Oil and Gas in Indonesia

Investment and Taxation Guide

May 2018, 9th Edition

pwc

www.pwc.com/id

Photo source: PT Chevron Pacific Indonesia

Cover photo courtesy of: PT Chevron Pacific Indonesia

Regulatory information is current to 12 April 2018.

Contents

Glossary

Term	Definition
AFE	Authorisation for Expenditure
APBN	*Anggaran Pendapatan dan Belanja Negara* (State Budget)
APMI	*Asosiasi Perusahaan Pemboran Minyak, Gas dan Panas Bumi Indonesia* (Association of Indonesian Oil and Natural Gas Drilling Companies)
ASC	Accounting Standard Codification
ATIGA	ASEAN Trade in Goods Agreement
BBC	Bare-boat charter
BI	Bank of Indonesia
BiK	Benefits in Kind
BKPM	*Badan Koordinasi Penanaman Modal* (Indonesia's Investment Coordinating Board)
BP Migas	*Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi* (Oil and Gas Upstream Business Activities Operational Agency)
BPH Migas	*Badan Pengatur Hilir Minyak dan Gas Bumi* (Oil and Gas Downstream Regulatory Agency)
BPKP	*Badan Pengawasan Keuangan dan Pembangunan* (the Financial and Development Supervision Agency)
BPR	Branch Profit Remittance
BPT	Branch Profits Tax (i.e. on BPRs)
BUMD	*Badan Usaha Milik Daerah* (Regionally Owned Business Enterprise established by the Regional Government)
BUMN	*Badan Usaha Milik Negara* (State-owned Enterprise)
C&D Tax	Corporate and Dividend Tax
CBM	Coal Bed Methane
CD	Community Development

Term	Definition
CIF	Cost, Insurance, Freight
CITR	Corporate Income Tax Return
CNG	Compressed Natural Gas
CoD	Certificate of Domicile
DEN	*Dewan Energi Nasional* (National Energy Council)
DER	Debt-to-Equity Ratio
DGB	Directorate General of Budget
DGoCE	Directorate General of Customs and Excise
DGOG	Directorate General of Oil and Gas
DGT	Directorate General of Taxes
DMO	Domestic Market Obligation
DPR	*Dewan Perwakilan Rakyat* (House of Representatives)
DRM	*Daftar Rekanan Mampu* (vendors qualified for Government procurement bidding)
EIT	Employee Income Tax
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement, and Construction
FCR	Foreign Currency Report
FDC	Foreign-owned Drilling Company
FIFO	First In, First Out (inventory accounting method)
FOB	Free on Board
FPSO/FSO	Floating Production Storage and Offload (vessel)/Floating Storage and Offload (vessel)
FPU	Floating Production Unit
FQR	Financial Quarterly Report

Term	Definition
FSRU	Floating Storage Regasification Unit
FTP	First Tranche Petroleum
FTZ	Free Trade Zone
G&G	Geological and Geophysical
GAAP	Generally Accepted Accounting Principles
GoI	Government of Indonesia
GR	Government Regulation (*Peraturan Pemerintah*)
GTL	Gas to Liquids
IAS	International Accounting Standards
ICP	Indonesian Crude Price
IFAS	Indonesian Financial Accounting Standards
IFRS	International Financial Reporting Standards
IGA	Indonesian Gas Association
IKTA	*Izin Kerja Tenaga Kerja Asing;* now *IMTA/Izin Mempekerjakan Tenaga Asing* (Work Permit for Foreign Workers)
IPA	Indonesian Petroleum Association
IPKA	*Izin Penggunaan Kapal Asing* (Permit to Use Foreign Vessels)
IPPKH	*Izin Pinjam Pakai Kawasan Hutan* ("Borrow-Use" Permit For Forest Area)
ITO	Indonesian Tax Office
JCC/JO	Joint Cooperation Contract/Joint Operation
JOA/JOB	Joint Operation Agreement/Joint Operating Body
KBLI	*Klasifikasi Baku Lapangan Usaha Indonesia* (Indonesian Standard Industry Classification)
KEK	*Kawasan Ekonomi Khusus* (Special Economic Zone)

Term	Definition
KPBU	*Kerjasama Pemerintah dan Badan Usaha* (Cooperation of Government and Business Entity)
LIFO	Last In, First Out (Inventory Accounting Method)
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LST	Luxury-goods Sales Tax
MBOEPD	Thousand Barrels of Oil Equivalent per Day
MBOPD	Thousand Barrels of Oil per Day
MIGAS	*Minyak Bumi dan Gas Alam* (Oil and Gas)
Minister of EMR	Minister of Energy and Mineral Resources
ML	Master List
MMSCFD	Million Standard Cubic Feet per Day
MoEMR	Ministry of Energy and Mineral Resources
MoF	Ministry of Finance
MoT	Ministry of Trade
MoU	Memorandum of Understanding
NBV	Net Book Value
NGRR	New Grass Root Refinery
NJOP	*Nilai Jual Objek Pajak (Tax Object Selling Value)*
Non-CR	Non - Cost Recoverable
NPWP	*Nomor Pokok Wajib Pajak (Tax Payer Identification Number)*
NTB	*Nomor Transaksi Bank (Bank Transaction Number)*
NTPN	*Nomor Transaksi Penerimaan Negara (State Revenue Transaction Number)*
O&M	Operation and Maintenance

Term	Definition
OPEC	Organisation of Petroleum Exporting Countries
PBB	*Pajak Bumi dan Bangunan* (Land and Building Tax)
PBI	*Peraturan Bank Indonesia*
PCO	Parent Company Overhead
PE	Permanent Establishment
PEB	*Pemberitahuan Ekspor Barang* (Export Goods Notification)
PER	*Peraturan Dirjen Pajak* (DGT Regulatory)
PGN	*Perusahaan Gas Negara* (State Gas Company)
PIS	Placed Into Service
PMA	*Penanam Modal Asing* (Foreign Investment Company)
PMK	*Peraturan Menteri Keuangan Republik Indonesia* (Ministry of Finance Regulation)
PoD	Plan of Development
PP&E	Property, Plant & Equipment
PSC	Production Sharing Contract, one of the type of Joint Cooperation Contracts (KKS - *Kontrak Kerja Sama*)
PT	*Perseroan Terbatas*
PTK	*Pedoman Tata Kerja*
R&D	Research & Development
RDMP	Refinery Development Master Plan
RIM	Energy Market Data Provider
RPTK	*Rencana Penggunaan Tenaga Kerja* (Annual Manpower Plan)
RPTKA	*Rencana Penggunaan Tenaga Kerja Asing* (Foreign Manpower Employment Plan)
SE	*Surat Edaran*

Term	Definition
SFAS	Statement of Financial Accounting Standard
SIUPAL	*Surat Izin Usaha Perusahaan Angkatan Laut* (Shipping Company Business Licence)
SKK Migas	*Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi* (Special Taskforce for Upstream Oil and Gas Business Activities)
SKS	*Satuan Kerja Sementara*
SKUP	*Surat Kemampuan Usaha Penunjang* (Supporting Business Capacity Certificate)
SPOP	*Surat Pemberitahuan Objek Pajak* (Notification of PBB Objects)
SPPT	*Surat Pemberitahuan Pajak Terutang* (Official Tax Payable Notification)
SSP	*Surat Setoran Pajak* (Tax Payment Split)
TAC	Technical Assistance Contract
TCF	Trillion Cubic Feet
TDR	*Tanda Daftar Rekanan* (Registered Vendor ID)
TPAA	Trustee Paying Agent Agreement
US GAAP	Generally Accepted Accounting Principles (in the United States)
VAT	Value Added Tax
WAP	Weighted Average Price
WHT	Withholding Tax
WOP	Write-Off Proposal
WP&B	Work Program & Budget
WTI	West Texas Intermediate (Crude Oil Price)

Foreword

"

Welcome to the 9th edition of the PwC Indonesia Oil and Gas in Indonesia – Investment and Taxation Guide. This edition captures the latest tax and regulatory changes that have occurred in the oil and gas industry during the past year, including our early views on the new "Gross Split" PSCs.

This publication has been written as a general investment and taxation guide for all stakeholders interested in the oil and gas sector in Indonesia. We have therefore endeavoured to create a publication which can be of use to existing investors, potential investors, and others who might have a general interest in the status of this important sector for the Indonesian economy.

As outlined on the contents page, this publication is broken into chapters which cover the following broad topics:

1. Industry overview;
2. Regulatory framework;
3. (Conventional) upstream sector;
4. Gross Split PSCs;
5. Downstream sector; and
6. Service providers

As most readers will know, oil and gas production has a long and relatively successful history in Indonesia, with the sector historically characterised by its relatively stable and well-understood regulatory framework. In many areas, including the development of the Production Sharing Contract (PSC) model and the commercialisation of Liquefied Natural Gas (LNG), Indonesia has been an international pioneer.

However, the industry is arguably now in a transitional phase, with a growing domestic need for gas for both consumers and industrial use. Indonesia's production and opportunity profile has also moved steadily away from oil and towards gas – a trend which may ultimately represent a permanent shift.

In terms of where the industry is right now, readers are probably aware that crude oil production in Indonesia has been on a downward trend for the past decade, with most oil production now coming from mature fields. As a result, the country became a net oil importer in late 2004. Despite the Government's efforts to stimulate exploration through offering new acreage and a joint study facility, these initial incentives have not been particularly successful in attracting new investors.

Many readers may argue that the most critical barrier to Indonesia's oil and gas investment is the regulatory hurdles and bureaucratic processes associated with the approval of expenditure. Whilst this is true to some extent, it should also be noted that the concerns are often connected to delays in areas outside of the control of the Ministry of Energy and Mineral Resources (MoEMR) (e.g. those connected to tax, forestry, the environment, etc.) as well as to local government authorities. During 2017 and earlier this year, the Government also sought to reduce the overall bureaucracy with steps aimed at simplifying the current regulations and providing more clarity on key areas of uncertainty such as fiscal terms. As part of this, the Government introduced the new "Gross Split PSC" concept in early 2017. We have highlighted the most significant regulatory changes in this Guide for your reference.

How Indonesia performs on these issues, including on improving its reserve replacements and guaranteeing its domestic energy security, will have a significant bearing on Indonesia's continued relevance as an international oil and gas player, as well as on Indonesia's share of global investment dollars. If successful, Indonesia should continue to be an important component of the region's energy marketplace from both a demand and supply perspective – with the supply side leveraged to achieving an increase in underlying exploration and development activity.

Finally, readers should note that the regulatory content in this publication is largely current as at 12 April 2018. Whilst every effort has been made to ensure that all information was accurate at the time of printing, many of the topics discussed are subject to interpretation, and regulations are changing continuously. As such, this publication should only be viewed as a general guidebook and not as a substitute for up to date professional advice. As such, we recommend that you contact PwC's oil and gas specialists (see page 148) as you consider investment opportunities in the Indonesian oil and gas sector.

We hope that you find this publication of interest and of use, and we wish all readers success with their endeavours in the Indonesian oil and gas sector.

1 Industry Overview

1.1 Introduction

The oil and gas industry, both in Indonesia and globally, has experienced significant volatility in the last five years. Global geopolitical and economic considerations play a significant role in driving the sensitivity of oil prices. Records show that from its peak in mid-2008 (US$ 145 per barrel), the oil price collapsed by more than 70% and ended 2008 at US$ 40 per barrel following the global financial crisis. As market confidence returned, buoyed by confidence in growth in China and other emerging markets, crude prices rose again to an average (on an annual basis) of approximately US$ 94-98 a barrel of West Texas Intermediate (WTI) from 2011 to 2014.

However, the development of shale technology reduced the oil and gas import dependency of the United States, which was the biggest net-oil importer, and turned the market back into turmoil. This consequently led oil to be oversupplied in oil-producer countries and so became a key factor for the falling oil price, even to below US$ 30 a barrel at the beginning of 2016. At the end of 2016, the Organisation of Petroleum Exporting Countries (OPEC) reacted to the oil price plunge by restricting oil production in an attempt to stabilise the supply and bring some moderation to global oil prices. Despite the market's fear of failure of any OPEC arrangement and the USA's high oil and gas production, which led to price falls in mid-2017, the OPEC policy around production controls, an increase in global oil and gas demand, and below-expectation US exports supported the oil price recovery in 2017, with WTI crude rising above US$ 60 per barrel at the end of 2017, and the Indonesian Crude Price reaching US$ 51.19 per barrel.

In a more local sense, investment in the oil and gas industry in Indonesia was around US$ 10.3 billion in 2017 (based on Government data), the lowest in a decade. The rise in oil prices is expected to trigger investment interest and the government set a target of US$ 17.04 billion in 2018. However, the industry's contribution to the state revenue has fallen sharply from 14% in 2014 to 3% in 2016, before recovering to 5% in 2017. The Government has set a moderate target of 4.2% for 2018, which allows for influence from the rising oil price while reserving some space for volatility in prices.


Photo source: PT Pertamina (Persero)

While oil prices have risen to more normal levels, the problem of a lack of new reserve discoveries and reserve depletion still remains, resulting in a decline in the contribution to state revenue from the Oil and Gas sector. These factors also contributed to the relinquishment of numerous oil and gas working areas during 2016-2017. As of 15 September 2017, SKK Migas reported 46 oil and gas exploration blocks classified as 'in termination' due to insufficient economical levels. In 2016, there were only two new contracts signed from 17 contracts offered, while no new contracts were signed in 2017, which may result partly from investors taking time to consider the change in the contract system from the traditional cost-recovery model to the new gross-split methodology. The 2017 oil and gas tender was delayed until the end of the year, when five new contracts were announced in February 2018 from the fifteen blocks on offer.

Aside from the changes in the PSC system, March 2018 also saw the Government revoke 18 regulations and 23 requirements for certifications, recommendations, and permits, in an attempt to reduce duplication in certification, shorten bureaucracy and simplify the business. The effectiveness of this reform remains to be seen.

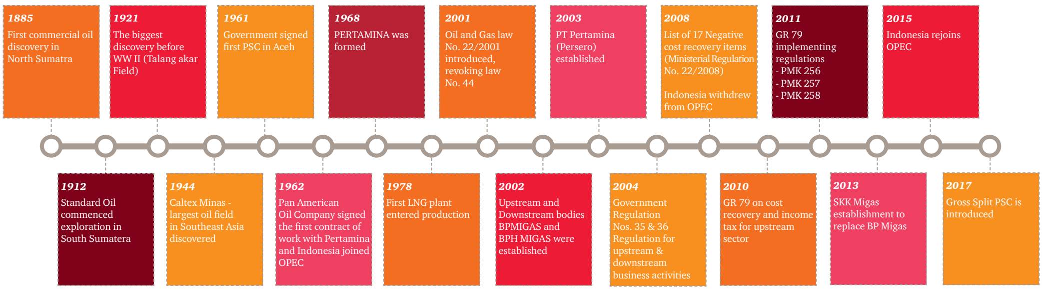
1.2 *Indonesian Context*

Historically, Indonesia has been active in the oil and gas sector for nearly 130 years after its first oil discovery in North Sumatra in 1885. Indonesia continues to be a significant player in the international oil and gas industry.

A longtime member of OPEC, Indonesia suspended its membership in 2008 after years of declines in production, but rejoined the bloc in 2015, signalling its commitment to the industry.

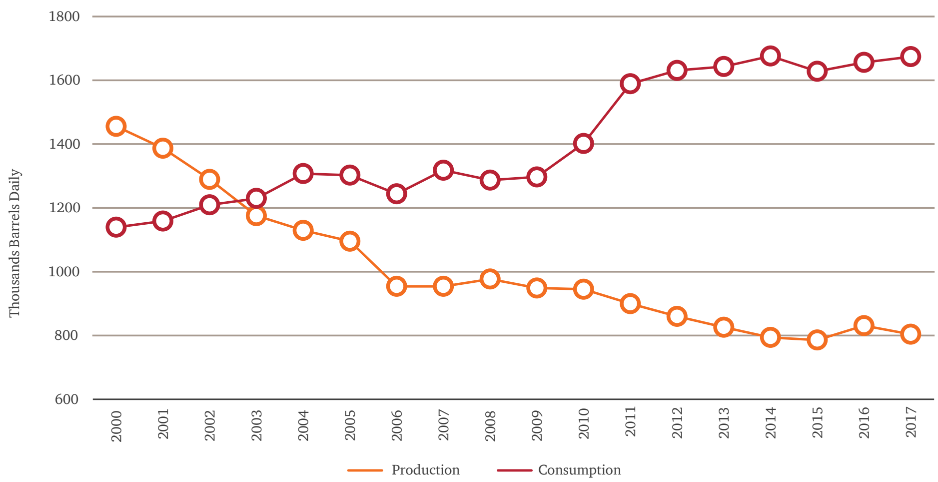
Indonesia holds proven oil reserves of 3.7 billion barrels and is ranked in the top 20 of the world's oil producers.

Significant events in the history of Indonesia's Oil and Gas Sector



However, declining oil production and increased consumption has resulted in Indonesia being a net oil importer since 2004. This factor, along with high oil prices before 2015, led the Government to gradually but substantially scale-back the domestic fuel subsidy during 2009-2014.

Indonesian Oil Production and Consumption



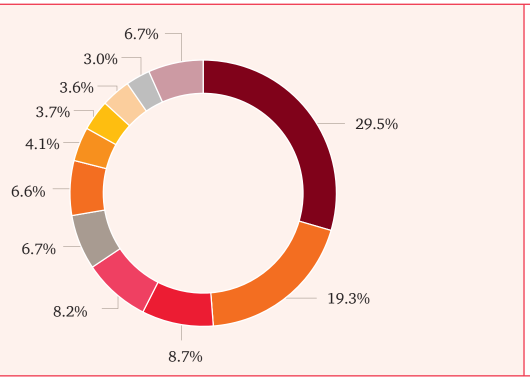
Source:
**Oil Production and Consumption 2000-2005: BP Statistical Review 2011*
**Oil Production 2006-2016: SKK Migas, MoEMR*
Oil Production and Consumption 2017 : SKK Migas, EIA/BMI

Indonesia is ranked 10th in terms of global gas production, with proven reserves of 102 Trillion Cubic Feet (TCF) in 2016. On a reserve basis, Indonesia ranks 15th in the world and the third in the Asia-Pacific region (following Australia and China). Indonesia's relevance in seaborne LNG is more critical.

Indonesia's gas industry is being pressured by more competitive LNG markets, new pipeline exports, and increasing domestic gas demand. Indonesia's natural gas production market share actually decreased in recent years (from 2.6% of the world's marketed production of natural gas in 2010, to 2.0% in 2016) coupled with a declining global LNG market share particularly due to new LNG production coming on-line in Qatar and Australia. After announcing its 2006 policy to realign natural gas production to domestic needs, Indonesia dropped from the world's largest exporter of LNG in 2005 to the world's fifth largest exporter in 2016, behind Qatar, Australia, Nigeria, and Malaysia.

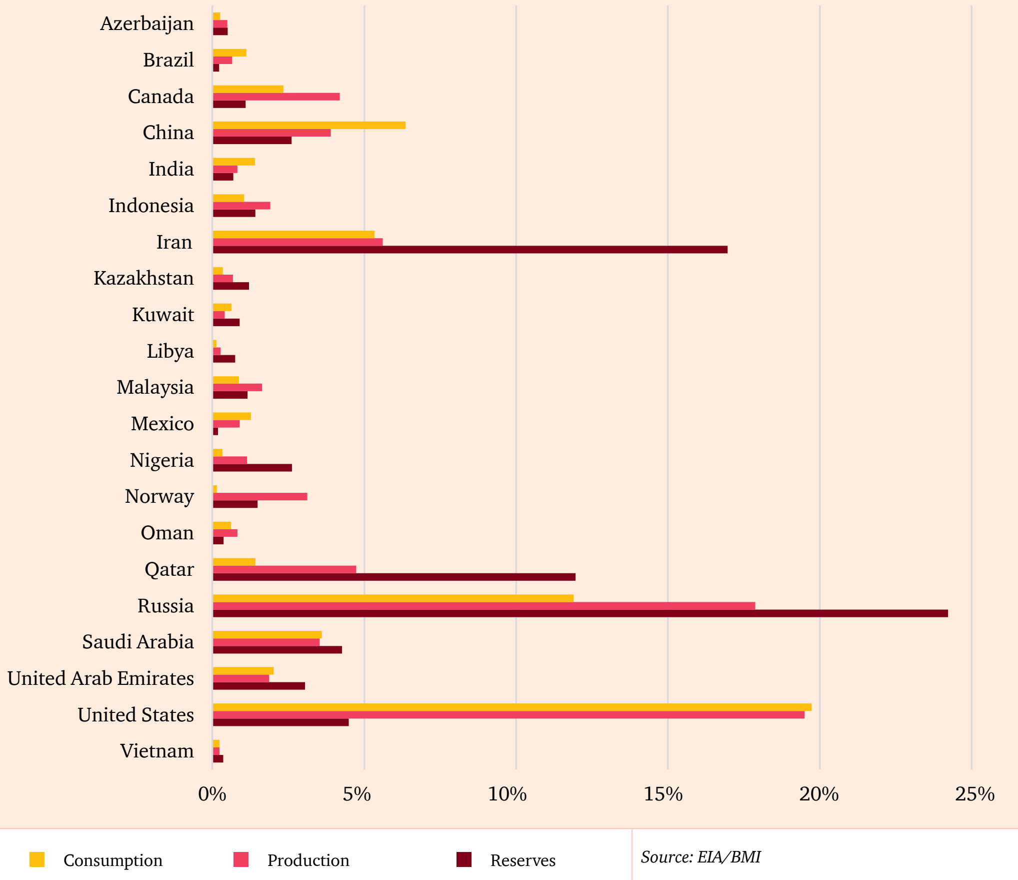
Indonesia's existing LNG facilities are based in Bontang in East Kalimantan, Tangguh in West Papua and Donggi Senoro in Sulawesi. Arun LNG, which was one of the world's first LNG facilities and one of the biggest LNG exporters in the 1990s, has been converted into a storage and regasification terminal due to declining gas reserves.

World's Top LNG Exporters 2017



Source: EIA/BMI

Share of World's Gas Reserves 2017



Source: EIA/BMI

1.3 *Resources, Reserves and Production*

Indonesia has a diversity of geological basins that continue to offer sizeable oil and gas potential. Indonesia has 60 sedimentary basins, including 36 in Western Indonesia that have already been thoroughly explored. Fourteen of these are producing oil and gas. In under-explored areas of Eastern Indonesia, 39 tertiary and pre-tertiary basins show rich promise in hydrocarbons.

About 75% of exploration and production is located in Western Indonesia. The four oil-producing regions are Sumatra, the Java Sea, East Kalimantan and Natuna. The three main gas-producing regions are East Kalimantan, South Sumatra and Natuna.

Indonesia's crude oil production declined over the last decade due to the natural maturation of producing oil fields combined with a slower reserve replacement rate and decreased exploration/investment. During 2017, Indonesia's crude oil production was about 804 Thousand Barrels of Oil Per Day (MBOPD), a slight reduction from 831 MBOPD in 2016. The daily oil lifting target in 2018 is 800 MBOPD, a slight reduction from the previous year, while the gas production target in 2018 is equivalent to 1,200 Thousand Barrels of Oil Equivalent per Day (MBOEPD). However, with few significant oil discoveries in Western Indonesia in the last ten years, Indonesia still relies upon the mature oil fields that continue to decline in production. Hence, the Government encourages Contractors to explore Eastern Indonesia's frontier and deep-sea areas.

Further demonstrating the importance of gas, Indonesia's gas production represents 60% of total oil and gas production in the country. This portion is estimated to increase to 70% in 2020 and 86% in 2050. However, similar to oil, the gas reserves are predicted, slowly but surely, to decline: current proven reserves are estimated at 101 TCF. Following the depletion of some major fields, e.g. the gas-rich Mahakam block, reserves are estimated to decline to 96 TCF by 2020 unless significant new proven reserves are discovered.

