PETROLEUM DIVISION

DEPARTMENT OF PETROLEUM AND ENERGY

2005 ANNUAL REPORT

ON

PETROLEUM ACTIVITY IN PAPUA NEW GUINEA

Compiled by the Exploration Branch

May 2006

PREFACE

This Annual Report contains the summary of all the events and corresponding information concerning all activities directly related to the exploration, development and production of petroleum in Papua New Guinea for the year 2005. The events and information contained within are sourced from reports furnished by the operating petroleum companies to the Petroleum Division of the Department of Petroleum and Energy as the regulator, promoter and monitor of all petroleum activities in the country. Also covered and equally important are corresponding non-technical information regarding licence management, policy, legal and landowner issues directly related to the petroleum activities. Confidential information, however, has been excluded. All values are quoted in US dollars to ensure consistency, but where necessary, the Kina currency is used for ease of flow of information and simplicity.

The report serves to provide a continuous and summarised review of the petroleum activities in Papua New Guinea.

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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
Ft	Feet
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	• Management of MOA funds was transferred from DPE to EIC • Completion of NapaNapa Refinery
February	• PRL5 extension for a second 5 year term granted • PPL 244 awarded to Talisman Energy Ltd • PPLS 254, 255 & 256 awarded to Chinampa Ltd, all offshore in the Gulf Papua
March	• PPL 260 awarded to Transeuro Energy Corp • TransEuro takes over Grey Creek's interests in PPLs 257 and 258
April	• Black Bass-1well spudded by SPI InterOil
May	• The appointment of Sir Moi Avei as Deputy Prime Minister • OSL celebrates 75 years of investment in PNG
June	• PPL 259 awarded to TransEuro Energy Corp • Hides landowner database established by Coordination office • Participation by female officers at the Women in Mining Conference
July	• Ministerial delegation tours rural Queensland as part of the PNG Gas Progect roadshow
August	• Signing of the revised Moran Development Agreement • PPLs 266, 267, 268 & 269 all awarded to New Guinea Energy Ltd • Oil prices surge past US$70
September	• NW Moran-1 well brought online for production under extended well test • Triceratops-1 well spudded by SPI InterOil • Ministerial announcement of the reservation of blocks for a planned licensing round for petroleum prospecting rights in Gulf of Papua • GPCSA Awareness trip to Hides • Comalco Ltd signs between 14-50 PJ of PNG Gas
October	• Memorandum of Understanding signed with Syntroleum Corp for feasibility study on gas convertor plant
November	• TransEuro Energy Corp opens PNG office
December	• Konebada Petroleum Park project plans gaining momentum

Section 1.0 SUMMARY

The year 2005 saw an increased intensity of petroleum exploration with a larger number of exploration wells being drilled, more geophysical surveys and a greater usage of airborne gravity and magnetic surveys as a cost effective preliminary exploration tool. Since the introduction of the Incentive rate Petroleum Taxation rate by the National Government in 2003 that were put in place to encourage exploration, there have been more exploration activities.

Effects of the natural decline in oil production have been offset by vigorous reservoir and drilling management and applications, resulting in more development wells completed as producers.

Three new licences were awarded offshore Gulf of Papua and Coral Sea areas will test previously unexplored deep water plays. This year saw the Ministerial reservation of parts of the offshore area, and the Department, together with Fugro Holdings have been preparing for a Licensing Round. Three wildcat exploration wells, the Kapul-1, Black Bass-1 and Triceratops-1 were drilled this year, but unfortunately all tests were unsuccessful at finding hydrocarbons. Eight development wells were drilled in various fields and all were completed as oil producers. A notable first for PNG in the South East Mananda field development was that all the surface holes for the wells SEM 3,4 and 5 were batched drilled. There are currently seven producing oil fields in the country.

The Petroleum Division continued its role as the regulator, promoter and monitor of the industry. The Division ensured all exploration, development and production activities were carried out within the provisions of the Oil and Gas Act and Regulation.

The Division managed 29 petroleum prospecting licences (PPLs), 5 petroleum development licences (PDLs), 3 pipeline licences (PLLs), 11 petroleum retention licences (PRLs) and 1 petroleum processing facility licence (PPFL) for the year. Four active licences are within the North New Guinea Basin, one in the Cape Vogel Basin and the remaining licences are within the Papuan Basin.

In 2005, the Kutubu oil fields oil production averaged 21,266 BOPD, whilst Moran oil fields averaged 16,410 BOPD and the Gobe fields averaged 16,775 BOPD for the same period. The Hides gas field produced 5.101 BCF of gas over the year.

There have been on-going landownership issues in some of the project areas with some presently before the Courts. Most other issues have been manageable. One highlight of the year was the successful signing of the Revised Moran Development Agreement for the Moran Project. Beginning in 2005, all royalty benefit payments are now administered by MRDC and the management of MOA funds has also been transferred from DPE to EIC.

Section 2.0 LICENCE MANAGEMENT

2.1 Year 2004 in review

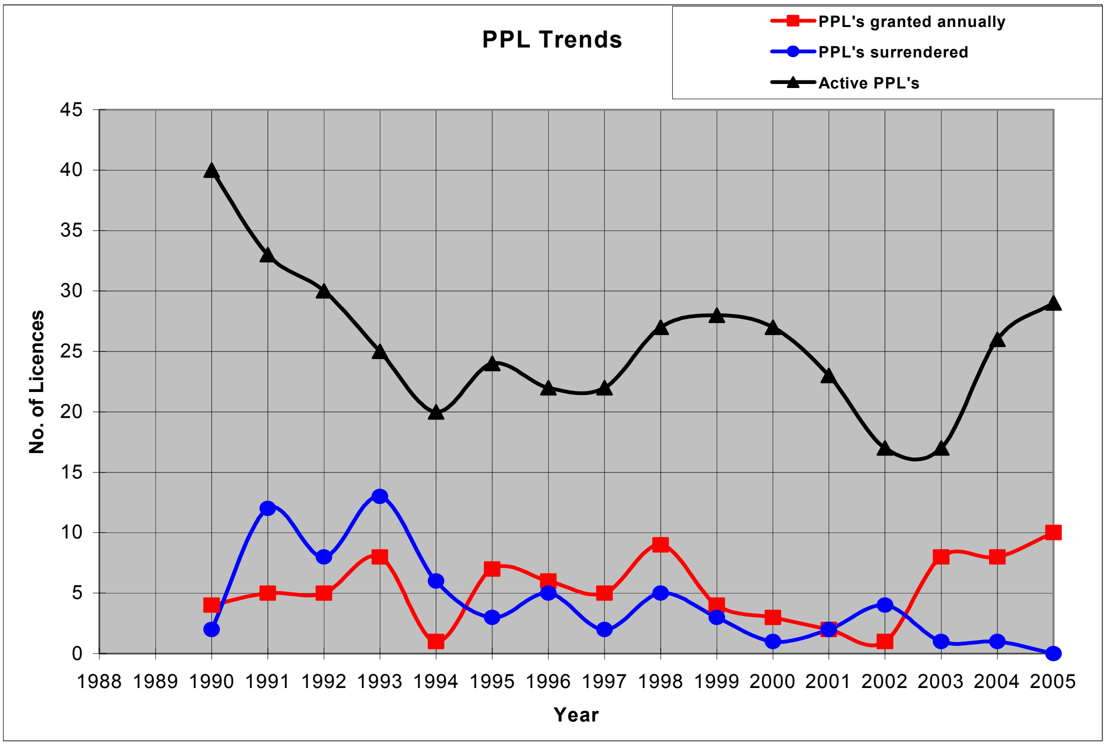
Twenty six Petroleum Prospecting Licences (PPLs), five Petroleum Development Licences (PDLs), three Pipeline Licences (PLLs), ten Petroleum Retention Licences (PRLs) and one Petroleum Processing Facility Licence (PPFL) were active between January to December 2004. In essence, eight PPLs were granted that year whilst five other applications (APPL) were refused. One PRL application was on offer and may well be granted in early January or February 2005. Moreover, there were 5 APPLs pending necessary reviews, and there was only one licence surrendered, this was Barracuda Limited's PPL 228. In regards to the overall licensing permit locations, PPL 245, 249, 252, and 258 were in the North New Guinea Basin while PPL 257 was in Cape Vogel basin. The remainder of the above petroleum licenses were all situated in Papuan basin.

2.2 Licensing Year 2005

Twenty nine Petroleum Prospecting Licences (PPLs), five Petroleum Development Licences (PDLs), three Pipeline Licences (PLLs), eleven Petroleum Retention Licences (PRLs) and one Petroleum Processing Facility Licence (PPFL) were active between January to December 2005. Three of the new licences awarded were in offshore deep water (2,000m), namely, PPL 254, 255 and 256 in the Gulf of Papua and granted to Chinampa Exploration Pty Limited. Chinampa is a subsidiary of Fugro Holdings (Australia) Ltd. These new licensed areas are essentially unexplored and hence they present new exploration challenges and opportunities in the region.

Ten new PPLs and one new PRL were granted in 2005, whilst two PPL applications were refused. There were no licences surrendered in the same reporting period. Moreover, as of the end 2005, fourteen Petroleum Prospecting Licence applications were pending necessary reviews. Amongst these pending applications were PPL 219 licence extension application and a topfile application lodged by Oil Search Limited on behalf of itself and the joint venture partners. The award of this permit is critical as it is one of the most prospective acreage in the country where most of the oil fields were discovered. There are five licences outside of the Papuan Basin. PPLs 245, 249, 252 and 258 are situated in the North Niugin Basin, whilst PPL 257 is situated in the Cape Vogel Basin. The remainder of the above Petroleum licenses are all situated in the Papuan Basin.

Figure 2: PPL Trends



Section 3.0 EXPLORATION & DRILLING

The total number of surveys carried out this year increased when compared to previous years. Seven surveys were conducted in various licences. **Tables 3.1 & 3.2** contain the summaries of all the field surveys for the year.

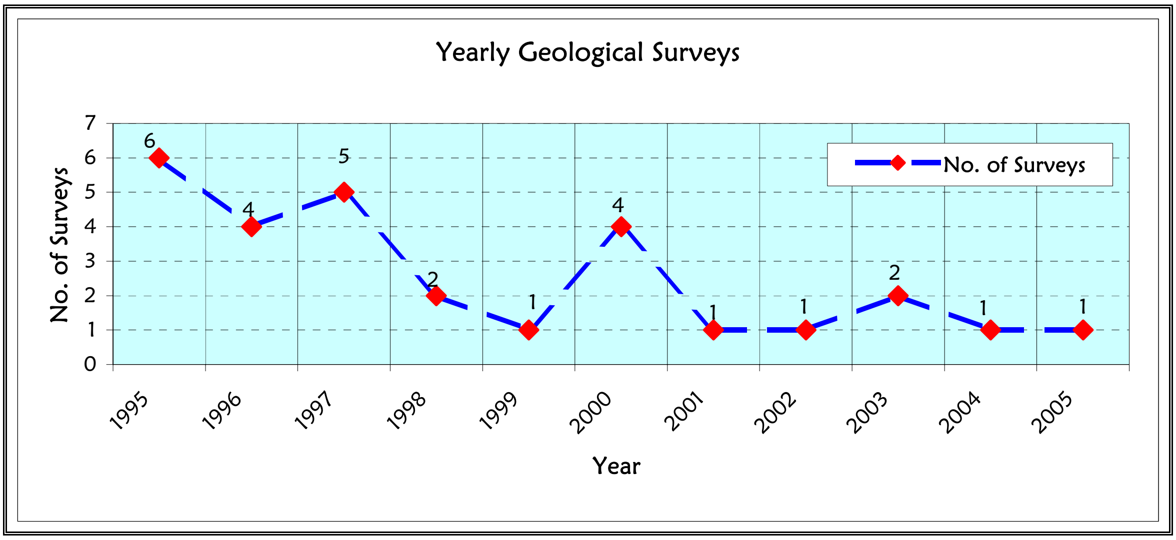
3.1 Geological Field Mapping

Only one geological survey was conducted in 2005. SPI InterOil conducted the Pale Distribution Mapping Program in PPLs 238 and 250 in which a total of 120km of geological traverse was acquired. The aim of the survey was to investigate the spatial and palaeogeographic distribution of the Pale and Subu Sandstone east of its known outcrop in PPL 238. The survey is summarized in **Table 2.1**. **Figure 2** shows the graphical representation of the yearly geological surveys since 1995.

Table 3.1: Geological Surveys

Licence/ Permit	Operator	Geographic / Tectonic Area	Name/ Contractor	Line Length - Km	Cost US$
PPLs 238 & 250	SPI InterOil	Gulf Province *Papuan Basin, Onshore*	Pale Distribution Mapping Program	**120**	**66,152**
TOTAL				**120**	**66,152**

Figure 3.1: Yearly Geological Surveys



3.2 Geophysical Field Surveys

The number of geophysical surveys increased slightly when compared to the previous year. All four seismic surveys, the Bwata, Aure, Aure Supplement and Mananda/Paua/Iwa were conducted onshore by SPI-InterOil and Oil Search Ltd respectively. In the same year, three airborne surveys were conducted, and again by SPI InterOil and Oil Search respectively. They were the Aure-Crater High Resolution, the Era-Vailala High Resolution and Mogulu Aeromag airborne surveys. All these surveys are summarized below in **Table 3.2**.

Figures 3.2 and 3.3 show the graphical representations of the yearly seismic and aeromagnetic surveys since 1995.

The Bwata Seismic Survey objective was to improve subsurface control on the Bwata Structure, and test for possible wider structure (as per Elk) and/or a larger attic. A line length of 12.08km was acquired.

The Aure Seismic and Aure Supplement Surveys were used to control subsurface structures, detect shallow targets, establish orientation, geometry, dip of Aure Fault, locate the proposed thrust below Rhino prospect and to determine the depth of the limestone objective. A line length of 161km was acquired.

The Mananda/Paua/Iwa Seismic Survey (Phase III) was aimed at completing the line PN05 in the Mananda portion, mature the NW & NE Paua prospect and leads in the Paua portion and assist in maturing the Iwa/Agogo South leads in the Iwa portion of the survey. The total line length of the survey was 74.07km.

There were two airborne surveys namely, SPI InterOil's Aure-Crater High Resolution Airborne Survey and Oil Search's Mogulu Aeromag Survey, which were conducted with flight lengths of 380km, and 5912.1km respectively. The Aure-Crater High Resolution Airborne Gravity & Magnetic Survey was conducted to differentiate between two proposed geological models of the Longhorn Prospect area while the Mogulu Aeromag Survey was used to acquire conventional gravity and magnetic data to better define the subsurface structure and exploration risk of the Mogolu feature and hence assist in the design of a seismic survey.

Table 3.2: Geophysical and Aeromagnetic Surveys

Licence Area	Operator	Geographic Area	Name/Survey Type/Contractor	Line Length Km	Cost (US$)
SEISMIC SURVEYS					
PPL 237 **Onshore**	SPI InterOil	Gulf Province	**Bwata Seismic Survey** Oilmin	**12.08**	**634,833**
PPL 238 **Onshore**	SPI InterOil	Gulf Province	**Aure Seismic Survey** Oilmin		
PPL 238 **Onshore**	SPI InterOil	Gulf Province	**Aure Seismic Survey Supplement** Oilmin	**161**	**8,981,538**
PPLs 219&233; PDLs 2&5 **Onshore**	Oil Search Ltd	Southern Highlands Province	**Mananda/Paua/Iwa Phase III Seismic Survey** Geophysical Management Consultants	**74.07**	**5,953,853**
TOTAL				**247.15**	**15,570,224**
AEROMAGNETIC SURVEYS					
PPLs 238 & 237	SPI InterOil	Gulf Province	**Aure-Crater High Resolution Airborne Gravity and Magnetic Survey** Sander Geophysical Ltd	**380**	**233,258**
PPL 239	Oil Search Ltd	Southern Highlands Province	**Mogulu Aeromag Survey** MLSC	**5912.1**	**341,703**
TOTAL				**6292.1**	**574,961**

