PETROLEUM DIVISION

DEPARTMENT OF PETROLEUM AND ENERGY

2002 ANNUAL REPORT

ON

PETROLEUM ACTIVITY IN PAPUA NEW GUINEA

Compiled by the Exploration Branch

December 2002

PREFACE

This Annual Report on Petroleum Activities in Papua New Guinea comprises information contributed by the branches of the Petroleum Division, Department Of Petroleum and Energy. Most of it was sourced from daily, weekly and monthly reports submitted by licensed petroleum companies. All values are quoted in US dollars (US$) to ensure consistency.

It is a summary of exploration, development, production and facilities activities of companies within various petroleum licenses managed by the Department of Petroleum and Energy in the year 2002. Non-technical, but equally important are the licence management, policy, legal and landowner aspects associated with these activities.

The information included in this report, alongside previous reports, is intended to provide a continuous and summarised historical review of the petroleum activities in Papua New Guinea.

TABLE OF CONTENTS

TABLES AND FIGURES

ATTACHMENTS

TABLE OF ABBREVIATIONS

APF	Agogo Production Facility
APDL	Application for Development Licence
APPL	Application for Petroleum Prospecting Licence
APRL	Application for Petroleum Retention Licence
BBL	Barrel
BCF	Billion Cubic Feet
BHP	Bottom Hole Pressure
BOPD	Barrels of Oil Per Day
BSP	Bank South Pacific
BWPD	Barrels of Water Per Day
CGS	Concrete Gravity Structure
CNGL	Chevron Niugini Limited
CPF	Central Production Facility (Kutubu)
CTU	Coil Tubing Unit
EWT	Extended Well Test
GM	Gobe Main Field
GOR	Gas Oil Ratio
GPF	Gobe Production Facility
GTQ	Gas To Queensland
ILG	Incorporated Land Groups
KB	Kelly Bushing
Km	Kilometer
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LTC	Land Titles Commission
M	Thousand
MD	Measured Depth
MM	Million
MMSCF	Million Standard Cubic Feet
MMSCFD	Million Standard Cubic Feet per Day
MMSTB	Million Stock Tank Barrels
MOA	Memorandum of Agreement
MPLT	Multi Production Logging Tool
NGL	Natural Gas Liquids
OGOC	Original Gas-Oil Contact
OOIP	Original Oil In Place
OWOC	Original Water-Oil Contact
PDL	Petroleum Development Licence
PLL	Pipeline Licence
PLT	Production Logging Tool
PPL	Petroleum Prospecting Licence
PRL	Petroleum Retention Licence
RMT	Reservoir Monitoring Tool
RR	Rig Released
SEG	South East Gobe Field
SS	Sub-Sea
STB	Stock Tank Barrel
STB/D	Stock Tank Barrel per Day
ST	Sidetrack
STOIIP	Stock Tank Oil Initially In Place
TCF	Trillion Cubic Feet
TD	Total Depth
TVD	True Vertical Depth
US $	United States Dollar

MONTHLY HIGHLIGHTS

January	• PPL 230 awarded to SPI InterOil
February	• No Highlights
March	• Moran 7 development well spudded
April	• The Oil and Gas (Amendment) Act 2001 brought into effect
May	• No Highlights
June	• Gas Agreement for the Gas to Australia (GTA) Project signed • Fiscal Stability Agreement for GTA Project signed • National elections held • Moran 8 development well spudded • SEG 10 ST1 development well spudded
July	• No Highlights
August	• Formation of the new Papua New Guinea National Government • New Government appoints Sir Moi Avei as Minister for Petroleum and Energy
September	• IDT 21 development well spudded
October	• Bilip 1 exploration well spudded • Petroleum Wardens appointed
November	• Oil and Gas Regulations approved by National Executive Council
December	• PRL 8 over Kimu Gas Discovery awarded to Oil Search Ltd • PRL 9 over Barikewa Gas Field awarded to Barracuda • PRL 10 over Uramu Gas Field awarded to Oil Search Ltd • Bilip-1 well tested, recovered oil • Oil and Gas Regulations came into effect.

Section 1.0 SUMMARY

The year 2002 saw the Petroleum Division continue to carry out its regulatory functions in respect of the activities of the State's petroleum licensees. In doing so, it attempted to ensure that all exploration, development and production activities were performed in compliance with licence conditions, the Oil and Gas Act and applicable regulations. The Petroleum Division managed 45 current petroleum licences, and various applications and surrenders. All active licenses were solely concentrated in the Papuan Basin.

Exploration activity remained low. The Bakari prospect was drilled by the Bakari 1 well and was unsuccessful. The Saunders and Bilip structures were proven to be hydrocarbon bearing by the Saunders 1 and Bilip 1 wells respectively. Of the seven wells drilled this year, three were exploration wells and four were development wells. The total exploration footage drilled was 26,792 feet at a cost of US$39.8 million. The development wells drilled 49,655 feet at a cost of US$ 47.7MM. Five field surveys of geophysical, geological and geochemical nature were carried out in the various PPLs at a total cost of US$4.8 million.

The Kutubu oil fields oil production averaged 21,200 BOPD in 2002, whilst Moran oil fields averaged 9,300 BOPD and the Gobe fields averaged 16,200 BOPD for the same period. The Hides gas field produced 3,728 MMSCF of gas over the year.

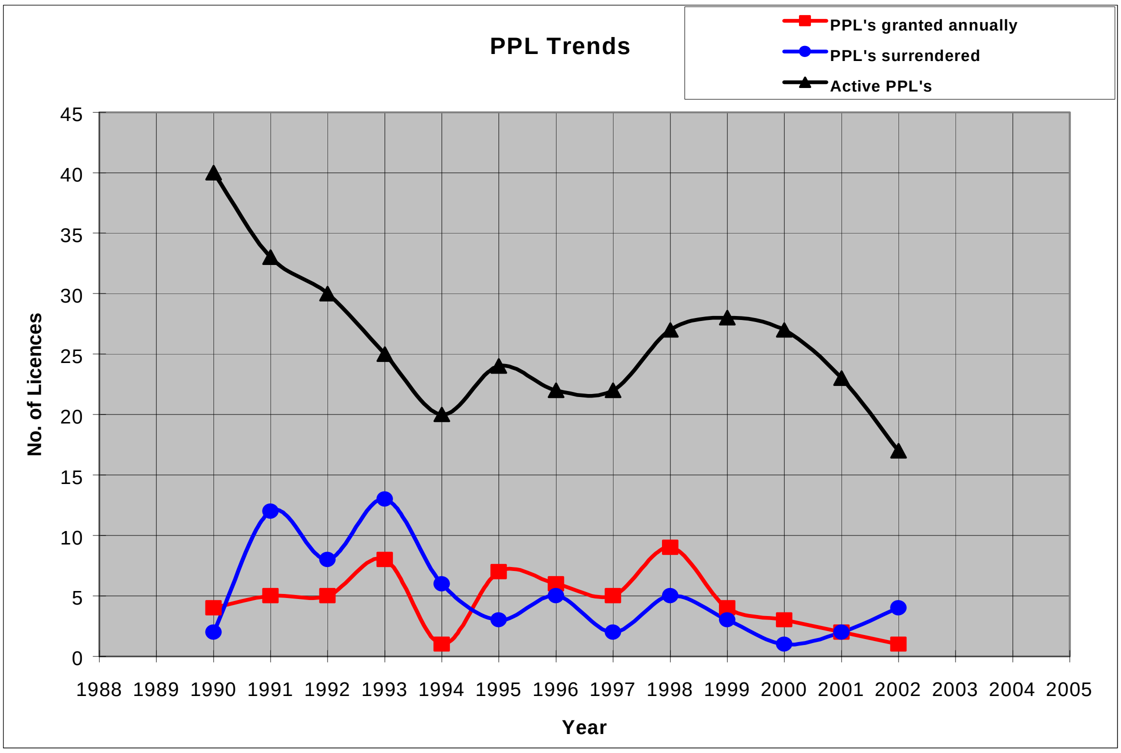
This has been a challenging year in dealing with impacted communities, however, all issues have manageable.

Major gas agreements were executed with the proponents of the PNG Gas Project for supply of gas to markets in Australia. Attention has now turned to making provisions for the future arrangements for benefits sharing.

Section 2.0 LICENCE MANAGEMENT

Seventeen Petroleum Prospecting Licences (PPLs), five Petroleum Development Licences (PDLs), three Pipeline Licences (PLs), ten Petroleum Retention Licences (PRLs) and one Petroleum Processing Facility Licence (PPFL) were active between January to December 2002. The only extended license this year, PPL138 expired in June this year, whilst Oil Search Ltd applied for an extension to their PPL199. One PPL and three PRLs were granted this year. A further two Petroleum Retention Licences were on offer while the Minister also refused two other applications. There are seven pending applications comprising one PPL extension and eight APPLs. Two licences expired; these were PPL184 and PPL185 in the North New Guinea basin. There are no other licences outside of the Papuan Basin.

Figure 1: PPL Trends



Section 3.0 EXPLORATION & DRILLING

The number of surveys conducted remained the same as that of last year. There were five surveys conducted in various licences. **Tables 1 & 2** contain summaries of all the field surveys for the year. **Figure 2** shows the yearly geological surveys whilst **Figure 3** shows the total number of line kilometres of seismic acquired since 1992.

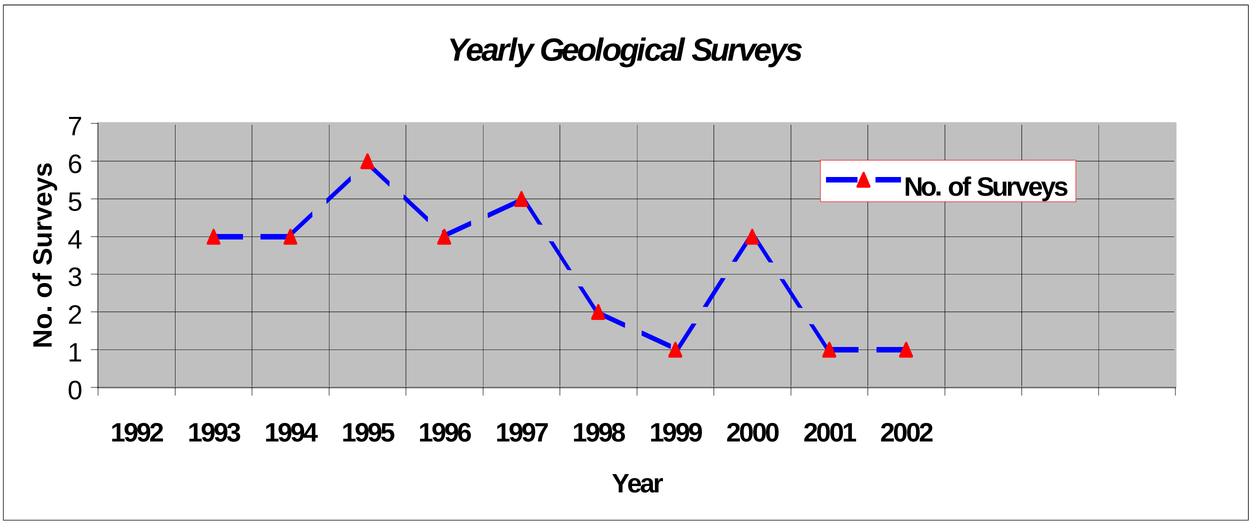
3.1 Geological Field Mapping

Only one geological survey was conducted in 2002. SPI Inter Oil conducted the Phase 1 Mapping Project in central PPL 230. The aim of the survey was to undertake geological mapping and acquire gravity data in portions of PPL 230.

Table 1: Geological Surveys

Licence / Permit	Operator	Geographic / Tectonic Area	Name	Contractor	Line Length - Km
PPL 230	SPI (208) Limited	Gulf Province/ Papuan Foreland	PHASE 1 MAPPING PROJECT	OilMin	117.5 Km
TOTAL					117.5 Km

Figure 2: Yearly Geological Surveys



3.2 Geophysical Field Surveys

The number of geophysical surveys in 2002 dropped from that of four in the previous year to only three. All three were conducted onshore. ChevronTexaco conducted two seismic surveys onshore, whilst SPI InterOil conducted a refraction survey. They are summarised below in **Figure 3**.

The North West Moran Seismic Survey was aimed at defining the NW Moran prospect, in preparation for the PPL 219 commitment well – NW Moran. Total line length acquired was 20km.

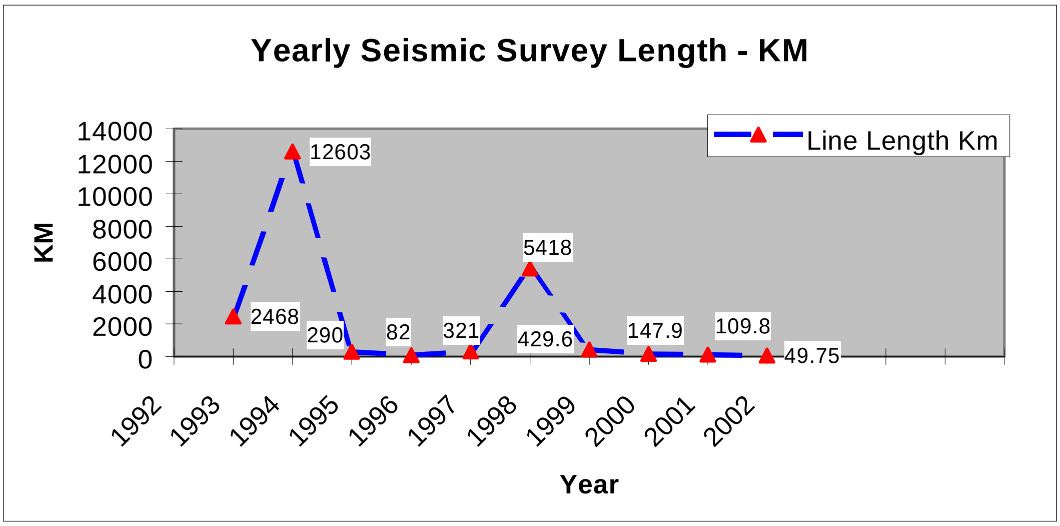
The South East Mananda Seismic Survey's objective was to evaluate and better define the hydrocarbon accumulation discovered by the SE Mananda 1 and 2 wells. A line length of 28.5km was acquired.

