Exhibit 1

REPORT OF

DAVIS POLK & WARDWELL

TO

THE SHELL GROUP AUDIT COMMITTEE

EXECUTIVE SUMMARY

MARCH 31, 2004

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Executive Summary

I. Retention of Davis Polk & Wardwell

On January 9, 2004, following an internal review by Shell* management ("Project Rockford"), the Company announced that it would recategorize approximately 3.9 billion barrels of oil equivalent ("boe") of its reported "proved" reserves.** Shell released its unaudited results for 2003 on February 5, 2004, including details of the recategorization. On that date, Shell also disclosed that the Shell Group Audit Committee ("GAC") was conducting an independent review of the facts and circumstances surrounding the recategorization.

On February 3, 2004, the GAC engaged Davis Polk & Wardwell ("DP&W" or "Davis Polk") to act as independent counsel and lead an investigation into the facts and circumstances of the recategorization. The GAC also commissioned a special working group of Shell present and former employees to assist with the investigation. Broadly speaking, Davis Polk's mandate was to investigate, thoroughly and expeditiously, the conduct of Shell's involved management and to determine whether remedial actions were warranted, both in terms of personnel changes and broader control measures. A written report was to be submitted on March 31, 2004. The investigation was also requested by KPMG Accountants N.V. and PriceWaterhouseCoopers LLP (the "External Auditors") in order to satisfy their obligations under Section 10A of the United States Securities Exchange Act of 1934.

Early in the investigation, it was agreed with the GAC and the External Auditors that Davis Polk would focus on the following areas: an examination of the knowledge and conduct of Shell's most senior management with respect to Shell's reserves disclosures; an examination of the extent to which Shell's own internal guidelines for the booking of proved reserves (the "Shell Guidelines") were consistent with the requirements of the United States Securities and Exchange Commission ("SEC") applicable to disclosure of "proved reserves"; and four geographic areas of operation – the Gorgon gas field offshore North

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* References to "Shell" or "the Company" herein refer to Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, Public Limited Company, combined with their respective subsidiaries and affiliate companies.

** See Tab A supra, for the discussion of the regulatory definition and standards for "proved" and other reserve categorizations.

West Australia; Brunei [BSP]; Nigeria [SPDC]; and Oman [PDO]. These four geographic areas were chosen because, individually, they each represented at least 300 million boe recategorized and, together, they reflect over 60% of the January 9, 2004 recategorization.

II. Overview of Investigative Procedures

Shell has cooperated fully with the internal investigation, providing the investigation team with complete access to its records, files, electronic data, and personnel. DP&W has been assisted by an internal team provided by Shell consisting of Renger Bierema (Director Technology Gas & Power), Jim Cooper (Head of Executive Talent Management EP), Jakob Stausholm (Group Chief Internal Auditor) and Neil Sullivan (retired General Counsel of Chemicals Gas & Power). DP&W has also engaged Gaffney, Cline & Associates, Ltd ("Gaffney Cline"), independent petroleum engineers, to advise as to technical issues, including an analysis of Shell's Guidelines. Fox Data Ltd. had been retained to perform forensic analysis and data retrieval from individual desktops and laptops and Shell servers.

Interviews

In its investigation, DP&W has conducted approximately 130 interviews of over 90 witnesses, including directors, senior executives, members of the executive committee of Exploration & Production ("EP"), reservoir engineers, reserve coordinators and management from the different operating units under review, the Group Reserves Coordinators from the relevant time periods ("GRC"), the internal Group Reserves Auditor ("GRA"), external auditors and personnel from the various functional areas at Shell including finance and legal. Some of these individuals were interviewed several times. (A list of the persons interviewed, along with their titles, can be found at Tab J.)

These interviews were not conducted under oath and Davis Polk was unable to subpoena or otherwise compel the attendance of former employees. Because of the time pressures and the disparate geographical regions at issue, some interviews were conducted by phone and not all could be conducted with the benefit of review of all relevant documentation. Three of the Shell employees that were interviewed, Sir Philip Watts, then Chairman of the Committee of Managing Directors ("CMD"), Walter van de Vijver, then Chief Executive Officer of EP, and Judith Boynton, Group Chief Financial Officer, were represented by their respective individual counsel during the interviews.

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Documents

In addition to these interviews, DP&W has reviewed hundreds of thousands of pages of documents obtained from hard copy files and reviewed electronic files from approximately 50 individuals and from server data and back-up tapes for select individuals. In addition to electronic mail, the documents reviewed include, among others, the following: CMD meeting minutes, presentations and reports to the CMD, EP Executive Committee ("Excom") meeting minutes, including presentations and reports to the Excom; GAC meeting minutes, including presentations and reports to GAC; Conference meeting minutes, including presentations and reports to Conference; EP Business Plans and Group Operating Plans; Year End reserve submissions from the relevant Operating Units; Year End Reserves summaries and reports by the Group Reserves Auditor; SEC Proved Reserves Audits by the GRA; Annual Reports; EP and Operating Unit Scorecards and Appraisals and Strategy Reviews; Letters of Representations to the Group Controller; SEC Comment Letters and Responses; SEC rules and Shell Guidelines and interpretations; Shell's public filings; presentations and transcripts of analyst and investor presentations; documentation related to the LEAP program and other strategic initiatives; and hard documents from the desk files and/or archives of select individuals.

Again, given time constraints, there is a significant quantum of documents and electronic information that has not been reviewed. Nonetheless, many of the factual findings described herein are based upon documentary evidence. Many of the key documents are clear and unambiguous; in this matter, the axiom "the document speaks for itself" often applies.

Issues relating to Document Integrity

During the investigation, two instances were discovered in which the integrity of documents might have been compromised.

First, described more fully below, on December 2, 2003, in response to a "Script" that was prepared by the CFO of EP recommending that the Group immediately disclose the need to debook proved reserves, Mr. van de Vijver wrote to the author of the document that it should be destroyed. After receiving this e-mail from Mr. van de Vijver, the author consulted various internal counsel who secured an assurance that the document had indeed been retained and that no documents would be destroyed. Document preservation notices were also circulated. Copies of the document were maintained by its author, other recipients of the "Script" and counsel. The electronic version of the "Script" sent by the CFO of EP to Mr. van de Vijver was deleted from Mr. van de Vijver's computer's in-box.

Second, from the period of approximately May 2003 through early January 2004, the EP Unit moved office locations within The Hague. Some of the most senior executives of EP, including members of Excom, the Reserves Coordinator and the GRA moved offices in the period of November, 2003. This move was part of an effort started in the mid-1990s as a result of a study conducted by McKinsey & Company, to transform Shell's business practices to a "paperless" operation. The facilities to which EP moved provided very little storage space and "paper" documents were thrown away during the move. The vast majority of the paperwork and documents were also electronically maintained, but the possibility that relevant notes and other documents not electronically maintained were discarded cannot be dismissed.

Again, in the time period, it was not possible to complete full forensic analysis of all files to assess their integrity.

III. Summary of Findings

In mid-2001, Mr. van de Vijver succeeded Sir Philip as Chief Executive Officer ("CEO") of Shell's EP unit, recognized as the most capital intensive and profitable business unit of Shell. Sir Philip himself had ascended from that position to the post of Chairman of CMD and Chairman of The "Shell" Transport and Trading Company, Public Limited Company. Within the Group and the market, there was a perception that Sir Philip's own success could be attributed, in part, to his ability to meet or exceed reserve expectations.

Virtually from the time of Mr. van de Vijver's succession, the two executives engaged in a pointed dialogue concerning EP's ability to meet a number of targets or "external promises", particularly those relating to reserves. As described by Mr. van de Vijver in a letter dated March 22, 2004:

> "Soon after coming to office as head of EP in June 2001, I observed that the health of the EP business was not as robust as the Company-determined performance targets set under the former EP CEO. In fact, EP was in a far worse state in mid 2001 than was ever portrayed by my predecessor to senior management or the Conference."

Mr. van de Vijver consistently pressed the position that reserves booked during Sir Philip's term were "aggressive" or "premature", non-compliant with Shell Guidelines for booking and, implicitly, SEC rules. That Mr. van de Vijver was in the main correct cannot be gainsaid in light of January 9, 2004, when many of the questioned reserves were recategorized. While Mr. van de Vijver complained repeatedly that the premature booking of the reserves had frustrated his ability to meet business targets and reinforced an inaccurate perception in the market, this issue was viewed primarily as a serious and immediate business question but not, equally, as a regulatory and disclosure failing.

Some of this dialogue between Sir Philip and Mr. van de Vijver was conducted by private e-mails and meetings; some aspects took place in the setting of CMD. Accordingly, other executives and employees had, over time, varying degrees of exposure to the debate and, in various strata of management at Shell's Central Offices and in the field, involvement in the operations that were the subject of the bookings. However, by both responsibility and authority, Mr. van de Vijver and Sir Philip were uniquely placed to address these issues. These two executives were viewed as the most powerful forces in management – on one side, the present Chairman and on the other a leading candidate as Sir Philip's

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successor and the occupier of the position – CEO of EP – that had been the platform for the last two Chairmen. Also, this dialogue involved a technical issue – proved reserves – that was particularly within their expertise and concern.

Reserve reporting and the booking of reserves are viewed as much an art as a science. Shell's 2002 20-F speaks directly to the lack of precision with respect to reserves calculation: "Oil and gas reserves cannot be measured exactly since estimation of reserves involves subjective judgement and *arbitrary determinations*. Estimates remain subject to revision." Royal Dutch Petroleum/Shell 20-F, 2002 (emphasis added). Moreover, the calculation of the amount of reserves is a fluid process that requires analysis of the status of projects that are ever-changing.

Regardless, beginning in 2001, recognition of the strictures of SEC rules, in place since 1978, increased within the Company, in part due to the publication on the SEC website of SEC guidance regarding the importance of investment commitments and other indicia of "reasonable certainty," with a growing recognition that the Company's reserve numbers were not in full compliance with these rules.

There are a number of significant documents which capture the dialogue between Sir Philip and Mr. van de Vijver and its escalation. On February 11, 2002, Walter van de Vijver forwarded a Note for Information to CMD which warned that proved reserve exposures were as high as 2.3 billion boe because of non-compliance with SEC guidelines:

> "**<u>Exposures</u>**
> **Securities and Exchange Commission (SEC) Alignment**
> Recently the SEC issued clarifications that make it apparent that the Group guidelines for booking Proved Reserves are no longer fully aligned with the SEC rules. This may expose some 1,000 mln boe of legacy reserves bookings (*e.g.* Gorgon, Ormen Lange, Angola and Waddenzee) where potential environmental, political or commercial 'showstoppers' exist.
> **End of License**
> In Oman PDO, Abu Dhabi and Nigeria SPDC (18% of EP's current production) no further proved reserves can be booked since it is no longer 'reasonably certain' that the proved reserves will be produced within license. The overall exposure should the OU business plans not transpire is 1,300 mln boe. Work has begun to address this important issue."

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This Note is the earliest statement to upper management that the Company might have significantly overstated its proved reserve position.

The Note raised issues of sufficient concern to Sir Philip that he required that a further presentation be made to CMD. However, on May 28, 2002, before this second presentation was made, Sir Philip directed Mr. van de Vijver by e-mail to leave "no stone unturned" to achieve 100% RRR for 2002, a result inconsistent with significant debooking:

> "You will be bringing the issue to CMD shortly. I do hope that this review will include consideration of all ways and means of achieving more than 100% in 2002 – to mix metaphors... considering the whole spectrum of possibilities and leaving no stone unturned."

On July 22, 2002, the further presentation was made to CMD by way of a Note for Discussion submitted by Mr. van de Vijver. The Note failed to address the non-compliance with SEC rules which jeopardized 2.3 billion boe, highlighted in the February 11, 2002 Note. Rather, it is an example of a series of documents which suggest that EP management's plan was to "manage" the totality of the reserve position over time, in hopes that problematic reserve bookings could be rendered immaterial by project maturation, license extensions, exploration successes and/or strategic activity. Simply put, it is illustrative of a strategy "to play for time" in the hope that intervening helpful developments would justify, or mitigate, the existing reserve exposures. Ultimately, as described below in the discussions of Australia (Gorgon), Oman, Nigeria and Brunei, this strategy failed – as business conditions either deteriorated or failed to improve sufficiently to justify historic bookings.

The minutes of the same July, 2002 meeting establish that it was recognized that delay in debooking could not be continued indefinitely:

> "It is considered unlikely that potential over-bookings would need to be de-booked in the short-term, but reserves that are exposed to project risk or licence expiry cannot remain on the books indefinitely if little progress is made to convert them to production in a timely manner."*

On September 2, 2002, Mr. van de Vijver submitted a further note to the CMD (with a copy to Judith Boynton) describing the "dilemmas facing EP and the uncomfortable situation EP is in...":

> "Given the external visibility of our issues (lean organic development portfolio funnel, RRR low, F&D unit costs rising), the market can only be "fooled" if 1) credibility of the company is high, 2) medium and long-term portfolio refreshment is real and/or 3) positive trends can be shown on key indicators.
> Unfortunately...:
> ...

* Given the acknowledged production and other difficulties, the strategy of "playing for time" was unrealistic. (See Tabs F & G.)

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> - We are struggling on all key criteria ("caught in the box").
>
> ...
>
> The immediate risk that we are facing is on the "negative spiral" of our boxed situation:
>
> ...
>
> - RRR remains below 100% mainly due to aggressive booking in 1997-2000."

Sir Philip and Mr. van de Vijver met to discuss these concerns privately over dinner. Thereafter, in October 2002, Sir Philip responded to Mr. van de Vijver's concern, described in the September memorandum, defending the business plan targets, including RRR of 100%. On October 22, 2002, Mr. van de Vijver replied:

> "I must admit that I become sick and tired about arguing about the hard facts and also cannot perform miracles given where we are today.
>
> If I was interpreting the disclosure requirements literally (Sorbanes [sic]-Oxley Act etc) we would have a real problem."

After this exchange and meeting, on November 15, 2002, Mr. van de Vijver circulated a brief outline of business plan issues to members of his EP staff and stated:

> "We finalized our plan submission and could easily leave the impression that everything is fine.
>
> ...
>
> The reality is however that we would not have submitted this plan if we
>
> 1) were not trying to protect the Group reputation externally (promises made) and
> 2) could have been honest about past failures (business focus w.r.t. aspired portfolio, disconnects with reality, poor performance management, reserves manipulation)."

Throughout this dialogue, it is clear that both Sir Philip and Mr. van de Vijver were alert to the differences between the information concerning reserves that had been transmitted to the public, "external," and the information known to some members of management, "internal." An insight into this conflict is provided in Mr. van de Vijver's "strictly confidential" personal Note to File of September, 2002:

> "During the last 1.5 years the technical competence and overall integrity of the EP business within Shell has been questioned both internally and externally, most prominently through lowering of the production growth target in August/September 2001 and due to a

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> deteriorating proved reserves replacement ratio. Providing credible explanations for these issues proved near impossible given the disconnects between external promises/expectations and the reality of the state of the business.
>
> ...
>
> Bottomline was that both reserves replacement and production growth were inflated:
>
> - Aggressive/premature reserves bookings provided impression of higher growth rate than realistically possible.
>
> ...
>
> The concerns around the "caught in the box" dilemma and stretch in the EP business plan have been flagged at the highest level in the company, but obviously "transmitted" in a careful fashion as not to compromise/undermine the previous leadership. The severity and magnitude of the EP legacy issues may therefore not have been fully appreciated."

The discussion continued in 2003. On February 28, 2003, Mr. van de Vijver sent Sir Philip a copy of a February 23, 2003 e-mail in which Mr. van de Vijver stated to his EP staff:

> "We know we have been walking a fine line recently on external messages... Promising that future reserves additions are expected in 2003... whilst we know that there is some real uncertainty around this... [W]e know our ongoing exposures on Oman/Nigeria reserves and on early bookings, notably Gorgon and Ormen Lange."

On August 25, 2003, Mr. van de Vijver directed a draft of his "Mid-year 2003 Review Summary" to Sir Philip, complaining that: "The single largest issue facing EP is the shrinking opportunity portfolio exacerbated by... too aggressive reserves bookings in the past...."

On November 9, 2003, after receiving what he considered an unfairly critical performance review from Sir Philip, Mr. van de Vijver e-mailed to Sir Philip that:

> "I am becoming sick and tired about lying about the extent of our reserves issues and the downward revisions that need to be done because of far too aggressive/optimistic bookings."

Sir Philip did not disclose receipt or content of this e-mail to anyone until well after Project Rockford had started, either in late December 2003 or early January 2004.

There can be no issue that proved reserves and RRR were understood to be of significance to the market. On November 8, 2003, the day before this

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e-mail to Sir Philip complaining that he was tired of "lying" about proved reserves, Mr. van de Vijver wrote in an e-mail to a colleague:

> "As you know 2003 RRR is the most important share price 'influencer' also as expectations are high and they do not know that we are still paying for aggressive reserves bookings [including thos[e] that have not reached FID yet!!] in the past!"

RRR had previously been described as a "kpi," key performance indictor, and Mr. van de Vijver had participated in analysts presentations in which the issue of proved reserves and RRR were a focus.

In late 2003, catalyzed by the troublesome results of reserves studies and audits from Nigeria and Oman, and, perhaps, a draft memorandum prepared by EP which included legal advice from Cravath, Swaine & Moore, the process was begun – Project Rockford – that ultimately resulted in the disclosures of January 9, 2004.* While different interviewees provide different explanations for starting this project, the advice provided by outside counsel is significant.

In a December 2, 2003 memorandum entitled "Script for Walter [van de Vijver] on the proved reserves position" prepared by EP staff, the assumption was made that approximately 2.3 billion boe of proved reserves were non-compliant, (approximately the same amount identified as exposed on February 11, 2002), and that this was "material" to the market. Given these facts, the following legal conclusion was described:

> "If and from the time onwards that it is accepted or acknowledged by the management of the issuers (Royal Dutch and STT), that, when applying the SEC rules, the 2002 proved reserves as reported in the Form 20-F are materially wrong, the issuers are under a legal obligation to disclose that information to all investors at the same time and without delay. Not to disclose it would constitute a violation of US securities law and the multiple listing requirements. It would also increase any potential exposure to liability within and outside the US. Note that the reserves information also appears in the non 20-F Annual Reports.

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* There are indications that in December 2002 and again in November 2003, Mr van de Vijver considered the idea of a comprehensive debooking of all known "exposed" reserves. In December 2002, he asked the Group Reserves Coordinator for an analysis of the effect of a debooking of all "questionable" reserves. And in late November 2003, he stated in a message to the Coordinator, "I would prefer to re-state our 1/1/03 reserves and de-book all remaining legacies to allow for a clean start." At about the same time, however, Mr. van de Vijver delivered an encouraging message on planning goals to all senior EP executives in which he warned: "One final word on 2003. It would be an enormous blow to the Group's credibility with the Market if we do not deliver on RRR this year."

Disclosure cannot await the next Form 20-F appearing in April, 2004."

On the same day this "script" was provided to Mr. van de Vijver, he immediately e-mailed one of its authors:

> "This is absolute dynamite, not at all what I expected and needs to be destroyed."

Because of prompt interdiction by internal counsel, the document was retained.

Even in the recategorization process, a controversy arose concerning the explanation that should be given for the recategorization, particularly whether it should be made clear when the original reserves were booked and whether the recategorization was the result of recent SEC rulings and other developments. Mr. van de Vijver e-mailed a colleague:

> "[W]e are heading towards a watershed reputational disaster on Rockford and I do want to stick to some very firm criteria: the problem was created in the 90's and foremost in 97-00 and any clean-up must reflect that..... I will not accept cover-up stories that it was Ok th[e]n but not OK with the better understanding of SEC rules now and that it took us 2 1/2 years to come to the right answer."

Similarly, on December 8, 2003 Mr. van de Vijver e-mailed his colleagues in EP:

> "When looking at SPDC and PDO is it really valid to portray that we only recently discovered the problem in Oman and Nigeria? I think we [k]new much earlier. . . ."

However, the explanations given to a press and analysts conference, on February 5, 2004 when Mr. van de Vijver presented the 2003 results and commented on the January 9 recategorization, strike a different chord:

> "There were two events in 2003 that were the catalyst for what we ultimately announced on the 9th of January. The first was a detailed review in Nigeria. . . . The other area where we last year put a lot of effort in was around Oman.
>
> . . . .
>
> The shock outcome of [the Nigeria and Oman] reviews immediately sort of triggered the process to look at the whole globe and make sure that we had a totally consistent approach at everything."

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The statements made by Sir Philip at the same conference also need to be scrutinized in the light of the documentary record:

> "We've always believed – and I've always believed – that Shell in aggregate was materially compliant with its own and the SEC guidelines, and we relied on audits and assurance processes.
>
> . . . .
>
> This thing came up late last year, catalytic events coming out about reviews in Nigeria, also the Middle East. As soon as that came to my attention, it was a matter of all hands on deck. And I remember writing down the words 'get the facts and do the right thing.'"

And, on January 16, 2004, Sir Philip Watts has been quoted as saying:

> "[D]uring the fourth quarter of last year in-depth reserves studies were completed that triggered a broad review of our previously booked proved reserves.... Based on those reviews, I believe that individuals concerned worked in good faith to the interpretations in use when the bookings were made, following proper processes, and that there is no evidence of any misconduct."

* * * * * * * * *

While the dialogue, described above, confirms that these two senior executives were aware of the issue of "aggressive" proved reserves bookings and, in a manner, attempted to address it, these documents do not reveal the causes of the questionable bookings. To ascertain the need for the recategorization, the investigation has focused upon developments in four geographic areas – Australia (Gorgon), Nigeria, Oman and Brunei. While the findings of those inquiries are described in detail at Tabs E through H, it is worth observing that there is no common explanation.

<u>Australia (Gorgon)</u>. As of December 31, 1997, the Group booked over 500 million boe of Gorgon gas reserves as proved. The Shell Guidelines at the time allowed proved reserves based on an "expectation of availability of markets," and for a brief period, commercial expectations for Gorgon arguably met this loose requirement. From its inception, the Gorgon "proved" reserves did not meet the overriding SEC standard of "reasonable certainty." There is no written audit trail indicating who made the decision to categorize Gorgon reserves as proved, or the basis of that decision. Sir Philip, EP CEO at that time, reports no recollection of the Gorgon booking, notwithstanding its size and impact on RRR for 1997. The questionable status of Gorgon was re-visited at several points, beginning with the January, 2000 decision – reviewed in a presentation to EP Excom attended by Sir Philip – to "freeze" the booking despite a 20% increase in technical reserves. In October, 2000, the Group Reserves Auditor affirmed this

"freeze" status, against a local technical opinion in favor of debooking. While debooking continued to be debated, no action was taken until January, 2004. In the words of the current Group Reserves Coordinator, Gorgon had long "stuck out like a sore thumb," but, at over 500 million boe, debooking of the reserve was "too big to swallow."

Oman. Proved reserves were increased in 2000 in response to "top down" encouragement from Shell to bring its proved reserves of mature fields in line with its expectation reserves. Insufficient technical work was done to support this increase. When serious production declines were suffered thereafter, these increased reserves were maintained based upon aspirational production targets. It is clear that various members of management at EP, including Mr. van de Vijver, were aware of this situation since late 2001, when the production problems increased and Shell agreed to make a $30 million "down payment" (in the form of a deduction against its 2001 net reward) in partial payment for an inchoate debooking of expectation reserves.

Nigeria. SPDC accumulated over the 1990s and, particularly, in the late 1990s very large volumes of proved oil reserves. No later than early 2000, however, it became clear to EP management that SPDC's substantial proved reserves could not be produced as originally projected or within its current license periods. Rather than de-book reserves, an effort was undertaken to "manage" the problem through a "moratorium" on new oil and gas additions, in the hope that SPDC's production levels would increase dramatically to support its reported reserves. This solution remained in place for the next several years, until January, 2004, notwithstanding the knowledge of EP management that, in fact, production was not increasing to a level which could support the booked proved reserves.

Brunei. The large volume of debookings is attributable to reserves that were either uneconomic to develop or had been booked well ahead of any final investment decision or analogous financial commitment being made, and at a time when the Shell Guidelines did not specifically require such a commitment prior to booking. Part of the recategorization was attributable to "legacy" volumes, which did not comply as proved reserves and were being debooked gradually to avoid "major swings" in the reserves.

* * * * * * * * *

The booking of "aggressive" reserves and their continued place on Shell's books were only possible because of certain deficiencies in the Company's controls. For example, the internal reserves audit function was both understaffed and undertrained. This function was performed by a single, part-time, former Shell employee; his cycle of field audits was once every four years; he was provided with virtually no instruction concerning regulatory requirements, or the role of an independent auditor and no internal legal liaison. While the GRA made occasional attempts to bring proved reserves into compliance with both SEC rules and Shell Guidelines, he had neither the power nor facilities to insure such

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compliance. Moreover, the GRA has recently speculated that, had he been aggressive in this effort, his very position would have been at risk:

> "On the few occasions in my early years where I signaled a conflict with SEC rules I was called back by [GRC] and by the OUs who argued, rightly, that the only rules they should be bound by were the Group guidelines. These are the backbone of our internal controls on reserves. The spear-point of the SEC reserves auditor's control should therefore have been on a correct formulation of the Group guidelines. With hindsight, I should have been more forceful in this respect. It would have been a clear break with all my predecessors and it would probably have cost me my job in those days, but I should have."

And, consistent with the views of management described above, he acquiesced in or attempted to assist Shell in "managing", rather than debooking, its non-qualifying reserves. The moratoria in Australia and Nigeria and his advice not to de-book the 40% non-compliant Oman reserves are examples of this approach. However, assuming vigorous efforts made entirely in good faith, a single, part time, former employee could not constitute an effective check on "aggressive" reserve bookings. (*See* Tab D.)

In that regard, it is important to note that the Shell guidelines:

- blurred the distinction between reserves reporting for internal decision-making and the requirements for regulatory reporting of proved reserves;
- were slow to incorporate SEC staff interpretations and, while reflecting an increased awareness of SEC rules, occasionally adopted an expedient of partial compliance;
- did not encourage OUs to review existing bookings for continued compliance and did not adequately address the need for debooking; and,
- were not clearly and succinctly written or organized to offer useful guidance to reservoir engineers in the OUs.

In short, the Shell guidelines were not adequately designed to yield compliant reporting of proved reserves. (*See* Tab A.)

Also, the compliance role of the finance function was not effective with respect to these bookings. For example, Ms. Boynton attended CMD meetings beginning in 2001 and became a member of CMD in 2003. Her responsibilities were different than other members of CMD; she had direct responsibility to ensure that the Company's financial disclosures to the market and to regulators were correct. Ms. Boynton took virtually no action, prior to the initiation of

Project Rockford, to inquire independently into the underlying facts relating to the "aggressive bookings". Rather, she relied upon the "checks and balances" of Shell's representation and assurance process and the work of its independent external auditors to ensure compliance. Specifically, she reports that she was reassured that EP was focused upon the issues and that year-end reserve reporting was a strenuous process – closely monitored by financial executives in whom she had faith. At the same time, Ms. Boynton's ability to act effectively in a compliance function was somewhat impaired because, until recently, none of the business units' CFOs reported to her. For this and other reasons, on the issue of reserves, it may be that her responsibility exceeded her authority.

The "external" checks on reserves abuses were also frustrated. Specifically, Shell's outside directors and GAC were not presented with the information that would have allowed them to identify or to address the issue. A specific example of this failure occurred as late as October, 2003; after it had requested a briefing on the topic of proved reserves, the GAC was not provided with critical, current information – an unfavorable audit report relating to Nigeria and a significant decrease in the reserve "offset" supposedly available due to "fuel and flare".

Mr. van de Vijver, in March 22, 2004 correspondence, excuses his own conduct by suggesting that either Shell's culture or Sir Philip and Ms. Boynton frustrated his efforts at disclosure:

> "Throughout this entire process, my attempts to bring the reserve issues to management's attention were met with resistance. The atmosphere between myself and the Chairman became gradually more tense as I identified issues in EP.
>
> ....
>
> It is the responsibility and role of the Chairman and/or the CFO to alert the Group Audit Committee to business control weaknesses or external reporting issues. Because the unspoken rule within the Company is that you are not supposed to go directly to individual Board members or to the Group Audit Committee, I had to rely on the Chairman and the CFO to advise the GAC and assumed that happened in early December."

In his Note to File of September, 2002, Mr. van de Vijver had conceded that, out of deference to Sir Philip's position, his internal disclosures of the "severity and magnitude" of the reserve dilemma may not "have been fully appreciated". In any event, it is clear that essential factual data was denied to the individuals and entities that might have addressed proved reserve abuses.

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After an interim report by DP&W to GAC on March 1, 2004, Sir Philip and Mr. van de Vijver submitted their resignations to the Shell Board. Considerations of the tenure of and appropriate assignment for others involved in the events which resulted in the recategorization are continuing pending review of the Report and consideration of its findings by the GAC and non-executive members of Conference.

To address perceived structural and control deficiencies, certain remedial measures have been proposed (some of which have already been accepted in response to recommendations made previously in connection with this investigation):

- Rewrite Shell's Guidelines for proved reserves to ensure regulatory compliance.
- Reinforce roles and responsibilities of the Shell personnel involved in proved reserves on compliance responsibility.
- Remove consideration of reserve replacement targets from the compensation "scorecard."
- Provide for formal review on an annual basis by CMD and the GAC of Shell's proved reserve positions.
- Reorganize reporting structure to require that the Chief Financial Officers of Shell's business units report directly to the Group Chief Financial Officer.
- Integrate the Group Legal Director role with CMD, the Boards and Conference to ensure compliance with all regulatory obligations.
- Reinforce the line responsibilities and compliance training for reserve reporting from local reservoir engineers upwards.

In addition to these changes, it is critical that Shell enforce a culture of compliance – that, regardless of business concerns, all decisions must be made to insure compliance with regulatory and fiduciary obligations. Management and employees must recognize that their conduct is required to be in accord with the highest ethical and legal standards.

IV. Index to the Report

The Report of Davis Polk & Wardwell to the Shell Group Audit Committee of March 31, 2004 (the "Report") is divided into the following sections:

Davis Polk & Wardwell

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REPORT OF

DAVIS POLK & WARDWELL

TO

THE SHELL GROUP AUDIT COMMITTEE

TAB A:

ANALYSIS OF THE REGULATORY FRAMEWORK AND THE SHELL GUIDELINES

MARCH 31, 2004

Analysis of the Regulatory Framework and the Shell Guidelines

Analysis of the Regulatory Framework and the Shell Guidelines

I. Summary

A. The Regulatory Background

Royal Dutch Petroleum Company ("Royal Dutch") and The "Shell" Transport and Trading Company, p.l.c. ("Shell Transport") must provide disclosure of "proved reserves" of oil and gas for the Royal Dutch/Shell Group of Companies ("Shell" or the "Group") in their annual reports on Form 20-F. The Securities and Exchange Commission (the "SEC" or the "Commission") adopted its definition of "proved reserves" in 1978. The definition has remained unchanged since that time. The definition is relatively brief and provides a limited number of specific geological and other criteria that must be observed when estimating "proved reserves." Otherwise, the overriding requirement is "reasonable certainty":

> "[P]roved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions." (Emphasis added.)

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"Proved reserves" are the only type of oil and gas reserves that SEC registrants like Royal Dutch and Shell Transport may include in their SEC filings.

Estimation of "proved reserves" is a complex process for which there are few bright-line rules. Given the range of complex geological, engineering, economic and political conditions that can confront the reserves estimator, the application of the concept of "reasonable certainty" will inevitably involve judgment. Interpretations of "reasonable certainty" are heavily fact-specific and can vary from case to case. Because of this subjective element, the estimation of proved reserves should take place subject to appropriate controls that reflect an appropriate awareness of technical requirements and the importance of proved reserves as a component of an oil and gas company's public disclosure.

Since 1978, the staff of the SEC's Division of Corporation Finance (the "SEC Staff" or the "Staff") has published a limited amount of interpretive guidance regarding the definition of proved reserves. For the purpose of this Report, the most important guidance was that issued by the SEC Staff in June 2000 and reissued in largely identical form in March 2001. The guidance focused on a number of issues, including "reasonable certainty" in connection with projects in "frontier" areas. Specifically, the Staff expressed the view that in these areas, a commitment by the company to develop the necessary production and transportation infrastructure was essential to the attribution of proved undeveloped reserves. The Staff went on to state that "[s]ignificant lack of progress on the development of such reserves may be evidence of a lack of such commitment." The Staff also identified various concrete examples of the form this commitment could take (e.g., signed sales contracts, requests for proposals to build facilities, "firm plans and timetables established," loan approvals and environmental permits).

On a related theme, the guidance also addressed "reasonable certainty" in situations where development and production depended on the issuance or renewal of government licenses or permits. In particular, the SEC Staff made clear that issuers could not assume that renewal of a license or permits would be automatic. There must be "a long and clear track record" supporting the conclusion that the renewal is "a matter of course."

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B. The Shell Guidelines

Since the 1970s, Shell has relied on internally produced "guidelines" to set standards for the estimation of reserves, both "expectation reserves" for the purpose of supporting company decision-making and "proved reserves" for external reporting pursuant to SEC requirements.

Although the SEC's definition of "proved reserves" has never changed, Shell has issued ten different versions of the guidelines since 1988. Over this period, the guidelines have changed significantly. The guidelines evidenced a growing awareness of the importance of "proved reserves" reporting and the application of the SEC's definition. This trend became more noticeable from the late 1990s. Even then, the guidelines were slow to reflect the SEC staff's guidance discussed above and even in 2003 continued to deviate from SEC requirements in certain respects.

General observations regarding the Shell guidelines from 1988 to 2003 include the following:

- The guidelines were not clearly written and were too cumbersome to give reservoir engineers in the Group's operating and other reporting units (collectively, the "OUs") adequate guidance.
- The guidelines blurred the distinction between reporting reserves internally for decision making and the external disclosure of "proved reserves" in accordance with SEC requirements.
- The guidelines were amended frequently and late in the year, which left reserves estimators in the OUs with little time to digest changes in the way reserves were to be determined prior to reporting deadlines.
- The guidelines failed to reflect certain aspects of the SEC's "proved reserves" definition. Occasionally, they encouraged an expedient approach to reporting "proved reserves" by adjusting the results of Shell's own methods in order to approximate rather than to achieve SEC compliance.
- The guidelines did not provide OUs with concrete guidance on key issues relating to "reasonable certainty" such as evidence of Shell's commitment to develop a project.

In short, the guidelines were not designed adequately to yield compliant reporting of SEC "proved reserves."

There were also developments in the guidelines from 1988 to 2003 that in practice facilitated the aggressive or premature reporting of proved undeveloped reserves and the continued carrying of proved undeveloped reserves that were no longer compliant. For example, in 1998, the guidelines prescribed the adoption of "deterministic" methods to estimate proved reserves in "mature" fields and the setting of proved reserves as equal to expectation reserves in such fields, which led to substantial increases in proved developed reserves and, to a lesser degree, proved undeveloped reserves. As applied, in part because of a failure to define field "maturity" appropriately, this principle led OUs to equate "proved" with "expectation" reserves in situations, both developed and undeveloped, where the requisite "reasonable certainty" did not necessarily exist. Likewise, the guidelines consistently failed to define with enough clarity when a project was sufficiently advanced in terms of planning and execution such that it could support the reporting of proved reserves with "reasonable certainty." The guidelines also failed to instruct OUs properly on the need to review existing bookings for the continued presence of "reasonable certainty." This shortcoming gave rise to a compliance risk that grew as the guidelines' standards for initial bookings, especially for proved undeveloped reserves, tightened in response to the SEC Staff's guidance.

II. The Regulatory Framework: The Definition of "Proved Reserves" and Related Guidance

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A. The SEC Definition and FAS 69

As foreign private issuers with material oil and gas operations, Royal Dutch and Shell Transport are required to provide supplementary material information concerning the Group's "proved" oil and gas reserves in their annual reports on Form 20-F. Appendix A to Item 4.D of Form 20-F incorporates the Commission's definition of "proved reserves." This definition also appears in Rule 4-10 of Regulation S-X, the SEC's comprehensive rule governing financial disclosures. Rule 4-10 was adopted by the SEC pursuant to Accounting Series Release No. 253 on August 31, 1978. Since its adoption, the definition of proved reserves in Rule 4-10 has remained unchanged.

Rule 4-10 defines proved reserves as follows:

> "*Proved Oil and Gas Reserves.* Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, *i.e.*, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.
>
> (i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
>
> (ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
>
> (iii) Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves;" (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects;

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> and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.
>
> (3) *Proved Developed Oil and Gas Reserves*. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.
>
> (4) *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 <u>where a relatively major expenditure is required for recompletion</u>. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled." (Emphasis added.)

Under Item 102(5) of Regulation S-K, the SEC's comprehensive rule regarding the content of disclosure documents, issuers may not disclose estimates of oil and gas reserves other than "proved reserves" in filings made with the SEC unless such disclosure is required under state law or the law of a non-U.S. jurisdiction.