Figure 3.2: Yearly Seismic Survey Length

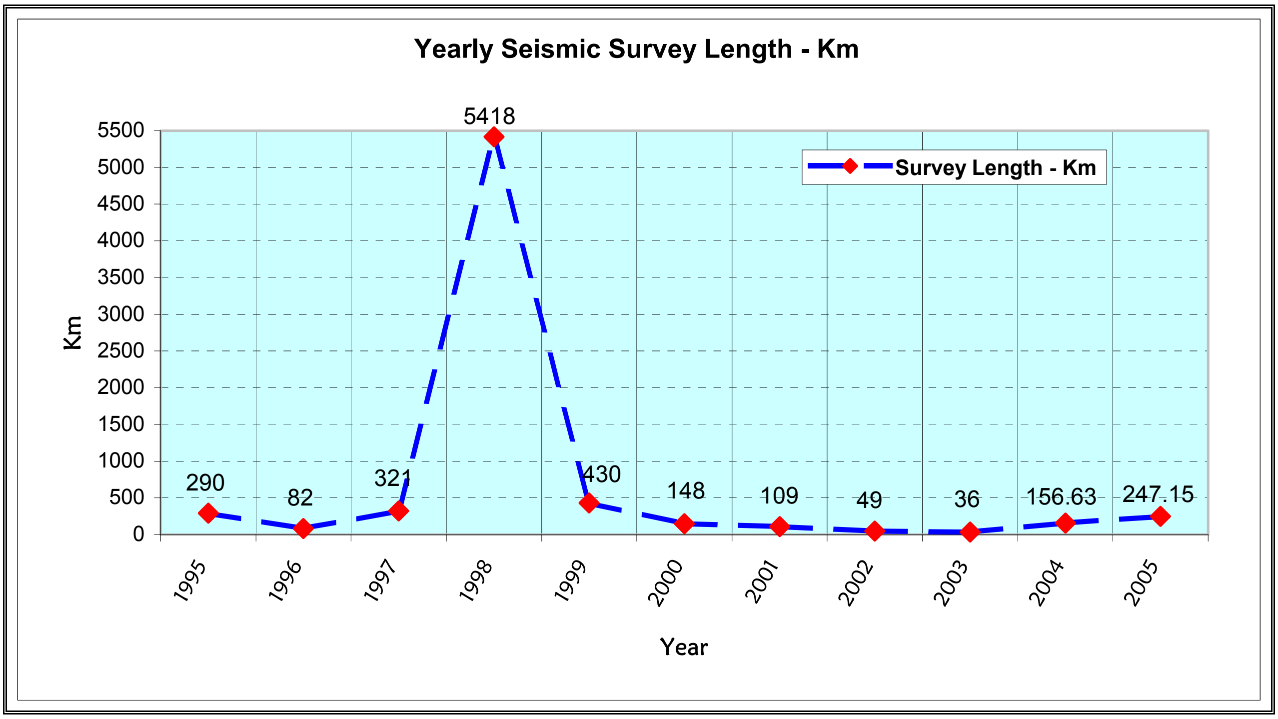
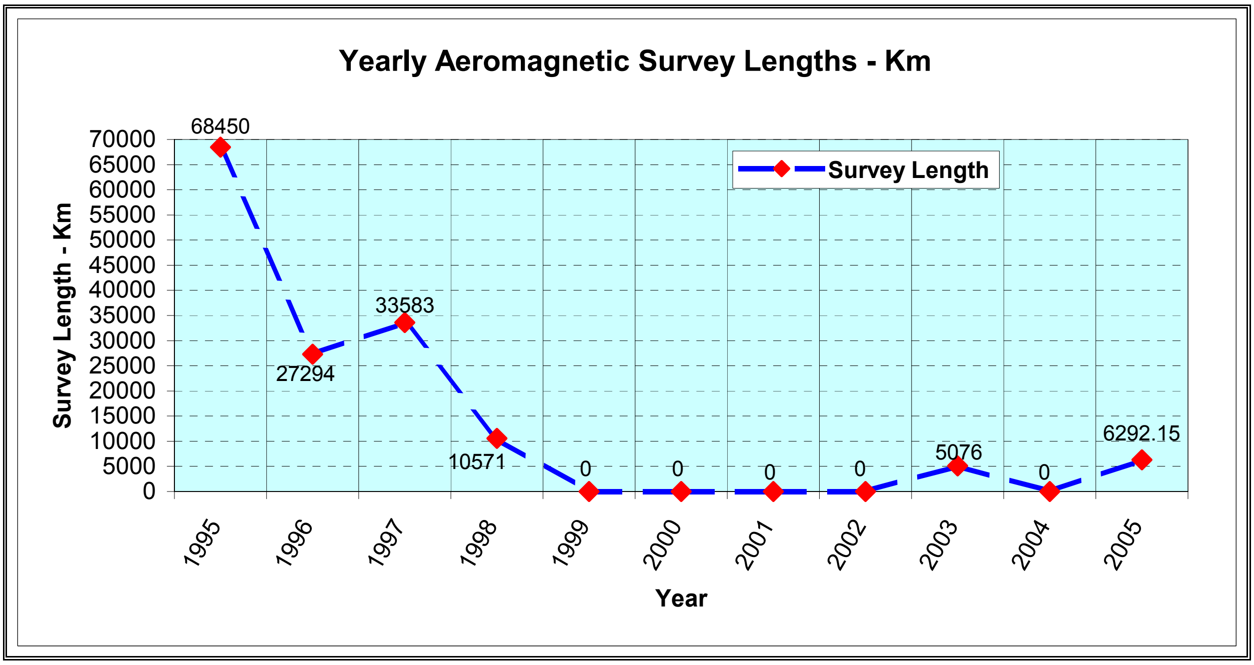


Figure 3.3: Yearly Aeromagnetic Survey Length



3.3 Geochemical

No geochemical surveys were undertaken in year 2005.

3.4 Drilling and Rig Activities

3.4.1 Summary of Exploration Wells

There were three onshore exploration wells drilled in 2005. Of these three wells, one was spudded in 2004 but completed in 2005. The other two were spudded and completed or plugged and abandoned in 2005 without the discovery of hydrocarbons. The wells were Kapul 1, Black Bass 1 and Triceratops 1, spudded on the 20th December 2004, 25th April and 26th September 2005.

Table 3(b) shows the exploration wells drilled in 2004-2006. There were no offshore exploration wells drilled in 2005. The total footage of the three exploration wells drilled was 8,489m (27,851 feet) at a cost of US$ 41.016MM.

Kapul 1

Kapul 1, located in the Gulf Province of PNG, was a vertical exploration well. Drilling commenced on 20th December 2004 at 04:00 hrs. The total depth (TD) of 2,980m MD was reached on the 22nd January 2005 at 17:00 hrs.

After evaluation logs were run and the well was plugged and abandoned (P&A) as the logs showed no indication of hydrocarbons. The well-cost estimate was US$9.16MM including the cost of the rig and the P&A program.

Black Bass 1

The Black Bass 1 well was to test a seismically defined reefal structure, for hydrocarbons. The Black Bass prospect lies, approximately 135km N-NW of Port Moresby in InterOil's PPL 236 located within the Eastern Shelf Province of the Papua Basin. This prospect was identified by InterOil during reinterpretation of reprocessed data from seismic line H87-33.

A secondary objective of the well was to evaluate the reservoir potential of the Wedge Hill Limestone (-316m mSL). The Wedge Hill limestone is believed to be laterally continuous and to have developed patch reefs and carbonate build-ups on emergent anticlinal structures developed during Late Miocene and Pliocene compression. Outcrop sample analysed have yielded porosities of up to 30%.

Black Bass 1 well was spudded on 25 April 2005 and reached a total well depth of 1789m MD/TVD from a prognosed depth of 1800m MD. The rig was released on the 18th July 2005. The actual total well cost was US$5.79MM from an AFE of US$4.5MM.

Triceratops 1

The Triceratops 1 well was a wildcat exploration well in InterOil's PPL 237 aimed at testing a seismic and gravity data defined anticlinal feature known as the "Triceratops structure". The Triceratops structure is situated approximately 3.5km north of the Bwata gas field. The well's primary target was the fractured sequence of the Puri Limestone, with a potential secondary target of the Mendi Limestone.

The well was spudded on 26 September 2005 and was plugged and abandoned as a dry hole after reaching total well depth of 2026m MD from a proposed total depth of 2150m MD. The rig was released on the 22nd December 2005 with a total well cost of US$10.081MM from an AFE of US$8.808MM.

Table 3.3: Exploration Wells Summary

WELL I.D.	LICENSEE	PPL / PDL	SPUD DATE	R.R. DATE	T.D. (m.MD)	FOOTAGE DRILLED (m)	RESULT	COST US$	TYPE OF SIDETRACK (GEOL/MECH)
Kapul 1	Oilsearch	PPL 240	20/12/04	27/01/05	2,980	2,980	P/A & Dry	9,157,865	N/A
Black Bass 1	InterOil	PPL 236	25/04/05	18/07/05	1,789	1,789	Dry	5,790,274	N/A
Triceratops 1	InterOil	PPL 237	26/09/05	23/12/05	2,026	2,026	Dry	10,081,155	N/A
TOTALS						**6,795**		**25,029,294**	

3.4.2 Summary of Development Wells

All the development wells drilled in 2005 were in the Kutubu, South-East Gobe, Moran and South-East Mananda Fields. A total of eight wells were drilled including two sidetracked wells. All of the wells were completed as oil producers including the two sidetrack wells. Of the eight wells drilled in 2005, two were to be completed in 2006.

Table 3.4 shows the development wells drilled in 2005. The total footage of the seven development wells drilled was 22,998m (75,453 feet) at a cost of US$ 115.480MM.

IDT 22

The IDT 22 well was spudded on 18th January 2005 on the same well pad as IDD 3 and reached a total depth of 2,844m (measured depth or MD). The objective of the well was achieved after penetrating the target Toro Sand, in the saddle area of the main block Toro. The well was completed as an oil producer.

After the rig was released on the 8th March 2005 at 14:00 hours, the actual well cost was US$10.128MM from an AFE of US$9.104MM including the cost of the rig move and final completion.

IDT 23

The IDT 23 well was spudded on the 18th April 2005, which had surface location on the IDD 3 well pad. The well reached a total depth of 2,620m MD with the primary target designed to appraise the Toro C sands and to delineate the extent of the oil in place discovered in the successful IDT 4ST1 well.

As drilling progressed in the 12 ¼" hole, the drillstring got stuck at 2,099m MD in the Bawia Member of the Ieru formation. A sidetrack was initiated after the Bottom Hole Assembly (BHA) parted from the drillstring and had to be cemented in. The well was then directionally drilled to TD at 2,620m and evaluated using logs. The well was then completed as an oil producer at a total cost of US$16.272MM that covered costs for rig move, sidetrack and completion. The rig was released on the 8th June 2005.

South-East Gobe 11

The South-East Gobe 11 well was spudded on the 4th March 2005 and reached TD at 2,265m MD.

After evaluation of logs, the SEG 11 well was completed as an oil producer at a total well cost of US$16.272MM from an AFE of US$12.491MM. The cost included rig move and final completion of the subject well. The rig was released thereafter on 17th May 2005 at 13:30 hours.

Moran 11 ST1

The Moran 11 ST1 well was spudded on the 21st August 2005 at 02:00 hrs using Parker Rig 226 and drilled to 4,024m TD. The log analysis showed a water wet reservoir in the Digimu Sandstone so Moran 11 was plugged back to 3,158m MD and Moran 11 ST1 was started at 22:00 hrs on the 14th October 2005. Moran 11 ST1 was drilled to a TD of 3,855m MD. After evaluation logs, the well was completed and rig released at 02:00 hrs on the 13th November 2005. The well cost estimate was US$18.3MM including the cost of the rig move, sidetrack and the completion.

South East Mananda 3

The SEM 3 well was spudded in the SE Mananda Field on 11th July 2005 and reached a TD of 2,855m MD with the Toro C sand as the primary target and the Digimu sand being a secondary objective. The SEM 3 reservoir intervals were perforated after the results of SEM 5 were evaluated. The well was drilled as part of the batch drilling of the SEM 3/4/5 wells pursuant to the SE Mananda development plan.

Upon resuming drilling operations after the well was initially suspended, no major drilling or hole problems were experienced. After evaluation logs, SEM 3 was completed as an oil producer before the rig was released at 24:00 hours on the 26th May 2005. The total well cost was US$18.672MM from an AFE of US$9.00MM that included rig skid and final completion.

South East Mananda 4

Actual drilling operations for SEM 4 well commenced on 31st July 2005 after drilling the top-hole section of SEM 3. The rig was skidded to SEM 4 before drilling commenced on the subject well. The well reached a total depth at 2,669m MD. After evaluation of well logs, SEM 4 was finally completed as an oil producer at a total cost of US$12.066MM. The rig was released thereafter on at 24:00 hrs on the 31st January 2006.

South East Mananda 5

The SEM 5 well was spudded on 15th August 2005 and drilling was suspended after reaching a depth of 2,235m MD. This was primarily done as the surface holes for SEM 3/4/5 were batched drilled. Rig 2 was subject of mast and other repairs after the SEM well surface holes were drilled between 2nd September and 11th November. The rig was also off location for further operations on SEM 4 and SEM 3 between 13th December and 24th March 2006 before returning to SEM 5 for completion work.

The SEM 5 well was left suspended until enough information from the other 2 wells was available to allow a decision on the future of the SEM 5 well. Following the drilling of SEM 4 and SEM 3, it was decided to complete the SEM 5 well. The well was completed and Rig 2 was released at 03:00 hours on the 11th April 2006. The actual well cost was US$16.952MM from an AFE of US$7.5MM including the cost of the rig skid and the completion.

Table 3.4 Development Drilling Summary

WELL ID	LICENSEE (Operator)	PPL / PDL	SPUD DATE	R.R. DATE	T.D. (m.MD)	FOOTAGE DRILLED (m)	RESULT	COST US$	TYPE OF SIDETRACK (GEOL / MECH)
IDT 22	OSPL	PDL 2	18/01/05	8/03/05	2,844	2,844	Oil & Gas	10,128,307	N/A
IDT 23	OSPL	PDL 2	18/04/05	7-8/06/05	2,620	2,620	Oil & Gas	14,501,439	Mechanical
SE Gobe 11	OSPL	PDL 4	04/03/05	17/05/05	2,265	2,265	Oil	16,272,023	N/A
Moran 11 ST1	OSPL	PDL 5	21/08/05	13/11/05	3,855	3,885	Oil	18,334,043	Geological
Moran 7 ST1	OSPL	PDL 5	03/12/05	04/01/06	3,318	3,318	Oil	8,589,246	Mechanical
SE Mananda 3	OSPL	PDL 2	11/07/05	26/05/06	2,855	2,855	Oil	18,672,664	NA
SE Mananda 4	OSPL	PDL 2	31/07/05	01/02/06	2,669	2,669	Oil	12,066,558	NA
SE Mananda 5	OSPL	PDL 2	15/08/05	11/04/05	2,542	2,542	Oil	16,915,975	NA
TOTALS						**22,998**		**115,480,225**	

3.5 PNG Petroleum Drilling History

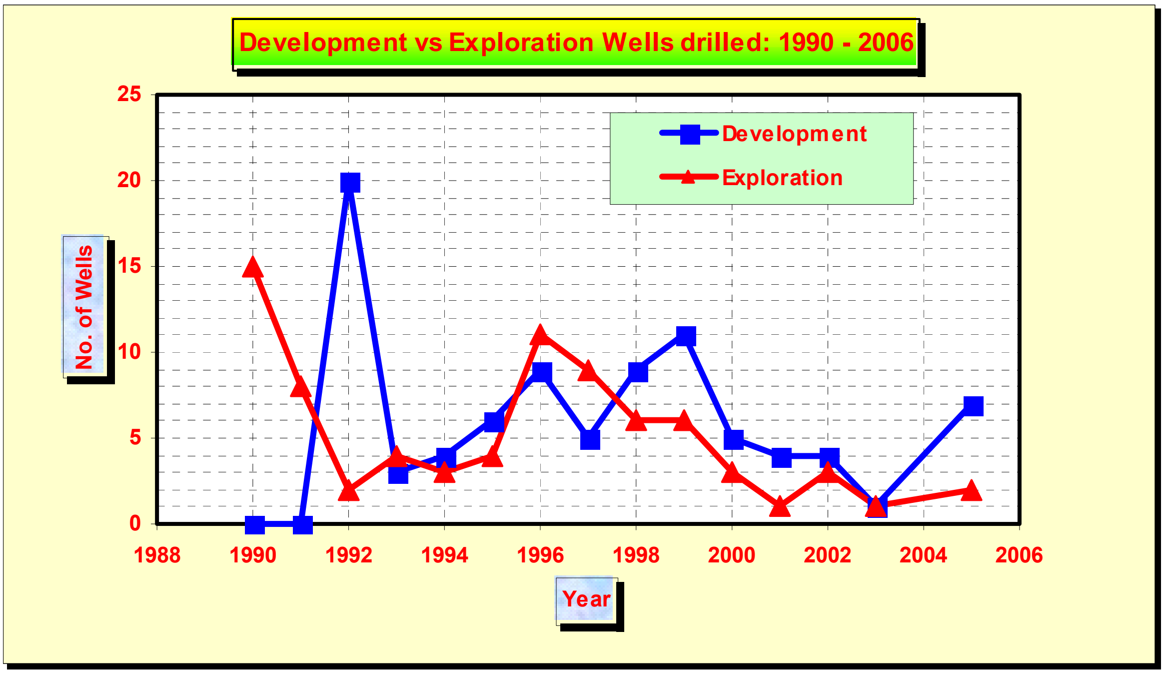
The Papuan Basin is currently the most explored and developed of the five petroleum basins in PNG. The Papuan Basin has had a total of ***290*** wells drilled to date, since the commencement of exploration in PNG. Except for the historic Marienberg well in the Sepik, all discoveries have been in the Papuan basin. **Table**

3.5 contains a summary of all the discoveries to-date (in the Papuan Basin) and **Figure 3.4** illustrates the number of wells drilled from 1995 to 2005.

Table 3.5: 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 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 / PPL 161	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 160	Santos	Bilip	2002	PPL 190	Santos	Oil	1	Gulf

Figure 3.4: Chart Showing Total Yearly Development & Exploration Wells



Section 4.0 FIELD DEVELOPMENT

4.1 Hides

During the year, Hides produced a total of 5101.846 MMSCF of gas. The total liquid production was 120,747.58 BBLs of condensate, which yielded 67,389.98 BBLs of naphtha, 22,819. 67 BBLs of diesel and 7,491.13 BBLs of residue.

GAS CONDENSATE:

The gas condensate is stored on site in tanks and used for feedstock in their Microstills.

NAPHTHA:

Naphtha is supplied to PJV and held in storage on their site. Some of it is "re-delivered", i.e. sold on to Gigara Development Corporation (GDC) a landowner company who on-sell it. Approximately 5590 BBLs of naphtha is sold to Porgera Joint Venture (PJV) and approximately 480 BBLs naphtha is sold to GDC on a monthly basis.

DIESEL:

Approximately 1500 BBLs of diesel was sold to GDC, 85 BBLs diesel sold to PJV and 90 BBLs diesel to Camp & Community. These numbers do vary due to road conditions, access and local "clan politics".

Camp and Community includes company vehicles, Police, Hospital (Ambulance) and Landowner vehicles on a gratis basis.