The Orloli Refraction Survey was used as a guide to properly plan for anticipated seismic surveys and to allow for casing point determination for future drilling. The objective was to detect shallow changes in lithology by analysis of seismic velocities, and to derive an indication of rock types and depths. A line length of 1.25km was acquired.

Table 2: GEOPHYSICAL SURVEYS

Licence Area	Operator	Geographic Area	Name/Survey Type/Contractor	Line Length Km	Cost US$
PPL 219 PDL 2 PDL 5 Onshore	Chevron	Southern Highlands Province	**NW Moran PN 02-508 & 509 Seismic Survey** Exploration Services Providers Int'l	20 km	1.7 MM
PPL 219 PDL 2 Onshore	Chevron	Southern Highlands Province.	**SE Mananda PN 02-511 & 508 SW Extension Seismic Survey** Exploration Services Providers Int'l	28.5 km	2.5 MM
PPL 230 Onshore	SPI InterOil	Gulf Province	**Orloli Refraction Survey** Oilmin	1.25 km	0.055 MM
TOTAL				**49.75**	**4,255,000**

Figure 3: Yearly Seismic Survey Length



3.3 Geochemical

Oil Search conducted the Mogulu Geochemical Survey in PPL 218. They acquired sampling over a 20x40km area, east of Nomad village, Western Province. At a cost of $370,000, the objective of the survey was to obtain surface geochemical data over the Mogulu lead to mitigate structural risk.

3.4 Drilling and Rig Activities

Summary of Exploration Wells

There were a total of three exploration wells drilled this year, all onshore. Saunders-1 and Bakari-1 were spudded last year (2001) and completed this year (2002) whilst Bilip-1 was spudded and completed this year. The total footage for the three wells drilled was 26,792 feet at a cost of US$ 39.8MM. They are summarised in **Table 3a**.

Saunders 1

The Saunders-1 well was designed to test the Iagifu sandstone as the primary target in the Saunders anticline east of the Southeast Gobe Field. The well was spudded on 03rd December 2001 and was drilled to a total depth of 7220 feet MD, 7109 feet TVD. The Toro and Iagifu sandstones were penetrated and wireline logs indicated the upper Iagifu sandstone oil to be filled and the lower Iagifu to be water-wet. The well reached total depth after intersecting a repeat Darai limestone section and was completed as a Iagifu oil producer. The well cost US$ 6.841MM.

Bakari 1

The primary objective of the Bakari-1 well was to drill and evaluate the Toro and Digimu sands to a depth of 10,761 feet. Bakari-1 spudded on 25th December 2001 and was drilled to a total depth of 8583 feet. The well intersected a thrust fault within the Ieru formation and penetrated a repeated section of the Darai limestone. Strontium and biostratigraphy analysis indicated that the objective Toro and Digimu sections were likely 5905 feet deeper than planned, eliminating the potential for structural closure within the prospect at those reservoir levels. After log evaluation, the well was plugged and abandoned at 2179 feet, shallower than planned. The well cost US$ 26MM.

Bilip 1

Bilip-1 was an exploration well in PPL 190 proposed to be drilled to 164 feet below the Gobe Thrust estimated at approximately 8136 feet TD. Its objective was to test the hydrocarbon potential of the Iagifu and Toro sandstone in a doubly thrusted structural closure. The primary objective was to establish the presence of moveable hydrocarbons in the sandstone and to penetrate the Gobe Thrust. The well was spudded on 17th October and it encountered two minor faults within the Ieru, which further deepened the Ieru formation against prognosis. The well penetrated the secondary reservoir Toro and Digimu. The well was evaluated and logs gave positive indications of hydrocarbons within the primary objective, the Digimu sandstone. Further drilling, saw the penetration of the Gobe Thrust Fault at 9016 feet.

Drilling continued ahead into the footwall encountering repeats of the Juha and Alene members at 9016 feet and 9065 feet respectively. Toro sandstone was identified and top Imburu formation encountered at 9833 feet, no shows were visible. The top Iagifu footwall was penetrated at 10,689 feet. The well reached total depth within the lower Imburu formation footwall at 10,991 feet. A well test was carried out in the hanging wall to test the Digimu sands. A closed chamber DST was adopted to test the hanging reservoir and recovered oil. The well was plugged and suspended for future re-entry for production. The cumulative well cost was US$ 7.009MM.

Summary of Development Wells

The development wells drilled in 2002 were in the Kutubu, Gobe and Moran Fields. A total of four wells were drilled. One was a side track well, and one a horizontal well, whilst two were conventional vertical wells. All four were completed as oil producers. The total footage of the four development wells was 49,655 feet at a cost of US$ 45.7MM. They are summarised in **Table 3b**.

IDT 21

IDT 21 well was designed as a horizontal development well in the Iagifu-Hedinia field in PDL 2. The well objective was to produce incremental Toro B and C oil reserves at a lower gas-oil ratio (GOR) in the saddle area of the field. The well was spudded on 15th September and drilled through the various formations to reach Toro reservoir objective. An intermediate casing was set and drilling proceeded from heel to the horizontal toe through the reservoir and approximately 2000 feet of horizontal section was penetrated. The well reached a total depth of 8,731 feet TVD after encountering all objectives. Following evaluation, the well was completed for production. The well cost US$16.5MM.

Moran 7

The Moran 7 well was designed as a Central Moran Unit delineation/production well located in Block A of the Moran field in PDL 5 and proposed as a directional hole to penetrate the primary objective Digimu reservoir. The secondary objective was to delineate the structural features of Blocks A and B. The well was spudded on 28th March. After casing-off the Darai Limestone, directional drilling kicked off within the Ieru formation. Loss circulation was encountered through the Ieru, resulting in major downtime. The well reached a total depth of 11,135 feet MD and a logging program was conducted and initial evaluation indicated a water-wet reservoir. The well was plugged back and a decision made to deepen the well in an effort to intersect the Block B bounding fault, thought to underlie the bottom hole location of the well. Drilling proceeded to a total depth of 11,810 feet TVD. However, a fault intersection could not be interpreted from the data. The sand was evaluated as being water-wet. The well cost US$ 10.210MM.

Moran 8

Moran 8 was proposed as a Central Moran Unit delineation well, located in Block B of the Moran field in PDL 5. The well was programmed to be deviated and to penetrate the primary Digimu objective at a total depth approximately 300 feet below base Digimu. The well was spudded on 07th June and was drilled to a total depth of 10,692 feet TVD. The reservoirs intersected were the Toro C and Digimu sands. Following log evaluation, Moran 8 was proposed as a gas injector well to provide timely Block J pressure support to the producing Moran 4 and 6ST2 wells. A dual selective completion was made in the Toro for later injection into Block J for pressure support. The well cost US$11.86MM.

SEG 10 ST1

The SEG 10ST1 well was proposed as a development well to provide a take point along strike of the SEG 2 well. The well was located between the SEG 2 and SEG 5ST1 take points, approximately 380 meters east of SEG 2 and 760 meters west of SEG 5ST1. After cutting the 13-3/8" casing and recovering the 9-5/8" casing within the SEG 10 well, the well kicked-off on 22nd June and was drilled as a conventional deviated well. The objective was to intersect the upper and lower Iagifu reservoirs and the well was planned to terminate at a total depth within the sand at the oil-water contact. A completion was planned over two zones - the upper and lower Iagifu and it employed an open hole gravel pack completion across the pay zones and maintained the standoff from the oil-water contact. The well reached a total depth of 7,445 feet TVD, and cost US$ 7.16MM.

Table 3(a) Drilling Activities – Exploration Wells

WELL I.D.	LICENSEE	PPL / PDL	SPUD DATE	R.R. DATE	T.D. (MD)	FOOTAGE DRILLED	RESULT	COST US$	TYPE OF SIDETRACK (GEOL / MECH)
Saunders 1	Chevron	PDL 4	03/12/01	09/01/02	7220	7,208	Oil	6,841,518	N/A
Bakari 1	Esso	PPL138	25/12/01	01/03/02	8583	8,408.7	Dry	25,900,000	N/A
Bilip 1	Barracuda	PPL190	17/10/02	26/12/02	10,991	11,175	Oil	7,009,998	N/A
						26,792		**39,751,516**	

Table 3(b) Drilling Activities – Development Wells

WELL I.D.	LICENSEE	PPL / PDL	SPUD DATE	R.R. DATE	T.D. (MD)	FOOTAGE DRILLED	RESULT	COST US$	TYPE OF SIDETRACK (GEOL / MECH)
IDT 21	Chevron	PDL 2	15/09/02	27/12/02	12,440	19,222	Oil	16,446,476	N/A
SEG 10ST1	Chevron	PDL 4	22/06/02	09/08/02	7683	4103	Oil	7,164,026	Geological ST
Moran 7	Chevron	PDL 5	28/03/02	23/05/02	12185	12149	Dry	10,210,895	N/A
Moran 8	Chevron	PDL 5	07/06/02	25/08/02	11,200	14,181	Oil	11,859,781	N/A
TOTAL						**49,655**		**$45,681,178**	

3.5 PNG Petroleum Drilling History

The Papuan Basin is currently the most explored and developed of the five petroleum basins in PNG. The Papuan Basin has had a total of 392 exploration and development wells drilled to date, since the commencement of exploration in PNG. Except for historic Marienberg well in the Sepik, all discoveries have been in the Papuan basin. **Table 4** contains a summary of all the discoveries to date in the Papuan basin and **Figure 4** illustrates the number of wells drilled from 1992 to 2002.

Table 4: Summary of Discoveries to Date

ORIGINAL LICENCE/ PERMIT	ORIGINAL OPERATOR	FIELD	DISCOVERY YEAR	CURRENT LICENCE/ PERMIT	CURRENT OPERATOR	TYPE OF DISCOVERY	EXISTING WELLS IN FIELD	PROVINCE
Permit 37	Island Exploration	Barikewa	1958	PPL 189	Barracuda	Gas	2	Gulf
Permit 37	APC	Bwata	1960	PPL 191	Barracuda	Gas/ Condensate	1	Gulf
Permit 12	APC	Iehi	1960	PPL 189	Barracuda	Gas	1	Gulf
Permit 39	Phillips	Uramu	1968	PPL 188	Oil Search	Gas	1	Gulf
PPL 18	Niugini Gulf Oil	Juha	1983	APRL 2	Chevron	Gas/ Condensate	3	Western
PPL 17	Chevron	Kutubu	1986	PDL 2	Chevron	Oil / Gas	47	SHP
PPL 27	BP	Hides	1987	PDL 1 and PPL 138	Oil Search/ Esso	Gas/ Condensate	4	SHP
PPL 100	Chevron	SE Hedinia	1987	PDL 2	Chevron	Gas	5	SHP
PPL 82	IPC	Pandora	1988	PRL 1	IPC	Gas	2	Gulf
PPL 100	Chevron	Usano	1989	PDL 2	Chevron	Oil	2	SHP
PPL 100	Chevron	Agogo	1989	PDL 2	Chevron	Oil	1	SHP
PPL 27	BP	Angore	1990	PPL 138	Esso	Gas/ Condensate	1	SHP
PPL 81	BP	Elevala	1990	PPL 157	Santos	Gas/ Condensate	1	Western
PPL 101	Chevron	P'nyang	1990	APRL 3	Chevron	Gas/ Condensate	2	Western
PPL 81	BP	Ketu	1991	PPL 157	Santos	Gas/ Condensate	1	Western
PPL 56	Command	SE Gobe	1991	PDL 3	Chevron	Oil / Gas	5	SHP / Gulf
PDL 2	Chevron	SE Mananda	1991	PDL 2	Chevron	Oil / Gas	2	SHP
PPL 100	Chevron	Gobe Main	1993	PDL 4	Chevron	Oil / Gas	6	SHP
PPL 138	BP	Paua	1995	PPL 138	Esso	Oil	1	SHP
PDL 2, PPL 161/138	Chevron	Moran	1996	PDL 2, PPL 161/138	Chevron	Oil	4	SHP
PPL 157	Santos	Stanley	1999	PPL 157	Santos	Gas	1	Western
PPL 193	Oil Search	Kimu	1999	PPL 193	Oil Search	Gas	2	Western
PDL 4	Chevron	Saunders	2002	PDL 4	Chevron	Oil	1	Gulf
PPL 190	Santos	Bilip	2002	PPL 190	Santos	Oil	1	Gulf

