DEPARTMENT OF PETROLEUM & ENERGY

PETROLEUM DIVISION

2010 PETROLEUM ANNUAL REPORT

ON

PETROLEUM ACTIVITY IN PAPUA NEW GUINEA

Compiled by the Exploration Branch

APRIL 2011

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 2010. 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.

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	Compagnie Générale de Géophysique 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	✓ Highlands Seismic Survey conducted in PDL 8, PRL 11 and PPL 233
February	✓ Operations as normal
March	✓ Bwata Seismic Survey conducted in PPL 237 of InterOil's Licence
April	✓ Operations as normal
May	✓ Operations as normal
June	✓ Worin Seismic Survey conducted in PRL 4 by Talisman Energy Niugini
July	✓ Kwano Seismic Survey conducted in PPL 268
August	✓ 2010 Whale Seismic Survey conducted in PPL 236 onshore of the Gulf Province
September	✓ Highlands Seismic Survey conducted in PDL 8, PRL 11 and PPL 233
October	✓ Bwata Seismic Survey (Phase II) conducted onshore of the Gulf Province
November	✓ Spudded Mananda 5 Well on the 09th ✓ Start of the Solwara 3D Seismic Survey offshore of the Papuan Gulf covering a total area of 4715km^2
December	✓ Eaglewood Energy's Ubuntu-1 Well spudded onshore in the Western Province and the discovery of gas

SUMMARY

A record of sixty four PPLs, nine PDLs and eight PL were operating in 2010 since 1994. Papua Basin was intensively competed for prospecting licences as hydrocarbon potential of the basin continued to lure investors into the country. Twenty two APPLs were receipted, processed by the PAB and determined by the Minister. About 9 percent were granted PPL status, 26 percent were refused, 17 percent were withdrawn and 48 percent were pending Ministerial determination.

A record total of 5,369 line kilometres were shot at the cost of approximate US$67,486,924 for seismic; geological field survey of 15km; 30,186.3km gravity and magnetic.

Five wells were drilled in the Foreland basin at an estimated total cost of US$200,000,000.

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 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 per 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 2010

Sixty four petroleum prospecting licenses (PPLs), nine petroleum development licenses (PDLs), eight pipeline licenses (PLs), twelve petroleum retention licenses (PRLs) and two Petroleum Processing Facility Licenses (PPFLs) were active between January and December 2010. These are reflected in Figures 1.1, 1.2, 1.3, 1.4, 1.5, 1.6 and 1.7

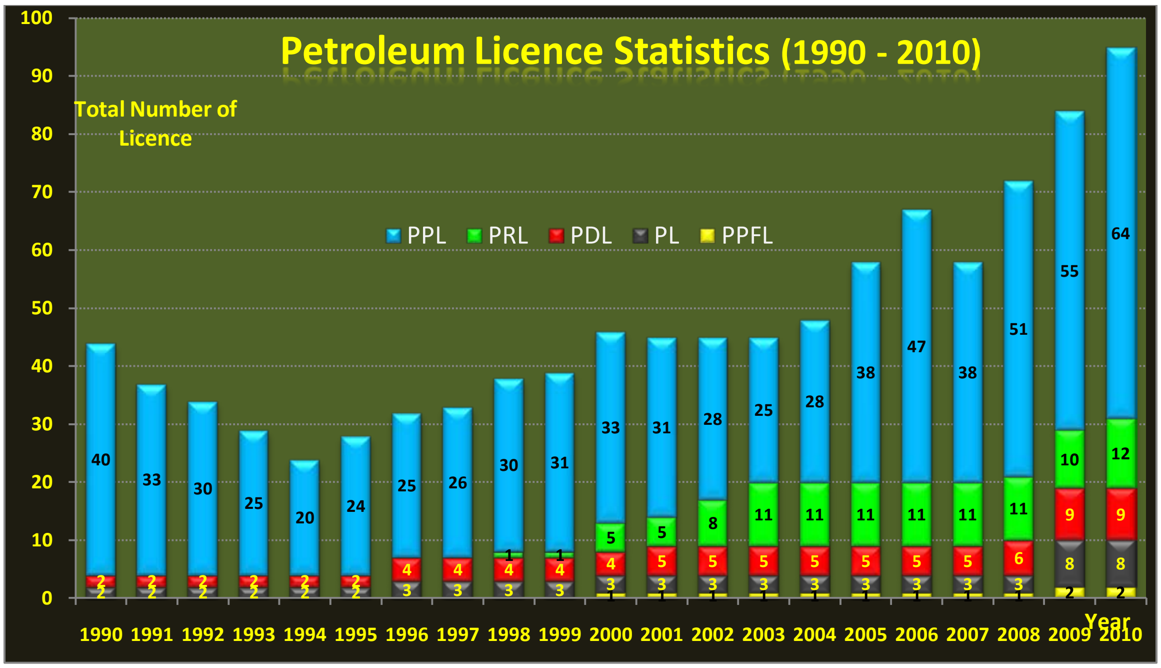


Figure 1.1: Petroleum License Statistics from 1990 to 2010.

1.2 Application for Petroleum Prospecting Licence (APPL)

Twenty-two applications for Petroleum Prospecting Licenses were lodged with DPE between January and December of 2010. Two of these applications were awarded as Petroleum Prospecting Licenses, four were withdrawn, and six were refused while eleven were pending the Petroleum Advisory Board's deliberations. The applications were made by both current Operators of existing licenses and some new entrants. Figure 1.2 illustrates this distribution.

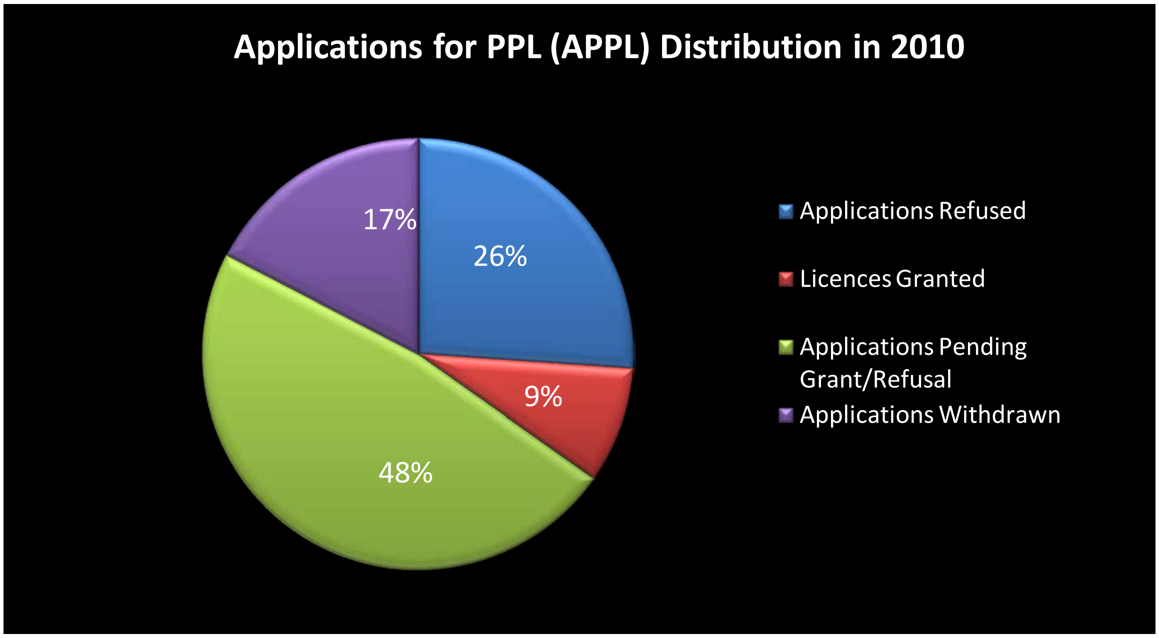


Figure 1.2: Applications for Petroleum Prospecting Licence (APPL) in 2010.

1.3 Petroleum Prospecting Licence (PPL)

A total of sixty four Petroleum Prospecting Licenses were active between January and December 2010. Two PPLs were awarded during the year. All of these licenses are situated in the Papuan Basin.

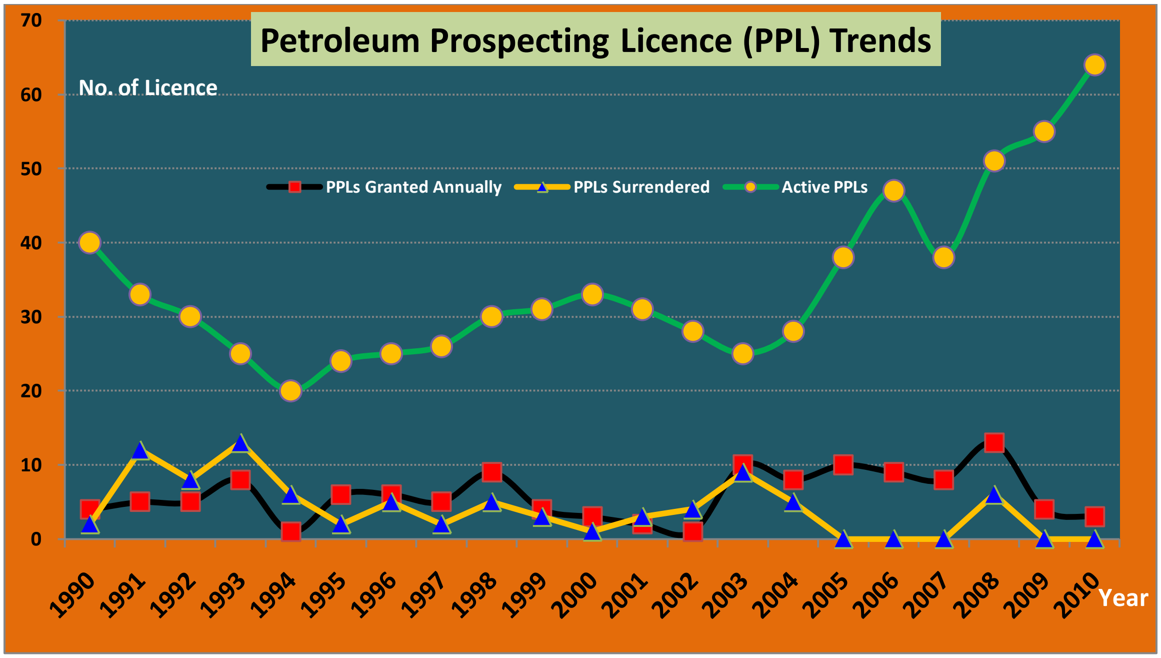


Figure 1.3: Petroleum Prospecting Licence (PPL) Trends.

1.4 Petroleum Retention Licence (PRL)

At year end, twelve Petroleum Retention Licenses (PRLs) were in operation in the Papuan Basin of PNG. One of these licenses, PRL 2 was awarded an extension during the year while PRL 14 and PRL 15 were the new ones. Figure 1.4 represents the trend in the PRLs since 1990.

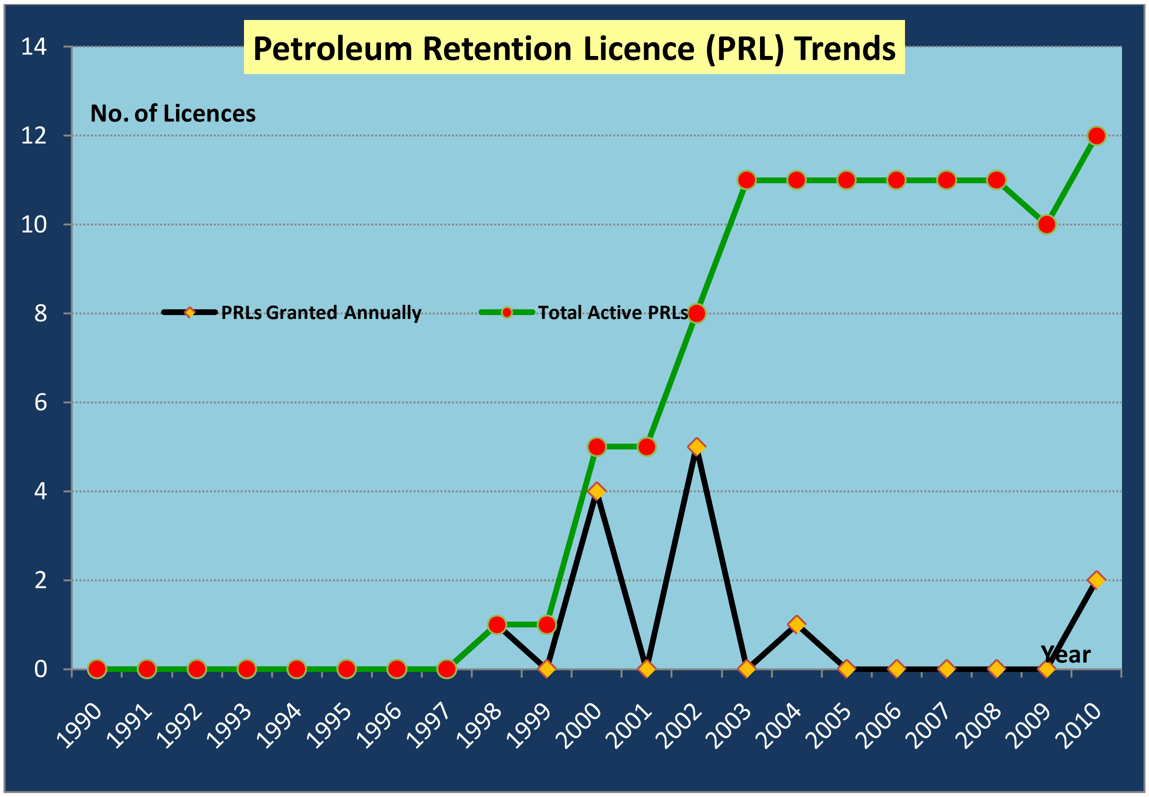


Figure 1.4: Petroleum Retention Licence (PRL) Trends.

1.5 Petroleum Development Licenses (PDLs)

There was no Petroleum Development Licenses (PDLs) were awarded during the year. Therefore, at year end the total number of development licenses remained at nine. Figure 1.5 shows the number of PDLs granted annually and the total number of active PDLs since 1990.

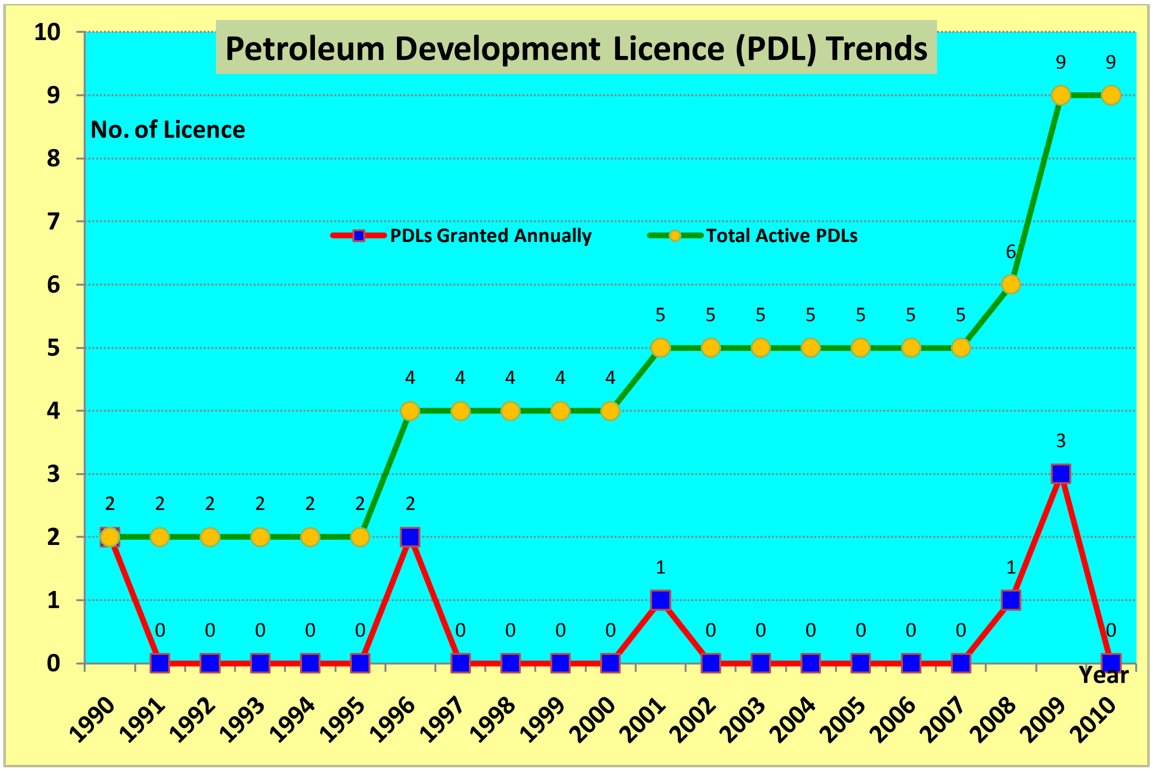


Figure 1.5: Petroleum Development Licence (PDL) Trends

1.6 Pipeline Licenses (PLs)

Three pipeline licenses were current up to 2009 when five new 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 of 2009 when a second PPFL was issued to PNG LNG Project proponents for the LNG plant to be constructed near Port Moresby as shown in Figure 1.7.

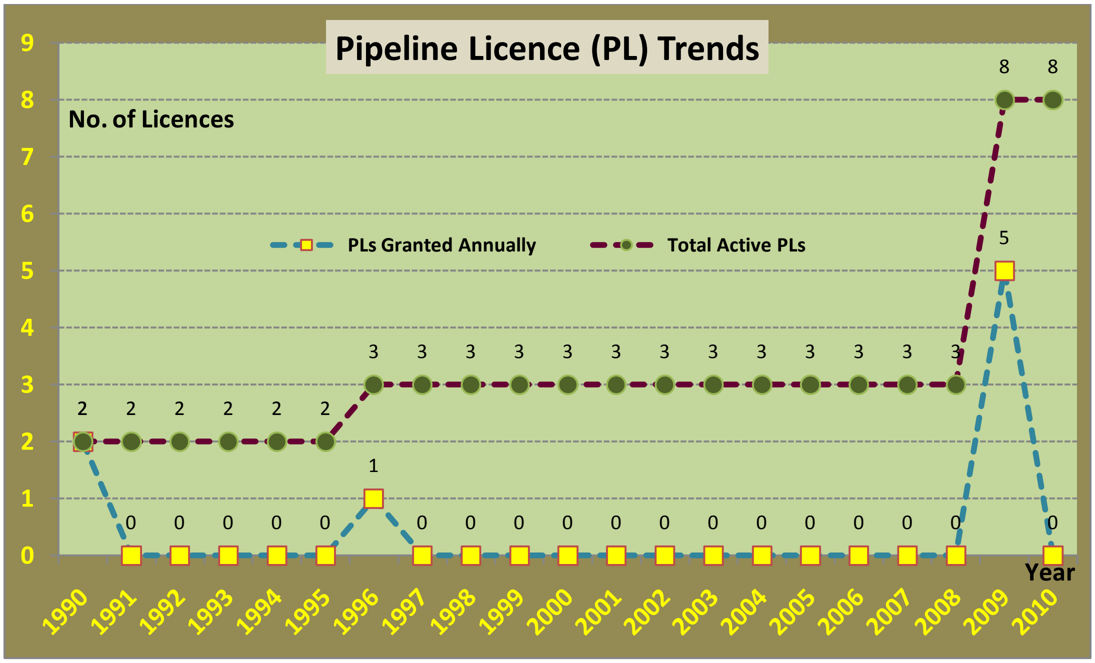


Figure 1.6: Pipeline Licence (PL) Trends.

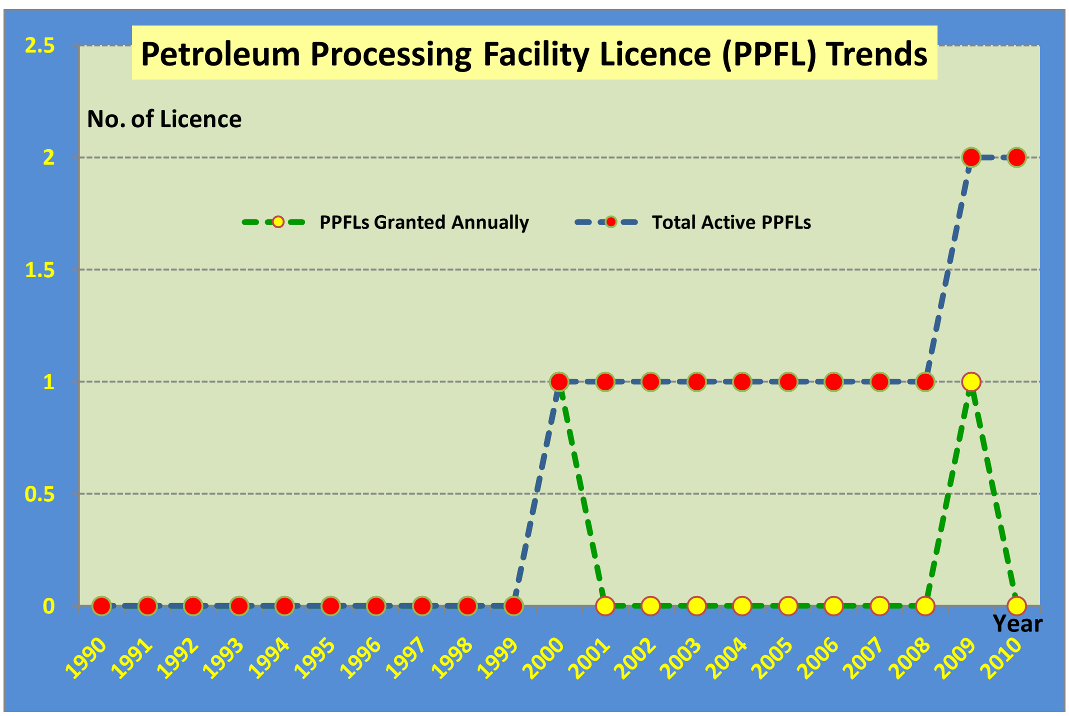


Figure 1.7: Petroleum Processing Facilities Licence (PPFL) Trends.

2.0 EXPLORATION ACTIVITIES

The total number of field surveys conducted this year increased by three compared to the previous year. A total of thirteen surveys were conducted in various licences both onshore and offshore. Twelve 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** and **Table 2.2** contain the summaries of all the field surveys for the year.

2.1 Geological Field Mapping

Only one Geological Field Mapping or Survey was conducted during the reporting year.

Table 2.1: Geological Surveys.

Licence	**Operator**	**Geographic Area** Tectonic Area	**Survey Name**	**Line Length - Km**	**Cost US$**
PPL 233, PRL 11 & PDL 8	Oil Search (on behalf of EHL)	**Southern Highlands Province** Onshore, Papuan Basin		**15**	

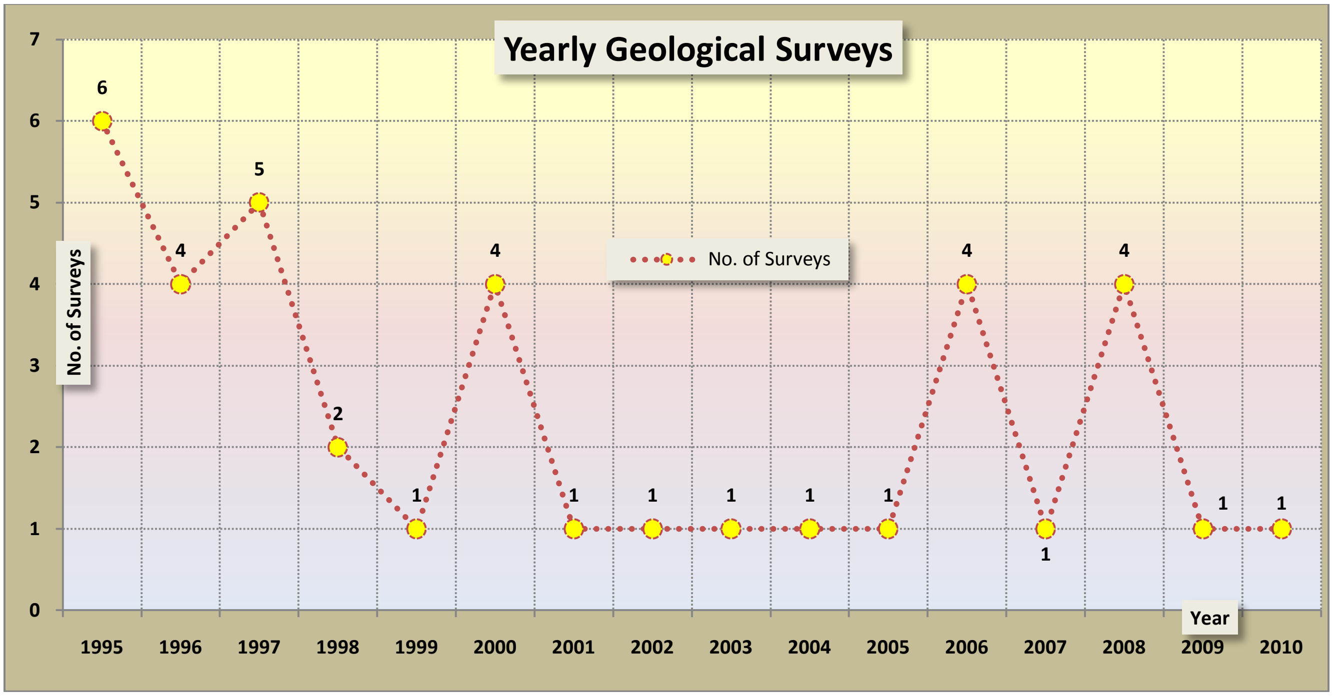


Figure 2.1: Yearly Geological Survey.

2.2 Geophysical Field Surveys

In total, twelve geophysical surveys were conducted during the year, which is a significant increase from the previous year. Nine of these surveys were reflection seismic surveys of which eight were conducted onshore while one was conducted offshore. There was one ground gravity and magnetic survey conducted during the reporting year and one airborne gravity/magnetic survey was conducted in two different basins. 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 2010.

The objective of the *2009 Antelope Seismic Survey* was to *define Optimal seismic parameters to image the carbonate targets and also to exted and increase seismic coverage over the Antelope and Elk structures.* A total length of 101 line-kilometers was acquired.

The objective of the *Barikewa Seismic Survey* was to *Better define subsurface structure and exploration risks for leads*. A total length of 59 line-kilometers was acquired.

The *Reke Seismic Survey's* objective was to *high grade possible leads and prospects identified during in-house studies. This seismic will better define the prospects in preparation for a 2010 exploration well*. A line length of 216 line-kilometers was acquired.

The *2010 Bwata Seismic Survey's* objective was to *define Optimal seismic parameters to image the carbonate targets and also to extend and increase seismic coverage over the Bwata structure*. A line length of 58 line-kilometers was acquired.

The *2010 Wolverine Seismic Survey's* objective was to *define Optimal seismic parameters to image the carbonate targets and also to extend and increase seismic coverage over the Wolverine structure*. A line length of 45.4 line-kilometers was acquired.

The *Poroman Seismic Survey* was conducted to *provide seismic coverage over leads in southeastern portion of PPL 319. This seismic survey was conducted also to define optimal seismic parameters to image carbonate targets*. A line length of 27 line-kilometers was acquired.

The purposes of conducting the *Solwara 3D Seismic Survey* were to *redefine and delineate leads and expend geophysical database for the exploration market for the offshore area*. The portion of this survey completed within 2010 totals to 4715 square kilometres.

The *Worin Seismic Survey* in PRL 4 was *conducted to delineate the crest of Stanley Field and also delineate leads in Stanley North area*. A line length of 36.28 line kilometers was acquired.

The *Raggiana Seismic Survey – Phase 1's* aim was to further delineate the Ubuntu structure in preparation for drilling of Ubuntu-1. A total line length of 111.32 line kilometers was acquired.

The *2010 LNG Energy Airborne Gravity and Magnetic Survey* was aimed at *acquiring aerogravity and magnetic data over the LNG Energy licences in the country*. A total of 30,081 kilometers of data was acquired.

Table 2.2a: Geophysical Surveys – Seismic Surveys.

Licence Area	**Operator**	**Geographic Area**	**Name of Survey** Contractor	**Line Length Km**	**Cost (US$)**
SEISMIC SURVEYS					
PPL 237 & PPL 238 *Onshore*	InterOil Ltd	Gulf Province	**2009 ANTELOPE APPRAISAL SEISMIC SURVEY** CGG Veritas	**101.0**	**10,441,465**
PRL 9 **Onshore**	Oil Search (PNG) Ltd	Western Province	**BARIKEWA SEISMIC SURVEY** GMC	**59.0**	**6,300,000**
PPL 235 & PPL 261 *Onshore*	Talisman Oil Ltd	Western Province	**REKE SEISMIC SURVEY** GMC	**216.0**	**12,900,000**
PPL 237 **Onshore**	InterOil Ltd	Gulf Province	**2010 BWATA SEISMIC SURVEY** CGG Veritas	**58.0**	**2,745,459**
PPL 238 **Onshore**	InterOil Ltd	Gulf Province	**2010 WOLVERINE SEISMIC SURVEY** CGG Veritas	**45.4**	
PPL 319 **Onshore**	LNG Energy Ltd	Gulf Province	**POROMAN SEISMIC SURVEY** CGG Veritas	**27.0**	**Pending**

PPL 234 & 244 **Offshore**	Oil search & Nippon Oil	Gulf Province	**SOLWARA 3D SEISMIC SURVEY** CGG Veritas	**4715.0 sq.km**	**26,000,000**
PRL 4 **Onshore**	Talisman Oil Ltd	Western Province	**WORIN SEISMIC SURVEY** GMC	**36.28**	**3,300,000**
PPL 259 **Onshore**	Eaglewood Energy Ltd	Western Province	**RAGGIANA SEISMIC SURVEY – PHASE 1** GMC	**111.32**	**5,800,000**
TOTAL ONSHORE				**654.0**	**67,486,924**
TOTAL OFFSHORE				**4715.0 sq.km**	

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**

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

<table>
<tr><th>Licence Area</th><th>Operator</th><th>Geographic Area</th><th>Name of Survey
Contractor</th><th>Line Length Km</th><th>Cost (US$)</th></tr>
<tr><td colspan="6">AIRBORNE GRAVITY & MAGNETIC SURVEY</td></tr>
<tr><td>PPL 319
Onshore</td><td rowspan="4">Telemu No. 18 (LNG Energy Ltd)</td><td>Gulf Province</td><td rowspan="4">2010 LNG ENERGY AIRBORNE GRAVITY & MAGNETIC SURVEY
Sander Geophysical</td><td>15,261.0</td><td>Pending</td></tr>
<tr><td>PPL 320
Onshore</td><td>West Sepik Province</td><td rowspan="3">14,820.0</td><td>Pending</td></tr>
<tr><td>PPL 321
Onshore</td><td>East Sepik / Madang Provinces</td><td>Pending</td></tr>
<tr><td>PPL 322
Onshore</td><td>East Sepik Province</td><td>Pending</td></tr>
<tr><td colspan="4">TOTAL</td><td>30,081.0</td><td></td></tr>
</table>

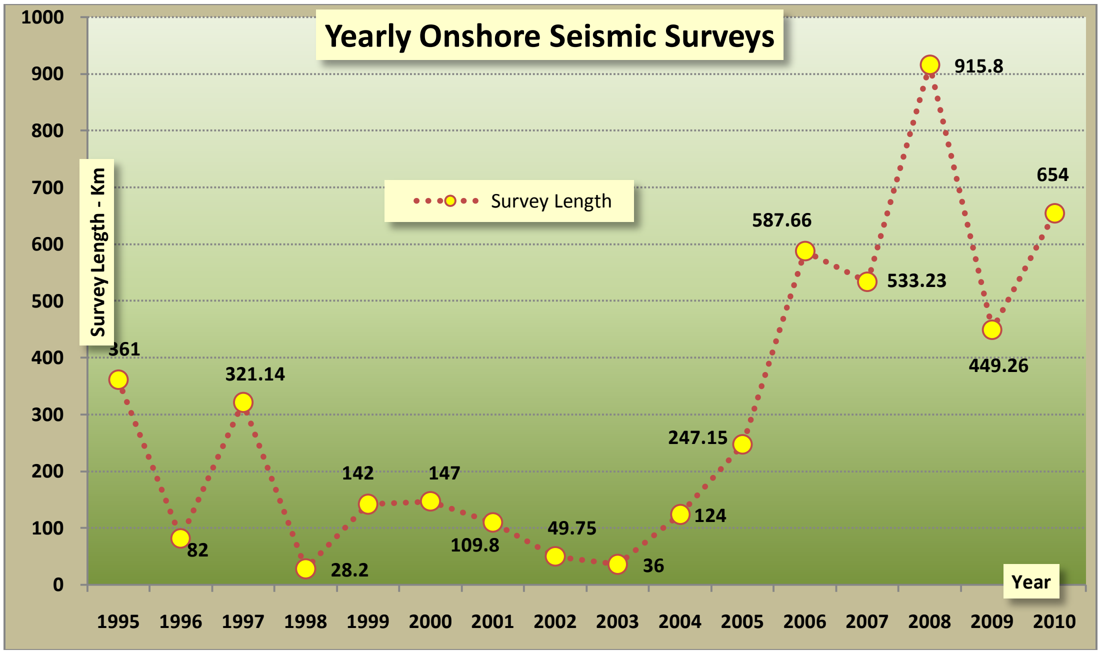


Figure 2.2a: Yearly Onshore Seismic Survey Length from 1995-2010

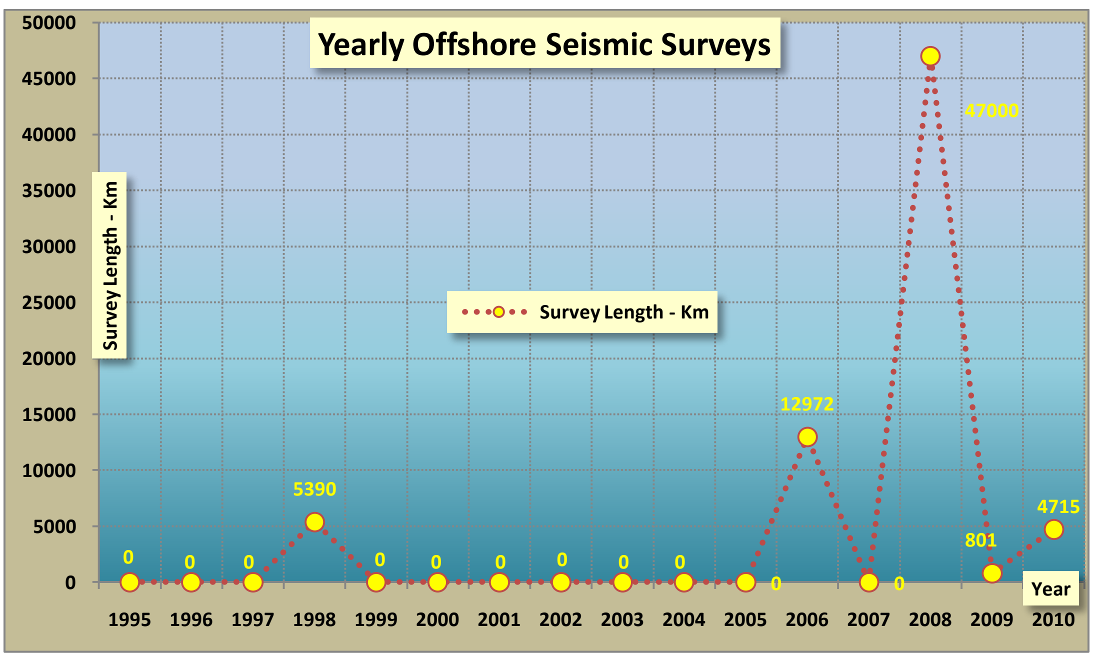


Figure 2.2b: Yearly Offshore Seismic Survey Length from 1995 to 2010

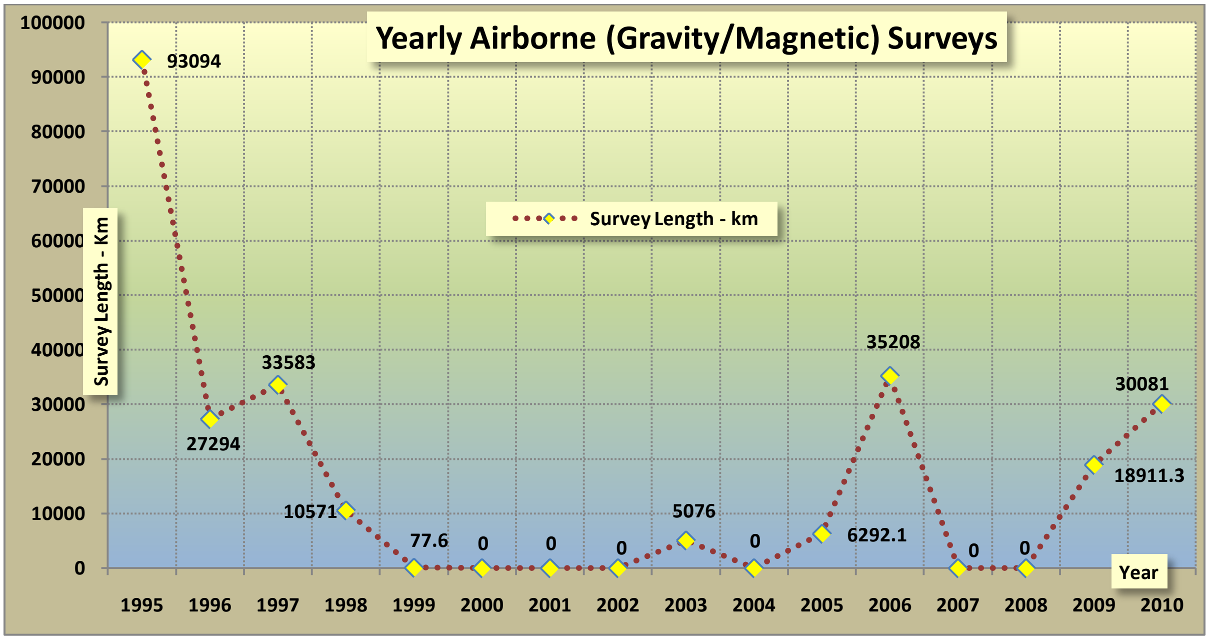


Figure 2.2c: Yearly Airborne Survey Length from 1995 – 2010

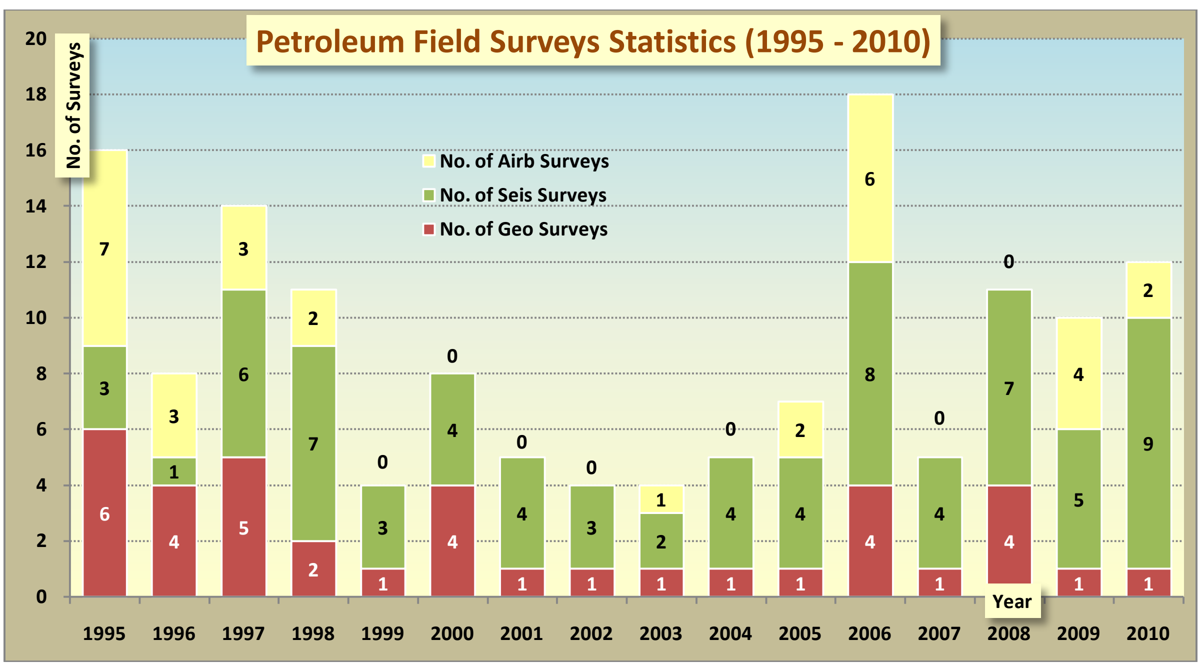


Figure 2.2d: Field Survey Statistics from 1995 to 2010

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

2.3.1 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.

2.3.2 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.

2.3.3 Data Access

The Department of Petroleum and Energy receives its data from petroleum companies as a requirement under the Oil and Gas Act of 2007. 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 2010 alone, a record of 672 data types was furnished by operators and contractors.

To access data from the Department, a formal letter is required and addressed to the following:

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

Attention: Registrar.

A cost schedule can also be obtained from the DPE with details of the costs. If you have any questions concerning data please send email to Solomon.andili@petroleum.gov.pg or contact us on telephone +675 3211 936.

SECTION 3.0 Drilling

3.1 Introductory Summary of 2010 Drilling Operations

A total of nine wells were drilling and or drilled in 2010, and all wells drilled were exploration wells. Oils Search Limited drilled five wells and InterOil, Eaglewood Energy, Niugini Energy and Horizon Oil drilled a well each. Four of the wells drilled were Wild Cat Exploration Wells while the other wells drilled were Appraisal Wells. Of the nine wells, six wells released rigs in 2010 and operations of three wells were carried over into 2011.