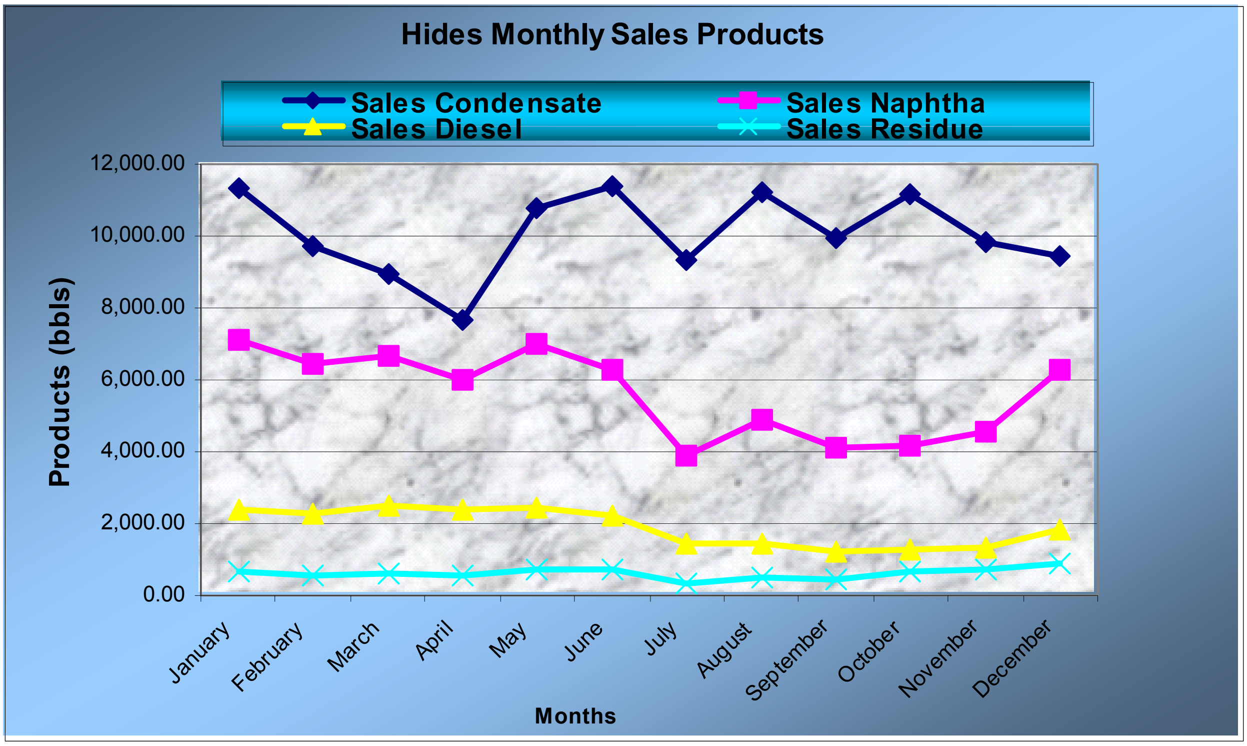
RESIDUE:

Residue is used to fire the Microstill furnaces and Waste Garbage Incinerator. Any excess is incinerated in a high temperature incinerator.

The Hides Gas plant's concern during the year was the shutdown of the processing gas plant during the Month of November for some days. This was due to the sabotage of a power pylon connecting the PJV gold mine and some maintenance carried out at the Microstills. Apart from this, the year's production was good compared to the previous year. Routine checks, preventative maintenance and maintenance to the micro-stills and other process equipment were on going throughout the year.

Pipeline inspections and pigging operations were also on going during the year.

Figure 4.0: Hides Monthly Liquid Production Graph



Section 5.0 PRODUCTION

Kutubu produced a total of 7,109,765 MBBLS in 2005 at an average daily production rate of 21,266 BOPD. The major concern during the year was the shutting in of all the Kutubu wells as well as Moran and Gobe fields in February due to storage limitations as a result of the delay in the next cargo loading.

Total **Moran oil** field production for 2005 was 6,190,641 BBL. Total gas produced from the Moran field was 17,012,967 MSCF. Oil production averaged at about 16,410 BOPD, which was an increase of 3,410 BOPD, compared to year 2004 as a result NW Moran field contribution. Oil production from NW Moran EPT was 237,227 BBL since it was brought online in September. On a monthly basis, NW Moran EPT produced 63,252 STBO, 78,6561 MSCF of gas and 116 BBL of water. Oil production averaged 2,108 STB/D.

NW Moran oil field produced at an average oil rate 2,108 STB/D with negligible water production, whilst it was on line. The well BHP was closely monitored and the off-take rate has been restricted to obtain a suitable rate of pressure decline. Some indications of slugging have been observed at the NW Moran well but these have not been significant enough to cause problems at the APF.
The EPT is planned to continue until an application for a development license is prepared.

Total oil production from the **Gobe** fields in 2005 was 3,808,136 BBL at an average rate of 10,775 BOPD. Total volume of gas produced was 13,265,096 MMSCF with Gobe Main and SE Gobe producing 22,363,173 MSCF. Oil production in Gobe was steady at around 11,000 BBL per month.
Gobe Main contributed a total of 1,120,927 BBL averaging at 3,071 BOPD and **South East Gobe (SEG)** produced a total of 2,687,209 BBL of oil averaging at 7,362 BOPD. The increase in production in PDL 4 compared to last year was attributed mainly to the 91 MMSCF per week flare approval for a four months trial period and continued swing well management. The flare consent was in force for its first full month. This gave the opportunity and flexibility to optimise some of the wells.

The total oil production for the year 2005 was 17,019,488 BBL at an average production rate of 46,628 BOPD. The monthly average production was approximately 1,418,295 BBL and a total of 139,540 MMSCF of associated gas was produced.
Tables 5.1 through to 5.5 and **Figures 5.1 through to 5.5** summaries the monthly and yearly figures for the Kutubu, Moran, Gobe Main South East Gobe and the Hides fields in 2005. **Table 5.6** shows the yearly oil and gas production and **Figure 5.7** shows the graph for the yearly oil and gas production since 1991. Furthermore, **Figure 5.6** shows the yearly production history and forecast.

5.1 Hides

Table 5.1: Hides Monthly Gas Production

	GAS		LIQUID			
MONTH	Total Production	Total sales	Condensate	Naphtha	Diesel	Residue
	(MMSCF)	(MMSCF)	(BBL)	(BBL)	(BBL)	(BBL)
January	465.229	465.229	11,329.22	7,121.37	2412.541	680.523
February	400.121	400.121	9,706.95	6,421.44	2293.461	551.675
March	441.028	441.028	8,940.04	6,681.48	2,514.45	626.298
April	387.918	387.918	7,658.08	6,005.02	2,376.81	542.661
May	445.198	445.198	10,804.29	7,019.37	2,432.72	709.614
June	438.772	438.772	11,372.46	6,259.23	2,246.59	739.975
July	353.992	353.992	9,344.28	3,883.43	1,429.56	317.458
August	478.048	478.048	11,204.83	4,898.27	1,460.13	521.533
September	427.741	427.741	9,961.94	4,133.06	1,229.44	471.365
October	465.471	465.471	11,151.36	4,163.05	1,281.13	687.7
November	342.824	342.824	9,844.32	4,545.11	1,326.75	746.40
December	455.504	455.504	9,429.82	6,259.15	1,816.10	895.933
TOTALS	5101.846	5101.846	116,230.10	67,389.98	22,819.67	7,491.13

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

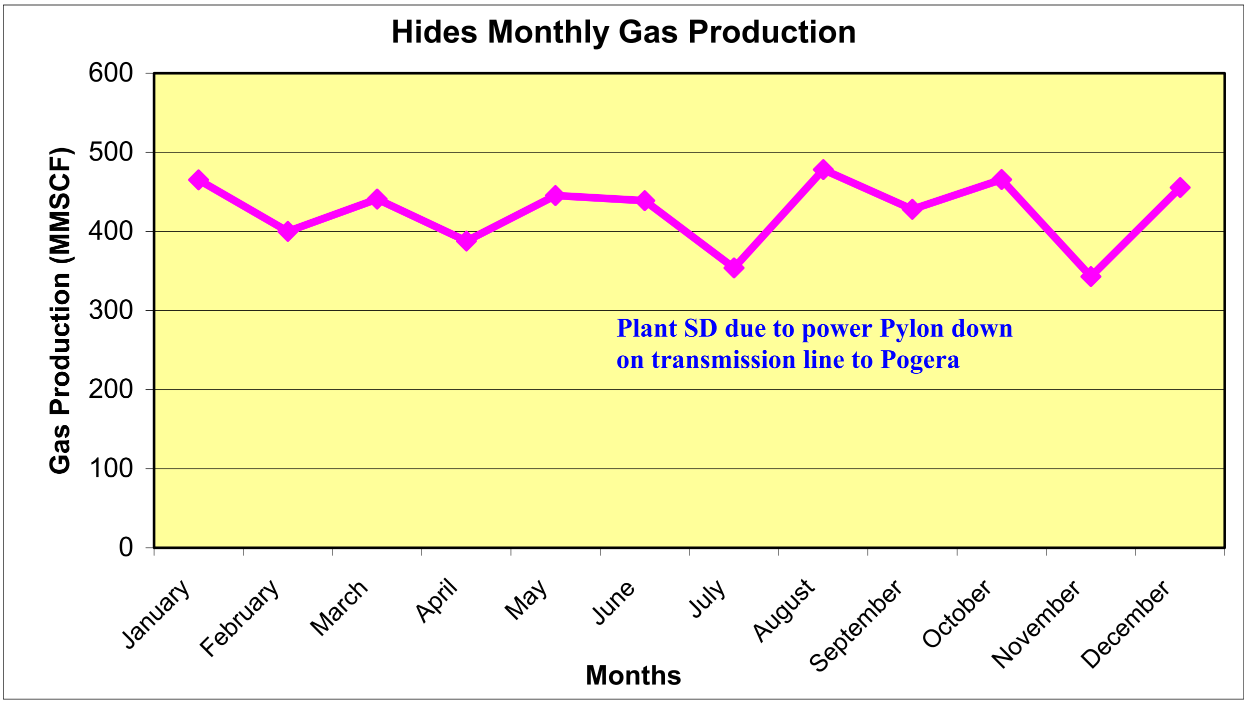


Figure 5.1: Hides Monthly Gas Production Graph

5.2 Kutubu

Table 5.2: Kutubu Monthly 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	594,041	7,711,307	289,834.028	871,170.503	19,163	248,752
FEBRUARY	224,439	3,547,759	290,060.177	874,571.769	8,016	126,706
MARCH	498,259	6,796,568	290,381.787	880,843.201	16,073	219,244
APRIL	631,631	8,038,238	291,186.968	889,581.172	21,054	267,941
MAY	664,347	8,086,728	291,851.315	897,667.900	21,431	260,862
JUNE	629,912	7,635,076	292,481.228	905,302.976	20,997	254,503
JULY	620,686	7,635,076	293,101.914	912,377.381	20,022	246,293
AUGUST	724,463	7,962,885	293,826.400	920,340.300	23,370	256,867
SEPTEMBER	634,079	7,322,532	294,460.500	927,662.800	21,136	244,084
OCTOBER	652,003	7,593,444	295,112.500	935,256.300	21,032	244,950
NOVEMBER	606,602	7,181,657	295,719.100	942,437.900	20,220	239,389
DECEMBER	629,303	7,387,551	295,415.800	938,847.100	20,300	238,308
YEARLY AVERAGE	592,480					
SUB-TOTALS						
YEARLY TOTALS	7,109,765					

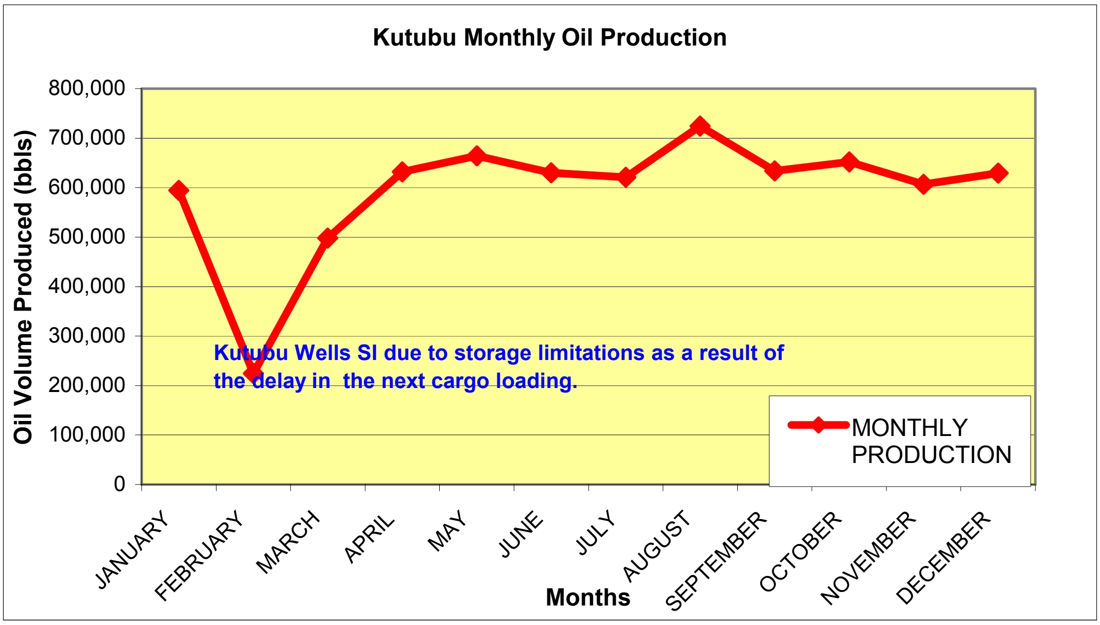


Figure 5.2: Kutubu Monthly Oil Production Graph

5.3 Gobe Main

Table 5.3: Gobe Main Monthly Production

	MONTHLY	MONTHLY	CUMULATIVE OIL	CUMULATIVE GAS	AVG. DAILY	AVG.DAILY
MONTH	OIL PRODUCTION	GAS PRODUCTION	PRODUCTION	PRODUCTION	OIL RATE	GAS RATE
	BBL	MSCF	BBL X 1000	MMSCF	BOPD	MSCFD
JANUARY	96,952	1,020,569	23,082.32	80,445.12	3,128	32,922
FEBRUARY	69,758	732,625	23,152.08	81,177.75	2,491	26,165
MARCH	104,913	1,001,494	23,256.99	82,179.24	3,384	32,306
APRIL	103,523	1,114,984	23,360.52	83,294.23	3,451	37,166
MAY	97,995	1,144,173	23,458.51	84,438.40	3,161	36,908
JUNE	97,335	932,183	23,555.85	85,370.58	3,244	39,933
JULY	93,549	1,197,999	23,649.40	86,602.27	3,017	38,645
AUGUST	95,027	1,186,274	23,766.04	89,338.02	3,911	49,235
SEPTEMBER	94,714	1,194,461	23,860.75	90,532.48	4,202	55,189
OCTOBER	89,660	1,190,368	23,952.00	91,887.95	4,057	52,212
NOVEMBER	88,448	1,303,187	24,043.24	93,243.42	3,747	54,710
DECEMBER	89,054	1,246,778	25,097.00	94,565.00	3,902	53,461
YEARLY AVERAGE	93,411	1,105,425				
SUB-TOTALS						
YEARLY TOTALS	1,031,873	13,265,096				

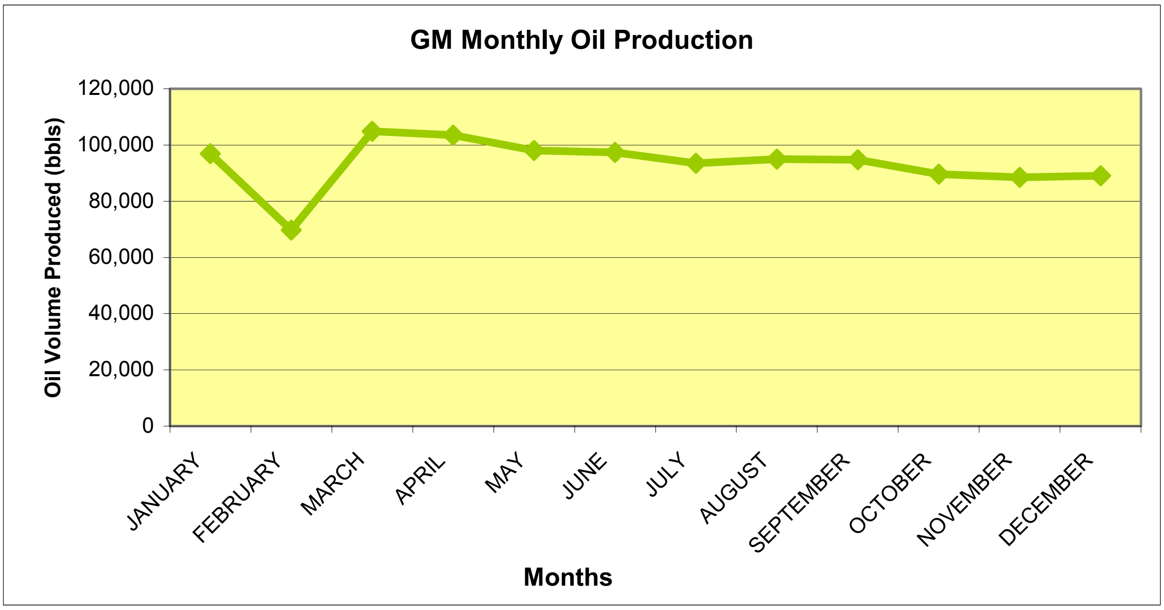


Figure 5.3: Gobe Main Monthly Production Graph

5.4 South East Gobe

Table 5.4: South East Gobe Monthly Production

MONTH	MONTHLY OIL PRODUCTION BBL	MONTHLY GAS PRODUCTION MSCF	CUMULATIVE OIL PRODUCTION BBL X 1000	CUMULATIVE GAS PRODUCTION MMSCF	AVG. DAILY OIL RATE BOPD	AVG.DAILY GAS RATE MSCFD
JANUARY	200,827	2,155,572	29,231.82	106,044.46	6,871	75,681
FEBRUARY	148,677	1,437,744	29,380.50	107,482.20	8,191	78,783
MARCH	191,186	1,847,915	29,571.69	109,330.12	8,161	79,597
APRIL	204,967	1,558,015	29,776.65	110,888.13	7,769	64,286
MAY	223,725	1,882,235	30,000.38	112,770.37	7,788	67,306
JUNE	228,354	1,857,067	30,228.73	114,627.43	8,650	67,169
JULY	244,151	1,908,523	30,472.89	116,488.35	8,470	68,964
AUGUST	264,437	2,028,845	30,740.01	121,320.87	9,021	72,150
SEPTEMBER	245,900	1,879,478	30,985.91	123,200.35	8,927	72,762
OCTOBER	255,169	1,954,162	31,228.24	125,194.57	8,857	72,456
NOVEMBER	234,820	1,917,690	31,470.57	127,188.79	8,787	76,590
DECEMBER	244,995	1,935,926	32,349.29	129,191.23	8,822	74,523
YEARLY AVERAGE	223,934	1,863,598				
SUB-TOTALS						
YEARLY TOTALS	2,687,209	22,363,173				

