DEPARTMENT OF PETROLEUM & ENERGY

PETROLEUM DIVISION

2009 PETROLEUM ANNUAL REPORT

ON

PETROLEUM ACTIVITY IN PAPUA NEW GUINEA

Compiled by the Exploration Branch

December 2010

PREFACE

The contents of this annual report reflect accounts of events and information about activities related to the exploration, development and production of petroleum in Papua New Guinea during 2009. Nearly all events and information contained herein are sourced from data furnished by the operating petroleum companies as required by Oil and Gas Act and Oil and Gas Regulation. The Department of Petroleum & Energy regulates, monitors and promote petroleum activities in the country. Also covered are challenges faced as a regulator relative to issues affecting petroleum activities. All confidential information have been excluded in this report. Cost and expenditure values are stated in US dollars to ensure consistency, but where necessary, the Kina currency is used for simplicity.

The report attempts to provide a continuous and summarized review of the petroleum activities in Papua New Guinea. Please note that accounts on community affairs mandated by DPE is absent from this report.

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ABBREVIATIONS

AFE	Appropriation for Expenditure
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
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOPD	Barrels of Oil Per Day
BRT	Below Rotary Table
BWPD	Barrels of Water Per Day
CGG	CGG Varitas
CPF	Central Production Facility (Kutubu)
DA	Development Agreements
DEC	Department of Environment and Conservation
DPE	Department of Petroleum and Energy
EIC	Expenditure Implementation Committee
EPT	Extended Production Testing
EWT	Extended Well Test
FEED	Front End Engineering Design
GM	Gobe Main Field
GMC	Geophysical Management Consultant
GPCSA	Gas Project Cooperation Sharing Agreement
Ft	Feet
GOR	Gas Oil Ratio
GPF	Gobe Production Facility
HCGP	Hides Conditioning Gas Plant
ILG	Incorporated Land Groups
KB	Kelly Bushing
km	Kilometre
LLG	Local Level Government
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LTC	Land Titles Commission
M	Thousand
MD	Measured Depth
MDRT	Measured Depth Rotary Table
MM	Million
MMSCF	Million Standard Cubic Feet
MMSCFD	Million Standard Cubic Feet per Day
MMSTB	Million Stock Tank Barrels
MRDC	Minerals Resources Development Company
MOA	Memorandum of Agreement
MSTBO	Million Stock Tack Barrels of Oil

NEC	National Executive Council
NGL	Natural Gas Liquids
NWM	North-West Moran Filed
OGOC	Original Gas-Oil Contact
OOIP	Original Oil In Place
OPEC	Organization of Petroleum Exporting Countries
OSL	Oil Search Limited
OWOC	Original Water-Oil Contact
PALO	Project Area Land Owner
P&A	Plugged and Abandoned
PCR	Petroleum Cost Reporting
PDL	Petroleum Development Licence
PJ	Peta Joules
PJV	Porgera Joint Venture Limited
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
SEM	South-East Mananda Field
SS	Sub-Sea
STB	Stock Tank Barrel
STBPD	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	✓ Antelope-1 was completed and flowed at 382mmscfd or 5000 STBD by InterOil in PPL 238 ✓ UDT-11 was completed as an Oil producer in PDL 2 by Oil Search Ltd ✓
February	✓ Awapa Seismic Survey conducted in PPL 285 by Sasol Petroleum Ltd
March	✓ 17th – 19th, InterOil had its EIS Roadshow or Public Consultations ✓ Kanau South Seismic Survey conducted by Sasol Petroleum Ltd in PPL 287
April	✓ 2nd, World Wide Fund presented its Lake Kutubu Management Plan to Stakeholders. Lake Kutubu was gazetted a Wildlife Management Area on 25th June 1992. ✓ GP09 Marine Seismic Survey was conducted in PPL 234 by OSL ✓ Buna Offshore Seismic Survey was conducted by Eaglewood Energy Ltd in PPL 257
May	✓ IDT 24 was completed as an oil producer in PDL 2 by Oil Search Ltd ✓ 22nd, signing of PNG LNG Gas Agreement between the State - Government of Papua New Guinea and the Operator – Exxon Mobil and its JVP (Nippon Oil Exploration, Santos, Eda Oil, Mineral Resources Development Corporation and Oil Search) ✓ 23rd, completion and signing of UBSA in Kokopo, East New Britain
June	✓ Antelope-2 was spudded by InterOil Ltd in PPL 237
July	✓ UDT 12 was completed as an oil producer in PDL 2 by Oil Search Ltd
August	✓ 15th – 20th, Judge Kandakasi ruled that Gobe Alternative Dispute Resolution (ADR) with all its identified clans within PDL 4 convene at Gobe Oil Search Camp to “tok stret na wanbel” or resolve to demarcate clans customary land boundaries ✓ Moran 6 ST2 was completed as an oil producer in PDL 2/5 by Oil Search Ltd
September	✓ ADD 5 was completed as an oil producer in PDL 2 by Oil Search Ltd
October	
November	✓ 21st, commencement of PDL4 LBSA in Gobe. Officiated by the Petroleum and Energy Minister, Hon. William Duma, accompanied by, Independent Public Business Corporation Minister Hon. Arthur Somare, Southern Highlands Province Governor, Hon. Anderson Aigiru, Minister for Sports Hon. Philemon Ambel, Gulf Governor Hon. Havila Kavo and Memer for Kagua-Erave Mr. James Marabe.
December	✓ 4th, PDL 4 LBSA signed in Gobe, ending the 13 days Forum. ✓ UBSA Expenditure Report compiled by Policy Branch and submitted to Department of Finance and Treasury ✓ 8th, FID signing in Port Moresby - Esso Highlands Limited, a subsidiary of Exxon Mobil Corporation and operator of the PNG LNG Project,

SUMMARY

A record of fifty five PPLs, nine PDLs and eight PL were operating in 2009 since 1994. Papua Basin was intensively competed for prospecting licences as hydrocarbon potential of the basin continued to lure investors into the country. Thirty one APPLs were receipted, processed by the PAB and determined by the Minister. About 14 percent were granted PPL status, 24 percent were refused, and 62 percent were pending Ministerial determination.

A total of 1,588.36kilometres were shot at the cost of approximate US$18.5million for seismic; geological field survey of 71.68km; 25,964.3km gravity and magnetic at US$2,824,189.63

Interoil Ltd and Oil Search Ltd were main licensees that continued to demonstrate their wells commitment by drilling 13 wells altogether. Four wells were drilled by Interoil in the Foreland basin while the remaining were drilled by Oil Search Ltd in the Foldbelt basin. The AFE for the wells drilled by each Operator were US$177,970,000 and US$112,900,000 respectively.

As intentions of the petroleum license Operators to explore for oil and gas heightened, oil production from oil fields in the Southern Highlands of PNG continued to drop significantly. Production history chart forecasted a declining rate of 2,000MBBLs to 3,000MBBLs annually since in 2006. Gas from these fields will be fed into PNG LNG gas streamline and will be exported with rest of the gas from non-associated gas fields at volume rate of 6.6 million ton by year. The Final Investment Decision made on 8th December 2009 has paved way for this multibillion dollar project to commence and also has triggered other conceptional development of potential oil and gas fields for LNG projects.

1.0 LICENCE MANAGEMENT

1.1 Licensing Year 2009

Fifty five petroleum prospecting licenses (PPLs), six petroleum development licenses (PDLs), three pipeline licenses (PLs), eleven petroleum retention licenses (PRLs) and one Petroleum Processing Facility Licence (PPFL) were active between January and December 2009. A further three PDLs, five PLs and one PPFL were added to the above to bring totals to nine PDLs, five PLs and two PPFLs by year end. These are reflected in Figures 1.1, 1.2, 1.3, 1.4, 1.5, 1.6 and 1.7

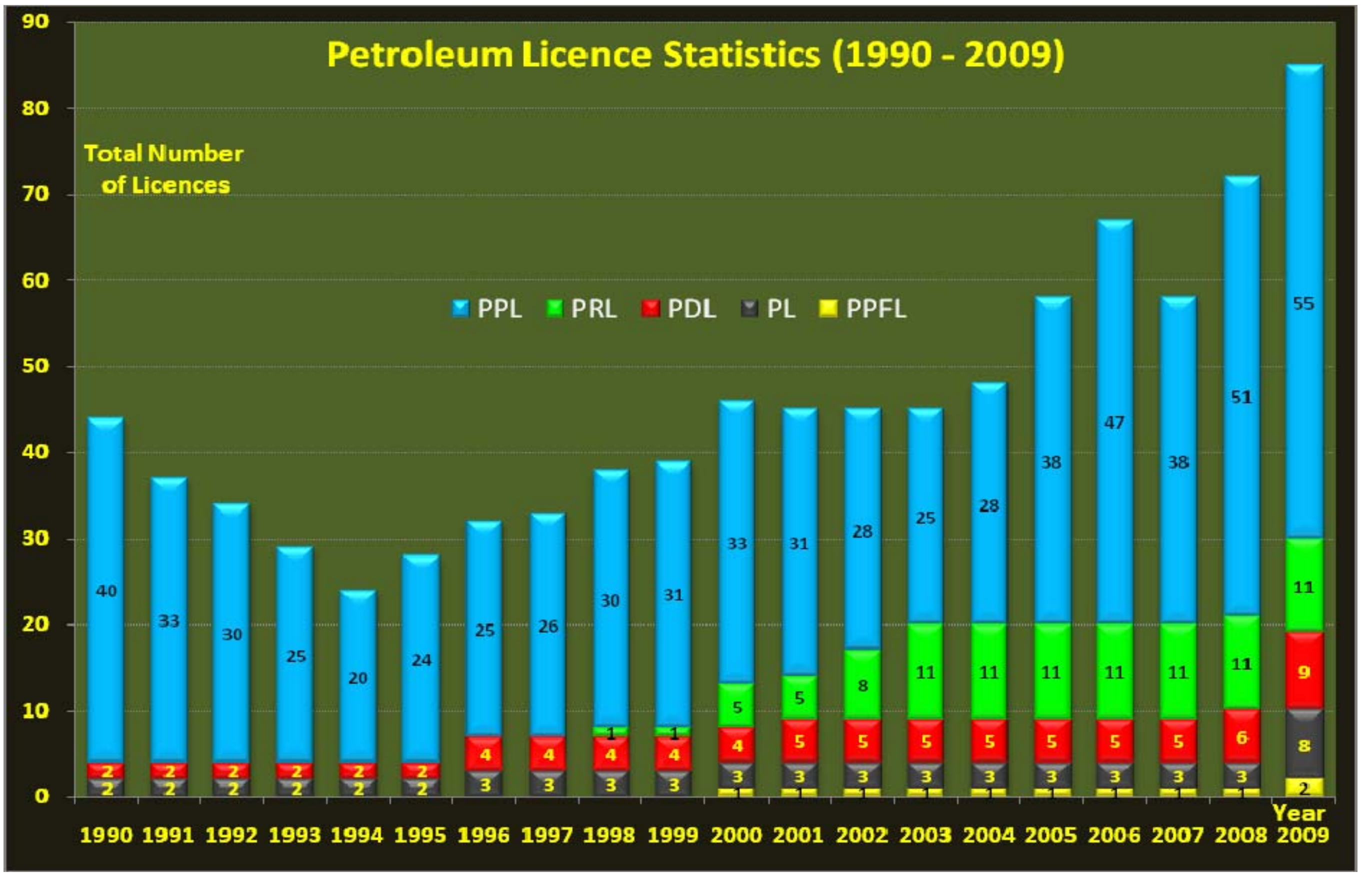

Figure 1.1: Petroleum License Statistics from 1990 to 2009.

1.2 Application for Petroleum Prospecting Licence (APPL)

Thirty one applications for Petroleum Prospecting Licenses were received by the Licence and Compliance Branch between January and December of 2009. Ten of these applications were awarded as Petroleum Prospecting Licenses while eighteen were pending the Petroleum Advisory Board's resolutions to advise the Minister to award or refuse at year end. The applications were made by both current Operators of existing licenses and some new entrants. Figure 1.2 illustrates this distribution.

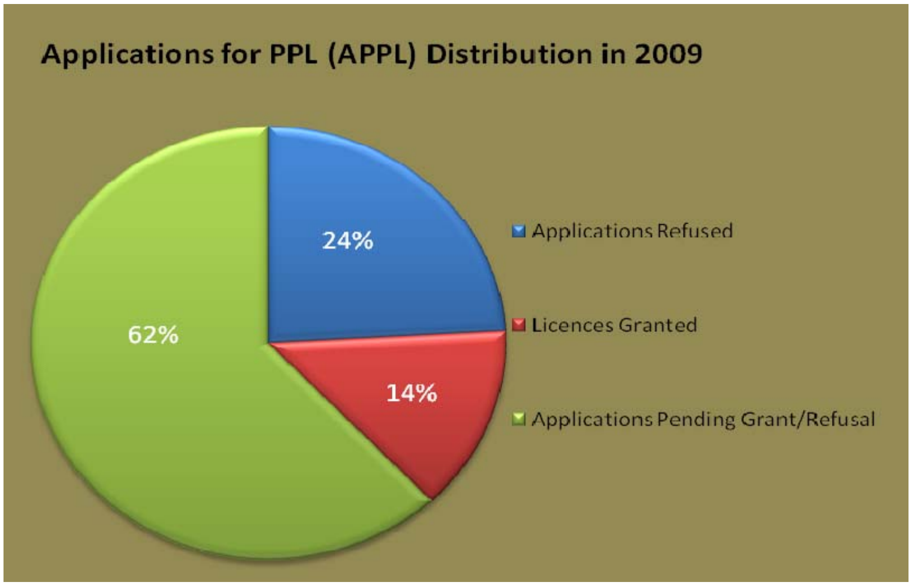

Figure 1.2: Applications for Petroleum Prospecting Licence (APPL) in 2009.

1.3 Petroleum Prospecting Licence (PPL)

A total of fifty five Petroleum Prospecting Licenses were active between January and December 2009. Ten PPLs were awarded during the year. Four of these licenses are situated in the North New Guinea Basin while six licenses are located in the Papuan Basin. There were no license surrenders for the year and no licenses were cancelled during the year.

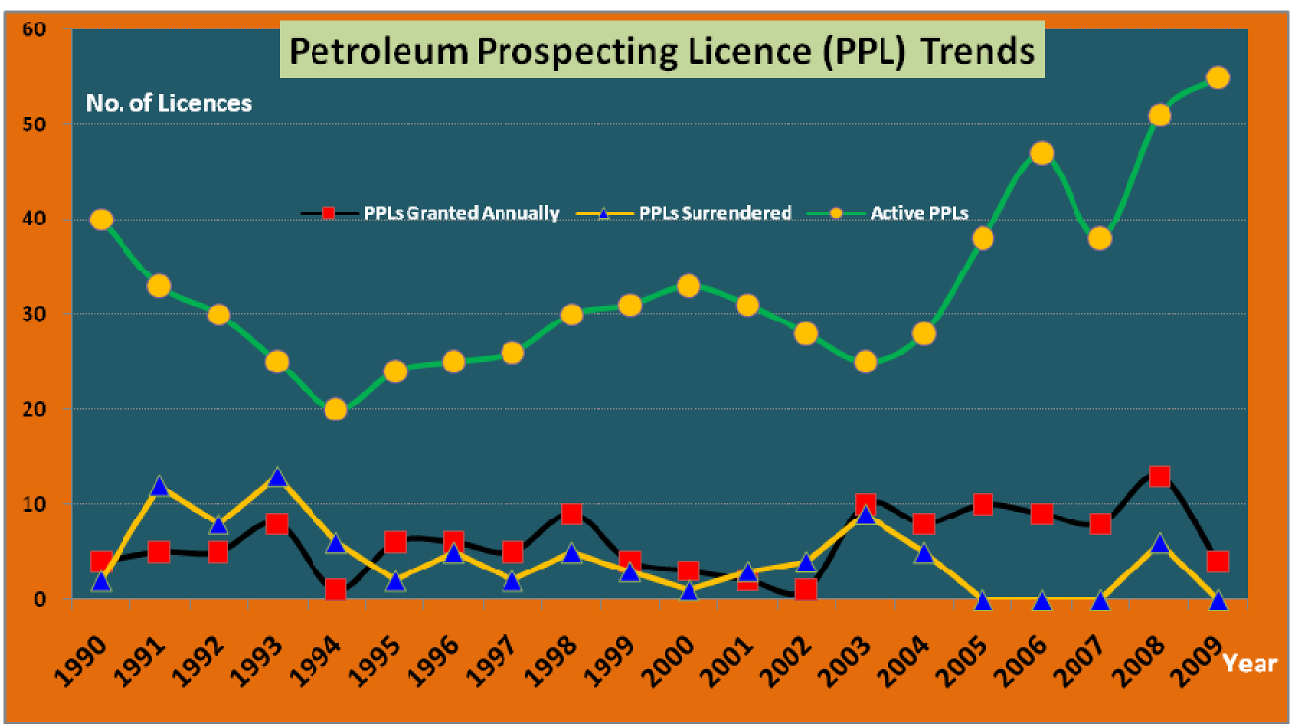

Figure 1.3: Petroleum Prospecting Licence (PPL) Trends.

1.4 Petroleum Retention Licence (PRL)

At year end, nine Petroleum Retention Licenses (PRLs) were being operated both on and offshore in the Papuan Basin of PNG as opposed to the initial eleven licenses at the beginning of the year. One of these licenses, PRL 2 expired during the year while PRL 12 in hides had all of its blocks awarded to the PNG LNG Project as PDL 7. Five blocks in PRL 11 were awarded to the PNG LNG Project as PDL 8 while three blocks remain in this license. Figure 1.4 represents the trend in the PRLs since 1990.

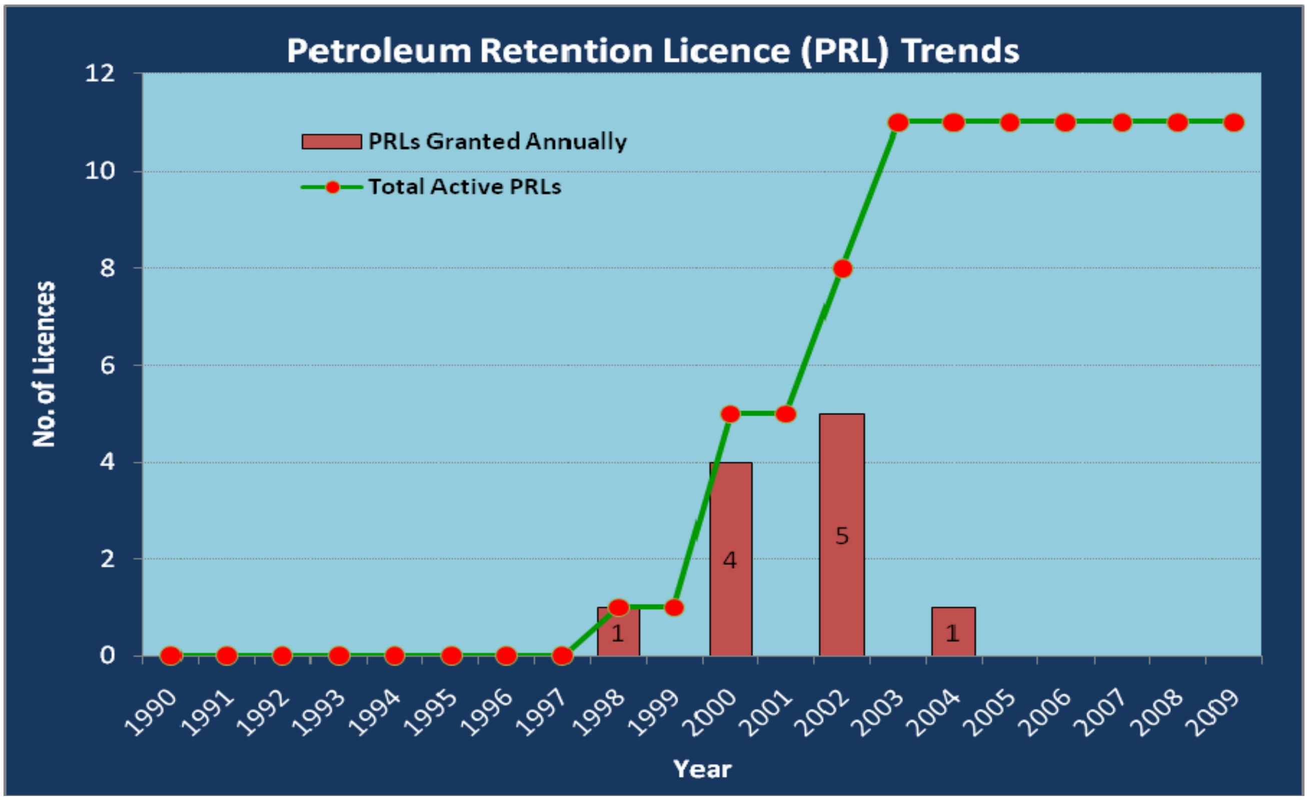

Figure 1.4: Petroleum Retention Licence (PRL) Trends.

1.5 Petroleum Development Licenses (PDLs)

Three Petroleum Development Licenses (PDLs) were awarded during the year to PNG LNG over the non-associated gas fields in the Papuan Basin in the Highlands of PNG – PDL 7 over the Hides field, PDL 8 over the Angore field and PDL 9 over the Juha field. Therefore, at year end the total number of development licenses had risen to nine while the existing five out of six licenses, PDLs 1, 2, 4, 5, and 6 which have been sanctioned to contribute to the PNG LNG gas were extended for a further twenty years to accommodate for the life of the project. Figure 1.5 shows the number of PDLs granted annually and the total number of active PDLs since 1990.

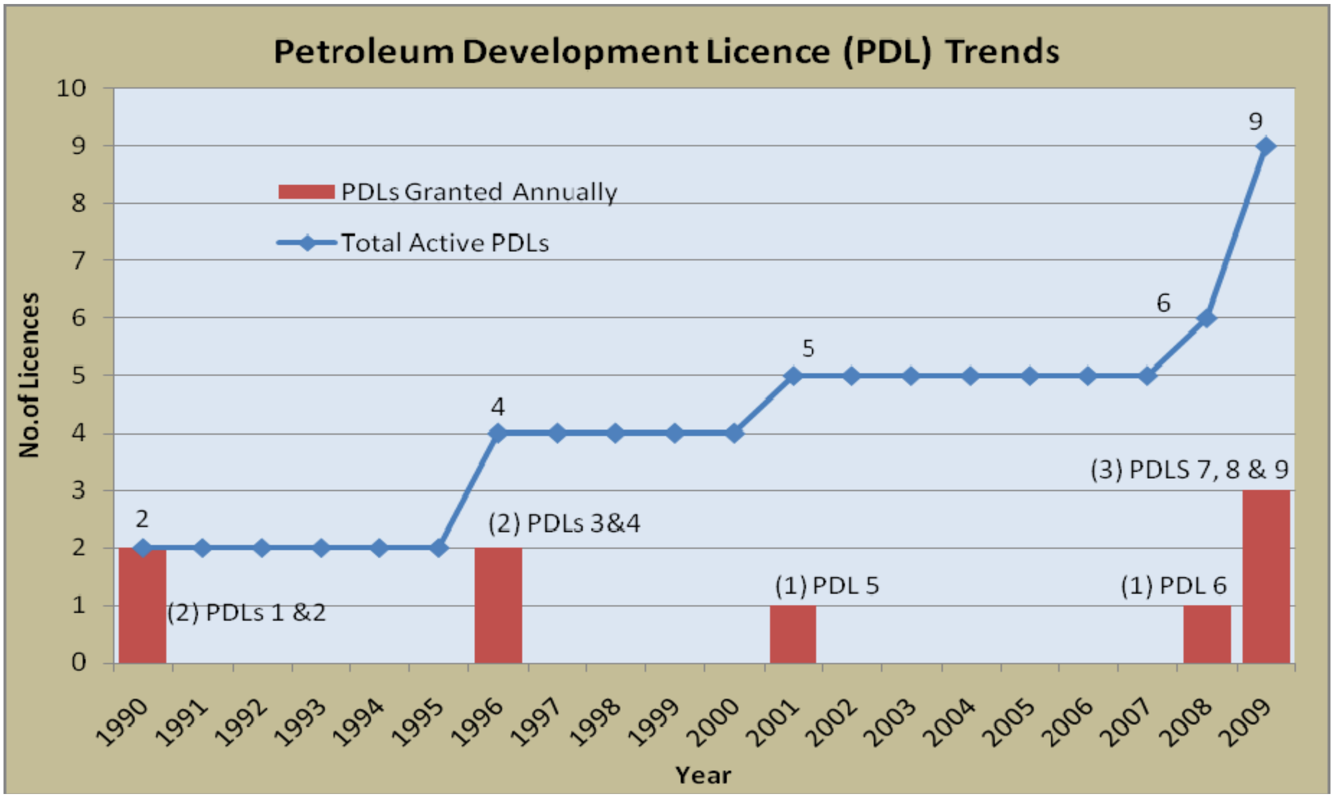

Figure 1.5: Petroleum Development Licence (PDL) Trends

1.6 Pipeline Licenses (PLs)

Three pipeline licenses were current up to 2009 when five other pipeline licenses were awarded as part of the PNG LNG Project bringing the total to eight pipeline licenses at year end. Two PLs were awarded in 1990 and a third PL was awarded in 1996. Represented in **Figure 1.6** are the numbers of awarded PLs and subsequently the total number of PLs to date.

1.7 Petroleum Processing Facility Licence (PPFL)

The first Petroleum Processing Facility Licence (PPFL) was issued in February 2000 and remained the only PPFL in operation till end 2009 when one other PPFL was issued to PNG LNG Project for the LNG plant to be constructed near Port Moresby which sees two PPFLs in place as shown in Figure 1.7.

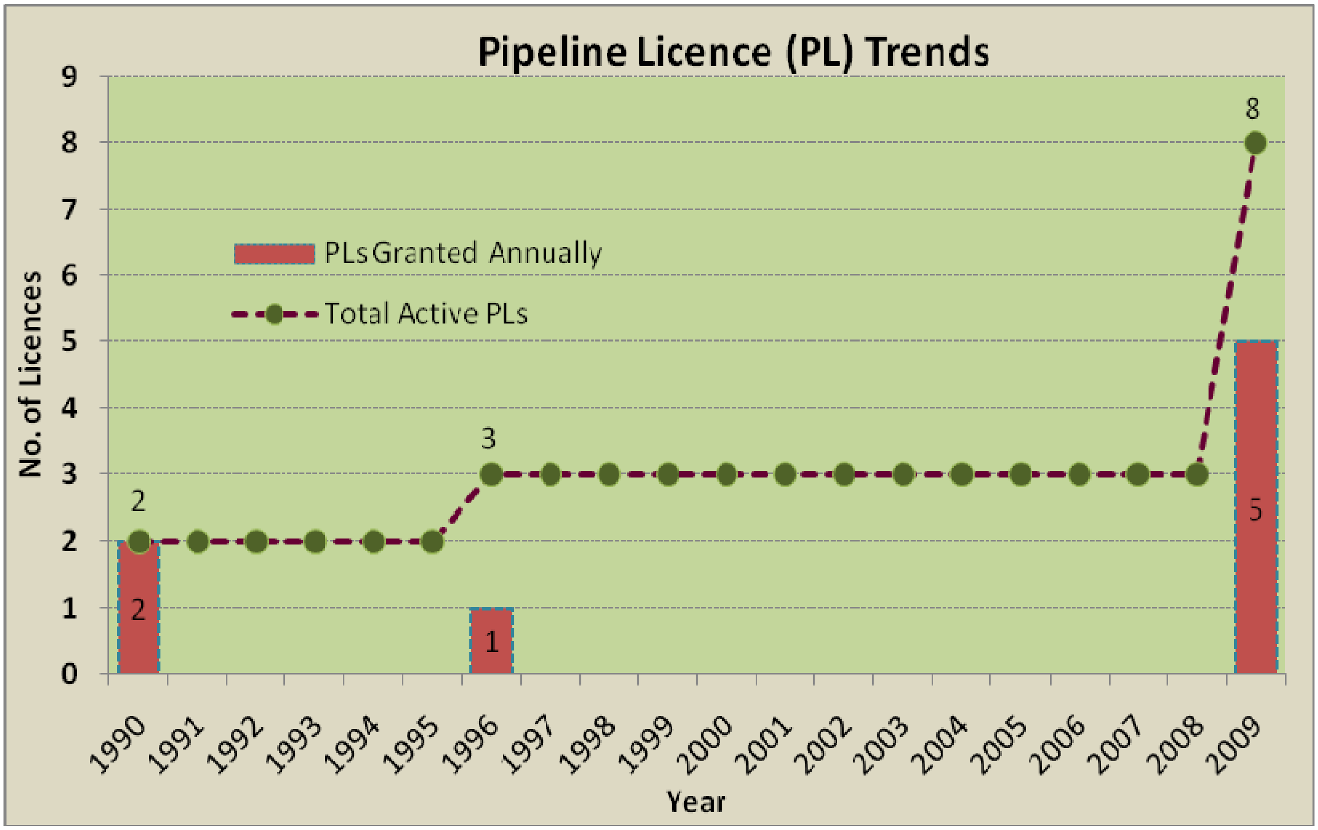

Figure 1.6: Pipeline Licence (PL) Trends.

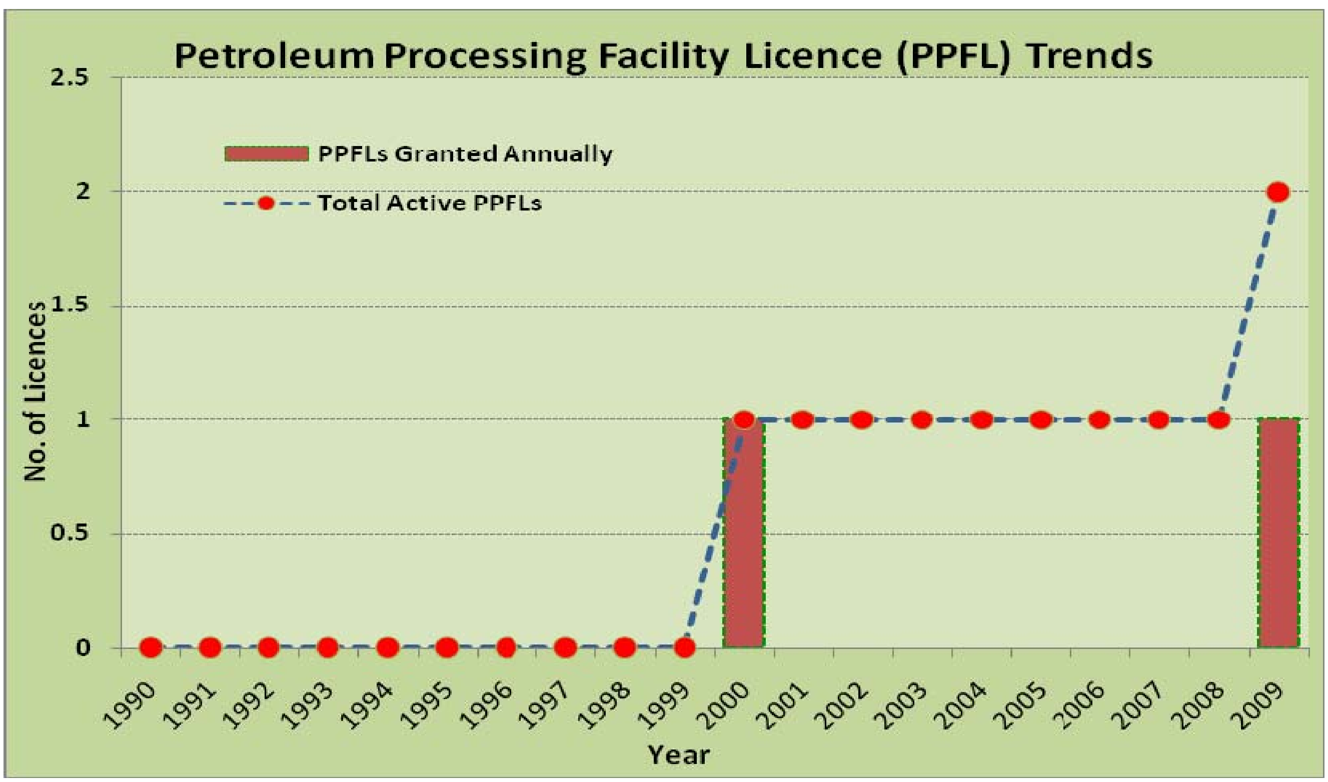

Figure 1.7: Petroleum Processing Facilities Licence (PPFL) Trends.

2.0 EXPLORATION ACTIVITIES

The total number of field surveys conducted this year increased by three compared to the previous year. Eleven surveys were conducted in various licences both onshore and offshore. Five seismic surveys were conducted both onshore and offshore in the Papuan and Cape Vogel basins, while only one geological survey was conducted during the reporting year. Table 2.1. – Table 2.2 contain the summaries of all the field surveys for the year.

2.1 Geological Field Mapping

The Auwi Geology Traverse by Oil Search Ltd on behalf of Eaglewood Energy was the only geological survey undertaken in 2009. This survey comprised a total of 71.68 line-kms. Table 2.1 displays information on this survey and Figure 2.1 is a graphical representation of geology surveys from 1995 to 2009.

Table 2.1: Geological Surveys.