Oil Search Limited drilled ADT2, ST1, ST2, ST3; Moran 15 ST1, Wasuma 1, Korka 1 and Mananda 5. InterOil Limited Drilled Antelope 2, and its Horizontal Sidetracks, namely Antelope 2 H1, H2 & H2A, while Niugini Energy, Eaglewood Energy and Horizon Oil drilled Panakawa 1, Ubuntu 1 and Stanley 2 ST1 respectively.

The wild cat wells throughout 2010 operations were Panakawa 1, Wasuma 1, Korka 1 and Mananda 5. Wells that were completed in 2010 are ADT2 ST3 and Moran 15 ST1. Antelope 2 H2A was plugged and suspended for future completion, whilst Korka 1, Wasuma 1 and Panakawa 1 were plugged and abandoned.

Antelope 2 was spudded in 2009 and was carried over into 2010. The existing ADT 2 was re-entered, de-completed, abandoned and initiated as an exploration well. ADT 2ST1 targeted a new potential reservoir layer below the existing oil bearing Toro formation that had run low. ADT 2ST1 underwent two more side tracks as ADT 2ST2 and ADT 2ST3, due to mechanical problems. ADT 2ST3 drilling continued into 2010.

The cost of drilling operations, are summation of the wells that released rigs with the estimate of wells of drilling operations carried over into 2011.

The cost of wells that released rigs in 2010 is **US$295,123,369;** added to cost of wells carried over (cost of operation at 31/12/20210) **US$71,963,296**, totals up to ***US$367,086,665***

3.2 Exploration and Wild Cat Wells

3.2.1 Wasuma 1

Wasuma 1 is an exploration well in a wild cat field in the Southern Highlands Province of Papua New Guinea, in PPL219. The objective of this well was to penetrate the Toro and Iagifu sandstones. The well was originally designed a vertical well.

Haes Rig 103 was rigged up on Wasuma 1 wellpad and the 26” conductor hole was drilled, in a pre spud activity, to 52m and the 18 5/8” conductor casing was run and set at 46.2m.

The rig crew arrived at Wasuma 1and officially spudded at 02:30 hours, on January 18, 2010. The 17 ½” hole was drilled to section TD at 1204m and the Upper Ieru was encountered at 1003m. The 13 3/8” surface casing was run and set shoe at 1130m.

Drilling continued with the 12 ¼” hole, ahead to 1373m. The Darai Repeat was encountered at 1362m. Drilling continued to 2337m, where total down hole loss was encountered. The 9 5/8” casing was RIH to 2358m, but could get reamed past this depth and was cemented here.

The 8 ½” hole BHA drilled out the 9 5/8” shoe track and the rathole was cleaned out to bottom at 2365m. A FIT of 10.9ppg EMW was conducted and the 8 ½” hole was drilled ahead to 2628m. The Upper Ieru Repeat Formation was confirmed at 2588m. OSL drilled ahead the 8 ½” hole 3268m and MWD showed inclination of 32.3 degrees at 3226m. OSL decided to directionally drill after results of increased inclination.

An 8 ½” directional BHA was utilized to drill onwards but the whole operation experienced excessive down hole losses and total loss was encountered at 3070m, which prompted the XRMI-GR image logging. Logging up from 2994m confirmed existence of fractures in the Repeat Darai Formation below the 9 5/8” casing shoe. The Ieru section had been over gauged by a diameter of 12”.

The well bore was plugged back with a 7” liner run across the repeat Darai section. Cement plugs were pumped from 3030m to 2837m. The 8 ½” rotary BHA was RIH and dressed off cement from 2837m to 2850m, where the string packed off. The string was plugged to the cement and attempts to unplug the string were unsuccessful.

The 7” Vam Top HT liner was RIH to 2849m and the liner hanger was was successfully hung of and cemented in place.

Operations were transferred to Wasuma 1 ST1 on March 10, 2010, at 05:00 hours.

Wasuma 1 ST1

A 6” directional BHA consisting of 4 ¾” motor was RIH but a hammer union wing nut failed at 2800psi calibration. The 6” BHA tagged cement in 7” liner at 2798m but operations were suspended to investigate the wing nut. Inspection and repairs were made and drilling operation was resumed

Attempts on breaking circulation with the 6” BHA had the string plugged and attempts to unplug string were unsuccessful. The bit and mud motor were plugged with cement and barite.

A 6” rotary was RIH drilled out the 7” liner shoe track and cement to 2857.5m. A FIT was conducted to 13.0ppg EMW.

A 6” directional BHA with 4 ¾” motor slide drilled from cement plug at 2857.5m to 2874m with 100% formation returns. The hole was drilled ahead to 3018m in slide mode and dropped inclination. Drilling continued in rotary mode from 3018m to section TD at 3921m and inclination dropped to 4.3 degrees at 3905m. Top Toro was encountered at 3572m and Top Iagifu was at 3807m.

Wire line was rigged up and triple combo log RIH. Obstruction encountered 3240m had the tool stuck. An overshot BHA with side entry sub was RIH. The overshot latched onto logging tool and successfully worked free tool to surface but the triple combo parted. 7.9m of fish was left in hole.

A poor-boy spear BHA recovered a wireline centralizer at 3250m and a 5 ¾” overshot BHA recovered the second centralizer at 3241m. The next overshot assembly redressed and RIH engaged fish at 3257m but did not retrieve fish.

Two 6” concave mill run (BHA#21 & BHA#22) had the fish milled from 3253m to 3256m, and 3256m to 3258.2m, respectively. Both mills wore out and it was decided that to cement plug and sidetrack around the fish.

Cement plug was set from 3006m to 2885m and operations were transferred to Wasuma 1 ST2 on March 30, 2010, at 15:00 hours.

Wasuma 1 ST2

A 6” BHA was RIH to 2787m and light reamed to TOC at 2885. Slide drilling commenced and drilled to with dropped inclination to 3082m. Drilling continued in rotary mode to section TD at 3900m. Top Toro was encountered at 3567m and Top Iagifu at 3809m.

An RDT was made up on a Tool Pusher and RIH on drill pipe to 2821m. The RDT/Tool Pusher hung up at 3584m and attempt to work through obstructions were unsuccessful. RDT log was aborted due to deteriorating hole conditions

Wasuma 1 ST2 was finally decided to be plugged and abandoned. A total of four abandonment plugs were set. Plug #1 was set from 3585m to 3485m, to isolate Toro formation. Plug #2 was set from 2899m to 2799m, to isolate the open hole. Plug # 3 was set from 2319m to 2174m, to isolate the 7” liner top. Plug # 4 was set from 75m to 25m as the final surface plug.

The rig was released from Wasuma 1 ST2 on April 14, 2010, at 24:00 hours. The actual well cost incurred was ***US$52,701,357***

3.2.2 Korka 1

Korka 1 was an exploration well in a wildcat field in the Southern Highlands of Papua New Guinea, in the License area PPL260. The objective of the well was to penetrate the full thickness of the Toro sandstone, and evaluate the data to confirm fluid content, fluid contacts, reservoir quality and structural dip in Giero and Toro sandstone.

The conductor hole of 26" was drilled to 67m using Rig 104, offline, with the Leapfrog crew while Rig 103 was operating at Wasuma. An 18 5/8" conductor casing was run and cemented to 65.25m. Operations were transferred from Rig 103 on Wasuma 1 ST2 to Korka at 00:00hrs on April 15, 2010.

Korka 1 was formally spudded with 17 ½" hole at 1600hrs on April 18, 2010. The hole was drilled from 65m and encountered water table at 125m. Drilling continued to 804m.

Geological intersections differed significantly from expectation and seismic interpretations indicated presence of a "high amplitude' event at 1150m, which held concerns over potential shallow gas charged sands.

Operations POOH for wireline runs to assist in correlating between Korka 1 and offset wells, Egele 1X and Muller 1X. Gamma ray (GR) data were transmitted, but the live GR log did not correlate with cutting samples observed at surface, holding concerns for the integrity of live GR data.

Two more logs were run but both hung at 584m. Logging was discontinued when EMT MWD data showed GR data compressed 2.2 times.

Developing only tentative correlations between Korka 1 and offset wells cautioned 13 3/8" casing run due to presence of seismic 'high amplitude' event originally interpreted as Base Darai. In upper Ieru, revised geological model suggested high amplitude event correspond to presence of sands. 13 3/8" casing was run and set at 1075.5m

The 12 ¼” hole was drilled from 1075.5m to 1636m, encountering a Repeat Darai section at 1115m corresponding to seismic ‘high amplitude’ event. Drilling continued to 2148m, in which Base Darai was encountered at 1706m, with the intersection of Top Haito Shales.

The 12 ¼” hole was drilled ahead to section TD at 2607m in the Giero Member. The 9 5/8” casing was run and set at 2604m and cemented in place.

The 9 5/8” shoe track was drilled out and two metres of new formation was drilled to 2609m and a FIT to 19.0ppg EMW was conducted. The 8 ½” hole was drilled to 2880m. Drilling break was encountered at 2865m. This was identified as top of the Bawia Formation. The secondary target of Giero was not encountered, with only shale being intersected.

The hole was back reamed from 2783m to 2694m.The 7” liner originally designed to isolate high pressure Giero sands from lower pressure Toro sands was not run. Instead, the 8 ½” hole was drilled through the Toro sands and onto well TD, since the Giero sands had been shaled out, and drilled ahead to 3138m and Top Toro was encountered at 3135m.A precautionary wiper trip was performed for hole-conditioning before drilling further into Toro, from3138m to 2880m, in which tight hole was experienced in both directions.

An RDT wireline was opted for after string was jarred free at 3138m to determine Toro pore pressure, to assess differential sticking risks. The third test after two unsuccessful RDT tests indicated 10.0ppg pore pressure at 3138m. The RDT tool stuck at 3138m and wireline jar was fired to free tool. RDT was aborted and VSP/Check-shot tool was RIH above Top Toro at 3130m then logged up from 528m obtaining 29, but of poor quality.

Confirmation of 3.3ppg overbalance on Toro Formation determined the running of 7” liner. Tight hole experiences at 2733m had the liner reamed to setting depth at 3135.5m, with the top of liner at 2497m. The Toro was left open for further RDT tests at later time after reduction of MW.

The 6” BHA, with Gr-Res-Density-Neutron-AFR LWD string was RIH. A FIT was conducted to 12.0ppg EMW. The 6” hole was drilled from 3181m to well TD at 3340m. The base Toro was identified at 3272m and 6” POOH. RDT tool was RIH and hung up 3187m. Eight pressure points and six fluid samples were successfully obtained over Toro A sands. The pressure data identified a 0.438 psi/ft water gradient. Two RDT runs were unsuccessful and no data was acquired over Toro B and C sands

The well was plugged and abandoned with a 3 ½” cement stinger in hole, with three unsuccessful attempts to pass hand up depths at 3188m. Three abandonment plugs were subsequently pumped with plug#1 pumped from 3189m to 3025m to isolate the open hole. Plug#2 was pumped from 2525m to 2425 over the liner top, and tagged at 2425 with 10klb WOB and pressure tested to 1000psi. Plug#3 pumped from 140m to 38m as the surface plug

The Rig104 was released from Korka 1 at 00.00hrs on the 4th June 2010, with an actual cost of ***US$35,628,825,*** which is US$10,237,145 less than the AFE well cost.

3.2.3 Panakawa 1

Panakawa 1 was drilled in PPL 267 in Western Province, Papua New Guinea. The primary objective of the well was to penetrate the Toro Sandstone, at a depth prognosis of 1728m.

The well was spudded on June 26, 2010, at 00:30 hours, utilizing ADS Rig#6. The surface hole was initially drilled with 12 ¼” pilot hole to 351mRT. The hole was opened out with the 17 ½” bit to same depth. The 13 3/8” casing was run in and cemented at 351m.

The 12 ¼” hole was drilled from 351m to 1246m. Partial lost returns began at 378m and complete lost circulation occurred at 479m. Samples could not be properly attained from shakers and thus cutting sample of bit was returned to surface on trip out of hole.

Precise palynological measurement given found formation as Alene with the actual top at 1209m. The prognosed Toro formation was significantly higher than expected. The 9 5/8" casing was therefore run in hole and set at 1241mRT.

Drilling continued with the 8 ½" hole section from 1246m to 1249m, performed FIT to 10.5ppg EMW. The hole was drilled ahead to 2089mRT. Wireline log, Suite#1 was performed at this depth with 4 runs : Quad Combo (DLL-MSFL-SDL-DSN-FWS-GR); RDT.

Drilling continued to 2424mRT and wireline log, Suite#2 was conducted with 5 runs: Triple combo (DLL-SDL-DSN-GR); RDT; Seisnic (check shot); Percussion Side Wall Cores.

The percussion sidewall core attempted 96 cores attempts over the interval of 1344.0m to 2330.0m and recovered 66.

It was decided and Panakawa 1 was plugged and abandoned as a dry hole. The rig was released on August 8, 2010, at 10:30 hours. The estimated total cost for this well was ***AU$11, 500 000***

3.3 Exploration and Appraisal Wells

3.3.1 ADT 2 SIDETRACKS

Brief History, ADT 2

Located in the Agogo fields and drilled by Oil Search Limited in PDL 2, the ADT 2 well was originally a re-entry into the original Agogo 5X well bore after the 9 5/8" casing was cut at 4600ft MD and retrieved to surface. ADT 2 was drilled out from below the 13 3/8" casing shoe at 4385ft MD and reaching a TD of 8556ft MD on 5th November 1992.

Production commenced on the 27th January 1993 from Toro A without gas lift, but was shut-in in 1994 due to high gas oil ratio (GOR). It was then plugged and abandoned in June 1996.

ADT 2 ST1

ADT 2 ST1 was planned as an exploration well, sidetracking out of the existing ADT 2 well bore and targeting the Koi-Iange reservoir sands using OSL Rig 104.

The ADT 2 well was re-entered on the 31st of October 2009 and the ADT 2 ST was kicked off at 2475.0mMDRT with an 8 ½" BHA and the hole was directionally drilled to section TD at 2865m. CSNG-RDT-GR wireline tool was run in hole and seven test points were logged in the "Hedinia A" formation. The 7" casing was set and cemented at 2860m.

A FIT was conducted to 17.0ppg EMW with 11.5ppg mud, after drilling cement out to 2865m. The 6" hole was directionally drilled ahead to 3225m. RDT-MCS-CSNMG wireline logged 15 points from 3060m before tool got stuck at 3132m. The fish was recovered to the surface. Drilling continued with 6" BHA consisting of 4 ¾" MWD/LWD, to 33664m, with losses, and built inclination to 30^{o}. Another wireline log, XRMI-FWS, was run and logged up from3305m to 7” casing shoe at 2860m. Drilling continued to section TD at 3775m with losses.

The drilling string was differentially stuck at 3775.0mMDRT while attempting a wiper trip. The string backed off at 2953.0m. After multiple attempts to free the drill string the string was remade to fish and a DCST tool was used that detonated and severed the drill string successfully at 3146m. OSL decided to do a mechanical sidetrack.

ADT 2 ST2

ADT 2 ST2 kicked off from the ADT 2 ST1 well bore at 3060mMDRT with a 6” hole. The well was drilled to 3714mMDRT before the drill string got stuck again due to differential pressure. The drill string severed at 3525mMDRT. RDT tool run in hole on wireline hung up at 3065m and could not work past the hang up depth successfully. ADT 2 ST2 was cemented to 3522m.

ADT 2 ST3

ADT 2 ST3 kicked off from the ADT 2 ST2 well bore at 3484mMDRT in the 6” hole. The 6” hole was drilled to section TD at 3667m. A 5” liner was RIH on 4” drill pipe to 3227m. the liner was precautionary reamed down to 3663.5m. Poor progress aborted attempts to ream to TD and the liner was successfully set.

The well was drilled out in the 4 1/8” hole at the total depth of 4140mMDRT.

A DST was performed at approximately 3610mMDRT but no fluid was recovered. No coring was planned or carried out.

The ADT 2 ST3 did not achieve the original objective. The Koi-Iange, however, was intersected in the hanging wall. TD was reached within the inverted Juha 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 ADT 2 ST3 well was completed as an oil producer with a 5 zones. These included; Inverted Digimu, Digimu Repeat, Digimu Repeat-Inverted, Toro C and Toro B (lower). The rig was released on January 28, 2010 at 12:00hours. The actual cost for the well was ***US$39,033,854***.

3.3.2 Antelope 2

The Antelope 2 is the fourth follow up 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. Antelope 2 was programmed to drill and test the southern extent of the Antelope Reef Play in PPL237, by InterOil Limited.

The primary objective of this well is to drill into the Antelope Limestone and prove hydrocarbons at a proposed total depth (TD) of 2550m ±200m MD. The offset wells to Antelope 2 are Elk 4, Elk 1 and Antelope 1

Antelope 2 well was spudded on July 27, 2009 at 0700 hours. They drilled the 24”, 17 ½”, 12 ¼” and 8 ½” holes respectively to 246.5m, 1101m, 1832m and 2250m. The respective casings of 18-5/8”, 13-3/8”, 9-5/8” and 7” were set at 247m, 1101m, 1832m and 2222m.

The top of the Antelope Limestone was intersected at circa 1831mMD when circulation samples tested 100% limestone during operations. A drill break was taken and an attempt was made to run logging with Schlumberger Log#1, Calibrating log tools (DSI, Density, PPC, GPIT, GR, AIT, CNL). Logging was unable to get past 1140m and in due course the 9-5/8” casing was set at 1832mRKB. Vertical Seismic Profile (VSP) logs were run where the first could not pass obstruction in the 9-5/8” liner at 1560m and was logged up from this point up. Another VSP was done from 1830m – 1512m

A liner and the tie-back were run to accommodate the tandem down hole deployment valve (DDV), the Lower DDV is at 1042.6m while the Upper DDV is at 1022.6m The well was then cored from 1846mMD to 1882mMD. The top of the producible, hydrocarbon bearing quality reservoir was encountered at circa 1840m based on the cutting analysis, mud logs and rate of penetration

InterOil performed DST#1 with objectives of determining reservoir pressures, flow properties, productivity, deliverability based on PI and permeability; they also wanted to collect surface samples for PVT Analysis and determine any possible boundary effects.

DST#1 was completed with a casing packer at interval 1832m – 1882mMDRT. InterOil's preliminary test results show gas rate measured at 14.1 million cubic feet per day with a maximum rate record at 18.2MMscfd. Condensate ratio of 16.5 barrels per million cubic feet flowed through a 35/64" choke with 2,070psi flowing tubing pressure.

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

While drilling and coring the reservoir limestone to 2214m MD, the drill string twisted off. String weight loss at this depth was suspected as string being parted and the CCL log run tagged top of fish at 1608m, leaving 606m of fish (inclusive of the Core BHA).

The pipe was plugged for safe retrieval of fish in the gaseous well. The over shot BHA was then RIH and tagged top of fish at 1610m, picked up and pulled out to surface. The core barrel was laid down with 9.5m of the 30.5 core was recovered (31.3%)

Following successful fishing operations the well was drilled to 2250m and halted for logging and sidewall cores operations. An additional 10m was then drilled to 2260m to perform logging operations.

SPI carried out another commercial, ceremonial test on December 1, 2009. The test was done in an open hole after the 9-5/8" depth with the use of the two down hole deployment valves to control excess flow. The highest gas rate was 705.66 MMCFD with a choke size of 280/64th.

The 7" liner casing was set at 2222m and the 6-1/4" hole was then drilled to a total open hole depth of 2465m. Within this interval DST#2 and DSR#3 were done, before the well was plugged back with a Tam packer at 2400m followed by two cement plugs up to the 7" liner shoe.

DST#2 was proposed with the objective to intersect the platform carbonate section of the Antelope carbonate reservoir (Unit A) at a sub sea depth towards the base of the Antelope Field gas column. The DST was to assess gas deliverability of the platform carbonate and provide an additional Condensate Gas Ratio (CGR) data point.

DST#2 was originally run with insignificant flow results noticed. They pulled out of hole and reran the tool as DST#2A. DST#2A was RIH to test interval from 2222m to 2325m. The casing packer was set inside the 7"liner at 2188m. The total test duration was 117 hours. The flow rates are of Initial flow of 2.06MMcfd to 3.49MMcfd

DST#3 was proposed to test the open hole interval from 2330m – 2365m using dual compression packers with the same objectives as in DST# 1 and DST#2. DST#3 assembly was RIH with a compression packer. The preflow gas rate was 3.2MMscfd with no associated condensate at surface. The main flow conducted for 2 days had a final gas rate of 2.3MMscfd on a 24/64th choke. A total of 6.9MMscf of gas was flared. DST#3 string was pulled out. A straddle pack test was initiated and DST 3A string was RIH to conduct flow test with the straddle packer. The packer failed after testing and when flow started. Further attempts to re seat packer were unsuccessful and DST#3A was pulled out of hole.

A new formation was drilled from 2365m to 2465m. The following logs were run at a depth of 2465m: S20 R1: [Density-HRLA-GR]; S21 R1: [APS-HGNS-HSTS-GR] and S22 R1: [FMI-GPIT-GR]. A total of 223 out of 239 sidewall cores were recovered, and the lubricator and the wire line equipment were rigged down.

Antelope vertical well was drilled to a total depth of 2465m, when it was decided to drill horizontally. A TAM Packer was set at 2400m and the well was plugged back to a depth of 2218m by setting cement plugs

Antelope 2 Horizontal Sidetrack 1

InterOil proposed to drill and evaluate a horizontal lateral in the Antelope 2 well Accordingly their understanding of the reservoir analysis of wireline logs, core, DST flow and transient data and reservoir modeling, had matured to a point in evaluating and appraising to better understand the lateral reservoir heterogeneity. They also aimed at enhancing wellbore deliverability of the horizontal section in the lower pay intervals and to validate the liquid composition in the lower section of the reservoir, away from the effects of extreme water losses of the parent well.

InterOil, after approval, plugged back Antelope 2 vertical well to 2218m. The plug back above the water contact provided a seal off to the aquifer and to conduct additional drilling.

The Antelope 2 Horizontal Sidetrack#1 kicked off at 2240m and built angle to 89.42 degrees and azimuth of 90.16 degrees, with a 61/4" hole to 2407m. The hole was then opened with an under reamer to 7" from 2227m to 2407m. The 5 ½" liner was run in hole to 2405m and washed down to 2406m cemented with top of liner at 2156m.

The 4 ¾" horizontal drilling assembly drilled out cement from 2397m to 5 ½" liner shoe at 2406m, drilled, and 1m rathole was cleaned to 2407m. New formation was drilled from 2407m to 2408m.

2m of open hole was washed to 2408m and a final MWD survey at 2393m confirmed the hole inclination of 7 degrees and proved well was sidetracked accidentally with under reamer. InterOil decided to sidetrack the well. A cement plug was set with top of cement at 2290m.

Antelope 2 Horizontal Sidetrack 1 ended when a Whipstock oriented with tool face set at 84 degrees was set with bottom at 2156m and top at 2150.70m.

Antelope 2 Horizontal Sidetrack 2

Antelope 2 Horizontal Sidetrack 2 started with milling of window in 7" Liner from 2150.50m to 2153.50m. Formation milled to 2162m. Directional drilling from 2162m to 2178m, could not get past 2178m, POOH inspect and found Bit and section of motor plus Stator left in hole, a total Fish length of 7 meters. Cement plugged to an estimated top of cement at 2093m. Cement was drilled from 2090m to 2153.39m. Continued milling to 2155.5m. Rigged up and ran wireline survey at 2154.37, inclination 3 degrees. POOH for directional assembly.

6 1/8" hole drilled to 2167m and slide drilled from 2167m to 2203.2m. Drilling parameters were changed to improve rate of penetration. Directional drilling was continued from 2217m to 2337.5m. Gamma Ray signals upon drilling with rotary mode from 2303m showed erratic/abnormal values not within expected range of values. A re-

log was planned and run from 2303m to 2337.5m. All tests were okay. Drilling continued with rotary and slide to 2385m when POOH and found that lower part of motor was lost down hole. Fishing out the junk was unsuccessful therefore it was decided to cement plug the junk down hole.

Another sidetrack was approved and InterOil drilled from KOP at 2301. The sidetrack is believed to be in the same window as Antelope 2 Horizontal Sidetrack 2 and therefore the same name was used, according to InterOil.

Drilling continued with a 6 1/8” hole to 2426m before opening up the hole with an under reamer to 7” hole. The 5 ½” liner was run with top of liner at 2078m in the vertical well bore and the shoe at 2418m. Drilling continued with a 4 ¾” open hole and before reaching TD at 2806m, InterOil proposed to deepen the well to 3100m. Just before reaching 3100m another proposal was made to deepen to 3300m to elongate the horizontal section, approximately 90 degrees on plain. A Total Depth of 3201mMD was reached with True Vertical Depth of 2335m

DST#4 was run at intervals from ±2418m to 3200m. Its objective was to assess the deliverability of the horizontal completion and validate the produced liquids composition away from the extreme water losses in the parent well bore. DST#4 test did not have a shut in pressure. Pressure transient analysis performed on available DD data results carried high degree of uncertainty. Test information, however, is said to be good of the horizontal well flow rate and CGR. Flow rate was lower than expected (~8-12MMscf/D).

DST#5 was proposed when InterOil resolved to set a 4 ¾” packer at 2955mMD and test the bottom part of the interval, from 2955m to 3201mMD. A test peak flow rate of 6.5MMcfd was achieved during the extended flow and CGR of 19.9bbls/MMscf was calculated from cumulative gas and condensate volume. Average water was less than 10bblas/day and a cumulative gas volume of 343.3MMSCFD was flared.

Antelope 2 H2 was decided to be plugged back and suspended after reaching 3201mTD. A TAM packer was set at 2506m and cemented to 2299m in the 5 ½” casing liner.

Antelope 2 Horizontal Sidetrack 2A

InterOil drilled and evaluated a second horizontal lateral leg below Antelope 2 H2 well. The horizontal section was drilled at a dropped angle 2345m True Vertical Depth right out from the 5 ½” casing shoe at 2418mMD.

The objective of this section was to validate liquid composition in the deep section of the reservoir and confirm water free production at this deep reservoir.

Drilling commenced with 4 ¾” BHA, drilling out the cement from 2299m to 2423m. Firm cement was then drilled from 2423m to 2429m.

The 7” Polish mill and BHA was run in hole to 1731m. The top of the 7” liner was tagged at 1719m and the Polish Bearing Receptacle (PBR) was polished. A 7” tie-back was run in hole. At 99m the lower 7” DDV was connected. The casing was run to 117m and the upper 7” DDV was connected. The Depths of the 7’ DDV was set at 1618.82m and 1600.42m, respectively. The seal stem was stung into the PBR at 1718m.

A 4 ¾” BHA inclusive of MWD commenced drilling and continued to a new formation at 2431m. The hole was washed and reamed from 2329m to 2431mTD. Survey revealed an inclination of 84.6º, 314.4 azimuths. Drilling resumed in slide mode from 2430.5m and proceeded ahead in slide and rotary mode. Drilling halted at 2594m for new BHA. The new BHA was RIH to 2027m and the drillstring was plugged. The string was surged and unplugged.

A new directional assembly was made up tripped in hole to 2594mMD and drilling resumed in slide and rotary mode to 2703mMD, 2347mTVD; and noted MWD failed. A resolution was made to run DST#6. The Weatherford slimhole Logging tool was RIH for logging runs. The hole was logged from 2697m to 2418m with MAI-MSS-MPD-MDN-MGS-MSS.

DST#6 was conducted by Farley Riggs Testing Services utilizing slimhole tests equipment. The compression packer was at 2620m but further work on tool could not open the tool. The packer was unseated POOH and found a missing piece of rubber at packer top. DST#6A assembly was made and RIH and conducted over the interval of 2622m to 2703mMD. The compression packer was set at 2620m top and 2622m bottom. Fluid level in annulus dropped and due to foam and additional water produced at surface, the rates could not be measured successfully at separator points. The gas rate ranged from 2.3 to 3.4MMscfd with single CGR at 24.2bbls/MMscf. Final gas rate measured was 1.5MMscfd.

A rerun bit and directional BHA was RIH. A survey taken at 2622m revealed hole angle of 89.8º, 104 azimuth. Drilling proceeded to in slide and rotary mode to 2731m and experienced full lost circulation. Drilling went ahead in rotary and slide mode and dropped angle to 81.6º at 2816mMD. Drilling proceeded and built angle to 89.3º at 2960mMD, 2360mTVD. BHA was POOH and electric logging tools were prepared. The hole was logged up from 2960m to 2367m with MAI-MSS-MPD-MDN-MCL-MGS-MMS.

DST#7 and the final DST assembly was prepared and RIH. The test was carried out at intervals 2851.7m to 2960mMD, with a compression packer, in the 4 ¾”. Due to packer failure, the test was unsuccessfully concluded. Initially the flow indicated two different reservoirs. The estimated reservoir pressure was 3721psi.

InterOil resolved to plug and suspend Antelope 2 H2A temporarily for future completion of gas and condensate production. A prior variation was made before the operations to plug back. The hole was cemented from 2713m up to the top of the 5 ½” liner casing. An EZSV with cement retainer was set 2411mMDRT and at 2089mMDRT, 11m inside 5 ½” liner top.

InterOil Rig 2 was released on October 12, 2010 at 2030hrs. The estimated well cost involved in drilling the parent well and its horizontal sidetracks is approximately ***US$109,922,360***.

3.3.3 Moran 15

Moran 15 is a moderate angle appraisal well located in the Southern Highlands Province in PDL 2/5/6 and is operated by Oil Search Limited (OSL). The well was drilled from the existing Moran 5X/7 well pad, to appraise reservoir sands updip of Moran 5X.

The primary objectives were to appraise the reservoir quality and fluid content of the Backlimb Toro C and Backlimb Digimu reservoirs in the Moran C Block.

Moran 15 rig move commenced on the 4th June 2010. By the 10th June, Rig 104 was rigged up over Moran 15 cellar but due to pressure integrity issues (live annulus) on Moran 5XST2, operations were suspended on Moran 15 and Rig 104 was skidded to Moran 5XST2 for urgent workover.

After suspending Moran 5XST2 in a safe manner, Rig 104 skidded back to Moran 15 and drilling operations commenced on the 20th June 2010.

The 26” hole was drilled to 35.5m with full returns. The 18 5/8”conductor casing was run and set at 34.06m MDRT.

The 17½" surface hole was drilled to 123m before POOH to install the 9½" EMT MWD (GR-DIR) and then running to bottom and drilling vertical hole to 504m. From 504m to 699m, the hole was drilled with a 9⅝" Sperry 5/6 3.0 motor (with 17" string stab) to section TD at 1155m. A 160m step-out and 25° inclination was achieved, although 40m away from the plan. The 13⅜" surface casing was run in hole and was cemented in place at 1150m..

A 12¼" BHA was made up and RIH and the 13⅜" shoe track drilled out to 1150m. At 1158m, a LOT was conducted to 13.1 ppg EMW. The 12¼" hole was then drilled ahead to 1198m in preparation for the subsequent GeoPilot BHA. The 12¼" drillout BHA was then POOH to surface. Due to a weak 13⅜" shoe, 5½" open ended drill pipe was run in hole to 1196m and a hesitation cement squeeze was performed.

A 12¼" GeoPilot BHA was then RIH and drilled out cement to 1158m where a second formation test was carried out to 12.5 ppg EMW. Because of the weak 13-3/8" shoe, it was decided that the 9⅝" shoe would be elevated from the Toro to Alene before drilling ahead to 1343m.

The 12¼" hole was drilled ahead to 1343m with the Geopilot BHA where total losses were encountered coinciding with the intersection of the Moran A-C Block boundary fault. From 1343m, the 12¼" hole was control drilled to 2019m where section TD was called shallower than planned, to prevent intersection of high pressure Toro Sands with a weak 13⅜" shoe.

The 9⅝" casing was RIH to TD after a RDT logging run was aborted due to the RDT being dressed for 8½" hole and not 12¼". The casing was hung off in the wellhead and cemented and t*he wellhead packoff bushing installed and pressure tested successfully.*

An 8½" directional BHA with a 6¾" 6/7 5.0 Sperry motor and LWD was RIH and drilled ahead to 2022m after drilling out the 9⅝" shoe track. A FIT was conducted to 18 ppg without leak off and the hole drilled ahead to 2041m before the 8½" BHA was POOH due to a fault in the LWD cause by rubber debris above the LWD pulsar.

The LWD was changed out and an identical 8½" directional BHA run and the 8½" hole drilled ahead from 2041m to 2125m. Top Toro was intersected at 2054m. RDT logs indicated that Toro C was partially depleted and not virgin as previously thought. The drilling of the 8½" hole was continued from 2125m to the intermediate logging point at 2272m, past the Toro and Digimu.

RDT logging of Toro and Digimu failed and Third logging attempted on Toolpusher. Maximum trip gas of 44% was detected after breaking circulation at 9 5/8" casing shoe. The well was shut in mud weight increased from 13.0ppg to 13.5ppg and gas brought down to 2%.

RDT logging on toolpusher indicated that both zones were oil-bearing but partially depleted.

The 8 ½" hole was drilled ahead to 2294m and the Hedinia Sand was intersected at 2233m. The 7" liner was run and set cement at 2294m successfully

A 6" rotary BHA with LWD tagged 7" landing collar at 2268m and drilled out the shoe track. Drilling progress was slow at 1m/hr and upon POOH of the bit, 50% of bit was missing. A reverse circulation junk basket was RIH and milled junk to 2296m and POOH. Junk was recovered. A leak off test was conducted at 17.0ppg EMW.

The 6" hole was drilled ahead to 2445m and a drill break was taken. The well circulated maximum gas of 22%. The to 2885 and a fold axis was encountered at 2415m as formations overturned. Overturned Digimu and Toro sequences were not intersected. The well was instead drilled directly into overturned Alene, Juha and Bawia. The Moran Main Thrust is believed to have been intersected at 2790m.

RDT log was RIH on wireline and failed twenty tests. Only one successful point test was achieved in the Hedinia Sands.

The well TD objective was and ballooning with mobile gas reached the decision to plug and abandon Moran 15, isolating all sand zones intersected. The top most cement plug was tagged at 2302m.

Moran 15 ST1

Operations were handed over to Moran 15 ST1 on September 3, 2010. A 6” BHA kicked off operations, tagged cement at 2302m and drilled to 2347m with time drilling over 24hr. 100% cement returns were observed and kick-off run was abandoned.

After another successful kick-off attempt, drilling resumed with a 6” BHA from 2330m to 3271m. Inclination dropped from 33º to vertical wellbore at 13º. The Hedinia and Iagifu sand were intersected but of poor quality. The Main Thrust had yet to be identified by this depth so drilling continued.

Drilling continued to 4074 with the 6” hole size. Well deepening was aborted due to deteriorating hole conditions.

A Cast-F log was run over the 7” liner to confirm casing conditions. The 6” open hole was abandoned with 7 cement plugs to TOC at 2180m.

Moran 15 ST1 completion phase began on October 2, 2010. Cement was dressed off to 2265m and the TCP gun was RIH to 2231m. The lower completions assembly had 5 packers set at 2223.39m, 2214.83m, 2116.32m, 2121.26mm and 2074.90m.

Upper Toro A was completed by second perforation at two perforated intervals of 2054m to 2064.5m; and 2066.5m to 2069m

The rig was released on October 12, 2011, at 18:00 hours. The actual operations cost was ***US$46,336,973.***

FIGURE 3.3.1. Development Wells vs Exploration & Appraisal Wells

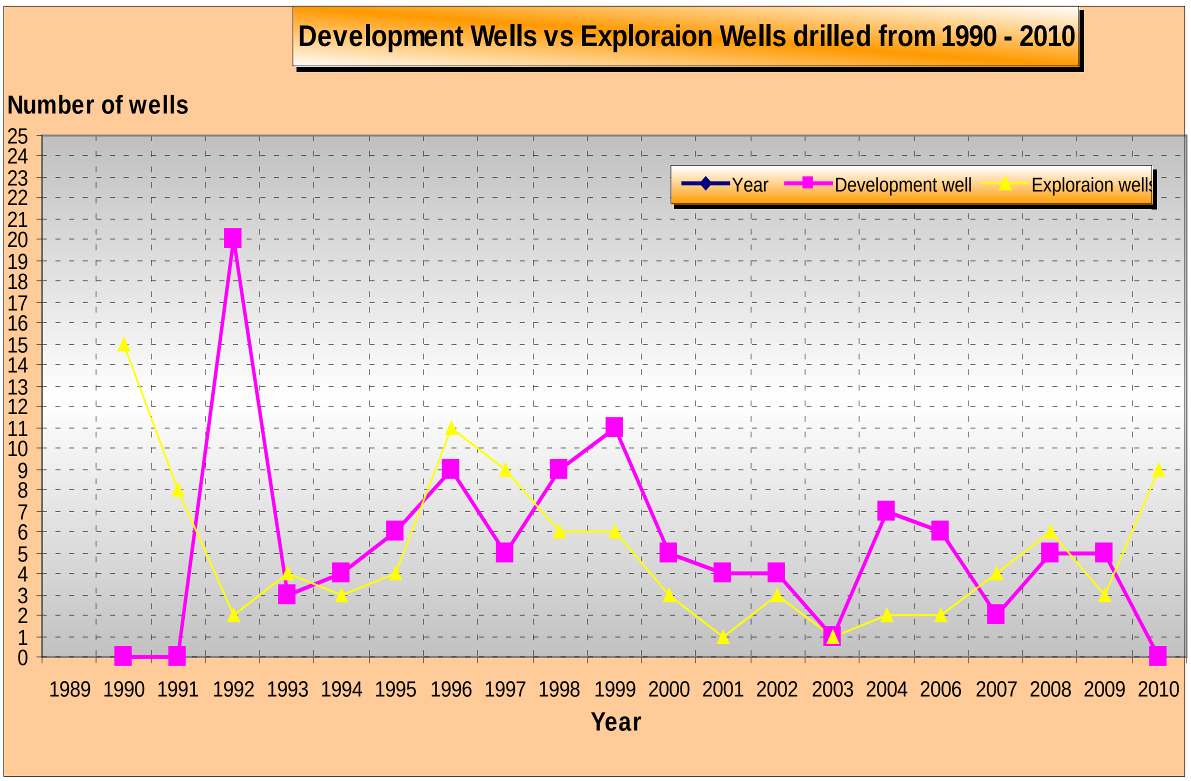


Table 3.1 Summary of Discoveries to Date

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

SECTION 4 PNG LNG REPORT
Executive Summary

Esso Highlands Limited (EHL), a subsidiary of ExxonMobil Corporation (EM) is constructing and will operate the PNG LNG project on behalf of the co-ventures and subsidiaries.

The Department of Petroleum and Energy (DPE) for/on behalf of the Independent State and the People of Papua New Guinea is the Regulatory body overseeing the regulatory compliance by the Project.

The PNG LNG is an integrated development that includes gas production and processing facilities in the Southern Highlands and Western provinces of PNG. It incorporates liquefaction and storage facilities (located on the northwest of Port Moresby) with a capacity of 6.9 million tonnes per year. There are over 700 km of pipelines connecting the facilities. The Project involves the development of a number of reservoirs and facilities in a series of development phases to produce LNG from an inlet feed gas capacity of 1,180 kSm3/h (1000 Mscfd). The full development of the Hides, Juha, Angore, and SE Hedinia Gas fields along with the blow down of the gas cap from the existing Kutubu, Agogo / Moran, and Gobe Oil fields will supply the gas resources.

The investment for the initial phase of the project, excluding shipping cost is estimated at US$15 billion. Over the life of the project, it is expected that over nine (9) trillion cubic feet of gas (Tcf) will be produced and sold. The project will provide a long-term supply of LNG to four major customers in the Asia region including: Chinese Petroleum Corporation, Taiwan; Oska Gas Company Limited; The Tokyo Electric Power Company Inc.; Unipec Asia Company Limited, a subsidiary of China Petroleum and Chemical Corporation (Sinopec).

The Project is progressing in a series of development phases with the first LNG deliveries scheduled in 2014.

Since the last report (2009) on the PNG LNG, the Project has made considerable progress. On all project fronts, early works and construction activities have already started. The project moved into full execution in March 2010, commencing with early works activities. Detailed engineering, execution planning and procurement activities continued to progress at the main office locations of the Engineering, Procurement and Construction (EPC) contractors. Accordingly, for construction to proceed, the Project Operator has submitted Permit to Construct and Modify applications. These included the LNG Plant and Marine Facilities (PPFL 2), the LNG Gas Pipeline (PL 4), Associated Oil Facilities (PDL 4 & 2), and HGCP (PDL 1&7).

The Project has also made some significant changes to the Project Design Basis (PDB). Notably, at the upstream, the diameter of the offshore section (approx. 407 km) of the LNG Gas Pipeline has been changed from 34-inch to 36-inch pipeline and at the downstream, the LNG plant capacity has been increased from 6.3 Million tonnes per annum (Mtpa) to 6.9 Million tonnes per annum (Mtpa). These changes according to the Operator, will not affect the capacity of the LNG plant or the pipeline, as the changes were part of the original design. Apart from these changes, the Project has also sought exemptions from certain sections of the PNG Oil and Gas Act and Regulations.

Regulatory compliance has been a major concern to the DPE for a large scale project like this. The DPE has maintained and contracted Granherne; a consulting company specialized in the oil and gas industry, to provide technical advisory services on the PNG LNG. Granherne has assisted DPE in the review of the Project Design Basis (PDB) documents submitted as proposals for the Licence and the Permit to Construct applications. Their technical assistance and advice as been proved a major success as they have achieved significant results for the State in meeting and achieving its regulatory requirements. These included attaching licence conditions to licences, issuing directions under the Act, identifying areas for new regulations and adding further conditions to the permit to construct. DPE through Granherne has and will maintain and ensure that all PNG LNG related technical issues/queries raised from the Licence and Permit reviews has been/or are and will be adequately addressed, clarified, verified and assured by the Operator for the overall integrity and safety of the project.