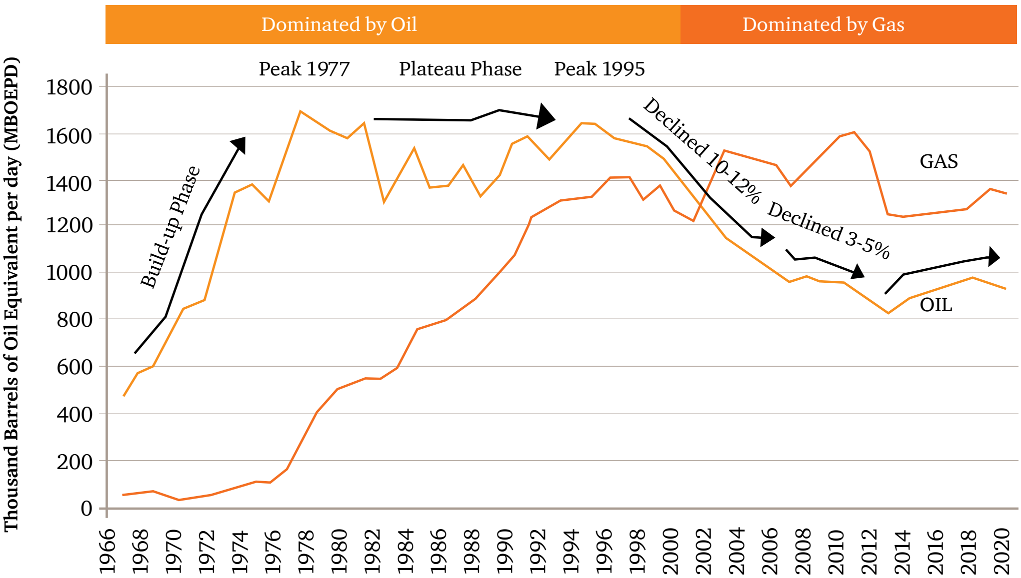
In order to boost production, the Government declared several new upstream oil and gas strategic projects e.g. the Jangkrik field development, Tangguh Train-3, the Indonesia Deepwater Development Project, and Genting's Kasuri block. The Jangkrik Floating Production Unit (FPU) has operated since May 2017, ahead of schedule by six months. Jangkrik FPU production capacity has surpassed 600,000 standard cubic feet of gas per day, or 100 MBOPD at the end of October 2017, which is around 5% of the national oil and gas production target in 2018.

Key Indicators - Indonesia's oil and gas industry

Indicator	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Reserves											
Oil (Million Barrels)	8,400	8,220	8,000	7,760	7,730	7,410	7,550	7,370	7,305	7,251	7,535
Proven	3,990	3,750	4,300	4,230	4,040	3,740	3,690	3,620	3,603	3,307	3,171
Potential	4,410	4,470	3,700	3,530	3,690	3,670	3,860	3,750	3,702	3,944	4,364
Gas (TCF)	165.00	170.10	159.63	157.14	152.89	150.70	150.39	149.30	151.33	144.80	143.70
Proven	106.00	112.50	107.34	108.40	104.71	103.35	101.54	100.26	97.99	102.00	101.40
Potential	59.00	57.60	52.29	48.74	48.18	47.35	48.85	49.04	53.34	42.80	42.30
Production											
Crude oil (MBOPD)	972	1,006	994	1,003	952	918	825	789	786	831	802
Natural gas in Million Standard Cubic Feet per Day (MMSCFD)	7,283	7,460	7,962	8,857	8,415	7,110	6,826	8,218	8,102	7,939	7,621
New contracts signed	28	34	34	21	31	39	14	7	12	2	0

Source:
Reserves of oil and gas are obtained from DGOG, MoEMR
2007-2012 Crude Oil and Natural Gas Production: BP Statistical Review of World Energy
2013-2015 Crude Oil and Natural Gas Production: SKK Migas Annual Report 2013-2015
2016 Crude Oil and Natural Gas Production: Press release of MoEMR on CNN Indonesia
2017 Crude Oil and Natural Gas Production: SKK Migas Website
New contracts signed: MoEMR, SKK Migas

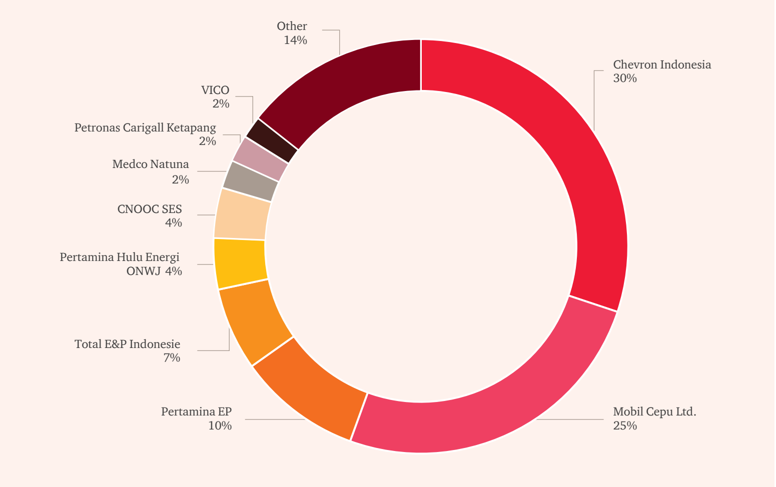
Indonesian Oil and Gas Production Profile (MBOEPD)



Source: SKK Migas Annual Report 2015

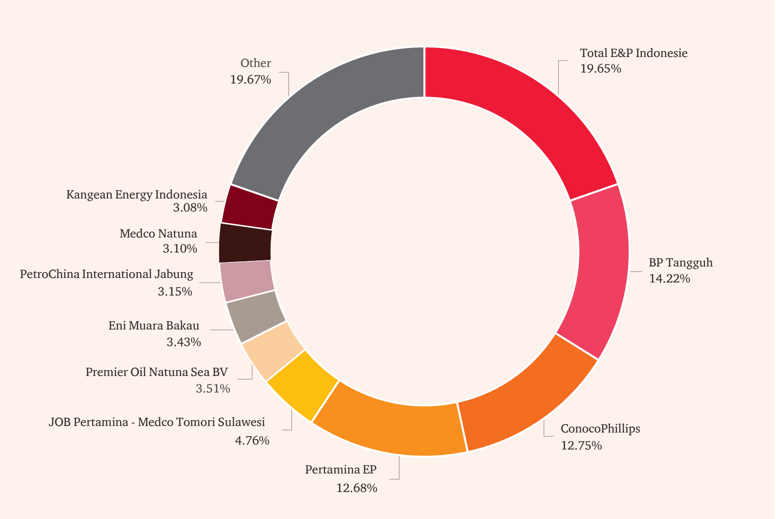
Most oil and gas production is carried out by foreign Contractors under PSC arrangements. The major crude oil and natural gas producers (as PSC operators) as of January 2018 were as follows:

Major Oil Producers

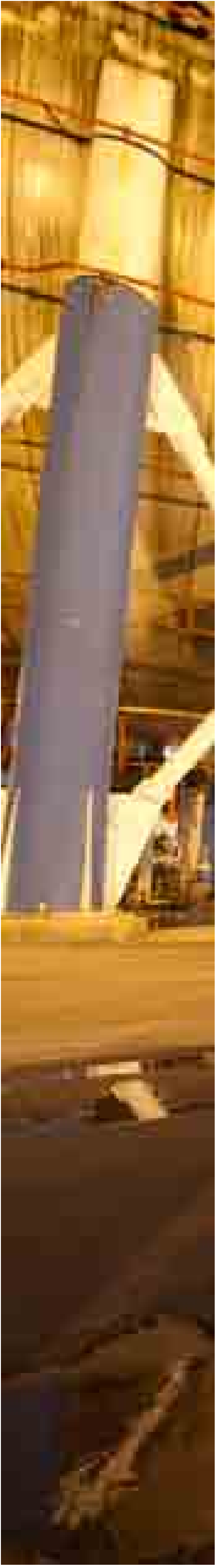


Source:
PwC Analysis

Major Gas Producers

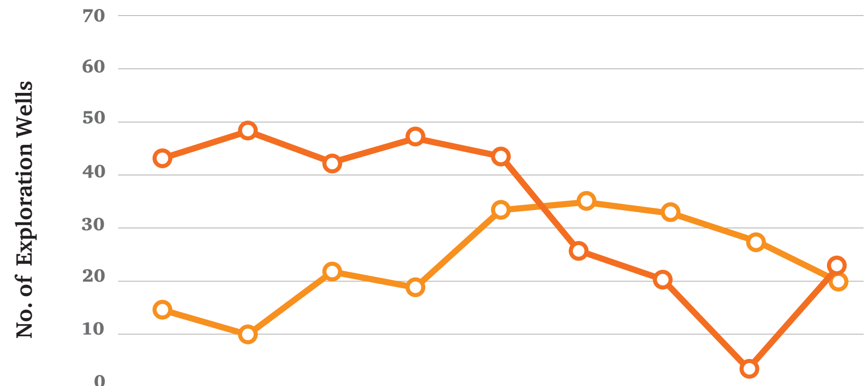


Source:
PwC Analysis



Indonesian exploration activities were also hit by the recent oil price shock: the number of exploratory wells drastically decreased from 64 in 2014 to 35 in 2015. Moreover, only two offshore wells were drilled in 2015. The number has recovered to 43 in 2016, and the rising oil price may have had an influence on the further increase to 54 in 2017, although it was still below 40% of the 2017 target of 138. The Government has lowered the target in 2018 to 103 exploration drilling wells.

Drilling Exploration Activities



	2008	2009	2010	2011	2012	2013	2014	2015	2016
Onshore	16	11	26	22	41	43	40	33	20
Offshore	54	61	54	59	55	31	24	2	23

Source:
2009-2013: Indonesia Oil and Gas Book 2015
2014-2016: SKK Migas Annual Report 2014-2016

With Coal Bed Methane (CBM)'s reserves of 453 TCF, Indonesia ranks 6th in the world. The CBM reserves are estimated to be larger than the natural gas reserves. The first CBM contract was signed in 2008, and by the end of 2015 there were 46 CBM cooperation contracts in place. Indonesia's shale gas reserves are estimated to be 574 TCF. However, the development of CBM and Shale Gas in Indonesia has to date not been significant. The latest update from SKK Migas in late November 2016 even showed that around ten Shale Gas and CBM blocks were in the process of being terminated and returned to the Government.

1.4 *Downstream Sector*

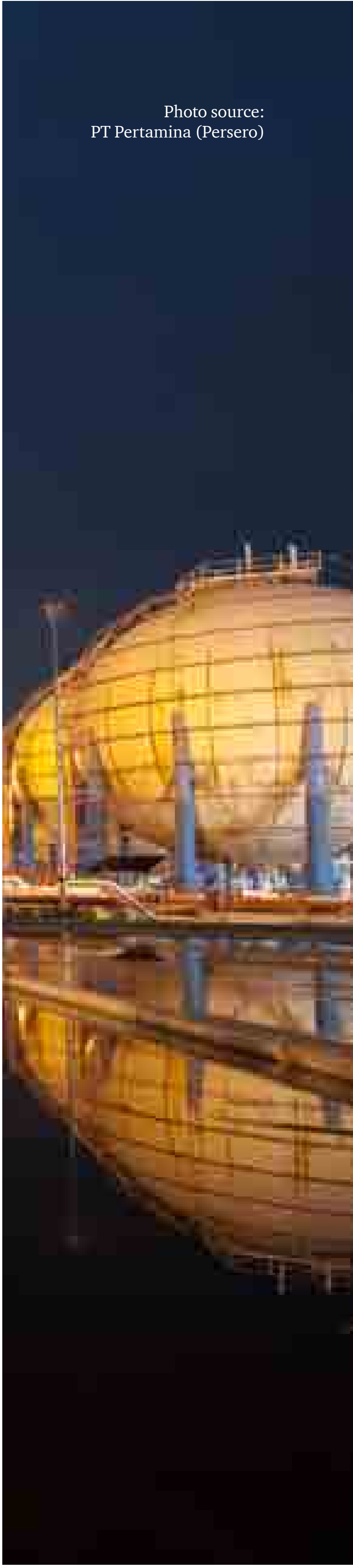


Photo source:
PT Pertamina (Persero)

Although the market was formally liberalised in 2001, PT Pertamina (Persero) and its subsidiaries continue to dominate certain parts of the downstream sector. Whilst Pertamina's retail monopoly for petroleum products ended in July 2004 when the first licences for the retail sale of petroleum products were granted to Shell and Petronas, Pertamina remains the dominant distributor of fuel products because of its network. However, aiming to stabilise the state budget, the Government recently removed the fuel (gasoline) subsidy, limiting gasoline's distribution and sales in developing regions, and replacing it with non-subsidised fuels such as Pertalite, Pertamax and Pertamina Dex. As a consequence, to promote more equal access to and distribution of affordable fuel, the Government prioritises gasoline sales for the least developed regions and imposes the "One-fuel" price policy.

For industrial fuels, Pertamina is still the dominant player but other foreign and local players have increased their market share by importing industrial fuels. However, the current move of the government to bring PT Perusahaan Gas Negara Tbk. (PGN), a state-owned enterprise that transports and distributes natural gas across Indonesia, under Pertamina as regulated in the new GR 6/2018, may see the national oil and gas holding company re-establish its dominance in the oil and gas downstream sector.

Pertamina also owns and operates seven of the country's nine oil refineries (the eighth is owned by a private entity, while the ninth is owned by the Research and Development Agency of the MoEMR). The combined installed capacity of the country's refineries is only 1.1 million barrels per day, which means that Indonesia imports significant amounts of refined products to meet demand. To deal with this situation, Pertamina (with the Government) has been expanding investment opportunities. Several refinery expansion programs are planned under the Refinery Development Master Plan (RDMP) and New Grass Root Refinery (NGRR), among others, Cilacap, Dumai, Balongan, Balikpapan (RDMP), Tuban, and Bontang (NGRR). Additionally, plans for several new private-investment refineries are under discussion, among others the Musi Banyuasin, Batam and Bojonegara refineries.

As the Indonesian economy continues to grow, the local demand for fuel will continue to outpace the country's refinery capacity and the production of crude oil and natural gas. Furthermore, with China's One Belt One Road initiative, it is likely the downstream sector will attract more foreign investment related to fuel import activities, including receiving, storage and bunkering, and distribution network infrastructure.

1.5 Contribution to the Economy

Indonesia spent decades relying on the oil and gas sector's contribution to economic growth. However, in recent years, the oil and gas sector's contribution to state revenues decreased significantly along with the decline in reserves and production. Thus, the state revenue from the oil and gas industry decreased by almost 80% from Rp 216 trillion in 2014 (14% of state revenues) to Rp 44 trillion in 2016 (2.8% of state revenues), before rising oil prices improved the contribution of the oil and gas sector in 2017. A press release from MoEMR indicated an unaudited state income of Rp 138 trillion from the oil and gas sector in 2017, which was 117% of the target. Figures from the Ministry of Finance (MoF) show Rp 69.7 trillion as of November 2017.

Year	State Revenue	Oil and Gas Revenue	% of Contribution
	Rp Trillion		
2004	403	85	21.09%
2005	494	104	21.05%
2006	636	158	24.84%
2007	706	125	17.71%
2008	979	212	21.65%
2009	847	126	14.88%
2010	992	153	15.42%
2011	1,205	193	16.02%
2012	1,338	205.8	15.38%
2013	1,438	203.6	12.56%
2014	1,538	216.9	14.11%
2015	1,508	78.2	4.46%
2016	1,555	44.1	2.84%
2017*	1,396	69.7	4.99%
2018**	1,895	80.3	4.24%

Source: MoF Website
**2017 audited data is limited to November*
***2018 is target of state budget*

Investment levels in the upstream sector continue to fluctuate. An increase ranging from 15%-27% was reported in 2010-2014 before reaching US$ 19.3 billion in 2013 and 2014. However, the total of upstream oil and gas investment declined to US$ 14.8 billion in 2015, and finally US$ 7.65 billion up to the third quarter of 2017, with SKK Migas indicating the total investment in 2017 was around US$ 10.3 billion, the lowest in a decade. This figure was below the already modest target in the 2017 revised work plan and budget that was expected to be US$ 12.3 billion. In 2018, however, the Directorate General of Oil and Gas (DGOG) expects the investment level to grow significantly to US$ 14.5 billion, in line with rising global oil prices.

Uncertainty around oil prices influenced the Government to instruct Contractors to focus on efficiency in operations and to develop the new Gross Split PSC system in early 2017 under MoEMR Regulation 8/2017, which was later amended by MoEMR Regulation 52/2017. The impact of this new PSC framework is yet to be seen.

Upstream Oil & Gas Investment
(in million US$)

Type of operation	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Exploration	532	633	670	719	1,439	1,877	1,735	1,345	947	565
Administration	981	730	833	958	1,016	1,199	1,157	1,286	1,156	944
Development	2,523	2,671	2,495	3,149	3,288	4,306	4,048	2,116	1,322	705
Production	6,579	6,391	7,033	9,196	10,370	11,960	12,336	10,883	8,156	8,053
Total Expenditure	**10,615**	**10,425**	**11,031**	**14,022**	**16,113**	**19,342**	**19,275**	**15,630**	**11,581**	**10,267**

Source:
2008 - 2017: Calculated by PwC based on BP Migas/SKK Migas Annual Reports

Photo source: PwC

2 Regulatory Framework

> "All the natural wealth on land and in the waters falls under the jurisdiction of the State and should be used for the greatest benefit and welfare of the people."
>
> *Article 33, Constitution of the Republic of Indonesia, 1945*

2.1 *Oil and Gas Law No.22/2001*

The law regulating oil and gas activities is Law No. 22 dated 23 November 2001 (Law No.22). The law's objective (Article 3) is to:

a. Guarantee effective, efficient, highly competitive and sustainable exploration and exploitation;
b. Assure accountable processing, transport, storage and commercial businesses through fair and transparent business competition;
c. Guarantee the efficient and effective supply of oil and gas as a source of energy and to meet domestic needs;
d. Promote national capacity;
e. Increase state income; and
f. Enhance public welfare and prosperity equitably, while maintaining the conservation of the environment.

In the past few years, especially after the decision of the Constitutional Court relating to BP Migas, one of the most talked about issues has been when the Government will amend Law No. 22. While several versions of "draft" Oil and Gas Laws have been circulated there is still no clear timeline on this matter.


Photo source: PwC

2.1.1 Control of Upstream and Downstream Activities (Articles 4-10 and Articles 38-43)

Oil and gas activity is controlled by the Government (generally via a PSC) as the grantor of the relevant concession. Law No.22 differentiates upstream business activities (exploration and exploitation) and downstream business activities (processing, transport, storage and commerce) and stipulates that upstream activities are controlled through "Joint Cooperation Contracts" (predominantly PSCs) between the business entity/permanent establishment and the executing agency (SKK Migas - *Satuan Kerja Khusus Pelaksanaan Kegiatan Usaha Hulu Minyak dan Gas Bumi*) (Article 6). Downstream activities are controlled by business licences issued by the regulatory agency (BPH Migas - *Badan Pengatur Hilir Minyak dan Gas Bumi*) (Article 7). SKK Migas and BPH Migas supervise upstream and downstream activities respectively to ensure:

a. The conservation of resources and reserves;
b. The management of oil and gas data;
c. The application of good technical norms;
d. The quality of processed products;
e. Workplace safety and security;
f. Appropriate environmental management such as preventing environmental damage;
g. The prioritisation of local manpower, goods and services and domestic engineering capacities;
h. The development of local communities; and
i. The development and application of oil and gas technology.

Upstream and downstream business activities may be carried out by state-owned enterprises, regional administration-owned companies, cooperatives, small-scale businesses or private-business entities. Upstream business activities can include branches of foreign incorporated enterprises as a Permanent Establishment (PE). However, upstream entities are prohibited from engaging in downstream activities, and vice versa (Article 10) except where an upstream entity must build transport, storage or processing facilities or other downstream activities that are integral to supporting its exploitation activities (Article 1).

Dissolution of BP Migas and Creation of SKK Migas

On 13 November 2012 the Constitutional Court of Indonesia issued a decision which cancelled certain articles within Law No.22 and effectively dissolved BP Migas. On the same day, the President issued Presidential Regulation No.95/2012 transferring the roles and responsibilities of BP Migas to the MoEMR, and MoEMR issued MoEMR Decree No.3135K/08/MEM/2012 and No.3136K/73/MEM/2012, to establish *Satuan Kerja Sementara* (the SKS or Temporary Working Unit) under the MoEMR.

On 10 January 2013, the President issued Presidential Regulation No. 9/2013 establishing SKK Migas to replace the SKS. The personnel originally employed by BP Migas and subsequently by the SKS were transferred to SKK Migas. The role and management of the upstream oil and gas sector is overseen by a supervisory body consisting of the Minister and the Deputy Minister of Energy and Mineral Resources, the Deputy Minister of Finance and the Head of the Investment Coordinating Board (BKPM).

There were no significant changes in the management of the upstream oil and gas sector, although the authority of SKK Migas is only in place until the issuance of a new Oil and Gas Law.

Photo source: PT Chevron Pacific Indonesia

2.1.2 GR 79 as amended by GR 27 on Cost Recovery and Income Tax for the Oil and Gas Sector

After a two-year discussion period, Government Regulation 79 was issued on 20 December 2010 (GR 79) and contained the first ever framework on cost recovery and tax arrangements for the upstream sector. Numerous implementing regulations have now been issued, although there remains a number outstanding. For more on this, refer to Chapter 3.4.2.

In response to the concerns highlighted by the upstream industry with regard to the application of GR 79, the Government enacted GR 27 on 19 June 2017, amending GR 79 (GR 27). We elaborate on several key provisions set out under GR 27 in Chapter 3.4.2.

2.1.3 Restrictions on Foreign Workers

On 24 October 2013 the MoEMR issued Decree No.31/2013 on Expatriate Utilisation and the Development of Indonesian Employees in the Oil and Gas Business (Decree 31/2013), which covers employees in the upstream and downstream sectors as well as support services companies. In the spirit of reducing bureaucracy and simplifying the licensing process, on 5 February 2018 the MoEMR revoked Decree 31/2013 by issuance of MoEMR Decree No. 6/2018. By revocation of Decree 31/2013, certain positions that were previously restricted for expatriates are “arguably” open for expatriates unless restricted under the general manpower regulations.

2.2 *Other Relevant Law*

2.2.1 The Energy Law No.30/2007

The Energy Law No.30/2007 dated 10 August 2007 provides a renewed legal framework for the overall energy sector, with an emphasis on economic sustainability, energy security and environmental conservation (Article 3). Under this Law, the National Energy Council (DEN) was established in June 2009 with the task of formulating and implementing a House of Representatives-approved National Energy Policy, determining the National Energy General Plan and planning steps to overcome any energy crisis or emergency.

National Energy Policy

Government Regulation 79/2014 was issued on 17 October 2014 regarding the National Energy Policy, as originally formulated by DEN.

The National Energy Policy covers the overall management of energy and seeks to address issues such as:

a. The availability of energy to meet the nation's requirements;
b. Energy development priorities;
c. The utilisation of national energy resources; and
d. National energy buffer reserves.

The National Energy Policy aims to achieve an optimal level of energy resources mix at 2025 and 2050 target dates as follows:

Energy Source	2025	2050
New and renewable energy	minimum 23%	minimum 31%
Crude oil	less than 25%	less than 20%
Coal	minimum 30%	minimum 25%
Natural gas	minimum 22%	minimum 24%

DEN is chaired by the President and Vice-President with the Energy Minister as Executive Chairman. DEN has 15 members, including the Minister and Government officials responsible for the provision, transportation, distribution and utilisation of energy; and other stakeholders (2 from academia; 2 from industry; 1 technology representative; 1 environment representative; and 2 from consumer groups).

2.2.2 The Investment Law No.25/2007 and Company Law No.40/2007

Form of Business

The permitted mode of entry for foreign investors in the upstream oil and gas sector can either be by way of a branch of a foreign company (i.e. as a PE) or an incorporation as a limited liability company domiciled in Indonesia (i.e. as a foreign investment business entity or PT (PMA - *Penanam Modal Asing*)).

Due to the "ring-fencing" principle (see Article 13 of Law No.22), where only one PSC can be granted for each PE or PT, separate entities must be set up for each work area. For example, after the passing of Law No.22, Pertamina was required to establish subsidiaries and enter into PSCs with SKK Migas for each of its work areas.

Investment Law No.25/2007 (Law No.25) dated 26 April 2007 applies to PTs operating in the downstream sector. Law No.25 allows investors to repatriate profits (although see Chapter 2.2.4 for details of developments in the Bank Indonesia regulations on the repatriation of funds), and pay interest and dividends in foreign currencies (Articles 6, 7 & 8) as well as for capital facilities. These facilities include the exemption from Import Duty and the exemption or postponement of Value Added Tax (VAT) on imports of capital goods needed for production (Article 18).

Based on MoEMR regulation no. 40/2017, the authority to issue certain licences from MoEMR is delegated to the BKPM, including for trading, refineries and various support services.