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The definition of proved reserves neither does nor could account for the range of geological and business scenarios that may be confronted in connection with making proved reserves estimates. At the same time, the definition provides little in the way of specific rules for the estimation of proved reserves. Other than a limited number of limitations on the definition of the reservoir (e.g., the "lowest known structural occurrence of hydrocarbons," the one "offset" location limitation on undrilled acreage), the overriding requirement is "reasonable certainty" that the oil and gas reserves exist and can be recovered under existing economic and operating conditions. The existence of "reasonable certainty" in any particular case ordinarily depends on the analysis of complex geological, engineering and economic data. This analysis will inevitably have a subjective element. Thus, the SEC's definition of proved reserves in Rule 4-10 calls for the use of considerable judgment by issuers which can lead to varying interpretations. The necessity of judgments in reserves estimation, especially those involving financial and economic matters, means that the estimation process must be carried out in a controlled environment with the input of appropriate expertise in order to ensure the reporting of compliant data on a consistent basis.

In addition to SEC requirements, publicly-traded oil and gas companies that report in U.S. GAAP are required under Financial Accounting Standard 69, which was issued in 1982, to disclose information on proved and proved developed oil and gas reserves when presenting a complete set of annual financial statements. Paragraphs 10 to 17 of FAS 69 set out specific presentational requirements for the disclosure of proved oil and gas reserves (e.g., classification of changes in volumes according to revisions, extensions and discoveries, production, improved recovery and sales or purchases of minerals in place). FAS 69 also mandates the disclosure of a standardized measure of discounted net cash flows relating to proved oil and gas reserves (the "Standardized Measure"). The Standardized Measure must be calculated on the basis of (1) year-end oil and gas prices, (2) estimated future development expenditures based on year-end costs and assuming continuation of "existing economic conditions" and (3) estimated future income tax expense at year-end statutory rates. These future net cash flows are then discounted at a standard rate of 10%. Under FAS 69, the proved reserves data and the Standardized Measure are "supplementary information" that must be disclosed with the financial statements. They are technically not part of the financial statements and are not covered by the opinion of an external auditor. Proved developed reserves, however, provide the basis for depletion of production assets in an oil and gas company's financial statements.

Paragraph 9 of FAS 69 also makes clear that the foregoing disclosures are not required in interim financial reports. Paragraph 9 goes on to say, however, that interim financial reports shall include information about "a major discovery or other favorable or adverse event that causes a significant change from the information presented in the most recent annual financial report concerning oil and gas reserve quantities."

Although FAS 69 became effective in 1982, Shell began disclosing the Standardized Measure on a voluntary basis in 1996.*

B. Subsequent Interpretive Guidance

The original adopting release for Rule 4-10 did not provide interpretive guidance as to its definition of proved reserves. In 1981, the SEC Staff, through its Office of Engineering, published limited guidance on the application of the proved reserves definition as part of "Topic 12" of the Staff Accounting Bulletin ("SAB Topic 12"), which covers financial reporting issues for oil and gas production activities.

Since 1978, the SEC Staff has also interpreted the definition of proved reserves in Rule 4-10 through the process of commenting on registration statements and other filings, a process

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* Technically, Royal Dutch and Shell Transport are not obligated to provide the Standardized Measure because they file their Form 20-Fs under "Item 17," which means that they are not required to provide the same level of footnote and other supplementary financial disclosures as a U.S. registrant reporting under U.S. GAAP. While Item 17 is adequate for purposes of securities registered under the Securities Exchange Act of 1934 (i.e., secondary market trading on the New York Stock Exchange), the fuller financial disclosures required under Item 18 would generally be necessary if either company were to register securities under the Securities Act of 1933 (i.e., in connection with an offering of securities for cash or as consideration in an acquisition). Whether Royal Dutch and Shell Transport elect to comply with Item 17 or Item 18, Item 4.D. of Form 20-F still requires the disclosure of proved reserves data.

which is not public. The majority of companies subject to SEC review are smaller, independent companies dependent on external capital markets financing to develop their proved reserves. Because Shell has not needed to finance its operations through the public capital markets in the United States, Shell had not received extensive comment on the proved reserves data contained in its reports on Form 20-F until early this year. Shell received a limited number of comments on the proved reserves disclosure in its 1998 Form 20-F. It also received comments in late 2002 and the first half of 2003 regarding proved reserves issues relating to its deepwater Gulf of Mexico operations, which are described briefly below.

In June 2000, the SEC Staff published its first written guidance concerning the definition of proved reserves since the publication of the Topic 12 guidance. This guidance appeared in a publication entitled "Current Accounting and Disclosure Issues." In March 2001, this guidance was re-released by the Staff in largely identical form in the Division of Corporation Finance's "Frequently Requested Accounting and Financial Reporting Interpretations and Guidelines," except that the 2001 guidance included additional material on estimating proved reserves subject to production sharing contracts.

Following is a summary of the various guidance concerning the proved reserves definition that has been issued from 1978 through the present.

1. *Staff Accounting Bulletin – Topic 12*

The guidance supplied in SAB Topic 12 is presented in a "question and answer" format. Following are notable excerpts from this guidance pertaining to the producibility of reserves:

> "Question 1: The definition of proved reserves states that reservoirs are considered proved if "economic producibility is supported by either actual production or conclusive formation test." May oil and gas reserves be considered proved if economic

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producibility is supported only by core analyses and/or electric or other log interpretations?

Interpretive Response: Economic producibility of estimated proved reserves can be supported to the satisfaction of the Office of Engineering if geological and engineering data demonstrate with reasonable certainty that those reserves can be recovered in future years under existing economic and operating conditions. The relative importance of the many pieces of geological and engineering data which should be evaluated when classifying reserves cannot be identified in advance. In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test.

Question 2: In determining whether "proved undeveloped reserves" encompass acreage on which fluid injection (or other improved recovery technique) is contemplated, is it appropriate to distinguish between (i) fluid injection used for pressure maintenance during the early life of a field and (ii) fluid injection used to effect secondary recovery when a field is in the late stages of depletion? The definition in Rule 4-10(a)(4) does not make this distinction between pressure maintenance activity and fluid injection undertaken for purposes of secondary recovery.

Interpretive Response: The Office of Engineering believes that the distinction identified in the above question may be appropriate in a few limited circumstances, such as in the case of certain fields in the North Sea. The staff will review estimates of proved reserves attributable to fluid injection in the light of the strength of the evidence presented by the registrant in support of a contention that enhanced recovery will be achieved."

Topic 12 also contained an interpretation regarding the price assumption to be used in estimating proved reserves for gas that will be produced after the expiration of an existing sales contract. This interpretation may be read to imply that a sales contract is not necessary in all cases to record proved gas reserves. At the same time, the example presupposed that an initial sales contract had already been concluded for the field and thus has limited relevance to estimating proved gas reserves in areas distant from existing gas markets.

2. *The SEC's June 2000 & March 2001 Interpretive Guidance (the "2000/2001 SEC Guidance")*

In 1999, the SEC's Division of Corporation Finance added two petroleum engineers to its Office of Engineering – Jim Murphy and Ron Winfrey. Because of their expertise, Murphy and Winfrey have been active participants in the review of the reserves disclosure by Shell and other oil companies. In June 2000, the SEC Staff published, for the first time since the Topic 12 interpretations, interpretive guidance on proved reserves as defined in Rule 4-10. According to the SEC Staff, this guidance was necessary because the estimation and classification of petroleum reserves had been "impacted by the development of new technologies such as 3-D seismic interpretation and reservoir simulation," and because the increased use of probabilistic methods had "led to issues of consistency and, therefore, some confusion in the reporting of proved oil and gas reserves." In March 2001, the SEC Staff re-published its June 2000 guidance in substantially the same form as the original release (except for the inclusion of an additional discussion of production sharing contracts).

Following are the most relevant aspects from the 2000/2001 SEC Guidance, particularly as it relates to the criteria demonstrating the "reasonable certainty" required for the reporting of proved undeveloped reserves:

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(a) *"Reasonable Certainty" — Geological and Engineering Data*

The SEC's petroleum engineers noted that the determination of "reasonable certainty" calls for the review of supporting geological and engineering data. There must be data available which indicate that assumptions such as decline rates, recovery factors, reservoir limits, recovery mechanisms and volumetric estimates, gas-oil ratios or liquid yield are valid. If the area in question is new to exploration and there is little supporting data for decline rates, recovery factors, reservoir drive mechanisms, etc., a conservative approach is appropriate until there is enough supporting data to justify the use of more liberal parameters for the estimation of proved reserves. Emphasizing the conservatism underlying the proved reserves definition, the SEC Staff added that the concept of reasonable certainty implies that, as more technical data becomes available, initial estimates of proved reserves should be much more likely subject to positive or upward revisions than to downward or negative revisions.

(b) "Existing Economic and Operating Conditions"

The SEC Staff noted that the phrase "existing economic and operating conditions" refers to the product prices, operating costs, production methods, recovery techniques, transportation and marketing arrangements, ownership and/or entitlement terms and regulatory requirements that are extant on the effective date of the estimate. An anticipated change in conditions must have reasonable certainty of occurrence; the corresponding investment and operating expense for such change must be included in the economic feasibility analysis at the appropriate time. These conditions include estimated net abandonment costs to be incurred and duration of current licenses and permits. The Staff also stated that if oil and gas prices are so low that production is actually shut-in because of uneconomic conditions, the reserves attributed to the shut-in properties can no longer be classified as proved and must be subtracted from the proved reserves data base as a negative revision. Those volumes may be included as positive revisions to a subsequent year's proved reserves only upon their return to economic status.

(c) What are Not Proved Reserves

The SEC Staff also noted several factors which, in their view, weigh against an estimation that proved reserves exist. Among these factors, they stated that "geologic and reservoir characteristic uncertainties such as those relating to permeability, reservoir continuity, sealing nature of faults, structure and other unknown characteristics may prevent reserves from being classified as proved." The Staff also noted that economic uncertainties such as the lack of a market (e.g., stranded hydrocarbons), uneconomic prices and marginal reserves that do not show a positive cash flow can also prevent reserves from being classified as proved.

(d) Developing "Frontier Areas"

A particular focus of the 2000/2001 SEC Guidance was the development of fields in "frontier areas," or areas not previously explored and/or developed and which may not yet have the infrastructure needed for commercial production. With respect to such areas, the Staff stated:

> "[T]he existence of wells with a formation test or limited production may not be enough to classify those estimated hydrocarbon volumes as proved reserves. Issuers must demonstrate that there is reasonable certainty that a market exists for the hydrocarbons and that an economic method of extracting, treating and transporting them to market exists or is feasible and is likely to exist in the near future. A commitment by the company to develop the necessary production, treatment and transportation infrastructure is essential to the attribution of proved undeveloped reserves. Significant lack of progress on the development of such reserves may be evidence of a lack of such commitment. Affirmation of this commitment may take the form of signed sales contracts for the products; request for proposals to build facilities; signed acceptance of bid proposals; memos of understanding between the appropriate organizations and governments; firm plans and timetables established; approved authorization for expenditures to build facilities; approved loan documents to finance the required infrastructure; initiation of construction of facilities; approved environmental permits etc. Reasonable certainty of procurement of project financing by the company is a requirement for the attribution of proved reserves. An inordinately

SCA 00000032

> long delay in the schedule of development may introduce doubt sufficient to preclude the attribution of proved reserves." (Emphasis added.)

(e) Issuance and Renewal of Permits, Concessions, and Licenses

The SEC Staff added that the history of issuance and continued recognition of permits, concessions and commerciality agreements by regulatory bodies and governments should be considered when determining whether hydrocarbon accumulations can be classified as proved reserves. They clarified that "[a]utomatic renewal of such agreements cannot be expected if the regulatory body has the authority to end the agreement unless there is a long and clear track record which supports the conclusion that such approvals and renewal are a matter of course."

(f) Continuity of Production – Certainty Required

The SEC Staff stated that proved reserves for certain undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from an existing productive formation. In addition, they noted that continuity of production requires more than the technical indication of favorable structure alone (e.g., seismic data) to meet the test for proved undeveloped reserves. In general, proved undeveloped reserves can be claimed only for legal and technically justified drainage areas offsetting an existing productive well. However, proved reserves cannot be claimed more than one offset location away from a productive well if there are no other wells in the reservoir, even though seismic data may exist. The SEC Staff pointed out that while seismic data may be used to help support a claim that there is reservoir continuity between producing wells, it is not an indicator of continuity of production and therefore cannot be the sole indicator of additional proved reserves beyond the legal and technically justified drainage areas of drilled wells.

(g) Further "Topic 12" Guidance

The Staff expanded on certain guidance that had previously been given by the Division of Corporation Finance and the Office of the Chief Accountant in SAB Topic 12, regarding the permissible use, in certain circumstances, of electrical and other type logs and core analyses to estimate proved reserves in a field. The SEC's petroleum engineers noted that if the combination of data from open-hole logs and core analyses is overwhelmingly in support of economic producibility and the indicated reservoir properties are analogous to similar reservoirs in the same field that have produced or demonstrated the ability to produce on a conclusive formation test, the reserves may be classified as proved. The SEC's petroleum engineers added that the foregoing would probably be a rare event, especially in an exploratory situation, and noted that the essence of the SEC definition is that in most cases there must at least be a conclusive formation test in a new reservoir before any reserves can be considered to be proved.

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(h) Probabilistic and Deterministic Methodologies

The SEC Staff recognized that probabilistic methods of estimating reserves have become more useful, due to improved computer technology, and more importantly, because of its acceptance by professional organizations such as the Society of Petroleum Engineers ("SPE"). The Staff declined to pass on any specific degree of confidence, however. Separately, they noted that the SPE had specified a 90% confidence level for the determination of proved reserves by probabilistic methods, whereas many instances of past and current practice in deterministic methodology utilize a median or best estimate for proved reserves. Thus, the Staff's petroleum engineers observed that the use of the median or best estimate in deterministic analysis raised a possible inconsistency with its view of "reasonable certainty" (i.e., the likelihood of a subsequent increase or positive revision to proved reserves estimates must be much greater than the likelihood of a decrease). They went on to state that if probabilistic methods are used, the limiting criteria in the SEC definitions, such as lowest known hydrocarbon, are still in effect and shall be honored.

3. *Subsequent Guidance*

Industry participants, including Shell, generally perceived the 2000/2001 SEC Guidance as an effort by the SEC Staff to enhance the rigor with which issuers applied the proved reserves definition. Subsequent review of SEC filings and public statements by the SEC Staff appear to confirm this perception.

In October 2002, the SEC Staff issued comment letters requesting information about proved reserves to a number of companies, including Shell, who were operating in the "deepwater" Gulf of Mexico. The primary purpose of the Staff's review at this time was to obtain information related to the issue of lowest known hydrocarbon and the use of methods other than conclusive formation tests to prove the existence of reserves. Shell cooperated fully with the Staff in this inquiry, engaging in a dialogue that included the exchange of several letters on this topic as well as a meeting with them concerning proved reserves calculations more generally. During this process, Shell obtained additional clarity from the SEC Staff not only as to the "lowest known hydrocarbon" or LKH issue and related aspects of the estimation of proved reserves in accordance with the SEC's definition.

In October 2003, the two lead petroleum engineers on the SEC Staff spoke at a conference of the Society of Petroleum Evaluation Engineers ("SPEE"). During their presentation, the Staff's engineers made a number of remarks which suggested that the SEC was taking an increasingly conservative approach on proved reserves estimates. For example, as reported in a website publication by Ryder Scott, the independent petroleum engineering firm, the Staff's engineers made the following observations during the conference:

- Issuers should remove boilerplate verbiage in their annual reports that suggests that reserves estimates are inherently uncertain.

- Issuers should "win back the confidence of investors" by affirming and following SEC regulatory interpretations on lowest known hydrocarbon limits, on undeveloped locations offsetting producing wells and on other definitional rules.

- Internal and external engineers have additional liability under the Sarbanes-Oxley Act. Without elaborating on the statutory analysis underpinning their views on this legislation, the Staff's engineers noted that one provision of the act provides that "any person responsible for input into the financial statements accepts liability for those numbers."

- A 10% difference between originally reported reserves estimates and subsequent revised estimates may be considered material and significant enough to trigger further investigation by the SEC.

- The Staff accepts probabilistic reserves assessments, but only in reservoirs defined by well penetrations. The engineers stated that the Staff position on this point is similar to that of the Society of Petroleum Engineers.

C. Professional and Industry Organizations: the SPE-WPC Definitions

During the 1970s and 1980s, professionals within the oil and gas industry were also working to develop a comprehensive set of petroleum reserves definitions. In 1987, two organizations – the Society of Petroleum Engineers ("SPE") and the World Petroleum Congresses ("WPC") – separately produced strikingly similar sets of petroleum reserves definitions for known accumulations.

In March 1997, the SPE and WPC approved a set of revised petroleum reserves definitions. According to Gaffney, Cline & Associates, whom Davis Polk has retained as independent petroleum engineering consultants in connection with this investigation, these definitions have become a voluntary industry standard for non-SEC reporting companies. Importantly, they are not identical to the SEC's definition in several specific respects. The SPE-WPC definitions also cover probable and possible reserves.

One major development in the March 1997 SPE-WPC definitions was their endorsement of both the deterministic and probabilistic methods for estimating reserves. Previously, the SPE and WPC definitions of proved reserves did not specifically refer to probabilistic methods. An explanation of the differences between probabilistic and deterministic methods for estimating proved reserves appears below under "The Shell Guidelines – Probabilistic Methodology."

Whereas the current SPE-WPC standard recognizes that a P90 estimate (i.e., a 90% probability that actual volumes will exceed estimated volumes) may qualify reserves as proved, this confidence does not, by itself, satisfy the SPE-WPC's or the SEC's "reasonable certainty" test for proved reserves without meeting the specific criteria of the definition. In 2000, the SPE-WPC and the American Association of Petroleum Engineers (the "AAPG") endorsed definitions for contingent and prospective resources as a complement to the reserves definitions of 1997.

III. <u>The Shell Guidelines</u>

SCA 00000037

A. Introduction

Since the 1970s, Shell has relied on a series of "guidelines" for the purpose of advising OUs and other reporting units within Shell's exploration and production business ("EP") on the standards to be used for the determination of hydrocarbon reserves volumes. It is important to note that the reporting of proved reserves in accordance with the SEC's definition was not the only, nor even the principal, purpose of the Shell guidelines. The Shell guidelines were designed primarily to provide the basis for the generation of reserves data for internal reporting. Like virtually all other major oil and gas companies, Shell does not rely on "proved reserves" as defined by the SEC as the basis for internal reporting, planning, capital allocation and other decision-making. Rather, for internal decision-making, Shell has historically used expectation reserves (comparable to "proved" plus "probable" reserves). Other hydrocarbon resources are classified as "Scope for Recovery" or "SFR" (analogous to "contingent resources" plus "prospective resources" as defined by the SPE-WPC-AAPG).

Despite the multiple roles played by the Shell guidelines, it is important to note that they were typically the sole basis on which proved reserves were estimated. In other words, reservoir engineers in the OUs were not instructed to refer to the SEC proved reserves definition; instead, they were instructed to rely on the Shell guidelines to interpret the SEC's disclosure requirements. The Shell guidelines, as the Group Reserves Auditor (Anton Barendregt) observed in an e-mail to the EP CFO dated January 3, 2004, were the "bible" against which he carried out his work. Even when he signalled conflict between the Shell guidelines and the SEC's proved reserves definition, Barendregt noted that the Group Reserves Coordinator (Remco Aalbers) and the OUs would point to the guidelines as the only set of binding rules. SCA 00000038

Although EP personnel involved in reserves reporting did provide occasional presentations to EP finance colleagues on the topic, there was little or no training for EP or reservoir engineers on the SEC's criteria for disclosing proved reserves and the regulatory purpose of such disclosure as distinct from the purpose of internal reserves reporting. Interviews with EP personnel and review of their e-mails and other documentation indicate that many within EP failed to appreciate that Shell was fully subject to proved reserves reporting in accordance with the SEC definition by virtue of its New York Stock Exchange listings. As the Group Reserves Coordinator (John Pay) remarked in an e-mail to a colleague dated September 18, 2002, "we have development engineers who have no real idea why we have to make SEC filings every year or how the information is used by the external community." Even the Group Reserves Auditor noted in his annual report for 2000 that SEPCo deviated from the Shell guidelines in certain respects "due to SEPCo adhering to strict interpretations of SEC rules, which are enforceable in the U.S." (Emphasis added.)

Likewise, there has historically been a relative lack of awareness within EP regarding the technical aspects of proved reserves estimation in accordance with the SEC definition and the extent to which the definition differed from Shell's own reservoir engineering practices. Despite the heightened sensitivity within EP as a result of the events of the past year, as the EP CEO Malcolm Brinded observed during the March 18, 2004 investor teleconference on the Group's announcement of further proved reserves revisions, the level of awareness within EP of SEC requirements still needs improvement:

> "[I]t is very clear that we have to work on deepening the understanding of our technical staff . . . including ensuring full understanding that the technical data that is essential for their day to day jobs of reservoir management and business decision making may not always be applicable when booking proved reserves."

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For the purpose of this investigation, we have reviewed versions of the Shell guidelines from 1988 to 2003 (the "Guidelines," "Shell Guidelines" or "Group Guidelines"). As noted above, versions of the guidelines were published before 1988 but 1988 was the first year in which the Group Guidelines were issued in the comprehensive, multi-part format in use today (the first part setting forth methodology and standards for reserves estimation and calculation and the second part providing detailed standards for the presentation and submission of reserves data by the reporting units). Between 1988 and 2003, EP issued ten separate versions of the Guidelines (1988, 1993 and annually from 1996 to 2003). By comparison, the SEC's definition of proved reserves remained unchanged during this period and has been the subject of relatively limited interpretive guidance by the SEC Staff.

While the Group Guidelines developed incrementally over this period, the overall change in terms of methodology and other guidance has been significant. At the same time, especially from 1998 to 2003, certain year-to-year changes in the methods and standards that reservoir engineers in the OUs were asked to implement were dramatic. The best example of this trend was the Group's 1998 shift to a "deterministic" approach for estimating proved reserves in "mature" fields from its traditional "probabilistic" approach, which coincided with the setting of proved reserves as equal to expectation reserves in "mature" fields. Another trend in the development of the Guidelines during this period was an increased emphasis on the importance of externally reported "proved reserves." Despite this trend, there remained important areas where the Guidelines did not achieve consistency with the SEC definition.

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B. The Role of Gaffney, Cline & Associates

To assist in our analysis, we have engaged Gaffney, Cline & Associates ("Gaffney Cline"), an international petroleum management and technical advisory firm. The Gaffney Cline individuals involved in the review included William B. Cline, who co-founded the firm in 1962, and Dr. James Ross, a former member of the Society of Petroleum Engineers Oil and Gas Reserves Committee who has more than 28 years experience in the industry. Gaffney Cline has set forth its analysis of the Guidelines in a report dated February 29, 2004 entitled "SIEP Petroleum Resource Volume Guideline Review 1988-2003" (the "Gaffney Cline Report"). The Gaffney Cline Report consists of two parts: (1) a memorandum providing general observations regarding the development of the Guidelines over time and their suitability for the purpose of reporting "proved reserves" in accordance with SEC requirements (the "Overview Memorandum"); and (2) a series of spreadsheet tables, one for each version of the Shell Guidelines, analyzing the relevant version according to specific topics against SEC Staff commentary, industry practice and Gaffney Cline's own assessment.

C. *Gaffney Cline's Assessment of the Shell Guidelines*

Gaffney Cline's Overview Memorandum provides a general assessment of the Shell Guidelines for the purpose of the external reporting of proved reserves data. The analysis focuses not only on the consistency of the standards contained in the Shell Guidelines with the requirements of the SEC's definition of "proved reserves" but more importantly, on the effectiveness of the Guidelines from the standpoint of the reservoir engineer in an OU who must use them (that is, whether the Guidelines were adequately designed to yield compliant reporting of proved reserves data).

1. Summary Observations

Among the general observations regarding the Shell Guidelines made by Gaffney Cline are the following:

- The Guidelines have been generally too long, cumbersome and "wordy" to provide practicing engineers with adequate practical guidance.
- Given the range and number of case-specific situations facing Shell's OUs, no set of guidelines can hope to present in clear language a body of prescriptive rules for internal reserves estimation and external reserves reporting. Attempting to achieve this will run the risk of misinterpretation and failure to address case-specific circumstances adequately.

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- Although they reflect an increasing awareness of SEC disclosure standards, the Guidelines have not adequately distinguished between the purposes and requirements of internal reserves reporting and the external reporting of "proved reserves" data as required by the SEC. For example, the Guidelines have not generally required OUs to produce a production forecast based on the "proved area" and otherwise reflecting "reasonable certainty" that could be separately assessed on the basis of "existing conditions, prices and costs" as required by the SEC definition. For this purpose, a separate "low-case" production forecast is necessary. Even in 2003, the Guidelines only "recommend" but do not require that OUs generate such a proved production forecast.

- The Guidelines do not cite the decisions of joint venture partners, whether private companies or state-owned enterprises, as a factor in reserves estimation, even though their commitment decisions could fundamentally determine whether or when a field is developed and therefore whether volumes can be treated as "reasonably certain" and thus classified as proved reserves.

- The Guidelines have not historically provided adequate guidance on how to address the issue of "de-booking" existing proved reserves that may no longer comply with the SEC's definition, whether as a result of unfulfilled expectations, changed circumstances or interpretive guidance by the SEC staff.

- The Guidelines have been amended frequently and changes have typically been implemented in the third quarter or even early in the fourth quarter of the year, just before the OUs are called on to prepare their year-end submissions. This could have contributed to confusion among reservoir engineers in the OUs and created pressure to find quick, easy solutions to issues raised by changes in the Guidelines.

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2. *Assessment of the 2003 Shell Guidelines*

Gaffney Cline's Overview Memorandum also contains a separate, detailed analysis of the current 2003 Guidelines (in addition to the tabular analysis in the attached spreadsheets). Gaffney Cline notes that despite the growing level of awareness within the Group regarding the

SEC Staff's position on various aspects of the proved reserves definition, there remain certain aspects of the Guidelines that do not conform to the Staff's view on specific issues. In some cases, the 2003 Guidelines may adopt a position that could result in an overly conservative application of the concept of "reasonable certainty." In others, they may reflect industry practice, which may not be entirely consistent with SEC Staff interpretations.

Gaffney Cline characterizes some of these issues as matters requiring clearer language in the Guidelines (e.g., the statement that proved reserves for major projects can be recorded in advance of final investment decision on the basis of a "clear public demonstration" of the Group's intention to proceed with development). They identify other issues as more fundamental ones that could potentially lead to non-compliant disclosure. These issues include, among others, the treatment of production constraints such as OPEC quotas on production forecasting, various aspects of the volumetric definition of the "proved area" (e.g., the reliance on seismic data, log and/or core data and analogy to other reservoirs) and pricing assumptions with respect to volumes covered by production sharing agreements. Shell has publicly stated that certain of these issues will be addressed in a new version of the Shell guidelines to be developed over the course of 2004.

On the basis of this assessment, Gaffney Cline has made specific recommendations for the improvement of the Shell guidelines and the proved reserves estimation and reporting process. These recommendations have been taken into consideration in the formulation of the recommendations for remedial action discussed elsewhere in this Report.

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D. Significant Issues in the Development of the Guidelines: 1988-2003

Over the period for which the Guidelines have been analyzed, certain developments in the Guidelines stand out because of their importance to reserves reporting across the Group generally and their relevance to the underlying reasons for much of the recent recategorization.

These developments include:

- the Group's reliance on a "probabilistic" methodology in estimating proved reserves for external reporting;
- the Group's adoption of a "deterministic" approach for the estimation of proved reserves for "mature" fields (while it continued to rely on a "probalisitic" methodology in other, less "mature" situations) and the equation of proved with expectation reserves in such fields;
- the Group's standards for the initial booking of proved gas reserves;
- the development of criteria for the reporting of proved undeveloped reserves in terms of "field development plans" or other evidence of "reasonable certainty" of development on the part of the Group;
- the treatment in the Guidelines of license expiration and other production constraints in the reporting of proved reserves; and
- the lack of clear standards for the "de-booking" of existing proved reserves that could no longer be carried under the Guidelines or SEC staff interpretations.

The following section contains a narrative discussion of each of these themes based on the Shell Guidelines, Group Reserves Audit reports and other documents, e-mail correspondence, interviews conducted with EP personnel and the relevant analysis set forth in the Gaffney Cline Report.

1. Probabilistic Methodology

In the late 1970s, Shell began to use a probabilistic methodology for the estimation of reserves for both internal reporting and decision-making and the determination of proved reserves for inclusion in the Group's Form 20-F.

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(a) Probabilistic Versus Deterministic Methodology

Appendix A to Gaffney Cline's Overview Memorandum contains an explanation of the basic differences between the probabilistic and deterministic approaches to reserves estimation. A summary of this discussion follows. The principal task of reserves estimation, especially for undeveloped fields, is to assess the level of uncertainty associated with the various factors used to estimate the volume of recoverable hydrocarbons in a reservoir, such as the area and thickness of the reservoir and the recovery factor. The recovery factor refers to the proportion of in-place hydrocarbons that can be recovered economically. The overall uncertainty associated with the reservoir can be estimated on either a deterministic basis or a probabilistic basis. The former approach typically involves the consideration of three scenarios having discrete parameters that yield a low, best and high case. The low-case estimate would typically be the conservative production forecast that reflects the "reasonable certainty" required to record proved reserves and other specific criteria of the SEC's proved reserves definition (e.g., lateral extent of the "proved area," "lowest known hydrocarbon"). The selection of, and the determination of the values given to, these parameters will necessarily depend on the judgment of the estimator. SCA 00000045

Under the probabilistic approach, by contrast, a probability distribution of uncertainty for each parameter (e.g., the recovery factor, formation thickness, net-to-gross) is determined. Although each distribution will theoretically describe the full range of possible outcomes, the selection of the correct probability distribution for these parameters will also be judgmental. These individual distributions will then be combined using a "Monte Carlo" simulation or similar technique in order to yield an overall distribution from which any particular level of probability (i.e., P15, P50, P85 in Shell's case) can be selected. The "expectation" value will be the mean of the overall probability distribution and in most cases is not the same as the P50 value (i.e., the median value). Mathematically, such methods can account for possible dependencies among the individual parameters (e.g., porosity and hydrocarbon saturation) used in generating the probability distribution, but this requires the estimator to identify those parameters which are not independent of one another. In practice, there is a risk that such dependencies will be ignored simply because they may be difficult to determine based on available technical or other data regarding the reservoir. This can lead to a range of outcomes that is too narrow, which will tend to overstate the low probability case (e.g., P85).

(b) Shell's Use of Probabilistic Methodology to Estimate Proved Reserves

Historically, deterministic methods have been more commonly used for the estimation of proved reserves to be disclosed in filings made with the SEC, especially those of U.S. exploration and production companies. Within EP, the deterministic approach was sometimes referred to as the "American method" of reserves estimation. In part, the reason that the deterministic method is more commonly used in the United States is because it is easier to honor specific aspects of the SEC's definition of proved reserves using a deterministic approach. Examples of these criteria are the SEC's requirement that the lateral extent of the proved area for which volumes are estimated must be limited by one "offset" location from an existing well and the limitation on including as proved reserves those volumes below the "lowest known hydrocarbon" or "LKH." At the same time, as noted in Gaffney Cline's Overview Memorandum, the definition of proved reserves does not preclude the use of probabilistic methods to determine whether the "reasonable certainty" needed to record proved reserves exists so long as the explicit provisions of the definition are observed. In the 2000/2001 SEC Guidance, the Staff noted that probabilistic methods had become more useful due to improvements in information technology and, while not passing judgment on the suitability of the methodology for proved reserves estimation, made clear that the specific requirements of the definition such as LKH had to be observed regardless of the statistical method used to assess "reasonable certainty."

Since 1979, Shell's Guidelines had specified that proved reserves were those volumes for which there was "an 85% confidence level that the actual volume will be greater than the reported volume." Gaffney Cline believes that the selection of a P85 confidence level was consistent with the concept of "reasonable certainty" underlying the SEC's definition of proved reserves. In the 2000/2001 SEC Guidance, the SEC Staff observed that registrants used a range of values to establish "reasonable certainty" from a "median" value or "best estimate" to the P90 value embodied in the SPE-WPC's 1997 reserves definitions. While not endorsing any particular value, the SEC Staff stated its view that the concept of "reasonable certainty" implied that proved reserves volumes for a field should be "much" more likely to be revised upward than downward in the future. As noted by Gaffney Cline in its Overview Memorandum, a P85 confidence level would be consistent with this interpretation.

Although the Guidelines relied on a P85 value as the indicator of "reasonable certainty," they did not originally specify that the estimated volume must be constrained by the "proved area" as defined by the SEC rule. On the contrary, the 1997 Guidelines reflected an awareness that such constraints were mandated by the SEC proved reserves definition but explained that to apply the probabilistic method to the proved area alone and select the P85 value would result in understated proved reserve volumes:

> "Under 'deterministic' reserves definitions . . . 'proved' reserves are the expectation volumes associated with areas where drilling has proved petroleum to be producible at commercial rates. Shell

> uses a 'probabilistic' rather than a deterministic approach. For the purpose of reporting 'proved' reserves externally, as required by the SEC, the P85 confidence level for Shell's reserves classification is used as the probabilistic estimate is not intended to be restricted to the proved areas of a field only. Similarly, the scope of initially agreed development plans should not restrict reserve estimates, particularly where plans could be modified to optimise recovery under differing geological conditions which might be encountered. To apply such restrictions in the Shell reserves classification system, and subsequently use the P85 confidence level for proved reserves is to 'double discount'." (Emphasis added.)

The Guidelines did not explain how this "double discount" could justify deviation from the explicit requirement of the regulatory definition.

As reflected in the 1996 and 1997 Guidelines, Shell instead adopted an expedient approach to the problem created by the fact that its own probabilistic method of internal reserves estimation did not reflect the explicit volumetric constraints of the SEC's proved reserves definition. Under the Guidelines, the OU estimators were advised to compensate for the failure to observe these constraints by artificially modifying the probabilistic distribution to yield zero proved reserves outside of the defined areas. For example, volumes for an area on the undrilled side of a fault block would be treated as having no proved reserves. The 1998 Guidelines addressed this issue more explicitly:

> "Estimates of proved reserves should be benchmarked against the 'proved area' deterministic method consistent with the SEC and SPE definitions. . . . If the proved and proved developed reserve estimates are significantly different using the proved area method (as generally used in the industry), a reconciliation should be made for the OU to assure itself that the reported reserves are a true reflection of shareholder value."

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As Gaffney Cline observes in its report, it is not clear which value should be chosen when there is a "significant difference" but the reference to "shareholder value" could be construed as recommending that the OU should select the higher value. The reference to the SPE definition is also inappropriate in this context, at least for the purposes of external reporting. Similarly, the 1998 Group Guidelines stated that "[w]hen the estimate assumes significant volumes of hydrocarbons outside the defined fluid contacts, or when the recovery mechanism is untested in the field or analogue fields, a lower estimate should be used that reflects this uncertainty" instead of actually observing these volumetric constraints. The Guidelines identified this approach as "Shell's Interpretation of SEC Reserve Definitions" without indicating that it was potentially a departure from the regulatory definition.

As with the lateral definition of the proved area, the Guidelines from 1993 to 2000 did not explicitly address the SEC's specific criteria regarding LKH. As Gaffney Cline notes, the Group presumably relied on the P85 confidence level of the probabilistic analysis to address this and other volumetric uncertainties instead of implementing the explicit volumetric constraints embedded in the SEC's definition of proved reserves. As a consequence, the Guidelines did not provide the Group's reservoir engineers with adequate guidance regarding the ways in which probabilistically determined reserves for purposes of internal reporting could not be used as the basis for externally reported proved reserves and created the risk that the Group's proved reserves would reflect volumes that the SEC Staff would not have viewed as compliant. Although the SEC Staff did not publish its views regarding the need for probabilistic methods to reflect the specific constraints of the proved reserves definition until 2000, Gaffney Cline observes in its Overview Memorandum that "it should have been clear to SIEP that failing to honour all the criteria of the definitions, through the unconstrained use of a P85 value, was not consistent with the external reporting requirements."

The Guidelines continued to prescribe the approaches described above for addressing certain of the volumetric constraints in the SEC's definition of proved reserves until 2000. Both the 2001 and the 2002 Guidelines reflected closer attention to incorporating these requirements into Shell's estimation of proved reserves. For example, the 2001 Group Guidelines indicated that "proved reserves should be consistent with the 'proved area' as defined by SEC/FASB," but provided no concrete guidance on how that should be applied in practice when using the probabilistic method.