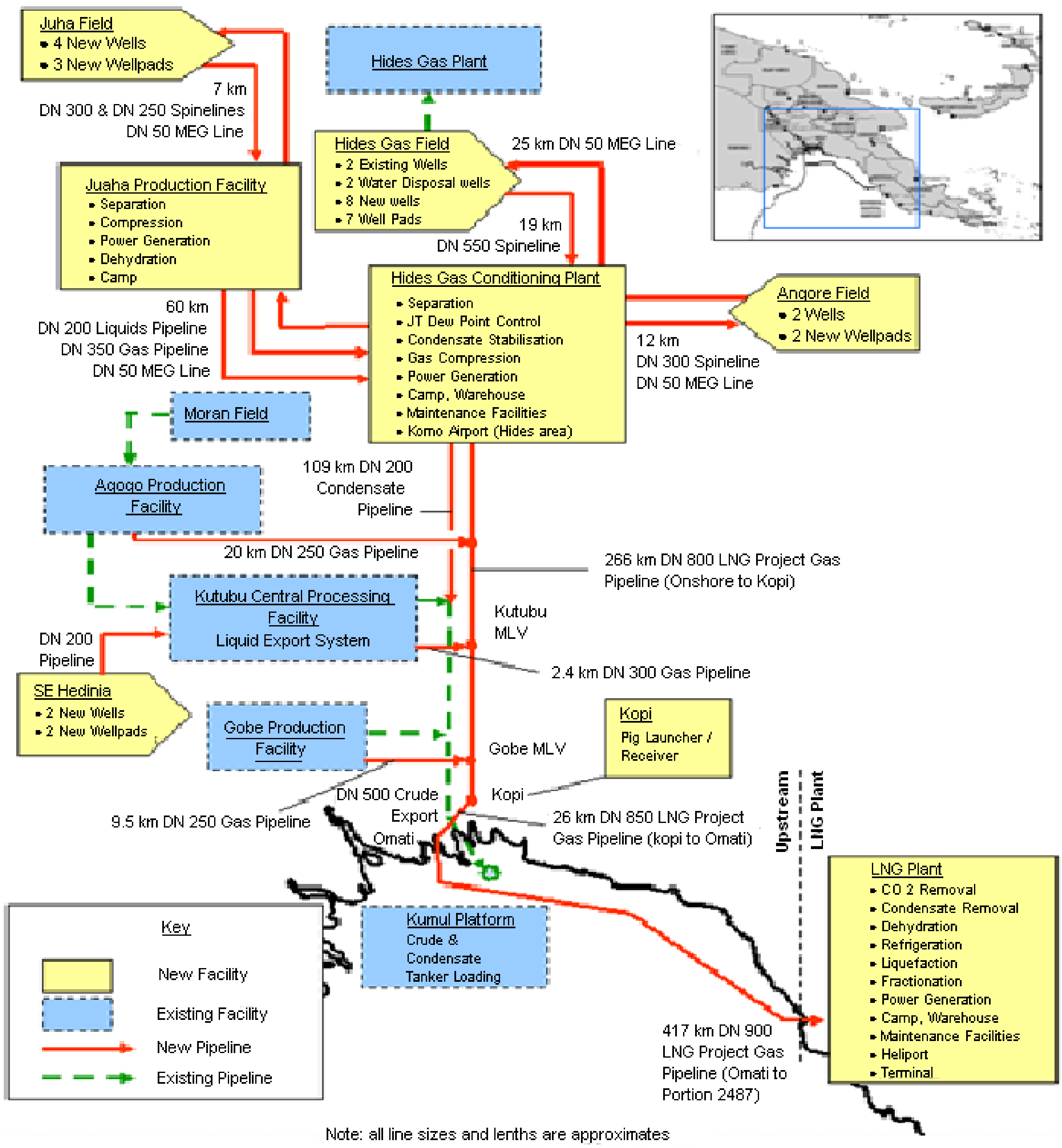


Figure 4.1: LNG Project Facilities Overview

4.1 Introduction

This report on the PNG LNG project is a continuation from the last report of 2009. In the last report, the overview of the PNG LNG project was presented as described by the Project Design Basis (PDB) submitted as proposals for the 21 Licence applications by the Project operator as required under the PNG Oil and Gas Act and Regulations of the Independent Sate of Papua New Guinea.

In this report, it will discuss the progresses and the changes achieved by the project as of since the last report. The Project has made considerable progress. On all project fronts, early works and construction activities have already started. Detailed engineering, execution planning and procurement activities continued to progress at the main office locations of the Engineering, Procurement and Construction (EPC) contractors. Accordingly, the Project operator has submitted applications for Permit to Construct and Modify for the LNG Plant and Marine Facilities (PPFL 2), the LNG Gas Pipeline (PL 4), Associated Oil Facilities (PDL 4 & 2), and the Hides Gas Conditioning Plant (HGCP, PDL 1 & 7).

The Project has also made some changes to the Project Design Basis (PDB). Notably, the diameter of the offshore section (approx. 407 km) of the LNG Gas Pipeline has been changed from 34-inch (DN850) to 36-inch (DN 900). The LNG plant capacity has also been increased from 6.3 Mtpa to 6.9 Mtpa. Apart from the design changes, the project has also applied for exemptions under the Oil and Gas Act and Regulation.

The progress, the changes and the exemptions will all be discussed in the subsequent sections of this report including the Permit to construct for the facilities. Also discussed in this report is the important role that DPE plays as the regulator - monitoring and ensuring regulatory compliance by the Project as the project progresses through each stage. Included within the discussion of the DPE is Granherne, a consulting company specialized in the oil and gas industry, contracted by the DPE to provide technical advisory services on the PNG LNG.

4.2 Pre - Construction Activities

Much has been achieved since the Project was sanctioned in December 2009, but in the context of the Project's scope and scale, it is only getting started. The construction for the PNG LNG project is scheduled for four years. The project has so far achieved a full year of construction.

Some of the highlights of the pre-construction activities: the project has developed environmental and social management plans; safety management plans; health management plans; regulatory compliance plans and security management plans for the purpose of disclosing, monitoring and reporting for the investor/lender group and the stakeholders including the government and people of Papua New Guinea. These achievements have enabled the operator to secure external funding which reflects EHL's ability to deliver on commitments, working with its co-ventures.

The project continues to conduct pre-construction surveys to identify potential impacts of construction activities on community infrastructure as well as environmental and/or social sensitivities. For the onshore pipeline, 58% of the 292 km main pipeline route is surveyed. In the project time line, the upstream infrastructure contractor completed pre-construction surveys for all its writes.

4.3 Construction

The project moved into full execution in March 2010, commencing with early works activities. Clearing at more than ten sites, scattered over a distance of 300 km, creating the appropriate road access and linking the required infrastructure. Works are continuing on improving and upgrading infrastructure, including road and bridge works, and installation of construction camps.

Early works have provided a foundation for scaling up construction activity late in the year as the onshore pipeline contractor and the LNG plant and Marine Facilities contractors and subcontractors mobilized. Rig construction activities commenced following the finalization of detailed drilling and completion designs.

Table 4.1 Provides an Overview of Construction highlights: Contracts and Main construction activities

Contract	Contractor	Major Activities
Upstream Infrastructure (C1)	Clough Curtin Brothers Joint Venture	Mubi River ferry works were completed and the ferry became operational Kutubu Central Processing Facility Bypass roadwork completed and ridge Bypass road work nearing completion.
	Telecommunications (EPC 1) – TransTel Engineering	Construction begins at the first of six mountain top communication sites. Complete installation of satellite communications at one additional construction camp.
LNG Plant Early Works (C2)	Curtain Brothers PNG Ltd	Upgrade of the Papa Lea Lea Road
Offshore Pipeline (EPC 2)	Saipem	Completed onshore line pipe welding mechanical testing
LNG Plant and Marine Facilities (EPC 3)	Chiyoda and JGC Corporation	Clearing vegetation areas in preparation for the jetty test piles and for the temporary seawater intake pipeline. Installing the temporarily concrete batch path.
Hides Gas Production Facilities and Wellpads (EPC 4)	CBI Clough Joint Venture	Bulk earthworks progressed. Installation of the boundary fence along with foundation for camp accommodation
Onshore Pipeline (EPC 5A)	SpieCapag	First deliveries of line pipe arrived at Kopi Shore Base. Stripping off line pipe commenced along the right of way.
Komo Air Field (EPC 5B)	McConnell Dowell and	Bulk earth works were

	Consolidated Contractor Group Offshore	completed in the terminal area. The 173-bed Pioneer Camp was completed along with the installation of foundations, accommodation units and the kitchen in the main camp.
Oil Search Limited Associated Gas Development	Aker Solutions	Fabrication of the replacement offloading buoy commenced. Preparatory civil works commenced at Kutubu Central Processing Facility
Drilling (new Wells and workovers)	Nabors Drilling International Ltd	Rig Construction activities commenced
Port Moresby construction Training Facility	Eos	Officially Opened and operating

4.4 Engineering, Procurement and Execution Planning

Detailed engineering, execution planning and procurement activities continued to progress at the main office locations of the Engineering, Procurement and Construction (EPC) contractors.

The Hides Gas Conditioning Plant (HGCP) is in the process of detailed engineering, procurement and planning at the contractor's office in Singapore and Brisbane.

The Onshore pipeline contractor, after the first delivery of line pipe, is progressing with construction activities with Right of Way (ROW) clearing commenced near Kopi Scrapper Station.

The Offshore pipeline contractor so far progressed detailed engineering, execution, and installation planning activities at their Singapore office.

The LNG plant contractor is progressing with detailed engineering, procurement and planning activities with the completion of the 60 percent model review, human factors constructability review and the continuing of Hazard and Operability Study reviews of Vendor packages.

The Associated Gas Development contractor continued detailed engineering, equipment procurement and execution planning for the Kutubu Central Processing Facility, Gobe Production Facility, crude export system and Kumul platform upgrades.

4.5 Licence Variations and Exceptions

The Project has increased the diameter of the offshore section (approx. 407 km) of the LNG Gas Pipeline from 34-inch (DN850) to 36-inch (DN 900). The Project has also increased the LNG plant capacity from the original design capacity of 6.3 Mta to 6.9 Mta.

The increase in the diameter of the offshore section of the pipeline has resulted in the operator submitted an application for variation to the Pipeline Licence No. 4 (PL4) issued to Exxon Mobil on the 8th December 2009 pertaining to the PNG LNG Gas Pipeline. In summary, the application has requested to increase the offshore section (approx. 407km) pipeline diameter from 34-inch (DN850) to 36-inch (DN900). The variation in diameter increases the design capacity of the system from 960 MMscfd to a range of 960-1,020 MMscfd capacity with compression from 1,360 MMscfd to a range of 1,435-1,535 MMscfd. The variation comes as a result of the increase in the maximum design inlet capacity of the LNG Facility. EHL proposes to increase the pipeline system capacity to align with the LNG Facility and capture the associated commercial benefits to the overall PNG LNG Project.

The LNG Plant capacity had to increase from 6.3 Mtpa to 6.9 Mtpa to match the upstream system design capacity from 960 MMscfd to a range of 960-1,020 MMscfd capacity with compression from 1,360 MMscfd to a range of 1,435-1,535 MMscfd. According to EHL, the increase capacity was part of the original contractor bid package and will have no impact but with compression possibly enough for a 3rd LNG train. DPE is to review against the Gas Agreement and the PNG Oil and Gas Act and Regulation to advice the Operator whether the increase in the LNG plant capacity constitutes a variation.

Apart from the licence variations, the Operator has also been seeking approval for exemptions from the PNG Oil and Gas Act and Regulation. The operator has requested to be exempted from the following:

- Section 195 (4) of the PNG Oil and Gas Regulation (2002) - Tanks and Storage;
- Section 40 (7) of the PNG Oil and Gas Regulation (2002) - for Flaring at the HGCP;

- Section 233 of the PNG Oil and Gas Regulation (2002) - for Construction and Operational Reporting; and

- Applied for an exemption to use ASME B31.8 for the design of the slug catcher instead of the AS 2885 at the HGCP.

4.6 The Permit to Construct

The Operator has submitted to the DPE the Permit to construct for the following:

- LNG Plant and Marine Facilities (PPFL 2),
- The LNG Gas Pipeline (PL 4),
- Upgrade of Associated Oil Facilities (PDL 4 & 2), and
- Hides Gas Conditioning Plant (PDL 1 & 7).

Accompanied with these applications, the operator has submitted technical documents about detailed engineering, execution planning and procurement activities to satisfy regulatory requirements for each of the permits.

4.7 DPE and Granherne Consultants

Regulatory compliance has been a major concern to the DPE for a big scale project like this. The DPE has maintained and contracted Granherne, a consulting firm specialized in the oil and gas industry, to review the documents and provide feedback advising DPE of the technical issues that the Operator needs to address, clarify, verify and assure that the facilities applied for in the permits satisfy regulatory requirements.

Granherne, a Perth based Australian company and a subsidiary of KBR, an Engineering Consultancy Company based in Houston is providing construction engineering and technical consultancy services. Granherne consultants provide such services to numerous Oil and Gas companies in the world and has been involved in major LNG projects in the region.

Granherne has involved in the PNG LNG project providing technical advisory services to the Department of Petroleum and Energy since the Project licensing. Their technical assistance and advice has been proved a major success as they have achieved significant results for the Sate in meeting and achieving its regulatory requirements. This includes attaching conditions to licences, issuing directions under the Act, identifying areas for new regulations and adding further conditions to the permit to construct and modify applications.

To satisfy regulatory requirements, DPE and Granherne has been invited by the Project to attend a number of key technical discussions and/or workshops with the Operator, Contractors, Subcontractors and Vendors (of their design reviews, HAZOPS, Risk assessments, Model reviews, FEED Validation reviews, SIL reviews, etc.) at the main office locations of the Engineering, Procurement and Construction (EPC) contractors.

For the DPE, the purpose and objective of the meetings were for EHL to provide the information that could enable DPE to study, identify and classify what facilities EHL applied for in its permit to construct. The least DPE expected in those meetings were for EHL to clearly and accurately demonstrate the compliance of regulatory requirements by providing the technical information on the facilities to be constructed i.e. the project design specifications that lists the design codes and standards and industry best practices. Also to some extent, DPE has to be informed of the technical specifications of EM that provides a linkage to other international codes, standards and practices. Subsequently, the Operator has to assure DPE that no major design changes have occurred to the Project Design Basis, apart from the normal design development as reported and captured in the Management of Change (MOC) process.

The next report on the PNG LNG will discuss the completion of the detail engineering, procurement and construction.

SECTION 5 DOWNSTREAM PETROLEUM PROCESSING

NAPANAPA OIL REFINERY – 2010 REVIEW

General Overview

InterOil's NapaNapa oil refinery at is located 4km from Port Moresby on the eastern side of Port Moresby harbour, and is currently the only petroleum refining facility operating in PNG, apart from Oil Search (PNG) Limited's mini refinery at Kutubu and some micro stills at the Hides Gas Processing Facility. It is the first downstream petroleum project to have been granted a Petroleum Processing Facility Licence (PPFL) by the PNG Government in February 2000.

The NapaNapa refinery was commissioned in the third quarter of 2004 and commenced full-time operations in 2005. In 2010, the refinery operated normally throughout the year except in October when the Crude distillation Unit (CDU) and HDS were shut down for a scheduled Turnaround and Inspection (T & I) to comply with external audit recommendations and to assess the process unit's fitness for further service. This was the first planned and complete inspection of the CDU and HDS since commencement of refinery operations.

5.1 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 of oil per day (BOPD) of light sweet crude similar to the Kutubu crude. It has achieved a sustainable federate of 35,700 BOPD and peaked at 36,000 BOPD in third quarter of 2009. Currently it has an average throughput of 20,000 BOPD.

The hydro skimming unit is designed to operate continuously producing the following refined products:

- Fuel Gas
- Liquefied Petroleum Gas (Propane and Butane)
- Light Naphtha
- 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 which then is blended with butane and light naphtha to produce gasoline.

5.2 Crude Supply & Productions

Low sulfur and high middle distillate yield crudes are imported from abroad (Mutineer, Thevenard, Cossack, Varanus, and Legendre Crude) as well as bought locally (Kutubu Crude). All crude were purchased as spot deals except for Thevenard for which the contract term started in 2010.

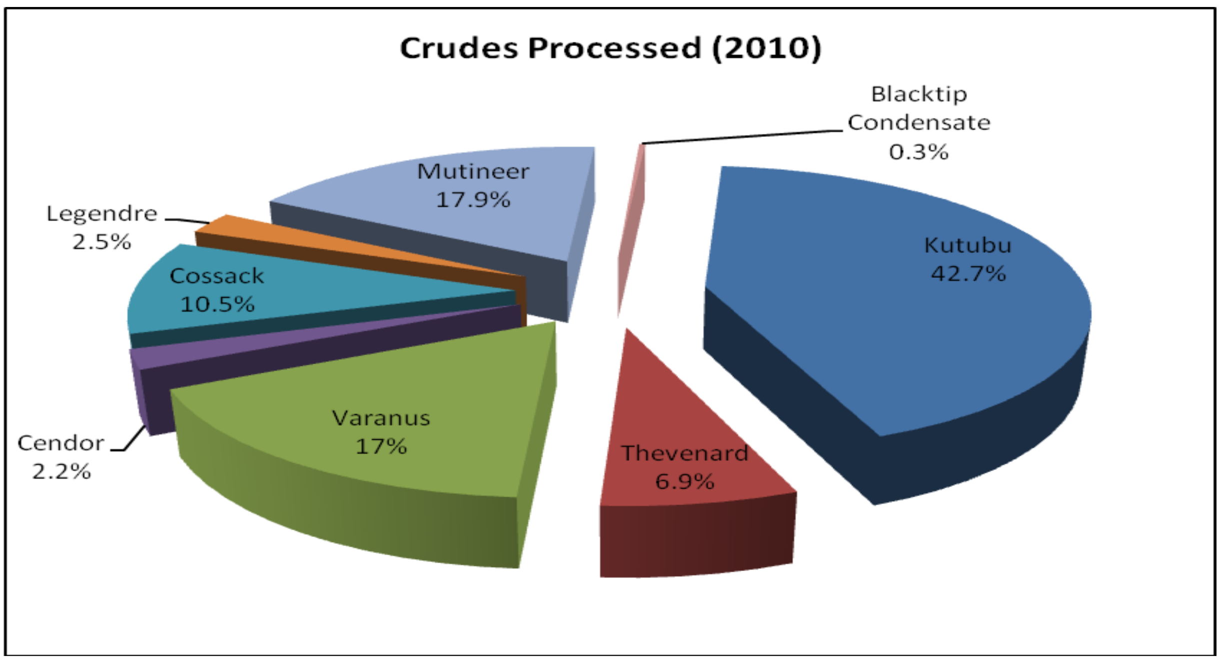


Figure 5.1: The different crudes processed at the refinery in 2010.

In 2010, the refinery processed 6,997,533 barrels of crude or approximately 19,171.4 barrels of crude oil per day on average – about 60 percent of what the refinery was designed to process. This was mainly as a result of the scheduled T & I in October and also in part to temporary unit shut downs such as in February due to low crude inventory and delayed crude arrival. Although the amount of crude processed was affected, this did not have an effect on the overall supply of all product requirements. (Refer to Fig. 2 below)

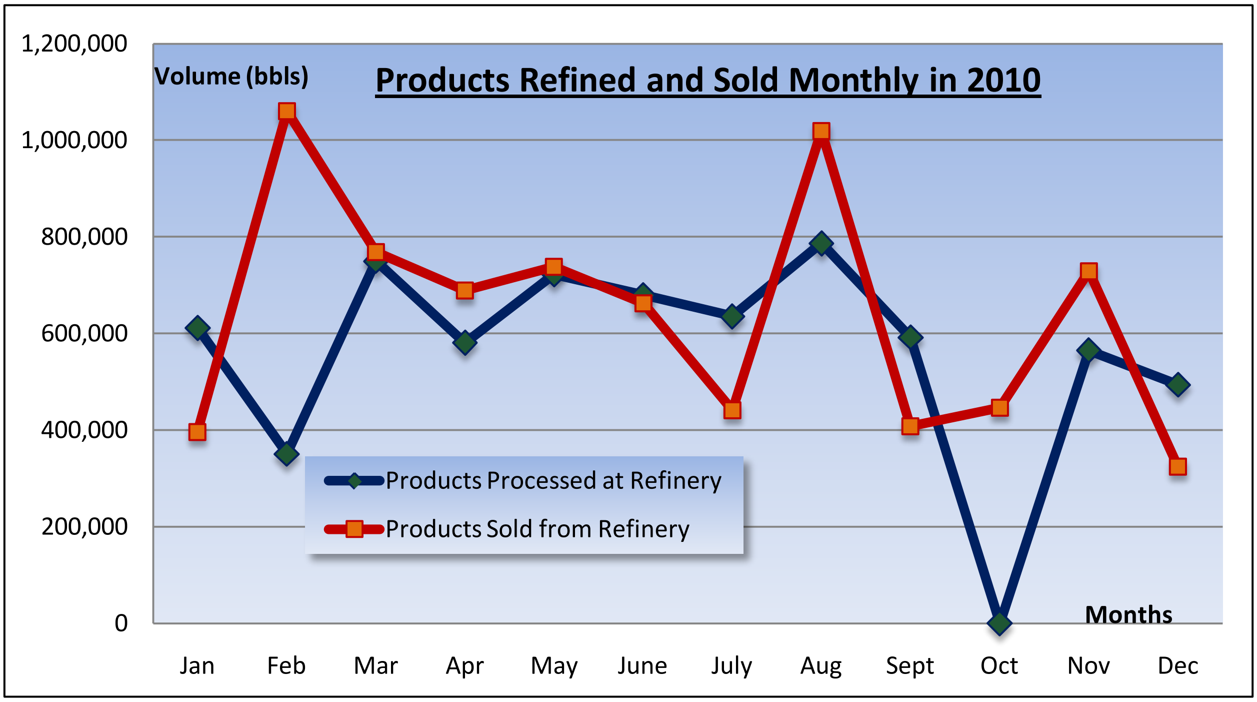


Figure 5.2: Total Products processed at and sold from refinery in 2010

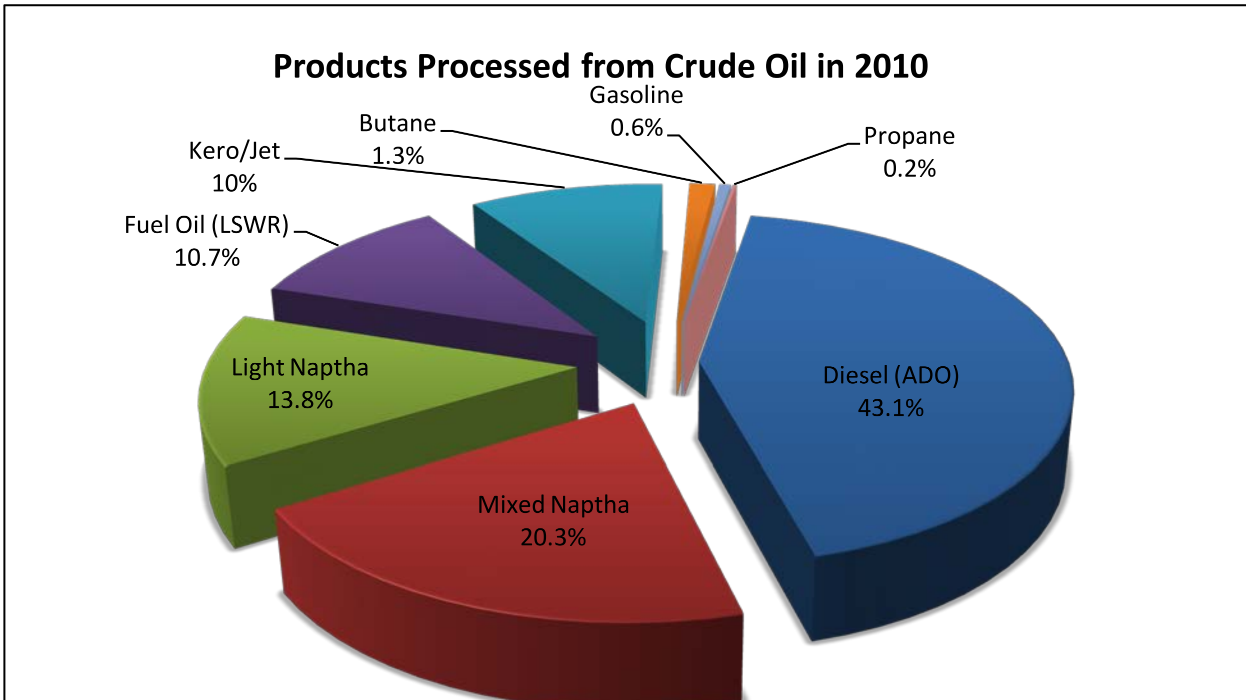


Figure 5.3: Refined Products recovered from crude in 2010

Of the 6,997,533 barrels of crude oil that was processed, approximately 97% liquid was recovered as refined products. As in previous years, diesel continues to be the main product with 2,916,749 barrels produced in 2010 with the production of mixed naphtha second with 1,373,620 barrels produced. The majority of Gasoline, Kero/Jet and Diesel were sold on the domestic market, mainly to the mining, logging and exploration industries. All the Naphtha (mixed and light) was exported since there is no market for this product in the country.

Period Covered: 2010 Total				
1. Crude Oil Processed, in barrels =				6,997,533
2. Production, in barrels:				
	Product			
	Propane			13,098
	Butane			88,519
	Light Naptha			936,707
	Mixed Naptha			1,373,620
	Gasoline			39,025
	Kero/Jet			674,172
	Diesel (ADO)			2,916,749
	Fuel Oil (LSWR)			726,064
	Liquid Recovery			**6,767,954**
3. Product Slopping, in barrels				45,945
4. Fuel - Liquid (LPG/ADO/LSWR), in barrels				136,544
5. Fuel Gas + Unaccounted Loss + Flaring, in barrels equivalent:				47,090
6. Sales (Lifted from the Refinery), in barrels:				
	Product	Ship/Vessel From Jetty	Road Tanker From Gantry	
	Propane	13,006	0	13,006
	Butane	85,394	0	85,394
	Light Naptha	1,329,687	0	1,329,687
	Mixed Naptha	1,292,544	0	1,292,544
	Gasoline	268,078	102,849	370,927
	Kero/Jet	294,258	409,670	703,928
	Diesel (ADO)	2,942,681	295,784	3,238,465
	LSWR	627,244	20,133	647,377
	Total Sales			**7,681,328**

Table 5.1: Production and product disposition

5.3 Marketing

PNG still remains the principal market for the refinery products with the exception of naphtha and low sulphur waxy residue. Naphtha is exported in two grades, light naphtha and mixed naphtha to be used for petrochemical and Naphtha reforming feedstock. In 2010, 67% of products from the refinery were sold domestically while 33% was exported.

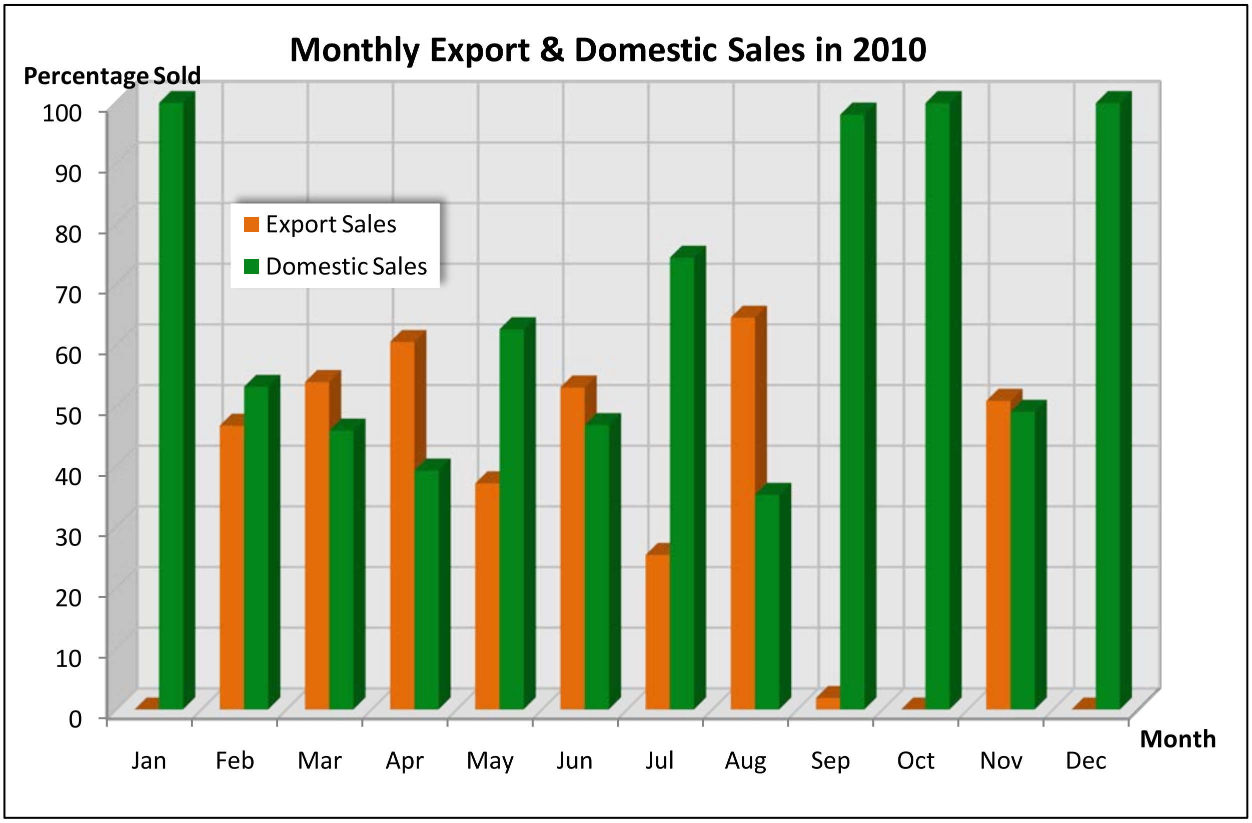


Figure 5.4: Refined Products recovered from crude in 2010

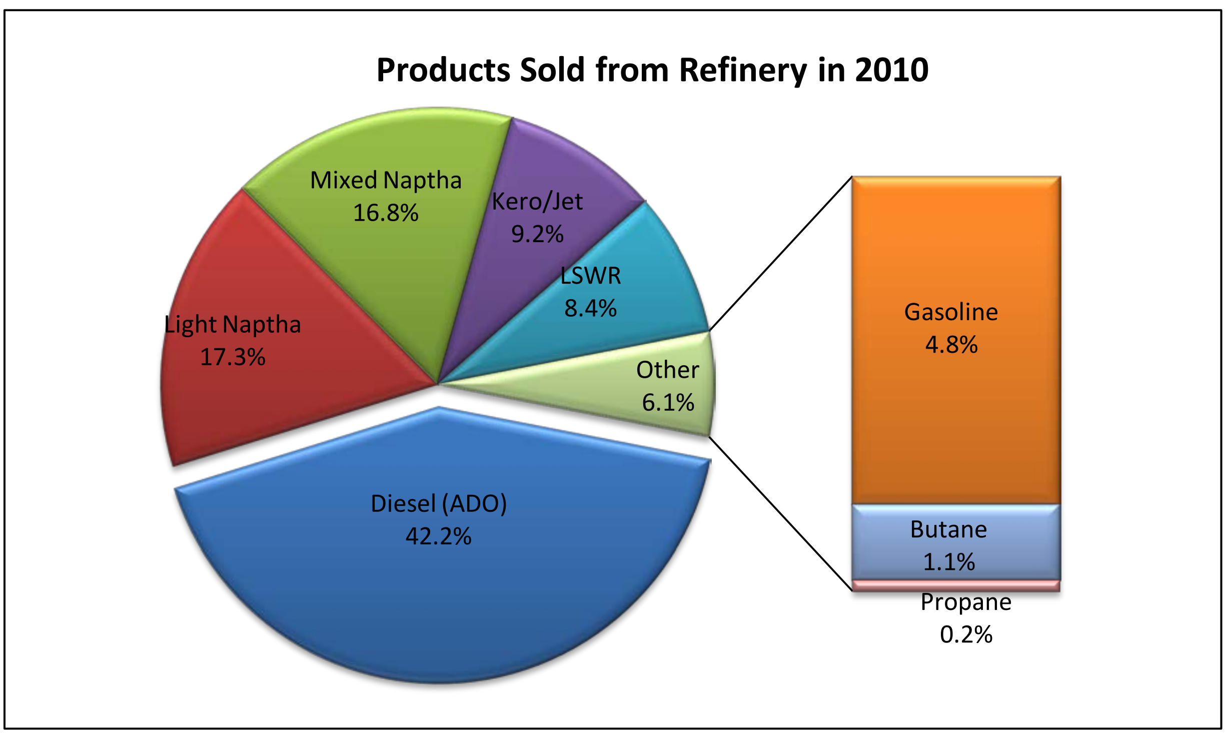


Figure 5.5: Products sold from the refinery in 2010

The consumption of diesel product has increased in the local market as reflected in the high diesel production from Table1 and Figure 3. Within PNG, apart from fuel being sold at InterOil's own fuel outlets, vessels transporting fuel out to other centers are mainly contracted by Shell and Mobil. Ok Tedi Mining Ltd (OTML) uses its own vessels, which come in to load from the jetty. Total product sales for 2010 were 7,681,328 barrels of which 89.2% loaded via vessel at the refinery jetties and 10.8% via road tankers from the refinery gantry.

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.

SECTION 6.0 RESERVES

Commercial production of oil and gas commenced in Papua New Guinea in 1991 after more than 80 years of exploration. Petroleum Resources discovered in Papua New Guinea to date is concentrated along the Papua Basin, a large basin covering approximately 212 000 km^2. Despite a long history of exploration, vast areas remain largely unexplored. Lately large reserves of gas have been discovered along this basin and a Development Licence 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 and Associated gas fields 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 Kutubu, Agogo, Moran, North West 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.

Gas production from these fields are used either as fuel gas, flared or re-injected while gas production from Hides is used for power generation at Porgera Gold Mine.

The summary of Reserves as depleted from the OOIP from the above fields with the respective cumulative productions and the remaining reserves as at 31 December 2010 are shown in **Table 6.0** below. 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 modelings, which are not included here as of the time of this report.

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 2010.

Field (s)	Category	OIIP (MSTBO)	Recovery Factor	Ultimate Recovery (MSTBO)	Cum. Oil Prod. as of Dec 2010 (MSTBO)	Remaining Reserves (MSTBO)
	1P		0.593	313,471	287,503	25,968
Kutubu	2P	529,002	0.602	318,589	287,503	31,087
	3P		0.615	325,164	287,503	37,661
	1P		0.361	45,142	37,541	7,601
Agogo	2P	125,040	0.386	48,305	37,541	10,764
	3P		0.419	52,425	37,541	14,884
	1P		0.446	101,052	66,576	34,476
Moran	2P	226,649	0.483	109,398	66,576	42,822
	3P		0.532	120,636	66,576	54,061
	1P		0.381	30,435	28,005	2,430
Gobe Main	2P	79,979	0.389	31,129	28,005	3,124
	3P		0.398	31,850	28,005	3,845
	1P		0.341	44,185	41,401	2,784
SE Gobe	2P	129,712	0.349	45,244	41,401	3,843
	3P		0.364	47,175	41,401	5,774
	1P		0.086	2,909	2,671	238
SE Mananda	2P	34,000	0.092	3,134	2,671	463
	3P		0.098	3,346	2,671	675

- 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 2010 Reserves Report

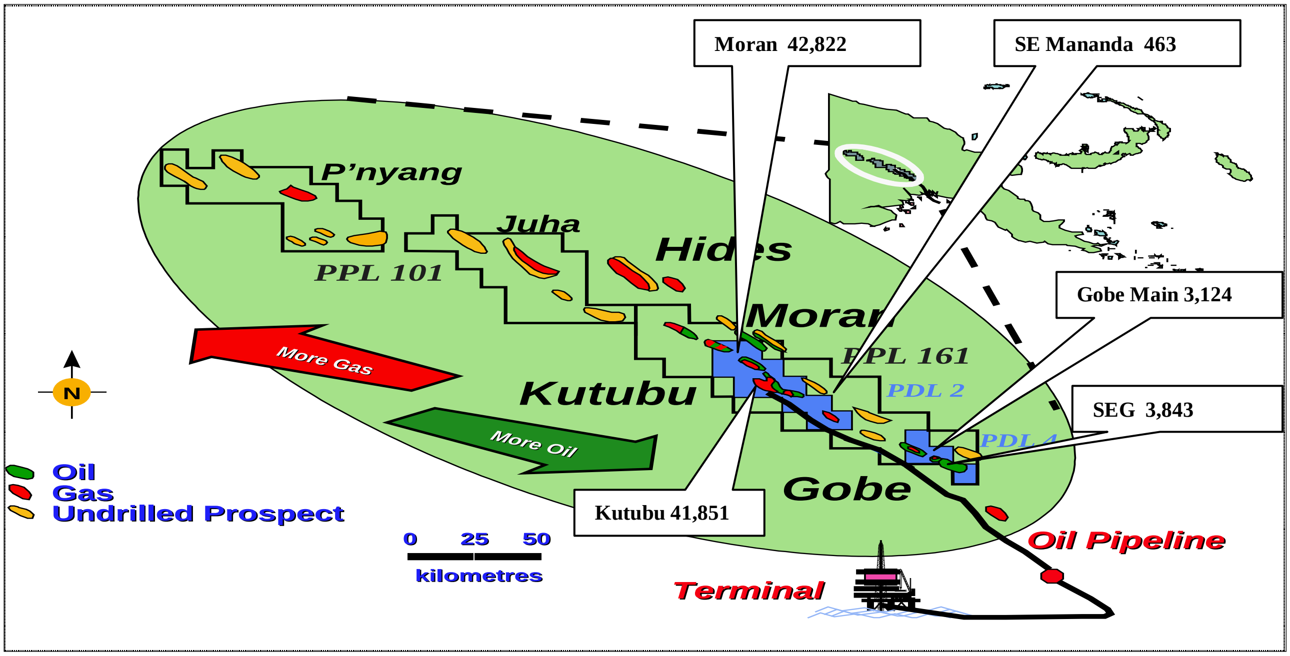


Figure 6.1. – Oil fields with remaining 2P reserves as of 31 December 2010 in Mstb.

6.1. 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 reservoirs' characteristics and to improve reservoirs' performances.

In this reserves report under each section that follows, we have introduced to the reader the identities of all the reservoirs in the seven oil fields and summarized their performance characteristics and the field activities undertaken between July 2008 and June 2009 referred to as 'the reporting period' hereafter.

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

6.2. KUTUBU

Background

The Kutubu field is a mature, developed field that has produced 307 MMBBL of oil since commencing production in the late 1991. Oil production peaked in March 1993 at a rate of over 137 thousand barrels of oil per day (MBOPD). Since 1996 the field production rate has declined as the gas-oil ratios (GOR) have increased.

The 2009 production performance has shown significant growth with gross production rates 19% higher than in 2008. Natural field decline was mitigated through careful well and facilities management. Development Drilling at Usano, which commenced in 2008, continued with UDT 11 and UDT 12 wells brought on stream and producing at or above expectation rates. Five new development wells have now been successfully completed at Usano and production rates from the field have increased from 2000 bopd to over 9000 bopd.

The use of "intelligent" completions in the wells has enabled production to be optimized by allowing the management of gas and water breakthrough using zone changes without the need for wireline intervention. During the year, gas injection was initiated in UDT 3AST1 which is proving pressure support to the new production wells in the Usano Main Block.

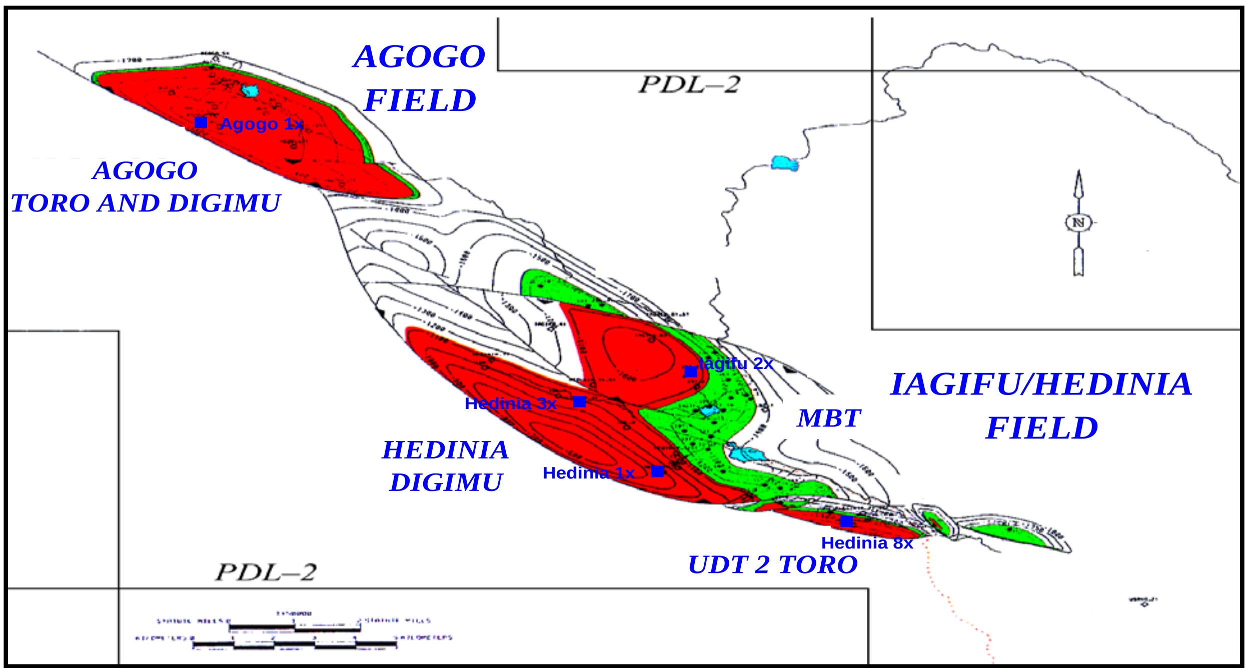
6.2.1 Kutubu Reservoir Performance

Kutubu Field Development can essentially be split according 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 6.11** 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



6.2.2 Main Block Toro (MBT)

The MBT simulation model history match was completed in November 2008. The simulation model was used to try and identify poorly swept, unswept and undrained infill locations. An unswept region in the central southern area along the saddle of the Main Block was identified and subsequently drilled by the IDT24ST1 well. It is the longest horizontal well drilled in PNG to date, with over 800m horizontal section. This well was completed with a 4 zone Intelligent Well System (IWS) selective Toro C completion in the CU, CM1, CM2 and CL zones.