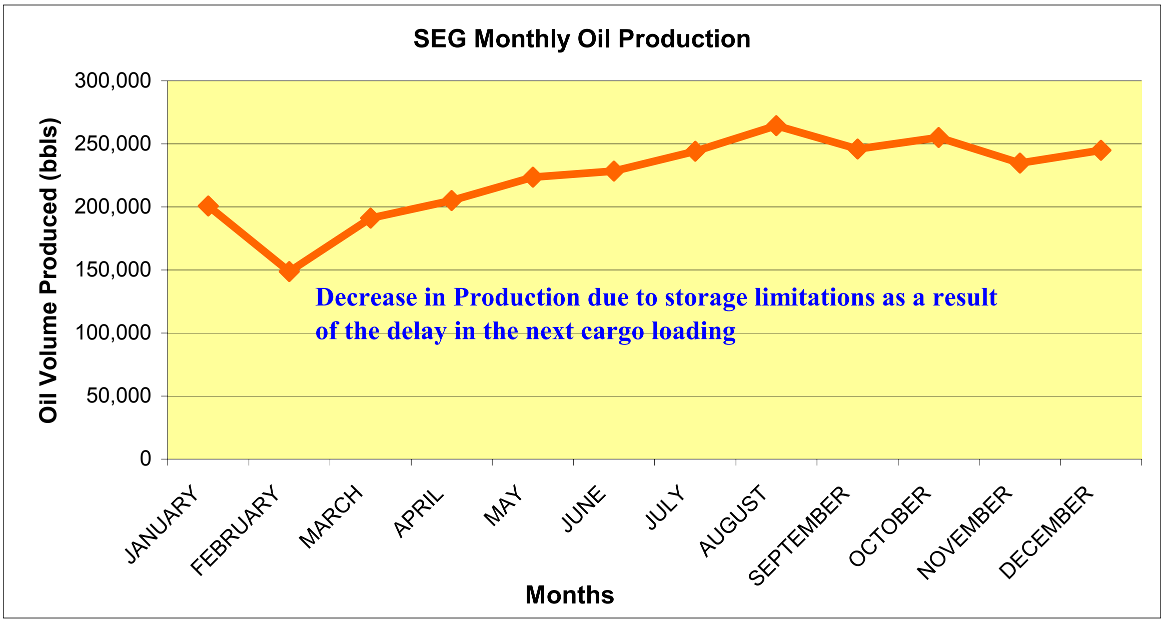


Figure 5.4: S.E. Gobe Monthly Oil Production Graph

5.5 Moran

Table 5.5: Moran Monthly 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	475,000	1,428,621	28,816.69	75,519.33	15,323	46,085
FEBRUARY	165,396	512,489	28,982.09	76,031.65	5,907	18,303
MARCH	404,557	1,032,395	29,387.96	77,063.99	13,050	33,303
APRIL	499,020	942,114	29,888.71	77,971.92	16,634	31,404
MAY	624,398	1,289,122	30,513.11	79,261.04	20,142	41,585
JUNE	581,494	1,412,689	31,094.60	80,673.73	19,383	47,090
JULY	461,388	1,215,136	31,555.99	81,888.87	14,883	39,198
AUGUST	579,643	1,576,280	32,135.63	83,465.15	18,698	50,848
SEPTEMBER	599,363	1,857,040	32,734.99	85,322.19	19,334	59,905
OCTOBER	623,092	1,935,871	33,358.08	87,172.93	20,100	62,447
NOVEMBER	577,162	1,895,516	33,935.24	89,068.45	18,618	61,146
DECEMBER	600,127	1,915,694	33,647.00	88,121.00	19,359	61,797
YEARLY AVERAGE	515,887	1,417,747				
SUB-TOTALS						
YEARLY TOTALS	6,190,641	17,012,967				

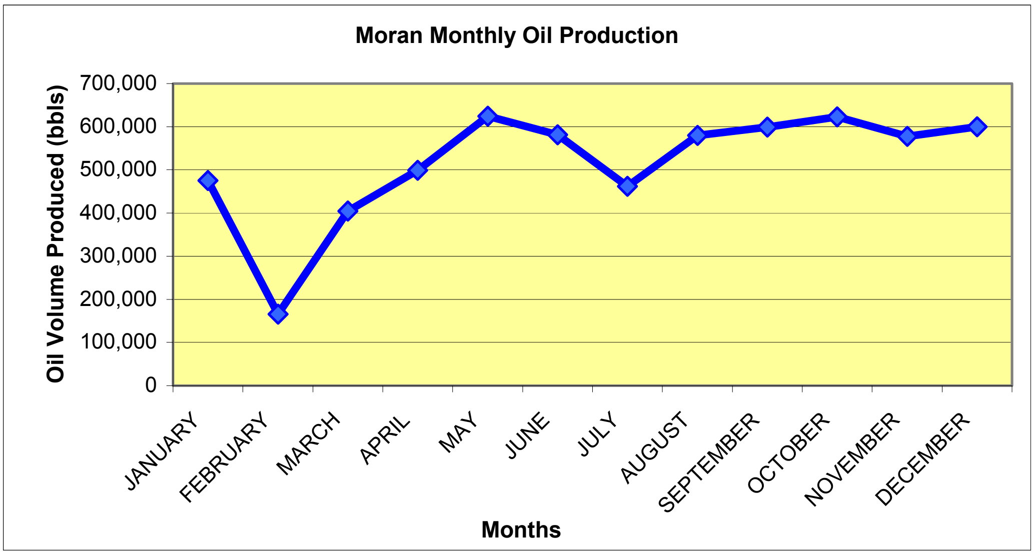
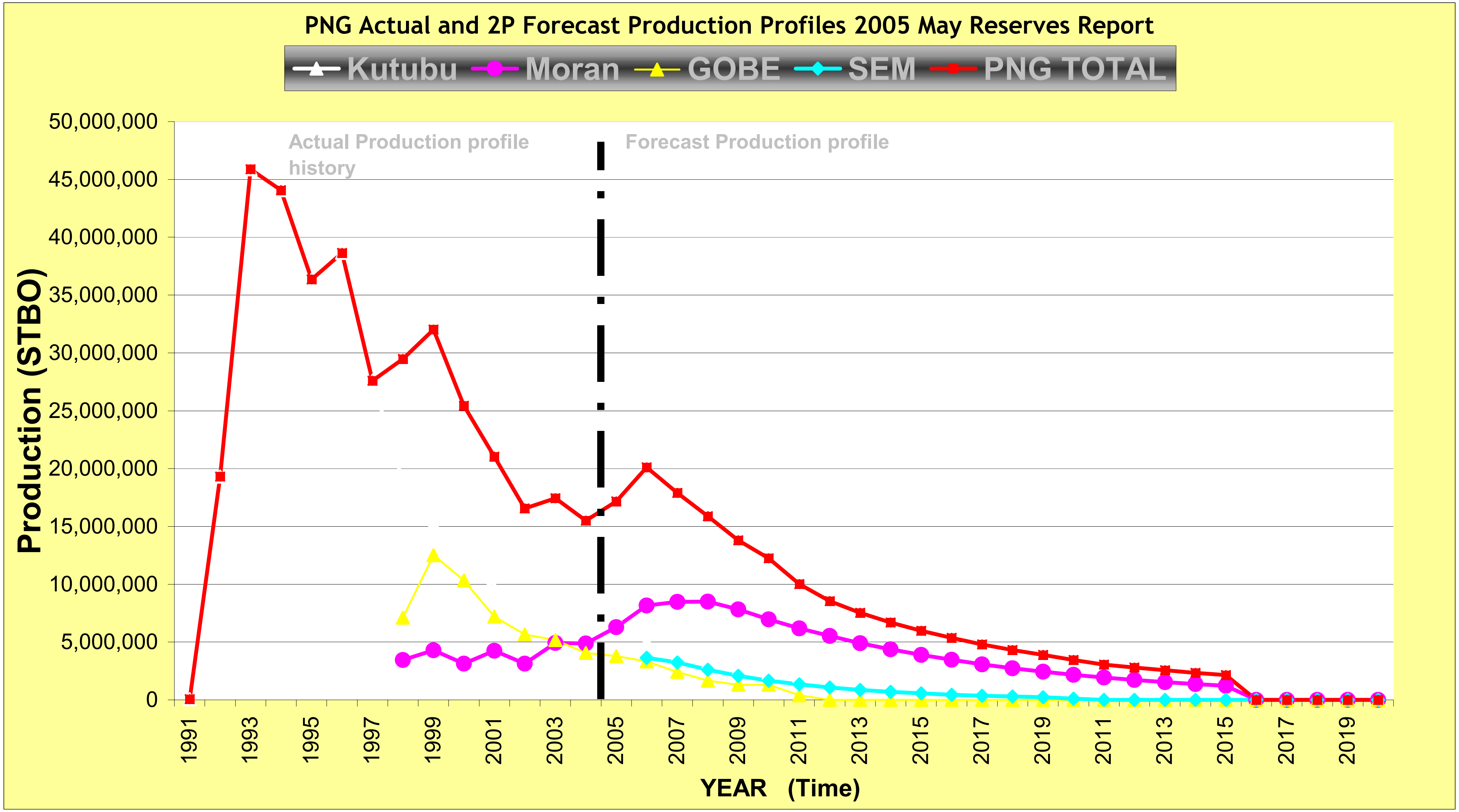


Figure 5.5: Moran Monthly Oil Production Graph

Figure 5.6: Yearly Oil Production Showing History and Forecast



5.6 Others

YEAR	KUTUBU YEARLY OIL PROD BBL	KUTUBU YEARLY GAS PROD. MSCF	GOBE MAIN YEARLY OIL PROD. BBL	GOBE MAIN YEARLY GAS PROD. MSCF	S. E. GOBE YEARLY OIL PROD. BBL	S. E. GOBE YEARLY GAS PROD. MSCF	NWM EPT YEARLY OIL PROD. BBL	NWM EPT YEARLY GAS PROD. MSCF	MORAN YEARLY OIL PROD. BBL	MORAN YEARLY GAS PROD MSCF	TOTAL OIL PRODUCTION BBL	TOTAL GAS PRODUCTION MSCF
1991	68,162	84,532									68,162	84,532
1992	19,314,212	16,951,949									19,314,212	16,951,949
1993	45,883,975	49,059,949									45,883,975	49,059,949
1994	44,077,868	58,666,246									44,077,868	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	18,926,771	69,562,381	3,568,005	8,568,296	3,539,421	6,718,805			3,445,286	6,403,723	29,479,483	91,253,205
1999	15,210,458	77,238,216	6,109,245	12,333,827	6,402,314	15,032,976			4,298,414	8,519,774	32,020,431	113,124,793
2000	11,985,875	77,528,038	5,497,312	11,665,081	4,827,260	16,112,863			3,124,070	7,048,093	25,434,517	112,354,075
2001	9,607,802	75,276,974	2,635,005	11,873,584	4,548,431	13,280,821			4,244,244	9,492,554	21,035,482	109,923,933
2002	7,759,851	77,897,708	1,961,814	11,488,765	3,697,018	12,788,514			3,144,086	8,120,984	16,562,769	110,295,971
2003	7,355,608	82,912,796	1,772,286	11,105,424	3,397,974	18,884,792			4,921,071	15,431,663	17,446,939	128,334,675
2004	6,552,222	84,791,755	1,446,375	12,125,889	2,621,193	21,378,237			4,874,683	17,899,235	15,494,473	136,195,116
2005	7,091,513	86,475,178	1,111,074	13,408,486	2,684,188	22,474,800	238,220	294,085	6,279,220	17,414,849	17,404,215	140,067,398
TOTAL. PROD.	**296,411,516** BBL	**949,933,774** MSCF	**24,101,116** BBL	**92,569,352** MSCF	**31,717,799** BBL	**126,671,808** MSCF	**238,220** BBL	**294,085** MSCF	**34,331,074** BBL	**90,330,875** MSCF	**386,799,725** BBL	**1,259,799,894** MSCF

Table 5.6: Yearly Oil and Gas Production since 1991

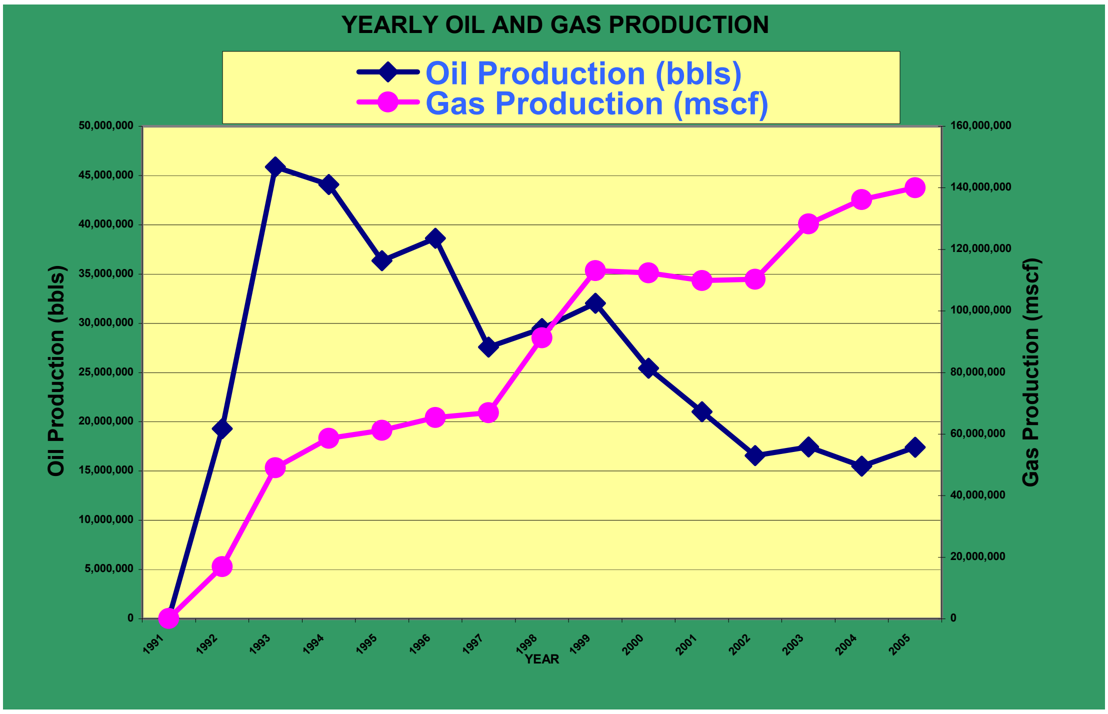


Figure 5.7: Yearly Oil and Gas Production since 1991

Section 6.0 SPECIAL PROJECTS

6.1 PNG GAS TO AUSTRALIA PROJECT

The PNG Gas Project seeks to develop certain of the gas fields of Papua New Guinea and transport a specification sales gas to customers in Australia through a 3,200 kilometer long pipeline down the east coast of Australia with spur lines to customers in the Northern Territory, and into South Australia. The concerned fields are located in the PNG highlands area and include gas reserves lying in whole or in part of the following fields: the Iagifu-Hedinia, South East Hedinia, Agogo and Usano oil and gas fields (collectively referred to as the Kutubu fields); the Gobe Main, South East Gobe, and Gobe 2X oil and gas fields (collectively known as the Gobe fields); the South East Mananda oil field (a satellite field adjacent to the Agogo field of the Kutubu fields); the Moran oil field, and the Hides gas field.

The Project proponents are ExxonMobil Inc, Oil Search Ltd, Nippon Oil Exploration Ltd., and the State-owned Mineral Resources Development Company.

It is envisaged that the Project will cost around US$ 2.2 billion for field development, and facility and pipeline construction in Papua New Guinea and about US$ 1.8 billion for pipeline construction and associated compression facilities in Australia.

The Project aims to produce around 6 trillion cubic feet of gas from which some 150 million barrels of condensates will be extracted, transported and sold through the existing Kutubu Project export pipeline that currently conveys crude oil to the Kumul Marine Terminal in the Gulf of Papua.

It is anticipated that revenues to the Government and other PNG stakeholders will amount to US$ 3.3 billion from taxation, royalty and development levies and about US$ 1.1 billion from equity interests before the deduction of equity acquisition costs.

The Government intends to participate in the Project. It will achieve this through exercising its option to buy at sunk costs a 22.5% interest in the large Hides gas field. Together with its present 20.5% interest in the Moran field, this will earn the Government a net 11.2389% interest in the overall Project.

The Project preparations have involved: the completion of front end engineering and design (FEED) works for both the PNG field developments, facilities and pipelines as well as the Australian pipelines; marketing of the gas to customers; definition of commercial arrangements amongst the participating stakeholders; re-certification of reserves; field development planning; pipeline and facility detailed design. Furthermore, the firming up of the financing arrangements, including due diligence of the project by the Asian Development Bank and the European Investment Bank in respect of the Government's request for financial assistance;

finalization of environmental submissions to the Government; preparation of arrangements to negotiate landowner benefit sharing agreements; identification of licensing and regulatory approval requirements, including third party access arrangements to facilities and pipelines; revision of project costs; and planning of project management, contracting and procurement processes. Amongst these, the conclusion of arrangements with customers and the finalization of the benefits sharing arrangements with the landowners are vital to the Project's success. With regard to the latter, it is highly unlikely that customers will finalize their purchases without the confidence that the landowner arrangements are well formulated and durable and that the likelihood of the interruption of gas supply is voided. Whilst minor interruptions to crude oil production have been manageable, interruptions in gas supply would be far less tolerable.

A timetable was set for project sanction by April/May 2006, and the commencement of construction by September 2006. First gas sales to customers are scheduled for mid-2009. The FEED was to be concluded by the end of 2005.

Market

The marketing of the gas has been led by the operator, Esso Highlands Ltd. and customers have been identified with demand of 180-190 PJ per annum who have variously agreed term sheets and gas sales agreements.

The definition of the market has been a constant issue during the promotion of the Project in recent years, which only diminished from being a project impediment when the project proponents committed to the Front End Engineering and Design (FEED) in October 2004. On two occasions before (late 2002 and mid 2003), the project experienced a run-up in potential customers only to be followed by a flight of customers as no initiative was taken at those times to commence the FEED.

To cater for future demand, including demand growth in Australia and domestic utilization projects, the pipeline system as conceived will be capable of transmitting up to 1300 MMCFD natural gas through the onshore PNG section, from Kutubu to Kopi, with additional investments in compression and control facilities. However, due to constraints in the pipeline section across the Torres Strait, ultimate transmission of gas to Australia will be limited to 800 MMCFD.

The project faces considerable challenges and much work remains to be done. Whilst project sanction by the proponents is now time-tabled for August 2006 and subsequent financial close anticipated November/December 2006, it does seem that a tremendous effort would need to be made on aspects of project preparation to meet such targets. However, for first gas sales to be achieved by 3Q 2009 little slippage can be afforded and construction would need to commence in 1Q 2007.

