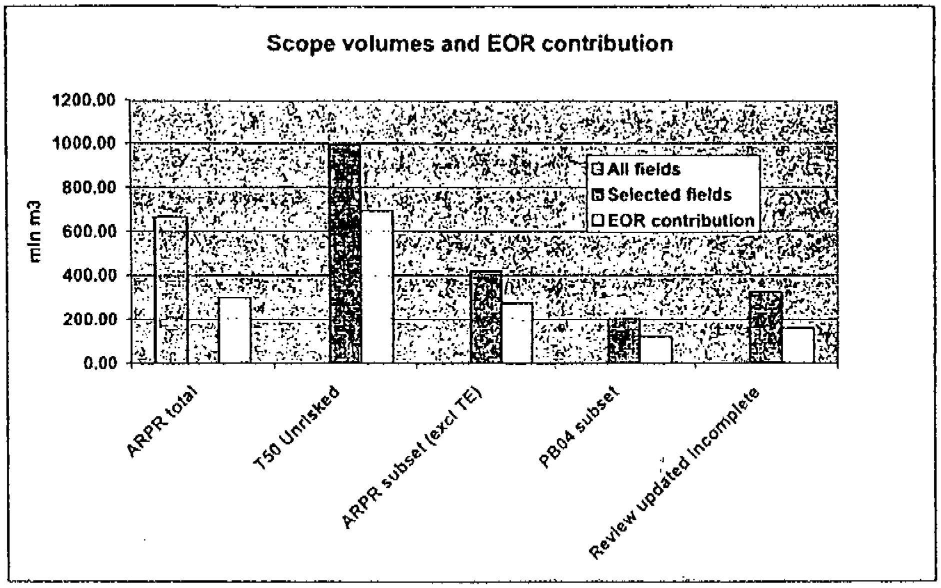
For PDO's current state of maturity, far too low a proportion of STOIIP has been identified in the ARPR as Scope for Recovery (SFR). Although a full scope identification exercise was outside the objectives of this review team, the arrow indicates the magnitude of change that might be appropriate for PDO. This is important because it flags the need for additional studies to mature the STOIIP to reserves. Unless the scope is identified and studies resources are justified by the promise held by the scope volumes, there will be no progress.

The following plot shows a comparison of the 2001 T50 exercise with ARPR scope projects, the PB04 programme build and the review team's view, for the fields reviewed:



From the plot it can be observed that:

- The unrisked T50 estimates are considerably higher and considered as optimistic. However, they represent the true aspiration, including a large EOR contribution.
- The PB04 covers only about half of the scope identified in the ARPR for the subset of fields reviewed, i.e., there are insufficient resources planned in the work programme to follow up on scope ideas and aspirations
- Review team has identified a number of scope upsides, and reclassified some reserves to scope due to lack of maturity

Further observations are:

- There is no systematic scope identification process across PDO;
- Except for 3 EOR projects (Mukhaizna, Harweel and Qarn Alam), there is a general lack of a life cycle approach to development planning, which should include the options for EOR. This seems especially true for the heavy oil accumulations;
- There is little ownership in many asset teams of all the scope projects in the ARPR. Staff are, in general, too busy with ongoing projects.
- PDO is moving towards better scope (SC will include scope as part of VAR2,3) and long term EOR options (EOR strategy team reporting out in March)

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3.5 *Scope in 2004/2005 forecast*

The review team was asked for an opinion on the elements of the 2004 and 2005 forecasts still labelled as scope, since this suggested a lack of robustness. The following table lists the fields with the PB04 and review team views.

Field	Scope production 2004 / 2005 (b/d) PB04 2004	PB04 2005	Review Team 2004	Review Team 2005	Comment
Fahud	3500	9660	3500	9660	WF scouting study proposed project risked at 50 %
Al Burj	2040	3940	2040	3940	MSZ infill drilling: low risk
Lekhwair	2640	6080	940	4530	Lekhwair B LS-A at risk
Al Huwaisah	1550	2930	1550	2930	East Flank has reserves status, Main Area properly risked
Rima	630	2340	630	2340	Not reviewed
Irad		2790		2790	Not reviewed
Total	10360	27740	8660	26190	

- In general, there is not a large threat to the forecast as most of the projects are robust, but have not gone through the official booking process. The main exceptions are Fahud and Lekhwair B, Lower Shuaiba A.
- The Fahud production pertains to waterflood pilot projects, which in PB04 took forecasts from the water flood scouting studies (WFSS) risked at 50%. The status of the planning in October 2003 is that the location and design of the wells is still under discussion but that data acquisition will take priority over production.
- The review team recommend delaying the Lekhwair-B, LS-A scope project by one year to allow completion of an FDP for the combined development of the LS-A and B including miscible WAG analysis. The impact of a one-year re-phasing on 2004/2005 production is reflected in the above table, PB04 versus review team.

As a general point, there are many Undeveloped Reserves projects that have a similar risk to the above scope projects, particularly with respect to potential delays on project approvals related to tight study programmes, VAR3 and FDP schedules. The Dhulaima Lower Shuaiba waterflood development is one example (see Appendix). Such scheduling/ approval exposures are not (transparently) captured in the PB04 forecasts.

The review team notes that inclusion of scope volumes in the short term (<2 years) production forecast is not a recommended practice, unless these volumes are sufficiently risked for the possibility that these volumes do not pass the FDP and VAR milestones.

3.6 *Hydrocarbon Maturation*

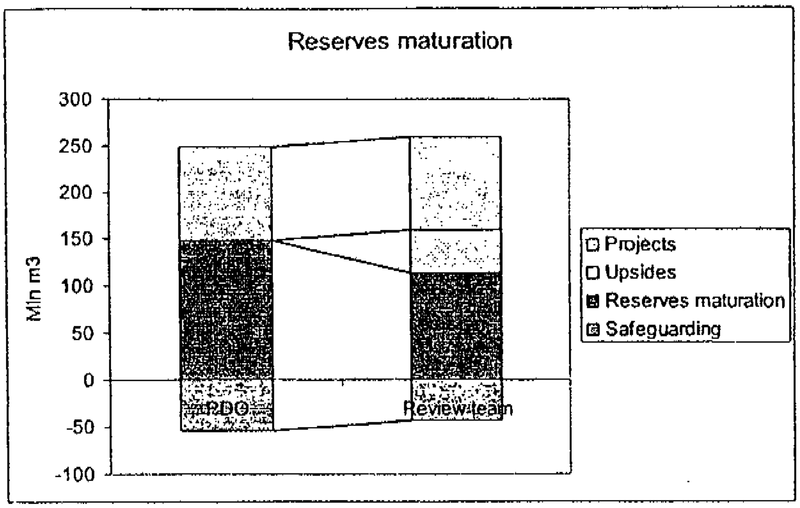
PDO reserves maturation plans were reviewed. PDO's maturation efforts will be focused on three areas:

- Safeguarding, i.e. doing studies and producing FDPs aimed to prevent de-booking of reserves for which the basis is no longer clear
- Maturing scope volumes to reserve volumes through studies and producing FDPs
- The Mukhaizna and Harweel project implementations will also result in reserves maturation

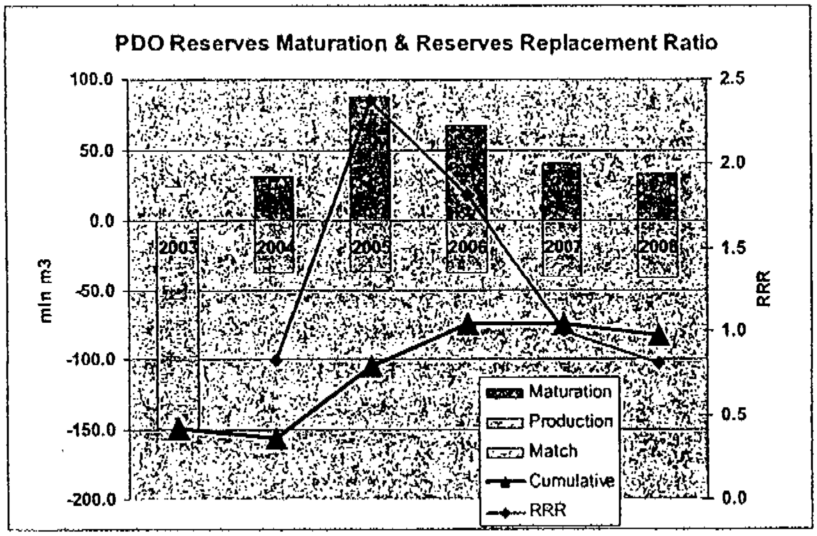
PDO's plans to safeguard reserves, and mature scope volumes to reserves through studies and FDPs are supported, although some of the volumes and timings appear to be optimistic.

However, the review team identified a number of potential upside opportunities, demonstrating that there are significant additional maturation opportunities not identified or captured in the 2004 Study Plan. A comprehensive exercise could yield more upsides.

This is summarised below for the 5 year period from 2004-2008, from the PDO perspective and with the review team's opinion alongside.



Aggregation of the maturation and production forecast data (i.e. assuming safeguarding is successful) results in the following overall picture of PDO's annual and cumulative reserve replacement, starting with the match volume:



- The reserves expected to be matured through studies, along with the upsides examples identified by the review team result in an average Reserves Replacement Ratio (RRR) of about 1 over the 5 year period
- The additional reserves expected to be matured by the Harweel and Mukhaizna projects help to compensate for about half of the reserves match volume.

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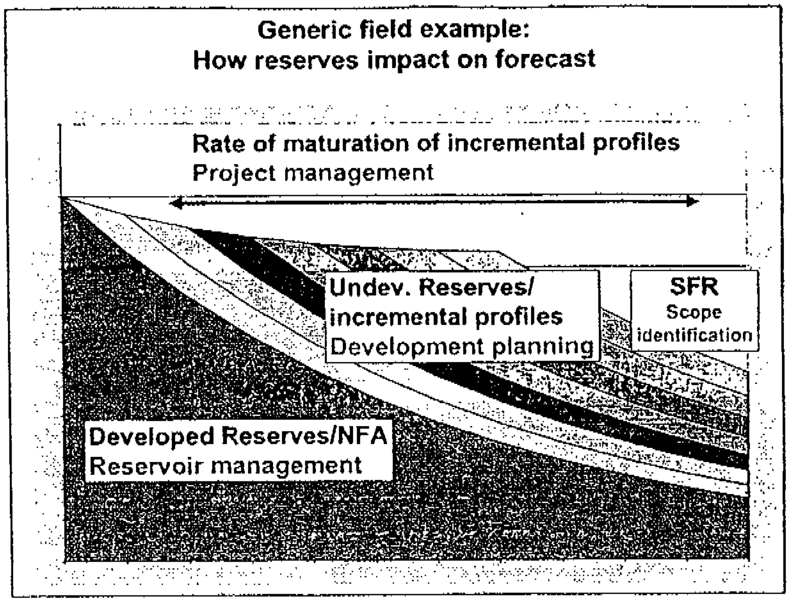
- The declining RRR at the end of the 5 year period indicates the necessity to maintain or increase the pressure on the hydrocarbon maturation process, with likely more emphasis on IOR and EOR processes.

The review team had considerable difficulty in unravelling the audit trail for the data underpinning the 5 year study plan:

- ARPR Scope Sheets / Study Plan TORs were inconsistent e.g.Yibal field Natih reservoir STOIIP missing from ARPR; old scope sheets, etc
- TORs included data from the waterflood scouting studies which superseded the 1/1/2003 ARPR with no clear audit trail
- Inconsistent approach to process. E.g., in some cases POS not applied to volumes
- In many instances the scope identification process appears rushed and unstructured. Perhaps a technical limit approach template/check list should precede the scope sheets as an aide to retain corporate memory through annual ARPR and programme build exercises
- The study plan is ambitious and will require careful management. Caution is advised with respect to planning multiple key VARs towards year ends – end 2004 already appears to suffering from a VAR logjam.
- In general, it appears that it is very difficult to get a consistent approach across multiple fields and asset teams – this applies to ARPR, Program Build, Scope & Maturation. Great care will need to be taken for the new Reserves Guidelines

3.7 *Impact of business processes*

The overall production forecast is made up of several elements, each of which is the result of a distinct business process, as illustrated in the following generic field example:



The overall quality of the reserves and production forecasts depends on the quality of the business process itself. For example, developed reserves are estimated in various ways, as part of the reservoir management process. How well this can be done depends on the quality of the data, the quality of the Well and Reservoir Management process, the quality of the models they use, etc. This chapter reports on the business processes as they impacted on PDO's reserves estimation and production forecasting, as seen by the review team.

3.7.1 Reservoir management

Good well and reservoir management (WRM) is fundamental to optimising recovery, and even more important when embarking on expensive EOR projects. The review team found a number of shortcomings in WRM in PDO.

There are serious weaknesses in production **metering** in most fields (refer field Appendices for details). Improvement plans are being implemented but this will take another 1-2 years to complete. Even if metering improvements are implemented, it will be difficult to compensate for lost historical measurements. Since locating the remaining oil in reservoirs depends on good historical data, some ultimate recovery may have been compromised. Only a sustained effort of intensive surveillance, good measurements, intensive WRM and studies can help to redress the balance. It can be difficult to evaluate the **benefits of good metering**, to justify the investments. In Qarn Alam, a retrospective evaluation of the errors in production measurement and allocation, that caused a 2 year deferment of the project, put the cost at $45mln from deferred NPV, and 10 man years of PE staff.

In most cases, developed reserves were estimated using **decline analysis**. This could be well decline, reservoir decline or field decline. Decline analysis has a large uncertainty and very little physics. Furthermore, the way decline analysis has been applied varies by field team and was, in some cases, quite arbitrary, with fitting of exponential decline curves to a few historical points (e.g. Marmul). As a consequence, there is a risk that undeveloped reserves, and the activities needed to realise them, may be over- or underestimated.

In many fields the focus of water injection has been more on **water circulation** than on waterflood management. By-passing of injected water via fractures, whether induced or natural, is evident in a number of reservoirs (Yibal, Haima West, parts of Lekhwair, Saih Rawl etc.). Increased water circulation brings no additional oil and there is concern that additional facilities are being planned/installed, that may not be required, as production and value generation might be better achieved through enhanced focus on waterflood management.

Water injectors are not routinely temperature surveyed to determine whether **water is injected out of zone**, for example, into shallow aquifers. It is recommended that all water injectors are temperature logged to identify where the water goes. This could, potentially, save considerable costs from ineffective injection, as well as protect shallow aquifers.

There are **opportunities** to improve WRM. An excellent example was noted in Saih Rawl, where the temperature sensors on ESP pumps were used to detect induced fracturing and by-passing of injected water. With the increased focus on WRM it can be expected that more opportunities will emerge.

Oil content of injection water in many PDO fields is around 200 ppm or more, plus solids. It is very difficult to inject such water into low permeability reservoirs without fracturing/short-circuiting. Such learnings should be shared across PDO, to prevent unnecessary induced fracturing, recovery damage and production deferments.

