tough times real solutions

OIL SEARCH LIMITED ANNUAL REPORT 2000

a matter of fact

The Year 2000 was a difficult period for Oil Search. Company performance in a number of key areas was below our targets and expectations in 2000. Value creation for our shareholders comes primarily from exploration success, commercialisation of gas and superior financial performance from our solid production base. A number of issues impacted our performance in these areas during 2000.

Financial performance was affected by delays in commencement in production from the Moran-4 well, which reduced our total annual production by around 600,000 barrels, exacerbated by the impact of substantial oil hedging required under the terms of our 1999 refinancing. This resulted in the Company not fully benefiting from prevailing high oil prices.

Exploration activities were also below our requirements for reserve growth. Despite having seven firm wells in our Joint Venture budgets, only two were drilled. Despite a number of significant achievements, progress to bring the huge PNG to Queensland Gas Project to commercial close was slower than anticipated. Some important milestones were achieved, including agreement by producers to provide reserve certainty to the project and fiscal agreements with the PNG Government. Marketing efforts, to confirm the required volumes of gas to make this project a commercial success, were impacted by various issues in Queensland, particularly the State Election in February 2001. We remain convinced that the fundamental commercial basis for this massive project to proceed is within our grasp. It is far too important for the economy and stability of Papua New Guinea, and its relationship with Australia, for it not to go ahead. We share the commitment and responsibility to ensure its success.

Our experiences in 2000 have led to development of a number of strategies that will ensure enhanced performance in 2001 and beyond. These are outlined in this report.

Exploration activity in 2001 and commercialisation of our large gas reserves have the ability to significantly add value for our shareholders. We are totally committed to realising this huge potential.

Trevor Kennedy, AM
Chairman of the Board

moving forward

→

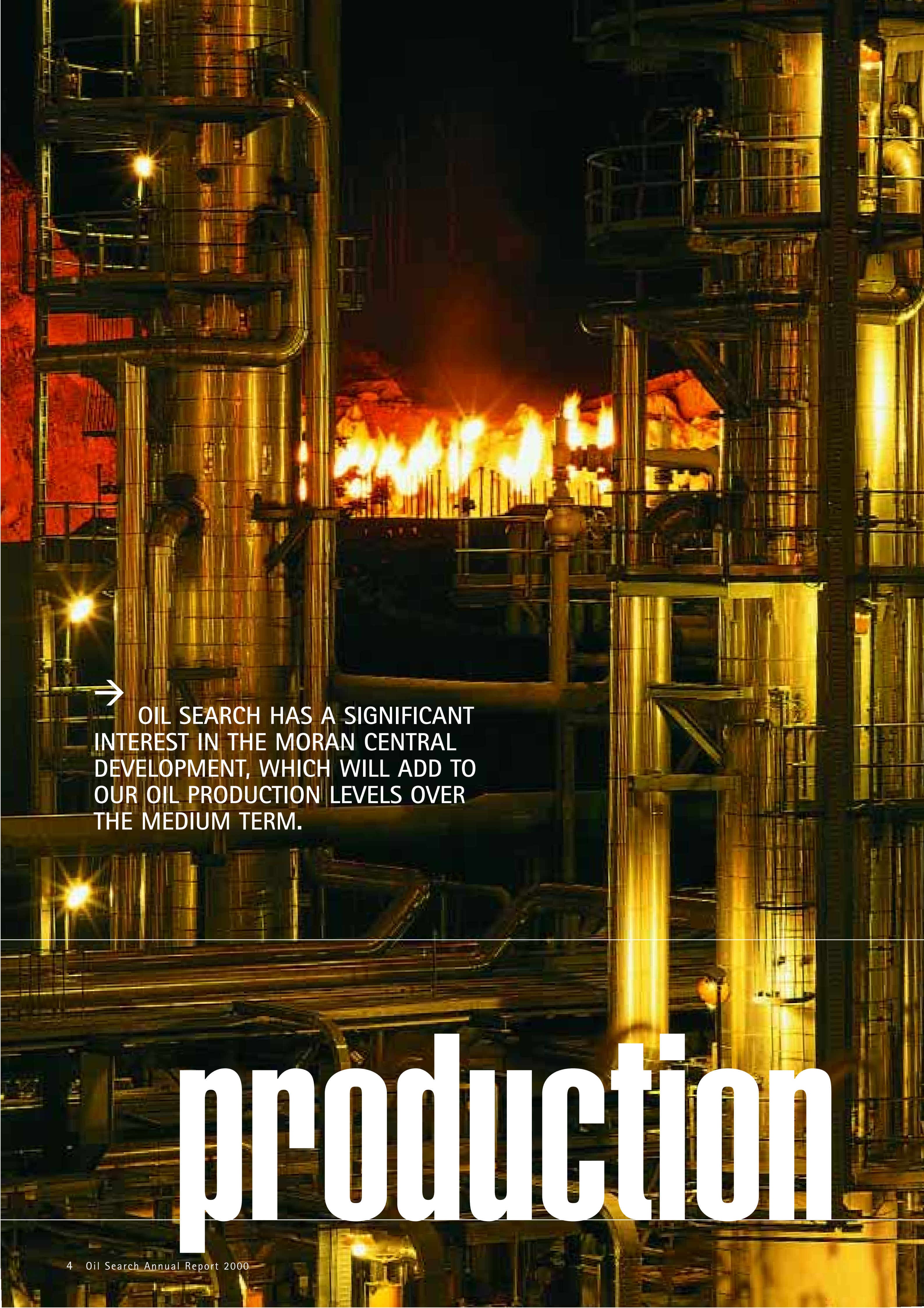
Significant Board and Management review of issues that held back performance in 2000 have resulted in a series of strategies and initiatives to significantly improve performance in 2001. Although a number of important challenges remain, the outlook is very positive. Value creation and share price performance still centre on exploration success, increasing our production base and the commercialisation of our large gas reserves.

In order to ensure that an appropriate level of exploration activity for reserve growth is achieved, it has been necessary for our various Joint Ventures to contract a firm programme that will see a continuous drilling effort, testing a number of high-impact, low-risk prospects in 2001 and 2002. This programme has already commenced and has the potential to more than double our existing reserve base.

Oil production in 2001 will be positively impacted by the 6 month acceleration of drilling the Moran-6 well. Production will increase again in 2002 as the Moran Central development is completed. The original oil hedging position is now rapidly unwinding and the Company will benefit fully from the higher prices now being achieved. Any further required oil hedging will be undertaken through put options, ensuring shareholders capture the value of elevated prices, whilst limiting their downside exposure. These initiatives will result in revenue performance being materially improved in 2001 and 2002.

Continued emphasis will be placed on the PNG to Queensland Gas Project – a company maker for Oil Search. Reinvigorated marketing efforts, utilising a flexible customer-sensitive approach, appropriately balancing risk for all protagonists, have recommenced following the Queensland Election and all efforts will be made to reach commercial close this year. We remain confident that this will be achieved. The commercial fundamentals of success are there and the project is too important to all stakeholders for it to fail.

Peter Botten
Managing Director



→ OIL SEARCH HAS A SIGNIFICANT INTEREST IN THE MORAN CENTRAL DEVELOPMENT, WHICH WILL ADD TO OUR OIL PRODUCTION LEVELS OVER THE MEDIUM TERM.

production

CURRENT POSITION

Oil production from Papua New Guinea will decline over the next three to four years. The Kutubu and Gobe fields are expected to decline at rates of between 20% and 30% per year over this period, even with ongoing development work and good field management. The Company has a significant interest in the Moran Central field, which is now undergoing the next stage of development. Our high equity level and commercial unitisation terms will see our production increase over two years, despite predicted decline at Kutubu and Gobe.

OUR STRATEGY

The Company will continue to actively analyse development opportunities within its existing fields to identify economic remaining reserves and new areas, close to infrastructure, that can readily augment near-term production. We will continue to carry out independent reservoir and reserve audit work to influence workover and development activities. This has been successful in identifying drilling opportunities at Kutubu, Gobe Main and SE Gobe. We will push for acceleration of the Moran Central development and evaluation of reserve potential in adjacent targets. We will pursue a material reduction in operating costs, in line with production trends, to maintain and improve profitability.

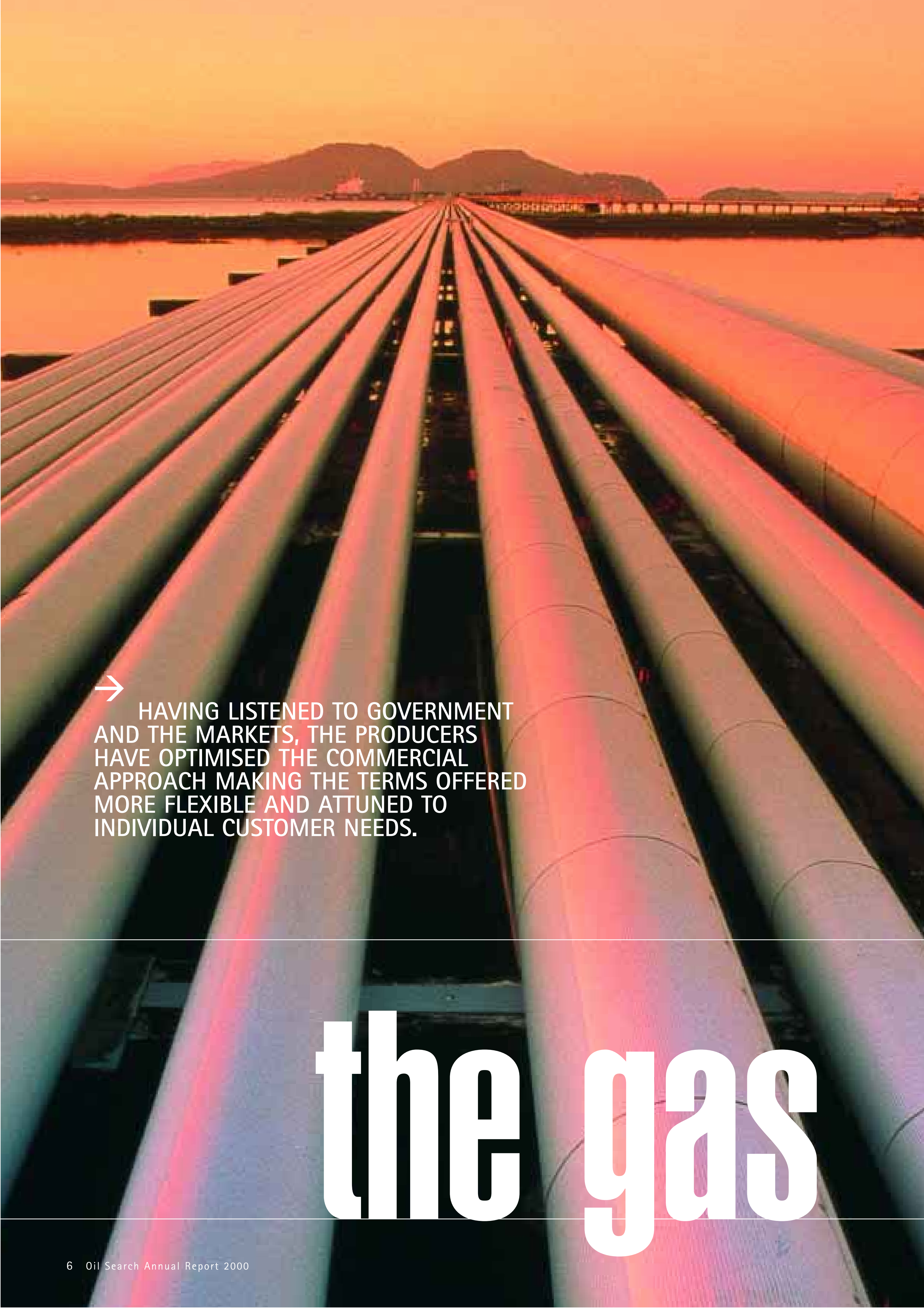
OUR EXPECTATIONS

The Company's production outlook is very healthy (compared to other PNG participants) in that we expect 2001 production to be of similar magnitude to 2000, but that 2002 will see an increase of at least 20%, based on present commercial arrangements in the Moran Central Unit section. The size of the increase will depend on the timing of completion of the Moran-6 well and the next stage of Moran Central development. Moran production continues to be above budget, with Kutubu performing predictably.