Whilst Esso Highlands as Project operator has undertaken most diligent marketing work and customers have now been amassed to satisfy the threshold and foundation volumes required for the Project, up until such time as the commitments are finalised in binding contracts for supply and delivery, will there be certainty of the market uptake.

Resource Base

It is important that while the envisaged development of certain of PNG's natural gas resources is portrayed as a singular and finite Project, sight is not lost of the fact that this initial large-scale gas development will lay the foundations for the development of other discovered gas fields and for fields expected to be discovered, but not yet discovered. For instance, with the PNG gas project realising market off take of 215 PJ/a (529 MMSCFD), some 4.786 TCF of gas would be sold over a period of 20 years from wellhead production of 5.580 TCF of raw gas. With estimated 3P recoverable reserves of 25 TCF, subject to the proving up of the gas fields and their reserves by delineation, this rate of gas production could endure for 91 years. If as conjectured the ultimate recoverable gas resource potential of PNG is of the order of ~50 TCF, clearly there could be gas production at these rates well into the next century and beyond.

6.2 LICENSING ROUND

In September 2005, the Minister for Petroleum and Energy officially announced the reservation of certain blocks of the offshore area. It is planned that these blocks will be subject to a formal invitation under the Oil and Gas Act for applications as part of a forthcoming licensing round towards the end of 2006/early 2007.

This follows the introduction by the Government of reduced tax rate for "incentive rate petroleum operations" meaning petroleum operations arising from a petroleum prospecting licence granted during the period 1st January 2003 to 31st December 2007 and in respect of which a Petroleum Development Licence has been granted on or before 31st December 2017. The rate of tax in respect of income from incentive rate petroleum operations is just 30% of the 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 1st 2001 and 45% for projects thereafter.

The Government's objective is to offer the petroleum industry access and the opportunity to explore the hydrocarbon potential of PNG. It is also the Government's intention to actively encourage and work together with new explorers who are interested in entering into one of the most prospective, but still under explored, areas of Papua New Guinea.

To date exploration in the offshore area of PNG has been sporadic and mainly focused in the shallower waters of the Gulf of Papua with only several small sub-commercial gas and gas condensate discoveries being made over the last 30 years as a result of the few exploration wells drilled. Despite limited well control and scarcity of seismic data, the onshore, shallow and deepwater offshore areas offer a frontier region opportunity with a number of large structures capable of holding significant volumes of hydrocarbons.

A new major regional study based upon new data has been conducted in the offshore areas and has identified a variety of established and a host of new Palaeozoic to Recent play types. Geological conditions that have resulted in a number of the onshore discoveries are also predicted to be also present.
A new and possibly thick Permian petroleum system similar to the hydrocarbon producing provinces in Eastern Indonesia has also been recognised, significantly improving the prospectivity and questioning previously established ideas about the area. New exploration targets possibly sourced by a variety of hydrocarbon-prone source rocks have been identified in many areas some of which are suitable for drilling by companies active in this region.

Early in 2006 a major seismic contractor will conduct a large non-exclusive survey in areas not previously covered by seismic data under a scientific consent provided by the Government. This seismic survey is planned for 12,000kms and will take about four months. A non-exclusive seismic survey has never been undertaken in PNG before, despite such surveys becoming increasingly important on a global scale in key exploration areas. The benefit is that the contractors, in addition to oil companies, active in the area take the exploration risk and thereby fast-track the exploration cycle by initially providing a larger seismic data coverage. This data will be marketed worldwide to any interested oil company in late 2006 focusing on the acreages. The intention of the long application period and preparation of data packages is to allow new explorers the chance to familiarise themselves with the geology, data and the new attractive fiscal terms offered in Papua New Guinea

Many of the areas considered for the 2006 release have never been analysed by any petroleum prospecting licensees and as such are true frontier areas with unknown potential.

It is anticipated that the licensing round will open in late third quarter 2006 and that invitation should close second quarter 2007, and the announcements would be made on the successful applicants.

6.3 NAPANAPA OIL REFINERY

General Overview

The NapaNapa oil refinery operated by InterOil Limited is the first downstream petroleum project to have been granted a Petroleum Processing Facility License (PPFL) by the PNG Government in February 2000. It is located 4km across the eastern side of Port Moresby Harbour. On January 31st, 2005, the NapaNapa refinery was formally completed following vigorous reliability and performance testing.

Design Configuration

The refinery is rated to process 32,500 BOPD. The design configuration uses light sweet crudes such as the Kutubu crudes, to produce the following refined products:

- Propane;
- Butane;
- Light, medium and heavy naptha
- Jet fuel (kerosene) and gasoline;
- Diesel, and marine diesel; and low sulfur waxy residue

The reforming unit converts heavy naptha into reformate. The reformate is then blended with butane and light naptha to produce gasoline. The unit is capable of processing 3,500 BBLs naptha per day.
In 2005, the yield of diesel, gasoline and jet fuel accounted for 57% of the refinery's output.

Crude Supply

There were eight different crude feedstocks including the Kutubu crude processed as part of the refinery's crude optimization program in 2005. The 2005 average daily crude through the refinery was 20,655 BBLs per day which is only 63.4% of its normal capacity.

Marketing

PNG remains the principal market for the refinery products with the exception of naptha and low sulfur waxy residue. Naptha is exported to the Asian market in two grades, the light naptha and mixed naptha. These are then utilised in petrochemical feedstocks.
In harmony with the 30-year project agreement, the Government is to ensure all domestic distributors purchase their refined petroleum products from the refinery. For each refined product produced and sold locally, the import parity price is calculated by adding the costs that would typically be incurred to import such a product to the average posted price for such a product in Singapore as reported by Platts. The costs that are added to the reported Platts' price include insurance and freight costs, landing charges, losses incurred in the transportation of refined products, demurrage and taxes.

6.4 ASSET DATABASE PROJECT

The Asset Data Base (Asset DB) Project is an incentive of the Gas Development and Technical Assistance Fund provided by the World Bank to properly manage and safe-guard more than 70,000 petroleum data in the Department of Petroleum & Energy's physical repositories. The project commenced in June 2002 and lapses at the end of September 2006.

The project utilises a highly specialised petroleum asset management software, known as the AssetDB to integrate and consolidate different databases and physical repositories within the Department, into a single and centrally located database. AssetDB is a physical records management software package designed by Schlumberger Oil Company to help oil companies manage their Exploration and Production (E&P) physical records (data). This is intended to enhance efficiency in management and quality control of the data contained therein.

The project is envisioned to assist in the promotion of PNG's potential in the Oil and Gas Industry by allowing public access to the country's million dollar petroleum data and potential (acreage) on the World Wide Web. It includes establishing an integrated DBMS using various geological, database and internet technologies. Since its inception the project has embarked on bar coding and populating the database with records of all physical data types. This will be followed by data transcription of all physical data sets to electronic format, which will be made available for public referencing via web interface, and this will be known as the "Decision Point". This *Decision Point* will be for purposes such as enticing potential foreign oil companies to invest in the oil and gas industry in the country.
AssetDB Project has three phases. In the order of priority:

- Phase 1 include bar coding of all petroleum related hard copy reports exiting in the Petroleum Division;
- Phase 2 include all hard reports to be converted to electronic documents and;
- Phase 3 include displaying PNG petroleum data on the World Wide Web.

Since the Project started mid-2002, twelve geoscientists have been variously engaged in the first phase of the project as data entry operators. To date just four remain and continue working on the project.
It is estimated that of the 70,000 petroleum data that exists in the Petroleum Division, 32,000 have been accounted for and recorded into the AssetDB. The data entry consultants are currently populating the database with the remaining reports and anticipated completion of the task towards the end of August 2006.

Section 7.0 RESERVES

All the petroleum reserves discovered to date are located in the Papuan Basin, both onshore and offshore. The table below provides an update on the oil reserves figures for PNG.

Table 7.1: PNG Oil Reserves

Field	Category	OOIP	Recovery Factor	Ultimate Recovery	Cum. Oil Prod as Of DEC 2005	Remaining Reserves
		MMSTB		MMSTB	MMSTB	MMSTB
Kutubu	1P		0.537	321.14	296.33	24.81
	2P		0.558	333.715		37.385
	3P	598.482	0.587	351.597		55.267
Moran	1P	187.047	0.256	89.956	34.624	55.332
	2P	251.713	0.342	120.134		85.51
	3P	351.525	0.426	149.925		115.301
SE Gobe	1P		0.261	34.117	31.727	2.39
	2P		0.299	39.132		7.405
	3P	130.9	0.334	43.75		12.023
Gobe Main	1P		0.298	24.877	24.107	0.77
	2P		0.32	26.908		2.801
	3P	83.5	0.34	28.366		4.259
SE Mananda	1P	39.6	0.105	8.139		8.139
	2P	56.7	0.267	20.748		20.748
	3P	77.7	0.418	32.48		32.48

NB. Saunders field within PDL 4 is now shut in due to limited production of crude oil. Cumulative production from this field is 24 000 BBLs.

7.1 Kutubu Reservoir Engineering (PDL 2)

Reservoir engineering work in 2005 was mainly aimed towards identifying oil pockets around the Kutubu field. This year saw the drilling of IDT 22 and 23 wells respectively to undertake this objective, as well as the re-entering of IDT 10 to meet these objectives.

IDT 22 and 23 (including its sidetracks) were able to discover more reserves in the Toro sands while IDT 10 found the Iagifu sands to be oil bearing. Further well test analysis of this well deemed it to be in a separate compartment with no pressure support from an aquifer or initial gas cap. This was confirmed by the increasing gas production from the well.

Some planned studies and evaluation work using the MPLT (Memory Production Logging Tool) and MPNN (Memory Production Neutron-Neutron) was carried out and identified candidate wells within the Kutubu field that may require well work to target bypassed oil bearing sands. This work was carried out and although positive results were achieved, more work is now being carried out to determine whether or not the potential rewards will justify the work-overs that will surely need to be undertaken to access these reserves.

The chart below illustrates the production for Kutubu in terms of the forecast and actual rates. It clearly demonstrates that actual production is still exceeding the forecasts due to the work plans the operator has undertaken to arrest a steep decline in reserves and thus oil rates achieved.

Figure 7.1(a): Kutubu Reserves Forecast (2P) and Actual Rates

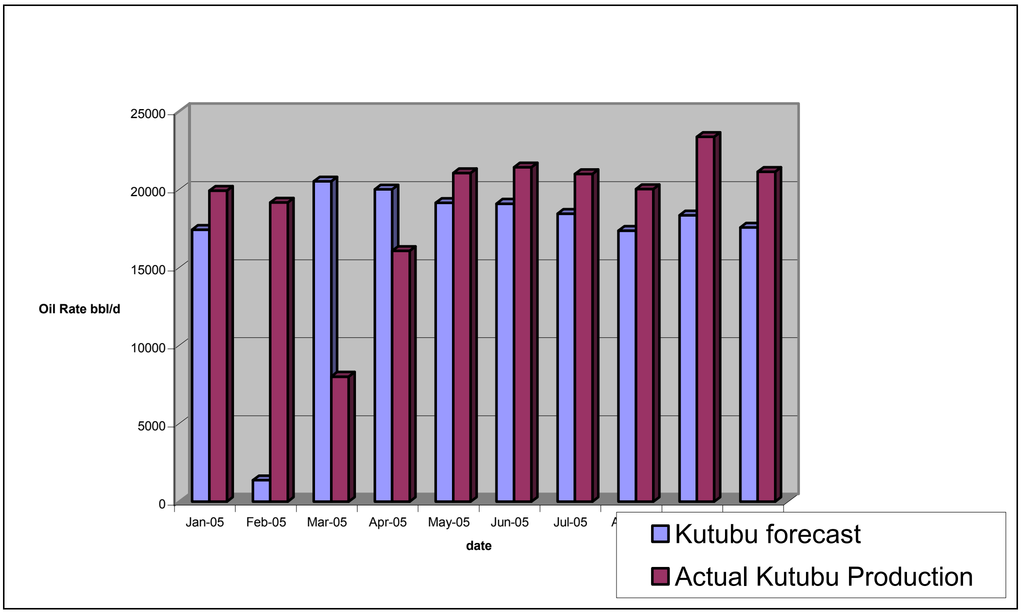
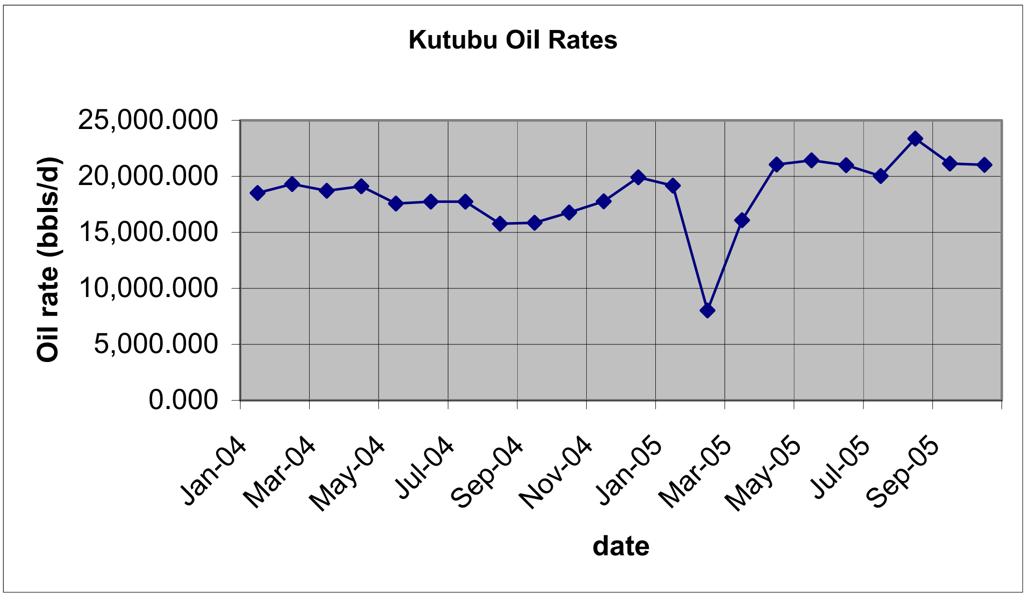


Figure 7.1(b): Kutubu Oil Rates for 2004 and 2005



The graph above shows the production rates achieved for Kutubu in 2004 though to 2005. As can be seen the increased work to arrest a steep oil rate decline has meant that the average rates for 2004 and 2005 are 17,900 BBLs/D and 19,200 BBLs/D respectively. The sharp drop in February 2005 was due to mooring problems encountered at the SPM at the Marine terminal.

7.2 Gobe Reservoir Engineering (PDL 4)

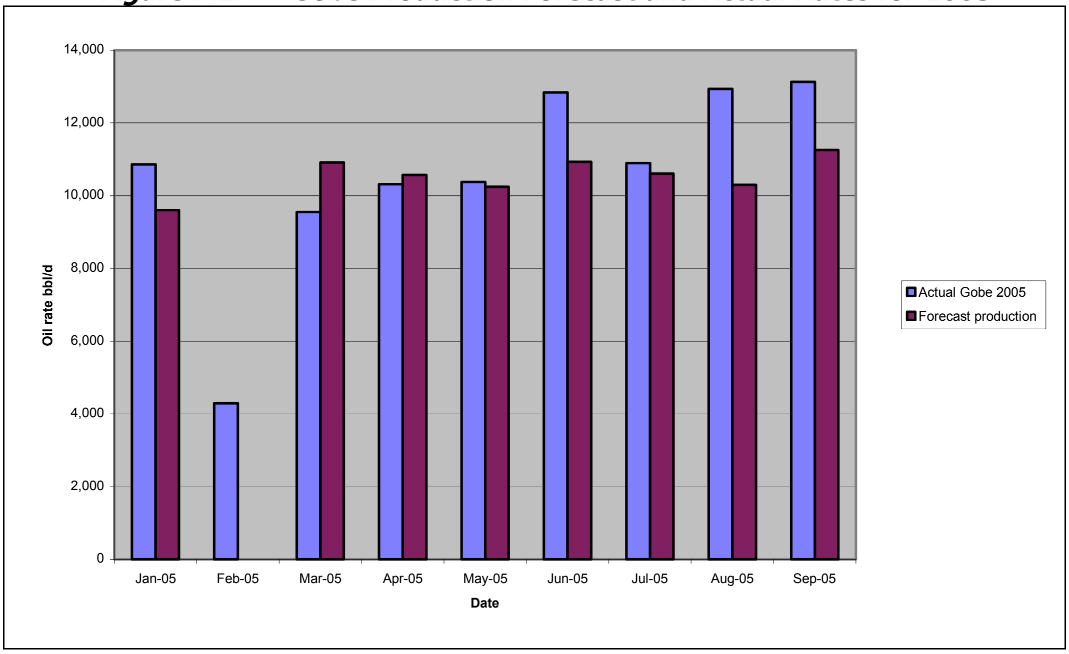
Gobe reservoir engineering work for 2005 has been limited mainly to swing well optimisation and the drilling of new wells to locate more oil reserves. The operator requested approval from the DPE for a four-month period to increase gas flare rates from the approved 3MMSCFD to 13MMSCFD. This increase in the flare consent was shown to increase the production rates attained for the field.

SEG 11 was drilled in 2005 and successfully perforated in the oil filled Upper and Lower Iagifu. This well is a constant producer.
The small satellite field, the Saunders field has been shut in for an extended period after a cumulative production of only 24,000BBLs.

The main study carried out this year was the swing well program where gauges were used to gather the FLP and Tubing head pressure data on selected wells during flowing and shut in periods so that this data could be used to optimise the swing well cycles for these wells.

The figure below represents the oil rates achieved for the Gobe field in 2005. As can be seen the forecast production rates were higher than the actual production rates attained.