2. *"Mature" Fields: the Adoption of Deterministic Methodology and the Equation of Proved with Expectation Reserves*

A significant shift in the Group's approach to the estimation of proved reserves occurred in 1998 when the Group Guidelines first prescribed the use of a deterministic approach for proved developed and proved undeveloped reserves in "mature fields" and introduced the idea that proved reserve volumes for "mature" fields should converge to expectation volumes. As stated in the 1998 Group Guidelines, this and other changes to the Guidelines were the result of recommendations of the "Hydrocarbon Resource Volume Value Creation Team" within EP (the "Value Creation Team"), a Focused Results Delivery Project or "FRD" that was established as part of the LEAP initiative.

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(a) *The Value Creation Team and Its Recommendations*

EP BusCom established a group of "Value Creation Teams" in 1997 as part of an effort to identify and address "value gaps" within Shell. Each Value Creation Team was "championed" by a member of EP BusCom and consisted of a team of more junior team members. Each team was assigned a specific issue. One group, known as the "Volumes to Value" team (the "Value Creation Team"), focused on reserves reporting. This group had two objectives : (1) to develop a clear process for "migrating" hydrocarbon resources from "SFR" to "reserves" to production; and (2) to assess whether Shell was conservative in reporting proved reserves compared with its competitors.

The Value Creation Team prepared a report for EP BusCom that was widely distributed within EP entitled "Creating Value through Entrepreneurial Management of Hydrocarbon Resource Volumes." A presentation accompanying the report contained several bar graphs under the heading "Do your Asset Holders make full use of the Resource Volumes Guidelines?" that compared the Group to its competitors as of January 1, 1998 in terms of (1) the ratio of proved developed reserves to annual production, (2) the ratio of total proved reserves to annual production and (3) the ratio of proved developed reserves to total proved reserves. The report noted that Shell's proved developed reserves were low in comparison to those of its peers both when measured as a percentage of total proved reserves and in terms of years of production. Commentary to the graphs stated that "[d]iscussion indicates that we are both early in registering reserves and conservative in reporting <u>proved developed</u>." (Emphasis added.) The cover letter dated September 16, 1998 from Wouter van Dorp, Head Planning and Strategy, that accompanied the 1998 Guidelines when they were distributed to the Operating Units stated that the work of the Value Creation Team involved consultation with external petroleum engineers. Interviews with various EP personnel do not indicate, however, that the Value Creation Team obtained external advice or advice from SEPCo on the recommended changes to the Guidelines from the standpoint of compliance with SEC reporting requirements.

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The report contained several recommendations designed to "create value by actively progressing volumes from identification of scope [for recovery] to actual production (or profitable divestment)." The first recommendation was that the Guidelines should be updated to

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"emphasise the need to manage the maturing of resource volumes through the value chain in order to realise value." Second, reserve estimators were encouraged to use deterministic methods "when the main uncertainty is in the dynamic behaviour of the reservoir or when performance based estimates are being used." This would typically be the case in more "mature" fields with reservoirs that were already in production. Probabilistic methods, by contrast, would be best used "when the geological model and development concept are clear and the volumes in place are major uncertainties." The report went on to recommend that proved reserves should be defined to be "the larger of either the P85 of full field full lifecycle estimate (interim the P85 of the dependently added project estimate) or the expectation of the proved volumes . . . <u>Note all fields should have moved to the latter by the time expectation developed [reserves] exceeds P85 of the total volumes.</u>" (Emphasis added.) Therefore, the Value Creation Team's recommendations with respect to the Group Guidelines were focused primarily on encouraging growth in the Group's proved <u>developed</u> reserve base. The report noted that if the recommendations were implemented, the projected impact would be an increase in proved reserve volumes of approximately 500 million boe at year-end 1998 and an improvement in net income after tax (NIAT) of roughly $150 million for 1998 (presumably as a result, in part, of lower depreciation, depletion and amortization charges due to the increase in the base of proved developed reserves).

(b) Changes to the 1998 Guidelines

The main recommendations of the Value Creation Team were reflected in 1998 Guidelines. The introduction to the Guidelines stated that the recommendations of the Value Creation Team had been incorporated and that "[t]he primary changes are increased attention to

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realise maximum value from volumes and the modification of the definition for proved developed reserves." (Emphasis added.)

The 1998 Guidelines defined proved developed reserves to be "the reasonably certain portion of internally reported developed reserves (i.e. produced from existing wells through installed facilities)." The text went on to explain that:

> "[d]rilling and completing a well essentially proves the hydrocarbons that it develops and therefore proved developed reserves are based on the expectation estimate of developed reserves adjusted to take into account of undefined fluids contacts, untested recovery mechanisms, licence periods, government restrictions and market limitations. . . The expectation estimate is the mean value if probabilistic methods are used or the base case estimate if scenario deterministic methods are used."

Thus, the Guidelines essentially provided that, at least with respect to proved developed reserves, the "expectation" value rather than a P85 level of confidence would indicate "reasonable certainty" given the lower level of uncertainty associated with the available data regarding "mature" fields. This would be the case whether the value was derived probabilistically or on the basis of deterministic scenarios.

Critically, the changes to the Guidelines did not cover proved developed reserves only, however. New provisions also explicitly encouraged the application of a deterministic methodology for the estimation of all proved reserves in "mature fields": "In mature fields when most of the reserves have been developed . . . a deterministic approach should be used for both proved developed and proved undeveloped reserves consistent with the SEC and SPE definitions." The 1998 Guidelines did not otherwise define "maturity" for the purpose of guiding the OU as to when in the lifetime of a field the shift to deterministic methodology should take place.

The reason given for this change in policy, although not more fully explained in the Guidelines themselves, was that the approach prescribed by the previous (i.e., 1997) Guidelines could yield values that were "no longer reasonable" for mature fields. Under the heading "Uncertainty Estimates," the 1998 Guidelines also explained that:

> "The uncertainty range of ultimate recovery generally decreases as a field is developed and produced. However, the uncertainty range as a percentage of remaining reserves may not always decrease with time. As a field matures, initial in place volumes and recovery should shift from a volumetric to a performance-based estimate, incorporating the additional production data to reduce the uncertainty range. Once the reservoir performance has been established with reasonable certainty, a fairly small difference between low, expectation and high estimates would be expected. Definition of the low and high estimates may no longer be of value in mature fields with relatively little uncertainty and use of a single expectation estimate should be considered in this situation."

A graph appeared underneath this text illustrating how the high and low estimates of a field's future recovery converge to the expectation estimate as cumulative production increases over time. Gaffney Cline has characterized the adoption of deterministic methods in mature fields as a major shift in company policy. They have also observed that the use of a single expectation estimate in mature fields was not inconsistent with industry practice for mature fields, as subsequently acknowledged by the SEC Staff in the 2000/2001 SEC Guidance. However, the Guidelines failed to provide any guidance as to how to determine what levels of field maturity were sufficient or what might be considered as "relatively little uncertainty" in order to justify this approach.

The 1998 cover letter referred to above contained further direction on the reasons for the changes in the Guidelines and how they were to be applied. It stated that:

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> "[w]ith the amended guidelines, special emphasis has been placed on the evaluation method for proved and proved developed

> reserves in view of their importance for the financial calculations (through tax and depreciation) and for investor assessment. The amended guidelines have moved closer to industry practice, e.g. in allowing for the deterministic approach to be applied for proved developed reserves in mature fields. The amended guidelines are in full compliance with the FASB and SEC requirements and definitions."

The letter also requested reporting entities to quantify separately how much of any revision in proved reserve volumes over the prior year was due to the change in the Guidelines.

A document entitled "Reserves Guidelines Principles; Recommendations of the Hydrocarbon Resource Value Creation Team" dated August 18, 1998 was also enclosed with the 1998 cover letter. This document noted that:

> "[t]he basis of the resource volume estimation remains probabilistic but supported with deterministic techniques . . . Already a combination of both techniques is being used, with reserves being calculated probabilistically and developed reserves often calculated (semi) deterministically."

Like the 1998 Guidelines, the document stated that this approach risked underestimating proved undeveloped reserves. Although it did not expressly direct OUs to equate proved and expectation reserves in mature fields, the document did observe that "a fully developed field will have proved developed reserves equal to the expectation total reserves."

The document attached to the 1998 cover letter also addressed a related issue: the impact of production on the determination of proved reserve volumes. Under the heading "Proved reserves are the reserves reported externally to the SEC," the document observed that:

> "In many OUs proved reserves are derived by year on year subtracting production from the low [ultimate recovery] estimate until ultimately 'nearly' zero (or sometimes even negative) proved reserves are carried for a field. This practice results in significant underestimation of the proved reserves for the field. A pragmatic technique is to keep the ratio of proved to expectation remaining recoverable volumes constant as long as production performance

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> does not give reason to change this ratio or move to a performance based estimate."

According to Gaffney Cline, this risk of underestimation will only be present where the reservoir engineer in the OU fails to update proved reserve estimates for the field with data regarding performance of the reservoir derived from the production. Rather than encourage the performance of this analysis, however, the document encouraged OUs simply to report proved reserves so as to hold the ratio of proved to expectation reserves constant unless they were faced with contrary production data. As noted below, the Group Reserves Auditor relied on this rule of thumb to illustrate the unrealized capacity for proved reserve additions in various OUs.

Despite the lack of specific guidance in the 1998 Guidelines regarding the implementation of the shift to deterministic methods and the equation of proved with "expectation" reserves in "mature" fields, the impact of the change was dramatic. The year-end 1998 Group Reserves Audit Report observed that the transition to deterministic methodology for proven areas in mature fields was "[t]he single most important factor affecting proved reserves." Overall, the total reserves replacement ratio for 1998 was 182%.

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(c) Further implementation: 1999-2003

The Guidelines for 1999 and 2000 were essentially unchanged from 1998 with respect to the use of deterministic methodology. At the same time, the principle that proved reserves in mature fields should approach or equal expectation reserves, together with guidance as to the requisite level of "maturity," became more explicit in other EP documents relating to reserves reporting. For example, the Group Reserves Audit Report for 1999 stated that "[t]here appears to be significant scope for further increasing proved reserves in some areas (Brunei, Oman, and others), where estimates tend to be conservative in comparison with expectation volumes <u>and</u>

thereby not fully in line with latest Group guidelines." (Emphasis added.) The report went on to observe:

> "A review of the margin between proved an[d] expectation reserves for major OU fields has shown a tendency for conservative estimating, in particular in some mature fields. . . Potential increases in proved reserves could be up to 100 [million] m3 oil equivalent. Field proved reserves are in principle expected to grow closer to expectation reserves with increasing field maturity. Group guidelines also recommend that proved developed reserves are made equal to expectation developed reserves for mature fields (e.g. where cumulative production exceeds some 30-40% of expectation ultimate recovery)." (Emphasis added.)

The Group Reserves Auditor (Anton Barendregt) noted that "it is clear that many fields do not fulfill these requirements" both for proved undeveloped and developed reserves. The first of his recommendations for reserves reporting in 2000 was "[e]ncourage OUs with low proved reserves in comparison with their expectation levels, to review and upgrade these on an urgent basis."

Barendregt emphasized similar themes in his report for year-end 2000. Again, he stated that the current Group Guidelines "prescribed that externally reported Proved and Proved Developed Reserves should be brought closer to, or made equal to, expectation reserves in mature fields." Although this principle had led to proved reserve additions of roughly 50 million m^3 (or 315 mboe) oil equivalent in 2000, he observed that "[u]ptake of the new Reserves Guidelines in the OUs has in some cases been somewhat slower than anticipated." To illustrate the capacity for reserve additions, the report included graphs plotting the ratio of proved and expectation reserves against field maturity (expressed as cumulative production as a fraction of total expected ultimate recovery without regard to license expiration) for various OUs. Barendregt surmised that one reason for the slow adoption of the Guidelines was that "the new rules [were] not being emphasised enough in the Group Guidelines." Consequently, he recommended that EP staff "consider ways of strengthening the message in the updated Guidelines due out in 2001 and re-emphasise it in the cover letter."

This recommendation was incorporated in the 2001 Guidelines. For the first time, the Guidelines explicitly defined a "maturity" threshold at which proved reserve volumes should approach or equal expectation reserves. In the case of proved developed reserves,

> "[w]ith increasing cumulative production, the Proved estimate should gradually grow until it equals the Expectation estimate when the field is mature. A mature field is broadly seen to be a field with a maturity ratio (cumulative production divided by expectation ultimate recovery) of 40% or more."

By comparison, "Proved undeveloped reserves can be taken as equal to Expectation reserves for fully mature fields (broadly with a maturity ratio of 80% or more)." It was noted, however, that there may be uncertainties regarding future well performance (e.g., the future need to complete new horizontal wells in a field previously developed through conventional wells) that would require proved estimates to be "somewhat conservative." The Group Reserves Audit Report for year-end 2001 again noted that the 1998 revision to the Guidelines had resulted in significant (200 million m^3 oil equivalent or 1.26 billion boe) proved reserves additions in mature fields "in recent years" and also included graphs similar to those provided for 2000. For 2001, however, these graphs indicated that most mature OUs had achieved "Proved / Expectation ratios close to 1 for their developed and undeveloped reserves."

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There is evidence that reservoir engineers in the OUs simply relied on this axiom – that proved reserves should approach or equal expectation reserves in mature fields – to justify increases in their proved reserves bookings. For example, an e-mail from former Group Reserves Coordinator (Remco Aalbers) to the Group Reserves Coordinator (Jan-Willem Roosch) dated January 7, 2002 described how proved undeveloped reserves for the Groningen field were increased to "restore" the ratio of proved undeveloped to expectation undeveloped reserves from 85% to the 97% level that had prevailed before certain undeveloped reserves became classified as developed. The 1998 Guidelines were invoked to justify this "adjustment."

One consequence of the Guidelines' equation of proved and expectation reserves for "mature" fields appears to have been the reporting of significant volumes of proved undeveloped reserves on the assumption that the relevant fields were "mature." These proved undeveloped reserves could include fields for which there was no "reasonable certainty" that Shell would develop the relevant volumes. SPDC in Nigeria and PDO in Oman are good examples of this trend and are described in detail in Tabs F and G of this Report.

Although he did not call into question the convergence of proved and expectation reserves in mature fields, Barendregt did express the concern that the 2000/2001 SEC Guidance meant that current Shell standards for the first-time bookings of proved reserves in new fields were too lenient. Unlike the report for 2000, the GRA Report for 2001 did not contain a recommendation to emphasize the need to encourage further application of the Guideline revisions first made in 1998. In his narrative of the recategorization written in early 2004, Barendregt observed in hindsight that the shift to a deterministic methodology adopted in the 1998 Guidelines effectively eliminated a balance that existed in Shell's reporting of proved reserves. On the one hand, Shell's probabilistic methodology overstated proved reserves for immature assets, in part due to the failure to observe fully the "proved area" constraints discussed above. On the other hand, its reporting of proved reserves in mature, producing fields tended to be conservative. Once additional proved undeveloped reserves were recorded as a result of the 1998 change to the Guidelines, there remained the overstatement of proved reserves at the immature end of the spectrum.

The 2002 Guidelines retained the principle that proved volumes should converge to expectation volumes in mature fields, but they no longer contained the bright-line definition of "maturity" as an express ratio of cumulative field production to expected recovery. The definition reappeared in the 2003 Guidelines, however, but only for proved developed reserves (i.e., where cumulative production equals 40% of expected developed ultimate recovery volumes). The 2003 Guidelines stated that, while it should be possible to make a "robust case" for reporting proved developed reserves in these circumstances, lower thresholds than 40% may be appropriate where reservoirs are especially well understood and higher thresholds may be needed where "relatively novel (but still proved) recovery techniques" are being employed or a more cautious approach is otherwise warranted. As noted in its Overview Memorandum, Gaffney Cline considers such absolute measures of "maturity" to be inappropriate and thinks that they could lead to the use of an expectation value for proved reserves that is materially higher than a low case forecast that would be a correct basis for estimating proved reserves.

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3. Gas Market Availability

Because a worldwide spot market for gas does not exist as it does for crude oil and it can be difficult and expensive to liquefy natural gas and transport it to distant markets, oil and gas production companies have traditionally required clear evidence that the relevant gas volumes can be sold before proved reserves in respect of gas can be recognized. Such evidence often takes the form of an executed gas sales contract, especially in frontier areas. Gaffney Cline notes in its Overview Memorandum, however, that an executed contract would not always be necessary to establish the "reasonable certainty" of sale required for reporting proved reserves. For example, as discussed above, one of the Staff interpretations in SAB Topic 12 implies that proved gas reserves do not always depend on an executed sales contract. Consistent with this view and industry practice, the 1988 Guidelines provided that proved gas reserves could be reported for quantities that are either, "contracted for sales . . . or can be considered as reasonably certain of being sold." An example of such a situation is where, consistent with "reasonable certainty," the gas can and, under the company's business plan, will, if necessary, be delivered to a viable spot market that could absorb the relevant gas volumes at a clearing price sufficient to make the project economically viable. In Gaffney Cline's view, this alternative language implies a sufficiently high degree of confidence to be consistent with the concept of "reasonable certainty."

In 1990, the Shell Guidelines were amended to relax this requirement. The amendment took the form of a letter dated October 12, 1990 circulated throughout EP and was signed by, among others, Sir Philip Watts. The letter noted that the Group had traditionally used "a more stringent definition of proved gas reserves used for external reporting than that of the SEC and other major oil Companies." (The letter failed to observe that the SEC definition of proved reserves contains no specific requirements relating to sales contracts for gas reserves other than the need for "reasonable certainty" that the reserves will be developed commercially.) The effect of this "self imposed restriction" had been to exclude gas reserves from external disclosures even though the developed portion of the excluded reserves were included for purposes of depleting and depreciating production assets. To address this anomaly, the letter mandated the amendment of the relevant Guidelines provision to bring it into line with the Group's accounting practice. Under the new standard, effective for years from 1990 onwards,

> "Proved reserves of natural gas should include only quantities falling into the following categories: 1) volumes that are contracted to sales; 2) volumes that can be considered as reasonably certain of being sold based on a reasonable expectation of the availability of markets, along with transportation/delivery facilities that are in

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> place; 3) volumes that under current Group screening criteria, have been reasonably shown to be capable of being technically and economically developed, and, while not firmly planned, have been earmarked for future development and hence may reasonably be anticipated to be sold based upon expectation of availability of markets and project financing."

The letter stated that the proposed change "is in line with SEC requirements and the practice of other major oil companies." In its Overview Memorandum, however, Gaffney Cline disputes the assertion that this change was in line with the policy of other major oil companies and considers the third prong of the amended Guidelines provision "to fall short of the level of certainty required by the SEC at all times during the period under review."

The letter noted that, based on estimates from operating companies, adoption of the change would result in a dramatic increase in proved gas reserves but would have an immaterial impact on EP net income since the developed portion of such reserves were already reflected in depletion, depreciation and amortization. The authors of the letter cited these factors as the justification for the change, which they characterized as "the re-adoption of the SEC/FASB definition."

The new, relaxed standard for proved gas reserves was incorporated essentially unchanged in the full version of the Shell Guidelines issued in 1993 and remained in subsequent versions of the Guidelines from 1996 through 2000. In 2001, the Guidelines retained the three-prong test but in an apparent tightening of the requirement added: "For major gas projects critically depending on new gas market capture, proved reserves booking should in principle be deferred until agreements have been signed, generally at or around project sanction (FID)." The 2002 Guidelines eliminated the previous test and instead permitted proved gas reserves only where

> "the product is: (1) contracted to sales; or (2) considered as reasonably certain of being sold based on an expectation of the availability of markets, along with transportation/delivery facilities."

In 2003, the Guidelines were tightened further by adding that "[f]or major gas reserves that rely on the creation of access to market (e.g. those reliant on negotiation of LNG sales contracts), reserves booking should in principle be deferred until certainty exists concerning sales agreements. A Letter of Intent generally will not provide sufficient assurance that a Sale and Purchase Agreement will be concluded."

4. Proved Undeveloped Reserves – "Reasonable Certainty" of Development

During the period from 1988 to 2003, the Guidelines reflected significant change in the standards applicable to the initial recording of proved undeveloped reserves. Earlier versions of the Guidelines provided little guidance regarding the relationship between the status of development plans for a specific field as a matter of the Group's internal planning and capital allocation process and the booking of proved undeveloped reserves in respect of that field on the basis that development was "reasonably certain." The Guidelines' treatment of this issue became more explicit over time. It was not until 2001, however, that the Guidelines identified the stage of Shell's own internal "Value Assurance Review" or VAR planning and screening process that a project had to have reached before proved undeveloped reserves could be reported.

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(a) 1988-1999: Little Focus

The 1988 Guidelines provided little guidance with respect to the estimation of proved undeveloped reserves. The Guidelines distinguished between "developed" and "undeveloped" reserves, which are those that would normally form the basis for drilling and engineering activity over a six-year "Objectives Period." There was no explicit guidance as to what portion of these undeveloped reserves would qualify as proved reserves based on the likelihood of future development.

By 1993, the Guidelines noted that "[e]xternal reporting requirements dictate that reserves are only those volumes which can and are firmly planned to be produced and sold and to which the company has an entitlement." The 1993 Guidelines thus identified the need to distinguish between "volumes for which there is a development plan and volumes that have not reached this stage." To address this need, the 1993 Guidelines introduced Shell's own concept, "technical maturity," as a prerequisite for recording reserves (presumably whether "proved" or not). To be technically mature, a project had to be based on "[a]n auditable project development plan, based on a resource and development scenario description, with drilling/engineering cost estimates, a production forecast and economics evaluated." The plan could be "notional or it may be an analogy of other projects in similar resources," although there should be little doubt that "a robust development plan can, with time, be matured." Reserves could exist before project approval was received or even sought, an outcome that was arguably at odds with the concept of "reasonable certainty." The 1996-1999 Guidelines contained essentially the same definition of technical maturity. In 1998 and 1999, a diagram known as the "cascade model" developed by the Value Creation Team appeared in the Guidelines. The "cascade model" illustrated the "migration of volumes between resource categories during the development life cycle." In the diagram, "undeveloped reserves" appeared before "final investment decision" or FID (although the diagram does not make clear whether these volumes include proved undeveloped reserves).

Beginning in 1993, the Guidelines also introduced the concept of "commercial viability" (or later, "commercial maturity") as a counterpart to technical maturity. As explained in the 1996 Guidelines, commercial viability implied that the project would yield an expected positive

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net present value (NPV) based on "advised Group reference criteria for commerciality." Such viability was adequate for the inclusion of "reserves," even though a more robust demonstration of "economic viability" (i.e., positive NPV under a number of technical risk downside scenarios) was necessary to obtain investment approval. In other words, it appears that the Guidelines permitted the booking of reserves (whether proved or expectation) with respect to projects that would not survive the Group's capital allocation process, again a result that appears to fall short of "reasonable certainty."

As Gaffney Cline notes, these criteria do not distinguish between "technically mature" projects for which "reserves" are reported internally and those which are "reasonably certain" and appropriate for external reporting. The Guidelines presumably relied on reserve estimators in the OUs to take the probabilistic P85 value in such circumstances to indicate "reasonable certainty." Although the SEC Staff had not yet published its views on the need for a commitment to develop reserves that appeared in the 2000/2001 SEC Guidance, in Gaffney Cline's view, general industry practice was that some evidence of such a commitment was necessary to establish "reasonable certainty." For example, as noted above, SEPCo had required "final investment decision" or FID as a condition for recording proved reserves for significant projects since the mid-1980s.

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(b) 2000-2003: Attempts to Tighten Standards

The 2000 Guidelines contained essentially the same requirement for technical and commercial maturity as appeared in previous versions but for the first time attempted to map this concept on to Shell's own planning and decision-making procedures. The Guidelines noted that "[s]uccessful completion of a Value Assurance Review (VAR) with sufficient definition supports technical maturity." (VAR refers to the scheme for planning and screening new ventures that was introduced within EP during the late 1990s.) Under the VAR scheme, new EP projects must move through five separate stages of increasing economic, technical and operational scrutiny: VAR 1 (project initiation), VAR 2 (project feasibility), VAR 3 (project concept selection), VAR 4 (immediately prior to final investment decision) and VAR 5 (post-implementation review). Although "notional" development plans could still support proved undeveloped reserves, the reference to completion of VAR suggested an intention to encourage reliance on a more concrete indication that development was planned. At the same time, the 2000 Guidelines did not specify which level VAR would suffice and thus, as Gaffney Cline notes, offered little practical guidance, at least as to evidence of the "reasonable certainty" required for external reporting.

In 2001, the Guidelines became more specific, stating that the project should preferably have reached VAR 3 before reserves (both internally and externally reported) could be booked. According to the EP Project and New Venture Value Assurance Guide (EP2002-5306), VAR 3 referred to "project selection" and occurred prior to "project definition." The selected development concept must be

> "realistic and realizable. The business case must be clear and supported by economics, including that the commercial terms are still appropriate and cover the range of project uncertainties. . . . A forward plan must exist, be realistic and identify the resources needed to deliver. Key execution requirements (e.g., contractual, strategic) and the necessary organization . . . must have been identified for the remaining phases."

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As described by the SEPCo Reserves Manager, while VAR 3 means that there is a detailed plan, especially for drilling and other geological work, based on extensive preparatory work, the timing and exact steps of execution (e.g., selection of contractors and negotiation of contracts) remain to be worked out. As he explained, there can still be "showstoppers" (i.e., issues such as government licenses or permits, contractual negotiations or technical issues that could prevent development), which would preclude the existence of "reasonable certainty." By VAR 4, many of these issues will have been resolved, permitting FID to be taken.

The 2001 Guidelines also introduced what appeared to be more rigorous (if not entirely clear) standards for the requisite "commercial maturity." While proved reserves could be reported before project approval was sought, there must be an "expectation that economic viability will be achieved and a plan to seek approval some time in the future. The project should also be included in the annual Business Plan." Despite this apparent tightening, the Guidelines still offered little practical guidance on the application of the concept and the extent to which it might overlap with technical maturity.

Neither the 2000 nor the 2001 Guidelines clearly reflected nor mentioned the SEC Staff's 2000/2001 SEC Guidance regarding the need for "reasonable certainty" of development in "frontier" projects. It is worth noting in this regard, that the SEPCo Reserves Manager had forwarded a copy of the 2000/2001 SEC Guidance by e-mail to both the Group Resources Coordinator (Remco Aalbers) and the Group Reserves Auditor (Anton Barendregt) in late October 2000. The Staff's interpretive position was mentioned in the Group Reserves Audit Report for year-end 2001, however. Barendregt noted that the SEC's "clarifications . . . have shown that current Group reserves practice regarding the first-time booking of Proved reserves in *new* fields is in some cases too lenient." He also pointed out that, at least in the case of <u>first-time</u> bookings, industry practice tended to follow the SEC Staff guidance more closely and cited as examples BP, which had not yet booked any reserves in Angola Block 18 (a field where Shell had first booked proved reserves in 2000 but where Barendregt had rejected additional proved reserve bookings in 2001), and Exxon and SEPCo, which tended to record proved reserves only at or close to FID. Barendregt went on to recommend a tightening of the Guidelines:

particularly large or "frontier" projects must have successfully passed VAR 3 or a "serious financial or contractual commitment." The project must have achieved "project viability," not simply "commercial viability," and any "identified show stoppers" that could jeopardize development must have been resolved.

At roughly the same time, the Group Reserves Coordinator (Jan-Willem Roosch) was urging similar improvements in the Guidelines. In e-mails and other communications within EP, Roosch had expressed concern about the premature booking of proved undeveloped reserves. The Guidelines were revised in 2002 to incorporate many of the recommendations made by Barendregt.

The 2002 Guidelines tightened requirements for both technical and commercial maturity before reserves could be recorded for a project. Technical maturity depended on a "documented definition of a viable project that is anticipated to be implemented with 'reasonable certainty'," including development scenarios, drilling/engineering cost estimates, a production forecast and economics. To support proved reserves, "independent review and challenge is required . . . to preserve integrity of the external disclosures." In the case of "major projects," VAR 3 must have been completed. "In all cases, there should be 'reasonable certainty' that nothing is standing in the way of a firm development plan (i.e. there are no technical issues that could de-rail the project)." To achieve commercial maturity, the project had to meet profitability criteria, funding by the Group had to be "reasonably certain" and market availability for the resource had to be assured. In Gaffney Cline's view, the new requirement for VAR 3 for "major projects" was not inconsistent with the SEC's proved reserves definition but it remained open to OU interpretation (and hence inconsistent application) due to the lack of definition of "major project" as well as the reference to "technical" but not "commercial" issues that could de-rail the project. Still, the

Shell Guidelines risked inconsistent application by OUs given the failure to define "major projects" for which VAR 3 was necessary and the lack of clarity regarding evidence that capital allocation was "reasonably certain."

In the 2002 Group Reserves Audit Report, the issue of the Group's commitment to developed reserves again received considerable attention. Barendregt expressed the view that "the passing of a VAR 3 review is too 'soft' a hurdle" because "VAR teams are rarely asked to make a clear statement whether the VAR was good, satisfactory or unsatisfactory." This lack of clarity, in his view, led to debate about bookings that was often motivated by scorecards. Consequently, he recommended further tightening of the Guidelines to require either FID or "another strong public commitment" by the OU such as a "binding declaration of commerciality to the authorities" confirming that the project will proceed. This desire to implement the 2000/2001 SEC Guidance was somewhat at odds with Barendregt's conclusion that the development of the Gorgon project remained "reasonably certain" in light of the absence of "clear showstoppers." In this respect, it is worth noting that, despite the tightening in 2002, the Guidelines did not yet reflect the SEC Staff's view that significant lack of progress in development over time could call into question the continued viability of proved undeveloped reserves.

As in 2002, the 2003 Guidelines were amended to impose even more stringent criteria for the initial reporting of proved undeveloped reserves. The principal change was the shift from VAR 3 to FID as the basis for proved reserves in respect of "major projects" (now defined as those with proved reserves in excess of 50 million boe or requiring more than $100 million of Group capital expenditure). In exceptional cases, FID may not be needed where there is a "clear public demonstration" of the Group's intention to execute the project. "Intermediate development projects" (10 to 50 million boe in proved reserves) required VAR 3 to support proved reserves. In other cases, a development plan should suffice.

Gaffney Cline views these provisions as providing clear and explicit guidance for first-time bookings of proved reserves, except that the phrase "clear public demonstration of the Group's intention to proceed" lacks adequate definition for the user of the Guidelines. Moreover, they point out that it does not make sense to define the planning milestones the project must reach in order to support proved reserves based on the volumes sought to be booked rather than the amount of capital expenditure required since the latter rather than the former will likely define the nature and level of internal review necessary for the project to proceed. In addition, there is also a conceptual circularity in defining the indicia for "reasonable certainty" of development in terms of the volume proposed to be booked, which could lead to confusion in application.

5. *License and Other Constraints on Production*

Since 1993, the Guidelines have dealt consistently with the problem posed by reserves that could be classified as "proved" but for existing or future constraints on production imposed by the expiration of licenses or OPEC or similar quotas. The basic approach has been to estimate proved reserves based on an "accelerated development program" for reserves that would otherwise be produced after the license expiration or in excess of the relevant constraint in order to "replace" any shortfall in production under the development plan.

For example, the 1998 Guidelines provided that:

> "For external reporting, Group share of reserves (proved, proved developed) is limited to production within the existing licence or contract period. However, production beyond the licence or contract period can be included if there is a legal right to extend a production licence or PSC, or if the government has formally

> indicated that it will favour substantiated requests for extensions in the future (letter of assurance). Then volumes recoverable during the extension period are included in the Group share, assuming currently existing or other anticipated terms."
>
> . . .
>
> "When operating under a combined production constraint (e.g. oil production quota) and production beyond the licence or agreement period is expected, the capability to accelerate the post licence production provides a safeguard against under-performance of the planned development programme during the licence period. This capability increases the confidence level that can be assigned to the constrained production forecast during the licence period. In this circumstance, the proved reserves should be based on an accelerated development programme that could be followed in the event that the base plan delivered less production than expected."

The 2000 Guidelines included an additional clarification that the relevant production forecasts should reflect all "system constraints, abandonment timing, expected operational performance (planned and unplanned deferment), production quota restrictions, contractual sales volumes, market and other expected production limitations (community disturbance, etc.)." By 2001, the Guidelines simply stated that "[i]t is reasonable to assume that whatever forecast has been assumed for the Expectation case can also be met by disappointing (i.e. Proved) reserves realisations in the fields, simply by accelerating their development."

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Gaffney Cline's assessment of this approach is that it is reasonable in principle but that the language is sufficiently unclear that it risks being misinterpreted. For example, it is not adequately clear, in their view, what is meant by a "base plan" without any comment on the level of commitment that would have to be demonstrated to support "reasonable certainty," especially in the case of "acceleration." In addition, based on their review of the Group Reserves Audit Reports, it appears to Gaffney Cline that the OUs did not generate individual proved reserves forecasts to support this analysis but instead appear to have used a truncated expectation forecast.

As Gaffney Cline comments in its report, this approximation method could lead to material errors in the proved reserve volumes.

A similar criticism was made by Barendregt in the Group Reserves Audit Report for 2001. In the report, he expressed concern that certain OUs had not made realistic assumptions regarding their future production profiles:

> "For a proper estimation of Proved reserves (which have to fulfil the criterion of 'reasonable certainty') it is important that OUs faced with the above constraints make realistic assumptions regarding their future production profiles. The selected build-up and plateau levels should preferably be in line with base case Business Plan assumptions and with profiles used for the SEC 'Standardized Measure' submission. In addition, post-plateau tail-end profiles should be technically defensible. It is noted that PDO still maintain a 850 kb/d plateau in their forecast, in spite of recent problems in maintaining that production level. SPDC seem to have included LNG trains 4&5 in their condensate forecast, while the associated gas reserves have not yet been included in gas reserves because of lack of market definition."

He pointed out that the Guidelines provided no guidance about what assumptions to take for future forecasts in these situations and recommended that this problem be rectified. The Guidelines for 2002, however, did not reflect this change. In his report for 2002, Barendregt expressed even more dire concerns and again urged that the Guidelines be amended to include concrete guidance on forecast assumptions.

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The 2002 and 2003 Guidelines were revised to reflect the relevant portions of the 2000/2001 SEC Guidance that relate to license expiration. In addition to requiring that license extension be either an enforceable right or "a matter of course" in order to justify post-license booking of proved reserves, the 2003 Guidelines also instructed the OUs to take account, where necessary, of "overriding constraints, such as evacuation system capacity, (likely) OPEC quota levels or funding levels, particularly if these affect the timing of development activities and the

Resource Volume for the project concerned is dependent on the timing of execution." As Gaffney Cline notes, this guidance with respect to other, non-license constraints is vague and potentially confusing (e.g., "likely" rather than existing OPEC quotas) for purposes of external reporting. They also note that a proved production forecast for this purpose remains only a recommendation in the 2003 Guidelines.

6. *De-booking*

The underlying premise of the SEC proved reserves definition is that hydrocarbon volumes booked as proved reserves must, at all times, meet the "reasonable certainty" test. If the development or production of a volume of proved reserves should become less than "reasonably certain," for any reason, then the volume cannot continue to be classified as proved. The de-booking of such a volume is accomplished by showing a negative revision in the proved reserves disclosure.

Historically, the Shell Guidelines have given sparse advice as to whether already recorded proved reserves should be de-booked as a result of changed circumstances or a more rigorous application of the regulatory definition. Generally speaking, if proved reserves are properly determined in the first place, sizeable downward revisions should not be usual events. In Shell's case, however, the combination of premature bookings and progressive tightening of the Guidelines in response to SEC Staff clarifications meant that large proved reserve volumes were exposed to the risk of de-booking. Unfortunately, the statements in the Guidelines regarding de-booking can be read to discourage OUs from reviewing bookings that may be exposed.

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The 1993 Guidelines stated that "Operating Companies are to exert caution in transferring volumes between the reserves and SFR categories," so as to "minimise fluctuations [in proved reserves] over time." In Gaffney Cline's view, this is not an instructive statement for the estimating engineer since it provides no substantive guidance. These Guidelines also advised that "existing reserves not meeting the Group reference criteria for commerciality may be retained only in cases of overriding strategic interest or where a current small operating loss is expected to be reversed in the short term." From 1996 to 2001, the Guidelines provided essentially the same instructions with respect to reserves de-booking, as those stated in the 1993 guidelines. As noted by Gaffney Cline, this statement is inconsistent with the SEC's requirement that proved reserves must, at all times, be composed of economically recoverable volumes.