"THE COMPANY WILL CONTINUE TO ACTIVELY ANALYSE DEVELOPMENT OPPORTUNITIES WITHIN ITS EXISTING FIELDS TO IDENTIFY ECONOMIC REMAINING RESERVES THAT CAN READILY AUGMENT NEAR-TERM PRODUCTION"

activities

JOHN SPEED
Operations Manager



→ HAVING LISTENED TO GOVERNMENT AND THE MARKETS, THE PRODUCERS HAVE OPTIMISED THE COMMERCIAL APPROACH MAKING THE TERMS OFFERED MORE FLEXIBLE AND ATTUNED TO INDIVIDUAL CUSTOMER NEEDS.

the gas

CURRENT POSITION

Progress to bring this huge project to commercial reality was impacted by a number of factors during the year. These included the time taken to go through regulatory requirements for joint marketing and the lead-up to the Queensland State Election. Significant progress was made in market definition with the introduction of the Queensland Energy Policy, which underscores the use of gas for electricity generation in the State, as well as completing a comprehensive agreement between upstream suppliers of gas to coordinate the development. The immediate focus for our efforts is closing gas sales agreements with our customers in Queensland.

OUR STRATEGY

Following the recent Queensland State Election, and the return of the Beattie Government, the Project Team has reinvigorated marketing efforts using a focused cooperative approach. Having listened to the sensitivities of government and markets, we have used the period of the election to optimise our commercial approach, making the terms offered more flexible and attuned to individual customer needs. The Producers will continue to work closely with the Papua New Guinea and Australian Governments to ensure that appropriate participation by PNG entities is achieved in the Project, along with an efficient financing plan.

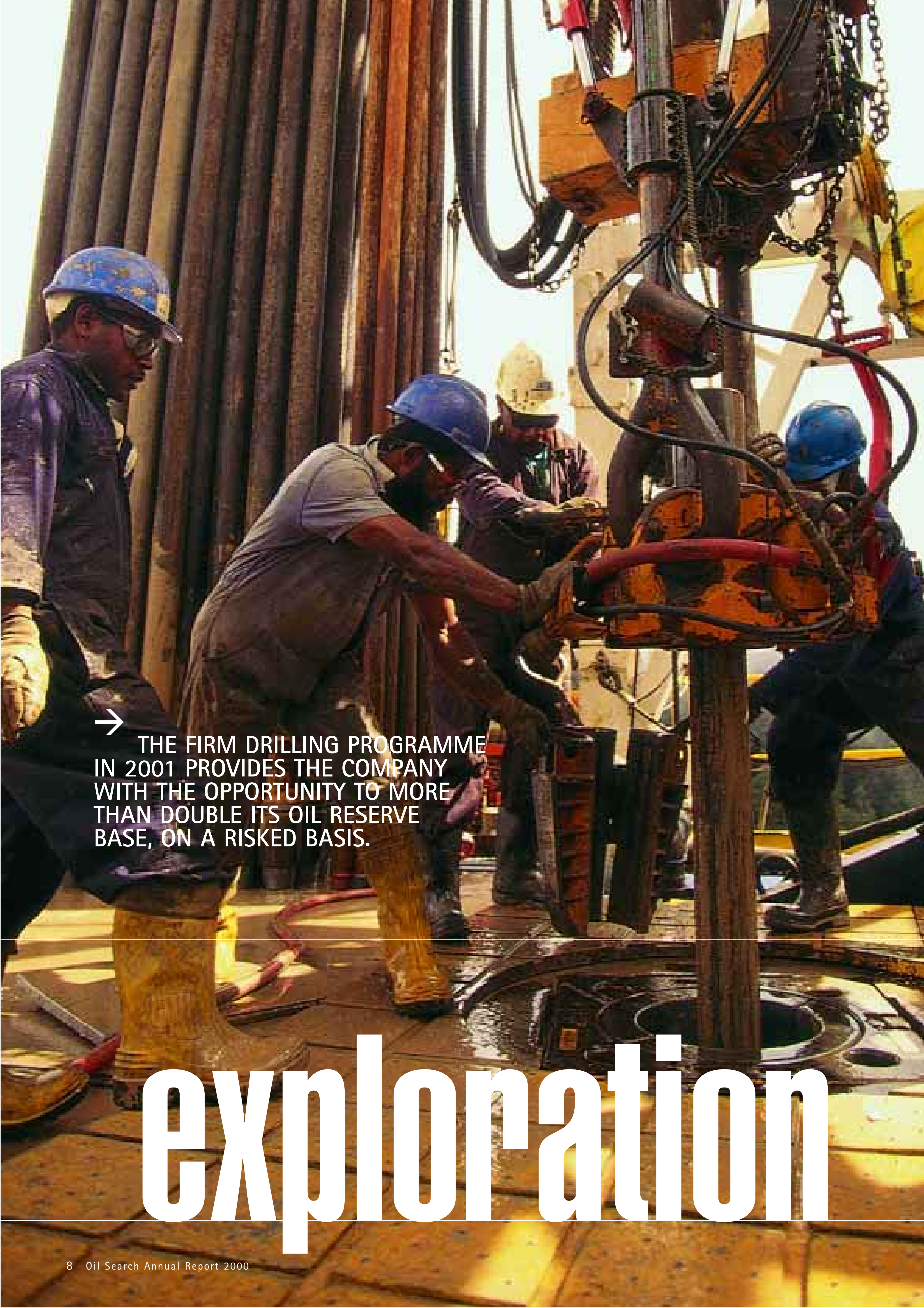
OUR EXPECTATIONS

The Producers have been poor at predicting the timing of key milestones for this project, with certain issues not in their control affecting progress. Marketing efforts during the first half of 2001 will lead to a clear picture of the size of the market for PNG gas. These efforts have shown that we are offering a highly competitive price and that key issues, such as volume requirements and country risk, are being successfully addressed. We expect to reach a position during this time to be able to commit to full engineering and evaluation work, leading to construction activities commencing in 2002 and first gas deliveries in 2005.

"WE EXPECT TO REACH A POSITION TO COMMIT TO FULL ENGINEERING AND EVALUATION WORK, LEADING TO CONSTRUCTION ACTIVITIES COMMENCING IN 2002"

NIGEL HARTLEY
Chief Financial Officer

project



→ THE FIRM DRILLING PROGRAMME IN 2001 PROVIDES THE COMPANY WITH THE OPPORTUNITY TO MORE THAN DOUBLE ITS OIL RESERVE BASE, ON A RISKED BASIS.

exploration

→

CURRENT POSITION

Exploration activities in 2000 fell below those required to materially increase our reserve base in Papua New Guinea. Despite having seven firm exploration wells in our various licences, only two offshore holes were drilled. Drilling activity in the Highlands area was limited to appraisal and development work in our known fields. This was due to differences between the partners on investment criteria and the need to develop new projects to replace depleting oil reserves.

Seismic activities in the Foldbelt were an outstanding success in delineating new prospects for drilling and decreasing risks for discoveries.

OUR STRATEGY

In order to ensure predictable, timely exploration drilling and reserve replacement, the Company required the various licence operators to agree on logistically viable contracted drilling activities, as part of the budget approval process applicable to the 2001 programme. Seismic activity in the Foldbelt has an approved firm programme that will mature up to 15 new prospects to drillable status over the next 18 months.
We will continue to review opportunities outside Papua New Guinea, where our technical and commercial knowledge, linked to excellent local expertise, provides us with an investment advantage.

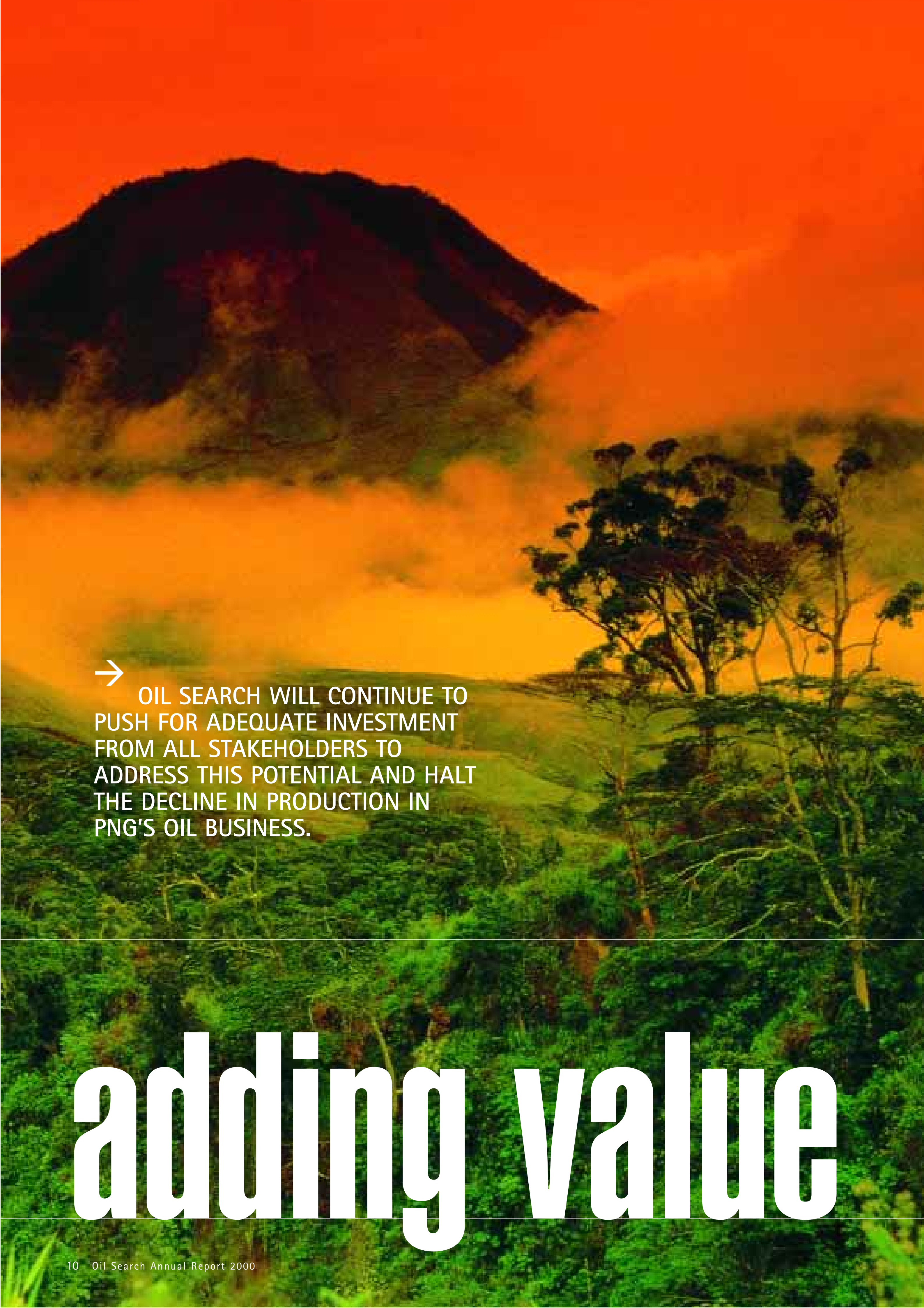
OUR EXPECTATIONS

The firm drilling programme in 2001 provides the Company with the opportunity to more than double its oil reserve base, on a risked basis. Important wells, such as Moran-6, Bakari and Saunders, all represent high-impact, low-risk wells, with significant reserve upside. We expect to have at least one discovery from our programme in 2001, which will add material reserves to our inventory. Continuation of the seismic acquisition in the Highlands will provide the Company with the highest quality of low-risk drilling candidates in our corporate history. →