The Negative Investment List

On 18 May 2016 a new negative investment list was issued through Presidential Decree No. 44/2016, which replaced Presidential Decree No. 39/2014. This restricts foreign investment companies (PMA entities) as follows:

- May no longer engage in onshore drilling.
- The maximum foreign shareholding for offshore drilling is 75%.
- May no longer engage in oil and gas construction services for onshore pipe installations, production installations, horizontal/vertical tanks and storage installations; the maximum foreign shareholding for oil and gas construction services for offshore pipe installations and spherical tanks is 49%, while for construction of oil and gas platforms it is 75%.
- May no longer engage in the operation and maintenance of wells, design and engineering support services, or technical inspections.
- For oil and gas survey services, the maximum foreign shareholding is 49%.

Legislative Responsibilities: Environment and Others

The Company Law No.40/2007 dated 16 August, 2007 provides obligations for companies undertaking business activities in the natural resources field, with the costs to be borne by the company (Article 74). Sanctions for non-compliance are covered in all related legislation. As at April 2018, the Government Regulation providing details of these social and environmental responsibilities had not been issued.

Obligations for PT companies are set out in Investment Law No.25 and include: prioritising the use of Indonesian manpower (Article 10), creating a safe and healthy working environment (Article 16), implementing corporate social responsibility programs (Article 15), and ensuring environmental conservation (Article 16). Investors exploiting non-renewable resources must also allocate funds to site restoration that fulfil the standards of environmental feasibility (Article 17). Sanctions for non-compliance with Article 15 include restrictions on business activities, and the freezing of business activities (Article 34 of the Investment Law).

2.2.3 The Environment Law No.32/2009 and Forestry Law No.41/1999

In October 2009, Environment Law No.32/2009 (Law No.32) was issued and entities are required to comply with standard environmental quality requirements and to secure environmental permits before beginning operations. Sanctions can include the cancellation of operating permits, fines, and/or imprisonment. After initially being postponed, Law No.32 is now operative.

Forestry Law

The Forestry Law No.41/1999 (and its amendments 1/2004 and 18/2013) prohibits oil and gas activities in protected forest areas except where a Government permit is obtained. Government Regulation No. 104/2015 allows projects, including for oil and gas activities, to take place in protected forests where they are deemed strategically important.

Under GR No.24/2010 (as amended by GR No. 61/2012 and GR No. 105/2015) the utilisation of forestry areas for non-forestry activities is permitted in both production forests and protected forests subject to obtaining a "borrow-and-use" permit (IPPKH) from the Ministry of Forestry. The "borrow-and-use" permit holder will be required to pay various non-tax State Revenues pursuant to these activities and will need to undertake reforestation activities upon ceasing its use of the land. The issuance and validity of the "borrow-and-use" permit depends entirely on the spatial zoning of the relevant forest areas.

The use of a forestry area will often also require land compensation transfers or compensation payments to local landowners.

Forestry Moratorium Extended

A two-year moratorium on permits for forest and peatland clearing was extended to 16 July 2019 based on Presidential Instruction No.6/2017. The moratorium allows exceptions for national development projects such as oil and gas.

2.2.4 Regulating Export Proceeds and Foreign Exchange

Bank Indonesia (BI) has issued three regulations ((PBI - *Peraturan Bank Indonesia*) No.18/10/PBI/2016, PBI No.14/25/PBI/2012 and PBI No.16/10/PBI/2014 as amended by PBI No. 17/23/PBI/2015) to regulate export proceeds and foreign exchange.

Broadly, the PBIs provide:

a. That all export revenue must be allocated through accounts with Indonesian banks, including Indonesian branches of offshore banks ("onshore accounts"), with reports/supporting documentation issued to the bank once the revenue has been allocated;
b. That any discrepancy between the amount received through the onshore account and the export value stated in the Export Goods Notification (PEB) must be explained in writing and supported by related evidence;
c. If foreign currency from external debt is withdrawn, the debtor must report the withdrawal to BI.
d. BI to supervise export proceeds and the withdrawal of foreign debt in order to optimise the benefit of export proceeds in the domestic market

The PBI states that all export revenue received in a foreign currency must be reported to BI, and deposited in a bank licensed to conduct foreign currency business (or *Bank Devisa*). When repaying foreign currency debt, companies must similarly use a *Bank Devisa*.

For the oil and gas sector, concerns with PBI include:

a) Inconsistency with the "contract sanctity" of the PSC which provides that the Contractor may freely lift and export their production share and retain the proceeds of any sale abroad;
b) Potentially reducing liquidity for Contractors and impacting development activities;
c) The effect on trustee paying agent mechanisms for gas/LNG sales and associated financial covenants; and
d) Being subject to requirements on minimum periods of deposit and/or mandatory conversions into Rupiah.

Despite the above concerns, most PSC companies have nevertheless been complying with PBI No.14.

2.2.5 Mandatory Use of Indonesian Rupiah

On 31 March 2015, BI issued Regulation No. 17 (PBI 17/3/2015) as implementing guidance for Law No. 7/2011 regarding the mandatory use of the Rupiah for cash and non-cash transactions in Indonesia. An important circular letter No. 17/11/DKSP (Surat Edaran (SE) 17) was issued on 1 June 2015.

From 1 July 2015, any cash or non-cash transactions made within Indonesia must use and be settled in Rupiah. All price quotations of goods and services must also be in Rupiah, and dual currency quotations are prohibited.

Through circular letter SE 17, BI clarified the following infrastructure projects as exempted from the mandatory use of Rupiah rules:

a. Transportation;
b. Road construction and irrigation systems;
c. Infrastructure for water supplies;
d. Power utilities including power plants and transmission system;
e. Oil and gas projects.

To obtain the exemption, the project owner should seek confirmation from the relevant Ministry and obtain a waiver letter from BI.

On 1 July 2015, the MoEMR and BI issued a press release (No. 40/SJI/2015) outlining a framework to classify transactions into three main categories (for the energy sector), as a transition towards the mandatory use of Rupiah. The categories are:

Category 1 – Transaction proceeds which can be directly converted to Rupiah (e.g., leases and salary payments to local employees – six-month transition);

Category 2 – Transaction proceeds which require time to be converted to Rupiah (e.g., long-term service contracts). These can continue to use foreign currency subject to future amendments to the contracts;

Category 3 – Transaction proceeds where it is fundamentally difficult to use Rupiah (e.g., salaries paid to expatriates, drilling services and the leases of ships). These may continue to use foreign currency for a maximum 10-years period.

The MoEMR and BI have formed a task force to set guidelines and procedures for the implementation of PBI 17/3/2015, especially for Category 3 types of transactions.

Photo source: PwC

2.3 *Key Stakeholders*

2.3.1 The Ministry of Energy and Mineral Resources (MoEMR)

MoEMR is charged with creating and implementing Indonesia's energy policy, ensuring that the related business activities are in accordance with the relevant laws and regulations, and awarding contracts. It is also responsible for the National Masterplan for the transmission and distribution of natural gas. The MoEMR is divided into directorates, with the DGOG responsible for the preparation, implementation, direction, supervision and implementation of various policies in the oil and gas industry, which includes:

a. The lifting calculation formula and its division between the local and central governments;
b. The policy on the gradual reduction of the fuel subsidy;
c. The offering of new exploration and production blocks; and
d. The preparation of other policies on the oil and gas industry.

2.3.2 SKK Migas

SKK Migas controls upstream activities and manages oil and gas Contractors on behalf of the Government through Joint Cooperation Contracts. Under Law No.22 (Articles 44 and 45) all of Pertamina's rights and obligations arising from existing Cooperation Contracts, for and on behalf of the Government, were transferred to SKK Migas.

SKK Migas has the following roles:

a. To provide advice to the MoEMR with regard to the preparation and offering of work areas and Joint Cooperation Contracts;
b. To act as a party to Joint Cooperation Contracts;
c. To assess first field development plans in a given work area and submit its evaluation to the MoEMR for its approval;
d. To approve development plans (other than those mentioned in point c.);
e. To approve work plans and budgets;
f. To report to the MoEMR and monitor the implementation of joint cooperation contracts; and
g. To appoint sellers of the State's portion of petroleum and/or natural gas to the Government's best advantage.

The MoEMR and SKK Migas may further stipulate provisions regarding the scope and supervision of upstream business activities. If necessary, the MoEMR and SKK Migas may jointly supervise upstream business activities. The Head of SKK Migas is appointed by the President and is responsible to the President.

2.3.3 BPH Migas

BPH Migas was established on 30 December 2002 to assume Pertamina's regulatory role in relation to downstream activities (Articles 46 and 47 of Law No.22). BPH Migas is charged with assuring sufficient natural gas and domestic fuel supplies and the safe operation of refining, storage, transportation and distribution of gas and petroleum products via business licences.

BPH Migas is managed by one chairman and eight members. The chairman and members of the Regulatory Body are responsible to the President, who appoints them after consultation with Parliament.

BPH Migas' regulatory, development and supervisory roles are set out in the following table:

Regulatory and Development Areas under BPH Migas	Supervisory Areas under the MoEMR
• Business licences • Type, standard and quality of fuels • Utilisation of oil fuel transportation and storage facilities • Exploitation of gas for domestic needs • Strategic oil reserves • National fuel oil reserves • Masterplan for a national gas transmission and distribution network • Occupational safety, health, environment and community development • Price setting including the gas selling price for households and small-scale customers • Utilisation of local resources	• Business licences • Type, standard and quality of fuels • Occupational safety, health, environment and community development • Employment • Utilisation of local resources • Oil and gas technology • Technical rules • Utilisation of measurement tools

Source: GR No. 36/2004

BPH Migas is also responsible for the supervision of fuel oil distribution and transportation of gas through pipelines operated by PT companies.

Supervision and Distribution of Fuel Oil	Transportation of Gas by Pipelines
• Supply and distribution of fuel oil • Supply of fuel oil in remote areas • Allocation of fuel oil reserves • Market share & trading volumes • Settling of disputes	• Development of transmission segment and distribution network area • Determination of natural gas pipeline transmission tariffs and prices • Market share of transportation and distribution • Settling of disputes

Open Access to Gas Pipelines

In line with Decision of the MoEMR No.2700K/11/MEM/2012 regarding the National Core Plan for Gas Transmission and Distribution Network, in 2018 BPH Migas indicated the plan to auction concessions for the construction of gas pipelines for sections between Natuna – West Kalimantan, West Kalimantan to Central Kalimantan and Central Kalimantan to South Kalimantan on the basis of open (third party) access. BPH Migas rules supporting open access have existed since 2008 and stipulate that the owners of gas pipes must allow access by third parties.

2.3.4 House of Representatives (DPR) and Regional Governments

Commission VII of the House of Representatives (DPR) is in charge of energy, mineral resources, research and technology, and environmental matters. This includes oversight of oil and gas activities, the drafting of oil and gas related legislation, the control of the State Budget and control of related Government policy. It also advises the Government of the oil and gas sector's contributions to the State Budget (APBN).

Regional Governments are involved in the approval of Plans of Development (PoD) through the issuance of local permits and land rights.

2.3.5 PT Pertamina

On 18 June 2003, PT Pertamina (Persero) was transformed from a state-owned oil and gas enterprise governed by its own law into a state-owned limited liability company. In recent years, Pertamina has expanded its scope to include gas, renewables and upstream operations both within Indonesia and abroad. It now has upstream operations in Vietnam, Malaysia, Sudan, Qatar and Libya, and provides aviation fuel services at ten international airports. Pertamina has also entered into several joint operations within Indonesia.

2.3.6 PGN

PGN was originally a Dutch-owned gas company called Firma L.I. Eindhoven & Co. In 1958, the firm was nationalised and changed its name to PT Perusahaan Gas Negara (PGN) effective May 13, 1965. In 2003, PGN began trading on the Jakarta and Surabaya Stock Exchanges. PGN is 57% owned by the Government of Indonesia.

PGN operates a natural gas distribution pipeline network and a natural gas transmission pipeline network. Its subsidiaries and affiliated companies are involved in upstream activities, downstream activities, telecommunications, construction and a floating storage and regasification terminal.

The Government has indicated strong support for establishment of a BUMN holding company in the oil and gas sector, combining the business of PGN with Pertamina to become the holding company. The Government has issued GR No. 6 of 2018, confirming appointment of Pertamina as the holding company of government-owned entities serving the oil and gas industry (GR 6/2018). Based on this GR 6/2018, Pertamina will be the shareholder holding the shares with special rights, replacing the Government's position while PGN continues to be a publicly listed company.

The establishment of an oil and gas BUMN holding is expected to streamline and synergise the similar business activities of Pertamina and PGN, such as the gas production and pipeline businesses, so the management and operation of both Pertamina and PGN will be more efficient in the future and therefore will be more beneficial to the State.

2.3.7 Industry Associations

The Indonesian Petroleum Association (IPA) was established in 1971 in response to growing foreign interest in the Indonesian oil and gas sector. The IPA's objective is to use public information to promote the exploration, production, refining and marketing aspects of Indonesia's petroleum industry. Other industry associations include drilling company associations (APMI – *Asosiasi Perusahaan Pemboran Minyak, Gas dan Panas Bumi Indonesia)* and fuel importer associations.

The Indonesian Gas Association (IGA) was established in 1980 under the sponsorship of Pertamina and key gas producers. The IGA's objective is to provide a forum to discuss matters relating to natural gas and to advance knowledge, research and development in the areas of gas technology. The IGA also aims to promote the development of infrastructure and cooperation among the producing, transporting, consuming and regulatory segments of the gas industry.

The Unconventional & Enhanced Oil Recovery (EOR) Committee within the IPA represents the interests of participants in the coal bed methane, shale gas and other unconventional gas industries as well as participants that conduct EOR activities in their business.

Photo source: PT Pertamina (Persero)

3 (Conventional) Upstream Sector

As indicated earlier, the GoI has introduced the new paradigm of the "gross split" PSC for upstream business activities which should be applied to new PSCs starting 2017/2018.

This new paradigm has fundamentally "shifted" the key principles and regulatory framework of the (conventional) cost recovery model in the upstream sector which have been in place for more than 40 years.

Following are the key principles and regulatory framework of the upstream sector as applicable to the (conventional) cost recovery model. Some may still be relevant for the new Gross Split PSC model – although readers may find more specific comments on this new gross split PSC model in Chapter 4.

This chapter covers the following topics:

3.1 Upstream Regulations;
3.2 Production Sharing Contracts (PSCs);
3.3 Upstream Accounting;
3.4 Taxation and Customs;
3.5 Commercial Considerations; and
3.6 Documentation for Planning and Reporting

3.1 *Upstream Regulations*

Activities in the oil and gas upstream sector are regulated by Law No.22, its implementing regulation GR 35/2004 and the amending GR 34/2005, as well as GR 55/2009 and GR 27 (as amendment to GR 79). A summary of Law No.22's key sections is set out below.

Photo source: PT Pertamina (Persero)

3.1.1 Work Areas

Upstream business activities (i.e. exploration and exploitation) are conducted in regions known as “work areas”. Work areas are formalised upon approval from the MoEMR in consultation with SKK Migas and the relevant local government authorities and then specified in a Joint Cooperation Contract.

A work area can be offered either through a tender or a direct offer (see below).

Every business entity or PE (Contractor) can hold only one work area (the “ring-fencing” principle) and must return it, in stages or in its entirety, as commitments are fulfilled in accordance with the Joint Cooperation Contract. Once a work area is returned it becomes an open area.

3.1.2 Awarding of Contracts – Direct Offers or Tenders For New Acreage

Direct Offers for New Acreage

In a direct offer, a company that performs a technical assessment through a joint study with the DGOG receives the right to match the highest bidder of the tender round.

Pertamina can apply for a direct offer, with MoEMR approval, when: (1) the area is an “open” area; (2) the Contractor is transferring its PSC interest to a non-affiliate; or (3) the area has expired or been relinquished. MoEMR Regulation No. 15/2015 (as amended by MoEMR Regulation No. 30/2016) regulates that expiring PSCs can be managed by either:

a. PT Pertamina (Persero);
b. The existing Contractors (via an extension); or
c. A joint operation between the PSC Contractor and PT Pertamina (Persero)

For work areas where PSCs have expired, the Government has issued MoEMR Regulation No. 26/2017 as amended by MoEMR Regulation No. 47/2017 regulating the return of unrecovered costs for investment performed within five years of the end of the PSC. This regulation was issued to ensure that Contractors of a PSC nearing its expiry will continue to invest and perform sufficient work programs to continue production, knowing that the cost will be recoverable in accordance with this MoEMR Regulation.

Tenders for New Acreage

The majority of new acreage is awarded through a tendering process.

The tendering steps are as follows:

a. Register as a tender participant by obtaining the official bid information package from the DGOG as the MoEMR representative. The fee for the bid information package is US$ 5,000 and is non-refundable.
b. Purchase an official government data package for the particular block being tendered to support the technical evaluation and proposed exploration program to be submitted with the tender. The fee for the data package will vary depending on the nature of the block.
c. Attend a clarification forum a few days prior to the tender date;
d. Submit two identical copies of the completed bid documents by the tender closing date. The tender documents consist of the following:

Tender Document Checklist		
No.	Subject	Remark
1.	Application Form	A completed application form.
2.	Work Program & Budget	A proposed work program and budget for six years of exploration (a sample work program and budget for a tender is provided below).
3.	Technical Report & Montage	The geological and technical justification for supporting the exploration program including a seismic survey commitment and the completion of one exploration well.
4.	Company profiles	Profile describing the current business activities and human resources of the participant and the parent company of the participant.
5.	Financial statements and financial projections	Annual financial statements of the participant and the parent company of the participant for the last three years audited by a certified public accountant. Financial projection of the participant for the next three years. A statement letter from a bank confirming the participant's ability to finance all work program commitments for the first three years.
6.	Statement letter that new entity will be established to sign the PSC	-
7.	Statement letter expressing support from the partner company	-
8.	A statement regarding bonuses	A statement confirming the participant's ability to pay any required bonuses.
9.	Copy of bid bond	A bid bond expressing a Bank's undertaking to guarantee and provide funds in respect of the offer from the participant for 100% of the value of the signature bonus valid for six months.
10.	All Consortium Agreement	For a consortium bid agreement between and/or among the consortium members together with confirmation as to which member of the consortium is the designated operator.
11.	A statement agreeing to the PSC Draft	A statement agreeing with the terms of the draft PSC agreement which will be signed by the winning bidder.
12.	PSC Draft	A draft of the PSC agreement.
13.	Original receipt of payment	A copy of the payment receipt for the bid information document.
14.	Copy of data package payment	A copy of the proof of purchase of the official government data package.
15.	Copy of notarised deed/articles of establishment	A copy of the participant's notarised articles of incorporation.
16.	A compliance statement	A letter stating the participant's compliance with the results of the bidding process.

e. The evaluation and grading of the tender bid document is carried out by the MoEMR Oil and Gas Technical Tender Team for New Acreage. Bid evaluations consider technical evaluation (major evaluation), financial evaluation (second evaluation) and performance evaluation (third evaluation).
f. The winner of the tender is determined by the DGOG after recommendation from the Tender Team.

Photo source: PT Chevron Pacific Indonesia

A typical template for the Work Program and Budget for six years of exploration is as follows:

PSC Work Program and Commitment						
NO	CONTRACT YEARS	DESCRIPTION	COMMITMENT			
			ACTIVITY		BUDGET	
			UNIT	AMOUNT	UNIT	AMOUNT
A.	**BONUS**					
I		Signature			US$	
II		Equipment and/or Service Bonus			US$	
III		Production Bonus:				
		At Cumulative 25 MMBOE			US$	
		At Cumulative 50 MMBOE			US$	
		At Cumulative 75 MMBOE			US$	
B.	YEARLY COMMITMENT					
	FIRM EXPLORATION COMMITMENT					
I	First	G and G			US$	
		Seismic 2D Acquisition and processing	KM		US$	
		Seismic 3D Acquisition and processing	KM2		US$	
		Exploratory well	Well		US$	
II	Second	G and G			US$	
		Seismic 2D Acquisition and processing	KM		US$	
		Seismic 3D Acquisition and processing	KM2		US$	
		Exploratory well	Well		US$	
III	Third	G and G			US$	
		Seismic 2D Acquisition and processing	KM		US$	
		Seismic 3D Acquisition and processing	KM2		US$	
		Exploratory well	Well		US$	
THE SECOND 3 YEARS EXPLORATION COMMITMENT						
IV	Fourth	G and G			US$	
		Seismic 2D Acquisition and processing	KM		US$	
		Seismic 3D Acquisition and processing	KM2		US$	
		Exploratory well	Well		US$	
V	Fifth	G and G			US$	
		Seismic 2D Acquisition and processing	KM		US$	
		Seismic 3D Acquisition and processing	KM2		US$	
		Exploratory well	Well		US$	
VI	Sixth	G and G			US$	
		Seismic 2D Acquisition and processing	KM		US$	
		Seismic 3D Acquisition and processing	KM2		US$	
		Exploratory well	Well		US$	

3.1.3 General Surveys and Oil and Gas Data

To support the preparation of work areas, a general survey (geological and geophysical) must be carried out, but any survey conducted by a business entity is done at its own expense and risk and only after receiving permission from the MoEMR.

General survey and exploration and exploitation data becomes the property of the State, such that any utilisation, transmission, surrender and/or transfer of data inside or outside of Indonesia requires permission from the MoEMR. Data resulting from exploration and exploitation activities must be surrendered to the MoEMR (through SKK Migas) within three months of collection, processing and interpretation.

Prior to a work area being returned to the Government its oil and gas data can be kept secret for between four years (basic data) and eight years (interpreted data). Once the work area is returned, the data is no longer secret.

3.1.4 Joint Cooperation Contracts (JCC)

Upstream activities are executed via a Joint Cooperation Contract, defined under Law No.22 to be a PSC or other form of Joint Cooperation Contract (such as a Service Contract, Joint Operation Agreement, or Technical Assistance Contract) concerning exploration and exploitation activities that is signed by the business entity or PE with SKK Migas (the executing agency).

The JCC contains provisions that stipulate as follows (Article 6):

a. That ownership of the oil and gas remains with the Government until the point of delivery;
b. That ultimate operational management control remains with SKK Migas; and
c. That all capital and risks are borne by the Contractor.

The JCC also contains provisions that stipulate (Article 11):

a. “State revenue” terms;
b. Work areas and their reversion;
c. Work programs;
d. Expenditure commitments;
e. Transfer of ownership of production results of oil and gas;
f. The period and conditions of the extension of the contract;
g. Settlement of any disputes;
h. Domestic supply obligations (a maximum 25% of production is generally given up to meet domestic supply) (Article 22);
i. Post-mining operation obligations;
j. Work place safety and security;
k. Environmental management;
l. Reporting requirements;
m. Plans for the development of the field;
n. Development of local communities; and
o. Priority on the use of Indonesian manpower.

Historically, there were two categories of contracts for Indonesia’s petroleum industry. The first category referred to the bundle of rights and obligations granted to an investor to invest, in cooperation with the Government, in oil and gas exploration and exploitation (i.e. PSCs; Technical Assistance Contracts (TAC); and EOR Contracts). The second category referred to the agreements that participants in a PSC, TAC or EOR entered into regarding how they would conduct the petroleum operations such as Joint Operation Agreements (JOAs) and Joint Operation Bodies (JOBs). Since the passing of Law No.22, most new contracts have been in the form of PSCs.

MoEMR has now introduced a new form of PSC based on the gross production split without a cost recovery scheme (see Chapter 4 below).

3.1.5 Activity, Expenditure and Bonus Commitments

Contractors are required to begin their activities within six months from the effective starting date of the JCC and to carry out the work program during the first six years of the exploration period.

The Contractor is responsible for all financing requirements and bears full risk if exploration is not successful. This financing is expected to be US Dollars. Any costs incurred by Contractors are subject to recovery from the Government.

The PSC includes annual exploration expenditure requirements for both the initial six years and any extension. While the annual commitment is established in the PSC, details must be approved by SKK Migas via annual work programs and related budgets (for PSC with cost recovery mechanism). The Government will typically require the Contractor to take out a performance bond to cover the first three contract years of activity. Excess expenditure can be carried forward but under-expenditure can only be made up with SKK Migas' consent. Failure to carry out the required obligation may lead to termination of the JCC and any under-expenditure may need to be paid to the Government along with the loss of any related performance bonds.

The bid usually includes a commitment to pay bonuses to SKK Migas (and increasingly the Government is requesting a bond to cover the signing bonus as part of the bid). These bonuses are of two types:

a. Signature Bonuses – payable within one month of the awarding of the contract. These bonuses generally range from US$ 1 million – US$ 15 million.
b. Production Bonuses – payable if production exceeds a specified number of barrels per day, e.g. US$ 10 million when production exceeds 50,000 bbl./day, or cumulative production.

