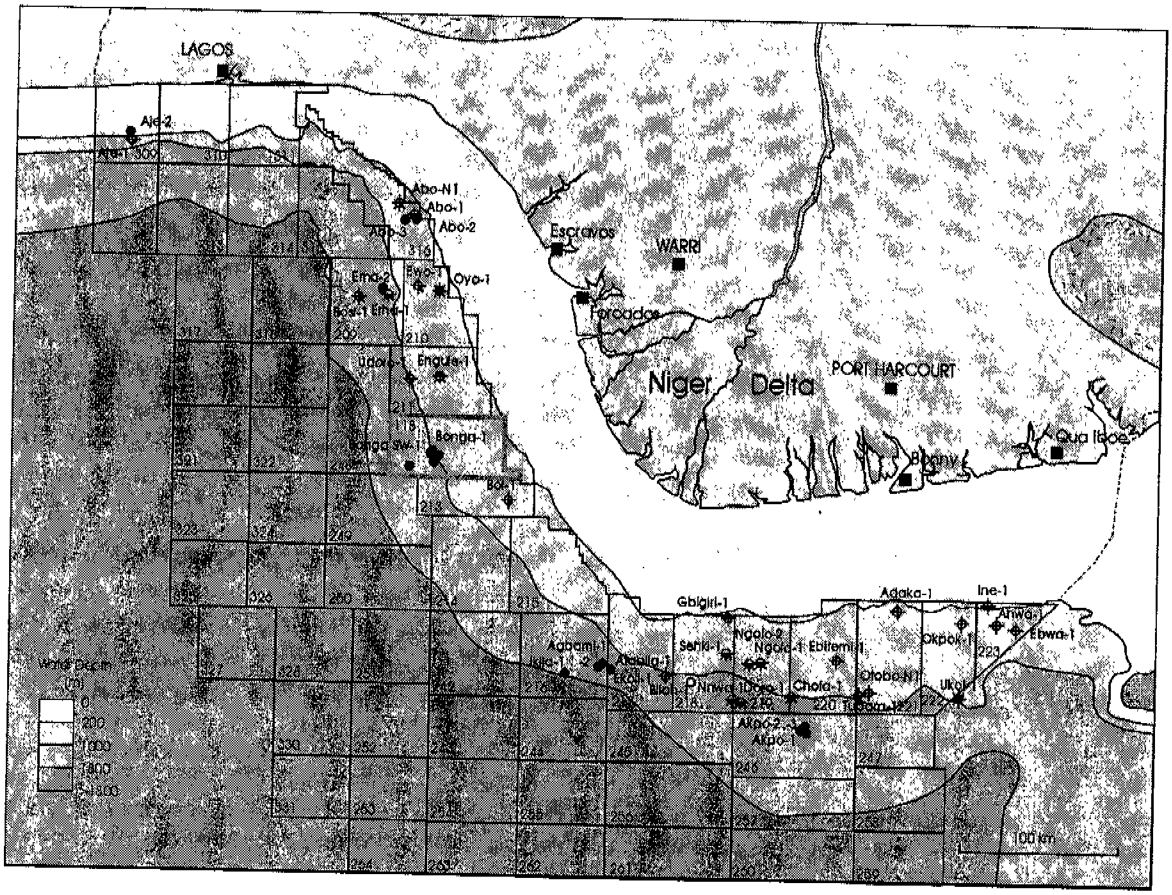
Presentation on Bonga-SW:

Chris Varley gave a brief presentation on the current status of Bonga-SW Development Planning. SNEPCO have made a significant discovery at Bonga-SW (base case reserves of ~600 MM bbls), some 10-15 Km away from the Bonga Field in OML 118. They wish to adopt a fast-track approach to developing Bonga-SW with a FID target date of end 2002, and a first oil target date of end 2005. The base case is an FPSO and subsea "hub" development, although a tie-back to the Bonga Field is also thought feasible.