By 2002, when it was known within EP that there were large proved reserve "exposures," the Guidelines advised that "[m]ajor reserves volumes that are no longer judged to be commercially mature should only be de-booked after thorough (re-)evaluation." This instruction to de-book, in Gaffney Cline's view, is not unreasonable but it could lead to delays (e.g., past the annual reporting deadline in which the problem is identified or where the de-booking issue is potentially material) in de-booking reserves that may obviously no longer be commercial. Also, the provision does not refer to proved reserves that are no longer "technically" as opposed to "commercially" mature, both of which are features of proved reserves under the 2002 Guidelines. Although subjecting de-bookings to a "thorough re-evaluation" is not on its face inconsistent with the SEC definition, a user of the Guidelines could read this language to impose a higher standard for de-booking than for an initial booking of proved reserves. Interestingly, despite the fact that they addressed the Staff's recent clarification of the SEC definitions, the 2002 Guidelines contained a statement (below the introduction) that "[n]o material change in the volume of reserves reported by the Group is expected nor intended by these guidelines." (Emphasis added.) Likewise a May 2003 EP presentation entitled "Reserves Accounting in

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Shell" contained a similar statement regarding the changes to the 2002 Guidelines: "2002: numerous aspects CLARIFIED. The guidelines did NOT change." (Emphasis in original.)

At roughly the same time (October 2002), a note to EP ExCom entitled "EP Proved Reserves Management" urged a deliberative approach to de-booking:

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

The 2003 Guidelines addressed the issue of de-booking risk in a more straightforward fashion. They stated that the EP Hydrocarbon Resources Coordinator would maintain an inventory of "proved reserves in the current portfolio that could potentially be at risk." The Guidelines explained that "[these volumes] generally [consist] of volumes which were booked previously but which may not fulfill the present guidelines (which may have been revised since the bookings were made)." The 2003 Guidelines also stated that "de-booking of [proved reserve] volumes was held pending while the results of imminent actions or decisions are awaited, for example appraisal drilling or FID." As Gaffney Cline observes in their Overview Memorandum, this provision of the Guidelines is not unreasonable but could lead to inappropriate delays in de-booking in more obviously non-commercial cases. The 2003 Guidelines further stated that the inventory of at-risk proved reserves volumes would be considered by the Reserves Committee "at least twice annually, with direction being given as to the continued booking or de-booking of reserves as appropriate."

REPORT OF

DAVIS POLK & WARDWELL

TO

THE SHELL GROUP AUDIT COMMITTEE

TAB B:

"TONE FROM THE TOP": ANALYSIS OF THE CONDUCT OF MANAGEMENT WITH RESPECT TO THE EVENTS LEADING TO THE RECATEGORIZATION

MARCH 31, 2004

Tone from the Top

PAGE

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HIGHLY CONFIDENTIAL

Tone from the Top

I. Summary

From the 1990s, Shell placed great institutional emphasis on a number of performance metrics, including the reserves replacement ratio. The emphasis on such metrics originated from an understandable response to increased capital market demands for enhanced guidance on future performance. While most of the criteria used were entirely appropriate measures of operating performance, competitive and market pressures could, and in fact did, lead to an overly aggressive approach to meeting these publicly disseminated targets. A corporate culture was eventually fostered whereby booking reserves was highly encouraged, but de-booking reserves was considered a "last resort." When confronted with reserves exposures, placebos were employed such as imposing "freezes" and "moratoria" rather than de-booking the questionable reserves.

Although potential exposures involving significant volumes had been identified by February 2002, a thorough investigation into those exposures was not conducted for almost two years. Executives within Shell responsible for addressing the reserves issues had an internal focus and tried to "manage" their way out of the problem, without focusing on the need for compliance with SEC definitions and for promptly providing corrective information to the market. In spite of an acknowledgement by management in July 2002 that certain questionable reserves could "not be maintained indefinitely," there was no sense of urgency to resolve these issues. The failure to act in early 2002 stands in contrast to the rapid mobilization effort that took place in late 2003, after two adverse country audits and legal advice from Cravath, Swaine & Moore made it clear that there could be no further delay in reporting the material errors in proved reserves bookings.

Sir Philip Watts and Walter van de Vijver were Shell's senior-most executives with specialized knowledge of the Exploration and Production ("EP") business and especially the reserves issues associated with that business. These two executives signed attestations that EP's financials were materially correct. Yet, Watts and van de Vijver appear to have approached the reserves problems without full consideration of the regulatory aspects presented. They focused only on business concerns and, perhaps, on personal agendas. Van de Vijver clearly resented what he regarded as "premature" bookings of reserves during Watts' tenure as Head of EP, which he believed now limited his own ability to book proved reserves. Van de Vijver has conceded that the "severity and magnitude" of the reserves issues may not have been fully appreciated by other members of executive management.

During this investigation, the authors of the documents discussed herein have been given the opportunity to provide any helpful "context" with regard to the documents or more generally, the issues under review in this investigation. However, in the end, the axiom "the documents speak for themselves" applies and the documentary evidence sets out a reliable account of the "tone from the top."

* * *

This Report is divided into three time periods: from 1990 through 2001, a period that provides industry context and which is critical for understanding the factual evolution of proved reserves issues at Shell; from 2002 until mid-November 2003, the period during which some elements of senior management were demonstrably placed on notice of potential exposures related to proved reserves; and from mid-November 2003 through February 5, 2004, the period during which the materiality of the eventual reserves recategorization was acknowledged, leading to Project Rockford and ultimately to public disclosures.

II. 1990 – 2001: The Backdrop

The general pressures that Shell has confronted with respect to its reserves replacement through the 1990s to date provide an important backdrop for understanding the events that led to the major recategorization of reserves that was announced on January 9, 2004. By way of background, in the mid to late 1990s, Shell responded to the demands of the international capital markets for more "visibility" regarding its expected future performance over defined periods. Like its competitors, Shell guided the market's expectations as to several key performance measures, including: Return on Average Capital Employed ("ROACE"), average per annum production growth and, most notably for present purposes, the rate of replacement of oil and gas reserves consumed through production, or the reserves replacement ratio ("RRR").

In connection with RRR, oil and gas companies that are also U.S. registrants are required to disclose "proved reserves" based on the definition of that term established by the SEC in 1978. Reporting on a common and consistent basis in accordance with these definitions should permit companies' hydrocarbon resources to be compared on a similar basis. Proved reserves, as defined by the SEC, are also the only measure of a company's oil and gas resources permitted to be disclosed in SEC filings, including the annual reports filed by foreign issuers on Form 20-F. Given their importance, proved reserves are appropriately a matter of concern to the management of the Group and, in particular, to the EP business unit.

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It is clear, however, that proved reserves are estimates subject to significant elements of judgment regarding factors affected by, among other things, geological, engineering, economic and political/regulatory conditions. As might consequently be expected, the measurement of proved reserves and the rate at which produced reserves are replaced are capable of more subjective interpretation than other critical measures (such as production growth and, to a lesser extent, ROACE) that are commonly applied by the market to assess the performance of an EP business. The judgmental nature of reserves determinations requires that senior management ensure these determinations are made subject to proper controls.

As early as 1990, there were concerns within Shell that its policies and practices with regard to booking of reserves were too "conservative" relative to its key competitors. While no evidence was found to refute or affirm this perception of relative conservatism, significant modifications were made to the Shell Guidelines at different times in the 1990s in order to attempt to realign Shell's approach. These changes to the Shell Guidelines resulted in large increases in proved reserves and boosted Shell's RRR.

The modifications to the Shell Guidelines of the 1990s eventually led to considerable increases in proved developed reserves, and to a lesser extent proved undeveloped reserves.[1] The methodology underpinning the increases in undeveloped reserves was less robust and, from the time of booking (predominantly in 1997/1998) to the present day, these undeveloped reserves have largely failed to mature or be fully developed. Thus, the changes to the Shell Guidelines of the 1990s produced a significant share of the recent recategorization requirement.

Also during the 1990s, there appears to have been a general lack of understanding regarding the SEC's proved reserves definitions within Shell, including certain critical areas such as the Group Reserves Coordinator and Group Reserves Auditor. Awareness of SEC definitions increased within Shell beginning in 2000, once the SEC published written guidance for the industry to employ in making proved reserves determinations. In that guidance – which the SEC

[1] It should be noted that the main increases in proved reserves resulting from the Value Creation Team's revised Guidelines in 1997/1998 (*See* Section II C, below) related to proved developed reserves. Such proved developed reserves did not make up a significant portion of the reserves recategorization announced on January 9, 2004.

re-issued with minor additions in 2001 – the SEC emphasized the need for investment commitment and other evidence of commitment to develop in order to support the booking of proved reserves.

A. The Relaxation in Booking Practices for Proved Gas Reserves

In 1990, Shell relaxed its approach to booking proved gas reserves to permit, for the first time, the "reasonable certainty" standard to be satisfied without a signed sales contract in place, so long as there existed an expectation that a market and project financing was available. This change materially impacted subsequent reserves estimates and in 1990 RRR reached a record-high 334%.

This relaxation of requirements for booking proved gas reserves was proposed to EP by three senior executives in Shell's EP business, including Watts, who at the time was the Head of EP Economics.[2] The proposal was submitted in response to a perception within Shell, described above, that its booking procedures for proved gas reserves were more conservative than those of its key competitors. The proposal indicated it was intended to harmonize proved reserves reported to the SEC and those used for depletion calculations in Shell's Financial Statements. The proposal for the change noted:

> "For some years the Group has had a more stringent definition of proved gas reserves used for external reporting than that of the SEC and other major oil companies. This has been queried by Group External Auditors since it has contributed to differences between proved reserves reported in Financial Statements to the SEC and reserves used for depletion calculations by Finance.

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[2] The other two executives, the Head of EP Production Development and Head of EP Finance, have not been employed by Shell since May 1994 and March 1999, respectively.

> The proposed change that will harmonize these two sets of figures, is in line with SEC requirements and the practice of other major oil companies."[3]

With that introduction, the proposal recommended that Shell use the following as one of the standards for booking proved gas reserves in the future:

> "[V]olumes that under current Group screening criteria, have been reasonably shown to be capable of being technically and economically developed, and, while not firmly planned, have been earmarked for future development and hence may reasonably be anticipated to be sold based upon expectation of availability of markets and project financing." (Emphasis added.)

This proposal was approved and implemented by EP, effective as of December 31, 1990.[4]

In connection with this investigation, the foregoing standard for booking gas reserves was examined by Gaffney, Cline & Associates Ltd ("Gaffney Cline"), independent petroleum engineers. According to Gaffney Cline, this standard was not compliant with the SEC's requirement of "reasonable certainty" in 1990, nor has it been at any time since.

B. The Gorgon Booking

For the year-end 1997, Shell booked over 500 million boe of proved reserves for the Gorgon gas field in a "frontier" area off the northwestern coast of Australia. The Gorgon booking was a material contributor to the RRR growth in that year, alone representing 37% RRR out of the total 158% RRR for the year. Gorgon was also the largest single field de-booking announced on January 9, 2004.

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[3] Memorandum to EP from EPD, EPE, EPF re: Proposed Change to Group Definition of Gas Reserves (effective 31.12.90) as Published in Group Financial Statements, Oct 12, 1990.

[4] While the change in approach to proved gas reserve booking was implemented in 1990, it was not formally incorporated into Shell's Guidelines until 1993

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No written audit trail indicates who, in late 1997 or early 1998, made the decision to categorize the Gorgon reserves as proved, or the specific basis for that decision. While there are documents that provide some insight into the basis for the booking, it is clear that none of the required indicia of commercial viability were present at the time Gorgon was booked. All that exists is an exchange of letters with a potential buyer in 1998. These letters, however, cannot be viewed as a "letter of intent" (as was suggested as recently as Shell's January 9, 2004 announcement), and in any case they post-date December 31, 1997, the effective date of the booking, by months. (*See* Tab E.)

Watts, who was the Chairman of EP Buscom (and the CMD member with responsibility for EP) at the time of the Gorgon booking, and other key EP executives claim no recollection of the Gorgon booking, notwithstanding its substantial impact upon RRR for 1997. During a recent interview published in *The Sunday Telegraph* on February 8, 2004, Watts was asked about the Gorgon booking and stated: "I just don't specifically remember that one." A similar response was provided by Watts in an interview during this investigation.[5]

C. Revisions to the Shell Guidelines – "Volume Value Creation Team"

In each of 1997 and 1998, Shell's RRR performance significantly exceeded 100%. During these years Shell's proved reserves were significantly boosted, not by exploration and development activity, but rather by significant modification to Shell's methodologies for booking proved developed reserves. This change was at least partly the result of a review that was conducted under the auspices of a "Hydrocarbon Resource Volume Value Creation Team" (the "Value Creation Team") within EP that was, in turn, established as part of Shell's Leadership

[5] Interview of Watts, Feb. 19, 2004.

and Performance "LEAP" Focused Results Delivery Project. Similar to the relaxation in standards for booking proved gas reserves in 1990, this initiative was driven by the perception that Shell's approach to booking proved developed reserves was more conservative than its competitors', and that Shell's reserves were therefore not maximizing value.

Additionally, this initiative would have addressed the continuing pressures of external market expectations, which, as noted in the 1997 and 1998 EP Business Plans, continued to be a foremost concern:

> "After delivering below average profitability for the past decade, analysts now expect <u>Shell EP Worldwide</u> to deliver the <u>highest returns by 2001</u> amongst the majors... In production growth, they expect Shell to be the leading company with forecast annual production growth to 2001 of 7%, compared to an average of 4.9% for the top ten companies... [T]argets set in this [1997 EP business] plan reflect a <u>high level of ambition</u>, although analysts clearly expect that they will be achieved and <u>the market may have factored this into current share pricing</u>."[6] (Emphasis original.)
>
> "<u>It is clear that EP is in the 'show me' world – we have to deliver</u>."[7] (Emphasis original.)

The Value Creation Team sought to represent more accurately Shell's resource base in order to impact "the financial valuation of the Shell Group as a whole" positively. The Value Creation Team reviewed the Group resource volume management methodologies, including the Shell Guidelines, and suggested that Shell should "move towards an entrepreneurial style of management of the hydrocarbon resources with a clear <u>focus on value</u>." (Emphasis original.)

The Value Creation Team issued a report containing several recommendations. Most notable among these was the recommendation that the Shell Guidelines should be updated to

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[6] 1997 EP Business Plan, Dec. 1997.

[7] 1998 EP Business Plan, Nov. 26, 1998.

"emphasize the need to manage the maturing of resource volumes through the value chain in order to realise value." Specifically, reserves estimators were encouraged to use deterministic methods "when the main uncertainty is in the dynamic behaviour of the reservoir or when performance based estimates are being used;" typically the case in more "mature" fields with reservoirs already in production. By contrast, probabilistic methods were encouraged for use "when the geological model and development concept are clear and the volumes in place are major uncertainties." The report went on to recommend that proved developed reserves should equal expectation developed reserves by the time that the expectation developed reserves exceeded the total proved reserves (i.e., the P85). The report noted that, if these recommendations were implemented, the impact would be an increase in proved reserves volumes of approximately 500 million boe at year-end 1998 and an improvement in net income after tax ("NIAT") of roughly $150 million for 1998 (as a result of lower depreciation, depletion and amortization charges due to the increase in the base of proved developed reserves). A retrospective analysis performed by Shell in February 2002 concluded that the net effect of this revision to the Shell Guidelines was an addition of approximately 1.2 billion boe of proved reserves between 1997 and 2001.

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Although the Value Creation Team's recommendations were not officially incorporated into the Shell Guidelines until 1998, it appears that reserves estimators began applying those recommendations as early as 1997. The shift to deterministic methodologies for mature fields was recommended on the belief that the continued use of probabilistic methodologies for such fields might lead to double discounting if limited to proved area. A document entitled "Reserves Guidelines Principles," attached to a July 1998 Group Audit Review memorandum, noted that "a fully developed field will have proved developed reserves equal to the expectation total reserves" and that "[o]nce a field is at this level of maturity, the [Operating Unit] should adopt a deterministic approach to both proved reserves and proved developed reserves."

Critically, the resulting changes to the Guidelines did not cover proved developed reserves only. The new provisions also explicitly encouraged the application of a deterministic methodology for the estimation of all proved reserves in "mature fields": "In mature fields when most of the reserves have been developed . . . a deterministic approach should be used for both proved developed and proved undeveloped reserves consistent with the SEC and SPE definitions." The 1998 Guidelines did not otherwise define "maturity" for the purpose of guiding the operating units ("OUs") as to when in the lifetime of a field the shift to deterministic methodology should take place. As a result, this led OUs to equate "proved" with "expectation" reserves in situations without necessarily analyzing whether "reasonable certainty" existed.

It appears to have been understood at the time by Shell's senior-most executives that the strong RRR results of 158% and 182% (for 1997 and 1998, respectively) were largely attributable to the foregoing modification to the Shell Guidelines' standards. For example, the minutes of a CMD meeting on October 28, 1997 reflect a discussion of the EP business plan in which it was observed that "the increase in reserves was attributable to the application of a different methodology, rather than new physical discoveries."

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D. The Moratorium/Freeze on Reserves Bookings in Nigeria and Australia

In 2000, EP ExCom was aware of a "moratorium" on new proved oil reserves in Nigeria and was informed of a "freeze" on new reserves bookings in Australia (Gorgon). These decisions to suspend new reserves bookings are significant for two reasons: (1) they reflect that, early in 2000, Shell recognized that there existed within its portfolio two major questionable reserves positions; and (2) they demonstrate the approach EP elected to embrace to address those questionable reserves positions – i.e., to attempt to "manage" the situations rather than to de-book.

In the case of Nigeria (SPDC), the moratorium on new proved oil reserves was instituted in January 2000 and related back to 1999. This was based largely on the recognized risk that SPDC, Shell's principal Nigerian asset, would not meet its steep forecasted production targets and would not be able to produce its proved reserves prior to the expiration of its current license in 2019. Accordingly, the EP business decided to suspend further proved oil reserves bookings by SPDC – i.e. a "moratorium" was imposed. There appears to have been, however, no detailed re-examination as to the basis for existing bookings in Nigeria or any inquiry concerning whether it was appropriate to continue to carry those volumes as "proved." SCA 00000088

In the case of Australia (Gorgon), a freeze on additional reserves bookings was implemented after a debate involving the Group Reserves Coordinator and Shell Development Australia ("SDA") in late 1999 and early 2000. (*See* Tab E.) At the end of January 2000, a formal presentation on reserves to EP ExCom included a description of this freezing of the Gorgon proved reserves. It seems, however, that, as with Nigeria, no inquiry was undertaken concerning prior bookings, in spite of the fact that at this January 2000 EP ExCom meeting – which was chaired at the time by Watts – Watts asked a presenter at the meeting, then-EP Planning and Strategy Manager, Roelof Platenkamp, to inquire whether the Gorgon license partners (i.e. Chevron, Mobil and Texaco) had booked proved reserves for Gorgon. Platenkamp subsequently asked then-Group Reserves Coordinator Remco Aalbers to look into this issue. Aalbers did so and learned that two of the license partners had not booked Gorgon. Platenkamp has stated that when he learned this information, he relayed it to the EP Director of Strategy and Planning and New Business Development, and, probably, the Regional Business Director for

Australasia, – both members of ExCom.[8] There is, however, no evidence of any EP ExCom members' reaction to the information.

Had Gorgon been de-booked in any of the years 1998-2002, the effect on RRR would have been as follows:

Year	RRR Reported	RRR if Gorgon de-booked
1998	182%	140%
1999	56%	14%
2000	69%	28%
2001	74%	33%
2002	117%	79%

Thus, a retrospective review and de-booking of existing reserves bookings for Gorgon would have materially impaired RRR.

At the same January 2000 meeting of EP ExCom, slides were presented regarding the EP business plan for 2000. The Note accompanying the presentation also proposed an RRR of 37% for the year 1999. While first-hand accounts of the meeting vary, it became known within EP that Watts had an extremely negative reaction to the presentation. This incident was cited by several individuals in EP as contributing to the widely-held perception that bad news on reserves was not welcomed and that the messenger carrying bad news could expect a harsh reception.

E. SEC Publishes Written Guidance

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On June 30, 2000, the SEC supplied interpretive guidance with respect to its definition of "proved reserves." This was the SEC's first written guidance on this subject since it had first

[8] E-mail from Platenkamp to Davis Polk, Mar. 26, 2004. The EP Head of Strategy and Planning has reported no recollection of either an EP ExCom request for information from the Gorgon participants or his receipt of such information. He has stated, however, that the subject of competitors' proved reserves determinations was often raised at EP ExCom meetings, and that it would not be surprising if the subject had been raised as to the Gorgon participants at the January 31, 2000 meeting. The Regional Business Director for Australasia was not asked about this specific topic.

published its proved reserves definition in 1978. (*See* Tab A.) Among other points, the SEC clarified the types of data needed to support proved reserves estimates. The SEC also explained that a commitment to develop the necessary production, treatment and transportation infrastructure was essential to the attribution of proved undeveloped reserves, and noted that significant lack of progress as to any of these factors could be evidence of a lack of such commitment. The SEC's guidance also stated that economic uncertainties such as the lack of a market, especially for gas, could prevent reserves from being classified as proved. On March 31, 2001, the SEC re-issued, with minor additions, the written guidance of June 30, 2000. Both the June 2000 and the March 2001 guidance were posted and available to the public on the SEC's website.

It appears that beginning in 2001, perhaps as a result of the additional SEC guidance, there was a growing recognition within Shell that its past reserves booking practices were not fully aligned with the SEC definitions. The focus of this analysis, however, was a prospective, rather than a retrospective one.

For example, in 2001 the Group Reserves Coordinator and Group Reserves Auditor began to revise the Shell Guidelines to ensure that first-time bookings were in accordance with their updated understanding of the SEC definitions. The Group Reserves Coordinator also gave a presentation to the Regional Business ("RBA") and Regional Finance ("RFA") Advisors to inform them of the changes in SEC guidance. This presentation requested that the RBAs and RFAs contact the Group Reserves Coordinator if a "big ticket" new booking was planned, so as to ensure compliance with the new SEC guidance.[9]

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[9] Reserves Presentation, early 2001; Interview of McKay, Mar. 10, 2004.

Similarly, in his 2001 Audit Report, the Group Reserves Auditor noted the following:

> "[C]urrent Group reserves practice regarding the first time booking of Proved reserves in new fields is in some cases too lenient. The Group guidelines should be reviewed. First time bookings should be aligned closer with SEC Guidance and industry practice and they should be allowed only for firm projects with technical maturity and full economic viability . . . .
>
> . . .
>
> Awareness of Group and SEC reserves booking guidelines was seen to be less than desirable at senior levels in the OUs and in support functions in the centre . . . ." (Emphasis added.)

There was no examination of whether past bookings had to be re-evaluated in light of the new SEC guidance.

The focus on prospective compliance rather than de-booking was consistent with the manner in which EP ExCom had handled the questionable reserves positions that existed in Australia and Nigeria as of 1999 and 2000. Furthermore, during interviews it was reported that there appears to have existed an institutional culture within Shell that generally resisted the review of prior bookings and, more significantly, treated de-booking as a "last resort."[10] As Walter van de Vijver put it when interviewed recently: "Booking is one thing, de-booking is quite a big step."[11]

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[10] *See generally* interview of van de Vijver, Feb. 10, 2004; Interview of Barendregt, Feb. 11, 2004; Interview of Graham, Feb. 12, 2004; Interview of Pay, Feb. 17, 2004; Interview of Frasier, Feb. 20, 2004; Interview of Aalbers, Mar. 12, 2004. In a Presentation dated April 15, 2002 by then-Acting Group Reserves Coordinator Peter van Driel during workshop in Lagos, Nigeria on proved reserves stated that SPDC proved oil reserves were "'under tension' from a Group perspective as they may not be able to be turned into production by licence expiry in 2019 (due to quota restrictions and an inability to deliver programme)." The presentation noted that, absent license extensions, increased production or quota or increased Shell investment in SPDC (thereby increasing the Shell share), a de-booking of about 800 million barrels would be necessary. It described the option of de-booking as a "last resort only" and added that EP ExCom had been advised of the possibility of a de-booking of that amount.

[11] Interview of van de Vijver, Feb. 10, 2004.

F. Change in Management

On July 1, 2001, Watts was elevated to Chairman of CMD and van de Vijver succeeded him as EP-CEO. Almost from the outset, van de Vijver was concerned about the "external promises" regarding EP's future performance given his perception of the state of the business and his concerns that he would be unable to meet the production expectations for EP that Shell had announced to analysts and investors. For example, on August 22, 2001, van de Vijver wrote to Watts regarding production growth, stating:

> "There is no way that I can get back to the 5% growth even in a 100 % success case . . . .
>
> . . .
>
> We can obviously 'over-engineer' all of this and we need to find the external story that can not be translated into technical incompetence . . . .
>
> <u>I believe that we are experiencing 'pay-back time' for our past successes.</u>" (Emphasis added.)

The same day, Watts replied, as follows:

> "You will have to put your Group hat on and ask whether the hard 2% is better than saying 2-3% (which includes 2) for the sake of not having to precipitate a change that could be very damaging for the Group."

In the end, it appears that van de Vijver was persuasive as to the challenges that EP faced in the area of production growth. As of September 2001, the EP business downgraded Shell's previously stated guidance of 5% per annum production growth over five years, to just 3%.[12]

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[12] In February 2003, Shell further changed its production growth forecast from 3% per annum on average over a five year period to a qualified statement that Shell was "capable of" 3% per annum on average.

This was also the first of several issues relating to Shell's "external promises" that was debated between Watts and van de Vijver over the following two years. In addition to general issues concerning Shell's ability to meet its production targets, van de Vijver also specifically expressed concerns that some of Shell's proved reserves of 1997-2001 – the period during which Watts led the EP business – had been "aggressive" or booked "prematurely."[13] Unlike his success in obtaining reductions to EP's production growth forecasts, van de Vijver was not as persuasive as to reserves issues, and there was no significant de-booking of proved reserves or corrective disclosure until 2004. The tensions over this issue were foreshadowed in an e-mail exchange, dated September 21, 2001, between van de Vijver and an investment banker who had previously been employed by Shell and who had written to van de Vijver concerning the production growth forecast change from 5% to 3% that occurred earlier in the month; in response, van de Vijver wrote:

> "Legacies are painful and particularly [t]he handover situations where the previous CEO is still around, think about it!"

III. <u>2002 – Mid-November 2003: Notice of Proved Reserves Exposures</u>

Although earlier documents suggest that the lack of compliance with the SEC definitions may have been a burgeoning issue within Shell, the first irrefutable evidence that Shell executives knew about reserves issues is contained in a document dated February 11, 2002. As of that date, at the latest, Shell senior executives were provided with information that as much as 2.3 billion boe of booked proved reserves were potentially exposed. As is discussed in greater detail below, it is clear that van de Vijver, in particular, understood that at least part of the reason

[13] E-mail from van de Vijver to Watts, Nov. 9, 2003.

for the potential exposure was related to "aggressive bookings" in the past and the related point that those bookings were "no longer fully aligned with the SEC definitions."

Watts, the most senior of the group of executives to whom the February 11, 2002 document was provided and one of the most knowledgeable about the EP business, appreciated that reserves presented a "real issue" in 2002 with implications for Shell's performance measures. In May 2002, for example, Watts told van de Vijver that, in dealing with the reserves issue, van de Vijver should leave "no stone unturned" to find a resolution that would result in an RRR of "more than 100% in 2002."[14]

The documentary record during this period – from 2002 through mid-November 2003 – evidences senior management's response to the issues concerning exposed proved reserves and its lack of concern for the related disclosure implications.

A. February 2002 – Note for Information to CMD

The first document that raised potential reserves compliance issues to the attention of the CMD was a Note for Information for CMD, dated February 11, 2002.[15] This document, entitled "EP Hydrocarbon Resources Update 1/2002," was submitted by van de Vijver and distributed in advance of the February 19, 2002 CMD meeting to all CMD members and to Judith Boynton, the

[14] E-mail from Watts to van de Vijver, May 28, 2002.

[15] The Committee of Managing Directors (CMD) advises the group holding companies that are jointly owned by Shell's parent companies. Each member has specified areas of responsibility. It is currently comprised of the CEOs of each of the major business units: Exploration and Production, Oil Products, Gas and Power and Chemicals. The Group CFO was added as a member of CMD in 2003. Prior to that, the Finance Director attended CMD meetings regularly by invitation.

Shell's "Group Governance Guide" states that decisions by CMD are taken collectively, but given the considerable subject matter expertise of each unit CEO, outside of capital allocation discussions there is little evidence of cross-discipline challenge especially as to decisions regarding more technical issues that were perceived as within the purview and expertise of the individual unit heads.

Group CFO who, while not a CMD member until mid-2003, received CMD notes and attended CMD meetings from the time of her arrival at Shell in 2001.[16]

The February 11, 2002 Note for Information contained a section entitled "Exposures," which stated as follows:

> **"Securities and Exchange Commission (SEC) Alignment**
>
> Recently the SEC issued clarifications that make it apparent that the Group guidelines for booking Proved Reserves are no longer fully aligned with the SEC rules. This may expose some 1,000 mln boe of legacy reserves bookings (*e.g.*, Gorgon, Ormen Lange, Angola and Waddenzee) where potential environmental, political or commercial 'showstoppers' exist.
>
> **End of License**
>
> In Oman PDO, Abu Dhabi and Nigeria SPDC (18% of EP's current production) no further proved reserves can be booked since it is no longer 'reasonably certain' that the proved reserves will be produced within license. The overall exposure should the OU business plans not transpire is 1,300 mln boe. Work has begun to address this important issue." (Emphasis added.)

Thus, the Note warned that legacy proved reserve exposures due to clarifications of the SEC definitions and license issues combined were as high as 2.3 billion boe.

Within two months of this Note being circulated to CMD, Shell filed its 2001 *Annual Report on Form 20-F* with the SEC. No further inquiry was undertaken as to whether the proved reserves estimates stated therein needed to be revised. During interviews with Watts and Boynton, the failure to pursue these "exposures" was explained in the following terms: First,

[16] The members of CMD at the time of this February Note were Phil Watts (Chairman); Walter van de Vijver (EP); Paul Skinner (OP) and Jeroen van der Veer (Chemicals). While CMD member van der Veer does not recall seeing the Note at the time, he surmised in his interview of March 19, 2004 that a discussion of "potential exposures" likely suggested a need for further investigation and potential action by the individual CMD member with responsibility and expertise in the area, in this case van de Vijver. Neither Malcolm Brinded nor Robert Routs received this presentation as they were not yet members of CMD.

these potential exposures were presented in a "Note for Information," which would not ordinarily have received as much attention by CMD as would either a "Note to CMD" or a "Note for Discussion"[17]; Second, and in any event, these potential exposures represented business issues which were being actively managed by EP and the local operating units that reported to EP.[18] During an interview, Watts added that when he saw the potential exposures identified in the February 11, 2002 Note he specifically commissioned van de Vijver to have EP examine these issues and report back to CMD mid-year.[19] With respect to his consideration of the reserves issues at the time he signed the Royal Dutch Petroleum Company *Annual Report on Form 20-F* for 2001, Jeroen van der Veer stated that he relied on the comprehensive system of cascading assurances and certifications, including the certifications that would be given by EP. Van der Veer indicated that he viewed proved reserves disclosures as a technical matter under the control of EP and he relied on EP management to address those issues.[20]

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[17] According to Boynton and Watts, CMD is formally informed of issues through three forms of documents. A "Note to CMD" carries the greatest importance. This form of document is normally accompanied by a formal presentation at the relevant CMD meeting. The next highest level of priority is a "Note for Discussion" which is intended for a discussion at CMD. The lowest level of priority is a "Note for Information." Such a Note is meant to be read by CMD members but is not necessarily intended to form the basis of any CMD discussion. Interview of Boynton, Feb. 21, 2004; Interview of Watts, Feb. 19, 2004.

[18] Interview of Watts, Feb. 19, 2004; Interview of van de Vijver, Feb. 10, 2004; Interview of Boynton, Feb. 26, 2004.

[19] Interview of Watts, Feb. 19, 2004. There is some dispute as to whether the subsequent report on reserves that was prepared and delivered to CMD in July 2002 was undertaken at the insistence of Watts. According to van de Vijver, it was done on his own initiative. Interview of van de Vijver, Feb. 10, 2004.

[20] Interview of van der Veer, Mar. 31, 2004.

B. July 2002 – Note for Discussion to CMD

The reserves issues were explored in greater detail in a July 2002 Note for Discussion to CMD. Before this mid-year report to CMD was to be made, Watts e-mailed van de Vijver on May 28, 2002 and stated:

> "You will be bringing the issue [of reserve replacement] to CMD shortly. I do hope that this review will include consideration of all ways and means of achieving <u>more than 100% in 2002</u> . . . considering the whole spectrum of possibilities and <u>leaving no stone unturned.</u>" (Emphasis added.)

The next day, van de Vijver wrote the following reply e-mail to Watts:

> "You will appreciate that this has my highest attention:
>
> – <u>remaining legacy proved reserves (de-booking risks)</u>
> – constraints on further appreciation
> – <u>negative impact of Oman and Nigeria growth absence (losing volumes to post license [sic] expiry dates)</u>
> – hit squads to find other growth opportunities on bookings
> – impact of FID's.[21]" (Emphasis added.)

Several hours later, on May 29, 2002, Watts responded to a separate e-mail by van de Vijver which sought "clarification on the final storyline on the investment for EP for 2003," and expressed "worry about consistency and credibility of storyline both internally and externally." Watts advised van de Vijver as follows: "[N]o new signals may be given to the external market. I trust that this is now clear. If not, please have a discussion with me."[22]

The July 2002 Note for Discussion to CMD was entitled "Reserves Outlook" and was presented to CMD on July 22, 2002 by the EP Director of Strategy and Planning and New Business Development, Lorin Brass. In attendance at this CMD meeting were Watts, van de

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[21] E-mail from van de Vijver to Watts, May 29, 2002.

[22] E-mail from Watts to van de Vijver, May 29, 2002.

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Vijver, van der Veer, Malcolm Brinded and Boynton. Although Paul Skinner received the Note, he was not present for the discussion at the CMD meeting.

While this Note was described as a "comprehensive note" on the reserves position in EP, it failed to address the SEC compliance questions that had been expressly raised in the February 11, 2002 Note for Information. Nor did the July 2002 Note address the SEC's proved reserve definitions or its central requirement of "reasonable certainty." Instead, the Note described a plan for "managing" the reserves issue commercially through the acceleration of bookings that would be certain in future years but which were less than certain in 2002. "Managing" the reserves would also involve acceleration of the maturity of some projects that had been prematurely booked, negotiation of license extensions and strategic acquisition activity.

In a section entitled "Historical Context," the July 2002 Note stated:

> "With the benefit of hindsight, some of the organic revisions made in recent years now appear somewhat aggressive: principally Australia (Gorgon, struggling to reach maturity) and SPDC (bookings continued on the back of expected production growth that has still to materialize, contributing to a bow-wave problem in the remainder of the licence.)" (Emphasis added.)

In an attachment to the July 2002 Note, van de Vijver and his EP team included a list of operating units that had potential reserves exposures, entitled "Hydrocarbon Resource Challenges by OU," which identified potential exposures in Nigeria[23] ("Oil production must increase by 70% . . . in order to produce the currently booked Proved Oil Reserves (2500 MMboe)"); Australia ("Gorgon stranded gas (560 MMboe Proved Reserves booked), possible

[23] Nigeria was also the subject of a Note to CMD entitled "Nigeria Country Review Update," which was presented to CMD at an earlier meeting on June 5, 2002. In that Note, CMD was informed that "SPDC proved oil reserves are potentially exposed" and that a "moratorium" had been imposed to address these potential exposures ("As a protective move, EP decided to freeze the level of reserves in 2000."). (*See* Tab F.)

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barriers to commercialization of much of the SFR portfolio"); and Oman ("Challenge to yield target production rates and hence reserves delivery.")[24]

In a section headed "External Storyline," the July 2002 Note remarked that although Shell had not promised a specific RRR to the market, the market had implied that, if Shell's reserves life was to remain intact while Shell achieves its stated 3% production growth target, a RRR of 140% p.a. would be required. The document notes, however, that RRR in actuality was likely to be approximately half the 140% figure on average over the plan period.

The minutes of the July 22/23, 2002 CMD meeting recognized that this proposed "management" plan could not succeed long-term without successful maturation of projects and production increases:

> "With regard to when reserves could be booked, it was noted that the SEC was tightening its requirements in this area. It is considered unlikely that potential over-bookings would need to be de-booked in the short-term, <u>but reserves that are exposed to project risk or licence expiry cannot remain on the books indefinitely if little progress is made to convert them to production in a timely manner</u>." (Emphasis added.)

Indeed, in light of the production challenges that existed in some of the regions with exposed reserves – such as Oman and Nigeria – it would have been very unlikely that reserves issues could be timely "managed" through production growth. Both Watts and van de Vijver were well aware of the operational struggles that existed in these countries. With respect to

[24] The minutes from the July 22/23 2002 CMD meeting also noted the observation that "any reserves booked had to be approved by the Group Controller" and that these "also had to pass both an internal and external audit check." In fact, however, there was no audit process outside of EP for proved reserves, with the exception of the Group Deputy Controller, whose involvement was limited to receipt of a year-end report and participation in an annual meeting to discuss that report. Furthermore, the internal reserves audit function at Shell consisted of a retired Shell employee working on a 90 days per year contract who visited major properties only once every four years. (*See* Tab D.) Finally, the minutes of this CMD meeting recorded that: "It was also recognised that some booking practices had been too aggressive in the past." Extract from the Minutes of a Meeting of the Committee of Managing Directors, CMD No. 2526, 22/23 July, 2002, at 23.