GR 79 as amended by GR 27 stipulates that bonuses are not cost-recoverable (see comments below). Therefore, in accordance with the uniformity principle, bonuses would also not be tax deductible.

The bonuses to be paid and the amount of committed expenditure stated in a PSC are usually negotiated and agreed to by the Contractor and SKK Migas before signing the PSC.

3.1.6 Contract Period

JCCs remain valid for a maximum of thirty years from the date of approval. After this time, the Contractor can apply to the MoEMR for extension of a maximum twenty-years period per extension (Article 14), which can be submitted no earlier than ten years and no later than two years before the JCC expires.

The maximum thirty-year period includes both the exploration and exploitation periods. The exploration period is generally six years and is extendable for a further (maximum) four years (Article 15). If there are no commercial discoveries in the exploration period, the JCC is terminated. After the contract period expires, the Contractor must return the remaining work area to the MoEMR.

3.1.7 Amendments to a Joint Cooperation Contract

A Contractor may propose amendments to the terms and conditions of a JCC. These may be approved or rejected by the Minister based on the opinions of SKK Migas and their benefit to the State.

3.1.8 Participating Interests - Transfers

A Contractor may transfer part or all of its participating interest with the prior approval of the MoEMR and/or SKK Migas, depending on its PSC. The transfer of a majority participating interest to a non-affiliate is not allowed during the first three years of the exploration period. The taxation issues associated with PSC transfers are discussed in Chapter 3.5, including under GR 79 as amended by GR 27.

The Contractor is required to offer a 10% participating interest (at the Net Book Value (NBV) of expenditure incurred up to that date) to a regionally owned business entity (BUMD) upon first commercial discovery. On 29 November 2016, the MoEMR enacted Regulation No. 37 of 2016 regarding the requirement to offer 10% participating interest in an oil & gas block (MoEMR Regulation 37). Under MoEMR Regulation 37, the Contractor is required to "carry" the financial obligations on the 10% participating interest of BUMD and obtain repayment from the oil and gas production without any uplift.

If the offer is not taken up by BUMD, the Contractor is required to offer the interest to a national company. The offer is declared closed if the national company does not accept the offer within a period of 60 days from the date of receiving the offer. In practice, these timeframes may not be observed strictly.

3.1.9 Occupational Health and Safety, Environmental Management, and Community Development

Contractors are required to comply with relevant laws and regulations on occupational health and safety, environmental management and local Community Development (CD). For PSC contracts executed on or after 2008, the Contractor is explicitly responsible for conducting CD programs during the term of a PSC.

A Contractor's contribution to CD can be in kind, in the form of physical facilities and infrastructure, or through the empowerment of local enterprises and the workforce. CD activities must be conducted in consultation with the Local Government with priority given to those communities located nearest to the work area. Contractors are required to provide funds for undertaking any CD programs.

For PSCs executed prior to 2008, expenditure on CD is usually cost recoverable. CD expenditure during the exploitation which was non-cost recoverable according to GR 79, becomes cost-recoverable under GR 27 (see comments on GR 27 at Chapter 3.4.2).

3.1.10 Reservoir Extension and Unitisation

A reservoir extension into another Contractor's work area, an open area, or the territory/continental shelf of another country must be reported to the MoEMR/ SKK Migas. Unitisation arrangements may be formalised in these cases. If the reservoir extends into an open area, a unitisation must be formalised if such an open area later becomes a work area. However, if such an open area does not become a work area within a period of five years, a proportionate extension of a contract's work area can be requested. All unitisations must be approved by the MoEMR.

3.1.11 Non-profit Oriented Downstream Activities Allowed

The activities of field processing, transportation, storage and sale of the Contractor's own production are classified as upstream business activities. These should not be profit oriented. The use of facilities by a third party on a proportional cost sharing basis is generally allowed where there is excess capacity, SKK Migas' approval has been obtained, and the activities are not aimed at making a profit. If such facilities are used jointly with an objective of making a profit, these will represent downstream activities and require the establishment of a separate business entity under a downstream business permit.

3.1.12 Share of Production to Meet Domestic Needs

The Contractor is responsible for meeting demand for crude oil and/or natural gas for domestic needs. Under GR No.35 the Contractor's share in meeting domestic needs is set at a maximum of 25% of the Contractor's share of production of crude oil and/or natural gas. GR 79 as amended by GR 27 Article 24(8) indicates that the Domestic Market Obligation (DMO) is now set at 25% of the produced petroleum and/or natural gas.

GR 27 introduces an incentive in the form of DMO holiday that can be issued by the MoEMR after obtaining approval from the MoF.

3.1.13 Land Title (Articles 33-37 of Law No.22 and Section VII of GR 35/2004)

Rights to working areas are a "right to the sub-surface part" and do not cover land surface rights. Land right acquisitions can be obtained after offering a settlement to owners and occupiers in accordance with the prevailing laws (Article 34). Consideration for land is based upon the prevailing market rate. Where a settlement is offered, land title holders are obliged to allow the Contractor to carry out their upstream activities (Article 35).

Upstream and downstream activities are not permitted in some areas unless consent is provided by the relevant parties (such as the relevant government and/or community). Restricted areas include cemeteries, public places and infrastructure, nature reserves, state defence fields and buildings, land owned by traditional communities, historic buildings, residences or factories. Resettlement might be involved as part of any consent. Section VII of GR 35/2004 sets out detailed provisions regarding the procedures for settlement.

A Contractor holding a right of way for a transmission pipeline must permit other Contractors to use it after consideration of safety and security matters. A Contractor that plans to use a right of way can directly negotiate with another Contractor or party that holds the right of way and, if agreement between parties cannot be reached, the MoEMR/SKK Migas can be approached for settlement.

3.1.14 Use of Domestic Goods, Services, Technology, Engineering and Design Capabilities

All goods and equipment purchased by Contractors become the property of the Government. Any imports require appropriate approvals from the MoEMR, the Ministry of Finance and other minister(s) and can be imported only if they are not available domestically and meet requirements in terms of quality/grade, efficiency, guaranteed delivery time and after sales service.

The management of goods and equipment rests with SKK Migas. Any excess supply of goods and equipment may be transferred to other Contractors with the appropriate government approval before any amounts can be charged to cost recovery. Any surplus inventory purchased due to bad planning is not available for cost recovery. This position is supported by GR 79 as amended by GR 27, Article 13 (r).

SKK Migas is required to surrender excess goods and equipment to the MoF if the equipment cannot be used by another Contractor. Any other use of such goods and equipment, including through donation, sale, exchange or use for capital participation by the State, destruction or rental, requires MoF approval, based on the recommendation of SKK Migas/MoEMR.

All goods and equipment used for upstream activities must be surrendered to the Government upon termination of the JCC.

For greater detail on the treatment of inventory; property, plant, and equipment; and the tendering for goods and services, please refer to these respective titles in Chapter 3.2.4.

3.1.15 Manpower and Control of Employee Costs and Benefits

Contractors should give preference to local manpower, but may use foreign manpower for expertise that cannot be provided by Indonesian personnel. SKK Migas controls the number of expatriate positions and these positions are reviewed annually. The current manpower laws and regulations applying to the employees of a Contractor are dealt with in Chapter 2.1.3 above. Contractors are required to provide development, education and training programs for Indonesian workers.

As part of the annual work plan and budget review SKK Migas reviews training programs/ costs, salary and benefit costs and planned localisation of expatriate positions. Manpower or organisation charts for both nationals and expatriates (RPTK and RPTKAs) are to be submitted annually for SKK Migas review and approval. SKK Migas controls the salaries and benefits which can be paid and costs recovered through salary caps. In an effort to offset any inequity in salary caps, PSC operators may offer employee benefits such as housing loan assistance, car loan assistance, and long-service allowances etc., which are cost recoverable if approved by SKK Migas.

PSC operators, under the guidance of SKK Migas, must offer a pension for employee retirements or a severance for general terminations, referred to as *Tabel Besar* or Big Table. A Big Table scheme is a form of defined benefit whereby an employee is given a certain number of months' pay based on years of service.

Accordingly, some PSC operators have established defined contribution pension plans, managed by a separate trustee in which the PSC operator and the employee contributes a percentage of an employee's salary. Pension contributions are charged as costs recoverable. Some PSC operators also purchase annuity contracts from insurance companies. Pension contribution accruals cannot be cost recovered until funded (i.e. paid).

Some PSC operators have opted to manage their pension plans by funding them with bank time deposits with interest earned reinvested and used to reduce future funding. All pension schemes require PSC operators to prepare an actuarial assessment of the fair value of assets and the future pension liabilities, whether fully funded or unfunded. Historically, any unfunded liability is maintained off balance sheet for PSC basis Financial Reporting.

3.1.16 Jurisdiction and Reporting

JCCs are subject to Indonesian law. Contractors are obligated to report discoveries and the results of the certification of oil and/or gas reserves to the MoEMR/SKK Migas. Contractors are required to perform their activities in line with good industry and engineering practices, which include complying with provisions on occupational health and safety and environmental protection and using enhanced oil recovery technology as appropriate.

3.1.17 Dispute Mechanism - Arbitration

SKK Migas has introduced a special PSC cost recovery dispute mechanism via *Pedoman Tata Kerja* (PTK) 051. This provides guidelines to SKK Migas and the Contractor in the deferral of cost recovery as a result of audit findings, analysis and the evaluation of the Financial Quarterly Report (FQR), the audit of Authorisation Financial Expenditure (AFE) Close-outs, and/or expenditure for which SKK Migas questions the validity from a legal, technical or operational point of view.

Prior to the deferral of cost recovery, discussions shall be held with successive tiers of management in SKK Migas and the Contractor for a period of six months from the issuance of an audit report. Any deferred cost recovery shall be settled within 90 working days through a maximum of three discussions. In the event that discussions fail, the Contractor may exercise its rights in accordance with the PSC.

3.2 *Production Sharing Contracts (PSCs)*

3.2.1 General Overview and Commercial Terms

PSCs have been the most common type of JCCs used in Indonesia's upstream sector. Under a (conventional) PSC, the Government and the Contractor agree to take a split of the production, measured in terms of revenue, based on PSC-agreed percentages. Operating costs are recovered from production through Contractor cost oil formulas as defined by the PSC, and the Contractor has the right to take and separately dispose of its share of oil and gas (with title to the hydrocarbons passing at the point of export or delivery).

On 13 January 2017, MoEMR issued Regulation No. 08/2017 ("Regulation-08") introducing a new PSC scheme based upon the sharing of a "Gross Production Split" without a cost recovery mechanism, which later was amended by MoEMR Regulation No. 52/2017 (refer to Chapter 4 for more details).

Generations of (Conventional) PSCs

PSCs have evolved through five "generations" with the main variations on the production sharing split. The second and third generation PSCs issued after 1976 removed the earlier cost recovery cap of 40% of revenue and confirmed an after tax oil equity split of 85/15 for SKK Migas and the Contractor, respectively. The third generation model of the late 1980s introduced First Tranche Petroleum (FTP) and offered incentives for frontier, marginal and deep-sea areas. In 1994, to stimulate investment in remote and frontier areas (the Eastern Provinces), the Government introduced a 65/35 after-tax split on oil for contracts in the region (fourth generation). Since 2008, a fifth generation of PSC with cost recovery mechanism has been introduced. While the after tax equity split is negotiable, the latest model limits the items available for cost recovery (negative list for cost recovery as regulated under GR 79 in conjunction with GR 27) and offers incentives in other areas such as via investment credits. More details on cost recoverable items and the negative list are provided in Chapter 3.2.2.

Photo source: PwC

Relinquishments

The PSC sets out the requirements for areas to be relinquished during the exploration period. Specific details are set out in the contract but the parties must consult with SKK Migas and the areas must be large enough to enable others to conduct petroleum operations.

Key differences between the later and earlier generations are as follows:

a. Rather than a fixed after tax share, recent PSCs have had some flexibility regarding the production sharing percentage offered;
b. PSCs now prescribe a DMO for natural gas;
c. SKK Migas and the Contractor are both entitled to FTP of 20% of the Petroleum production;
d. The profit sharing percentages appearing in the contract assume that the Contractor is subject to tax on after tax profits at 20% (i.e. not reduced by any tax treaty);
e. Certain pre-signing costs (e.g. for seismic purchases) may be cost recoverable (although this is less clear in recent PSCs);
f. MoEMR and/or SKK Migas must approve any changes to the direct or indirect control of the PSC entity; and
g. The transfer of the PSC's participating interest to non-affiliates is only allowable:
    - With MoEMR and/or SKK Migas' approval; and where
    - The Contractor has retained majority interest and operatorship for three years after signing.

Pre-PSC Costs

The recipient of a PSC will typically incur expenditure before the PSC is signed. This pre-PSC expenditure cannot be transferred to the PSC and so will generally become non-recoverable.

Commercial Terms

The general concept of the PSC is that the Contractor bears all risks and costs of exploration. If production does not proceed these costs are not recoverable. If production does proceed then the Contractors can claim a share of production to meet cost recovery, an investment credit (where granted) and an after tax equity interest in the remaining production.

Terms of a PSC include that:

a. The Contractor is entitled to recover all allowable current costs (including production costs), as well as amortised exploration and capital costs;
b. The recovery of exploration costs is limited to production arising from the contracted "field" that has an approved PoD – effectively quarantining cost recovery to the initial and then subsequent "fields" (earlier generation PSCs did not "ring fence" by PoD and/or by field);
c. The Contractor is required to pay a range of bonuses including a signing, education (historically) and production bonus. The production bonus may be determined on a cumulative basis. These bonuses are not cost-recoverable or tax deductible;
d. The Contractor agrees to a work program with a minimum exploration expenditure over a certain number of years;
e. All equipment, machinery, inventory, materials and supplies purchased by the Contractor become the property of the State once they land in Indonesia. The Contractor has a right to use and retain custody during operations. The Contractor has access to exploration, exploitation and geological and geophysical data but the data remains the property of the MoEMR;
f. Each Contractor shares its production less deductions for the recovery of the Contractor's approved operating costs. Each Contractor must file and meet its tax obligations separately;
g. The Contractor bears all risks of exploration;
h. Historically, each Contractor was subject to FTP of 15% (for fields in Eastern Indonesia and some in Western Indonesia pursuant to the 1993 incentive package) or 20% (for other fields). This was calculated before any investment credit or cost recovery. Recent contracts provide for the sharing of FTP of 20%;
i. The Contractor is required to supply a share of crude oil production to satisfy a DMO. The quantity and price of the DMO oil is stipulated in the agreement. New contracts require a gas DMO;
j. After commercial production the Contractor may be entitled to recover an investment credit historically ranging from 17% to 55% of costs (negotiated as part of the PoD approval) incurred in developing crude oil production facilities; and
k. The Contractor is required to relinquish portions of the contract area based on a schedule specified in the PSC.

Cost Recovery Principles

Basic cost-recovery principles include allowing the following items:

a. Current-year capital (being current-year depreciation charges) and non-capital costs;
b. Prior years' unrecovered capital and non-capital costs;
c. Inventory costs;
d. Home-office overheads charged to operations; and
e. Insurance premiums and receipts from insurance claims.

Other principles have been developed over time via SKK Migas/BP Migas/Pertamina and Indonesian Tax Office (ITO) regulations. For example oil-generating PSC Contractors generally obtain an after-tax equity share of 15%. However, DMO must be met out of this "equity" oil or gas. A Contractor therefore typically earns a return of less than 15%. This is because there is no cost recovery or tax deductibility for unsuccessful "fields" and because of the DMO requirement. FTP arrangements have also separately enabled the Government a share in production before the Contractor has fully recovered its costs.

From 1995, PSCs indicated that site restoration was the responsibility of the Contractor and their budgets needed to provide for clearing, cleaning and restoring the site upon completion of the work. Funds set aside in a joint account for abandonment and site restoration are cost recoverable once spent or funded. Unused funds will be retained in the joint account and not refundable to the Contractor.

On 29 March 2017, MoEMR issued Regulation No. 26/2017 ("Regulation 26", as later amended by MoEMR Regulation No. 47/2017) stipulating the mechanism for PSC Contractors to recover their (unrecovered) "Investment Costs" at the termination of the PSC. Investment costs are essentially costs incurred by PSC Contractors to conduct activities with an objective of maintaining an equitable level of production as stated in the PoD and/or Work Program & Budget (WP&B).

In summary, Regulation 26 stipulates that:

a) for (conventional) PSC:- unrecovered investment costs can be carried forward to the Extended (conventional) PSC;
b) for (new) Gross Split PSC (refer to Chapter 4):- unrecovered investment costs shall be taken into account as an additional split/take for the existing Contractor. If a new Contractor comes into the PSC, the new Contractor should proportionately bear the unrecovered costs and the existing Contractor shall deduct that same portion from its share. The settlement of such unrecovered costs should be formalised into a written agreement between the existing Contractor and new Contractor.

Accounting Standards

The PSC outlines the accounting standards to be applied by the Contractor. Under this clause, operating, non-capital and capital costs are defined together with the related accounting method to be used for such costs. This differs from Generally Accepted Accounting Principles (GAAP). Most companies however, do not prepare Indonesian Financial Accounting Standards compliant financial statements and instead prepare PSC statements adjusted at the home office level to comply with GAAP. SKK Migas issued PTK 059 as general guidance on PSC accounting however the detailed PSC accounting must be referenced to each PSC agreement.

3.2.2 Equity Share - Oil

Investment Credits

An investment credit is available on direct development and production capital costs as negotiated and approved by SKK Migas.

In recognition of the delays in generating income inherent in the processes of exploration a credit ranging from 17% to 55% of the capital cost of development, transport and production facilities was historically available. The second generation PSC allowed a rate of up to 20% for fields that became commercial after 1976.

The investment credit must be taken in oil or gas in the first year of production but can generally be carried forward.

In earlier PSCs investment credits were capped where the share of total production taken by the Government did not exceed 49%. This condition was eliminated in later generation PSCs.

Under GR 79/27 the Minister has the authority to determine investment incentive credits. The criteria for such credits are not however provided in GR 79/27.

Cost Oil

Expenses generally allowable for cost recovery include:

a. Current-year operating costs from a field or fields with PoD approval, intangible drilling costs on exploratory and development wells, and the costs of inventory when landed in Indonesia (as distinct from when used - although this has changed in recent PSCs). The Contractor can also recover of head office overheads (typically capped at a maximum of 2% of current year costs) provided the cost methodology is applied consistently, disclosed in quarterly reports and approved by SKK Migas (see further guidance below under Management and Head Office Overheads);
b. Depreciation of capital costs calculated at the beginning of the year during which the asset is placed into service (although for recent PSCs only monthly depreciation is allowed in the initial year). The depreciation method determined is either the declining balance or double declining balance method, and is based on the individual asset amount multiplied by depreciating factors as stated in the PSC. Generally the factor depends on the useful life of the asset, such as 50% for trucks and construction equipment; and 25% for production facilities and drilling and production equipment. Title to capital goods passes to the Government upon landing in Indonesia but the Contractor can claim depreciation; and
c. Un-recouped operating and depreciation costs from previous years. If there is not enough production to recoup costs these may be carried forward to the following year with no time limit.

In December 2010, GR 79 increased non-cost recoverable (non-CR) items to 24 items. However the list of non-CR was then revised under GR 27 becoming 22 items starting 19 June 2017. Following is “the list” of the non-CR items under GR 27.

a. Cost charged or incurred for personal and/or family members, management, participating interest holders and shareholders;
b. Establishment or accumulation of a reserve fund, except costs for field closure and restoration deposited in the joint account of SKK Migas and the Contractor in an Indonesian bank;

c. Granted assets;
d. Administrative sanctions such as interest, fines, and surcharges as well as criminal sanctions in the form of penalties related to the tax law and regulation implementation as well as claims or fines resulting from the Contractor;
e. Depreciation of assets which do not belong to the Government;
f. Incentives, payments of pension contributions and insurance premiums for personal account and/or family members of foreign manpower, management and shareholders;
g. Expatiate manpower costs which do not comply with the procedures of the RPTKA or Expatriate Manpower Permits (IKTA);
h. Legal consultant's costs which have no direct relation to oil operations in the context of PSC;
i. Tax consultant's fees;
j. Marketing costs of oil and/or gas of the Contractor's entitlement except marketing costs for gas as approved by SKK Migas;
k. Representation costs, including entertainment costs in any name and form, except if completed with the nominative list and the relevant tax ID number (NPWP);
l. Training costs for expatriate manpower;
m. Merger and acquisition costs or Participating Interest costs;
n. Interest expense on loans;
o. Employee Income Tax (EIT) borne by Contractor, except when paid as a tax allowance or third party EIT which is borne by Contractor or grossed up;
p. Procurement costs which are not in accordance with the arm's length principle and costs exceeding the approved AFE by more than 10%, except for certain costs which are specifically regulated under MoEMR
q. Surplus material due to bad planning;
r. Costs incurred due to negligently operating "Placed into Service" facilities;
s. Transactions which are written off, not through tender process or against the law;
t. Bonuses paid to the Government;
u. Cost incurred prior to the signing of the relevant cooperation contract; and
v. Commercial audit costs.

Previously the reserve fund was deposited in a joint account between the Contractor and the implementing body instead of SKK Migas, and the cost of the commercial audit was also exempted in a rare circumstances. Chapter 3.4.2 provides more detail on issues surrounding GR 79 and GR 27.

Sharing of Production - Oil

Crude production in excess of amounts received for FTP, cost recovery and investment credits is allocated to the Government and to the Contractor before tax (but adjusted by the DMO supply obligations).

Since a PSC involves the sharing of output the production to be shared between the Government and Contractor is made up of:

a. Cost oil;
b. Any investment credit; and
c. Equity oil.

Management and Head Office Overheads

The Contractor has exclusive authority to conduct oil and gas operations in its work area and is responsible to SKK Migas for the conduct of those operations. In practice, SKK Migas exercises considerable control through its approval of the Contractor's annual work programs, budgets and manpower plans.

Some general and administrative costs (other than direct charges) related to head office overheads can be allocated to the PSC operation based on a methodology approved by SKK Migas. A Parent Company Overhead (PCO) Allocation Cap ((PMK - *Peraturan Menteri Keuangan*) 256 dated 28 December 2011) was introduced in 2011 and seeks to govern the cost recoverability and tax deductibility of overhead costs. PMK 256 stipulates a general cap for PCO allocations of 2% p.a. of annual spending for cost recovery and tax deductibility purposes. However, the amount that a PSC can actually recover will be dependent upon approval from SKK Migas and may be lower than 2%. The overhead allocation methodology must be applied consistently and is subject to periodic audit by SKK Migas. For producing PSCs, SKK Migas will often travel abroad to audit head office costs. Please refer to Chapter 3.5 for further discussion.

First Tranche Petroleum (FTP)

Under pre-2002 contracts, Contractors and the Government were both entitled to take FTP and received petroleum equal to 20% of the production before any deduction for operating costs. FTP was then split according to their respective equity shares as stated in the contracts.

Under later PSCs, the Government was entitled to take the entire FTP (although at a lower rate of 10%) with no sharing with the Contractor.

For recent PSCs the FTP of 20% is now once again shared with the Contractor.

Although FTP is considered equity oil an issue has arisen over whether the Contractor's share is taxable if the Contractor has carried forward unrecovered costs. See Chapter 3.4 for a discussion.

Equity Share - Oil

Any oil that remains after investment credit and cost recovery is split between SKK Migas and the Contractor. Second and third generation PSCs involve an oil split of 85/15 (65/35 for frontier regions) for SKK Migas and the Contractor respectively. This is an after-tax allocation being what the Contractor is entitled to lift after paying taxation at the grand fathered rates (i.e. when the PSC was signed). This is summarised as follows:

	New Contracts (%)	1995 Eastern Province PSC (%)	1995 PSC (%)	1985 - 1994 PSC (%)	Old PSC (%)
Tax rate	40*	44	44	48	56
Share of production after tax:					
Government	Varies	65	85	85	85
Contractor	Varies	35	15	15	15
Contractor's share of production before tax:	Ranges from 44.64 – 62.50				
35/(100-44)		62.50			
15/(100-44)			26.79		
15/(100-48)				28.85	
15/(100-56)					34.09

** The general combined "C&D" tax rate fell to 42.4% in 2009 and 40% in 2010. The gross sharing rates were adjusted for in the 2013 PSCs.*

DMO

According to the PSC, after commercial production commences the Contractor should fulfil its obligation to supply the domestic market. The DMO (for oil) is calculated at the lesser of:

a. 25% of the Contractor's standard pre-tax share or its participating interest share of crude oil; or
b. the Contractor's standard share of crude oil (either 62.50%, 26.79%, 28.85% or 34.09% - as described in the table above) multiplied by the total crude oil to be supplied and divided by the entire Indonesian production of crude oil from all petroleum companies for the PSC area.