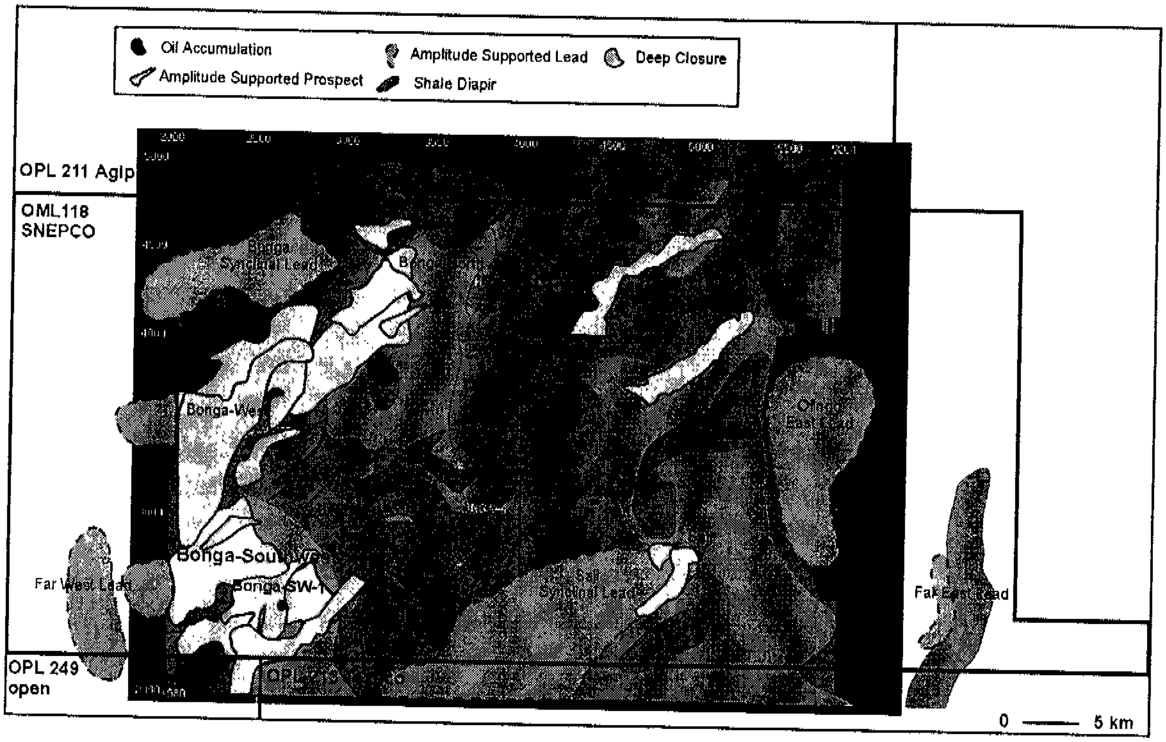
Feedback:

- Consider combining VAR 1 and VAR 2 with a September 2001 target date, so that the Bonga-SW Project may benefit from early "VAR" input.
- During the VAR, the team should demonstrate that "fast-track" is both the right technical and commercial approach.
- Will the fast-track approach allow sufficient time for any potential negotiations with NNPC on PSC terms, and with TEXACO on unitisation issues?
- Develop a tangible manpower plan for the Bonga-SW Project that reflects the increased needs to be successful in delivering a fast-track project.
- Clarify the appraisal and development strategy.
- Is it necessary to drill 2 or 3 appraisal wells given the similarity to Bonga?
- Aggressive "fast-track" may be appropriate given what we know of the Bonga Field.
- Appears that it would be better to drill Bonga-W in 2001 to make the optimal development decisions for the reserves in the area (i.e. which to develop first? What is the optimal size and location of the FPSO?)
- As in Bonga, we will have to demonstrate that we have developed an optimal subsea architecture at Bonga-SW.
- Make sure recent learnings from contracting and commercial negotiations on Bonga, as successfully applied at Erha, are further developed and applied to the Bonga-SW Project.
- Due to the similarities to Bonga for VAR 2 issues and deliverables, build upon what has been addressed already (at Bonga), and focus in on what is new at Bonga-SW.
- Project and VAR Team should incorporate "new blood" for renewal and fresh perspectives.
- Try to arrange for same VAR Team Leader for combined VAR 1/VAR 2, and for VAR 3.
- Incorporate informal input from VAR team using Shell Oil's pre-VAR workshop approach (Nakika is a good example of this).
- Bonga-SW Project will probably require a large commercial team.
- Gas utilisation will be a significant VAR 1/VAR 2 issue.
- For fast-track approach, it will be important to demonstrate that all staff and pointing in same direction early in the project.
- If VAR 1/VAR 2 goes well, VAR 3 could be smaller review.

OML 118 Location Offshore Nigeria



OML 118 prospect overview map



An underlying structure map highlighting the structural highs (yellow) and shale withdrawal synclines (green). The structure map depicts the outline of the currently available 3D seismic. A new 3D seismic survey (as part of the Bonga Field 4D) over the entire block is scheduled to be ready for interpretation in first quarter 2002.