3.7.2 Studies/field development planning

Since 2001, PDO has been implementing new guidelines whereby reserves can only be booked once a VAR3 has been approved and an FDP issued. This has necessitated a large "catch-up" programme of study work. A study centre has been set up, with the aim of bringing 80% of PDO's undeveloped reserves to VAR3 maturity within 5 years.

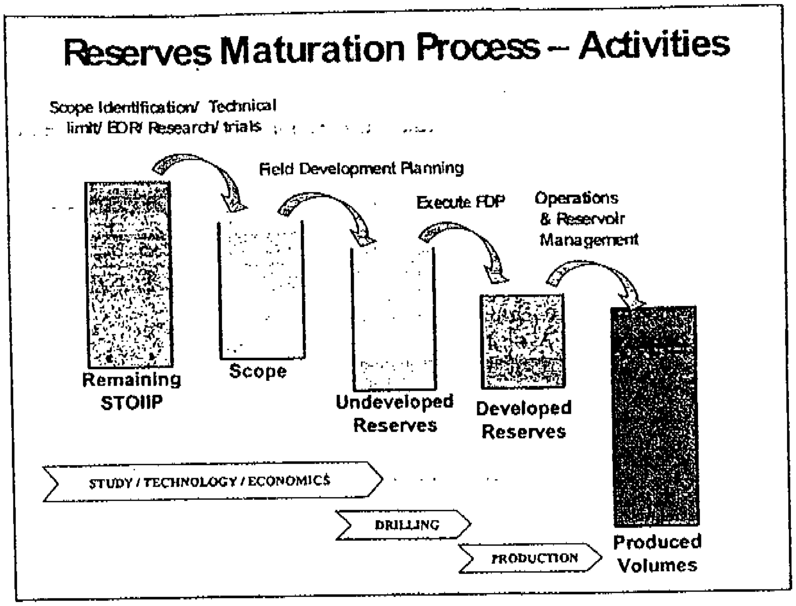
The review team noted that a progressive disconnect often occurred between an issued Field Development Plan (FDP) and subsequent Programme Build exercises, which tend to take priority (e.g. Saih Rawl). It is important that an issued FDP has an owner, who will continue to use the FDP as the basis for field development, notwithstanding annual programme build updates, which may be more recent, but do not have the same depth as FDPs.

3.7.3 Scope identification

As discussed in section 3.4, scope identification has not received sufficient priority. As a result, scope volumes are low in relation to the remaining STOIIP, and insufficient effort has been assigned to scope maturation to reserves, and this is now starting to impact the production level.

3.7.4 Maturation management

PDO has recognised that insufficient attention has been paid to maturation of resource volumes. A process is being put in place to manage volumes maturation. The following diagnostic picture helps to assess the state of health of a producing asset:



- STOIIP volumes are matured successively into scope, undeveloped reserves, developed reserves and, finally, production, by executing the processes shown above the buckets.
- To sustain a production level for the long term, it is necessary to mature the same volume (risked) from each bucket to the next in the same time
  - For example, to sustain 650 kb/d, it is necessary to move a risked volume of 237 mln bbls from each bucket to the next, every year
- If volumes are concentrated on the right, in developed reserves, production is likely to decline soon unless action is taken; for sustainable production there needs to be a balance of volumes at all levels of maturity

Christian/Wim: We had an automated plotting facility for this. Maybe it can be run for all fields and one or two illustrative examples selected ?

3.7.5 Organisational capability

The review was not specifically targeted at assessing organisational capability, yet it was clear from the review results that there were shortcomings in this area. Although we were on occasion asked to include in our review assessments of the "right" staffing levels, this was beyond the scope of this review. With the large increase in Petroleum Engineering staffing level during the course of the review, any assessment would have been out of date before it was published.

Nevertheless, it was possible to draw some conclusions about organisational capability, supporting PDO's increases in PE staffing level.

The main shortcomings in PDO's hydrocarbon maturation process are:

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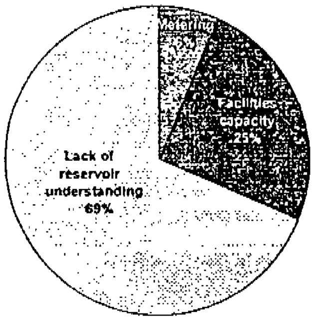
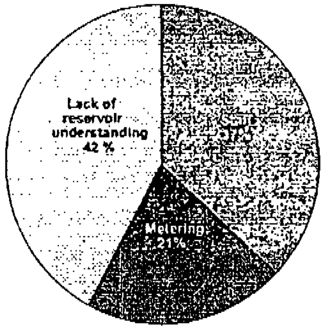
- lack of staff work in studies and generation of FDPs;
- lack of metering;
- lack of Well and Reservoir Management (WRM).

The underlying reason for these shortcomings is the (lack of) organisational capability. Clearly, there were many activities that needed to be done, but did not have resources assigned to them. The manpower shortage manifested itself in many ways. As shown in the following figures, the key bottlenecks to production are not facilities, but understanding of the reservoir. Petroleum engineers do not understand their reservoirs sufficiently well to know how to get more production from them. When asked about the key bottlenecks to (short term) production, and the threats to hydrocarbon maturation (longer term production), the 16 field teams answered as follows:

Key bottlenecks to production



Threats to HC maturation



The lack of staff and lack of reservoir understanding go hand in hand. This is compounded by the lack of metering so that, even if the staff were available, their task is made more difficult by the lack of adequate production data. Clearly, it is essential to improve reservoir understanding, and this is currently being addressed by the creation of a studies centre and the staffing up of petroleum engineering departments.

A factor closely linked to both staff shortages and lack of reservoir understanding is the loss of corporate memory due to staffing discontinuities in teams and frequent internal staff moves. The lack of a centrally managed library and document management system has also led to a poor retention of, and accessibility to, key reports and data and hence further loss of corporate memory.

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4 Recommendations

Well and Reservoir Management

- Continue to improve the measurement of all fluids produced from, or injected into, all reservoirs. Adopt minimum quality requirements for such measurements, and audit facilities against these standards.
    - Devise methods/surveillance to compensate for lost historical production data
- Continue to implement, and improve the standard of, well and reservoir management (WRM), as this is a pre-requisite to optimising recovery, particularly when implementing expensive EOR processes.

Field development

- Implement company-wide technical standards and quality control for saturation height functions and petrophysical properties (N/G, porosity, saturation, fluid contacts)
- Key to successful field development and unlocking production are to understand what is happening in the reservoir. This means, for example:
    - Knowing the location of the remaining oil (this includes measuring production, good WRM, good reservoir models etc.);
    - Knowing where injection water is going from the well bore (temperature surveys), how it travels in the reservoir, and how it displaces and recovers oil;
    - Having field development plans (FDPs) that capture the current development in the context of the full life cycle strategy, working the plans and updating them when necessary (e.g. 4 year cycle, unless a shorter cycle is advised);
        - Field developments should be designed using a life cycle approach, including the Well and Reservoir Management activities and surveillance required to optimise ultimate recovery.
    - Managing reservoir voidage to optimise oil recovery;
- Integrate reservoir knowledge of all subsurface disciplines in state-of-the-art reservoir models, keep these up-to-date and use these to support business planning (e.g. programme build)
    - Simulation models should be kept "evergreen" i.e. used as a reservoir management tool on a daily basis and regularly updated with the latest data.

Reserves and scope accounting/planning procedures

- Develop Code of Practice for reserves booking according to the new standards, including rules for managing transition from old to new standards, and how to align with MOG
    - It is recommended that PDO, in agreement with the MOG, provide guidelines on when STOIIP and/or Ultimate Recovery figures should be updated
    - Consider alternatives to the current 30 year reserves booking window, to reflect the true ultimate recovery for a given development plan/process
- Identify scope systematically, develop maturation plans, inc. EOR, work the plans and track progress. This is a pre-requisite to sustaining production. A VAR approach is recommended, starting with the formulation of an EOR strategy, definition of range of EOR options, etc.
- Improve the QA/QC of the technical content of centrally coordinated submissions (reserves reporting, programme build input, scope volumes inc. POS assignment, maturation estimates)
- Agree on a company wide approach for handling reserves match volumes and communicate this clearly to the teams

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- Company wide guidelines and standards are required for forecasting tools and methods. This should include decline curve analysis methods and simulation generated forecasts with advice on which methods are preferred in which contexts.
- Increased consistency is required between FDP's (issued every 3-5 years) and PB projects (issued annually). Life-cycle costs and longer term development considerations identified and accounted for in FDP's need to be incorporated and maintained in PB projects.
- Increased focus within PDO at the corporate, team and staff levels to ensure corporate databases are kept up to date.

Reserves Maturation

- To manage the maturation process successfully it will be necessary to have clear and auditable processes, with consistency between ARPR, scope sheets, programme build, maturation plans and study plans, with clarity of application of various POS factors
- The study plan is ambitious and will require careful management. Caution is advised with respect to planning multiple key VARs towards year-ends. End-2004 already appears to be suffering from a VAR logjam.

Corporate Processes

- In general, it appears that it is very difficult to get a consistent approach across multiple fields and asset teams. This applies to ARPR, programme build, scope and maturation. Great care will need to be taken for the new reserves guidelines.

Part 2. Review Findings

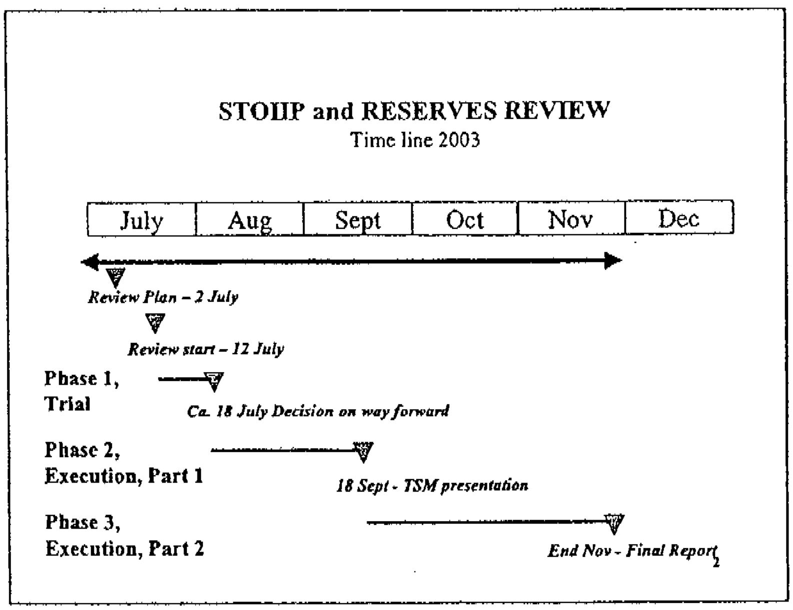
5 Introduction

Concerns about the robustness of PDO's STOIIP and reserves were raised by PDO's failures since 2001 to produce the forecast volumes. In early June 2003 Shell and MOG agreed that Shell would review PDO's STOIIP and reserves. The review objectives were for Shell to provide a second opinion on the robustness of:

- PDO's STOIIP estimates;
- PDO's oil reserves estimates, including views on:
  - the 700MMb reserves "match" volume (booked reserves without development plans)
  - scope volumes in the 2004/2005 forecast;
- PDO's reserves maturation plans, including looking at the pre-requisite activity plans/study work.

The review included 16 of PDO's largest fields, plus some of the fields in the waterflood scouting studies, such that about 80% of PDO's STOIIP was covered, with priority given to fields with the above issues. It was expected that the main systemic issues would be identified using this field selection.

The review was started in July, interim results were presented at the TSM on 18th September, and the review was completed in November.



STOIIP estimate was formulated based on a brief review of key field data and associated evaluations, and on the assessment of quality of work behind both the existing ARPR and current PDO view STOIIP estimates. The derivation of developed reserves was reviewed and the portfolio of undeveloped reserves and scope projects was examined. Simple checks and balances were applied, like various forms of decline analysis and Buckley-Leverett displacement calculations. In addition to interviewing field teams in PDO, study teams in Rijswijk, Aberdeen and Houston were contacted for their views.

The technical content of all the field Appendices was verified by the PDO field teams before finalising the report. The main report findings were also shown to PDO to ensure that there are no misunderstandings.

The review process is described in more detail in Appendix……(processes, team members, explanation of analyses)

6 STOIIP findings

PDO's expectation total STOIIP volume is supported by this review. Taken as a whole, the fields reviewed (accounting for ~68% of PDO's total STOIIP) had differences in STOIIP between ARPR1.1.2003, PDO's current view, and this review team estimate of less than 5%. At the individual field level, however, differences in STOIIP estimates between these three views were significant in some cases.

Definitions:

1) **ARPR1.1.2003**: These STOIIP volumes reflect official booked volumes. In some fields the "official" volumes have remained unchanged for 10 or more years.
2) **PDO Current View**: In many fields a significant amount of studies work (wells drilled, etc.) has taken place since the last official update of the ARPR STOIIP volumes. In some cases this has resulted in PDO's current view of a field's STOIIP volume being substantially different from volumes quoted in the ARPR.
3) The **Review team's** STOIIP estimate was formulated based on a brief review of key field data and associated evaluations, and on the assessment of quality of work behind both the existing ARPR and current PDO view STOIIP estimates.

The table and plot below summarise the differences between Review Team's expectation STOIIP estimate, and both the "official" volumes from the ARPR1.1.2003 and PDO's current view on STOIIP volumes.