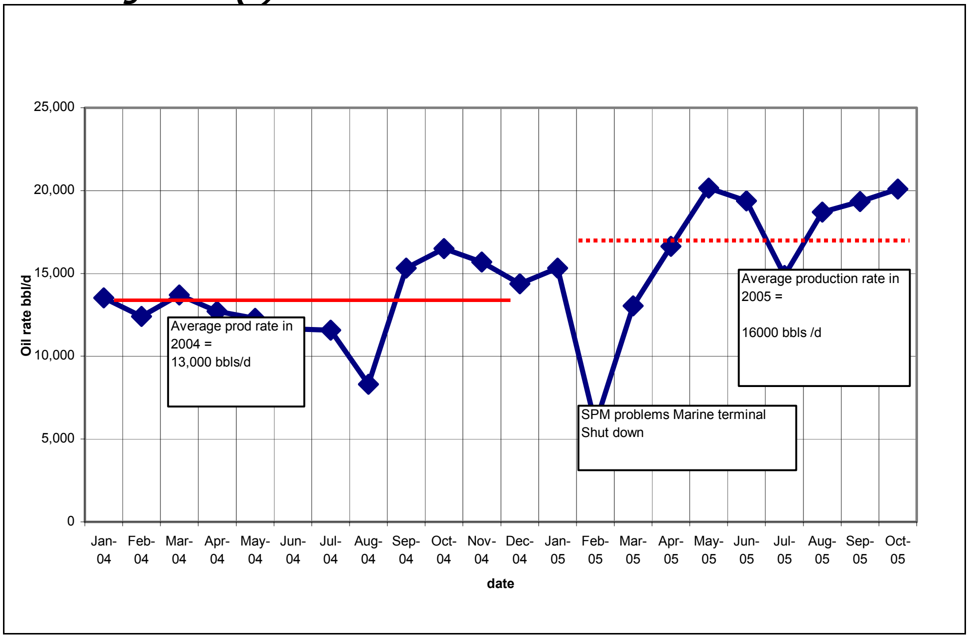
Figure 7.2: Gobe Production Forecast and Actual Rates for 2005



7.3 Moran Reservoir Engineering (PDL 5)

In 2005 Moran gas injection rates optimised due to the Moran compressor upgrades. The compressor upgrades as well as the use of the Temporary Production system on Moran 9 saw increased production rates from the field. A comparison between 2004 and 2005 production rates for the Moran field saw an improved production rate, mainly due to increased gas injection as shown below.

Figure 7.3(a): Moran Production Rates for 2004-2005

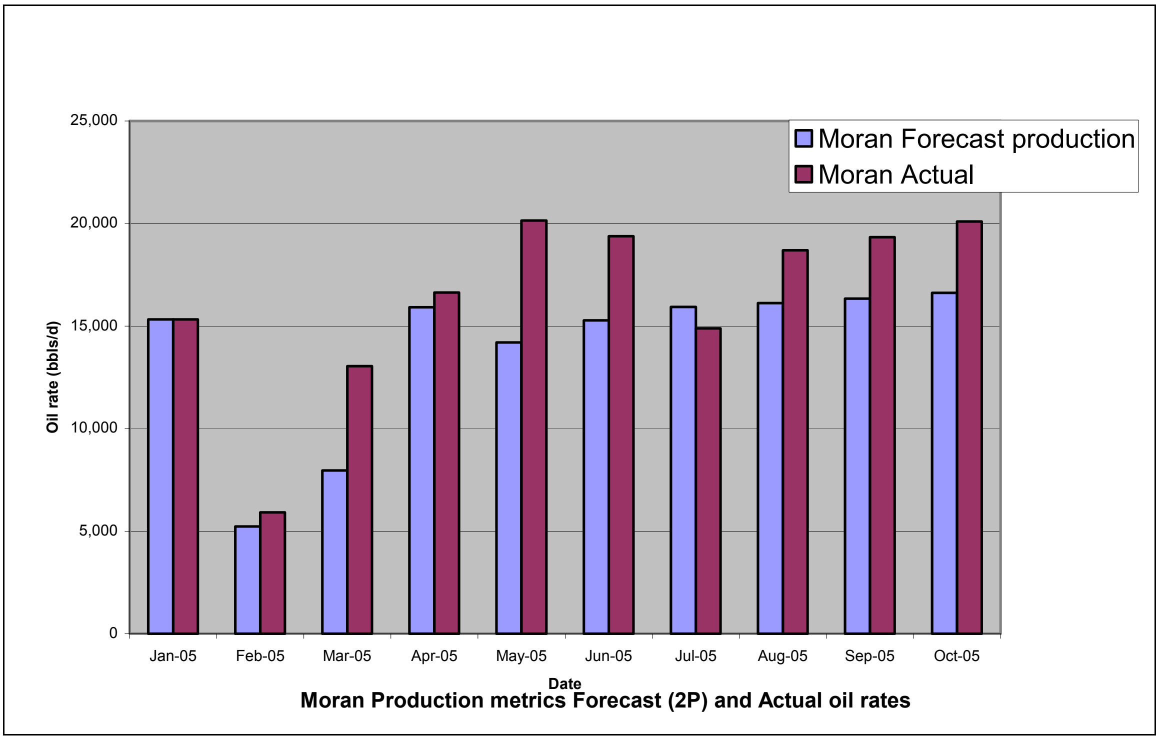


Also contributing to good production this year was the use of the EPT line that helped alleviate backpressure on the Moran wells and also production received this year (September) from NW Moran.
The decrease in production this year was mainly caused by reduced production due to bad weather at the SPM. Hydrate problems on Moran 2 well also affected production.
History matching and reservoir simulation modeling work have been ongoing this year in an attempt to obtain a better working modeling for this field.

Moran 10 was brought online this year with good production rates from the well until increased gas production from the well resulted in the well being choked back. This occurrence was predicted by the Moran reservoir simulation model.

The main studies undertaken in 2005 for Moran were production through the Temporary Production facility on Moran 9, Agogo Gas Deliverability studies for Moran Gas injection and the injection tracer work that was carried to show whether the gas being injected into the Moran field was reaching the planned targets.

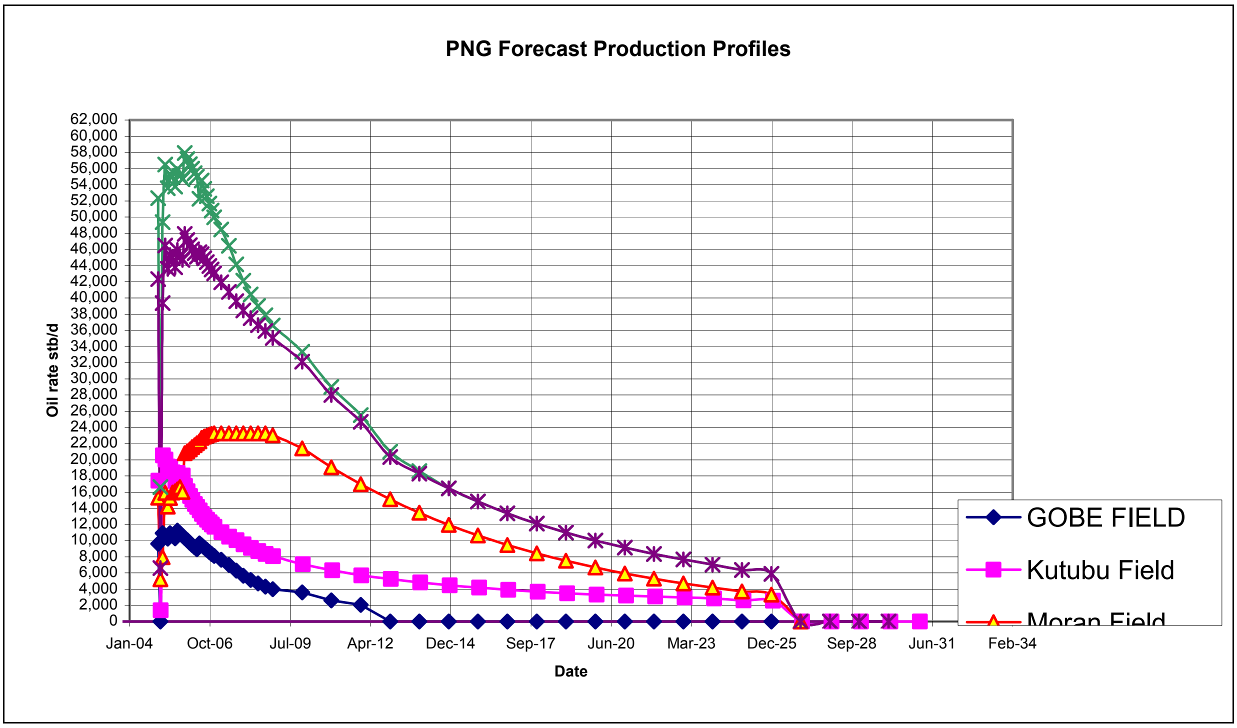
Figure 7.3(b): Moran forecast and actual production rates



7.4 SE Mananda (PDL 2)

South East Mananda was planned to be on line in August of 2005 however to date the field is still in its construction stages. The graph below shows the additional forecast production that may be attained for PNG once SE Mananda is on production. The additional oil rates will be around 10,000BOPD (2P).

Figure 7.4: Total PNG Forecast Production Profile



7.5 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 ALSO refined on site and sold locally. Full field development of Hides and other fields are contingent upon the viability of markets as envisaged gas export projects such as the PNG Gas Project are developed. **Table 7.2** gives a summary of all known gas fields.

Table 7.2: PNG Gas Fields

						Gas Reserves			Condensate Reserves		
Field	**Discov. Year**	**Type**	**STOIIP MMBO**	**STCIIP MMBO**	**GIIP BCF**	**1P BCF**	**2P BCF**	**3P BCF**	**1P MMB**	**2P MMB**	**3P MMB**
Pandora	1988	Gas	-	-	1,110	511	644	893	-	-	-
Pasca		Gas	-	29	435	-	160		-	6	-
Uramu	1968	Gas	-	-	178	-	92	122	-	-	-
Kimu	1999	Gas	-	-	4	-	3		-	-	-
Barikewa	1958	Gas	-	-	759	-	605	692	-	-	-
Iehi	1960	Gas	-	-	104	-	11	72	-	-	-
Bwata	1960	Gas/Cond	-	-	139	48	66	128	-	-	-
Gobe	1992		257	-	708	-	-	476	-	-	-
Kutubu	1986		552	-	2,166	-	-	1,522	-	-	-
Moran	1996		259	-	539	147	219	377	-	-	-
SEMananda	1991	Oil/Gas	84	-	307	-	-	221	-	-	-
Angore	1990	Gas/Cond	-	100	6,951	-	3,328	5,881	-	5	33
Hides	1987	Gas/Cond	-	182	9,584	3814	5,371	7,513	57	101	300
Juha	1983	Gas/Cond	-	269	5,293	638	1,536	3,805	32	38	90
Elevala	1990	Gas/Cond	-	35	611	-	433	526	-	3	15
Ketu	1991	Gas/Cond	-		704	-	18	585	-	-	16
Pnyang	1990	Gas/Cond	-	23	3,439	-	1,160	2,554	-	9	16
TOTAL			**1,152**	**638**	**33,031**	**5,158**	**13,646**	**25,367**	**89**	**162**	**470**

7.6 Forecast Production Profiles

The figure below represents forecast oil production from 2005 to the end of field life for the current producing fields – Kutubu, Moran and Gobe.

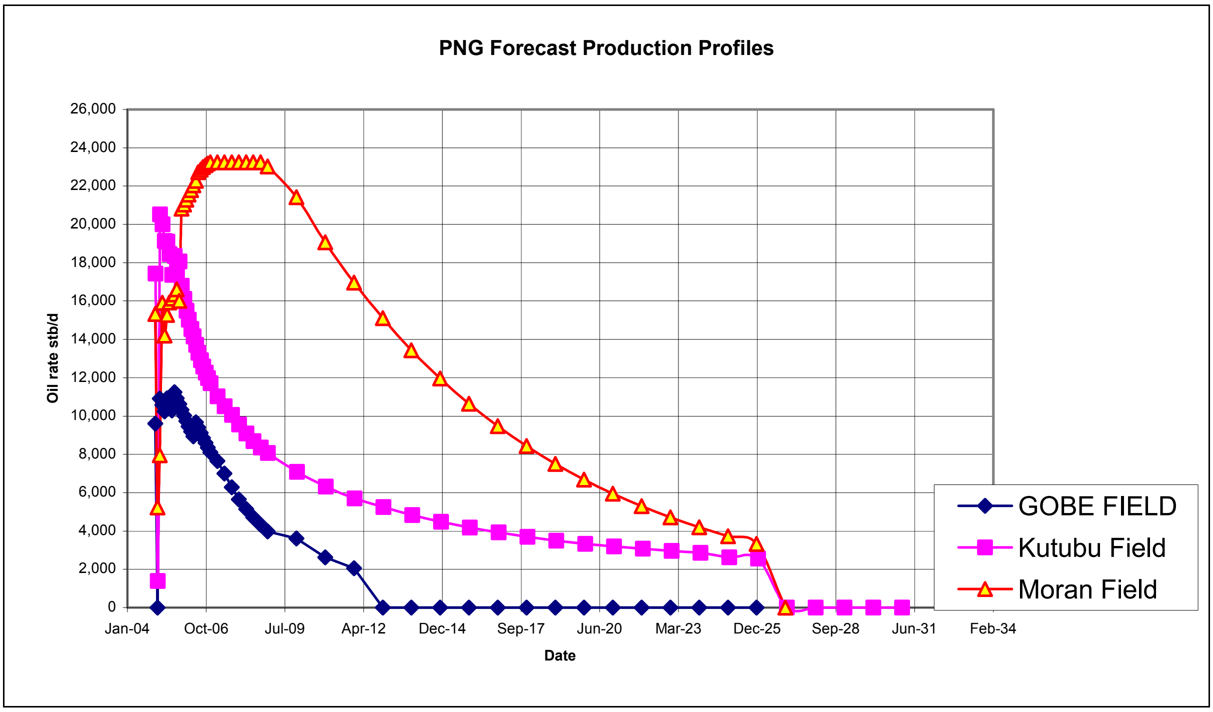
The Kutubu curve shows a classic hyperbolic decline only arrested from steeper decline by the Operator’s work programs which included production from new pool limits in the Iagifu sands and more efficient well optimisation work.

The Gobe field is on a steeper decline as can be expected with Gobe Main nearing its expected field life and economic limits.

Moran oil field is expected to attain its plateau production rates in October 2006 with increased gas injection rates and planned development wells to be drilled.

The graph displays the expected production declines for the Kutubu, Gobe and Moran fields.

Figure 7.5: Forecast Oil Production



Section 8.0 POLICY

The following are some of the general policy activities undertaken for the year 2005:

8.1 White Paper on Downstream Processing of PNG Gas

The White Paper on Downstream Petroleum Processing of PNG Gas presents the Government's intention to encourage and promote downstream petroleum activities in the country. This is aligned with the Government's overall desire of encouraging export-based industries and the Medium Term Development Strategy (MTDS).

The policy sets out three interconnected strategies.
First strategy is to encourage the development of the PNG Gas Project. This will see the development of gas reserves in the central highlands of PNG and transportation via an export pipeline to customers in Australia. The project will be the largest commercial investment in PNG and a catalyst for further commercialisation of gas resources.
Second strategy is to ensure the PNG Gas Project facilitates the development of the domestic processing industries that utilises gas as a feedstock. This may not be restricted to LPG fractionation, methanol, di-methyl ether (DME), ammonia, urea, synthetics and LNG production.
The *third strategy* is to expand gas fired electricity.

8.2 Fiscal Incentives

The Policy/Economics Branch played a significant role in the Government's decision to introduce the new fiscal incentives towards the end of 2002. The incentives included reduction of corporate tax from the standard rates of 50% (for projects developed before 2001 and 45% for projects developed after 2001) to 30% and the complete removal of Additional Profit Tax (APT). The incentives are effective for a five-year period, i.e., from 1 January 2003 to 31 December 2007. For companies to qualify for the incentives they must apply for, and be awarded a PPL in that five-year period, and that any discoveries emanating from these licenses must be developed on or before 2017.

Since the introduction of the fiscal incentives, the Policy Branch has been actively participating in the promotion of the fiscal incentives at various conferences and exhibitions such as AAPG, APPEA and the Asia Upstream Conference. Articles have also been written on these incentives, and have been published in certain journals. The Policy Branch is participating in the promotion of the proposed license round of the 15 areas reserved offshore PNG. The Policy Branch has already made representations at the *Asia Upstream Conference* in Singapore and intends to present again at the APPEA Conference and Exhibition in Australia in early 2006, and will continue to assist the Department in combined promotional efforts.

8.3 Financial Analysis

The Policy Branch as part of its ongoing activities continues to assist in the review, evaluation and analysis of applications for petroleum prospecting licenses. The Branch specifically reviews, evaluates and analyses the finances of oil companies applying for a new license, renewal or variation of a licence. Submission of financial reports of companies applying for a licence is required as part of the application. This information is reviewed and evaluated in line with the companies work programs. This assists the branch to establish whether or not the applicant has adequate finances at its disposal to implement the work programs over the life of the licence. The views and recommendations formed from the analysis are provided to the Petroleum Advisory Board through the Registry Branch.

8.4 PNG Gas Project Financing

8.4.1 State's Participation in the Project

The Government has approved exercising a 22.5% equity participation option available to the State in respect to Hides. As Hides gas will represent approximately 50% of the PNG Gas Project, the PNG equity interests in Hides will reduce by half when measured as equity in the PNG Gas Project's upstream development component (namely the wells, gathering lines and associated production facilities in the gas fields). When current landowner and provincial government equity interests in Kutubu, Gobe and Moran are also taken into account, the total PNG participation interest in the upstream would be 14.27%.

The Gas Project Developers have offered PNG an additional stake between 15% and 30% in the project pipeline infrastructure. If the State were to acquire the additional interest this would require the State to raise additional finance to participate in the gas project.

However, it is unlikely the State will secure additional finance for such infrastructure. The State has indicated that it will not be able to raise necessary finance for an Additional Infrastructure Interest and instead have the option deferred until post-construction.

8.4.2 Financing

Financing of the State's participating interest in the PNG Gas Project is led by the Department of Treasury, supported by Department of Petroleum and Energy and the PNG Gas Coordination Office. A finance committee, chaired by ExxonMobil, is coordinating the project financing. The PNG Government engaged Macquarie Bank to undertake phase one work which included providing strategic advice on Hides (partial) sale, identify debt funding and political risks insurance, development of ownership structure for the State and a detailed work plan and schedule. The Financing Plan was submitted in late June 2005. The stage two assignments, among others, involve implementation of the financing plan including review of the plan itself.

From the current calculations the State would require more than US$400 million to participate in the upstream sector of the Gas Project. The Government approved the setting aside of K400 million (US$120 million) from the 2005 Budget towards equity requirements with the balance of equity requirements to be sourced externally. The State is currently talking to various funding sources such as the Asian Development Bank, European Investment Bank, Itochu and JBIC of Japan.