Licence	Operator	Geographic / Tectonic Area	Survey Name	Line Length - Km	Cost US$
PPL 260 Onshore	Eaglewood Energy	Koroba/Kopiago, Southern Highlands Province Papuan Basin,	**AUWI GEOLOGY TRAVERSE**	**71.68**	**Cost included in Auwi Seismic Survey Cost**
Total				**71.68**	

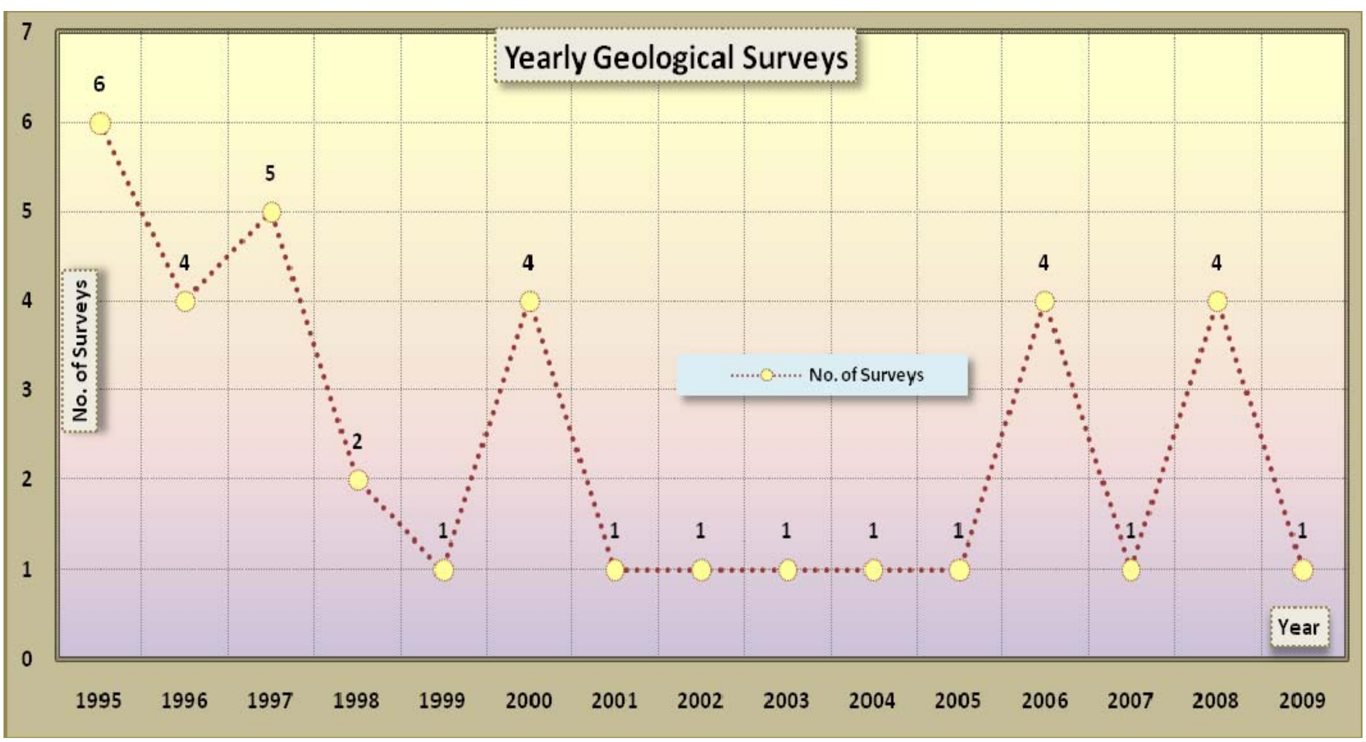

Figure 2.1: Yearly Geological Survey.

2.2 Geophysical Field Surveys

In total, twelve geophysical surveys were conducted during the year, which is a significant increase from the previous year. Five of these surveys were reflection seismic surveys of which three were conducted onshore and two were conducted offshore. There was one ground gravity and magnetic survey conducted during the reporting year and six airborne gravity and magnetic surveys. The surveys are summarized in Tables 2.2a, 2.2b and 2.2c and the graphical representations of the yearly seismic and aeromagnetic surveys are shown in Figures 2.2a, 2.2b and 2.2c. Displayed in Figure 2.2d are field survey statistics from 1995 to 2009.

The objective of the *Auwi Seismic Survey* was to better define the subsurface structure and exploration risk of the Auwi and Kelebo Leads in order to mature these features as potential future drilling targets. A total length of 71.46 line-kilometers was acquired.

The objective of the *Awapa Seismic Survey* was to extend seismic data coverage over the licence area. A total length of 355.8 line-kilometers was acquired.

The *Kanau South Seismic Survey's* objective was to obtain seismic data within the licence area and extend seismic coverage across the licence. A line length of 23.6 line-kilometers was acquired.

The *GP09 Marine 2D Seismic Survey's* objective was to infill the previous purchased Lahara 2D seismic grid over the most prospective identified leads with the aim of delineating them as future drilling candidates. A line length of 779 line-kilometers was acquired.

The *Buna Offshore Seismic Survey's* aim was to delineate the Buna Structure. A line length of 357 line-kilometers was acquired.

The PPL 237-238 Ground Geophysics Survey 2008 *(Ground Gravity and Magnetic Survey)* commenced in December 2008 and was completed in January 2009. This survey aimed to assist in anomaly confirmation and defining leads. A line length of 105.3 kilometers was acquired.

2.3 Petroleum Data Management

The Archives or Data Management Section of the Petroleum Division has a wealth of petroleum information that has been amassed over the years, dating back to 1900. The overall aim of the Archives or Data Management Section is to act as the National Petroleum Data Repository for a series of aggregated data and make it available to the industry when needed. In particular, the Sections main objectives are:-

- To ensure that petroleum data generated from petroleum activities is captured, memorialized and made available to the industry when needed

- To increase the accessibility of data to encourage foreign investment for the prosperity and future aspirations of the Nation
- To ensure petroleum companies or petroleum licence holders are in compliant with data submissions as required under the Oil & Gas Act. and
- To ensure that DPE and the State are defended in future litigations

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2.3.2 Dataset

There are many types of data in the DPE Archives, but some of the major data types include

a) **Drilling** (Well Completion Reports, End of Well Reports, Well/Drilling Proposals, reports on DSTs, Fluid Analysis, Logs, Biostratigraphy Paloe-ernvironments, Reservoir Engineering, Reservoir Studies, Core/Water Analysis, Daily Drilling etc.);

b) **Seismic** (Processing Report, Gravity Profiles, Station Location and Line Maps, Interpretation Reports, Gravity Profiles, Contour Maps, Data Processing etc.);

c) **Social Mapping** (Genealogy Studies, Social Mapping, Economic Impact Studies, Land Studies, Economic Impact Studies etc.);

d) **Legal** (Contracts & Agreements);

e) **Licence Administration*** (Licenses, Licence Register, Transfer & Dealings, Licence Applications, Six Monthly Reports, Annual Reports, Correspondence etc.); and

f) **Health Safety & Environment** (Environmental Impact Studies, Environmental Plan, Contingency Plan, Emergency Response Plan, Monthly Incident & Employment Reporting, Waste Management & Disposal Plan etc.) and many others. In addition DPE also has Cores, Samples and Cuttings.

2.3.3 Media Type

Data stored at DPE Archives include the following media types:- Hardcopy, CD, DVD, External Hard Drives, 3590 tape cartridges, Exabyte -8mm, and 3 ½ floppy drive. The latter is no longer support hence; data are not encouraged to be submitted in it.

2.3.4 Data Access

The Department of Petroleum and Energy receives its data from petroleum companies as a requirement under the Oil and Gas Act of 2006. Data submitted to DPE is available for public access through the Data Management Section at cost. Most data held by DPE Archives maybe released to the public after 2 years but there are some types of data that are required remain confidential. Since 2001, about 484 types of data have been submitted to DPE annually by the industries. In 2009 alone, a record of 576 data types was furnished by operators and contractors.

To access data from the Department, a formal letter is required which must be addressed in the following manner.

The Director, Oil & Gas Act
Petroleum Division
Department of Petroleum and Energy
PO Box 1993
Port Moresby
NCD

Attention: Registrar.

Table 2.2a: Geophysical Surveys – Seismic Surveys.

Licence Area	Operator	Geographic Area	Name of Survey Contractor	Line Length Km	Cost (US$)
SEISMIC SURVEYS					
PPL 260 **Onshore**	Oil Search Ltd (Eaglewood Energy)	Southern Highlands Province	**AUWI SEISMIC SURVEY** Geophysical Management Consultants (GMC)	**71.46**	**6.6M**[1]
PPL 285 Onshore	Bisset Ltd (PPU/SASOL)	Western Province	**AWAPA SEISMIC SURVEY** GMC	**357.3**	**7,396,307**
PPL 287 **Onshore**	Potts Ltd (PPU/SASOL)	Western Province	**KANAU SOUTH SEISMIC SURVEY** GMC	**23.6**	2,628,215
PPL 234 **Offshore**	Oil Search Ltd	Gulf Province	**GP09 MARINE SEISMIC SURVEY** CGG Veritas	**779**	**799,680**
PPL 257 **Offshore**	Eaglewood Energy Ltd	Oro Province	**BUNA OFFSHORE SEISMIC SURVEY** CGG Veritas	**357**	**1,041,867**
TOTAL				**1588.36**	**18,466,069**

Table 2.2b: Geophysical Surveys – Ground Gravity & Magnetics Surveys.

Licence Area	Operator	Geographic Area	Name of Survey Contractor	Line Length Km	Cost (US$)
GROUND GRAVITY & MAGNETIC SURVEY					
PPLs 237 & 238 **Onshore**	SPI (210) Ltd - InterOil	Gulf & Central Provinces	**PPL 237-238 GROUND GEOPHYSICS SURVEY 2008** Oilmin	**105.3**	**607,117.63**
TOTAL				**105.3km**	**607,117.63**

[1] *USD Exchange Rate @ 0.3570 as at 30/06/2009*

Table 2.2c: Geophysical Surveys - Airborne Gravity/Magnetic Surveys.

Licence Area	Operator	Geographic Area	**Name of Survey** Contractor	Line Length Km	Cost (US$)
AIRBORNE GRAVITY & MAGNETIC SURVEY					
PPL 285 **Onshore**	Bisset Ltd – (PPL/SASOL)	Western Province	**AWAPA AEROGRAVITY SURVEY** GMC UTS Geophysics	**6177**	**426,117**
PPL 287 **Onshore**	Bisset Ltd – (PPL/SASOL)	Western Province	**KANAU SOUTH AEROGRAVITY SURVEY** GMC UTS Geophysics	**627**	**59,857**
PPL 257 **Onshore**	Eaglewood Energy Inc	Oro Province	**PPL 257 2009 AIRBORNE GRAVITY AND MAGNETIC SURVEY** UTS Geophysics Ltd	**3778**	**426,907**
PPL 258 **Onshore**	Bisset Ltd – PPL/SASOL	Western Province	**PPL 257 2009 AIRBORNE GRAVITY AND MAGNETIC SURVEY** UTS Geophysics Ltd	**7260**	**439,327**
PPL 286 **Onshore**	Honner Ltd (PPL/SASOL)	Western Province	**SOUTH FLY AEROGRAVITY SURVEY** GMC	**7390**	**501,895**
PPL 288 **Onshore**	Rowell Ltd (PPL/SASOL)	Western Province	**PPL 288 AEROGRAVITY SURVEY** GMC	**627**	**362,969**
TOTAL				**25,859**	**2,217,072**

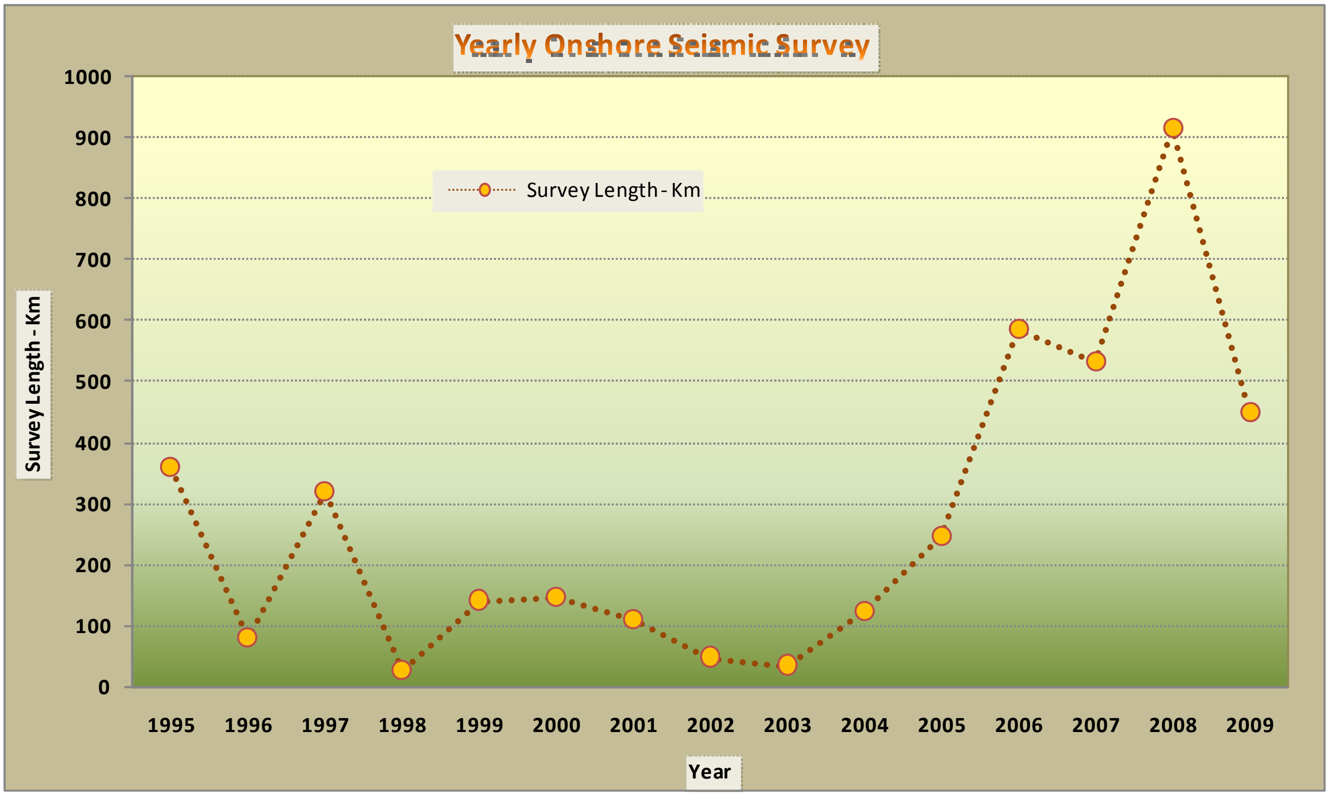

Figure 2.2a: Yearly Onshore Seismic Survey Length from 1995-2009.

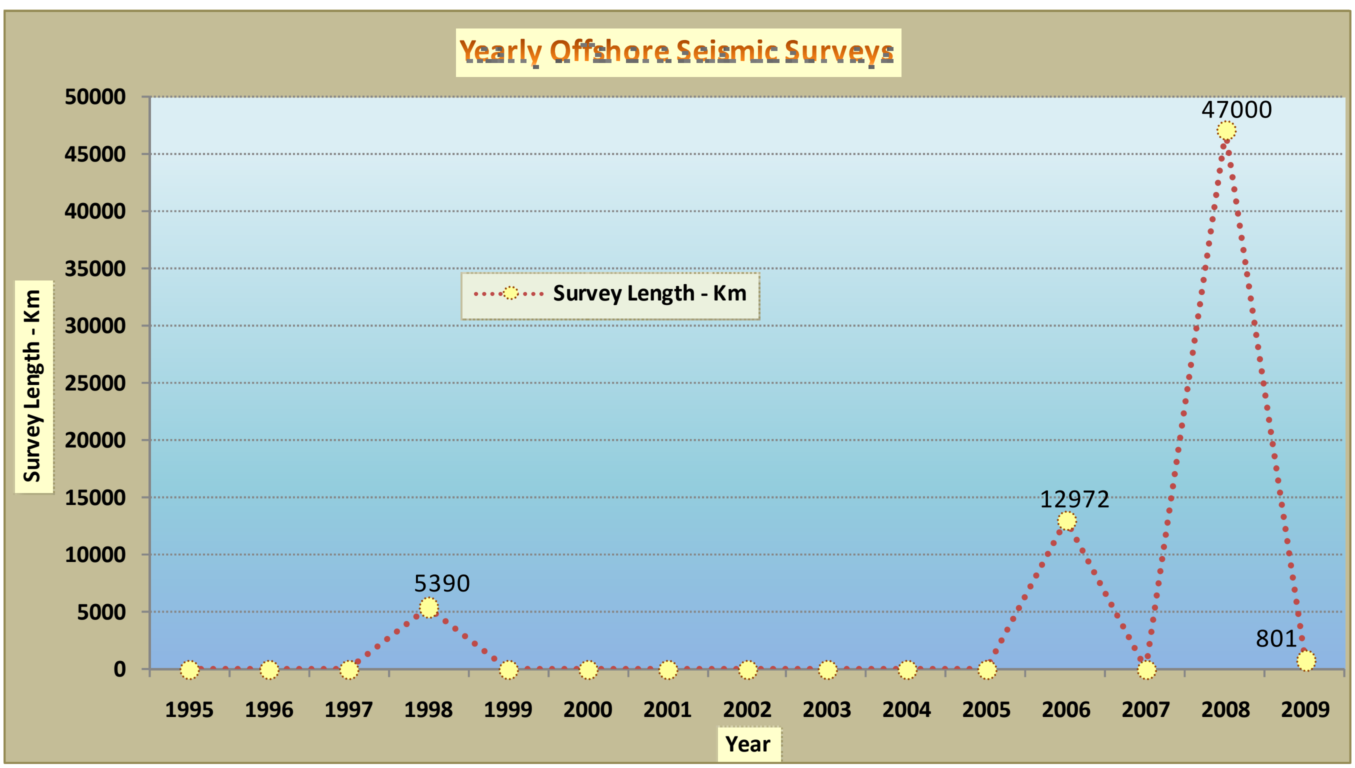

Figure 2.2b: Yearly Offshore Seismic Survey Length from 1995 to 2009

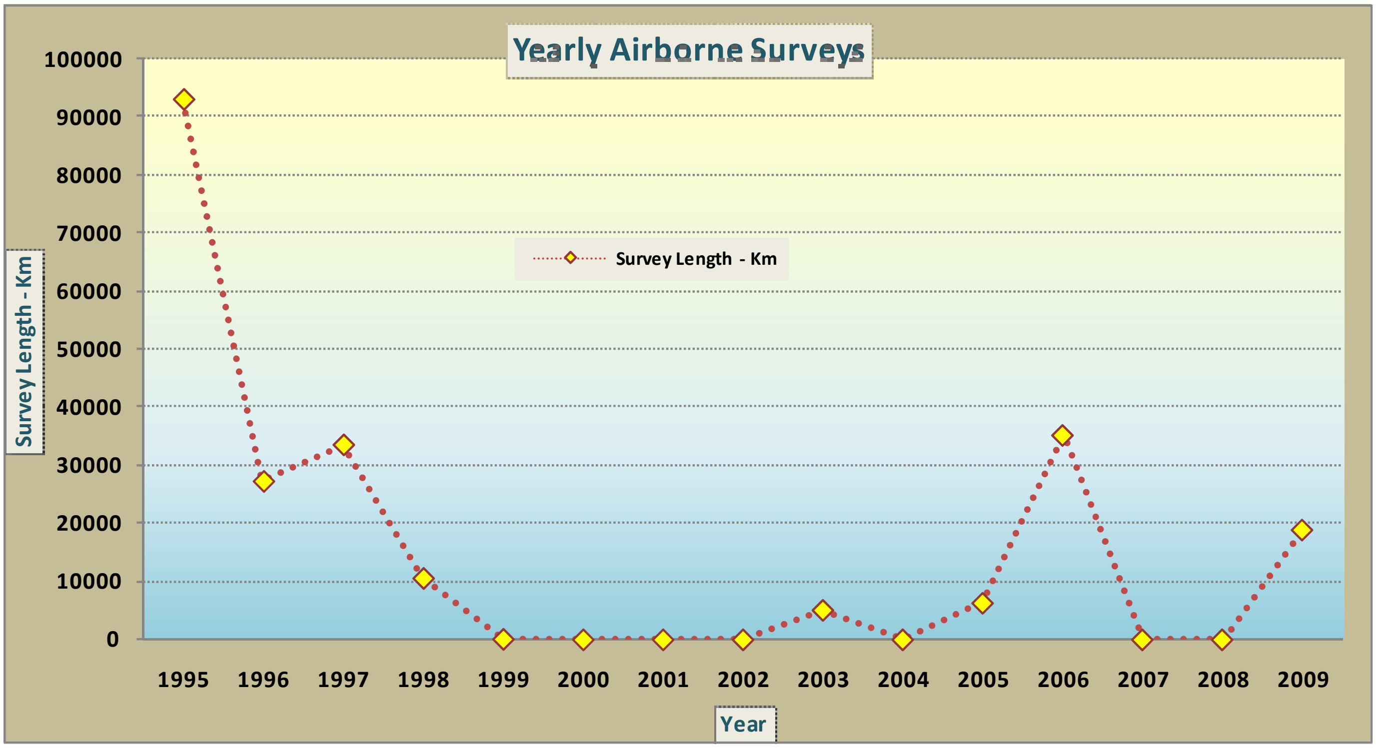

Figure 2.2c: Yearly Airborne Survey Length from 1995 – 2009

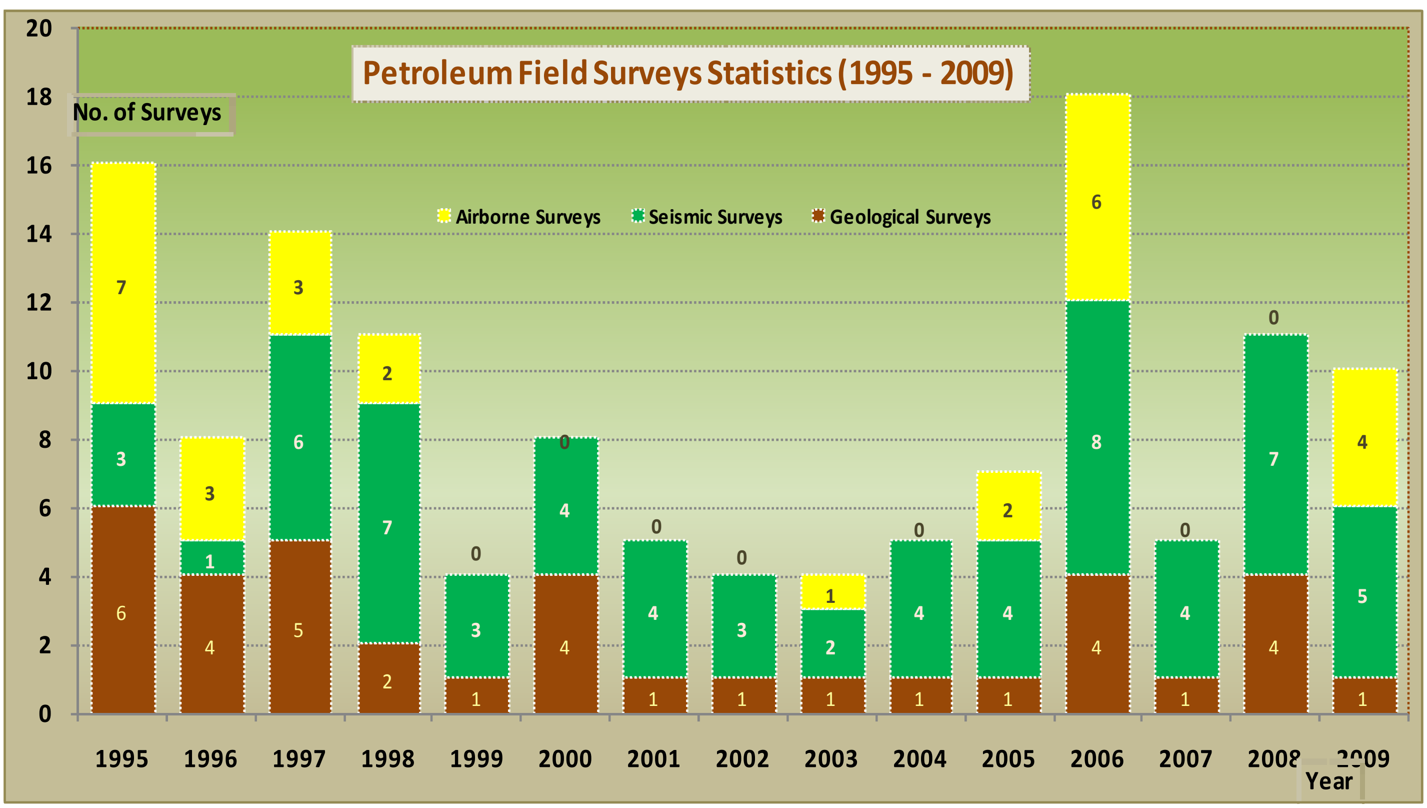

Figure 2.2d: Field Survey Statistics from 1995 to 2009

3.0 DRILLING OPERATION

3.1 Summary of 2009 Drilling Operations

A total of thirteen wells were drilled in 2009, six of which were development wells while others were exploration wells. From the thirteen wells, two wells were carried over from 2008, nine wells were spudded and completed within the year, and remaining two wells continued drilling into 2010.

Oil Search Ltd (OSL) drilled six development wells including UDT 11, UDT 12, Moran 6ST3, IDT 24, IDT 24 ST1 and ADD 5, and three exploration side track wells, ADT 2 ST1/2/3. InterOil Limited (IOL) drilled four wells and these include Antelope-1, Antelope–1 ST1, Antelope–1 ST2 and Antelope-2.

OSL's UDT 11 was carried over from 2008 and completed in 2009 as an oil producer. OSL also carried out two wire line re-entries with the objective of optimizing production. Moran 6ST3 was initiated following the unsuccessful Moran 6ST2 well's loss production. The existing ADT 2 well was re-entered, de-completed, abandoned and initiated an exploration well, ADT 2ST1, targeting a new potential reservoir below the existing oil-bearing Toro Formation that had depleted. ADT 2ST1 underwent two more side tracks as ADT 2ST2 and ADT 2ST3, due to mechanical problems. ADT 2ST3 continued into 2010 and operations were current at the time of this report.

Interoil Limited spudded the Antelope-1 well in 2008 which continued into 2009 with two sidetracks, Antelope 1 ST1 and Antelope 1 ST2. The wells were plugged and suspended for future completion as gas-producers. In July 2009, InterOil spudded Antelope-2 as an appraisal well to appraise the Elk/Antelope structure. This well continued into 2010.

The total unaudited well expenditure for Oil Search Ltd and Interoil Ltd in 2009 are estimated to be **US$177,970,000** and **US$112,900,000** respectively**.** Figure 3.1 is a graphical representation of all exploration and discovery wells statistics from 1989 to 2009. APPENDIX 3 presents a summary of all well discoveries made in PNG to date.

3.2 Exploration and Appraisal Wells

Year 2009 recorded three exploration and appraisal wells. These include Antelope-1, vertical exploration well; Antelope-2, directional exploration well and ADT 2 Sidetracks, which was a planned exploration well. Table 3.1 captures the summary of the wells.

3.2.1 Antelope 1

Antelope 1 was drilled in PPL 238, in the Gulf Province approximately 4.1 km to the south of the Elk4 well by InterOil Ltd with InterOil's Rig 2. This well aimed to test a potential reefal culmination and spudded on 15 October 2008 with a primary objective of drilling to the Puri/Mendi Limestone. Gas flows of 2 – 3 MMSCFD occurred in the interval 1747mRT to 1780mRT where the well was drilled under balance. Antelope-1 reached a total depth (TD) at 2710m on 25 January 2009.

Three conventional cores were acquired for geological analysis. Core#1 was taken from 2370m – 2374m with a recoverable core length of 2.97m (74.25% recovery). Core #2 was taken from 2374m – 2392m and recovered core length of 0.45m (2.5% recovery). Core#3 was taken from 2392.5m – 2399m with a recovered core length of 2.24m (37.23% recovery). A total of 160 side wall cores were recovered from 188 points.

A total of 8 DSTs were performed in the 8-1/2" open hole from 9-5/8" casing shoe to 2710m total depth (TD). DST#1 did not achieve isolation and flow by-passed the packers. DST# 2, 2a, 4, 5 and 7 failed due to poor hole conditions. The only successful DSTs were DSTs 3 and 6. DST# 3 produced saline water (>13000ppm) with slight oil, and flowed within the first 20hrs at a rate of 308 bbl/day water and a final average water rate of 223 bbl/day. DST#6 flowed gas at rates between 12 and 18 MMSCFD. Average condensate yielded was 12 STB/MMSCF and there was no water.

A non-technical, ceremonial flow test, for commercial reasons, was conducted through the 7" completion tubing where the well was flowed through a 10-5/8" flow line with a production flow rate of 382 MMSCFD gas and 5000 STBD condensate rate.

3.2.2 Antelope 1 ST1

Antelope-1 ST1 kicked off at 2335m with the objective of obtaining valid data through the transition zone from 2370m – 2550m which has not been fully evaluated by the log data in the original well. Wireline logs (AIT, PPC, GPIT and GR) were run and three DSTs (DST#8, DST#9 and DST#10) and a re-run (DST#9 RR) were performed to test for the presence of gas or reservoir fluids within this interval, and flow fluids if present. Of these tests, DST# 8 and 10 were successful having cumulative production over 30 hours of 57.6 bbl of water, 5.7 bbl condensate/light oil of 44 API and no gas; and cumulative production over 60 hours of 1269 bbl of water, respectively. DST#9 tool failed and upon recovery of the test tool various parts were missing: door from lower double recorder carrier, clamps from packers, bolts and rubbers from packers. The top of the junk was tagged at 2414.5m and the top of the Junk was cemented. A second side track was initiated.

3.2.3 Antelope 1 ST2

Antelope-1 ST2 kicked off at 2050m and was designed to test the lower intervals which were not tested due to failed DSTs #2, #4 and #5 during well testing of the original well – Antelope 1 and DST #9 in Antelope 1-ST1 well. DST#11 was performed from 2294 to TD of 2347m with a peak gas flow rate of 10.12 MMCFD and peak condensate rate of 169.27 bbl/day recorded. DST#12 was performed from 2323m to 2402m and had a pre-flow estimated average gas rate of 2.1 MMCFD and an average water rate of 26 bbl/day. The main flow resulted in gas rates fluctuating between 1.5 to 2.6 MMSCFD with an average CGR of 15.2bbl/MMSCF. DST#13 sampled light oil/condensate. DST#14 was performed over an interval of 2419.5m and 2452m and DST 15 was performed from 2452m to 2490m, but failed due to tight hole at 2481m to 2490m. The well was then plugged back at TD 2456m.

The Antelope-1, Antelope-1 ST1 and Antelope-1 ST 2 operations ran for a total of 254.35 days and the rig was released on 26 June 2009. The well was completed at a well cost of **US$61,000,000** which was **$37,000,000** more than the AFE Cost.

3.2.4 Antelope 2

Antelope-2 was spudded on 27 July 2009 with InterOil's Rig 2 and was the fourth follow-up well to the Elk 1 gas discovery, lying 3.6 km south, south east of the Antelope-1 well and 9 km south of the Elk 1 well. This well was drilled to test the southern extent of the Antelope Reef Play in PPL237 with the primary objective to drill into the Antelope Limestone and prove hydrocarbons at a proposed total depth (TD) of 2550m ±200m MD. DST#1 was performed at interval 1832m and 1882m and flowed gas at rates of 14.1 MMSCFD with a maximum recorded rate of 18.2 MMSCFD and a condensate ratio of 16.5 bbl/million cubic feet.

Three conventional cores were obtained in Antelope 2. Core#1 had a 100% recovery from 1835m to 1840m MDRT. Core#2 cored from 1846m to 1881m MDRT had 99.4% recovery. Core# 3 was cut at interval 2185m – 2214m MDRT with 31.07% recovery.

Another ceremonial test for commercial reasons was carried out on this well on 1 December 2009 and the well flowed at an extraordinary high rate of 705.66 MMCFD.

Total Depth was reached at 2282m on 31 December 2009 and the AFE cost is estimated at **US$9,200,000.**

3.2.5 ADT 2 Sidetracks

The ADT 2 well in the Agogo Field was originally a re-entry into the original Agogo 5X well which had previously reached a TD of 2608mMD (8556ft) on 5 November 1992. Production from this well commenced on 27 January 1993 from the Toro A reservoir without gas lift, but was shut-in in 1994 due to having high gas oil ratio (GOR). It was then plugged and abandoned in June 1996.

3.2.6 ADT 2 ST1

ADT 2 ST1 was planned as an exploration well, sidetracking from the existing ADT 2 well bore and targeting the Koi-Iange reservoir sands using OSL Rig 104. The re-entry of ADT 2 well commenced on 31 October 2009 and the well was kicked off at 2475.0mMDRT. However, the drill string became differentially stuck and attempts to free the drill string were unsuccessful requiring a mechanical sidetrack.

3.2.7 ADT 2 ST2

ADT 2 ST2 kicked off from the ADT 2 ST1 well bore and drilled to 3714mMDRT before the drill string experienced the same problem as in ADT 2 ST1. The string was backed off at 3525mMDRT.

3.2.8 ADT 2 ST3

ADT 2 ST3 kicked off from the ADT 2 ST2 well bore at 3484mMDRT and drilled to a total depth of 4140mMDRT. A DST was performed at 3610mMDRT, but no fluid was recovered. The ADT 2 ST3 did not achieve the original objective. The Koi-Iange, however, was intersected in the hanging wall. The well reached TD within the inverted Juha Formation after a series of fault compartments containing inverted Digimu, and the Toro reservoirs were penetrated. Petrophysical data interpretation indicated an oil column in the first inverted Digimu and implied that the deeper Digimu and Toro sands may also be hydrocarbon bearing. The well was continuing operations at the end of 2009. The AFE for the well is estimated to be **US$13,656,628.**

Table 3.1: Exploration and Appraisal Well Summary 2009.