STOIIP Findings (mln m3)							
Field	Reservoir (major, minor)	ARPR	PDO latest view	Review Team	% Change vs ARPR	% Change vs PDO latest	Comment
Fahud	Natih Shuaiba	1017	1017	1004	-1%	-1%	Possible further reduction associated with E/F/G reservoirs pending ongoing PDO study team
Yibal	Shuaiba Kharib	687	602	602	-12%	0%	Reduction due to removal of "relic oil" below the OWC
Marmul	Haima Al Khalata Gharif	595	523	540	-9%	3%	Still significant uncertainty in Haima low resistivity zone
Natih	Natih Shuaiba	458	458	458	0%	0%	Well constrained by seismic and well data
Nimr	Gharif Al Khalata Amin	426	437	593	39%	36%	ARPR and PDO latest view do not reflect the significant amount of field potential outside booked polygons and upward volume estimates from recent studies.
Mukhaizna	Gharif	375	375	375	0%	0%	Study underway which will yeild new volume estimate by year end 2003
Lekhwair	Shuaiba Kharib	311	311	311	0%	0%	Further upside possible on B, C & D area flanks
Al Huwaisah	Shuaiba	244	216	216	-11%	0%	Reflects results of onging high quality study. Further upside probable associated with NFE
Amin	Al Khalata Mahwis	202	192	173	-14%	-10%	Recent PDO view of West area supported; STOIIP of East not supported, recent depth map of East not based on all wells
Qarn Alam	Shuaiba	186	186	186	0%	0%	GR reduction offset by Sh increase
Ghaba North	Shuaiba	119	119	119	0%	0%	
Saih Rawl	Shuaiba	119	77	77	-35%	0%	Reflects the significant amount of well and study data available since the ARPR booking
Dhulaima	Shuaiba Kharib	94	94	185	97%	97%	Lr Shuaiba + Kharaib supported pending results of ongoing study. Increase reflects 1999/2000 Up Shuaiba review.
Amal-West	Al Khalata Amin Gharif	93	93	110	18%	18%	Potential Sh and minor GRV increase
Al Burj	Mezozoic Clastics Gharif	87	100	115	33%	15%	Inclusion of non-booked producing areas and preliminary study results
Barik	Gharif	64	64	64	0%	0%	Well supported by studies
Total		5077	4864	5128	1%	5%	

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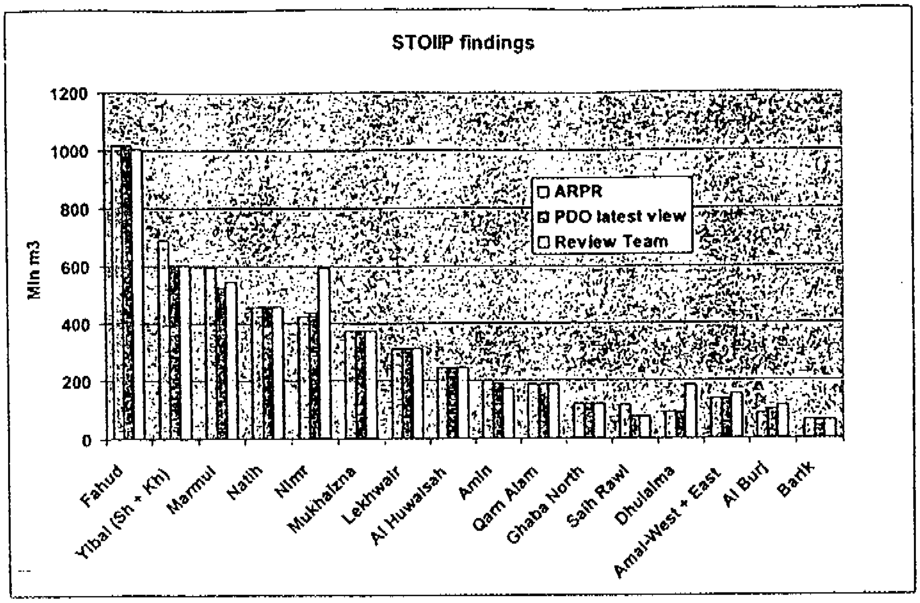

6.1 Discussion By Field

The colour coding of the field names in the sections below is used to highlight direction of STOIIP volume changes between the ARPR1.1.2003 and the Review Team's view (red=decrease; black=no change; blue=increase).

Fahud: Natih reservoir STOIIP values were improperly revised in ARPR2002 (from 1029.9 to 1004.2 mln m3, rather than the intended 992.1 mln m3). This book-keeping error was caused by unclear wording and structure of Fahud STOIIP and reserves revision documentation, and by lack of ownership of values in the ARPR document by the field team. As a result Natih STOIIP volumes in the ARPR for Fahud SW were not updated in the ARPR as intended.

There is also potential for a revision in STOIIP volumes associated with the Natih E, F, and G reservoirs. Early work by the field study team indicates a calculation error may have been made in the SUPERVOL calculations associated with the current ARPR volumes for these reservoir units. Additional work by the field study team to confirm this is in progress.

Yibal: The Review team supports PDO's field team proposal to de-book STOIIP volume associated with possible low saturation "relic oil" below the OWC. There is conflicting evidence as to whether this "relic oil" exists or not. A core is planned below the OWC to provide definitive evidence and is required to support any de-booking.

Marmul (Haima West): The review team supports PDO's view that currently booked expectation STOIIP (202 mln m^3, ARPR1.1.1999) volume should be reduced to 126 mln m^3. Significant uncertainty still exists associated with the "upper" Haima lower resistivity interval which should be reflected in the high and low case uncertainties. Additionally, the GRV used in the ARPR1.1.1999 volume calculation appears incorrect as it does not match the GRV volume (which was 11% smaller) quoted in the associated 1999 studies report.

Marmul (Al Khlata): Current ARPR STOIIP volume (234 mln m^3) dates from 1983 despite some 200 wells having been drilled since. A current PDO study indicates expectation STOIIP

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will increase to at least 250 mln m³. Quality of reviewed ongoing study work is considered excellent.

Marmul (Gharif): ARPR STOIIP (38 mln m³ in S-rim, 75 mln m³ in N-rim) is supported. This is based on a detailed South rim study and a North rim study which is being finalised. Both Gharif rims have moderate levels of uncertainty related to structural depth maps. Net pay uncertainty is an additional issue in the South rim area.

Natih: STOIIP volume is well constrained by abundant well and reservoir data. While minor revisions are possible the existing booked STOIIP volume is supported.

Nimr: PDO's current approach to Nimr, as a series of discrete field sub areas each with tightly defined booked area, has resulted in a very significant underestimation of STOIIP in the total field area. This cookie cutter approach and lack of ownership of near field potential by either the field team or exploration has resulted in volumes outside the existing booked polygons being effectively missed out.

A review of existing and ongoing Nimr area studies indicates that STOIIP, as reflected in the ARPR and in the field team's current view, very likely underestimates total Nimr STOIIP by a wide margin (426 vs 593 mln m^3). This conclusion is supported by the success of recent wells drilled outside the booked areas. Nimr also has production from wells located outside any booked STOIIP volume.

Nimr C which, based on the most recent study, contains 115 mln m³ of STOIIP, has been effectively orphaned by the PDO field team as a result of lack of manpower.

The Review Team recommends a major shift in PDO's studies approach to Nimr with a view to understanding the field area as a whole, rather than the current approach which focuses entirely on limited discrete subsections (Nimr A, B, C, E) of the field.

Mukhaizna: The field team does not have a current view on STOIIP. However, a field study, coupled with extensive data gathering and new seismic, is under way and is expected to provide a revised STOIIP estimate by year end 2003. Pending the results from that study the Review Team supports retaining the existing ARPR volumes, as volumetric issues are too complex for a quick estimation.

Lekhwair: The existing STOIIP volume is supported. Upside potential does, however, exist primarily associated with the B, C, and D area flanks which are not always well constrained by available data.

Al Huwaisah: The existing STOIIP volume will likely be reduced following completion of the ongoing study. Upside potential does exist, primarily associated with the flank areas and near field exploration opportunities. The current field study, coupled with new seismic acquisition and planned near field exploration wells, is addressing this.

Amin: A recent field study (2002-2003) updated the Amin Field volumes. The review team supports this revised STOIIP volume for the developed west side of this structure. For the undeveloped east side however, which has only limited well control, the map from the recent study was found to significantly overestimate STOIIP, as it did not utilize all available well control. Exploration wells Khaleel 1 to 3 were unknown to the study team, but are essential depth control points. Until the new structure map is revised on the eastern accumulation to account for these wells, the Review team recommends the ARPR volumes for the east side of Amin remain unchanged.

Qarn Alam (Shuaiba): While minor revisions are possible, the existing booked STOIIP volume is supported. Current view is that a GRV reduction associated with a steepening of the flanks will be offset by an increase in oil saturation, which has been supported by sponge core results.

Ghaba North (Shuaiba): Issues associated with Ghaba North STOIIP are very similar to those in Qarn Alam. Ghaba North's lower ranking as an EOR target, however, has resulted in the field being effectively orphaned by PDO due to a lack of manpower.

Saih Rawl (Shuaiba): Current ARPR volumes for the Shuaiba reservoir date from 1995 and as such do not reflect the substantial volume of knowledge (wells, new seismic, petrophysical) gathered about the field since that time. The Review Team supports and commends the quality of the ongoing detailed field study, which is likely to lead to a substantial STOIIP reduction.

Dhulaima: Current ARPR volumes for the Lower Shuaiba and Kharaib are accepted by the Review Team, on the understanding that an update is likely once the current reservoir study is finalised. For the Upper Shuaiba the review team's STOIIP estimate is 127.4 mln m^3 vs the ARPR volume of 36.4 mln m^3. The Review Team volume includes the scope STOIIP volume from in the ARPR and is intended to highlight the large upside potential of this Shuaiba pancake structure. PDO will begin a study of the Upper Shuaiba in January 2004

Amal West: Current structural model in which arbitrary faults are used to "box in" the field is inappropriate and likely to underestimate flank STOIIP volumes by up to 10%. Oil saturations used for the 2000 STOIIP update do not reflect petrophysical work available since 1999. Oil saturation and wettability are key reservoir uncertainties, which require further focus and data collection. Realistic upside in current oil saturation estimates could add 10+ mln m^3 to the current STOIIP volume.

Al Burj: Upward revision of STOIIP volumes reflects the inclusion of areas in the field which are currently producing, yet have never been booked, and the preliminary results of the ongoing field study.

Waterflood Scouting Studies

Fields covered by PDO's Waterflood Scouting Study (WFSS) were also reviewed at a high level.

The bulk of the WF field scouting studies were found to have used the ARPR STOIIP volume as the given STOIIP volume, and focused on accessing the potential of converting those volumes to economic reserves.

For some fields, however, STOIIP volumes were assessed by the WFSS Cluster teams. For some of those fields (Bahja, Wafra, Zauliyah, Hasirah, Rima, and Runib) Petrel models utilizing QC'd existing maps and petrophysical data were constructed. Results of this work yielded STOIIP values within ±10% of ARPR volumes. Smaller fields with limited well and seismic control have a larger STOIIP uncertainty, but would still have only a limited impact on PDO's total STOIIP picture.

6.2 *Issues & Observations from the STOIIP review*

Staff fluctuation has greatly hampered building and maintaining knowledge about fields, aggravated by often poor document and information management. The net result is that some field teams had little direct ownership or understanding of previous work or field knowledge. Direct contributors to the issue are:

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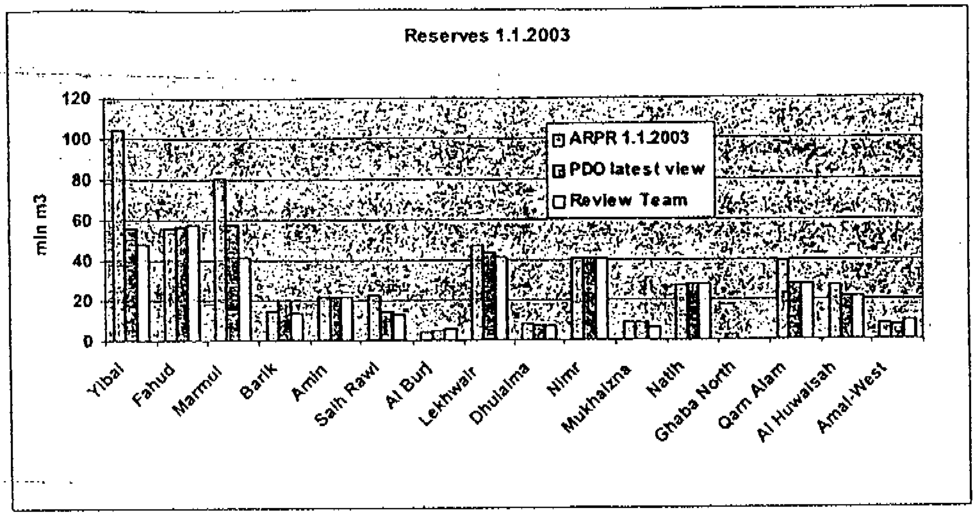
- Frequent reorganisations and initiatives over recent years coupled with frequent staff moves has resulted in most field PE teams having no-one with more than 1 to 2 years experience on the field.
- Lack of a managed central library for document capture and management.
  - Historically, while PDO has not had a strong central library, field/area teams maintained data rooms containing well files and reports. Over recent years, driven by office space shortages and frequent reorganisations, these data rooms have ceased to exist. Individual staff efforts have retained some of these files in office cupboards, but a significant amount of data and captured knowledge has been permanently lost.
  - Many staff are either unaware of how to use Livelink, or reports entered into the system (or it's precursor EDMS) were not indexed properly and can no longer be found. Proper planning, roll out and training are essential for a system like this to function effectively.
- Poorly maintained data in corporate database
  - Petrophysical curves (POR, SH, etc) and other data generated as part of studies have in many cases in recent years not been loaded into the corporate database. Therefore, the data can be out of sync with PDO current view of a field, resulting in a risk of other disciplines' using incorrect data.
  - Lack of strong team and staff ownership and commitment for loading QC'd data to corporate database.

6.3 Conclusions & Recommendations

Consistent application across PDO of saturation height functions and petrophysical parameters like N/G and porosity would help to improve the quality of STOIIP estimation.

7 Reserves findings



Reserves 1.1.2003 (mln m3)				
Field	ARPR 1.1.2003	PDO latest view	Review Team	Comment
Yibal	104	56	48	mostly due to 300 MMbbl debooking of undeveloped reserves
Fahud	56	57	58	
Marmul	81	57	41	Haima- West reduction in undeveloped reserves
Barik	9	20	14	Undeveloped reserves reclassified as scope
Amin	22	22	22	
Saih Rawl	23	14	13	Reduction in undeveloped reserves
Al Burj	4	4	5	
Lekhwair	48	44	43	
Dhulaima	8	7	7	
Nimr	41	41	41	
Mukhaizna	9	9	7	
Natih	27	28	28	
Ghaba North	2	0	0	
Qarn Alam	39	28	28	Reduction in reserves following measurement errors
Al Huwaisah	27	21	21	
Amal-West	7	7	9	
Total	507	417	384	

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PDO's developed reserves are approximately correct. Undeveloped reserves are overestimated, partly because of historical overbookings and partly because insufficient staff work has been done to mature the volumes from STOIIP through SFR to reserves.

The STOIIP and Reserves team has not concentrated on identifying scope volumes. Therefore, team view of Scope for Recovery (SFR) shown in the diagram should not be seen as a view on the overall scope in PDO. Nevertheless, there important conclusions can be drawn about scope and maturation. Please refer to sections 3.4 and 3.6 for more details.

For the 16 fields reviewed, the ARPR 1.1.2003 reserves are 507 mln m3, PDO's June view was 417 mln m3 (-18%), and the review team's view is 384 mln m3 (-24%).

A confusing element in the reserves definition is the 30 year window. As a result, the reported ultimate recovery is not a reflection of the technical recovery process, especially for GOGD and heavy oil developments.