Nigeria, Watts had served as Managing Director of SPDC in the early 1990s, and was thus familiar with the unique operational constraints it faced. Also, for example, van de Vijver had made several trips to Nigeria in recent years during SPDC's continued failure to reach production targets. There is evidence that van de Vijver shared information about these trips and about other experiences in Nigeria with Watts.

With respect to Oman, it is clear that various members of management in EP, including Van de Vijver were aware of the production problems at PDO – the Shell-Omani government joint venure – as early as late 2001. During this period, production challenges increased and Shell agreed to make a $30 million "down payment" (in the form of a deduction against its 2001 net reward) in partial payment for an inchoate de-booking of expectation reserves. Van de Vijver was personally involved in arriving at this agreement.

Notwithstanding his knowledge of the production set-backs in these countries, Watts stated in his recent interview that he viewed the July 22, 2002 CMD Note as comprehensive and was reassured that the exposures were being "managed" and that no adjustments were deemed necessary for the foreseeable future.[25] Boynton described the Note as a "transparent paper" which indicated to her that the EP organization was dealing with issues.[26] Brinded, who had just become a member of CMD in July 2002, did not recall the presentation.[27] Van der Veer did not recall any discussion at this meeting concerning the propriety of any bookings, but recalled that

[25] Interview of Watts, Feb. 10, 2004.

[26] Interview of Boynton, Feb. 21, 2004.

[27] Interview of Brinded, Feb. 25, 2004.

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van de Vijver focused the discussions on RRR as part of an effort to get CMD to devote even more capital resources to EP.[28]

C. *September 2002 – "Caught in the Box" – "EP Delivery Note"*

A few months after the July 22, 2002 CMD meeting, van de Vijver personally prepared a document he captioned "EP Delivery" Note addressed "To: CMD, Cc: Judy Boynton."[29] It described the "dilemma's [sic] facing EP and the uncomfortable situation EP was in with obvious implications for the Group overall."[30]

When he wrote this document, van de Vijver was preparing his 2003 business plan and seeking ways to ensure that EP would achieve its targets.[31] Van de Vijver intended this document to provide a framework for CMD's discussion, during the business planning process, about some of the main challenges facing EP in the coming year. According to Watts, the issues raised in the EP Delivery Note were discussed during a CMD "away day" in September 2002.[32]

In the EP Delivery Note, van de Vijver described EP as being "caught in the box" and stated the following:

> "Given the external visibility of our issues (lean organic development portfolio funnel, RRR low, F&D unit costs rising), <u>the market can only be "fooled" if</u> 1) credibility of the company is high, 2) medium and long- term portfolio refreshment is real and/or 3) positive trends can be shown on key indictors.

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[28] Interview of van der Veer, Mar. 19, 2004.

[29] At this time, Watts, van de Vijver, Brinded, Skinner, and van der Veer were members of CMD. Although the document is undated, it appears to have been created around September 2, 2002.

[30] E-mail from van de Vijver to Watts, attaching "EP Delivery" document and stating that the attached note is for "planned further discussion at CMD this month", Sep. 2, 2002; Interview of van de Vijver, Feb. 10, 2004.

[31] Interview of Watts, Feb. 19, 2004.

[32] Interview of Watts, Feb. 18, 2004.

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Unfortunately . . . [w]e are struggling on all key criteria ("caught in the box").

Evolving facts
Through a combination of external and internal factors several performance issues have emerged on our EP portfolio:

. . .

– Premature promises to external market (Sakhalin, Brasil DW, FLNG realise the limit, etc.)

. . .

So where do we go from here?

. . .

The immediate risk that we are facing is on the 'negative spiral' of our boxed situation:
– 15% ROACE with 3% production growth unachievable in 2002-2004 timeframe with original $7-8 billion plan-average investment level
– RRR remains below 100% mainly due to aggressive booking in 1997-2000." (Emphasis added.)

In a graphic that was attached to a "Note to File" prepared by van de Vijver around that same time (see below in Section III. E.), he attempted to explain "EP's caught in the box" problem, as well as the "thinking/behavior that led to external promises made." As to the cause of the described dilemma, van de Vijver blamed the "caught in the box" problem on (i) an "unchallenged EP CEC [Watts] campaign to make everything look as good as possible (1999/2001)", (ii) "fear of challenge culture" and (iii) "aggressive/premature reserves bookings (topdown instructions)."

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When asked to explain his references in the EP Delivery Note to the market being "fooled" and to "aggressive booking in 1997-2000," van de Vijver stated that during this time he was trying to ensure that the real condition of the business was understood. He also stated that, in his view, the EP Delivery Note is evidence that he had been working on reserves issues in a manner that was "transparent" to CMD.[33] According to Watts and Boynton, both of whom saw the EP Delivery Note in September 2002, this document did not alarm them because they believed it merely reflected van de Vijver's struggle to deal with his business plan and manage the trade-offs between profitability and growth, hence the phrase "caught in the box."[34]

Brinded recalled the "caught in the box" discussion by van de Vijver as focused on production growth and unit costs reduction.[35] Similarly, Jeroen van der Veer recalled the "caught in the box" phrase as being employed in connection with van de Vijver's continuous efforts to extract more funding for EP projects, at the expense of other business units such as Chemicals and Oil Products. Van der Veer also stated that he did not get the impression that van de Vijver was concerned about any deception of the market.[36]

It appears that the issues raised before CMD by van de Vijver in the EP Delivery Note concerning the various challenges facing the EP business were also the subject of private discussion between van de Vijver and Watts. In that setting, van de Vijver had expressed frustration that, although he was moving to FID on major projects, he was unable to book reserves for those projects because they had already been booked during Watts' tenure as CEO of EP. Specifically, van de Vijver noted his inability to take personal credit for successes such as Angola Block 18.

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[33] Interview of van de Vijver, Feb. 10, 2004.

[34] Interview of Watts, Feb. 18, 19, 2004; Interview of Boynton, Feb. 21, 26, 2004.

[35] Interview of Brinded, Feb. 25, 2004.

[36] Interview of van der Veer, Mar. 19, 2004.

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D. October 2002 –"If I was interpreting the disclosure requirements literally (Sorbanes [sic] – Oxley Act etc), we would have a real problem"

In mid-October 2002, not long after the September CMD "away day" during which van de Vijver's EP Delivery Note was discussed, van de Vijver and Watts had dinner together. Both Watts and van de Vijver recalled discussing various issues, including many of the points raised in the EP Delivery Note.[37] In response to van de Vijver's complaints about legacy reserves issues, Watts told him that, as with every position, there are good and bad inheritances. Watts also tried to "counsel" van de Vijver that if van de Vijver was in his position long enough, van de Vijver would have a legacy of his own making, good or bad, to pass down to his successor.[38]

About one week after their dinner meeting, on October 21, 2002, Watts sent van de Vivjer the following e-mail message:

> "I enjoyed our conversation over dinner last Monday and have reflected over this weekend on the EP part of the Group Plan.
>
> You have a real challenge but that is not unusual.
>
> A few points, if I may, on the "box" in which you talk of being trapped.
>
> . . .
>
> 2. Reserves
> - We have a real issue but the Enterprise acquisition allows us to keep to the 100% replacement ratio averaged over, say, 3 years.
>
> . . .
>
> 4. ROACE
> - I think that this is the key vulnerability. . . ." (Emphasis added.)

---

[37] Interview of Watts, Feb 18, 19, 2004, Feb. 19, 2004; Interview of van de Vivjer, Feb. 26, 2004.

[38] Interview of Watts, Feb. 19, 2004.

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On the following day – and just a week after a presentation was made to CMD concerning the recently enacted Sarbanes-Oxley legislation, van de Vijver e-mailed Watts and said:

> "Thanks for your note . . .. I am currently in Oman dealing with another legacy problem and will fly back to London for meetings on [T]hursday. I will see whether we can [then] have a brief chat.
>
> I must admit that I [have] become sick and tired about arguing about the hard facts and also can not perform miracles given where we are today. If I was interpreting the disclosure requirements literally (Sorbanes [sic] - Oxley Act etc) we would have a real problem."[39] (Emphasis added.)

Watts did not recall ever having seen this e-mail. When asked about language used by van de Vijver in this and other documents, such as "fooling the market" and "reserves manipulation," Watts was dismissive, suggesting that van de Vijver was often intemperate and any such language reflected van de Vijver's frustration with some of the business challenges he faced as the leader of the EP business.[40]

E. Fall 2002 – Finalization of EP's 2002 Business Plan

As the 2002 EP business plan was put into final form during the latter part of 2002, van de Vijver expressed his concerns about "external promises" that had been made by Shell in the past and that continued to be made about the state of the EP business and reserves. For example, on November 15, 2002 van de Vijver e-mailed the EP Director of Strategy and Planning and New Business Development, Lorin Brass, and the EP CFO, Frank Coopman, and said:

[39] In his interview of Feb. 10, 2004, van de Vijver explained that there were gray areas with respect to possible disconnects between external messages and the hard facts. Further, van de Vijver denied familiarity with the Sarbanes-Oxley Act. CMD, however, received presentations on the Sarbanes-Oxley Act in mid-October 2002, and again in early December 2002. These presentations included a discussion of a new procedure that was implemented to require each business CEO to provide certifications in connection with the Act's requirements.

[40] Interview of Watts, Feb. 18, 2004.

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> "We finalized our plan submission and could easily leave the impression that everything is fine"
>
> . . .
>
> The reality is however that we would not have submitted this plan if we
> (1) were not trying to protect the Group reputation externally (promises made) and
> (2) could have been honest about past failures (business focus w.r.t. aspired portfolio, disconnects with reality, poor performance management, reserves manipulation.)
> The plan is therefore not a 50/50 plan but a real stretch. . . ."
> (Emphasis added.)

Also in late 2002, van de Vijver personally prepared a "strictly confidential" "Note for File," that pulled together his thoughts surrounding the EP business challenges. He began his Note with a discussion of the disconnects between external promises and the reality of the state of the business, especially in light of the "strictest disclosure rules that had been put in place following the various corporate scandals in 2001/2002."

> "Introduction
> During the last 1.5 years the technical competence and overall integrity of the EP business within Shell has been questioned both internally and externally, most prominently through lowering of the production growth target in August/September 2001 and due to a deteriorating proved reserves replacement ratio. Providing credible explanations for these issues proved near impossible given the disconnects between external promises/expectations and the reality of the state of the business.
>
> As the new CEO of the business, which I relish and believe passionately in, this period has been extremely frustrating and uncomfortable, perhaps even more so with the emergence of stricter disclosure rules following the various corporate scandals in 2001/2002.
>
> The initial "due diligence"
> Significant issues emerged during the initial due diligence phase mid 2001, concurrently with the development of the 2002 business plan. . . .
>
> . . .

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> The actual gaps between external promises in Sept. 2001 and reality were significant and created the "EP in the box" storyline internally....
>
> . . .
>
> The deeper understanding
> A full understanding of the gaps between external promises and reality is important to ensure learning for the future.
>
> . . .
>
> Some of the causes are very serious also as the positive external (or even internal) portrayal would lead to a false sense of security and optimism within EP and the Group whilst in reality:
> – Portfolio weaknesses could only be hidden for so long . . .
>
> . . .
>
> Bottomline [sic] was that both reserves replacement and production growth were inflated:
> – Aggressive/premature bookings provided impression of higher growth rate than realistically possible
> - Bottoms-up production forecasts ...... only gave 1-2% aai on production growth compared to 3-5% promises." (Emphasis added.)

With this preface, van de Vijver detailed his next steps:

> "Where next?
>
> . . .
>
> The 2002 Bushiness [sic] Plan for 2003/2004 contains a significant stretch in order to stay as close as possible to external commitments: . . .
>
> . . .
>
> – Continue 3% production growth, although "watered down" (capable of i.s.o. direct promise) . . .[41]
>
> . . .

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[41] As noted above, in February 2003, Shell changed its production growth forecast from 3% per annum on average over a five-year period to a more qualified statement that Shell was "capable of" 3% per annum on average. When asked what was intended by the qualification "capable of," Shell executives referred to growth limitations outside of Shell's control, such as OPEC restraints, and limitations of Shell's choosing, such as opting not to develop less profitable assets. No mention was made of a large amount of proved reserves that presented maturation challenges.

> – 5-year average RRR to remain above 100% . . .
> As a consequence there is no safety margin in external commitments and a requirement to deliver a plan with POS <<50%."

Significantly, within this internal Note to File, van de Vijver also acknowledged that, while he had flagged issues – including potential reserves exposures for his colleagues - he had done so in a "careful fashion" and, as a result, the "severity and magnitude" of the reserves problem may not have been fully appreciated.

> "Commencing an internal 'witch-hunt' with negative consequences for the Group reputation and requiring tremendous energy that would distract from the improvement drive, is not seen to be productive nor [sic] beneficial for the Group in these uncertain times.
>
> For future reference it was however considered prudent to record the issues and provide the context for the decision as taken.
>
> The concerns around the "caught in the box" dilemma and stretch in the EP business plan have been flagged at the highest level in the company, but obviously "transmitted" in a careful fashion as not to compromise/undermine the previous leadership. The severity and magnitude of the EP legacy issues may therefore not have been fully appreciated." (Emphasis added.)

F. Year-End 2002 – De-bookings Are Considered

At the end of 2002, van de Vijver considered de-booking certain exposed proved reserves. For example, in an e-mail dated December 4, 2002 from van de Vijver to then-Group Reserves Coordinator, John Pay (cc: Pay's superior, Lorin Brass, the EP Director of Strategy and Planning and New Business Development), van de Vijver described a desire to "improve the integrity of our reserves base and achieve full compliance with SEC reporting requirements." In this e-mail, van de Vijver asked Pay and Brass to consider "legacies that were being worked out" and he listed Gorgon, Ormen Lange, non-contracted LNG and Brunei.

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The same day, Pay responded to van de Vijver, providing a list headed "Potential Reserves Exposure Catalogue," and stated that:

> "It would be defensible to leave all bookings intact (refer to comments on each one) with the possible exception of Enterprise."

He also stated:

> "Removing all items from the attached list would reduce . . . (Proved RRR = 50% . . .). <u>I am working on the assumption that this is not something we want to do</u>, but it would have the advantage of removing these issues once and for all. The timing seems opportune."[42] (Emphasis added.)

Ultimately, only a small number of the proved reserves bookings that had been identified in 2002 as exposed were de-booked at the end of that year. That de-booking comprised less than 1% of Shell's total proved reserves as of December 31, 2002, compared with the approximately 20% of December 31, 2002 proved reserves that were recategorized on January 9, 2004.

There are indications that van de Vijver considered the idea of a comprehensive de-booking of all known "exposed" reserves on at least one other occasion. In late November 2003 he stated in a message to the Group Reserves Coordinator, John Pay, "I would prefer to re-state our 1/1/03 reserves and de-book all remaining legacies to allow for a clean start." As discussed below, however (*See* Section III. K, below), during this same time period van de Vijver

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[42] Several months earlier, on September 23, 2002, Pay had been preparing a presentation to EP ExCom concerning proved reserves. On that date, Pay forwarded to his predecessor as Group Reserves Coordinator, Remco Aalbers, a document entitled "Reserves Management Survey" which detailed approximately 800m boe to 1.2m boe proved reserves exposure. Upon forwarding this document, Pay asked Aalbers <u>not</u> to disseminate the document further and instructed him to "delete it from [his] system when [he was] finished with it." The following day, on September 24, 2002, Aalbers responded to Pay and stated:

> "I hope you have not send [sic] this to too many people because I have great difficulty with the list in Appendix B. If anything I would mark it strickly [sic] confidential [and] would not give it out to anyone. If [this] gets in the hands of either the auditors or SEC we could have some real trouble."

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Part 3

continued to emphasize to EP executives the importance of delivering on external promises with respect to RRR.

G. *Year-End 2002 – Reserves Audit*

On January 31, 2003, Anton Barendregt, the Group Reserves Auditor, issued his *Review of Group End-2002 Proved Oil And Gas Reserves Summary Preparation* to various EP ExCom members, as well as to a representative of each of KPMG and PwC. This report noted that despite serious efforts to align Shell's proved reserves with SEC rules and the Group Guidelines, there remained a number of smaller items "that are not (or not fully) supported by the present SEC or Group reserves guidelines." The report added that these items amount to approximately 1% of Shell's proved reserves portfolio. The report also included the caveat that in trying to ascertain whether Nigeria (SPDC) and Oman (PDO) were subject to de-booking risks as a result of license duration constraints, answers to questions had been difficult or impossible to obtain from the local units. The report noted that: "Both SPDC and PDO will be the subject of Proved reserve audits this year."

The Group Reserves Auditor's report concluded with eight recommendations for changes to Shell's proved reserves booking procedures. These recommendations were presented to the Group Audit Committee ("GAC") as part of the external auditors' annual presentation concerning the previous year-end audit, which was delivered on March 4, 2003. The minutes of that meeting reflect the discussion that ensued, as follows:

> "With regard to the oil reserves data, Group Auditors stressed the importance of the work done by the Group Reserves Auditor (a former Shell reservoir engineer) from an external audit perspective. They referred to the recommendations which the Reserves Auditor had made as a result of his work, and these were to be reviewed by the EP ExCom.

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> Group Auditors also noted the increased attention being paid by the SEC to the area of reserves reporting generally. The Group, along with others in the industry, has recently received written enquiries from the SEC in connection with specific issues to which management has responded."

Following the presentation, the GAC requested a follow-up meeting to discuss reserves in greater detail at the next available scheduled meeting of the GAC in July. However, the July Presentation was subsequently postponed until October, 2003. (*See* Section III.J, below.)

H. February 2003 – EP Performance Appraisal

At a mid-February 2003 meeting of the CMD, the EP CFO, Frank Coopman, presented EP's 2002 Business Appraisal in connection with CMD's review of Shell's annual results for 2002. After reviewing a draft of the minutes of this CMD meeting, van de Vijver e-mailed Brass, Pay and Coopman to voice his objection to the inclusion of draft language which characterized the external messages given on reserves replacement as "unduly pessimistic":

> "We know we have been walking a fine line recently on external messages:
>
> - No disclosure on aggressive/premature bookings in the past
>
> . . .
>
> - demonstrating that we apply "SEC type strict guidelines" to SFR [scope for recovery] quoted numbers from exploration
>
> - booking 380 MM boe on Kashagan (it is becoming more clear that we have been more aggressive again on this) to limit further exposure." (Emphasis added.)

Van de Vijver subsequently wrote an e-mail to Watts (which included the forwarded text of his prior e-mail to Brass, Pay and Coopman) complaining about the language included in the draft minutes and noting "all the legacy issues around reserves."

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The minute entry was ultimately revised.[43] However, within two months of the EP CEO's admission in the above-described e-mail to members of his team that Shell was walking a "fine line" with respect to reserves disclosure (and the forwarding of that e-mail to the Shell Group Chairman), Shell submitted its annual report on Form 20-F to the SEC without further inquiry. Watts, van der Veer, and Boynton each signed, for the first time, certifications that the Group's financial reporting was complete and accurate, pursuant to recently enacted Sarbanes-Oxley Act requirements. In addition, van de Vijver signed a Sarbanes-Oxley sub-certification for the EP business, in which he attested that he had:[44]

> "[D]isclosed, or caused to be disclosed . . . all significant deficiencies and material weaknesses in the design or operation of internal controls and procedures for financial reporting which could adversely affect the Group's ability to . . . report financial information required to be disclosed by the Group in the reports that it files with or submits to the SEC . . . [and] any fraud . . . ."

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[43] The revised minute read as follows: "[T]he committee commented, in particular, that the external messages given on reserves replacement could perhaps have been better presented."

[44] During an interview on February 26, 2004, Boynton stated that she placed great reliance on this sub-certification. She added that she also received comfort that the reserves issues were being adequately considered for their potential disclosure implications based on numerous "checks and balances" built into Shell's internal financial reporting process. Among these "checks and balances," Boynton pointed to the following: quarterly meetings between the Group Controller and the business CFOs, thereby giving the Group Controller exposure to their reporting issues; participation by regional CEOs in an annual CMD meeting for the purpose of raising significant reporting issues; and the regular year-end due diligence process, which included a review of the financials by the external auditors (handled by Boynton), the preparation of representation letters (handled by the Group Controller), and a wrap-up presentation by the external auditors to the CMD. Finally, Boynton stated that she also took comfort in Shell's Group-wide assurance process, which she claimed was taken very seriously by management. In apparent reliance on this process, Boynton did not recall affirmatively following-up on the potential reserve exposures that were the subject of presentations and e-mails on which she was copied.

With respect to his consideration of the reserves issues at the time he signed the Royal Dutch Petroleum Company Annual Report on Form 20-F for 2002 and accompanying Sarbanes-Oxley certification, van der Veer relied, as he had done previously, on the comprehensive system of cascading assurances and certifications, including the certifications that would be given by EP. Van der Veer indicated that he viewed proved reserves disclosures as a technical matter under the control of EP and he relied on EP management to address those issues.

I. ***July/August 2003 – Reports to CMD***

On July 22, 2003, a Note for Discussion entitled *EP Reserves Outlook* was presented to CMD; the Note was sponsored by van de Vijver.[45] The cover memorandum attached to the Note stated as follows:

> "The issue of RRR is receiving a very high level of attention. Given the external profile we should not disclose the very confidential information contained in the note."

This Note, like the earlier July 2002 Note, discussed Shell's reserves outlook largely from an operational and market reaction perspective, rather than in the context of SEC compliance issues. A section captioned "Opportunities to Improve 2003 Performance" contained a one-paragraph summary of each of Nigeria (SPDC) and Oman (PDO) and stated that although there were de-booking risks with each area, such de-bookings could be avoided or mitigated. This section added that a potential "upside" or "net increase" was present in each country. The Note included the following discussion:

> "The Potential Reserves Exposure Catalogue has been updated (Appendix C). <u>Of the Group's 19350 million boe proved reserves, some 1040 million boe (5%) is currently considered to be potentially at risk.</u> . . .
>
> . . .
>
> <u>Gorgon remains the largest single potential exposure (560 million boe)</u>." (Emphasis added.)

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In reference to this observation, however, the Note made the following recommendation to CMD: "At this stage, no action in relation to entries in the Catalogue is recommended."

In addition, the Note informed CMD that a potential offset existed to address the issues raised in the potential exposures catalogue. This could be achieved, according to EP, by revising

[45] Present at the meeting were Watts, van der Veer, Skinner, van de Vijver, Brinded, Boynton, and Routs.

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Shell's booking practices with respect to reserves consumed as "fuel and flare," which could yield, it was estimated, a 1 billion boe reserves addition or offset:

> "It should be noted that the total potential exposure listed in Appendix C is broadly offset by the potential to include gas fuel and flare volumes in external reserves disclosures . . . .
>
> The potential addition has yet to be precisely quantified, but it is expected to be in the order of 1 billion boe and therefore on a scale that would make its inclusion an attractive option to offset any action that is taken with respect to the Potential Reserves Exposure Catalogue. . . ." (Emphasis added.)

Watts, van der Veer, and Boynton all assert that they were reassured about the reserves exposure given the fuel and flare discussion. Boynton further stated that this presentation underscored her sense that EP management team was closely tracking and managing the issue concerning reserves.

J. Fall of 2003 – The "August Paper" for GAC/CMD

On August 26, 2003, a briefing paper that was to be submitted to GAC in October was submitted for information to CMD by van de Vijver. This "August Paper" referred to the year-end 2002 report of the Group Reserves Auditor (Barendregt); noted that all of Barendregt's recommendations for changes to Shell's reserve booking procedures had been accepted; discussed the ongoing SEC correspondence (regarding, principally, lowest known hydrocarbon issues ("LKH")); and mentioned the requirements of the Sarbanes-Oxley Act regarding increased disclosure compliance. It also included a section entitled "Possible areas of non-compliance with SEC regulations," which referred to reserves booked without FID, lack of sufficient drilled wells to prove all the barrels booked for certain fields, and the need to use actual year-end prices and

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not internal reference prices for determining proved reserves subject to production sharing contracts.[46]

However, the August Paper concluded that:

> "Much if not all, of the potential exposure arising from interpretation of the factors listed above is offset by Shell's practice of not disclosing reserves in relation to gas production that is consumed on site as fuel or (incidental) flaring and venting."

The suggestion that the amount of fuel and flare offset was enough to cover listed exposures was based entirely on a rough estimate prepared by the Group Reserves Coordinator (Pay) on the basis of a competitor's fuel and flare figures.[47] Indeed, in the Cover Memorandum to the August Paper, van de Vijver specifically noted that before the Note was presented to the GAC in October, "we would get to the bottom of the fuel and flare issue."

By October 20, 2003, when a Note for Information entitled *2003 Reserves Replacement Status at October 2003* was submitted to EP ExCom, the potential offset for fuel and flare had been reduced from 1 billion boe to approximately 300 million boe:

> "The fuel and flare increment is much lower than had been expected based on ExxonMobil and ConocoPhillips figures, which indicate that some 10% of their wellhead gas production is consumed in this manner. The corresponding fraction for the

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[46] Attachment 3, Appendix C of the August Paper listed the number of barrels exposed to the various risks and provided comments regarding certain of the individual fields. The comments made with respect to all of the fields are similar to the July 2003 Note to CMD, were brief, and did not directly address SEC compliance For example, the comment relating to Gorgon consisted of the following:

> "Booked in 1997 in anticipation of imminent FID, subsequently deferred indefinitely by the downturn in Asian economies and the consequent reduction in demand for LNG. It is inevitable that a resource of this magnitude will be developed eventually."

[47] Despite her avowed reassurance from the July 2003 presentation to CMD for the proposition that the potential reserves exposure presented no reporting risks, Boynton's handwritten notes on her personal copy of the August Paper stated: "'potential exposure' some look like they should be de-booked."

> Group is only 3 – 4%. The reasons for this difference are not yet understood."

In addition to discussing the reduced estimate for the fuel and flare offset, this Note to EP ExCom also referred to the Group Reserves Auditor's review of Nigeria and his determination that "some extreme exposures might need to be de-booked in 2003," which "could pose a serious threat to the Group's reserves replacement."[48] Coopman, the EP CFO was in attendance at this October 20, 2003 meeting of EP ExCom.

The following day, Coopman made a presentation to the GAC on proved reserves based on the August Paper, which was submitted to the GAC in its original form (i.e., not updated). The presentation to GAC omitted two critical pieces of information regarding proved reserves that had been shared with EP ExCom the day before, namely, the Reserve Audit of Nigeria and the reduction of the offset that could reasonably be expected from fuel and flare.

With respect to the first omission, there was no disclosure to the GAC that on September 30, 2003, an "unsatisfactory" reserves processes audit report with respect to SPDC had been delivered to EP ExCom by the Group Reserves Auditor (Barendregt).[49] Most notably, this audit report stated: "[T]here can be no doubt that the portfolio of proved oil reserves per 1.1.2003 has been overstated due to insufficient maturity in the underlying future projects." The presentation also failed to mention that an internal team had been instructed to review SPDC and determine the amount of reserves at risk of de-booking.

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[48] In addition, in Oman, 233 million boe of proved reserves write-downs and exposures were identified based on a failure to achieve technical maturity in those projects. However, license extensions, viewed as relatively certain, could offset the potential de-booking amount from Oman. Finally, a de-booking of 260 million boe due to the SEC's ongoing enquiry concerning LKH was also contemplated.

[49] Proved Reserves Process Audit – SPDC (Nigeria), September 18–19 2003 from the GRA to the EP CFO, the EP Head of Strategy and the Managing Director of SPDC with copies to various SPDC, EP Regional and EP Central personnel, EP's internal auditor and a representative of each of the external auditors.

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With regard to the second omission, Coopman, the EP CFO, did not disclose that the previously estimated 1 billion boe offset for fuel and flare was no longer valid, even though the day before ExCom – during a meeting he had attended – had been informed that 300 million boe was a more accurate estimate of that offset. As a result of this omission, the GAC was only presented with the August Paper, which stated that the fuel and flare offset was of an amount sufficient to offset "much, if not all, of the potential exposure arising from interpretation of the factors listed above." The factors listed above included the potential need for FID before a proved reserve could be booked, post-license entitlements, production sharing contract rules, and other factors which, in fact, accounted for more than 1 billion boe of the January 9, 2004 recategorization.

Putting aside the issue of the quantity of the fuel and flare offset, there is a question as to whether, given its cost implication, taking an offset for fuel and flare would have ever been an acceptable strategy for EP in any event. Had EP claimed the fuel and flare offset, the cost of each barrel of oil/gas utilized in this process would have been added to the cost of each barrel Shell produced, a sensitive key performance indicator ("kpi") for EP and one as to which it had already suffered in comparison to its competitors. Had 1 billion boe of fuel and flare been included in reserves in order to mitigate the reserves exposure, there would have been a considerable effect on this market sensitive measure. Boynton stated in a recent interview that she did not think that EP considered an offset for fuel and flare to be a viable opportunity given its attendant costs.[50]

[50] Interview of Boynton, Mar. 26, 2004.

K. *November 2003 – "Sick and Tired About Lying About the Extent of Our Reserves Issues"*

In parallel to the foregoing, van de Vijver maintained a focus on Group performance metrics, including RRR. In an e-mail to a colleague on November 8, 2003, van de Vijver acknowledged the importance of RRR to the external market:

> "As you know 2003 RRR is the most important share price 'influencer' also as their expectations are high and they do not know that we are still paying for aggressive reserves bookings (including on thos [sic] that have not reached FID yet!) in the past!"

Van de Vijver's views on the importance of RRR to the external market were reiterated in a November 11, 2003 message on planning goals that he delivered to all senior EP executives. The message included the following statement: "One final word on 2003. It would be an enormous blow to the Group's credibility with the Market if we do not deliver on RRR this year."

During van de Vijver's mid-year performance review, Watts made reference to the SEC's ongoing inquiry into Shell's compliance with the SEC's proved reserve rules regarding not booking proved reserves below the LKH. Van de Vijver took exception to a perceived implication by Watts that the LKH issue was to be found in the Gulf of Mexico only, for which van de Vijver had been responsible in his previous position.[51] In an e-mail dated November 9, 2003, van de Vijver wrote to Watts:

> "Reference our discussion on reserves on [M]onday [sic] 3/11, please find attached the summary on LKH. The issue of LKH is

[51] The comments surrounding van de Vijver's mid-year appraisal process included an exercise of blame-shifting for EP's reserve problems between Watts and van de Vijver. On August 25, 2003, van de Vijver directed a draft of his "mid-year 2003 Review Summary" to Watts, complaining that "the single largest issue facing EP is the shrinking opportunity portfolio exacerbated by . . . aggressive reserve bookings in the past."

> not just a US issue (perhaps you were implying something there?)."

He added:

> "I am becoming sick and tired about lying about the extent of our reserves issues and the downward revisions that need to be done because of far too aggressive/optimistic bookings in the past, aside from the embarrassment of having booked reserves prematurely." (Emphasis added.)[52]

Upon his receipt of the November 9, 2003 "lying" e-mail, Watts did not share this document with anyone for at least six weeks.[53]

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[52] Recently, in a letter to members of CMD and Conference dated March 22, 2004, van de Vijver provided an explanation of his reference to "lying" in the foregoing e-mail as follows:

> "I was not suggesting, and did not believe, that the Company had been intentionally misrepresenting its reserves. Rather, my comment was an outburst of frustration with the Chairman for what I perceived as a personal attack. I had been working hard on the reserves issue since 2002, leading the charge on evaluating, and communicating about, the potential problems and had taken care to be professional in sticking to the facts and not laying blame on the Chairman for the booking problems. However, in my 2003 mid-year review, the Chairman made what I perceived to be an insinuation that I was responsible for the LKH issue in the Gulf of Mexico. I strongly resented the suggestion, which was unfounded, as the LKH problems were totally unrelated to my tenure in the U.S. In forwarding information to the Chairman supporting my position, I vented my frustration with him."

[53] In an interview, Watts stated that he decided not to respond to van de Vijver immediately because he wanted to "think about what the e-mail meant." Watts also stated that he was quite surprised by the e-mail, that he could not recall van de Vijver invoking the word "lying" before, and that he determined that it would be better to respond to van de Vijver face-to-face. Shortly after receiving the e-mail on November 9, Watts traveled on business and did not return to London until on or around November 18, 2003. It was on that date that van de Vijver reported to CMD that he had received two unsatisfactory audit reports in Nigeria and Oman and that approximately 1 to 2 billion boe of proved reserves were exposed. According to Watts, at that point, it would have been counterproductive to confront van de Vijver about "lying" because the first priority had to be addressing the reserves issues.

IV. Mid-November 2003 – February 5, 2004: Disclosure Becomes Inevitable

In the wake of two unsuccessful reserves audits in Nigeria and Oman in the fall of 2003, a process began which brought to an end the effort to internally manage the proved reserves exposures that ultimately culminated in the January 9, 2004 recategorization announcement.

The process of disclosure became inevitable after a memorandum – entitled "Script for Walter" – analyzing the scope of the reserves recategorization included a summary of advice from Cravath, Swaine & Moore ("Cravath") that there was a legal requirement to disclose without delay any material misstatement of the proved reserves as reported in Shell's 2002 *Annual Report on Form 20-F*. This legal analysis was predicated on an estimate that 2.3 billion boe of proved reserves were non-compliant – roughly the same volume that had been identified as potentially "exposed" nearly two years earlier in the February 11, 2002 CMD Note for Information. Van de Vijver, who regarded the "Script for Walter" as "dynamite," directed that it be destroyed.

Soon after this incident, Project Rockford was initiated in order to ascertain the extent of the required recategorization. Project Rockford was also imbued with controversy. While van de Vijver internally vowed not to succumb to "cover-up stories" that "everything was fine until we learned about stricter guidelines in 2001" or that "the Group only recently discovered . . . the problem in Oman and Nigeria," the external messages disseminated to the market, by van de Vijver and others, identified the recent negative audit results from Nigeria and Oman as the "catalyst" for Project Rockford.[54]

A. The "Script for Walter"

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[54] E-mail from van de Vijver to Pay, Dec. 8, 2008; e-mail from van de Vijver to Coopman, Dec. 18, 2003.

On November 16, 2003, following his receipt of the unsatisfactory audit reports for Oman and Nigeria, respectively, van de Vijver sent an e-mail to Judith Boynton in advance of a meeting of the CMD. The e-mail stated:

> "Some early warning. . .
> We now have two unsatisfactory reserves audits to deal with. . .
> Both countries have had the following:
> . . .
> history of aggressive reserves bookings 'stimulated' by reserves fees in our NIAT contract . . .
> - lack of technical staffwork (no quality reserves maturation plans) [and]
> - countries not delivering on production promises and hence reserves defered [sic] until after license expiry date
> All highly embarrassing for a company that is supposed to be conservative!"

At the conclusion of a CMD meeting on November 18, 2003, van de Vijver reported news of the Oman and Nigeria audits and stated that EP was looking into the issues. Thereafter, van de Vijver instructed a team within EP to begin working on these issues, and he asked that a report of findings be prepared in advance of the next CMD and Conference meetings that were scheduled to be held on or around December 2 and 3, 2003, respectively.[55] Van de Vijver's team, led by the EP CFO, Frank Coopman, worked intensively from approximately November 25 through November 30 in order to prepare an analysis of the developing reserves situation. Their work product came to be known as the "five-day report."

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[55] Board members of Royal Dutch, STT, and the Group Holding Companies meet regularly in Conference. The purpose of Conference is to receive information from members of CMD and other senior Group executives about major developments, and to review Group strategy, organization, plans, and performance, as well as risks and the system of internal control. The Conference is not a decision-making body. Rather, the boards of the Parent Companies and Group Holding Companies meet separately after the Conference in order to make any decisions they consider appropriate.

At one point, one of the team members, the Corporate Secretary of Royal Dutch Petroleum Company, sought the advice of Shell's regular outside counsel, Cravath, in connection with some of the work he had been asked to perform regarding disclosure issues. The Corporate Secretary summarized the legal advice he received within a section of the three-page "Script for Walter," as follows:

> "If and from the time onwards that it is accepted or acknowledged by the management of the issuers (Royal Dutch and STT) that, when applying the SEC rules, the 2002 proved reserves as reported in the Form 20-F are materially wrong, the issuers are under a legal obligation to disclose that information to all investors at the same time and without delay. Not to disclose it would constitute a violation of US Securities law and the multiple listing requirements. . . ."