The majority of the Kutubu remaining reserves are associated with the Iagifu Hedinia Main Block Toro (MBT) reservoir, which is a large gas cap reservoir having an OOIP volume of 377 MMBBL representing a recovery factor of 62 percent of the 3P OOIP.

Simulation model continues to be updated supporting justification for workover opportunities and to optimizing water and gas injection. The Hedinia north area is under investigation for potential infill drilling prospects. The summary of the status of the production wells in MBT are shown on **Table 6.1**

Swing wells:		Constant Producers:	
Well	Zone	Well	Zone
IDT 2	Toro CL	IDT 1	Toro CU2
IDT 3	Toro C	IDT 4ST1	Toro C
IDT 5	Toro BL	IDT 6	Toro CL
IDT 12	Toro C	IDT 10	Iagifu C
IDT 15	Toro AL	IDT 11	Toro A
IDT 16	Toro BL	IDT 14	Toro A
IDT 20	Toro CU	IDT 18	Toro A
IDT 22	Toro CL	IDT 21	Toro BL
IHT 1A	Toro BL	IDT 23ST2	Toro CL
IHT 2	Toro BL	IDT 24ST1	Toro CU,CM1,CM2,
IHT 5	Toro C	IHT 4	Toro C

Table 6.2 – Summary of the status of the production wells in MBT

Swing well management is continued to be optimised in order to reduce field gas off-take and improve voidage balance in key areas. This strategy also helped with flaring and made better use of plant capacity.

6.2.3 Iagifu 3X/8X Block Iagifu

IDT 10 is the only well on production from the Iagifu C. Cumulative oil production from the I3X/8X Iagifu as of June 2009 stands at 477 MSTB.

A static pressure gradient survey was performed in IDT 10 in May 2009 indicates that pressure continues to decline in this reservoir.

6.2.4 Hedinia Digimu

Currently two wells, IDD 1 and IDD 5, are constant producers. 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.

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.

6.2.5 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. Cummulative 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.

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 improve the match. Once complete the new model will be used to develop a new history matched simulation model.

Static pressure gradient surveys indicated that field pressures stayed constant from 1999 to 2007 when there was no production from the field, and the field does not appear to receive any gas or water support, but after increasing production off-take from the four new wells, UMBT is experiencing significant recent pressure decline.

6.2.6 Usano East Block

As of the end of June 2009 UMBT has 2 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 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.

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
- 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.

6.2.7 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.

6.2.8 Agogo Digimu

Production from the Digimu reservoir were from ADD 1, ADD 2. ADD 4 well was shut-in in November 2008 with corrosion at the well head and liner top. 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.

6.2.9 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.

During the year the Agogo dynamic model was revised using a new structural interpretation and re-history matched. An initial depletion strategy has been developed by running several cases with further optimisation to be carried out in the future. Further work will be carried out to try and identify additional infill wells locations, workovers, and improve on gas injection strategy and production strategy. The work to date indicates that zonal management will be required moving forward now that additional Toro, Hedinia A and Iagifu zones are accessible through the selective completions.

6.3.0 Moran

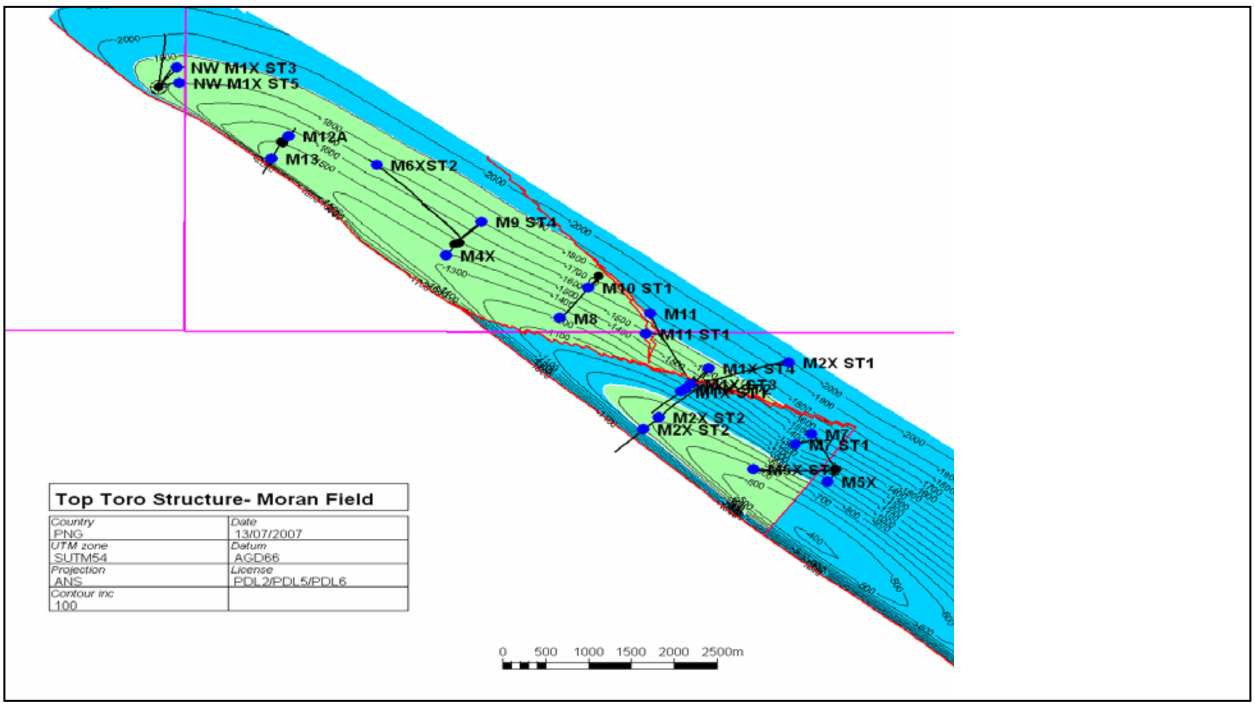
Background

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 6.12 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.

Figure 6.3 – Moran Field Top Toro Structure Map



Production from the Moran field was 20% lower than in 2008, primarily due to curtailment of production in the half of the year due to unplanned facility repairs, a prolonged shut-in of the Moran 6 ST2 well during workover and sidetrack operations, and the decline in underlying base production.

6.3.1 Moran Reservoir Performance

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.

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 Digimu in the J Block, based on early pressure data from M4X well prior to the well commencing production in 2000.

6.4.0 SE Mananda

Background

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.

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.

There are 3 completions in Toro C reservoir of which only SEM 4 was on continuos production during the reporting period whilst SEM1 and SEM5 were shut-in during January and May 2009 respectively.

There is only one well completed in the Digimu reservoir; SEM 3, which was on production during the reporting period. The shut in BHP at the PDHG at 6,536 ft md has been observed to have decreased from 2,561 psia in July 2008 to 2,401 psia in June 2009.

Despite low reservoir pressure, the oil rate continued to hold up, during the year suggesting partial pressure support bleeding in slowly, possibly from a lower sand layer and/or an additional compartment. Gas lift is required to flow this well.

6.5.0 Gobe Main Field (PDL4)

Background

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/southeast 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 km2.

Production for the field commenced in 1998 with the production rate peaked at over 20 MBOPD in September 1999. This year the 1P estimate of ultimate recovery stands at 29.32 MMBBL, while 2P estimate of ultimate recovery is 30.02MMBBL. The reserves are summarized on Table 6.

Compartmentalisation of the reservoir by faulting is evident from pressure data and the variation in fluid contacts. Most fault blocks have original gas caps, with a general increase in the size of the gas cap to the north. The oil column in the Lower Iagifu of the Gobe Main 3 fault block is 58m compared to 95m in the Central and Southern fault blocks.

6.5.1 Gobe Main Reservoir Performance

The field has been evaluated by 23 wells or sidetracks that are separated into 5 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.

During the year, there was continued emphasis on minimizing natural decline from this mature field through the optimization of existing well and surface facility performance. Production rates have generally exceeded expectation due primarily to sustained production from Lower Iagifu production wells GM 1ST2 and GM 5ST3 and Upper Iagifu production well GM 2ST1.

There was no drilling or workovers during the last 12 months in the Gobe Main field but there were several routine and unscheduled well interventions. The activities being:

- An MPLT on G4XST1;
- G6XST2 slickline programmes to clear wax build-up, conduct a flowing gradient survey, and fishing and sand bailing operations.

The MPLT was conducted on G4XST1 to obtain the gas injection flow distribution. In summary the results showed that 85 percent was being injected into the U.Iagifu and 15 percent was being injected into the L.Iagifu. This has been used to update the reservoir model to get a better idea of how the injector is supporting the different zones and blocks.

According to pressure review exercises, Gobe Main bottom-hole pressures show decline since 1994 due to indirect production from the Lower Iagifu wells suggesting a degree of pressure communication between the Lower(B) and Upper(A) Iagifu reservoirs. The pressure data does indicate that there is some connectivity between lower and upper reservoirs as the pressure is lower than the historical values in 1998/99 although the GM5 pressure in 2001 does suggest to declining pressures.

The GM3ST1 and GM7 steep pressure declines are thought to be due to the wells being located in a small reservoir compartments.

In the Lower Iagifu reservoir, Bottom-hole pressure measurements from Lower Iagifu continue to show two distinct pressure regimes.

(1) Wells located within the Gobe Main 3 Fault Block (GM 3ST1) and Gobe Main 2 Fault Block (GM 2ST1, GM 4ST3 and G 4XST1 gas injector) exhibit a common trend in bottom-hole pressures.

(2) Bottom hole pressures from the GM 1 and G 6X Blocks in the south-eastern end of the field, where GM 1ST2, GM 5ST3, and GM 7 Lower Iagifu wells are located, are approximately 150 psi lower.

6.5.2 Gobe 2X Block (PDL 4)

Background

The Gobe 2X Block, located in PDL 4, currently produces from the Lower Hedinia after plugging off the Lower Iagifu in April 2008. It is thought that the Gobe 2X Block has a large gas cap and thin oil column which results in a low oil recovery that is highly dependent on producing criteria such as limiting gas-oil ratios and well head flowing pressures. The Gobe 2X Block structure map is shown in **Figure 6.15.**

The G2XST1 well was shut-in for the first 8 months of the 2009, and eventually brought on line as a swing well in early 2010. It is brought on line when flare and flow line condition allows and it was backing out SE Gobe production due to the high producing pressure and GOR. When the SEG4 and G7X wells were put on permanent swing from late January 2009 this gave an opportunity to re asses G2X impact which was found to be minor when only one of the wells is on line. So since this time G2X has been brought on line when only SEG 4 or G7X is on line on their own. This has successfully added on average about 54 stbpd when on line.

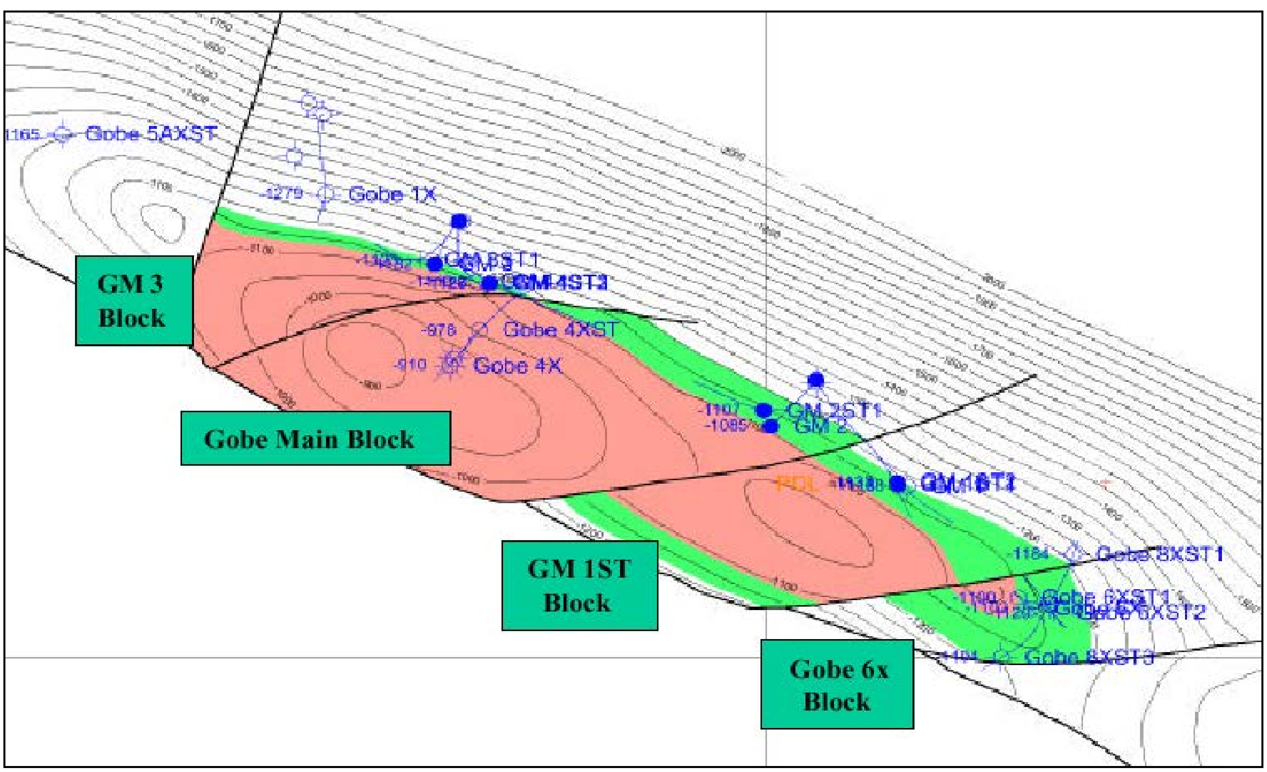


Figure 6.4 – Gobe Main Iagifu Top Structure Map

Production Summary

Total production over the last 12 months averaged 6 stbpd giving a total cumulative production for the period of 2,221 stb resulting in a cumulative volume at the end June of 4,404 STB. The Lower Hedinia contributed approximately 0.7 percent of total GM production during the past year.

6.6.0 SE Gobe Field (PDL 3 and PDL 4 Unit)

Background

Southeast Gobe Field (SEG) is a northwest to southeast anticline that is asymmetric to the south-west with a steep to overturned, highly sheared forelimb. The south-east end of the structure plunges gently toward the south-east as defined by surface geology and topography. The field has a productive closure area of approximately 13 km2. The field was discovered in 1991 and has been evaluated by 23 wells and/or sidetracks.

Field production is from the Upper Iagifu and Lower Iagifu 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 structure is fault bounded to the southeast and dip closed toward the northwest. A series of northeast to southeast trending transverse faults segment the reservoir into separate fault compartments.

Compartmentalization of the reservoir by faulting is evident from pressure data and variation in fluid contacts between fault blocks. Most of the fault blocks have original gas caps, and the northern fault blocks generally have the largest ratio of gas cap volume to oil volume. The oil column in the Gobe 7X Fault Block is 62 metres compared to 115 metres in the Central and SEG 2 Fault Blocks.

6.6.1 SE Gobe Reservoir Performance

Production for the field commenced in April 1998 with the production rate peaked at over 20 MBOPD in March 1999. This year the 1P estimate of ultimate recovery stands at 44.128 MMBBL, while 2P estimate of ultimate recovery is 45.618 MMBBL.

Field data for detail reservoir performance and status of individual wells were not available at the time of this report.

6.7.0 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 is 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 has 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 undertaken by Exxon Mobil. The reserves will feed the Project required rate of 960 MMscf/d at twenty years of plateau production.

Contingent gas resources discovered from current explorations around the country has a total volume of 7.5 TCF OGIP. Further drilling of appraisal wells 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 6.20 and Table 6.21 respectively. **Figure 6.2** shows the boundaries of the reserves from both the Gas Fields and Associated Gas Oil fields.

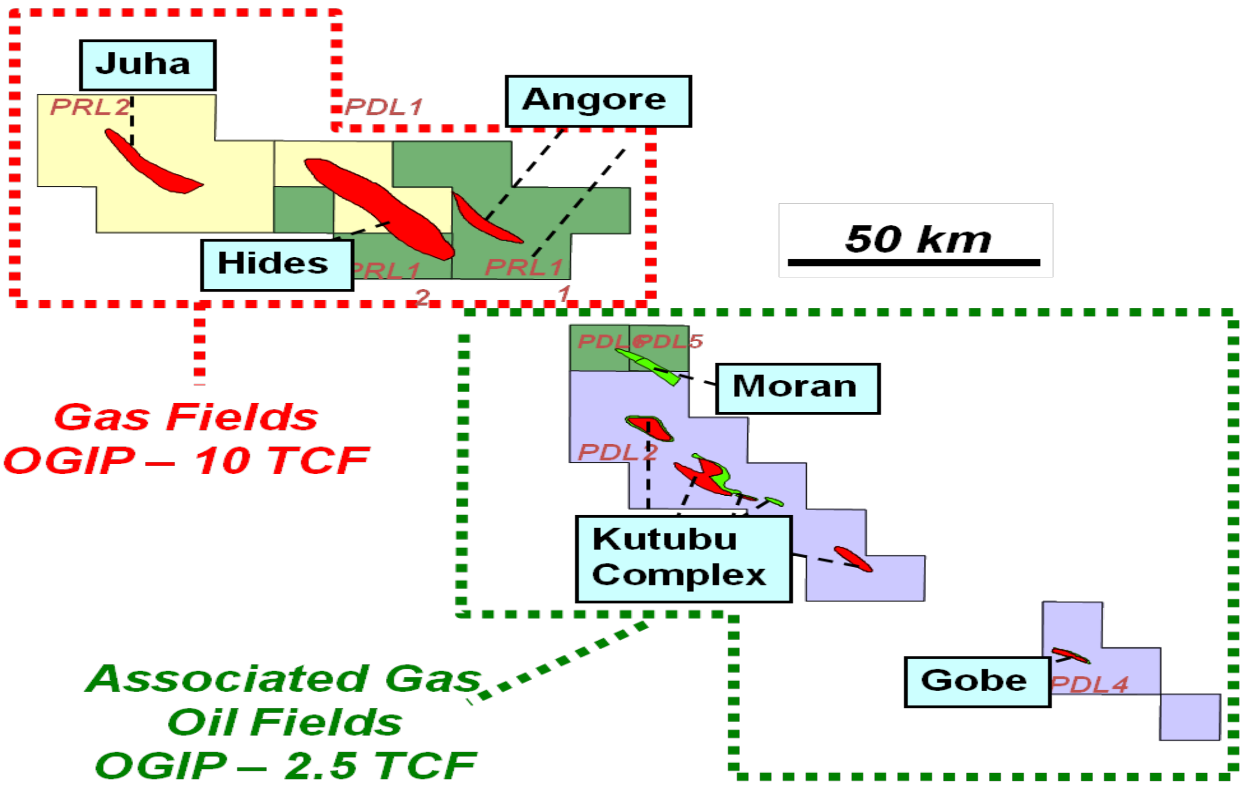


Figure 6.5: Boundaries of reserves from the Gas Field relative to the Associated Gas Fields

Table 6.3 Summary of Associated Gas Reserves in Original In-Place Volumes and Estimated Gas Reserves and Contingent Resources as of 31 December 2010

Original In-Place Volumes						**Gas Reserves and Contingent Resources**				
Field	**Category**	**OCIP** (MSTB)	**Solution OGIP** (BCF)	**Free OGIP** (BCF)	**Total OGIP** (BCF)	**Category**	**RF** (BCF)	**Solution Gas** (BCF)	**Free Gas** (BCF)	**Total Gas** (BCF)
Gobe Main*	**Low**	1,000	51.3	90.9	**142.2**	**1P**	0.68	28.2	68.2	**96.4**
	Best	1,400	68.6	109.5	**178.0**	**2P**	0.74	44.6	87.6	**132.1**
	High	1,700	75.3	116.5	**191.7**	**3P**	0.81	56.5	99.0	**155.4**
SE Gobe	**Low**	1,000	137.0	91.9	**229.0**	**1C**	0.63	75.4	68.9	**144.3**
	Best	1,300	152.1	96.3	**248.4**	**2C**	0.71	98.9	77.0	**175.9**
	High	1,500	167.6	100.6	**268.2**	**3C**	0.79	125.7	85.5	**211.2**
SEMananda	**Low**	-	17.4	17.9	**35.3**	**1C**	0.65	9.6	13.4	**23.0**
	Best	300	20.8	20.3	**41.1**	**2C**	0.72	13.5	16.2	**29.7**

	High	600	27.0	23.2	**50.2**	**3C**	0.79	20.2	19.7	**39.9**
	Low	10,900	424.1	933.8	**1,357.9**	**1P**	0.69	249.9	695.0	**941.9**
Kutubu*	**Best**	15,700	475.7	1,090.6	**1,566.3**	**2P**	0.76	322.1	866.1	**1,188.2**
	High	23,600	551.4	1,360.3	**1,991.7**	**3P**	0.81	407.6	1,149.1	**1,556.7**

■ OCIP = Original Condensate In-Place, ■ OGIP = Original Gas In-Place, ■ RF = Recovery Factor, ■ RFG = Recoverable Free Gas, ■ TRRG = Total Recoverable Raw Gas.

Note: □ Kutubu Totall include that of Agogo, Moran and South East Hedinia

□ The above associated gas reserves figures were extracted from the 2010 Oil Search Ltd Reserves Report

□ * Gas fields that will feed the PNG LNG gas plant.

Table 6.4 PNG Gas Reserves

Field	**Type**	**STOIIP** (MMBO)	**STCIIP** (MMBO)	**GIIP** (BCF)	**Gas Reserves** **1P** (BCF)	**2P** (BCF)	**3P** (BCF)	**Condensate Reserves** **1P** (MMB)	**2P** (MMB)	**3P** (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, STOIIP = Stock Oil Initially In-Place, STCIIP = Stock tank Condensate Initially In-Place, GIIP = Gas Initially In-Place

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 6.20 above.

6.7.1 Hides

Hides Gas Field was discovered with the drilling of Hides 1 in 1987 and appraised with 5 additional reservoir penetrations, all of which intersect gas within sandstones of the Toro and Upper Imburu formations. The topographical elevation at the crest is approximately 2750m above sea level and 1550m above the floor of the Tagari Valley to the northeast. 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 can be estimated.

The reservoir section is comprised of 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 reserves 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 an average yield of 18 stb/mmscf of gas. The primary reservoir intervals are from the Toro and Imburu sands.

6.7.2 Production History

Production from the Hides reservoir was initiated in the Hides 1 well in December 1991, to provide gas to a power plant, generating electricity for the Porgera gold mine. The Hides 2 well was subsequently brought on production in February 1992. Gas supply to the power plant continues to the present day, with gas supply requirements met by alternately producing the Hides 1 and Hides 2 wells.

Cumulative production at the time of the drilling and completion of the Hides 4 in May 1998 was 24.2 bscf. Cumulative production through the end of December 2008 was 74.8 bscf with production continuing to present day.
During this time, pressure monitoring has been undertaken in the two producing wells Hides 1, Hides 2, and the static Hides 4 (Hides 3 after sidetracking, was plugged and abandon). The pressure data is significant from a reservoir assessment point of view, as it demonstrates:

a) lateral communication between Hides 1 and Hides 4 de-risking the chance of field compartmentalization and reducing volumetric uncertainty over a significant portion of the field,
b) vertical communication between Toro A and Toro C as interpreted from initial reservoir pressure data at time of drilling. Current production in Hides 1 and Hides 2 is from the Toro A interval. Hides 4 is completed in the Toro C and experienced drawdown from production from Hides 1 and Hides 2 confirming a single vertical reservoir system of approximately 140 m true vertical thickness (TVT), and
c) that the volumetric results provides information on potential 'tank size' which can be integrated into a deterministic volumetric analysis to estimate gas distribution within the field and allows calculation of the potential hydrocarbon contact elevation.

6.7.3 Basic Reservoir Data - Formation Pressures

There are three primary sources of reservoir pressure data for Hides: initial pressures from open-hole wireline tools acquired during drilling; static gradient surveys acquired on initial completion and subsequent survey campaigns; and, a long-term (14 month) bottomhole pressure survey (pressure interference test) acquired in the Hides 4 postcompletion.

Gas-on-rock has been intersected in all wells with no established field specific aquifer data. Regional aquifer pressure data sourced from formation pressure surveys do however provide some constraint on defining potential field hydrocarbon-water contact. The central area wells (Hides 1, 2, 3 and 3 ST1) lie on a common gas gradient of approximately 2.65 kPa/m (0.384 psi/m), established by both pressure and PVT data and probably share common fluid contacts (Figure 2.1).

Static pressure surveys run in Hides 1 and 2 in 1996 showed both wells were drawn down by a similar amount (average of 164 kPa / 23.8 psi) after an initial 15.7 bscf of production. This confirmed that the wells were communicating not only over geological time but also on a production time scale. Formation pressure survey data from Hides 4 also plot on a gradient of 2.65 kPa/m (0.384 psi/m), but are offset from the virgin (pre-production) line by approximately -141 kPa (-20.5 psi). This offset was interpreted as drawdown in a response to gas production, which at the time of the RFT survey in the well, was approximately 654 Msm3 (23.1 Gscf).

To confirm the interpretation of connectivity with the central region, pressure gauges were set in Hides 4 to monitor drawdown. These gauges were retrieved after approximately a year of field production from Hides 1 and Hides 2.

Results showed a well defined trend of continuous pressure drawdown of approximately 34 kPa (5 psi) (relative to the Hides 4 RFT pressures), demonstrating hydraulic communication over an approximate distance of 12.5 km across the PRL 12 / PDL 1 permit boundary. Additional static bottomhole pressure data were acquired in Hides 4 and Hides 2 in mid-2005. These data confirmed continued drawdown associated with production offtake.

6.7.4 Fluid Contacts

The Hides hydrocarbon-water contact has not been penetrated to date. The downdip Hides 4 well defines LKG at –1509 m TVDSS, proving at least a 1240 m gross gas column. Regional aquifer pressure data from penetrations in nearby wells and possible intake areas of outcropping Toro sandstone in the Lavani Valley define a family of highlands aquifer trends that may apply to the Hides accumulation. These data have been used to estimate potential gross gas column height at Hides. This family of pressure data probably represent regional pressure cells which share a similar uplift history and are isolated from the lower pressure foreland area. Extrapolation of the preproduction Hides gas gradient with current regional highland aquifer gradients provides a range of potential GWC from –1850 m TVDSS to –2150 m TVDSS

6.7.5 Estimates of Hydrocarbons-in-Place

Analysis has been conducted on the total data set, including the use of full field reservoir simulation to assess the potential uncertainties associated with material balance analysis. This evaluation of dynamic performance data has been coupled with volumetric scenarios to establish an assessment of resource range at Hides. This assessment provides an estimated original gas in-place (OGIP) for Hides of 7.8 Tcf, with a range of 6.6 – 8.9 Tcf. These in-place estimates are based on a full field simulation model integrating dynamic and static bottom hole pressure data, and are supported by deterministic analysis from geologic modeling.

6.7.6 Reservoir Engineering

Reservoir Engineering studies have focused on the Hides reserves/resource description and gas deliverability. The approach used in this analysis is to begin with simple tools and analysis and build in complexity and sophistication only as required to appropriately assess uncertainties. The main elements of study associated with the Reserves/Resource description are:

− In-place volumes - integrating the dynamic data from production history with deterministic geologic scenarios

− Recovery Factors - assessing the gas and liquid recoveries achieved under development plan scenarios.

The main elements associated with Hides gas deliverability are:

− Pressure – understanding the impact of pressure depletion on development plans

− Productivity – Assessing reservoir productivity and the implications on the number and size of wells required

6.8. ANGORE

Introduction

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 MMscf/d 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 an estimated GWC at 2560 m TVDSS was used. The estimated closure area for the most likely case is 27 km2.

As part of the PNG LNG Project, the Angore field will be fully developed for production from the gas accumulation in the Toro and Imburu reservoirs. The proximity of Angore to the Hides Gas Conditioning Plant and its low unit development cost make it attractive for early development to supplement total gas capacity as Hides depletes. Development of the Angore Gas Field is planned as part of Phase 2 of the overall PNG LNG Project.

Two new drill wells, a gathering system consisting of a flowline from the Angore A well to the spineline that runs from Angore B to the HGCP and an Angore MEG pipeline will be required. Angore flowlines and wells will be designed to deliver a stream-day rate of 250 MMscf/d of raw gas to the HGCP. Average production rates will be approximately 125 MMscf/d per well.

Initial well capacity for the new wells should be similar to Hides wells at approximately 250 MMscf/d per well. However, initial production rates from Angore will be below total well capacity. This will limit the liquids impact from back-out of the richer Hides gas while providing valuable reservoir information, such as lateral continuity across Angore, the gas volumes in communication with the two development wells, and the potential for additional development should the volume be significantly higher than currently assessed.

6.8.1 Reservoir Architecture

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.

6.8.2 Pressure Data

Angore 1A had three production tests run, one in the Imburu and two in the Toro reservoir intervals. No RFT/MDT formation pressure data was acquired.

6.8.3 Reservoir Modelling

A 3D geological model has been constructed using the preferred Fault Propagation Fold structural model. The model area extends to a depth of 4485 m TVDSS, approximately 2000 m below the LKG (LKG at 2420 m TVDSS from Angore 1A). The model boundary represents the most likely aquifer limit.

6.8.4 Estimates of Hydrocarbons-in-Place

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 is 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.

6.8.5 Reservoir Engineering

Reservoir Engineering studies have focused on the Angore resource and gas deliverability. The approach used in this analysis is to begin with simple tools and analysis and build in complexity and sophistication only as required to appropriately assess uncertainties. The main elements of study associated with the resource description are:

− In-place volumes - integrating reservoir engineering data with deterministic geologic scenarios,

− Recovery Factors - assessing the gas and liquid recoveries achieved under development plan scenarios,

The main elements associated with Angore gas deliverability are:

− Pressure - understanding the impact of pressure depletion on development plans,

− Productivity - Assessing reservoir productivity and the implications on the number and size of wells required.

6.8.6 Production Forecast and Resource Volume

Production profiles associated with the PNG LNG Project were developed using the Gas Deliverability Model (GDM) which integrates production from all source fields in the gas supply network. Production profiles generated by the GDM are driven by the particular market demand outlook adopted for a specified forecast period. As a result, Angore production is a function of both the market demand forecast and the relative volumes of gas coming from other fields within the integrated gas network. The production profile from the simulation model shows that a gas production plateau of 250 MMscf/d can be maintained for approximately 3.5 years.

Angore will be initially produced at a reduced rate of approximately 50 MMscf/d. Pressures measured during this period will provide the means to generate production based estimates of in-place gas volumes in communication with the two development wells. It will also be possible to alternate production from each well and thereby conduct an interference test between the wells. Observation of a pressure response at one well due to production of the other well will confirm reservoir continuity between the wells and simultaneously reduce the uncertainty about the possibility of compartmentalization.

6.8.7 Gas Recovery

Assessments of Angore indicate that high gas recovery factors are achievable. Ultimate recovery factors were assessed using the most likely simulation model and the current development plan as outlined in this report and the PNG LNG Project Project Design Basis (PDB).

Based on a full field compositional simulation, a run has been made for a facility design of 30 years. This assessment provided a gas recovery factor of 76 percent. If the simulation is extended until the wells reach their hydraulic limit, the recovery factor increases to approximately 86 percent.

6.8.8 Reservoir Management Strategy

The key reservoir management objectives for Angore are to maintain reliable gas deliverability and meet sales contracts while optimising liquid recovery. The following data acquisition will provide the information required for these objectives to be met:

− Initial well tests on each new well to confirm deliverability prior to first gas,

− Early interference testing between wells,

− Permanent down-hole pressure and temperature monitoring on all new wells,

− Continuous well-head pressure and temperature monitoring and,

− Metering of produced volumes from each well.

6.9. JUHA

Introduction

The Juha Gas Field is located some 35 km northwest of the Hides gas field. Juha was discovered in 1983 by the exploration well Juha 1X. The Juha surface structure, which was first identified during field work in 1948, is a broad gentle anticline immediately in front of the first major thrust front of the PNG Foldbelt.

he field is delineated by four well penetrations and a grid of 2D seismic lines of different vintage. The Juha structure, with a crest at about 1200 m above sea level, extends in 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.

The Juha resource is part of the PNG LNG project and is planned to go on stream in 2022 (Phase 4). The Juha North gas accumulation drilled by Juha 4X is currently not part of the LNG project. The penetrated part of the Imburu formation (Juha 5X) consisted predominantly of shales and very fine-grained silts. Sandstones were encountered in thin layers insufficient to form reservoir.

The Juha field in will be fully developed as part of the PNG LNG Project. Development of the Juha field is planned as part of Phase 4 of the overall PNG LNG Project, approximately 8 years after first gas production. It will require four new drill wells and “fit for purpose” production facilities and pipelines to separate the gas and liquid streams for transportation to Hides Gas Conditioning Plant (HGCP).

Juha field development timing is based on several factors including, 1) Juha is the most remote field to the LNG Plant and therefore has a relatively high unit development cost, 2) Juha gas capacity is used to back-fill earlier PNG LNG Project field developments to maintain production plateau as total gas capacity declines, and 3) optimisation of capital investment timing adds value to the overall project.

The Juha Production Facility (JPF) will have a design capacity of 250 MMscf/d. Rates from individual wells will be monitored and adjusted during project life to meet the overall reservoir management and economic objectives while maintaining production requirements. Therefore, it is expected that the individual well rates and field rate may vary significantly over the project life. Well production will typically be prioritized based on condensate-gas-ratio (CGR) to maximize liquids for a given amount of gas produced, subject to other reservoir management and facility considerations.

6.9.1 Reservoir Architecture

The Lower Toro reservoir interval is about 100 m thick and has been described based on core and log data from Juha 2X (4 conventional cores), Juha 3X (ST 1, 11 conventional cores) and Juha 5X (2 conventional cores).

6.9.2 Basic Reservoir Data

Formation Pressures

There are two primary sources of reservoir pressure data for Juha: initial pressures from open-hole wireline tools acquired during drilling; and static bottom-hole measurements during Drill Stem Tests (DST). Juha 1X, 2X, and 3X are interpreted to all lie on a common gas gradient of approximately 2.83 kPa/m (0.41 psi/m), established by both pressure and PVT data and probably share common fluid contacts.

6.9.3 Fluid Contacts

The Juha-3X defines LKG at –2442 m TVDSS. The Juha-5X well intersected waterbearing reservoir with residual hydrocarbons. The water gradient derived from Juha-5 RDT data (1.38 psi/m) is consistent with other known aquifer gradients in the PNG Southern Highlands. Extrapolating the Juha 5X pressure data to an intersection with the Juha 1X/2X/3X gas gradient yields a GWC of -2479 m TVDSS.

Juha 3X provided the most consistent reservoir temperature data with an interpreted formation temperature of 118°C (244°F) at approximately 2518 m TVDSS.

Drill stem tests were conducted in Juha-1X, Juha-2X and Juha-3X across the Toro sands. . These tests demonstrate the commercial producibility of the formation at Juha.

6.9.4 Estimates of Hydrocarbons-in-Place

An assessment of the original gas in place (OGIP) in the Juha field was conducted incorporating all available data. A full field 3D Geologic Model was constructed for the Juha field using the most likely structural interpretation, regional reservoir trends, depofacies and lithofacies descriptions from core, and an integrated petrophysical model using both data from logs and core. 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.

6.9.5 Reservoir Engineering

Reservoir Engineering studies have focused on the Juha resource volumes and gas deliverability. The approach used in this analysis is to begin with simple tools and analysis and build in complexity and sophistication only as required to appropriately assess uncertainties. The main elements associated with the resource description are:

− In-place volumes – integrating reservoir engineering data with deterministic geologic scenarios
− Recovery Factors – assessing the gas and liquid recoveries achieved under development plan scenarios
The main elements associated with Juha gas deliverability are:
− Pressure – understanding the impact of pressure depletion on development plans
− Productivity – assessing reservoir productivity and the implications on the number and size of wells required

6.9.6 Simulation Model Results

Cumulative gas production from the reservoir simulation was 0.65 Tcf, resulting in a gas recovery factor of 71 percent. The cumulative condensate production at the HGCP was 24 Mbbl. Note: Additional condensate above the reservoir simulation results will be recovered at the LNG Plant since this process in not modelled in the simulation.

6.9.7 Production Forecast

Production profiles for the PNG LNG Project were generated using the Gas Deliverability Model (GDM) which integrates production forecasts from all fields in the gas supply network. Production profiles generated by the GDM are driven by the particular market demand outlook adopted for a given forecast period. As a result, future Juha production is a function of both the market demand forecast and the relative volumes of other gas coming from other fields within the integrated gas network.

6.9.8 Reservoir Management Strategy

The key reservoir management objectives for Juha are to maintain reliable gas deliverability while optimising liquid recovery. The following data acquisition will provide the information required for these objectives to be met:

- Initial well tests on each new well to confirm deliverability
- Early interference testing between wells
- Permanent down-hole pressure and temperature monitoring on all wells
- Continuous well-head pressure and temperature monitoring on all wells
- Metering of produced volumes from each well.

SECTION 7 PRODUCTION

7.1 2010 Production Summary

In 2010, the average oil production rate was 1,084.32 Mstb with an annual total of 13,011.87 Mstb which was a 7% increase from 2009. Gas production from oil fields, decreased by 2% with the total of 131.91 BCF at a rate of 361.40 MMSCFD. In Hides, (non-associated gas field) the Sales Gas to PJV remained somewhat steady with a total of 5.52 BCF at a rate of 14.34 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 modeling 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 7.1 summarized the trend of oil and gas production in 2010. A detailed summary of the monthly oil and gas production from respective fields is shown in Table 7.2 while Table 7.1 shows comparative overall production rates of oil, gas and condensate from respective fields in PNG for 2009 and 2010.

During the year, annual plant maintenances were undertaken and processing facilities were shut down for several days to undergo general maintenance. Such shut downs are essential to production, as the fields are mature and the facilities have been over 20 years in service.

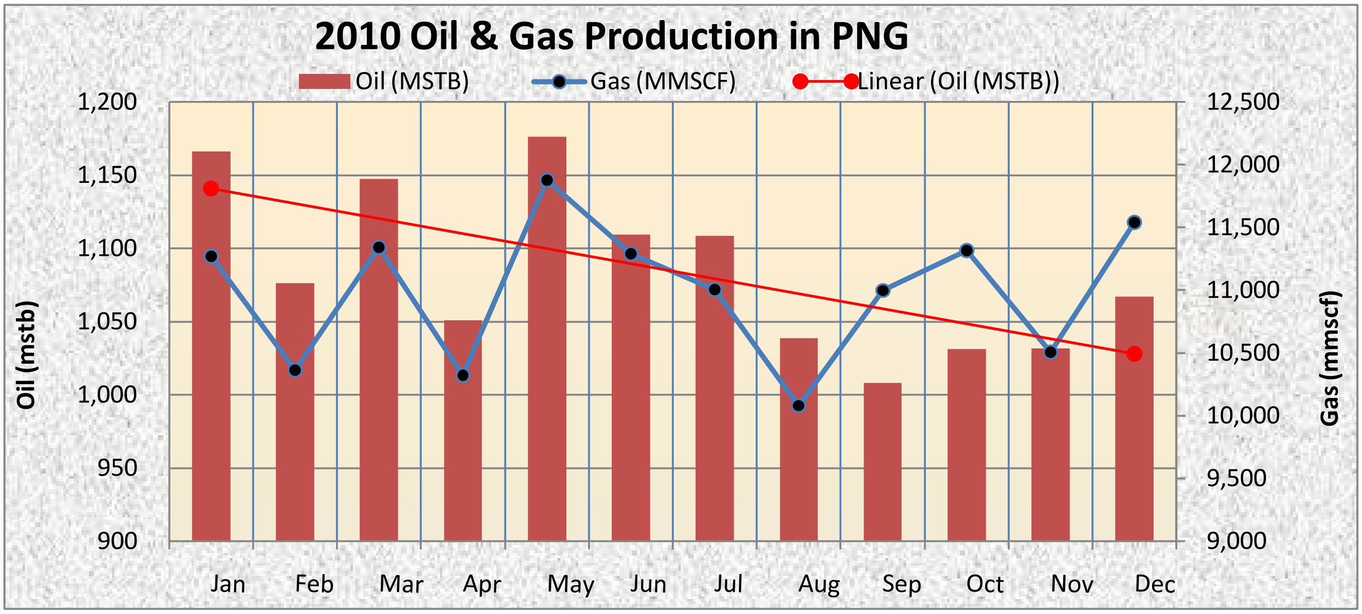


Figure 7.1: Graph illustrating Oil & Gas Production in PNG.