	Developed Reserves (mln m3)			Undeveloped Reserves (mln m3)			Comment
Field	ARPR 1.1.2003	PDO latest view 1.1.2004	Review Team 1.1.2004	ARPR 1.1.2003	PDO latest view 1.1.2004	Review Team 1.1.2004	
Yibal	25	23	34	80	29	10	
Fahud	55	52	52	1	2	2	
Marmul	18	16	16	63	41	24	Halma West WF increment considered scope
Barik	2	2	2	7	19	12	
Amin	8	12	12	13	8	8	
Saih Rawl	13	10	10	10	2	1	
Al Burj	1	1	1	4	4	4	
Lekhwair	35	31	31	12	9	7	
Dhulaima	0	1	1	8	6	6	
Nimr	15	17	17	26	19	19	
Mukhaizna	5	3	3	4	5	3	
Natih	24	25	25	3	1	1	
Ghaba North	0	0	0	2	0	0	
Qarn Alam	1	0	0	38	28	28	Measurement errors lead to use of low case Steam Injection forecast
Al Huwaisah	9	10	10	18	10	10	
Amal-West	7	5	8	1	0	0	
Total	219	207	221	289	182	135	

7.1 Developed Reserves

- Estimates for a large proportion of PDO developed reserves are based on decline analysis, which has a large uncertainty, and very little physics. The risk of this approach is that undeveloped reserves are over or underestimated, with a knock-on effect on development projects (esp. well numbers).
- Based on the evidence presented, the review team found little reason to deviate from the latest PDO view of developed reserves for 1.1.2004, except for Yibal, where some undeveloped reserves were re-classified as developed leading to an increase in developed reserves from 25 mln m3 to 34 mln m3, as these volumes can be realised from NFA optimisation activities without the need for additional wells.

7.2 *Undeveloped reserves*

- Hardly any of the undeveloped reserves in the fields under review are supported by Field Development Plans. This is a new requirement (since 2001) and PDO's studies plan aims for 80% compliance within 5 years. Although the review team has not recommended any change of reserves classification as a result of this transition, it is important that the compliance target is monitored and managed.
- The Yibal reserves reduction identified by PDO has resulted from overestimation of reserves in recent years. The review team also reclassified some of the undeveloped reserves as developed (see above). The recovery factor from the current waterflood, after the above reserve and STOIIP reductions, is still a commendable 56%. In Marmul the Haima West development has been disappointing and the Qarn Alam reduction followed serious metering errors.

7.3 *Reserves Match*

- The reserves match is defined as the difference between the booked ARPR reserves and the development/NFA projects in the program build PB04. A positive match is a reason for concern since it points at booked reserves which cannot be produced during the planning period.
- The following table (in MMbbl, for consistency with earlier reporting) gives the reserves match numbers by field:

Reserves match (MMbbl)			
Field	**PDO view**	**Review Team**	**Comment**
Yibal	301	337	Reduction in undeveloped reserves
Qarn Alam	61	67	Quoted match volume was lower than PB04 numbers. Match caused by low case SI project in PB04
Saih Rawl	42	60	Original quote (42) was low. STOIIP considerably lower
Barik	33	1	PB04 entry error - due to handling of uncertainty in GI project
Lekhwair	18	39	Immature reserves moved to scope
Dhulaima		4	
Al Huwaisah	11	38	Lack of well targets
Ghaba North	14	14	Part of other fractured carbonates in original PDO view
Fahud		-4	
Natih		-8	
Other Haushi	41	41	Not evaluated by review team
Other fractured carbonates	12	12	Not reviewed
Total North	**533**	**600**	
Marmul	151	245	Haima West WF increment is scope until proven by pilot
Al Burj	0	-6	Undeveloped reserves were underreported
Mukhaizna		15	Match project with uneconomic wells removed
Amal-West		-10	Developed reserves were underreported to comply with ARPR bookings
Amin		2	
Harweel		63	Added later, not reviewed
Hazar	16	16	Not reviewed
Rahab	15	15	Not reviewed
Total South	**183**	**340**	
Total PDO	**716**	**940**	

- The review team found a match volume of 877 MMbbl (940 if Harweel is included) as against 716 MMbbl quoted by PDO at the start of the exercise. Increases in the match volume are caused mainly by volumes booked as notional match projects and by reclassification of undeveloped reserves.to scope.
- In the table the column "PDO view" lists the reserves match as provided by PDO at the review kick off in June. In the review team column the Harweel match volume is added.
- The final PDO programme, issued for the TSM in September 2003, includes a number of small Southern fields as well as 63 MMbbl for Harweel and adds up to a reserves match of 921 MMbbl (difference between ARPR reserves and corresponding PB04 projects)
- Obtaining a clear picture of the company wide reserves match or "reserves at risk" is complicated by the fact that the teams in PDO use different methods to account for differences between ARPR and Program Build
    1. ***Include match projects.*** In this method a project is introduced in the program to account for the difference between booked reserves and project plans. Disadvantage of this approach is that the program total shows consistency with the ARPR leading to a false sense of security. (Mukhaizna, Marmul GNR)
    2. ***Fit NFA volume to UR.*** In this case the developed reserves are used as a matching parameter. (Amal West)
    3. ***Accept differences.*** The discrepancy between program and ARPR is left as is and thus clearly visible (Fields in the Northern directorate, Nimr)
    4. ***Include a match project after the planning period.*** Same as the previous method, except that a match project is introduced, which produces the match volume after the planning period (Al Huwaisah)
- Quality of audit trails on reserves bookings and programme build forecasts is poor.
    - Numerous mostly small errors and omissions
    - Unclear status of volumes: Studies are done but bookings not updated. e.g. lost track of 12 mln m3 STOIIP variation in Fahud. This may also lead to instances of negative reserves in the books
    - Programme build forecasts could not always be reproduced
    - QA/QC process of technical work may be too superficial to detect technical errors and inconsistencies. Closer technical supervision of not only the process, but also the contents is required. The review team found that the field teams appreciated a detailed discussion of their technical work.
    - Post 2033 production is not reported by field teams in a consistent manner, and sometimes creates confusion and unclear understanding of the real picture of the reserves (this is particularly important in fields with long production tails, such as GOGD, heavy oil, as in Fahud, Marmul)
    - PDO does not have current code of practice for reserves bookings
- The maturation level of reserves is sometimes overestimated
    - Considerable additional effort is required to secure the volumes: e.g. hc maturation (studies, pilots), reservoir management, facilities and wells integrity management

7.4 Reservoir management

- Metering is still a major issue in most fields
    - Improvement plans will take another 1-2 years to implement
    - Difficult to compensate for lost historical measurements
    - Locating the remaining oil relies on good historical data

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- There tends to be much focus on water circulation, but not enough on waterflood management in the reservoir
    - By-passing through fractures from high injection pressures occurs in a number of reservoirs (Haima West, Saih Rawl, Lekhwair etc.). Increased water circulation brings no additional oil.
    - Injection water in many fields contains around 200 ppm oil, plus solids. It is very difficult to inject this into low permeability reservoirs without fracturing.

7.5 Recommendations

- Intensify technical supervision of the production forecasting and program build exercises.
- Agree on a company wide approach for handling reserves match volumes and communicate this clearly to the teams
- Agree on a company wide policy to deal with long production tails in the program build forecast and in the ARPR (e.g. in GOGD and heavy oil fields, as in Fahud, Marmul), accounting for:
    - Booking tails as scope, clearly showing the full UR of the field
    - Proper subtraction of annual production from reserves and addition of last year of plan period production to reserves
- Develop reservoir simulation models and keep them alive for use in production forecasting exercises. Simple (sector or well) reservoir simulation models should support or replace the currently used decline analysis methods.
- The review team supports and emphasises the requirement that reserves can only be booked when a FDP and VAR3 have been completed.

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8 Scope

This review has not concentrated on identifying scope volumes. Therefore, the quantification of scope volumes is not complete. Nevertheless, some important conclusions can be made about scope in the context of resource maturation.

8.1 *Historical Initiatives in PDO*

Historically, PDO has been eager to improve recovery and production through new initiatives and new technology, as evident from the many tests done. These tests range from technology tests (UBD, well completions, shut-off, seismic) to pilots of key EOR techniques (e.g. polymer / steam in Marmul, hot water / steam in Qarn Alam, steam soak in Amal etc).

Unfortunately, these efforts have not yet led to a clear strategy and have only for individual fields resulted in improved production and low UTC production. One of the causes of this has been the focus on UTC ranking and a lack of the definition of a portfolio of choice, except for some key difficult fields. There are currently three clear EOR projects: Qarn Alam, Mukhaizna and Harweel.

In 2000, the focus changed from short term to understanding the longer-term issues and defining such strategy:

- Portfolio analysis (2000), resulting in a better understanding of common reservoir characteristics across PDO.
- EOR analysis (2000), as a first pass of possible techniques
- T50 analysis (2001), as a first order estimate of the potential "size of the prize", but with poor follow through.
- Portfolio Review (2001), to bring information together
- Waterflood FRD (2002) highlighted best practices (gap analysis), area planning and organisational capability issues
- Waterflood scouting studies (2002), which gave focus in a few key areas
- Full support (already since late 90s) for the 3 key EOR projects.
- Initiatives to form an EOR department, to house the three key EOR projects
- Set up of a PDO study centre to focus on proper field development planning and scope maturation (2003)
- EOR Strategy Definition (Oct 2003, to be completed Q1 2004)

It is considered a very good initiative to formulate a forward look at Life Cycle field development, which are / will be documented in Field Strategy Notes. This will feed scope definition and maturation requirements. The following picture shows a recommended link to the VAR process.

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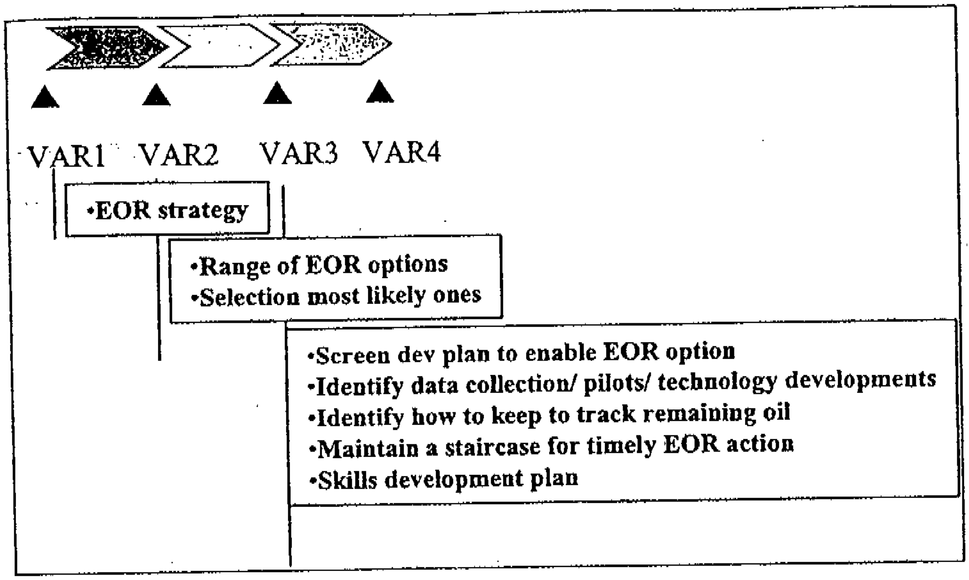
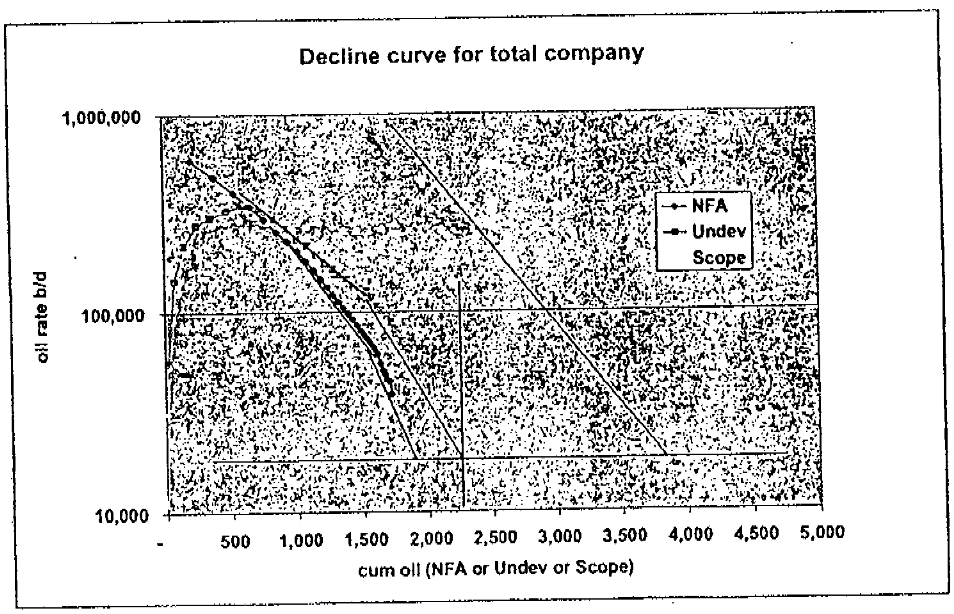


The actual process is still under discussion in PDO.

8.2 *Scope Volumes for selected fields*

A first impression of the life cycle reserves based on PB04 can be obtained from a simple decline curve extension (using rate versus cumulative) for the individual forecasts for NFA, development projects and scope projects:



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Comparing this to the ARPR shows a slight reduction in life cycle reserves and quite similar scope volumes. However, the PB04 has a larger proportion of the life cycle reserves beyond the 30 year window.

ARPR (oil only)

prod in 2003: 40 mln m3

mln m3	30 yrs	> 30 yrs
Developed	292	54
Undeveloped	422	
Scope	612	
Life cycle Reserves		768
Life cycle Reserves+Scope		1380

PB04

30 yrs	> 30 yrs
274	40
295	85
404	230
	694
	1328

The main table in this section shows the comparison between 1.1.2003 ARPR, the T50 results, the PB04 and observations by the STOIIP & Reserves review team. Some of the differences stem from classification changes proposed by the Review Team.

The PB04 and Review Team's evaluations do not include the tail end production of existing reserves projects. This can be a large contribution to scope, especially for GOGD and heavy oil fields. In the ARPR these data are not entered for all fields, which gives a patchy impression.