> "WE EXPECT TO HAVE AT LEAST ONE DISCOVERY FROM OUR PROGRAMME IN 2001, WHICH WILL ADD MATERIAL RESERVES TO OUR INVENTORY"

KEIRAN WULFF
Exploration and New Ventures Manager

activities



→ OIL SEARCH WILL CONTINUE TO PUSH FOR ADEQUATE INVESTMENT FROM ALL STAKEHOLDERS TO ADDRESS THIS POTENTIAL AND HALT THE DECLINE IN PRODUCTION IN PNG'S OIL BUSINESS.

adding value

→

CURRENT POSITION

Oil Search is now Papua New Guinea's largest company and the largest single investor in the country. We expect to spend close to US$100 million on exploration and development during 2001. The Company plays a key role in attracting foreign investment in the country, whilst promoting Papua New Guinea around the world as an excellent place to invest.

Since the Company's formation over seventy years ago, we have reinvested heavily in order to grow our business and develop PNG's oil and gas resources. We also invest in our people, through training and job development, as well as in the places in which we operate, working with the local communities in providing employment, schooling, health care and infrastructure.

OUR STRATEGY

The focus of Oil Search's business strategy is to build shareholder value, providing material capital growth and superior return on capital, based largely on our PNG asset base.

Our long history in Papua New Guinea has provided us with a competitive advantage over our competitors. We have an unmatched database which, when combined with specialist technical, commercial and landowner/government affairs personnel, provides us with the expertise and cultural sensitivity to manage the complex issues that typify the PNG operating environment.

We will actively pursue sufficient investment to at least maintain the oil and gas business as a key part of the country's economy.

OUR EXPECTATIONS

Oil Search has the potential to more than double its value in the next two years, through exploration success and commercialisation of its large gas reserves. Few other companies have this potential.

We will continue to push for further investment through exploration and development of gas resources. We share a responsibility in ensuring these resources are developed and the ensuing benefits are appropriately distributed in the country. →

"WE WILL ACTIVELY PURSUE SUFFICIENT INVESTMENT TO AT LEAST MAINTAIN THE OIL AND GAS BUSINESS AS A KEY PART OF THE COUNTRY'S ECONOMY"

to PNG

GEREA AOPI
Government and Corporate Affairs Manager

Share price performance in 2000 was impacted by slow progress on the PNG to Queensland Gas Project, lack of exploration activity in our core licence areas and the inability to benefit fully from the high oil prices because of required hedging.

As we enter the new year, our oil hedge position is declining rapidly, allowing for fuller exposure in the oil price. Drilling activity has started, with some key wells to be drilled in the contracted programme. Gas Project momentum is building, with ongoing meetings with customers, likely to lead to a commercial resolution.

We remain confident that these issues are being addressed to enable the Company to add real value to its shareholders in 2001 and beyond.

CONTENTS

14 THE RESULTS

18 PRODUCTION

20 THE GAS PROJECT

22 EXPLORATION

24 RESERVES

26 PERMITS MAP

the

performance

the performance the results

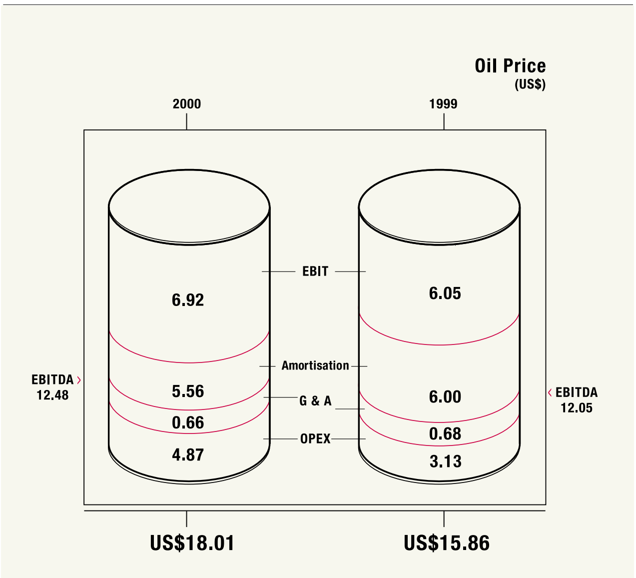
The Company realised a record profit after tax and before abnormals of US$36.3 million (A$63.4 million) for the year 2000, an increase of almost 44% from 1999. The rise in profits was derived from a lift in pre-tax profits to US$38.3 million (A$66.9 million), up 5.2% on 1999, and a low effective tax rate. The result in Australian dollars was even stronger – up 18% on 1999 levels, reflecting the Group's decision not to hedge its Australian dollar currency exposures.

2000 RESULTS

Oil sales were marginally down on 1999 at US$139.6 million, however, actually increased by 8% in Australian dollars to A$243.9 million. Oil liftings of 7.06 million barrels were 15% down on the prior year, reflecting natural field decline in the Kutubu and Gobe fields and some delays in commissioning the Moran-4 production well.

Although a record profit for the Group was recorded this year, the result was disappointing in that it was negatively impacted by the oil hedging programme that the Company was required to put in place in early 1999 as part of its refinancing. The realised oil price for 2000 was stronger at US$18.01/barrel, up from US$15.86/barrel in 1999. This was substantially below spot prices recorded in the market during 2000, reflecting the Company's hedge position. In future, required hedging will allow the Company to benefit from higher oil prices, whilst protecting the downside. This can be achieved by the purchase of appropriate put options. This policy is currently being implemented.

Operating costs were up during the year by US$8.8 million to US$40.5 million (A$70.7 million) whilst amortisation decreased by US$11.7 million to US$42.5 million (A$74.2 million).



Operating costs were impacted by the Operator's relatively flat cost base, thus production decreases did not flow through to the operating cost line. This has been addressed during the year by a joint venture initiative to reduce base costs, the benefits of which will first be felt in 2001. Administration costs remain highly controlled at US$5.5 million, the lowest level since 1997.

Net interest was down 15% to US$12.8 million from US$15.0 million. This reflected efforts to reduce the debt burden, with borrowings declining from US$299 million to US$249 million over the calendar year. This flowed through to a further material decrease in gearing (debt / debt+equity) to 35.8% from 42.6% in 1999.

Tax expense was unusually low at US$2 million.
A comprehensive tax review took place during the year, including the assessment by the Internal Revenue Commission of up to eight years' tax returns. In future, tax expense is expected to more closely match prima facie rates in the range of 40-45%.

The dividend to preference shareholders reduced to US$5.1 million (A$9.0 million) from US$7.2 million (A$11.3 million). This was a consequence of the Company's replacement of the Converting Preference Shares (CPS) with a smaller programme in 2000.

The combination of an increase in pre-tax profit, low effective tax rate, and smaller CPS dividend resulted in a sharp rise in earnings per share to A9.5 cents (diluted) from A6.4 cents.

Operating cash flow of US$58.6 million (A$102.4 million) was down on 1999's flow of US$82.0 million (A$128.5 million). Timing of oil sales materially impacted cashflow in the latter part of the year. Additionally, US$3.0 million of expenditure was related to interest withholding tax, a one off charge paid in 2000.

CONVERTING PREFERENCE SHARES

During the year, the Company successfully refinanced a proportion of the existing Converting Preference Shares into a new tranche of CPS, CPS 2000. The issue of CPS 2000 was offered to all holders of CPS 1998, aimed at minimising dilution of ordinary shareholders and reducing the dividend payable on the old CPS.

Dividends are payable to preference shareholders at a rate of 9% of the issue price of $100 per CPS 2000. These dividends are payable in May and November, until conversion, which is to be completed in two tranches, in May 2002 and May 2003.

OUTLOOK FOR 2001

FINANCING

The Company has arranged a restructure of its debt finance, including a consolidation of its Gobe and Corporate Term facilities into a revised Corporate Term facility.

The new facility of US$215 million has a number of key features, including an interest only period in 2001 to accommodate Moran development expenditure, an extension of tenor by two years to 2005, and a US$40 million final repayment in December 2005. This should allow substantial cash flow to be released to the Company through to 2003, to support an active exploration programme and gas project costs.

The new facility will also result in substantially reduced funding costs with a margin including political risk insurance of 315 basis points (bp) over LIBOR reducing to 290 bp over LIBOR from January 2002. This compares to the existing corporate facility, which was due to increase to 350 bp from June 2001.

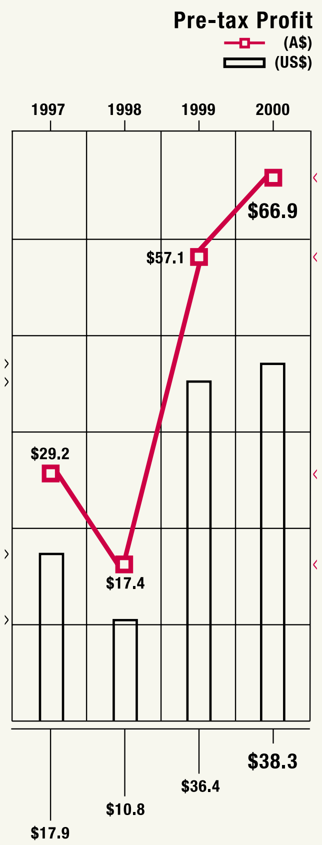
HEDGING

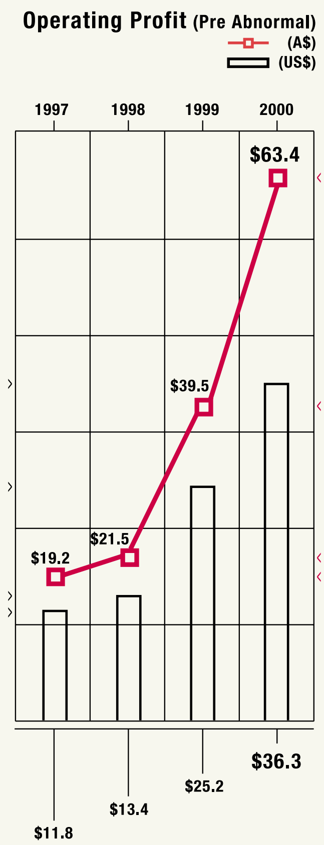
A substantial oil hedging programme was required in 1999, primarily to support the Company's term facility. As this facility was put in place in January 1999, the majority of the hedges were achieved at between US$14 and US$15/barrel, at a time when the spot price was around US$10/barrel.