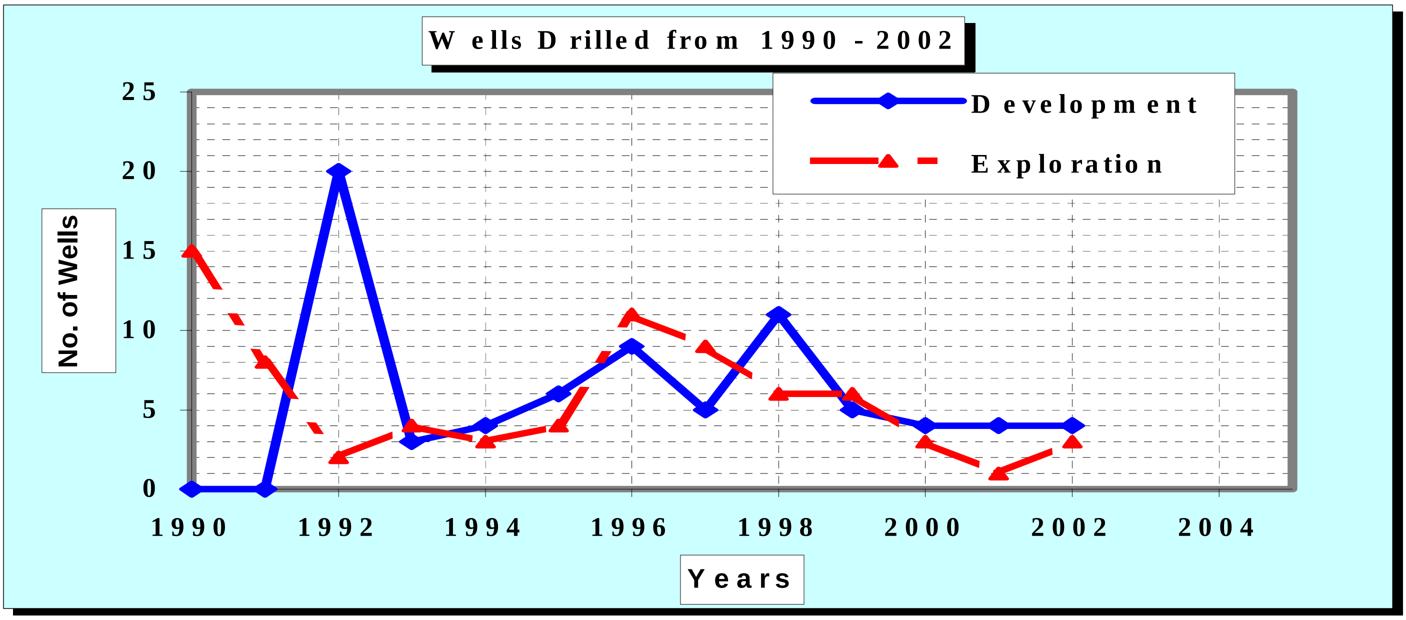


Figure 4: Total Yearly Wells

Section 4.0 FIELD DEVELOPMENT

4.1 Hides

During the year, Hides produced a total of 3728.47MMSCF of gas. The total liquid production was 82,706.81 barrels of condensate, which yielded 20,428.78 barrels of naphtha, 6,172.98 barrels of diesel and 1,007.80 barrels of residue.

The Hides Gas plant's major concern during the year was the frequent shutdown of the processing plant. This was due to sabotage of the PJV power pylons from Nogoli to the Porgera Gold Mine. The problem was addressed through enhanced community policing and heightened security. Production from the micro-stills has been restricted due to the lack of road tankers to export diesel and naphtha to sales markets, and civil unrest. Routine checks, preventative maintenance and maintenance to the micro-stills and other process equipment was on-going through out the year. The plant shut down period was an opportune time during which most of the mechanical and electrical repair jobs on the equipment were performed.

The pipeline inspection and pigging operations were on-going during the year. A full inspection of the pipeline and pigging station was conducted after an earth tremor in January. There was no damage to the plant equipment or buildings.

4.2 Kutubu

Routine checks, preventive maintenance and minor modifications to the facilities underpinned normal operations throughout the year. Major activities during the year included the gearbox change-out to the CPF Gas Compressor, media filter work, inspection of the Inlet Test separator and the relocation and construction of the incinerator. The incinerator was relocated after much discussion between the operator and inspectors. Other activities included completion of action items identified by the DPE audit team during the 2001 Annual Inspection. Produced water upgrade work was also a major activity during the year. This involved the modifications and installation of the level interface meter on the Inlet Separator "C". Corrosion inspections and thickness tests were also done on the produced water system and the installation of level switch on the hydro-cyclone tank was also completed.

The Coriolis Meter Calibration works were completed in February. The Operator received a final report for the calibration works from Intertek Testing Services in March and ChevronTexaco maintenance personnel addressed the recommendations from the report.

The incinerator package was dismantled and assembled at a new location in the CPF area 50m from the nearest hydrocarbon source vessel. Re-assembling and commissioning of the incinerator at the new location was completed in August. The incinerator has been commissioned to burn oily sand and is currently in operation.

Routine checks, preventive maintenance and minor modifications to the facilities took place in the year. Production operations at the topping plant have been normal through out the year.

Kutubu oil production continued to decline. The Operator has continued to take an aggressive approach utilising conventional techniques available to identify potential well work to stabilise the decline. These efforts have resulted in the drilling of IDT-21 well and a number of successful wire-line inter-zonal isolations in the year.

4.3 Moran

4.3.1 Agogo Processing Facility

The Agogo processing facility (APF) underwent normal operations through the year. The Agogo Test Separator clean out was carried out and completed in June and the processing facility was shut down on 28th June for the Moran by-pass tie-in. The APF expansion and construction activities for the Moran Petroleum Project facilities continued throughout the year and were completed in September. Coriolis meter proving calibrations were completed for the Moran separator oil meter and prover.

4.3.2 Moran Flowline

Monthly geotechnical inspection of the Moran Flowline landslip area was carried out in compliance with DPE requirements. There was no significant landslip activity along the EWT route this year and no immediate action items were reported. The monthly geotechnical surveys have now been suspended and will be conducted on an annual basis as the unstable sections of the Moran EWT flow line had now been bypassed.

4.3.3 Moran MFI Meter

Relocation of the Moran 2ST2 multi-phase flow meter (MFI) onto the Moran 6ST2 flow line was completed on 01st January. This was done to ensure Moran 6ST2 flows through a dedicated MFI as requested by the DPE. Moran 6ST2 and Moran 4 each have a dedicated MFI. The Moran 4 MFI, which was measuring Moran 6-production rate, was turned back to read Moran 4. A proposal by the Operator to use a single MFI meter to measure produced fluids from multiple wells was submitted to DPE for review in December.

4.3.4 Moran Gas Re-Injection

The Moran-8 well started gas re-injection after a new choke was re-installed to the well-head. First gas re-injection was achieved on the 15th September.

4.4 Gobe Main

4.3.1 Gobe Processing facility

Calibration of the coriolis meters at the Gobe Production facility was conducted in February. ITS completed the calibration of the prover meter at the export station in the Gobe Processing Facility in October. Correction factors will be implemented after the final reports are approved by the Operator.

A lease contract was signed with Gas Services International (GSI) for the rental of two reciprocating compressors for a three-year period. At end of December the compressor and all the other equipment were ready for start up and commissioning.

The Gobe Production Separator C was converted to a produced water tank to allow for greater retention time and to control the sanding problem. The produced water upgrade project was completed in July and became operational by the end of August.

The fire and gas control panel with the gas, smoke and fire detectors arrived on site in March. The current plan is to commission the fire and gas detection system in the first quarter of 2003.

In February, a review of the surface sand problems at Gobe was initiated because the proposed drilling and workover programs anticipated significantly higher sand production. The preferred equipment available for removing sand are cyclone desanders as their performance and reliability is proven at the GPF. Initial consideration was given to the installation of two skid-mounted units:

1. A manually operated Well-Head Desander for each of the main sand producing wells.
2. A fully automated Well-Stream Desander and sand washing facility.

Three cases were identified:

1. Four Well-Head Desanders, one each for SEG 10, SEG 2, SEG 9, and SEG 1.
2. Central sand removal and washing facility near SEG 3.
3. Central sand removal and washing facility near GPF plant inlet manifold.

Design for the replacement LP compressor recycle valve was completed and the new control valve purchased. The new recycle valve was installed in March. Engineering review for increasing the LP compressor discharge pressure is nearing completion.

Section 5.0 PRODUCTION

Kutubu produced a total of 7,760 MBBLS in 2002 at an average daily production rate of 21,255 BOPD. The daily production rate decreased slightly during June and July due to most of the Agogo production wells being shut in to allow for the Moran Tie-in and re-commissioning of the Agogo Processing Facility (APF). It was anticipated that the total production from Kutubu would be boosted in 2002 by 3,000 BOPD once the new development well IDT 21 was brought onto production.

The total Moran oil production for 2002 was 3,423,515 barrels and the total gas produced was 9,130,413MSCF. Oil production averaged at about 10,0000 BOPD and there was a decrease from 13,000 in February to 5,300 BOPD in July due to the Moran flowline tie-in, commissioning of the APF and Moran Gas Injection Compressors. Following this work, production increased to 11,000 BOPD in December. Wells alternatively produced from the Moran field are Moran 1X, 2X, 4X and 6X. Gas Injection commenced in October, and any significant increase in the production remains to be seen.

The total oil production from the Gobe fields in 2002 was 5,658,881 barrels at an average rate of 15,504 BOPD. This is a decrease of 1,524,555 barrels from the previous reporting period. Total volume of gas produced in association with the oil production was 24,278 MMSCF with Gobe Main and SE Gobe producing 11,488,765 MSCF and 12,788,514 MSCF respectively. Oil Production in Gobe continued on a steady natural decline trend.

The total oil exported from Gobe was 5,697,747 barrels with Gobe Main and SE Gobe contributing 2,964,008 and 2,733,739 barrels respectively.

Gobe Main contributed a total of 1,961,814 barrels of oil averaging at 5,375 BOPD. There was a general increase in production attributed to the sustained higher production from GM-5ST#3 well after the workover at a rate of 3000 BOPD, and the GPF water handling facility upgrade that enabled high water cut wells to be on production for longer periods.

South East Gobe (SEG) produced a total of 3,697,067 barrels of oil averaging at 10,129 BOPD. Oil production from the SEG field generally decreased due to the shutting-in of the SEG-5 ST1 and the SEG-10 ST1 wells caused by sanding and high water cut problems respectively. Other wells shut in through the year were the SEG 4 and G7X ST3.

The oil production total for the year 2002 was 16,850,772 barrels at an average production rate of 46,166 BOPD. The monthly average production was approximately 1,366,585 barrels and a total of 77,798 MMSCF of associated gas was produced. A total of 16,379,379 barrels of stabilised crude was exported during the year.

Tables 5, 6, 7, 8, 9 & 10 and **Figures 5, 6, 7, 8, 9,10, & 11** summarise the monthly and yearly figures for the various fields in 2002.

5.1 Hides

Table 5: Hides Monthly Gas Production

	GAS		LIQUID			
MONTH	**Total Production**	**Total sales**	**Condensate**	**Naphtha**	**Diesel**	**Residue**
	(MMSCF)	**(MMSCF)**	**(BBL)**	**(BBL)**	**(BBL)**	**(BBL)**
January	**422.48**	**422.48**	**9,056.32**	**974.36**	**369.34**	**2.83**
February	**380.62**	**380.62**	**8,445.59**	**2,237.38**	**602.2**	**51.26**
March	**387.38**	**387.38**	**8,716.53**	**77.20**	**12.58**	**3.08**
April	**376.219**	**376.219**	**7,726.40**	**2,003.55**	**475.77**	**117.62**
May	**414.49**	**414.49**	**9,155.49**	**1,897.69**	**490.3**	**103.15**
June	**373.02**	**373.02**	**8,408.69**	**0**	**0**	**0**
July	**123.9**	**123.9**	**2,877.89**	**222.73**	**81.71**	**11.7**
August	**31.83**	**31.83**	**749.23**	**668.73**	**172.97**	**20.25**
September	**0**	**0**	**0**	**0**	**0**	**0**
October	**354.36**	**354.36**	**7,771.15**	**5,586.95**	**1,934.71**	**355.07**
November	**430.56**	**430.56**	**10,153.89**	**4,290.47**	**1,233.29**	**184.70**
December	**433.61**	**433.61**	**9,645.53**	**2,469.72**	**800.11**	**158.14**
TOTALS	**3728.47**	**3728.47**	**82,706.71**	**20,428.78**	**6,172.98**	**1,007.80**

Note: Total condensate is not equal to total sum of liquid products as it is an average account for the amount of condensate sent direct to PJV turbines