WELL ID	LICENSEE	LICENSE	SPUD DATE	RIG RELEASE	T.D (mMD)	RESULT	CUM COST IN US$MM	SIDETRACK
Antelope 1	SPI	PPL 238	15/10/08	Rig end this well on 10/03/2009	2490	Gas Prospect	33.3	Mechanical
Antelope 1 ST1	SPI	PPL 238	Began Sidetrack on 04/11/2009	Rig end this well on 26/04/2009	2414.5	Gas Prospect	8.9	Mechanical
Antelope 1 ST2	SPI	PPL 238	Began Sidetrack on 27/04/2009	26/06/2009	2456	Gas Prospect	17.5	Completed
Antelope 2	SPI	PPL 237	27/07/09	Rig end this well on 10/02/2010	2325	Gas/Condensate Prospect	53.2	Mechanical
ADT 2 ST1	OSL	PDL 2	31/10/09	04/11/2009	2953	Oil Prospect	2.9	Mechanical
ADT 2 ST2	OSL	PDL 2	Began Sidetrack on 05/11/2009	Rig end this well on 08/12/2009	3525	Oil Prospect	18.2	Mechanical
ADT 2 ST3	OSL	PDL 2	Began Sidetrack on 15/12/2009	28/01/2010	4140	Oil Prospect	33.7	Completed

3.3 Development Wells

3.3.1 UDT 11

The UDT 11 well was drilled using the OSL Rig 103 in PDL 2 between UDT 4AST1 production well and Arakubi exploration well. The well was spudded on 21 October 2008 and continued drilling into 2009. The main objectives of the well were to drain the un-swept oil from Toro A, Toro B (Upper), Toro B (Lower) and Toro C reservoirs and gain evaluation data to confirm overburden and reservoir structure, fluid content in the Toro formation and the reservoir quality. The well was drilled to a total depth (TD) of 3810.0mMDRT and it was successfully completed utilizing a two-zone selective completion; Toro A and B in one zone, Toro C in the other zone. The rig was released at 1945hrs on 19 February 2009. The Well Cost was **US$50,155,078** after all operations.

3.3.2 IDT24 / IDT 24 ST1

The IDT 24 well's primary objective was the Toro C reservoir and was anticipated to acquire specific evaluation data throughout the overburden to confirm structure. The well spudded on 6 March 2009 using OSL's Rig 104 and the top of Toro was intersected at 2453.3m. The well was plugged back at 3151m when the string got stuck at

2698m. The well was then sidetracked and commenced operations from the depth 2454m and drilling continued before reaching a final well TD of 3450m. The well was completed as an oil producer from the Toro C reservoir and the rig was released on 27 May 2009. The well cost was **US$42,216,481** which is US$7 million above its original AFE.

3.3.3 UDT 12

UDT 12 was drilled in the Usano Field in PDL 2 with the primary objective of acquiring all specific evaluation data through the overburden and reservoir sections to confirm structure, Toro fluid content and reservoir quality. The well spudded on 7th July 2009 and was drilled to a total depth of 2810m. UDT was finally completed as an oil producer with a five-zone completion with perforations in Toro A, Toro B Lower and Toro C1, C2 and C3 Sandstone formations. The rig was released on 2400hrs on 6th July 2009 and the actual well cost was **US$15,700,000,** which was **US$4,077,402** less than the AFE Cost.

3.3.4 Moran 6ST3

The Moran 6 ST3 well was initiated upon re-entry and sidetracking of the Moran 6ST2, which was abandoned after work over operations ended in a fish being lost down hole. The well was drilled directly adjacent to the Moran 6ST2 well bore and the primary targets were the Toro C and Digimu A and C reservoirs. Moran 6 ST3 kicked off from 3711m and drilled to total depth of 4010.0m and was completed with a five-zone selective completion over Toro C Upper, Toro C Lower, Digimu A, Digimu C Upper and Digimu C Lower. The rig was released on 18 August 2009 at 1200hrs. The well was drilled and completed under budget at **US$10,802,314** compared to the AFE Cost of **US$15,037,915**.

3.3.5 ADD5

The primary objective of the ADD 5 well was to penetrate the oil bearing leg of the Digimu reservoir and to target the Hedinia and Iagifu Members, and the Toro Sandstone which was expected to be gas-bearing. The well was spudded on 15 August 2009 at with OSL's Rig 104. The well was drilled to total depth (TD) at 3068m, intersecting the secondary targets, Hedinia and Iagifu and was completed as an oil producer with a seven zone completion across the Toro, Digimu, Hedinia and Iagifu reservoirs at an actual well cost of **US$23,504,004**.

Table 3.2 presents a summary of all Development Wells drilled and completed within the reporting year, while Figure 3b.1 shows all development wells versus exploration and appraisal wells since 1990.

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Table 3.2: Development Wells Summary 2009.

WELL ID	OPERATOR (LICENCE)	SPUD DATE	RIG RELEASE	TD (mMD)	RESULT	COST (US$MM)	SIDETRACK
UDT11	OSL (PDL 2)	21/10/08	19/02/09	3810	Oil	19.5	Completed
IDT24	OSL (PDL 2)	06/03/09	End well on 26/04/09	Plugged back at 3151		23.1(approx.)	Mechanical
IDT24/ST1	OSL (PDL 2)	Start well on 27/04/09	27/05/09	3450	Oil	42.2	Completed
UDT12	OSL (PDL 2)	70/06/09	06/07/09	2810	Oil	4.07	Completed
MORAN 6 ST3	OSL (PDL 2/5)	18/07/09	18/08/09	3985	Oil	10.8	Mechanical
ADD 5	OSL (PDL 2)	15/08/09	28/09/09	3068	Oil	23.5	Completed

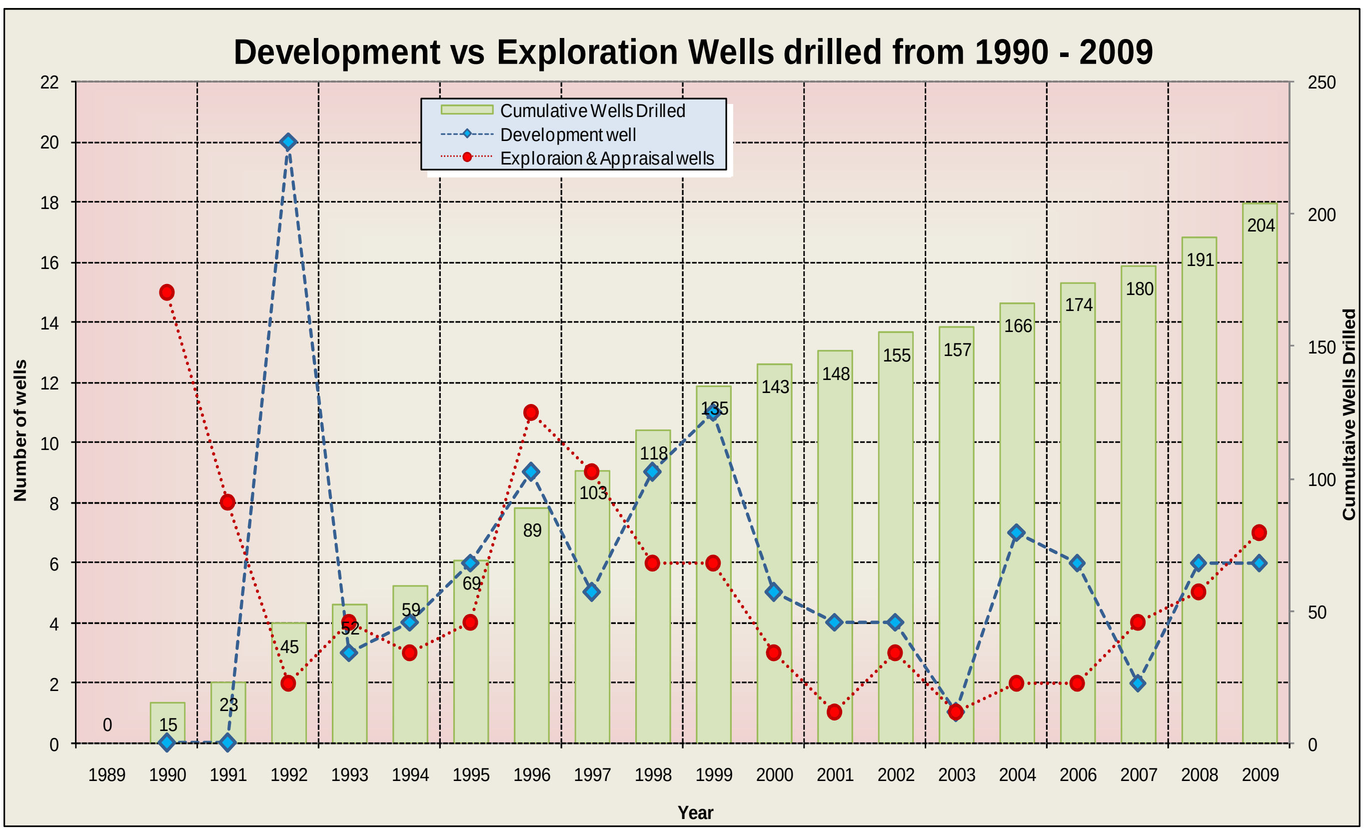


Figure 3.1: Trend of Development Wells vs. Exploration- Appraisal Wells.

4. PRODUCTION

4.1. 2009 Production Summary

In 2009, the average oil production rate was 38,201 BOPD with an annual total of 13,943,095 STBO which was a 7% decline from 2008. Gas production from oil fields, decreased by 11% with the total of 134.38 BCF at a rate of 11, 844 MSCFD. In Hides, (non-associated gas field) the Sales Gas to PJV increased in production for sales with a total of 5.63 BCF at a rate of 15.45 MMSCF per day.

The three main factors that influenced the decrease of oil and gas production in the associated fields were the cut-back in gas production in light of the PNG LNG project, the natural decline in the oil production and the normal daily operations hindered by hydrates, rising gas/oil ratios (GORs) and mechanical downhole problems on regular producers. These challenges were successfully addressed by application of reservoir and surface network modelling of the sequences and adjustment in the length of swing cycles along with utilization of new downhole technology.

Furthermore, work was undertaken to optimize the performance of existing wells and surface facilities in order to slow down decline rates in the underlying base field production. In addition, work continued to increase production through the drilling of in-field wells, to access oil pools not swept by existing wells.

Figure 4.1 and Figure 4.2 summarized the trend of oil and gas production in 2009. A detailed summary of the monthly oil and gas production from PDLs 2, 3, 4, 5 and PDL 6 is shown in Table 4.1 while Table 4.2 shows comparative overall production rates of oil, gas and condensate from respective fields in PNG for 2008 and 2009. Both Tables 4.1 and 4.2 are in APPENDIX 4 and can be used as reference to all the graphs for each PDL area.

In February, an annual plant maintenance was undertaken and all the processing facilities were shut down for 5-10 days to undergo general maintenance. These are reflected in Figures 4.1 and 4.2**.** Such shut downs are essential to production, as the fields are mature and the facilities have been over 20 years in service.

In April, the Agogo Processing Facility (APF) encountered export pump failure, hence production was restricted, this impeded the overall oil production as seen in Figure 4.1**.**

4.2. Shipment of Crude Oil

A total of 13.88 MSTBO was exported both offshore and within PNG collectively which was a decrease of 6% of that exported in 2008. Normal export operations had one vessel berth at KMT every 12 to 13 days from the last loading. Hindrance to normal operations occurred as a result of communication failures, mechanical problems, bad weather and delay of vessels. Moreover, export was also dictated by the loading capacity of the respective vessel, which ranged from a minimum of 150,000 STBO tankers to 650,000 STBO super-tankers. The highs and lows of export as seen in Figure 4.3 gives an overview of one or all the elements described above at play, rather than marginalized exporting. Despite low exports from production restrictions such as export pumps being out of service from the respective facilities in February, April and August, OSL has improved its overall storage capacity by using two of the three storage tanks in GPF for additional storage beyond 12 days. Details of this are covered in **Section 5.0**.

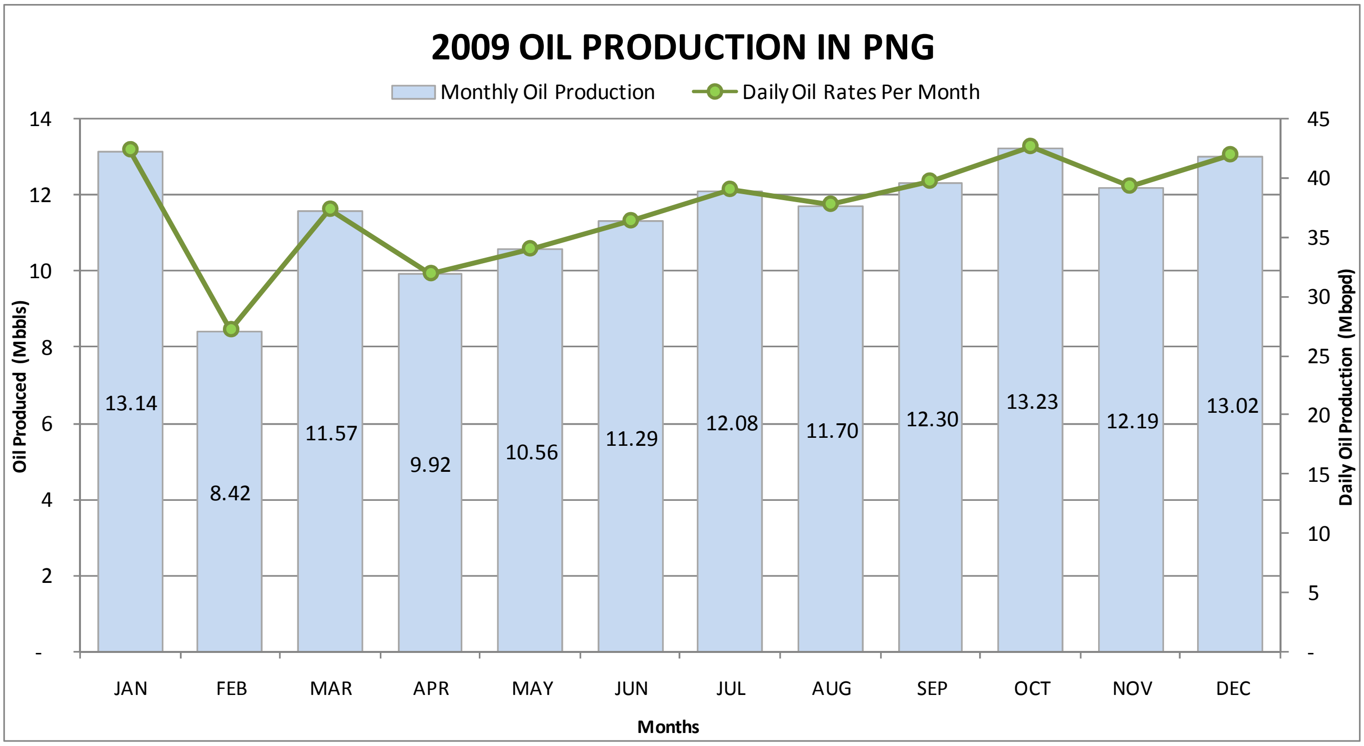


Figure 4.1: Graph illustrating Oil Production in PNG.

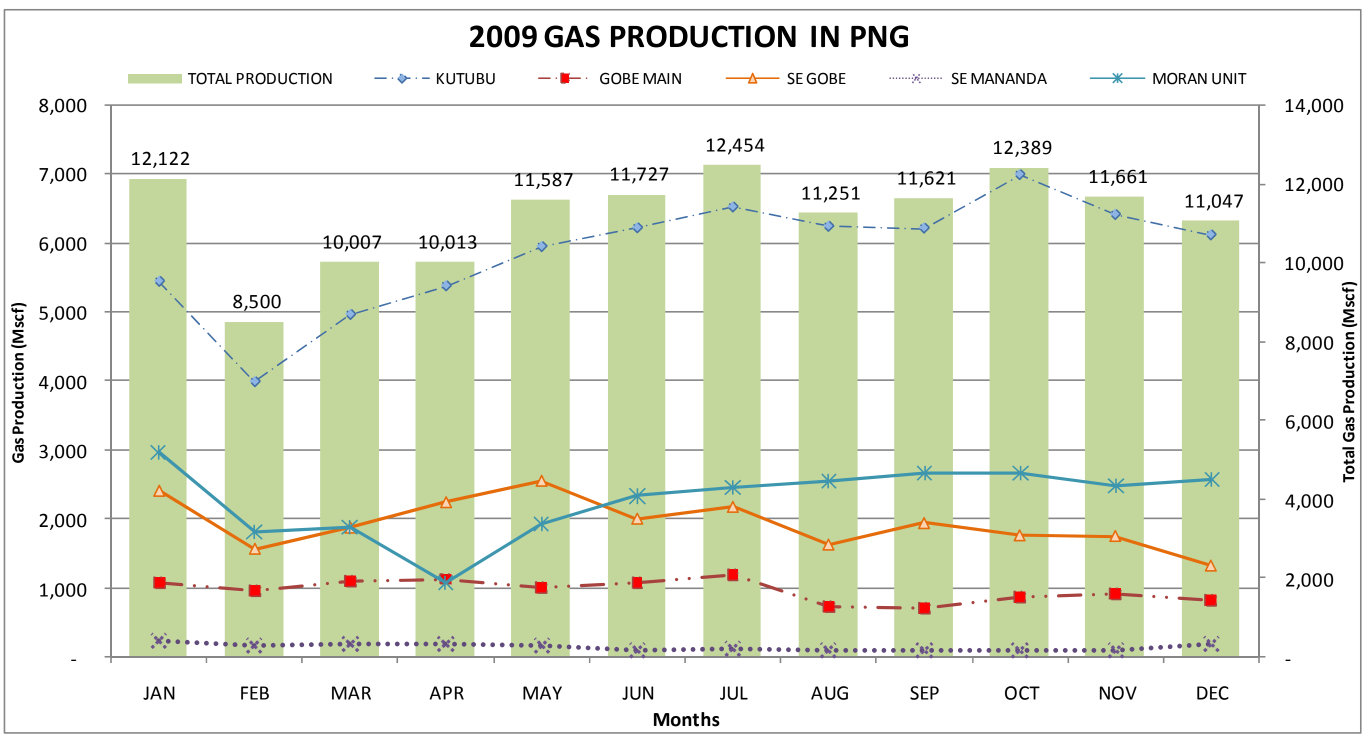


Figure 4.2: Illustration of gas production in PNG from the associated fields (PDLs 2,3,4,5 and 6).

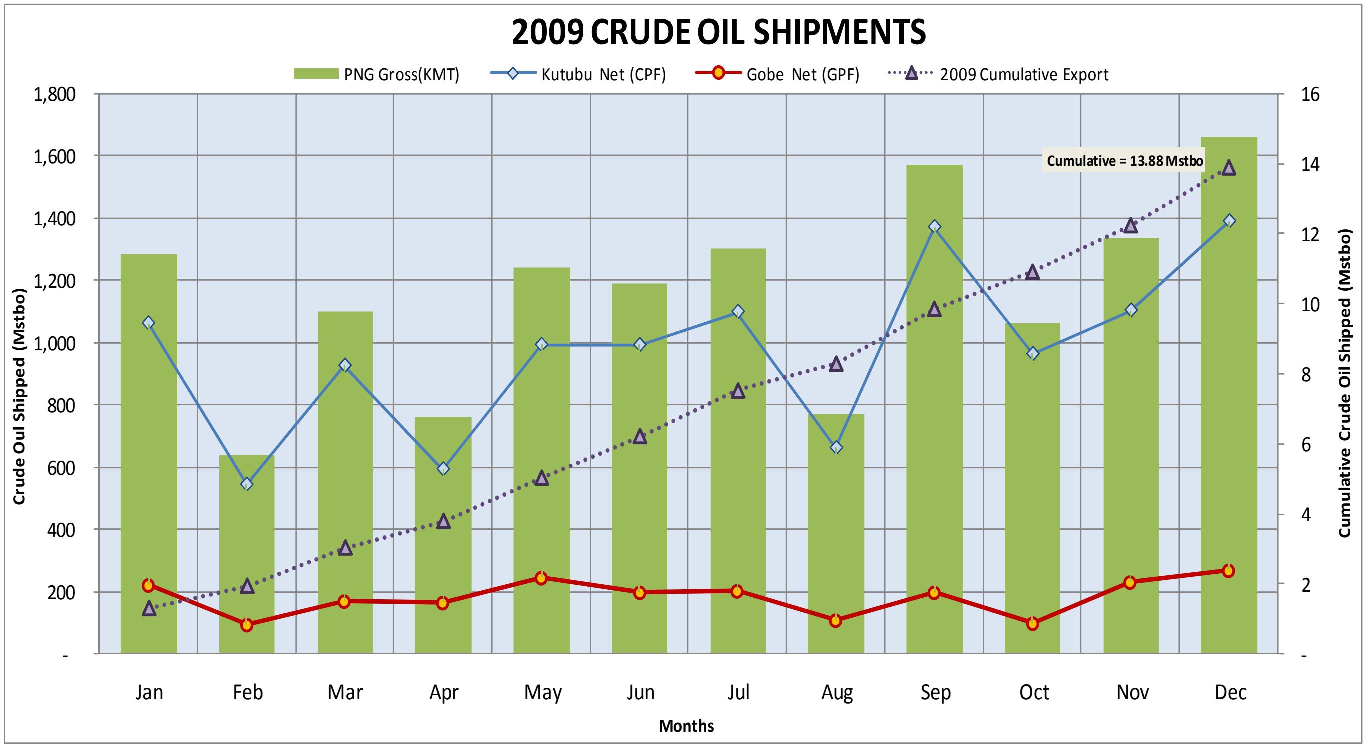


Figure 4.3: Crude Oil Exports for 2009

4.3. Hides (PDL 1)

Production was high in both gas and liquids at Hides throughout the year. A total of 5,511.35 MMSCF of gas was produced from this field, which was 9% higher than 2008. From this total production, 5,521.36 MMSCF were sales gas to PJV. The overall gas production figures are illustrated in Figures 4.4 and 4.5 and tabulated in Table 4.3, APPENDIX 5.

The year saw a daily average of 15.10 MMSCFD of gas production, although only 14.79 MMSCFD were sold to PJV. In addition, ongoing maintenance on the microstills affected normal production rates. However, condensate production was 4% higher than 2008 with a total of 134,875.27 BBLS that yielded 65,825.67 BBLs of naphtha, 24,289.56 BBLS of diesel and 6,505.54 BBLs of residue. According to the Operator's production reports, condensates production average at 369.52 bbl per day for the year with strong production rates of residue at 17.82 BOPD, naphtha at 180.34 BOPD, diesel at 66.55 BOPD. The overall liquid production figures are illustrated in Figures 4.5 and 4.6. Figure 4.4 and Table 4.3 in APPENDIX 3 are details of gas and liquid production and distribution to PJV, local sales and own usage in the Hides processing plant.

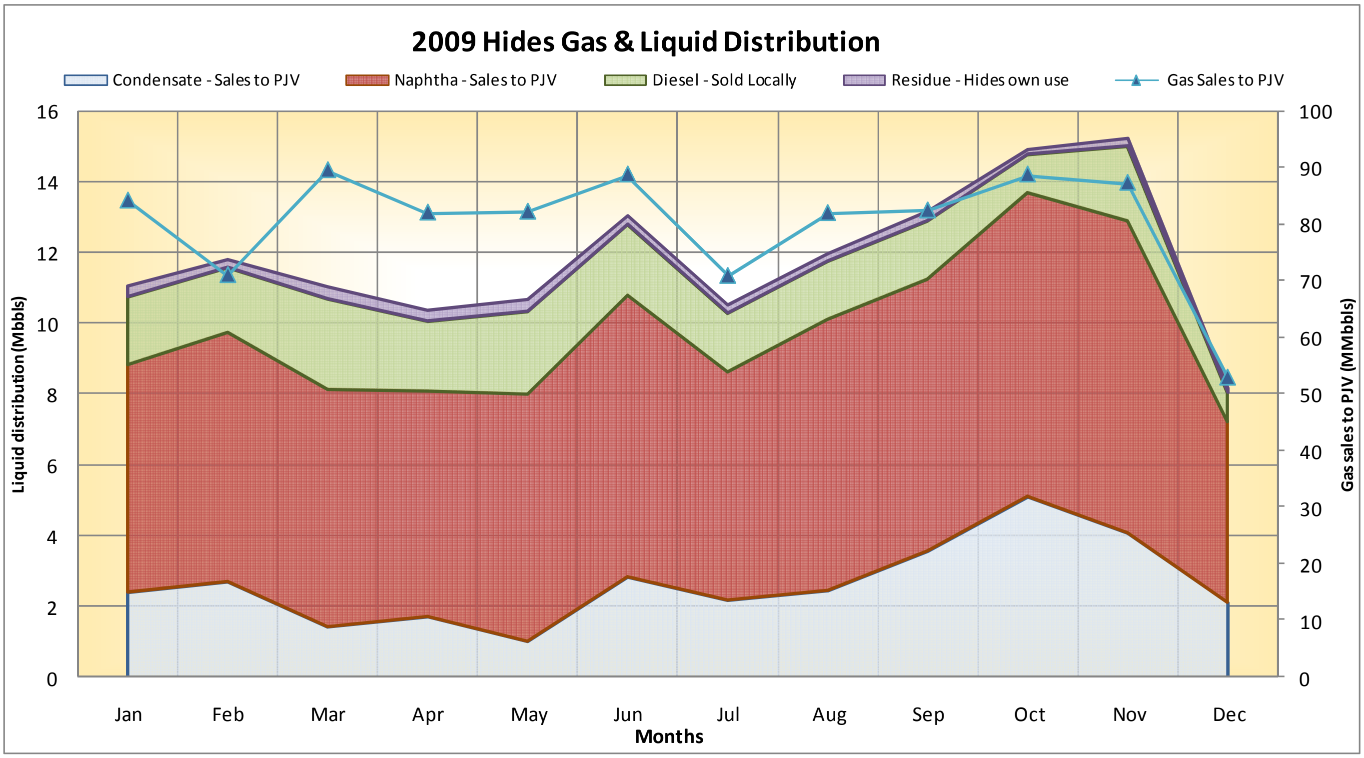


Figure 4.4: 2009 Hides Gas & Liquid Distribution.

4.1. Kutubu Fields (PDL 2)

Kutubu production performance was excellent with gross production rates 17% higher than in 2008. Kutubu produced a total of 6,316,222 BBLs in 2009 at an average daily production rate of 17,305 BOPD. Gas production also saw a decrease of 70,315,924 MMSCF at an average rate of 192.811 MMSCFD.

The natural field decline was mitigated through careful well and facilities management by OSL. Intervention work on several wells early in the year added significantly to field production. The production decrement in February was due to a scheduled ten-day field shut down to carry out repairs to the Central Production Facility. The year saw a steady increase in production as seen in Figure 4.7.

4.2. Gobe Fields (PDL 3 & 4)

During the year, there was continued emphasis on minimising natural decline from these mature fields through optimisating existing well surface facility performance. Although, sand production problems were prevalent at the Gobe fields, operations were kept under control as the previous years. Subsequently, GPF continuous compressor service resulted in net oil production rates from the Gobe fields being 21% higher than 2008 levels.

Gobe Main produced 607, 863 BBLs at a rate of 1,661 BOPD and the total gas produced was 11,596,327 MMSCF of gas at a rate of 31,684 MMSCFD. The months that attributed to production below monthly average of 50,655 BBLs were due to reduced oil cuts on production wells and problems with the compressors, which affected wells that relied on gas-lift and production restrictions due to the export pumps being out of service. Figure 4.8 sums up the overall oil and gas production from the Gobe Main field.

SE Gobe produced a total of 1,594,954 BBLs of oil at a rate of 4,358 BOPD, which is a 19% decrease from 2008, and the total gas produced was 23,236,440 MMSCF at a rate of 63,488 MMSCFD. The lows in production shown in Figure 4.9 are due to various operational problems causing wells to shut-in for slickline operations, obstructions in production tubing such as sand, wireline works and line restrictions on wells and compressor shutdowns that affected wells that were dependent on gaslift.

4.3. South East Mananda (PDL 2 & PDL 6)

The South East Mananda (SEM) field production was 44% lower than in 2008 levels. In 2009, SEM produced a total of 291,870 BBLs of oil with an average daily rate of 797 BOPD. Total gas produced from the South East Mananda field was 1,756,784 MMSCF with an average daily rate of 4,800 MMSCFD.

Although production decline in most wells was consistent with expectations, the SEM 1 and 3 wells ceased to flow during the year due to high water cut and SEM 3 had additional downtime due to hydrate formation as shown in Figure 4.10. This affected field performance from July to November as summarised in Table 4.1-APPENDIX 4 showing monthly statistics. In addition, the Agogo Production Facility (APF), which normally processed produced fluids from SEM, was shut down for ten days of maintenance scheduled for February hence production was below the 2009 monthly average of 24,323 BBLs.

4.4. Moran Unit (PDL 2, 5 & 6)

Production from the Moran Unit was 20% lower than in 2008 primarily due to declines in the underlying base production and a delay in the drilling of additional production wells, with no new well brought into production during 2009. However, ongoing technical studies at Moran are focused on identifying additional infill and near field appraisal well locations with well and facility optimisation projects. The rising GORs and the impact of hydrate formation in some wellbores were successfully overturned by application of reservoir and surface network modelling of the sequence and length of swing cycles along with utilisation of new technology at respective wells.

Total Moran Unit oil production for 2009 was 5,132,186 BBLs at a rate of 14,022 BOPD while gas produced from the same field was 27,414,152 MSCF at a rate of 74,902 MSCFPD, which is lower than 2008 productions.

4.5. Production History and Forecast

Figure 4.12 shows the decline in oil production as forecasted to 2009. In 2006 where the actual production failed to meet the forecasted 2P production, there was an increase in gas production and lesser oil being produced due to increased GORs, hydrates in wellbores and sand production problems. Since 1991, estimated oil production accumulated to a total of 0.449 MMBBL.

In Figure 4.13, the graph shows clearly how gas production has increased since production commenced over 18 years ago and has accumulated a total of 183.2 BCF in gas production by 2009. The trend signifies field maturity and also the increase in gas to oil ratio in the respective matured fields. From the total gas produced since 1991, over 132.9 BCF of gas have been injected back into the reservoirs while flaring, fuel-gas and gas-lifts consumed only about 51.8 BCF of gas.

Table 4.4 in APPENDIX 6 is a detailed summary of the oil and gas production since the first production commenced in 1991 and can be used as reference to Figures 4.12 and 4.13. In APPENDIX 7, the graph illustrates the actual and forecasted 2P oil production from 1991 to 2030 when oil production is estimated to end. The data was extracted from the 2009 Annual Reserves Report from the oil and gas production fields' operator, Oil Search Limited.

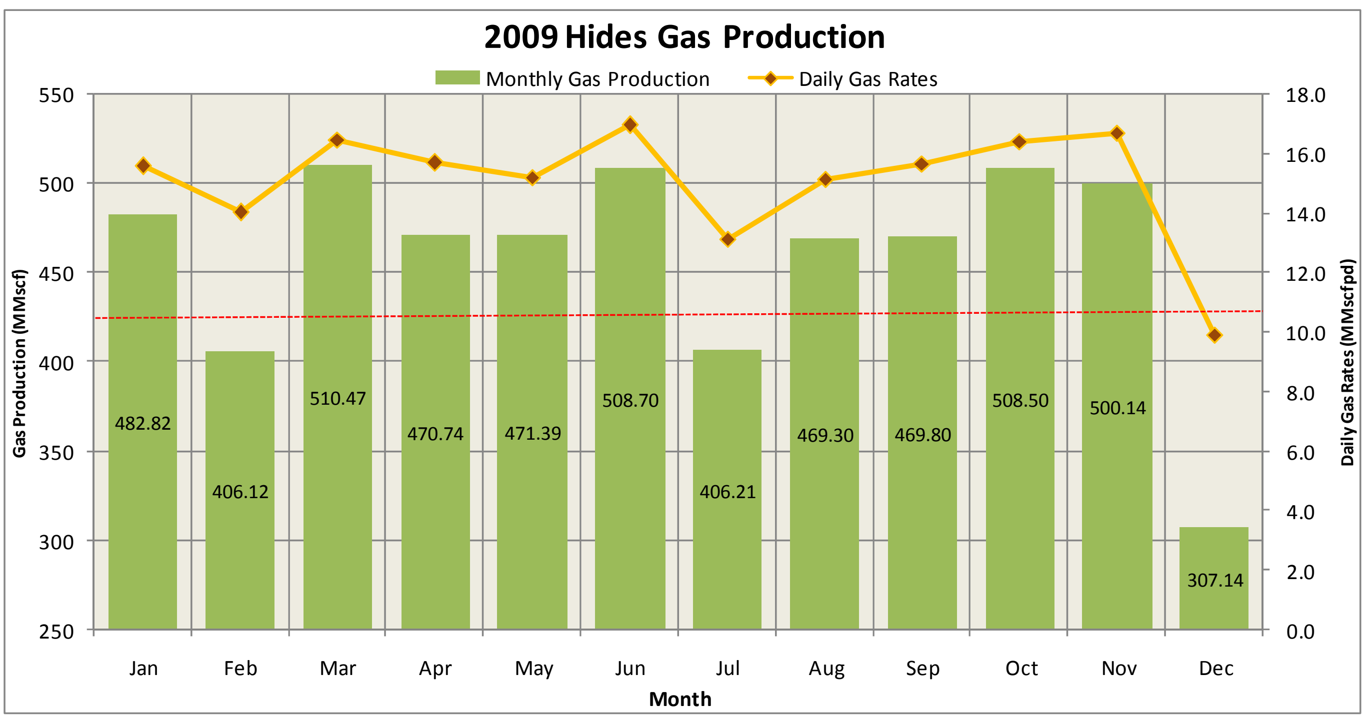


Figure 4.5: Hides Gas Production for 2009.