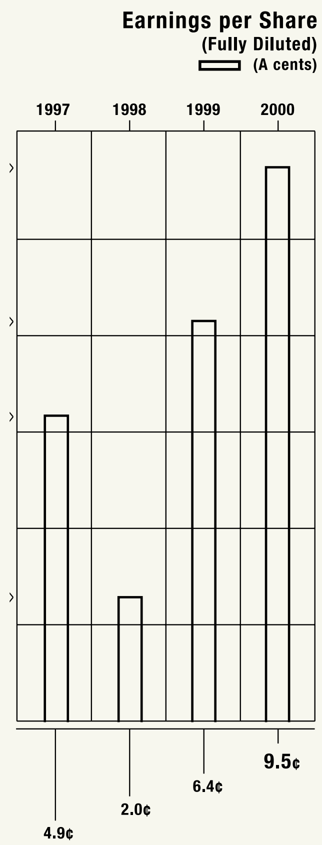
The unprecedented threefold rise in oil prices seen between 1999 and 2000 resulted in a significant portion of the Company's oil production being covered by this hedge position and therefore not able to realise the full benefit of these high prices.

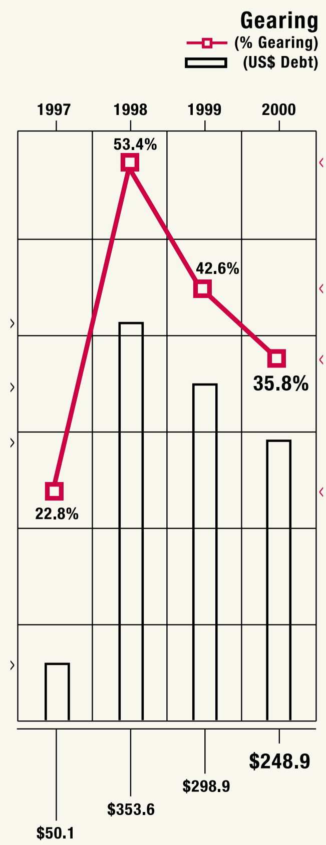
Looking forward, only 2.4 million barrels of these original swaps, at around US$14.50/barrel, remained at 1 January 2001, representing approximately 35% of the likely 2001 production. These will be fully unwound by 30 June 2001, giving far greater exposure to elevated spot prices this year. As such, Oil Search will see a likely material increase in sales revenues this year. Furthermore, any hedging programme required under the new finance facility will be based on put options, allowing shareholders to retain any upside in oil prices. →

driving shareholder value 1997–2000 in millions, except as noted









creating increased shareholder value

The result – over the past few years, Oil Search has produced consistent earnings growth, superior revenue growth and improved returns.

US$	1996 000	1997 000	1998 000	1999 000	2000 000
PROFIT AND LOSS					
Sales revenue	61,594	36,358	90,788	143,487	139,612
Operating expenses*	8,057	7,532	24,922	31,733	40,527
Administration costs	5,365	4,556	5,557	6,054	4,980
EBITDA	**48,172**	**24,270**	**60,309**	**105,700**	**94,105**
Amortisation & depreciation	13,088	9,211	41,221	54,261	43,003
EBIT	**35,084**	**14,846**	**18,732**	**51,439**	**51,102**
Net Interest	2,032	3,029	(7,891)	(15,004)	(12,775)
Operating profit (loss) before abnormals & income tax	37,116	17,875	10,841	36,435	38,327
Income tax expense (credit) (excl. abnormals)	16,919	6,117	(2,568)	11,227	2,013
Operating profit (loss) after income tax before abnormals	20,197	11,758	13,409	25,208	36,314
Abnormals (net of tax)	1,718	(2,412)	4,073	2,169	3,224
Operating profit (loss) after income tax before extraordinary items	18,479	14,170	9,336	23,039	33,090
Extraordinary items	–	–	–	–	–
Operating profit	**18,479**	**14,170**	**9,336**	**23,039**	**33,090**
Dividends – Ordinary	3,757	2,641	–	–	
– Preference		–	3,585	7,194	5,147
Movement in retained earnings	14,722	11,529	5,751	15,845	27,943
Earnings per Share (fully diluted) (cents)	4.1	3.0	1.2	4.1	5.4
BALANCE SHEET					
Total assets	226,358	241,644	745,832	831,839	834,403
Exploration expenditure incurred	25,826	22,272	28,747	38,276	32,482
Development expenditure incurred	3,383	47,067	21,129	22,819	22,012
Acquisition Exploration	–	–	218,325	–	–
Acquisition Development	–	–	221,288	–	–
Total cash	48,988	49,797	23,305	58,341	34,886
Total debt	–	50,100	353,600	298,981	248,909
Shareholders' equity	206,170	169,986	308,810	402,417	446,281
OTHER INFORMATION					
Average realised oil price	**20.42**	**20.24**	**13.15**	**15.86**	**18.01**
Operating cashflow	38,698	19,533	44,802	82,018	58,631
Operating cashflow per ordinary share (cents)	8.3	5.0	9.0	16.0	10.2
Gearing (%)	0.0%	22.8%	53.4%	42.6%	35.8%
Number of issued shares (000) ordinary	467,937	468,745	468,860	525,713	576,454
Number of issued shares (000) preference	–	–	1,189	1,189	802
EXCHANGE RATES					
Year End A$:US$	0.7915	0.6468	0.6069	0.6470	0.5489
K:US$	0.7360	0.5635	0.4710	0.3585	0.3120
Average A$:US$	0.7907	0.7698	0.6239	0.6384	0.5725
K:US$	0.7538	0.6822	0.4667	0.3759	0.3498

* Operating Expenses includes operating costs, provision for site restoration, marketing costs, royalties and insurance

A$	1996 000	1997 000	1998 000	1999 000	2000 000
PROFIT AND LOSS					
Sales revenue	80,155	59,494	145,517	224,760	243,864
Operating expenses*	10,485	12,451	39,945	49,707	70,790
Administration costs	6,539	7,360	9,478	9,483	8,699
EBITDA	**63,131**	**39,683**	**96,665**	**165,570**	**164,375**
Amortisation & depreciation	17,293	15,083	66,070	84,996	75,114
EBIT	**45,838**	**24,271**	**30,024**	**80,574**	**89,261**
Net Interest	2,644	4,954	(12,648)	(23,503)	(22,314)
Operating profit (loss) before abnormals & income tax	48,482	29,225	17,376	57,071	66,947
Income tax expense (credit) (excl. abnormals)	22,018	10,002	(4,116)	17,586	3,516
Operating profit (loss) after income tax before abnormals	26,464	19,223	21,492	39,485	63,431
Abnormals (net of tax)	2,417	(3,944)	6,528	3,397	5,631
Operating profit (loss) after income tax before extraordinary items	24,047	23,167	14,964	36,088	57,800
Extraordinary items	–	–	–	–	–
Operating profit	**24,047**	**23,167**	**14,964**	**36,088**	**57,800**
Dividends – Ordinary	4,869	4,318	–	–	–
– Preference		–	5,746	11,269	8,990
Movement in retained earnings	19,178	18,849	9,218	24,819	48,810
Earnings per Share (fully diluted) (cents)	5.2	4.9	2.0	6.4	9.5
BALANCE SHEET					
Total assets	283,377	369,519	1,228,920	1,285,686	1,520,136
Exploration expenditure incurred	32,332	34,371	47,347	59,159	59,176
Development expenditure incurred	4,235	72,635	34,815	35,269	40,102
Acquisition Exploration		–	359,738	–	
Acquisition Development		–	364,620	–	
Total cash	61,328	76,158	38,400	90,172	63,556
Total debt	–	76,612	582,633	462,104	453,468
Shareholders' equity	258,104	259,941	508,832	621,973	813,046
OTHER INFORMATION					
Average realised oil price	**25.80**	**31.23**	**21.67**	**24.84**	**31.46**
Operating cashflow	50,360	31,936	71,810	128,474	102,412
Operating cashflow per ordinary share (cents)	11.7	7.0	13.0	24.0	17.8
Gearing (%)	0.0%	22.8%	53.4%	42.6%	35.8%
Number of issued shares (000) ordinary	467,937	468,745	468,860	525,713	576,454
Number of issued shares (000) preference	–	–	1,189	1,189	802
Net Annual Production					
Oil (mmstb)	3.00	2.14	6.29	8.35	7.09
Gas (bcf)	0.26	0.22	3.56	5.05	5.44
Total BOE (mmboe)	**3.04**	**2.18**	**6.88**	**9.19**	**8.00**

doing well by doing it better

Q. The realised oil price was only US$18.01 per barrel. Will this improve in the current year?

A. It is correct that the oil price in 2000 averaged around US$29 per barrel. However, in 1999 it was necessary to hedge a significant portion of estimated production to support US$345 million of term debt raised at that time.

With oil prices at around US$10.00 per barrel, the forward market was very subdued and most of the swaps were struck at around US$14.50 per barrel. The majority of these contracts expired during 2000, resulting in the realised oil price being only to US$18.01 per barrel.

Only 2.4 million barrels of these swaps remained at 1 January 2001, and all of these will expire by June 2001, giving the Company full exposure to the oil price beyond that time. If prices remain at current levels, our realised oil price will rise substantially in 2001.

Q. What was the logic behind the Converting Preference Share (CPS) issue?

A. The Company was faced with the conversion of A$118.9 million of 1998 preference shares in June 2000. For a number of reasons, including the level of hedging, slow progress with the gas project and limited exploration in 2000, the share price did not, in our opinion, reflect the value of the Company. As a result, the conversion of the 1998 CPS issue would have resulted in heavy dilution of the ordinary shares.

As a result, we decided to offer the 1998 holders the opportunity to roll over into a new CPS called CPS 2000. The logic is that with the progress of the Company over the next two to three years we expect the share price to strengthen and result in much lower dilution to ordinary shareholders when ultimately converted. The offer of CPS 2000 was restricted largely to CPS 1998 holders, as the relatively small new issue, A$30 million, could not be offered across our 27,000 ordinary shareholders.

→

the performance production

Oil production for 2000 fell by 15.1% to 7.09 million barrels. The decline in output was largely due to the natural field decline in the Kutubu and Gobe projects, offset, later in the year, by production from the Moran-4 well. Gas production from the Hides field rose by 4% during the year.

It is expected that, despite a number of workover and new development drilling activities that are planned in the Kutubu and Gobe fields, production decline will continue in the range of 20-30% per year for 2001 and 2002. The Company will more than make up for this decline by the development of Moran Central where we have a significant interest and, where under the present commercial arrangements, we expect to receive around 49% of field production during this time. Although our 2001 production rates are likely to be similar to those in 2000, there will be a material increase (over 20%) in 2002 with the next stage of Moran Central development being completed. The net and gross oil production, on a field-by-field basis, is given in the table on page 19.

KUTUBU PROJECT PDL 2 (OIL SEARCH SHARE 27.14%)

The Company's share of production from the Kutubu project fell by 21.2% to 3.253 million barrels, or 8,887 bopd. This was due to natural field depletion, a similar decline rate to that achieved during 1999. Gross production from the Kutubu field for 2000 totalled 11.986 million barrels, at an average rate of 32,748 bopd. Production decline was again partially mitigated during the year due to the success of workover activities, producing zone changes, and continued operations optimisation to minimise associated gas production that is constraining oil rates.