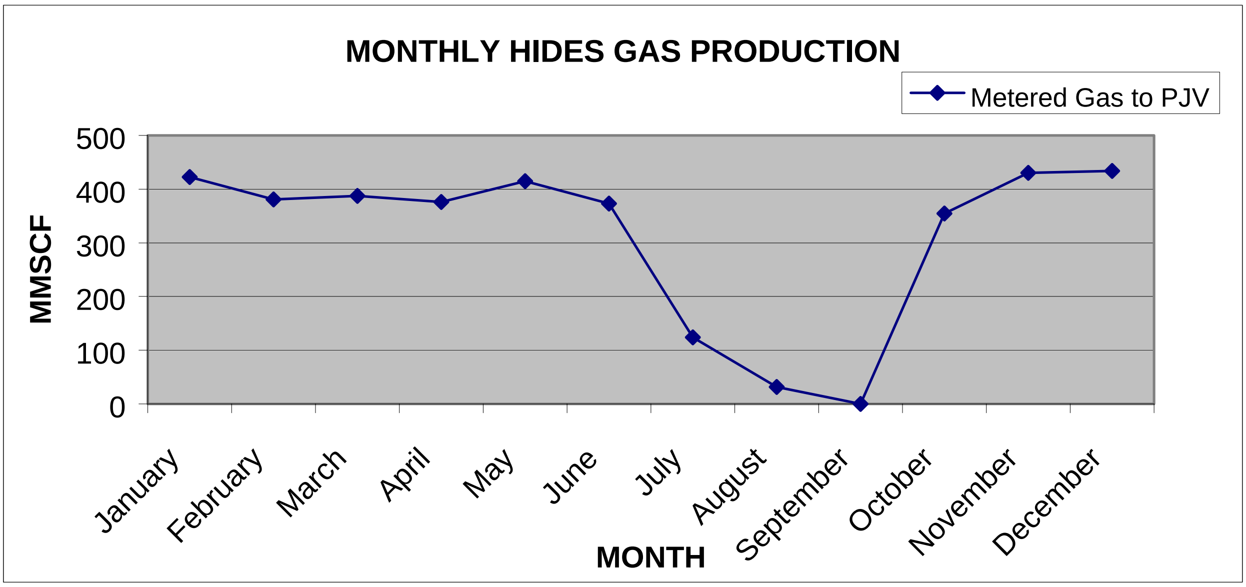


Figure 5: Hides Monthly Gas Production Graph

5.2 Kutubu

Table 6: Monthly Kutubu Production

MONTH	MONTHLY OIL PRODUCTION	MONTHLY GAS PRODUCTION	CUMULATIVE OIL PRODUCTION	CUMULATIVE GAS PRODUCTION	AVG. DAILY OIL RATE	AVG.DAILY GAS RATE
	BBL	MSCF	BBL X 1000	MMSCF	BOPD	MSCFD
JANUARY	744,103	6,637,289	268,326.41	624,494.23	24,003	214,106
FEBRUARY	640,370	5,997,824	268,966.78	630,492.05	22,870	214,208
MARCH	700,616	6,383,261	269,667.39	636,875.31	22,601	205,912
APRIL	660,142	6,213,268	270,317.54	643,088.58	22,005	207,109
MAY	624,783	6,521,661	270,942.32	649,610.24	20,154	210,376
JUNE	605,186	6,054,951	271,547.51	655,665.19	20,173	201,832
JULY	637,860	5,765,450	272,185.37	661,430.64	20,576	185,982
AUGUST	663,785	6,790,081	272,849.15	668,220.72	21,412	219,035
SEPTEMBER	613,032	6,504,570	273,462.18	674,725.29	20,434	216,819
OCTOBER	632,712	6,799,728	274,094.89	681,525.02	20,410	219,346
NOVEMBER	630,433	7,234,768	274,725.328	688,759.788	21,014	241,159
DECEMBER	615,353	6,895,298	275,340.68	695,655.09	19,850	222,429
AVERAGE	647,365	6,483,179				
YEARLY TOTALS	7,768,376	77,798,149				

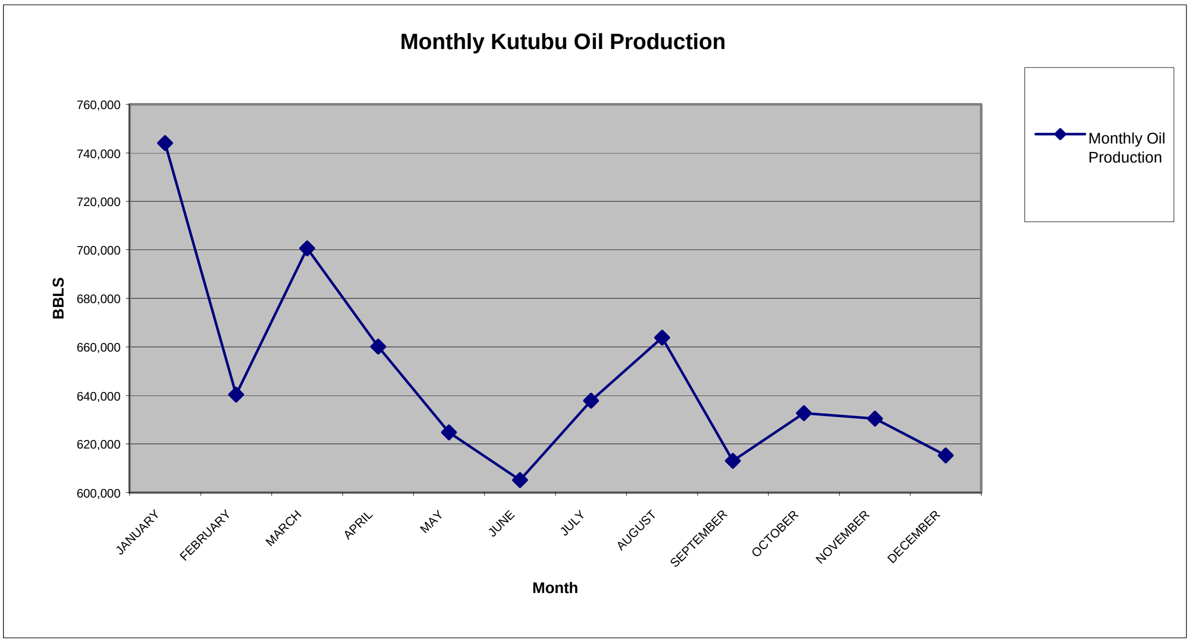


Figure 6: Kutubu Monthly Oil Production Graph

5.3 Gobe Main

Table 7: Monthly Gobe Main Production

MONTH	MONTHLY OIL PRODUCTION	MONTHLY GAS PRODUCTION	CUMULATIVE OIL PRODUCTION	CUMULATIVE GAS PRODUCTION	AVG. DAILY OIL RATE	AVG.DAILY GAS RATE
	BBL	MSCF	MBBL	MMSCF	BOPD	MSCFD
JANUARY	148,807	974,874	17,958.34	45,415.60	4,800	31,448
FEBRUARY	131,243	823,986	18,089.58	46,239.59	4,687	29,428
MARCH	166,315	898,234	18,255.90	47,137.82	5,365	28,975
APRIL	206,175	948,120	18,462.07	48,085.94	6,873	31,604
MAY	192,306	927,889	18,654.38	49,013.83	6,203	29,932
JUNE	179,944	827,719	18,834.32	49,841.55	5,998	27,591
JULY	171,978	1,032,842	19,006.30	50,874.39	5,548	33,317
AUGUST	150,462	1,037,614	19,156.76	51,912.01	4,854	33,471
SEPTEMBER	130,242	1,036,741	19,287.00	52,948.75	4,341	34,558
OCTOBER	170,873	991,322	19,457.88	53,940.07	5,512	31,978
NOVEMBER	149,552	988,047	19,607.43	54,928.12	4,985	32,935
DECEMBER	163,918	1,001,378	19,771.35	55,929.49	5,288	32,303
AVERAGE	**163,484**	**957,397**				
YEARLY TOTALS	**1,961,814**	**11,488,765**				

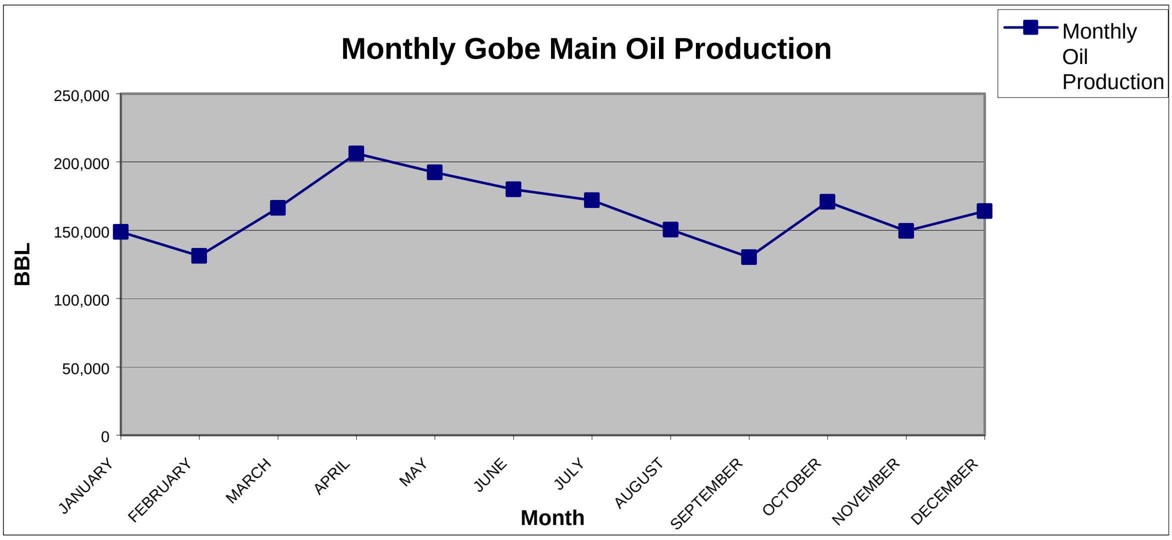


Figure 7: Gobe Main Monthly Production Graph

5.4 South East Gobe

Table 8: Monthly S.E. Gobe Production

MONTH	MONTHLY OIL PRODUCTION	MONTHLY GAS PRODUCTION	CUMULATIVE OIL PRODUCTION	CUMULATIVE GAS PRODUCTION	AVG. DAILY OIL RATE	AVG.DAILY GAS RATE
	BBL	MSCF	MBBL	MMSCF	BOPD	MSCFD
JANUARY	340,245	953,132	19,657.61	52,085.21	10,976	30,746
FEBRUARY	280,448	938,879	19,938.06	53,024.09	10,016	33,531
MARCH	328,384	1,017,731	20,266.44	54,041.82	10,593	32,830
APRIL	310,688	1,057,974	20,577.11	55,099.72	10,356	35,266
MAY	308,833	1,067,816	20,885.94	56,167.61	9,962	34,446
JUNE	297,571	1,024,442	21,183.51	57,192.06	9,919	34,148
JULY	336,967	1,060,654	21,520.48	58,252.71	10,870	34,215
AUGUST	352,796	1,202,751	21,873.28	59,455.46	11,381	38,798
SEPTEMBER	298,009	1,128,149	22,171.28	60,583.61	9,934	37,605
OCTOBER	306,206	1,165,459	22,477.49	61,749.07	9,878	37,595
NOVEMBER	272,272	1,085,098	22,749.76	62,834.17	9,076	36,170
DECEMBER	264,648	1,086,430	23,014.41	63,920.60	8,537	35,046
AVERAGE	308,089	1,065,710				
YEARLY TOTALS	3,697,067	12,788,514				

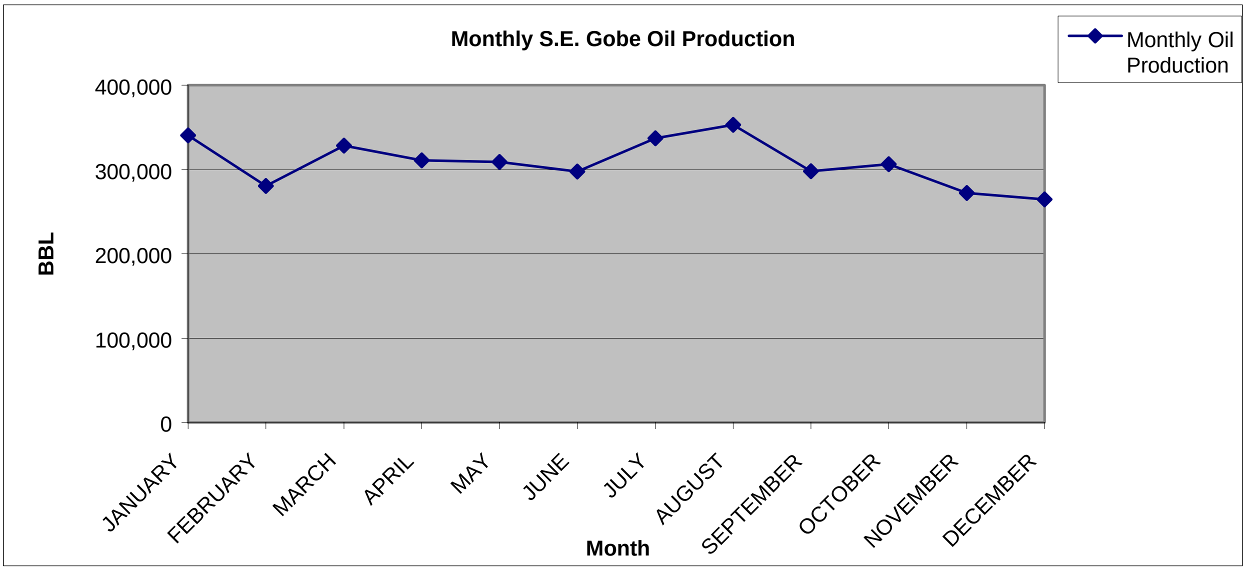


Figure 8: S.E. Gobe Monthly Oil Production Graph

5.5 Moran

Table 9: Monthly Moran Oil Production

MONTH	MONTHLY OIL PRODUCTION	MONTHLY GAS PRODUCTION	CUMULATIVE OIL PRODUCTION	CUMULATIVE GAS PRODUCTION	AVG. DAILY OIL RATE	AVG.DAILY GAS RATE
	BBL	MSCF	BBL X 1000	MMSCF	BOPD	MSCFD
JANUARY	344,532	750,273	15,456.67	32,500.83	11,114	24,202
FEBRUARY	366,703	671,914	15,823.37	33,172.74	13,097	23,997
MARCH	401,799	725,368	16,225.17	33,898.11	12,961	23,399
APRIL	381,615	924,351	16,606.79	34,822.46	12,721	30,812
MAY	331,410	991,161	16,938.20	35,813.62	10,691	31,973
JUNE	301,146	923,565	17,239.41	36,737.19	10,038	30,785
JULY	61,130	117,520	17,300.54	36,854.71	1,972	3,791
AUGUST	165,781	555,289	17,466.32	37,409.99	5,348	17,913
SEPTEMBER	224,530	991,448	17,690.85	38,401.44	7,484	33,048
OCTOBER	261,587	925,078	17,952.44	39,326.52	8,438	29,841
NOVEMBER	255,865	710,730	18,208.30	40,037.25	8,529	23,691
DECEMBER	327,417	843,716	18,535.72	40,880.97	10,562	27,217
AVERAGE	285,293	760,868				
YEARLY TOTALS	3,423,515	9,130,413				