The "Script for Walter" noted that Oman and Nigeria reserves were overstated by 1.3 billion boe and that LKH compliance would require an additional 300 million boe de-booking. It also noted that approximately 757 million boe of the reserves disclosed in the *2002 Annual Report on Form 20-F* (including Gorgon), which formerly had complied with the Shell Guidelines when booked, now were "possibly at odds with the strictest possible interpretation of the SEC guidelines." The Script observed that a decision had been made not to de-book these exposed reserves in the past because, in the aggregate, they were thought to be "immaterial in relation to our total proved reserves position." This document therefore confirms that the decision not to de-book Gorgon was based on a "materiality" judgment made by Shell, as opposed to a principled, albeit erroneous, decision that Gorgon satisfied "proved" reserve criteria.[56]

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[56] Materiality here was measured in terms of Shell's overall proved reserve numbers and it does not address the fact that RRR is itself a kpi. As demonstrated by the table above at Section I D., had Gorgon been de-booked it

(...continued)

In addition, the Script re-confirmed that EP's previous speculation concerning a 1 billion boe offset for fuel and flare had been overstated and that, in fact, only 300 million boe, at most, could be used as an offset for any de-booking. The Script further acknowledged that, given the "detailed work" that would be required to understand the impact on the financial statements from booking fuel and flare reserves, such an offset was not recommended on apparent referral to the cost implications described above. Finally, in a section captioned "IR issues," the Script noted that any announcement of "restating or de-booking the reserves will be a significant negative IR event."

The "Script" was e-mailed by EP CFO Coopman to van de Vijver and Boynton on the morning of December 2, 2002. In advance of a CMD meeting scheduled for that day, Boynton read the Script and reacted immediately, e-mailing van de Vijver as follows:

> "Neither the Group Controller nor I were consulted about the script before it was written or sent. Frank was out of bounds in documenting views without full consultation. This is a very serious matter . . . ."[57]

Shortly after receiving Boynton's e-mail expressing her concerns with the "Script," van de Vijver wrote back to Boynton:

> "I will investigate. Indeed this whole issue is extremely serious and I had concluded from my numerous discussions with Frank (and your separate discussions) that Frank knew he was expected to do the staffwork and create options, ie not come up with a firm recommendation. Indeed the full consultation needs to happen

(continued...)

would have had a "material" effect on RRR, regardless of how many "stones were turned" and would have effectively precluded the 100% RRR expected the market.

[57] Boynton stated in an interview that the information contained in the Script was new to her and had to be verified before presenting to the Conference, and that Coopman should have merely prepared the information for a broader group to analyze.

> with all key stakeholders and I was assured by Frank that he knew what was expected from him."

Approximately one hour later, van de Vijver e-mailed Coopman directly:

> "This is absolute dynamite, not at all what I expected and needs to be destroyed!
>
> We are only at this stage flagging issues and creating options, not making a firm recommendation. You well know that I have not accepted the latest audit reports and need far more answers before coming to a recommendation (given the Group impact this needs formal sign-off by CMD, GAC, etc). I have been absolute [sic] clear on this at numerous occasions."[58]

Coopman did not destroy the document. Van de Vijver's e-mail suggesting that the Script be destroyed was brought to the attention of internal Shell lawyers who promptly issued a document preservation notice and retention instructions. The electronic version of the "Script" sent by Coopman to van de Vijver was deleted from van de Vijver's computer's in-box.[59]

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[58] During an interview, when asked why he had given this instruction to destroy the "Script," van de Vijver stated that he believed Coopman's offer represented incomplete staff work and that it had reached conclusions prematurely. In his March 22, 2004 letter to CMD and Conference, van de Vijver also gave an explanation for his instruction to destroy the Script:

> "At the end of November 2003, I asked Frank Coopman to prepare a status report based on the then-existing non-final data. Upon receiving Coopman's report in early December, I considered the report to be incomplete and prematurely conclusive, a view with which the Group CFO concurred, as indicated in an email she sent to me. Therefore, by an email dated December 2, 2003, I instructed Coopman to destroy the report. As clearly demonstrated by the remainder of the language in my email and by my prior and subsequent efforts and reports, I was in no way trying to conceal information about the reserves issue, but instead was simply trying to make sure the process was conducted responsibly and included all the technical facts before considering the accounting/disclosure issues. Indeed, nothing was concealed. The first part of the technical analysis had not yet been completed (and was not completed for first review until December 8, 2003)."

[59] Van de Vijvers' outgoing message to Coopman was retained in his computer's out-box without the attachment; thus, the "Script" no longer resided on van de Vijver's computer.

B. Project Rockford and Subsequent Events

After receipt of the "Script" on December 2, 2003, Boynton consulted van der Veer because Watts was traveling on business in Moscow. Van der Veer directed that a team be mobilized to thoroughly investigate the exact nature and magnitude of the reserves recategorization requirement. He also suggested that certain individuals be included on the team based on their expertise. Upon Watts' return from Moscow, van der Veer discussed the situation with Watts, and Watts at that point assumed overall leadership for the review. Van de Vijver and Boynton were appointed to serve as the day-to-day co-heads of the initiative. Given the highly sensitive nature of the issues, the initiative operated in secrecy and was given the codename "Project Rockford."

Throughout December, there was a period of intense activity and review. The team developed a methodology for reviewing the remainder of Shell's portfolio (i.e., besides Nigeria and Oman, which had just been reviewed and received unsatisfactory audits, and the Kashagan field in Kazahkstan, which had been the subject of SEC inquiries). Around this time, Boynton had a discussion with van de Vijver during which van de Vijver told her that it was his "dream scenario" to restate reserves so that he could then rebook those reserves over time, improving EP's performance going forward.[60] Accordingly, Boynton was particularly concerned about confirming the accuracy of the recategorization numbers before dissemination to the market to ensure that the numbers were not distorted by any personal agendas.

[60] Interview of Boynton, March 26, 2004. Because this information was learned after van de Vijver's resignation from Shell, his explanation of this comment could not be ascertained. Subsequent to his resignation, van de Vijver refused to be interviewed in connection with this Report absent certain conditions, which were deemed unacceptable.

During this time period there were also weekly meetings of CMD in which the reserve issues were discussed and analyzed. In connection with this review, there was a discussion at a CMD meeting as to why Gorgon had not been de-booked in 2002. According to Watts, EP CFO Coopman, who was presenting at the time, responded that Gorgon had not been deemed material; but then added that Gorgon had been a "fudge."[61]

By January 8, 2004, the Project Rockford team arrived at recommendations concerning the Group-wide volumes of reserves that required adjustment.[62] On January 9, 2004, Shell announced that it would re-categorize approximately 3.9 billion boe of its reported proved reserves.

During Project Rockford, as the reserves review was ongoing, there appears to have been an effort by van de Vijver to ascribe blame to Watts for the recategorization. For example, on December 18, 2003, van de Vijver e-mailed a colleague:

> "[W]e are heading towards a watershed reputational disaster on Rockford and I do want to stick to some very firm criteria:
> the problem was created in the 90's and foremost in 97-00 and any clean-up must reflect that . . . .
> . . .
> <u>I will not accept cover-up stories that it was OK than [sic] but not OK with the better understanding of SEC rules now and that it took us 2 ½ years to come to the right answer.</u>" (Emphasis added.)

Also, on December 8, 2003, van de Vijver had previously e-mailed his colleagues in EP to state:

> "<u>I still feel uncomfortable with the 'increased tightening of the SEC guidelines' as if the SEC is the reason we have a problem</u>

[61] Interview of Watts, Feb. 19, 2004.

[62] The work of Project Rockford, is in many respects, ongoing as Shell is still in the midst of addressing a series of comments it has received from the SEC concerning its reserves recategorization and, following further reserves recategorizations announced on March 18, 2004, Shell is now working with independent petroleum engineers to further examine its reserves base.

> today! The reality appears to be with us driving for aggressive reserves bookings as far as we could stretch the SEC rules! . . .
>
> . . .
>
> When looking at SPDC and PDO is it really valid to portray that we only recently . . . discovered the problem in Oman and Nigeria? I think we knew much earlier and this was reflected in formal assurance letters/audit reports?" (Emphasis added.)

Finally, on December 18, 2003, van de Vijver expressed the sentiment once again, when he wrote an e-mail to EP CFO, Coopman:

> "I do not want us to fall in the trap that everything was fine until:
>
> - we learned about stricter guidelines in 2001
> - we finally did some more work in 2003
>
> Whilst in reality:
>
> - we had to live with prior year aggressive bookings
> - the engineering logic and ammunition for late [nineties] changes on Oman and Nigeria were very weak[.]" (Emphasis added.)

Despite acknowledgement that the reserves issues were long-standing, the explanations given by van de Vijver during a Press and Analysts Conference on February 5, 2004, incorporated the themes he previously referred to as the "cover stories":

> "There were two events in 2003 that were the catalyst for what we ultimately announced on 9 January. The first was a detailed review in Nigeria . . . . The only area where we last year put a lot of effort in was around Oman . . . .
>
> . . .
>
> The shock outcome of [the Nigeria and Oman] reviews immediately sort of triggered the process to look at the whole globe and make sure that we had a totally consistent approach at everything." (Emphasis added).

Similarly, the statements made by Watts at the same conference need to be scrutinized in the light of the documentary record:

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> "[W]e've always believed that for a global portfolio, in aggregate, Shell has been materially compliant with it's [sic] own and SEC guidelines. We relied on audits and assurances . . . .
>
> . . .
>
> This thing came up late last year, catalytic events coming out of our reviews in Nigeria, also the Middle East. As soon as that came to my attention, it was a matter of all hands on deck, and I remember writing down the words 'get the facts and do the right thing[.]'" (Emphasis added.)

On January 16, 2004, Watts circulated a letter to senior Shell executives, stating:

> "[D]uring the fourth quarter of last year in-depth reserves studies were completed that triggered a broad review of our previously booked proved reserves . . . . Based on those reviews, I believe that individuals concerned worked in good faith to the interpretations in use when the bookings were made, following proper processes, and that there is no evidence of any misconduct."

In an interview, van de Vijver expressed satisfaction with the ultimate disclosures that were made by Shell in its January 9, 2004 announcement.[63]

C. *Other Notable E-mails*

Throughout the 2002-late 2003 period there is considerable evidence to suggest that more junior Shell personnel were also aware of Shell's reluctance to re-examine prior reserves booking decisions and the disconnect between external message and internal assessments of performance capabilities. The evidence that the "tone from the top" permeated the structure of EP includes, among others, the following documents:

- *February 25, 2002.* Jan-Willem Roosch (Acting Reserves Coordinator) e-mails Peter Van Driel: "It is regrettable to observe, that the horse (project developing teams) is put more and more behind the (proved reserves bookkeeping) cart . . . . Report, regardless of substance. The Group needs

[63] Interview of van de Vijver, Feb. 10, 2004

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to book reserves is the same as saying the group needs to report big profits. . . . Very, very dangerous!"

- *March 22, 2002.* Roosch e-mails Stuart Evans (PDO Petroleum Engineering Value Assurance Manager), copying others including Pay: "RRR is now such an important external KPI, that Excom and CMD will always pay a lot of attention to it ('attention' occasionally translating in 'pressure'). . . . The SEC notion, that proved reserves disclosures should only be in relation to projects that are 'reasonably certain' to go ahead was pushed to the background. . . . It is clear to all, that by being 'liberal' with the implementation of guidelines one can prop up the numbers temporarily but there will be a moment where the portfolio (=reality) catches up with us and that is what we see happening now."

- *September 23, 2002.* Pay e-mails Dave Johnson: "Historical reserves bookings that might today appear somewhat aggressive are, nevertheless, water under the bridge. We should not de-book unless and until it is absolutely clear that development will not proceed within a reasonable time frame."

- *November 29, 2002.* Pay e-mails van de Vijver a presentation slide charting Proved RRR from 1990 through 2007 and notes: "Note the cyclicity – it takes a couple of years to raid the larder and several to restock it. It is only fair to warn you that a certain Mr Watts signed off on the 1990 booking, although the skyscraper might be accident, rather than design."

- *July 19, 2003.* Aidan McKay (Major Projects Manager SEPCo) e-mails van de Vijver: "[T]he EP plan data tells the same old story, we struggle to deliver what we said we could deliver last year. . . . EP is not in a terrible performer, [sic] just a terrible place vs external promises."

- *January 3, 2004.* Barendregt e-mails Coopman: "I have added a reference to the internal guidelines. These were, after all, the 'bible' against which I had to carry out my audits in the OUs. On the few occasions in my early years where I signalled a conflict with SEC rules I was called back by Remco [Aalbers] and by the OUs who argued, rightly, that the only rules they should be bound by were

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> the Group guidelines. These are the backbone of our internal controls on reserves. The spear-point of the SEC reserves auditor's control should therefore have been on a correct formulation of the Group guidelines. With hindsight, I should have been more forceful in this respect. It would have been a clear break with all my predecessors and it would probably have cost me my job in those days, but I should have." (Emphasis added as to all the above.)

Perhaps most emblematic of the impediments to de-booking that existed at Shell is the following excerpt from a document meant to "capture the Rockford issues." The document is entitled "Note for Discussion -- Proved Reserves Potential Exposure: Basic Data" and it sets forth both the "official" and "unofficial" reasons for not having de-booked Gorgon:

> "Official: it is certain that a field of this magnitude, CLOSE TO A VERY LARGE AND WELL DEVELOPED LNG MARKET will be developed eventually.
>
> "Unofficial: Debooking would reduce RRR in the year concerned by approximately 40%. During 1997 – 2002, the clear drive was to achieve 100% - RRR for the Group (a target that proved to be very difficult to hit). At least among the technical and coordination community, awareness of the SEC's interpretation of the rules and of the company's obligations for compliance either were not fully appreciated or were considered secondary issues: a view that appeared to have been reinforced by top-down messages. In this atmosphere, the debooking was considered too big to swallow."[64] (Emphasis added.)

Indeed, the "tone from the top" appears to have been that – given the importance to the market of RRR – any significant de-booking was simply "too big to swallow."

* * *

Following an interim report of this investigation to the Group Audit Committee on March 1, 2004, the boards of the Parent Companies requested that Sir Philip Watts and Walter van de

[64] Email from John Bell to John Pay, December 28, 2003.

Vijver tender their resignations; they have done so. As noted in the Executive Summary, deliberations as to the possible retention, discipline or re-assignment of other members of management involved in the foregoing events are continuing pending review of the Report and consideration of its findings by the Group Audit Committee and non-executive members of Conference.

REPORT OF

DAVIS POLK & WARDWELL

TO

THE SHELL GROUP AUDIT COMMITTEE

TAB C:

THE SCORECARD SYSTEM AND ITS IMPACT ON BOOKING RESERVES

MARCH 31, 2004

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The Scorecard System and Its Impact on Booking Reserves

PAGE

The Scorecard System and Its Impact on Booking Reserves

I. The Impact and Perception of RRR in Scorecards

As described in greater detail below, scorecards were introduced throughout the Royal Dutch/Shell Group in the mid-1990s. Proved reserves additions targets, whether expressed as a reserves replacement ratio ("RRR") or an absolute number of barrels of oil equivalent, featured as performance measures on the Exploration and Production ("EP") Business scorecard and, to a greater or lesser extent, the scorecards of individual Operating Units ("OUs") within EP, from 1996 through 2003. These scorecards were used both as a basis for monitoring and assessing the relevant organization's performance and also as a basis for determining the variable portion (i.e., bonus) of their employees' compensation.

The Group's practice of including RRR or similar targets in scorecards, particularly OU scorecards, came under persistent criticism from the Group Reserves Auditor, Anton Barendregt. Barendregt did not in fact express any concerns about the inclusion of RRR in scorecards in his year-end reviews of the Group reserves for 1998 and 1999, the first two years of his audits. He first raised the issue in his year-end 2000 review, in which he noted his concern that "the resulting pressure on staff does raise concerns with respect to the quality of future reserves bookings." (Emphasis in original.)[1] One year later, in his year-end review for 2001, Barendregt wrote more emphatically: "The widespread use of reserves targets in scorecards affecting variable pay is seen to affect the objectivity of staff in some OUs when proposing reserves additions." He proposed de-emphasizing RRR targets in scorecards in favor of targeting field development milestones such as VAR3 or project decisions such as FID, which were more closely tied to the "maturation" of reserves from SFR to development and production.[2]

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Barendregt's change in attitude and sharper criticism resulted from his experiences in dealing with personnel in Angola and at SNEPCO in Nigeria, where, in his view, the personnel were influenced by scorecards and openly admitted to it. He had no first-hand knowledge of any other similar scorecard-related behavior, but believed the inclusion of reserves targets in scorecards created similar problems at SPDC in Nigeria, PDO in Oman and Shell Deepwater Services ("SDS") in the United States.[3] SDS was critically involved in the decision to book reserves from Angola in 2000.

Barendregt felt supported in his criticism of RRR in scorecards by the publication of new Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information by the Society of Petroleum Engineers ("SPE") in June 2001. Article 4.3 of the SPE Standards enumerated the circumstances under which a consulting reserves estimator or consulting reserves auditor would not normally be considered independent. Among these was paragraph (j), which provided that such reserves estimators or reserves auditors would not be independent with respect to an entity whose reserves they were estimating or auditing if they:

> "[w]ere engaged by such Entity to estimate or audit Reserve Information pursuant to any agreement, arrangement or understanding whereby the remuneration or fee paid by such Entity was contingent upon, or related to, the results or conclusions reached in estimating or auditing such Reserve Information."

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By definition, these standards are intended to preserve the independence of an external estimator or auditor from his or her client. Their relevance to reservoir engineers and other technical staff who are employees of the company for which they have reserves responsibilities is much less clear.

The Group Controller at the time reacted to Barendregt's year-end review for 2001 by raising the issue of "scorecard behavior" at a CMD meeting held to review the letter of assurance to the auditors. According to the Group Controller, the Chairman, Sir Philip Watts, reacted very negatively, asserting that he was out of order and that the suggestion to de-emphasize RRR from scorecards was ridiculous.[4]

On September 23, 2002, the Group Reserves Coordinator, John Pay, at the urging of Barendregt, made a similar proposal as part of a draft note he circulated to some OUs (ultimately intended to be sent to EP Excom) on "Proved Reserves Management." The draft contained a proposal to the effect that proved reserves additions should be removed from the OU scorecards starting in 2003 and that higher weighting should be given to achieving project milestones that could provide the basis for booking additional reserves (such as VAR3 and FID).[5]

Although some responses to Pay's proposal from the OUs were positive,[6] others disagreed and took the position that proved reserves targets on scorecards focused personnel on an important part of EP's business.[7] Following these exchanges, on October 1, 2002, Pay sent an e-mail to Barendregt in which he reported:

> "Scorecards — I'm getting quite a lot of push back from the OUs on removing Proved Reserves from scorecards — those that play by the rules see this as a very important focus for their business. One has even said they will keep it on their local scorecards regardless of what the centre advises. Makes me think: is it better to simply to [rein] in the rogue OUs and make sure everyone understands what Proved reserves are, rather than remove the metric all together?"[8]

On the next day, Pay circulated a new version of the note in which the proposal to do away with RRR targets from the OU scorecards had been withdrawn. It was replaced with a suggestion that a mechanism be developed to ensure that OUs were rewarded for "maturing genuine proved reserves earlier than planned."[9]

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Even aside from Barendregt's experiences, there is anecdotal evidence to suggest that individuals felt under pressure as a result of the inclusion of RRR targets in the applicable scorecards.[10] By the same token, there was a strong sense that RRR or similar reserves targets on scorecards were a legitimate way of setting business objectives and priorities and trying to meet them.[11]

What does emerge from these differing views is a clear awareness that RRR was on the scorecards because it was considered to be an important corporate objective. In that sense, the scorecards may best be seen as part of a very clear "message from the top." However, for the reasons described below, it is far less clear that the scorecards provided any material financial incentives to abuse the process of booking reserves.

II. The Structure and Organization of Scorecards

Performance scorecards were first introduced in the Royal Dutch/Shell group in the mid-1990s.[12] There are three main levels of scorecards in the group: (1) the Group scorecard; (2) Business scorecards (one for each Business, such as EP); and (3) OU scorecards (one for each OU within a particular Business).[13]

A. The Group Scorecard

The Group scorecard covers the following categories of employees:

- CMD Members. The annual bonus amount payable to any CMD member is based entirely on the results of the Group scorecard. There is no additional individual performance measure that has an impact on a CMD member's bonus. The rolling three-year average of the Group scorecard's results for Core Performance Measures (as described below) also affects the stock option grant levels to CMD members.[14]

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- Corporate Centre Directors, Senior Executive Group and staff. The annual bonus amount payable to a member of this group is, in the case of the six Directors, determined by a Business Performance Factor ("BPF"), and, in the case of the approximately 200 Senior Executives and the approximately 6,000 staff, by both a

BPF and an Individual Performance Factor ("IPF"). The BPF is multiplied by the IPF and the product is then multiplied by the individual's Target Bonus Percentage ("TBP"), which is expressed as a percentage of the individual's base compensation, to determine the bonus amount. The TBP for Corporate Centre Directors is 65% of base compensation; for Corporate Centre Senior Executives, 50%; and for staff, depending on the country in which they are located, from 5% to 35%. The bonus amount is also subject to a maximum percentage limit of 100% of an individual's base compensation. For Corporate Centre Directors, Senior Executives and staff, 100% of their BPF is determined by the Group scorecard result. For Corporate Centre Senior Executives and staff, the IPF is determined solely by individual performance. BPFs and IPFs are both measured on a scale from 0 (lowest performance) to 2 (highest performance). The IPFs for a particular population group — such as Corporate Centre Senior Executives and staff — must, in the aggregate, average 1. The rolling three-year average of the Group scorecard's results for Core Performance Measures (as described below) also affects the stock option grant levels to Corporate Centre Directors and Senior Executives.[15]

- <u>Senior Executive Group and Staff in Group Service Organizations (e.g., Finance Services Organization)</u>. Depending on the relevant Group Service Organization, from 50% to 100% of an individual's BPF is determined by the Group scorecard result. The balance of the BPF will be determined by the Group Service Organization's own scorecard result, if it has its own scorecard. Certain Group Service Organizations have their own scorecards, but these are being phased out.

The bonus amount is otherwise calculated in the same way as described above for Corporate Centre Senior Executives and staff: an individual's BPF is multiplied by his or her IPF and the product is multiplied by the individual's TBP, subject to a maximum percentage limit of 100% of an individual's base compensation. The TBP for Group Service Organization Senior Executives is 50% of base compensation; for Group Service Organization staff, depending on the country in which they are located, TBP ranges from 5% to 35%. If an individual in this group is subject to both the Group scorecard and a Group Service Organization scorecard, the BPF of each is averaged in accordance with the relative weighting of the scorecards.[16]

- Business, Regional and OU Senior Executive Group. For any member of this group, 50% of the individual's BPF is determined by the Group scorecard result. The balance of the BPF will be determined by the Business scorecard result in the case of a Business Senior Executive, the Regional scorecard result in the case of a Regional Senior Executive, and the OU scorecard result in the case of an OU Senior Executive. The BPF of each scorecard applicable to an individual in this group is averaged. The bonus amount is otherwise calculated in the same way as described above for Corporate Centre Senior Executives and staff.[17] The TPB for any member of this group is 50% of base compensation.

The Group scorecard is recommended by CMD to the Remuneration Committee ("REMCO") in December of each year. REMCO reviews the Group scorecard and, when satisfied with its contents, recommends it to the Conference. If the Conference approves, the Group scorecard becomes effective for the following year. The Group scorecard uses five possible results to rate the Group's performance in each performance measure: Outstanding, Above Target, On Target, Threshold, Below Target. On a numerical scale, 2.0 is Outstanding, 1.0 is On Target and 0 is Below Target.[18]

From 1996 through 2003, the Group scorecard's overall form and structure did not change significantly. The scorecard was divided into two main categories of performance measures:

(i) Core Performance Measures (Financial Results/Measures from 2001 onwards). These generally accounted for 60% of the overall score in all years other than 1999 and 2000 (when they accounted for 80%), and generally consisted of financial measures such as Total Shareholder Return (measured against the Group's major competitors) and both Absolute and Normalized ROACE (Return On Average Capital Employed). Unless these measures received scores in the Threshold – On Target range (0.75-1.25) or above, the Additional Performance Measures described below did not count towards the overall Group score.[19]

(ii) Additional Performance Measures (Non-Financial Measures from 2003 onwards). These generally accounted for 40% of the overall score in all years other than 1998 (when they accounted for 30%) and 1999 – 2000 (when they accounted for 20%), and generally consisted of non-financial measures such as people, health, safety, environment, and social or other sustainable development measures. In 2003, Non-Financial Measures were split into two sub-parts: Sustainable Development (health and safety, environment, people and reputation) and Portfolio Value Growth (which included Group- and Business-specific measures, such as unit cost reduction for the Group, RRR and production growth for EP, and three other Business-specific measures). The five measures under Portfolio Value Growth were weighed collectively and thus were not assigned an individual weighting.[20]

From 1996 to 2003, RRR appeared as a performance measure on the Group scorecard in three years: 1996-97 and 2003. RRR was included under "Management of Physical Resources" as one of seven Additional Performance Measures in the 1996 and 1997 Group scorecards. In both years, the Core Performance Measures were scored On Target or Above Target, which meant that the Additional Performance Measures counted towards the overall Group score. In both years, the Additional Performance Measures were scored On Target, with Management of Physical Resources being On Target in 1996 and Above Target in 1997. No breakdown of individual weightings within Additional Performance Measures is available. Assuming, for the sake of simplicity, that each measure within Additional Performance Measures received an equal weighting, Management of Physical Resources would have accounted for 5.7% of the overall Group score.[21]

In 1996, the maximum bonus payable to a CMD member was 40% of base compensation.[22] Management of Physical Resources would thus have had a potential impact of 2.28% of base compensation for a CMD member that year. In 1997, the maximum bonus payable to a CMD member rose to 50% of base compensation (in more recent years, this has risen to 100%).[23] Management of Physical Resources would thus have had a potential impact of 2.85% of base compensation for a CMD member in 1997.

RRR did not appear as a performance measure on the Group scorecard from 1998 through 2002.[24] It reappeared in the Group scorecard in 2003, as one of five Portfolio Value Growth measures under Non-Financial Measures.[25] The proposal to include RRR – which was listed as EP's Portfolio Value Growth measure – was made by the EP CEO, Walter van de Vijver, and was supported by the CMD, REMCO and the Conference because it was recognized that analysts were focusing on RRR as a key performance indicator.[26] However, because the score for Financial Measures in 2003 was below On Target, no weighting was given to Non-Financial Measures and consequently no bonus payment of any individual, to the extent the payment was affected by the Group scorecard, was attributable to RRR as a performance measure in 2003.[27]

B. The EP Business Scorecard

From 1996 through 2003, the EP Business scorecard covered the following categories of employees:

- EP Centre Senior Executive Group (i.e., ExCom members). The annual bonus payment amount payable to a member of this group is determined by both a BPF and an IPF applied to the individual's TBP (for this group, 50% of base compensation), subject to a maximum percentage limit of 100% of base compensation, in the same way as described for Corporate Centre Senior Executives and staff under subsection A, "Group Scorecard," supra. For EP Centre Senior Executives, 50% of their BPF is determined by the EP Business scorecard result and 50% is determined by the Group scorecard business result, with the two BPF's being averaged to produce a single, combined BPF.[28]
- Regional Senior Executive Group. The annual bonus amount payable to a member of this group is determined by both a BPF and an IPF, applied to the individual's TBP (for this group, 50% of base compensation), subject to a maximum percentage limit of 100% of base compensation, in the same way as

described for Corporate Centre Senior Executives and staff under subsection A, "Group Scorecard," supra. For Regional Senior Executives, 50% of their BPF is determined by a combination of the EP Business scorecard and the Regional scorecard results and 50% is determined by the Group scorecard result. In this case the Regional and EP Business BPF would be averaged to produce a combined Regional/EP Business BPF, and then this would be averaged with the Group BPF to produce a single, combined BPF.[29]

- OU Senior Executive Group. The annual bonus amount payable to a member of this group is determined by both a BPF and an IPF, applied to the individual's TBP (for this group, 50% of base compensation), subject to a maximum percentage limit of 100% base compensation, in the same way as described for Corporate Centre Staff Executives and staff under subsection A, "Group Scorecard," supra. For OU Senior Executives, 50% of their BPF is determined by the OU scorecard result and 50% is determined by the Group scorecard result, with the two BPFs being averaged to produce a single, combined BPF.[30]
- EP Centre staff. The annual bonus amount payable to a member of this group is determined by both a BPF and an IPF, applied to the individual's TBP (which, depending on the country in which the staff member is located, ranges from 5% to 35% of base compensation), subject to a maximum percentage limit of 100% of base compensation, in the same way as described for Corporate Centre Senior Executives and staff under subsection A, "Group Scorecard," supra. For EP Centre Staff, 100% of their BPF is determined by the EP Business scorecard result.[31]

The EP Business scorecard is recommended by the EP Executive Committee to the CMD each year. When satisfied with its contents, the CMD approves the scorecard.[32]

The EP Business scorecard uses the same scoring system as the Group scorecard. It is also supposed to use the same basic structure as the Group scorecard. However, although the EP Business scorecard is generally broken down into two or three main categories of Financial, Operational and Additional Performance Measures, much like its Group counterpart, from 1996 through 2002, the organization and contents of those categories underwent numerous modifications. One constant was that RRR or "Management of Physical Resources," on a proved reserves basis, appeared every year, with the following weightings and results (and, where applicable, numerical scores):[33]

Year	Weighting	Result/Score*
1996	6%	Above Target
1997	6%	Above Target
1998	6%	Above Target
1999	5%	On Target
2000	5%	Above Target
2001	5%	Below Target/0
2002	5%	Outstanding/1.85
2003	15%	Below Target/0

From 1997 through 1999, members of the Senior Executive Group qualified for a bonus ranging from 25% to 50% of base compensation. From 2000 onwards, they qualified for a bonus ranging from 50% to 100% of base compensation.[34]

The potential impact of the EP Business scorecard RRR result on a member of the EP Senior Executive Group, such as an EP ExCom member with a base compensation of GBP 200,000, may be measured by taking 1999 as an example. In 1999, the Group BPF was 1.2 and the EP BPF was 1.75.[35] The ExCom member's combined BPF would thus have been 1.475. If

* Numerical scores were not applicable in 1996 – 2000.

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the EP Excom member's IPF was 1.0 and his TBP was 50% of base compensation, his bonus payment would have been 1.475 x 1.0 x GBP 100,000, or GBP 147,500. Assuming, for the sake of simplicity, that the EP Business scorecard RRR result of On Target represented 5% of the EP BPF (and, therefore, 2.5% of the combined BPF) , GBP 3,687.50 of the EP Excom member's bonus (or 1% of his total compensation) would be attributable to RRR.

The Group Director of Human Resources and his staff recently analyzed the impact of RRR targets and their weightings on the EP Business scorecard's BPF for the years 1996 through 2003. In the 1996 through 1998 EP scorecards, RRR was found to have had a "positive, but unmeasurable" impact on EP's BPF for the simple reason that, although RRR was Above Target for each of those years, CMD did not allocate a specific weighting to RRR and did not calculate a specific BPF for EP. Moreover, the collapse of oil prices in 1998 caused EP to fail to meet any of its Core Performance Measures, which in turn meant that no weighting was given by CMD to the Additional Performance measures, which included RRR (under Management of Physical Resources). In the 1999 and 2000 EP scorecards, RRR was On Target and Above Target, respectively, but the absence of any specific weighting allocated to RRR by CMD meant that RRR's impact on EP's BPF remained "unmeasurable."[36]

In the 2001 EP scorecard, RRR was Below Target with a specific weighting of 5% and thus had a negative impact of 0.05 on EP's BPF.[37] An Outstanding RRR result in 2002 with a specific weighting of 5% was found to have had a positive impact of 0.09 on EP's overall BPF of 1.2.[38] Finally, the Below Target result in 2003 with a specific weighting of 15% — caused by the recategorization of reserves in January 2004 — had a negative impact of 0.15 on EP's BPF of 0.85.[39]

To return to the example of an EP ExCom member with a base compensation of GBP 200,000, a TBP of 50% and an IPF of 1.0, his bonus payment in 2002 would have been 1.15 (the average of the EP BPF of 1.2 and the Group BPF of 1.1) x 1.0 x GBP 100,000, or GBP 115,000. If the EP BPF had been 0.09 less (i.e., without the positive impact of RRR), the average bonus payment would have been GBP 110,500. Consequently, the impact of the Outstanding RRR result on the ExCom member's bonus was GBP 4,500, (or 1.4% of his total compensation).

C. *The OU Scorecard*

The OU scorecard covers the employees of each OU and affected 100% of the bonus of those employees. The overall form and structure of the OU scorecards are similar to those of the EP Business scorecard, but the performance measures can be chosen by the OUs and thus may differ from those of EP. In OU scorecards, the only relevant BPF is that of the OU, unless it is an OU with both OU and Function scorecards (in which case each may have a BPF).[40]

According to a review performed by the Group Human Resources staff, from 1997 to 2003, RRR was included as a performance measure in the OU scorecards of PDO in Oman, SPDC in Nigeria and SDA in Australia for some but not all of the years concerned, with weightings ranging from 4% for SDA in Australia to 20% for PDO in Oman.[41] In addition, Brunei BSP included RRR as a performance measure in its "joint venture" scorecard for the years 1996-2003, but based its RRR on expectation reserves rather than proved reserves.[42]

In the absence of more detailed information about RRR scorecard results and weightings in the relevant OU scorecards and individual compensation information, it is not possible to give specific examples of the potential financial impact of OU scorecard results for RRR on employees of the relevant OUs. The most that can be offered at this stage are generic examples, such as the following:

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The reservoir and petroleum engineers and other technical and support staff responsible for reserves in the various OUs are generally employees that fall within Group salary levels A, 1 and 2. The TBPs for employees at these job levels range from 5% to 25% of their base compensation, depending on the country in which they are located or, if they are expatriates, the "home country" that determines their compensation level.[43] For example, a level 1 engineer assigned to an OU on a UK expatriate package may have a base compensation of GBP 90,000 and a TBP of 25% of base compensation. Assuming an OU BPF of 1.3 and an IPF of 1.0, the engineer's bonus would be 1.3 x 1.0 x GBP 22,500, or GBP 29,250. If RRR contributed 10% (or 0.13) to the OU scorecard's BPF of 1.3, the impact of RRR on the engineer's compensation would be the difference between a bonus of GBP 29,500 and a GBP of 26,325, or GBP 2,925 (or 2.5% of the engineer's total compensation).

On the basis of the foregoing analysis, it seems difficult to conclude, with respect to CMD members and Corporate Centre, EP or Regional Senior Executives or staff, that including RRR targets in the Group or EP scorecards created sufficient financial incentives to cause proved reserves to be booked more aggressively than they should have been. At the level of OU employees and perhaps even OU Senior Executives, without more detailed information about the results and weightings of RRR and other factors in the OU scorecards, as well as individual compensation information, it cannot be excluded that reserves targets on scorecards may have had a relatively more significant financial impact.

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[1] Review of Group End-2000 Proved Oil and Gas Reserves Summary Preparation, January 30, 2001
[2] Review of Group End-2001 Proved Oil and Gas Reserves Summary Preparation, January 30, 2002.
[3] Interview of Barendregt, March 11, 2004.
[4] Interview of Frank Coopman, Feb. 18, 2004.
[5] E-mail from John Pay to Jim Chapman, et al., Sept. 23, 2002.
[6] E-mail from R.K. Moon to Pay, Sept. 27, 2002; e-mail from Sarah Bell to Pay, Oct. 1, 2002.
[7] E-mail from Johan van Luijk to Pay, Sept 24, 2002; e-mail from Remco Aalbers to Pay, Sept. 24, 2002.
[8] E-mail from Pay to Barendregt, Oct. 1, 2002.