Table 7.2: Daily Production Rates Summary for the Year2010

	2009	2010	% Difference
	Gross Daily Production (BOEPD)	Gross Daily Production (BOEPD)	Gross Daily Production
Oil Production			
Kutubu	17,305	16,364	-5%
Moran Unit (PDL 2,5,6	14,061	14,548	3%
SE Mananda	800	383	-52%
Gobe			
Gobe Main	1,665	1,607	-3%
SE Gobe	4,370	2,725	-38%
Total Gobe	6,035	4,332	-28%
Total PNG Oil			
Liquid Production Hides			
Condensate Production	370	490	33%
Naptha Production	180	239	32%
Diesel Production	67	72	8%
Residue Production	18	20	12%
Gas Production			
Hides Gas in bbls	15	19	29%
Hides Gas in MMscf	15	20	30%

Table 7.1: Oil & Gas Production Summary for 2010

2010 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	Daily Oil Rates Per Month	Monthly Gas Production	Daily Gas Rates Per Month
Jan-10	546,914	6,476,040	50,068	960,480	75,277	1,294,169	481,563	2,437,837	12,580	101,227	1,166,402	37,626	11,269,753	363,540
FEB	470,613	5,436,548	51,258	951,958	89,160	1,714,000	452,229	2,177,019	13,090	84,030	1,076,350	38,441	10,363,555	370,127
MAR	528,996	6,309,906	54,604	1,082,374	86,045	1,721,145	462,437	2,123,236	15,270	103,312	1,147,352	37,011	11,339,973	365,806
APR	494,619	5,748,053	53,351	957,155	83,491	1,702,258	401,066	1,831,792	10,570	83,603	1,043,097	34,770	10,322,861	344,095
MAY	541,457	6,667,229	61,516	1,035,134	92,940	1,848,886	466,841	2,182,589	13,270	143,484	1,176,024	37,936	11,877,322	383,139
JUN	488,911	6,447,831	53,816	971,586	85,916	1,792,948	468,205	1,923,468	12,500	155,090	1,109,348	36,978	11,290,923	376,364
JUL	496,122	5,850,081	53,697	981,926	89,460	1,998,095	459,751	2,055,362	9,480	119,756	1,108,510	35,758	11,005,220	355,007
AUG	499,520	5,839,100	37,740	746,720	67,240	1,506,780	426,570	1,898,000	7,670	89,100	1,038,740	33,508	10,079,700	325,152
SEP	477,410	5,855,820	42,010	1,028,650	59,140	1,959,040	418,810	2,029,000	10,810	124,800	1,008,180	33,606	10,997,310	366,577
OCT	498,270	6,287,360	45,620	937,500	88,660	1,875,570	386,440	2,049,440	12,170	167,810	1,031,160	33,263	11,317,680	365,086
NOV	453,100	5,363,510	42,030	935,480	88,000	1,820,500	437,690	2,236,300	10,760	151,240	1,031,580	34,386	10,507,030	350,234
DEC	477,000	6,456,710	40,700	976,810	89,340	1,888,880	448,440	2,097,820	11,650	120,310	1,067,130	34,424	11,540,530	372,275
TOTAL	**5,972,932**	**72,738,188**	**586,410**	**11,565,773**	**994,669**	**21,122,271**	**5,310,042**	**25,041,863**	**139,820**	**1,443,762**	**13,003,873**	**427,708**	**131,911,857**	**4,337,404**
Daily Ave	16,364	199,283	1,607	31,687	2,725	57,869	14,548	68,608	383	3,956	35,627	1,172	361,402	11,883
Weekly Ave	114,864	1,398,811	11,277	222,419	19,128	406,198	102,116	481,574	2,689	27,765	250,074	8,225	2,536,766	83,412
Monthly Ave	497,744	6,061,516	48,868	963,814	82,889	1,760,189	442,504	2,086,822	11,652	120,314	1,083,656	35,642	10,992,655	361,450

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

7.2 Shipment of Crude Oil

A total of 12.84 MSTBO was exported both offshore and within PNG collectively which was a decrease of 7% of that exported in 2009. 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 7.2 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.

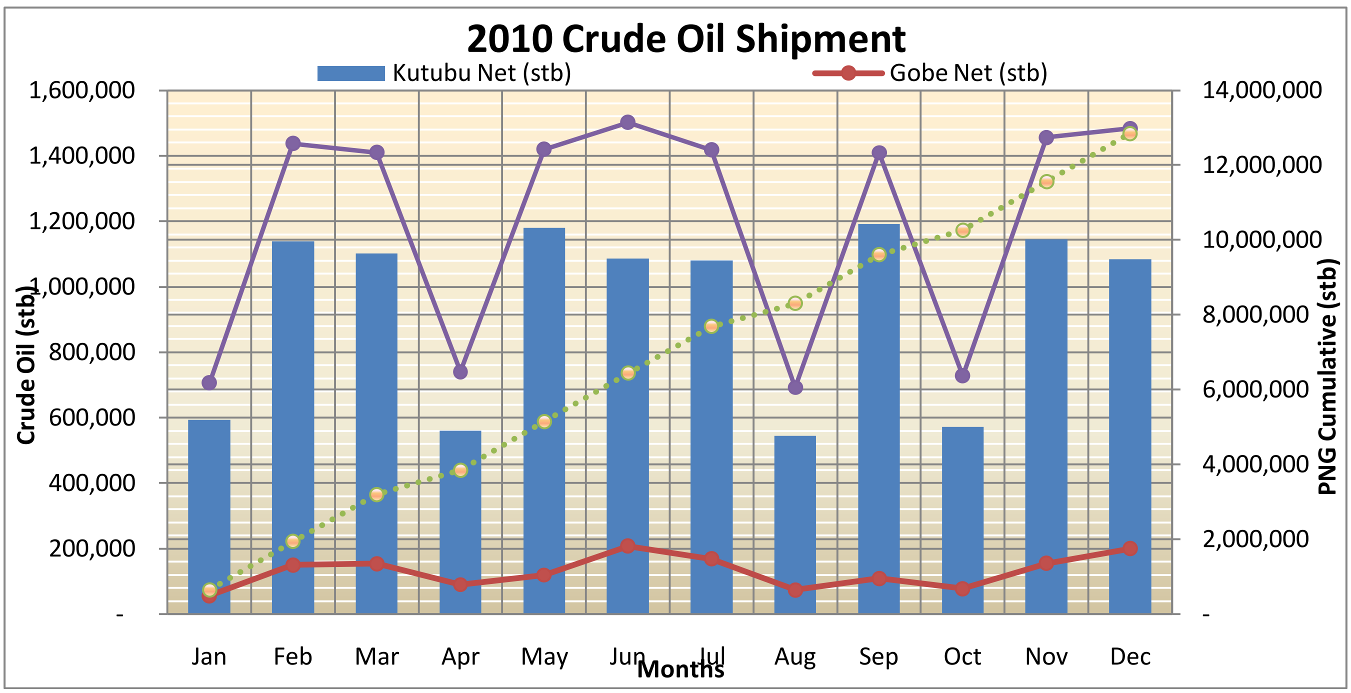


Figure 7.2: Crude Oil Exports for 2010

7.3 Hides (PDL 1)

Production was slightly lower in both gas and liquids at Hides throughout the year compared to 2009. A total of 5,347,630 mscf of gas was produced from this field, which was 3% lower than 2009 gas production. From this total production, 5,232,730 mscf were sales gas to PJV. The year saw a daily average gas production of 14,650 mscfd. The overall gas production figures for the year are illustrated in Figures 7.3.

Condensate production was 1% lower than 2009 production with a total of 133,743.42 bbls that yielded 65,195.43 bbls of Naphtha, 19,538.65 bbls of Diesel and 5,449.08 bbls of residue. According to the production reports, condensate production averaged at 366.42 bbl per day for the year.

The overall liquid production figures are illustrated in Figures 7.11 and Table 7.3.

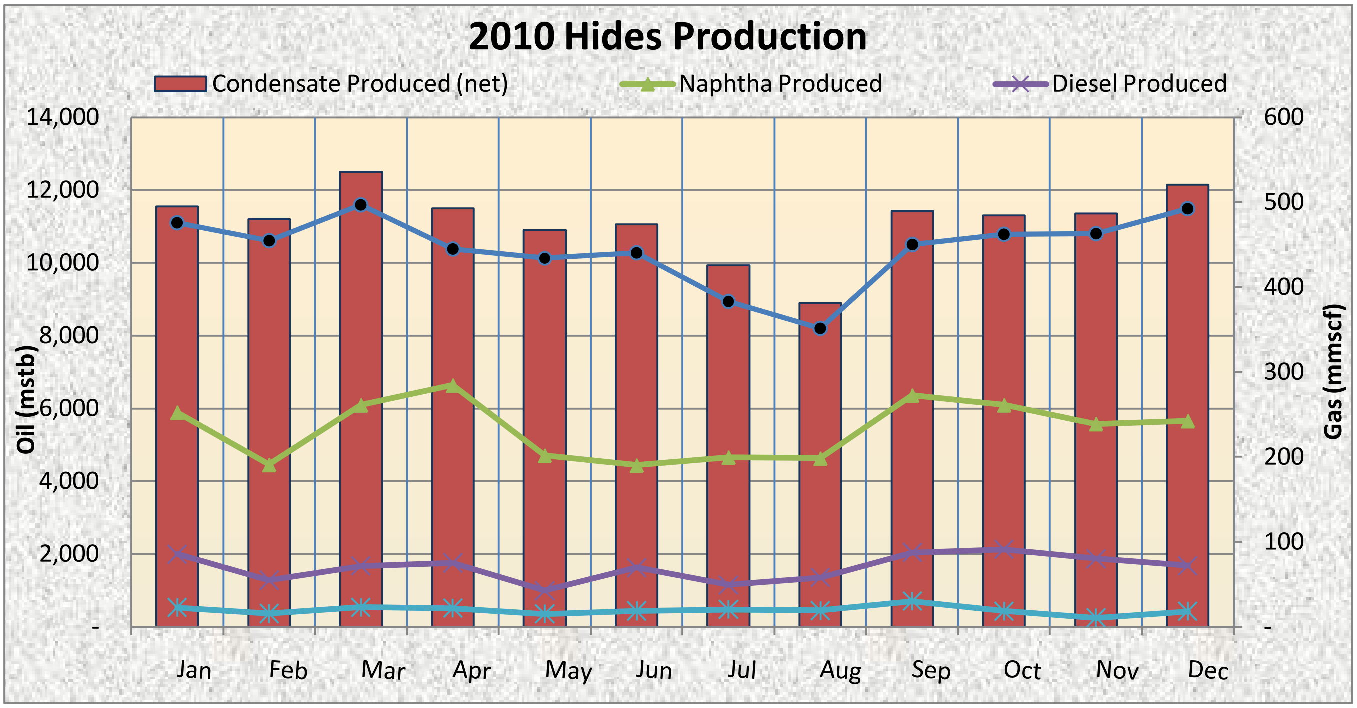


Figure 7.3: 2010 Hides Gas & Liquid Production.

Kutubu Fields (PDL 2)

Kutubu production performance was slightly lower with gross production rates 5.4% lower than in 2009. Kutubu produced a total of 5,972,930 bbls in 2010 at an average daily rate of 16,360 bopd. Gas production was 72,738,190 Mscf at a daily average of 199,280 Mscf, a 3% increase from 2009 production.

The natural field decline was mitigated through careful well and facilities management by OSL. High production on several wells early in the year added significantly to the field production. Towards the back end of the year, oil production in Kutubu declined, shown in the graph on **Figure 7.6**. The slight decline in production towards the second half of the year was due to an increase in well down time associated with flare management. In general production performance in Kutubu was good for the year.

Gobe Fields (PDL 3 & 4)

During the year, there was continued emphasis on minimizing 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.

Gobe Main produced 586,410 bbls at a rate of 1,610 bopd and the total gas produced was 11,565,780 mscf of gas at a rate of 31,690 mscfd. The month that attributed to significant production drop was August where due to the total planned field and plant shutdown, hydrate issues, 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 7.7 sums up the overall oil and gas production from the Gobe Main field.

SE Gobe produced a total of 994,660 bbls of oil at a rate of 2,730 bopd, which is a 38% decrease from 2009. The total gas produced was 21,122,270 mscf at a rate of 57,870 mscfd. The significant months that contributed to low production are August and September where various operational problems occurred. The drop in production in the South East Gobe (SEG) field was mainly due to SEG 4 remained off line for the 2 months waiting on availability of slickline to recover slickline tools stuck in the hole. Also SEG GST 1 remained shut in for 16 days for chemical treatment to remove wellbore restrictions. Furthermore, obstructions in production tubing such as sand, wireline works and line restrictions on wells and compressor shutdowns that affected wells that was dependent on gaslift.

South East Mananda (PDL 2 & PDL 6)

The South East Mananda (SEM) field production was 52% lower than in 2009 oil production, SEM produced a total of 139,830 bbls of oil with an average daily rate of 380 bopd. Total gas produced from the South East Mananda field was 1,443,760 mscf with an average daily rate of 3,960 mscfd. Gas production in SEM was 18% lower than 2009 production. Oil production in the South East Mananda averaged 380stb/d during the year, a 52% decrease from last year which was due to down time associated with each well during the year.

Although production decline in most wells was consistent with expectations, the SEM 5 well was offline for the majority of August due to a leaking grease nipple on the intermediate casing valve. Also the SEM 4 well suffered from a significant downtime during August as a result of high flowing tubing head pressure and a damaged production choke. Other problems that contributed to downtime in most wells throughout the year were associate with restrictions down hole and at the surface due to hydrates and wax, high flow line pressures, and reduced gas lift volumes.

Moran Unit (PDL 2, 5 & 6)

Total Oil production from the Moran Unit was 4% higher than in 2009, a total production of 448,440 bbls at daily average of 14,570 bopd. Gas production was 9% lower than 2009 production. A total of 25,041,870 mscf was produced for the year 2010 at a daily average of 68,610 mscfpd.

Production throughout the year was generally good compared to the previous year (2009). Although production was good, notable downtime where seen in the months of April and October due to planned APF shut-in, NWM1 well being shut-in for slickline work, planned HP compressor service impacting gas lift supply to wells and an emergency shut down at the APF in the respective months. However, ongoing technical studies at Moran are focused on identifying additional infill and near field appraisal well locations with well and facility optimization projects.

Production History and Forecast

Figure 4.11 shows the decline in oil production as forecasted for the year 2010. 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 0.463 MMBBL.

In Figure 4.12, the graph show clearly how gas production has increased since production commenced over 18 years ago and has accumulated a total of 1.965 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.

Table 7.3 below 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 4.11 and 4.12. In figure 4.11, 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.

Table 7.3: Yearly Oil and Gas Production since 1991.

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 Forecast (BBL)		Gas (Mscf)	Cumulative Gas (Mscf)
													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	1,594,954	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
2010	5,972,932	72,738,188	586,410	11,565,773	994,669	21,122,271	5,310,042	25,041,863	139,820	1,443,762	13,003,873	462,831,717	35,627	13,003,873	131,911,857	1,964,679,507
Total	324,630,587	1,323,324,132	27,266,939	156,202,749	39,206,347	249,842,247	66,378,274	220,092,146	2,647,687	15,218,233	462,831,717				1,964,679,507	

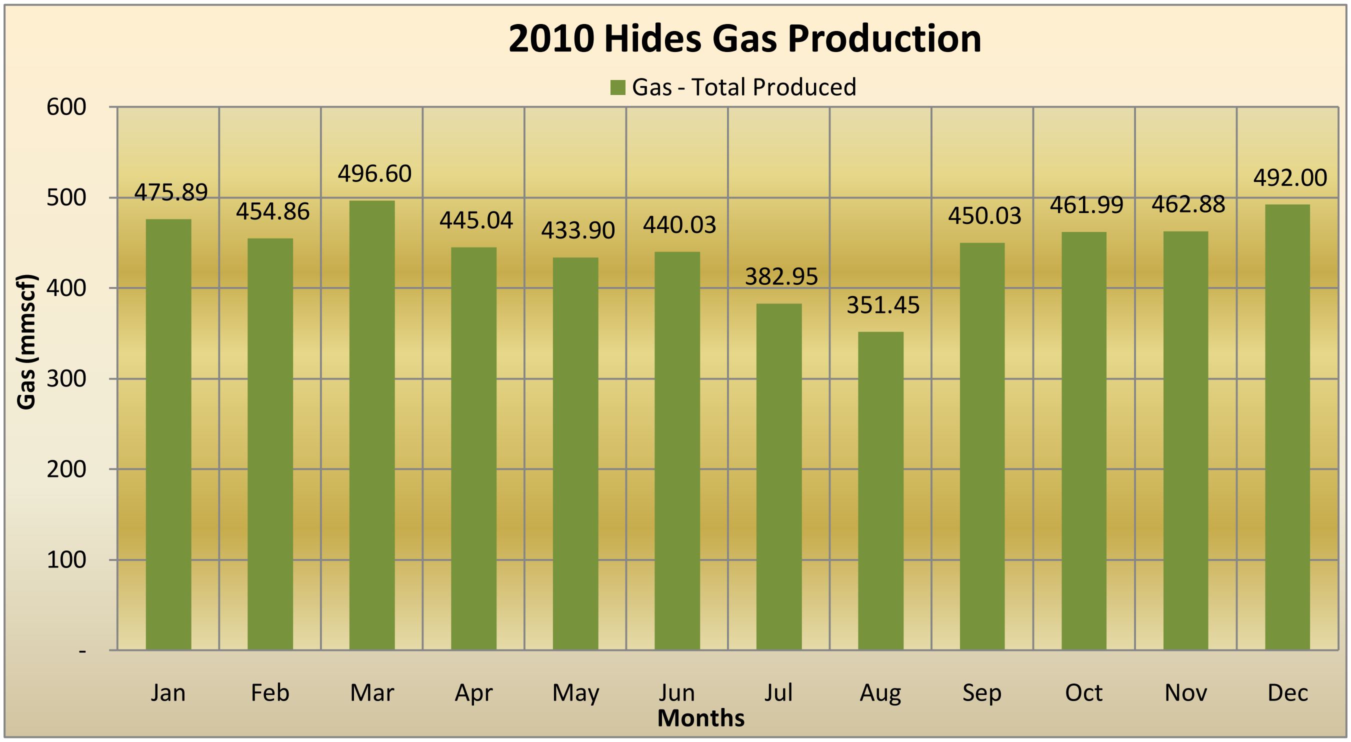


Figure 7.4: Hides Gas Production for 2010.

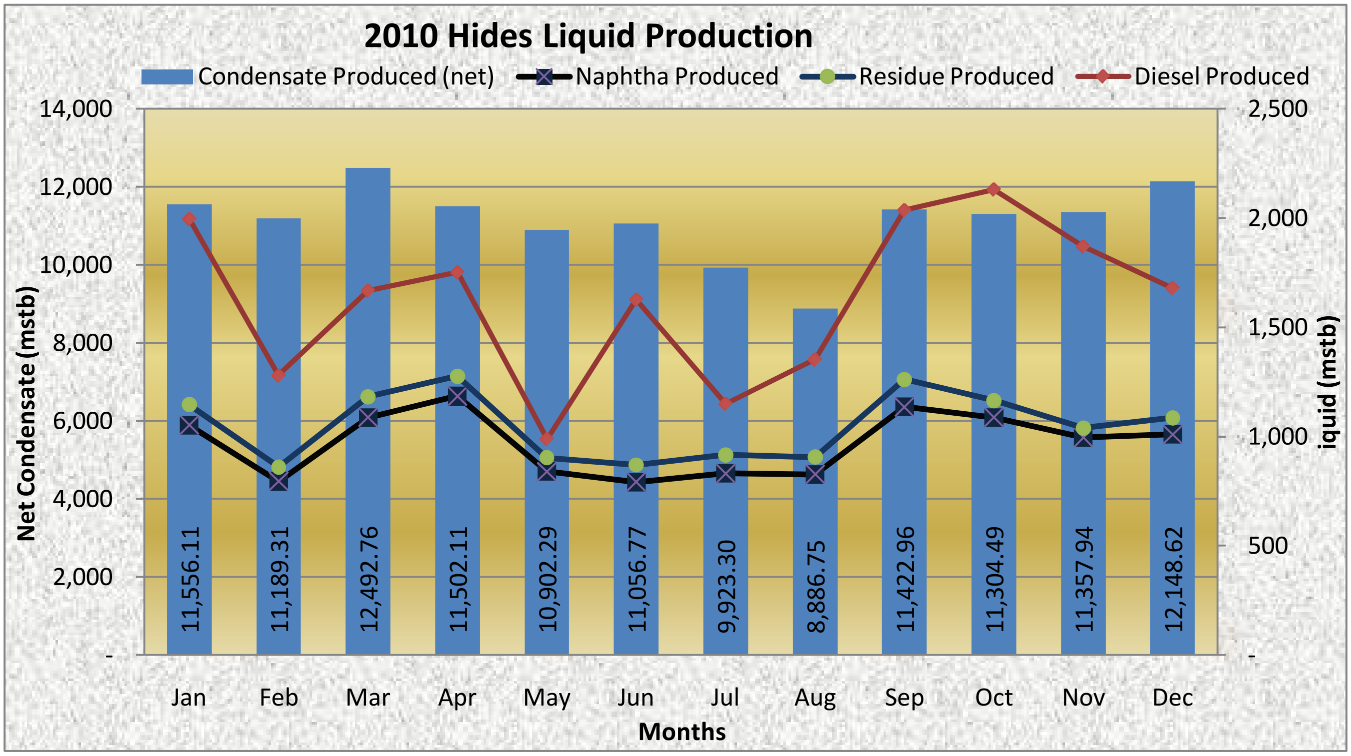


Figure 7.5: Hides Liquid Production for 2010.

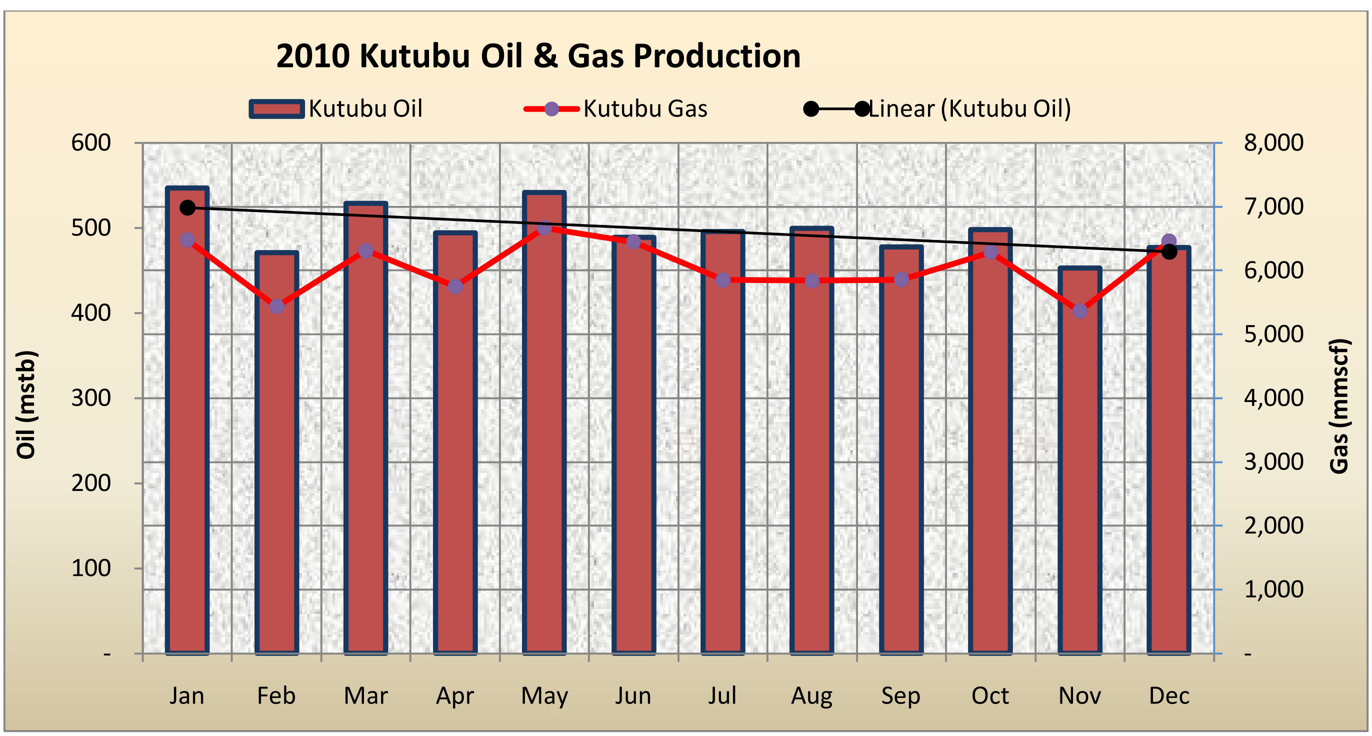


Figure 7.6: Kutubu Oil & Gas Production (2010).

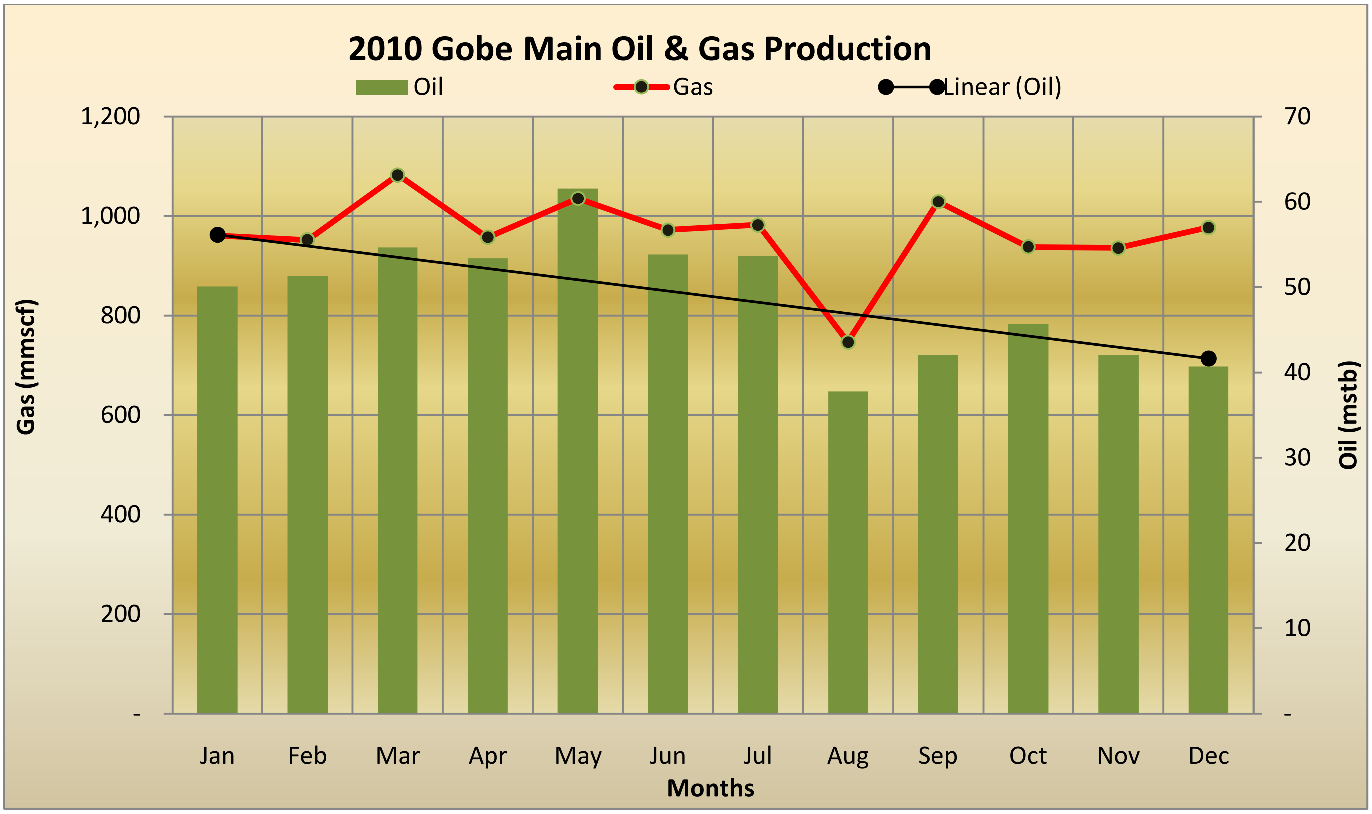


Figure 7.7: 2010 Gobe Main Oil & Gas Production.

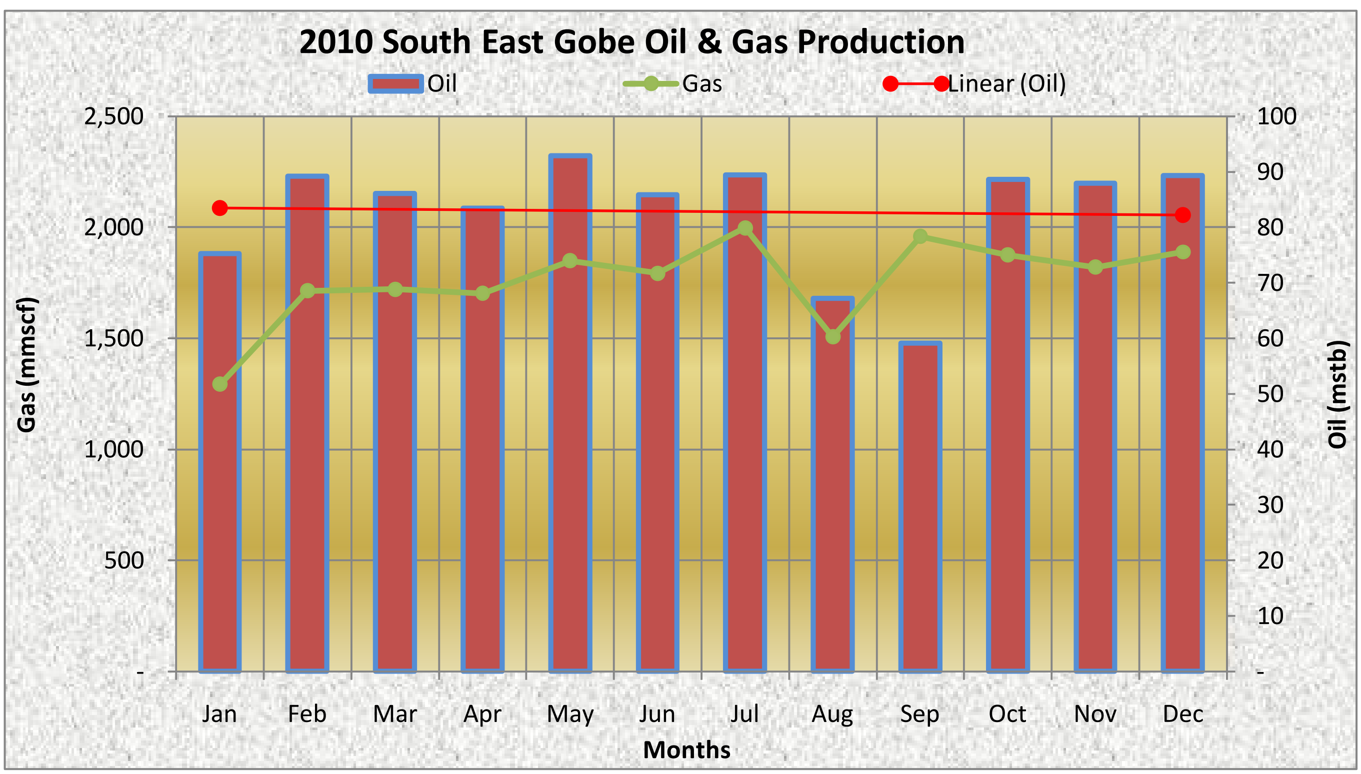


Figure 7.8: 2010 SE Gobe Oil & Gas Production.

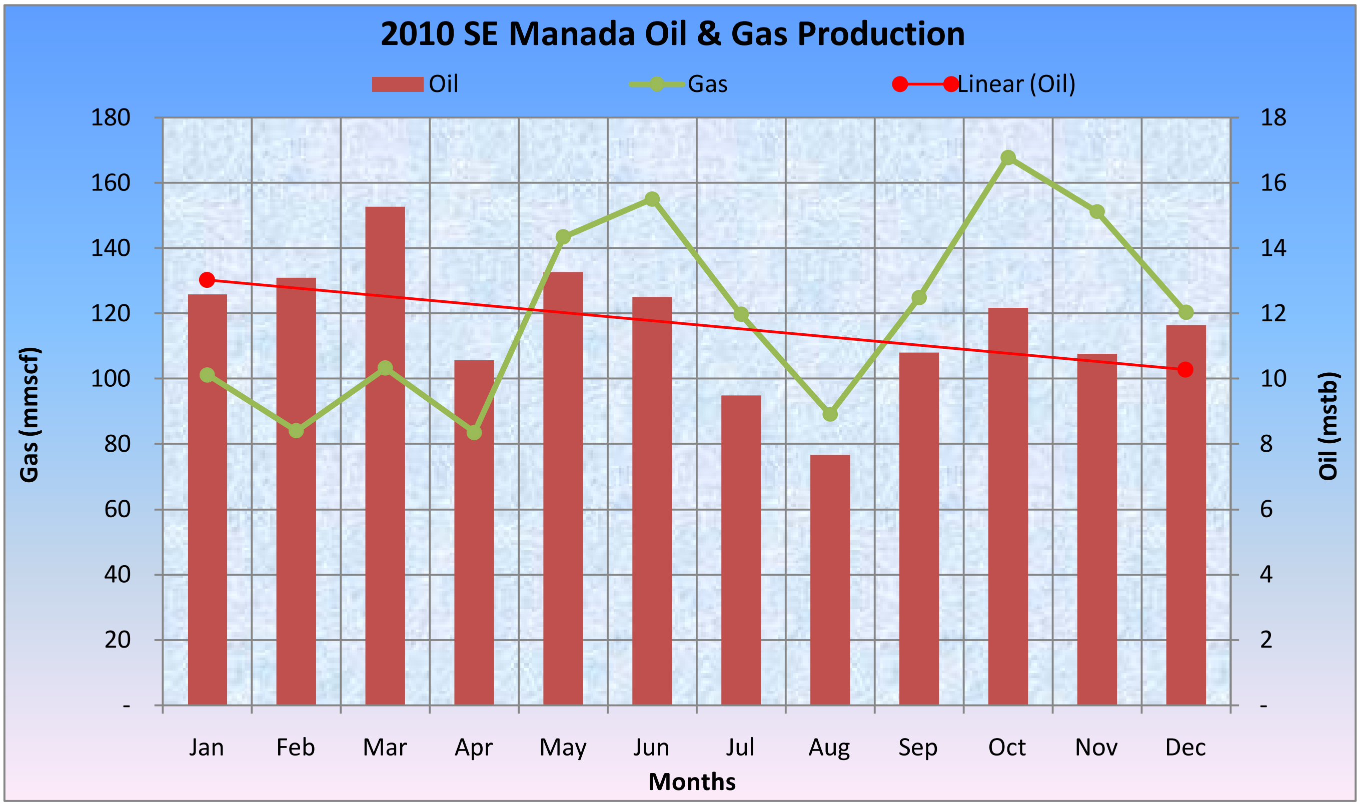


Figure 7.9: 2010 SEM Oil Productions.

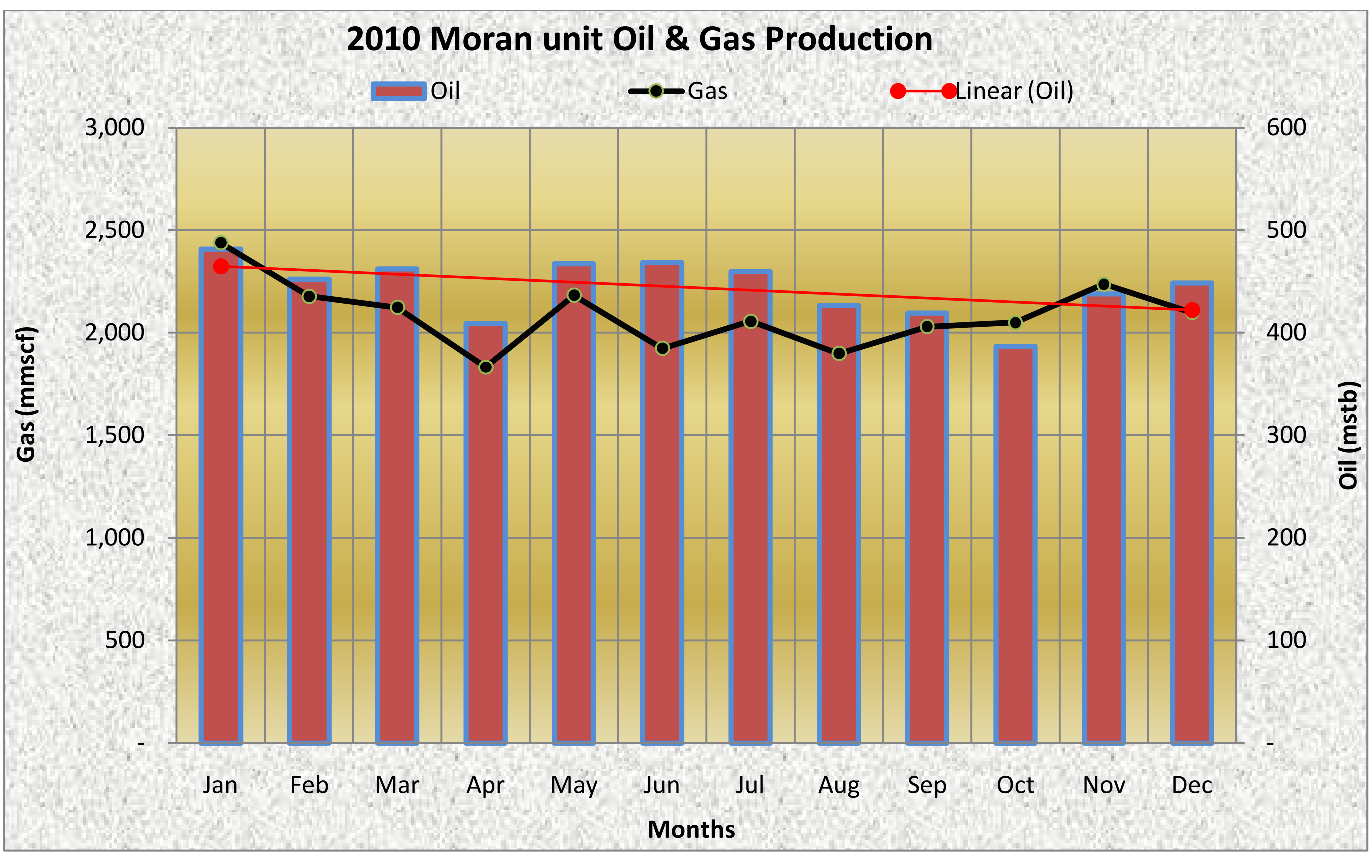


Figure 7.10: 2010 Moran Unit Oil & Gas Production.

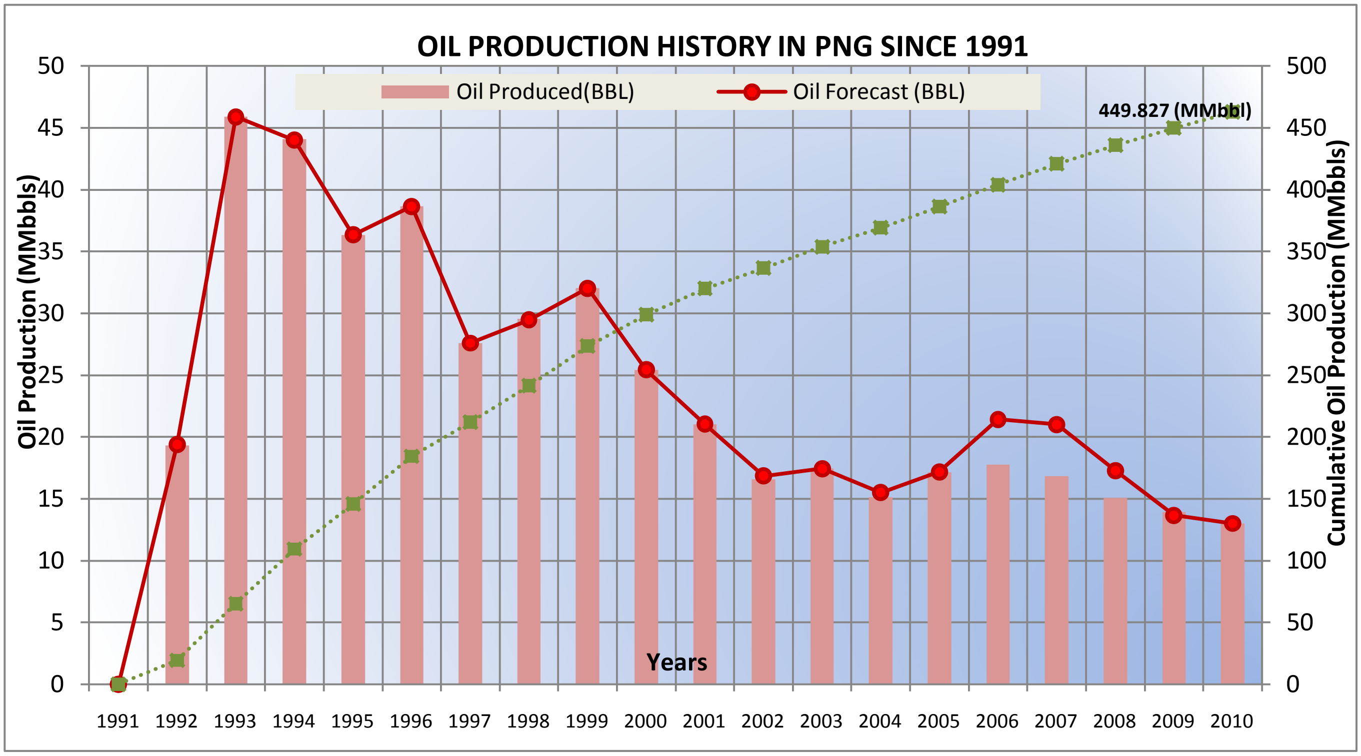


Figure 7.11: Oil Production History in PNG since 1991.