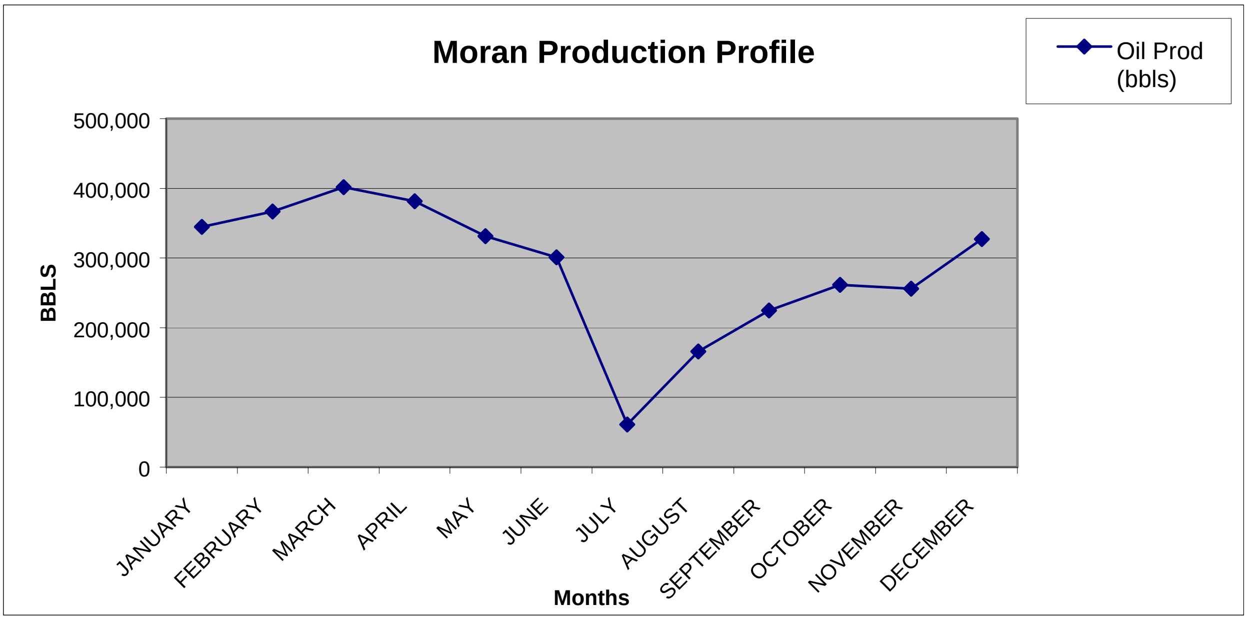
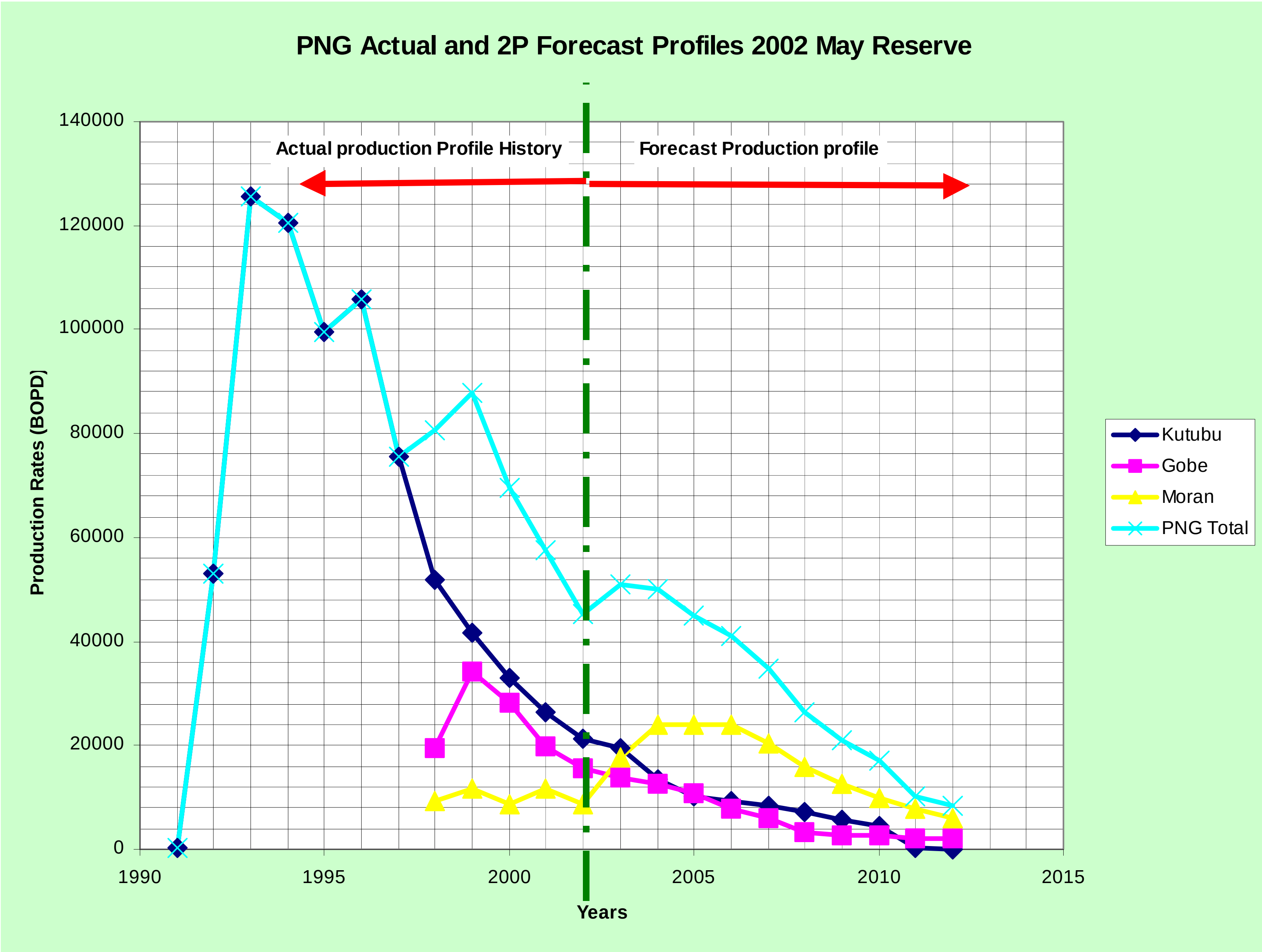


Figure 9: Moran Monthly Oil Production Graph

Figure 10: Yearly Oil Production Showing History and Forecast

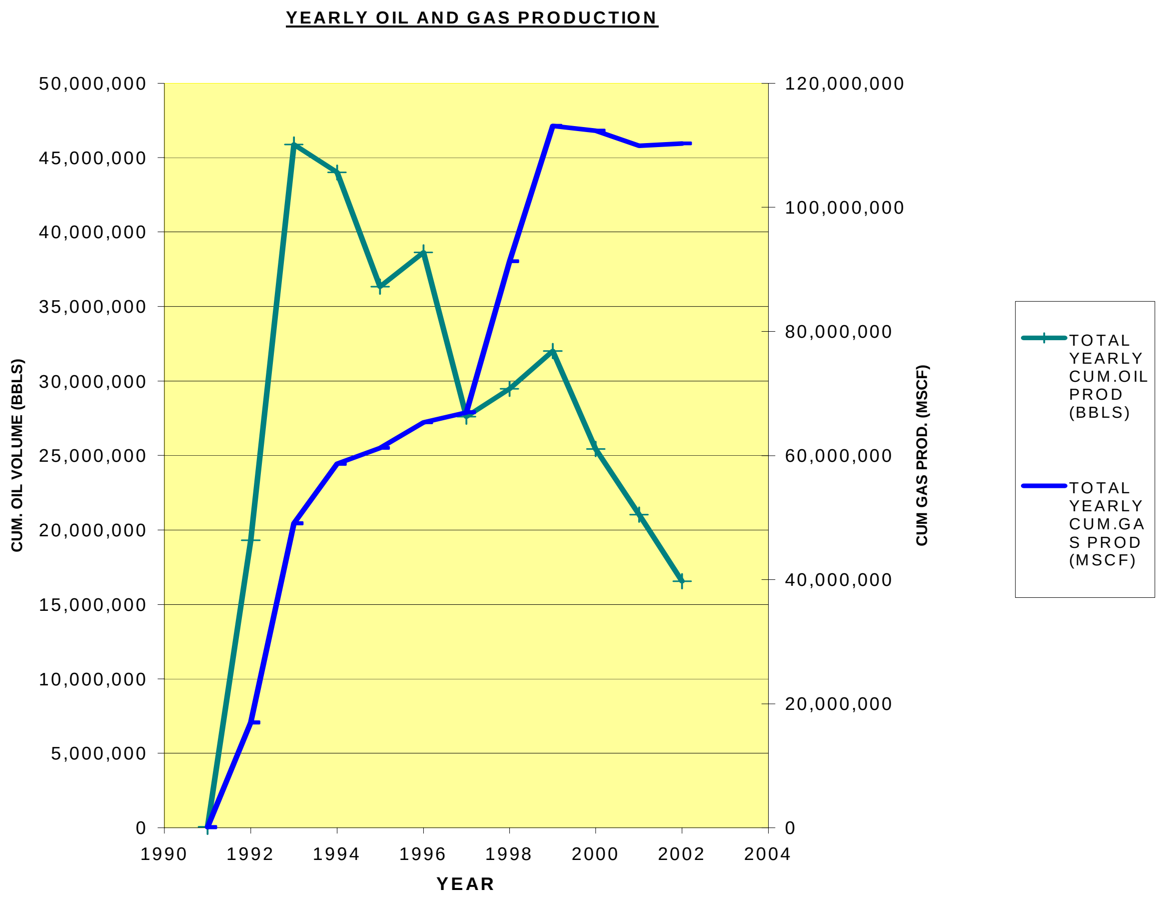


5.6 Others

Table 10: Yearly Production – Oil and Gas

YEAR	KUTUBU YEARLY CUM.OIL PROD (BBLS)	KUTUBU YEARLY CUM.GAS PROD (MSCF)	GOBE YEARLY CUM.OIL PROD (BBLS)	GOBE YEARLY CUM.GAS PROD (MSCF)	MORAN YEARLY CUM.OIL PROD (BBLS)	MORAN YEARLY CUM.GAS PROD (MSCF)	TOTAL YEARLY CUM.OIL PROD (BBLS)	TOTAL YEARLY CUM.GAS PROD (MSCF)
1991	68,162	84,532	-	-	-	-	68,162	84,532
1992	19,314,212	16,951,366	-	-	-	-	19,314,212	16,951,366
1993	45,883,975	49,059,949	-	-	-	-	45,883,975	49,059,949
1994	44,007,868	58,666,246	-	-	-	-	44,007,868	58,666,246
1995	36,344,233	61,184,516	-	-	-	-	36,344,233	61,184,516
1996	38,640,602	65,343,500	-	-	-	-	38,640,602	65,343,500
1997	27,592,364	66,960,036	-	-	-	-	27,592,364	66,960,036
1998	18,926,772	69,562,381	7,107,426	15287101	3,445,286	6,417,692	29,479,484	91,267,174
1999	15,210,458	77,238,216	12,511,559	27366803	4,298,414	8,519,774	32,020,431	113,124,793
2000	11,985,875	77,528,038	10,324,572	27782955	3,124,070	7,048,093	25,434,517	112,359,086
2001	9,607,802	75,276,974	7,183,436	25154404	4,244,244	9,492,554	21,035,483	109,923,933
2002	7,759,851	77,897,708	5,658,832	24277280	3,144,086	8,120,984	16,562,770	110,295,972
CUM. PROD	275,342,174	695,753,460	42,785,826	119,868,544	18,256,101	39,599,098	336,384,101	855,221,102

Figure 11: Yearly Oil and Gas Production since 1991



Section 6.0 SPECIAL PROJECTS

6.1 PNG GAS TO AUSTRALIA

The GTA Project has not commenced the Front End Engineering and Design (FEED) phase of the project due to the slow progress in confirming the sales contract of potential consumers in the Australian market.

ExxonMobil took over as the Operator of the project in early 2002 and has made some changes to the route of the gas pipeline. It has proposed the pipeline to be connected to Moomba in Queensland, and from there, into the gas pipeline grid to Queensland and New South Wales.

The produced raw gas is rich in gas liquids and condensate and will be processed to meet sales gas specifications and to extract, store and export the valuable natural gas liquids.

The facility will be required to process about 600 million standard cubic feet per day of wet gas to produce up to:

- 88% of specification sales gas for export to Australia
- 10% of Liquefied Petroleum Gas for the domestic market and for export; and
- 2% of condensate for export

FEED should commence as soon as sufficient foundation customer's sales agreements are in place. Equity financing sources should follow upon completion of the FEED stage.
Project construction should begin immediately following financial close, and with the completion of the construction, the first PNG gas should flow.