Technical studies completed during the year identified a large number of reserve and rate enhancement activities to be carried out in 2001 and beyond. The Joint Venture partners approved the drilling of two horizontal infill/extension wells in Iagifu/Hedinia Field, two rig workovers and two coiled tubing workovers during 2001, a large increase in improved recovery activity relative to recent years.

The immediate development programme was initiated in March 2001, with the drilling of the IDT-20 well. This development activity in 2001 will be aimed primarily to target oil not presently being swept with the existing well drainage pattern and will recover an estimated 4.3 million barrels of reserves at an incremental gross rate of approximately 4,000 bopd.

Workover activity is to also be accelerated in the current year, with the use of a Coiled Tubing Unit (CTU). This work is trialing a new, cost-effective gas shut-off technology with significant potential for use in other wells and is expected to commence in Kutubu early in the second quarter of 2001.

GOBE PROJECT PDL 3 & PDL 4 (OIL SEARCH SHARE 15.5% AND 27.14%)

The Company's share of output from the Gobe Main and SE Gobe fields declined by 10.0% and 27.0% to 1.492 million barrels and 1.023 million barrels respectively. The decline in output was due to higher levels of gas production and the impact of field complexities.

During 2000, gross Gobe production averaged 28,212 bopd – down from 34,277 bopd in 1999, with total Gobe cumulative production reaching 30 million barrels by year end. Oil production was restricted during the year due to gas compression limitations. Gas management strategies for both well completions and facilities continued to be a major focus area throughout the year.

Three new development wells were drilled during the year. Gobe-6X ST2 sidetrack operations commenced in February following mechanical difficulties with Gobe-6X ST1. Gobe-6X ST2 was successfully drilled as a horizontal well, allowing oil rates to be maximised while protecting the wellbore from early arrival of gas and water.

The SE Gobe-8 and 9 wells were successfully drilled late in the year, with pressure data from offset wells indicating that the new wells were communicating with their respective fault blocks. These wells are being brought on line gradually to reduce sand production.

Several completions and workovers were carried out, both with conventional rigs and the CTU. SE Gobe-7 was completed in August and is now being configured for production from the upper zones. SE Gobe-4 was re-completed in April, after production experienced significant gas breakthrough. Mechanical difficulties have affected the success of the operation. A remedial programme is now being planned.

The CTU was mobilised in late December to commence a programme including Gobe-7X ST3 and Gobe Main-3 ST1. Workover activities were also undertaken on the Gobe-7X and Gobe Main-3 wells during the year. Further workover activity is planned throughout 2001, aiming at reducing the rate of oil production decline from the fields.

The PDL 3 and PDL 4 licence groups carried out an interim redetermination of interests in the SE Gobe Unit during the year. The interim redetermination resulted in Oil Search's interest changing from 21.9% to 20.3% from July 2000, which was offset by a cost adjustment payment to Oil Search of US$5.3 million. A further redetermination will be considered in April 2001, to include all data from recent development drilling activities.

Reservoir simulation and material balance studies carried out during the year were utilised in optimising development drilling activities, reserves determination and facilities expansion studies. Oil Search will continue to pro-actively look for new opportunities to improve the recovery efficiency from these fields.

MORAN CENTRAL EXTENDED WELL TEST PDL 2 & PDL 5 (OIL SEARCH SHARE 27.14% AND 52.50%)

The Oil Search share of output from the Moran Central Extended Well Test (EWT) rose by 13.3% to 1.34 million barrels during the year. The majority of the increase was due to production from the Moran-4 well, which commenced on 21 April 2000. Total gross production from the EWT, at year-end 2000, was 10.8 million barrels.

Moran-4 production, delayed by some four months due to commercial negotiations on tariff and processing fees, flowed from the Toro and Digimu reservoirs at rates up to 14,000 bopd. In the latter part of the year, Moran-4 and Moran-2 continued to flow in excess of 13,000 bopd. A landslide and partial burial of the Moran–Agogo flowline resulted in an extended shut-in of the field while a section of the flowline was replaced. The relocation and repair of the flowline was completed in September, following a four-week production hiatus.

The pressure response resulting from the production of more than 1 million barrels of oil from Moran-4 has provided valuable reservoir information, confirming the presence of a significant hydrocarbon resource in this area, and providing indications of the presence of additional pressure support, presumably through a field extension to the north-west.

The Moran development licence was awarded on 17 February 2001, providing the impetus for increased expenditure on the field. Initial development activity will be focused on development drilling and road construction, and the expansion of the nearby Agogo facilities, which will process the expanded oil and gas output from Moran. Upon award of the licence, the Unitisation Agreement comes into force, allowing construction to proceed and production balancing to commence. The Company's net share of total project production, due to equalisation, will increase to 49% during 2001 and 2002.

The drilling phase of the development will consist of three new wells, two additional producers and one gas injector. The first well, Moran-6, has now been accelerated and will be spudded immediately following completion of IDT-20, as part of the contracted Rig 226 programme. This well will provide significant additional production volumes for the Company during 2001 and gather geological and reservoir information to aid in the further delineation of the north-westerly extent of the field. The second and third wells will be drilled following the Bakari-1 exploration well.

HIDES PROJECT PDL 1 (OIL SEARCH SHARE 100%)

The Hides project operated well during 2000, producing 5.2 Bcf of gas, up 4% on the 1999 levels. Gas sales averaged 14.2 mmcfgd over this period. There were no significant field activities during the year.

net and gross oil production on a field-by-field basis

	Net Oil Search Production				Gross Field Production			
	2000 Production		1999 Production		2000 Production		1999 Production	
	bopd	Million barrels	bopd	Million barrels	bopd	Million barrels	bopd	Million barrels
Kutubu	8,887	3.253	11,309	4.128	32,748	11.986	41,672	15.210
Moran PDL 2	929	0.340	3,196	1.167	3,424	1.253	11,776	4.298
Moran PDL 5	2,684	0.982			5,112	1.871		
Gobe Main	4,076	1.492	4,542	1.658	15,020	5.497	16,738	6.109
SE Gobe	2,796	1.023	3,842	1.402	13,192	4.828	17,541	6.402
Total Oil	19,372	7.090	22,889	8.354	69,496	25.435	87,727	32.019
Hides (mmscfd/Bcf)	14.2	5.2	13.6	5.0	14.2	5.2	13.6	5.0
Total boe	**21,740**	**7.957**	**25,156**	**9.184**	**71,864**	**26.302**	**89,994**	**32.849**

the performance gas project

Frustratingly slow progress was made to bring this huge, complex project to commercial reality. Although slower than anticipated and hoped for, the Project did achieve a number of very significant milestones during the year.

Significant milestones achieved during the year:

- Announcement of the Queensland Government Energy Strategy, framing the use of gas for electricity generation in the State.
- Completion of a Co-operative Development Agreement between the Kutubu and Hides Joint Ventures, allowing full access to these large gas reserves and the optimal path to commercial development of both fields.
- Announcement by the State Government of construction of a gas pipeline between Townsville and Gladstone as an effective early build of the line to PNG, stimulating market growth in these areas.
- Completion of a full technical due diligence of the design concept of the project prior to commencement of full Front End Engineering and Design (FEED) activities.
- Progress towards finalisation of the fiscal terms applicable to the Gas Project with the PNG Government.
- Progress on finalising a finance plan and equity arrangements for PNG Government and Landowner participation in the infrastructure, in conjunction with the Australian Federal Government and other sources of finance.
- Receipt of ACCC approvals for joint marketing of PNG Gas, including ExxonMobil and Santos for the first time.
- Material progress to finalise gas sales agreements with customers in Queensland and establish gas fired electricity generation as a viable option in the State.

These achievements also complement other previous milestones, such as choice of pipeline route and endorsed Native Title approach, environmental approvals in Australia and PNG, approval by the Regulators for tariffs and access principles for the pipeline, all representing the essential framework for the development.

Key elements that require resolution and finalisation are as follows:

- Confirmation of markets for both electricity and industrial customers.
- Finalisation of the equity position, and financing plan for PNG Government entities and Landowners in the PNG infrastructure.
- Finalisation of the Gas Agreement, covering fiscal terms for the Gas Project in PNG. The framework of these terms has been agreed and is being documented. The methodology of how PNG entities will take equity in the Hides field is now being discussed.

GAS MARKET CONFIRMATION

Following approval from the ACCC for ExxonMobil and Santos to jointly market gas with other PNG developers, a detailed set of Term Sheets was presented to all customers in Queensland. Material negotiations have taken place with customers since that time, albeit through a period of government uncertainty leading to the Queensland State Election.

Primary customers for the gas include a number of Queensland Government-owned corporations (GOCs) that wish to buy the gas for electricity generation and as aggregators for various industrial customers. The primary base for required volumes for the project to proceed is underscored by mid-range electricity generation in Townsville and in the south-east of Queensland. The sensible and financially sound application of the Government's Clean Energy Policy will result in sufficient volumes of gas to underpin the project.

Discussions with customers and government have highlighted the benefits of the project to Queensland and how these volumes can be accommodated as part of the policy application. Detailed discussions are continuing and, following the recent State Election and the re-election of the Beattie Government, marketing activities will receive new impetus and guidance as the government works into a new term.

Discussions with customers have highlighted the price competitiveness of PNG Gas over any competition. Coordinated management of electricity generation under the Energy Policy is now being proposed, along with risk sharing elements of the contracts.

In line with public statements made by Timor Sea gas developers, we do not see the PNG and Timor projects in direct competition. Each project is focused on primarily different markets, with Timor Sea in the Northern Territory and the Moomba gas hub, and with PNG strongly focused on providing competitively priced energy for Queensland. Analysis of market demand indicates that both projects can proceed and indeed are needed to provide gas to replace existing but diminishing supplies and new markets.

PNG GOVERNMENT AND LANDOWNER PARTICIPATION

Various constructive discussions have taken place between the PNG and Australian Federal Governments regarding the potential to finance a portion of PNG participation in the pipeline and infrastructure. These opportunities are being pursued at both working group and ministerial level to finalise an appropriate commercially based plan for participation. Significant progress has been made in this area. It is recognised by both governments that the future economic health and stability of PNG is largely dependent on a successful outcome for this major project.

The Australian Federal Government has indicated its strong support of the project and, although there is no mechanism that will allow provision of concessional loans from the Government to PNG to finance their participation, the Australian Government is actively providing direct and indirect support in a number of other ways to ensure that PNG entities are able to take up meaningful equity in the project. They have also signalled that they are willing to provide political risk insurance to cover various aspects of force majeure events for both the project sponsors and customers.

GAS AGREEMENT WITH PNG GOVERNMENT

Material progress was made in finalising outstanding fiscal terms and conditions applicable to development in PNG. Discussions are now focusing on the most practical method of formally documenting these terms. Key fiscal issues, such as tax rates, that will apply to the Project, were passed as part of the 2000 Budget in December.

OTHER ACTIVITIES

Various commercial activities have continued in developing an appropriate operating structure for FEED activities and construction.

Discussions to finalise transportation arrangements in Australia have continued which, however, can only be completed when the final initial contract volumes are better defined.

THE WAY FORWARD

Emphasis of Project activities is to close the terms for contracts to customers in Queensland. These negotiations have recently received new impetus following the re-election of the government in Queensland. Substantial progress has been made in this area and the remaining issues between the parties are being actively addressed.