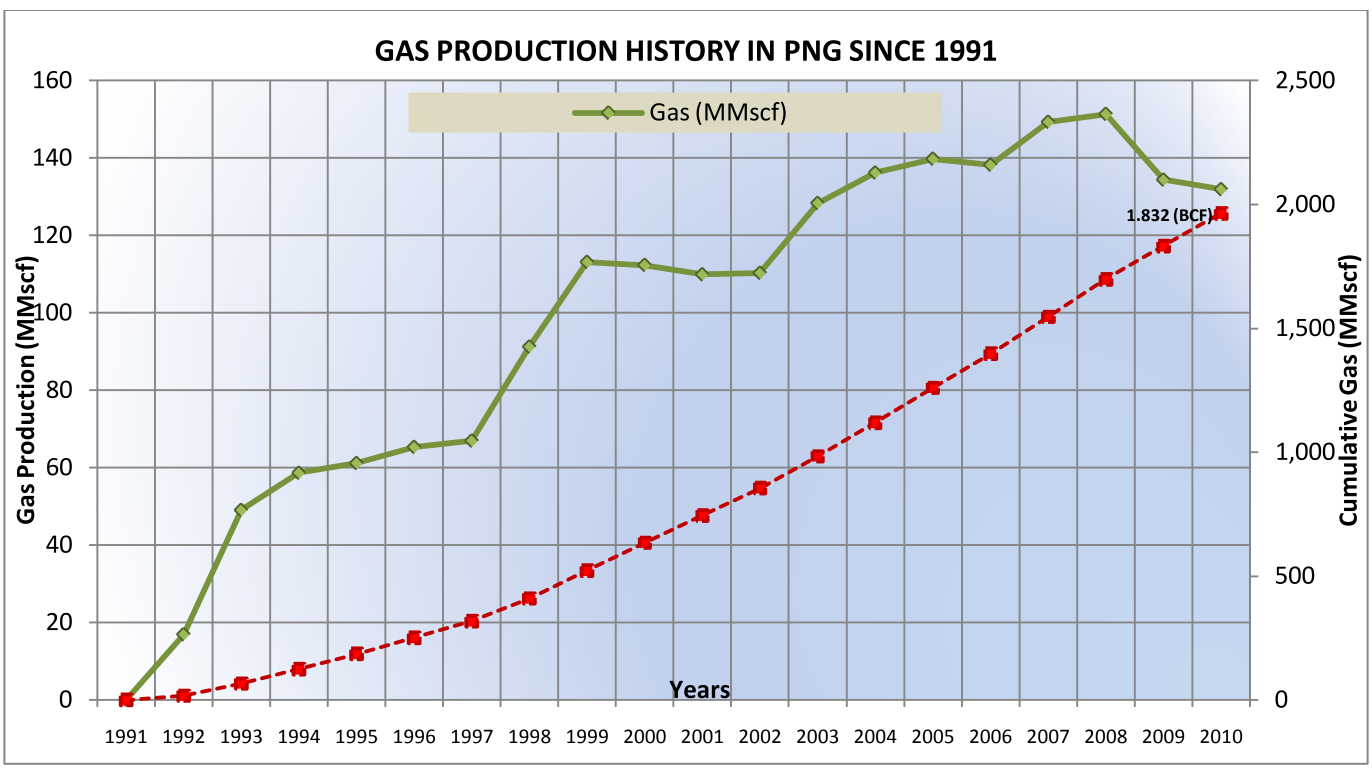


Figure 7.12: Gas Production & Distribution History in PNG since 1991.

Section 8.0 Associated Gas Related Project

PROJECT OVERVIEW

The Associated Gas Related Project (AGRP) is part of the phase in the PNG LNG project that involves the modification of existing oil field facilities at Central Processing Facilities (CPF) in Kutubu, Agogo Processing Facilities (APF) and Gobe Processing Facilities (GPF) in Gobe. These processing plants are being modified to gather associated gas produced from the existing wells and then to export as feed gas to the LNG plant.There will be spur lines connecting the CPF, GPF and APF to the gas pipeline. The dew pointed HGCP gas will be blended with the richer associated gas to provide on specification feed gas to the LNG Plant.

The PNG LNG project is expected to come on-stream by 2014 and the AGRP is to supply 23% of the total gas (960 mscfd) as feed gas whilst the 77% of the gas will come from Hides Gas Processing Facility (HGPF).

However, the oil field is ultimately at its decline and with no new major oil field discovery in the last 20 years. Therefore the LNG from the AGRP is an essential part of the project phases to support the PNG LNG project and the country’s economy.

The following subsections will provide an overview of the AGRP as part of the PNG LNG development phases, and the subsequent development of the oil field facilities.

8.1 PNG LNG Project Phasing

The project in itself engages in the modification of the CPF and GPF in phase-1 of the development to produce liquefied natural gas (LNG), while APF’s modification is in phase-5 of the whole project development phase. Hence, the AGRP is expected to commercialize LNG from the following Petroleum Development Licence (PDL) areas; PDL 1, PDL 2, PDL 3, PDL4, PDL 5 and PDL 6. Table 7.1 presents the implementation timing for various phases of project development

Table 8.1 Project Development Phasing.

Facilities	Development Timing	Project Year Timing
Hides gas field and HGCP	Phase 1	Year 1 / 2
Associated gas from CPF	Phase 1	Year 1 / 2
Associated gas from GPF	Phase 1	Year 1 / 2
Hides gas from well pads F and B	Phase 2	Year 5
Angore gas from well pads A and B	Phase 2	Year 5
HGCP booster compression	Phase 3	Year 6
Juha gas field and production facility	Phase 4	Year 10
Associated gas from APF	Phase 5	Year 12
SE Hedinia field development	Phase 6	Year 23

Phase 1

The first phase development will include the Hides field development, HGCP and the LNG Project Gas Pipeline that will deliver gas to the LNG plant. Upgrades to facilities at the CPF and GPF will also be implemented during this phase to deliver dew pointed associated gas to the LNG Project Gas Pipeline.

Included in this phase are developments at the CPF to install commissioning gas facilities to supply commissioning gas for the commissioning of the PNG LNG Project. The CPF's crude storage and export pump facilities will also be modified to receive, store and export HGCP condensate with CPF crude via the oil export system.

Phase 2

The second phase will see to further development of the Hides field and the connection of new wells to the existing Hides spine line. Phase 2 will also include development of the Angore field with new wells connected to the HGCP via the Angore spine line.

Phase 3

The third phase will engage in the provision of additional booster compression at HGCP upstream of the gas dew point control units to account for reservoir pressure depletion.

Phase 4

This phase is the development of the Juha field, including flow lines, spine lines, Juha Production Facility (JPF) and pipelines between the HGCP and Juha established for construction and operations.

Phase 5

This phase is expected several years later after the first LNG production and will be to upgrade the APF to produce dew pointed associated gas and interface/tie-in facilities to deliver this gas to the LNG Gas Project Pipeline.

Phase 6

Finally the last phase will involve the development of the South Hedinia (SE) field including the construction of a pipeline approximately 30km long from the field to CPF.

8.2 Modifications to Oil Field Facilities

The existing oil field facilities, which include the CPF, GPF, APF and KMT are currently operated by oil search Limited (OSL). The modification of the oil field facilities in their support to the PNG LNG Project is divided into three separate fundamental projects;

- The Associated Gas Project.
- The Condensate Handling Project.
- The Commissioning Gas Project.

8.3 Associated Gas Project

The project covers various upgrades of the existing oil production facilities such as new gas dehydration units will replace existing units to condition the associated gas in order to meet the LNG Project Gas Pipeline moisture specification.

Control system modifications will be employed at CPF to ensure that gas at the required pressure is available to the PNG LNG Project. The flow of gas to the LNG Project Gas Pipeline will be controlled by the new flow control valve and associated equipment at the PNG LNG Project metering facilities. Whilst the overall flow control at each location shall be achieved via the new LNG Project Gas Pipeline management systems. The compressed gas not taken by the PNG LNG Project will be used for gas lift re-injection in the existing oil field. Utilities and service connection will be provided from existing oil field facilities to the PNG LNG Project custody transfer metering facilities.

8.4 Condensate Handling Project.

Stabilized HGCP condensate will be transported to the CPF via the PNG LNG Project Condensate Pipeline. At the CPF, HGCP condensate will be with stabilized crude oil from the CPF and store 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.

The HGCP has no condensate storage facilities as part of the plant, therefore storage will be handled from the CPF storage and export systems. Consequently, in an extreme scenario, an unplanned shut down of the CPF storage facilities will lead to an HGCP shut down and consequently the LNG Plant shut down. However, careful management plans and control mechanisms are an inaugural and major part of the modification designs and reviews which will certainly be employed at all cost for safety.

Significant changes are being made to the existing storage facilities in terms of the filling and mixing operation to provide a blended product to specification prior to export. However, the facilities will not be designed to export either 100% condensate and / or 100% crude oil as segregated products. Other major changes to the CPF includes the upgrading of the Emergency Shutdown (ESD) System, the fire and gas detection system and the fire protection system, to ensure the high availability and safe operation of its oil storage and export system.

8.5 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. Therefore, the LNG Plant start-up is expected to be accelerated by up to six months with the supply of the commissioning gas from the CPF prior to the completion of the HGCP. Temporary commissioning gas facilities are to be installed at the CPF to process high pressure gas from the discharge of the re-injection compressors. The 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.

8.6 Future Developments

Specific to the AGRP, there are four major additional oil field development activities that have been identified to be executed over the next few years;

1. **Modifications to facilities at the APF**

Whilst modifications to the CPF and GPF will occur in phase-1, modifications to the APF will need to occur prior to Agogo / Moran gas being included as part of the associated gas Project in phase 5.

2. **South East (SE) Hedinia**

The proposed development of this dry gas field is to utilize CPF facilities as existing associated gas declines. This is not expected to be executed until after phase-5.

3. **Additional oil field wells**

Two additional wells will be required in the Kutubu and Gobe fields for gas cap blow down in later years.

4. **Reversal of existing wells and flow lines**

The field development plans have not been finalized, hence it is expected that a number of gas injectors will be converted into gas producers to utilize existing flow lines where possible.

8.7 Regulatory Requirements

The permit to modify Central Processing Facility and Gobe Production Facilities was received on the 05th March, 2010 ***(Items to be replaced is discussed in the above sections).*** Several high level discussions were held in Melbourne, Perth and Port Moresby with DPE with the assistance of Granherne Consultants prior to the granting of the permit to modify CPF and GPF.

An intensive HARZOPS (Hazard Operations) and a 90% model review were done by Aker Solutions, Oil Search Limited (OSL), Exxon Mobil and DPE. All outstanding items were then discussed and reviewed. DPE was satisfied with the HARZOPS, model and discussions review, therefore a permit to modify CPF and GPF was granted on the 15 December 2010. Both facilities will process and deliver both oil and gas.

The only outstanding issue currently being looked at is the life expectancy of the existing oil producing facilities. Where the new gas facilities with a life expectancy for another 30 years, the question raised is, will the 20 year old oil processing facilities be able to support the new PNG LNG Gas Project for that extended period? Consequently, Oil Search as the operator of these facilities have been relentlessly doing a massive and tremendous job in constructing and modifying the facilities to international and industrial specification, standards, codes and also the government regulations.

9.0 POLICY

The Petroleum Policy Branch of the Petroleum Division deals with four (4) core-regulatory functions of the Department. These functions are executed respectively by distinct sub-sections namely; the Policy Planning and Implementation Section, the Environment Section, the Economic Services Section and the Legal Services Section. This section of the Annual Report, presents major activities and development highlights from each of these sub-sections, for the year 2010.

9.1 Policy Planning, Implementation & Monitoring Section

9.1.1 National Petroleum Policies

With the expansion of development in PNG's hydrocarbon sector since the mid-1980's, the government of PNG enacted and implemented various national petroleum legislations and policy instruments, aimed at promoting, regulating and maximizing returns from exploration and development of the country's hydrocarbon resources. Some of these major petroleum legislations and policies, currently in use, are provided in table x below.

Table 9.1: Current Petroleum Legislations and Policies

#	Document Title	Document Type
1	The Oil and Gas Act (1998)	Legislation
2	The Oil and Gas Regulation (1998)	Legislation
3	The Konebada Petroleum Park Authority Act (2009)	Legislation
4	The Petroleum Policy Handbook (2003)	Policy
5	Gas Commercialization Policy (2005)-White Paper	Policy
6	Petroleum Pipeline Policy (1998)-Green Paper	Policy
7	Natural Gas Policy (1995)- White Paper	Policy

9.1.2 Policy Development Plan

In January 2010, the Department identified a number of key tasks, which were incorporated into its overall corporate plan. These tasks include a number of petroleum policies, which the Department hoped to have in place to address existing and eminent policy gaps facing the sector. Most of these policies are considered working drafts at present and due to the overall delays, attributed to manpower and technical resources, the Branch has considered engaging external assistance from recognized national institutions, such as the PNG National Research Institute (NRI), to collaborate in research and drafting of selected policies. Major policies, earmarked under the Branch's policy development plan, are highlighted in table XI below.

Table 9.2: Pending Policies

#	**Document Title**
1	*Marginal Field Policy*
2	National Content Policy
3	Downstream Petroleum Policy
4	Gas Flaring & Emission Policy
5	*National Energy Policy*
6	Geothermal Policy
7	*Rural Electrification Policy*
8	Electricity Industry Policy
9	Offshore Operations Policy
10	Abandonment & Decommissioning Policy
11	Production Policy for Matured Fields
12	Petroleum Reservations Policy
13	Petroleum Promotions & Bidding Policy
14	Petroleum Policy Handbook Review
15	Petroleum Licensing regime Review

9.2 The Petroleum Policy Handbook

The Petroleum Policy Handbook is an "all in one" compilation of prime government policy statements, development objectives, development goals and regulatory measures (both fiscal and non-fiscal), on hydrocarbon development in PNG. The document serves as a one-stop-shop, simplifying and presenting key regulatory policies, in a manner accessible to all interested parties. The document is reviewed annually by the Petroleum Policy Branch, to maintain currency with policy developments and/or amendments. The last review of the document was done in 2003 and was made available for use in 2005. The next and current review of the document, commenced around November this year (2010), and is anticipated for completion in May 2011. This pending review will incorporate both policy and legislative aspects of natural gas development.

9.3 General Policy Highlights

9.3.1 Review of Mineral Policies and Legislations

In June 2010,the Branch reviewed and provided comments on a number of draft mineral policies and legislations circulated by the Department of Mineral Policies and Geohazards (DMPGH). These Draft legislations and Policies included;(i) the Mining Act;(ii) the Mineral Policy;(iii) the Mining Safety Act and (iV) the Offshore Mineral Policy.

The Branch's involvement in these reviews provided valuable experiences, particularly with the process of analyzing, formulating and implementing regulatory policies. In essence, the activity greatly assisted our officers in comprehending and drawing comparison in terms of the relative policy issues and policy gaps in the petroleum sector, that remained to be addressed by the Department. Several such areas of policy focus included; clear definition, delineation and management of minerals such as, Geothermal and Coal Seam Methane (CSM), which provisions under existing PNG legislations, particularly the Mining Act and the Oil and Gas Act, are unclear on, with respect to regulatory jurisdiction, as presented in the case involving regulatory confusion over Lihir Gold Mine utilizing geothermal energy (an energy resources), within a mining tenement. Another similar area of policy focus for the petroleum sector, involves guiding and regulating offshore petroleum activities. The Oil and Gas Act, does not cover offshore operations in detail, neither does the Department have a regulatory policy, which makes the need critical, as interests in offshore exploration and development grows.

9.3.2 WTO Review of Petroleum Policies

Another tasks involving policy analysis and policy commentaries, which the Branch was involved in is the World Trade Organization's (WTO) review of Trade Policies in each development sectors in PNG. Three (3) separate Consultations were held with the Branch, for the Petroleum Sector. These included, 17th of May 2010 (first consultation), 30th of June 2010 (second consultation) and 24th of September 2010 (review and discussion of draft report, submitted to WTO for presentation in Amsterdam). A consultation paper submitted to this review, outlined the regulatory roles and responsibilities of both the Petroleum Division and the Energy Division, particularly in terms of the type and nature of renewable and non-renewable energy policies and current energy policy developments, enforced by the Department. A specific focus of this review was on trade policies, which seeks to understand the PNG petroleum taxation regime, the fiscal structure of PNG economy, existing trade incentives and trade barriers, import and export movement of PNG hydrocarbons and the overall hydrocarbon extraction trend. Similar, policy review was carried out for mining, forestry, fisheries, manufacturing, agriculture, tourism and eco-tourism. The World Bank presented the final PNG Paper, in Amsterdam in December 2010.

9.3.3 PNG Development Strategic Plan (PNG DSP)-Petroleum Sector Input

A further involvement of the Branch includes compilation and submission of petroleum data towards computation of the petroleum sector, Medium Term Development Plan (MTDP) log frame, required by the Department of National Planning and Monitoring, for completion and finalization of the PNG Development Strategic Plan (PNG DSP). This task was completed in June 2010, in collaboration with officers from the Policy Planning Branch of the Department of National Planning and Monitoring.

PNG’s Development Strategic Plan is a twenty (20) year development plan, spanning from 2010 to 2030.These twenty year time frame is further comprised of four (4) Medium Term Development Plans (MTDP), which are from; 2011-2015, 2015-2020,2020-2025 and 2025-2030.

9.2 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.

9.2.1 Environmental Monitoring

9.2.1.1 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.

9.2.1.2 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.

9.2.2 Environmental Issues

9.2.2.1 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.

9.2.2.2 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.

9.2.2.3 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.

9.2.3 Environment Policy and Internal Developments

9.2.3.1 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.

9.2.3.2 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.

9.2.3.3 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.

9.3 Economics Aspect

9.3.1.1 Oil Prices

Crude Oil prices in the recent years have reached historic high, peaking in mid 2008 at around US$140 per barrel. There has been sudden and vertical drop in crude oil prices in the second half of 2008 with a barrel selling for about US$40 in December of 2008. There was a general upward movement in Crude Oil prices since then despite marginal fluctuations in 2009 and reaching a high of about US$85.00 per barrel by the end of December.

The Average Kutubu Platts[1] price was just under US$80.00 per barrel beginning 2010 and soared to a high of US$85.00 per barrel in April than dropped by 9% in May to US$77.00 per barrel. Generally, there was an upward trend recorded for the Average Kutubu Platts Price for the rest of 2010 from US$77.00 per barrel in July and peaking at around US$94.00 per barrel in December.

Actual trading prices on the spot markets or Net Realized Price[2] for Crude Oil, as per the cargo transaction reports (CTR), commenced at an average of around US$70.00 per barrel at beginning of 2010, which was a hefty US$10 lower than the average Platts price, but steadily rose to around US$87.00 per barrel at the end the of first quarter. There was a plunge in selling price by US$13.00 in May then began climbing gradually in the second half of the year peaking just under US$95.00 per barrel in December 2010 which was at par with the Average Kutubu Platts prices.

Table 9.1 shows the monthly movements of Average Kutubu Platts prices against the actual spot market prices for crude oil. The Kina per barrel prices are also provided to illustrate the kina value for the crude oil due to the volatility of Kina against major currencies.

The movements in the average crude oil price in Kina terms are largely affected by the movement of Kina against the US Dollar which is the widely accepted standard international trading currency. The annual

[1] Average Kutubu Platts price were extracted from the Royalty return statements submitted by JVP Operators & Licensees.

[2] Net Realized Prices are Spot Market prices for Crude Oil export extracted from CTR, or the statements in footnote 1, submitted by the Operators.

average exchange rate for Kina against US Dollar was US$0.3832, thus K2.695 would buy one US Dollar on average. Therefore the annual average price of US$81.708 per barrel of crude oil would translate to an average K213.225 per barrel of crude oil.

Table 9.3: Crude Oil Price Movements

2010 Crude Oil Prices Movements			
Months	**Average Kutubu Platts US Dollars/barrel**	**Net Realized Price US Dollars/barrel**	**Average Kutubu Platts Kina/barrel**
January	79.216	70.063	203.955
February	76.614	72.064	199.412
March	81.016	77.261	215.870
April	85.750	86.887	228.850
May	77.378	73.807	209.640
June	76.558	74.703	205.801
July	76.667	79.598	201.437
August	78.206	79.598	205.751
September	80.034	80.598	206.753
October	85.886	85.494	215.995
November	88.404	88.076	224.040
December	94.768	94.256	239.598
2010 Average	**81.708**	**80.200**	**213.092**

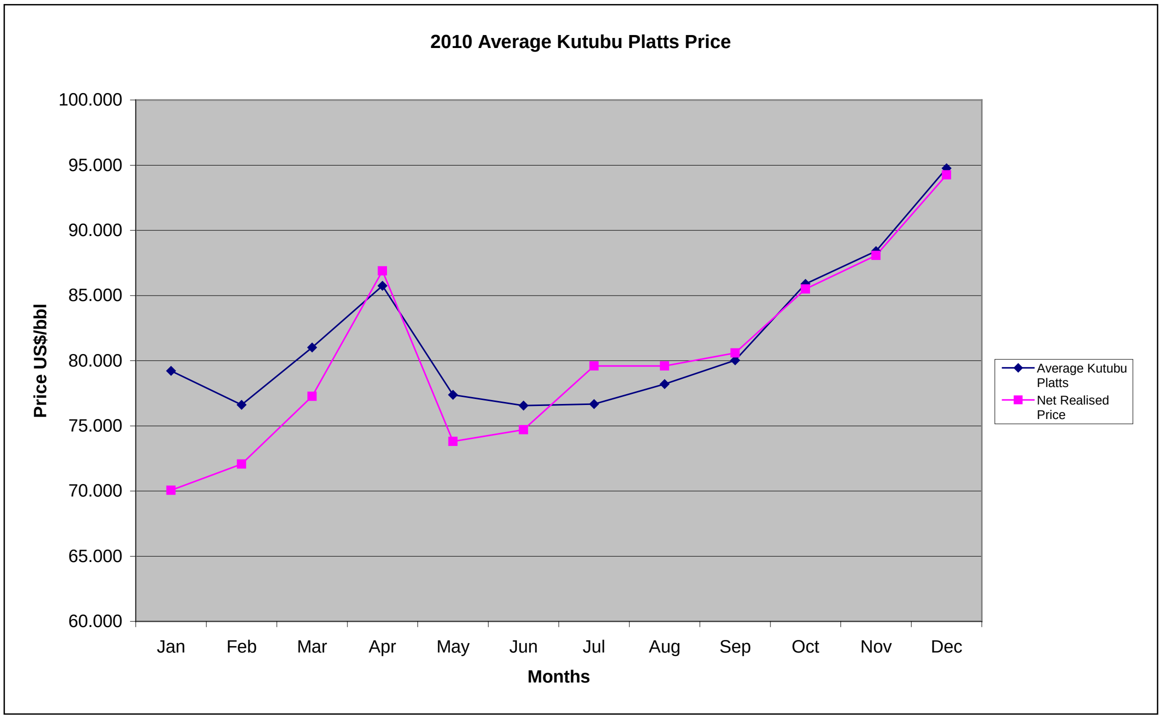
- Note: The data in Table 9.3 have obtained as stated in Footnotes 1 & 2, and the Exchange Rates for Kina against the US Dollar have also been sourced from the Royalty Statements as per footnote 1.

There were some deviations of the net realized prices from the Average Kutubu Platts prices through the first, second and third quarter, whilst the deviation in the final quarter was very marginal. These were mainly attributed to the actual spot market prices differing from the Average Kutubu Platts, which as the name indicates, is an average of all spot market prices for a specific period, usually on a monthly basis.

The general rising trends in the movements of Crude Oil prices are largely attributed to the global economic recovery from the financial crisis in 2009 as well as the geo-political crisis looming in the major oil producing countries in the Middle East and North Africa and also the increasing energy demands by the booming Asian economies, particularly China and India.

Figure 9.1 illustrates graphically the crude oil price movements' trend for Average Kutubu Platts prices as well as the actual spot market prices for crude oil exports.

Figure 9.1: Crude Oil Price Movements



As a producer of oil, albeit a minor one, PNG can benefit immensely from the increasing price for crude oil but, as a net importer of gasoline, consumers will consequently pay higher prices for diesel, petrol and kerosene. Moreover, cost of other goods and services, whether manufactured locally or imported are also expected to increase as the rise in crude oil prices will also trigger imported inflation on PNG's domestic economy.

9.3.1.2 PNG Crude Oil Export and Revenue

The soaring oil prices meant higher than projected revenue for Papua New Guinea from crude oil exports. The cumulative crude oil production and export from the various oilfields in Southern Highlands Province for 2010 was 12.835 million barrels, which was a decline of 6% from the 2009 annual production of 13.631 million barrels. The export production figure obtained from the Operators was slightly lower than production figure projected by the Department of Petroleum & Energy. The plunge in annual crude oil production is mainly attributed to the natural decline in reservoir volumes of the oilfields as result of depletion due to production.

The revenues from the crude oil export is a function of crude production and price; hence with the annual average Kutubu Platts crude oil price being US$81.71 per barrel, gross revenue from oil exports was almost US$1.049 billion for 2010. With the average exchange rate of US$ 0.3827, the gross crude oil export revenue in PNG Kina terms was K2.741 billion.

The annual average Kutubu Platts crude oil price of US$81.71/bbl in 2010 was 28% higher than that of 2009, thus the gross export revenue for 2010 was just over 20% higher than 2009 in US Dollar terms, whilst the increase in PNG Kina terms was over 16% with the difference being explained by the fluctuations in the exchange rates.

Therefore, the high oil prices had positive impacts on the overall export earnings and also cushioned the effects of natural decline in oil production from the above projects on gross export revenue.

9.3.1.3 Royalty

The higher crude oil prices in 2010 resulted in favorable returns in terms of benefit stream to the State and the resource owners. Thus the total royalty payments made in 2010 to the State was K49.130 million, which was an increase of over 19% compared to the royalty payments of 2009.

The disbursement of these funds to the affected landowners, Provincial Governments and Local Level Governments has not been made in 2010 but it is anticipated that they will receive their share of benefits within the second quarter of 2011.

9.3.1.4 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 biannually, 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. However, due to frequent non-compliance issues pertaining to the terms and conditions of certain license by some companies or licensees, DPE was unable to update PCR reports on a regular basis. Therefore the Department should take tougher actions against those companies not complying with the requirement for the Oil & Gas Act, which they as operators are obliged to adhere.

9.4 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.

9.4.1 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.

9.4.2 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.

10 COORDINATION BRANCH

10.1 EXECUTIVE SUMMARY

The Coordination branch of the Department of Petroleum and Energy this year was not able to send offices to the field this year 2010 to carry out its normal coordination and liaison activities as well as ensuring a constant National Government presence in the field.

The absence of Coordination officers in the field was primarily due to the lack of funding for liaison activities for the branch to execute its functions. The lack of Government presence at the respective project site meant that the National Government could not obtain independent advice from its officers in the field concerning landowner issues as well as project operational issues which used to be the norm when funding was available enabling officers to be at the project sites.

The National Government due to lack of presence of Coordination Branch officers in the field had to rely on second hand information either from the project developer, industry or project area landowners. This will inevitably put the Department and State in a situation where conflict of interest and dependency will be inevitable surely for Government to be put in such a position is ludicrous.

Lack of National Government presence in the field also meant that there was a higher influx of landowners to Port Moresby to raise their queries or issues with the Department or Government. This has in a lot of cases resulted in landowners submitting claims to the Departments whether it be the Department of Petroleum and Industry, National Planning Department or the Department of Finance and Treasury for their costs to be reimbursed. There have also been instances where they blamed their deaths in Moresby being a direct result of lack of Government presence in the field forcing them to come to Moresby and meeting their fate..

With the commencement of the PNG LNG project the need for officers from the Coordination branch to be based in the field on a rotational basis so that they become the eyes and ears of the State at the project sites and maintain continuous dialogue, awareness and information dissemination with the project operators and more importantly with the landowners is becoming more important. Especially when project security is of uttermost important in a multibillion kina project such the PNG LNG project and other prospective projects that the Government is boasting about in the New Year and years to come.

The Coordination Branch wants to see both the Department of Petroleum and Energy and the National Government gives serious consideration to funding and equipping the Branch to effectively and diligently carry out its designated function. Especially, when we know and have experienced how important it is to take a proactive approach in mitigating and addressing landowner issues. While at the same time, working side by side with the project developers in their project development and community affairs programs.

The program that the branch has put together is a reflection of the realistic issues and the activities that need to be undertaken by the Coordination branch and the State to ensure that stability and normalcy is maintained at the project site.

10.2 2011 WORK PROGRAM COST SUMMARY

The work programs for specific projects are covered in detail in Section 8 of this report but the summary shown below gives that total of the costs associated with the projects as per their work program. From the summary it is obvious that the outstanding reviews of the existing projects will cost almost half of the total budget of the projects operational budget.

The cost looks significant but this is only a tiny fraction of how much these projects make or will make for the country for instance this year in the month of October alone the Finance Department received in tax from two petroleum companies K 120 million kina if the State is serious about the well being of the petroleum industry. This is tax from two companies and other direct and indirect benefits that the State receives clearly will make the amount that we have budgeted for and are requesting based on our work programs clearly justifiable. If the state is serious about the well being of the petroleum industry then it should adequately fund the department to execute its core functions as the coordinator of the oil and gas Act and regulations of the petroleum industry.

If the State is serious about the necessity for the State to implement its planned activities and work programs that it should give serious consideration to funding the Coordination Branches work program for all the project areas *(refer Table 10.1)*.

Table 10.1: Coordination Branch Project Budget Outline 2010

Project	Activity	Budget
Hides PDL1		**4,200,000.00**
Kutubu PDL2		**4,625,505.00**
Gobe PDL3&4		**2,098,000.00**
Moran PDL5&6		**2,100,000.00**
PDL7		**1,160,000.00**
PDL8		**1,440,000.00**
PDL9		**1,683,000.00**
PPFL		**1,361,000.00**
Branch		**126,200.00**
	Cumulative total	**18,793,705.00**

Table 10.2: Actual Coordination Branch Project Expense 2010

Project	Activity	Budget
Hides		2,500,000.00
SEM Supplementary MOA		1,300,000.00
Kutubu MOA review		2,565,505.00
Gobe Review		1,500,000.00
Moran Review		1,500,000.00
	Cumulative total	**9,365,505.00**

11.0 GENERIC ISSUES

Throughout all the nine Petroleum Development Licenses, (PDLs) the Petroleum Processing Facility License area and the pipeline licenses there were several issues that were identified as being generic throughout these project areas and these issues are captured below.

10.3 FUNDING

Funding has been a major impediment for all the projects in executing their work program. The Funding will cover normal liaison activities which will require field officers to be engaged full time in the field with funding requirements to cover travel to and from the project sites on a rotational fly in fly out basis, meals, accommodation, office facilities and stationary and incidental allowances.

Previously in the Oil Search operated project the Government used to have the Facilities Use Agreement (FUA)with the Developer Oil Search where the facilities were used by the Coordination branch and the Department and the costs were later back charged to the State. This arrangement has since been terminated

The Branch is of the view that if the State must maintain a strong National Government presence in the field either by negotiating with the project developers to re-establish the FUA arrangement so that Government can again have officers of the Branch deployed at the project sites or give direct funding to the Branch and Department to look after its own.

10.4 UBSA BENEFIT SHARING BETWEEN PG AND LLG

Having concluded most of the sharing amongst the PNGLNG project area landowners there remains one major challenge for the Department and Branch. This is the sharing of the benefits between the respective provincial Governments of the project and the Local Level Governments within each of the Provinces.

It is important that the PG and LLG need to decide their sharing arrangement. This will again require a forum for all the provincial governments and their LLGs to attend meet and discuss their sharing arrangement. Budgets have been prepared for this to eventuate and when funding becomes available, then these plans will be executed.

11.5 UBSA LBSA CLAIMS/BILLS

The State in its endeavor to meet the financial closure deadline of the PNG LNG project made decisions and conducted meetings on a tight schedule. In doing so there were a lot of oversights especially in relation to control of landowner movement and expenditure. The landowners while riding on the wave of the LBSA and UBSA meetings used this as an opportunity to incur bills which although related to the UBSA and LBSA were in a lot of instances not sanctioned by the Department or the State.

The bills that were submitted were categorized into categories A, Claims authorized by DPE, Treasury or Gas Coordination Office, Categories B, claims not authorized by DPE, Treasury or Gas Coordination Office but with merit, verified and justified and subsequently approved by state and Category C, claims not authorized by DPE, Treasury or Gas Coordination and do not comply with the procurement requirements of Public Finance management Act. Category A and B were settled by the State while category c claims or bills were advised to use the court system to address their claims. This decision in theory at that time was right but now the landowners are approaching the officers of the branch and other senior Department officers and even the Secretary, issuing threats that they do not want to see DPE or even officers from the State at the project site until their bills have been settled.

In our branch program for next year 2011, we are planning to send officers to the project sites who will be based full time in the field on rotational, but these threats are of serious concern to us and we do not want to place our field officers in a situation where their lives will be put at risk.

The Department and the State need to seriously consider addressing this issue because it will affect the work program of the branch. We are of the view that the state set aside some funds per project and at least settle all the bills not fully but may be 10 – 20% of their total bills with them taking not to pursue the matter further.

10.6 ILG INCORPORATION

The ILG incorporation exercise for the Green field areas including PDL6 is still outstanding. The State as we are aware has made a decision that the lands Department will take charge to the ILG incorporation exercise and the actual vetting and incorporation of the ILG will be undertake by Heritage Consultants.

This decision is supported by the branch but the ILG incorporation exercise needs to be undertaken quickly so that landowners in a project can be clearly identified in a structure that is user friendly to the State especially for benefit sharing purposes but also for representation purposes, especially when all sorts of people are claiming to represent in clan in a project.

10.7 MOA REVIEWS

The Review of all the existing projects are well overdue. We are of the concern that the landowners may take the State to court for breaching the Terms of respective License Agreements, especially the clauses which call for reviews to be held after certain periods which in the case for all the existing projects have elapsed.

It is therefore important that we review all existing Agreements**.**

Table 11.1: MOA Budget Outline 2010

Project	**Comments**		**Budget**
Hides	REVIEW WELLOVER DUE	As per the Moran Petroleum Agreement the Review for the PDL5 petroleum project was due in 2008. LOs may take the State for breach of Agreement	2,500,000.00
SEM Supplementary MOA		As per the Moran Petroleum Agreement the Review for the PDL5 petroleum project was due in 2008. LOs may take the State for breach of Agreement	1,300,000.00
Kutubu MOA review	REVIEW WELLOVER DUE	As per the Moran Petroleum Agreement the Review for the PDL5 petroleum project was due in 2008. LOs may take the State for breach of Agreement	2,565,505.00
Gobe Review	REVIEW WELLOVER DUE	As per the Moran Petroleum Agreement the Review for the PDL5 petroleum project was due in 2008. LOs may take the State for breach of Agreement	1,500,000.00
Moran Review	REVIEW WELLOVER DUE	As per the Moran Petroleum Agreement the Review for the PDL5 petroleum project was due in 2008. LOs may take the State for breach of Agreement	1,500,000.00
		Reviews Cumulative total	**9,365,505.00**

10.8 BRANCH FUNCTION

Papua New Guinea unlike many other countries in the world, about 96% of the land is owned by Tribes, Clans Sub-clans and individuals. That is the reason why there is a special need for members of the resource industry as well as Government to develop a special relationship with the people who owned the land commonly referred to in the PNG contest as landowners.

For the National Government of Papua New Guinea the Department of Petroleum and Energy is Tasked with the responsibility of regulating the Petroleum industry.

The National Government while allowing the Department to be the regulator also saw the need for government to have special relationship with the landowners and to gain their confidence to enable the landowners to work in synergy with the Government to address their issues and to develop mechanisms to ensure that they also derive benefits from the projects.

The Coordination branch apart from its other functions has two key functions which are carried out by the coordinators and liaison officers.

The first one is that they are the coordinators of communication between the company and the relevant national and Provincial Departments and Authorities. Their ability to liaise both formally and informally reduces the risks of surprises and misunderstanding and reduces that need for a company person to wait outside Waigani office in the hope of background briefing a public servant

Secondly the coordination and liaison officers are very often the only National Government representatives to appear in the field. They communicate on behalf of the National Government and disseminate information between landowners and the State. There exists a need for close interaction between the developers and coordinators and a relationship based on trust and corporation. This should be established as soon as possible. Companies should take the initiative of requesting a departmental Coordinator as soon as exploration intensifies.

The Coordination branch is crucial in representing the National Governments interest and presence at the project site.

The Branch also has a special Liaison Officers Structure which was created specifically to deal with LNG Liaison activities**.**

10.8.1 2011 WORK/ISSUES PROGRAM MATRIX

Find below the work program the issues matrix for the branches work program for next year. You will not that the implementation of most of these programs and planned activity depend heavily on the availability of funding. If like this year the funds for these planned activities for next year are not forthcoming then the planned activities will not proceed.

10.8.2 Coordination branch Work Program

The Branches work program covers the overall management and administration of the various projects. Currently there are only 09 work stations within the branch that are being used by fifteen (15) permanent staff which means that the office is over crowded.

Although here is adequate space within the branch for extension, this space is taken up by archives materials. If funding is made available then clearance and renovation can be done.

Table 13.1: Coordination Branch Work Program

NO.	WORK PROGRAM	OBJECTIVE	PLANNED SCHEDULE	STATUS	CONSTRAINTS	WAY FORWARD	EST. BUDGET
1	Office space clearance and Renovations	To move archive stuff out & renovate office space	Oct.2010	Job 30% done	Explorations branch not cooperating	Purchase 20ft containers and store archive stuff	35,000.00
2	Electronic Data Maintenance for all closed files	To safely store all Coordination information	Oct-Dec.2010	Planned for 8yrs and never been done	Unclear directions from Director & Secretary	Engage IT specialist to scan and archive files	31,200.00
3	Coord.Branch IT upgrade	To improve branch IT	Oct. to Dec.2010	Outstanding task	Funding	Supp.Budget	60,000.00
4	Upgrade and Maintenance of Field Ops Office	To improve Moro, Hides, Gobe & Kopi DPE office	Oct. to Dec.2010	Outstanding task	DPE Management and Funding	Discuss funding and Plan with DPE management	-
5	Liaison with Issues Committee	To establish clear dialogue	Oct. to Dec.2010	Outstanding task	Issues Committee being non-transparent	Write letter to organise a meeting	-

6	Facilities Use Agreement with OSL and Esso HL	Establish FUA for our field officers travel to project sites	Oct. to Dec.2010	Outstanding task	No clear dialogue between Treasury, Finance and DPE	Organize meetings with DPE and OSL/Esso HL	-
							126,200.00

The Branches work program covers the overall management and administration of the various projects.

10.8.3 HIDES PDL1

In all the projects there is an obvious need for funds to be made available for liaison activities and this is reflected in each of the programs.