Scope estimates for ARPR, T50, PB04 and S&R Review for selected fields

						within 30 yrs window				
Field	ARPR 1.1.2003			T50 unrisked		PDO PB04		Review Team (modifications, no full view)		
	Total	TE	EOR	Total	EOR	Total	EOR	Total	Shift Und>scope	EOR
Yibal	47.0	47.0		0.0	0.0	0.0		24.5		7.5
Fahud	44.9	-15.4	39.6	69.0	26.0	36.7		36.7		
Marmul	44.5		18.3	70.0	70.0	9.2		22.7	11.4	4.0
Barik	14.3			no data		0.0		9.6	7.2	
Amin	4.9			no data		1.3		7.8		
Saih Rawl	22.6		15.8	42.0	30.0	0.0		9.3	1.3	8.0
Al Burj	22.9			no data		8.2		8.3		
Lekhwair	44.5	7.8	21.1	120.0	30.0	26.9	15.0	35.7	4.0	15.0
Dhulaima	13.1		5.6	32.0	0.0	6.6		6.6		
Nimr	27.4		24.9	145.0	135.0	5.1		36.3		8.4
Mukhaizna	73.2		71.9	182.0	135.0	70.3	70.3	70.3		69.3
Natih	51.1	13.0	37.2	140.0	140.0	16.9	16.9	13.3		13.3
Ghaba North	5.0		2.4	80.0	80.0	5.0	5.0	7.5		7.5
Qarn Alam	23.1		23.1	35.0	35.0	13.6	13.6	13.6		13.6
Al Huwaisah	20.9			76.0	11.0	3.7		10.2		
Amal-West	0.7	0.6		no data		0.2		0.2		
Amal-East	13.0		13.0	no data		0.0		13.0		13.0
Total	473.0	53.0	272.9	991.0	692.0	203.6	120.8	325.7	23.9	159.7
Total ARPR	666.0	54.6	296.9							

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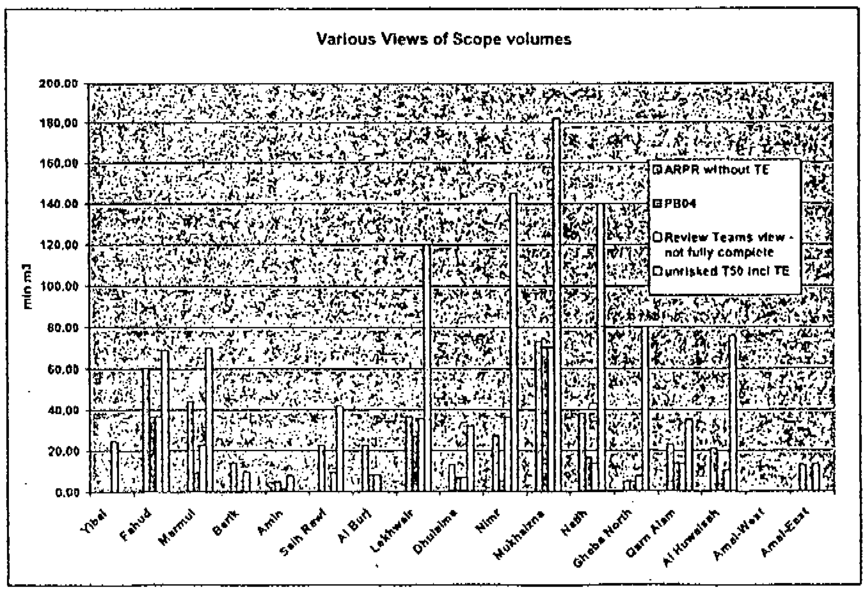
Comments per entry:

Yibal	ARPR contains a large TE. IOR options added
Fahud	ARPR includes Natih B
Marmul	HW project moved to scope and added risked (80%) polymer in AK plus risked EOR in HW.
Barik	WI project moved to scope, including full forecast. Potential GI extension are not covered
Amin	PB04 projects are based on infill drilling, WI project to raise abadonment WC to 99.5%. Long term thermal recovery does not feature
Saih Rawl	Flank development moved to scope, EOR based on GI is included with a POS of 10%
Al Burj	
Lekhwair	AN-LS flank & AS infill moved to scope. TE has been excluded
Dhulaima	
Nimr	Field extension contributes 18 , Ptential polymer/steam options add 8.4
Mukhaizna	Main part is Steam project in 2 phases.
Natih	Thermal GOGD. Risk factor reduced from 50% to 40%
Ghaba North	Thermal GOGD. Assumed RF of 25% with 30% pos. This resulted in a higher than included in PB04
Qarn Alam	Tail-end of 4 is excluded
Al Huwaisah	Majority of scope concerns WI infills, which are unrisked and some are already produced. Infill in Main area does not appear in PB04
Amal-West	Many infill wells. EOR option not quantified.
Amal-East	themal option identified by Asset Team but not included in PB04

The data illustrate that half of the scope volumes are based on EOR projects with the remainder coming from infill and waterflood projects. In the South EOR projects are quoted mostly as marginal/uneconomic with UTC>$ 10/b (Amal, Marmul, Mukhaizna), while in the North most EOR projects are quoted as commercial options with UTC< $10 /b (Fahud/Natih, Lekwair, Qarn Alam). The various views of field scope volumes are shown below:



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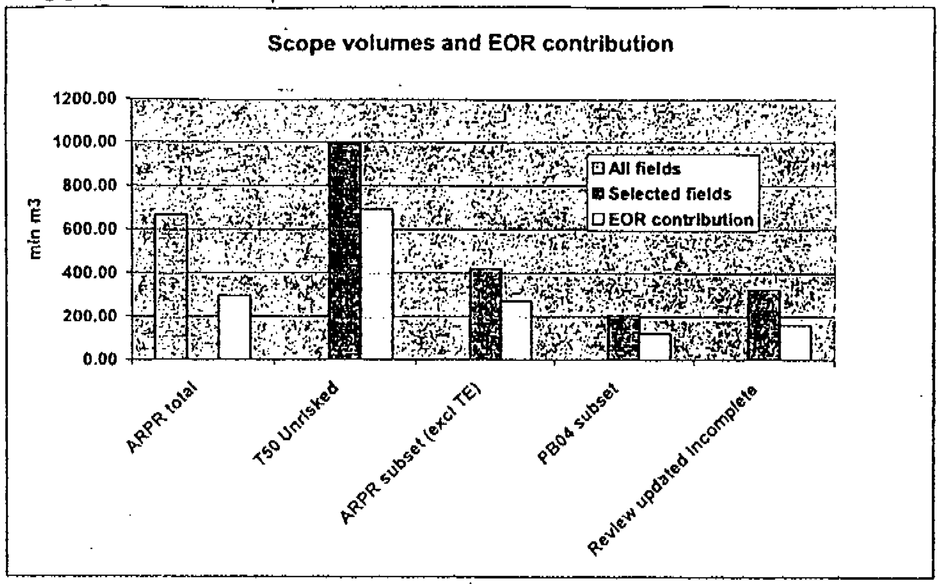
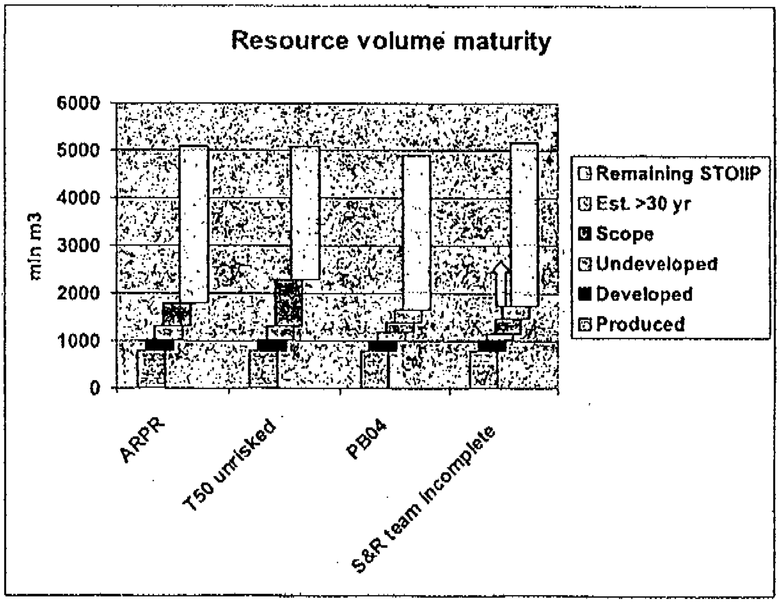
The following graph shows a comparison of total volumes:



PB04 only covers about half of the scope identified in the ARPR. The main reason for changes from PB04 to the STOIIP and Reserves review position is the shift of Undeveloped Reserves to Scope in view of lack of maturity, which in this case is based on judgement and the requirement for a pilot test.

The STOIIP and Reserves review team did not attempt to fully define the EOR potential, like in Amal, Amin and Ghaba North.

The unrisked T50 estimates are considerably higher and considered often as optimistic. However, they represent the true aspiration. A comparison with total resource volumes of the fields considered in this review, still illustrates the challenging target for PDO to increase the overall recovery:



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For PDO's current state of maturity, far too low a proportion of STOIIP has been identified in the ARPR as Scope for Recovery (SFR). A proper scope identification exercise was outside the objectives of this review team, but the arrow indicates the magnitude of change that might be appropriate for PDO. The reason this is important is that it flags the need for additional studies to mature the STOIIP to reserves. Unless the scope is identified and studies resources are justified by the promise held by the scope volumes, there will be no progress.

8.3 Scope in Forecast

Those fields with scope projects which show production in the next two years, are listed in the following table. In general there is not a large threat to the forecast as most of these projects are robust but have not gone through the booking process.

Field	Scope production 2004 / 2005 (b/d) PB04		Review Team		Comment
	2004	2005	2004	2005	
Fahud	3500	9660	3500	9660	WF scouting study proposed project risked at 50 %
Al Burj	2040	3940	2040	3940	MSZ infill drilling: low risk
Lekhwair	2640	6080	940	4530	Lekhwair B LS-A at risk
Al Huwaisah	1550	2930	1550	2930	East Flank has reserves status, Main Area properly risked
Rima	630	2340	630	2340	Not reviewed
Irad		2790		2790	Not reviewed
Total	10360	27740	8660	26190	

The Fahud production pertains to waterflood pilot projects which in PB04 took forecasts from the WFSS risked at 50%. The status of the planning in October 2003 is that the location and design of the wells is still under discussion but that data acquisition will take priority over early production. As such the forecast rates are considered uncertain and to some extent at risk.

The review team recommend delaying the Lekhwair-B, LS-A scope project by one year to allow completion of an FDP for the combined development of the LS-A and B including miscible WAG analysis. The impact of a one year re-phasing on 2004/2005 production is reflected in the above table, PB04 versus review team.

8.4 Conclusions

- For PDO's current state of maturity, far too low a proportion of STOIIP has been identified in the ARPR as scope. Furthermore, The PB04 covers only about half of the scope identified in the ARPR, thus leading to insufficient resources planned in the work programme to follow up on scope ideas and aspirations
- The reserves have a 30 yr window. Therefore the Ultimate Recovery is not a fair reflection of the recovery process.
    - o This is especially significant for GOGD and heavy oil fields.
    - o It influences perception of potential for Scope projects.
    - o Deletion of the 30 year window would improve accounting and avoid misconceptions.
- Except for the key 3 EOR projects, there is a general lack of a Life Cycle approach to development planning which should include the options for EOR. This seems especially true for the heavy oil accumulations.

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- There is no full ownership in many Asset teams of all the scope projects in the ARPR. Staff are, in general, too busy with ongoing projects.

Key aspects for further definitions have been identified by PDO. Some of the key issues are:

- A gas source for potential miscible gas flood is ill defined.
- The relative benefits of Thermal versus Polymer has not been articulated bu are sofar based on historical trends.
- A new options through wettability modifiers to stimulate imbibition in highly heterogeinous rock (macro and micro) will be pursued.
- Especially for justification of expansive EOR projects, proper surveillance to define size and location of target oil, is essential. This should go hand-in-hand with good reservoir characterization in full field models.
- A strategy for enhanced Waterflooding and EOR will be formulated.
- Proper testing and a flexible implementation will be key for maturation.

8.5 Recommendations

- The ARPR should be updated with proper assessments of the aspirations and for the Tail End (TE) production for all fields.
- PDO should create a full life cycle view for all fields to steer the Reserves Maturation Process

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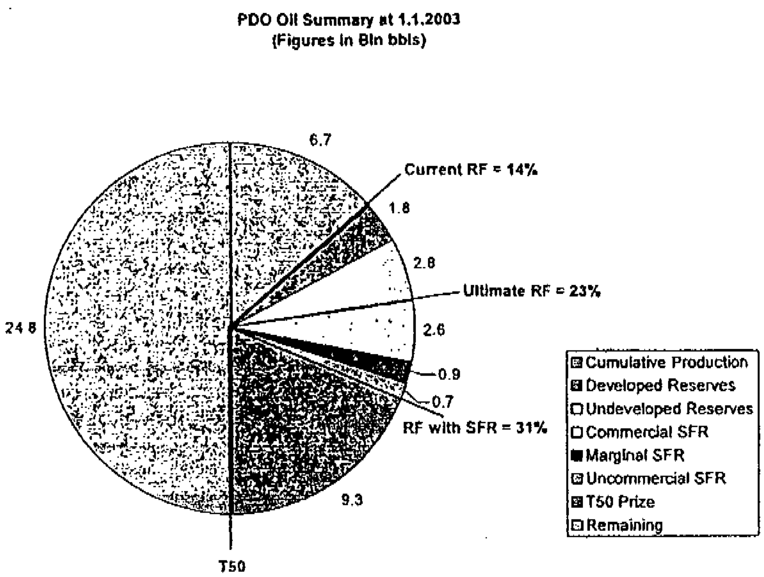
9 Hydrocarbon Maturation

As of 1.1.2003, only 14 % of PDO's booked STOIIP (7.89 bln m3, 49.6 bln bbl) has been recovered against the current ultimate recovery factor of 23 %. The current size of the prize for maturing scope to reserves is 670 mln m3 (4.2 bln bbls). To achieve the T50 target an additional 1.5 bln m3 (9.3 bln bbls) would have to be matured to reserves.



The review team was requested to review and provide an independent opinion on PDO's reserves maturation plans, including looking at the pre-requisite activity plans/study work.

As the PDO hydrocarbon maturation plan was (is) under development the review team principally focused on the "2004 Five-Year Study Plan" issued in September 2003.

9.1 *Reserves Safeguarding*

A substantial part of the initial study effort is aimed at "safeguarding" reserves.

Definition: Safeguarding is defined as conducting studies and producing FDPs for reserves "at risk" (developed or undeveloped). Although these volumes have been booked as reserves in the past, unless staff work is done to produce FDPs, they would have to be de-booked.

The safeguarding category was one of the ranking criteria utilised in developing the 2004 study program and, although it is not accounted for in the total maturation plan it would contribute to additional match volumes if the volumes were not matured.

The following plot shows the PDO plans for volumes safeguarded (i.e. preventing them from being de-booked) through studies each year from 2004-2008. The review team view is also shown alongside, for each year.