In general, a Contractor is required to supply a maximum of the 25% of total oil production to the domestic market out of its equity share of production. The oil DMO is satisfied using equity oil exclusive of FTP.

It is possible for the oil DMO to absorb the Contractor's entire share of equity oil. If there is not enough production to satisfy the oil DMO there is no carry-forward of any shortfall. Generally, for the first five years after commencing commercial production, the Contractor is paid by SKK Migas the full value for its oil DMO. This is reduced to 10% of that price for subsequent years. The price used is the Weighted Average Price (WAP). Earlier generations of PSCs provided for a price of only US$ 0.20 per barrel.

Historically there was no DMO obligation associated with gas production. However, under the GR 35/2004 and recent PSCs a DMO on gas production has been introduced.

Valuation of Oil

To determine the sharing of production, and for tax purposes, oil is valued by using a dated Brent price and alpha variable determined by the MoEMR. The value is calculated monthly by SKK Migas. Under a PSC, the Contractor receives oil or in-kind products for the settlement of its costs and its share of equity. This makes it necessary to determine a price to convert oil into US Dollars in order to calculate cost recovery, taxes and other fiscal items such as under/over lifting. In the past, the ICP was determined monthly by BP Migas/Pertamina based on the moving average spot price of a basket of a number of internationally traded crudes, but its value did not properly account for significant fluctuations in movements in oil prices and was considered deficient for this reason.

Monthly tax calculations are based on ICP and actual Contractor liftings. The actual year-end annual PSC Contractor entitlement (cost plus equity barrels) is based on the average ICP for the year. The average ICP during the respective year is known as the WAP.

3.2.3 Equity Share - Gas

Sharing of Production - Gas

The provisions for the sharing of gas production are similar to those for oil except for the equity splits and DMO. When a PSC produces both oil and gas production costs will be allocated against each according to the proportion of production in value terms in the year or another means of allocation as approved by SKK Migas. The costs of each category that are not recouped can either be carried forward to the following year or taken against the production of the other category in the same year only.

The main difference between oil and gas production relates to the equity split. The majority of PSCs are based on an 85/15 after-tax split for oil. For gas, the after-tax split is usually 70/30 for the Government and the Contractor respectively although some older PSCs are based on an after-tax split of 65/35. After the 1995 incentive package, Eastern Province gas Contractors use an after-tax split of 60/40.

These provisions result in the following entitlements:

	New Contracts (%)	1995 Eastern Province PSC (%)	1995 PSC (%)	1985 - 1994 PSC (%)	Old PSC (%)
Tax rate	40*	44	44	48	56
Share of production after tax:					
Government	Varies	60	70	70	70
Contractor	Varies	40	30	30	30
Contractor's share of production before tax:	Depends on the share of production – most are still at 71.43				
40/(100-44)		71.43			
30/(100-44)			53.57		
30/(100-48)				57.69	
30/(100-56)					68.18

** The general combined Corporate and Divident (C&D) tax rate fell to 42.4% in 2009 and 40% in 2010. The gross sharing rates were adjusted for in the 2013 PSCs.*

If the natural gas production does not permit full recovery of natural gas costs, the excess costs shall be recovered from crude oil production in the contract area. Likewise, if excess crude oil costs (crude oil costs less crude oil revenues) exist, this excess can be recovered from natural gas production.

Illustrative Calculation of Entitlements

An illustration of how the share between the Government and Contractors is calculated is presented in the tables below.

Illustrative calculation of entitlement for old PSC			
Assumptions:			
Contractor's share before tax =	34.0909%		
Government's share before tax =	65.9091%		
WAP per barrel =	US$ 60		
Corporate & dividend tax =	56%		
Description	Formula used	Year to date	
		bbls	US$
Lifting:			
- SKK Migas	US$ [a1] = bbls x WAP	2,500	150,000
- Contractors	US$ [a2] = bbls x WAP	4,500	270,000
Total lifting	[A]	7,000	420,000
Less : FTP (20%)	[B] = 20% x [a]	1,400	84,000
Total lifting after FTP	[C] = [a] - [b]	5,600	336,000
Less :			
- Cost recovery	Cost in bbls = cost in US$: WAP	4,000	240,000
- Investment credit	Cost in bbls = cost in US$: WAP	100	6,000
Total cost recovery	[D]	4,100	246,000
Equity to be split	[E] = [c] - [d]	1,500	90,000
SKK Migas' share :			
- SKK Migas' share of FTP	65.9091% X [b]	923	55,380
- SKK Migas' share of equity	65.9091% X [e]	989	59,340
- DMO	25% X 34.0909% X [a]	596	35,760
SKK Migas' entitlement	[F]	2,508	150,480
Over/(under) SKK Migas' lifting	[G] = [a1] - [f]	(8)	(480)
Contractor's share :			
- Contractor's share of FTP	34.0909% X [b]	477	28,620
- Contractor's share of equity	34.0909% X [e]	511	30,660
Less :			
- DMO	25% X 34.0909% X [a]	(596)	(35,760)
Add :			
- Cost recovery		4,000	240,000
- Investment credit		100	6,000
Contractor's entitlement	[H]	4,492	269,520
Over/(under) Contractors' lifting	[I] = [a2] - [h]	8	480

Illustrative calculation of corporate and dividend taxes for Contractor's entitlement in old PSC			
Description	**US$**		
Contractor's share :			
- Contractor's share of FTP	28,620		
- Contractor's share of equity	30,660		
- Cost recovery	240,000		
- Investment credit	6,000		
Less : DMO	(35,760)		
	269,520		
Less : Lifting price variance	(26,949)	**	
Contractor's net entitlement:	242,571		
Less : - Cost recovery	(240,000)		
Add :			
- Actual price received from DMO	22,908	*	
Contractor's taxable income	25,479		
Less :		56%	
- Corporate tax (45%)	11,465		Combined effective tax rate :
- Dividend tax (11%)	2,803		= Corporate and dividend tax/ Contractor's taxable income
Corporate and dividend tax (56%)	14,268		= 14,268/25,479
			= 56%
Contractor's net income	11,211		
* DMO comprised of two items :	Quantity in barrels	US$	Price of DMO
- Old oil (40% of total DMO in barrels)	238	1,428	10% From WAP
- New oil (60% of total DMO in barrels)	358	21,480	WAP
Actual price received from DMO	596	22,908	
** Calculation of lifting price variance :	US$		
Entitlement by using WAP	269,520		
Entitlement by using ICP	242,571		
Lifting price variance	26,949		
@ The entitlement is calculated by using the monthly ICP during the respective year			

Illustrative presentation of old PSC in SKK Migas financial quarterly report – FQR

Description	US$
Gross revenue/lifting	420,000
Less : FTP (20%)	84,000
Gross revenue/lifting after FTP	336,000
Cost recovery :	
- Cost recovery	240,000
- Investment credit	6,000
Total cost recovery	246,000
Equity to be split	90,000
SKK Migas' share :	
- SKK Migas' share on FTP	55,380
- SKK Migas' share on equity	59,340
- Lifting price variance	26,949
- Government tax entitlement	14,268
Add: DMO	35,760
Less: Domestic market adjustment	(22,908)
Total SKK Migas' share	168,789
Contractors' share:	
- Contractor's share on FTP	28,620
- Contractor's share on equity	30,660
- Lifting price variance	(26,949)
Less: DMO	(35,760)
Add: Domestic market adjustment	22,908
Less: Government tax entitlement	(14,268)
Add: Total recoverables	246,000
Total Contractors' share	251,211

Photo source: PT Chevron Pacific Indonesia

Domestic Gas Pricing

Gas pricing in domestic supply contracts is reached through negotiations on a field-by-field basis among SKK Migas, buyers and individual producers based on the economics of a particular gas field development. Historically, all domestic gas had to be supplied to Pertamina under a gas supply agreement. Pertamina then in turn sold the gas to the end-user. Prices were fixed for a designated supply for the duration of the contract.

Under Law No.22, individual producers can sell directly to end users with contract terms and conditions negotiated directly between the producer and the buyer (with assistance from SKK Migas). There continues however to be Government involvement in steering contracts towards certain domestic buyers rather than the producers' preference to export due to favourable pricing and terms.

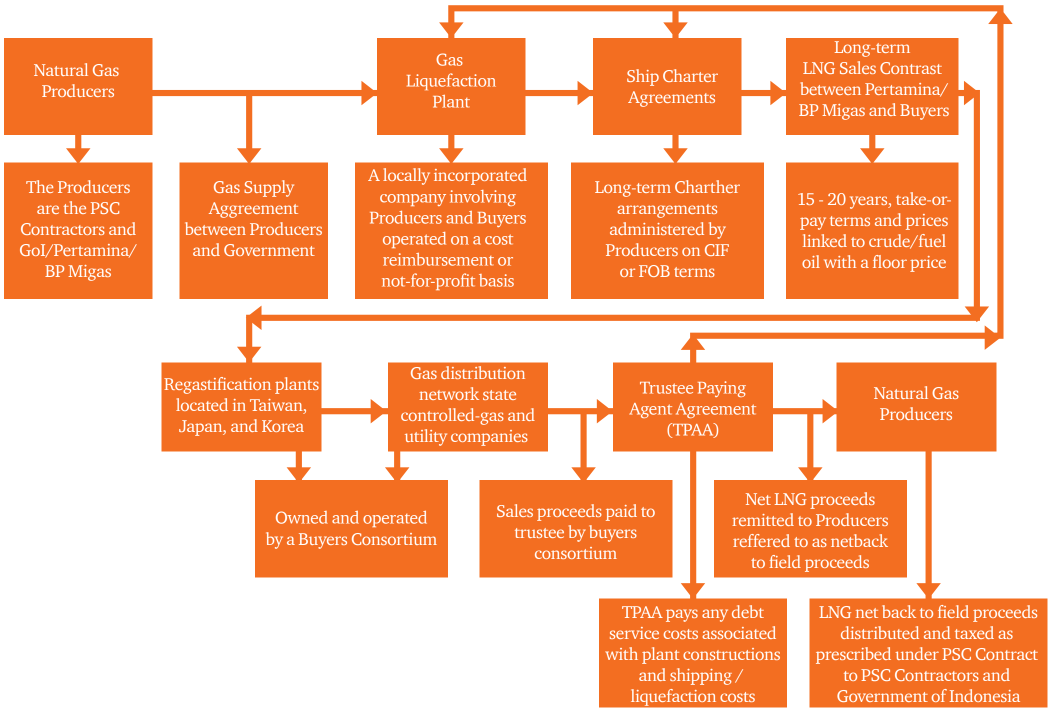
Take-or-pay arrangements have been negotiated in some circumstances. Although this concept has long been accepted the policy around its treatment from a tax, accounting (revenue recognition) and reporting perspective varies in practice.

PSC Contractors and potential investors should also consider the credit risk inherent in any domestic gas sales arrangements when negotiating contract terms and conditions and how they might protect themselves.

Over/(Under) Lifting

Lifting variances will occur each year between the Contractor and the Government. These under/over lifting amounts are settled in cash or from production with the Government and can be considered to be sales/purchases of oil or gas respectively. The individual members of the PSC may in turn have under/over liftings between themselves which will be settled according to joint venture agreements but generally in cash or from production in the following year.

Under MoF Regulation No.139/PMK.2/2013 any under-lifting position between the Contractor and the Government should be settled in cash within 17 days (subject to the time taken for examination and processing of the request) after the Directorate General of Budget (DGB) verifies the request from SKK Migas. There is no specified period for the settlement of any over-lifting position. In practice though, the amount is most often settled when the year-end Financial Quarterly Report is finalised in March of the subsequent year.



For Bontang, PT Badak NGL was established as a continuance of upstream operation from several PSCs to process gas into LNG on a not-for-profit basis. A number of sales contracts were initially entered into under fixed long-term supply arrangements and minimum prices in order to augment risk for the Producers. The initial contracts carried Cost, Insurance, Freight (CIF) terms. From the late 1980s the shipping arrangements were changed to allow buyers and/or others to participate in long-term shipping charters on a Free on Board (FOB) basis.

These LNG projects were effectively project financed with an implied Government guarantee which allowed lower financing costs. A trustee paying agent arrangement was also established to service this debt and the Operation and Maintenance (O&M) costs. These processing and financing costs are first netted against LNG proceeds with the net proceeds then released back to the PSC calculation (i.e. under the so-called “net back to field” approach). The Tangguh LNG facility employs a similar concept to Bontang and is operated by BP Indonesia on behalf of the gas producers.

Non-integrated LNG Projects

Non-integrated projects involve the legal/investor separation of the gas extraction and LNG production assets. Issues under this model focus on the gas offtake price to be struck between the PSC Contractors and LNG investors. In a non-integrated LNG model the investors in the LNG plant separately require a designated rate of return on their investment to service project finance etc. (i.e. unlike the "net back to field" approach outlined above for integrated projects which effectively allow financiers to benefit from the value of the entire LNG project).

The non-integrated LNG structure is relatively new to Indonesia and, as such, it is difficult to assess the Indonesian tax implications. Withholding tax, VAT, tax rate differentials (and associated transfer pricing) and permanent establishment issues need to be considered. In addition any offshore project company would need to consider tax treaty entitlements.

An example of a non-integrated project is the Donggi Senoro LNG plant in Sulawesi. The Donggi Senoro LNG plant is owned by Medco, Mitsubishi Corp. Kogas and Pertamina but Mitsubishi does not have a participating interest in the two PSCs that supply gas to the LNG plant.

3.2.4 Other PSC Conditions and Consideration

The Procurement of Goods and Services

Procurement of goods and services by oil and gas Contractors is regulated to give preference to Indonesian suppliers. For purchases in excess of certain values detailed procedures must be complied with including the calling of tenders and approval by SKK Migas.

The Government sets guidelines for the procurement through Presidential Regulation No. 54/2010, which was lastly amended by Presidential Regulation No. 4/2015. Guidance No.007/SKKO0000/2017/S0 on the Management Framework for the Supply Chain for Cooperation Contracts (Pedoman Tata Kerja Pengelolaan Rantai Suplai Kontraktor Kontrak Kerja Sama) that was derived and amended from the previous regulations is the current referred guidance on asset management, customs and project management. However, some aspects may change after Presidential Regulation No. 16/2018 change the procurement of goods and services after 1 July 2018, after revoking the previous regulation of Perpres No. 54/2010 on 22 March 2018, especially considering the shift from tender-based procurement to a system similar to e-marketplace.

In general, all purchases are done by either tender or direct selection/direct appointment (with certain requirements) and only vendors with Registered Vendor IDs (TDR - *Tanda Daftar Rekanan*) are considered qualified Contractors (DRM - *Daftar Rekanan Mampu*) and able to bid. A PSC Contractor can write its own tenders but require SKK Migas approval at the preparation of procurement list and planning stage if the package is worth over Rp 50 billion or US$ 5 million.

Changes in the scope or terms of a contract which can increase the contract value must be approved by SKK Migas as follows:

a. For contracts where the appointment of the supplier was through approval by SKK Migas and where the overruns exceed 10% of the initial contract or above Rp 200 billion or US$ 20 million; and
b. For contracts where the appointment of the supplier was made by the Contractors and where the cumulative amount of the initial contract plus overruns exceeds Rp 200 billion or US$ 20 million.

Bid documents provided by PSC Contractors contain an invitation to bid and instructions to the bidder which consists of: general provisions; qualifications; and administrative, technical and commercial requirements.

The plans for procurement should be based on the WP&B and/or AFE approved by SKK Migas. This AFE/WP&B is used as the ceiling for the available funds. Procurement activities that do not require an AFE can begin by using the WP&B as a reference, according to the type of activity and the related budget.

PTK 007/2015, replaced PTK 007/2009 from 27 January 2015. While the procurement methods remains unchanged, the 2015 revision allows SKK Migas and Contractors to audit vendors on compliance with Anti-Bribery and Corruption Law and/or Foreign Corrupt Practices Act as well as providing more stringent local content criteria.

It is however still not clear to what extent (if still applicable) the new Gross Split PSC Contractor should follow the procurement rules under PTK 007.

Tender awards are based on price, Indonesian local content, technical advantage and reputation. Wholly foreign-owned Indonesian entities may generally participate as local Indonesian companies. The tendering process requires domestic goods or services to be used, if available, and if they meet technical requirements. In general, Indonesian-made equipment must be purchased if it meets requirements even if this is at a higher cost.

All equipment purchased by PSC Contractors is considered the property of the Government when it enters Indonesia. Oil and gas equipment may enter duty free if used for operational purposes (however please see our comments in Chapter 3.4.8 below). Imported equipment used by service companies on a permanent basis is assessed for Import Duty unless waived by the BKPM. Import duties on oil and gas equipment ranges from 0% to 29%. The position for temporary imports of subcontractor equipment is covered in Chapter 3.4.8.

The Government issued Decision Letter KEP-0066/BP00000/2008/S0 (KEP 0066) with respect to payments for goods and services. KEP 0066 requires National General Banks to be used in performing payments to Goods/Services Providers in terms of both the payer's and receiver's accounts. SKK Migas subsequently clarified that PSC Contractors can use any banks that are legally operating within Indonesia during the exploration stage but that once the PSC enters production the PSC should use a State-Owned Bank.

Inventory

Under the PSC, inventory is separated into capital and non-capital. Non-capital inventory is charged to cost recovery immediately upon landing in Indonesia. A contra-account is usually maintained to track the physical movement and use of non-capital inventory. For later generation PSCs inventory is however charged based on usage.

Under SKK Migas guidelines, any excess or obsolete inventory must be circulated to other PSCs and receive SKK Migas approval before any amounts (capital inventory) can be charged to cost recovery. Under PTK 007, any dead stock and material surplus above 8% of non-capital inventory is not recoverable.

If inventory is transferred or sold to another PSC the selling price must be at carrying cost. Generally, the sale of inventory is not subject to VAT. If a PSC Contractor cannot dispose of the inventory a write-off proposal (WOP) must be submitted to SKK Migas for approval. Once approved, the inventory is usually charged to cost recovery (if not yet charged) and transferred to a SKK Migas warehouse or facility.

Property, Plant and Equipment (PP&E)

Under the PSC, PP&E (including land rights) purchased under the PSC becomes the property of the Government when landed in Indonesia. The Contractor continues to have the use of such property until it is approved for abandonment by SKK Migas.

The net book value of such property, as reflected in the PSC financial statements, represents expenditure by the Contractor which has not yet been cost recovered. Intangible drilling costs of unsuccessful exploratory wells are charged to operating expenses as incurred. If commercial reserves are determined in the contract area and the exploratory wells subsequently become productive the associated costs are capitalised. Additionally, the tangible costs of successful development wells are capitalised.

Depreciation is calculated at the beginning of the calendar year during which the asset is placed into service (PIS). Earlier generation PSCs allow a full year's depreciation during the initial year whereas later generation PSCs require a month-by-month approach so that an asset placed into service in December is only allowed one month's depreciation during the initial year. Under PTK 033, PIS approval is required prior to the commencement of depreciation. The PIS approval should be submitted with the AFE Close-out Report in order for the final depreciable project cost to be agreed.

The method used to calculate each year's allowable recovery of PP&E or capital costs is either the declining balance depreciation method or the double declining balance method. The calculation of each year's allowable recovery of PP&E is based on the individual PP&E assets at the beginning of such year multiplied by the depreciation factors as stated in the PSC. In general, PP&E is categorised based on the useful life according to three groups: group 1, group 2 and group 3.

The un-depreciated balance of assets taken out of service is not charged to recoverable costs but continues to be depreciated based upon the useful lives described above except where such assets have been subjected to unanticipated destruction.

Site Restoration and Abandonment Provision

PSC Contractors that signed contracts after 1995 must include in their budgets provisions for clearing, cleaning and restoring sites upon the completion of work. For those PSCs signed from 2008 onwards any cash funds set aside in a non-refundable joint account for abandonment and site restoration should be cost recoverable. Any unused funds will be transferred to SKK Migas. For PSCs that do not progress to development any costs incurred are sunk costs and cannot be recovered. Under PTK 040, cash funds must be placed into a State Owned Bank under a joint account between SKK Migas and the PSC Contractor. The PSC Contractor shall be liable if the funds are not sufficient to cover the cost of site restoration and abandonment.

It has been suggested that any abandonment and site restoration costs and liabilities related to PSCs signed before 1995 remain SKK Migas's responsibility. However, consistent with PSCs signed since 1995, SKK Migas may, at some point, require the Contractor to contribute to the cost of restoration and abandonment activities.

There is a new MoEMR Regulation No. 15/2018 regarding the post-operation of oil and gas upstream activities. Based on this regulation, Contractors are obligated to conduct post-operation activities by using post-operation activity funds and submit a post-operation activity plan to SKK Migas. Contractors are also obligated to reserve post-operation activity funds, which must be deposited in a joint account between SKK Migas and Contractors, in accordance with the estimated post-operation activity costs. However, application of this MoEMR Regulation No. 15/2018 was unclear at the time of writing.

3.3 *Upstream Accounting*

The table below shows some of the key standards relating to upstream oil and gas companies under PSC accounting, United States Generally Accepted Accounting Principles (US GAAP) and International Financial Reporting Standards (IFRS).

Accounting in Upstream Oil and Gas Business			
Key standards reference and comparison between PSC accounting and US GAAP and IFRS			
Area	**PSC**	**US GAAP**	**IFRS***
Amortisation of capital costs	Accelerated depreciation	Units of production	Method not specifically determined: to be allocated on a systematic basis over useful life, reflecting the consumption of assets' benefits
Non-capital/controllable stores	Expensed upon receipt (except for later generation PSCs which are charged to cost recovery as they are consumed).	Expensed as consumed	Expensed as consumed
Obsolete stores or idle facilities	Written-off only when approved by SKK Migas	Expensed/ impaired when identified	Expensed/impaired when identified
Deferred taxes	Not provided	Accounting Standard Codification (ASC) 740	International Accounting Standard (IAS) 12 treatment
Contingent liabilities	Recognised when settled or approved by SKK Migas	ASC 450	IAS 37 treatment
Severance and retirement benefits	Pay as you go basis	ASC 715	IAS 19 (Revised) treatment
Decommissioning and restoration obligation	Recorded and recovered on cash basis	ASC 410 treatment	Provision to be provided under IAS 37 treatment
PSC licence acquisition costs	Expensed (generally not cost recoverable)	Capitalised	Capitalised as long as meeting IFRS asset recognition criteria
Exploration and evaluation - dry holes	Expensed	Expensed	Expense
Exploratory wells-successful: Tangible costs Intangible costs	Capitalised Expensed	Capitalised Capitalised	Not specifically addressed; Capitalised as long as meeting IFRS asset recognition criteria
Development - dry holes	Expensed	Capitalised	Not specifically addressed; capitalised as long as meeting IFRS asset recognition criteria under IAS 38 or IAS 16

Accounting in Upstream Oil and Gas Business			
Key standards reference and comparison between PSC accounting and US GAAP and IFRS			
Area	**PSC**	**US GAAP**	**IFRS***
Development wells-successful: Tangible costs Intangible costs	Capitalised Expensed**	Capitalised Capitalised	Not specifically addressed; capitalised as long as meeting IFRS asset recognition criteria
Support equipment and facilities	Capitalised	Capitalised	Capitalised

** Currently, Indonesia Financial Accounting Standards (IFAS) do not significantly differ from IFRS*
*** New PSCs signed in 2011 capitalise intangible cost*

3.3.1 Statement of Financial Accounting Standard (SFAS) 66/IFRS 11 – Joint Arrangements

Joint arrangements are frequently used by oil and gas companies as a way to share the risks and costs, or to bring in specialist skills to a particular project. The legal basis for joint arrangements takes various forms such as; a formal joint venture contract or governance arrangement as set out in a company's formation documents. The feature that distinguishes a joint arrangement from other forms of cooperation is the presence of joint control.

Unanimous consent is generally present for financial and operating decisions in order for joint control to exist. An arrangement without joint control is not a joint arrangement.

Under SFAS 66/IFRS 11, participants must account for their interest in a joint operation as a share of assets, liabilities, revenue and costs. However, a joint venture is accounted for under SFAS 15 using equity accounting.

In the oil and gas industry, upstream joint working arrangements use forms of joint arrangement but do not commonly operate through separate vehicles. Such arrangements are generally classified as joint operations under SFAS 66/IFRS 11, meaning that many upstream joint arrangements in the Oil & Gas industry are unlikely to see a major change in their accounting. Midstream and downstream joint working arrangements generally operate through separate vehicles and incorporated entities, meaning that participants who previously chose proportionate consolidation, will see a major change if the arrangement is assessed as a joint venture under SFAS 66/IFRS 11.