Table 13.2: Hides PDL1 Planned Schedule

NO.	WORK PROGRAM	OBJECTIVE	PLANNED SCHEDULE	STATUS	CONSTRAINTS	WAY FORWARD	EST. BUDGET(K)
	PDL 1 GTE	PDL 1 GTE					
1	**General Liaison Activities**	**Perform liaison activities with Stakeholders both in the project sites and in POM**	**Ongoing planned activity**	**2 field trips taken in 2010. Plan for 2 more.**	**Funding and logistics**	**Secure funding for additional trips**	**600,000.00**
2	Royalty payments for 2010	Complete all royalty payments for year 2010	Aug-Sept 2011	Completed field trip	>	>	covered in liaison activities
3	Conduct 2 Landowner General Meetings	facilitate meetings with key leaders to discuss project related issues	Sept.2010	Trip yet to be undertaken	Funding and logistics	Secure funding for additional trips	covered in liaison activities

4	Annual update of Hides LO database	Update existing Hides LO Database	Dec.2010	Outstanding task	Funding and logistics	Secure funding and equipment	10,000.00
5	ILG Incorporation	To provide assistance to the Heritage Consultants in the incorporation of ILGs for LNG beneficiaries.	Nov.2010	Outstanding task	Heritage contract and funding	Follow-up with LNG Coordinator. Budget for Airfares only	covered in liaison activities
6	Hides MOA Review	To organise meeting for the Sate & Los to review the Hides MOA.	Re-Plan for 2011	Cannot be undertaken in 2010	Funding proper planning and logistics	Plan for Feb.2011	2,500,000.000
7	Inspection & monitoring of Hides MOA funded projects	To assist the EIC to carryout inspection & monitoring the status of project implementation funded under Hides MOA.	Re-Plan for 2012	Cannot be undertaken in 2011	Funding proper planning and logistics	Plan for Jan.2011	covered in liaison activities
							3,110,000.00
	PDL 1 PNG LNG TASKS						
8	Payment of outstanding LBSA Invoices to Creditors & Service Providers	Approved service providers should be paid prior to going into the field due to high risk.	Plan for Dec.2011	Some payments have been made. Some claims outstanding	Funding and delay of Supp.Budget	Complete by Dec. 2010 depending on Supp. Budget Approval	To be addressed by issues committee and finance & Treasury

9	ILG Incorporation & Vetting exercise (Includes PDL 1, PRL 11, PRL 12, JUHA,	This budget is part of the K5.4 Million for Heritage Consultants (Includes K2 Million for DPE Administration & Cost)	Re-Plan for 2011	Outstanding task depending on contract and funding approvals	First Heritage Contract yet to be signed by CSTB	Liaise with Dick Steven and Gas Project Coord Committee - GPCC	
10	ILG Incorporation & Vetting exercise for Portion 152, Pom Pipeline & PDL 6.	The above budget submission (K5.4m) did not include these 3 areas which are now considered extra. Since the Heritage contract will be managed from Hides, the budget has been included in the PDL 1 budget	Re-Plan for 2011	Outstanding task depending on contract and funding approvals	First Heritage Contract yet to be signed by CSTB	Liaise with Dick Steven and Gas Project Coord Committee - GPCC	First Heritage to assist
11	Issues Committee & Management of Issues	This program will run concurrently with the ILG & Vetting exercise to benefit from Synergies	Plan start execution of Work Program Nov.2010	Office has been Set up with K54m funding	Funding has not been released to this office	Prepare work plans and convince Treasury to release funds	Covered by Liaison activities
12	Mini Forum to allocate Clan percentages and BD seed capital distribution	The UBA and LBBSA have general splits agreed. Mini forum will have clans agree on	Plan for Nov - Dec.2010	Outstanding task. Depending on Supp. Budget in Nov. 2010	Funding	Camp reconstruction K450,000, mini forum 480,00, ILG security K1,050,000	660,000.00

		splits				(provision for local security and troops call out if need arises)	
13	HIDES Growth Centre Implementation	Provision of supervision to ensure that the projects are implemented as planned.	Ongoing	Outstanding task	Funding	Supplementary Budget 2010	300,000.00
14	Mini Forum to facilitate meeting and negotiations on sharing of benefits between affected LLGs and PG	LLGs & PGs will have to meet to further agree on general splits under UBSA and LBBSAs	Re-Plan for 2011	Outstanding.	Funding	Should be implemented after Mini forums for clans	130,000.00
15	Current (local) Security Arrangements	Provision of security services to the forum area camp and its contents, containers, fence and others etc.	Plan for Nov - Dec.2010	This will be needed when the Mini forums are held	Funding	Identify reputable security service provider	Covered by Liaison activities
							1,090,000.00
						Cumulative Total (K)	**4,200,000.00**

10.8.4 KUTUBU PDL2 & SOUTH EAST MANANDA

Table 13.3: Kutubu PDL2 and South East Mananda Planned Schedule

NO.	WORK PROGRAM	OBJECTIVE	PLANNED SCHEDULE	STATUS	CONSTRAINTS	WAY FORWARD	EST. BUDGET (K)
1	**General Liaison activities**	**To perform ongoing liaison tasks in POM and project sites**	**Ongoing in 2010**	**This is ongoing daily**	**Funding**	**Plan for 2 trips in November 2010**	**600,000.00**
2	Royalty pmts for 2009	To payout LO royalties	Plan to payout by Dec.2010	Outstanding	Funding	Liaise with MRDC	cost covered in liaison activities
3	Equity/Dividends for 2009	To assist MRDC payout dividends	Plan per MRDC strategy	Outstanding	Funding	Liaise with MRDC	cost covered in liaison activities
4	Inspections of MOA funded projects	Per EIC Guidelines to inspect Govt. funded projects	To complete by Nov. 2010	Outstanding	Funding	Source funds from Supp. Budget	cost covered in liaison activities
5	ILG Maintenance for both PDL2, SEM and PL2	To prepare ILGs for LNG benefits and current oil benefits	Plan to start by Nov.2010	Outstanding (See details below)	Funding	LNG ILG plan under Heritage. See details below	-
6	Landowner General Project Meetings	To meet and discuss project related issues	Oct.2010	Outstanding	Funding	to have 4 meetings with leaders, PDL2, SEM, PL	cost covered in liaison activities
7	SEM Leadership resolution meetings	DPE to attempt consensus meetings to allow leaders to sort out internal issues	Oct.2010	Outstanding	Funding and Logistics support	Source funding from Supp. Budget 2010	cost covered in liaison activities
8	Decision on SEM Association	Minister to give recognition for one SEM Association	Oct.2010	Outstanding	Funding and Logistics support	Source funding from Supp. Budget 2011	cost covered in liaison activities

9	Finalisation of ILG listing and Registration from ROT - Lands Dept	ROT - Lands to provide certified ILG documents	Oct.2010	Outstanding	Funding and Logistics support	Source funding from Supp. Budget 2012	
10	Legal Advice and clarification on all SEM court orders and litigation matters	To get legal branch or AG or provide clear advice on all SEM legal issues	Sept.2010	Outstanding	>	Prepare brief to Legal Branch	
11	UJV and Business Development matters	UJV and SEM LANCOs need to agree to work on a umbrella concept for LNG	Sept.2010	Outstanding	Logistics/funding and lack of cooperation amongst leaders	Source funding to coordinate meetings	30,000.00
12	SEM Supplementary MOA (Under Kutubu Project/Kutubu MOA)	To have SEM Supp. MOA signed	re-plan for 2011	Outstanding. Subject to Kutubu MOA review	Funding and Logistics support	Secure funds under Supp.Budget in Nov.2010	1,300,000.00
13	Kutubu MOA Review	To have KMOA reviewed per MOA clause for review	re-plan for 2011	This task has been ongoing for 4 years	Political, Funding, Logistics and LO leadership issues	Secure funds under Supp.Budget in Nov.2010	2,565,505.00
14	Irakorahi specific issues on Supp. MOA similar to SEM	To address Irakorahi specific issues	Oct.2010	Ongoing	Funding	Give more attention to this group of landowners	
15	Lower Foe (Kantobo) demands on BD grants and MOA funds	To address issues relating to MOA and BD funds as promised by various Ministers	Oct.2010	Ongoing	Funding and Logistics support	Review MOUs signed by previous Ministers and plan ahead	
16	Issues relating to IBUGA group of Kutubu landowners	TO address issues in re to this new group in Kutubu brought about	Oct. 2010	Ongoing	Funding	Collate specific issues and address	

		by PNG LNG Project					
17	MOA inspections for Kikori PL	To inspect and report on MOA funded project under Kutubu/Kikori MOA	Nov. 2010	Outstanding	Funding and Logistics support	Get funding under Supp. Budget	
18	General Liaison Activities for Kikori pipeline areas affected by Kutubu PL2	To have ongoing government presence to address queries/issues	Dec.2010	Outstanding. Depending on funding	Funding and Logistics support	Secure funds under Supp.Budget in Nov.2010	
19	Fasu ILG Reviews/Maintenance	To review or do maintenance work on 119 Fasu ILGs	Dec.2011	Outstanding. Depending on funding	Funding and Logistics support	V	
20	Foe ILG Reviews/Maintenance	To do maintenance on 92 Foe ILGs	Dec.2012	Outstanding. Depending on funding	Funding and Logistics support	V	
21	SEM ILG incorporation and follow-up	To ensure ROT formally endorses and registers the 142 SEM ILGs	Dec.2013	Outstanding. Depending on funding	Funding and Logistics support	V	
22	Kikori (IKP, Kibiri, Kerewo, Rumu) ILG maintenance	Maintenance on Kikori PL ILGs	Dec.2014	Outstanding. Depending on funding	Funding and Logistics support	V	
	PNG LNG RELATED TASKS - KUTUBU	PROJECT - PDL2, PL2, SEM AND	IRAKORAHI LOWER FOE				
23	Business Development Grants	To follow up with Commerce Dept. on cheque payments	Sept-Oct.2010	Outstanding	>		
24	Infrastructure Development Grants	Prepare matrix and records of all IDG	Sept.-Oct.2010	Outstanding	>		

		submissions and advice MRDC/EIC/Planning Dept.					
25	Creation of Up-to-date Landowner Database for LNG	To have a proper master record for all landowner entities	Nov.-Dec.2010	Outstanding	Funding	Supp.Budget 2010	35,000.00
26	Outstanding issues post-LBBSA Agreement clauses	Review LBBSA and identify issues/tasks for post-LBBSA work	Sept.2010	Outstanding	Funding	Organise workshop/meetings	
28	LNG related ILG Database	To have alignment with Heritage Consultant and have standard LNG ILG records	re-plan for 2011	Outstanding	Funding	Work with Heritage Consultant	
29	Specific MOA Project submissions or issues that have LNG Implications	Follow up on sensitive MOA issues in the Fasu and Foe regions	Sept.-Oct.2010	Outstanding	>	Review MOUs signed by previous Ministers and plan ahead	
30	DPE Moro Office Upgrade and Security Issues	Beef up DPE/Govt. presence in Moro as the base	re-plan for 2011	Outstanding	Funding	Supp.Budget 2010	60,000.00
							4,590,505.00

10.8.5 Gobe Project (PDL3 and 4)

Table 13.4: Gobe PDL3 and 4 Planned Schedule

NO.	WORK PROGRAM	OBJECTIVE	PLANNED SCHEDULE	STATUS	CONSTRAINTS	WAY FORWARD	EST. BUDGET
1	**General Project Liaison Activities Samberigi / Kikori**	**Ongoing liaison with stakeholders in POM and villages**	**Ongoing 2010**	**Ongoing**	**Funding**	**Secure funding from Supp.Budget 2010**	**450,000.00**
2	MOA Review (well overdue)	Meeting with landowners and the State to review the existing MOA to be held in the project site. Pending LTC review	Re-plan for 2011	Well overdue for review and signing	Funding and logistical problems	Secure funds from Supp.Budget 2010 and park it safely for 2011	1,500,000.00
3	Gobe Project ILGs	Review and maintenance of 23 Gobe ILGs in line PNG LNG objectives	Sept.to Nov. 2010	Outstanding	Funding and LTC/ADR issues	>	
4	Update and Review of all Gobe Project related cases	Keep updated on all litigation and ADR processes in Gobe Project	Sept.to Nov. 2010	Outstanding	>	>	
5	Legal/ADR	Fast track final Decision of the Judge on Gobe ADR and LTC	Oct.2010	Outstanding	Funding	>	
6	MOA inspections	To undertake MOA funded project	To carry out on site inspections on MOA projects	Outstanding	Funding	Secure funding from Supp.Budget 2010	

		inspections with EIC	implementation status & expenditure.				
8	Royalty and Equity Pmts	To pay out landowner royalty and equity	Nov.-Dec.2010	Pending advice from MRDC	Funding	Get advice from MRDC	
PNG	LNG PROJECT RELATED	TASKS AND ISSUES - PDL 4					
9	Outstanding Police accommodation costs	Settle Samberigi tribal war police accommodation allowances	Nov.-Dec.2010	Pending invoice from CDI	Funding	Secure funding from Supp.Budget 2010	98,000.00
10	Post LBBSA workshop/reviews	To peruse LBBSA clauses and understand issues	Oct.2010	Outstanding	Funding	Secure funding from Supp.Budget 2011	5,000.00
11	BD grants payments	To follow up with Commerce Dept.	Sept.to Nov. 2010	Outstanding	>	>	
12	Infrastructure Dev.Grants	To collate all submissions and make report to EIC/Planning Dept.	Sept.to Nov. 2010	Outstanding	>	>	
13	Gobe Social Monitoring Committee	To establish GSMC	Sept.to Nov. 2010	Outstanding	>	>	
							2,053,000.00

10.8.6 Moran PDL5/ PDL 6

Table 13.5: Moran PDL5 and 6 Planned Schedule

NO.	WORK PROGRAM	OBJECTIVE	PLANNED SCHEDULE	STATUS	CONSTRAINTS	WAY FORWARD	EST. BUDGET
1	General liaison work	Ongoing Liaison activities in field & Port Moresby.	ongoing	ongoing	Funding	Secure funds in Supp. Budget	500,000.00
2	Royalty & Equity payments	Moran Royalty/equity Payments March - December 2009	Ongoing	Pending advise from MRDC	certain court cases	Secure funding and work with MRDC	
3	MSPA Investigation	Ensure that MSPA establishment is legally in order	End-September 2010	90% complete	>>>>>>>>>>>>>>	Request for office bearers appointment papers	-
4	Update Royalty Equity Payments	To have proper records in place regarding payments. Update statements with OSL, MRDC and finance	Oct-10	pending	funding	Plan meetings with MRDC, OSL and Finance to reconcile statements	
5	Update List of LLG Presidents	To have proper record of LLG officer bearers	Oct-10	Pending	>>>>>>>>>>>	Organise meeting with Dept. Inter Govt Relations	
6	Landowners Database	Update landowner database of PDL 5 & 6	Oct. to December 2010	ongoing	funding	Seek funding in Nov. budget	

7	Monitoring of security and tribal conflicts in PDL5 &6	To ensure quick reporting and countering of tribal fights	Ongoing	ongoing	>>>>>>>>>>>>>	Keep contact with OSL	-
8	Monitoring of ongoing land disputes (e.g. Nano Webo)	To ensure land disputes are addressed at the earliest	Ongoing	ongoing	>>>>>>>>>>>>>	Keep contact with OSL	-
9	Update all court/legal issues in Moran PDL5 & 6	Keep a active file on all court cases where management can be briefed effectively	Ongoing	ongoing	>>>>>>>>>>>>>	Work with Legal Branch	-
10	Review of Moran PDL5 DA	To have PDL 5 DA reviewed per Agreement	Dec-10	Outstanding	funding	Seek funding in Nov. budget	1,300,000.00
	PNG LNG PROJECT	POST LBBSA TASKS					
11	Complete signing of PDL5 LBBSA	To close on PDL 5 LBBSA	Dec-10	Outstanding	funding	Funding under Supp. Budget Nov.2010	
12	NWM PDL 6 Development Agreement signing	To have PDL 6 DA signed and completed	Dec-10	Outstanding	funding	Funding under Supp. Budget Nov.2010	
13	NWM LBBSA mini-forum and signing	To have PDL 6 LBBSA signed for LNG Project	Nov. 2010	Outstanding	funding	Funding under Supp. Budget Nov.2010	

14	PDL 5 leaders meeting on outstandin g PDL5 LBBSA	To complete action item that State promised in PDL 5 LBBSA signing	Nov. 2010	Outstand ing	funding	Funding under Supp. Budget Nov.2010	-
15	PDL6 Ministerial Determinat ion on Beneficiar y groups	Minister to Determine Beneficiari es for PDL6	Nov. 2010	Outstand ing	>>>>>>>>>>>	>>>>>>>>>>>>> >>>>	-
16	Monitorin g of tribal conflicts in PDL6 LNG areas	To monitor tribal conflicts in LNG Project areas	Ongoing	ongoing	>>>>>>>>>>> >>>>	Work with OSL	-
							1,800,000 .00

10.8.7 PDL7 Hides 4

Table 13.6: Hides 4 PDL7 Planned Schedule

N O.	**WORK PROGRA M**	**OBJECTI VE**	**PLANNE D SCHEDU LE**	**STATUS**	**CONSTRAINTS**	**WAY FORWA RD**	**EST. BUDGE T**
1	General liaison work	Ongoing Liaison activities in field & Port Moresby.	ongoing	ongoing	Funding	Secure funds in Supp. Budget	500,000.0 0
1	Payment of outstanding LBSA Invoices to Creditors & Service Providers	To settled all creditors and services providers, which is an issues stopping	November - December 2010	Approved service providers should be paid prior to going into the field due to high risk.	No funding for this activity	Seek Govt. Support and Funding	4,538,074 .00

		field work					
2	ILG Incorporation & Vetting exercise (Includes PDL 1, PRL 11, PRL 12, JUHA, PDL 2,PDL 3 & 4, PDL 5 and Pipe line) does not include Portion 152 & Pom Pipeline & PDL 6.	To have all ILG for Greenfield LNG areas prepared for the PNG LNG project	Jan - Feb 2011	Outstanding	GPCC and MEC yet to give final approval for the budget and work program	Heritage Consultants need to give full scope of work to GPCC and MEC	1,800,000.00
3	Issues Committee & Management of Issues	Government has decided to set up the Committee		Office established	Funding	Supp. Budget Nov.2010	300,000.00
4	Mini Forum to allocate Clan percentages and BD seed capital distribution	To have forums to further distribute shares per LBBSA	May - Dec 2010	Outstanding	Funding	Supp. Budget Nov.2010	660,000.00
5	PRL 12 Growth Centre Implementation	Per PDL 7 LBBSA	Oct.2010	Outstanding	Funding	Supp. Budget Nov.2010	300,000.00
6	PRL 12 Relocation Exercise	To monitor relocation of villagers out of HGCP site	Oct.2010	Compensation payments yet to be completed	>>>>>>>>>>	Liaise with Exxon	0.00

7	Mini Forum to facilitate meeting and negotiations on sharing of benefits between affected LLGs and PG	Per requirements of Oil & Gas Act and UBSA	Oct. to Dec.2010	Outstanding	Funding	Seek Govt. Support and Funding	130,000.00
8	PRL 12 Gas Condition Plant	Monitor construction work and address issues on site	Oct.to Dec. 2010	Ongoing	>>>>>>>>>>>>>>>>	Liaise with Exxon	0.00
9	Monitor leadership and LANCO issues	To address leadership problems associated with LANCOs and LOAs	Oct.to Dec. 2010	Ongoing	>>>>>>>>>>>>>>>>>	Liaise with Exxon	0
							7,728,074.00

10.8.8 ANGORE PDL8

Table 13.7: Angore PDL8 Planned Schedule

NO.	WORK PROGRAM	OBJECTIVE	PLANNED SCHEDULE	STATUS	CONSTRAINTS	WAY FORWARD	EST. BUDGET
1	Payment of outstanding LBSA Invoices to Creditors & Service Providers	To settle all outstanding bills in re to LBBSA/UBSA	Nov. to Dec.2010	Approved service providers still to be paid	Funding and policy directions	Seeking funding under Supp. Budget Nov.2010	4,538,074.00

2	ILG Incorporation & Vetting exercise (Includes PDL 1, PRL 11, PRL 12, JUHA, PDL 2,PDL 3 & 4, PDL 5 and Pipe line) does not include Portion 152 & Pom Pipeline & PDL 6.	To incorporate PNG LNG Project ILGs per Government strategy	Oct. to Dec. 2010	This budget is part of the K5.4 Million for Heritage Consultants (Includes K2 Million for DPE Administration & Cost)	Funding and policy directions	Prepare full brief for GPCC and MEC with the support of Lands Dept. and legal advise from Attorney Gen. on which ILG Act to apply	0.00
3	Issues Committee & Management of Issues	Issues Committee to address all outstanding issues	Oct. to Dec. 2010	This program will run concurrently with the ILG & Vetting exercise to benefit from Synergies	Funding and policy directions	Seek funding from Treasury	300,000.00
4	Angore, Komo & Benaria Law & Order Restoration Services (Supervision)	Major task for the Issues Committee to address	Oct. to Dec. 2010	Outstanding task	Funding	Discuss with Issues Committee Team	0.00
5	Mini Forum to allocate Clan percentages and BD seed capital distribution	An outcome of LBBSA. To conclude benefits sharing arrangements	Ongoing	Outstanding task	Funding	Seek funding from Treasury	660,000.00

6	Current (local) Security Arrangements	To have security in place when mini forums take place in Angore areas	Ongoing	Outstanding task	Funding and policy directions	Discuss with Issues Committee Team	50,000.00
7	Mini Forum to facilitate meeting and negotiations on sharing of benefits between affected LLGs and PG	To comply with UBSA and LBBSA requirements	Ongoing	Meetings not conducted yet	Funding and policy directions	Plan with State team	130,000.00
8	Angore Growth Centre Implementation	To comply with UBSA and LBBSA requirements	Ongoing	Outstanding task	Funding	Discuss with Issues Committee Team	300,000.00
	KOMO ISSUES						
9	Relocation of Komo Airport	To monitor local, industrial and land issues on site	Sept. to Dec. 2010	Works ongoing in Komo	>>>>>>>>>>>>>>>>	Liaise with Exxon Mobil	0.00
10	Supervision of Komo Township Construction & Implementation	To monitor local, industrial and land issues on site, in line with State requirements	Sept. to Dec. 2010	Works ongoing with Exxon Mobil contractors	>>>>>>>>>>>>>>>>>>	Liaise with Exxon Mobil	0.00
							5,978,074.00

10.8.9 PDL9 Juha

Table 13.8: Juha PDL9 Planned Schedule

NO.	WORK PROGRAM	OBJECTIVE	PLANNED SCHEDULE	STATUS	CONSTRAINTS	WAY FORWARD	EST. BUDGET
1	General liaison work	Ongoing Liaison activities in field & Port Moresby.	ongoing	ongoing	Funding	Secure funds in Supp. Budget	500,000.00
1	Challenges on Ministerial Determination for PDL 9	Per requirement of Oil & Gas Act and PDL9 LBSA, Determination was done	Oct-10	Court challenge by J.Sala and Febi clans of WP	Court injunction restraining BDG and benefits to Los	Monitor court actions	2,000.00
2	Land ownership claims by *Huli* clans from SHP into WP	To monitor such land issues that may impede LNG progress	Ongoing	Land claims made but no formal court or dispute registered	>>>>>>>>>>>>>>>>>>	Monitor court actions	2,000.00
3	LNG BDG payments	To implement PDL 9 LBSA to pay BDG	Nov - Dec.2010	Court action by J.Sala restraints payments	>>>>>>>>>>>>>>>>>>	Follow up with DCI and monitor legal suit	5,000.00
4	Benefits re-distribution within confines of PDL 9 LBSA	To have mini-forums to decide on further splits of benefits per LBSA	Nov - Dec.2010	Court order restraints any meetings on benefits	>>>>>>>>>>>>>>>>>>>	Monitor court actions	5,000.00

5	Implementation of Infrastructure Development Grants	To implement LBSA requirements	Nov - Dec.2010	Court order restraints any meetings on benefits	>>>>>>>>>>>>>>>>>>>>	Monitor court actions	5,000.00
6	Preparation of Clan lists and major landholding clans per SMLIs	To have lists of clans for PDL 9 for ILG Inc. work	Oct. 2010	Pending	Funding to have independent review	Source funds	7,500.00
7	Juha ILG Incorporation	To have PNG LNG ILGs prepared	Oct - Dec. 2010	Heritage Consultants to undertake task	Funding	Liaise with Treasury	0.00
8	Outstanding Juha bills and service providers claims	To settle genuine bills and claims, so that officers can go out to the field	Oct. to Dec. 2010	Warrants from Treasury not released yet	Funding	Liaise with Treasury	1,500,000.00
9	Compensation claims and land use agreements under drilling program	To expedite the payments of all outstanding compo and land use claims in re drilling ops	Oct - Dec. 2010	Per disputes monies held in trust by OSL	funding to have meetings with Los	Liaise with OSL to organise trip to meet landowners on site	0.00
10	Establish Clan Vetting & ILG Task Force for Juha	Per Juha LBSA clause 20.	Oct. to Dec. 2010	Not formally established	>>>>>>>>>>>>>>>>>	Get DPE directives and endorsement of Lands Dept.	0.00

11	Establishment of Umbrella Juha Association per Juha LBSA clause 6.5	to implement clause 6.5 of Juha LBSA	Oct. to Dec. 2010	Court injunction	>>>>>>>>>>>>>>>>>	Seek DPE legal advise on way forward	6,500.00
12	Mini forums between PGs and LLGs and landowners	To further re-distribute royalty benefits and for PGs and LLGs to decide on sharing	Oct. to Dec. 2010	Court injunction	>>>>>>>>>>>>>>>>>>	Seek DPE legal advise on way forward	150,000.00
							1,683,000.00

10.8.10 PPFL 2 PNG LNG PLANT SITE

Table 13.9: PPFL 2 PNG LNG Plant Site Planned Schedule

NO.	WORK PROGRAM	OBJECTIVE	PLANNED SCHEDULE	STATUS	CONSTRAINTS	WAY FORWARD	EST. BUDGET
1	General liaison work	Ongoing Liaison activities in field & Port Moresby.	ongoing	ongoing	Funding	Secure funds in Supp. Budget	500,000.00
1	Payment of outstanding LBSA Invoices to Creditors & Service Providers	To settle all bills so that officers can access project sites	Oct. to Dec. 2010	Completed			-
2	Land Group Incorporation & Vetting exercise	To review and update ILGs for LNG Project	Oct. to Dec. 2010	Heritage to complete all tasks	Funding	Seek funds from Treasury	300,000.00

3	Issues Committee & Management of Issues	To establish and operate the Committee to address outstanding landowner issues	Oct. 2010	Committee has been established	Operational funding	Seek funding in Supp. Budget	350,000.00
4	Facilitate meeting with landowners to negotiate distribution on the break-up of 60% royalty and equity	Per Plant Site LBSA	Oct. to Dec. 2010	Outstanding task	Funding	Seek funds from Treasury	36,000.00
5	Facilitate meeting with individual villages for break-up of benefits to individual clans	Per Plant Site LBSA	Oct. to Dec. 2010	Outstanding task	Funding	Seek funds from Treasury	100,000.00
6	Ministerial Determination on Beneficiaries and Splits	Per Plant Site LBSA and Oil & Gas Act requirement	Oct. to Dec. 2010	Outstanding task	Policy advice and decision	Follow up with Policy and Legal Branches	-
7	Facilitate signing of LBSA by Hiri LLG and CPG	Per LBSA and Oil & Gas Act	Oct. to Dec. 2010	Outstanding task	Funding	Seek funds from Treasury	20,000.00
8	Facilitate meeting and negotiations on sharing of LLG and PG benefits between affected plant and pipeline LLGs and PGs	Per LBSA and Oil & Gas Act	Oct. to Dec. 2010	Outstanding task	Funding	Seek directions from Management and Funds	50,000.00
9	Facilitate negotiation on break up of	Per LBSA for PPFL/Plant	Oct. to Dec. 2010	Outstanding task	Funding		20,000.00

	benefits between Hiri LLG and CPG	site					
10	Facilitate meeting to negotiate distribution of infrastructure development grant between affected PALOs, Hiri LLG and CPG	Per LBSA for PPFL/Plant site	Oct. to Dec. 2010	Outstandi ng task	Funding		300,000.0 0
11	Facilitate distribution of the 80% balance of business development grants to four landowner companies as per LBSA	Per LBSA for PPFL/Plant site	Oct. to Dec. 2010	Outstandi ng task for DCI not DPE	DCI working in isolation	DPE request DCI to provide BDG work plant for PPFL2	-
12	Facilitate umbrella representative body for PPFL area	Per the requiremen ts of LBSA	Oct. to Dec. 2010	Outstandi ng task	Funding	Seek funds from Treasury	20,000.00
13	Monitoring of day to day operations in the project area	To work closely with Exxon to monitor works	Ongoing	ongoing		Liaise with Exxon	-
14	See project view on DPE budget for construction and operations in terms of officers' accommodatio n etc.	To have DPE office reside on site during full-constructio n phase	Ongoing	Need DPE managem ent support	Funding	See DPE manageme nt	-
15	Obtain approval for purchase of a full time project vehicle	To logistics available during full constructio n phase	Ongoing	Seek DPE managem ent support	Funding	See DPE manageme nt	145,000.0 0

16	Kido village BDG payment	To ensure landowners have nominated a LANCO transparently	Oct. 2010	Yet to have village meeting to agree on an LANCO	Funding	Seek funds from Treasury	20,000.00
17	Fortnightly update with Exxon on plant site construction/works	To keep DPE abreast on works on the plant site	Ongoing				-
							1,361,000.00

10.8.11 Pipeline License Areas

Table 13.10: Pipeline License Planned Schedule

NO.	WORK PROGRAM	OBJECTIVE	PLANNED SCHEDULE	STATUS	CONSTRAINTS	WAY FORWARD	EST. BUDGET
1	Settlement of outstanding bills and service providers claims	To settle bills so that officers can be free to travel to project sites	Oct.-Dec.2010	Most of the bills have been paid. Only few left	Funding	Allocate funds to settle outstanding genuine bills	1,400,000.00
2	Repatriation of stranded landowners	To repatriate all leftover landowners back to their villages	Oct.-Dec.2010	Some landowners claim that they are still in POM	Funding	Seek funds from Treasury	70,000.00
3	Mini forums to for the 8 segments to decide clan based equity share	Per Pipeline LBSA clause 6.1.1(d), 8 segments	Oct.-Dec.2010	Outstanding task	Funding and Govt. decision	Seek funds from Treasury	800,000.00

		to decide on clan based equity					
4	Mini forums for 8 segments to decide on clan based royalty	Per LBSA clause 6.3 (e) (f)n(g)	Oct.-Dec.2010	Outstanding task	Funding and Govt. decision	Seek funds from Treasury	-
5	Mini forum for 8 segments to decide on regional LANCOs for BDG	Per LBSA clause 6.4 (g) (h) to be implemented	Oct.-Dec.2010	Outstanding task	Funding and Govt. decision	Seek funds from Treasury	350,000.00
6	Meetings with 8 regions to have agreed lists of IDG Projects	To implement clause 6.6 of the Pipeline LBSA	Oct.-Dec.2010	Outstanding task	Funding	Possible funding under Supp. Budget in Nov.2010	-
7	Meetings between PGs and LLGs for further sharing of benefits	To implement LBSA provisions	Oct.-Dec.2010	Outstanding task	Funding and Govt. decision	Possible funding under Supp. Budget in Nov.2010	200,000.00
8	Meetings between LLGs and landowners to share benefits	To implement LBSA provisions	Oct.-Dec.2010	Outstanding task	Funding and Govt. decision	Possible funding under Supp. Budget in Nov.2010	200,000.00
9	ILG Incorporation for PL areas	To prepare ILGs for PNG LNG Project	Oct.-Dec.2010	Heritage Consultants will undertake task	Funding and Govt. decision	Seek funds from Treasury	-
10	Establishment of Issues Committee	Committee to address outstandin	Oct.-Dec.2010	Office has been established	Funding from Govt.	Meet with Chairman Chris	3,000.00

		g landowner matters				Haivetta	
11	Monitoring of tribal fights along PL routes	To monitor and report on civil unrest	Oct.-Dec.2010	Situation tense in some areas	>>>>>>>>>>>>>>>	Keep contact with ExxonMobil	-
12	Monitor BDG payments	To liaise with DCI on pipeline payments of BDG	Oct.-Dec.2010	Regional LANCOs are not nominated yet	DCI not talking to DPE	Liaise with DCI	3,000.00
13	Complete signing of Pipeline LBSA	To get Gulf and Central Governors to sign LBSA	Oct.-Dec.2010	Outstanding task	>>>>>>>>>>>>>>>>>>	Liaise with Minister's office	15,000.00
14	Ministerial Determination of PL beneficiaries	To have Minister determine beneficiaries per Oil & Gas Act	Oct.-Dec.2010	Outstanding task	Funding	Liaise with Treasury for funds	10,000.00
15	Waterways MOU for Kikori area	Monitor MoU for shipping and barge along waterways	Ongoing	Exxon signed MoU with Kikori people	>>>>>>>>>>>>>>>	Liaise with Exxon	-
							3,051,000.00

10.9 PROJECT UPDATE

Each project has had its own unique issues and challenges mainly due to the location of the project. In the project up date we will look at the work that each of project team undertook in their respective project sites the success and challenges that they faced in 2010 as they carried out their duties as per that responsibilities and in line with National Government Policy and directive.

10.9.1 HIDES PDL1, HIDES 4 PDL7

10.9.1.1 PROJECT INFORMATION

Hides PDL1 and Hides 4 PDL7 license areas are covered by two projects in the two license area. Gas to Electricity covers majority of the Landowners in PDL 1 and some Landowners of PDL 7.These Landowners are currently benefiting from Royalty payments and MOA funds that's coming from power supplied to Pogera. The Landowners of these project areas main concern is that what ever benefits they are suppose to get for the power to electricity project must be delivered to them before the Government starts to implement the LNG related programs. LNG is a new project and its benefits will materialize in 2014. However the manner in which the Government is not meeting a lot of its UBSA and LBSA commitments will cause the Landowners to stop the projects process and the project may not meet its time frame.

10.9.1.2 PAYMENT OF OUTSTANDING LBSA INVOICES TO CREDITORS AND SERVICE PROVIDERS

Hides PDL 1, Hides 4 PDL 7 and Angore PDL 8's Service providers claim was group into three categories, A, B and C. A group were the ones that were endorse by the department, B group were not endorse by the Department but were considered genuine service providers and the C group were the ones incurred cost at LBSA meeting and thought that DPE has to pay their creditors for cost they incurred. Department paid the A and B categories service providers in beginning of this year. The C category groups are the ones that are constantly fronting up at the Coordination counter every week and enquiring when their creditor's payment will be made by the department. When funding is made available, some consideration to be given to the C category group and pay those that incurred cost directly related to LBSA meetings.

Landowners have issued threats to DPE field officers if the department doesn't pay their creditors.

10.9.1.3 ILG INCORPORATION AND VETTING EXERCISE

Heritage Consultants has been engaged by the department to Incorporate ILG's for PDL 1 and PDL 7 Landowners. Heritage Consultants will definite need DPE officers on the ground to clarify certain issues when carrying out the ILG incorporation exercise. They are new to the project area people, their culture, social groupings, land tenure system and will need DPE Officers expert advice to carry out the exercise.

10.9.1.4 MINI FORUM TO ALLOCATE CLAN PERCENTAGE

During the ILG incorporation exercise all the clans that will be beneficiaries in the LNG project will be identified.DPE will organize a mini forum to divide the percentage each block or zone got at LBSA to clan level. All ILG Chairmen will attend the mini forum that will be conducted at a venue outside of the project area. The reason for choosing venue outside of the project area is isolate the Landowner from other issues and get them concentrate on dividing of the percentage to clan level.

10.9.1.5 MINI FORUM TO ALLOCATE PERCENTAGE BETWEEN PG AND LLG's

DPE will have to facilitate a mini forum for Provincial government Administrator or his representative to meet with the LLG President's of the project area to divide percentage that given to PG and LLG's. The venue can be within the province or outside of the province.

10.9.1.6 HIDES GTE (POWER TO POGERA) ROYALTY PAYMENT

The Gas to Electricity project at Hides PDL 1's royalty payment is paid to project impacted Landowners on a six monthly basis. Two lots of payment for 2009 were paid in August 2010. The Hides team was suppose pay early this year but due to financial constrain the payments were made in August. Payments for the first quarter of 2010 are ready. When the department secures some funds for, travel, accommodation, cash advance then the Hides team will travel up to the project side and make payments.

10.9.1.7 WORK PLANS FOR 2011

Work plan for 2011 is shown on 2.2 2011 WORK/ISSUES PROGRAM MATRIX. These work programs must be done for the LNG project to progress without interference from Landowners. Funding must be source and made available for the Hides team to carry out these programs

10.9.1.7 ISSUES

The main issues raised by the Landowners in PDL 1 and PDL7 are these?

(1) Government must honor its commitments made in UBSA and LBSA.

(2) Make payments to all outstanding MOA commitments

(3) Make payment to the Seed capital (BD grants) quickly before the construction phase is mid way to completion.

(4) Make payments of outstanding LBSA invoices to creditors/service provider**s.**

10.10 WAY FORWARD

Threats were issued by the Hides Landowners to Officers of DPE if the government of PNG doesn't attend to issues they raised. All the four issue that are raised by the Landowners must be attended to by the government before the Coordination staffs are send to the field to carry out the work program for 2011.

10.10.1 KUTUBU PDL 2

This is an update of the progress of the work in the beginning of the year 2010 and the issues that are still pending to date and will be brought forward to next year 2011 as we move on.

In the beginning of this year (2010), the Kutubu project has been inundated with many issues since the launching of the LNG Project. Under the Kutubu Project PDL 2, South East Mananda (SEM) is a new project and a lot of interested groups have come in from as far as Hides and Koroba pusi\hing for recognition.

Straight from UBSA in Kokopo in year (2009), State has not delivered on some of the issues that have been agreed during the forum and that has resulted in a lot of demand from landowners wanting the state to meet its commitment.

10.10.1.1 Issues Outstanding

1) South East Mananda is a new project which is considered as part of the Kutubu project

2) ILGs listing and verification have been done resulting in the recognition of 35 ILGs in the Manada project and also other project like Foe, Fasu and other subsidiary ILGs under Kutubu that needs to be reviewed

3) Finalisation of all SEM outstanding issues through consultation with legal officers with the aim of settling them.

4) The Kutubu MOA Review that was executed in 1996 which was supposed to be reviewed after 5 years is over due , Irakorahi MOA will also be under taken as part of Kutubu Review, and South East Mananda Supplementary which has been a long outstanding issue.

5) Liaise with other statutory bodies on how to handle matters relating, BD Grants, MOA and other benefits agreed by State on UBSA and LBSA signings. That is the allocation of K2.5 million.

6) There is also an ongoing Foe Leadership Tussle between Hami Yawari, Sese Vege and Sere Sai. An election was conducted in 2008 resulting in the recognition of Sese Vege as the chairman of upper Foe. Due to disputes on his election special meeting was conducted on the 6th of May 2010 which again resolved that Sese Vege represent Foe Association on any matters concerning Foe association with the support of his executives. This decision has not gone down well with Mr Hami Yawari and Sere Sai who also claim to be the Chairman's of Foe association and are seeking legal action.

7) South East Mananda Women Association are constantly pushing for recognition from the Department and request for equal participation and benefits derived in the Multi-Million Project (LNG).

10.10.2 Matrix

Table 14.1: Land Owner Association Matrix

Name of Association (Status)	**Chairman/Chairlady**	
Mananda Women Association Inc	Mrs Erele Tawa	Sought recognition & DPE advised her to consult Mananda Association but appealing secretary for Recognition & it is still pending
Mananda Project Women Ass	Mrs Helen Tarele Pebe	Advice DPE of the establishment of the ass. They Claim to be Sillape based & not seeking any recognition.
Mananda Land Owner Ass	Mr. Kopol Pepe	In existence since Kutubu project and benefit with Fasu under Tonny Dambo now led by Kopol Pepe, endorsed by 35 ILG identified at Moro
South East Mananda LO ass	Philip Tukuyawini	Benefit entitlement reinstated & backdated since they left out of royalty & equity since 2006 to date
Foe Women Ass	Noami Samaul	Seeking Assistance of launching of rice project. We advised that they should seek assistance from MRDC through Sese Vege

Foe Association Yaimo Gira Inv.	Sere Sai Richard Buden	Revocation & appointment of Chairmanship. They stated that any matters regarding Foe should see Sere Sai but this case is still pending up to date Outstanding claims incurred during LBSA bills totalling K256 940. We advised them that Dept.of Treasury is no longer accepting anymore claims.
Mananda Land Owner	Potara Wandule (Togapali Clan) ILG	Break up of 9% royalty and has come up with his own proposed break up. Since Maria Teke is on parole leave , I always refer them to her or MRDC because I have no record of royalty payment
SEM	Arawi Parapu ILG (Homani)	3% entitlements to be reinstated & backdated missed out. I refer them to check with MRDC
Mananda Ass	Peter Talipu (ILG)	Project submission requesting funds totalling K69 000 for infrastructure development refer to EIC
SEM Fasu	ILG Chiefs Paul Yawe	Requesting inclusion of new list of chief fees referred to to Kopol Pepe as Chairman Distribution of BD grants of K1.275 million to be paid to their umbrella company we refer them to DCI

10.10.2.1 Issues summary

Kutubu in terms of production is one of the biggest oil fields in the country is a bigger project like any other project in southern highland Province. The wapiago clan of PDL 2 seek legal action on the release of funds held in the trust. But the Department managed to resolve these issues during a Benefit Sharing Forum held at the Muiri Lee Inn outside of Port Moresby, witnessed by OSL, MRDC and DPE. The break up was done upon agreement signed by various representatives of each clans and Chairman of the affected project areas.

The percentage breakup of specific benefits or the inclusions of benefits have been refered back to them to address.

There is also the generic issue of outstanding claims of costs incurred during LBSA and UBSA, which have been referred to the Department of Treasury.

In south East Mananda, there are 35 ILGs under Kopol Pepe's Chairmanship and the department is reluctant to endorse or recognise new ILGs.

10.10.2.2 Recommendation

- Business Development Grant, MOA, Funds, Infrastructure Development should be properly screened to verify the legitimacy of the companies before paying.
- Outstanding royalty should be paid.
- Secure funding for early next year (2011) for conducting Kutubu Review and South East Mananada Supplementary
- Lands Identification studies/ land verification exercise and ILG incorporation should be conducted as early as next year
- DPE officers should be sent to project sides so that they can deal direct with Land Owners back at home rather than coming to the city and submitting unnecessary claims

10.10.2.3 Conclusion

To conclude, there are many issues that are outstanding which the Government needs to adequately addressed following the signing of UBSA and LBSA which is important so that we safeguard the security of the projects as well as honour our commitments.

10.11. GOBE PDL3 & PDL4

10.11.1 <u>Introduction:</u>

The report provides an introduction and overview into the Gobe Project issues scene. It is intended to provide an updated report on the progress of key project prerequisites and what is yet to be delivered by the department. Funding continues to be the biggest impediment when it comes to executing our work programs that will deal with the prerequisites outstanding. We hope that in providing a full report on Gobe as a Project, the Stakeholders involved will appreciate the gravity of the issues and urgency to deal with them.

From the Kokopo Umbrella Benefit Sharing Agreement last May 2009, Gobe has ventured into uncharted waters to progress its issues and project prerequisites as its sails into the Post LBSA. The Project had to deal with the 17 years old land dispute through the ADR process. The Project as an oil project is a unitized Project, however with the PNG LNG project, only PDL 4 was in the Gas Project and not PDL 3. The segregation issues become a sticky issue of landowners as well as DPE and Exxon Mobile to deal with before we could even talk of ADR. These are some of the challenges the Project has overcome through hard work and very good collaboration by all stakeholders to ensure there was clarity in the issues before hand.

The PDL 3 /4 separation was more a sentimental perspective than that of a commercial sound basis. Gobe Main refused to have South East Gobe landowners involved; however, this issue became a clarified in the ADR Process. The PDL 4 Development forum had delivered one of most successful signing LBSAs despite the killing of a young Bogasi man by the Tiprupekes. This resulted in a tribal clash between the two clans. All in all, despite the challenges, the Gobe Landowner leadership continues to make the difference between themselves and other projects. Their issues continue to influence the manner in which the Industry regulates and manages the landowner related issues.

10.11.2 <u>Project Profile</u>

The Gobe Oil fields including Petroleum Development License 3 (South East Gobe –SEG) and 4 (Gobe Main –GM) came into production soon after Kutubu Oil Fields. To date oil production is fast declining, with SEG being the main producing field; however it is the GM gas reserves that has been designated for the PNG LNG project. To date that there is no determination of the land dispute.The Gobe landowners recently under WS.No.1711 of 2009, Ope Hapuake vs. the State, under the directions of Justice Kandakasi have in a consensus referendum agreed to go for the Alternative Dispute Resolution (ADR). The Court sanctioned ADR process has been completed. The Courts will be endorsing the Agreements which will consequent in a 17 year land dispute resolved by way of mediation –through ADR. The Project is unique in its issues and challenges.

The Project had three deliverables in 2009 to deliver, the Gobe ADR, the LBSA and MOA Review, to date the MOA review is pending. Deliverables were delivered within the required timeframe .The team has delivered the prerequisites despite the challenges. This was possible through effective synergy and teamwork, to effectively deliver the work programs.

10.11.3 Existing Ministerial Determination

Currently there are 21 Incorporated Landowners have been determined as beneficiaries as a one arrangement based on the Lae-Inter agreement. Until such time, the ADR Report with the Agreements are endorsed by the Court, the landowners will determine the Clan level Benefit sharing of each clan beneficiaries. Current each clan is identified in their respective zones; GOBE MAIN, SOUTH EAST GOBE (SEG) and FACILITIES.