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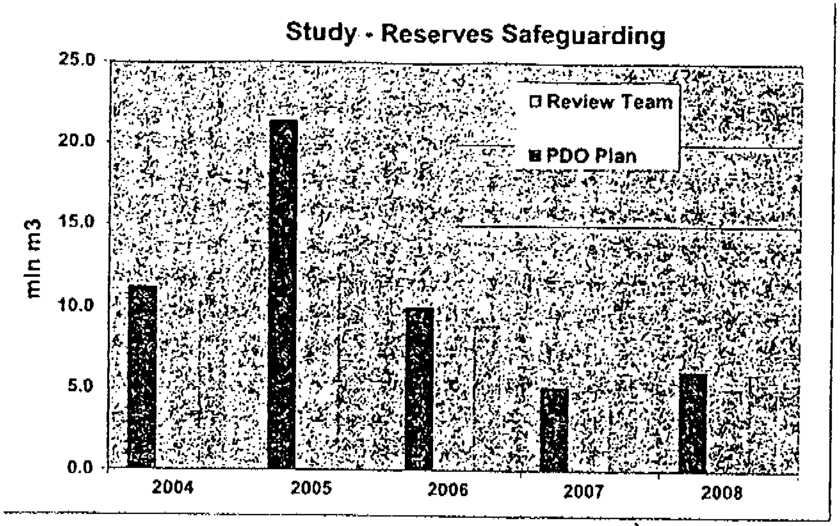


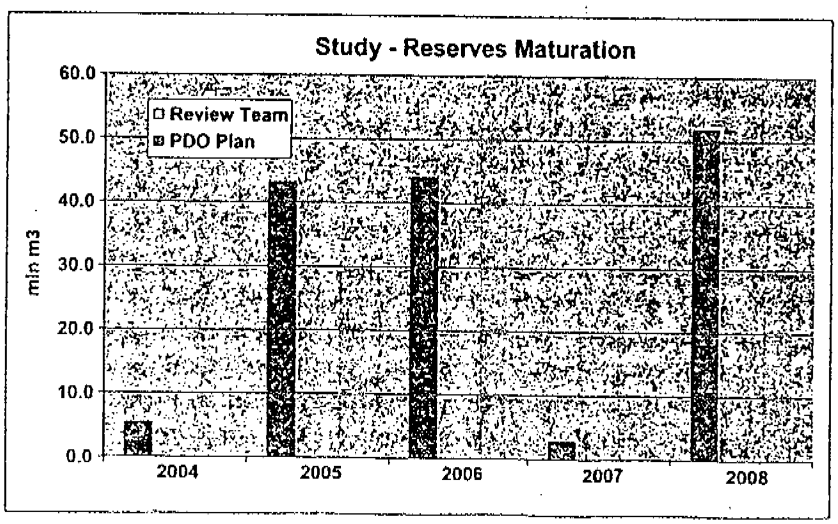
PDO's view is that 54.0 mln m3 will be safeguarded over the 5 year period. In the opinion of the review team, this figure is reduced to 42.8 mln m3 for the following main reasons:

- **2005:** Yibal : 5.8 mln m3 to 0 mln m3. Ref TOR in Draft 2004 Study Plan - this proposed Study is Scope Identification, not Reserves Safeguarding hence wrongly categorised.
- **2005 to 2008:** Various Fields N.Oman : 13.7 mln m3 to 9.1 mln m3. Safeguarding volumes corrected to include POS (as per TORs)

9.2 Studies Reserves Maturation

Definition: Maturation of scope volumes to reserves results from conducting studies and producing FDPs to give the necessary confidence to book the volumes as reserves. In some cases, it is necessary to conduct pilot tests in the field to prove the process to give the necessary confidence.

The following plot shows the PDO plans for volumes matured from scope to reserves through studies each year from 2004-2008. The review team view is also shown alongside, for each year.



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PDO's view is that 148.1 mln m3 will be matured over the 5 year period. In the opinion of the review team, this figure is reduced to 112.8 mln m3 for the following main reasons:

- **2004:** Al Burj Cluster volumes : 5.0 mln m3 moved to 2005 to reflect latest integrated FDP plans (a change that occurred late October as a result of the project framing exercise)
- **2005:**
  - Yibal Natih Oil Rim FDP: 6.5 mln m3 to 3.2 mln m3. The Scope Sheet carries a POS of 50%, hence value quoted is inconsistent. Scope Sheet has maturation date of 2006 while the latest Study Plan currently shows VAR3 end 200. It is recommended to slip booking to 2006 due to Nov/Dec VAR Traffic.
  - Al Huwaisah FDP Follow-up: 9.1 mln m3 moves to 2006. 2004 Study Plan: VAR3 planned for 2006.
  - Nimr C: 0.8 mln m3 moved to 2006 in line with study plan (more upside identified; see maturation upside examples under Section 3.6.3)
  - Karim West: 1.9 mln m3 moved to 2007 based on need to have project follow-on learning derived from the Haima West (Marmul field Mahwis reservoir) water injection projects.
- **2006:**
  - Dhulaima Lower Shuaiba FDP Follow-up: 2.6 mln m3 moved beyond 2008. Pending completion of FDP and subsequent development the review team considers this item as highly speculative. The safeguarding of reserves booked in 2000 (FDP planned for 2004) will already be a challenge. Note there is potential scope in the Upper Shuaiba but it has a longer lead time.
  - Mabrouk FDP Follow-up: 2.4 mln m3 moved beyond 2008 - the only remaining SFR is surfactant flood.
- **2007:**
  - Ramlat Rawl MG FDP: 0.6 mln m3 moved beyond 2008 as it is not in the study program.
- **2008:**
  - North Miscible Flood Study: 20.7 mln m3 moved beyond 2008. The preliminary schedule has already slipped 1 year, meaning the Lekhwair A North Pilot will start-up at earliest in 2008. Allowing for evaluation period this will result in an earliest booking in 2009/10.
  - Habur/Mafraq TAGOGD FDP: 7.2 mln m3 to 0 mln m3. Ranked out of study plan – hence volumes will slip beyond 2008

9.3 Maturation Upside Opportunities: Examples Identified by the Review Team

During the course of the review the team identified a number of potential upside opportunities. The opportunity list below is not exhaustive but clearly demonstrates that there are significant additional maturation opportunities not identified or captured in the 2004 Study Plan build.

The total upside of 46.5 mln m3 is broken down as follows:

- **2005:**
  - Yibal Polymer Shutoff: 5.0 mln m3 (POS 50%)
  - Musallim FDP: 7.9 mln m3. Saih Rawl look-alike - though thinner. Latest view of asset team is that STOIIP decreases from 74 to 60 mln m3 but recovery factor will increase from 4% to 20%. Review Team recommend a POS of 70% resulting in 8.5 mln m3 as opposed to the 0.6 mln m3 currently carried. Note that a VAR3 is planned for end 2004, a period of high VAR traffic in the plan. Hence, it is recommend to slip the booking to 2005.

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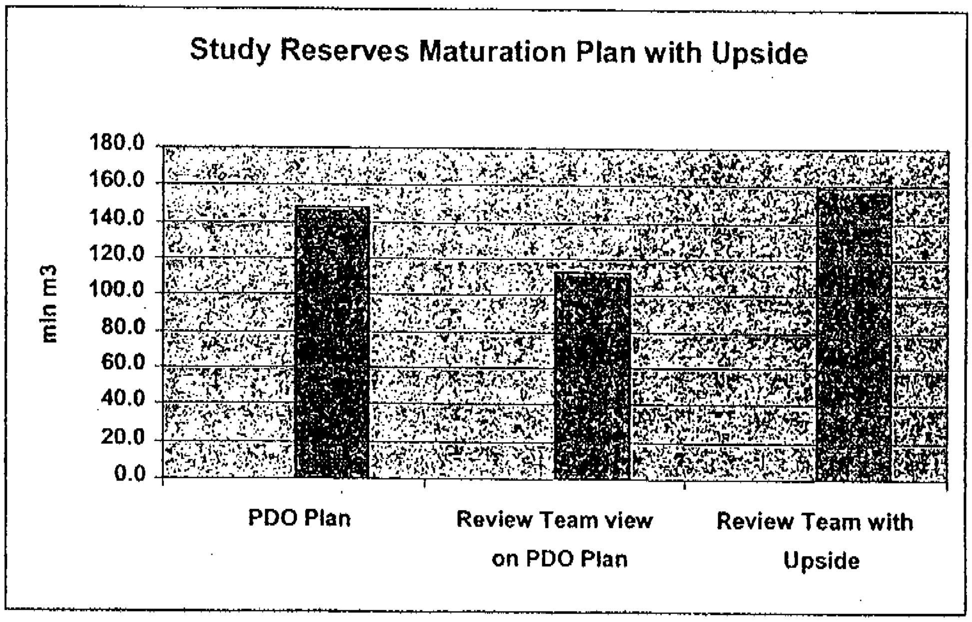
- Rima FDP: 6.0 mln m3. Recent data gathering indicates a So of 20% in the Haima. These data will be brought into the FDP update and is likely to result in a 15% increase in UR. This has been risked by 50% by the Review Team. (Note that the currently booked UR is likely to be reached by 1/1/2006)

- **2006:**
  - Yibal Flank Oil Development: 10.5 mln m3 (POS 50%)
  - Nimr C: 5.7 mln m3. (POS 50%). Existing ARPR STOIIP 56.5/UR 10 mln m3. Review Team sees STOIIP potential of 115 mln m3 with a recovery factor of 20% giving some 23 mln m3. This an incremental of 13 mln m3 above the existing plan with a POS of 50% giving 6.5 mln m3 risked. Existing plan carries 0.8 mln m3 for this project.
- **2007:**
  - Yibal Improved sweep : 1.5 mln m3 (POS 25%). Improved sweep by targeting zones with So>40%.
- **2008:**
  - Yibal Surfactant Flooding : 7.5 mln m3 (POS 5%). Surfactant flooding for wettability change.
  - Yibal Miscible WAG on attic oil: 2.5 mln m3 (POS 50%).
  - Al Huwaisah Miscible Flood FDP: 2.4 mln m3 (POS 10%) Assume miscible flood pilot results are available by 2007 - POS 10% due to timing of the pilot needing to be complete, gas source, etc . (miscible flood ~ 10% STOIIP following WF ~24 mln m3)

The following diagram summarises the review team's view of the PDO plan, and the potential from the inclusion of just some examples of upsides.



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9.4 5 year Plan – Reserves Maturation and Production

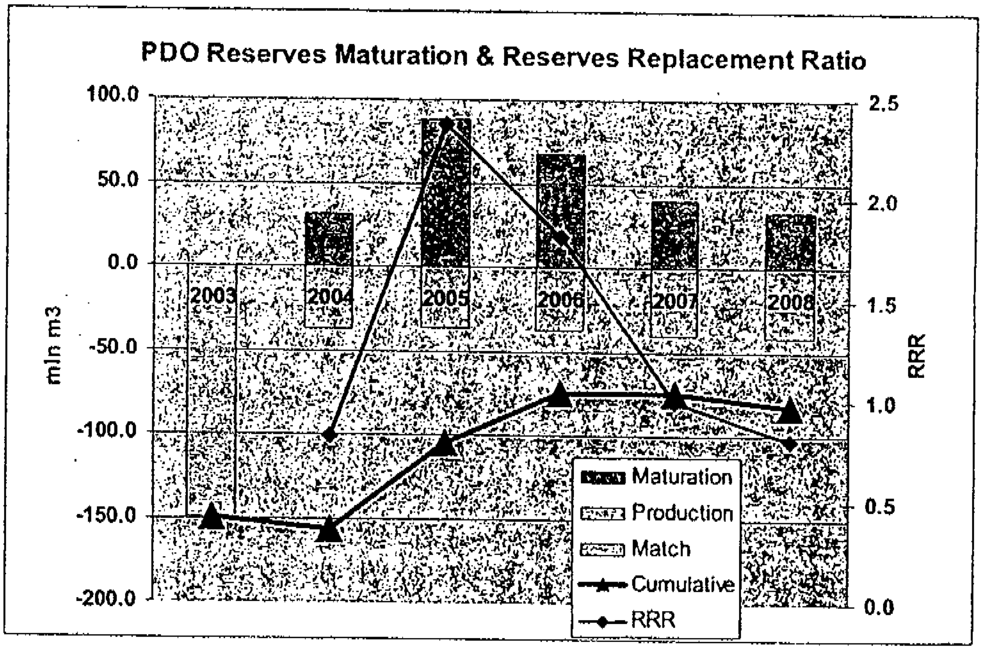
To complete the reserves maturation picture for PDO, the expected reserves bookings as a result of the major project developments over the next 5 years have been added to the reserves bookings expected from studies and FDPs and the review team upsides.

Mln m3	2004	2005	2006	2007	2008
Study Plan maturation (exc. safeguarding), including Upsides		48.8	68.1	9.1	33.3
Harweel		38.8			
Mukhaizna *	31.1			31.1	
TOTAL	31.1	87.6	68.1	40.2	33.3

* *Timing is contingent on adoption of the SIEP-EPT proposal for progressing the project*

Including the reserves matured through major project developments the average Reserves Replacement Ratio for the objectives period is 1.35.

Aggregation of all the maturation and production forecast data results in the following overall picture of PDO's annual and cumulative reserve replacement, starting with the match volume:



The reserves expected to be matured through studies, along with the upsides examples identified by the review team, approximately balance production in the 5 year period, providing a reserves replacement ratio of close to 1. The additional reserves expected to be matured by the Harweel and Mukhaizna projects help to compensate for about half of the reserves match volume. The declining reserves replacement at the end of the 5 year period indicates the necessity to maintain or increase the pressure on the hydrocarbon maturation process, with particular emphasis on Improved and Enhanced oil recovery processes.

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9.5 *Recommendations & Observations*

Results

- PDO's plans to mature scope volumes to reserves through studies are supported, although some of the volumes and timings appear to be optimistic
- The upside examples identified by the review team illustrate the potential that might be available from doing such an exercise comprehensively and in-depth.
- The reserves expected to be matured through studies, along with the upsides examples identified by the review team result in an average reserves replacement ration of about 1 over the 5 year period
    - The additional reserves expected to be matured by the Harweel and Mukhaizna projects help to compensate for about half of the reserves match volume.
    - The declining reserves replacement at the end of the 5 year period indicates the necessity to maintain or increase the pressure on the hydrocarbon maturation process, with particular emphasis on Improved and Enhanced oil recovery processes.

Process

The review team had considerable difficulty in unravelling the audit trail for the data underpinning the 5 year study plan:

- ARPR Scope Sheets / Study Plan TORs inconsistent e.g.Yibal Natih STOIIP missing from ARPR; old scope sheets, etc
- TORs including data from the waterflood scouting studies which superseded the 1/1/2003 ARPR with no clear audit trail
- Inconsistent approach to process e.g. in some cases volumes were without POS being applied.
- In many instances the scope identification process appears rushed and unstructured. Perhaps a technical limit approach template/check list should precede the scope sheets as an aide to retain corporate memory through annual ARPR and programme build exercises
- The study plan is ambitious and will require careful management. Caution is advised with respect to planning multiple key VARs towards year ends – end 2004 already appears to be suffering from a VAR logjam.
- In general, it appears that it is very difficult to get a consistent approach across multiple fields and asset teams – this applies to ARPR, Program Build, Scope & Maturation. Great care will need to be taken for the new Reserves Guidelines

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10 Business Processes

10.1 Introduction

This Chapter touches on a range of issues which directly or indirectly impact Reserves Maturation. The objective is to provide a picture of the "state of health" of the reserves maturation process across PDO and hence to give pointers to possible improvements.

The text is based partly on interviews with field teams. Questionnaires were used to capture the status and practices in areas of Well and Reservoir Management, Field Development Plannning, Hydrocarbon Maturation and Organisational Capability. This has been complemented by brief analysis and spot-checks of existing documents such as the ARPR, Reserves notes and Field Development Plans. The analysis has been far from comprehensive but was intended to give a representative view of how business processes impact reserves maturation at the field level.

10.2 Reservoir management

Good well and reservoir management (WRM) is fundamental to optimising recovery, and even more important when embarking on expensive EOR projects. The review team found a number of shortcomings in WRM in PDO.