6.2 NAPA NAPA OIL REFINERY

Facilities Construction

InterOil contracted Clough Engineering based in Perth, Australia to procure and construct the refinery. The refinery completed earth works in March and the process engineering PFD's and P&ID's was issued for design with Clough's Engineering Design Team. The HAZOPS study of the refinery was conducted from July to August in Perth. The jetty earth works was completed and steel piling started in late October. It is anticipated that once the jetty is completed, all refinery components will be shipped in and off-loaded at the jetty. Approval was given to InterOil to engage a third party inspection and verification company to conduct inspection on all refinery components prior to shipping them to the refinery

Refinery Process

This process will be relatively small and simple. The basic process will involve simple processing of the crude oil.

Crude Distillation: - This will be the first stage of the refinery process and will distillate LPG, naphtha, diesel, kerosene and gas oil.

The LPG – Gas Recovery Unit: - Will produce LPG from the gas recovered from the refinery process. Some gas will also be used as fuel gas for the refinery operations.

The Naphtha Unit: - Will convert naphtha to reformate to be used as feedstock for gasoline production. Most of the naphtha will be sold as stock-feed for petrochemical industry in Japan.

The Refinery Feedstock will be 32,000 barrels per day. This stock will most likely be from the Kutubu export crude and from regional spot market purchases in Singapore.

Section 7.0 RESERVES

All the petroleum reserves discovered to date are located in the Papuan Basin, both onshore and offshore.

There has been little change in the ultimate recoverable reserves for all the producing fields. As a result of work-over, re-drills and infill drilling particularly in the Moran and Gobe fields, there is a re-allocation of reserves to the 1P, 2P and 3P reserves (reserves shifting) without any impact on the 3P ultimate recoverable reserves. Moran reserves are expected to change as more infill wells are drilled. For Saunders, only in place volumes are presented at this time.

7.1 Oil Fields

7.1.1 Kutubu Oil Fields (PDL 2)

The Kutubu oil fields comprise Iagifu-Hedinia, Agogo and the Usano reservoir block.
The current 3P estimated ultimate recovery is 310.8 mmstbo. The Kutubu field contains original-oil-in-place of 557 mmstbo.
The cumulative production as of December 2001 is 275.34 mmstbo.

7.1.2 Gobe Oil Fields (Gobe Main and Gobe 2X) (PDL 4)

The 3P estimated ultimate oil recovery for Gobe Main and Gobe 2x blocks is 31.2 mmstbo. The Gobe Main field contains original oil in place is 100.6 mmstbo.
Cumulative production to year-end is 19.78 mmstbo.

7.1.3 SE Gobe (PDL 3)

The 3P estimated ultimate recovery for SE Gobe is 44.2 mmstbo. The original oil in place is estimated at 156.7 mmstbo. Cumulative production as of 31st December 2001 is 23.03 mmstbo. SE Gobe came on production in April 1998.

7.1.4 Moran (PDL 5)

The estimated ultimate recovery (3P) is 140.3 mmstbo. The Moran field contains original oil in place of 259 mmstbo. Cumulative production as of December 2001 is 18.54 mmstbo.

7.1.5 SE Mananda (PDL 2)

The 3P Ultimate Oil Recovery for the SE Mananda field is 33.5 mmstbo. The SE Mananda field contains original oil in place of 107 mmstbo. No production has yet been recovered from this field.

7.1.6 Saunders Field (PDL 4)

Original oil in place is estimated at 17 mmbo. No oil production has been achieved yet.

7.1.7 SE Hedinia (PDL 2)

SE Hedinia is a dry gas discovery. The estimated recoverable gas reserve is 157 BCF.

Total gas in place is 209 BCF.

Table 11: Oil Reserves

FIELD	OOIP (MMSTB)	1P (MMSTB)	2P (MMSTB	3P (MMSTB)	CUMULATIVE PRODUCTION (MMSTB)	ULTIMATE RECOVERY (MMSTB)
KUTUBU	557.00	22.06	26.06	35.46	275.34	310.80
MORAN	259.00	48.49	65.40	140.3	18.54	140.3
GOBE MAIN	100.60	5.00	8.4	12.8	19.78	31.20
SE GOBE	156.70	15.6	19.4	23.6	23.03	44.20
SE MANANDA	107.00	0.0	0.0	33.50	0.0	33.50
SAUNDERS*	17.0	0.0	0.0	0.0	0.0	0.0
TOTAL	**1197.30**	**91.15**	**119.26**	**245.66**	**336.69**	**560.00**

** Reserves in Saunders subject to review.*

7.2 Gas Fields

Hides is a large onshore gas field, located in the central Papuan Foldbelt. Minor production for gas sales to the Porgera Gold Mine for electricity commenced in late 1991. Minor amounts of condensate are refined on site and sold locally. The gas produced in the oil fields is reinjected back into the reservoir to maintain reservoir pressure and conservation for future gas demand. Full field development of Hides and other fields are contingent upon the viability of markets as envisaged gas export projects such as the GTA. **Table 12** gives a summary of all known gas fields.

Table 12: Gas Reserves *Need to check this table with PEB - Reserves*

Oil & Gas Reserves as of 1st January, 2003.

Field	**Year**	**Field type**	**Oil in Place**	**Gas In Place**	**GAS**			**OIL / CONDENSATE**		
	discovered				**Reserves (01/01/03)**			**Reserves (01/01/03)**		
					1P	**2P**	**3P**	**1P**	**2P**	**3P**
			mmbbl	**bscf**	**bscf**	**bscf**	**bscf**	**mmbbl**	**mmbbl**	**mmbbl**
Angore	1990	gas-cond	n/a	9,034	n/a	4,089.00	8,185.00	n/a	6.10	61.30
Barikewa	1958	gas	n/a	121	n/a	69.10	86.39	n/a	0.00	0.00
Bwata	1960	gas	n/a	92	n/a	40.70	77.10	n/a	0.00	0.00
Elevala	1990	gas-cond	n/a	611	n/a	432.80	526.40	n/a	2.50	15.20
Gobe	1992	oil/gas	257	708	n/a	476.00	476.00	16.85	27.79	36.33
Hides* **	1987	gas-cond	n/a	9,584	6100.00	6,700.00	7,800.00	57	101.00	300.00
Iehi	1960	gas	n/a	104	n/a	11.10	72.27	n/a	0.00	0.00
Juha	1983	gas-cond	n/a	1,541	n/a	452.00	1,344.10	n/a	19.20	57.10
Ketu	1991	gas-cond	n/a	544	n/a	17.70	452.70	n/a	0.10	13.10
Kimu	1999	gas	n/a	No Reserves evaluations done						
Kuru**	1956	gas	n/a	84	n/a	**	**	n/a	0.00	0.00
Kutubu	1986	oil/gas	557	1958	n/a	1366.00	1366.00	22.09	31.10	40.50
Moran	1996	oil/gas	259	654	153.70	197.20	425.50	47.53	66.09	124.85
Pandora	1988	gas		1738	n/a	513.59	1492.63	n/a	0.00	0.00
Pasca*	1968	gas	n/a	610	n/a	*	*	n/a	0.00	0.00
Pnyang	1990	gas-cond	n/a	2487	n/a	1,078.20	1,862.70	n/a	9.10	16.60
SE Hedinia	1987	gas	0	209	n/a	157.00	157.00	n/a	0.00	0.00
SE Mananda	1991	oil/gas	107	301	n/a	0.00	226.00	n/a	0.00	33.55
Uramu	1968	gas	n/a	137	n/a	32.00	122.46	n/a	0.00	0.00

Definition for Abbreviations:

mmbbls means million barrels, bscf means billion standard cubic feet,

1P means Proven Reserves, 2P means Proven + Probable Reserves, 3P means Proven + Probable + Possible Reserves.

Oil/Condensate Reserves: Refer to Field Type, ie. Oil reserves to Oil/gas fields and Condensate reserves for Gas/Condensate fields.

Notes:

* Pasca: A-3 Well blowout in 1983. Continuous blowout at the sea-floor.

** Kuru: Reserves not determined due to low reservoir pressure.

*** Hides is the only current producing gas field for power generation (production rate of 14 million scf/day)

Kutubu, Gobe are producing oil fields and have free gas & solution gas but these gas are behind pipe or at the reservoir crest.

Other field have gas but are classified as Probable & Possible due to no pipeline/facilities in place to process and sale.

References:

Department of Petroleum & Energy archive reports: May, 2002 Reserves Report PDL 2,3,4,5, Monthly Technical Reports (2002), The Oil & Gas Reserves of PNG - SSI Report (1992,1994), BP Survey Report (1996)

Section 8.0 POLICY

8.1 Policy Handbook Update

The Policy Branch is reviewing and updating the Policy Handbook to give it a "one-stop shop" look for investors intending to invest in the petroleum sector as well as others who wish to know the general policies of the industry in Papua New Guinea. Amongst the changes are two important sections incorporated into the Petroleum Policy Handbook. The first regards the Government's recent fiscal incentives styled "incentive rate petroleum operations". The 2003 budget provisions have introduced the special package, which include:

a) Abolition of Additional Profits Tax (APT)
b) Reduction of the Corporate Tax Rate to 30%

To qualify for the special fiscal terms, oil companies need to be granted a Petroleum Prospecting License within the designated period of 1st January 2003 to 31st December 2007, from which a PDL is granted on or before 31st December 2017. It is anticipated the new fiscal terms will encourage investments into the country. Secondly, a new section dealing with environmental legislation and policies is being incorporated.

8.2 Tax Incentives

The 2003 budget provisions have included a special package of incentives for the petroleum industry. This was due to the Government's concerns on the lack of exploration activity in Papua New Guinea, particularly in the drilling of exploration wells, and the projected steep decline in oil production from the existing Kutubu, Gobe and Moran oil fields over the period 2003-2010. The Government has introduced special fiscal terms that are to provide an incentive to the industry to explore. Those terms are styled as "incentive rate petroleum operations".

Fundamentally, incentive rate petroleum operations will be subject to a revised income tax of just 30% of taxable income. This is a significant decrease from normal petroleum operations, the income of which is currently assessed at 50% of taxable income for petroleum projects established prior to January 01st 2001 and 45% for projects thereafter.

Additionally, the incentives provide for the removal of the two tiers of APT with respect to all petroleum operations becoming effective from 01st January 2003. The APT is an incremental tax on the accumulated value of net project receipts, that is: net income less deductions uplifted at a set accumulation rate each year. The normal provisions for APT were for a 20% tax on any positive balance of net projects receipts after applying a 15% accumulation rate, and a further 25% tax on any positive balance after applying a 20% accumulation rate. For all petroleum operations both tiers of APT will be removed except the Gas to Australia project, it will retain the two tiers of APT in line with the Gas Agreement.

The new 30% rate of taxation will be available for petroleum operations pursuant to a Petroleum Development Licences granted on or before 31st December 2017. In order to qualify for this incentive rate, companies need to be granted a petroleum prospecting licence within the designated period of 1st January 2003 to 31st December 2007.

It is hoped that during this five-year period, petroleum companies will apply for and be granted new licences undertaking aggressive exploration programmes that would lead to new discoveries. As standard licence provisions are for an initial six-year term followed by a five-year extension (in respect of half the area), the incentive programme period will cater for discoveries throughout the life of such new Petroleum Prospecting Licences. These provisions should reward new and renewed investment by the petroleum companies in exploration. Their reward will be a significantly reduced tax on eventual petroleum production emanating from these new licences.

The incentive rate petroleum operations designation will be available for all petroleum operations arising from newly granted licences throughout all of the petroleum basins of Papua New Guinea. The incentives are thus provided to all basins including existing productive basins, under-explored basins and unexplored basins. Exploration activity is in dire need of encouragement, not only in productive and recognised petroliferous areas, but also in lesser explored or frontier areas. The terms are in recognition that basins other then the Papuan basin are relatively unexplored and that there is a need to spur the exploration of such frontier areas through the application of incentives.

Equally, it is recognized that drilling has already tested many of the large prospects of the Papuan Basin and that exploration in the Papuan Fold and Thrust Belt and the Papuan Foreland has been very expensive. Incentive provisions intend to stimulate the petroleum industry to explore smaller prospects and find oil and gas fields, which would otherwise have been left unexplored for and unidentified.

The Petroleum Division will monitor the incentive rate exercise over the next five years and may reserve certain areas for bidding at certain points in time.

8.3 Legal Issues

8.3.1 Amendments to Oil and Gas Act

The Oil and Gas (Amendment) Act 2001 was passed by Parliament in November 2001 and was brought into effect on 17th April 2002. The amendments were consolidated into the principal Act as a new document and are in circulation.

8.3.2 Oil and Gas Regulations

The Regulations were approved by the National Executive Council and certified by the Governor General on 20th November 2002. They came into effect on 19th December when notice was published in the National Gazette No. G218 of 2002. It is cited as the Oil and Gas Regulation, No. 10 of 2002.

8.3.3 Gas Agreement

The proponent companies of the PNG gas to Queensland Project, the Central Bank and the State, on 06th June, signed the Gas Agreement for the Gas to Australia (GTA) project. A Fiscal Stability Agreement for the GTA project was also signed on the 07th of June. This agreement related to the stability of the fiscal terms applying to the GTA project at the time of execution of the Gas Agreement.

8.3.4 State participation in the Moran Project

The State formally gave notice to the PDL5 Joint Venture partners about its intention to exercise its right under the PPL 138 Petroleum Agreement to acquire a 22.5% participating interest in PDL 5. The State also formally advised the PDL5 Joint Venture partners that the Mineral Resources Development Company would be the nominee for the State's interest.