The financing of the State's participating interest in the Gas Project is critical. The State must make its preparations at the same pace with the other project partners in the project so that it does not hold back the other parties. At the time of financial close, the State must have the necessary funds secured, and available an appropriate corporate relevant vehicle.

8.5 Legal Issues

8.5.1 Amendments to Oil and Gas Act

In 2005 two sets of amendments to the Oil and Gas Act 1998, were considered for introduction to Parliament. This was to have been done in two phases. The first phase related to amendments specifically assigned to support the PNG Gas Project, while the second phase related to administrative provisions and provisions relating to the distribution of landowner benefits. The first phase of amendments, have only just been completed.

These amendments to the Act were specific to the PNG Gas Project to give comfort to the Project sponsors on the security of tenure and their ability to carry out early works. The security of tenure is vital for the financing aspects of the project hence it is important that the changes were made in the Act to provide that security and ultimately comfort to potential financiers of the Gas project.

It is envisaged that only one development forum will be held for the PNG Gas Project to deal with the Gas Project Cooperation and Sharing Agreement (GPCSA) and the distributions of benefits arising from the development of the PNG Gas Project to project area landowners and affected Local-Level Governments and affected Provincial Governments. The project sponsors want the State to have the GPCSA executed with relevant stakeholders by end of March 2006. It was therefore vitally important that the change was made to the law to enable this to happen.

Two other important changes to the Act considered as necessary for the delivery of the Gas project are the changes relating to additional rights of entry of a licensee and the introduction of provision relating to the pre-submission of information.

Section 116 was amended to enable an applicant or intending applicant for a licence to apply to the Minister for an authorisation to conduct activities relating to or in preparation for construction works which are or will be proposed in the applicant or intending applicant's licence application.

For purposes of the PNG Gas Project, the licensees will need to enter upon private land and undertake "temporary operations". Authorisations can be given to them using the provisions of Section 116 for early works such as the building of roads, wharves and bridges and the construction of temporary camps for use during pipeline construction.

If it is considered necessary or expedient for an applicant or intending applicant for a licence to conduct activities relating to or in preparation for construction works which are or will be proposed in the applicant or intending applicant's licence application, then the Minister may, by instrument authorise that person to enter on any land for that purpose for such period as may be reasonably required for the conduct of those activities specified in the instrument. The applicant or intending applicant for a licence however must comply with the requirements of Section 118 relating to compensation for entry onto private customary land and any damages caused by their activities.

In relation to the issue of pre-submission of information a new Section 152A was to be inserted in the Act to ensure that information, particulars, proposals, studies, investigations, reports, accounts, documents or other like material to be furnished or provided, under any section of the Act, to an inspector, the Director - Oil and Gas Act, or the Minister for consideration in connection with that section, may be submitted in a complete draft form for discussion purposes without prejudice to the rights of the submitting party or the State arising under the relevant section. This is intended to assist in the preparation and submission of a complete formal submission of that information, particulars, proposals, studies, investigations, reports, accounts, documents or other like material in due course and in accordance with the Act.
It will facilitate and promote the timely delivery of approvals, decisions, authorisations, permits and grants by an inspector, Director - Oil and Gas Act and the Minister, relating to approvals, decisions, authorisations, permits and grants required to be made or given under relevant sections of the Act. In the case of the PNG Gas Project, this change will enable the Department and other relevant government departments and agencies to receive and review draft documents requiring regulatory approvals in advance to provide inputs on so that when the final document is received the required decisions or approvals can be made or given in a timely manner through a transparent consultative process.

Oil and Gas (Social Mapping) Regulations
A draft social mapping regulation for application to the petroleum industry, has been prepared.

The drafting instructions for the Oil and Gas (Social Mapping) Regulation were submitted to the Office of First Legislative Council who drafted the Regulation and sent back to the Department to be reviewed by the Department before it can be finalised for submission to NEC for approval.

The Regulation however has not gone to the NEC for approval and promulgation by the Head of State since the industry has raised concern on the draft saying it did not reflect the document agreed to between the industry and government. It remains outstanding and it should be one of the regulations that need to be finalised in early 2006.

8.5.2 Gas Agreement Amendment

The project scope as envisaged in the original PNG Gas Project Gas Agreement executed on 6th June 2002, has changed considerably, hence changes need to be made to the Gas Agreement. The parties held numerous meetings on the changes throughout 2005 and hope to conclude a restated Gas Agreement by mid-2006.

8.5.3 Gas Project Co-operation and Sharing Arrangements

It is envisaged that only one development forum will be held for the Gas Project to deal with the Gas Project Cooperation and Sharing Agreement and the distributions of benefits arising from the development of the Gas Project to project area landowners and affected Local-Level Governments and affected Provincial Governments. The project sponsors want the State to have the GPCSA executed with relevant stakeholders by end of first quarter 2006.

Two drafts were prepared in 2005, one was circulated in May 2005 and the latest draft was circulated in December 2005. The conclusion of this agreement depends on the conclusion of issues dealt with by the Coordination Branch and the Gas Coordination Office.

8.5.4 Standard Petroleum Agreement

This is outstanding since 1997. The A new revised Standard Petroleum Agreement has been prepared and is being reviewed internally, before circulation to the industry. It is envisaged that this outstanding task will be settled in 2006.

8.5.5 Expenditure Implementation Committee

A joint working committee was established by the Department, with members from both 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 equity benefits that flow to the Local-Level Governments and Provincial Governments. The benefits are that of tax credit expenditures, equity benefits and royalty benefits 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.

There has been wide spread abuse of the benefits and few projects have been seen and no proper reports submitted. Funds have been subsumed into the provincial recurrent expenditure and the commitments from the Provincial Government have not been met.

A draft guideline was drafted together with the standing orders. The EIC was established by Section 178 of the Oil and Gas Act.

8.5.6 Court Cases

The Legal Services represents the Department in cases that are 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 update reports are sent to officers concerned in the Coordination Branch.

8.6 Environment

The Environment section within the Petroleum Division is tasked with a general monitoring role to ensure that activities related to Oil and Gas exploration, development, production and marketing, comply with the environmental requirements within the Oil and Gas Act as well as other relevant environmental legislations of Papua New Guinea.

8.6.1 Decommissioning/Abandonment Policy Paper

PNG has been producing petroleum for more then a decade, hence oil reservoirs are depleting fast and will one day be uneconomic to maintain. The oil producing wells will be reaching closure and abandonment stage and Section 139 of the Oil and Gas Act in regards to removal of property by the licensee is an important requirement

The Oil and Gas Act appropriately covers the abandonment plan but is shy of detailing a policy framework for addressing project closure issues. This policy sets out the Government's intention to manage the project closure issues and the three important aspects that include decommissioning, rehabilitation and sustainability:

- Decommissioning - involves the removal, disposal or reuse of industrial plant/equipment;
- Rehabilitation - involves measures taken to return sites to stage where it is usable; and
- Sustainable Development - regards the continued availability of a resource in the future. Thus, sustainable development is the use of scarce resources without depleting the resource for use by future generation.

The policy is currently being worked on and will be circulated for comments.

8.6.2 PNG Gas Project Environmental Permits and Petroleum Licenses

The Project Operator has made application for the Environmental Permit for the PNG Gas Project to the Government through the Department of Environment and Conservation. The environment unit within the Policy Branch has been tasked to liaise with the Department of Environment and Conservation and appraise the application. The review and appraisal of the application will assess the following:

- Risk of environmental impact;
- Social and economic implications and potential impacts of the project; and

- Various methods and means proposed in the Environmental Plan to avoid or mitigate any damaging or adverse impacts that might otherwise occur.

The Environmental Plan is under review by the Department of Environment and Conservation.

8.7 Economics

8.7.1 Oil Prices

In 2005 the world crude oil prices rose as supply limits became more apparent on the back of a rising growth in world demand for crude oil that started off in 2004 after the start of the Iraq war in 2003. The Kutubu Light oil price being quoted in reference to the Malaysian Tapis rose by 33% in 2005 were it average in January 2005 at US$41.72 a barrel and in December 2005 at US$55.32 a barrel.

Table 8: Monthly averages for the Kutubu Light Crude

Month (2005)	Average Price (US Dollar/barrel)
January	41.72
February	46.19
March	55.83
April	56.86
May	49.72
June	52.71
July	56.71
August	65.06
September	68.42
October	62.70
November	55.72
December	55.32

The rise in oil prices have meant a rise in the oil revenue that leads to a rise in the corporate tax and royalty receipts in 2005.

8.7.2 PNG Gas Project Economic Model

The PNG Gas Project concept is to extract gas from the gas fields in the Southern Highlands of PNG and export it to Australia for industrial, commercial and residential energy consumption. The project involves an upstream gas production and processing project located in PNG and a downstream gas transportation project made up of a dry gas pipeline and associated facilities in Australia.

The Project's economic benefits to PNG would include capital investment, recurrent expenditure, boost to export, employment, boost to exploration and production activity, opportunity for State participation, tax revenue, development levy, royalty, direct compensation, local business dividends and other benefits.

The project's economic indicators in 2005 in a scenario where the total project's gas sales rate is 6,115 petajoules at a 30 years average nominal price of US$3.75 per gigajoule, condensate volume of 171 million barrels at a 34 years nominal average of US$40 per barrel, a capital cost of US$2 billion and an operating cost of US$2.7 billion is that the project's total revenue will be US$36 billion giving an internal rate of return of 16.3% with a net present value at 10% discount of US$846 MM.

The project requires more committed foundation customers to take the projected 6,115 petajoules and work has commenced on the Front End Engineering Design (FEED) phase. Efforts are continuing to firm up more customers and the completion of the FEED phase may see some adjustments to the economic indicators.

8.7.3 Petroleum Cost Reporting

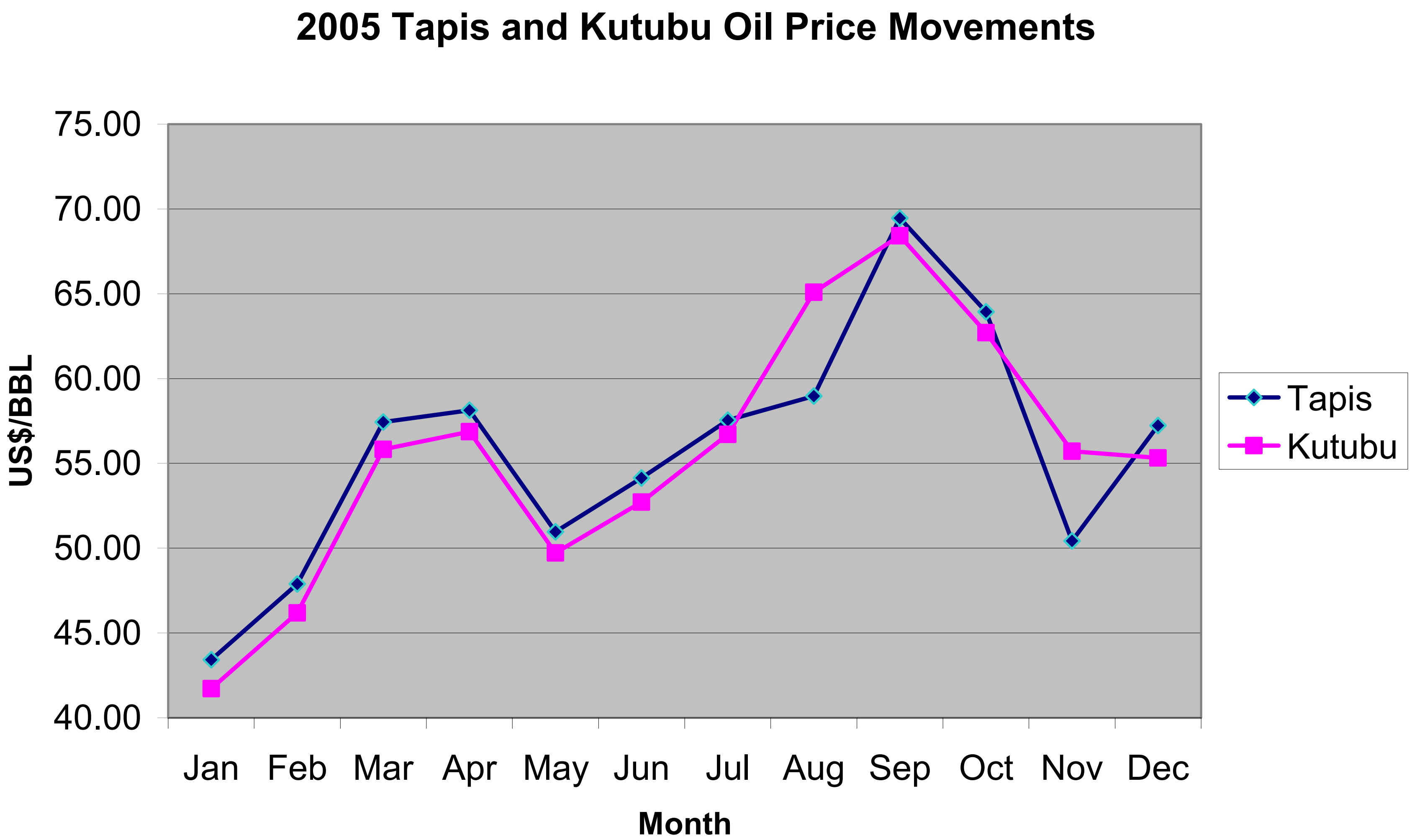
All petroleum companies are required to furnish reports under the Oil and Gas Act 1998. In line with this provision, a petroleum cost reporting database was established in the Policy Branch. The licenses are required to submit to the Department the capital and operating costs incurred by the licensees solely or jointly, and to ensure consistency in each reporting period. The Department uses this data to monitor the cost trend.

Different forms have been structured for different costs whereby licensees can enter the costs and reports:
Form 1 (a) relates to Joint Venture Exploration Billing Cost Summary;
Form 1 (b) relates to Joint Venture Development Cost Summary;
Form 2 (a) relates to Joint Venture PPL or PDL Operating Cost Summary;
Form 2 (b) relates to Joint Venture Pipeline Cost Summary;
Form 2 (c) relates to Joint Venture Petroleum Processing Facility Summary;
Form 3 relates to Sole Cost Summary; and
Form 4 relates to Royalty Net Back.
The licensees are required to supply the data six monthly. Upon receipt of the data the Policy Branch enter the information into the database for analysis and reporting purposes.

In 2005, an update was done on the company addresses and contact details of personals. An acknowledgement receipt was also developed which could either be faxed or developed.
These two developments were essential for better communication with the petroleum companies and for information search within the Department.

Eight returns were made in 2005 for the last 2 quarters in 2004 and it followed with eight reminders sent 5 for the first 2 quarters of 2005.

Figure 8: Year 2005 Oil Price Graph



Section 9.0 COORDINATION

9.1 Overview

9.1.1 Branch Objectives

The Coordination Branch is responsible for the coordination of petroleum development project issues with local communities. The specific roles of the Coordination Branch are:

- Liaising with affected communities and affected provincial and local level governments to ensure that all their queries or issues relating to petroleum projects affecting them are diligently dealt with and that relevant information is disseminated to them;
- Organising and coordinating meetings with representatives of both National and Provincial Governments, Industry, Landowner Associations, and Project area communities to discuss land and community issues affecting specific petroleum projects;
- Planning and coordinating the staging of Development Forums for new petroleum projects and the review of Project Memorandum of Agreements relating to existing projects;
- Reviewing social impacts on developments and preparing programs for community assistance or inclusion in development agreements and MOAs;
- Assisting and overseeing landowner identification and related social mapping work undertaken by Developers in the petroleum license areas;
- Ensuring that royalty benefits and equity benefitpayments are made to the correct beneficiaries and disbursed in a given timeframe;
- Ensuring infrastructure projects and non-cash benefits are fairly distributed in the project areas; and
- Completion of the construction of DPE Moro field office including two accommodation units and the extension of the current Hides field office in Nogoli to accommodate Gas project field officers.

9.1.2 Staff on strength

The Assistant Director manages the branch with the support of six project coordinators, three liaison officers, seven contracted local specialists and four ancillary staff. One senior coordinator was assigned on a full-time basis to the Gas Office on the PNG Gas Project and one liaison officer was on study leave.

The current petroleum development projects of Hides, Kutubu/SE Mananda, Gobe, Moran and the Proposed PNG Gas Project are managed by coordinators and assisted by liaison officers, with support from contracted local specialists based at project sites at Kopi camp Kikori, Gobe, Moro, and Nogoli.

9.1.3 Branch Milestones

Milestones achieved during the year include:

- Successful facilitation of payment of Gobe royalty and equity payments.
- Successful signing of the revised Moran Development Agreement in August 2005.

- Establishment of a Hides project landowner database.
- Mitigation of the number of Kutubu project landowners traveling to Port Moresby Coordination office.

9.2 Kutubu Project

The Kutubu project was generally quiet in 2005, with landowner issues very minimal.
One notable event was the development of the South East Mananda field, which is now in production. South East Mananda landowners have not held amicable discussions and there remains division among the current beneficiaries and other members of the three ethnic groups, as well as an internal leadership dispute.

Two Liaison Officers and a Senior Co-coordinator deal with the Kutubu Project with the help of two contracted officers. In 2005, a Liaison Officer was based permanently in Kikori and responsible for all Kikori Landowner and project related issues.

All royalty payments to beneficiaries are now administered by MRDC. DPE now oversees and authorises the release of payments only. There are less Kutubu landowners coming to the Coordination Office with grievances than in previous years. Internal landowner politics and political play has hindered completion of the Kutubu and Gulf MOA Reviews.

9.3 Gobe Project

Landowner issues have marred the Gobe Project, the prime reason is that there has been no determination of landownership within the Gobe Project area. However, there exists a ministerial determination of beneficiaries recognizing 21 land groups (claimants) for the purpose of receiving monetary benefits. This was supposed to be an interim arrangement for landowners to receive their benefits, whilst awaiting the rehearing of LTC, this has heightened Gobe landowner issues which have taken much time at the Department. The issues involve the Lands Title Commission (LTC) Review, Gobe outstanding MOA review, Ministerial determination revocation, royalty payment, creditors, election petition and leadership infighting.