3.4 Taxation and Customs

This section sets out the industry specific aspects of Indonesian taxation and customs law for (conventional) upstream Contractors and includes an analysis of some common industry issues. Taxation obligations common to ordinary taxpayers are not however addressed (please see our annual publication the PwC Pocket Tax Guide for discussion of this area).

Issues around taxation of Gross Split PSCs are outlined in Chapter 4.

3.4.1 Historical Perspective

"Net of Tax" to Gross of Tax

The modern regulatory era dealing with the framework of oil and gas activities in Indonesia began with the passage of the Oil and Gas Mining Law No.44/1960 on 26 October 1960. Pursuant to Law No.44, the right to mine Indonesian oil and gas resources was vested entirely in Indonesian State-owned Enterprises. Law No.44 did however, allow for State-owned Enterprises to appoint other parties as Contractors.

Pursuant to GR No.27 of 4 September 1968, Pertamina was formed as a State Enterprise. Pursuant to Law No.8/1971 issued on 15 September 1971, Pertamina was granted exclusive powers in regard to the appointment of private enterprises, including those which are foreign incorporated, as Contractors under oil and gas mining arrangements. This began the era of the PSC and similar contractual arrangements.

From the early 1960s until the late 1970s, PSC entities were entitled to take their share of production on a "net of tax" basis (i.e. with the payment of Indonesian Income Tax made on their behalf by the State/Pertamina).

In the late 1970's this was changed to a "gross of tax" basis to accommodate US foreign tax credit rules. This change led, for the first time, to a calculation of taxable income being necessary and an actual payment of Income Tax by PSC entities. Notwithstanding this alteration, there was an understanding that a "net of tax" entitlement for PSC entities was to continue.

Uniformity Principle

As the change from a "net of tax" to a "gross of tax" basis was not meant to disturb the "desired" production sharing entitlements (i.e. the after-tax take), it became necessary to adopt the so-called "uniformity principle" in relation to the calculation of taxable income. This principle, as outlined in MoF Letter No.S-443A of 6 May 1982, provides that the treatment of income and expenditure items for cost recovery and tax deductibility purposes should be identical (with limited exceptions such as for signing/production bonuses). This long-standing principle has now been recognised (at least partially) in GR 79 which requires that there be a general "uniform treatment" between cost recovery and tax deductibility.

Uniformity therefore meant that the calculation of Income Tax for PSC entities differs to the calculation applying to other Indonesian taxpayers. Significant differences include:

a. That the taxable value of oil "liftings" is to be referenced to a specific formula (currently ICP) as opposed to an actual sales amount (gas "liftings" generally reference the GSA Contract price);
b. That the classifications for intangible and capital costs are not necessarily consistent with the general Income Tax rules relating to capital spending;
c. That the depreciation/amortisation rates applying to these intangible and capital costs are not necessarily consistent with the depreciation rates available under the general Income Tax rules;
d. That there is a general denial of deductions for interest costs (except where specially approved) whereas interest is usually deductible under the general Income Tax rules;
e. That there is an unlimited carry forward of prior year unrecovered costs as opposed to the five year restriction under the general Income Tax rules; and
f. That no tax deductions will arise until there is commercial production as opposed to a deduction arising from the date of the spending being expensed or accrued under the general Income Tax rules.

3.4.2 Government Regulation No.79/2010, as amended by GR No. 27/2017 (GR 79/27)

After a discussion period of over two years, including for industry feedback, a landmark regulation dealing with cost recovery and tax in the upstream sector finally issued as GR 79 on 20 December 2010. GR 79 was the first dedicated regulation dealing with both the cost recovery and tax arrangements for this important industry. Since the issuance of a number of implementing regulations for GR 79 however many issues remain outstanding (please refer to the table below for a summary of the issues which remain unclear and the respective regulation or guidance pending).

Article	Unclear Area	Regulation Pending	Guidance Pending	References to further clarification
Article 3, Article 5, Article 12	Definition of the principle of effectiveness, efficiency and fairness, as well as good business and engineering practices			Absent in: Articles 3(2), 11(1) Is Article 5(3) WPB approval by SKK Migas sufficient?
Article 7	Ring fencing by field or well			Absent in Article 7(2)
Article 8	Minimum Government Share of a Work Area		Yes, Article 8(2) - from the Minister	
Article 10	FTP amount and share			Absent in Article 10(1)
	Investment incentives (form/extent)			Absent in Article 10(2)

Article	Unclear Area	Regulation Pending	Guidance Pending	References to further clarification
Article 12	Limitations on indirect charges from Head Office	See our comments on head office costs		
Article 13	Negative lists - transactions procured without a tender process or cause a loss to the state			Insufficient detail in Article 13(t) elucidation.
Article 14	Income from by-products (sulphur/ electricity)			Absent - consider condensates
Article 17	The use of reserve funds for abandonment and site restoration	Yes, Article 17(4)		
Article 18	Severance for permanent employees paid to the undertaker of employee severance funds	Yes, Article 18(2) - procedures for the administration of employee severance	Yes, Article 18(1) Minister to determine	
Article 19 (See also Article 7)	Deferment of cost recovery until a field is produced - Ring fencing by field?			Absent in Article 19(1)
	Policy with regard to the plan of development to secure State Revenue		Yes, Article 19(2) – Minister to determine policy	
Article 22	Procedures to determine the methodology and formula for Indonesia's crude oil price	Yes, Article 22(2)		
Article 24	DMO fee for delivery of crude oil and gas	Issued as MoF Reg. No. 137/2013	Yes, Article 24(9), to be determined by Minister	

Article	Unclear Area	Regulation Pending	Guidance Pending	References to further clarification
Article 25	Tax assessment for foreign tax credit purposes	Issued as DGT Regulation No.29/ PJ/2011 on Income Tax Payments		
Article 26	Maximum amount of deductions and fee/ compensation paid by the Government	Yes, Article 26(2) from Minister.		
Article 27	Guidance on the procedures for payment of income taxes on PSC transfer and uplift income	Issued as PMK 257 in 2011 (see below)		
Article 31	Form and contents of annual income tax return	Issued as DGT regulation (PER-*Peraturan Dirjen Pajak*)-05/2014 (see below)		
Article 32	Tax ID registration for PSC (so called "Joint Operation" tax ID number)		Yes, Article 32(1)	
Article 33	Procedures to calculate and deliver government share in the event of tax payment in kind	Yes, Article 33(3) PMK 70/2015 (see below)		
Article 34	Standard and norms of costs utilised in petroleum operations		Yes, Article 34(2)	
Article 36	Independent third party appointment to perform financial and technical verification			Elucidation in Article 36(1) appears to limit to natural disaster
Article 38	Transitional rules and adjustment to the Government Regulation			Absent in Article 38(2)

Effective Date

GR 79 stipulates that:

a. It is effective from its date of signing. This means that GR 79 operates from 20 December 2010 (but see below);
b. It applies fully to JCCs, consisting of PSCs and Service Contracts, signed after 20 December 2010; and
c. JCCs signed before 20 December 2010 continue to follow the rules relevant to these JCCs until expiration. This is except for areas on which pre-GR 79 JCCs are silent or which are not clearly regulated. In these cases Contractors should adopt the "transitional" areas covered in GR 79 within three months – a provision which has caused considerable unrest to many holders of pre-GR 79 PSCs. This is primarily because the transitional provisions (at Article 38b) apply in respect of eight significant areas as follows:

i) Government share;
ii) Requirements for cost recovery and the norms for claiming operating costs;
iii) Non-allowable costs;
iv) The appointment of independent third parties to carry out financial and technical verifications;
v) The issuance of an Income Tax assessments;
vi) The exemption of Import Duty and Import Tax on the importation of goods used for exploitation and exploration activities;
vii) The Contractor's Income Tax in the form of oil and gas from the Contractor's share; and
viii) Income from outside of the JCC in the form of uplifts and/or the transfer of JCC/PSC interests.

Whilst the exact scope remains unclear some holders of pre-GR 79 PSCs have been concerned that the transitional rules could result in the largely retroactive operation of GR 79. This was particularly noting that there is uncertainty as to how to determine what areas were "not yet regulated or not yet clearly regulated".

Amendment of GR 79 (i.e. GR 27/2017)

On 19 June 2017, the President signed GR 27/2017 to amend the industry-critical GR 79/2010. The main changes are summarised as follows:

a) Article 10 in regard to State Revenue including Government Share and FTP

This Article has been amended to allow for a range of upstream "incentives" including:-

i) a DMO holiday (albeit with no time limit specified);
ii) a range of tax incentives where they are in accordance with the prevailing tax laws; and
iii) a range of non-tax State revenue incentives which may include the use of State owned assets for upstream activities.

The elucidation indicates that this amendment primarily targets the historical PSC-embedded incentives such as investment credits and DMO holidays. It is not clear however whether this will extend to general tax concessions such as those under GR 9/2016. Whilst this amendment appears positive in principle, the true value will not be clear until implementation.

These amendments also include a new Article 10(a) to allow for a "sliding scale" equity split to be determined by the Minister of Energy and Mineral Resources (Minister of EMR). It is unclear at this stage how this scale will interface with the splits shown in the PSCs themselves (although see discussion on Article 38 below).

b) **Article 11 in regard to recoverable costs**

This Article has been amended to positively confirm the recoverability of LNG processing costs.

c) **Article 13 in regard to non recoverable costs**

This Article has been amended to remove a number of items from the list of non-cost recoverable spending being:-

i) tax allowances related to employee Income Tax (which appears to be Employee Income Tax where remitted on a grossed up basis);
ii) interest formally approved for cost recovery; and
iii) community development during an exploitation phase.

As a result spending on these items should now be cost recoverable at least to the extent that this is in accordance with the requirements of the relevant PSC;

d) **Article 16 in regard to depreciation**

This Article has been amended to allow for the residual value of assets that are "no longer able to be used" to be cost recovered outright. Under the previous arrangements, and Exhibit C of most PSCs, this spending was to continue to be depreciable based upon the original useful life of the asset.

e) **Article 25 dealing with the Income Tax calculation**

This Article has been amended to include:-

i) a new Article 25(7a) which requires that Assessments arising out of a tax audit are to be issued within 12 months from the receipt of a "complete" tax return (previously there was no formal timeline except in a tax refund case).

   The intent/impact is not clear particularly noting the current joint-audit framework with the BPKP and SKK Migas. It is possible however that this amendment will mean less of a role for the Directorate General of Tax (DGT) in Income Tax related audits;

ii) new Articles 25(12) and (13) which provide that Income Tax on FTP is to be due when "accumulated" FTP exceeds the relevant cost recovery balance.

   This amendment is not entirely clear but could mean that FTP is to be accumulated as non-taxable income until reaching exhaustion of unrecovered costs (and so an equity oil position) at which point the entire accumulated FTP becomes taxable.

f) **Article 26 dealing with Tax Facilities**

This Article has been amended to include new Articles 26(A) to (E) to provide specific tax facilities as follows:-

i) a "duty/import tax exemption" in relation to physical imports by PSCs during both the exploration and exploitation phases;

ii) reductions in PBB of 100% (during exploration phase) and up to 100% (during exploitation phase).

Note that MoF approval is required for these import related and PBB incentives during exploitation (the incentives during exploration phase appear to be automatic);

iii) that income arising out of charges from the shared use of assets by PSCs is to be exempt from withholding tax (WHT) and VAT. Interestingly the amendment does not formally provide that the income itself is otherwise exempt;

iv) that "indirect head office allocations" do not constitute Income Tax "objects" or VATable "supplies". This appears to be a formalisation of the long established principle set out under MoF letter S-604 issued in 1998 which has been challenged by the DGT in recent years.

The consequence of this amendment is presumably to render cost allocations exempt from WHT and VAT. There is however no elaboration on the meaning of a "head office" and so it is unclear how widely this incentive can be extended to affiliate charges from overseas.

g) **Article 27 dealing with Uplifts and PI transfers**

This Article has been amended to include:-

i) a new Article 27(1a) which provides that taxable income arising from uplifts, after being reduced by Final Income Tax, is to be non-taxable; and

ii) a new Article 27(2a) which provides that taxable income arising from PSC transfers, after being reduced by Final Income Tax, is to be non-taxable.

In these cases the consequence of the after tax income becoming non-taxable is presumably that no further tax should apply to the after tax income. This should therefore now formally exclude the levying of Branch Profits Tax (BPT) on the after tax income from PSC transfers presumably in either a direct or indirect transfer scenario. Readers should note however that this outcome is not actually stated.

Readers should also note that the BPT on PSC transfers was introduced via PMK 257 and so was arguably never part of the original GR 79 architecture. It is not clear whether a complementary amendment of PMK 257 will now be issued to ensure complete clarity on this matter.

h) Article 31(2) dealing with PSC Transfer Reporting

This Article has been amended to require that the value of a PSC transfer be reported to both the DGOG of the MoEMR and the DGT. Previously the GR 79 reporting was only to the DGT.

i) Article 37 and 38 dealing with Transitional Provisions

The transitional provisions provide that:-

i) for PSCs signed before GR 79 but post Law No.22/2001:-the relevant PSC holders should elect to either:-
   - continue follow the provisions of the relevant PSC (i.e. exclusive of any GR 27 adjustments); or
   - "adjust" their PSC as to comply with GR 27 (although with no guidance on the adjustments mechanism). This election is to be made within six months of the issuance of GR 27 (i.e. by mid December 2017 – which has obviously already passed and with no guidance on the election mechanism);

ii) for PSCs signed post GR 79 but prior to GR 27 issuance:- the outcome here appears to be similar to i) although presumably with any election to "opt-out" of GR 27 still leaving the PSC holder subject to a PSC as impacted by GR 79 (although this is not clear).

The most likely interpretation of these transitional provision is that GR 27 operates to "immediately" amend GR 79 on all matters outline in GR 27. However, GR 27 will still not apply to the extent that GR 27 is inconsistent with the provisions of the relevant PSC. These inconsistencies can then be overcome only by the PSC Contractor agreeing to amend the PSC so as to render the PSC to be entirely consistent with GR 27.

Whilst the range of PSC–specific matters requiring PSC amendments is debatable, it may not extend to the BPT due on a PSC transfer as the taxation of PSC transfers is not typically prescribed in PSCs. As a result BPT on PSC transfers appears to have been removed with effect from June 2017 irrespective of the position taken on any GR 27 related election (although this should be confirmed as part of any transaction advice).

Overall, the package of amendments under GR 27 should, on balance, be viewed positively by the industry and particularly for newer PSCs. However, all PSC holders will need to carefully weigh-up the economic implications before making an election to opt-in to GR 27.

State Revenue and Payment of Tax

The Income Tax payments of a PSC entity were historically counted by the Government as oil revenue rather than as an Income Tax receipt. The Income Tax was also remitted to the DGB as opposed to the ITO.

On 31 March 2015, the Minister of Finance issued PMK 70 amending the previous PMK 79/2012, as a further implementing regulation of GR 79. PMK 70 outlines updated procedures for remitting and reporting “State Revenue” arising from PSC activities. The following high level points are noted:

a. PMK 70 was issued in response to the dissolution of BP Migas (replaced by SKK Migas) and amends the terminology in the previous PMK 79/2012 accordingly;
b. Similar to PMK 79/2012, most of the terms in PMK 70 are consistent with GR 79;
c. State Revenue is formally defined as Government Share and the Corporate and Branch Profit Tax (i.e. the so-called C&D Tax);
d. Final lifting is to be calculated at year end with procedures on how to settle over/under liftings to be separately regulated;
e. Income Tax for PSC Contractors to consist of the monthly and annual C&D Tax;
f. If requested, the C&D Tax must be paid “in-kind” based on the ICP (for oil) or the weighted average price (for gas) of the month when the tax is due. The possibility of tax being paid in-kind is not altogether new although the PMK is the first guidance on a calculation/value mechanism;

With the introduction of PMK 70 Income Tax payments of PSC Contracts are therefore generally now on an equal footing with general taxpayers. Under GR 79, a facility also now exists for a Tax “Assessment” letter evidencing the payment of Income Tax. Prior to this the Directorate General of Taxes (DGT) issued a Temporary Statement.

C&D Tax payment procedures are as follows:

a. For cash payments:
   i) The tax payments are to be remitted into the (general) State Treasury account rather than into the Oil & Gas accounts (i.e. the MoF account #600.000411980 at the Bank of Indonesia). The payment/remittance is still in US$ and the transfer shall be made via a "Foreign Exchange" Designated Bank (i.e. *Bank Persepsi Mata Uang Asing*).
   ii) A tax payment slip is to be completed. Directorate General of Taxation (DGT) Regulation No.25/PJ/2011 provides different tax payment codes for Petroleum Income Tax, Natural Gas Income Tax and Branch Profits Tax.
   iii) The monthly and annual C&D Tax payment deadlines are the 15th of the following month and the end of the 4th month following year end. Tax will be considered paid when the funds are received into the State Treasury account (i.e. the tax payment slip (SSP) will be marked with NTPN (*Nomor Transaksi Penerimaan Negara*) and NTB (*Nomor Transaksi Bank*).

b. For in-kind payments:
   i) The payment deadlines are the same as for cash payments.
   ii) Contractors and SKK Migas will record the in-kind payments in a "minutes of in-kind handover" (*berita acara serah terima*) to be signed by both parties.
   iii) The SSP shall be completed based on the minutes of in-kind handover including the hand-over date. PMK 70 provides two attachments – Template for the Minutes of Handover and Attachment II – Tax Payment Slip (SSP) specifically for (in-kind) C&D Tax;

c. Where C&D Tax is overpaid the overpayment should be settled in accordance with the prevailing tax laws meaning that tax refunds could be subject to a tax audit (the historical practice has been that PSC entities simply offset overpayments against future C&D Tax instalments). The instructions in Per-05 for completing the Annual Corporate Income Tax Return (CITR) do not result in the disclosure of under or over payments in the main CITR form;

d. The C&D Tax reporting procedures include:
   i) Operators prepare monthly and annual State Revenue Reports using the template provided in PMK 70 and submit to the DGT (generally the Oil & Gas Tax Office), the DGB (specifically the Directorate of Non-Tax State Revenue in this case), and SKK Migas. PMK 70 is silent on the reporting obligations during exploration (i.e. where no State Revenue obligation should exist).
   ii) The reports should include the relevant SSP and payment evidence. This will be the transfer evidence (for cash payments) or the minutes of in-kind handover (for in-kind payments);

e. Any late payment or reporting is subject to administrative sanctions under prevailing tax laws. The reports also require the declaration of Government Share and (as outlined above) extend the reporting obligations to the DGB, the DGT and SKK Migas.

Cost Recovery/Tax Deductions

GR 79/27 requires that there be a “uniform treatment” between cost recovery and tax deductibility. This is pivotal as it appears to formally enshrine the long-standing “uniformity principle”. To satisfy uniformity the amount should still:

a. Be spent on income producing activities;
b. Satisfy the arm’s length principle (for related party transactions);
c. Be consistent with good business and engineering practices; and
d. Be approved by SKK Migas and be included in the relevant Work Program and Budget.

GR 79/27 also outlines two items of spending that are not allowed for cost recovery. For this list please refer above (3.4.2).

Indirect Taxes

Indirect taxes, regional taxes and regional levies are stated as cost recoverable. Indirect taxes include VAT, Import Duty, Land and Building Tax (PBB), regional taxes and regional levies. These taxes have generally been reimbursable in the past.

Import Duty and other import taxes (such as VAT and Article 22 Income Tax) related to exploration and exploitation activities are to generally exempted (see below).

PBB for Post GR 79-PSCs

On 12 April 2013, the Minister of Finance (MoF) issued Regulation No.76/PMK.03/2013 (“PMK 76”) on Land and PBB for the oil & gas sector replacing Regulation No. 15/PMK.03/2012 (“PMK 15”). The effective date of PMK 75 was 12 May 2013. PMK 76 has led to a major change in the PBB regulatory framework for PSCs.

General PBB regime

Pursuant to Article 5 of Land and Building Tax Law No.12/1994 (Law 12) the PBB tax rate is 0.5% of a “deemed” tax base. The “deemed” tax base ranges from 20% up to 100% of the “object value” (being a statutory value called “NJOP”). The taxable event is the tax base of land and buildings “held” as at 1 January each year. PBB should be paid within six months of the receipt of an Official Tax Payable Notification (SPPT). Whilst an SPPT is not an assessment it is still a legal notice from the Tax Office against which taxpayers can object.

PBB and PSCs

Article 11(4)(f) of GR 79 indicates that indirect taxes (including PBB) should be cost recoverable. Post GR 79 PSCs accommodate this by requiring indirect taxes to be cost recovered (in earlier PSCs the Government bears all taxes except Income Tax). On 1 February 2012, the MoF issued PMK 15 updating the PBB procedures (including overbooking) applicable to the PSC sector. The key features were:

a. That PMK 15 was effective on 1 February 2012 and cancelled all previous regulations relating to the PBB compliance for PSCs;
b. That the Tax Office should issue the SPPT by the end of April of each fiscal year;
c. That the PBB due should be settled through an overbooking made by the DGB from the oil and gas revenue account into the Tax Office/DGT account (i.e. PBB is not paid by the PSC Contractor); and
d. That the taxable base value will be covered by further regulations.

On 12 April 2013 the MoF replaced PMK 15 with PMK 76. PMK 76 specifically references GR 79 and changes the PBB treatment as follows:

a. For pre GR 79 PSCs the overbooking process continues to apply; and
b. For post GR 79 PSCs the overbooking does not apply and the PSCs are required to self-remit the PBB and claim as cost recovery.

With the automatic overbooking entitlement for post GR 79 PSCs withdrawn, the DGT began to directly "assess" post GR 79 PSCs.

On 30 September 2013, the DGT issued SE-46 to provide further clarification on completing the SPOPs (notification of PBB objects) for the "offshore" component of objects. Perhaps the most significant aspect of SE-46 was to clarify that the NJOP should only extend to areas "utilised" by the PSC interest holder. Whilst the term "utilisation" was not defined the intent appeared to be to reduce PBB exposure for these PSCs going forward.

On 20 December 2013, the DGT issued PER-45 on the compliance and calculation procedures for PSCs (and effectively therefore SE-46). The key points outlined in PER-45 (which came into force in 1 January 2014) were as follows:

a. Definition of "Offshore Area": the definition did not refer to utilisation meaning a question arose over whether PER-45 revoked the utilisation interpretation of an "Offshore Area".
b. The introduction of a "zone" concept: the "zone" utilised for oil and gas activities to include areas outside of the PSC contract area.

This outcome left post - GR 79 PSCs exposed to PBB liabilities and resulted in a significant industry issue.

PBB reduction for explorations PSCs

On 31 December 2014, and in response to the above, the MoF issued Regulation No.267/2014 ("PMK 267") which provided tax incentives for exploration PSCs in the form of a PBB reduction.

The reduction was granted on the sub-surface component and can amount to up to 100% of the PBB due on that component. This incentive is applicable for 2015 onwards where the Contractor fulfils the following requirements:

a. Its PSC was signed after 20 December 2010 (i.e. the effective date of GR 79);
b. Have submitted a SPOP (notification of PBB objects) to the DGT; and
c. Provided a recommendation letter from the MoEMR which stipulates that the PBB object is still at exploration stage.

The reduction is granted annually for a maximum of six years from the PSC signing date and can be extended by up to four years (subject to a recommendation letter from the MoEMR).

Bookkeeping and Tax Registration

A PSC entity is automatically entitled to maintain its books, and calculate its Income Tax liability, in English and using US Dollars (reconfirmed by MoF Regulation No.24/PMK.011/2012 as lastly amended by MoF Regulation No. 1/PMK.03/2015). However, a PSC entity should still file a notification (three months before the relevant accounting period) with the Tax Office. Transactions denominated in currencies others than US dollars are to be converted into US Dollars using the exchange rate as the date of the transactions.

VAT and WHT continue to be calculated in Rupiah irrespective of any US Dollar bookkeeping notification.

GR 79/27 does not affect the bookkeeping requirements as set out above. However, GR 79/27 also indicates that:

a. Contractors shall carry out their transactions in Indonesia and settle payment through the banking system in Indonesia; and
b. Transactions and the settlement of payments (referred to in paragraph a) can only be conducted outside of Indonesia if approval from the MoF is obtained.

A Contractor is required to register for its own tax ID number. Registration of the JCC itself should be carried out by the operator of the particular JCC. This development is similar to that applying to existing Joint Operating Body arrangements.