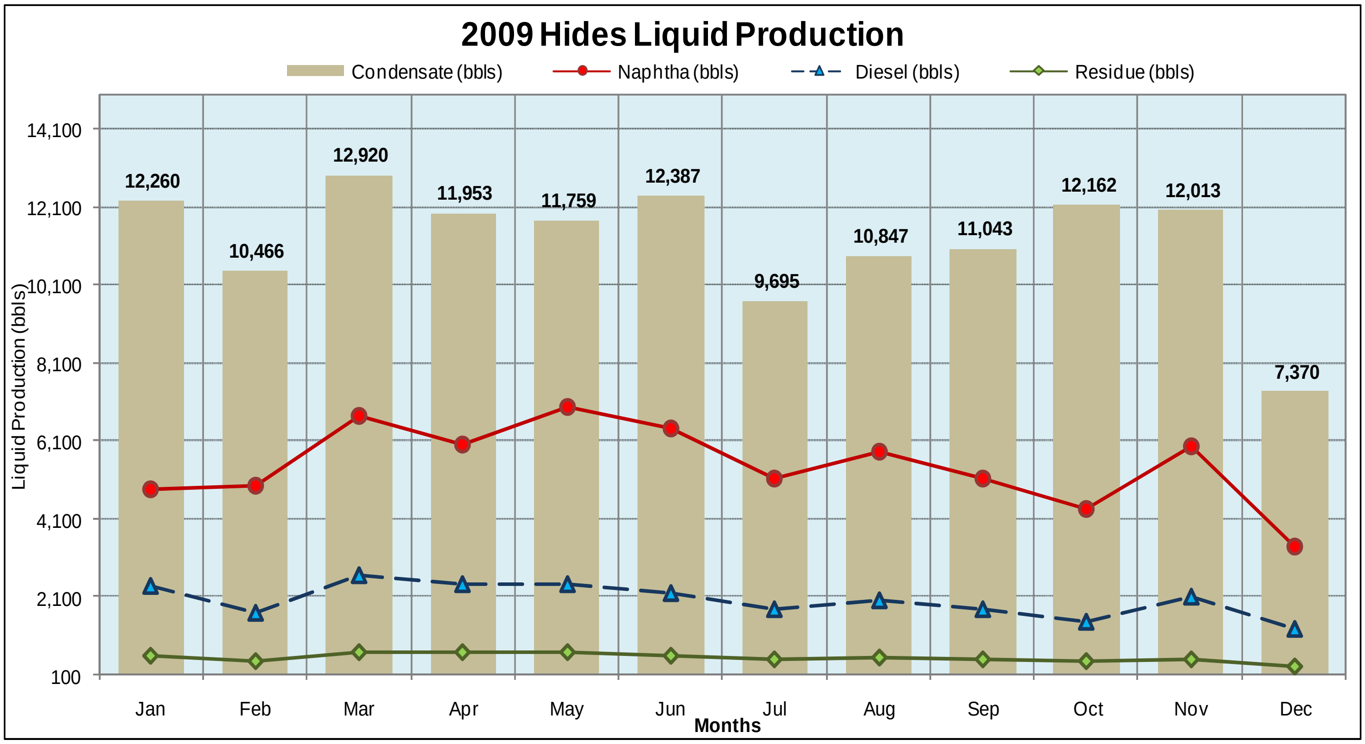


Figure 4.6: Hides Liquid Production for 2009.

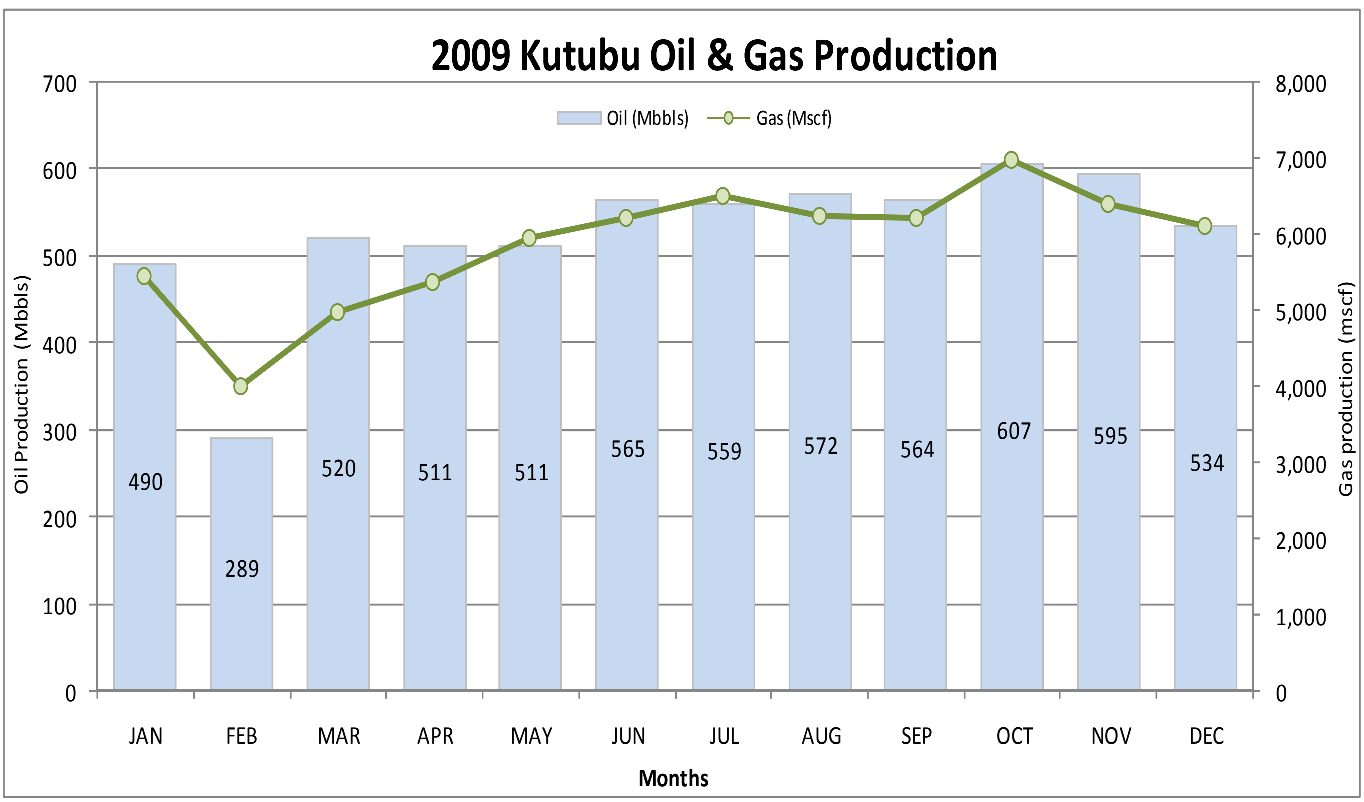


Figure 4.7: Kutubu Oil & Gas Production (2009).

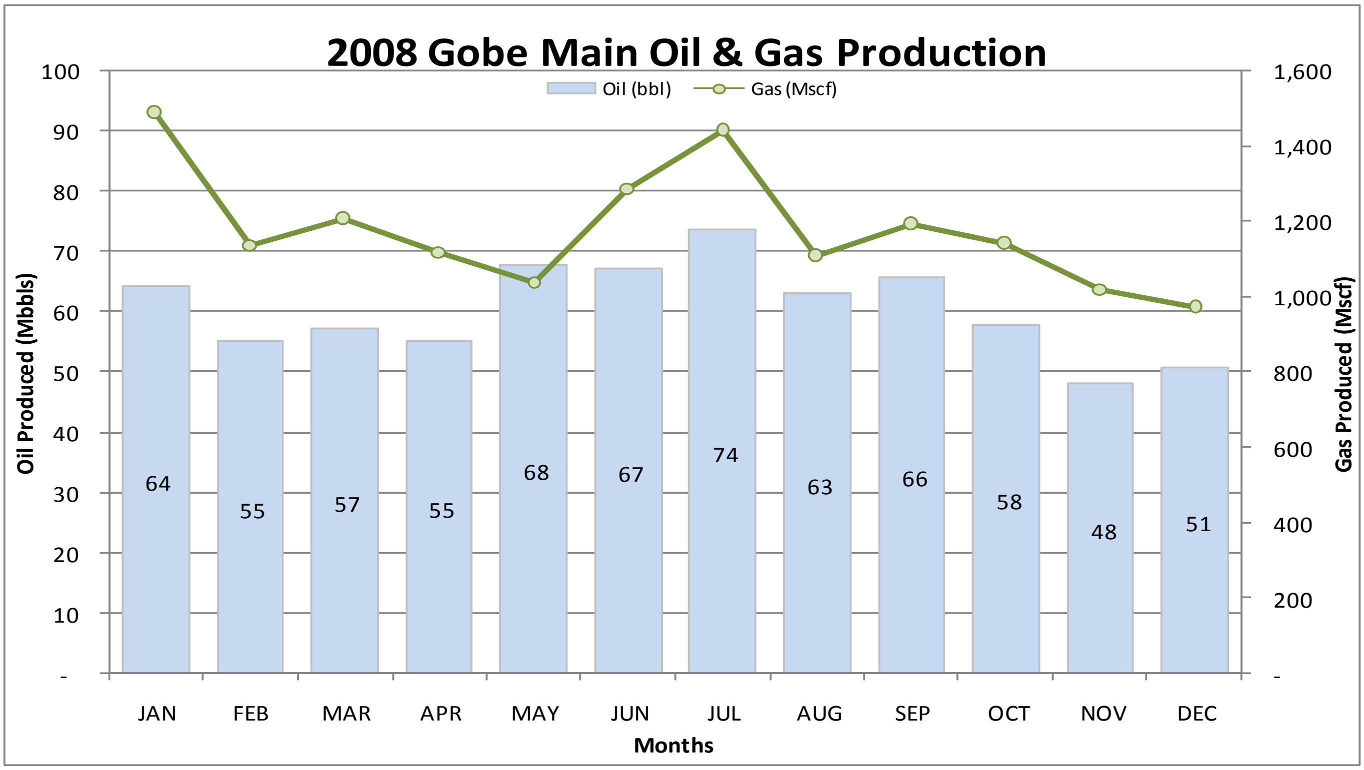


Figure 4.8: 2009 Gobe Main Oil & Gas Production.

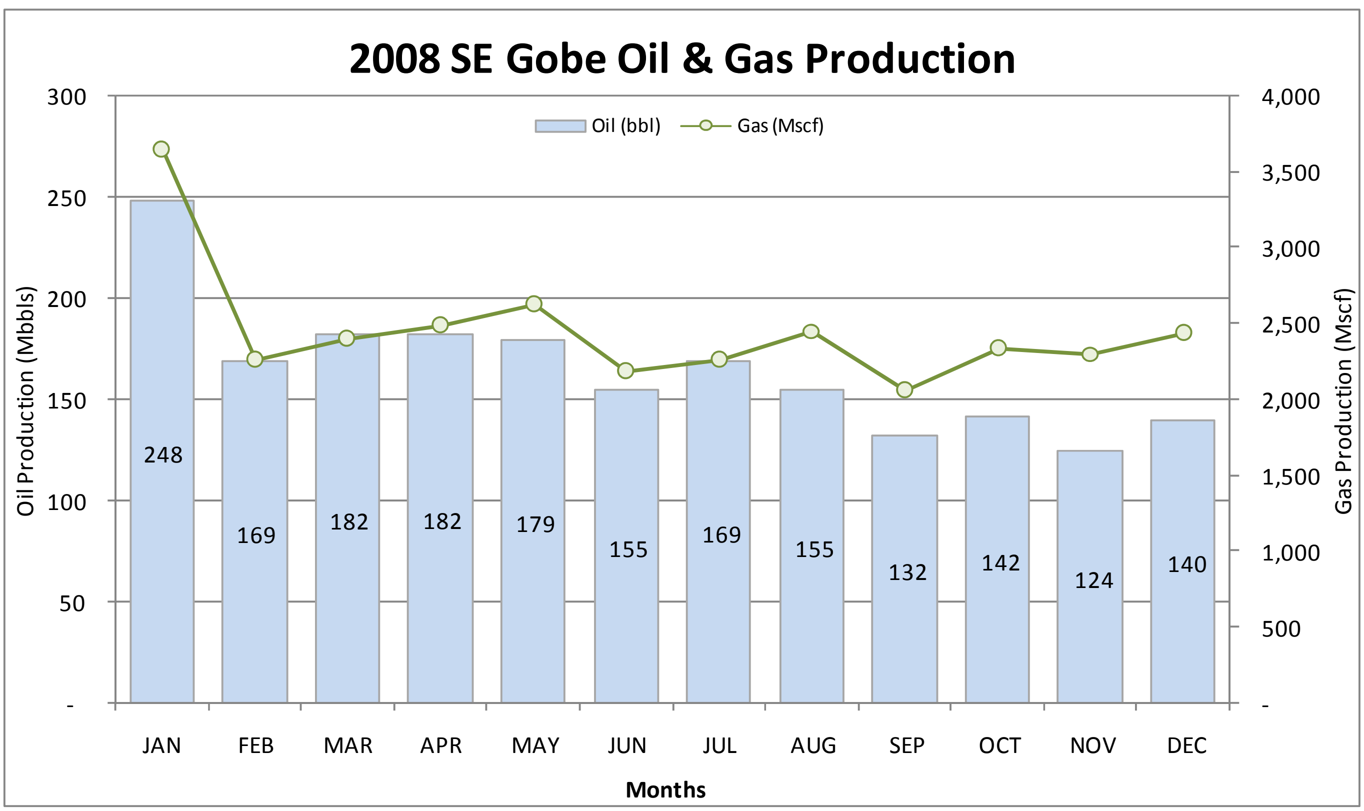


Figure 4.9: 2009 SE Gobe Oil & Gas Production.

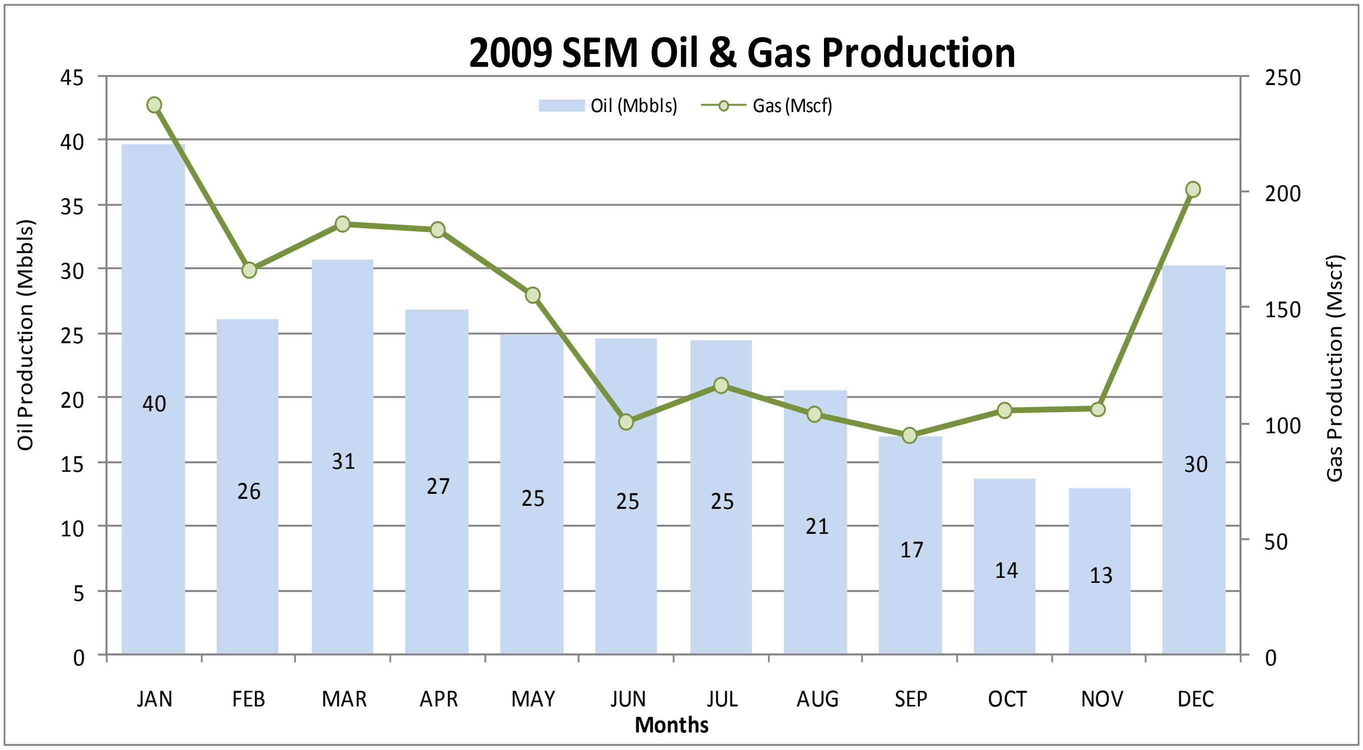


Figure 4.10: 2009 SEM Oil Productions.

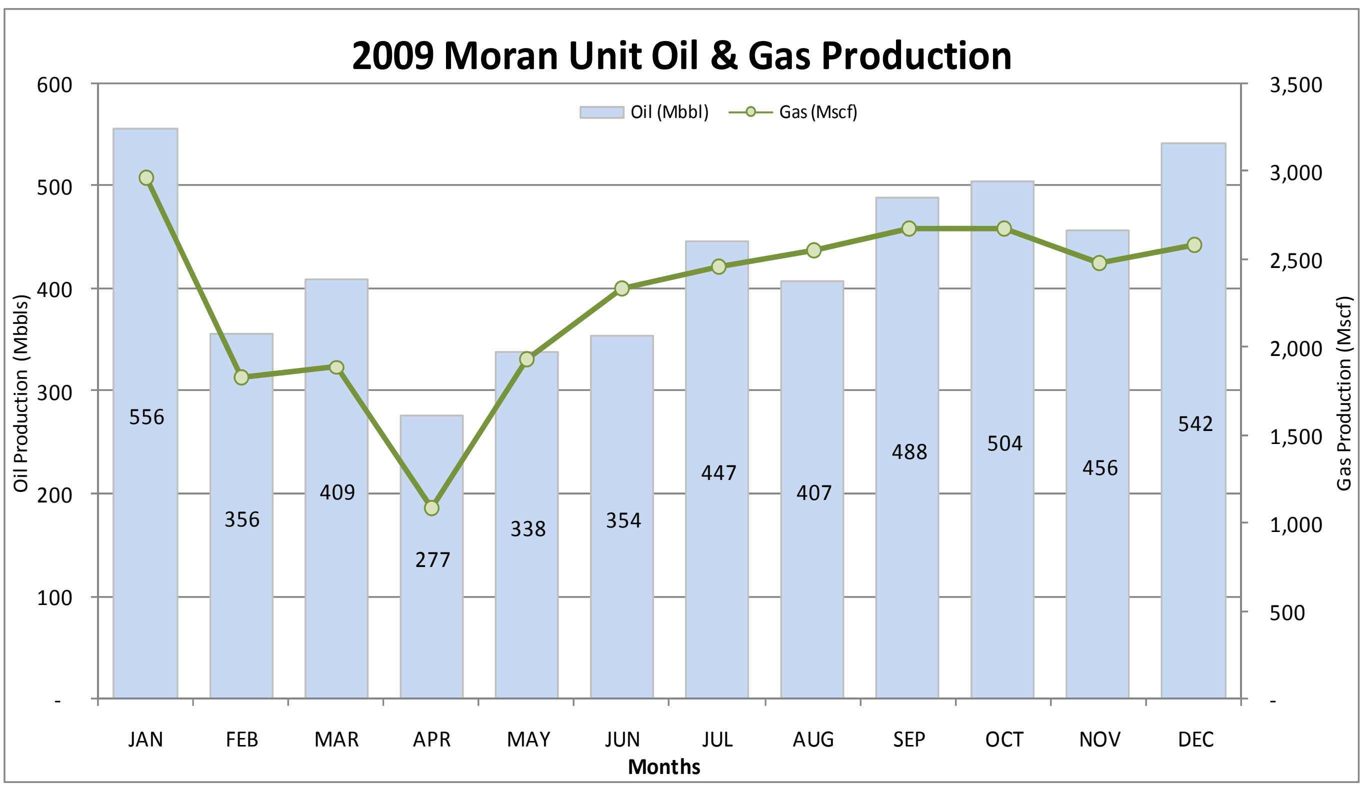


Figure 4.11: 2009 Moran Unit Oil & Gas Production.

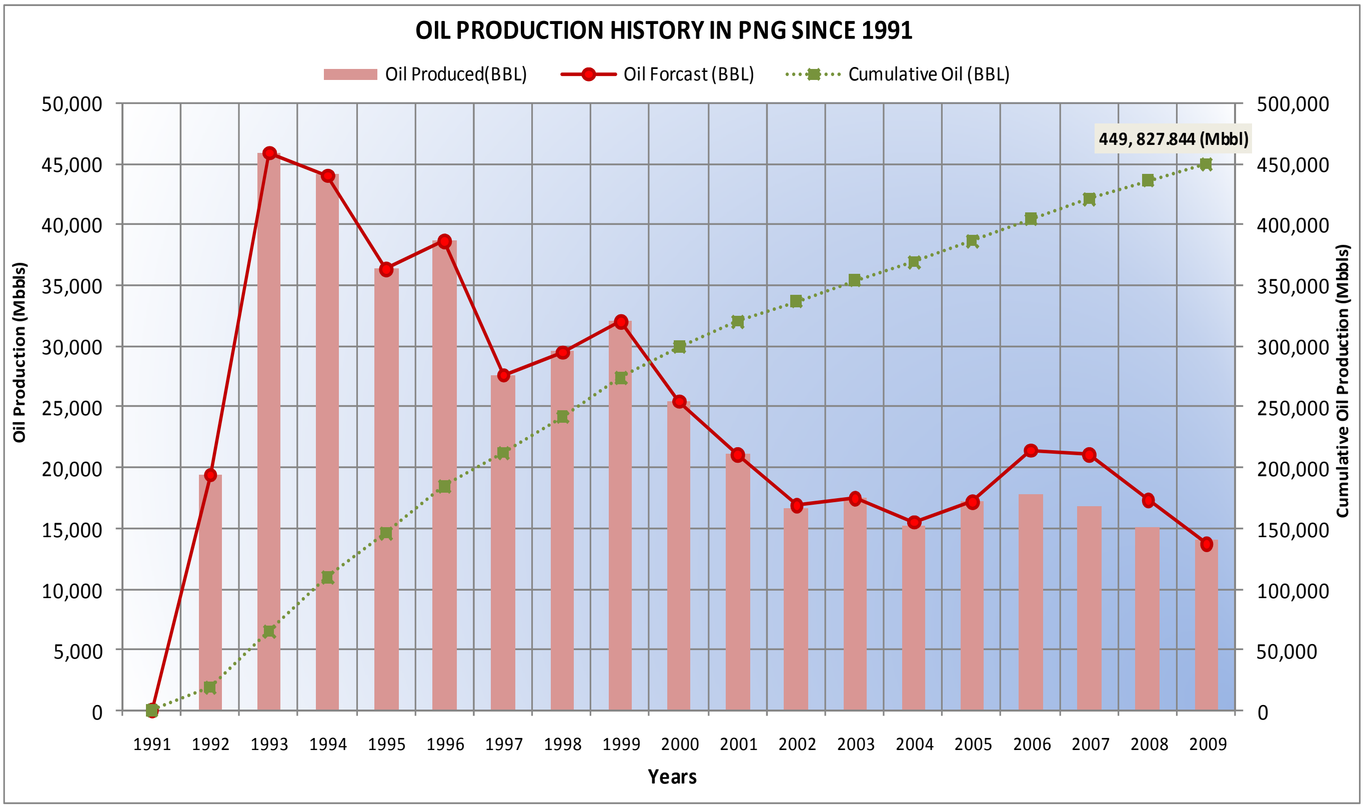


Figure 4.12: Oil Production History in PNG since 1991.

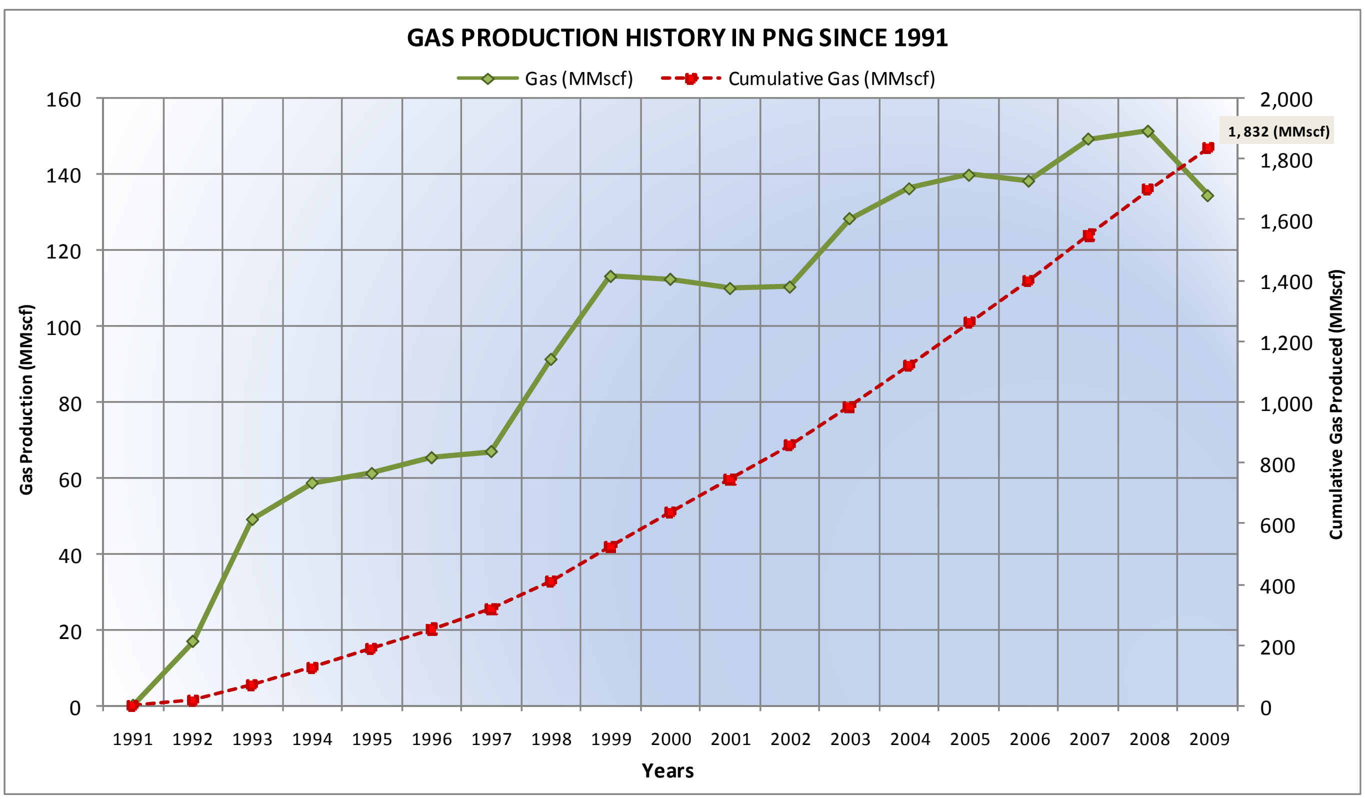


Figure 4.13: Gas Production & Distribution History in PNG since 1991.

5. FIELD DEVELOPMENT

This section briefly discusses the field development for current oil producing fields operated by Oil Search Limited.

The oil field operator Oil Search Limited will continue to operate and develop the oil fields with associated gas taken as fields deplete to supplement gas production from the non-associated gas fields. For the PNG LNG Project, this gas will be delivered into gas pipeline downstream of the Hides Gas Conditioning Plant (HGCP) and blended with the outlet gas to ensure water and hydrocarbon dew point specification are met for the PNG LNG project operated by Exxon Mobil.

Other field development plans by Interoil, Horizon Oil Limited and Talisman were submitted and are currently being reviewed and are at their conceptual stage.

5.1. Hides (PDL 1)

The Hides gas and condensate field is one with vast proven gas reserves. It supplies gas to a power plant, generating electricity for the Porgera Gold Mine Limited. It also has a mini refinery that produces petroleum products from the condensate for local sales and consumption. Routine maintenance and repairs were done throughout the year on facilities with no major shutdown and downtime.

5.2. Kutubu (PDL 2)

Routine checks, tests and preventive maintenance underpinned normal operations at the central processing facilities whilst the management of wells and process performance continued to be the focus for the year.
Kutubu complex will continue to be a major focus for oil development opportunities. During the first part of 2009, two (2) additional wells have been drilled. The first IDD5 well came in as predicted and has been completed as a Digimu oil producer. The second well, IDT24, also came in as predicted and has been completed as a Toro producer. The results of these two wells and the impact of future oil opportunities are being evaluated.

One of the major projects undertaken was the **CPF to GPF Crude Transfer System**. This project was undertaken to utilize one of GPF crude storage tanks to increase the storage capacity prior to exporting. Apart from delay of export shipments, the issues of high tank tops at CPF due to high production rates were a leading factor to this upgrade. Approval of modification and installation was given on the 24th of July 2009. All installations were completed, and as part of the pre-commissioning mechanical and piping function checks, a test flow transfer was conducted. This includes function check on the new valves of the new instrumentation equipment; planned maintenance checks on tank level gauges; reconciliation of meter readings between CPF, KMT and GPF meters and the proposed valve line up sequence. The project commenced full testing and commissioning between the 22nd to the 30th September 2009, witnessed by two DPE Engineers.

During the year there were sub-surface developments involving constant review of zonal opportunities to reduce high GOR production, hence freeing gas capacity and reducing flow line pressures so that low-pressure wells could perform better. Key zonal benefits were experienced in IDT4ST1, IDT6 and IDT5. **IDT 4ST1** had zone changed from Toro A to C, which reduced gas production by 2,000 MSCF/D and gave an extra 100 STB/D.

IDT 16 was zone changed from Toro AL to AU and produced 15 MSTB of flush production. At the same time GOR dropped from 21,000 to 2,500 SCF/STB. The GOR subsequently rose quickly and so returned to the Toro BL in June 2009. Initial tests for this zone were showing low oil and gas and high water rates.

IDT 20 was zone changed Toro CM/CL to CU, which increased oil production by 140 STB/D and reduced gas production by 13000 MSCF/D. GOR dropped from 26,000 to 4,500 SCF/STB.

The following wells had several workovers to optimize well performances due to rising GOR's and increase oil rates.

- **IDT 1**

The objective of this work over was to improve Toro C recovery by replacing the existing completion by splitting the Toro C zones into 3 zones whilst retaining Toro A, BU, BL zones. The well was brought on line and initially produced at a well test rate of about 2,000 STB/D and 2000 GOR. When the rate dropped below 1000STB/D, it changed zone to Toro C upper (CU1).

- **IHT 2**

The objective of this well was a selective completion in Toro A, B and C zones as the well currently had no isolation, compared to IHT 1A, which was producing well from Toro B. Well was brought on line in 10th November 2008 to 26th December 2008. The well continued to produce 100% water. The well was then alternated to Toro A and produced from the 10th January 2009 to 29th January 2009 with 100% water. Further simulation studies forecast significant reserves remaining in Toro C of the order of 2.5 MMSTB.

IDD1 well tests showed slow improvement in oil rate; gas rate also continued to rise with an overall slight reduction in GOR. The well may be subjected to the effects of excessive injection into the Digimu reservoir.

IDD5 produces from the Digimu C only. The well indicated increased oil and gas rates with an overall slight reduction in GOR.

UDT7ST1 was choked back in response to rising GOR

UDT8 production rates reduced after a choke change out due to sand erosion. Optimization of gas lift is ongoing.

UDT9 Oil rates have stabilized since September although gas rates continue to slowly increase. This may be the first sign of gas injection support reaching this well from UDT3AST1.

UDT10 has experienced an increase in oil gas and water rates since September. This is in response to an increase in choke with no accompanying gas increase.

UDT12 Toro A was shut in November2009 with positive results. The GOR reduced from 5,500SCF/STB to 1,400 SCF/STB and oil rates increased from 1,100 to 1,500 STB/D

5.3. Modifications of Central Processing Facility

Central Processing Facility (CPF) will undergo modification phase during year 2010 - 2014 from an oil production facility to oil and gas production facility to be aligned with the PNG LNG Project specification and design. Transmission of associated gas to the LNG Plant (via the PNG LNG project gas Pipeline) will involve changes to the gas management and control systems to meet associated gas specifications, hence the modification of the CPF Facility.

5.4. Moran (PDL 5)

For the Moran fields, the operator focused its operations on the management of wells and process performance with regular scheduled inspections and maintenance of equipment.

At the APF in July 2009, a third crude transfer pump was installed to address the pump redundancy issue at the plant and as a result production was no longer restricted by pump capacity limitations.

Moran-6 Sidetrack 2 (M6ST3) was kicked off on 18th July 2009 and was completed using a 5 zone selective completion string, accessing Toro J upper and lower; and the Digimu block J, A and C. On the 19th August 2009 the well commenced production from Digimu Block J at rate of approximately 4,000 STB/D with solution GOR. Between 22nd and 23rd August there was zone change to the Toro C block J upper and brought on line prior to opening up Toro C lower to aggregate production. The operator cleaned up the well during October to meet the target of 3000 STB/D but only managed to have the well averaged at 2899 STB/D at solution GOR.

At M12 the Digimu GOR had risen to 12,000 SCF/STB and on the 21st October the zone changed to Toro C which resulted in a low GOR at 1,800scf/STB and oil rates at about 1,500 STB/D. The shut in of the zone was for four months which proved beneficial for the Toro C zone. The operator plans to monitor the well GOR as there are concerns that the gas cap is nearby.

M13 (inverted/Digimu/Toro zone) swing producer was brought on line on the 16 of October for about 8 days following a 90 day shut-in and produced initially with good oil rates of over 1,000STB/D compared to previous rates of about 500 STB/D although GOR remained high at 11,000 SCF/STB.

5.4.1. Forward Plans to Develop Moran Field

The M12A well currently producing from high GOR Digimu and is scheduled to be zone changed to the Toro C to reduce gas off take and lower line pressures which should reduce back pressure on NWM1 well which is slugging.

On M14ST1, there is a concern that Toro C may not flow due to low BHP even using the low rate temporary gas lift line. The view is, it will be more prudent to do this work in late decembe2009 or early January 2010 when regional pressures are better understood. The scheduled zone change on M12 to the Toro C up dip of Moran 14, coupled with production pressure data that is being acquired from the recently M6ST3 when brought online, should better assess the risks and benefits.