10.2.1 Metering and Well Testing.

Metering and well testing has stood out as one of the reservoir management areas requiring particular improvement. This is reflected by historically poor reconciliation factors (wells to field and between fields) of 0.7 to 0.8 in many cases and by poor quality or infrequent well testing. Metering is an issue across PDO but is particularly relevant to the Qarn Alam area and to South Oman. In the worst cases – mainly small fields, or fields producing at low rates– uncertainty on historic production data can be as much as a factor 2 to factor 6 (see Ghaba North).

Improvements to install more meters and better quality meters are underway and will take another 1-2 years to implement. Maintaining and operating the new installations will require a sustained effort, particularly from Production Operations.

Metering and well test data are essential for understanding field and reservoir performance. Locating the remaining oil in a mature field development depends largely on good historical data. Hence for many fields, even if metering is improved it will be difficult to compensate for lost historical data. Only a sustained effort of intensive surveillance, good measurements, well/reservoir management and studies can help to redress the balance.

In some cases data quality can have a pivotal effect on development decisions. In the Qarn Alam field, doubts on the credibility of production data prior to and during the Thermal Enhanced GOGD Pilot led to a postponement of the project by 2 years. As a rough estimate this resulted in $45mln from deferred NPV, and cost (at least) 10 man years of PE staff effort to get the project back on track (see Qarn Alam).

10.2.2 Surveillance and Monitoring

Reservoir surveillance and monitoring has in general taken a low priority in most PDO fields. This is reflected, company wide, by very little data acquisition in such areas as time lapse saturation logs (RST's, TDT's) in observation wells, production logs (PLT's), pressure surveys. Seismic data quality is insufficiently good across much of Oman to allow wide application of time-lapse seismic (4D). The shortcomings in reservoir surveillance data are now being addressed by the formation of Well and Reservoir Management (WRM) teams in some of PDO's fields. This is expected to yield additional production and reserves.

Lack of dedicated field resources (hoists and people) still frustrates PDO efforts to implement effective reservoir surveillance programs.

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10.2.3 Waterflood Management

Waterflood developments will provide a significant component of PDO's production in the near to medium term future. Improved waterflood management is the topic of a number of initiatives within PDO through such groups as Technical and Operations Excellence (T&OE). The successful implementation of improved waterflood practices will have a significant effect on the Developed and Undeveloped Reserves of waterflood fields.

The STOIIP and Reserves Review has identified areas which require particular attention:

- Too great a focus on **maximising/ increasing gross rates.**
    - For **heavy oil waterfloods** there is some merit in maximising gross rates to increase recovery ("washing machine" effect). However, once water-cut exceeds 90% it becomes difficult to accurately measure oil-cut and rates for individual wells. The tendency is to produce the field "blind" without meaningful data being gathered on well or reservoir rates. This will have a detrimental effect on characterising reservoir performance and hence future reservoir management and decisions. Furthermore, not enough attention has been given to the Life Cycle management of the reservoirs, e.g., what are the possible future recovery processes, and is there any risk that the current development activities might jeopardise future plans?
    - For **partially or heavily fractured reservoirs**. In fields such as Yibal and Saih Rawl the recent field history has seen a 1.5 to 3 fold increase in gross rates, due to the combined effects of infill drilling, longer horizontal wells, increased artificial lift capability (ESP's) and facilities expansion. The gross rate increase resulted in a brief period of net oil increase but was followed by rapid water-cut increase and net oil decline. It is believed that a large percentage of the produced water is simply being re-cycled from injectors via fractures in the reservoir and hence is not sweeping additional oil (see Yibal field Appendix). Despite these observations, it is planned to increase gross capacity at Yibal from 150,000 to 180,000 m3/d. It is recommended to move away from the practice of maximising gross rates to one of managed production and injection with much more focus on the reservoir displacement process, through careful monitoring of individual well performances.
- **Water injection rates, pressures and distribution.** In many fields water injection targets have been set to meet overall field or area voidage replacement targets. In those fields where gross rates have massively increased this has meant a massive increase in injection. In Yibal, insufficient attention has been given to pressure sinks, water distribution and the injection of large volumes into natural fractures. The Yibal WRM team is now addressing this issue. In Saih Rawl, recent ESP temperature data illustrate how excessive injection pressures are causing induced fracturing and water recycling between injectors and producers. The importance of the dependency between reservoir pressure and frac pressures, and hence the limits that should be set on injection rates, pressures and injection water quality, is now being recognised. This experience and know-how needs to be shared in all fields where this may be of relevance. Lekhwair A-North provides an example of where injection rates, distribution and management of fracture versus matrix injection have had a positive impact on waterflood performance.
- **Water injection out of zone.** Hardly any of PDO's water injectors have temperature surveys to identify where injected water enters the formation. This is not only essential for reservoir management, but to prevent injection water loss into non-reservoir zones, such as shallow aquifers, causing unnecessarily high operating costs and possible pollution of shallow aquifers.
- **Injection Water quality.** The attention given to water quality both in terms of measurement and control varies between the fields. Oil-in-water exceeds 100-200 ppm in most fields (for example, Lekhwair and Marmul). It is very difficult to inject water of this quality into low to medium permeability formations without plugging. If

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the injection pressure is sufficient, fractures will be induced. With continued injection of dirty water, the fractures will propagate, often causing by-passing of oil. Clear guidelines are required on appropriate water quality targets, measurements procedures and filtering/ cleaning methods with a clear link to the impact/ implications for the reservoir displacement process.

- **Targeting Undrained Oil.** In most waterfloods heterogeneous sweep will affect larger volumes of the reservoir over time. Targeting remaining undrained/ unswept oil pockets will depend on an understanding of the displacement process. Only in a few fields – Yibal as the best example – has sufficient saturation data been acquired to characterise the sweep. As additional data is acquired under the increased surveillance programme, reservoir models should attempt to match the sweep patterns that are observed. The current Yibal studies are aiming to history match heterogeneous sweep patterns. This type of characterisation and history matching needs to be applied in other waterflooded fields (but is dependent on gathering appropriate data).

10.2.4 Forecasting tools.

In the fields surveyed as part of this review there was no single case where a simulation model has been maintained or updated longer than 2 or 3 years since the model was originally built. This contributes to the following observations made in the review:

- Programme Build forecasts are based largely on decline analysis. Developed reserves (NFA forecasts) are mostly defined by individual well declines or the decline of a grouping of wells. Undeveloped reserves (Development project forecasts) are defined by so-called conduit models that provide initial well rates and decline rates based on previous well performance. Hence, there is no verification of undeveloped reserves. The method only adds wells to reach the previously booked number. Only in a few cases were simulation models available to provide comparison forecasts. These were mostly models under construction.
- There were no recorded cases where the simulation model used for a reserves booking was still maintained. Consequently, staff have a very limited understanding of previous models and hence of the basis of the booked reserves figures and associated forecasts (if any).

10.3 Studies/Field Development Planning

10.3.1 General

Most FDP's are significantly out-of-date (more than 3 years old) and the degree of ownership or familiarity within the field teams for these now outdated FDPs is limited. Development projects in the latest Programme Build (PB04) have often deviated in some way away from the Development Plan as defined in the most recent FDP. The status varies from field to field, but a large majority of Undeveloped Reserves are, strictly speaking, unsupported by an FDP.

Since 2001, PDO has been implementing new guidelines whereby Reserves can only be booked once a VAR3 has been approved and an FDP issued. This has necessitated a large "catch-up" programme of study work. The current study plan aims to bring 80% of PDO's Undeveloped Reserves to VAR3 maturity within 5 years.

Where activities cannot be identified to support current reserves figures, reserves are at risk. In the interim period, many projects will proceed without the support of an FDP in order to meet production targets.

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10.3.2 Basis for reserves bookings – consistency with FDPs.

Historically, reserves have been booked without the requirement of an accompanying FDP. Typically, reserves have been booked based on a conceptual development plan supported by reservoir characterisation and simulation studies.

A typical case example is the last reserves revision for Saih Rawl booked at 1.1.1996. Here 2D and 3D sector models were populated with representative properties and history matched with production data calibrated by pilot results. Various development options were then screened by varying such criteria as well spacing, well pattern, production and injection rates, pressures, artificial lift. The model is run in forecast mode for the 30-year reserves period for a number of development scenarios. An optimum plan is then chosen based on the results of economic screening criteria and overall reservoir performance (eg. recovery over time). A Recovery Factor is calculated at the end of the 30-year period for the chosen development plan. Sensitivities to the Recovery Factor are tested. For waterfloods, as in Saih Rawl, the key sensitivity to recovery factor in the models is usually identified as relative permeability, in particular residual oil saturation, Sor. A range of recovery factors is derived by using a realistic range of Sor values.

A comparison is then made between the simulation model and the total field or a sub-part of the field (area of development) such that the Recovery factors can be multiplied by the STOIIP to give Ultimate Recovery. In the Saih Rawl case, for example, Recovery Factors (low, medium and high) are derived per vertical reservoir slice and multiplied by the equivalent field-wide STOIIP in the same slice. In most cases a probability curve for STOIIP and Reserves is derived by varying key STOIIP input parameters and Recovery factor. This allows determination of P15, P85 and Expectation STOIIP and Reserves figures.

In the Saih Rawl case an FDP was issued in 1995 and reserves booked at 1.1.1996. The 1996 booking was, however, an update on a 1.1.1995 booking but with the well spacing halved (and recovery factor increased). The reserves notes do not show forecasts. The corresponding FDP in contrast does show forecasts but does not quote reserves figures. No comparison is provided since none was required. It is, therefore, very difficult to check for consistency between the reserves note and FDP.

In an attempt to compare the Saih Rawl FDP and reserves note, the forecast featured in the FDP has been used to estimate reserves over a 30-year window. The calculated Ultimate recovery is 32.5 mln m3 which compares with 38.6 mln m3 booked as expectation Ultimate Recovery in the reserves note. The discrepancy of 6 mln m3 is appreciable. It may in part be related to the scheduling of the wells which is defined in the FDP but (probably) not accounted for in the reserves note. Other possible sources of the discrepancy are more or less impossible to trace without interrogating the original simulation models (probably unavailable).

As a general conclusion from the Saih Rawl case study, the historical de-coupling of reserves notes and FDP's has led to inconsistencies in the evaluated volumes matured by a particular development.

Since 2001, PDO has been implementing more rigorous criteria for reserves bookings. Reserves can only now be booked if a VAR3 has been passed and an FDP issued. This will ensure much closer consistency between booked reserves and forecasts and that the forecasts pertain to defined and approved activities.

10.3.3 Programme Build – Consistency with FDPs

This review was initiated in part by the recognition of "match" volumes. This recognition came out of a drive by PDO to improve consistency between booked reserves (ARPR) and Defined Activities (Programme Build). Likewise the criteria for booking reserves are being tightened – reserves bookings have to be supported by a VAR3 and FDP. In order to "close the loop" on these business processes the next logical step will be to improve consistency between FDP's and the annual Programme Build. PDO have yet to draw up guidelines as to how to achieve this.

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The following observations have been made during the Reserves review, with respect to the impact of the annual programme build on the Reserves maturation process and the interface with Field Development Planning:

- Projects tend to get spilt up into "bite-sized chunks". This facilitates sequencing of wells in the short term and the phasing of projects in the medium term. It, however, tends to cut out a group of wells and a chunk of CAPEX as a stand-alone item without a clear description of how the wells, forecasts and expenditure is related to the total field picture (FDP).
- The programme build is redone annually. Projects therefore tend to get redefined or modified each year, e.g., number of wells, sequencing and expenditure. This provides positive opportunities for optimisation and flexibility. However, it also tends to lead to a step-wise shift away from the most recently issued FDP. Since the FDP provides an overview and life-cycle perspective, a disconnect is then created between the shorter-term projects and the total field development picture.
- The level of technical review for the PB projects and forecasts is fairly superficial. Data and analysis is usually only readily available in "powerpoint format". It is therefore difficult to question and interrogate the basis for certain forecasts and a chosen sequence of wells. This is not a concern if the activities are part of and consistent with an issued FDP. Where, however, there has been significant migration away from the latest issued FDP the basis for the project is more sketchy.
- In line with the previous points the audit trail for most projects – basis and origin of fluid forecasts, CAPEX profiles and the definition of activities eg. well types, targets and objectives – is often superficial.
- When a new staff member takes over PB from another staff member it is often difficult or impossible for the new staff member to reproduce the forecasts or project definition of the previous year because of the absence of documentation and an audit trail. There were numerous occasions during the review when staff members were unable to describe how forecasts were derived within the current PB04 because the forecasts had been inherited from previous staff members or had been taken direct from PB03.

The following recommended actions are expected to have a positive effect on reserves maturation:

- Greater consistency between PB projects and issued FDP's will ensure that a more detailed analysis and a life-cycle approach as published in the FDP under girds the shorter term projects in PB.
- Non-oil generating activities such as observation wells and data acquisition which is identified and defined in the FDP should be maintained and accounted for in the PB projects.
- Where opportunities are identified to optimise a development subsequent to the issue of an FDP then this should be documented as an FDP update or addendum to provide an audit trail and the appropriate justifications and links to the original plan.

10.3.4 Acceleration, Infill drilling and Well Designs

A possible explanation for reserves shortfalls is that some developments have mainly produced accelerated oil (oil that would have been produced by existing wells but at a later time). This would be potentially most applicable for infill campaigns. However, elements of acceleration can also occur when horizontal well developments replace vertical well developments and/or where longer multilateral wells are chosen in preference to shorter single lateral wells.

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Each field case is in many respects unique. It is beyond the scope of this review to quantify how much oil previously booked as reserves may in fact be acceleration oil. A simple discrimination is far from straight forward. (Note that because of the 30-year reserves window acceleration will often bring extra oil and hence reserves inside the window).

Yibal is an example where the introduction of horizontal infill wells into a vertical pattern waterflood probably gave an initial short-term spurt to production. Subsequently the horizontal wells have proved problematic for waterflood management. The horizontal holes have an increased risk of intersecting vertical fractures and hence of short-circuiting injection water to producers. This, along with a drive to maximise gross rates and increase injection rates, has led to a massive re-cycling of water and increased water-cut. With respect to medium and long-term reserves, the horizontal wells are more problematic to manage vis-à-vis diagnosis of water producing zones and application of water shut-off. The review team has recommended to the Yibal team that the new simulation model be run without the horizontal drilling activities of recent years, to estimate the proportion of production that was acceleration.

Saih Rawl is an example where the FDP development of single lateral producers and dual lateral injectors was modified as the development progressed to multilateral producers and injectors with up to seven legs. The well/ leg spacing was also decreased from the planned 125 metre producer-injector spacing to 80 and more recently to 40 metres. The changes to the development were justified by accelerated / higher peak oil rates and lower overall well costs for the total development. The accelerated peak production was indeed achieved. However, the field is now on rapid decline and the field management is significantly complicated by the long multilateral boreholes. It is very difficult and costly to obtain production data for each individual leg, to control flow from each leg or to re-enter each leg for measurement or remedial activities. It is recommended that field developments be designed using a life cycle approach, including the Well and Reservoir Management activities and surveillance required to optimise ultimate recovery.

10.4 Scope Identification

10.5 Maturation Management

10.6 Corporate Processes

10.6.1 ARPR

The STOIIP and Reserves review cross-checked the current data held in the 1.1.2003 ARPR. This has been far short of a thorough audit of the figures but nevertheless several observations can be made about the data.