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[9] E-mail from Pay to Lorin Brass, copying Malcolm Harper, et al., Oct. 2, 2002.
[10] Interview of Jan-Willem Roosch, Feb. 25, 2004; Interview of Sheila Graham, Feb. 12, 2004; Interview of Dominique Gardy, Feb. 20, 2004; Interview of Yap Kong-Fah, Feb. 24, 2004.
[11] Interview of Brian Ward, Feb. 25, 2004; Interview of Lorin Brass, Feb. 18, 2004; Interview of Dominique Gardy, Feb. 20, 2004; Interview of John Hofmeister, Feb 16, 2004, and March 18, 2004; Interview of John Pay, Feb. 17, 2004.
[12] Memorandum from John Hofmeister to Lord Oxburgh, Jan. 29, 2004.
[13] Interview of Hofmeister, March 18, 2004. There are also Regional scorecards, one for each Region, such as Asia, but as these cover relatively few individuals, they are not discussed in this section. OU scorecards may also be further subdivided into Function scorecards for different Functions (e.g. Technology, Production, etc.) within an OU.
[14] Memorandum from Hofmeister to Lord Oxburgh, Jan. 29, 2004.
[15] Interview of Hofmeister, March 18, 2004; Memorandum from Hofmeister to Lord Oxburgh, Jan. 29, 2004
[16] Interview of Hofmeister, March 18, 2004.
[17] *Id.*
[18] Memorandum from Hofmeister to Lord Oxburgh, Jan. 29, 2004.
[19] *Id.*
[20] *Id.*; Interview of Hofmeister, March 18, 2004.
[21] *Review of Scorecards – 1996 to 1999*; Group scorecards, 1996-1997.
[22] *Historic Philosophy of MD Remuneration* (April 1997).
[23] Interview of Hofmeister, March 18, 2004.
[24] Group scorecards, 1998-2002.
[25] Group scorecard, 2003.
[26] Interview of Hofmeister, March 18, 2004.
[27] *Review of Scorecards - 2000 to date*.
[28] Interview of Hofmeister, March 18, 2004.
[29] *Id.*
[30] *Id.*
[31] Interview of Michael Reiff, March 31, 2004
[32] Memorandum from Hofmeister to Lord Oxburgh, Jan. 29, 2004.
[33] EP scorecards, 1996-2002; e-mail from Dave Smith to Hofmeister, March 12, 2004.
[34] Interview of Hofmeister, March 18, 2004.
[35] Group scorecard, 1999; EP scorecard, 1999.
[36] *Review of Scorecards – 1996 to 1999*; *Review of Scorecards - 2000 to date*.
[37] *Review of Scorecards - 2000 to date*
[38] *Id.*
[39] *Id.*
[40] Interview of Hofmeister, March 18, 2004.
[41] E-mail from John Bell to Hofmeister, March 15, 2004.
[42] *See* Tab H.
[43] Interview of Hofmeister, March 18, 2004.

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REPORT OF

DAVIS POLK & WARDWELL

TO

THE SHELL GROUP AUDIT COMMITTEE

TAB D:

ANALYSIS OF THE ACTIVITIES OF SHELL'S GROUP RESERVE AUDITOR AND EXTERNAL AUDITORS

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MARCH 31, 2004

An Analysis of the Activities of Shell's Group Reserves Auditor and External Auditors

PAGE

An Analysis of the Activities of Group Reserves Auditor and External Auditors

This Report examines the roles played by the Group Reserves Auditor and the Group external auditors in auditing and reviewing Shell's supplementary oil and gas reserves information. In particular, it considers the shortcomings in this process that may have contributed to the January 9, 2004 recategorization of 3.9 billion barrels of oil equivalent.[1] Part I addresses the processes applied to Shell's supplementary reserves information and the respective roles and interactions of the Group Reserves Auditor and the external auditors in these processes. Part II addresses the manner in which various reserves-related issues evolved over time through the lens of the Group Reserves Auditor's annual audit reports and the external auditors' assurance letters.

I. The Audit Process and the Roles of the Group Reserves Auditor and the External Auditors

A. Overview of Year-end Audit Process

Each year, typically in October, the Group Reserves Coordinator distributed to the individual operating units ("OUs") a package containing a document entitled *Petroleum Resource Volumes Guidelines Submissions Requirements for Internal and External Reporting* (the "Submission Requirements"). The Submission Requirements provided a detailed list of instructions for the submission of each OU's oil and gas reserves. Each OU was required to respond by mid-January to Shell International Exploration and Production ("SIEP"), and in

[1] Documents referred to in this section set forth oil volumes in both cubic meters and barrels of oil or barrels of oil equivalent. Because the recategorization was reported in terms of barrels of oil equivalent, for the reader's convenience, where the document reports volume in cubic meters, a reference to an approximate number of millions of barrels of oil equivalent, as "___mboe," has been included. The conversion factor used was 6.28981 boe/m3.

particular to the Group Reserves Coordinator, in electronic format using a spreadsheet entitled *Reserves Reporting Workbook* (the "Workbook"). The Workbook required data on each OU's expectation and proved oil and gas reserves as of December 31, as well as a "reconciliation with the reserves reported at the end of the previous year." The Workbook also called for individual field data, a summary of the year's production, and a description in narrative form of the reasons for any changes in proved and expectation reserves. Typically, an OU's chief reservoir engineer was responsible for providing the data and the OU's chief petroleum engineer was responsible for signing off on the data. Before the submission of their reserves data, the OUs often discussed particular issues relevant to their submissions with the Group Reserves Coordinator, the Group Reserves Auditor, or both.

After receipt of the OU submissions, the Group Reserves Coordinator collated the data and prepared a summary of proved and proved developed oil and gas reserves on a Group basis (the "Supplementary Reserves Information") for purposes of external disclosure. The Group Reserves Auditor then reviewed the OU submissions and the Group summary and wrote a *Review of Group End-XXXX Proved Oil and Gas Reserves Summary Preparation* (the "Group Reserves Audit Report"). The Group Reserves Auditor stated that in performing this review, he focused on changes in a given year and on whether there was consistency within each OU between the financial numbers and the reserves submissions.

In his 2000 Group Reserves Audit Report, the Group Reserves Auditor summarized this process as follows:

> "In accordance with prescribed US accounting principles (SFAS 69), SIEP staff have prepared a summary of Group equity proved and proved developed oil and gas reserves for the year 2000. The summary forms part of the supplementary information that will be presented in the 2000 Group Annual Reports and has been

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> prepared on the basis of information provided by Group and Associated companies [i.e., OUs]. The submissions by these companies ... are based on the procedures laid down in the [Submission Requirements] which in turn are based on the requirements of SFAS 69. . . .
>
> I have reviewed the processes of preparing the above summary of proved and proved developed oil and gas reserves . . . . This review included, where possible, a verification of the reasonableness of major reserves changes and any omissions of such changes, as appropriate."

The Group Reserves Audit Reports concluded with an "overall finding from the audit visits and from the end-year review" as to whether the SIEP summary "fairly represent[s] the Group entitlements to Proved Reserves" and whether the changes in the summary "can be fully reconciled from the individual OU submissions." A detailed list of findings and observations was then attached. The Group Reserves Auditor distributed the Group Reserves Audit Reports, typically in late-January or early-February, to various members of SIEP (EP CFO, EP Corporate Support Director, copy to EP CEO) and to the Group's external auditors.

Once the Group Reserves Audit Report was distributed, an annual "challenge session" was held at The Hague, which was attended by the Group Reserves Auditor, the Group Reserves Coordinator, the Group Deputy Controller, and the external auditors.[2] During the challenge session, the Group Reserves Coordinator gave a presentation on the Group's proved and proved developed oil and gas reserves as of year-end, and the Group Reserves Auditor gave a presentation on his conclusions and findings regarding this data. During and following these presentations, there were discussions regarding the appropriateness of particular booking decisions. The session often lasted for several hours, with participants going page-by-page

[2] Three partners from each of PwC and KPMG have been interviewed in connection with their audit engagement with Shell.

through the Group Reserves Audit Report. Minutes were not taken. Each year, the external auditors prepared a report that was presented to the Committee of Managing Directors ("CMD"), usually in February, and then to the Group Audit Committee in March ("Report to GAC"). If the external auditors believed that significant issues remained outstanding after the challenge session, they included these issues in their Report to GAC.

After receipt of the Group Reserves Audit Report, certain supervisory officers of SIEP provided a letter of representation ("LOR") to KPMG The Hague, the entity charged with coordinating the reserves review process for the Group's external auditors. The LORs included the four following representations (with only minor deviations from year-to-year):

1. "We are responsible for the fair presentation of the oil and natural gas reserves information . . . in conformity with generally accepted US accounting principles.

2. The information has been properly prepared and disclosed in accordance with SFAS 69 and SEC Rules and Regulations, and as clarified by subsequent SEC staff accounting bulletins and interpretive guidance issued by the SEC.

3. The information and the underlying data have been prepared and reviewed by employees having appropriate experience and qualifications for estimating oil and natural gas reserves.

4. No matters have come to our attention to the present time which would materially affect the information in respect of oil and gas reserves included in the supplementary information referred to above."

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KPMG The Hague then provided a letter of assurance ("LOA") to the Group's external auditors in London. The LOA enclosed the Group Supplementary Reserves Information for the year at issue and a copy of the Group Reserves Auditor's Group Reserves Audit Report, typically without the attachments. The LOA stated (with only minor deviations from year-to-year) that, while KPMG The Hague neither audits nor expresses an opinion on the Supplementary Reserves Information, it has "applied the procedures prescribed by SAS [Statements of Auditing Standards ("SAS")] 52 issued by the AICPA."[3] SAS 52 is a specific reference to the procedures applicable to "Supplementary Oil and Gas Information" under AU Sections 558 and 9558, which are summarized below. On that basis, KPMG The Hague provided a "negative assurance" that "[e]xcept for the finding[s] set out in the attached addendum, no matters came to our attention as a result of the procedures performed that would cause us to believe that [the Supplementary Reserves Information] was not prepared in all material respects on the basis described in paragraphs 10 to 17 of Statement of Financial Accounting Standards No. 69." The exceptions set out in the Addendum for each relevant year are discussed below.

B. The Group Reserves Auditor's Duties

Since 1996, the tasks of the Group Reserves Auditor were set forth each year in the Terms of Reference appended to the *Petroleum Resource Volumes Guidelines Resource Classification and Value Realisation* (the "Group Guidelines"). In addition to the Group

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[3] Earlier versions of the LOA listed four specific procedures:

1. "Review of guidelines provided by the E & P function to local companies in respect of the procedures to be applied in the determination, compilation and presentation of oil and gas reserves information.

2. Discussions with the E & P function in respect of the control procedures applied by both central office and local companies in respect of the above determination, compilation and presentation.

3. Reconciliation of the oil and gas information prepared by the E & P function with the underlying documentation provided to the E & P function by local companies.

4. Analysis of the movements in the oil and gas reserves and subsequent discussion with the E & P function to obtain an understanding of these movements."

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Reserves Auditor's responsibilities outlined above – to review and report on the reasonableness of the Group's year-end reserves summaries – part of the Group Reserves Auditor's responsibilities included "Reserves Audit visits" to approximately five or six "Regions/Asset Holders" over the course of a given year, and the issuing of a *SEC Proved Reserves Audit* report for each region visited.

In conducting these audits, the Terms of Reference listed a number of tasks the Group Reserve Auditor was to perform. For example, the 1999 Terms of Reference listed the following tasks:

1. "To verify technical maturity of reported proved and proved developed reserves estimates by assessing quality of engineering data and study work supporting the estimates and by verifying that undeveloped reserves are based on identifiable projects that can be considered technically mature.

2. To verify commercial maturity of reported reserves volumes by assessing the robustness of project economics and by establishing that these volumes can reasonably be expected to be sold in present or future markets.

3. To verify 'reasonable certainty' of the reserves estimates by assessing validity of uncertainty ranges . . . , by verifying that appropriate methods are used for mature fields and by establishing that appropriate methods of reserves addition (probabilistic / arithmetic) have been applied.

4. To verify that the Group share of proved and proved developed volumes has been calculated properly and that these volumes are producible within prevailing license periods.

5. To verify that reported volumes are up-to-date and consistent with previous estimates, that changes are reported in appropriate categories and that the appropriate audit trails are in place . . . supporting the reported reserves estimates.

> 6. To verify that reported reserves are net sales volumes and that the reported annual production (sales) volumes are consistent with those reported in submissions to Group Finance."

The Terms of Reference also provided that "[i]n case of deviations from the Group and FASB guidelines, the auditor shall establish whether and to what extent resulting estimates are likely to differ significantly from those that might be expected from the application of the standard guidelines."

The Terms of Reference required the Group Reserves Auditor to interview OU staff, analyze a number of randomly-selected fields, prepare and discuss a draft audit report while at the OU, and prepare a final audit report in The Hague after reviewing the OU's comments. The Terms of Reference mandated that the final audit report include an overall judgment (Good, Satisfactory, or Unsatisfactory) and itemized conclusions and recommendations. The 2003 Terms of Reference specified that these final audit reports be addressed:

> "[T]o the Chief Executive of the Region/Asset Holder concerned, to the EP Chief Financial Officer (EPF), to the EP Corporate Support Director (EPS) and to the external Group Auditors. Copies are sent to selected individuals in the Region/Asset Holder, the EP Internal Audit function, and the Hydrocarbon Resource Coordination function in EPS and to the external Group Auditors."

A summary of the final audit report was also required to be included in the year-end Group Reserves Audit Report.

The Terms of Reference specified that each OU should in principle be audited once every four years. However, the Terms of Reference also noted that "[m]ajor reserves changes or concerns expressed during a previous audit may require an advancement of the next audit."

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The 2003 Terms of Reference indicated that the Group Reserves Auditor "will provide advice regarding the changes proposed [to the Group Guidelines]. He or she may also be called upon to provide other advice regarding issues that may arise from time to time with respect to Reserves reporting methods and procedures." In his January 2004 memorandum entitled *Project Rockford – A Historical Perspective*, Barendregt stated that he was "present at or closely involved in critical stages of the process of preparing and maintaining the Group reserves guidelines from the early 1990's onwards."

The 2003 Terms of Reference stated that the Group Reserves Auditor "reports directly to the EP [CFO] but acts independently."

C. Anton Barendregt – Group Reserves Auditor (1998 – 2004)

Like his predecessor, Anton Barendregt is a retired Shell reservoir and petroleum engineer. Barendregt has been Group Reserves Auditor since 1998. Barendregt was contracted to work 90 days per year but in each of 2002 and 2003 worked closer to 150 days. Barendregt received no specific training for his position, including no training with respect to SEC requirements; he was simply given a copy of the Group Guidelines. In addition, he had no legal liaison or contact within Shell's legal department with whom to discuss or raise potential compliance issues.

Barendregt's own view is that his job was largely ceremonial, that his influence was limited, and that – except for Frank Coopman when he became EP CFO in July 2002 – no one paid appropriate attention to his reports or views. Barendregt stated that Remco Aalbers was also generally supportive when Aalbers was the Group Reserves Coordinator.[4] However, Barendregt related one encounter in which, after sending an e-mail seeking production forecasts from an OU in order to assess the reasonableness of its proved reserves submission, he was approached by another former Group Reserves Coordinator and told that he should not interfere with reserves issues. Barendregt did not pursue the issue.[5]

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[4] It is clear that there was a fair degree of interaction between the Group Reserves Auditor and the Group Reserves Coordinator, as well as some overlap in their respective roles. However, it was only in 2003 that the responsibilities of the Group Reserves Coordinator were expressly addressed by the Group Guidelines. *Guide for the Administration of Proved Reserves and Production for External Disclosures*, July 2003 (Appendix D: EP Hydrocarbon Resource Coordinator: Accountabilities). Included were the following:

- Ensure that (i) hydrocarbon resource volume assessment and reporting practices are aligned with Group Guidelines and related documentation; (ii) proved reserves estimates comply with relevant accounting standards and regulations (i.e. as defined by SEC); and (iii) future changes in hydrocarbon resource volumes in each category are consistent with requirements of EP business planning.

- In relation to proved reserves, (i) deliver realistic view of proved reserves additions that is consistent with optimized EP business plan; (ii) deliver accurate progress reports of proved reserves additions in close cooperation with regional management; (iii) maintain inventories of proved reserves bookings that are potentially under threat (Potential Reserves Exposure Catalogue) and opportunities to add to the proved reserves base (Opportunities Catalogue); (iv) provide systems that ensure timely and accurate collection of information on petroleum resource volumes from OUs; (v) compile and submit quality-assured internal and external reserves reports; (vi) maintain Group Guidelines and Submission Requirements and ensure that Shell's practices are aligned with statutory standards, internal needs and industry practice; (vii) analyze hydrocarbon maturation performance versus target and (perceived) potential; (viii) maintain interfaces with Group Reserves Auditor, EP management, regional organizations, OUs, and Finance; and (ix) act as first point of reference for any topic related to proved reserves that requires consideration, clarification, or approval of appropriate course of action to be taken, including approach to be taken in reporting of significant proved reserves changes and points of clarification on interpretation and implementation of appropriate rules.

John Pay, the current Group Reserves Coordinator, was unclear as to the proper role of his position – i.e., whether it was to ensure compliance or to maximize reserves – and ultimately concluded that the Group Reserves Auditor's role was the former and his the latter, noting that, prior to 2003, conspicuously absent from his job description was any compliance function. Pay also viewed one objective of his job as finding plausible ways not to de-book reserves. Pay received no training on SEC guidelines when he became Group Reserves Coordinator. He believes his position was understaffed and under-resourced.

[5] *See* Tab F.

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Aalbers said that it was clearly not the Group Reserves Auditor's job to decide bookings, and that the Group Reserves Auditor had no authority to order de-bookings – such decisions were the job of senior management. The current Group Reserves Coordinator, John Pay, stated that Barendregt was competent but questioned his independence, noting that Barendregt was simply auditing to a standard comprised of the internal Group Guidelines, not the SEC rules. At various points in time, some Shell employees, including, at one time, Remco Aalbers, believed that Barendregt was actually an independent KPMG auditor.

There are indications that senior management exercised pressure and even editorial control over Barendregt's reports, although Barendregt has stated that he did not feel such pressure. For example, a March 3, 2002 e-mail from Walter van de Vijver to Dominique Gardy and John Bell stated:

> "[E]xternal audit report to CMD again refers to our reserves problem , too early with proved reserves and negative impact of scorecards. This is all the farewell present from [a former Group Reserves Coordinator], has anyone tried to manage him?"

John Bell replied:

> "Re the external auditors
>
> a) the report is written not by [the former Group Reserves Coordinator] but by Anton Barendregt, who has been doing this job for some 3 years, and we did moderate it, particularly in regard of the negative impact on scorecards[.]
>
> b) the external auditors are simply reporting the facts of our booking practices relative to others in the industry which in the face of changing SEC guidance does create an exposure; the external auditors are simply doing their job, painful though the underlying reserves situation is for us."

In a January 3, 2004 e-mail to Frank Coopman, Barendregt suggested that insisting on SEC compliance would have been career-threatening:

> "[The Group Guidelines] were, after all, the 'bible' against which I had to carry out my audits in the OUs. On the few occasions in my early years where I signalled a conflict with SEC rules I was called back by Remco [Aalbers] and by the OUs who argued, rightly, that the only rules they should be bound by were the Group guidelines. These are the backbone of our internal controls on reserves. The spear-point of the SEC reserves auditor's control should therefore have been on a correct formulation of the Group guidelines. With hindsight, I should have been more forceful in this respect. It would have been a clear break with all my predecessors and <u>it would probably have cost me my job in those days</u>, but I should have." (Emphasis added.)

There are also indications that Barendregt did not perform his duties independently of management's business agenda. At times, Barendregt consulted with the very OUs he was charged with auditing, offering advice on how to increase bookings and how to "manage" potential exposures. For example, in an effort to increase proved reserves numbers, Barendregt and Aalbers advised PDO (Oman) in a January 2, 2001 e-mail to adopt a methodology that equated proved undeveloped reserves with expectation undeveloped reserves for fields in excess of 60% maturity, despite the fact that PDO had indicated that such an approach was "difficult to argue in view of the additional uncertainty of the undeveloped reserves . . . ." In addition, in his November 2003 PDO Reserves Audit Report, Barendregt stated that "some 40% of the submitted proved total reserves at 1.1.2003 do not fulfil present reserves guidelines" and that "80-90% of the presently identified undeveloped reserves . . . do not fulfil present Group and SEC guidelines"; nevertheless, Barendregt recommended as "the way forward" that "the present volumes be continued unchanged per 1.1.2004 (reduced by 2003 production)," largely because "[a]n imminent agreement with the Government regarding an extension of the current production licence may provide further (partial) relief from the necessity to de-book the overstated volumes." In a November 6, 2003 e-mail to Frank Coopman, Barendregt defended this position:

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> "I could insist on debooking the 400 MMbls now, only to see most of it re-instated again a year later. But then I should also, and even more so, insist on debooking all projects for which we have no VAR3/FID at 1.1.2004. Our guidelines say we shouldn't do that, with some justification, I believe. Personally I'd rather defend the Oman case to the SEC than the SPDC [Nigeria] case, because in Oman we're looking at bridging a one-year gap, in SPDC it's bound to be (much?) longer."[6] (Emphasis in original.)

In addition, Barendregt had previously acquiesced in the moratorium imposed on SPDC (Nigeria) in January 2000 on the addition of new proved oil reserves.[7] Similarly, in his May 2002 Brunei Reserves Audit Report, Barendregt noted that so-called "legacy reserves" had long been recognized as non-complaint with Group Guidelines but that de-booking had been resisted in an effort to avoid reserves swings. Barendregt recommended that "[t]hese reserves should be addressed at the first available opportunity, while striving to avoid major reserves swings."[8]

Even had Barendregt performed his duties in an entirely independent fashion, however, the use of one part-time retired employee to perform all the duties of the Group Reserves Auditor was inadequate for the task. Barendregt, as well as many others, acknowledged that the Group Reserves Auditor position was severely understaffed and under-resourced. Barendregt noted in his 2002 Group Reserves Audit Report that "ExxonMobil maintains a 13-man team to carry out such annual reserves audits worldwide before reserves changes are accepted."[9]

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[6] *See* Tab G.

[7] *See* Tab F.

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[8] *See* Tab H.

[9] Prior to 1999, SEPCO reported its results independently in the U.S. A SEPCO reserves auditor said that SEPCO employed more than one year-round auditor to review reserves data, and further stated that it was impossible for one person to audit all of the Group's reserves information.

In addition, Barendregt's effectiveness was hindered by the infrequency of his audit visit cycle. In his 2003 Group Reserves Audit Report, Barendregt attributed part of the reserves problem to this reduced audit schedule:

> "The strengthening of auditor personnel numbers is seen as particularly important because the previous four-yearly cycle of reserves audits was not effective in providing a timely check of any deterioration in Asset Holder reserves booking procedures."

This timely check was extremely important because, as noted in Barendregt's 2003 Group Reserves Audit Report, de-bookings were rare:

> "The Reserves Coordination function in SIEP EPB-P, with its present staff numbers, can (and does) control only the major reserves additions, e.g. for new projects. Any smaller over-aggressive reserves bookings may be detected by the four-year cycle of SEC reserves audits but this is not effective in stopping these in a timely manner. <u>Furthermore, it is rare for booked over-aggressive reserves additions, when detected, to be de-booked again . . . . The practice tends to be to keep these volumes as 'exposed' on the books until they have either been overtaken by justified increases elsewhere or until they have been thoroughly re-evaluated.</u>" (Emphasis added.)

In its independent review of the evolution of the Group Guidelines, prepared in connection with this investigation, Gaffney, Cline & Associates ("Gaffney Cline") stated:

> "The approach of using a single individual to fulfil the extensive [duties] of the [Group Reserves Auditor] is wholly inappropriate. The advantage of a single auditor (and therefore presumably a common perspective and set of standards across the company) is more than offset by the necessarily minimal level of investigation and review of the company's many holdings. A minimal 3 or 4 day visit to each OU by the [Group Reserves Auditor] every 4 or 5 years, or so, is considered . . . to be wholly inadequate for proper and defensible audit or verification of the issues set out in the [Terms of Reference]."

In addition, Gaffney Cline noted that for a critical period of time the Group Guidelines failed to provide for ultimate accountability for the Supplementary Reserves Information:

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> "The [Group Reserves Auditor], prior to 1998, had the authority to sign-off on SIEP's annual SEC submission. Between 1998 and 2002 the SIEP guidelines did not indicate who had the responsibility for SEC submission sign-off and it was only in 2003 that the SIEP guidelines clarified that accountability rested with the EP Executive, and specifically with the Chief Financial Officer and the Corporate Support Director."

D. Role of the External Auditors

As noted above, the external auditors applied certain procedures prescribed by SAS 52 to their review of the Group Supplementary Reserves Information. SAS 52 incorporates the standards enunciated in AU 558 (supplementary information) and AU 9558 (supplementary oil and gas reserves information). The main procedural requirements of AU 558 can be summarized as follows:

- The auditor should ordinarily apply the following procedures: (1) inquire of management about the methods of preparing the information, including whether it is measured and presented within prescribed guidelines, whether the method of measurement or presentation has changed from the prior period, and any significant assumptions or interpretations, (2) compare the information for consistency with management's responses, the audited financial statements and other knowledge obtained in examining the financial statements, (3) consider whether specific management representations should be obtained with respect to the information, and (4) make additional inquiries if the foregoing procedures cause the auditor to believe that the information may not be measured or presented within applicable guidelines.

- The auditor's report on the financial statements need not refer to the required supplementary information or the procedures applied unless: (1) any required supplementary information is omitted, (2) the auditor has concluded that the measurement or presentation of the supplementary information "departs materially" from prescribed guidelines, (3) the auditor is unable to complete the relevant procedures, and (4) the auditor is unable "to remove substantial doubts" as to the whether the information conforms to prescribed guidelines. AU 558 provides examples of the explanatory paragraphs that might be used in those circumstances.

In addition, AU Section 9558 provides that the auditor should apply the following procedures:

- Inquire whether the person estimating the reserves information has the appropriate qualifications (citing as an example qualifications specified by the Society of Petroleum Engineers).

- Compare the entity's recent production with its reserves estimates for properties that have significant production or significant reserves quantities and inquire about disproportionate ratios.

- Compare the entity's reserves information with the corresponding information used for depletion and amortization, and make inquiries when differences exist.

- Inquire about the calculation of the standardized cash flow measure. Such inquiries might include matters such as (1) the use of year-end prices and appropriate reflection of the terms of sales contracts and government regulations, (2) the entity's estimate of the nature and the timing of future development of the proved reserves and whether production rates are consistent with development plans, (3) whether the estimates of future production and development costs are based on year-end costs and assumed continuation of existing economic conditions, (4) the use of appropriate year-end tax rates, (5) appropriate discounting of future net cash flows, (6) in the case of full cost companies, whether estimated future development costs are consistent with corresponding depletion and amortization amounts and (7) appropriate disclosure of the sources of changes in the standardized cash flow measure as required by FAS 69.

- Inquire whether the methods and bases for estimating the reserves information are documented and whether the information is current.

AU Section 9558 also provides that the auditor should ordinarily make additional inquiries if he has doubts about whether the Supplementary Reserves Information is presented within applicable guidelines, noting, however, that "because of the nature of estimates of oil and gas reserve information, the auditor may not be in a position to evaluate the responses to such additional inquiries," and, thus, "will need to report this limitation on the procedures prescribed by professional standards." AU Section 9558 provides a sample form of such a report. The example includes a statement that the auditor "has applied certain limited procedures prescribed by professional standards that raised doubts that [the auditor was] unable to resolve regarding whether material modifications should be made to the information for it to conform with

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guidelines established by the Financial Accounting Standards Board." The example also states that the auditor should consider including in the report a statement of the reasons why the auditor was unable to resolve his doubts.

On January 30, 2003, a KPMG auditor sent to Barendregt and Pay a draft *Highlights Memorandum Proved Reserves as at 31 December 2002* which included an overview of how KPMG applied the SAS 52 requirements in reviewing the Group Supplementary Reserves Information:

> "The [SAS 52] procedures . . . are coordinated through KPMG The Hague (on behalf of Group auditors) and are carried out centrally as well as locally, based on instructions issued by Group auditors in their year-end letter. Based on the pre-selection[,] a coverage of approx. 80% of the proved reserves is expected to be subject to local auditors review.
>
> For certain aspects of the work described above we make use of the work of the [Group] Reserves Auditor, who is engaged by RD/Shell in an independent audit capacity to ensure that OU's meet the requirements of RD/Shell's [Group Guidelines].[10] His

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[10] On December 13, 2002, KPMG drafted a memorandum addressed to the current Group Controller outlining the "independence aspects of the use by KPMG of the [Group] Reserves Auditor." The memorandum was later forwarded to the Group CFO, Judy Boynton, on December 5, 2003.

> "The [Group] Reserves Auditor, Anton Barendregt, is at present retired on a voluntary severance basis and will in May 2003 retire permanently under the RD/Shell pension scheme. From that point of view he can be considered as financially independent from RD/Shell. In addition, we have reviewed his present contractual arrangements. He is compensated under a contractor agreement and paid each month based on actual hours worked. Although he is on the payroll of Shell, this is for fiscal reasons as well as for pragmatic reasons (it is easier to operate in some countries within the organization then [sic] as a contractor). Both parties can terminate the contract at short notice. His objectivity and independence is further safeguarded by his ability to set his own program (i.e., the procedures he performs and the selections of OU's to be visited). The contract we have reviewed does not provide for any bonus/incentive option. His work requires 2 to 3 months per year of his time.
>
> During the time we have worked with Anton Barendregt we have regularly assessed his position and experienced him as objective and critical. We therefore concluded his competence and his objectivity as suitable for the review of the Supplementary Oil & Gas Information. . . .

(. continued)

> work, including visits to OU's, results in 'audit opinions' issued to EP management, stating generally that the audit resulted in a 'fair representation of group entitlements to proved reserves'. The audit opinions may from time to time include qualifications regarding the status of the proved reserves submission, ranging from 'good to satisfactory to unsatisfactory'. We collate the reports of local auditors and issue the 'negative assurance' report based on that work and the central work, including discussions with management and the [Group] Reserves Auditor, as well as a review of the program and outcome of the work of the [Group] Reserves Auditor."

As noted above, the Group Reserves Auditor sent his Group Reserves Audit Report to the external auditors every year. Barendregt stated that he rarely had significant discussions with the external auditors about his Group Reserves Audit Reports. Pay believes that the external auditors' review was limited to a check of the numbers contained in the Group Reserves Audit Report, the OU submissions, and the financial statements for internal consistency, that the external auditors did not look beyond consistency issues to evaluate compliance, and that the external auditors lacked the expertise to challenge or express an opinion on the quality of reserves. When asked what role local external auditors played in auditing reserves, Aalbers stated that it was the job of the Group Reserves Auditor to audit OU reserves, not the local external auditors.

The external auditors recalled significant discussions at the "challenge sessions" about the Group Reserves Audit Reports but their focus was on less technical issues, such as year-end pricing in production sharing situations. They also focused, especially at the local level, on

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(continued.)

> We do not believe that the present arrangements trigger any issues consequent to the Sarbanes Oxley Act, given our responsibilities under SAS52 and with regard to information in the Annual Report that does not form part of the financial statements as well as the extent of the reliance placed on the work of the [Group] Reserves Auditor."

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reserves reporting as it impacted the financial statements, and thus on proved developed reserves because of their impact on depletion and depreciation. However, the external auditors lacked the expertise to evaluate the technical aspects of reserves reporting, and thus relied heavily on the Group Reserves Auditor on such technical matters.

II. Evolution of Reserves Issues in Group Reserves Audit Reports, LORs, and LOAs

The following represents an overview of significant reserves issues raised in the Group Reserves Audit Reports, the SIEP LORs, and the KPMG LOAs from 1997 through 2002.

A. 1997

1. Group Reserves Audit Report

The 1997 Group Reserves Audit Report noted the booking of Gorgon but did not otherwise comment on the booking.

2. LOR

The 1997 LOR included no exceptions or caveats to the four standard representations (*see supra*).

3. LOA

The Addendum to the 1997 LOA mentioned only one concern: use of the technique of probabilistic addition. The Addendum indicated that the technique of probabilistic addition can lead to a "higher proved reserves outcome" and can have a "significant impact on proved reserves in fields with many reservoirs," and suggested a total "Difference in BOE" of 235 million against a total base of proved reserves of 9681 mboe. The Addendum did not address whether the technique was compliant with SEC rules and guidance.

B. 1998

1. Group Reserves Audit Report

The 1998 Group Reserves Audit Report noted a change in the Shell "project screening value" ("PSV") from $18/bbl Brent to $14/bbl Brent, which resulted in higher proved reserves in SNEPCO (Nigeria) and Oman, among others.

The Report also criticized OUs for failure to timely provide requested data:

> "Although companies were requested to submit brief summary reports highlighting the reasons and justifications for their reserves changes, not many have fulfilled this request. I recommend that a clearer and firmer format for justifications be included in next year's submission templates, in particular for proved developed reserves."

The Report included the following timetable for OU reserves audits:

> "Large OUs are to be audited once every 4 years, Medium OUs every 5 years, Small OUs every 6 years, unless recommended otherwise in audit reports etc, or when combinable with other audits."

2. LOR

The 1998 LOR has not been located.

3. LOA

The 1998 LOA has not been located.

C. 1999

1. Group Reserves Audit Report

The 1999 Group Reserves Audit Report addressed problems associated with license expiration, including an apparent reference to, and acquiescence in, the moratorium imposed on bookings for SPDC:

> "SEC and Group guidelines prescribe that proved and proved developed reserves can be demonstrated to be producible before the expiry of current production licences (or their extension if a right to extend is formally agreed). Whilst not a severe constraint in many cases, it is becoming a serious issue for large resource holders that are facing production or export level constraints, i.e.

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> SPDC Nigeria and ADCO Abu Dhabi and PDO Oman. The first two companies carry significant aspirational upturns in future offtake levels in order to justify their proved reserves levels. In view of the need for reasonable certainty of these levels, total proved reserves for SPDC Nigeria have been capped this year by not booking a bottom line increase of 49 10^6 m3 [308 mboe], arising from recovery improvements in a series of fields. This is supported." (Emphasis added.)

The Report also noted that Australia attempted to book 20% more reserves for the Gorgon field, which was rejected:

> "[C]ustomers for this additional gas cannot at this stage be readily identified and the incremental volumes . . . have not been included in externally reported proved reserves at this stage. This is in line with Group guidelines and is therefore supported."

Finally, the Report noted that Oman and Brunei had capacity to increase bookings of proved reserves:

> "There appear to be significant scope for further increasing proved reserves in some areas (Brunei, Oman, and others), where estimates tend to be conservative in comparison with expectation volumes and thereby not fully in line with latest Group guidelines."

During 1999, the Group Reserves Auditor visited nine OUs, including Oman, SNEPCO, and SPDC. On SPDC, the Report again referenced a "cap" on bookings for SPDC:

> "The considerable scope for increasing SEC proved reserves in the fields is overshadowed by the aspirational assumption of a doubling of Nigerian production levels in the coming decade, prior to the licence expiry in 2019. . . . Appropriate capping of reserves additions, to reflect the end-of licence and production constraint, has been applied in the 1999 submission." (Emphasis added.)

2. LOR

The 1999 LOR included no exceptions or caveats to the four standard representations (*see supra*). It was signed by Philip Watts and Linda Cook.

3. LOA

The Addendum to the 1999 LOA raised the issue of year-end pricing, noting that the Group proved reserves were determined using the PSV, which in 1999 was $14/bbl Brent, rather than the year-end price, which was $25.10/bbl Brent. The Addendum went on to state that while use of the PSV "avoids significant reserves fluctuations due to year-on-year price changes . . . , this does not seem to accord with [Rule 4-10(a)(2) of Regulation S-X]," which "is generally taken to mean that proved oil and gas reserves should be determined based on year-end prices." The Addendum indicated that the Group Reserves Coordinator estimated the impact of using PSV to be (i) 2.6% of total proved reserves for crude oil and NGL and (ii) 3.3% of total proved reserves for natural gas.

The LOA did not mention Gorgon. However, a January 2000 internal Shell presentation, entitled *Presentation ExCom 31st January 2000*, noted, in reference to the proposed additional bookings in Gorgon, that "[p]roved Gas volumes in Australia have been a point of challenge by the external Auditors (KPMG/PWC) for the last two years already and incremental booking at present would be hard to support." The external auditors could not recall any discussions about Gorgon.

The external auditors have disclaimed knowledge, prior to late 2003, of the moratorium imposed on SPDC, and have suggested that knowledge of the moratorium would have alerted them that Shell was attempting to manage a reserves problem. The external auditors do not recall any discussion about the "cap" language contained in the 1999 Group Reserves Audit Report and have said that, to the extent the issue may have been discussed, it was not discussed in terms of a "moratorium."

D. 2000

1 Group Reserves Audit Report

The 2000 Group Reserves Audit Report again noted that proved reserves "need to be confined to those volumes producible within duration of current production licenses, or their extensions if there is a right to extend," and concluded that:

> "At present, some 1200 mln m3oe [7500 mboe] Expectation Reserves are reported by OUs as being non-producible within existing licences. This corresponds to 25% of the current Group portfolio. The corresponding Proved volumes are not captured by the present submissions and are difficult to assess from centrally available data, but could exceed 100 mln m3oe [629 mboe]. This volume is likely to increase in coming years."

Nevertheless, the Report did not advise a de-booking of any of these reserves.

The Report expressed a concern regarding the inclusion of reserves addition targets in scorecards, noting that:

> "Finding genuine reserves additions will become an increasing challenge and the Group's desire to maintain future reserves additions at the same level as annual production (100% Replacement Ratio) will raise pressure on the staff responsible. Such pressure have this year led to the extremely marginal reserves booking for Block 18 fields in Angola, where e.g. the operator (BP) has considered the fields still to be too immature for any bookings at this stage."