A Deed of Amendment relating to the PPL 138 Petroleum Agreement is being revised for execution between the State and the PPL 138 partners. The Deed relates to the treatment of State participation in PDL5 and the interest rate on the carry by the companies.

8.3.5 Standard Petroleum Agreement

The Standard Petroleum Agreement has not been revised since 1997. A new draft is under internal review prior to industry circulation. It is envisaged that this task will be accomplished in 2003.

8.3.6 Social Mapping Regulations

The Coordination Branch in collaboration with the Policy Branch has been developing a draft social mapping regulation for application to the petroleum industry. It will be for the GTA and all new projects. The drafts will be finalised for submission to the National Executive Council by mid 2003.

8.3.7 Expenditure Implementation Committee

A joint working committee was established within the Department with members from the Policy and Co-ordination Branches, to work with relevant government agencies and formalise the establishment of EIC.

The purpose of the EIC is to manage and control the benefits that flow to the Provincial Governments. The benefits are that of MoA, SSG, Tax Credit and Equity. Royalty and Development Levy can be included if agreed to by the affected Provincial Governments. A central body is required to manage and implement projects so those government funds are used correctly for the intended purposes.

Few projects have been implemented and with proper reporting requirements met. Funds have been subsumed into the provincial recurrent expenditure and the commitments of the Provincial Government's have yet to be met.

A set of draft guidelines was prepared together with the standing orders for the EIC. The EIC would be established and funded as a policy of the State through Section178 of the Oil and Gas Act.
The EIC is anticipated to be established and operational in 2003.

8.3.8 Court Cases

The Legal Services represents the Department in cases before the District Court and has compiled monthly case updates on cases against the Department. The updates are based on the court appearances that were made and also after receiving updates from the Department of Attorney General on cases that are heard in the National Court. The updated reports are sent to the Coordination Branch.

8.4 Environmental Issues

The Environmental section ensures all petroleum companies conduct their exploration, development and production operations in accordance with all applicable environmental procedures and programs of the Oil and Gas Act.

The Department's environmental officers have received training to efficiently perform their regulatory and monitoring roles and to establish more comprehensive environmental policies. This training included general environmental matters such as the physical and biological environments, the related human impact, and the introduction of policies and regulations to manage the environment in an effective and sustainable manner. The importance of environmental protection in the petroleum industry, addressing both upstream and downstream sectors, together with the roles and responsibilities for DPE and that of the Department of Environment and Conservation (DEC) are emphasised.

A clear delineation between the roles and responsibilities of DPE and DEC, for the benefit of Petroleum project operators where environmental matters are concerned, avoids the duplication of roles and responsibilities by these two agencies.
The Environment section has handled three main environmental issues this year:

8.4.1 PDL 2 - Kukuma Sago Patch

The Environment section flew into Kutubu to the Sisibia village to assess their alleged claim of sago patch damage caused by runoff from the Moran road construction. A report was written and recommendations made, upon which a letter was forwarded to ChevronTexaco to require stabilisation of the side cast of the Moran road. The compensation claim was referred to the Petroleum Wardens for further deliberation.

8.4.2 PDL 2 – Mubi Bridge Disaster

There was a claim received by the Section regarding blockage of the Mubi River channel caused by debris being dumped in the narrow channel during the construction of the bridge resulting in the back up and flooding of waters upstream. There were series of meetings held between the Section, the DEC and ChevronTexaco, with the Department and Operator providing necessary information to assist the DEC in addressing the problem. Negotiations are underway regarding environmental damages and compensation claims.

8.4.3 PPL 194

Landowners are still pursuing compensation claims on environmental damage since the 1990s. The Department considers the claims time-barred under the statute of fraud and limitation.

8.4.4 Napa Napa Oil Refinery

InterOil gave an update on the progress of construction work at the NapaNapa oil refinery site, focused on the jetty earthworks. The Environment section expressed concern that according to the environmental plan for NapaNapa oil refinery there were three possible options for building the jetty. The option selected by the Operator will be implemented following proper consultation with the Department and the DEC. The Section is currently corresponding with the Operator on the matter.

8.5 Economics

8.5.1 Oil Prices

Two international benchmark crude oil prices and PNG's Kutubu crude oil price were monitored in the calendar year 2002. Brent Dated, (main international marker crude), Tapis, (Asia Pacific marker crude) and Kutubu, (PNG's export crude) were observed and reported on a monthly basis throughout the year.

The oil prices generally increased throughout the year. January saw prices at around US$19 per barrel and by November was up at US$27 per barrel. Throughout the year, the prices were generally above US$24 per barrel.

The major factors in the price movement throughout the year have been OPEC's ability to cut and increase production, the weather in the Northern Hemisphere, and the ability of refineries to meet the demands for specific products. The state of the US economy, and the continuing Palestinian – Israeli conflict and other terrorism acts in the Middle East were other significant factors.

The unusual warmer winter in the Northern Hemisphere and the global economic slow-down saw prices remaining below $20 per barrel in the first quarter of the year. However, OPEC's decision to cut production saw prices rise to about US$ 22 per barrel and continued to rise in the early part of the first quarter.

The oil price rose sharply during the second quarter and remained high. The main factors that influenced prices were the economic recovery in US and higher demand for oil products following the recession, the Indian and Pakistani tensions in Asia and the continued Middle East terrorism. Oil Prices reached their peak at $27 per barrel in the mid-second quarter.

The threat of possible US military action against Iraq, tropical storms in the US Gulf of Mexico, and OPEC's decision not to increase production after their much-anticipated September meeting in Japan, saw prices rise to their highest levels of the year. These prices were the highest since the immediate aftermath of the September 11 terrorist attack in the US in 2001. The prices were above US$26 per barrel in the third quarter and peaked at around US$29 per barrel.

Prices dropped sharply during the fourth quarter, and moderately increased towards the end of the quarter. The apparent breakthrough between the United Nations and the US on the issue of the return of weapons inspectors to Iraq, and world crude oil production being in excess of world demand pulled prices down. Prices stayed around US$25 per barrel for most of the fourth quarter.
Brent Dated averaged US$24.8 per barrel, Tapis averaged US$24.52 per barrel and Kutubu averaged US$24.53 per barrel in 2002. Tapis traded over Brent by 28 cents, while Kutubu traded under Brent by 27 cents.

Asia Pacific Price Index (APPI) was used as the prime source of price data. Other sources include the Energy Day Daily News Bulletin from Mackay Consultants, oilgasoline.com and oilnergy.com. For the year's overall price analysis, the APPI quotes were used as the price base for Tapis and Kutubu whilst the Brent was taken from the Energy Day Daily News Bulletin.

The price monitoring has aided the Department to monitor price movements against the supply and demand situation in the world market. The Department has then been able to verify the realised prices obtained on the export of Kutubu crude. APPI quoted prices have been particularly helpful in assessing the reports on each sale.

8.5.2 Royalty

Royalty to the State is calculated at the rate of 2% of the wellhead value of all petroleum produced from the license area less any deductions prescribed in the regulations.

A total of K27 million was due in royalties in year 2002 from the license area earnings as follows;

License	**Amount (Kina Million)**
PDL 1	0.552
PDL 2	13.289
PDLs 3 & 4	9.758
PDL 5	3.679
Total	**27.278**

8.5.3 Petroleum Cost Reporting

It was noted that that the current cost reports provided by the oil companies are insufficient and this highlights the need to keep good cost records for license monitoring purposes.

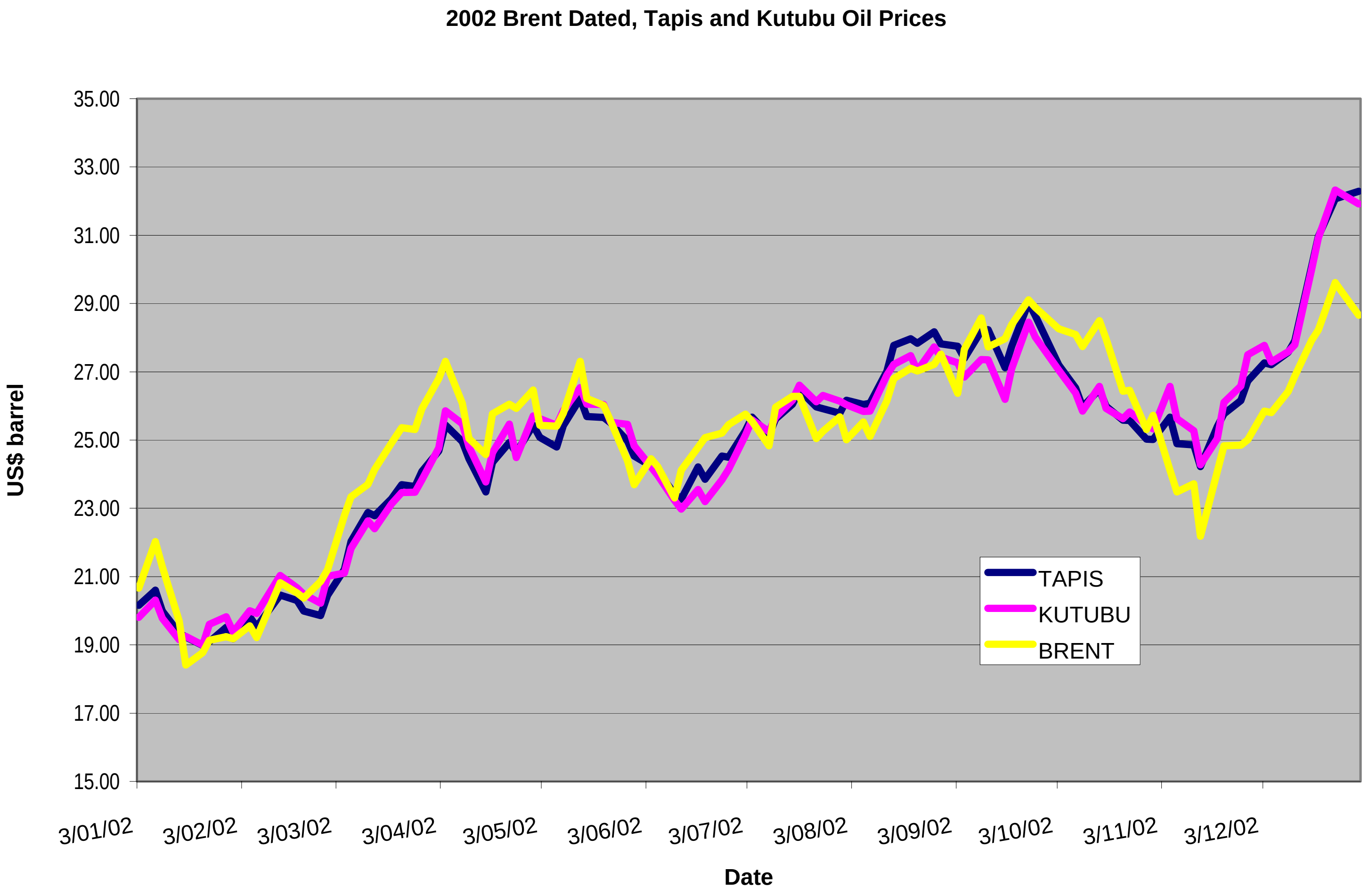
The cost reporting system set up in 1999 has been reactivated. It was agreed that the Policy & Exploration branches have to work on a single central file on the PPL work programs cost monitoring. The two branches have created a central spreadsheet and respective license coordinators will be updating the sheet that will also be accessed and used by the policy and legal officers.
Work was underway to engage a cost-reporting expert to assist in the overall exercise.

8.5.4 Financial Reviews

The Economic section of the Policy Branch did financial reviews on petroleum license applications. In this process, the financial statements and expenditure specifications of the applicants were reviewed and assessed. The financial strengths of PPL Applicants are reviewed and assessed with an opinion formed and forwarded to the Petroleum Advisory Board.

Three applications for PPL were lodged for financial assessments in 2002. These were for acreage in PPL 231 by Indo-Pacific Energy Ltd and Durum Energy Cons Corp, PPL 232 by InterOil (PNG) Ltd and PPL 235 by Indo-Pacific and Durum Energy Cons Corp.

Figure 12: Year 2002 Oil Price Graph



Section 9.0 COORDINATION

9.1 Overview

The Co-ordination Branch has had a challenging year. The potential threat disturbances could be considered as a direct response to the declining oil production and consequent decreases in level of royalty and equity benefits. The affected communities continue to explore avenues to increase or maintain their level of benefits by threatening closures to squeeze the government into making payments of one nature or another. In other cases, it is due to the non-implementation of MOA commitments by the Government (past or present) that has caused disruption of projects. The funding is usually minimal. The MRDC will take over those functions as per Oil and Gas Act requirements. It is hoped that lessons learnt from past management of equity, are utilised to improve on the management of cash benefits (royalty) to the landowners from the Hides, Kutubu, Moran and Gobe projects.

The Minister was directly involved to address these problems, and has visited the projects regularly and held discussions with landowners and the developers to ensure disruptions do not occur. All issues have been manageable.

Proper social mapping and landowner identification is required to ensure all people affected by the gas project benefit. Similarly, the management of benefits must be done in a transparent and efficient manner. The Branch has effectively managed the royalty payments to Hides, Kutubu and Moran landowners, while Gobe royalty was recently paid out after the prolonged legal wrangling over land ownership.

9.2 Kutubu Project

9.2.1 MOA Kutubu / Gulf Review

The Kutubu MOA review is well overdue and there are plans to review the MOA with preparations now in progress to convene this meeting. Three Position Papers were received from the Gulf Landowners, the Fugiki Association and Southern Highlands Provincial Government. The Foe and Namaoporo Associations are yet to provide their position papers. A meeting will be convened with other line governmental agencies, to discuss these papers and formulate the State's position on the issues raised, prior to the actual review.