Numerous **small errors or omissions** in the numerical data have been noted. Examples include errors in the Fahud and Marmul Haima West STOIIP figures, an error/ inconsistency in the quoted Barik Ultimate Recovery figure and omission of Yibal field Natih reservoir from the ARPR and Amal West from the ARPR Supplement.

For some fields and/or reservoirs a significant time period has elapsed since the last STOIIP or Ultimate Recovery update. This is a particular concern in areas where significant wells have been drilled, data acquired and studies undertaken in the interim period. In such cases the **booked figures are significantly out of date**. Examples include Marmul Al Khlata (last updated 1983) and Dhulaima Upper Shuaiba (last updated 1989).

It is recommended that PDO, in agreement with the MOG, provide guidelines on when STOIIP and/or Ultimate Recovery figures should be updated.

The existing **audit trail** for booked STOIIP and Ultimate Recovery data is, in general, **incomplete and very hard to trace.** Currently, reference documents (Reserves notes) are kept as a hard copy in Corporate files (custodian: DTEM/7). These have recently been scanned to provide electronic versions. Several spot-checks have revealed that these

Corporate files are incomplete (e.g., Marmul Al Khlata and Dhulaima Upper Shuaiba). In many cases it is very difficult to make a straightforward comparison between data quoted in the latest STOIIP or Reserves notes and the data quoted in the ARPR.

The audit trail is complicated in those fields/areas where STOIIP and Reserves updates have been carried out per reservoir layer and/or per sub-area of a field. Hence, several reference reports issued at different times may be required to provide the total STOIIP or reserves data for a field. This results in a highly tangled audit trail, particularly for large fields where multiple revisions have taken place. The tangled audit trail increases the risk of numerical errors (e.g., Fahud STOIIP).

A further complication is that the Corporate files contain some documents which specify an update in STOIIP or reserves but where the data was never entered into the ARPR, presumably because the update was not submitted to, or approved by, the MOG. Dhulaima Upper Shuaiba STOIIP is a case example. For a full audit trail, letters or notes of explanation for such cases should also be available.

It is recommended that an audit trail sheet is provided in the Corporate files for each field STOIIP and Ultimate Recovery update. This should provide a historic overview of updates with references. For fields with separate data per layer/area it is recommended to provide a clear inventorisation of the component parts, a key reference document (latest booking) for each part and how the parts add up to the total field figures. This level of clarity would take a significant effort to achieve, but without it, it can be fairly stated that no credible audit trail exists.

Another area of concern is the **split between Developed and Undeveloped Reserves** data quoted in the ARPR. Currently, there is a requirement that reported Net cumulative production plus Developed and Undeveloped Reserves add up to the booked Ultimate Recovery. For those fields where a large reserves match volume exists it is the Undeveloped Reserves figure that is inflated (too large) compared to Undeveloped Reserves figures in Programme build. However, the method appears to differ for other fields (those with minimal reserves match) where negative Developed reserves figures are commonly listed alongside a positive Undeveloped Reserves figure. In such cases it appears that the Undeveloped Reserves figure has been taken from Programme build and the Developed reserves figure has been used as a matching parameter. It is recommended that a consistent methodology be agreed and applied in future ARPR reporting vis-à-vis how to handle match volumes and the equivalent balancing of Developed and Undeveloped Reserves figures.

As noted in the Scope Chapter of this report there are significant shortcomings to the current scope figures and projects in the 1.1.2003 ARPR. Many of the Scope projects currently listed were inherited from previous versions of the ARPR and the current field teams have little familiarity with, and ownership of, the data presented. Improved reporting standards on Scope should run parallel with an increased focus on the identification and definition of Scope projects.

Unknown

From: Brass, Lorin L.L.
Sent: 20 February 2002 07:02
To: Gardy, D.; Cook, Linda Z.; Megat, Zaharuddin Z.; Warren, Tim T.; Sprague, Robert M.; WARD, BRIAN B.J.; Darley, John J.; Bichsel, Matthias M.; Dubnicki, Carol C.; VanDeVijver, Walter W.
Subject: Note For Information - Reserves - CMD - February 2002

CMD_NFI_FINAL1_RRR.ZIP   CMD note tachments final.ZIP.

Excom,

The following was the NFI to CMD regarding our Reserves situation. I should've put in Excom preread for last Monday but forgot. At the end are some of the "action items" identified, but clearly there are more.

EXHIBIT
Darley 18
11/17/06

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V00120472

Note For Information
CMD 11th February 2002
EP Hydrocarbon Resources Update 1/2002

This note summarises the end 2001 Group resources situation, cleared by external audit, and in part reported in the Q4'01 and FY'01 press release. All numbers include the effects of A&D activities unless otherwise indicated.

Summary

The total barrel of oil equivalent proved hydrocarbon reserves replacement ratio (RRR) for 2001 was **74%** (52% excluding A&D), leading to a proved RRR three year rolling average, including AOSP additions (mining reserves) in 1999 of **81%**, 101% excluding A&D). The 2001 RRR is below the results quoted by our main competitors (BP 191%, XOM 110%), and highlights a portfolio that is under-performing in terms of adding reserves through exploration and maturing existing scope. Future RRR performance over the plan period relies on the delivery of 'big ticket' bookings, *e.g.* Kudu, Sakhalin LNG and Kashagan.

Our overall resource base contains some 20 bln boe of proved reserves (c.f BP 16 bln boe, XOM 22 bln boe) , some 13 bln boe of expectation reserves (of which some 8 bln boe currently fall outside of license expiry), some 17 bln boe of discovered Scope for Recovery (SFR). Our total discovered resources base is thus ca. 50 bln boe (c.f. XOM 70 bln boe) and additionally we have some some 27 bln boe of undiscovered SFR. Together with any volumes resulting from new exploration licenses and acquisitions these volumes represent a significant opportunity to increase our proved reserves replacement performance and the EP organization is being geared up to tackle each and every element.

Reserves and Resources

2001 Actual Additions (See Table 1)

The Group proved reserves base at end 2001 is 19.1 bln boe (19.7 incl. AOSP) and remains split at 50:50 oil/gas. The 2001 proved RRR of 74% amounts to a reserves addition of 1020 mln boe, which in Figure 1 is broken out by type of revision;

- 360 mln boe of Discoveries & Extensions, mainly in USA, UK and Brunei
- 350 mln boe of Revisions & Improved Recovery, mainly Netherlands, Denmark and Sakhalin offsetting negatives from Canada (50 mln boe based on field performance), New Zealand (50 mln boe based on studies on Maui field) and Oman Gisco (110 mln boe as a consequence of the renegotiation of the GISCO contract and acceleration of repayments)
- 310 mln boe of Acquisitions & Divestments, mainly Fletcher and Pinedale.

The proved **oil** RRR is 65%, taking the 3 year average to 102% including mining reserves and 77% without, and the proved **gas** RRR is 86% contributing to a 3 year

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average of some 50%. During 2001 there were no changes to the reserves for AOSP. Including AOSP, the three year average proved boe RRR is 81% (101% excl A&D) and excluding AOSP, the equivalent numbers are 67% (86%).

The Total Resource base (the sum of expectation reserves and commercial discovered SFR) has increased by 2.7 bln boe to 49.4 bln boe (see Table 2); this includes a 1.3 bln boe addition from Venezuela Urdaneta West which falls outside of the current licence period. It should be further noted that total resources include some 1.1 bln boe from the consolidation of Sakhalin.

The Unit Finding and Development Cost (UFDC) for 2001 defined as the exploration and development cost incurred ($6.1bln) divided by Group oil and gas additions, excl. purchases and sales, (0.73 bln boe) now stands at $8.3/boe for the year 2001, and $4.8/boe on a 3-year rolling average base (up from $3.50/boe in 2000, see Figure 2). An increase in UFDC was forecast at the time of developing the Business Plan in 2000 when it was recognised that there would be a lag between stepping up capital spending and the increase in subsequent reserves bookings. Together with the lower than planned bookings in 2001 this impacts directly on our competitive position on this indicator where, up until this year, we were the leading player. The Unit Finding Cost (funding share) is $1.0/boe yielding a 3-year average of $0.62/boe, reflecting a continuation of an improving trend. Unit Finding Costs on a proved reserves additions basis are $ 3.8/boe.

Comparison versus Business Plan

The EP scorecard target for 2001 was 80% (excl. A&D and strategic options), or 1120 mln boe at target production. The actual addition excl. A&D and strategic options was 710 mln boe, or 52% RRR at actual production. The main contributors to the lower than planned RRR are detailed in Figure 3.

None of the strategic options associated with reserves bookings in 2001 materialised, e.g. Saudi Gas, T2T, Salym, Bangestan, China, Libya.

Total SFR maturation to expectation reserves over 2001 was 0.92 bln boe or 2.2% of the commercial SFR.

Exposures

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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Appraisal

Historical Perspective

In 1999 - 2001 the proved reserves additions have not fully replaced production and the 2001 3-year rolling average RRR's no longer benefit from the recent 'bookings rich' period of 1996-98 (see Figures 4/5, reflecting performance with and without the effects of A&D and showing the impact of AOSP). Over that period, substantial proved reserves additions were realised from major discoveries (Australia,Gorgon, SNEPCo (Bonga), total 1.2bln boe), major revisions (Venezuela 0.3mln boe) and new business (Oman GISCO, 0.4bln boe). In addition, in 1998 significant bookings were made by bringing proved reserves closer to expectation in mature fields (total 1.2 bln boe) - this action brought us to industry standard from a much more conservative position.

Competitive Landscape

The Group RRR of 74% is low in comparison with competitors who all posted RRRs in excess of 100% (Figure 6). The competitors are able to draw benefit from portfolios which, following the rounds of industry rationalisation, appear to offer wider choices in key exploration and scope maturation targets.

2002 and Beyond: Outlook for RRR

The outlook for Group reserves replacement in 2002 and beyond remains challenging (see Figure 7);

- We can expect fewer additions through the base plan, because of OUs affected by 'end of license', OUs with limited remaining exploration potential and the challenge to find ways to increase expectation reserve levels in mature fields.
- And an increased reliance on strategic options and other big-ticket bookings. Control on timing of these bookings is an issue, as they are commonly occur in frontier areas (Kashagan), face fierce competition for markets (T4/T5, Sakhalin LNG), rely on emerging technologies (Kudu, SURE), or are in areas with limited control (Saudi, Whale). The subsequent reserves booking profile may be "lumpier" than in the past and these major bookings will require additional steer to ensure delivery of new reserves within the tighter SEC framework.

Actions taken

In Q4 2001 and Q1 2002 a number of actions have been initiated to address this emerging issue;

- even greater focus is being placed on succeeding in exploration, a key challenge is to focus on the maturation of our 27 bln boe of undiscovered scope for recovery
- similarly EP is refocusing the organization to reinstate Technical and Operational Excellence across the whole of its core operations; hydrocarbon resources maturation is a key element of this drive
- EP is looking again at the opportunities to accelerate the maturation of our 17 bln boe of discovered scope for recovery and specifically with GP looking at the opportunities to monetize gas SFR

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- Stepping up the drive to extend licenses e.g. in Abu Dhabi, Nigeria, Brunei, Oman and open up the opportunity to move the 8 bln boe expectation reserves which currently fall outside of license expiry back into our within license resource base and ultimately move to proved reserves.

Conclusion

Our reserves replacement performance over the past few years clearly illustrates the emerging problems with our resource base and is becoming a source of competitive disadvantage. Over the plan period, the challenge will be to secure sufficient volumes from major bookings to supplement additions from a base plan portfolio and ensure that existing exposures, if they transpire, are adequately offset.

However, we do have some nearly 50 bln boe of SFR and expectation reserves currently outwith license in our overall resource base which presents a significant opportunity. We are refocusing our efforts on exploration and will pursue more aggressively the transfer from SFR to reserves but this will not be sufficient to reverse the trends – success in major strategic options in MRH's or a major acquisition is necessary.

Table 1 : Summary of 2001 Reserves/Resources Replacement

proved RRR	Production	1 year 2001				3 year 1999-2001				2002 Target Production	2002 Target	
		Incl A&D		Excl A&D		Incl A&D		Excl A&D				
		Incl AOSP	Excl AOSP	Incl AOSP	Excl AOSP	Incl AOSP	Excl AOSP	Incl AOSP	Excl AOSP		Incl A&D	Excl A&D
Oil/NGL	0.81	65%	65%	58%	58%	102%	77%	130%	106%	0.83	91%	49%
Gas	0.57	86%	86%	42%	42%	50%	50%	55%	55%	0.58	113%	69%
Total BOE	1.38	**74%**	74%	**52%**	52%	81%	67%	**101%**	86%	1.41	100%	57%

Additions bln boe	Production	1 year 2001				3 year 1999-2001				2002 Target Production	2002 Target	
		Incl A&D		Excl A&D		Incl A&D		Excl A&D				
		Incl AOSP	Excl AOSP	Incl AOSP	Excl AOSP	Incl AOSP	Excl AOSP	Incl AOSP	Excl AOSP		Incl A&D	Excl A&D
Oil/NGL	0.81	0.53	0.53	0.47	0.47	0.82	0.63	1.05	0.86	0.83	0.76	0.41
Gas	0.57	0.49	0.49	0.24	0.24	0.28	0.28	0.31	0.31	0.58	0.66	0.40
Total BOE	1.38	**1.02**	1.02	**0.72**	0.72	1.12	0.92	**1.39**	1.18	1.41	1.42	0.81

Resources (bln boe)	2000	2001	Delta
SFR (com discovered)	14.1	16.7	
Expectation (incl proved)	32.6	32.7	
Total	46.7	49.4	2.74
less Urdaneta West (license)			1.28
Resources added (net)			1.46
Production			1.38
Resources added (gross)			2.84

Reserves (bln boe)		Proved		Developed	
Balance 31.12.2000			20.1		9.0
Additions	*Extensions*	0.36			
	Revisions	0.35		0.17	
	A&D	0.31			
	Transfer to Dev			1.02	
			1.02		1.19
Production			-1.38		-1.38
Balance 31.12.2001			19.7		8.8

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Table 2: Total Resource Base as at 31.12.01

bln boe	Oil&NGL	Gas	Total
Proved Developed	*4.3*	*4.4*	*8.8*
Proved Undeveloped	*5.7*	*5.2*	*10.9*
Total Proved	**10.1**	**9.6**	**19.7**
Expectation minus Proved	*6.5*	*6.2*	*12.7*
Total Expectation	**16.9**	**15.8**	**32.7**
(of which in license)	*(12.7)*	*(12.0)*	*(24.7)*
SFR			
Proved techniques	*7.9*	*5.9*	*13.8*
Unproved techniques	*2.7*	*0.2*	*2.9*
Total Resources	**27.5**	**21.9**	**49.4**
Undiscovered	*15.6*	*11.9*	*27.5*
Non commercial	*2.4*	*2.6*	*5.0*
Total Volume	**45.5**	**36.4**	**81.9**

Table 2 *Total resource base at 1.1.2002. AOSP Mining reserves are included*

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