10.11.4 Outstanding Issues

10.11.4.1 Land Dispute Settlement through Alternative Dispute Resolution Process

This process was completed with all the Agreements signed by respective Disputants. This is first one its kind into the land dispute process or settlement. The ADR was a result of court direction by Justice Kandakasi under WS.1177 of 2009. The Process was facilitated by Justice Kandakasi and co-facilitated by George Fox. The State through Treasury allocated K3 Million for the process. All the disputants were mobilized into the project area which took almost three weeks to complete. This was a collaborated commitment by respective lawyers involved and designed a terms of reference for the courts to deliberate on it.

The courts endorsed the TOR which set the basis for the ADR process to commence. Mr.Sandy Talita was the Process Administrator. The Process involved the State, MRDC and landowners. Through the process, the issue of separation became very clear and SEG was still part and partial of the PDL 4 by virtue of the PDL 4 license area on the South East end of the license. Whilst the segregation was a commercial issue it impacted on the perspective of the landowners.

Currently the report is already compiled, however a table listing outstanding issues derived from the ADR is yet to be integrated into the ADR report. After this it will then be endorsed by Kandakasi at a date that is yet to be announced, most likely next year.

10.11.4.2 Segregation of PDL 3 & 4 Issue

Under the existing oil project, Gobe is a unitized license. It compromises of PDL 3 & 4. However, in the PNG LNG Project, PDL 3 is not a partner. This was a commercial decision made not to include the PDL 3 in the LNG Project. Whilst, the same volume of gas in PDL 4 is also in PDL 3. The Joint Venture partners decided not to include PDL 3. The separation issue caused a bitter argument amongst the Gobe Main and South East Gobe Landowners. The Gobe Main Leaders claimed that they were playing an observer role in the oil project whilst the South East Gobe landowners benefited greatly in establishing the construction of the Gobe –Samberigi road. The road which continues to face challenges or opposition within SEG and GM.

The GM demanded for compensation for loss of business opportunities. The SEG leaders maintained that whilst they may not be part of PDL 4 in terms of equity, Petroleum Resources Gobe bought into the PNG LNG project as PDL 3 & 4 hence they had an equitable and commercial interest. Exxon Mobil provided a presentation providing clarity to the decision of the JVs and the options the JVs were considering in terms of segregation issue.

It is understood that PRG through MRDC is negotiating for Gas Sales Agreement for PDL 3 to be third party supplier. Should these be executed, another Benefit sharing agreement for PDL 3 will be staged. The ADR Process demonstrated very clearly that SEG was still part of the PDL 4 by virtue of the license area. Whilst the JV partners may change or the exclusion of PDL 3 does not affect the beneficiaries. The equity sharing between PDL 3 &4 will be ironed out properly by professional accountants or business analyst in terms of the costs PDL 3 is incurring as result of this separation issue.

10.11.4.3 Payments of Outstanding MOA/EIC Commitments

The State has made a commitment that outstanding MOA and EIC commitments will paid after proper audits are carried out for the past payments. Some project proponents were yet to provide acquittals or expenditure report on the Project Grants allocated. The Function that once rested with EICS (Expenditure Implementation Committee Secretariat) has been transferred to MRDC per an NEC Decision.

Now that the supplementary budget has been passed EIC have to finalize and endorse for payments of outstanding Gobe MOA projects.

10.11.4.4 MOA Review

MOA review is an outstanding commitment from UBSA and LBSA. Under the Gobe LBSA it was to be conducted in March. This did not happen because of lack of funding. This is a priority and should eventuate early next year.

10.11.4.5 Outstanding LBBSA/UBSA Service Provider Bills

Gobe Still has a good number of outstanding service provider bills to settle. Currently the team is working on compiling and finalizing a list to send to Finance for approval and payment through the allocated funds in the Supplementary Budget.

10.11.4.6 CLAN BENEFIT SHARING PROCESS

The Clan benefit sharing process will have to be conducted immediately after the Court Endorses the ADR Agreements. Again funding will be the biggest impediment to progress this deliverable and this should happen in the first half of next year.

10.11.4.7 Payment of Gobe Royalty and Equity

Royalty and equity should be paid after the Court endorsed ADR Agreements. However this prerogative is MRDC's.

10.11.4.8 Police and CDI Accommodation Bills

This year a total of K71, 000 was paid for outstanding allowances for police who were engaged early this year to contain and manage the infighting in Samberigi between the two stock clans Imawe Bogasi and Tiprupeke. However the CDI bill for accommodation is yet to be paid. Currently a letter is with the Secretary for his approval to seek funds from OSL to pay for these outstanding bills.

10.11.4.9 BD Grants

All BD Grants were paid out to all Landco's in Gobe. Kobs Engineering, Kiki Investments and GFE, however CIVPAC is experiencing in-house issues which have resulted in them yet to receive their BD-Grants.

10.11.4.10. Category 'C' claims

Gobe has a large number of category 'C' claims. Currently a matrix is being developed and with it all the claims will be sent to Finance for further action. It is understood that from Finance the claims will be sent to the Attorney General's office to verify legitimate claims. Those which are legitimate will be sent back to Finance and those which are not will be advised if they want to pursue it further to take it up in Court.

10.11.5 CONCLUSIONS

To conclude all programs and budget has been submitted. Funding is the biggest constraint or the biggest impediment to execute our deliverables.

Nearly all outstanding tasks for Gobe will fall into next year as funding for this year was our biggest constraints.

10.12 MORAN PDL5 & PDL6

The Moran project is part of the greater unitized Moran field comprising of Kutubu PDL2, Central Moran PDL5 and North West Moran PDL6. These three projects have been unitized because they all draw from the same petroleum pool with a commercial sharing arrangement of 45% 44% and 1 % respectively the Moran project and the Kutubu project are currently the largest oil producing fields in the oil Search operated oil projects

In PDL5 this year there were no major issues. The Moran landowners unanimously agreed and signed the UBSA in Kokopo East New Britain Province. Following the signing of the UBSA the landowners were later flown down to Port Moresby to sign the LBSA at the Bomana Police College. They managed to sign the LBSA in one week. The key areas of their agreement were the inclusion of an addition umbrella company the Moran Ina Naga apart from the two existing landowner companies Moran Development Company (MDC) and Maka Investment Limited.

There were only two major issues of the Mt Palana Range this year for Moran PDL5, the first one was the release of the land dispute money for the land dispute between the Nano Webos and the Yumbis which was an on going land dispute that had been going on for almost 12 years. This dispute was eventually settled through a consent agreement between the two clans but the Yumbis have turned around and accused the Department and MRDC of conspiring with the Nano Webos and their affiliated Yumbis and releasing the payments, when the Yumbis in fact were party to the consent agreement. The Yumbis advised the Department that they would be taking the matter to court, however to date the Department or MRDC have never been severed with any notices to that effect.

The Second issue was the demand for the Department and the State to settle their outstanding commitment of K 50 million commitments to the Moran PDL5 landowners. The State had following the Kokopo UBSA released K 15 million to the Moran Landowners through their Association Homa Paua Peoples Association (HPPA). In Moran there are two ethnic groups the Hulis and the Fasus and HPPA is the Association representing the Hulis interest. The Fasus after finding out that the Hulis were paid demanded that their 10% as per their sharing arrangement in their Development Agreement be paid. The Department managed to address their issue by pointing out that the actual State commitment was K 50 million out of which only K 15 million was paid and the balance of K 35 million was still outstanding and that the Fasus would still get their 10% out of the K 35 million outstanding.

The PDL5 project also has it petroleum project review still outstanding with the deadline of the review elapsing in 2009 a budget for the review was done and presented to the Department of National Planning but there has not been any feed back since.

The SHPG has through it’s PBPC meeting advised that it will now picjup the full amount of the Development Levy for the PDL 5 project and has directed the Department against paying the 30 % to the Moran Special Authority (MSPA). This decision is in line with the terms of the Development.

10.12.1 NORTH WEST MORAN (PDL6)

The north West Moran project constitutes 1% of the unitized Moran field. It came into production in 2004 but the Development Agreement was only signed this year together with the LBBSA.

The landowners are yet to receive their royalties and equities even though the Minister had made the Ministerial determination this year.

The landowners want to receive the full 100% of their royalty and equity arguing that the benefits for them is not a lot and if the money goes to MRDC then MRDC would take out 60% leaving them with only 40%

Benefit cannot be distributed immediately because the ILG incorporation has not been completed yet meaning that there are no clearly identified persons to release the benefits to even though the social mapping report and Ministerial Determination have identified the clans that will receive the benefits..

10.13 ANGORE - PDL8

10.13.1 INTRODUCTION

This is a progressive report for PDL 08 or interchangeably Angore Project.

10.13.2 PURPOSE

The intention of this report is twofold;

- ☑ For the purpose of providing general background information of PDL 08 Project for the benefit of new Officers
- ☑ and perhaps to highlight some of the outstanding issues and provide recommendations accordingly.

10.13.3 PROJECT BACKGROUND

Like my other colleague officers looking after other Licenses would say about their own projects I would rather provide some brief descriptions of this Project from my experience as the LNG Field Officer concerned from 2008 to this date.

Angore is a new project or one of the green fields to this PNG LNG Project. This Project recently have changed its Petroleum Retention License Number Eleven (PRL 11) to Petroleum Development License Number Eight (PDL 08) after the Licensed Based Agreement was signed on the 7th of December, 2009. Previously, this project was under PRL 11 with seven (7) reticular blocks. But to apply for the PDL Exxon Mobil had interested in only five (5) Blocks.

PDL 08 currently has five Blocks. **1715** located in Tari-Pori Electorate is the Angore wellhead Block; Komo block **1787** is in the Komo-Margarima Electorate, Pureni block **1642** in the Koroba-Kopiago Electorate, Tamburuma/Hogombe block **1716** and Awatangi/Neango block **1788** located in the Huli – Benaria LLG and Komo-Margarima Electorate.

Angore is one of the very strategically complex projects to deal with. Geographically all these five blocks cover entire Hela Region there is no road linked to each other. Consequently, the clans are scattered all over and obviously with constant tribal fights. To meet all landowners in one or two locations is difficult and so expensive to exercise. PDL 01 and South Hides (PDL 07) Projects have less clans and landowners than Angore Project.

Angore is also a strategic Project that it covers the existing Hides Gas to Electricity (HGTE) Plant Site sharing boundary with PDL 01, covers part of current LNG Hides Gas Conditioning plant site sharing boundary with PDL 07, Komo Airport and the pipeline corridor.

This Project is one of the very complexes, expensive, tough and strategic Projects that I have been dealing with.

10.13.4 OUTSTANDING TASKS & ISSUES

10.13.4.1 Seed Capital / BD Grants

Like all other Licenses, PDL 08 Project Area Landowners are also waiting for State to honor its commitments as per agreed in the Umbrella and Licensed Based Benefit Sharing Agreements. One of its foremost commitments is the seed Capital or Business Development Grants allocated for the landowners to use that money to start up their business and become partners to this LNG Project.

From the total BD grants of K120 Million allocated from the UBSA, PDL 08 will be receiving K12 million. This money was to be distributed to their block companies according to their percentage of shareholdings agreed in the Licensed Based Agreement. Following indicates the seed capital breakup as per the LBBSA.

- 35% to wellhead block 1715
- 9% to Awatango/Neango Block 1788 towards the pipeline
- 7% each to block 1787, 1716 and 1642
- 5% to Imika as wellhead clan
- 30% to the Umbrella Company (ACL)

However, there is still disharmony among the Landowners themselves in with the arrangement and there are some opposing parties from each of the five Angore Blocks.

Despite this Landowner politics, one of the adding factors will be the delay in disbursing the payment to the genuine landowner companies by Department of Commerce and Industry. The delays have already frustrated the landowners as they feel that they are missing out their opportunity in participating in the early works and construction phase.

10.13.4.2 UBSA & LBBSA Approved Claims

For Angore Project, we do have some genuine service provider claims to be paid. Genuine service providers are threatening those landowners whom benefited from the services and landowners are pointing fingers to DPE. It is a kind of chain reaction thing. Thus, to avoid landowner threats and pressures at the Project site DPE need to recommend to treasury and make payments to those genuinely approved claims.

10.13.4.3 LBSA Allowance for Wellhead Block Landowners

This is one of the pressing issues in Angore at hand that needs to be settled before our Officers would be deployed to the field. Unlike PDL 01 and South Hides, Angore made LBSA Forum participants Allowance to their respective blocks through their leaders. Due to its complexities, populous and hence situation beyond teams control, landowner allowance was paid to each of the block Leaders to pay accordingly to the name list.

Payment was executed in all the blocks, however, with the wellhead block, landowners are complaining for their remaining K650.00 per person. 980 participants paid their K350.00 each and we have outstanding of 650 times 980 and that is K637, 000.00. We must at least pay them because there is already a threat at the project site.

10.13.4.4 Project Security

Due to delays in honoring the commitments on time, frustrated over some of the issues mentioned above, there are a lot of security threats being built up. Landowners are already frustrated with the way the state and developers are treating them. We all should be mindful of what we are doing and where we are going.

10.13.4.5 Incorporation of Land Groups (ILG)

Angore as one of the new fields to this LNG Project, there is a need to do a proper clan vetting and ILGs to be done. For the purpose of LBSA Forum participants list DPE Angore team together with the Heritage Consultants have done the vetting process and identified most of the major clans in PDL 08. For the ILG exercise as one of most importantly base component in Landowner identification, DPE Angore Team need work closely with Heritage Consultants to successfully complete the process. Hence, this process will be undertaken by Heritage Consultants in alliance with Lands Department, DPE and other concerned stakeholders.

10.13.4.6 Mini-Forums

Angore team will be looking at organizing mini-forums for allocating clan percentages and BD distribution for the clans identified in the Project and for Southern Highlands Provincial Government and the four (4) affected LLGs. These LLGs include; Hulia-Benaria, Komo, Hayapuga, South Koroba LLG. DPE will facilitate the meeting alongside with Issues Committee if needed.

10.13.4.7 Relocation for Komo Airport Construction

Komo Airport Construction is Exxon Mobil's project. However DPE as a regulator should have been monitoring them closely. Lack of initiative and unavailability of funds our presences at the Project site have been very poor. Despite, directly affected Landowners have relocated and construction is underway.

10.13.4.8 Other Pending Issues

Indicated hereunder are some of the outstanding commitments made as per UBSA and LBBSA. Currently these projects are monitored by Issue Committee members and we will obtain update from them.

- ☑ Angore, Komo & Benaria Law & Order Restoration Services (supervision)
- ☑ Angore Growth Centre Implementation
- ☑ Supervision of Komo Township construction & Implementation

10.13.5 CONSTRAINTS

Whilst considering the issues previously highlighted above, the following would be some possible factors which might hinder the plans and programs future.

- ☑ Funding Problems
- ☑ Security issues
- ☑ Failure to honor the commitments
- ☑ Disbursement of payments to non-genuine landowner companies
- ☑ Landowner leadership tussle
- ☑ Association & Company politics

- ☑ Landowner identification problem

10.13.6 RECOMMENDATIONS

- ☑ Security for Angore Project should be prioritized for it is one of tribal torn projects and safety for the Officers and even among landowners themselves is not really safe. For the upcoming ILG exercise and Mini- forums Security need to be boosted and fully funded.
- ☑ Expedite the Seed Capital payments to ***genuine*** landowner companies. Through Angore Corporation Limited (ACL) and their block companies before ILG
- ☑ DPE should push hard to make Funds available on time to dish out UBSA & LBBSA service providers bills for before the ILG exercise.
- ☑ Given Angore as geographically complicated with more scattered clans and landowners to deal with and will be expensive because of no road network and chopper will be the only means of transport, thus budget need to be increased.
- ☑

10.14 JUHA PDL9

10.14.1 PROJECT INFORMATION

The JUHA PDL 09 project is a new green field find and all or most of its construction work is proposed to commence in year 2015 or thereon by the licensee Esso Highlands Limited. The Gas reserve of this Project technically, is wholly deposited in the Western Province and there are only two small villages namely Siabi and Gesesu covered by the six (6) blocks in this Petroleum Development License area.

Even though the Project is in Western Province, Hulis have claimed ownership of land here and this is a real issue that requires more focus and attention at this initial stage before the benefits are dealt with.

10.14.2 PROJECT UPDATE

Since the execution of the LBBSA Forum and the subsequent Ministerial Determination that ensued for this particular Project, there has been no real fiscal progress of work in line with the planned Work Program meant for this year.

Principal landowner from Siabi village in Western Province Mr. John Wappi Sala has taken out Court proceedings in which he is challenging the legitimacy of the Ministerial Determination. on PDL 09 and the matter is still pending currently. He has also stopped the release of BDG by way of a Court Order until the substantive matter on the Ministerial Determination receives a ruling from the National Court in Waigani.
On the other hand, the dispatch of Officers to implement work programs was hampered due to non availability of funds and also more importantly due to threats received from disgruntled landowners who claimed for service provider payments.

Finally, landowners have and are being dealt with on daily basis when they frequent the Coordination Office for information relating to ILG, clan vetting, BDG and other related issues such as landowner UBSA and LBBSA claims.

10.14.3 <u>ISSUES</u>

The main immediate issues which need to be ironed out at this infant stage of the Project are;

- Clan vetting and land demarcation
- Consolidated addressing of the landowner claim culture.
- Address on request for repatriation of landowners from POM to Western Province and Hela for clan vetting and land demarcation.

10.14.4 <u>WAY FORWARD</u>

At this current stage, the way forward for JUHA PDL 09 is to implement the clan vetting and land demarcation process immediately. All genuine landowners of this Petroleum Development License area have aired their views that they want this process to take immediate effect so that the end result of this exercise will give rise and recognition to the true and original Project landowners. This is very healthy for both the Project and the Department as it will bring to light the genuine and legitimate landowners.

10.15 PIPELINE

10.15.1 INTRODUCTION

Reflecting on the successful completion of the PNG LNG UBSA and the signing of the respective LBSAs, each Project (s) drafted and submitted various 2010 Work Programs with the estimated implementation costs. The Work Programs were then integrated into a DPE 2010 operation plan that was submitted to the Department of Treasury for possible funding through the LNG Appropriation.

The Pipeline Team submitted a Work Program to the value of just over Four Million Kina (K4, 000, 000.00) however, to date as you are fully aware, consultative part of the 2010 LNG Work Program is been implemented but a large factor is yet to be undertaken due to Cash Flow constraints.

Areas of discussion include; (i) 2010 Work Program, (ii) Issues, (iii) Budget Allocation, and; (iv) Recommendations.

10.15.2 PURPOSE

This report purports to highlight the constraints confronting the Pipeline Team and proposes a way forward towards the conclusion. Recommendations proposed in this report should be deemed as suggestions on a way forward to address the prevailing issues along the footprint of the LNG Pipeline.

10.15.3 WORK PROGRAM

As introduced, the LNG PL Team was able to submit a Work Program to the sum of Four Million and Six Hundred and Seventy Thousand Kina Only (K4, 670, 000.00) to the DPE Management to be integrated into a larger document as a DPE 2010 Work Plan submission to the Department of Treasury for possible funding through the LNG Appropriation. There are seven (7) activities itemized in the PL WP Budget and they include, (1) PL LBSA Service Providers Bills, (2) ILG Consultation and vetting as per the eight (8) PL Segments, (3) Review of PL Segment Position Papers, (4) Business Development Grants, (5) PL LBSA Report, (6) PGs and LLGs Sharing Meetings, and (7) ILG Benefit Sharing Meetings with the eight (8) PL Segment landowners.

To date, financial constraints had limited the activities of the Pipeline Team to landowner liaison only within the premises of the DPE office here at Konedobu. The PL Team did not implement the 2010 Work Program.

Table 14.2: Activities undertaken by the Pipeline Team in 2010.

Item	Activity	Schedule	Status	Comments
01	PL LBSA Service Providers Bills	February – April 2010	Completed	Due to Financial constraints and landowner disputes and harassments of DPE officers, the screening and vetting exercise was prolonged and payments were done in early April 2010.
02	PL LBSA Service Providers Bills meetings with landowners	April - June	Completed	Conducted daily meetings with various disgruntled landowners. Beneria PL landowners have lodged a complaint with a Kumul Group of Lawyers and have registered a case against DPE.
03	Attending to Correspondences	January to December	Current	Correspondences have been received from various landowners across the footprint of the LNG PL on various issues but the common interest is the distribution of the LNG BDG.
04	Landowner Liaison	January - December	Current	Landowners are approaching the PL Team on daily basis to discuss various issues ranging from LNG BDG to identification of ILGs and the benefit distribution. This is an on going activity.

To further understand the scope of work and the compounding landowner demands confronting the PL Team, tabled below are the names of the eight (8) PL Segments.

10.15.4 PIPELINE SEGMENTS

The multibillion kina PNG LNG Project took a different twist when it recognized LNG Pipeline landowners as beneficiaries of the LNG Project unlike the Oil Project when separate benefits packages were allocated for the LNG PL Segment landowners.

The Pipeline landowners were categorized into eight (8) different segments. Tabled below are the different segments of pipeline borders.

Table 14.3: The eight (8) PNG LNG Pipeline Segments

Item	Pipeline Border	Province
1	Distance outside of PRL 2 & PRL 12 (PL Elbow Distance)	Western to Southern Highlands (Juha to Hides)
2	Distance from Angore to Maruba River	Southern Highlands
3	Distance from Maruba River to PDL *	Southern Highlands
4	Distance outside License (from PDL * to Kaimari Creek)	Southern Highlands
	Distance from PDL 2 to Gulf/Southern Highlands Border	Southern Highlands
	Distance outside from SHP/Gulf Border to Kaiam Crossing	Gulf
7	Distance from Kaiam crossing to Omati landfall	Gulf
8	Kido Pipeline Distance	Central

10.15.5 ISSUES

Issues highlighted along the footprint of the PNG LNG PL Segment are familiar.

Bulleted below are concerns that have been raised by the PL Segment landowners.

- ILG Identification and ILG Land Demarcation,
- ILG Benefits Sharing within each PL Segment as per the length of LNG pipeline,
- Benefits Sharing Packages of PGs, and LLGs,
- Landowner representation through Umbrella LANCOS and Associations,
- Equal participation and engagement of LANCOs in the construction phase of the PNG LNG Project

10.15.6 RECOMMENDATIONS

Here are suggestions deemed as a way forward to address these issues.

- Organise an in house (DPE) forum to outline and discuss issues affecting each LNG Project areas prior to rolling out the 2011 Work Program,
- LNG Manager (DPE) present the DPE perspective to Coordinators and Project officers in alignment with the 2011 Work Program, and,
- 2011 DPE Budget allocations should be made available to all Coordinators and Project Officers highlighting each Project areas' allocations.

10.15.7 CONCLUSION

In conclusion, 2010 Work Program for the Coordination Branch was stalled because of lack of funding from the Department of Treasury. In addition to that, the transfer of certain roles and functions to various government agencies including the PNG Gas Project Coordination Office, Department of Commerce, Trade & Industry, and the Department of Finance and Treasury had limited the activities of the officers within the Coordination Branch to mere landowner liaison, attending to meetings with various stakeholders with in Pom, and other activities as instructed by the Secretary, Director Petroleum and AD Coordination.

It is with much anticipation that the Department of Finance & Treasury release full funding of the 2011 DPE Budget allocation so that the DPE but especially the Coordination Branch can fully implement its 2011 Work Program.

10.16 PLANT SITE PORTION 152

10.16.1 PURPOSE:

A) To give a general update of the PETROLEUM PROCESSING FACILITY project for the PNG LNG Project in Papua New Guinea.

B) To highlight issues that may hinder the smooth progress and development of the Petroleum

Processing facility.

10.16.2 INTRODUCTION:

PLANT SITE, as it is general known, is the **PETROLEUM PROCESSING FACILITY LICENCE TWO (2),** in Central province. It is a green field area, in terms of the Petroleum Industry, and has been the most impact project, in Hiri LLG, and Central province, as a whole.

Since day one, it has had a big impact, on the lives of the people, and will continue to do so, during the tenure of the PNG LNG project.

10.16.3 BACKGROUND OF PROJECT:

The Petroleum Processing Facility, in Central province, is purposely, for processing of all the raw gas, from the upstream wellheads, especially Juha, in Western province, and Hides, Angore, Moran, NW Moran, Gobe, and Kutubu, in Southern Highlands province.

The raw gas, from these wellheads, will be transported, via a pipeline, that will begin from Juha, run through Southern Highlands province, connecting the other wellheads, and into Kikori area, in Gulf province, and go offshore, and run all the way, under sea and come up on shore (land) to **State Portions 2456, 2458 & 2459** (2456 is part of Formerly State Portion 152), in Central province.

The Petroleum Processing Facility, in central province, will process the raw gas, by changing it, into a liquid form, that will then, be loaded into Tankers (specially designed and made ships), for shipment to International overseas markets.

10.16.4 EARLY WORKS/CONSTRUCTION:

Early works, and construction, is progressing well, and smoothly. Over the last few months, since commencement of early works, and construction, the place has had a dramatic change, in terms of its physical, and geographical appearance, and will continue to do so, up until the end of construction and export of the first PNG LNG product.

10.16.5 LAND OWNER BENEFITS:

Land owner benefits, for the Petroleum Processing Facility License, starting with the UBSA in Kokopo, is as follows;

10.16.5.1 BUSINESS DEVELOPMENT GRANTS (BDG):

Business Development Grants, earmarked for this License, as per the Kokopo UBSA was 52% of the 28% of K120 million, which **is K17.5 million.**

BDG, for the License has all being paid out, or disbursed to the four LANCOs, namely, 1) Porebada Holdings Ltd, 2) Boera Holdings Ltd, 3) Papa Resources Development Ltd, and 4) Buria Rearea Caution Bay Ltd.

10.16.5.2 ROYALTY AND EQUITY BENEFITS:

In the PPFL BSA, only forty percent (40%), of the royalty and Equity Benefits, were agreed to, and equally shared, amongst the four villages, leaving out the "others", in their sharing arrangement, although the **Director's Proposal** was, as follows;

Porebada	19%	Boera	29%
Rearea	19%	Papa	29%
Others	04%		

10.16.6 ISSUES ON THE BENEFITS:

There are certain issues that are attached with the Land owner Benefits that need to be addressed immediately for the smooth progress of the PPFL project.

10.16.6.1 BDG Issue

In the PPFL BSA, it was agreed as per a clause, the Four Lancos will have to share with relatives as acknowledged living outside of the five kilometer buffer zone, namely "others", which are;

1) IDIBANA clan – Boera/Doura
2) NAMURA clan – Keiva
3) Gaibudubu clan – Gorohu
4) Iarogafa clan - Gorohu

The issue, now outstanding is that “Others”, have yet to receive their share, of the BDG, from these four (4) Lancos.

10.16.6.2 Royalty/Equity Issue

The parties were given a three (3) month period, in which to further negotiate, the remaining sixty percent (60%), which unfortunately has lapsed, and now pending Ministerial Determination.

10.16.7 <u>OTHER ISSUES:</u>

10.16.7.1 Land Investigation Report

The Land Investigation Report for the compulsory acquisition for Portions 2457 & 2458 need to be completed through the Land Title Commission or the Alternative Dispute Resolution for compensation purposes. Failure to do so may result in legal challenges, as these two particular portions (2457 & 2458) are integrated portions of the Petroleum Processing Facility.

10.16.7.2 “Others” Group

The issue of the “others” group must be deliberated on at Ministerial level to avoid legal challenges and to avoid disruptions to early works/construction. Through legal undertakings by this group.

10.16.8 LAND GROUPS INCORPORATION PROCESS

There are no problems in this area as through the DPE's vetting and verification process, the number of beneficiary clans for this License has been finalized and awaiting incorporation with Department Of Lands & Physical Planning.

10.16.9 CONCLUSION

All in all, the project is progressing very well. However, the issues highlighted must not be isolated in order that the scheduled time for delivery of the first PNG LNG product is realized, without any disruptions.

10.17 ELK ANTELOPE, INTEROIL PROJECT

10.17.1 Background Information.

The Elk/Antelope Project is situated in the remote highland area of Baimuru Sub-District - Gulf Province. All the existing infrastructures in the area were established during the colonial era by the Lutheran church of Kundiawa. Although Kerema is the provincial headquarter, most of the people from the area sought basic services such as health and education in Kundiawa - Chimbu Province.

Logging is the other major project in the area undertaken by RH Group of Companies. Landowners especially from the Purari delta receive royalties from those logging projects in the area.

Another major project currently being proposed is the Hydro Electricity Dam to be built just few kilometers up from Wabo village. Initially the project was proposed in the early 1970s but was aborted and moved to Yonki. If built, it will be one of the biggest Hydro Electricity Dam in the World.

10.17.2 Current Situation.

10.17.2.1 SMLIS.

The full scale SMLIS of the PDL area was already completed and forwarded to DPE to review and comment. (Respond still pending).

The SMLIS was focused in the proposed PDL areas only of which the Pawaia people were identified as the sole owners of the area with the exception of only two non Pawaia tribes from Evara village.

Other non Pawaia tribes are also claiming ownership of the Elk/Antelope project area however such claims will only be verified through the SMLIS report.

10.17.2.2 ILGs, Associations and LANCOs.

People who claim to be landowners of the project have already formed ILGs, Associations and LANCOs despite the status of the Project still under PPL.

The Gulf Provincial Administration has also advised the locals from both Baimuru and Ihu to register their ILGs, Associations, and LANCOs. This move is dangerous because SMLIS was not conducted in those areas and may raise expectations.

With the formation of the above entities, Landowners are already talking about financial assistance from the State such as Mobilization funds, SEED Capital, etc.

10.17.2.3 Awareness.

DPE has conducted awareness' in the proposed PDL areas only. We are still waiting for the Developer to indicate where the LNG Plant site and the Pipeline route would be so that more awareness can be conducted in those affected areas.

10.17.2.4 Non Pawaia Tribes.

Several non Pawaia tribes from down the Purari delta are also claiming to be Landowners of the Project through their ancestral history. They may challenge the SMLIS report in court due to the fact that none of them were identified in the SMLIS.

The Iare clan from downstream is also using a court decision over timber rights as a basis for claiming ownership of the PDL area.

Definitely non Pawaia tribes would become Pipeline landowners and Plant site landowners therefore it is important for the Developer to conduct SMLIS in those areas ASAP to ease the frustration.

10.17.3 Work Plan for 2011.

Basically we will focus on conducting more awareness' in the affected areas of the Project footprint. Officers from DPE, Lands, Environment & Conservation and other line agencies will be involved in the awareness drive so that all relevant matters shall be addressed on site.

A detailed awareness program and budget would be submitted once we know the exact location of the Plant site and the Pipeline route.

10.17.4 Recommendation & Way Forward.

Separate allocations for liaison activities in the field next year so that officers can make regular field trips and address issues on site.

The Developer has completed the full scale SMLIS for the PDL area only. Likewise they must conduct SMLIS in the Plant site and Pipeline areas because it is the same project despite different project partners and license holders. They cannot apply for a PDL for upstream only and hold onto it. Both upstream and downstream must be completed simultaneously.

InterOil must identify and inform us on the locations of the proposed LNG Plant Site and the Pipeline route ASAP so that we can deal with genuine landowners only instead of talking to everyone.

The Gulf Provincial Administration must work in consultation with DPE when dealing with their people with regard to the Project.

We may encounter serious problems in the future regarding the court decision over timber rights that awarded the "West Bank Purari" to the Iare tribe. Our legal officers must review that decision and clarify us on that matter.

The Pawaia people are confined to their own daily village life despite the massive LNG Project taking place right behind their back yard. It is important that we conduct more awareness in the area and help protect them from outside influences. From previous experiences, some of the problems that we encounter in the existing Oil Project areas were instigated by outsiders and not genuine landowners. We must not allow such cases to recur in this new Project.

10.18 CONCLUSION

This year our field liaison activities were stalled due to funding constraints. Hopefully we anticipate better support for our operations next year and look forward to delivering this second LNG Project for Papua New Guinea being developed.

The funding of the programs and addressing of issues is crucial in ensuring that the National Governments policies and directive for the petroleum projects are implemented to ensure that the States interest in the projects are implemented.

As evident from the matrix there are a lot of outstanding tasks from both the Departments perspective as well as the State that need to be address. It is important that these outstanding issues are addressed to ensure that the National Governments obligations and commitments are met.

The State cannot continue to ignore these issues by sweeping them under the carpet and employ a firefighting approach when these issues erupt. The State should rather be proactively tackling the issues highlighted by allocating ample funding to address these issues. After all the petroleum industry is one of the, if not the highest income earner for the country. Each project is unique because of Papua New Guineas cultural and geographical diversity and has its own unique activities and problems.

The need for LNG and Coordination officers to be in the field is a necessity as we prepare for the development of the LNG project and also continue to deal with the existing oil projects and prospective projects whether it be with the developers or the landowners.

Government presence at the project sites has been lacking this year 2010 and it the Branches hope that next year (2011) ample funding will be allocated to the Department to ensure that officers are in the field to address issues at the project sites and at the same time monitor the situation on the ground in existing oil fields as well as the LNG project locations so that the Department and the State can be reliably informed to issues as they develop.

11.0CONCLUSION

Year 2010 marks a significant growth in Petroleum activities such as licence administration, field operations, geological and geophysical operations however oil & gas productions continued to decline 2010.

A total of twenty two applications of prospective petroleum investors were receipted, compared to thirty one in 2009, two of which were granted Petroleum Prospective Licence status while the remaining were either refused, withdrawn or pending Ministerial determination. At the end of 2010, a record of 64 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 honour their work programs in the initial six-year licence tenure. Although only one geological study was undertaken, more priority was given to geophysical studies so as to upgrade leads and prospects to drillable stage. A record total of actual 35,570.3 line kilometres of data were acquired during the G&G studies at an estimated grand cost of US$250,000,000.00.

Thirteen wells were drilled in 2010: 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 2010 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.

APPENDIX 1: PETROLEUM EXPLORATION STATISTICS 2010

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
NEW PPL's GRANTED	4	5	5	8	1	6	6	5	9	4	3	2	1	10	8	10	9	8	13		3
PPL's EXPIRED, SURRENDERED OR CANCELLED	2	12	8	13	6	2	5	2	5	3	1	3	4	9	5	0	0	0	6		3
TOTAL NUMBER OF PPLs	40	33	30	25	20	24	25	26	30	31	33	31	28	25	28	38	47	38	51		64
TOTAL NUMBER OF PPL BLOCKS		2684	2143	1283	995	1130	1395	1372	1494	1535	1508	1066	1020	327	2136	1038	3215	3226	4865		3664
TOTAL AREA UNDER LICENCE (KM2)		228140	182155	109055	84575	96050	118575	116620	126990	130475	122148	90610	87308	89991	185604	84159	260415	261306	399411		298764
NEW PDLs GRANTED	2	0	0	0	0	0	2	0	0	0	0	1	0	0	0	0	0	0	1	3	0
PDLs EXPIRED, SURRENDERED OR CANCELLED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL NUMBER OF PDLs	2	2	2	2	2	2	4	4	4	4	4	5	5	5	5	5	5	5	6	9	9
TOTAL NUMBER OF PDL BLOCKS	16	16	16	16	16	16	21	21	21	21	21	22	22	22	22	22	22	22	23	37	37
NEW PLLs GRANTED	2	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0		0
TOTAL PLLs GRANTED	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3		8
NEW PRLs GRANTED	0	0	0	0	0	0	0	0	1	0	4	0	5	0	1	0	0	0	0	0	0
TOTAL NUMBER OF PRLs	0	0	0	0	0	0	0	0	1	1	5	5	8	11	11	11	11	11	11	11	13
APPROXIMATE EXPENDITURE	K225M	K170M	K80M	K60M	K70M	K117M	K190M	K258M	K120M	K144M	K157M	K238M	K194M	K110M	K70M	K80M	K285M	K430.8M	K695.9M	TBA	
EXPLORATION WELLS DRILLED	21	11	7	4	10	4	5	9	5	5	2	0	3	2	2	3	3	5	4	3	5
DISCOVERY WELLS	9	5	4	2	2	1	2	2	2	1	0	0	2	1	3	0	2	0	3	2	1
NEW FIELD DISCOVERIES	4	3	2	1	0	0	1	0	0	1	0	0	2	2	2	1	2	0	1	1	1
CUMULATIVE FIELDS	18	21	23	24	24	24	25	25	25	26	26	26	28	30	32	33	35	35	36	39	40
CUMULATIVE WELLS	213	224	231	235	245	249	254	263	268	273	275	275	278	287	294	298	201	306	310	323	333
% SUCCESS RATE	8.5%	9.4%	10.0%	10.2%	9.8%	9.6%	9.8%	9.5%	9.3%	9.5%	9.5%	9.5%	10.1%	10.5%	10.9%	11.1%	11.6%	11.4%	11.6%		
GEOLOGICAL SURVEY				4	4	6	4	5	2	1	4	1	1	1	1	1	4	1	3		1
GEO LINE KMS						869	238	674	53.85	63.35	158.4	16	117.5	175		120	149.45	83.75	50		15
GEOPHYSICAL SURVEY				7	3	12	6	9	9	6	4	4	3	3	4	6	17	4	7		14
AIRBORNE GRAVITY/AEROMAG					2	7	3	3	2	1	0	0	0	1	0	2	9	0	0		4
GRAVITY/AEROMAG LINE KMS					31796	93094	27294	33583	10571		0	0	0	5076	0	6292.1	35208	0	0		30081
SEISMIC SURVEY	15	6	8	3	1	3	1	6	7	2	4	4	3	2	4	4	8	4	7		9
SEIS LINE KMS ONSHORE	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		654
SEIS LINE KMS OFFSHORE	2576	661	879	2425	12568	0	0	0	5390	0	0	0	0	0	0	0	12972	0	47000		4715
SEISMIC TOTAL	5477	1405	1630	2468	12603	361	82	321.14	5418.2	142	147	109.8	49.75	36	124	247.15	13560	533.23	47916		5369
		3.7	5.8	7.9	9.2	9.6	13.5	11.5	13.3	13.1	12	14	10.2	14	11						

NOTES

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

(b) Figures at year end

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

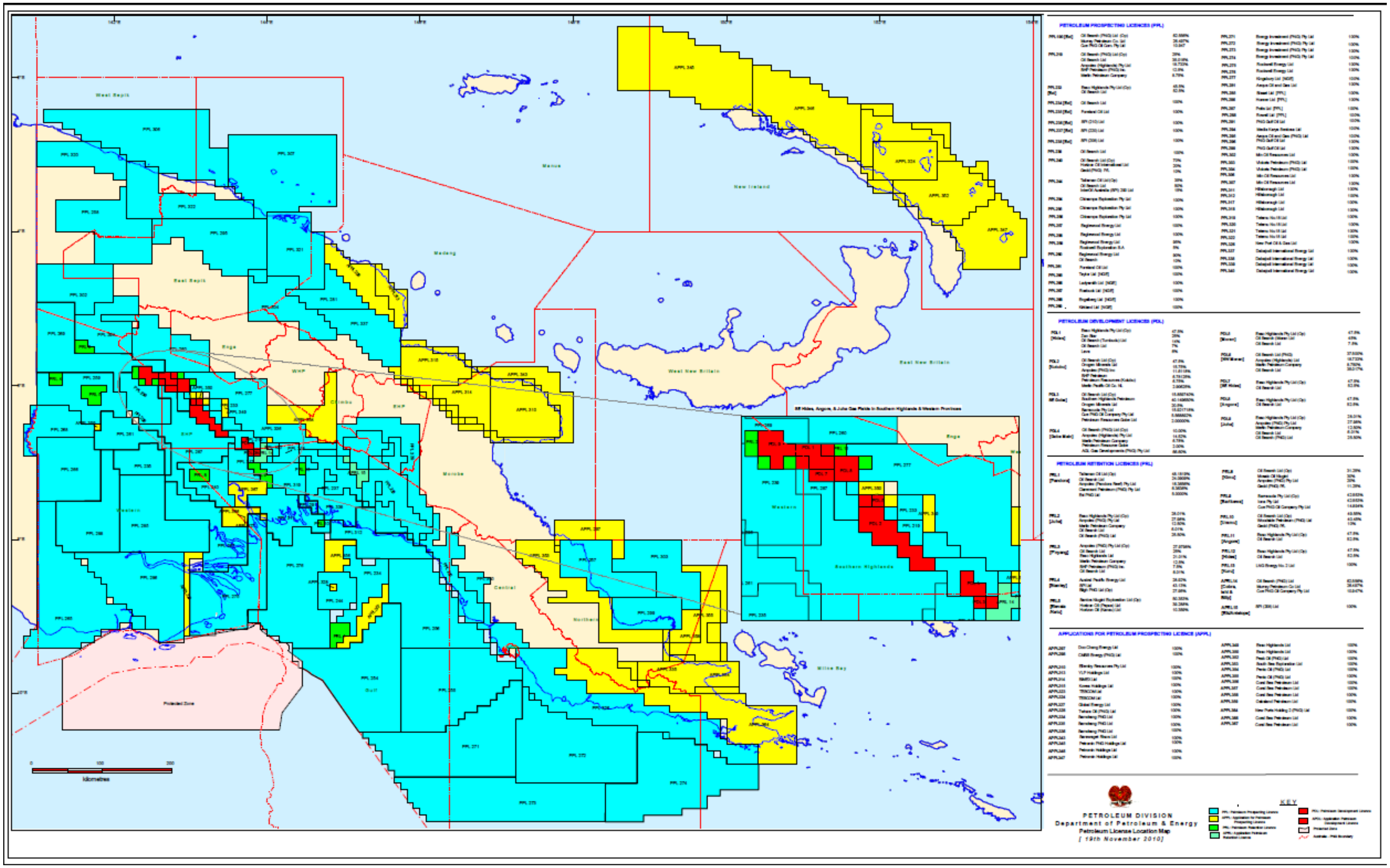
(d) 1986 = IAGIFU
1987 = SE HEDINIA, HIDES
1988 = HEDINIA, PANDORA
1989 = AGOGO
1990 = ANGORE, ELEVALA, PNYANG, USANO
1991 = KETU, SE MANANDA, SE GOBE

1992 = GOBE 2X, PANDORA B
1993 = GOBE MAIN
1996 = MORAN
1996 = KIMU
2002 = SAUNDERS, BILIP

(e) 3-D Pasca Survey

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

APPENDIX 2: Petroleum Licence Tenements Maps, 2010



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