The permanent gas lift system on M14, which is planned for January 2010 will be expedited following problems of restarting the well after shut downs. As an interim measure the temporary gas lift" kicker line" will be used to restart the well. Slickline intervention will be required to change out the valves in the gas lift mandrel.

M4 zone change to Toro C as gas injection will improve Toro J block Toro C pressures which have been low affecting Toro C performance. Preparation and planning will continue on the M5 simulation program, which is scheduled for second quarter of 2010.

5.5. Agogo/South East Mananda (PDL 6)

Routine checks, tests and preventive maintenance underpinned normal operations at the central processing facilities whilst the management of wells and process performance continued to be the focus for the year.
ADD1 well head integrity test was carried out and identified pressure within the tree void. Further investigation is planned to investigate the status of the tree and wellhead.

ADD2 and 3 wells continued to produce from Toro C and Toro A/B/C zones respectively and assisted the provision of gas for the Moran injection.

ADD 4 was brought on-line prior to the workover on the 2nd of November 2009. The first zone tested was the Digimu then the Iagifu D and Hedinia B/C. A zone change to the Hedinia A was planned for early December 2009.

ADD5 continued to produce well from the Digimu with rates of 1,800 STB/D at 2% water cut and GOR of 3,629 SCF/STB.

5.6. Modification of APF Facility

Agogo Processing Facility (APF) will be converted from an oil production facility to oil and gas production facility. Supply of associated gas to the PNG LNG project for transmission to the LNG plant (via the PNG LNG project gas pipeline) will involve changes to the gas management and control systems to meet associated gas specifications. This modification is anticipated in year 2020, Phase 5 of the PNG LNG Project.

5.7. Gobe Main / South East Gobe (PDL3/4)

5.7.1. Gobe Main

The Gobe Main field is located North West on the trend with South East Gobe Field. Field production is from the lower and upper Iagifu and lower Hedinia reservoirs.

There were no drilling or workovers in the last 12 months in the Gobe Main field, but there were several routine and unscheduled well interventions. The activities being MPLT on G4ST1 and G6XST2 slickline programs to clear wax build-up, conduct a flow gradient survey and fishing and sand bailing operations.

From January 2009, the 4 producing wells were put on swing to reduced the gas recycling and improved field void age

GM4ST3 well was converted from lower Iagifu to Upper Iagifu by setting a permanent Baker TTIBP and perforating under Iagifu. The well was brought on line with rates indicating an incremental gain of 600STB/D. The well has been allocated on average 131 STB/D with a GOR of 53,440 SCF/STB and a high water cut at 75%.

5.7.2. Gobe 2X and South East Gobe

The Gobe 2X block is located in PDL 4, currently produces from the lower Hedinia after lower Iagifu was plugged off in April 2008.

During the year no well workovers and drilling activities were carried out except for several routine interventions performed during the year.

In September, **SEG12** well stopped flowing due to lack of gas lift during compressor servicing, however it got online again once gas lift was available. In October, the well stopped flowing completely and the well could not be restarted due to a combination of wax/grease/ sand blocking the tubing intervention activities, Naptha injection and gas lift eventually brought the well back online.

In February 2009, **SEG6** production was averaging 475 STB/D and due to the impact of the low BHP, the well had to be shut-in on several occasions. In March 2009, the upper sleeve on **SEG13** was opened to allow additional water injection and as a result production was gradually seen to improve and by the end of June the well rates had increased to 850STB/D.

SEG1 remained shut-in during the period due to a combination of sand covering the perforations and high sand production was when attempting to flow.

During January 2009, a new swing well program was established for wells **G7X** and **SEG4** which produced large volume of recycled gas. Each well was tested after different shut-in periods to establish optimal swing cycle. Part of the improvement in field performance was thought to be reduction in line pressure, which had helped the low-pressure SEG wedge wells to flow more easily.

5.8. CPF to GPF Crude transfer

This project was undertaken to utilize one of GPF crude storage tanks, as production rates were high and at top tank levels at CPF.

Approval to modify and install was given on the 24th July 2009. All installations were completed, and as part of the pre-commissioning mechanical and piping function checks, a test flow transfer was conducted to physically function check the new valves of the new instrumentation equipment. Also conducted were PM checks on tank level gauges, reconcile the meter readings between CPF, KMT and GPF meters and the proposed valve line up sequence. The project commenced full testing and commissioning between 22nd to the 30th September2009, witnessed by two DPE engineers.

6 PNG OIL AND GAS RESERVES

Commercial production of oil and gas commenced in Papua New Guinea in 1992 after more than 80 years of exploration. The petroleum resources discovered in Papua New Guinea to date have been found mostly in the Papua Basin, a large basin covering approximately 212,000 km^2. Despite a long history of exploration, vast areas remain largely unexplored. In recent decades, large reserves of gas have been discovered in this basin. Approval was granted to Exxon Mobil in December 2009 to commercialize a total gas resource volume of 12.5 TCF OGIP from Hides, Angore and Juha gas fields, and the associated gas from the oilfields in the Southern Highland Province.

Crude oil is currently produced and exported by Oil Search (PNG) Ltd from seven different but adjoining fields which are shown in Figure 6.1. They are Iagifu - Hedinia, Agogo, Usano, Moran, Gobe Main, South East Gobe and South East Mananda fields. The Kutubu field came into production in late 1991 followed by the Moran and Gobe fields in 1998. North West Moran came into production in 2005 followed by South East Mananda at the end of March 2006.

The summary of remaining recoverable reserves and their depletion from the OGIP from the above fields relative to the cumulative production since 31 December 2008 is shown in Table 6.1. The proved (1P) proved plus probable (2P) and proved plus probable plus possible (3P) resource estimate defined as reserves in this table and elsewhere in this report conforms to the Petroleum Resource Management System prepared by the Oil and Gas Committee of the Society of Petroleum Engineers. This estimate may be slightly affected by additional resources from infill drilling or compositional modeling, which are not included here as of the time of this report.

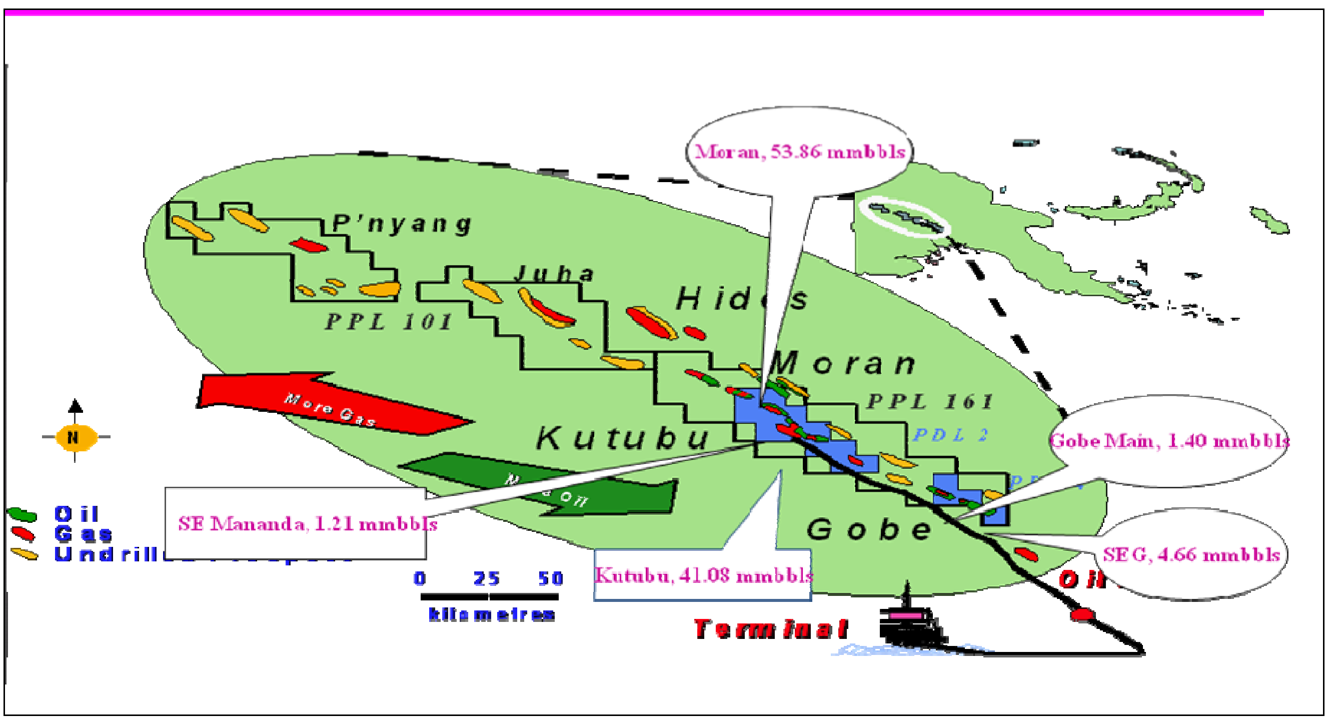


Figure 6.1: Oil fields with remaining 2P reserves as of 31 December 2008 (Sourced from ExxonMobil).

Table 6.1: Summary of the Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P) oil reserves in PNG as at 31 December 2008.

Field (s)	Category	OIIP (MSTBO)	Recovery Factor	Ultimate Recovery (MSTBO)	Cum. Oil Prod. as of Dec 2008 (MSTBO)	Remaining Reserves (MSTBO)
	1P		0.561	343,359	312,614	30,745
Kutubu	2P	612,400	0.578	353,699	312,614	41,085
	3P		0.589	360,457	312,614	47,843
	1P		0.415	89,518	56,136	33,382
Moran	2P	215,500	0.510	110,000	56,136	53,864
	3P		0.580	125,002	56,136	68,867
	1P		0.413	27,625	26,810	814
Gobe Main	2P	66,900	0.422	28,211	26,810	1,401
	3P		0.430	28,741	26,810	1,931
	1P		0.293	41,673	38,861	2,811
SE Gobe	2P	142,200	0.306	43,523	38,861	4,662
	3P		0.318	45,263	38,861	6,402
	1P		0.104	2,901	2,258	643
SE Mananda	2P	28,000	0.124	3,466	2,258	1,208
	3P		0.135	3,775	2,258	1,517

- 1P = [Proved] Reserves, 90% confident of recovery (10% uncertainty)
- 2P = [Proved + Probable] Reserves, 50% confident of recovery (50% uncertainty)
- 3P = [Proved + Probable + Possible] Reserves, 10% confident of recovery (90% uncertainty)
- 1PUR = Proved Reserves + Cumulative Production to Date
- 2PUR = 2P Reserves + Cumulative Production to Date
- 3PUR = 3P Reserves + Cumulative Production to Date

Note: □ Recovery factors were based on 3P OIIP
□ The above table was filled using data extracted from Oil Search Ltd's Papua New Guinea 2009 Reserves Report

6.2 Field operations on Reservoir and Reservoir Performance

Since first oil production commenced in Kutubu followed by the other subsequent fields, field operations activities on reservoirs for infill drilling opportunities, compositional modeling, pressure support, swing well programmes, workovers, pressure gradient surveys, and simulation modeling have been ongoing to have a better understanding of the characteristics of the reservoirs and to improve their performances.

Additionally, reservoir development for gas fields for the PNG LNG Project including Hides, Angore and Juha are also included.

6.3 KUTUBU

6.3.1 Kutubu Reservoir Performance

Kutubu Field Development is essentially referred to the main pools or reservoirs that make up the overall Kutubu Complex. These pools are effectively in different pressure regimes and so have differing production characteristics. Figure 6.2 shows these pools and are described briefly below:

- Main block Toro (MBT); this is made up of the Toro A, B and C reservoirs of the Iagifu and Hedinia structures. This is historically the main producing area.
- Iagifu I3X8X block is to the north of the Iagifu crest and produces from the Toro and Iagifu zones.
- Hedinia Digimu reservoir; wells from this pool are producing from the Digimu reservoir underlying the Hedinia structure.
- Usano Main and East blocks are down thrown south east of the MBT and separated by a sealing fault.
- Agogo Field - this comprises of the Toro A, B, C, Digimu, Hedinia, Iagifu sands. This field is about 10 kms North West of the Kutubu Hedinia and Iagifu structures.

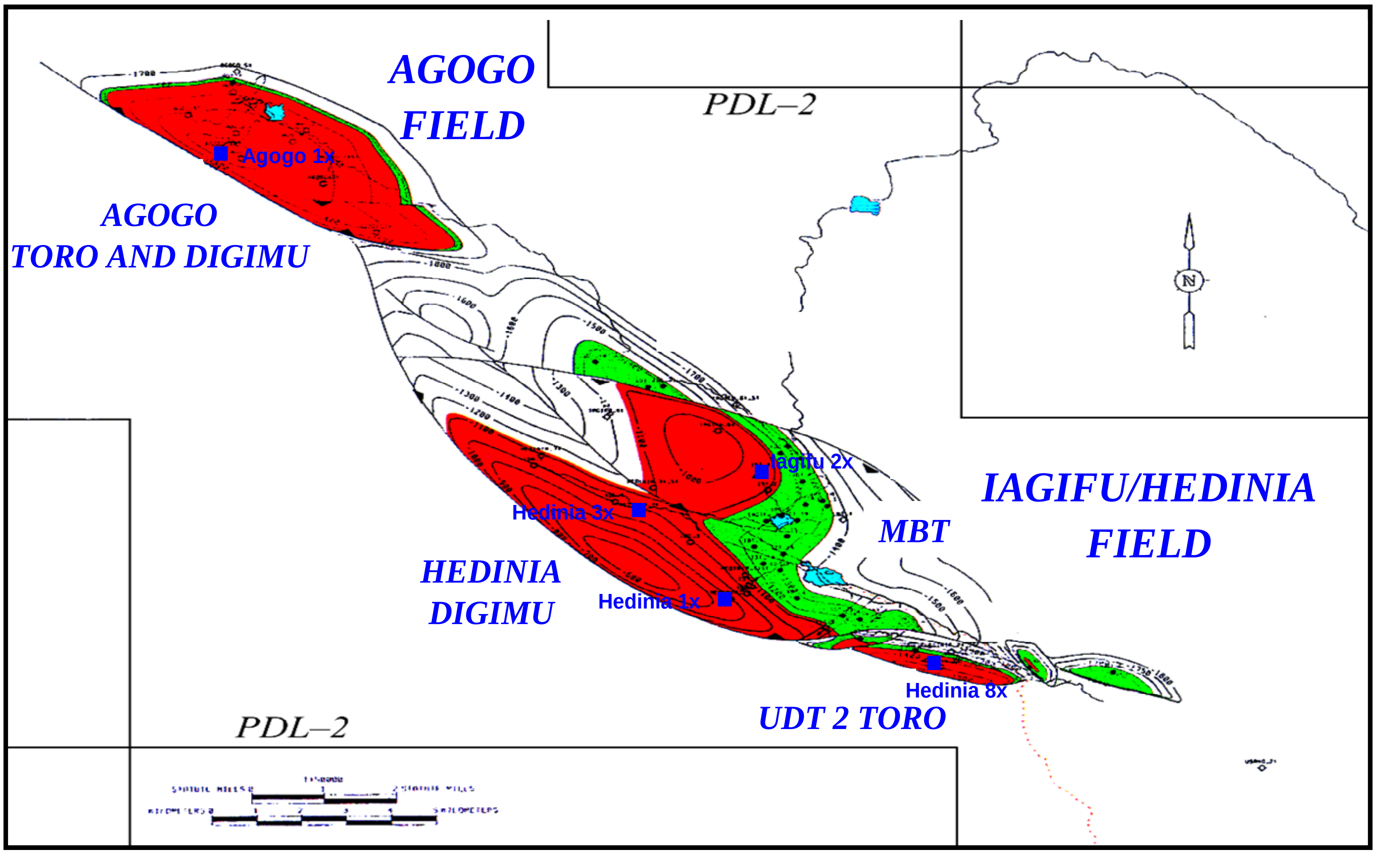


Figure 6.2: Kutubu main reservoirs (sourced ExxonMobil).

6.3.2 Main Block Toro (MBT)

6.3.2.1 Pressure Review

During the reporting period, eleven static pressure gradient surveys were taken as part of routine pressure acquisition programme and some of these have been added to a pressure plot. From this plot the pressure trends have been interpreted as showing that;

- The central wells, IDT 14, IDT 4ST1, IDT 5, IDT 22 and IDT 23ST2 are generally higher pressured because they have more direct access to injectors.
- The southern central wells, IDT 16 and IDT 20 have more baffled communication with the injectors.

6.3.3 Hedinia Digimu

Currently two wells, IDD 1 and IDD 5, are constant producers. Production from this reservoir over the reporting period averaged 1105 STB/D at 11,943 SCF/STB GOR and 47 percent water cut. The cumulative production from the reservoir as of June 2009 is 17,957 MSTB.

Simulation studies continue to monitor and identify infill opportunities to improve sweep and voidage balance. An infill opportunity may exist to the NW of IDD 1 designated the IDD B location. The plan is to evaluate this opportunity as part of the ongoing simulation work.

6.3.3.1 Pressure Data

In 2009 two static pressure gradient surveys were taken in IDD 3 and IDD 4 as part of routine pressure acquisition program in addition to the RFT and flowing buildup survey in the new IDD 5 well. These have been added to a pressure plot. From the plot the pressure trends have been interpreted as showing that;

- All wells have good communication across the field and follow a similar trend.
- IDD 1 appears to be at a lower pressure and this trend is thought to be due to the well having the highest off-take which is supported by the fact when off-take is reduced, the pressure converges with the other wells.
- RFT pressure suggests IDD 5 is slightly baffled from the rest of the field as the initial pressure is higher than nearby well IDD4.

6.3.4 Usano Main Block Toro

Production from the Usano Main Block Toro (UMBT) during the reporting period averaged 4,931 STB/D at 2,594 SCF/STB GOR and 16 percent water cut. Cumulative production from the reservoir as of June 2009 is 6573 MSTB. This is an increase as a result of 4 new wells coming on line; UDT 8,9,10 and 12. UDT 12 was completed on the 6th July 2009. It is a 5-zone Toro A, BL, CU, CM, CL selective completion.

As at the end of June 2009 UMBT has 4 constant producers; UDT 7AST1, UDT 8, UDT 9 and UDT 10. The UMBT has undergone significant pressure depletion since the commissioning of its three new wells. UDT 3AST1 was commissioned as a gas injector on the 18th June 2009. During the month of June a gas injection trial into UDT 3AST1 was conducted and injection rates of up to 10 MMSCFD were achieved. Following the results of the trial, the well was put on permanent injection on the 30 June 2009.

The Usano Main Block static simulation model is being updated to incorporate the results of the new wells. The new geological model plans to use a flow unit based properties model, which better incorporates, offset core data and hence improves the match. Once complete the new model will be used to develop a new history matched simulation model.

6.3.4.1 Pressure Data

Static pressure gradient surveys were taken in UDT 3AST1 Toro CU and UDT 7ST1 Toro A. Via the downhole gauge, bottom hole pressure build-up surveys were completed in UDT 8 Toro CU, A/C & A/B/C, UDT 9 Toro CL and CU/CL and UDT 10 Toro BL/C in 2009. RFT pressure points were collected on UDT 12 in June 2009. The pressure trends have been interpreted as showing that;

- Field pressures stayed constant from 1999 to 2007 when there was no production from the field.
- Field does not appear to receive any gas or water support.
- UMBT is experiencing significant recent pressure decline, due to increasing production off-take from four new wells.

6.3.4.2 Pressure support

The only pressure support for this block is from UDT3AST1 where injection trial was completed and continuous injection commenced since August 2008 to arrest the field pressure decline.

6.3.5 Usano East Block

Production from this reservoir during the reporting period averaged 1160 STB/D at 9,797 SCF/STB GOR and 0% water cut. The cumulative oil production from the reservoir as of 30th June 2009 is 5,931 MSTB.

As of the end of June 2009 UMBT has two constant producers; UDT 4A and UDT 11. UDT 11 was brought on-stream on the 19th February 2009 and at the end of June 2009 the well was producing 1835 STB/D with 0% water cut at a solution GOR 772 SCF/STB.

The Usano East simulation model is part of the static and dynamic re-build work described in the Usano main block section above. The static model will incorporate the plunging nature of the structure to the west of UDT 4A and the results of the recent UDT11 drilling. The properties model and PVT analysis are currently under revision.

6.3.5.1 Pressure Data

Between January and July 2009 static pressure gradient surveys were taken in UDT 4A Toro A/BU and UDT 6 Toro A as part of the ongoing pressure acquisition program. Via the downhole gauge a bottom hole pressure buildup survey was also completed in UDT 11 TC. These pressures have been added to the pressure plot and the pressure trends have been interpreted as showing that:

- Based on pressure history from March to November 1997 and December 2001 block pressures respond promptly to gas injection at UDT6; and
- The UDT 11 RFT data from the Toro C zone were at virgin pressure which indicates that this zone is isolated from Toro A in this location. The Toro A/B however was depleted showing that this zone communicates with UDT4 and 6 wells.

6.3.5.2 Pressure support

UDT 6 is the block’s only gas injector which injected on average 8 MSCF/D until the well had to be shut-in due to a wellhead problem in March 2009. The wellhead has since been repaired and is now back on injection.

6.4 Agogo Toro

The Agogo Field continues to provide make-up gas to the Moran Field for gas injection and is impacted when Moran field requires less injection make-up. Production was reduced by the shut-in of the field due to the extended shutdown at the APF and CPF in February 2009.

Production from the Toro reservoir during the reporting period averaged 729 STB/D, producing GOR averaged 30,884 SCF/STB and water-cut averaged 42 percent. During the reporting period there was a 55 percent increase in oil production compared to 2007 to 2008 due to a combination of field decline, workovers and plant downtime. GOR has increased to 30,884 SCF/STB and water-cut has decreased to 6 percent. The cumulative oil production from the Agogo Toro reservoir as of June 2009 is 7,704 MSTB.

Following the ADD 2 and ADD 3 workovers in November to December 2008 and December to February 2009 respectively production rates have increased in these two wells from 450 to 700 STB/D due to good liquid rates from ADD3T.

Static pressure gradient surveys were taken in AHT 2 Toro A/B/C, ADD 3 Toro A and a flowing buildup pressure survey in ADD 3 Toro B/C.

6.4.1.1 Pressure support

Gas injection into Agogo Toro reservoir via, AHT 2 has averaged 2.6 MMSCFD, with 945 MMSCF being injected from July 2008 to June 2009. A total injection of 48 BSCF had been injected into this well.

6.4.2 Agogo Digimu

Production from the Digimu reservoir during the reporting period averaged 485 STB/D, 14,524 SCF/STB GOR and 67 percent water cut. Compared to the previous year, oil production decreased by 64 percent, GOR decreased by 31 percent and water-cut increased by 31 percent. The cumulative production from the Digimu reservoir as of June 2009 is 28,346 MSTB.

- ADD 1 has been online continuously except in May of 2009 the well had some downtime due to water handling problems at the APF.
- ADD 2 contributed till November 2008 when the well was worked over in December 2008 to January2009
- ADD 4 produced till the well was shut-in in November 2008 with corrosion at the well head and liner top.

6.4.2.1 Pressure support

The AGD 1 well has remained on continuous gas injection during the reporting period averaging 5.2 MMSCFD. A cumulative 117.3 BSCF had been injected into the well by the end of June 2009. During the reporting period, 1.9 BSCF was injected into the well.

The AGD 1 well, although is open to the Toro behaves as though most of the gas is injecting into the Digimu reservoir.

6.4.3 Agogo Hedinia

Following completion of the workovers ADD 2 and ADD 3 wells, production from the Hedinia A reservoir from January to June averaged 224 STB/D, 13,500 SCF/STB GOR and 12 percent water cut. The cumulative production from the Hedinia A reservoir as of June 2009 is 41 MSTBO.

6.4.4 Agogo Workovers

One of the key objectives of the ADD2 workover was to access the Hedinia A and reduce the GOR. The well was completed with 4 zone selective completions in the Toro C, Digimu A, C and Hedinia A. The Hedinia A was brought online 23rd January 2009 and has so far produced 34 MSTB. The Toro C, Digimu A and C zones are still to be commissioned and tested.

The workover objectives on the ADD3 were to access the Hedinia A sands by deepening the well, perforate the Toro A, B and Toro C which would provide greater gas deliverability and better access to gas reserves. The well was completed as a four-zone Toro A, B/C, Digimu and Hedinia A selective completion.

6.5 Moran

The Moran Field which has been producing since 1998 has a structure of a north-west/south-east trending doubly plunging anticline with a productive closure area of approximately 18 square kilometres. There have been 56 reservoir intersections (Toro C & Digimu) that have been drilled to evaluate the Greater Moran Field.

For the first year, the reservoir performance for the NW Moran Field has been incorporated into the Moran Unit as PDL 6 is now part of the Greater Moran Unit. The field has been split into four main producing blocks; A, B, C, J and K blocks respective to the different pressure regimes. Figure 6.3 is the Top Toro Structure Map.

Oil production from the field since comes from the Toro C and Digimu A, B, and C reservoirs, which are laterally extensive with relative constant thicknesses of approximately 30-35 metres

6.5.1 Moran Reservoir Performance

6.5.1.1 Block A – Toro C

There are two completions in this reservoir, Moran 2XST2 Comp4 (M2XST2 C4) and Moran 5ST2 Comp2 (M5ST2 C2). M2XST2 has been producing from Toro C since June 2006 with a steadily increasing GOR and declining Bottom Hole Pressure (BHP). In October 2007, the Toro C sliding sleeve in M5ST2 was opened to give combined Toro C and Digimu injection to improve the Toro C block pressure.

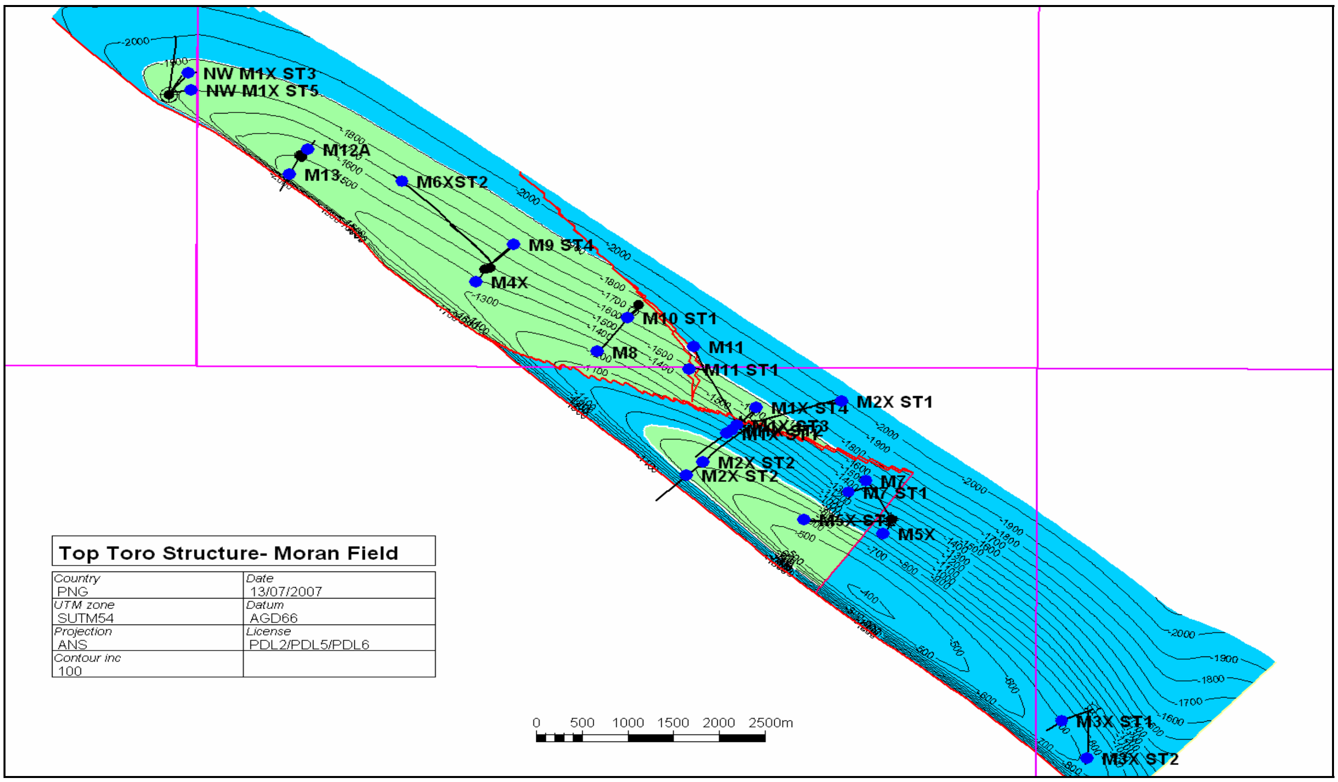


Figure 6.3: Moran Field Top Toro Structure Map (Source ExxonMobil).

6.5.1.2 Block A – Digimu

There are six completions in this reservoir, M2XST2 C1, M2XST2 C2, M2XST2 C3, M1XST4 C5, M5ST2 C1, and M7ST1 C1. The M2XST2 C1, C2 and C3 are in pressure communication. M5ST2 C1 is currently a gas injector but was briefly produced from the Digimu prior to its conversion to a gas injector in 2002. During the reporting period, Digimu Block A production was from M1XST4 C5 and M7ST1 C1.

Production from the Digimu Block A totalled 1.06 MMSTB over the reporting period with an average GOR of 7,748 SCF/STB. The cumulative production as of 30th June 2009 is 19.2 MMSTB with an average GOR of 3,645 SCF/STB.

6.5.1.3 Block B –Toro C

There are three completions in this reservoir M1XST4 C2, M11ST1 C2 and C3. During the year there was no production from this Block and so the cumulative production remains at 1.03 MMSTB.

6.5.1.4 Block B – Digimu

There are three completions in this reservoir, M1XST4 C3, C4 and M11ST1 C1. M1XST4 C3 and C4 are known to be in full pressure communication. This block receives no pressure support from any of the Moran gas injection wells and hence is on natural depletion drive only. The simulation model requires a weak aquifer to obtain a pressure history match.
During the year Digimu Block B production was from M11ST1 C1 only. The cumulative production as of 30th June 2009 is 4.38 MMSTB with an average GOR of 2,210 SCF/STB.

6.5.1.5 Block J – Toro C

There are ten completions in this reservoir M4 C2, M6ST2 C2, M8 C2, M9ST4 C2, M10ST1 C2, M12A C2, M13 C2, M14 C3/4 and NWM1 C2.

In 2009, Toro Block J production was from M9ST4, M10ST1, M12A and NWM1X C2 wells. The cumulative production as of 30th June 2009 is 3.7 MMSTB with an average GOR of 4,286 SCF/STB. Production from the Toro C totalled 1.6 MMSTB with an average GOR of 4,894 SCF/STB in 2009.

6.5.1.6 Block J - Digimu

There are seven completions in this reservoir. These include M4X C1, M6ST2 C1, M8 C1, M9ST4 C1, M10ST1 C1, and M12A C1. The NWM1X C1 and M8 C1 have always been gas injectors and commenced injection in the second quarter of 2002. The M4X C1 was initially a producer but was converted to gas injector in the second quarter of 2004.

During the year, Digimu Block J production was from M6ST2 C1, M9ST4 C1, M10ST2 C1, M12A C1 and NWM1X C1. The cumulative production as of 30th June 2009 is 24.2 MMSTB with an average GOR of 2,912 SCF/STB. Production from the Digimu totalled 1.3 MMSTB during the year with an average GOR of 5,087 SCF/STB.

6.5.2 Combined Toro C & Digimu - Block J

6.5.2.1 M9ST4 C2 – Toro C2 & Digimu C1

In March 2009, a slickline investigation program confirmed that the Digimu sleeve had been accidentally opened when running a plug to isolate the Digimu zone in order to change the well from Digimu production to Toro C production in March 2006. It is currently believed that this occurred when changing zone from Digimu to Toro C in March 2006.

From around the mid-2007 there was a suspicion that the well was on co-mingled production as productivity, water rates and GOR were much higher than would have been expected from the Toro C alone. Investigation work was carried out and in March 2009 it was identified that the Digimu sliding sleeve was open. Once this sleeve was closed then the subsequent production was as expected: low GOR, with minimal water rates and with low oil rates in line with Toro C PI's at about 1,100 STBPD.

To date the well has produced a cumulative volume of 1.3 MMSTB from the Toro C. During the year, the well produced 0.96 MMSTB (Toro & Digimu) with a GOR of 5,607 SCF/STB.

Both the M9 Toro and Digimu zones receive pressure support from M4 and M8 injectors although it is not as direct as that received between M6 and M4 due to baffles within the reservoir.

6.5.2.2 J/K Forelimb and M13 C1

There is one completion in this area, namely M13 C1. There is an uncertainty as to the volume in the J/K forelimb that M13 C1 is draining because the sand that this completion intersects is inverted and appears to contain both Digimu and Toro reservoirs. A review of production and pressure data suggests that M13 Toro/Digimu may be in the same pressure regime as NWM1X C1 although there is some ambiguity. Simulation work also suggests that the inverted Toro C/Digimu maybe be communicating with the M13 Toro C1 intersection in the main J block through a tortuous path. This will be further reviewed.

The M13 C1 has produced a cumulative 0.5 MMSTB. During the year, the well produced an additional 0.056 MMSTB with an average GOR of 12,184 SCF/STB. The well continues to be produced on an intermittent swing cycle as facilities and flowline conditions allow.

6.5.3 Inter Block Reservoir Communication

6.5.3.1 Toro

Reservoir performance indicates that there is no pressure communication in the Toro C reservoir between either A and B Block, A and J block, and B and J (K) Block. However there does appear to be pressure communication between M4 Digimu J-block and NWM1 Toro C K-block based on an increase of 300 psi observed in NWM1 in April 2006. This pressure support seems to have diminished due to M12 offtake as recent pressures show a significant decline.