The Group Reserves Auditor visited six OUs in 2000, including Australia. With respect to Australia, the Report stated that:

> "Maintaining the preliminary booked volume of Gorgon gas reserves (first done at 1.1.1999) was supported because a gas market was highly likely to be found in due course and because it must be considered likely that an extension of the current 5-year Retention Lease will be granted in 2002."

In addition, the Report included the following note on a visit to SEPCO, Shell's U.S. subsidiary:

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> "The comprehensive system of quarterly annual internal reserves audits was noted and commended. Main deviations from Group reserves guidelines are due to SEPCo adhering to strict interpretations of the SEC rules, which are enforceable in the US." (Emphasis added.)

The Report again noted that Brunei "still seem[s] to offer significant scope for raising Proved Reserves."

2. LOR

The 2000 LOR included no exceptions or caveats to the four standard representations (*see supra*). It was signed by Philip Watts and Lorin Brass.

3. LOA

The Addendum to the 2000 LOA addressed once again the year-end pricing issue but stated that the impact on reserves was "not significant." The Addendum did not list any other concerns.

In their March 2001 Report to GAC, however, the external auditors stated:

> "The review process by the Independent Reserves Auditor is considered to be very important from an external audit perspective.
>
> As a result of the year end 2000 review, and triggered in part by the recognition of new discovery in Angola, management have recognized that the determination of reserves additions and the related timing of their recognition, would benefit from further consideration."

E. 2001

1. Group Reserves Audit Report

The 2001 Group Reserves Audit Report concluded that the reserves information "fairly represent[s] the Group entitlements to Proved reserves at the end of 2001," but went on to note that:

> "There is a possibility of a minor overstatement of Group Proved reserves in some fields where historically booked reserves are not fully in line with recent SEC guidance. However, this overstatement is likely to be offset by reserves in areas where current Proved reserves are probably too conservative (e.g. Brunei)." (Emphasis added.)

The Report included a number of observations.

First, the Report stated that the Group Guidelines were too lenient for new fields:

> "[R]ecent clarifications of FASB reserves guidelines by the US Security and Exchange Commission (SEC) have shown that current Group reserves practice regarding the first-time booking of Proved reserves in *new* fields is in some cases too lenient. The Group guidelines should be reviewed. . . .
>
> The observation can also be made that, for first reserves bookings, industry practice tends to follow the SEC guidelines more closely . . . .
>
> It should be understood that tightening of the first time booking guidelines, necessary as they are from a SEC perspective, may affect reserves already booked in some major new fields (cf. Ormen Lange – Norway with 17 bln [sic][11] sm3 [103.6 mboe], NAM's Waddenzee reserves with 4 bln sm3 [25.2 mboe], Angola with 12 mln m3 [75.5 mboe] and possibly Gorgon – Australia with 86 bln sm3 [523.9 mboe] Group share Proved reserves)."

Nevertheless, the Report did not recommend a de-booking of any of these reserves or insist upon a retroactive application of the recent clarification.

Second, the Report criticized a lack of awareness as to Group and SEC guidelines for reserves reporting:

> "Awareness of Group and SEC reserves booking guidelines was seen to be less than desirable at senior levels in OUs and in support functions in the centre (RBDs, SDS, SEPTAR). This should be

[11] It is clear that the Report is in error in using billion rather than million for these figures. The mboe conversions are adjusted accordingly.

> improved by issuing appropriate high level guideline summaries, organisation of workshops etc."

Barendregt has opined that, other than at SEPCO, Shell did not appreciate the significance of SEC rules and guidance.

Third, the Report again criticized the inclusion of reserves in scorecards, and stated that this inclusion:

> "[I]s leading to a noticeable increase in attempts to book reserves which are not technically or commercially mature and which do not fulfill Group reserves guidelines, cf. the new field bookings in Angola and Nigeria."

Fourth, the Report again noted, with specific references to Nigeria and Oman, that proved reserves "need to be confined to those volumes producible within the duration of current production licences, or their extensions if there is a right to extend," and concluded that:

> "At present, <u>some 200 mln m3oe [1258 mboe] Proved field volumes (10% of the Group Proved Reserves portfolio) are reported by OUs as being non-producible within existing licences</u>." (Emphasis added.)

Nevertheless, the Report did not advise a de-booking of any of these reserves. The Report also criticized the OUs for failure to timely provide data on this issue:

> "During this year's reserves submission and accumulation process, the critical information about OU assumed production profiles could in some cases only be made available to the auditor after repeated requests and in a late stage, thus leaving insufficient time for a comprehensive review. This should be remedied in future submission by ensuring that full life cycle production profiles are requested from and made available by OUs in an early stage."

Finally, the Report indicated that the BONGA SW field in SNEPCO was not accepted for booking, and suggested that other SNEPCO fields may have been inappropriately booked in the past:

> "[T]he technical basis for the reserves in the Erha field, at its first time booking in 1999, was said by SNEPCO staff to be of lower quality than that for Bonga SW. A SEC reserves audit is planned for 2003. Advancement of this audit is being considered."

2. *LOR*

The 2001 LOR included no exceptions or caveats to the four standard representations (*see supra*). It was signed by Dominique Gardy and Lorin Brass.

3. *LOA*

The Addendum to the 2001 LOA again addressed the year-end pricing issue. The Addendum also mentioned the divergence between the PSV ($16/bbl Brent MOD flat) and the LTO ($14//bbl Brent MOD flat). The Addendum did not list any other concerns.

In their March 2002 Report to GAC, the external auditors noted the following issues:

> "The review process by the internal Reserves Auditor (a former Shell reservoir engineer) is considered to be thorough and to be very important from an external audit perspective. The findings of the 2001 review prepared by the Reserves Auditor included the following comments:
>
> - The internal guidelines for the determination and timing of first time proved reserves additions are lenient in some aspects compared to recent clarifications of SEC reserve guidelines for new reserve additions.
>
> - That widespread use of reserve targets in scorecards affecting variable pay is seen to affect the objectivity of OU management when proposing reserve additions. Even though compensating controls were considered to be in place, a shift in scorecard emphasis from reserve bookings to meeting project milestones was recommended."

An external auditor said that he never heard the Group Reserves Auditor articulate a view that the Shell Guidelines were not compliant with SEC requirements.

F. 2002

SCA 00000176

1. Group Reserves Audit Report

The 2002 Group Reserves Audit Report concluded that "there is a possibility of an overstatement of Group Proved reserves in cases where booked reserves are not fully in accordance with SEC or Group guidelines." The Report included a number of observations.

First, the Report again raised the 2001 SEC clarification of FASB rules, and again mentioned the same four fields as potentially impacted: Gorgon, Angola Block 18, Ormen Lange, and Waddenzee. On Gorgon, the Report stated:

> "The Gorgon gas field is a major gas resource (currently booked at a conservative 570 MMboe or 90 mln m3oe Proved volume) whose size and relatively remote location have thus far prevented it from being developed. . . . There can be little doubt that Gorgon will be developed at some stage (i.e. development is 'reasonably certain'), but the timing of development is still in question. However, since there are no clear 'show stoppers' there seems to be insufficient reason to de-book the (partly discounted) reserves already carried."

Other than for Waddenzee, the Report did not recommend de-booking any of these reserves. On Waddenzee, after noting that "there are those that hold the view that these fields will, with time, become developed" and that "exploration and pre-development costs for these fields have been written down in 2000," the Report stated:

> "It is the auditor's opinion, taking note of the 2001 clarifications by the SEC requiring 'reasonable certainty', that reserves should be de-booked or at the very least be reviewed closely each year."

Second, the Report repeated prior concerns regarding license duration and OPEC production constraints, and concluded:

> "At present, some 1600 mln m3oe [10,000 mboe] (45% of the Group's Expectation within-licence Reserves portfolio) is reported by OUs as being non-producible within existing licences."

On this issue, the Report was critical of the data received for proved reserves:

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> "Similar beyond-licence volumes can be estimated for Proved reserves. . . . OUs have been asked to provide this data also for Proved reserves but the submitted estimates for Proved reserves seem somewhat erratic (e.g. large variations from last year submissions). This should be challenged with the OUs and rectified."

The Report was especially critical of PDO and SPDC in this regard:

> "PDO and SPDC were asked to provide details of their assumed Business Plan and Proved forecasts in order to allow an assessment of the defensibility of the latter.
>
> PDO did not provide a clear answer to the query. Comparison of their stated Proved oil reserves volume against their latest Business Plan forecast showed that the Proved volume seems unrealistically high. . . .
>
> The above would suggest that the amount of PDO's Proved reserves overbooking might be some (92-80)% of 550 MMboe unproved Expectation reserves, i.e. some 65 MMboe (10 mln m3oe). The resulting Proved reserves of some 840 MMboe (134 mln m3oe) would still be slightly in excess of the present 'Tranche 1' (Mature Projects) forecast from the 2002 Business Plan (820 MMboe or 130 mln m3oe).
>
> SPDC did not provide any answer to the query at all. . . .
>
> The indications are . . . that the SPDC Proved reserves during recent years have been over-estimated in relation to then current licence duration assumptions. The magnitude of this over-estimation is difficult to assess but a conservative estimate . . . would suggest a Proved reserves volume that is some 20%, or 600 MMboe (100 mln m3oe) smaller than the presently booked value."

The Report went on to indicate possible reasons for the overbooking of reserves in PDO and SPDC:

> "The reason that such Proved reserves overbookings have arisen is that both OUs had at one stage Proved forecast assumptions that were highly ambitious. . . . When these assumptions turned out to be unfounded by subsequent disappointments . . . , both OUs failed to recognise (or chose to ignore) the full extent of the negative effects that this would have on bookable Proved reserves."

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Nonetheless, on this issue, the Report concluded as follows:

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

Third, the Report included a comment on year-end pricing:

> "The fact that this PSV is lower than the current end-year oil price means in principle that booked PSC Proved reserves have been overstated in comparison with SEC guidelines. . . .
>
> [T]he potential overstatement would amount to 296 MMboe (47 mln m3oe). . . .
>
> The effect of this overstatement of PSC reserves (in relation to SEC/FASB guidelines) is compensated by the conservative effect that the low PSV screening prices have on booked reserves in other areas. . . . An evaluation among OUs at end 2000 showed that the understatement effects brought significant, but not full compensation of the overstatement effects."

Fourth, the Report reiterated concerns over first time bookings in new fields, and again suggested that the Group Guidelines were not in full compliance with SEC requirements:

> "The auditor recommendation is therefore to strengthen the condition for booking Proved reserves for new major projects to either the passing of FID or to another strong public commitment by the OU (e.g. a binding declaration of commerciality to the authorities), which confirms that development is likely to go ahead. <u>This would bring the Group guidelines in full accordance with the SEC 2001 clarifications.</u>" (Emphasis added.)

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Finally, the Report once again elaborated on scorecard concerns, indicating that ExCom rejected suggestions to remove reserves from scorecards:

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

The Group Reserves Auditor expressed his disagreement with this approach.

> "It is the auditor's firmly held belief that the reserves addition targets in these score cards present a potential threat to the integrity of the Group's reserves estimates."

The Report concluded that if reserves continued to be included on scorecards, internal controls would have to be improved, as controls over initial bookings were insufficient and de-bookings were extremely rare:

> "The Reserves Coordination function in SIEP EPB-P, with its present staff numbers, can (and does) control only the major reserves additions, e.g. for new projects. Any smaller over-aggressive reserves bookings may be detected by the four-year cycle of SEC reserves audits but this is not effective in stopping these in a timely manner. <u>Furthermore, it is rare for booked over-aggressive reserves additions, when detected, to be de-booked again . . . . The practice tends to be to keep these volumes as 'exposed' on the books until they have either been overtaken by justified increases elsewhere or until they have been thoroughly re-evaluated.</u>"
>
> The auditor comment is therefore that, if reserves addition targets should remain on the Group's score cards, the quality of the booked reserves additions can only be assured in full if a much tighter control is exercised on the annual reserves bookings submitted by OUs. Good examples of such tight control are the annual reserves audits carried out by SEPCo in their Divisions prior to reserves changes being accepted for booking. . . . <u>It is understood that ExxonMobil maintain a 13-man team to carry out such annual reserves audits worldwide before reserves changes are accepted.</u>" (Emphasis added.)

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The Report concluded with eight specific "Recommendations to SIEP Reserves Coordinator":

1. "Maintain the present vigilance regarding the continued booking of Proved reserves volumes with poor justification, as highlighted in this report and re-consider the booking of these volumes as appropriate.

2. Consider a further tightening of conditions under which first-time booking of major project reserves can be allowed by Group reserves guidelines. . . .

3. Maintain and, if necessary, increase ExCom's attention to the preservation of the integrity of OU reserves bookings in the light of the potential threat emanating from reserves addition targets in score cards.

4. Consider a tightening of the control on reserves changes by introducing regional reserves audit teams which are to carry out annual reserves audits with OUs and which have the power to approve/disallow OU proposed reserves changes.

5. Re-evaluate the effect of using PSV oil prices instead of end-year oil prices on PSC and other reserves bookings at regular (bi- or tri-yearly) intervals.

6. Ensure that OUs, in particular PDO and SPDC, prepare proper composite production forecasts (built up from realistic individual field forecasts, both Proved and Expectation) demonstrating the reasonable certainty that Proved reserves can be produced within current licence durations. The annual forecast rates should not exceed those presented as the Base Plan in the latest Business Plan.

7. Challenge OUs with regard to their submissions of estimates of amounts by which Proved reserves should rise if there were no licence duration constraints.

8. Include guidelines with respect to appropriate methods on proved and Expectation forecasting in the next edition of the Group reserves guidelines."

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2. LOR

The 2002 LOR included the following caveat to the four standard representations:

> "During review of the final figures, certain areas of potential concern were brought to our attention (list attached). We are satisfied that these are not material to the total Shell Group proved reserves, but we will review them and take corrective action if necessary during 2003."

The LOR was signed by Frank Coopman and Lorin Brass. Attached to the LOR was a "Summary of areas of Potential Concern." The attachment identified the following areas of potential concern: Italy; KMOC (Russia); Netherlands (NAM, Waddenzee); Oman (license period); Kazakhstan (license period); and the net-effect of year-end pricing. The total amount of proved reserves listed as of potential concern was 197 mboe, or 1.0% of total proved reserves. The LOR did not include SPDC or Gorgon as potential concerns.

3. *LOA*

The Addendum to the 2002 LOA addressed several concerns.

First, the LOA stated that:

> "We have identified a number of issues that are not or not fully supported by the SEC or Group reserve guidelines. There findings are related to the acquisition of certain Enterprise Reserves (KMOC and Tempa Rossa) and to NAM's Waddenazee fields."

The LOA did not include Gorgon in this list. The external auditors could not recall any discussions about Gorgon; nor had they previously heard the term "show stoppers."

The LOA also commented on license constraints:

> "Reported volumes are restricted to volumes producible within the duration of current production licenses and extensions.
>
> Oman suffered the last years from disappointing production numbers. As at 31 December 2002 an unrealistic high proved undeveloped reserves/expectation undeveloped reserves ratio (taking limited license period into account) indicates that it is likely that PDO's Proved reserves are overbooked (Group reserve's auditor estimate is approx. 65 million barrels). In 2003

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> an SEC reserves audit by the Group reserves auditor will be performed to further investigate this matter."

Once again, the LOA noted the issue of year-end pricing. No volume amount was included, however.[12]

Finally, the LOA included a discussion of SPDC:

> "Although the leases of SPDC Nigeria include expiry dates, SPDC carries more reserves than producible before these dates. The management of SPDC has demonstrated, through legal advise, that the extension of the leases can be considered as a right of SPDC and consequently the reserves can be classified as proved. The extension of the licence is reviewed by Cravath, the US external legal counsel of the Royal Dutch / Shell Group which considered the treatment of this issue by SPDC to be in accordance with the FASB/SEC regulations."

The LOA attached the same "Summary of areas of potential concern" that was attached to the LOR.[13]

In addition, in their March 2003 Report to GAC, the external auditors listed verbatim the eight specific recommendations made by the Group Reserves Auditor in his 2002 Group Reserves Audit Report, noting:

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[12] In a January 2002 *Draft Highlights Memorandum*, KPMG noted a "downward effect of 299 M BOE if the reserves were to be calculated on a year end basis," offset by an upward impact of approximately 200 MBOE, "resulting in an estimated total effect of approximately -100 MBOE."

[13] It appears that this Summary derived from the January 2002 KPMG *Draft Highlights Memorandum*. In the Summary included therein, however, the total amount of BOEs listed as of potential concern was 297 million, or 1.5% of total proved reserves, instead of the 197 million (or 1%) listed in the Summary attached to the LOR and LOA. The difference is made-up from the 100 million attributed to year-end pricing that was included in the January 2002 Memorandum but was removed from the LOR and LOA.

In addition, the Memorandum stated that:

> "In 2000 local Reserves Focal Points have been asked to carry out an estimate of the impact of [year-end prices] on proved reserves. In total the impact was considered minor, although in specific cases the impact per company was significant. KPMG and the [Group Reserves Coordinator] mutually agreed not to repeat the request to local Reserves Focal Points in 2002."

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> "As a result of our review of the 2002 [Group Reserves Audit] report, we were able to confirm that nothing came to our attention to cause us to believe that the reserves information presented was not prepared in accordance with US GAAP. The [Group] Reserves Auditor included a number of important recommendations in his report. These will be considered by the EP Executive Committee before the next review commences. We concur with the recommendations . . . ."

The Report to GAC also mentioned Nigeria:

> "One potential issue arose in connection with certain oil reserves in Nigeria recognised beyond the present licence period. This treatment has been confirmed by outside legal counsel to be in conformity with the SEC definition of proved reserves. On this basis we concur with the treatment."

The external auditors recalled discussions during the challenge session for year-end 2002 regarding PDO and SPDC. For SPDC, there was significant discussion about booking reserves beyond the current license expiration. The external auditors said they were not satisfied with a legal opinion issued by a Nigerian lawyer but insisted on discussions with Shell internal counsel as well as advice from Cravath, Swaine & Moore.[14]

According to the external auditors, there were also discussions at the March 2003 Group Audit Committee meeting about production declines in Nigeria and Oman. One external auditor said that he understood such declines to be one-year blips – in Nigeria due to an election and ensuing unrest and in Oman due to technical reasons related to well pressure. The external auditors were not aware of production problems prior to 2002 for PDO or SPDC, and one auditor noted that production issues became more critical as an OU approached the end of a license.

III. Conclusion

[14] *See* Tab F.

The Group's internal controls and auditing processes regarding the disclosure of Supplementary Reserves Information were not sufficient. First, and in particular, the use of one part-time retired employee to perform all the duties of the Group Reserves Auditor was inadequate. Second, and one of the principal effects of the understaffed Group Reserves Auditor position, was the too infrequent auditing of OUs. Third, the Group Reserves Auditor did not exercise his duties independently. Company polices and members of senior management impacted the Group Reserves Auditor's reports, both directly and indirectly. Moreover, the Group Reserves Auditor at times advised OUs on how to increase reserves bookings and how to "manage" exposures. Fourth, the Group Reserves Auditor received no training on SEC regulations, the relevant standards against which he should have been auditing, and had no legal liaison within Shell with whom to discuss or raise potential compliance issues. Finally, despite these shortcomings in the Group Reserves Auditor position, the Group Reserves Auditor did raise a number of issues both in his Group Reserves Audit Reports and in his OU reserves audit reports that were either not heard by Shell senior management or were not properly acted upon.

REPORT OF

DAVIS POLK & WARDWELL

TO

THE SHELL GROUP AUDIT COMMITTEE

TAB E:

FINDINGS CONCERNING AUSTRALIA (GORGON)

MARCH 31, 2004

SCA 00000186

Australia (Gorgon)

PAGE

SCA 00000187

Australia (Gorgon)

I. Summary

The Group business unit Shell Development (Australia) Pty Ltd. ("SDA") holds a 28.6% interest in a joint venture that owns leases in the Gorgon natural gas field off the northwestern coast of Australia. At the end of 1997, the Group categorized as proved reserves 504 million boe of gas volumes identified in the Gorgon field. These reserves contributed 38 percentage points to the Group's 1997 reserves replacement ratio ("RRR") of 159%, and represented nearly 60% of the year's overall increase in gas reserves.

Despite the magnitude of the booking, there is no formal documentation as to who made the decision to categorize Gorgon volumes as proved reserves, or why the decision was made. Several managers present in Australia in 1997-98 have said that they did not even know of any Gorgon proved reserves until the January 9, 2004 recategorization announcement. Senior managers in The Hague at the time, including the EP Regional Business Director for Australasia and Philip Watts, then the Group Managing Director responsible for EP, disclaimed recollection of the booking. Nonetheless, there are a number of factors that appear to have contributed to the decision to categorize Gorgon as proved reserves.

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By late 1997, there was little doubt as to the existence of major technical reserves in the Gorgon field. The main barriers to categorizing proved reserves were related to Gorgon's remote location and demand uncertainty in the Asian gas market. Internal Shell documents show that in late 1997, various senior managers perceived a "window of opportunity" for Gorgon gas to be sold to a large Korean buyer beginning in 2002 or 2003. This perception was supported by, among other things, a series of 1997 meetings between the Korean buyer and representatives of the Gorgon joint venture. On the other hand, the ambitious goal of sales beginning in 2002 or

2003 faced many contingencies, including feasibility issues and complex negotiations within the joint venture and with various other parties. Other objectives that may have contributed to the decision to book proved reserves include a desire to enhance Gorgon's credibility relative to competing gas projects; a need to bolster SDA's asset value in contemplation of strategic plans with respect to Woodside Petroleum Ltd. ("Woodside"), an Australian company 34% owned by Shell; and the general pressure within the Group to improve reserves replacement statistics through a more "entrepreneurial" approach to categorizing proved reserves.

Whatever the initial impetus for booking, by February 1998, the ongoing Asian economic crisis had undermined demand for natural gas in Korea. In August 1998, the Korean buyer finally responded to overtures made in April by noting Korean "financial difficulties" and suggesting only "continuous discussion." If it were ever open, the "window of opportunity" had closed.

The status of the Gorgon reserves was revisited several times in the years following the initial booking, and each time the proved reserves categorization was retained, often despite the qualms or even direct opposition of SDA personnel. For example, in early 2000, SDA engineers recommended that recently identified additional Gorgon volumes not be booked as proved, and that the existing proved reserves be de-booked. After an internal debate involving SDA and The Hague, it was decided to maintain the Gorgon proved reserves but freeze them at their current level without adding the new volumes. At the end of January 2000, a reserves presentation to EP ExCom included a description of this freezing of the Gorgon proved reserves.

In October 2000, the Group Reserves Auditor, Anton Barendregt, traveled to Australia for an SDA reserves audit, the first such audit since 1996. Prior to the audit, the SDA Development Manager informed Barendregt that SDA intended to de-book the Gorgon proved

SCA 00000189

reserves. The Development Manager also informed the SDA Reserves Coordinator that he was "prepared to defend downgrading Gorgon." In late September 2000, the Group Reserves Coordinator instructed SDA personnel that during the reserves audit they should "justify why they had Gorgon proved reserves on the books," and further stated that "any plan to debook . . . would need to be cleared with ExCom directly as it has a very large impact on the Group reserves position." Although the effect of this intervention is unclear, Barendregt ultimately endorsed the Gorgon status quo in his written audit report.

In June 2001, a new Group Reserves Coordinator informed SDA personnel that Gorgon should be de-booked on the grounds that it was not commercially mature. Before he could act on this view during the year-end process of reviewing and reporting on Group reserves, the Coordinator left Shell for personal reasons. His successor, John Pay, was surprised when he learned of the Gorgon proved reserves, which to him "stuck out like a sore thumb." Nevertheless, in September 2002, Pay advised SDA personnel that historical reserves bookings were "water under the bridge," and that the Gorgon reserves should not be de-booked "unless and until it is absolutely clear that development will not proceed within a reasonable time frame."

In 2002, Walter van de Vijver began to communicate directly with Pay concerning the Group's proved reserves situation, and from early 2002 through 2003, Pay maintained a one-page "potential reserves exposure catalogue" that summarized the status of Gorgon and a growing list of other questionable proved reserves. In December 2003, Pay distributed in connection with "Project Rockford" a document summarizing "official" and "unofficial" reasons why Gorgon had not previously been de-booked. The official version: an LNG market would develop eventually. The unofficial: de-booking Gorgon would reduce RRR by about 40% and was "too big to swallow."

At a December 2003 CMD meeting, the EP CFO Frank Coopman was asked why Gorgon had not been disclosed in his February 2003 representation letter to the Group External Auditors. According to Sir Philip Watts, Coopman responded in words or substance that "500 million boe was not material," but then added, "OK, it was a fudge." Also according to Watts, after Coopman made this comment, "you could hear a pin drop."

On January 9, 2004, six years after the original booking, Pay instructed SDA to de-book the Gorgon proved reserves.

II. <u>The December 1997 Proved Reserves</u>

The Gorgon natural gas field was discovered in 1980 off the northwestern coast of Australia.[1] By 1997, SDA was a 2/7-share participant in a joint venture that owned retention leases in Gorgon and certain nearby fields. The other participants were Chevron (2/7 share), Texaco (2/7 share) and Mobil (1/7 share). Sometimes referred to as "CTMS", the Gorgon joint venture was initially operated by West Australia Petroleum Pty Ltd. ("WAPET"), a company owned by Chevron, Texaco and Mobil. In early 2000, Chevron took over as operator.[2]

In January 1996, the SDA *Annual Review of Petroleum Resources as at 1-1-1996* (the "1996 SDA ARPR") estimated the Gorgon field gas volumes at 9.40 tcf (2.69 tcf Shell share) and categorized these as expectation reserves. In January 1997, the SDA *Annual Review of Petroleum Resources as at 1-1-1997* (the "1997 SDA ARPR") maintained this categorization of the Gorgon volumes.

SCA 00000191

At the end of 1997, SDA categorized 2.39 tcf (Shell share) Gorgon volumes as proved reserves. The Shell Group then included this natural gas (504 million boe) among the data set forth in the supplementary section of the Group's 1997 Report on SEC Form 20-F filed April 17, 1998, specifically in the line in the natural gas table for "Revisions and reclassifications" (net 2.022 tcf). The Gorgon volumes were not reported in the natural gas table line for "Extensions and discoveries" (net 2.664 tcf). The Form 20-F description of Australian activities mentions that the Gorgon joint venture was "evaluating various LNG project options." The document otherwise contains no direct reference to the Gorgon field or its newly categorized proved reserves.

Shell's 1997 reserve replacement ratio ("RRR") including the Gorgon proved reserves was 159%. Without the 504 million boe of new Gorgon reserves, the 1997 RRR would have been 121%.[3]

III. 1997-98: The Missing Audit Trail

There is a dearth of formal documentation as to why and by whom the Gorgon proved reserves booking was first approved. In addition, no one has been identified who has acknowledged a specific recollection of the decision to categorize Gorgon volumes as proved reserves. The commercial and strategic background to the decision is, however, clearly described in a number of internal reports.

SCA 00000192

A. The "Window of Opportunity"

On December 12, 1997, Philip Watts, then the Group Managing Director responsible for EP, and a Group Managing Director responsible for Gas & Power ("GP"), approved and countersigned an SDA "Group Budget Proposal." Under the cover of a "Note for Discussion," the proposal was provided to the CMD at a meeting held on December 16, 1997.[4] The Note was jointly submitted by John Colligan, the EP Regional Business Director for Australasia, and the GP Regional Business Adviser for Australasia. Among other things, the budget proposal sought

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US$52.9 million to finance Shell's share of the costs of studies and appraisal wells aimed at a possible coordinated effort to develop and market gas reserves in Gorgon and the North West Shelf ("NWS"), a gas project also located off the northwestern coast of Australia and operated by Woodside, an Australian company 34% owned by Shell.

The budget proposal stated that "a window of opportunity" existed for both the Gorgon joint venture and NWS to "grasp market opportunities in 2003 in Japan and possibly earlier in Korea." The document identified the Korean market as "the most likely opportunity for at least one train of Gorgon LNG from 2003," and noted that a "second Gorgon LNG train is assumed to come on stream in 2005 to supply requirements in one or more" of the Asian markets. Previously, the September 1997 *SDA Business Plan for 1998-2002* had set the objective of reaching "a sales agreement for at least one train CTMS gas to Korea." In addition, the September 1996 *SDA Business Plan 1996* described a strategic goal of adding "two more LNG trains (or about 7 mtpa), coming on-stream in 2003-2005, for sales to Japan."[5]

Notwithstanding the LNG sales "window of opportunity," the December 1997 budget proposal acknowledged that a final investment decision ("FID") would not be taken "until satisfactory customer agreements are in place." The proposal also emphasized the importance of "demonstrated capability to supply" as the key to maintaining perceived buyer interest. The report made no mention of booking proved reserves, noting only that "[c]urrent work indicates that Gorgon reserves are sufficient for a co-operative development."

A "market window of opportunity" for Gorgon is mentioned at nearly the same time in a December 13, 1997 e-mail from Arthur Dixon, the GP Regional Business Director for Australasia, to Roland Williams, then the SDA Chairman (cc Colligan, van de Vijver, others).

The e-mail indicates that Williams was a strong supporter of the budget proposal to CMD, and that the proposal faced significant hurdles:

> "It is fair to say that within the Centre, there are mixed feelings towards the 'Gorgon' development. On the one hand, there are substantial reserves and they are developable as a brownfield (co-operative) expansion of the NWS facilities; on the other, the field is difficult to develop, it does contain CO2 and . . . well, the partners. I don't think I could support the CTMS stand-alone case and although this will be under constant review with you during next year, we should recognise that at present this looks most unlikely to enjoy shareholder support."

In other messages around this same time, Williams, Dixon and Colligan shared views on dealings with the Gorgon participants and other topics relating to possible development of the field. In this context, Colligan on December 12, 1997 mentioned a series of questions raised by Watts, and Williams in a December 15, 1997 response alluded to an upcoming visit by Watts, during which Williams intended to show him Barrow Island, the site of a stand-alone facility option that Williams opposed. (Watts did later visit SDA facilities, apparently in early 1998.)[6]

B. The SDA Appraisal & Strategy Review

Toward the end of February 1998, SDA finalized its *Appraisal of 1997 & Strategy Review* ("1997 SDA ASR"), the product of an annual series of meetings and discussions among SDA personnel and senior managers from The Hague. The 1997 SDA ASR reported that in June 1997, the Gorgon joint venture participants had agreed to pursue a unified marketing effort in order to avoid "potentially damaging forays into the Korean market by some of the Venture partners." The document also stated that numerous joint visits to the Korean buyer KOGAS had "established a good relationship" and led to a November 1997 discussion of KOGAS purchase conditions, and that KOGAS had "requested the feasibility of early LNG sales in 2002 which is presently being investigated."

In addition to these items, however, the 1997 SDA ASR reported that "[t]he recent Asian economic crisis has cast a shadow of uncertainty on projected LNG demands especially in Korea. Short term cuts in LNG imports appear likely but the impact on long term requirements is still unknown." The 1997 SDA ASR further stated:

> "Korean demand will likely be down against expectation by some 10-20% for 1998 and possibly 1999 . . . . Accordingly the response to previous discussions indicating a window of opportunity, if a late 2002 first delivery is possible (which would entail shortcuts to the normal approval and project processes and pre-investment before FID of some $300m (Shell Share of exposure $15m)) will not be pursued until an update on market condition is received."

As these February 1998 observations on 1997 marketing efforts and the effects of the Asian crisis demonstrate, circumstances that were later cited in questioning the Gorgon booking "in hindsight" were well understood at or about the time of the booking.

C. Recollections of SDA Managers

Marius Bremmer, the SDA General Manager in 1997-98, recalled that he had opposed characterizing Gorgon volumes as "commercial" reserves in a pair of October 1997 meetings in The Hague with Colligan, the EP Regional Business Director for Australasia, and Dixon, the GP Regional Business Director for Australasia. In addition, based at least in part on his own contacts with Watts, Bremmer understood that categorization of the Gorgon reserves had come to Watts's attention in connection with strategic planning as to Woodside, the Australian company that was 34% owned by Shell and that operated, among other things, the NWS project. According to Bremmer, since 1996, Shell had considered various options relating to Woodside, including acquisition, as part of an overall strategy of increasing Shell's position in the

Australian gas export market. He understood that it would have been helpful to this strategy if SDA's value reflected the unit's 2/7 share of the substantial Gorgon reserves.[7]

Bremmer has stated that he was unaware of the Gorgon proved reserves booking until the January 2004 recategorization announcement, and he has expressed the view that the booking was an "absurd" action that was inconsistent with reasonable reserving judgment.

Williams, the SDA Chairman at the time, generally recalled efforts in 1997-98 to develop a market for gas from the Gorgon field, but indicated that his focus was on commercial expectation reserves and that for him booking SEC proved reserves was irrelevant. He has also stated that there was nothing "funny" going on in connection with the Gorgon booking.[8]

The SDA CFO from mid-1997 to May 1999 had no recollection of any discussions among SDA management as to booking Gorgon reserves. He has stated that he was surprised to learn of the Gorgon proved reserves upon the January 2004 recategorization announcement.[9]

D. Recollections of Group Executives

Bremmer's version of late 1990s goals and strategies that related to the Gorgon reserves is generally consistent with an analysis offered by the former GP Regional Business Adviser for Australasia. The EP Regional Business Adviser for Australia has said that he has no specific recollection of any discussions as to booking Gorgon proved reserves, though he indicated that such discussions must have taken place and generally recalled an eagerness in 1997 to progress development of Gorgon. The EP Regional Business Adviser also indicated that he was surprised to learn of the existence of Gorgon proved reserves upon the January 2004 recategorization announcement.[10]

SCA 00000196

Colligan, who is retired from Shell, characterized proved reserves bookings, including Gorgon, as "routine" events, and he did not recollect that he had a role in categorizing the

Gorgon reserves. (He otherwise indicated an unwillingness to participate in a full interview conducted by outside counsel.)

Watts, Dixon, and the GP Regional Business Adviser for Australasia have all denied any recollection of the initial Gorgon booking. (It should be noted, especially in the case of Watts, that at the time these individuals were interviewed, various documents that might have refreshed their recollections were not available.)

*E. **Reporting the Proved Reserves***

Despite the lack of specific recollections and the absence of a clear audit trail with respect to the decision to book Gorgon proved reserves, there are records of the process whereby the proved reserves were reported by SDA.

On January 22, 1998, the SDA Reserves Coordinator delivered to Remco Aalbers, the Group Reserves Coordinator, signed worksheets providing data on Gorgon reserve categories as of January 1, 1998, including new proved reserves of 9.83 tcf, with Shell share of 2.81 tcf. A few days later, on January 31, 1998, Aalbers asked the SDA Reserves Coordinator by e-mail why the size of the newly reported 9.8 tcf (2.81 tcf Shell share) of proved reserves exceeded a reported 2.4 tcf (.68 Shell share) increase in expectation reserves. The SDA Reserves Coordinator responded to Aalbers the next day. He stated that proved reserves had been reported at zero as of January 1, 1997, and that the increase in proved reserves "must have been pending a revision which has now been implemented."[11] Aalbers recalled the message and has provided an explanation of this exchange.

SCA 00000197

According to Aalbers, as of January 1, 1997, a large volume of Gorgon expectation reserves had been booked but without any corresponding proved reserves. This was unusual, but not out of line in a situation such as Gorgon where there were large, technically probable volumes but little or no commercial maturity. However, because expectation reserves are usually associated with at least some proved reserves, the reporting system "books" proved reserves along with the expectation reserves, even if the proved category is marked "0". For these reasons, the SDA Reserves Coordinator at the time of the booking apparently believed – and Aalbers accepted – that the new proved reserves represented implementation of a revision to the existing (though empty) proved reserves category. A partial cause of this technical mix-up may have been that Aalbers had assumed the position of Group Reserves Coordinator just weeks earlier, with no specific training and no handover period with his predecessor. The Reserves Coordinator had only joined SDA in the fall of 1997, also without training or communication with his predecessor.[12]

All in all, these circumstances seem to provide a plausible explanation for the inclusion of the Gorgon proved reserves among "Revisions and reclassifications" rather than "Extensions and discoveries" in the 1997 Form 20-F natural gas data table. The potential confusion over Gorgon reserves "pending a revision" is, however, less satisfactory in explaining why the new Gorgon proved reserves were not reported in the narrative section of the Form 20-F. While noting that a modest oil reserves increase in 1997 arose mainly from revisions in Nigeria, UK and Oman fields, the 20-F makes no reference to the Gorgon "revisions," which accounted for nearly 60% of the year's overall increase in gas reserves.[13]

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On or about January 29, 1998, just days prior to his exchange with Aalbers as to classification, the SDA Reserves Coordinator distributed the *Annual Review of Petroleum Resources as at 1-1-1998* (the "1998 SDA ARPR") to various SDA managers. The report describes a "technical revision of Gorgon field" resulting in a 2.39 tcf (.68 tcf Shell share) increase in expectation gas reserves, but does not mention the recently reported 9.83 tcf (2.81 tcf

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