Substantial resources are being applied to finalise all remaining commercial issues. The final timing for gas deliveries to markets in Queensland is dependent on FEED activities and completion of remaining commercial issues. The Project Developers believe this can be achieved in the first half of 2005.

The Company will continue to devote all necessary resources to ensure the successful commercialisation of this project. We recognise this project, along with exploration success, is important in realising the value of our resource and asset base in Papua New Guinea and seeing that value translated to share price performance. →

PNG TO QUEENSLAND GAS PROJECT–
PROPOSED PIPELINE ROUTE

the performance exploration

Exploration activity in 2000 was slower than planned due to the success of the Highlands seismic programme and the lack of joint venture commitment to complete the budgeted drilling programme. The continued maturing of Highlands prospects by the seismic programme will see drilling accelerate in 2001, with a series of commitment wells to be drilled by year end.

Exploration activities in 2000 concentrated on the acquisition of seismic in the Highlands of Papua New Guinea and the appraisal of our Papuan Gulf licences with the drilling of two exploration wells. The implementation of our 2001 exploration strategy will result in the sequential exploitation of Oil Search's existing portfolio and in the acquisition of new, high quality areas to ensure the Company's exposure to material drilling and growth opportunities in the future.

The strategy has established a process that will:

- minimise exploration risk by the commitment to an extensive Highlands seismic programme prior to drilling;
- ensure a continuous, cost-efficient and predictable drilling and seismic programme (this has resulted in the establishment of an integrated seismic and drilling consortium, made up of all of the Foldbelt Joint Ventures, with contractual commitment to drilling rigs and seismic crews);
- fully appraise our PNG licences, where we operate, and can dictate the pace of exploration and subsequent developments so that efforts can be focused on the most value-adding areas and appropriate cost control;
- fully evaluate, as a matter of urgency, the full potential of our Highlands and Foreland licence base, maturing new prospect and play types for exploration (these include the footwall plays, now evident on seismic data and offshore areas, that have scope to materially increase our licence potential and value);
- add high-quality, low-cost exposure exploration licences within new venture focus areas in proven hydrocarbon provinces (e.g. the measured diversification of Oil Search's asset portfolio into the Middle East and Australasia).

The seismic activity in the Highlands is sequentially maturing a range of prospects that will form the basis of a continuous exploration and appraisal programme now contracted and taking place in 2001-02. Due to the excess production capacity in the existing infrastructure and the continued strength of the elevated crude prices, the respective Foldbelt Joint Venture partners have decided to concentrate activity on prospects in close proximity to existing developed fields. In this manner, early commercialisation of discovered fields can be achieved. In addition, extended well testing (EWT), that has proven to be successful at Moran Central by providing early cash flow as well as reservoir productivity and continuity information for development design, will be implemented where possible. The Saunders and Moran extension wells are candidates for this activity.

2001 DRILLING PROGRAMME

In order to ensure that exploration drilling was carried out in a cost-effective and predictable programme in the Foldbelt, Oil Search linked Joint Venture budget approval for 2001 to a contracted, logistically achievable programme. This has resulted in a northern drilling campaign that will see one rig active for around 18 months of continuous drilling. This programme started in March 2001 with the drilling of a Kutubu development well, to be followed by the important Moran-6 appraisal and development hole, and Bakari-1, a commitment exploration hole in PPL 138. This will be followed by further Moran and Kutubu development drilling. The Moran-6 well is particularly important to Oil Search in that it has the capability of extending Moran Central reserves to the north-west and, being a major producing well, Oil Search will receive up to 49% of its predicted 12,000–14,000 bopd initial production.

The Bakari exploration well is one of the most prospective exploration wells to be drilled in the Company's history. It is one of the first occasions where seismic coverage has been used to fully evaluate the prospect prior to drilling. Initial interpretation of seismic data indicates a large, relatively simple structure, on trend with the Moran Central discovery. Most likely reserves, based on a 50% gas and 50% oil fill, are in excess of 200 million barrels of recoverable oil. Oil Search holds a 52.5% equity in this well, thereby providing a material impact on Company value, given success, having the potential to more than double our present proven and probable oil reserves.

A second drill rig is also active in the Gobe area, initially drilling development holes on Gobe Main and SE Gobe. Other wells in the programme for this rig include the Saunders exploration well, a PPL 219 commitment hole (likely to be either Kutubu Attic or SE Moran) and a PPL 190 commitment hole (likely to be a Saunders appraisal or an Iehi well). The order and final timing of these wells is being decided as this report is being finalised.

Seismic acquisition in various areas of the Highlands Foldbelt will continue through 2001, with the programme leading to a sequential development of up to 15 prospects for drilling in 2002 and beyond. This represents a quality exploration portfolio, with seismic control for the first time, in the prospective Foldbelt area.

OFFSHORE ACTIVITY

During 2000, Oil Search also operated two offshore exploration wells in the Gulf of Papua, Anama-1 in PPL 188 and Dua Dua-1 in PPL 179. The results of the two wells were unfortunately disappointing, with wireline logs indicating the presence of residual hydrocarbon in the reservoir objectives. The wells have indicated that a substantial risk of preserving hydrocarbons exists south of the Komewu Fault on the Fly Platform. Oil Search did, however, drill the wells faster and cheaper than any well ever drilled in the basin attesting to the operational ability of the Company.

AUSTRALIAN DRILLING

During 2000, the Company participated in an extensive 3D seismic programme over the WA-281-P permit in the Browse Basin, North West Shelf. The purpose of the programme was to delineate the location of the 2001 commitment well, that will spud prior to September 2001. The Joint Venture recently confirmed that the Marabou-1 well will be drilled as the commitment well in this permit. Marabou-1 is a late Cretaceous Submarine Fan play, with a reserve target in excess of 120 million barrels. WA-281-P has recently been significantly upgraded by the exploration successes in the immediately adjacent WA-285-P licence, where multi Tcf gas/condensate fields have been reported to have been discovered by Inpex.

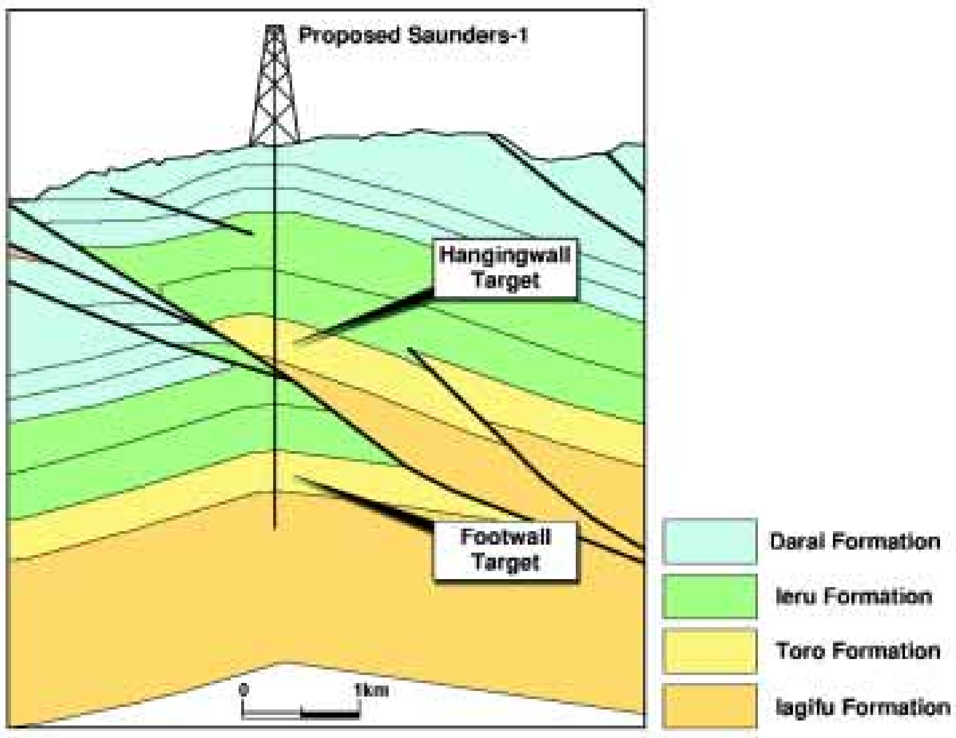
NEW VENTURE ACTIVITY

Oil Search reviews a large number of new venture opportunities, both within and outside Papua New Guinea. The Company has developed a range of specific technical expertise to address the challenges in its PNG portfolio. The Company is also adept at carrying out operations in difficult environments, with complex social and community issues, where government relations are essential. We have cultivated a range of contacts with like-minded companies, operating as specialists in a number of developing countries, again with excellent local knowledge and contacts.

Following a period of extensive regional evaluations, the Company acquired an 80.75% equity of Block 15, a large offshore exploration licence in Yemen that has proven hydrocarbon potential and a number of large untested play types. Following the initial review, the Company conducted a number of reprocessing trials on the existing seismic with dramatic results. Block 15 was last explored 16 years ago by AGIP who drilled 6 wells and acquired over 8000 km seismic data. Three of AGIP's wells discovered oil, with one well flowing 43^{o} API oil at a rate of 3054 bopd from the Eocene carbonates following acidisation. Subsequent to the award of the licence, we have now farmed out a 40% equity to Kufpec (the International arm of the Kuwait National Oil Company) in exchange for a substantial carry through the minimum exploration programme. Oil Search has retained control and the operatorship of the licence. A number of bids were received for the licence from large international companies, attesting to the potential of the area.

2001 OUTLOOK

The integrated and contracted 2001 drilling programme will drill the first exploration wells in the Highlands constrained by seismic. This programme has now commenced. With the reduction of subsurface risk, this drilling programme is one of the most exciting that the Company has participated in for many years. →



PROPOSED SAUNDERS-1 EXPLORATION PLAYS

the performance reserves

The annual audit of the Company's reserves by Netherland Sewell and Associates in Dallas for year ending December 2000 has recently been finalised. This review of the Company's reserves is carried out as an important part of our Corporate Governance procedures and our financing requirements.

The audit has resulted in a reduction in proven and probable reserves of 9 million barrels, after adjusting for annual production of 7 million barrels. Half of this reduction is because of an adjustment in the categorisation of certain Moran reserves from proven and probable to possible, and the remainder due to Gobe Main and SE Gobe downward adjustments.

The changes in remaining proven plus probable (2P) reserves for the Company's assets are outlined in the table below.

KUTUBU DEVELOPMENT

The ultimate recoverable reserves for Kutubu (including SE Mananda) were unchanged at 338 million barrels. After adjusting for 2000 production of 3.3 million barrels, Oil Search's net remaining proven and probable reserves at Kutubu are 22 million barrels.