The latest pressure and production data suggests that M12 C2 and M13 C2 are not in the same compartment or block. M12 C2 has a low GOR whereas M13 C2 has a very high GOR. In fact, latest data suggests that M13 C2 may be in communication with NWM1 C2 and hence could be in K block. As a result of this M13 C2 is under review for a possible pilot injection programme to see if the well will support NWM1 and M14 Toro C production. The main concern is premature gas breakthrough, so studies will take place to better understand this issue before proceeding.

6.5.3.2 Digimu

Pressure data indicates that Digimu A and B blocks do not communicate as the trends are very different. There is some indication from pressure data and simulation that B block gets some support either from a small gas cap or weak aquifer.

In the A block reservoir, the pressure data obtained from the producing wells, M2XST2, and M1XST4 C5 indicates that they continue to receive direct support from gas injection in M5ST2 C1. M7 also received good support from M5 gas injection, but there does appear to be a slight baffling effect at the pressure recorded is slightly lower than the other wells.

In the Digimu A block, gas injection into M5ST2 C1 has had the effect of increasing M1XST4 C5 and M7ST1 bottom hole pressures, indicating good pressure support from M5ST2 C1 injection.

Reservoir performance indicates that the Digimu reservoir in the A block does appear to communicate partially with the Digimu in the J Block, based on early pressure data from M4X well prior to the well commencing production in 2000.

In the J block, increasing reservoir pressure in M6ST2 C1 and M12A C1, indicate that these wells continued to receive good pressure support from M4X and to a lesser extent M8 as a result of gas injection. It has also become apparent from pressure data that there are baffles between the M4X and M8 injectors to M9ST4 and M10ST1 C1 which slow down the support from the gas cap. M10ST1 C1 receives good support from M8 and to a lesser extent from M4X, which suggests there may be a baffle between M4X and M10ST1.

Reservoir pressures recorded in NWM1XST5 C1 well during its shut-in cycles confirm that the Digimu in K block does receive support from the M4X Block J gas injector.

6.5.3.3 Gas injection

Gas was injected only into the Digimu reservoirs up to mid-October 2007 due to most of the production being from the Digimu except for M2XST2 C2, M12A C2 and NWM1XST5 C2 for a period of time. M5ST2 injects into a crestal location in the A block, supporting M1XST4, M2X ST2, and M7 ST1. M4X and M8 are located crestally in the J block supporting production wells M6ST2, M9ST4, M10ST1, M12A, M13 and EPT well NWM1XST5. Simulation work indicated that co-mingled injection was the optimal depletion strategy for developing Toro and Digimu zones.

During the year, total volume of gas injected was 31 BCF and injection rate averaged 84 MMSCFD compared to 95 MMSCFD in last year's report, which was a decrease due to compressor and gas supply issues in first half of 2009. Injection rates in the wells M4X, M5ST2 and M8 averaged 42, 24 and 18 MMSCFD respectively (based on total injection for the year).

Cumulative gas volumes injected into the Digimu and Toro up to 30th June 2009 was 194.2 BCF; with cumulative Toro C injection in M5 2.0 BCF and M4 7.13 BCF and cumulative Digimu injection in M4X 65.6, M5ST2 66.1 and M8 53.3 BCF respectively.

6.5.4 Reservoir Simulation Modeling

A detailed review and update of the existing Moran simulation model was undertaken early in the year with the aim to have a robust model available for depletion planning, infill well evaluation and gas blowdown studies.

A review of the J/K block gas injection strategy confirmed that to maximise recovery a higher proportion of future gas injection should be in the Toro rather than in the Digimu. This finding is consistent with current recovery factors and pressures. It was also noted that some Digimu potential should be preserved to maintain opportunities to zone change and allow Toro completions to recover in the future.

During the year, creation of an updated static model commenced. The update included a full field structural mapping exercise incorporating all recent well data and a re-evaluation of existing dipmeter logs as well as the petrophysical review mentioned above. This model will be ready for simulation early 2010 and will be used to review future infill well opportunities and depletion strategies.

6.6 SE Mananda

The South East Mananda Field is located approximately 12 kilometres to the north-west of the Agogo oil field and the Agogo Processing Facility (APF). SE Mananda was discovered in 1991 with the drilling of the SE Mananda 1x well and appraised by SE Mananda 2x in 1994. These wells encountered gas in the Toro A sand, with oil and water found in the Toro C sand.

The field was deferred for development due to its relative small size and high cost of development until in 2005/2006 it was developed with the drilling of three additional wells, the completion of the existing SE Mananda 1x well, and construction of a 400 metre pipeline suspension bridge across the Hegigio Gorge. A flowline connects the two pads via the bridge to the Agogo Processing Facility (APF). The facilities were commissioned in the first quarter of 2006 with production commencing at the end of March 2006.

Material balance work indicates that all Toro C wells (SE Mananda 1X, 4 and 5) are in pressure communication with SE Mananda 3 producing solely from the Digimu reservoir which is not in communication with the Toro C reservoir.
IP and 2P reserves have been estimated by exponential decline analysis based on well performance. The reserves are summarized on Table 6.1.

6.6.1 SE Mananda Reservoir Performance

There are two effective reservoirs in this field; Toro C and Digimu. Reservoir performance indicates that all Toro C wells (SEM 1X, SEM 4 and SEM 5) are in pressure communication whereas the Digimu (SEM 3) is in a separate pressure regime.

6.6.2 Reservoir Simulation Modeling & Evaluation

No work was done on the geological or Eclipse model during the year as there was considered to be no benefit in doing so. No further development drilling or major intervention work was carried out as all projects considered were sub economic. The technical team will continue to monitor and analyse the pressure and production data so that wells can be optimised.

6.7 Gobe Main Field (PDL4)

The Gobe Main Field is located northwest and on trend with the South East Gobe Field. Field production is from the Upper and Lower Iagifu and the Lower Hedinia reservoirs. The reservoirs are comprised of laterally continuous shallow marine sandstones with a combined thickness of 50 to 70 meters, a net to gross thickness ratio of approximately 80 percent, and average porosity of 16 to 18 percent. The Gobe Main Field is a doubly plunging asymmetric anticline within the north-west/south-east trending Gobe Anticline. The anticline at reservoir level is asymmetric to the south-west, with a steep to overturned, highly sheared forelimb which is truncated by a fault or series of faults to the south-west. The field has a productive closure area of approximately 8.4 km^2.

Production from the field commenced in 1998 and the production rate peaked at over 20 MBOPD in September 1999. This year the 1P estimate of ultimate recovery stands at 27.6 MMBBL, while 2P estimate of ultimate recovery is 28.8 MMBBL. The reserves are summarized on Table 6.1. Figure 6.4 illustrates top structure of Iagifu reservoir in Gobe field.

6.7.1 Gobe Main Reservoir Performance

The field has been evaluated by twenty three wells or sidetracks that are separated into five fault blocks. The productive reservoirs at the Gobe Main Field are the Upper and Lower Iagifu and the Lower Hedinia, with the Lower Iagifu historically being the higher quality reservoir.

GM4ST3 well was converted from Lower Iagifu to Upper by setting a permanent packer and perforating the Upper Iagifu. The well was initially brought online with rates indicating an incremental gain of 600 STBOPD. During the second quarter of 2008, the well has been allocated on average 131 STBPD with a GOR of 53,440 SCF/STB and a high water cut at 75 percent. From January 2009, the well was put on swing and this has reduced the gas recycling and improved field voidage.

6.7.2 SE Gobe Reservoir Performance

Production from the field commenced in April 1998 and the production rate peaked at over 20 MBOPD in March 1999. This year the 1P estimate of ultimate recovery stands at 41.6 MMBBL, while the 2P estimate of ultimate recovery is 43.5 MMBBL.

Production from the field during this time came from wells SEG2, 4, 5T1, 6ST1, 8, 9ST1, 11, 12 and G7XST3. Since late January 2009 G7X and SEG4 wells have been operating on independent swing cycles with minimal on line overlap and this has reduced gas recycling and helped to reduce rate of pressures decline. This strategy has also made it easier to control flare volumes in the plant.

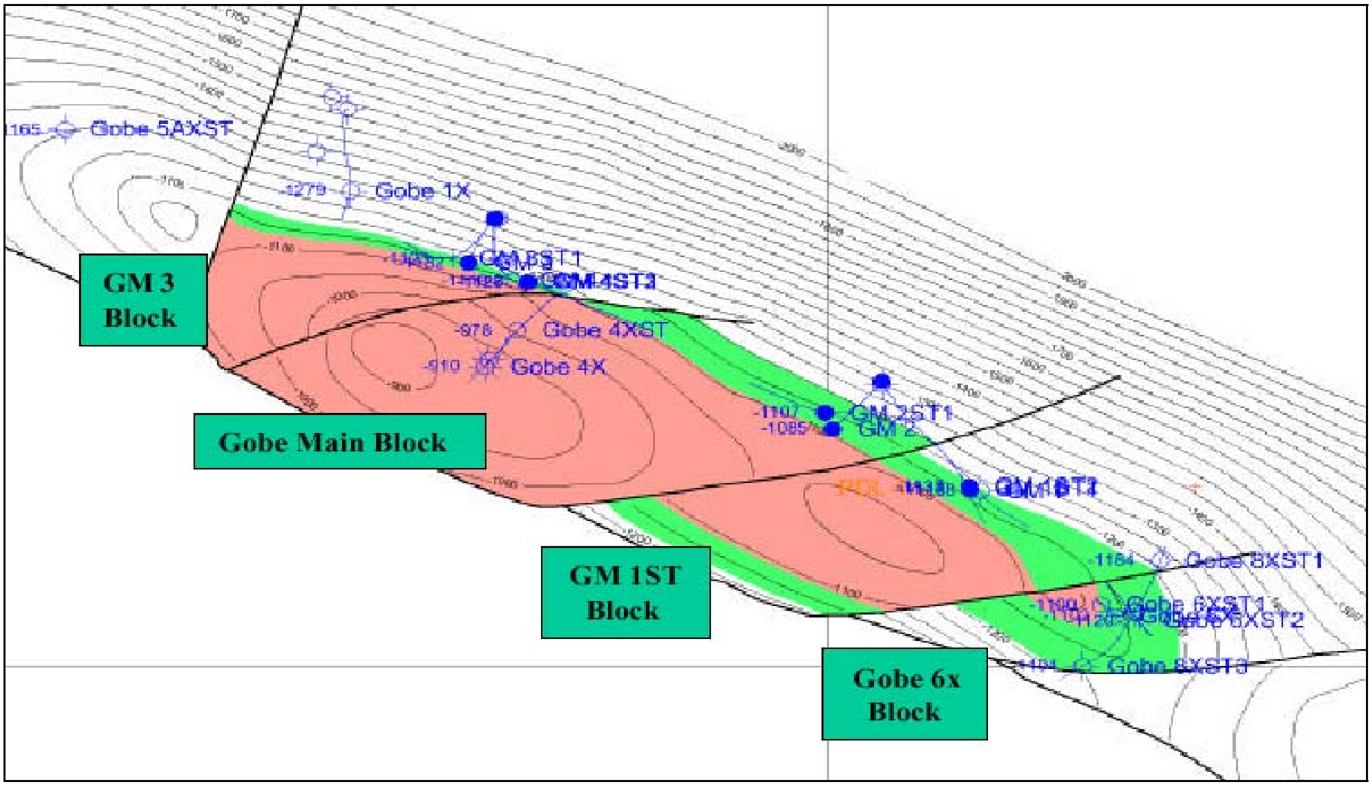


Figure 6.4: Gobe Iagifu Top Structure Map

There has been some downtime associated with the SEG3 compressors during the reporting period which has impacted gas injection into SEG7. Injection rates at SEG3 and SEG7 have averaged 41.9 and 14.0 MMSCFD respectively compared to the previous period of 42.1 and 14.4 MMSCFD respectively.

Water injection rates into the G3X and SEG13 wells averaged 1,741 and 3,996 BWPD respectively.

6.8 PNG LNG Gas Reserves

Total ultimate recoverable gas reserves in Papua New Guinea certified and conformed to the resource definition of the Petroleum Resource Management System prepared by the Oil and Gas Committee of the Society of Petroleum Engineers are estimated at 9.5 TCF. This represents 76 percent ultimate recovery of the 12.5 TCF of OGIP. This reserves estimate is from Hides, Angore, Juha and the existing oil fields (excluding SE Mananda and SE Gobe) only. Reserves from the existing oil fields are referred as associated gas reserves and have a volume of 2.5 TCF of OGIP. The certified reserves of 12.5 TCF OGIP is currently under development through the PNG LNG Project being developed by ExxonMobil. The reserves will feed the Project required rate of 960 MMSCFD at twenty years of plateau production.

Contingent gas resources discovered from current explorations around the country have a total volume of 7.5 TCF OGIP. Further drilling of appraisal from these discoveries will delineate the resource volumes which are optimistic to be increased.

The associated gas reserves and the PNG total gas reserves are tabulated on Table 6.3 and Table 6.4 respectively. Figure 6.5 shows the boundaries of the reserves from both the Gas Fields and Associated Gas Oil fields.

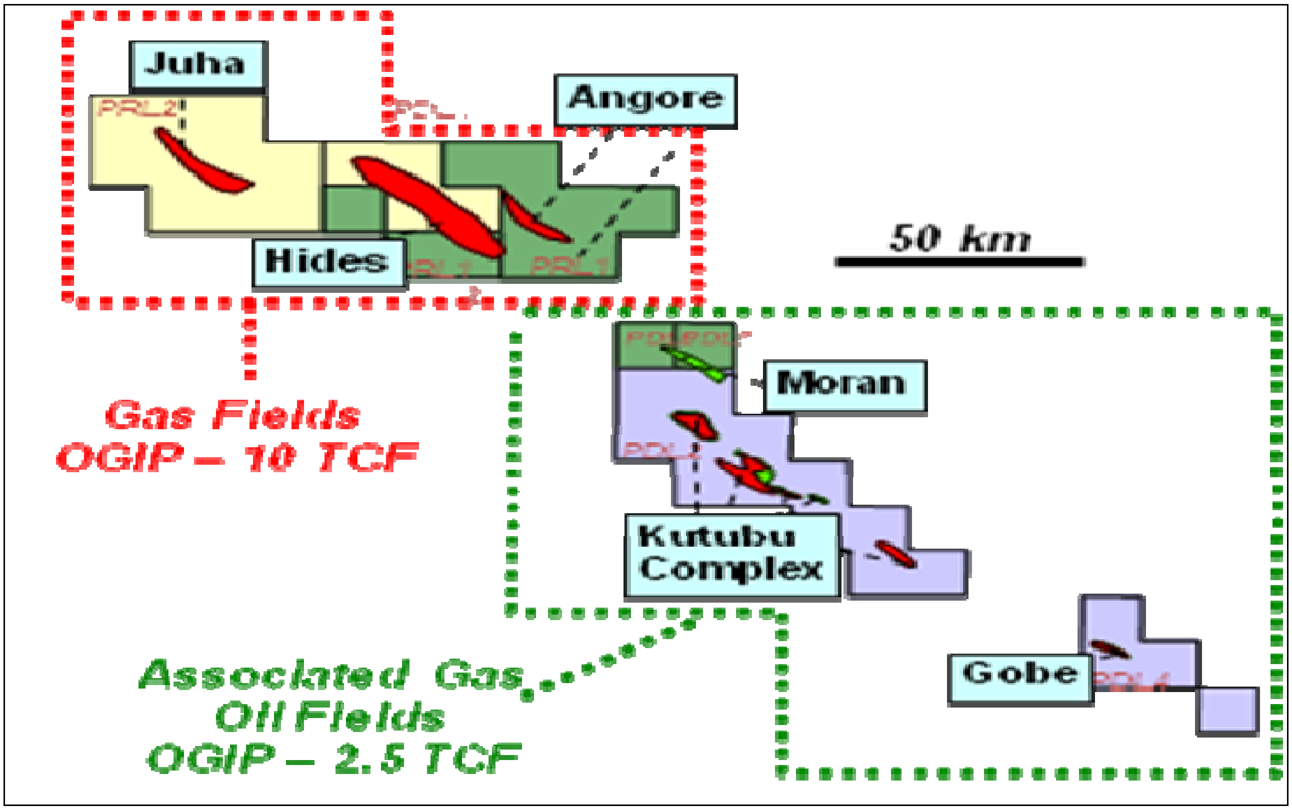


Figure 6.5: Boundaries of reserves from the Gas Field relative to the Associated Gas Fields (ExxonMobil).

Table 6.3: Summary of Associated Gas Reserves as at 31 December 2008 *2C Volumes.*

Field	**Solution OGIP** (BSCF	**SGRF** (%)	**SRG** **(**BSCF)	**Free OGIP** **(**BSCF)	**FGRF** (%)	**RFG** (BSCF)	**Total OGIP** (BSCF	**TRRG** (BSCF)
SE Gobe	152.1	-	98.9	96.3	71	77.0	248.4	175.9
Gobe Main*	68.6	-	44.6	109.5	74	87.6	178.0	132.1
SE Mananda	20.8	-	13.5	20.3	72	16.2	41.1	29.7
Kutubu*	648.6	-	430.6	1,623	76	1,290	2,271.2	1,720.6
Moran*	411.8	-	205.9	-	50	-	411.8	205.9

■ SGRF = Solution Gas Recoverable Factor, ■ RG = Solution Recoverable Gas, ■ FGRF = Free Gas Recoverable Factor, ■ RFG = Recoverable Free Gas, ■ TRRG = Total Recoverable Raw Gas.

Note:
- □ Recoverable raw gas includes condensate and LPG and no allowance has been made for fuel and flare Consumption.
- □ The above associated gas reserves figures were extracted from the 2008 Oil Search Ltd Reserves Report
- □ * Gas fields that will feed the PNG LNG gas plant.

Table 6.4: PNG Gas Reserves.

Field	Type	STOIIP	STCIIP	GIIP	Gas Reserves			Condensate Reserves		
					1P	2P	3P	1P	2P	3P
		(MMBO)	(MMBO)	(BCF)	(BCF)	(BCF)	(BCF)	(MMB)	(MMB)	(MMB)
Pandora	G	-	-	1,110	511	644	893	-	-	-
Pasca	G	-	29	435	-	160	300	-	6	6
Uramu	G	-	-	178	-	92	122	-	-	-
Kimu	G	-	-	2,000	-	3	1,000	-	-	-
Elevala	G/C	-	35	611	-	433	526	-	3	15
Ketu	G/C	-	-	704	-	140	585	-	-	16
Pnyang	G/C	-	23	343	-	1160	2554	-	9	16
Stanley	G/C	-	4.2	144	5	44	72	0.2	1.5	2.5
Douglas	G/C	-	30	2,000	400	800	1,500	3.5	7.5	15
Barikewa	G	-	-	759	-	605	692	-	-	-
Iehi	G	-	-	104	-	11	72	-	-	-
Bwata	G/C	-	-	139	48	66	128	-	-	-
Gobe*	-	-	-	-	-	-	-	-	-	-
Kutubu*	-	-	-	-	-	-	-	-	-	-
Moran*	-	-	-	-	-	-	-	-	-	-
SE Mananda	O/G	-	-	-	-	-	-	-	-	-
Angore*	G/C	-	100	6,951	-	3,328	5,881	-	5	33
Hides*	G/C	-	182	9,584	3,814	5,371	7,513	57	101	300
Juha*	G/C	-	269	5,293	638	1,536	3,805	32	38	90
Total			672.2	30,355	5,416	14,393	25,643	92.7	171	493.5

G = Gas, C = Condensate, O = Oil

Note:
- □ other gas discoveries not included here are yet to either be certified or have not been submitted to DPE.
- □ The PNG gas reserves given here are from the 2007 DPE Annual Report due to lack of updated data.
- □ Associated gas reserves for the Gobe, Moran, Kutubu and SE Mananda are given in Table 5.5a above.

6.8.1 Hides

Hides Gas Field was discovered with the drilling of the Hides 1 well in 1987 and appraised with five additional reservoir penetrations, all of which intersected gas within sandstones of the Toro and Upper Imburu formations. No water has yet been penetrated and as such the minimum vertical extent of hydrocarbons is taken as the lowest known gas (LKG) established at the base of the reservoir section in Hides 4 at –1509 m TVDSS. This results in a gas column height in excess of 1240 m. Using regional aquifer pressure data, a gas water contact depth range from approximately – 1850 m TVDSS to –2150 m TVDSS may be estimated.

The reservoir section comprised four individual sandstone units from the Toro and Upper Imburu formations. These sandstone units are informally referred to as the Toro A, B, C and Upper Imburu sands. Pressure data suggests that all Toro reservoir units act as a single system with wells located at the crest of the structure shown to be in communication with the Hides 4 well, located approximately 12.5 km to the southeast. Communication over such a large distance suggests the field is structurally relatively simple over much of its drilled extent. However, there are regions of the field that may be more complex and potentially compartmentalised. Such areas include the forelimb region and the north-western plunge end. As a result, a higher level of confidence in the resource exists within the central back-limb to southern plunge end areas of the field.

The structure has large gas accumulation extending to a total productive closure area of approximately 150 square kilometres. The total reserve as of March 2008 is 7.9 TCF of OGIP with an estimated ultimate recovery (EUR) of 6.2 TCF. Condensate volume in the reserve is estimated at 140 MBBLS with and average yield of 18 STB/MMSCF of gas. The primary reservoir intervals are from the Toro and Imburu sands.

6.8.2 ANGORE

The Angore gas discovery is located about 6 km northeast of the Hides 4 and 50 km northwest of the Kutubu Production Facility. The Angore 1A well was drilled in 1990 and resulted in a gas/condensate discovery within the Toro and Upper Imburu sandstones.

Wireline log data confirmed the presence of gas and drill stem tests conducted over various intervals within the reservoir section, flowed gas to surface at a maximum rate of 16 MMSCFD with 269 barrels per day of condensate. This well defined a lowest known gas (LKG) at a depth of 2420 m TVDSS with a proven gas column of 113.5 m in the well. No water wet sand has been penetrated as yet, but for the most likely in place volume calculations a estimated GWC at 2560 m TVDSS was used. The estimated closure area for the most likely case is 27 km^2.

The reservoir section penetrated by the Angore 1A well comprises three sandstone units of the Lower Toro Formation, and the Upper Imburu Sandstone which is age equivalent to the Digimu Sandstone to the southeast.

In order to estimate the OGIP in the Angore field, an assessment was conducted of the total Angore data set. A range of reservoir parameters were developed based on well log analysis, and the following parameters used to determine the most likely OGIP of 1.1 TCF:

- No field compartmentalization; the entire backlimb and forelimb are included in the most likely volume assessment.
- A field wide gas water contact of 2560 m TVDSS
- An average net to gross of 64 percent, representing the most likely parameter.
- An average porosity of 7.5 percent, representing the most likely parameter.
- An average gas saturation of 55 percent, representing the low side parameter.

6.8.3 JUHA

The Juha surface structure, which was first identified during field work in 1948, has a broad gentle anticline immediately in front of the first major thrust front of the PNG Foldbelt. It reaches about 1200 m above sea level and extends NW-SE direction over 25 km and 6 km in NE/SW direction.

Four wells have penetrated the Toro and Imburu section (Juha 5X) at Juha. Juha 1X, 2X, and 3X intersected gas on rock in the Toro Sandstone. Juha 5X was drilled 478 m down dip from the LKG intersected at Juha 3X (at 2442 m TVDSS). The well encountered water bearing Toro Sandstone. The interpreted GWC from RDT pressures, was 2479m TVDSS.

Pressure data suggest that potentially all reservoir units are in communication across the field area over a distance of approximately 13 km between Juha 1X and Juha 3X. Communication over such a large distance suggests that the field is structurally relatively simple over much of its drilled extent. However, there are regions of the field that may be more complex and potentially compartmentalised. Such areas include the north-western plunge and the area around the Baia Stock to the SE. The 2007 well Juha 4X proved the NE area (Juha North) to be a separate gas accumulation with significantly different pressures.

The reservoir section is about 96 m thick with 27 m net (TST) and comprised of three individual shallow marine cycles from the Toro formation. The Toro sandstone reservoir at Juha is composed of extremely clean quartz arenites with very low clay content. A high CGR of about 80 BBL/MMSCF was measured.

An assessment of the original gas in place (OGIP) in the Juha field was conducted incorporating all available data. Deterministic volumetric analysis from the geologic model estimates an original gas in-place of 0.9 TCF.

Low side and high side original gas in-place deterministic cases were developed to provide a range of possible resource volume outcomes. The low side case used an average water saturation of 46 percent and a low side gross rock volume, resulting in a gas in-place volume of 0.7 TCF. The high side case used an average water saturation of 26 percent and a high side gross rock volume, resulting in a gas in-place volume of 1.2 TCF.

7 DOWNSTREAM PROCESSING NAPANAPA OIL REFINERY – 2009 REVIEW

7.1 General Overview

NapaNapa InterOil refinery is located 4km from Port Moresby on the eastern side of Port Moresby harbour. It is currently the only major petroleum refining facility in PNG, apart from the mini refinery and micro-stills operated by Oil Search (PNG) Ltd at Kutubu and Hides Gas Processing Facility.

InterOil refinery used to be the only downstream petroleum project to have been granted a Petroleum Processing Facility License (PPFL) by the PNG Government since February 2000. It was commissioned in the third quarter of 2004 and was fully operational in 2005. However, the number of PPFL rose to two when ExxonMobil was granted a PPFL for the PNG LNG Project Plant late 2009.

There were no major events that took place in 2009; however the refinery was shut down several times during the year due to low crude inventory, maintenance, false alarms of flame detectors and once due to a tsunami warning. For instant, there was no crude processed for five weeks. This was due to minimum crude inventory and maintenance carried out at the refinery. No major modifications or changes in the operational equipment occurred.

7.2 Design Configuration

The simple hydro-skimming unit at the refinery distills crude and reforms naphtha using a semi-regeneration reformer and was designed for a throughput of 32,500 barrels per day (bpd) of light sweet crude similar to the Kutubu crude. It is designed to operate continuously producing the following refined products:

- Liquefied Petroleum Gas (Propane and Butane)
- Naptha (Light Naphtha and Mixed Naphtha)
- 91 RON Unleaded Gasoline
- Jet Fuel/Kerosene
- Diesel
- Low Sulfur Wax Residue (LSWR).

Heavy naphtha is converted into reformat in the reforming unit where it is then is blended with butane and light naphtha to produce gasoline.

7.3 Crude Supply & Productions

High middle distillate yield crude is imported from abroad (Mutineer-Thevenard Crude) as well as bought locally (Kutubu Crude). Imported crude is generally less favoured since it has less content of diesel than the Kutubu Crude.

In 2009, the refinery processed 6,002,055 barrels of Mutineer-Kutubu-Thevenard crude or approximately 16,444 barrels of crude oil per day on average – over half of what the refinery was designed to process. This was basically due to crude not being delivered occasionally. Although the amount of crude processed was affected, this did not have an effect on the supply of all product requirements as indicated in Figure 7.1.

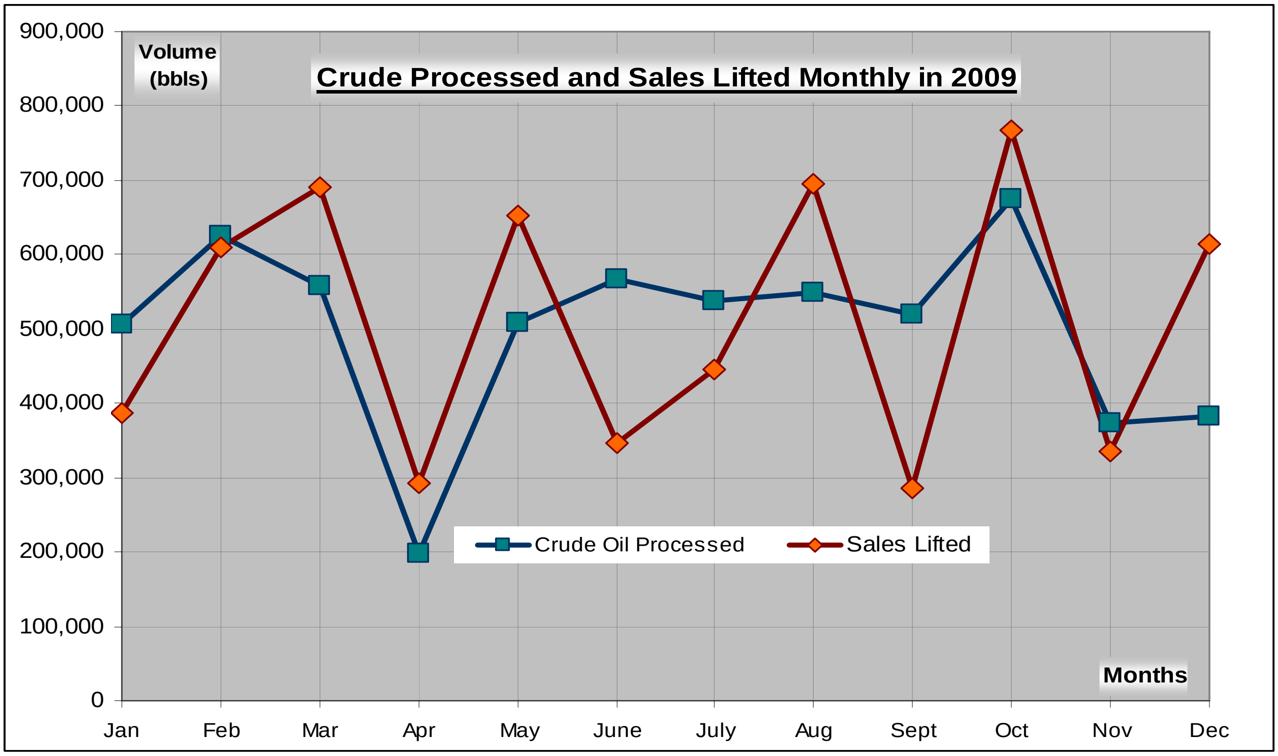


Figure 7.1: Total monthly sales lifted from the refinery against crude oil processed in 2009.

Of the 6,002,055 barrels of crude oil processed at the refinery during the year, approximately 98% liquid was recovered as refined products. As in previous years, diesel continued to be the main product with 2,929,200 barrels produced in 2009 which was sold and used around the country. Following this, production of naphtha (light and mixed) with 1,550,680 barrels for the year. Naphtha was exported since there is no market for this product in the country. Table 7.1 presents the production and products disposition for NapaNapa Refinery in 2009.

7.4 Marketing

PNG still remains the principal market for the refinery products from the refinery with the exception of naphtha and low sulphur waxy residue. Naphtha is exported to the Asian market in two grades, light naphtha and mixed naphtha to be used as feedstock for petrochemical plants. The consumption of diesel product has increased in the local market as reflected in the high diesel production from Table 7.1 and Figure 7.1. In-country, apart from fuel being sold at InterOil's own fuel outlets, vessels transporting fuel out to other centres are mainly contracted by Shell and Mobil. Ok Tedi Mining Ltd (OTML) uses its own vessels, which to load from the jetty.

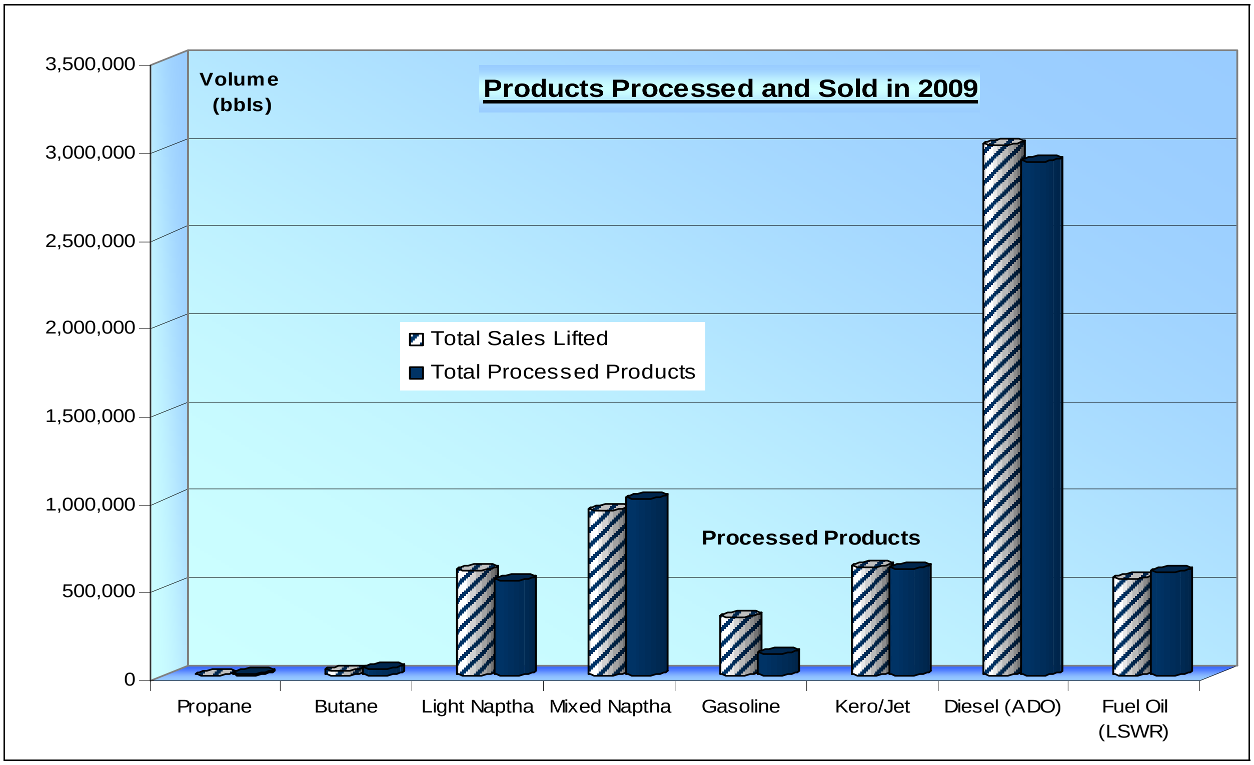


Figure 7.2: Total Productions in 2009.