From:	Church, John JP SIEP-EPT-DE
To:	Gause, Jerry JK SIEP-EPT-DE; Hines, Ian IM SIEP-EPT-DE; Sidle, Rod RE SEPCO; Sieler, Jeffery JJ SIEP-EPT-DEC
CC:	
BCC:	
Sent Date:	2001-09-12 20:14:18.000
Received Date:	2001-09-12 20:14:18.000
Subject:	Brazil reserves
Attachments:	

Guys
As part of the work efforts this year of the BS-4 integrated development team, we are attempting to book reserves this year. Shell Brazil have this as a scorecard target. They have asked us to have our workplans / timings reviewed internally in SDS. We would like to conduct this review 1st week in October if this is possible. Can you let me know if you would be willing to participate and your availibility that week (Oct 1-4). The review should last no more than half day.

Thanks
John

EXHIBIT
Sidle
21
10-31-06 73

Unknown

From:	Roosch, Jan-Willem JW SIEP-EPB-P
Sent:	14 January 2002 07:24
To:	Sidle, Rod RE SEPCO
Cc:	Van Driel, Peter P SIEP-EPB-P
Subject:	RE: SNEPCO Reserves questions
Importance:	High

Rod,

Will you be able to comply with our request?

Jan Willem

-----Original Message-----
From: Roosch, Jan-Willem JW SIEP-EPB-P
Sent: 11. januar 2002 15:12
To: Sidle, Rod RE SEPCO
Cc: Van Driel, Peter P SIEP-EPB-P; Nauta, Jaap J SIEP-EPB-P; Wilhelm, Chandler CT SIEP-EPT-DE
Subject: RE: SNEPCO Reserves questions
Sensitivity: Confidential

Thanks very much for your insights Rod,

The number that the SDS team has submitted for Bonga SW (Shell Share 19.35 mln cm) is consistent with 311 mln bbl proved total project reserves.

I appreciate that a VAR 3 review would be the ideal process to "solidify" proved reserves numbers for investor disclosure. It should however be noted, that it is now more than ever deemed in the corporate interest to reflect proved reserves as soon as we "realistically" can. I do not advocate bookings that have more downside than upside, nor do I advocate reporting expectation numbers as proved (even in mature fields, I believe that this is often not defensible).

In order to help bring this issue to close out fast (deadlines are near!), I would like to request you (and/or any other objective Shell professionals of your choice on the ground in Houston) to engage with the SDS team on our behalf, aiming to:

- Facilitate/influence the team to construct a notional development that fulfils the Group criteria for proved reserves booking.
- Give us your objective view of any revised assessment that the team may come up with in the next few working days.

The overall aim of such engagement is to help assure maximum OBJECTIVITY (and robustness) in our ultimate advice to corporate management.

I have no doubt, that time spent can be charged to EPB-P.

We would be very grateful for any help you could offer,
Also see attached.
<< Message: RE: SNEPCO reserves booking >>
Regards,

Jan Willem D. Roosch
Group Reserves Coordinator
Shell International Exploration and Production B.V.
Carel van Bylandtlaan 30, Postbus 663, 2501 CR The Hague, The Netherlands

Tel: +31 70377 7405 **Other Tel:** +31 621403855

EXHIBIT
Sidle
22
10-31-06 [illegible]

DB 07573

Email: janwillem.roosch@ope.shell.com
Internet: http://www.shell.com/eandp-en

-----Original Message-----
From: Sidle, Rod RE SEPCO
Sent: 10. januar 2002 22:29
To: Roosch, Jan-Willem JW SIEP-EPB-P
Cc: Van Driel, Peter P SIEP-EPB-P
Subject: RE: SNEPCO Reserves questions
Importance: High
Sensitivity: Confidential

Jan-Willem,

Please let me review the circumstances of our current discussion. My points of reference are from the VAR of early September when a new team to work Bonga SW had just been formed. My issues were known to be unresolved but being worked. As a VAR team, we can only comment on status as is. Thus we noted much that left us wanting in the description of the reservoir and ultimate recoveries. The BSW team has had time to work on these and other issues, presumedly with considerable progress, especially if they are still on schedule for a VAR3 in mid-2002. So if such new information has been used in justifying these volumes, I am not in a position to argue from the vantage point of four months past.

That said, here are some of the points that I would want to understand before accepting a proposal to book proved reserves at BSW:

Certainly I would want to understand what new data and/or work have made the several issues raised in the VAR about the reservoir understanding and especially the analogy to Bonga Main but if I accept from your comments this has been resolved, then I still would like to know --