9.2.2 Land Group Associations

Lower Foi

The Lower Fois have been recognised separately from the Upper Foi as Irakorahi people, and are now represented by the Fugiki Association. This was a result of the Mubi Valve station shut-down in October.

Mubi Bridge

There was a claim for K80 million by the Foi Mubi Bridge landowners over alleged destruction to vegetation up-river from the Mubi Bridge on the Kutubu access road. The flooding after heavy rain was alleged to have been caused as a result of a blockage created after debris from the bridge and road clearing was dumped into the river.

The concerned Government Departments met on several occasions and the State has formed a working committee to address the issue.

9.3 Gobe Project

9.3.1 Royalty and Equity Payments

Following twelve years of legal battle over the landownership rights to the Gobe oil field land, the State paid K18 million in royalty monies to the twenty-one recognised clans. The clans agreed to set aside their land disputes and various court proceedings and receive the royalty monies. The paid amount represents just 40% of the royalty. The balance of 60% remains in a trust account with the Finance Department awaiting a decision by the Minister. The Oil and Gas Act states that the funds be transferred to MRDC and that 30% be set aside for future generations whilst the remaining 30% be invested in projects.

MRDC through its subsidiary company PRG will pay out the equity demands once KPMG completes their audits.

9.3.2 MOA Review

The Gobe MOA is scheduled for review by early 2003. The Gobe MOA review is estimated to cost around K200,000 and is planned to be held at the project site.

9.3.3 Creditors Bills

Individuals and firms that have provide services to Gobe landowners are still awaiting their bills to be settled. A committee was formed comprising the Attorney General as chairman and the Departmental Secretary and Finance Secretary as members. The committee will review all bills and make decisions on the settlement.

9.4 Moran Project

All issues were manageable. This is the result of an efficient landowner relations program initiated by the Moran Project Coordination Team in its contribution towards maintaining stability for the project. The two main highlights for the year include the payment of Royalty Benefits and secondly, the engagement of the Petroleum Warden in the first compensation determination in the Petroleum Industry.

9.4.1 Royalty Payments

To date, all beneficiaries under the Moran Development Agreement (DA) have received two payments of royalty. The first payment was made in early October 2001 was the accumulated total received under the

Extended Well Testing Program (EWT) on Moran 4x, covering the period between April 2000 to February 2001. The second payment was made in June for the period between March 2001 to April 2002 under the normal PDL5 royalty payments. Only the Huli Tribe received these payments.

The Fasu Tribe has now been included to receive 10 percent of the royalty in PDL5 based on a Ministerial Determination dated 20th September as per the Gazette G172 of 21st November. Their portion of benefits was paid thereafter in November.

To date, the total number of landowner beneficiaries in PDL5, including the main clans and their sub-groups is 239. This figure is subject to change, mainly for the Hulis, as a result of a variation exercise conducted by ChevronTexaco or subsequently by other associated reasons.

9.4.2 Land Dispute - Yumbi vs Webo

The dispute over landownership along the Mt Palana Range between the Yumbi and the Webo resulted in several disruptions during the road construction phase to Moran 4x. The issue was partially resolved after a Deed of Release was signed between the disputing parties on 01st October following two years of mediation and court decisions to determine the ownership.

9.5 Hides Gas Project

The National Government undertook a firm commitment to restore peace and normalcy back into the Southern Highlands Province and in particular, Tari. A high-level delegation led by the InterGovernment Relations Minister, toured the Province in mid December. The trip shed much light on the peace process, and the people indicated a strong desire for peace and normalacy to return in the presence of the National Government and promised to support the Hides Gas Project because the State and other stakeholders have equal vested interests in the future development potential of this huge gas reservoir.

9.5.1 Project Operations

There were normal operations at the Hides project until mid 2002, when it was severely affected by the felling of power pylons to Porgera. Consequently, Porgera Mine had its gold production disrupted. Reduced gas production meant reduced royalties for Hides Landowners for that period.

9.5.2 Royalty Payments

The Hides Gas Project's biannual royalty payment for period January to June was effectively paid to the landowners in September. The July to December payment is pending processing of a cheque. The proliferation in sub-clans accounts is ongoing.

9.5.3 Peace Campaign

The Peace Campaign is ongoing and the Inter Government Minister has made three trips to Tari in the space of a month. Offensive weapons have been surrendered by the local communities back to the rightful authorities. Peace and normalcy are now returning to the Tari Basin area.

9.5.4 MOA Review

The finalisation of the Hides Memorandum of Agreement review was initially proposed for mid December but further delayed to early February 2003 due to funding difficulties. The Minister made an undertaking to conduct all MOA and DA reviews at the project sites for fair representation by landowners, transparency by the State and as a cost-saving measure.

9.5.5 Hides Zone ILG

The landowners of Hides 4 wellhead in PPL 138 have expressed strong opposition for the Zone ILG concept that has been proposed by the Operator of PDL1. In its stead, they are strongly advocating for clan-based ILGs. After much debate and discussion, the concept has been shelved.

9.5.6 Exploration Activity Involvement

The Bakari 1x well in PPL 138 was spudded on 25th December 2001and plugged and abandoned in March. All landowner-related issues were coordinated through the Department's Hides Office.

9.6 MOA Projects

9.6.1 2001 MOA Projects

A total of twelve projects were funded for implementation in year 2001. Funds for the operational cost of seven of the projects was released in 2002 to Department of Works & Transport (DOW&T) in Mendi, whilst the payment for the materials were paid directly to the contractors. The projects are as follows;

HIDES

Includes two staff housing for Para Community School as well as a classroom. The projects are currently being undertaken.

KUTUBU

Includes staff housing for Orokana Community School as well as a classroom. The project was completed in September.

GOBE

This includes staff housing for Mararogo Community School and the upgrading of the Mararogo Health Centre. Also includes staff housing for the Samberigi Community School and Health Centre. Construction work is in progress.

9.6.2 2002 MOA Projects

Unfortunately, funds earmarked for various projects were not committed to the projects in 2002. Instead, funds were diverted to meet the cost of Landowner meetings and recurrent costs.

GOBE

Most of the funding was spent on the Gobe road project as well as meeting the travel and accommodation costs for Gobe Landowners in sorting their leadership issues.

HIDES

A total of K1.3 million was released for various MOA projects in the Hides area. A physical audit inspection is planned to verify and certify the completion of projects.

KUTUBU – SHP MOA PROJECT

No projects were implemented this year as funds were diverted directly from the Department of Planning and Monitoring to the Kutubu Development Authority (KDA).

KUTUBU – GULF MOA PROJECT

No projects were implemented for the year.

MORAN MOA PROJECT

The construction of a Church at Paua village was the single project that was implemented. The Department committed K260,000 towards this project a physical audit inspection is planned to verify the implementation of the project.

9.7 Other Issues

9.7.1 Landowner Studies

The legal and administrative structures in place in PNG make unique provisions for the recognition of the rights of people living under customary law and enjoying customary land ownership rights to participate in the development of petroleum resources. These structures are intended to enable people who participate in common property ownership regimes to join together and receive benefits from petroleum projects in ways, which support the life and customs of the group.

Although the Department's management of landowner affairs has, to date, been based on sound, but limited administrative procedures, some of the administrative procedures have been identified as being inadequate in that they do not respond in an effective way to the difficult conceptual problems involved in joining customary law and modern law issues. As an initial step, consultancy firms undertook a number of studies.

The requirements of the Oil and Gas Act for Social Mapping and Landowner Identification Studies prior to the issuance of a Petroleum Development License had led to a considerable degree of uncertainty as to when and how the obligations specified in the Act could be assumed to have been met. A regulation for Social Mapping and Landowner Identification Studies was urgently required to remedy this situation. An initial step was to compile a study report in the form of an issues paper and to circulate this among landowner groups, industry, the PNG judiciary and other interested citizens. A regulation for social mapping and landowner identification studies has been drafted following from the process of public consultation.

Additional studies have resulted in discussion papers on the subjects of the economics of future generation's transfers among customary landowner groups; joining customary law-based property rights and modern law-based property rights; and, the codification of customary law principles for the implementation of landowner disputes by the Department's dispute resolution tribunal system.

9.7.2 Petroleum Warden

The Department, through the Director, Mining Act appointed Cletus Bomai and Stanley Pono as the Petroleum Wardens under the Mining Act (1992). Their appointments were made on 26th October 2001 and gazetted on the 09th January.

In 2002, only two determinations were made. The first Warden Determination was made on 05th April. It was for claims of eight sites in PDL2, by the Gogofora Sebere Land Group against ChevronTexaco, after the initial calculation valued at K94,424.67 was deemed to be insufficient by the Land Group against their claim of K565,000.

The second determination was made on the 22nd May for damages to Sago Patches owned by the Sebere Kukuma and Geso Land Groups. The amount of compensation claimed was K500,000, however the assessed value by ChevronTexaco was K111,825.69. ChevronTexaco appealed against both determinations.

Section 10.0 CONCLUSION

Although two small oil reserves were discovered, there was no improvement in the level of Petroleum activities.

The general declining oil production and depleting petroleum reserves trend experienced this year has provided many challenges to the Government of Papua New Guinea, the developers and landowners. Whilst the landowners have seen reduced royalty and equity payments, the developers have been developing their field facilities to optimise and sustain production. The Government has finally established a new tax incentive to encourage exploration for more discoveries, while at the same time handling associated landowner issues.

With the new tax regime that will come into effect as of 2003, it is hoped that this will boost and encourage exploration, sustaining the Government and landowner expectations of the petroleum industry.

PETROLEUM EXPLORATION & PRODUCTION STATISTICS

		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
NEW PPL's GRANTED **(a)**		4	5	5	8	1	7	6	5	9	4	3	2	1
PPL's EXPIRED, SURRENDERED OR CANCELLED		2	12	8	13	6	2	7	3	5	3	1	4	4
TOTAL NUMBERS OF PPL's **(b)**		40	33	30	25	20	25	25	22	27	28	27	23	17
TOTAL NUMBER OF BLOCKS			2684	2143	1283	995	1130	1395	1372	1494	1535	1508	1066	1020
TOTAL AREA UNDER LICENCE (KM^2)			228140	182155	109055	84575	96050	118575	116620	126990	130475	122148	90610	87308
NEW PDL's GRANTED		2	0	0	0	0	0	2	0	0	0	0	1	0
PDL's EXPIRED, SURRENDERED OR CANCELLED		0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL NUMBER OF PDL's		2	2	2	2	2	2	4	4	4	4	4	5	5
TOTAL NUMBER OF BLOCKS (PDL)		16	16	16	16	16	16	21	21	21	21	21	22	22
NEW PLL's GRANTED		2	0	0	0	0	0	1	0	0	0	0	0	0
TOTAL PLL's GRANTED		2	2	2	2	2	2	3	3	3	3	3	3	3
NEW PRL's GRANTED		0	0	0	0	0	0	0	0	1	0	4	0	3
TOTAL NUMBER OF PRL's		0	0	0	0	0	0	0	0	1	1	5	5	8
APPROXIMATE EXPENDITURE		K225MM	K170MM	K80MM	K60MM	K70MM	K117MM	K190MM	K258MM	K120MM	K144MM	K157MM	K238MM	K157MM
EXPLORATION WELLS DRILLED **(c)**		21	11	7	4	10	4	5	9	5	5	2	0	3
DISCOVERY WELLS **(c)**		9	5	4	2	2	1	2	2	2	1	0	0	2
NEW FIELD DISCOVERIES **(d)**		4	3	2	1	0	0	1	0	0	1	0	0	1
CUMULATIVE FIELDS		18	21	23	24	24	24	25	25	25	26	26	26	28
CUMULATIVE WELLS		213	224	231	235	245	249	254	263	268	273	275	276	278
% SUCCESS RATE		8.5	9.4	10	10.2	9.8	9.6	9.8	9.5	9.3	9.5	9.5	9.4	10.1
SEISMIC SURVEYS		15	6	8	3	1	1	3	5	7	2	4	4	3
LINE KMS SEISMIC	ONSHORE	2901	744	751	43	35	16	446.2	321.2	28.2	142	147	109.8	49.75
	OFFSHORE	2576	661	879	2425	12568**(e)**	0	0	0	5390	0	0	0	0
	TOTAL	5477	1405	1630	2468	12603	16	446.2	321.2	5418.2	142	147	109.8	49.75
PRODUCTION **(f)**	OIL (MBOPD)		1	53	126	120	100	106	130	81	88	70	56	47
Average per day	GAS (MMSCFD)		3.7	5.8	7.9	9.2	9.6	13.5	11.5	13.3	13.1	12	14	10.2

NOTES

(a) PPL is a Petroleum Prospecting Licence
PDL is a Petroleum Development Licence
PPL is a Pipeline Licence
PRL is a Petroleum Retention Licence

(b) Figures at year end

(c) Excludes development wells but includes extensions discoveries and purposeful sidetracks drilled and completed in c 1999 = KIMU.

(d) 1986 = IAGIFU
1987 = SE HEDINIA, HIDES
1988 = HEDINIA, PANDORA
1989 = AGOGO
1990 = ANGORE, ELEVALA, P'NYANG, USANO
1991 = KETU, SE MANANDA, SE GOBE
1992 = GOBE 2X, PANDORA B
1993 = GOBE MAIN
1996 = MORAN
1999 = KIMU

(e) 3-D Pasca Survey

(f) Oil Production – Kutubu/Moran/Gobe
Gas Production – Hides