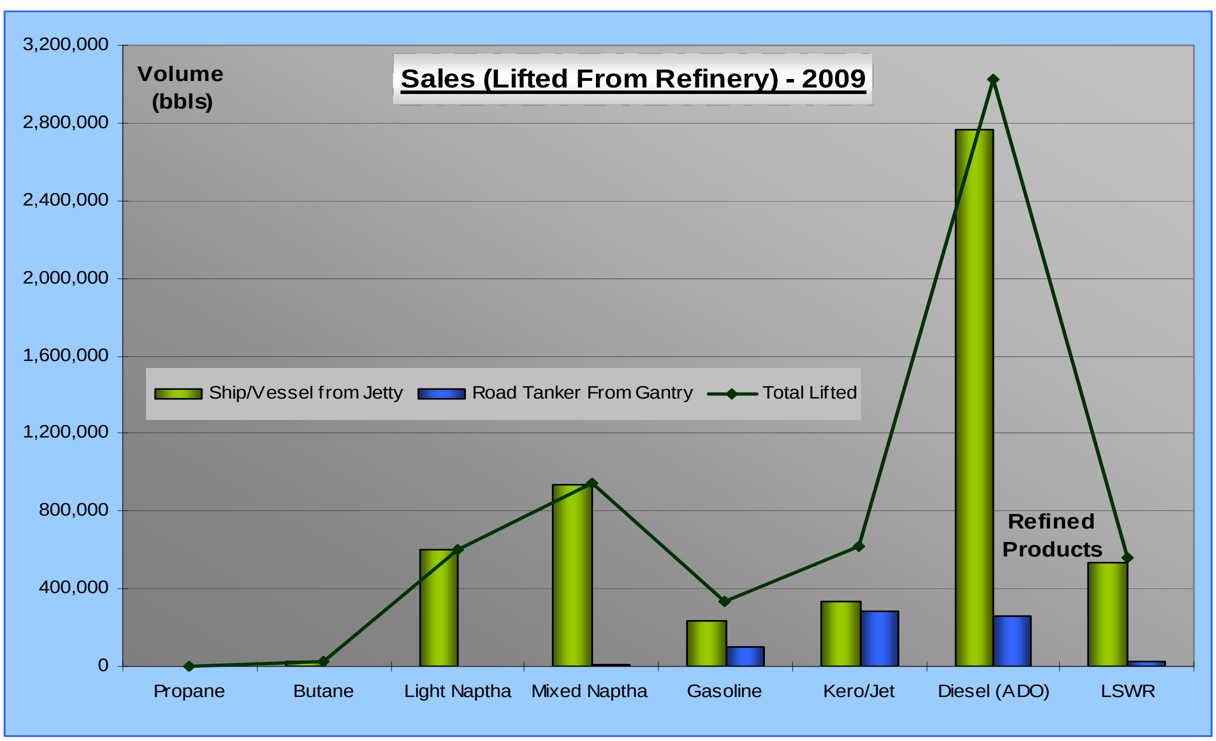


Figure 7.3: Total sales lifted from the refinery in 2009

Table 7.1: Production and Product Disposition.

Period Covered		TOTAL FOR 2009		
1. Crude Oil Processed in barrels				**6,002,055**
2. Production in barrels				
	Product			
	Propane			11,529
	Butane			39,722
	Light Naptha			543,235
	Mixed Naptha			1,007,445
	Gasoline			129,681
	Kero/Jet			607,312
	Diesel (ADO)			2,929,200
	Fuel Oil (LSWR)			588,271
	Liquid Recovery			**5,856,395**
3. Product Slopping in barrels				**2,388**
4. Fuel in barrels				
	Liquid (LPG/ADO/LSWR)			**94,920**
5. Fuel Gas + Unaccounted Loss + Flaring in barrels of oil equivalent				**48,352**
6. Sales (Lifted from the Refinery) in barrels				
	Product	Ship/Vessel From Jetty	Road Tanker From Gantry	
	Propane	2,830	279	3,109
	Butane	27,667	0	27,667
	Light Naptha	605,253	0	605,253
	Mixed Naptha	933,523	7,540	941,063
	Gasoline	236,830	101,473	338,303
	Kero/Jet	333,606	287,802	621,408
	Diesel (ADO)	2,768,706	256,168	3,024,874
	LSWR	531,730	25,654	557,384
	Total Sales			**6,119,061**

The import parity price for each of the refined products produced and sold locally is calculated by adding the costs that would typically be incurred to import such a product additional costs include insurance and freight, landing charges, losses incurred in the transportation of refined products, demurrage and taxes.

8 PETROLEUM PROJECTS

8.1 PNG LNG Project

Esso Highlands Ltd, a subsidiary of ExxonMobil is leading the Papua New Guinea Liquefied Natural Gas Project (PNG LNG), on behalf of the co-ventures, which include Oil Search, Santos, AGL, Nippon Oil, Mineral Resources Development Company (MRDC), EdaOil and the Independent Sate of PNG.

Figure 8.1 is a schematic of the PNG LNG Project's proposed development plans with new facilities and existing Oil Facilities with new and existing pipelines and their routes.

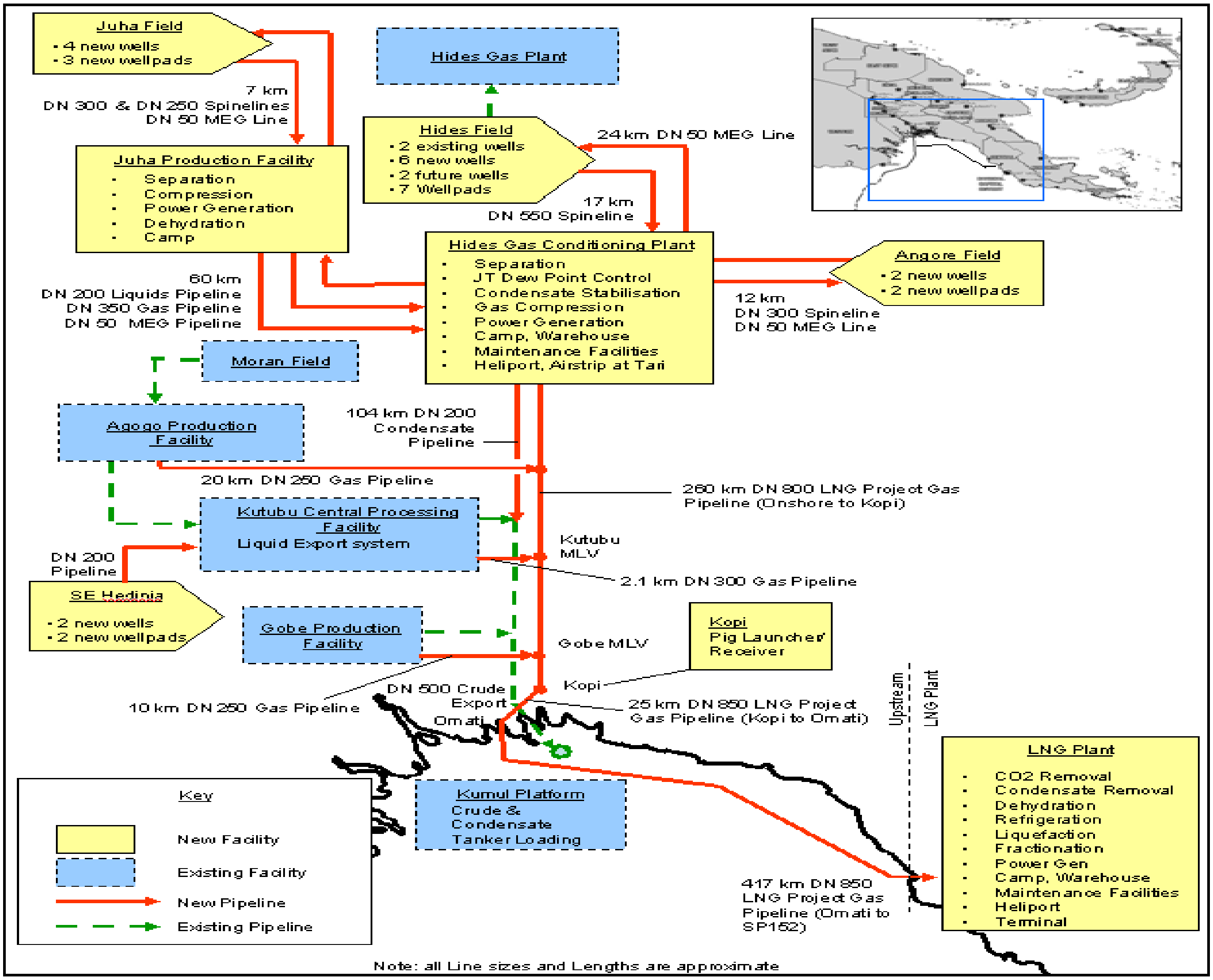


Figure 8.1: PNG LNG Project – Proposed development with existing and new facilities and pipelines and routes (Source: ExxonMobil's presentation to DPE).

ExxonMobil estimated its aggregated gas reserves to be between 7.0 and 9.2 Trillion Cubic Feet (TCF) from associated and non-associated gas fields in the highlands of Papua New Guinea. Recoverable resource range between 8 TCF to 12 TCF EUR.

The challenges of putting together the value chain of the PNG LNG Project have been both enormous and unique task. This includes finding enough gas resources in the rough terrains of the highlands of PNG, transporting it through onshore and offshore pipelines, securing LNG market, financing the project, construction and operation of LNG plant and shipping of LNG to customers – addressing all these activities and putting solutions together in an optimal package has been no easy feat.

The PNG LNG Project will develop gas resources and produce gas from the designated gas fields for a production life of 30 years. The project will include development of reservoirs and installation of facilities during different phases of the LNG Project to produce liquefied natural gas (LNG). Gas from the non-associated and associated gas fields will be used in the project. The non-associated gas fields include Hides, Angore, Juha, and SE Hedinia fields, while the associated gas fields include Kutubu, Agogo/Moran, and Gobe Oilfields. Procurement and construction are scheduled to begin in year-end 2009 with the first LNG cargo shipment in 2014.

The PNG LNG Project proponent submitted 21 licence applications for the development of non-associated and associated gas fields to DPE for review and approval. These included Applications for Petroleum Development Licences (APDLs - including Extensions and Variations to existing PDLs), Application for Pipeline Licences (APL - including Extensions and Variations to existing PLs) and an Application for a Petroleum Processing Facility Licence (APPFL). In support of those licence applications, the operator has submitted a set of documents containing highly technical information and referenced to the licence applications.

In this section, a general but brief technical overview on both the surface and subsurface development plans of the PNG LNG Project are mentioned. Detailed discussion of the project can be obtained from DPE.

8.1.1 Upstream Development –Surface Facilities and Pipelines

Currently there are three existing oil facilities. These include the Central Production Facility (CPF), Gobe Production Facility (GPF) and Agogo Production Facility (APF). These facilities will be modified to enable delivery of dewpointed-associated gas to the LNG Project Gas Pipeline. Spur lines will connect the CPF, GPF and APF to the gas pipeline. The dewpointed HGCP gas will be blended with the richer associated gas to provide specification feed gas to the LNG Plant.

A new LNG Project gas pipeline will extend onshore from the HGCP to Omati, then offshore through the Gulf of Papua to State Portion (SP) 152 and continuing onshore via a shore approach towards a 6.3 MTA LNG plant situated near Port Moresby. The new LNG Project gas pipeline route is expected to be approximately 710 km long. (See Figure 8.2).

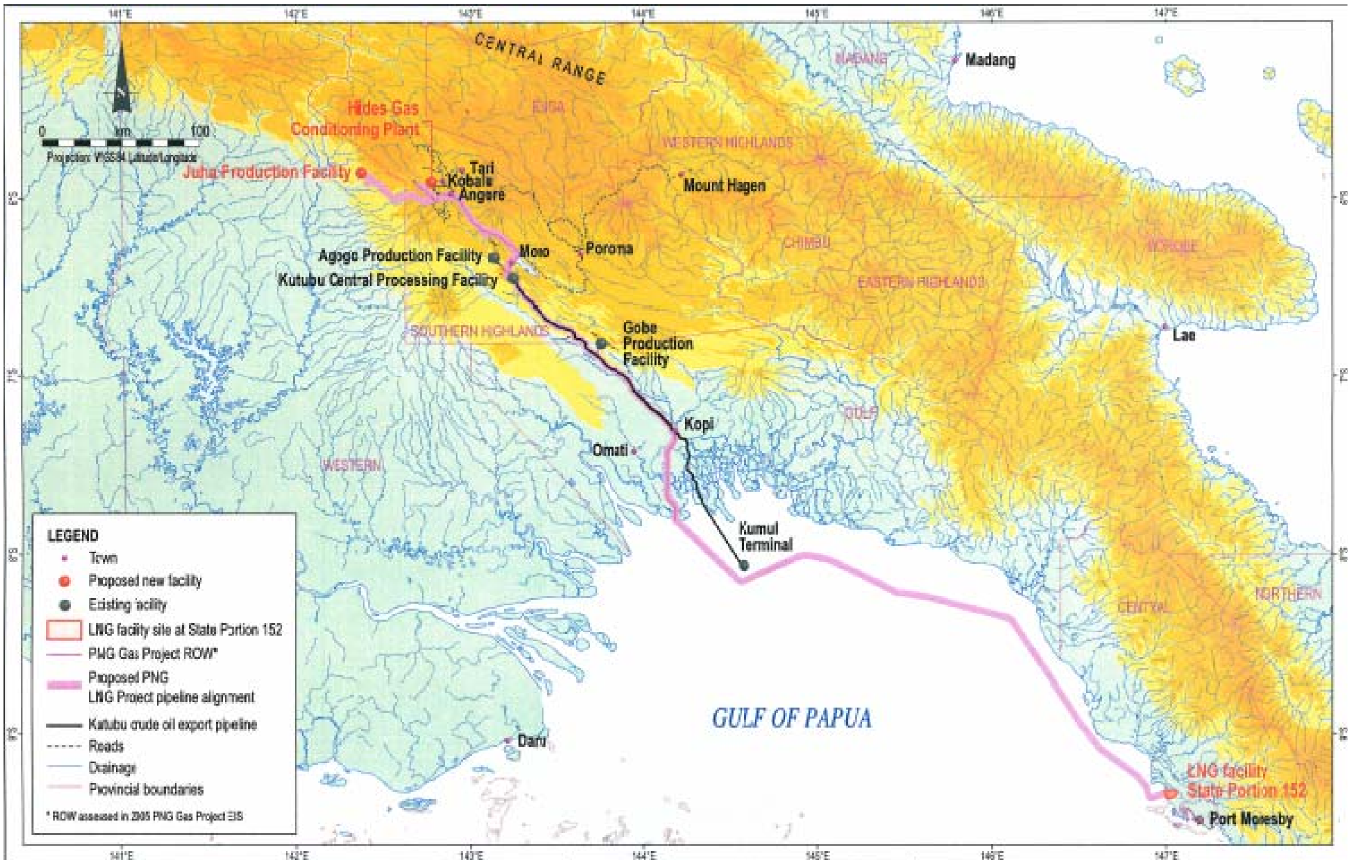


Figure 8.2: Proposed LNG Pipeline Route and Facilities, 710 km (sourced Exxon Mobil, 2009).

In the upstream development, ExxonMobil Engineering Practices System (EMEPS) will serve as the basis for Project Design Specifications (PDS). EMDC guidelines and environmental standards will also be applied to the project as required. The PDSs will be specific to PNG and will reference local codes and standards. The project will be designed and installed in accordance with the project specifications in the hierarchy of (1) Regulatory, (2) PDS, and (3) Industry and international standards. In some cases, where international codes and standards differ from PNG codes and standards, the PNG codes and standards will be used, or an exemption will be required to be obtained from the PNG regulatory body.

8.1.1.1 Hides Gas Conditioning Plant (HGCP)

Hides Gas Conditioning Plant (HGCP) has been designed to take in and process gas and liquids from the Hides, Angore and Juha fields. The gas from these fields will be piped by an extensive pipeline gathering system to HGCP. The HGCP will also accommodate condensate stabilisation process and the condensate will be transferred through a Condensate Pipeline to CPF. The HGCP condensate will be blended with the CPF crude oil to be exported via the existing oil export pipeline system to the Kumul Marine Terminal (KMT).

8.1.1.2 Juha Production Facility (JPF)

The JPF will receive full wellstream fluids from its wellpads and separate these into a rich gas and liquids stream. These fluids will be transported via rich gas pipeline and liquids pipeline from the JPF to the HGCP. A HGCP to JPF MEG Pipeline will deliver regenerated MEG with corrosion inhibitor from the HGCP to the JPF for storage.

8.1.1.3 LNG plant

Air Products and Chemical Inc (APCI) LNG Plant Technology has been selected for the PNG LNG project. The liquefaction section of the plant will be based on Air Products and Chemicals, Inc (APCI) and propane pre-cooled mixed refrigerant (C3MR) process. The refrigeration compressor drives will be gas turbines.

The plant will be designed to handle a stream day gas rate of 1133 kSm^3/hr (962 MSCFD) with an expected capacity of approximately 6.3 million tonnes per annum (MTA). It will also be capable to handle all expected inlet gas compositions over the life span of the development of different gas fields.

The LNG Plant's processing facilities include inlet gas receiving, an Acid Gas Removal Unit (AGRU), dehydration, mercury removal, refrigeration, liquefaction, and condensate stabilization/fractionation. The LNG Plant's major utilities include; power generation, hot oil, air and a nitrogen system. The major offsite systems at the LNG Plant include LNG Storage (2x160,000m^3 tanks), condensate storage (2x8500m^3 tanks), firewater system, flare systems, fresh water system and effluent handling system.

8.1.1.4 Marine Facilities

The LNG Plant's marine facilities will be designed to sustain loading capacity of LNG carriers from 125,000 m^3 to 220,000 m^3 and condensate tankers of 7,000 DWT. The facilities will include a LNG export berth, a condensate export berth, a tug landing area and material offloading facility (MOF) with permanent tug mooring berths.

8.1.1.5 Onshore Pipeline

The onshore pipeline will link HGCP with CPF, then to Omati Landfall where it will connect with the offshore pipeline. The onshore section will be of grade DN 800 API 5L X-60 pipeline with 32 inch diameter from HGCP to Kopi. From Kopi to Omati, the onshore section will be of grade DN 850 API 5L X-65 with 34 inch diameter. The length of the onshore pipeline will be approximately 285 km. The pipeline has a design flow rate of 1,133 kSm^3/h (960 MSCFD) with normal operating inlet pressure of 14.4 MPag at the HGCP and the minimum required outlet pressure (at LNG Plant) will be 7.5 MPag. The prescribed maximum operating pressure (MAOP) from HGCP to Kopi will be 15.4 MPag and 17.1 MPag from Kopi to Omati.

8.1.1.6 Offshore Pipeline

The offshore segment of the LNG Project Gas Pipeline will constitute pipeline route from Omati River Landfall, extending approximately 24 km to the open sea, and then cross the Gulf of Papua to the landfall at the LNG Plant site at SP 152. The length of the offshore pipeline will be approximately 407 km. The offshore pipeline will be of DNV Grade 450 (X65) carbon steel pipeline with 34 inch diameter. The pipeline will be on the seabed for most of the route and buried in shallow water at both ends. Concrete coating will be applied to ensure that the pipeline will be stable on the seabed. The pipeline will have a design flowrate of 1,133 kSm^3/h (960 MSCFD) with a design pressure at Omati Landfall of 17.1 MPag. At the LNG plant, the inlet pressure will be 7.5 MPag.

8.1.2 Modifications of Oil Field Facilities

The existing oil field facilities, including CPF, GPF, APF and KMT are operated by Oil Search Limited (OSL). These facilities will be modified to gather associated gas produced from the wells and then export these as feed gas to the LNG Plant. Interface facilities will also be required to handle the supply of the associated gas and condensate produced from the HGCP.

The modification of oil field facilities will accommodate a) Associated Gas, b) Condensate Handling, and c) Commissioning Gas. Two of which are briefly described below.

8.1.2.1 Condensate Handling

Stabilised HGCP condensate will be transported to the CPF via the PNG LNG Project Condensate Pipeline. At the CPF, HGCP condensate will be blended with stabilised crude oil from the CPF and stored in the existing CPF oil storage facilities. Export of this blended product from the CPF to the KMT will be via the existing oil export system.

8.1.2.2 Commissioning Gas Project

Commissioning gas is required by the PNG LNG Project to commission the LNG Project Gas Pipeline, the LNG Plant and the HGCP. Supply of commissioning gas from the CPF prior to the completion of the HGCP will accelerate start-up of the LNG Plant by up to 6 months. Temporary commissioning gas facilities will be installed at the CPF to process high pressure gas from the discharge of the reinjection compressors. This dry gas will meet the hydrocarbon and water dewpoint specifications that are to be used as feed to the LNG Project Gas Pipeline and the LNG Plant.

8.1.3 Technical Review of Licence Applications and Licence Approval

The Department of Petroleum and Energy (DPE) engaged Granherne Ltd and Gaffney Cline and Associates (GCA) to review the licence applications in collaboration and consultation with DPE's technical team, consisting of geoscientists and engineers. Granherne Ltd assisted engineers to review all upstream surface development proposals while GCA assisted the DPE geoscientists to review subsurface development proposals.

8.1.4 Licence Approval

On 8 December 2009, Final Investment Decision (FID) was executed with 21 licences granted to the developer, Exxon Mobile.

8.2 Umbrella Benefit Sharing Agreement (UBSA)

The *Oil & Gas Act* requires a Development Agreement to be executed between the State and affected Provincial Governments, Local Level Governments and the project area landowners. Hence DPE with its mandatory obligation ensured signed agreements complied with the provisions of the *Oil & Gas Act.* The State was also mindful of its existing and outstanding commitments under individual existing licenses in the oil project area. Accordingly, whilst the PNG LNG UBSA Forum offered stakeholders with the arena for dialogue on gas benefits, it also hosted forum to address outstanding oil project issues.

The UBSA forum was staged in Kokopo, East New Britain from April to June 2009 and was officially signed on May 23rd 2009 by the State through its Petroleum and Energy Minister Hon. William Duma and genuine Project Area Land Owners (PALO) representatives through-out Exxon Mobil PNG LNG Project foot-print.

The forum which was initially scheduled for 2 weeks was extended to 6 weeks as there were numerous issues to be dealt with, particularly those concerning the landowners and Provincial Governments. These issues include a) landowners' lack of understanding about the content of the agreement due to time limitation; and b) numerous court orders to stay the forum by disputed landowner groups. A successful equity increased of 5 % from the 2% was reached through negotiations.

8.3 License Based Benefit Sharing Agreement (LBSA)

The LBSA was a license-based forum that was held in August 2009 and focused specifically on landowners in designated Exxon Mobil permits. These license areas, identified under the ExxonMobil PNG LNG Project include PDL 1, PRL 12, PRL 11, PDL 2, PDL 4, PDL 5 and PDL 6.

Prior to the LBSA, the DPE organized several landowners meetings in Port Moresby for the city based landowners to seek alignments on various major projects issues and to know the project schedules for the three licenses namely PDL 1, PRL 11 and PRL 12.

The meetings attracted a lot of participants who raised issues concerning Incorporation of Landowner Group (ILG), business development grant, and outstanding MOAs. They insisted that a full scale social mapping must be carried out thoroughly in order to identify legitimate landowners so that genuine landowners can participate in the LBSA. This was not possible due to the limited time and so an option was agreed to by all parties for a clan vetting exercise to be undertaken.

The PDL 4 project LBSA was held in Gobe, Southern Highlands Province and was signed on December 4th 2009. Thirteen days after the commencement of the Forum. The forum was official opened on November 21st 2009 by Petroleum and Energy Minister, Hon. William Duma, accompanied by, Independent Public Business Corporation

Minister Hon. Arthur Somare, Southern Highlands Province Governor, Hon. Anderson Agiru, Minister for Sports Hon. Philemon Embel, Gulf Governor Hon. Havila Kavo and Member for Tari-Pori and Minister for Education, Hon. James Marabe.

These meetings were a success and led to the successful signing of the 3 LBBSAs for PRL 12, PRL 11 and PDL 1 , PRL 11 and 12 LBSAs on the 4th, 7th and 8th of December respectively just before the due date of the Financial Investment Decision on the 8th of December 2009. The signing of the 3 LBBSAs and other agreements in early December 2009 demonstrated commitments of the project developer, the PALO and the State to ensure that the PNG LNG Project commenced on schedule.

8.4 Economics of the PNG LNG Project

The PNG LNG Project will attract a Capital outlay of over US$15 Billion with a projected rate of return of over 14 per cent. Projected total revenue of the project will be well over US$100 Billion based on a 38-year economic life span. The LNG Project is the biggest ever to be developed in PNG since Independence with a projected Annual Revenue of over US$700 (i.e.; over PGK2 Billion) from Direct Benefits Streams alone from the LNG Project.

Under the Agreement, the Income Tax Rate for the LNG Project is thirty percent, which reflects the existing tax rate for gas projects. Condensates produced, as part of the LNG Project will be also taxed at the thirty percent gas tax rate.

The State's Participating Equity in the PNG LNG Project is 19.4%, which reflects the State's integrated equity in this project. Basically, this means that the 19.4% interest represents the State's proportionate interest in each of the Petroleum Development Licenses (PDLs) or projects that will supply feed gas to the PNG LNG Project.

8.5 LNGL PNG – Inter-Oil

The second major Gas Project in PNG is the proposed Liquid Niugini Gas Limited (LNGL) LNG Project, a proposal mooted by InterOil and a Consortium of strategic partners. This project is based on the newly discovered Elk/Antelope gas discoveries in the Baimuru area of the Gulf Province.

Elk/Antelope gas field is presumably the biggest carbonate reservoir in the Southern Hemisphere. Based on the preliminary data provided by the project proponents, this project will attract half the size of the Capital outlay in the ExxonMobil-led PNG LNG Project but the project will be as big as the PNG LNG Project. The key reason for reduced Capital cost in the LNGL LNG Project is because the Elk/Antelope gas fields are locate closer to a marine area and also comparatively located close to Port Moresby, where the LNG Plant will be built.

The Project Agreement was recently signed by the Developer and the State in November 2009. The signing of the Gas Agreement between the State and Developer is imminent.

8.6 Stanley Gas Project

This is a proposed Gas Project by Horizon Oil Limited to bring on to stream the Stanley gas field in Petroleum Retention License (PRL) 4 in the Western Province. The Operator is proposing to build mini LNG Plant to process the gas and sell the dry gas to Ok Tedi or the other mining towns for electrification and other industrial uses of energy. The technical and commercial analysis of the project, together with the draft proposed Gas Agreement has been submitted to DPE by the developer for review. This project is projected to come on stream in 2011. If this project gets off the ground, it will be the third gas project in PNG, another important project that will boost the economy of the country.

10.0 CONCLUSION

Year 2009 marks a significant growth in Petroleum activities such as licence administration, field operations, geological and geophysical operations although oil & gas productions declined by 7 and 11 percents respectively relative to 2008 production. The year also ended on a high note with successful FID made on 8th December 2009 when PNG LNG Project finally became a reality.

A landmark thirty one applications of prospective petroleum investors were receipted, ten of which were granted Petroleum Prospective Licence status while the remaining were pending Ministerial determination. At the end of 2009, a record of 55 PPLs, 9 PDLs and 8 PLs were active.

A significant increase in G&G studies, particularly geophysical studies this year demonstrated licence operator's commitments to honoured their work programs in the initial six-year licence tenure. Although only one geological study was undertaken, more priority was given to geophysical studies upgrade leads and prospects to drillable stage. A total of actual 27,624.34 line kilometres of data were acquired during the G&G studies at a grand cost of US$21,290,258.63

Thirteen wells were drilled in 2009: 6 development wells and 7 exploration and appraisal wells. The exploration and appraisal wells had oil/gas shows while the development wells indicate oil. Total expenditure for all these wells was US$290.87 million. These wells were drilled in licences operated by Interoil Ltd and Oil Search Ltd. Cumulative wells drilled since 1990 have risen to 204.

Oil production from existing oil & gas fields in PNG has declined, based on 2009 production history. The average oil production rate was 38,201 BOPD with an annual total of 13,943,095 STBO which was a 7% less than 2008. Gas production from oil fields decreased by 11% which was 134.38 BCF at a rate of 11, 844 MSCFD. The production trend will continue to decline unless more oil fields are discovered and brought on line.

In collaboration with Exxon Mobile, the main oil field operator Oil Search Ltd will optimize and develop oil fields with associated gas taken as these fields deplete to supplement gas production from the non-associated gas fields. Gas from non-associated gas field will be fed into HGCP downstream gas pipeline and blended with the outlet gas to ensure water and hydrocarbon dew point specification are met for the PNG LNG project operated by Exxon Mobil. It is estimated that about 6.3 million ton of gas would be exported by annum to international markets.

The total ultimate recoverable gas reserve in PNG is estimated to be 9.7 TCF. This is 76 percent the total ultimate recoverably of the 12.5 TCF OGIP. The Total OGIP is currently under development through PNG LNG Project by ExxonMobil and its partners.

Other field development plans by Interoil, Horizon Oil Limited and Talisman were submitted and are currently being reviewed and are at their conceptual stage.

9.0 POLICY

There are a number of disciplines that are dealt with by the Policy Branch. The Branch comprises environment, economics, and legal aspects of function of the Department. Herewith are some of the major tasks that transpired in 2009.

9.1. Environmental Section

As the regulator of the country's oil and gas industry, the Department has prioritized environmental protection as one of its key monitoring roles, in line with Papua New Guinea's Fourth National Constitutional Goal on Environmental Protection and Sustainable Development. It has an Environment Unit which monitors Health, Safety and Environment aspects of oil and gas exploration and development, to ensure compliance with environmental guidelines in key national legislations such as; the Oil and Gas Act, the Environment Act, the Industrial Health, Safety and Welfare Act and Best Industrial Practices, observed generally in the industry.

9.1.1. Environmental Monitoring

9.1.1.1. PNG LNG Project EIS Approval

The Environmental Impact Statement (EIS) of the PNG LNG Project was approved by the State in May 2009 after completion of preliminary assessments and public review processes, as required under the Environmental Act (2000) and the Oil and Gas Act (1998). The Department of Petroleum and Energy's Environment Unit contributed to the public review process of the PNG LNG EIS, through dissemination of EIS document to interested members of the public, provision of advice on the Environmental Impact Assessment (EIA) and EIS procedures, coordination and compilation of public reviews and actual appraisal of the EIS document through roadshows held in the project foot-print.

The public review of the PNG LNG EIS took place from 1st to 31st April 2009 while the actual approval (i.e. approval in principle by the Minister for Environment and Conservation) was granted in May 2009. The PNG LNG EIS Document is currently available in the DPE archive in both electronic and hard copy mediums.

The EIS is a regulatory pre-requisite for any Project construction. Equally important are the petroleum permits such as the Pipeline Licenses and Petroleum Development Licenses issued under the Oil and Gas Act. The issuing of these licenses/permits was an integral deliverable required for Project Financial Close on 8 December 2009.

9.1.1.2. Interoil LNG Project EIS

Following its recent gas discoveries in the Gulf Province, InterOil has begun planning the construction of an onshore LNG processing plant close to its existing refinery at NapaNapa in the Central Province. Subsequently, InterOil had its EIS Roadshow or Public Consultations from 17 – 19 March 2009 which were held in Wabo and Kerema town in the Gulf Province. Represented at the Public Consultations were representatives from the developer, InterOil, Douglas Environmental Services, the Department of Environment and Conservation and the Department of Petroleum and Energy.

Figure 9.1: InterOil EIS Public Consultation (PC), Wabo.

Figure 9.2: EIS PC Kerema, Gulf Province.

9.1.2. Environmental Issues

9.1.2.1. Presentation of alleged water pollution

This ongoing environmental issue dates back to 2006, which landowners from Yagerabo and Gese villages near Lake Kutubu, alleged that drilling-chemicals (notably barium) from the Kutubu 2X drill site, percolated and contaminated the adjacent underground water reservoir, which drains out to Lake Kutubu via Gese and Yakerabo Creeks. The alleged impacts, as compiled in various reports, included sedimentation and water turbidity, demise in aquatic life, at both creek confluences and sampled sites around Lake Kutubu, changing water chemistry (accumulation of heavy and trace metals and water discoloration), human deaths and elimination of aquatic sustenance (primarily freshwater fish and prawns).

Landowners undertook several scientific studies since 2006 and made several presentations to Oil Search, DPE and DEC, demanding Oil Search to pay environmental compensation. Nevertheless, studies were conducted by OSL into the matter in 2006 and maintained that the alleged impacts were part of natural environment process and could not accept the scientific criteria used by landowners in their assessments.

Upon direction by DEC in 2009, landowners engaged an independent consultant, Dr. Kulange Banda, a Senior Chemistry Lecturer at the University of Goroka, to scientifically re-evaluate evidence previously gathered by landowners. His findings were presented on 18 September 2009 (facilitated by DPE's Environment Unit), which only DPE and DEC attended. The Primary issue emanating from this presentation, which required further verification by DEC involved the location of Kutubu 2X drilling, which appeared to be within the boundary of the Kutubu Wildlife Management Area (KWMA). Further deliberation by DEC, OSL and the Landowners on this matter remains pending.

9.1.2.2. Lake Kutubu Catchment Area Management Plan

On 2 June 2009, the World Wide Fund presented its Lake Kutubu Catchment Management Plan to stakeholders. Lake Kutubu was gazetted a Wildlife Management Area on 25 June 1992 and was designated on 22 September 1998 by the Government of Papua New Guinea as a 'Wetland of International Importance' under the Ramsar Convention on Wetlands. The Lake is located in PDL 2 (Kutubu) and is not only home to a variety of endemic fish species but also serves as the primary source for food and water for the customary landowners.