Operators are responsible for transactional taxes (including WHT and VAT) meaning that the transactional taxes should continue to be reported under the Operator's tax ID number.

PSC Transfers

GR 79/27 provides that transfers of PSC/JCC interests will be taxed as follows:

a. During exploration stage, a final tax of 5% of gross proceeds will be levied. However the transfer will be exempted if undertaken for "risk sharing purposes" and the following criteria are met:
    i) Less than the entire PSC interest is transferred;
    ii) The PSC interest has been held for more than three years;
    iii) Exploration activities have been conducted; and
    iv) The transfer is not intended to generate a gain.
b. During the exploitation stage, a 7% final tax on gross proceeds is due except for a transfer to a "national company" as stipulated in the JCC (i.e. a national participating interest.

GR 79 via PMK 257 introduced the imposition of BPT on PSC transfers (either direct or indirect). This BPT imposition however appears to have been removed under GR 27 starting June 2017 (see comments above).

Head Office Costs

Head Office costs are recoverable subject to:

a. The costs supporting activities taking place in Indonesia;
b. The Contractor provides audited financial statements of the head office and an outline of the method of cost allocation this (as approved by SKK Migas); and
c. The head office allocation does not exceed a ceiling determined by MoF Regulation No.256/PMK.011/2011 being a maximum of 2% of spending (subject to approval from SKK Migas) being cumulative spending during exploration and annual spending thereafter.

Post Lifting Costs

Certain post lifting costs, including for transporting natural gas (such as marketing costs approved by SKK Migas) and other post upstream activities may be recoverable.

Tax Calculation, Payment and Audit

For JCCs signed after GR 79, the Income Tax rate is that which prevailed at the time of signing or that prevailing from time to time. This appears to breathe life into the Income Tax rate "election" which is included in Law No.22 (see below).

For JCCs signed before GR 79, the Income Tax rate is that which prevailed when the JCC was signed. This grandfathering is consistent with the retention of the uniformity principle.

If the Income Tax payment is reduced, including via a change in the domicile of the Head Office (for example due to a favourable tax treaty) the after tax "government share" shall be adjusted to ensure the pre-treaty split. This enshrines the recent trend in PSCs to counter tax treaty use.

Income Tax payments are subject to tax audit by the DGT. The DGT will issue any assessments after carrying out an audit. Contractors should be prepared for the tight deadlines that apply in a tax audit context and any associated tax dispute proceedings. This includes a 30-day time limit for producing documents, especially those that might be held at the Head Office. Apart from providing documents on time, there are also obligations to provide (written) responses to DGT enquiries on time.

Expatriate Costs

Expatriate costs are recoverable but should not exceed a ceiling determined by the MoF (in coordination with the MoEMR). MoF Regulation No.258/PMK.011/2011 ("PMK 258") provides details on the applicable cap which is dependent on the role and region that the expatriate comes from as per the table below. Remuneration is not well defined but seems to cover short-term compensation only.

Position classification	Rates for expatriates who hold a passport from			Remarks
	Asia, Africa, and Middle East	Europe, Australia, and South America	North America	
	(USD)	(USD)	(USD)	
Highest Executive	562,200	1,054,150	1,546,100	1st Ranking position in Contractor of Oil and Gas Cooperation Contract (President, Country Head, General Manager)
Executive	449,700	843,200	1,236,700	2nd Ranking position in Contractor of Oil and Gas Cooperation Contract (Senior Vice President, Vice President)
Managerial	359,700	674,450	989,200	3rd Ranking position in Contractor of Oil and Gas Cooperation Contract (Senior Manager, Manager)
Professional	287,800	539,450	791,200	4th Ranking position in Contractor of Oil and Gas Cooperation Contract (Specialist)

Although the cap applies for cost recovery and tax deductibility purposes, the Article 21/26 employee income tax withholding obligation is subject to the prevailing income tax law meaning the Article 21/26 withholding tax is based on the actual payment.

3.4.3 Income Tax Rates

Various Eras

The introduction of the uniformity principle (and its maintenance in GR 79/27) necessitated that the Income Tax rate should be "grandfathered" to the rate applying at the time that the PSC (or extension) was entered into. This is because the production sharing entitlements set out in the PSC are grossed-up to accommodate the Income Tax rate applying at the time. These rates then need to apply for the whole life of the PSC.

MoF Decree No.267 of 1 January 1978, and MoF Decree No.458 of 21 May 1984, provide "loose" implementing guidelines on the levying of Income Tax against PSC entities. Decrees No.267 and No.458 discuss taxable income in terms of a share of oil and gas production (or "lifting"). Deductions are discussed in terms of associated exploration, development and production costs.

Where the relevant entity holds an interest in a PSC signed before 1984, the applicable Income Tax rate applying should be 45%. This rate was reduced to 35% in 1984, and then to 30% in 1995 up to 2008. This rate was further reduced to 28% in 2009 and 25% starting in 2010 based on the new Income Tax Law No.36/2008 which was effective 1 January 2009.

The general assumption in the early years of PSC licensing was that PSC entities would be foreign incorporated. On this basis, the after tax profits of a PSC entity were subject to a further BPT. This tax was due at the rate of 20% giving rise to a total Income Tax exposure of (say) 56% for pre-1984 PSCs (i.e. 45% plus (55% x 20%)). In the relevant PSC this was shown as a (gross of tax) production share of 0.3409 for oil (i.e. 15%/1-.56%) and 0.6818 for gas (i.e. 30%/1-.56%).

In order to ensure a constant after tax take this gross-of-tax share has altered over the years as Indonesia's general Income Tax rate has been lowered. In addition, in some PSC bidding rounds the net-of-tax Contractor take has increased to (up to) 25% for oil and 40% for gas. This has also led to a variation in the gross production sharing rates.

These calculations can be summarised as follows:

PSC Era	Income Tax - General	Income Tax – Branch Profits	Combined Tax Rate	Prod. Share (Oil)	After Tax	Production Share (Gas)	After Tax
Pre-1984	45%	20%	56%	.3409	15%	.6818	30%
1984-1994	35%	20%	48%	.2885	15%	.5769	30%
1995-2007	30%	20%	44%	.2679	15%	.5357	30%
2008	30%	20%	44%	.4464	25%	.7143	40%
2009	28%	20%	42.4%	.6250	36%	.714	41.142%
2010	25%	20%	40%	.6000	36%	.685	41.143%
2013-2016*	25%	20%	40%	.583	35%	.667	40%

**Gross Split PSCs from 1 January 2017*

BPT – Treaty Use

The BPT rate can be reduced by a tax treaty. However, with the exception of a small number of treaties (most notably those with the Netherlands, the UK, Malaysia, and Singapore – although there are others) the BPT reduction in a tax treaty does not apply to PSC activities.

Any reduction in the BPT rate may lead to an increase in a PSC entity's after-tax production share. Consequently the relevant Indonesian government authorities have historically disputed a PSC entity's entitlement to utilise treaty benefits. In the late 1990s this issue led to the cancellation of the Netherlands' treaty (although this has since been renegotiated) and the threatened cancellation of others including that with the UK. In 1999, the MoF issued an instruction that the Government's production share should be increased to compensate for any PSC entity utilising treaty concessions.

PSCs issued in the last 15 years or so have sought to contractually negate the use of treaties by including provisions seeking to amend the production shares (i.e. as per the MoF instruction above). The typical PSC language is now as follows:

> "**SKK MIGAS** and **CONTRACTOR** agree that all of the percentages appearing in Section VI of this **CONTRACT** have been determined on the assumption that **CONTRACTOR** is subject to final tax on profits after tax deduction under Article 26 (4) of the Indonesia Income Tax Law and is not sheltered by any tax treaty to which the Government of the Republic of Indonesia has become a party. In the event that, subsequently, **CONTRACTOR** or any of Participating Interest Holder(s) comprising **CONTRACTOR** under this **CONTRACT** becomes not subject to final tax deduction under Article 26 (4) of the Indonesia Income Tax Law and/or subject to a tax treaty, all of the percentages appearing in Section VI of this **CONTRACT**, as applicable to the portions of **CONTRACTOR** and **SKK MIGAS** so affected by the non applicability of such final tax deduction or the applicability of a tax treaty, shall be adjusted accordingly in order to maintain the same net income after-tax for all **CONTRACTOR**'s portion of Petroleum produced and saved under this **CONTRACT**".

Indonesian Entities – Special Issues

The "gross of tax" calculation included in the production share assumes a foreign incorporated PSC holder with a liability to BPT at the rate of 20%.

A PSC can however, be awarded to an Indonesian entity. In such a case, the production sharing formula will typically be unchanged and so assume a dividend (rather than BPT) withholding tax also at the rate of 20%.

Where a PSC is held by an Indonesian entity with Indonesian shareholders the taxation of dividends should follow the general taxation rules. Under these rules, for an Indonesian entity, dividend income is generally tax exempt where the recipient shareholding entity holds no less than 25% of the dividend paying entity's paid in capital.

It is not clear however, that any PSC related Income Tax reduction will be accepted in practice.

Oil and Gas Law Election – Prevailing Tax Laws or those Prevailing when Contract Signed

Article 31(4) of Law No.22 allows parties to a PSC signed from 2001 onwards to choose which tax laws are to apply:

"The Co-operation Contract shall provide that the obligation to pay taxes referred to in paragraph (2) shall be made in accordance with:

a) The provisions of tax laws and regulations on tax prevailing at the time the Co-operation Contract is signed; or
b) The provisions of prevailing laws and regulations on tax."

However, the exact nature of this election is not clear, including whether the election could lock-in the uniformity principle. To avoid uncertainty, PSCs often include the following language:

"It is agreed further in this **CONTRACT** that in the event that a new prevailing Indonesia Income Tax Law comes into effect, or the Indonesia Income Tax Law is changed, and **CONTRACTOR** becomes subject to the provisions of such new or changed law, all the percentages appearing in Section VI of this **CONTRACT** as applicable to the portions of **CONTRACTOR** and GOI's share so affected by such new or changed law shall be revised in order to maintain the same net income after tax for **CONTRACTOR** or all Participating Interest Holders in this **CONTRACT**."

Photo source: PT Pertamina (Persero)

3.4.4 Administration

Regulation

A PSC entity (where foreign incorporated) is required to set up a branch office in Indonesia. This branch also gives rise to a PE. This is the case for all foreign incorporated PSC interest holders (i.e. operators and non-operators).

A PSC branch, as a PE, should register for tax by filing an appropriate registration application form including the following attachments:

a. A letter from the branch's "head office" declaring the intention to establish a branch in Indonesia including information on the branch's chief representative;
b. A copy of all pages of the passport of the branch's chief representative;
c. A notification letter on the chief representative's domicile (issued by a local government officer);
d. A notification letter on the domicile/place of business of the branch (usually issued by a building management company where the branch is located in a commercial office building);
e. A copy of the PSC;
f. A copy of the Directorate of Oil and Gas letter which declares the entity the PSC holder; and
g. A letter of appointment of the chief representative from the head office.

Compliance

The registration obligation applies from the time of commencement of business activities. Therefore, this includes the exploration phase (i.e. there is no entitlement to defer registration until, say, Commercial operations is declared).

Ongoing tax obligations include:

a. Filing annual Income Tax returns for each interest holder (although see comments on GR 79 above);
b. Filing monthly reports on the Income Tax due on monthly liftings as well as the remittance of Income Tax payments (for each interest holder-but obviously only after production);
c. Filing monthly returns for withholding obligations (for the operator only);
d. Filing monthly and annual Employee Income Tax returns (for each interest holder – noting that generally for a non-operator this will be a nil return);
e. Filing of monthly VAT reports (for the operator only);
f. Maintaining books and records (in Indonesia) supporting the tax calculations (for the operator only).

On 18 February 2014 the DGT issued Regulation No.5/2014 on the format and content of the annual income tax return for PSC taxpayers. In addition to distinguishing liftings and non-liftings income Contractors became required to complete and attach (as appropriate) six special attachments concerning:

a. Corporate Income Tax for PSC Contractors;
b. Branch Profits Tax/dividend tax for PSC Contractors;
c. Details of Costs in Exploration/Exploitation Stage for PSC Contractors;
d. Depreciation Schedule for PSCs;
e. Details of the Contractor's portion of their FTP share;
f. Details of Changes in the Participating Interests.

From April 2012, the DGT moved all PSC Contractors to the Oil and Gas Tax Office (KPP Migas) which has specific responsibility for the industry.

Joint Audits

Pursuant to a Memorandum of Understanding (MoU) entered into between SKK Migas, *Badan Pengawasan Keuangan dan Pembangunan* (BPKP) and the DGT Joint Audits by these bodies have been carried out on all operational PSCs and non-producing PSCs with an approved PoD since April 2012.

This was the first systematic DGT audit of PSCs meaning that many PSCs experienced a DGT tax audit for the first time.

Common issues raised by the DGT to date include:

a. Direct/Indirect PSC transfers – the DGT policy in this area continues to evolve. The "substance over form" concept is being applied with GR 79/PMK 257 tax levied in a wide range of PSC transfers scenarios. The DGT regularly reconciles taxpayer declarations on individual PSC values with public announcement, etc.
b. Long standing cost recovery audit findings – the DGT has unilaterally issued tax assessments despite long standing cost recovery audit findings still being subject to discussions/ negotiations with SKK Migas and/or BPKP. This creates risk around the coordination of work amongst the DGT, SKK Migas and BPKP.
c. General reconciliations between the financial reports and the monthly tax returns – the DGT often queries discrepancies between the amounts disclosed in financial reporting and the tax objects disclosed in the monthly WHT and VAT returns. Whilst this type of request is common with general taxpayers this should be less relevant for PSC entities as their financial data may be limited to the financial quarterly reports.
d. "Head office" overhead allocations – since 1998 WHT and VAT on head office overhead allocations has been (effectively) exempted through DGT Letter S-604. While the DGT appears still to be accepting S-604, the challenge has shifted to satisfying the nature of the charges as "head office".
e. Benefits in Kind (BiK) – BPKP/SKK Migas can have a different view on BiK costs with SKK Migas often allowing cost recovery but the DGT then arguing for an Article 21 Employee WHT obligation.

On 4 April 2018, MoF issued Regulation No. 34/PMK.03/2018 stipulating procedures and guidance for the implementation of Joint Audits conducted by SKK Migas, BPKP and DGT. MoF-34 was probably issued to accommodate the industry concern over the lack of coordination amongst the three institutions in performing audits on PSC Contractors.

Ring Fencing

Pursuant to MoF Regulation No.SE-75/1990, an entity may hold an interest in only one PSC (i.e. the "ring-fencing" principle). There are also no grouping or similar consolidation arrangements available in Indonesia. This means that the costs incurred in respect of one PSC cannot be used to relieve the tax obligations of another.

As noted in GR 79/27, PSCs are now ring-fenced by field rather than contract area. This thereby narrows even further the focus of the ring fencing principle.

3.4.5 Employee Income Taxes

For PSC entities (acting as the operator) the taxation arrangements for employees are largely identical to those for other employers. On this basis, there is an obligation for the operator to withhold and remit Income Tax, and to file monthly returns, in accordance with either Article 21 or 26 of the Income Tax law. The Article (and thus the tax rate) varies according to residency of the employee (please refer to PwC Pocket Tax Guide for further details).

Industry related tax issues include:

a. The treatment of "rotators" or similar semi-permanent personnel. This mainly relates to ensuring that the correct tax rates are applied; and
b. The treatment of non-cash "benefits in kind". The treatment can vary according to the era of the PSC, whether the personnel are working in designated "remote areas" and whether the operator claims cost recovery for the relevant benefit.

Further, resident employees without an NPWP (taxpayer identification number) are subject to a surcharge of 20% on Indonesian sourced income in addition to the standard WHT. On this basis, a PSC entity needs to ensure that all employees (including resident expatriates) obtain their individual NPWP especially if a PSC entity provides salaries on a net of tax basis.

3.4.6 Withholding Taxes (WHT)

For PSC entities (when acting as operator) the WHT obligations are largely identical to those for other taxpayers. On this basis, there is an obligation for the operator to withhold and remit Income Tax, and to file monthly WHT returns, in accordance with the various provisions of the Income Tax law (please refer to the PwC Pocket Tax Guide for details).

For PSC entities the most common WHT obligations arise with regard to:

a. Land and building rental (i.e. Article 4(2) - a final tax at 10%);
b. Deemed Income Tax rates (i.e. Article 15, for shipping at 1.2% and 2.64%);
c. Payments for the provision of services etc. by tax residents (Article 23 - at 2%); and
d. Payments for the provision of services etc. by non-residents (Article 26 - 20% before treaty relief - noting tax on services provided by foreign drillers is remitted by the driller (see Chapter 6.3 below)).

Photo source:
PT Pertamina (Persero)

3.4.7 VAT

General

The sale of hydrocarbons taken directly from the source is currently exempt from VAT. PSC entities have therefore never constituted taxable firms for VAT purposes and have never been registered for VAT purposes.

As clarity on 28 December 2012 the Minister of Finance issued Regulation No. 252 (MoF No.252) confirming that certain types of gas supplies are VAT exempt. These included natural gas transported through pipelines, Liquefied Natural Gas (LNG) and Compressed Natural Gas (CNG). Liquefied Petroleum Gas (LPG) in cylinders and "ready for public consumption" is however subject to 10% VAT.

VAT charged to/suffered by PSC entities is therefore not available as an input credit. Instead, and depending upon a number of factors, the VAT has historically either been:

a. Deferred (typically for in-country supplies); or
b. Exempted (typically for imports);
c. Reimbursed (by SKK Migas); or
d. Cost recovered (typically for post - GR 79 PSCs)

In-Country Supplies - VAT Deferment

Pursuant to Presidential Decree No.22/1989 (PD 22) and its implementing regulations, VAT payments arising from oil, gas and geothermal exploration and drilling services were deferred until the time of the Government Share (when the VAT was then reimbursed- see VAT Reimbursement). This arrangement effectively eliminated all but a small cash flow exposure on VAT charged in these scenarios.

In 1995 however, an amendment to the VAT Law sought to terminate all VAT deferments with effect from 31 December 1999. The Indonesian tax authorities took the view that this amendment ended the deferment available to PSC entities. In January 2000, assessments were issued for all VAT deferred up to this date. Around 30 taxpayers appealed these assessments through the Indonesian Court system. The outcome of these cases has been mixed.

New PSC entities assume no entitlement to defer VAT payments. On this basis, the 10% VAT charged on "in-country" goods and services will need to be paid and will not be refunded unless Government Share is achieved (and if permitted under the PSC).

Imports-VAT Exemption

See Import Taxes below in Chapter 3.4.8.

VAT Collectors

While PSC Contractors are not VATable firms they do constitute “collectors” for VAT purposes (except for the period January 2004 - January 2005). As a result, PSC entities remit the VAT that is charged on goods and services directly to the tax authorities (rather than to the suppliers). There is a monthly filing associated with the process. This remittance arrangement leaves suppliers to the upstream sector in a perpetual VAT refund position.

VAT Reimbursement

PSCs issued prior to GR 79 (see below) typically provide that Pertamina (now SKK Migas) is to:

> *“assume and discharge all other Indonesian taxes [other than Income Tax including VAT, transfer tax, import and export duties on materials equipment and supplies brought into Indonesia by Contractor, its Contractors and subcontractors………*

Photo source: PwC

The obligations of Pertamina [now SKK Migas] hereunder shall be deemed to have been complied with by the delivery to Contractor within one hundred and twenty (120) days after the end of each Calendar Year, of documentary proof in accordance with the Indonesian fiscal laws that liability for the above mentioned taxes has been satisfied, except that with respect to any of such liabilities which Contractor may be obliged to pay directly, Pertamina [now SKK Migas] shall reimburse it only out of its share of production hereunder within sixty (60) days after receipt of invoice therefore. Pertamina [now SKK Migas] should be consulted prior to payment of such taxes by Contractor or by any other party on Contractor's behalf".

PSC protection from non-Income taxes have therefore historically fallen into two categories. Firstly, those taxes were historically met directly by SKK Migas (e.g. Land and Building Tax) and secondly those taxes met by the Contractor (e.g. VAT) which have then been reimbursed. Further, and depending upon the PSC era, the reimbursement shall only be from SKK Migas' share of production (i.e. there is no entitlement to reimbursement until the PSC goes into production and reaches the Government share).

Reimbursement is, in practice, also subject to the PSC entity satisfying high standards of documentation (original VAT invoices, etc.). Where VAT is not reimbursed for a documentation related concern SKK Migas had, on occasions, allowed VAT to be charged to cost recovery.

VAT borne during the exploration phase by PSC entities who do not subsequently move into production will never be reimbursed and so the VAT will become an absolute cost.

The VAT reimbursement procedures are stipulated under MoF Regulation No. 218/2014 ("PMK 218"), as amended by MoF Regulation No. 158/2016 ("PMK 158"). Some of the key features are as follows:

a. That Government Share is to include the Government's entitlement to FTP (and hence, VAT reimbursement can be sought once FTP arises);
b. That reimbursement is to be subject to confirmation from the DGT via a "Tax Clearance Document";
c. That SKK Migas may offset a reimbursement entitlement against any Contractor "overliftings" (previously over-lifting was settled in cash);
d. That there is no timeframe for obtaining the full verification from SKK Migas; and
e. That reimbursement entitlement excludes input VAT arising from LNG processing, unless the PSC stipulates otherwise.

VAT reimbursements are denominated in Rupiah at the historical exchange rates and so the reimbursement mechanism also carries an exchange risk.

VAT Cost Recovery

As noted above, most recent PSCs, including those issued post GR 79, have seen the standard PSC language regarding VAT reimbursement removed in favour of an entitlement to include all indirect taxes (including VAT) as operating costs of the Contractor (i.e. as a cost recoverable item).

3.4.8 Import Taxes

Old PSCs

As indicated in Chapter 3.4.7 under VAT Reimbursement, PSCs signed prior to the Law No.22 (Old PSCs) typically provided that Pertamina (now SKK Migas) was to discharge, out of its share of production, all Indonesian taxes (other than Income Tax). These taxes included VAT, transfer tax, import and export duties on material equipment and supplies brought into Indonesia by the Contractor (subject to documentary proof).

The discharge of Import taxes (which includes Import Duty, VAT and the Article 22 Income Tax prepayment) has been historically accommodated via a Master List, which effectively led to an outright exemption of all import taxes on approved capital items. This covered both "permanent" imports (i.e. where title transfers to the State) and "temporary" imports (i.e. where the title remains with the importer).

However, under Law No.22, Contractors became required to pay import taxes meaning that "protection" may only be available via reimbursement or even cost recovery.

However MoF Regulation No.20/PMK.010/2005 dated 3 March 2005 provides an import tax exemption for Old PSCs until the end of the contract term. This regulation became effective on1 March 2005.

New PSCs

For PSCs signed post Law No.22 (referred to as New PSCs), the import taxes and duties facilities are no longer available under the Master List. However, facilities continue to be provided, via a number of separate regulations, as follows:

		Import Duty	VAT	Art. 22 Income Tax
Old PSC (Pre-2001)		✓	✓	✓
New PSC	Exploration Stage	✓	✓	✓
	Exploitation Stage	✓	✓	✓

**) clarified through the issuance of PMK 70 on 2 April 2013*

Where a new PSC is unable to claim an exemption it may be able to apply for a general "tax exemption letter" on Article 22 Income Tax from the relevant tax office.

GR79/GR27

Pursuant to Article 26A and 26B of GR 27, prima facie the Contractor should be protected from import taxes and duties for goods used in petroleum operations during both the exploration and exploitation stages. However, since GR 79 requires implementation of these facilities according to "the statutory law and regulations", PSC Contractors must look beyond GR 79/27 in order to obtain exemptions.

Import Duty

MoF Regulation No.177/PMK.011/2007 ("PMK 177") provides an Import Duty exemption for New PSCs effective from 16 July 2007. In contrast to VAT (see below) the regulation arguably applies to both exploration and exploitation activities, although it restricts the facilities for goods that have not yet been produced, or are not produced to the required specifications, or not produced in sufficient quantity in Indonesia.

In addition, MoF Regulation No.179/PMK.011/2007 ("PMK 179") provides for a 0% Import Duty on imports of drilling platforms and floating or submarine production facilities.

Article 22 Income Tax

MoF Regulation No.154/PMK.03/2010 ("PMK 154") dated 31 August 2010 (as lastly amended by MoF Regulation No. 34/PMK.010/2017) provides an exemption from Article 22 Income Tax for "goods used for upstream activities of Natural Oil and Gas, the importation of which is conducted by the Contractor" that are exempted from Import Duty and/or VAT.