PNG reserves and resources (as of 31/12/2000)[1]

			Gross		Net Oil Search	
Field	Licence	OSL Equity	2P Oil[2] (Million barrels)	2P Sales Gas[3] (Bcf)	2P Oil[2] (Million barrels)	2P Sales Gas[3] (Bcf)
Kutubu/SE Mananda	PDL 2	27.1%	80	0	22	0
Moran	PDL 2/PDL 5	40.5%	87	0	36	0
Gobe	PDL 3/PDL 4	15.9% & 27.1%	41	0	9	0
Hides (GTE)[4]	PDL 1	100.0%	2	111	2	111
Subtotal Reserves			210	111	70	111
Kutubu	PDL 2	27.1%	104	1,099	28	298
Moran	PDL 2/PDL 5	40.5%	27	275	11	111
Gobe	PDL 3/PDL 4	15.9% & 27.1%	29	231	7	55
Hides[5]	PDL 1	27.5%	156	3,059	37	734
Subtotal Gas Project Resources[6]			316	4,664	84	1,199
Hides[7]	PDL 1	27.5%	112	2,194	31	603
Other Resources[8]			194	5,975	40	1,672
Subtotal Other Resources			306	8,169	71	2,275
Total Proven & Probable Reserves & Resources			832	12,945	224	3,585

Notes:

(1) Numbers may not add due to rounding.
(2) Oil includes condensate and LPG.
(3) Sales Gas Reserves are quoted. Raw gas reserves can be obtained by increasing Sales gas reserves by 12.7%.
(4) Hides reserves associated with the Gas to Electricity (GTE) project only.
(5) Hides NSAI audited reserves are based upon mapped hydrocarbon volumes only and numbers shown exclude the Hides GTE Project Production and Reserves.
(6) Gas Project Resources are as audited by NSAI, as at January 2001 (excludes Hides GTE Project Production and Reserves).
After allowance for Hides GTE Production and Reserves and Hides Gas Project Resources.
(7) PDL 1 Joint Venture carry total 2P reserves of 5,400 Bcf on the basis of material balance estimates from the Hides 2 & Hides 4 1999 pressure surveys.
The estimate shown is the incremental over Hides Reserves and Hides Gas Project Resources.
(8) Other resources comprises fields which are initially outside the PNG Gas Project. Sales Gas estimates for these fields include inerts.

MORAN CENTRAL DEVELOPMENT

The ultimate recoverable reserves for Moran were adjusted down by 8 million barrels on a gross basis during the year due to the removal of Block K oil from the 2P simulation model forecasts. Gross ultimate recoverable reserves are estimated to be 98 million barrels, of which 10.8 million barrels have been produced as at December 2000.

The potential of Block K will be addressed as Moran-4 production history is extended and the results of Moran-6 appraisal/development well are known. This volume of oil has therefore been moved from the proven and probable to the possible category, subject to further review when test and well results are known.

GOBE DEVELOPMENT PROJECT

GOBE MAIN BLOCK

A review of Gobe Main proven and probable reserves has resulted in a reduction of around 7 million barrels from the proven and probable category. This reverses an upgrade given at the end of 1999.

Although the in-place reserves remain similar to those of last year, doubts about the nature and size of the final development programme have resulted in a reduction of proven and probable developed recoverable reserves of 7 million barrels (1 million barrels net to Oil Search).

Estimated ultimate recoverable reserves from this field now stand at 31 million barrels of which 15.2 million barrels have been produced. The reserves estimate will be reviewed following the results of the 2001 drilling programme.

SE GOBE

A review of the SE Gobe proven and probable reserves has seen a reduction from 50 million barrels to 39 million barrels, as a result of greater field complexity, uncertainty about the future development programme and increasing gas production in a number of key wells.

This has resulted in a reduction of 3 million barrels, net to Oil Search. Remaining proven and probable reserves, based on the existing development plan, are 24.2 million barrels. Further drilling and workover activity is planned in this field in 2001 and results will be reviewed as part of the year end audit.

GAS AND ASSOCIATED LIQUIDS RESOURCES

No significant changes to the Company's static gas and associated liquids resources have been seen in 2000. Oil Search's share of gas project reserves remain high at approximately 84 million barrels of liquids and 1,200 Bcf of Sales gas. In addition to these allocated reserves, a further 71 million barrels of liquids and 2,275 Bcf of gas is reported in other fields.

Total net proven and probable undeveloped reserves currently stand at 155 million barrels of liquids and over 3,400 Bcf of Sales gas, a total of over 700 million barrels of undeveloped oil equivalent reserves.

Moran Central Development

delivering growth summary table

Total cost	US$195 million.
Reserves under development	Total reserves 98 million barrels.
New drilling activity	Three additional wells to be drilled, 2 producers, Moran-6 and Moran-C plus a gas injector, Moran-B.
Oil production capacity	Pipeline capacity will be 24,000 bopd.
Gas recycling capacity	Gas injection capacity will be 100–120 mmcfgd.
Export system	Oil production will be processed at the nearby Agogo field and exported via the existing Kutubu pipeline facilities.
Development timetable	The initial phase of drilling will start in the first half of 2001. The second phase will be completed in the first half of 2002. Gas injection is scheduled for completion towards the end of first quarter of 2002.

MORAN DEVELOPMENT

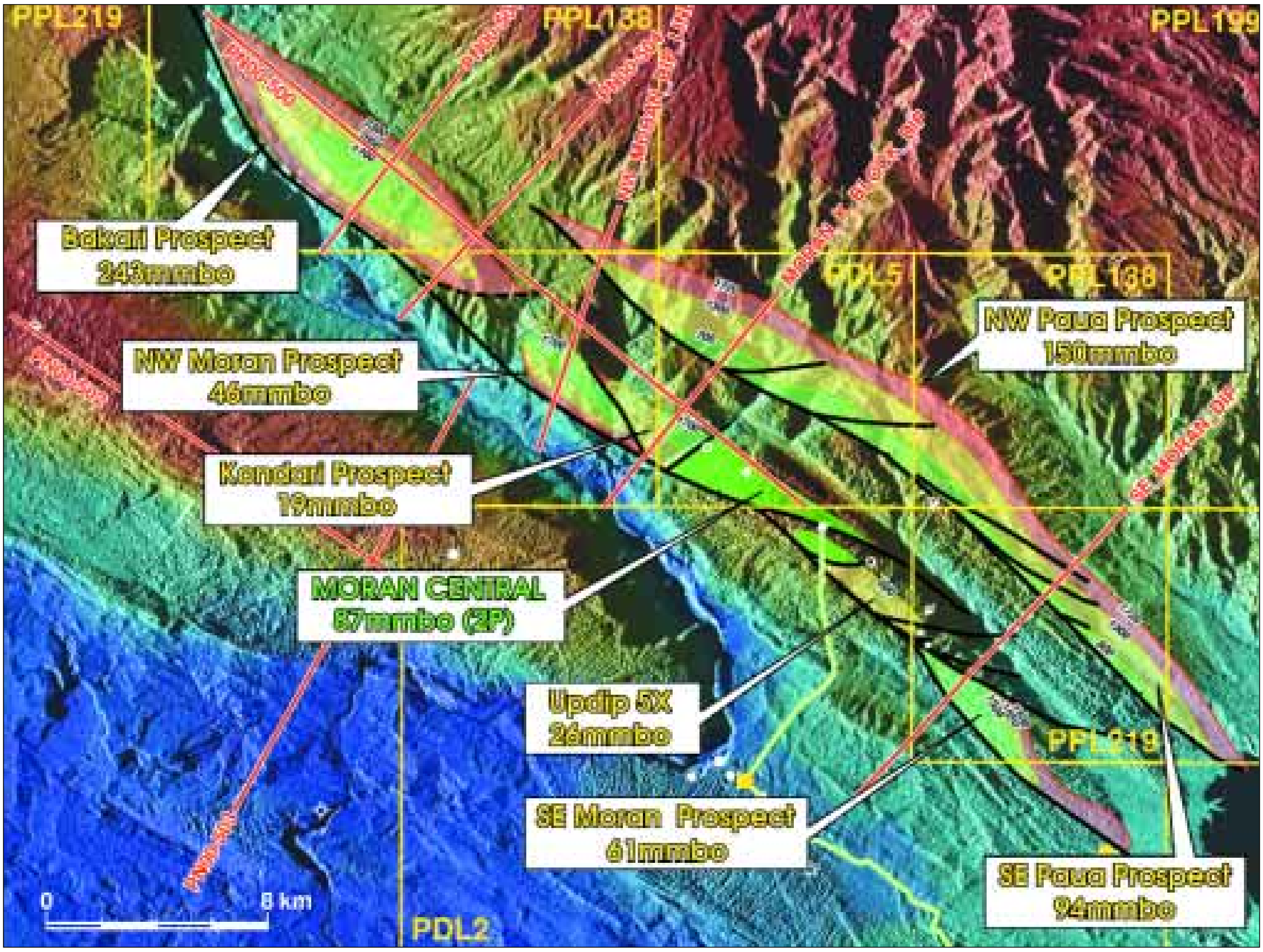
The Minister for Petroleum and Energy awarded the Moran Central Field Petroleum Development Licence, PDL 5, on 17 February 2001. This approval followed the finalisation of a number of other agreements during the latter part of the year among the key project stakeholders – State and Provincial Governments, Project Area Landowners and Developers. Importantly, the Development Agreement between Landowners and the Department of Petroleum and Energy, was executed in early January with agreement on project benefits, royalties and project equity share.

Project implementation is proceeding with the construction of roads and facilities. Approximately 22 km of roads will be constructed, linking the Moran Field with the existing Kutubu road network. Road access will reduce mobilisation costs for equipment and form the route for the majority of the gas injection pipeline system.

Facilities work will involve the expansion of the Agogo Processing Facility, and associated EWT facilities, to provide processing capacity for 24,000 bopd of Moran crude and injection of 100–120 mmcfgd of gas into the Moran field to assist in oil recovery. First gas injection is still expected in March/April of 2002 as the Joint Venture pre-ordered the critical path and long lead equipment items in order to maximise project schedule reduction opportunities. Total project expenditure is estimated at US$195.4 million, including a 10% contingency.

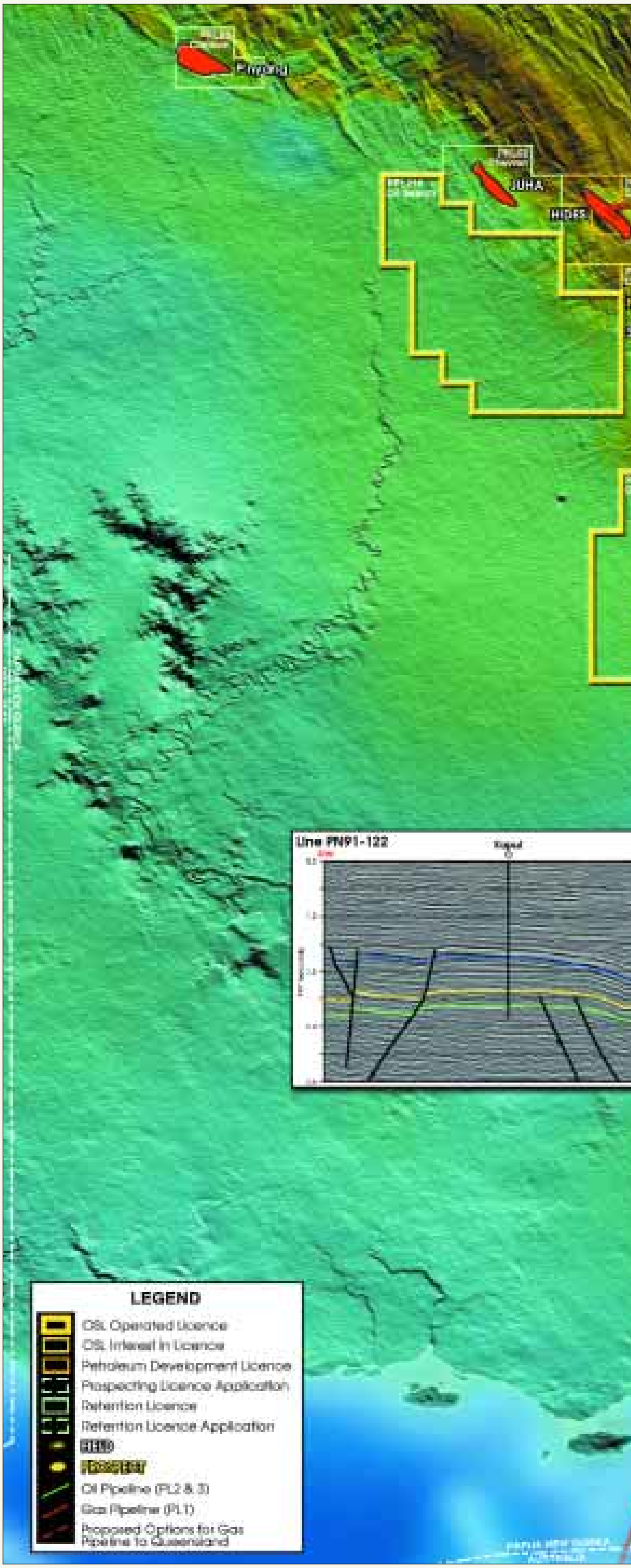
Based on remaining reserves of around 90 million barrels, development costs are approximately US$2 per barrel. →