9.1.2.3. Second National Communication (SNC) Project to the UNFCCC Greenhouse Gas Inventory

The DPE was involved in the SNC Project to the UNFCCC greenhouse gas inventory, funded by the UNDP's GEF, and administered by the OCCES in conjunction with the DEC. The aim of the Project was to collect and collate anthropogenic gas (carbon dioxide, methane and sulphur dioxide) source data from the respective sectors of energy, land use change and forestry, agriculture, waste and industrial processes (the five sectors of concern under the UNFCC as major contributors of anthropogenic gases). This analyzed data was presented to the Conference of Parties at the UNFCCC in December 2009.

9.1.3. Environment Policy and Internal Developments

9.1.3.1. Internal HSE matters

One of the Environment Unit's aims is to implement practical HSE measures within the Department and raise staff awareness on the importance of Occupational Health and Safety issues at work place. Amongst other internal HSE matters, such an organizational HIV/AIDS Policy, fire extinguisher demonstration, safe work practices awareness and installation of emergency evacuation charts, the Unit with the assistance of the Petroleum Division Director, was only able to issue safety reflector vests to most of our technical personnel, handy man and drivers within our three (3) divisions.

Figure 9.3: DPE Staff posing with their safety reflector vests.

9.1.3.2. PNG LNG UBSA Expenditure

Upon completion of the PNG LNG Umbrella Benefit Sharing Agreement (UBSA) in Kokopo, East New Britain Province on May 23rd 2009, the Policy Branch was tasked to compile a report on expenditures incurred during the Forum and submit to the Department of Treasury for assessment. The report was needed to outline expenses on accommodation, meals, allowances, vehicle usage, and overall administrative expenses. An important component of the report included outstanding payments, yet to be made to service providers in Kokopo. This report was completed in September and submitted to the Department of Finance and Treasury in December, 2009.

9.1.3.3. Policy Guidelines on Development Forum Expenditure

Using experiences from the Kokopo UBSA Forum, there was a clear need for an established policy guideline on acquisition and payment of services during oil and gas development forums. Such a guideline would set the criteria for engagement of services as well as payment of services- something, which DPE never had, but operated on ad hoc basis.

Immediately upon conclusion of the Kokopo UBSA, the Policy Branch compiled a guideline (currently a draft document) and used it during assessment of outstanding UBSA claims submitted by service providers from Kokopo. The intention now will be to formalize the document so that it can be used as a policy document for use by the Department in future oil and gas development forums as well as for other claims against the Department.

9.2. Economics Aspect

9.2.1. Oil Prices

International crude oil prices drastically decreased in the first half of 2009, trading well below the US$50 due to US Financial Crisis. However, in terms of export earnings in PNGK, the crude oil export prices gradually increased from as low as K102.00 per barrel and continued on an upward trend throughout the year and reached PNGK220.00 per barrel.

The decline in crude oil prices were largely attributed to US Financial Crisis, apart from the US Economic and Financial Crisis Oil producing countries enjoyed a relative low oil prices. Conflicts in the Middle East, booming economic growth in China and India, OPEC residue to maintain its cut in production and many other factors also attributed to an increase in the domestic increase in the oil prices.

The high oil prices were good for oil producing countries giving rise to higher revenues. However, the opposite was the case for the consuming countries as high crude oil prices inflated prices of manufactured goods, services and fuel. PNG enjoyed higher oil prices in 2008 than in 2009.

9.2.2. PNG Crude Oil Export and Revenue

The high oil prices increased the crude oil export revenue for PNG. Oil production from Kutubu, Moran, Gobe and SE Mananda oil fields totaled 13.631 million barrels of oil during the year. With the annual average Kutubu crude oil price (APPI) being US$63.92 per barrel, gross revenue from oil exports was almost US$0.871 billion for the year. With the average exchange rate of US$ 0.3710, the export revenue in PNG Kina is equivalent to K0.323 billion. The high oil prices offset the natural decline in oil production from the above projects.

Table 9.1: Kutubu Light Movements.

Month (2009)	Average Price (PNGK/bbl) Kutubu	Average Price (US$/bbl) Kutubu
January	102.00	41.42
February	125.00	49.57
March	133.00	46.83
April	145.00	45.92
May	130.00	45.22
June	155.00	65.56
July	183.00	74.59
August	185.00	81.06
September	190.00	85.79
October	181.00	82.31
November	188.00	74.97
December	220.00	73.82
2009 Average	**161.42**	**63.92**

9.2.3. Royalty

The royalty payments made in 2009 to the State totalled K41.322 million. They were given to the project area landowners, the affected Local Level Governments and the affected Provincial Governments.

With the decline in oil prices, royalty values decreased as compared to 2008. In 2009, royalty paid to the State by the licensees from oil producing fields totaled K41.322 million, a decrease of K25.438 million as compared to 2008 payments.

9.2.4. Petroleum Cost Reporting (PCR)

Petroleum Cost Reporting (PCR) by petroleum licensees has been a regular task undertaken by the Economic Services Branch since 2003. Petroleum license holders, under Section 148 of the Oil and Gas Act, are required to submit the following costs to the Director Oil and Gas Act; (i) Petroleum Exploration Cost, (ii) Petroleum Development Costs, (iii) Pipeline Operation Costs, (iv) Sole Costs and (v) Petroleum Processing Facility Costs. These costs are prepared by licensees and are submitted to the Department bi-annually, using cost reporting forms, prepared by the Department. The Department in various cost analysis and internal reports utilizes the cost reporting data submitted by licensees.

Petroleum Cost Reporting is ongoing as envisaged. Due to frequent non-compliance issues regarding the terms and conditions of certain license applications by some companies or licensees; DPE was unable to update PCR reports due to non compliance on the part of the licensees and or the Department's failure to take tougher actions against those companies not complying with the requirement to furnish reports on time.

9.3. LEGAL Section

Milestones achieved during the year include:

a) Drafting & Execution of the Kokopo PNG LNG UBSA;

b) Drafting & Signing of each individual PNG LNG LBSA despite, legal challenges;

c) Review of the *Oil & Gas Act* subsidiary regulations; and

d) Legal clearance obtained from Attorney General to brief litigation matters.

9.1.1. Litigation

Almost all (approx. 99%) litigation matters before the Courts are either directly related to or concerned with landowner issues. Most often, cases are instituted by factions contending leadership of their respective beneficiaries' entities and or benefit distributions. Pursuant to the strict requirements under the *Attorney Generals Act*, all cases are managed through the Office of the Solicitor General. This means that the Department has neither authority to litigate nor instruct private law firms for legal representation or advise without prior clearance from the Attorney General.

Moreover, the Department does not have the litigation capacity to handle 99% of the litigation matters, primarily because the functions of is legal services is more an advisory role to all stakeholders. Hence, over the years we have been managing court cases at an arms length through other lawyers.

Since 2007, the Department has embarked on an aggressive approach to litigation matters, and enhancing and encouraging our in-house lawyers litigate on proceedings. This approach we believe puts us in a position to advocate, enhance, develop and established oil and gas jurisprudence in PNG. In so doing, this year we did successfully obtain clearance from the Minister for Justice & Attorney General to brief several law firms with instructions to provide the Department's legal representation. This has come about due to the increase in PNG LNG project related court cases being filed and to manage in-house counsels' time to advisory and advocating drafting and negotiations.

The year has been a real challenge the Department in terms of managing ongoing tasks, administrative roles and the magnitude of PNG LNG Project-related Court cases simultaneously filed in Court. The two most publicized Court proceedings have been the case of WOLOTOU ILG and the DIGIMU LANDOWNERS ASSOCIATION.

Firstly, the Wolotou ILG proceedings primarily concerned the Gobe customary land dispute. Previous attempts to settle the dispute through Land Titles Commission (LTC) hearing became stagnant. However in 2009, tireless efforts of all Stakeholders and the Courts through the Wolotou case saw this dispute addressed by way of Alternative Dispute Resolution (ADR).

It must be noted that although Gobe land dispute issues started as being a landowners' dispute, the outcome has set a precedent setting for the PNG judicial system. That is to say that in future, rather than prolonging solution to disputes in Courts, they can be settled through ADR process guided by the principles founded in the *Wolotou case*. It is believed that with the Court's prominence in this case, possibilities of future Court challenges regarding issues of the same kind will be reduced.

The *Digimu Landowner Association*, is a culmination of conversion of a handful of proceedings filed by the Plaintiff, Hami Yawari. These cases concerned landownership disputes, landowner forum representation issues, claim for State's outstanding MOA commitments, and more recently contempt charges. The much publicized matter has been *OS. 201 of 2009*, which effectively restrained the UBSA far beyond project schedule. The means to end for injunctory orders to the progress of the Umbrella BSA, is a consensus reached on the part of all interested parties and the relentless efforts and sheer dedication of State lawyers and various professionals. The restraint was uplifted and the UBSA progressed successfully. However, the matter was resurrected in an attempt to foil the Kutubu LBSA. Despite restraint of the Kutubu LBSA, the forum was conducted. Thus, the matter has now resulted in Mr. Yawari's application under *OS. 558 of 2009* in an institution of contempt proceedings against various Ministers, namely Minister Duma and four other senior cabinet Ministers, for breach of Court Orders. The threat is on foot and all State Counsels have been working closely to coordinate and devise a strategy to defend the Ministers against the Contempt Motion.

Overall, the Legal Services Branch has the duty to ensure compliance and due administration of government policies and objectives. Regardless of the physical threats posed by some landowner parties to these proceedings, lawyers and other Department officers managed immense pressure to overcome and are still conquering the challenges. After all, it is a challenge upon every employee of the Department to ensure project security, landowners' support and protect the integrity of the *Oil & Gas Act*. In so doing, the investors' confidence is restored and maintained, that the State as regulator can manage its issues under any given circumstance.

9.1.2. Oil and Gas Regulations

The following oil and gas subsidiary regulations had been in draft form for some time until 2009.

(i) Oil and Gas (Social Mapping and Landowner Identification) Regulation 2009;

(ii) Oil and Gas (Determination Of Wellhead Value) Regulation 2009;

(iii) Oil and Gas (Forms) Regulation 2009; and

(iv) Oil and Gas (Petroleum Processing Facility) Regulation 2009.

Legal services branch treated this task as a priority and immediately conducted and completed review of each of the regulation. A brief was prepared for the Minister in July together with a NEC Submission for him to present to NEC. It is now for the NEC to enact and give proper direction to First Legislative Council to further finalize them.

The importance of this regulations is that due to the sudden expansion in industry activities attributed by commercialisation of the vast gas reserves, these regulations play a vital role in setting legal and regulatory framework for petroleum sector development.

We only hope that no further delayed is caused by administrative or political attrition to prolong enactment of the regulations.

APPENDIX 1: PETROLEUM EXPLORATION STATISTICS 2009

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009 (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	10	9	8	13	10
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	0	0	0	6	3
TOTAL NUMBER OF PPL's (b)	21	33	38	38	40	33	30	25	20	25	25	22	27	28	27	23	17	18	26	29	36	38	51	61
TOTAL NUMBER OF PPL BLOCKS						2684	2143	1283	995	1130	1395	1372	1494	1535	1508	1066	1020	1111	2136		3215	1289	1028	
TOTAL AREA UNDER LICENCE (KM²)						228140	182155	109055	84575	96050	118575	116620	126990	130475	122148	90610	87308	89991	185604	84159	260415	104409	83268	
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	0	1	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	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	5	5	6	6
TOTAL NUMBER OF PDL BLOCKS	0	0	0	0	16	16	16	16	16	16	21	21	21	21	21	22	22	22	22	22	22	22	23	23
NEW PLL's GRANTED	0	0	0	0	2	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL NUMBER OF PLL's	0	0	0	0	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3
NEW PRL's GRANTED		0	0	0	0	0	0	0	0	0	0	0	1	0	4	0	3	0	1	0	0	0	0	0
TOTAL NUMBER OF PRL's		0	0	0	0	0	0	0	0	0	0	0	1	1	5	5	8	11	11	11	11	11	11	11
APPROXIMATE EXPENDITURE	K45M	K74M	K116M	K149M	K225M	K170M	K80M	K60M	K70M	K117M	K190M	K258M	K120M	K144M	K157M	K238M	K194M	K110M	K70M	K80M	K285M	K430.8M	K695.9M	
EXPLORATION WELLS DRILLED	3	7	10	27	21	11	7	4	10	4	5	9	5	5	2	0	3	2	2	3	3	5	4	5
DISCOVERY WELLS	2	3	6	14	9	5	4	2	2	1	2	2	2	1	0	0	2	1	3	0	2	0	3	2
NEW FIELD DISCOVERIES	1	2	2	1	4	3	2	1	0	0	1	0	0	1	0	0	2	2	2	1	2	0	1	2
CUMULATIVE FIELDS	9	11	13	14	18	21	23	24	24	24	25	25	25	26	26	26	28	30	32	33	35	35	36	38
CUMULATIVE WELLS	148	155	165	192	213	224	231	235	245	249	254	263	268	273	275	275	278	287	294	298	301	306	310	315
% 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	10.3	10.9	10.7	11.1	
GEOLOGICAL SURVEYS								4	4	6	4	5	2	1	4	1	1	1	1	1	4	1	3	4
LINE KMS										869	238	674	53.85	63.35	158.4	16	117.5	175		120	149.45	83.75	50	
GEOPHYSICAL SURVEYS								7	3	12	6	9	9	6	4	4	3	3	4	6	17	4	7	6
• AIRBORNE / AEROMAGNETIC									2	7	3	3	2	1	0	0	0	1	0	2	9	0	0	2
LINE KMS									31796	93094	27294	33583	10571		0	0	0	5076	0	6292.1	35207.8	0	0	
• SEISMIC	3	7	8	14	15	6	8	3	1	3	1	6	7	2	4	4	3	2	4	4	8	4	7	4
LINE KMS ONSHORE	208	423	700	1630	2901	744	751	43	35	361	82	321.14	28.2	142	147	109.8	49.75	36	124	247.15	587.66	533.23	915.8	
OFFSHORE	229	4769	1878	1139	2576	661	879	2425	12568 (e)	0	0	0	5390	0	0	0	0	0	0	0	12972.38	0	47000	
TOTAL	437	5192	2578	2769	5477	1405	1630	2468	12603	16	446.2	321.2	5418.2	142	147	109.8	49.75	36	124	247.15	13560.04	533.23	47915.8	
PRODUCTION (f) OIL 000 BBLPD						1	53	126	120	100	106	130	81	88	70	56	47	48	47		49			
GAS MMCFPD						3.7	5.8	7.9	9.2	9.6	13.5	11.5	13.3	13.1	12	14	10.2	14	11		13.8			

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

(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

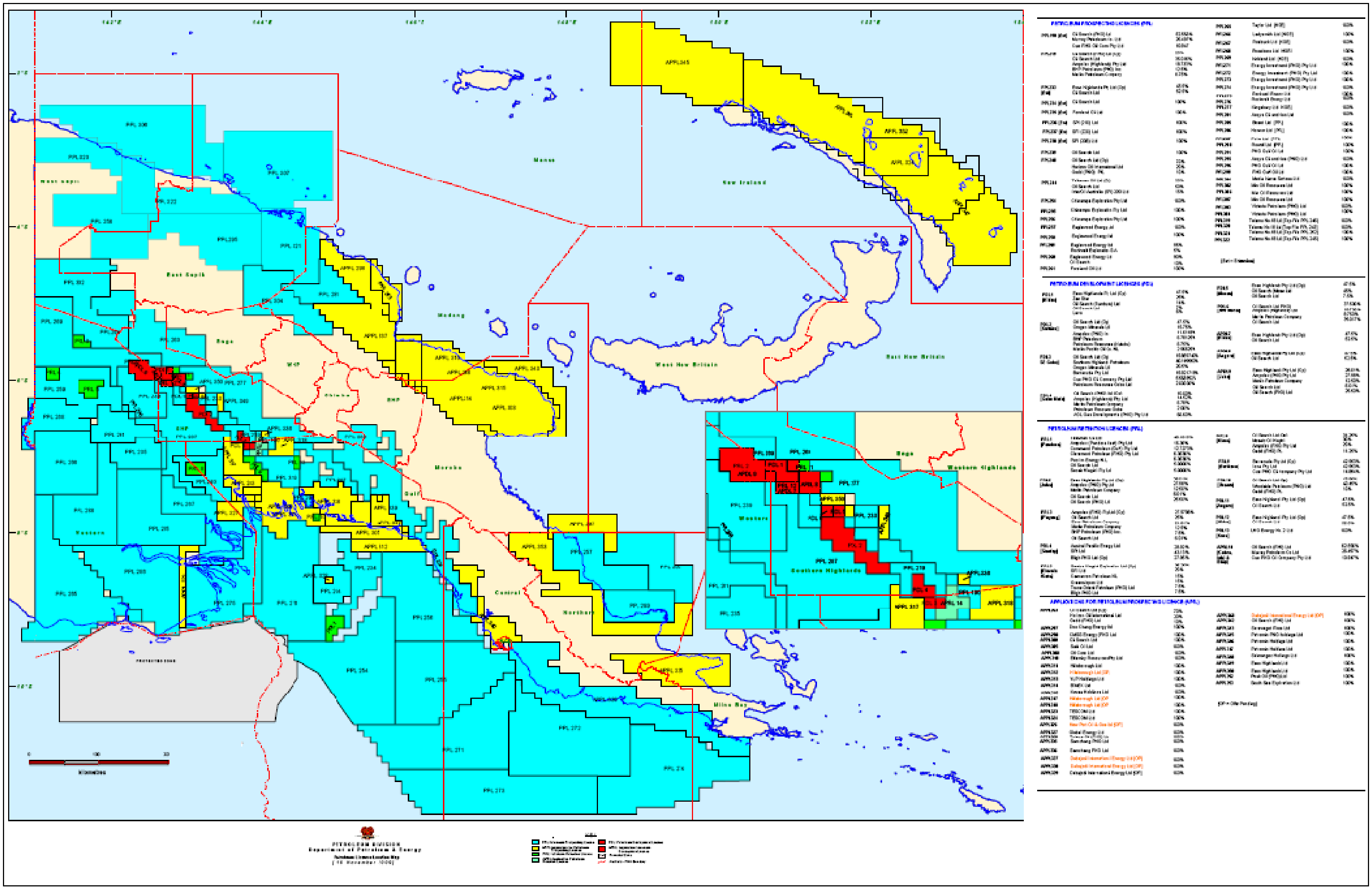
(e) 3-D Pasca Survey

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

extension discoveries and purposeful sidetracks drilled and completed in calendar year

1996 = MORAN
1996 = KIMU
2002 = SAUNDERS, BILIP

APPENDIX 2: Petroleum Licence Tenements Maps, 2009



APPENDIX 3: 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	PRL 9	Barracuda	Gas	2	Gulf
Permit 37	APC	Bwata	1960	PPL 237	InterOil	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
Permit 42	Phillips	Pasca	1968	PPL 234	Oil Search	Gas/ Condensate	3	Gulf
PPL 18	Niugini Gulf Oil	Juha	1983	PRL 2	Esso	Gas/ Condensate	5	Western
PPL 17	Chevron	Iagifu - Hedinia	1986	PDL 2	Oil Search	Oil / Gas	47	SHP
PPL 27	BP	Hides	1987	PDL 1/PRL 12	Esso	Gas/ Condensate	4	SHP / Western
PPL 100	Chevron	SE Hedinia	1987	PDL 2	Oil Search	Gas	5	SHP
PPL 82	IPC	Pandora	1988	PRL 1	Talisman	Gas	2	Gulf
PPL 100	Chevron	Usano	1989	PDL 2	Oil Search	Oil	2	SHP
PPL 100	Chevron	Agogo	1989	PDL 2	Oil Search	Oil	1	SHP
PPL 27	BP	Angore	1990	PRL 3	Esso	Gas/ Condensate	1	SHP
PPL 81	BP	Elevala	1990	PRL 5	Santos	Gas/ Condensate	1	Western
PPL 101	Chevron	P'nyang	1990	PRL 3	Esso	Gas/ Condensate	2	Western
PPL 81	BP	Ketu	1991	PRL 5	Santos	Gas/ Condensate	1	Western
PPL 56	Command	SE Gobe	1991	PDL 3	Oil Search	Oil / Gas	11	SHP / Gulf
PDL 2	Chevron	SE Mananda	1991	PDL 2	Oil Search	Oil / Gas	5	SHP
PPL 82	Mobil	Pandora B	1992	PRL 1	Talisman	Gas	1	Gulf
PPL 100	Chevron	Gobe Main	1993	PDL 4	Oil Search	Oil / Gas	6	SHP
PPL 138	BP	Paua	1995	PPL 233	Esso	Oil	1	SHP
PDL 2,/PPL161/138	Chevron	Moran	1996	PDL 2, /PDL 5	Oil Search /Esso	Oil	4	SHP
PPL 157	Santos	Stanley 1	1999	PRL 4	Horizon Oil	Gas	1	Western
PPL 193	Oil Search	Kimu	1999	PRL 8	Oil Search	Gas	2	Western
PDL 4	Chevron	Saunders	2002	PDL 4	Oil Search	Oil	1	Gulf
PPL 160	Santos	Bilip	2002	PPL 190	Oil Search	Oil	1	Gulf
PPL 235	Rift Oil	Douglas	2006	PPL 235	Rift Oil	Gas/ Condensate	1	Gulf
PPL 238	InterOil	Elk 1	2006	PPL 238	Interoil	Gas/ Condensate	3	Gulf
PPL 238	InterOil	Elk 4	2008	PPl 238	Interoil	Gas/ Condensate	4	Gulf
PPL235	Rift Oil	Puk Puk 1	2008	PPL235	Rift Oil	Gas/ Condensate	1	Western
PPL 238	InterOil	Antelope 1	2009	PPL238	InterOil	Gas/Condensate	4	Gulf

APPENDIX 4: 2009 Oil and Gas Production Summary

Table 4.1. 2009 Oil & Gas Production Summary

2009 OIL AND GAS PRODUCTION														
	KUTUBU		GOBE MAIN		SE GOBE		MORAN UNIT		SE MANANDA		TOTAL PRODUCTION			
Month(s)	Oil (bbl)	Gas (Mscf)	Oil (bbl)	Gas (Mscf)	Oil (bbl)	Gas (Mscf)	Oil (bbl)	Gas (Mscf)	Oil (bbl)	Gas (Mscf)	Monthly Oil Production (Mbbl)	Daily Oil Rates Per Month (Mbopd)	Monthly Gas Production (Mscf)	Daily Gas Rates Per Month (Mscfpd)
JAN	489,641	5,440,236	54,150	1,071,210	175,045	2,407,736	555,609	2,964,855	39,663	237,842	1,314,108	42,391	12,121,879	391,028
FEB	289,143	3,989,576	44,392	955,334	126,597	1,568,696	355,982	1,820,372	26,090	166,391	842,204	27,168	8,500,369	274,205
MAR	520,405	4,961,528	49,265	1,102,545	147,809	1,875,518	408,808	1,881,576	30,703	186,103	1,156,990	37,322	10,007,270	322,815
APR	510,774	5,375,264	46,486	1,133,885	130,737	2,241,876	276,739	1,078,094	26,853	183,748	991,589	31,987	10,012,867	322,996
MAY	511,102	5,941,710	47,153	1,009,887	135,178	2,551,859	337,569	1,927,884	24,928	155,268	1,055,930	34,062	11,586,608	373,762
JUN	564,863	6,213,648	50,809	1,073,056	135,006	2,004,446	353,937	2,335,083	24,524	100,745	1,129,139	36,424	11,726,978	378,290
JUL	558,845	6,513,823	57,866	1,195,593	120,367	2,174,826	446,774	2,453,717	24,502	116,156	1,208,354	38,979	12,454,115	401,746
AUG	572,180	6,234,933	50,481	734,277	119,255	1,629,456	407,473	2,549,115	20,612	103,432	1,170,001	37,742	11,251,213	362,942
SEP	563,679	6,208,429	44,203	707,272	117,853	1,940,000	487,795	2,670,716	16,965	94,669	1,230,495	39,693	11,621,086	374,874
OCT	606,728	6,981,683	58,367	868,662	140,589	1,762,705	503,597	2,670,716	13,772	105,491	1,323,053	42,679	12,389,257	399,653
NOV	595,228	6,404,547	53,373	917,108	101,798	1,753,450	455,777	2,480,258	12,996	105,924	1,219,172	39,328	11,661,287	376,171
DEC	533,634	6,110,547	51,318	827,498	144,720	1,325,872	542,126	2,581,766	30,262	201,015	1,302,060	42,002	11,046,698	356,345
Total	**6,316,222**	**70,375,924**	**607,863**	**11,596,327**	**1,594,954**	**23,236,440**	**5,132,186**	**27,414,152**	**291,870**	**1,756,784**	**13,943,095**	**449,777**	**134,379,627**	**4,334,827**
Weekly Ave	121,466	1,353,383	11,690	223,006	30,672	446,855	98,696	527,195	5,613	33,784	268,136	8,650	2,584,224	83,362
Monthly Ave	526,352	5,864,660	50,655	966,361	132,913	1,936,370	427,682	2,284,513	24,323	146,399	1,161,925	37,481	11,198,302	361,236
Daily Ave	17,305	192,811	1,665	31,771	4,370	63,661	14,061	75,107	800	4,813	38,200	1,232	368,163	11,876
										TOTAL PNG	**13,943,095**		**134,379,627**	

Average daily production are based on calender months and not from well test results

Table 4.2. The 2009 Year *Daily Production Rates Summary

	2008	2009	% Difference
YEAR TO 31 DEC 2008	Gross daily Production (BOEPD)	Gross daily Production (BOEPD)	Gross daily Production
Oil Production			
Kutubu	14,825	17,305	17
Moran Unit (PDL 2,5,6)	17,564	14,061	-20
SE Mananda	1,431	800	-44
Gobe			
Gobe Main	1,969	1,665	-15
SE Gobe	5,233	4,370	-16
Total Gobe	7,202	6,035	-16
Total PNG Oil	41,022	38,201	-7
Condensate Production			
Hides Sales Gas in bbls	365	389	7
Gas Production			
Hides Gas in bbls (boe)	2,384	2,694	13
Hides Gas in MMscf	14.31	15.45	8
Total Oil	41,022	38,201	-7
Total Oil & Condensate	41,387	38,590	-7

APPENDIX 5. 2009 Hides Gas and Liquid Production to Distribution

Table 4.3. 2009 Hides Gas and Liquid Production to Distribution

MONTH	GAS PRODUCTION		LIQUID PRODUCTION																		
	Total Production	Sales to PJV	Condensate (bbls)				Naphtha (bbls)				Diesel (bbls)				Residue (bbls)				
			Produced		Condensate - Sales to PJV		Produced		Naphtha - Sales to PJV		Produced		Diesel - Sold Locally		Produced		Residue - Hides own use		
	(MMSCF)	(MMSCF)	m^3	bbls	m^3	bbls	m^3	bbls	m^3	bbls	m^3	bbls	m^3	bbls	m^3	bbls	m^3	bbls	
Jan	482.82	472.22	1,949.11	12,259.68	381.24	2,397.97	773.38	4,864.46	1,022.97	6,434.37	380.81	2,395.23	303.16	1,906.85	92.29	580.50	47.00	295.63	
Feb	406.12	398.65	1,664.00	10,466.41	428.78	2,696.98	788.56	4,959.96	1,120.09	7,045.28	269.12	1,692.74	290.06	1,824.45	75.56	475.29	33.96	213.61	
Mar	510.47	502.21	2,054.11	12,920.17	225.88	1,420.76	1,073.79	6,754.05	1,066.56	6,708.56	425.02	2,673.35	405.42	2,550.05	107.30	674.88	53.11	334.08	
Apr	470.74	460.41	1,900.33	11,952.91	271.82	1,709.69	956.43	6,015.82	1,013.41	6,374.23	389.83	2,452.01	312.91	1,968.17	105.76	665.22	47.39	298.09	
May	471.39	461.23	1,869.44	11,758.62	160.61	1,010.21	1,111.94	6,993.97	1,110.84	6,987.05	386.19	2,429.10	370.12	2,328.02	105.48	663.48	52.28	328.85	
Jun	508.70	498.00	1,969.42	12,387.42	450.30	2,832.37	1,022.86	6,433.67	1,265.05	7,957.06	350.58	2,205.13	316.67	1,991.82	91.54	575.77	37.61	236.58	
Jul	406.21	397.84	1,541.40	9,695.22	345.60	2,173.80	815.92	5,132.07	1,025.84	6,452.44	287.61	1,809.06	262.57	1,651.54	77.47	487.28	35.31	222.12	
Aug	469.30	459.93	1,724.56	10,847.32	388.85	2,445.81	927.93	5,836.59	1,218.50	7,664.26	322.42	2,027.97	259.80	1,634.12	86.55	544.41	32.26	202.91	
Sep	469.80	462.52	1,755.70	11,043.20	566.24	3,561.61	817.47	5,141.77	1,221.82	7,685.09	285.50	1,795.77	260.81	1,640.47	83.17	523.13	40.84	256.89	
Oct	508.50	497.99	1,933.51	12,161.60	811.34	5,103.27	694.32	4,367.22	1,364.73	8,583.98	230.15	1,447.65	170.53	1,072.62	74.89	471.05	19.94	125.40	
Nov	500.14	489.76	1,909.92	12,013.21	647.98	4,075.70	946.03	5,950.41	1,401.89	8,817.75	333.84	2,099.80	333.84	2,099.80	83.28	523.85	32.96	207.32	
Dec	307.14	297.35	1,171.64	7,369.52	335.60	2,110.89	536.68	3,375.69	812.14	5,108.28	200.60	1,261.74	130.29	819.51	50.98	320.67	18.77	118.04	
TOTALS	**5,511.35**	**5,398.11**	**21,443.15**	**134,875.27**	**5,014.24**	**31,539.06**	**10,465.30**	**65,825.67**	**13,643.84**	**85,818.36**	**3,861.68**	**24,289.56**	**3,416.18**	**21,487.41**	**1,034.28**	**6,505.54**	**451.44**	**2,839.49**	
	Daily, Weekly and Monthly Averages																		
Daily Average	15.10	14.79	58.75	369.52	13.74	86.41	28.67	180.34	37.38	235.12	10.58	66.55	9.36	58.87	2.83	17.82	1.24	7.78	
Weekly Average	105.99	103.81	412.37	2593.76	96.43	606.52	201.26	1265.88	262.38	1650.35	74.26	467.11	65.70	413.22	19.89	125.11	8.68	54.61	
Monthly Average	459.28	449.84	1786.93	11239.61	417.85	2628.25	872.11	5485.47	1136.99	7151.53	321.81	2024.13	284.68	1790.62	86.19	542.13	37.62	236.62	

APPENDIX 6. Yearly Oil and Gas Production since 1991

Table 4.4.

YEARLY OIL AND GAS PRODUCTION SINCE 1991																
	KUTUBU		GOBE MAIN		SE GOBE		MORAN		SE MANANDA		TOTAL PRODUCTION					
Year (s)	Oil (BBL)	Gas (MSCF)	Oil (BBL)	Gas (MSCF)	Oil (BBL)	Gas (MSCF)	Oil (BBL)	Gas (MSCF)	Oil (BBL)	Gas (MSCF)	Oil Produced(BBL)	Cumulative Oil (BBL)	Oil Forcast (BBL)		Gas (MMscf)	Cumulative Gas (MMscf)
													bbl/d	bbl		
1991	68,162	84,532									68,162	68,162	-	-	84,532	84,532
1992	19,314,212	16,951,949									19,314,212	19,382,374	52,957	19,382,262	16,951,949	17,036,481
1993	45,883,975	49,059,949									45,883,975	65,266,349	125,710	45,884,150	49,059,949	66,096,430
1994	44,077,868	58,666,246									44,077,868	109,344,217	120,569	44,007,685	58,666,246	124,762,676
1995	36,344,233	61,184,516									36,344,233	145,688,450	99,574	36,344,510	61,184,516	185,947,192
1996	38,640,602	65,343,500									38,640,602	184,329,052	105,575	38,640,450	65,343,500	251,290,692
1997	27,592,364	66,960,036									27,592,364	211,921,416	75,596	27,592,540	66,960,036	318,250,728
1998	18,926,711	69,562,381	3,568,005	8,568,296	3,593,421	6,718,805	3,445,286	6,403,723			29,533,423	241,454,839	80,754	29,475,210	91,253,205	409,503,933
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	273,475,270	87,740	32,025,100	113,124,793	522,628,726
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	298,909,787	69,493	25,434,438	112,354,075	634,982,801
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	319,945,269	57,631	21,035,315	109,923,933	744,906,734
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	336,508,038	46,144	16,842,560	110,295,971	855,202,705
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	353,954,977	47,789	17,442,985	128,334,675	983,537,380
2004	6,552,222	84,791,755	1,446,375	12,125,889	2,261,193	21,378,237	4,874,683	17,899,235			15,134,473	369,089,450	42,376	15,509,616	136,195,116	1,119,732,496
2005	7,091,513	86,475,178	1,111,074	13,408,486	2,684,188	22,474,800	6,279,220	17,414,849			17,165,995	386,255,445	47,052	17,173,980	139,773,313	1,259,505,809
2006	5,626,802	80,521,971	1,065,855	10,753,194	2,815,576	23,912,103	7,495,270	20,250,472	747,171	2,788,621	17,750,674	404,006,119	58,689	21,421,485	138,226,361	1,397,732,170
2007	4,877,067	74,075,287	905,695	15,577,932	2,389,349	25,472,639	7,696,659	28,859,711	945,191	5,318,153	16,813,961	420,820,080	57,570	21,013,050	149,303,722	1,547,035,892
2008	5,426,108	75,678,988	725,572	14,140,171	1,976,311	29,426,986	6,413,043	28,195,073	523,635	3,910,913	15,064,669	435,884,749	47,251	17,293,866	151,352,131	1,698,388,023
2009	6,316,222	70,375,924	607,863	11,596,327	1594954	23,236,440	5,132,186	27,414,152	291,870	1,756,784	13,943,095	449,827,844	37,419	13,657,935	134,379,627	1,832,767,650
Total	318,657,655	1,250,585,944	26,680,529	144,636,976	38,211,678	228,719,976	61,068,232	195,050,283	2,507,867	13,774,471	449,827,844				1,832,767,650	

APPENDIX 7:. PNG FORECAST PRODUCTION PROFILES 2008 RESERVES