- Is this 311 mln bbl a Shell's share (55%) or total share? If total, then prior economics would suggest only a tieback to Bonga Main would be economic. Since the BSW wells would be produced after the Bonga Main IFO volumes, there could be a production cutoff when the production license expires in 2020 (or at least we cannot book proved reserves past that point). If the BSW wells are produced sooner, does this cause any IFO volumes to truncate at the license end date? If the 311 mln bbls is Shell's share then this suggests we have proved 565 mln bbls total which would be a large fraction of the potential maximum case shown in September. It would seem quite early to be that aggressive in our booking.
- Bonga SW is expected to need water injection to support the recovery per well required for an economic development. Do we have demostrated results from waterflooding in the Bonga reservoirs or close analogs to support proved reserves from waterflooding?
- How are the downdip productive limits defined? The existing well (B SW-1) penetrated the structure about mid-dip and then only some of the expected reservoirs. For proved reserves, only penetrated reservoirs can be booked and only to lowest penetrated oil unless very high quality seismic supports a lower oil-water contact. Again, as in my prior note, these reservoirs are largely channelized thus making seismic interpretation of an OWC very uncertain (ie, not proved).
- Do we have a production test from BSW with adequate fluid samples for flow assurance work? Has this work been completed to demostrate subsea flow back to Bonga Main is certain to work?

This should be enough to give you a flavor for my concern that we are premature in booking Bonga SW to proved. I would note that if they pass the VAR3 as scheduled, these reserves will be much easier to accept as ready for investor recognition.

Regards,
Rod

Rod Sidle
Manager, Oil and Gas Reserves
Shell Exploration & Production Company
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DB 07574

-----Original Message-----
From: Roosch, Jan-Willem JW SIEP-EPB-P
Sent: Thursday, January 10, 2002 10:40 AM
To: Sidle, Rod RE SEPCO
Cc: Van Driel, Peter P SIEP-EPB-P
Subject: RE: SNEPCO Reserves questions
Importance: High
Sensitivity: Confidential

Rod,

Further to this issue:

I was visited today by Keith Lewis, Kisito Okpere and Barry Knight, who were unanimous in their strong determination to have a substantial booking of proved reserves on Bonga SW (and possibly on a more recent discovery too).
Barry Knight advocated strongly for analogy of the reservoirs with Bonga Main and Keith Lewis concluded that the action at hand would be to deliver the evidence to me, that 311 mln bbl is a responsible booking of proved undeveloped on this discovery.
It concerns me, that we do not have the level of expertise here to come with a credible 2nd opinion, but I would expect, if we stick to the "proved area" principle and could in one way or another argue for analogy (or not link the pay zones to favorable analogues elsewhere), we may be able to present a credible case, of a sufficient size to be commercial. This would probably the "Limited Development Case" that you alluded to. I just wonder, what volume such a project could yield.
Grateful your early views.

Please do NOT copy Anton Barendregt at this stage, as his role is to take a final view as the auditor.

Regards,

Jan Willem D. Roosch

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Tel: +31 70377 7405 **Other Tel:** +31 621403855
Email: janwillem.roosch@ope.shell.com
Internet: http://www.shell.com/eandp-en

-----Original Message-----
From: Sidle, Rod RE SEPCO
Sent: 9. januar 2002 18:25
To: Van Driel, Peter P SIEP-EPB-P; Barendregt, Anton AA SIEP-EPB-GRA
Cc: Roosch, Jan-Willem JW SIEP-EPB-P
Subject: RE: SNEPCO Reserves questions

Peter and Anton,

From your comments and the email change below, I am assuming you have the Bonga SW VAR 1/2 Findings from Sept 2001. In these, from the work done at that time, are expressed the concerns of the subsurface specialists (myself included) that the Bonga SW work was still quite preliminary -- not yet to VAR 2 standards (Slide 6). One prime example was that analogs built from Bonga Main were questionable based on obvious differences with Bonga SW sands (as you noted, on Slide 14) especially in terms of the reservoir continuity. In summary, the subsurface story as of Sept was not sufficiently mature for booking proved reserves for the Bonga SW project.

In fact, it was not entirely clear that if the Bonga West exploration prospect was successful that Bonga SW may not end up third in a race where only the first two fields (Bonga Main, Bonga West) get developed. If the Bonga Main development no longer includes the In Field Opportunities (IFO) then I might be willing to consider a limited Bonga SW development case where a few wells are tied back to Bonga Main and develop the high confidence portion of the Bonga SW reservoirs assuming primary depletion. But as of September, the IFO volumes were prioritised in front of Bonga SW tie-backs to Bonga Main.

As to booking below lowest well penetrated hydrocarbon based on seismic or regional analogy, no discussion of this as a basis for proved reserves occurred during the VAR. Given the channelized nature of the Bonga SW reservoirs, I doubt the SEPCo seismic test of proved reserve confidence could be passed. This same situation failed the Plutonio Olig 72 reservoir (Angola Block 18) from additional proved volumes.

Please let me know if you have additional questions.

Regards,
Rod

Rod Sidle
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DB 07576