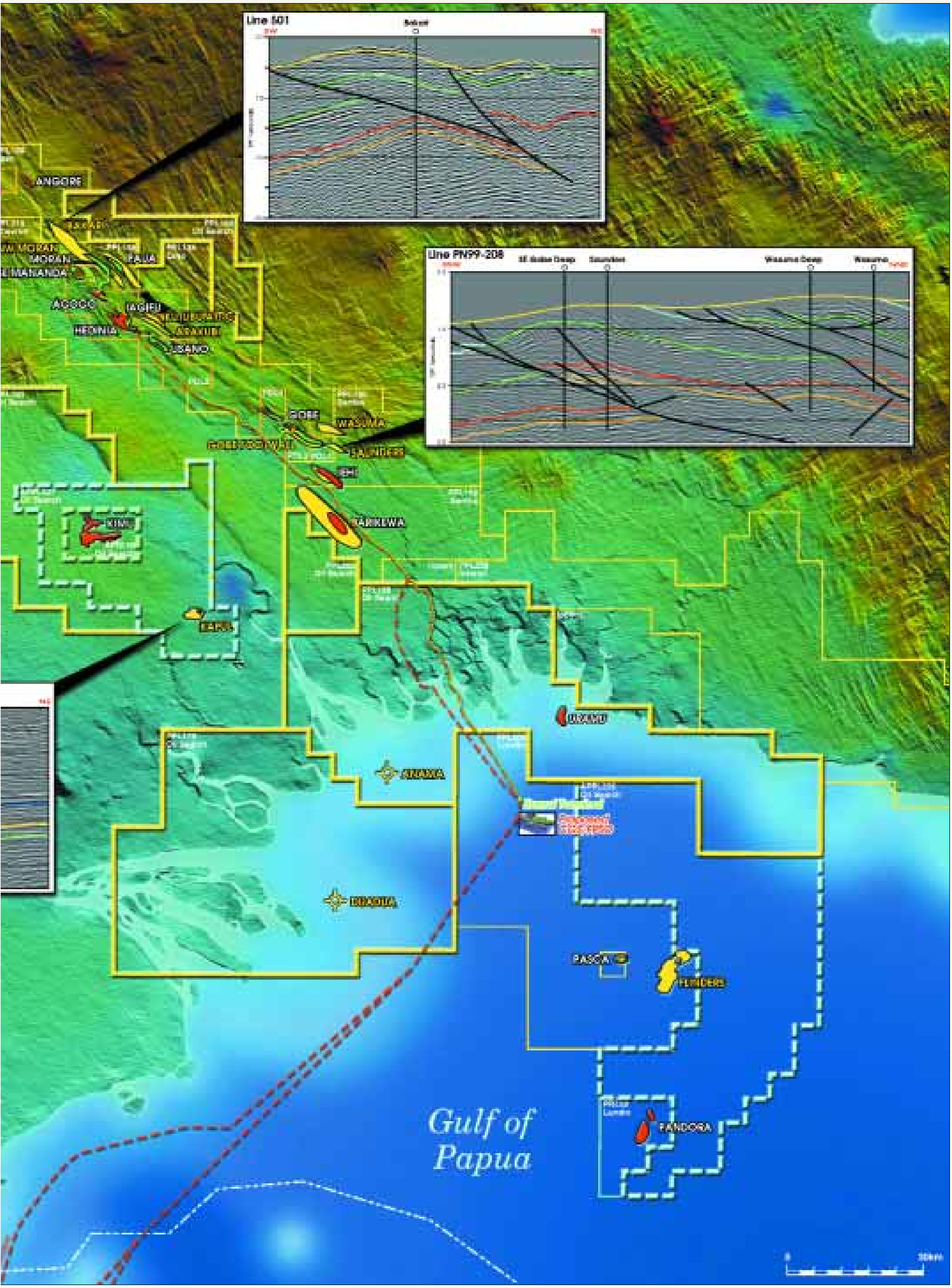
MORAN REGION — FUTURE PROSPECTS



Oil Search Limited PNG

permits map





Line 601
Line PN99-208
ANGORE
MORAN
AGOGO
IAGIFU
HEDINIA
GOBE
WASUMA
SAUNDERS
KIMU
BARIKEWA
KAPUL
UramU
ANAMA
IBIADUA
PASCA
FLINDERS
PANDORA
Gulf of
Papua

Oil Search Limited PNG permits map

licences

Licence	Interest %	Operator	JV partners
PDL 1	27.50	ExxonMobil	ExxonMobil, Santos
PDL 2	27.14	Chevron	Chevron, Orogen, ExxonMobil, Petroleum Resources, Merlin Pacific, Merlin/Mitsubishi
PDL 3	15.86	Chevron	Southern Highlands, Orogen, Santos, Cue, Petroleum Resources, Chevron
PDL 4	27.14	Chevron	Orogen, Chevron, ExxonMobil, Merlin, Petroleum Resources
PDL 5	52.50 *	ExxonMobil	ExxonMobil
PPL 138	52.50	ExxonMobil	ExxonMobil
PPL 179	80.00	Oil Search	Gedd, Drillsearch, Inland Oil
PPL 188	49.55	Oil Search	Woodside, Gedd
PPL 189	40.40	Santos	Santos, Cue
PPL 190	30.10	Santos	Santos, Murray, Cue
PPL 193	31.25	Oil Search	ExxonMobil, Mosaic, Gedd, Cue
PPL 199	50.00	Oil Search	Woodside, Interoil
PPL 200	50.00	Lundin	Lundin, Interoil
PPL 203	89.47	Oil Search	Gedd
PPL 208	25.00	Interoil	Interoil, Woodside
PPL 218	50.00	Oil Search	Woodside
PPL 219	35.02	Chevron	Chevron, ExxonMobil, Orogen, Merlin/Mitsubishi
APPL 226	100.00	Oil Search	–
APPL 227	70.00	Oil Search	Omati, Gedd
PRL 01	5.00	Lundin	Lundin, ExxonMobil, Command, Pacrim, Claremont, Secab
PRL 02	6.01	Chevron	ExxonMobil, Chevron, Merlin, Orogen
PRL 03	6.01	Chevron	ExxonMobil, Chevron, Merlin, Orogen
APRL 08	44.60	Oil Search	Mosaic, Omati, Gedd

* Subject to PNG Government back-in

2001–2002 exploration drilling candidates

Prospect	Interest %		Gross reserves Unrisked Most Likely Reserves Oil: million barrels (Gas: BCF)
Bakari (PPL 138)	52.5		240
NW Moran (PPL 219)	35.2		45
SE Moran (PPL 219)	35.2		60
NW Paua (PDL 5)	52.5		150
Kutubu Attic (PPL 219)	35.2		70
Saunders (PDL 4)*	27.1		30
SE Gobe Footwall (PDL 4)*	27.1		60
Kapul (APPL 227)	70.0		150
Flinders (PPL 200)	40.0		(1600)
Iehi – Iagifu (PPL 190)	31.3		100
Wasuma (PPL 190/PPL 219)	31.3		80
Marabou (WA-281-P)*	25.0		180
TOTAL		Oil	1165
		Gas	(1600)

* Reserves calculated on a 50/50 oil versus gas fill

QUESTIONS AND ANSWERS ON

CONSOLIDATED INCOME STATEMENT

for the year ended 31 December 2000

Q. Why did the amortisation charge drop by US$11.7 million?

A. Amortisation represents the write-down of capital expenditure (exploration and development) associated with producing fields. As this is written off on a "per barrel" basis, lower production will naturally result in lower amortisation. As well as this, the amortisation base is reduced by tariff recoveries that relate to capital. As Kutubu (PL 2) is now recovering capital tariffs from Moran (PPL 138/PDL 5) following the commencement of oil flows from Moran-4, this has further reduced the capital base for amortisation and thereby the annual charge.

Q. Why was the tax charge only US$0.9 million?

A. The tax charge on ordinary profits was in fact US$2.0 million. This was reduced to US$0.9 million by a credit related to abnormal items. During the year, extensive work has been done on the Group's tax returns, and up to eight years' tax returns have been assessed. This has clarified the tax balances remaining in the Group, which in some cases are significantly in excess of book value. Where these differences are not related to future timing differences (e.g. where tax depreciation differs from book amortisation), under Australian Accounting Standard AAS1020, it has been necessary to credit the tax effect of the differences to the tax expense line, which has materially reduced the annual charge.

In effect, the Group has taken a very conservative view in the past until various issues were clarified.

CORPORATE DIRECTORY

REGISTERED OFFICE

5th Floor, MMI Pacific Insurance Building
Champion Parade, Port Moresby
National Capital District
P.O. Box 1031, Port Moresby
PAPUA NEW GUINEA
Telephone: (675) 321 3177
Facsimile: (675) 321 4379

AUSTRALIAN OFFICE

15th Floor, NAB House
255 George Street
Sydney NSW 2000
GPO Box 2442, Sydney
New South Wales, 2001
AUSTRALIA
Telephone: (+61 2) 8207 8400
Facsimile: (+61 2) 8207 8500

SHARE REGISTRAR

BT Registries Pty Limited
Level 6, Chifley Tower
2 Chifley Square
Sydney NSW 2000
Telephone: (+61 2) 9259 8886
Facsimile: (+61 2) 9259 9100

REGISTER OF DEPOSITARY RECEIPTS

Bank of New York
ADR Division
22nd Floor, 101 Barclay Street
New York, NEW YORK, 10286
UNITED STATES OF AMERICA

Senior Management

Gerea Aopi CBE
Government & Corporate Affairs Manager
(Papua New Guinea)

Peter R Botten
Managing Director (Papua New Guinea)

Nigel D R Hartley
Chief Financial Officer (Australia)

John G Speed
Operations Manager (Australia)

Michael G Sullivan
General Counsel (Australia)

Keiran J Wulff
Exploration and New Ventures Manager
(Australia)

As at 31 December 2000, Oil Search employed 73 people in its operations.

To find out more about Oil Search's latest activities, developments and investor information

visit our Website:

www.oilsearch.com.au