There were calls for the staging an overdue Gobe MOA review in early 2004 by the landowners. Due to internal issues, the Minister directed that prior to convening the review, the landowners were required to validate their elected representatives. The leaders of the respective ILG consented that the DPE facilitate a one-off ILG election. With the assistance of the Electoral Commission, the elections were convened following 3 months of awareness campaign. The elections went well in most areas from Samberigi-Kikori-Kantobo except Erave, as all Erave zone ILGs have election petitions before the National court.

The Department gives due recognition to the leaders as per the election results unless the court order says otherwise. The Department has now taken the position that all internal ILG disputes/conflicts are left to their dispute Settle Authority as per their ILG constitutions or other means as they see fit to deal with such matters.

All royalty are now to be administered by MRDC in accordance with section 176(8) of the Oil and Gas Act, and DPE's role is to authorize, endorse and oversee the release of the payments only.

9.4 Moran Project

The Moran Project has had a busy year. The highlight of the Moran Project was the successful signing of the Revised Moran Development Agreement. The highlights of events that occurred during 2005 include:

1) The Moran landowner leaders meeting which was organised by Oil Search in Madang in February 2005. The purpose of the meeting was to discuss issues that impact on the Project. The meeting was also intended to facilitate and assist the leaders to resolve their issues and work peacefully in an environment conducive for the continued operations and investments for both OSL and the State.
2) The Revised Moran Development Agreement was finally signed at Fofari Camp, Moro, on 12th August 2005. The stakeholders that were present during the signing were the Moran Landowners, SHPG Governor, Gulf Governor, Deputy Prime Minister and Minister for Petroleum and Energy, Government Agencies & affected LLG's.

The current major Moran issues impinging on the Project include the 30% development levy demand from the Southern Highlands Provincial Government, the Yumbi & Nano Webo ILG's release of royalty and equity payments and the 2005 Development Levy payments for SHPG still pending the reconciliation of K3.45MM.

9.5 Hides Gas Project

It has being a challenging year for the Hides Gas to Electricity project, but generally quiet without any major disruption to project operations. The pressing issues include the Hiwa Koma ongoing landownership claim and Tabu clan royalty distribution formula and the use of MOA project funds.

Land disputes are common, and many issues are still outstanding. Even those clans that have won land titles through court are still facing problems. In December 2005, the Department assisted the Hiwa Komas with K110, 000 as repatriation assistance for them to go back to their villages and resolve outstanding issues.

The Hides royalty was paid to beneficiaries as per Hiwa Tuguba compromise agreement of 1993. It is an agreement made by the impacted landowners and royalty is paid in cash bi-annually to beneficiaries at the project site.

Two sets of royalty payments were executed in the year, one in the month of April and the other in the month of September. The former was for period July to December 2004 while the latter was for January to June 2005.

As a way forward to minimise royalty payments, a landowner database was established in June 2005. The database has more than 800 photographs of agents of about 180 sub-clans of the current beneficiary listing. This database has greatly assisted field liaison officers in the disbursement of royalties to correct beneficiaries.

The two main Hides MOA projects are the Para Komo road (Homako Brothers) and the Kulu Puba Road (Koyu Construction). They were monitored and inspection at the end of the year showed that work is still outstanding. In December 2005, a sum of K300, 000 MOA funds was paid to the Hides Landowner Umbrella Company " PEJV" (Petroleum Exploration Joint Venture) for MOA project implementation as per revised 2004 Hides MOA.

9.6 Other Issues

9.6.1 MOA Project Funds

The management of MOA funds was transferred from Department to Expenditure Implementation Committee in January 2005, hence the branch was unable to keep record of the use of the funds.

Kutubu project – From October to November 2005, K85,000 was paid to Paul Soni Timbers for the constructions of one classroom at Sisiba community school. All other infrastructure projects were funded under the Tax credit scheme.

Gobe project – May 2005, K3.5MM was released to Civpac Limited for the construction of the Gobe Samberigi road.

Hides project - May 2005, K7MM SSG funds was paid to Homako construction for work on the Para Komo road and in August, K300,000 paid to PEJV for implementation of MOA project. In October K600,000 was paid to Koyu construction for the Kulu Pupa road.

Moran project – K700,000 was collected at Finance in Feburary, 2005 by Homa Pawa Landowner association for implementation of projects.

9.6.2 PNG Gas Project

The Gas Office now deals with the Gas Project and DPE assists when required. Project awareness and information dissemination was carried through out the year via DPE field offices in Kopi, Gobe, Kutubu, Moran and Hides.

9.6.3 Field Offices

There was construction of two accommodation units and a DPE office block at the Moro camp in 2005. One DPE Field officer is based at Moro.

Extension work was also done to the Hides Field Office to accommodate three Gas Field officers and is now completed.

Section 10.0 CONCLUSION

Exploration activities have picked up pace this year. Respective operators undertook significantly more field activities then in previous years and more wells were drilled despite no discovery being made. The tax incentives introduced in 2003 are bearing fruit with licensees who took advantage of this opportunity now commencing active fieldwork. Aggressive development drilling programs have enabled the sustained life of the fields despite their natural decline.

The country's petroleum industry has received a boost to sector investment interest which is expected to ramp up in the coming year through a new major study regionally extensive study of the petroleum systems of offshore areas. The Ministerial reservation of blocks of large portion of these offshore areas has set the tone for exciting times ahead for the local industry with a Licensing Round to be hosted in 2006.

With the successful completion of construction works at the first ever local refinery this year, the Napa Napa refinery located on the eastern side of Port Moresby Harbour is now receiving crude feedstocks and refining to produce local naptha, gasoline, jet fuel and diesel. The same operator has continued with its ambitious multi-well program in the hopes of a discovery that will enable it to process from upstream through to downstream.

The PNG Gas Project has successfully entered the FEED stage and design and construction work are on-going. The Project aims to produce around 6 TCF of gas and the Project proponents have commitments of around 215 PJ per annum comprised of five significant foundation load customers. The risk remains of customers once again dropping their commitments to PNG gas, especially if there is any slippage in the project schedule and the targeted date for first gas deliveries of mid-2009.

Without doubt, PNG's oil and gas resources and PNG as a potential for previously untested deepwater plays will come into the spotlight in light of the Minister's official reservation of blocks offshore this year. The licensing round in collaboration with Fugro's reprocessed and newly acquired speculative data promises interest for the industry in the coming months.

PETROLEUM EXPLORATION STATISTICS

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005 (est)	2006 (est)
NEW PPL's GRANTED **(a)**	12	16	6	5	4	5	5	8	1	7	6	5	9	4	3	2	1	10	8	15	15
PPL's EXPIRED, SURRENDERED OR CANCELLED	3	4	1	5	2	12	8	13	6	2	7	3	5	3	1	4	4	9	5	2	2
TOTAL NUMBERS OF PPL's **(b)**	21	33	38	38	40	33	30	25	20	25	25	22	27	28	27	23	17	18	25	35	45
TOTAL NUMBER OF BLOCKS						2684	2143	1283	995	1130	1395	1372	1494	1535	1508	1066	1020		2136	0	1
TOTAL AREA UNDER LICENCE (KM²)						228140	182155	109055	84575	96050	118575	116620	126990	130475	122148	90610	87308		185604		
NEW PDL's GRANTED	0	0	0	0	2	0	0	0	0	0	2	0	0	0	0	1	0	0	0	0	0
PDL's EXPIRED, SURRENDERED OR CANCELLED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL NUMBER OF PDL's	0	0	0	0	2	2	2	2	2	2	4	4	4	4	4	5	5	5	5	5	6
TOTAL NUMBER OF BLOCKS (PDL)	0	0	0	0	16	16	16	16	16	16	21	21	21	21	21	22	22	22	22	22	
NEW PLL's GRANTED	0	0	0	0	2	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1
TOTAL PLL's GRANTED	0	0	0	0	2	2	2	2	2	2	3	3	3	3	3	3	3	3	2	1	1
NEW PRL's GRANTED		0	0	0	0	0	0	0	0	0	0	0	1	0	4	0	3	0	2	1	1
TOTAL NUMBER OF PRL's		0	0	0	0	0	0	0	0	0	0	0	1	1	5	5	8	8	10	11	12
APPROXIMATE EXPENDITURE	K45M	K74M	K116M	K149M	K225M	K170M	K80M	K60M	K70M	K117M	K190M	K258M	K120M	K144M	K157M	K238M	K194M	K156M	K70M	K80M	K180M
EXPLORATION WELLS DRILLED **(c)**	3	7	10	27	21	11	7	4	10	4	5	9	5	5	2	0	3	7	2	3	5
DISCOVERY WELLS **(c)**	2	3	6	14	9	5	4	2	2	1	2	2	2	1	0	0	2	2	0	1	1
NEW FIELD DISCOVERIES **(d)**	1	2	2	1	4	3	2	1	0	0	1	0	0	1	0	0	2	2	0	1	1
CUMULATIVE FIELDS	9	11	13	14	18	21	23	24	24	24	25	25	25	26	26	26	28	30	30	31	32
CUMULATIVE WELLS	148	155	165	192	213	224	231	235	245	249	254	263	268	273	275	275	278	285	287	290	295
% SUCCESS RATE	6.1	7.1	7.9	7.3	8.5	9.4	10	10.2	9.8	9.6	9.8	9.5	9.3	9.5	9.5	9.5	10.1	10.5	9.5	9.7	9.2
SEISMIC SURVEYS	3	7	8	14	15	6	8	3	1	1	3	5	7	2	4	4	3	2	4	4	4
LINE KMS SEIMIC ONSHORE	208	423	700	1630	2901	744	751	43	35	16	446.2	321.2	28.2	142	147	109.8	49.75	105	124	100	100
OFFSHORE	229	4769	1878	1139	2576	661	879	2425	12568 (e)	0	0	0	5390	0	0	0	0	0	0	0	0
TOTAL	437	5192	2578	2769	5477	1405	1630	2468	12603	16	446.2	321.2	5418.2	142	147	109.8	49.75	105	124	100	100
						3.7	5.8	7.9	9.2	9.6	13.5	11.5	13.3	13.1	12	14	10.2	10	10	14	14

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

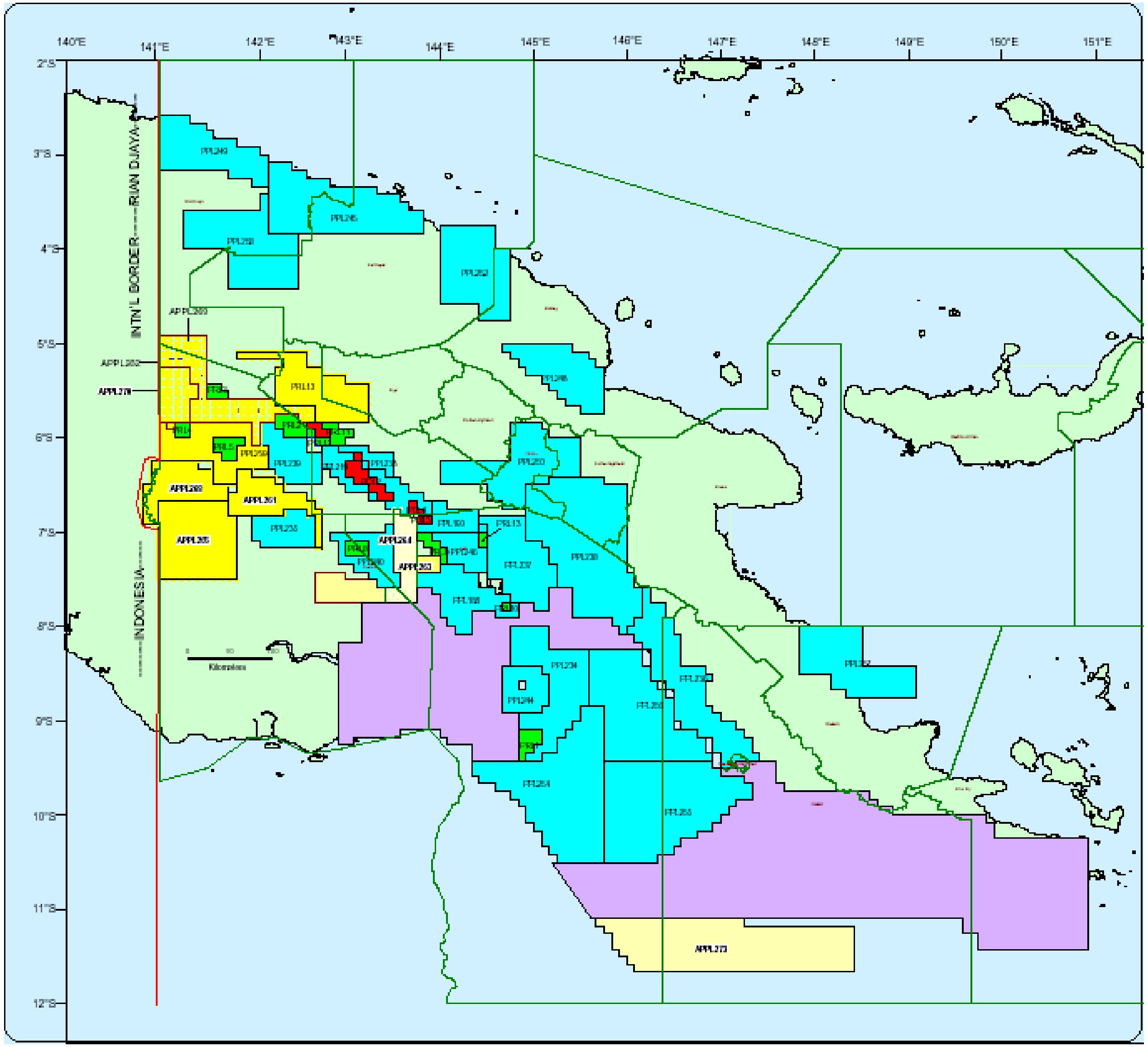
(b) Figures at year end

(c) Excludes development wells but includes extension discoveries and purposeful sidetracks drilled and completed in calendar year

(d) 1986 = IAGIFU
1987 = SE HEDINIA, HIDES
1988 = HEDINIA, PANDORA
1989 = AGOGO
1990 = ANGORE, ELEVALA, PNYANG, USANO
1991 = KETU, SE MANANDA, SE GOBE
1992 = GOBE 2X, PANDORA B
1993 = GOBE MAIN
1996 = MORAN
1996 = KIMU
2002 = SAUNDERS, BILIP

(e) 3-D Pasca Survey

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



PAPUA NEW GUINEA
PETROLEUM LICENCES LOCATION MAP

Petroleum Division
Department of Petroleum & Energy

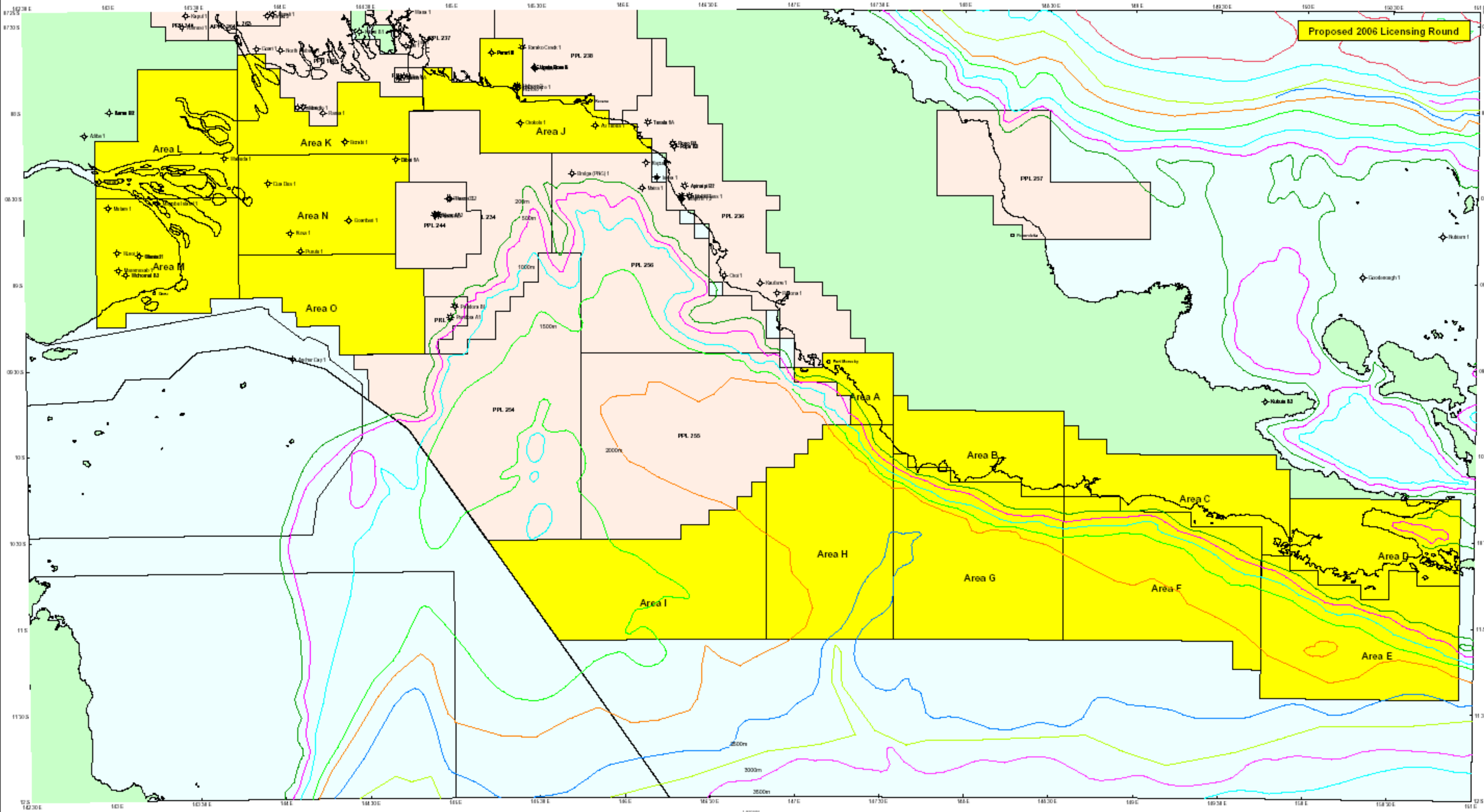
PETROLEUM PROSPECTING LICENCES (PPL)

PETROLEUM DEVELOPMENT LICENCES (PDL)

PETROLEUM RETENTION LICENCES (PRL)

APPLICATIONS FOR PETROLEUM PROSPECTING LICENCE (APPL)

Proposed 2006 Licensing Round



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