VAT

On 8 February 2012, the MoF issued regulation No 27/PMK.011/2012 ("PMK 27") which provides an exemption from import VAT on certain goods exempted from Import Duty. Under PMK 27, the import of goods used for upstream oil and gas exploration business activities, as well as temporarily imported goods, are among those exempted from Import Duty.

This marked an end to the previous "VAT borne by Government" mechanism provided via the annual State Budget which required the issuance of a MoF Regulation on annual basis.

PMK 27 however limited the facilities to the "exploration stage" meaning that import VAT arising during exploitation continued to be an issue.

On 2 April 2013, the MoF issued Regulation No.70/PMK.011/2013 ("PMK 70") providing a general VAT "exemption" (i.e. VAT not collected) on imports of goods for upstream oil & gas business. The exemption applies to imports carried-out during both exploration and exploitation phases and so dealt with the concerns over the previous PMK 27.

In summary:

a. The Regulation amends PMK 27, so that the import VAT exemption applies to PSCs signed after Law No.22;
b. PMK 70 continues the "harmony" between the import VAT exemption and the Import Duty exemption provided under PMK 177. However, some issues have arisen:
    i. PMK 177 restricts the Import Duty exemption to goods that are not locally produced, or not locally produced to the required specifications or in sufficient quantity. For the import VAT facility PMK 70 requires the same criteria for the exploration phase but is silent on the exploitation phase;
    ii. PMK 70 is unclear as to whether the facility applies to imported goods subject to 0% Import Duty (rather than an exemption). The question is therefore whether an import VAT exemption can also apply to, say, the import of drilling platform and floating/ submarine production facility (which is subject to 0% duty rather than exemption – see PMK 179 above).

3.4.9 Tax Dispute Process

Taxpayers are entitled to object against unfavourable tax assessments. Requirements include that the objection:

a. Be prepared for each assessment;
b. Be in Bahasa Indonesia;
c. Indicate the correct tax amounts;
d. Include all relevant arguments; and
e. Be filed within three months of the assessment date.

The ITO is required to decide on an objection within twelve months. Failure to decide within this timeframe means that the objection is deemed accepted. A taxpayer should pay at least the amount agreed during the tax audit closing conference before filing the objection. If the objection is rejected any underpayment is subject to a surcharge of 50%. This underpaid tax and surcharge is not due if the taxpayer files an appeal to the Tax Court with respect to the objected decision.

Appeals

Taxpayers are entitled to appeal to the Tax Court against unfavourable objection decisions. Requirements include that the appeal letter:

a. Be prepared for each decision;
b. Be in Bahasa Indonesia;
c. Indicate all relevant arguments;
d. Be filed within three months of the date of the objected decision; and
e. Attach a copy of the relevant decision that is being objected against.

Based on the Tax Court law, at least 50% of the tax due on the underlying assessment should be settled before filing an Appeal. However, this payment requirement now contradicts with the Tax Law (i.e. there is a mismatch between the Tax Administration law and the Tax Court law). In practice, the tax court will not insist on payment in these circumstances.

The Tax Court will typically decide on an Appeal within 12 months. Any underpaid tax resulting from the Tax Court decision is subject to a surcharge of 100%.

Requests for Reconsideration

For Tax Court decisions delivered after 12 April 2002, taxpayers are entitled to file "reconsideration requests" to the Supreme Court. Again, a three month action period is in place with the Supreme Court.

Interest Penalties/ Compensation

Late payments of tax are subject to interest penalties generally at the rate of 2% per month. Tax refunds attract a similar 2% interest compensation.

3.5 Commercial Considerations

When reviewing a PSC, potential investors should consider the following issues:

Topics	Issues
Abandonment Costs	• SKK Migas and formerly *Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi* (BP Migas) have included an abandonment clause in the PSC since 1995 which provides that Contractors must include in their budgets provisions for clearing, cleaning and restoring the site upon the completion of work. As any funds set aside for abandonment and site restoration are cost recoverable and tax deductible unused funds at the end of the contract are transferred to SKK Migas. • For PSCs which do not progress to the development stage any costs incurred are considered sunk costs.
DMO Gas	• Historically, there was no DMO obligation associated with gas production. • GR No. 35 introduced a DMO obligation on a Contractor's share of natural gas. • Recent PSCs have included the DMO obligation requirement for gas but as most of these PSCs are still in the exploration stage many practical issues are not yet resolved.
Carry arrangements (JOBs)	• Some PSCs (as JOBs), require private participants to match Pertamina's sunk costs and to finance Pertamina's participating share of expenditures until commercial production commences. These are known as carry arrangements. • After commercial production commences, Pertamina is to repay the funds provided plus an uplift of 50%. • It is unclear whether the uplift should be taxable at the general rate or follow the PSC income tax rate (although there has been a number of recent assessments in this area).
Head office costs	• The administrative costs of a "head office" can generally be allocated to a PSC for cost recovery purposes. PMK 256 stipulates a cap of 2% of annual cost recoverable spending. • PMK 256 also indicates that the amount that a PSC is able to recover will be dependent upon approval from SKK Migas, which may be lower than 2%. The type of approval required depends on whether or not the PSC is in the Exploration or Exploitation as follows: - Exploration: the approval is to be ascertained from the WP&B, and monitoring of the allocation cap will be done over the exploration period (i.e. it would not be adjusted until the end of the exploration period); or - Exploitation: specific written approval must be obtained from BP Migas and the cap will be monitored each year (i.e. the WP&B will not be sufficient evidence to support the allocation once exploitation has commenced). • Due to uniformity, a tax deduction is also available but allocations above the permitted cost recovery are not tax deductible. These allocations technically create WHT and VAT liabilities (i.e. as cross-border "payments"). Pursuant to MoF Letter No.S-604 of 24 November 1998, the Government indicated that it would implement arrangements to "bear" these taxes on behalf of PSC entities. • However, MoF Letter No.S-604 was arguably never fully implemented and so has never actually provided a tax exemption. The ITO historically have focused on head office costs in tax audits. • Recent development indicates that, Article 26C of GR 27 has now confirmed the "exemption" of WHT and VAT from indirect head office allocations. This appears to be a formalisation of the long established principle set out under S-604.

Topics	Issues
Interest recovery	• A PSC entity is generally not allowed cost recovery for interest and associated financial costs. • Subject to specific approval, Contractors may be granted interest recovery for specific projects. This facility should be pre-approved and included in the PoD. However SKK Migas states that interest recovery is only granted for PoDs that have been approved prior to the promulgation of GR 79. • From a taxation point of view, where a Contractor is entitled to cost recovery there is also an entitlement to tax deductibility. • The interest recovery entitlement will generally reference the pool of approved but un-depreciated capital costs, at the end of an agreed "period" of time. The "loan" attracting the respective interest is generally deemed to be equal to the capital spending on the project. Depreciation of the spending is treated as a repayment of the loan. Consequently, the "interest" in question may not be interest in a technical sense. • Interest paid is subject to WHT with potential relief granted under various tax treaties. As a precaution, most Contractors gross up the interest charged to reflect any WHT implications. • Pertamina typically allowed a gross up for Indonesian WHT at the rate of 20%. Some PSC entities have been successful in reducing this rate via a tax treaty. This is even though the "interest" may not satisfy the relevant treaty definition.
Investment credits	• An investment credit is provided as an incentive for developing certain capital intensive facilities including pipelines and terminal facilities. • The credit entitles a PSC entity to take additional production without an associated cost. An investment credit has therefore traditionally been treated as taxable. • More difficult questions have arisen with regard to the timing of investment credit claims. For instance, an investment credit should generally be claimed in the first year of production and any balance should be carried forward (although there are sometimes restrictions on carrying forward).
Take or Pay	• A gas supply agreement may include provisions for a minimum quantity of gas to be taken by buyers on a take-or-pay basis. If buyers take less than the committed quantity of gas they must still pay an amount (as per the agreement) in relation to the shortfall. • Take-or-pay liabilities may arise if buyers have taken less than the committed quantity of gas under the agreements. The shortfall in the gas taken by buyers, if any, results in a take-or-pay liability for make-up gas to be delivered to buyers in the future. • It is unclear whether the tax due should be calculated based on the payments (based on the committed quantity to be taken by the buyer) or based on the quantity of gas delivered to the buyer.

Topics	Issues
Land rights	• Historically, Pertamina (as a regulator which is assumed by SKK Migas) took a central role in acquiring surface rights for oil and gas development. • Oil and Gas Law No.22/2001 requires the Contractor to obtain the relevant land rights in accordance with the applicable local land laws and regulations. • The process of obtaining appropriate land rights can be time consuming and cumbersome although Law No.2/2012 on acquisition of land for development in the public interest (and its implementing regulation PR No.71/2012 and subsequent amendments in PR No.40/2014) seeks to overcome some of the issues. • Entitlement to the Contract Area under a PSC does not include any rights to land surfaces, however, given the change in the treatment of indirect taxes (including VAT and Land & Buildings Tax) under GR 79 this became a material exposure in 2013 for many PSC holders.
"Net Back to Field" Arrangements	• Contractor calculations for transactions involving Trustees or similar arrangements (e.g. for piped gas/LNG, etc.) typically commence with a revenue figure which has been netted against certain post-lifting costs (e.g. trustee, shipping, pipeline transportation, etc.). Once again, this follows the uniformity principle which generally disallows cost recovery on spending past the point of the lifting. • Net back to field costs are generally also treated as being outside of a PSC entity's WHT and VAT obligations. With the growing involvement of the DGT in joint audits, this position may be subject to review.
Sole risk operations	• Typically, all costs and liabilities of conducting an exclusive ("sole risk") operation for drilling, completing and equipping sole risk wells are borne by "the Sole Risk Party". The Sole Risk Party indemnifies the Non-Sole Risk Parties from all costs and liabilities related to the sole risk operation. • Should the sole risk operation result in a commercial discovery the Non-Sole Risk Parties have historically been given the option to participate in the operation. If the Non-Sole Risk Parties agree to exercise their options, the Non-Sole Risk Party pays to the Sole Risk Party a lump sum amount which can typically be paid either through a "Cash Premium" or "In-Kind Premium" to cover past costs incurred as well as rewards for risk taken. • It is not clear whether these premiums should be treated as taxable liftings income, other non-lifting income under GR 79/27 or ordinary income, although under GR 79/27 they are more likely to be treated as other non-lifting income.
Unitisations	• Unitisation is a concept whereby the parties to two or more PSCs agree to jointly undertake the E&P operations on a defined acreage (which typically overlaps between the two PSCs) and share risks and rewards from such activity in an agreed proportion. • Typical issues under a unitisation arrangement include: - Re-determination of costs and revenues; - Maintenance of separate records; - Ring-fencing; - Audits; and - Impact on overall PSC economics

Photo source: PwC

Topics	Issues
Transfer of PSC interests	• Historically, transfers of PSC interests had not generally been taxed. This was the case irrespective of whether the transfer was: 1. Via a direct transfer of a PSC interest (i.e. as an "asset sale"); 2. As a partial assignment such as a farm-out; or 3. Via a sale in the shares of a PSC holding entity (i.e. as a "share sale"). • Whilst previous tax laws could probably tax many transfers this rarely overrated. • GR79/27 now imposes a 5%/7% transfer tax according to whether the PSC is in the exploration or the exploitation stage. GR 79/27 still protects partial assignments such as farm-outs during the exploration stage if that interest has been held for more than three years and the transfer is not intended to generate a gain. However, where the transfer is for "non-risk sharing" purposes, the 5% final tax will be imposed on gross proceeds. GR 79/27 also imposes a 7% final tax on gross proceeds for transfers during the exploitation stage except where they are to a "national company". Please see Chapter 3.4.2 for more details. • In addition, at least prior to 19 June 2017, PMK 257 stipulates that a BPT applies to a transfer of a direct or indirect interest in the PSC. The BPT is due at a rate of 20% of the "economic profit" less the 5% or 7% tax already paid on the transfer. The imposition of BPT was then removed under the application of GR 27 starting 19 June 2017. • The overall of GR 79/PMK 257 is however unclear in many areas including: a. the application to share transfers especially where they fall outside Indonesian natural tax coverage (essentially GR 79's rules on tracing powers) b. how BPT should be accounted for and which treaties can be relied on (bearing in mind BPT is ultimately a tax cost for the vendor entity) c. is a group restructuring (i.e. with no change of control and therefore no requirement for SKK Migas approval) meant to be taxed? d. when does a carry provided as part of the farm-out constitute compensation for the PSC transfer? e. when is a contingent payment subject to tax? f. what is the cost base in calculating the profits for BPT purposes (at least for pre-GR 27 transfers)?

3.6 Documentation for Planning and Reporting

3.6.1 Plan of Development (PoD) (Articles 90-98 of GR 35/2004)

A PoD (also known as a field development plan) represents development planning on one or more oil and gas fields in an integrated and optimal plan for the production of hydrocarbon reserves, considering technical, economic and environmental aspects.

Prior to Law No.22, an initial PoD only needed Pertamina Director approval. After Law No.22, an initial PoD in a development area needs approval from both SKK Migas and the Minister of Energy and Mineral Resources. Subsequent PoDs in the same development area only need SKK Migas approval. Generally, the time needed for PoD approval is around ten weeks, although the process can take in excess of one year for very large projects.

A PoD is typically a complex document that outlines the proposed development of a particular commercial discovery. The scope and scale of PoDs will vary enormously depending on the size of the project but will typically cover the following information:

a. Executive summary;
b. Geological findings;
c. Development incentives;
d. Reservoir description;
e. EOR incentives;
f. Field development scenarios;
g. Drilling results;
h. Field development facilities;
i. Project schedule;
j. Production results;
k. HSE & community development;
l. Abandonment;
m. Project economics; and
n. Conclusion.

PoDs that are presented to the Minister (and therefore those that are for the development of oil or gas discoveries in the first field, as opposed to subsequent fields) must contain:

a. Supporting data and evaluation of Exploration;
b. Evaluation of the reserves;
c. Methods for drilling development wells;
d. Number and location of production and/or injection wells;
e. Production testing/well testing;
f. Pattern of extraction;
g. Estimated production;
h. Methods for lifting the production;
i. Production facilities;
j. Plans for use of the Oil and Gas; and
k. Plans for operations, economics and state and regional revenues.

A PoD revision could be performed in the following conditions:

a. Changes in the development scenario;
b. Significant changes to the oil and gas reserves compared to the initial PoD submitted; and
c. Changes in investment costs.

3.6.2 Authorisation for Expenditure (AFE)

As part of the SKK Migas supervision and control over the execution of the PSCs, each of the projects in the exploration and development phase should prepare an AFE for SKK Migas approval. For other projects, BP Migas approval is required if budgeted expenditure is equal to or greater than US$ 500,000.

An AFE should include the following Information:

a. Project information in sufficient detail to allow for BP Migas analysis and evaluation;
b. Total budgeted costs; and
c. Total costs that have been incurred.

The time required for AFE approval, AFE revision and AFE close-out is around 10-15 days, although the process is considerably longer for complex and large project AFEs.

An AFE can be revised:

a. Twice before the project commences or before the tender has been awarded.
b. Where the project has commenced prior to reaching 50% of total expenditure and prior to reaching 70% of physical completion.

Revisions should be made if the total AFE costs are projected to over/under-run 10% or more and/or the individual AFE cost component is projected to over/under-run by more than 30%.

3.6.3 Work Program and Budget (WP&B)

The WP&B is the proposal of a detailed action plan and annual budget as consideration for the condition, commitment, effectiveness and efficiency of the Contractor's operations in a contract area. The WP&B covers the following:

a. Exploration (seismic & geological survey, drilling and Geological and Geophysical (G&G) study), lead & prospect, exploration commitment;
b. Production and an effort to maintain its continuity:
    1. Development plan;
    2. Intermittent drilling;
    3. Production operations and work-overs;
    4. Maintaining production; and
    5. EOR projects (Secondary Recovery & Tertiary Recovery).
c. The costs allocated for those programs are as:
    1. Exploration;
    2. Development drilling & production facilities;
    3. Production and operations; and
    4. General administration, exploration administration & overheads.
d. An estimation of:
    1. Entitlement share;
    2. Gross Revenue, Oil & Gas Price, Cost Recovery, Indonesia Share, Contractor Share;
    3. Unit cost (US$/Bbl.);
    4. Direct Production Cost;
    5. Total Production Cost;
    6. Cost Recovery; and
    7. Status of unrecovered cost.

WP&B generally includes the following schedules:

a. Financial Status Report;
b. Key Operating Statistics;
c. Expenses/Expenditure Summary;
d. Exploration & Development Summary;
e. Exploratory Drilling Expenditure;
f. Development Drilling Expenditure;
g. Miscellaneous Capital Expenditure;
h. Production Expenses Summary;
i. Production Facilities Capital Expenditure;
j. Miscellaneous Production Capital Expenditure;
k. Administration Expenses Summary;
l. Administration Capital Expenditure;
m. Capital Assets PIS Old/New;
n. Depreciation Old/New;
o. Detailed Program Support Listing;
p. Production/Lifting Forecast; and
q. Budget Year Expenditure.

The WP&B proposal should be submitted to SKK Migas for approval three months before the start of each calendar year. Before SKK Migas grants approval, some changes to the WP&B proposal may be requested. In granting approval for WP&Bs, SKK Migas follows the guidance of GR 25/2004 Article 98, which lists certain mandatory considerations such as: long-term plans; success in achieving activity targets; efforts to increase oil and gas reserves and production; technical activities and the viability of cost units; efficiency; field development plans previously approved; and manpower and environmental management.

Once approved, the Contractor may revise the WP&B provided there is reasonable cause such as:

a. The annual work plan turns out to be unrealistic; or
b. The estimated cost departs significantly from the budget.

The proposed WP&B revision must be accompanied by the reason for the change. For urgent changes to an original annual WP&B, revisions may be submitted to SKK Migas before June.

Generally, the WP&B approval process takes around 22 working days, although the process is considerably longer for complex and large WP&B.

3.6.4 Financial Quarterly Report (FQR)

On a quarterly basis, an operator of a PSC area should submit its FQR to SKK Migas. The FQR primarily consists of a comparison between the budgeted and actual revenue and expenditures. The FQR should be submitted to SKK Migas within a month of the end of the relevant quarter. A typical FQR consists of a summary front page with supporting schedules attached.

3.6.5 Foreign Currency Report (FCR)

Based on Bank Indonesia Regulation No 4/2/PBI/2002 and subsequent revisions including the latest revisions in Stipulation Letter No 9/9/DSM dated April 9, 2007, non-financial institution companies (including oil and gas companies) with minimum assets of Rp 100 billion or annual gross sales greater than Rp 100 billion are required to report to the Bank of Indonesia (BI) their foreign currency transactions made with:

a. Overseas banks or overseas financial organisations; and/or
b. Other companies or offices domiciled outside of Indonesia. Companies that have overseas financial assets and liabilities are also required to produce BI reports.

The BI report consists of:

a. A monthly foreign exchange transaction report for all the company's financial assets and/or liabilities in foreign currency (to be submitted within a month following the month in which the transaction occurs); and
b. A half yearly report of the foreign currency financial assets and/or liabilities position for the period ended. The BI reports are used by the Government to prepare the Payment Statistic Balance Sheet and Indonesia's International Investment Position.

The Government has also issued decision letter KEP-0066/BP00000/2008/S0 (KEP 0066) which requires PSC Contractors to use a state-owned bank for both the vendor and payer's accounts with respect to payments for goods and services. Please see Chapter 3.2.4 above for further details.

3.6.5.1 Offshore Borrowing

Bank Indonesia Regulation No 16/21/PBI/2014 (as amended by PBI No. 18/4/2016) and Circular Letter No. 16/24/DKEM requires all non-bank corporations with offshore borrowings to implement prudential principles by fulfilling the following conditions:

a. a minimum hedging ratio being 25% of the negative difference between current assets and current liabilities which will be due between three months and six months after the end of a quarter;
b. a minimum liquidity ratio of 70%, calculated by comparing the company's current assets and current liabilities which will be due within three months of the end of the reporting quarter;
c. a minimum credit rating of BB or its equivalent from credit ratings agencies approved by the Indonesian Financial Services Authority; and
d. that non-bank corporations are required to submit reports and other documents including quarterly compliance reports and annual audited financial information to Bank Indonesia as evidence that they have fulfilled the requirements above.

Bank Indonesia is authorised to inspect submitted reports or other documents to assess compliance and may request clarifications, evidence, records or other supporting documents from the reporting corporation. It may also directly inspect the corporation or appoint a third party to do so. Failure to report will lead to administrative sanctions in the form of a written warning.

Photo source: PT Pertamina (Persero)

4 Gross Split PSCs

In 2017, the MoEMR issued Regulation-08 (as amended by Regulation-52), introducing a new PSC scheme based upon the "Gross Production Split". As part of the associated socialisation the Government has promoted this new paradigm as the model for how upstream business activities should be conducted going forward. In short the Government believes that the new scheme:

a) should incentivise exploration and exploitation activities due to the spending and operational "freedom" it conveys to Contractors. For instance, the scheme should better allow Contractors to focus on cost efficiency, and reduce delays from the bureaucratic approval process for expenditures; and
b) should nevertheless allow the State to retain appropriate control over the country's energy resources as the Government will continue to be involved in approving key phases of upstream business developments (i.e. from the PSC award up to production).

The salient features of Regulation-08 as amended by Regulation-52 are detailed below:

No.	Items	Description
1.	Key Features	• A Gross Split sharing concept based on a gross production split without regard to a cost recovery mechanism. • A retention of the following key principles: a) that the ownership of the natural resources remain with the State until the point of delivery of the hydrocarbons (as per existing PSCs); b) that control over the management of operations is ultimately with SKK Migas (as per existing PSCs – although see below); and c) that all capital and risks should be borne by Contractors (as per existing PSCs). • A Gross Split PSC should stipulate at least 17 items (including government take, financing obligations, settlement of disputes, etc.).
2.	Gross Split mechanism	• This can be illustrated as follows: Contractor Take = Base Split +/- Variable Components +/- Progressive Components Government Take = Government share + bonuses + Contractor's Income Tax

Photo source: PT Chevron Pacific Indonesia

No.	Items	Description
		• The base split shall constitute the baseline in determining the production split during the Plan of Development (PoD) approval. These splits are: a) for oil: 57% (Government); 43% (Contractor) b) for gas: 52% (Government); 48% (Contractor) • The variable components are adjustments which take into account the status of the work area, the field location, reservoir, supporting infrastructure, etc. • The progressive components are adjustments which take into account oil price and cumulative production. • The "actual" production split shall be agreed on a PoD rather than PSC basis. • Depending upon field economics the MoEMR has the authority to adjust the production split in favour of either the Contractor or the Government. • It has been reported that one Gross Split PSC (for a mature field) was set at 42.5% : 57.5% Government/Contractor. This demonstrates how flexible these splits might be in practice.
3.	SKK Migas' role	• This will be limited to control and monitoring of Gross Split PSCs. • Control will mean to formulate policies on WP&B (with the budget reportedly considered to be "supporting information" rather than requiring approval). The work program (i.e. not the budget) should be approved within 30 working days of complete documentation being received. • Monitoring will mean to supervise the realisation of exploration and exploitation activities according to the approved work program. The role of SKK Migas seems to be limited to the monitoring/approving of the work program rather than the budget. • The 1st PoD must be approved by the MoEMR. The Head of SKK Migas can approve any 2nd PoD. Any difference between the 2nd PoD and the 1st PoD should be discussed between the Head of SKK Migas and MoEMR with final approval by the MoEMR.
4.	Title	• As indicated ownership of natural resources remains with the State until the point of delivery of the hydrocarbons. • Goods and equipment including land (except leased land) used directly in PSC operations become the property of the State (as per existing PSCs). • Any technical data derived in relation to the PSC shall belong to the State (as per existing PSCs).
5.	Taxation	• The income tax treatment of Contractors is to follow specific tax rules for upstream activities. This is stipulated under GR 53/2017 (see below). • As relief for costs would be via tax deductions rather than cost recovery, it is likely that the key agency responsible for oversight of this area would also transfer to the Indonesian Tax Office.
6.	Procurement	• Contractors may carry out procurement of goods and services independently. This will mean that government procurement regulations (such as PTK-007) may have less influence in the Contractor's procurement process (particularly in terms of budget).
7.	Transitional Provisions	• The operation of existing PSCs should continue until expiry. Contractors can however propose changing to the new Gross Split scheme. • An option to change is also available for extended PSCs (if initially signed under the cost recovery arrangements). We understand that for extended PSCs the option to continue with the existing cost recovery arrangements will require approval from MoEMR. • If the PSC format is changed any unrecovered costs may be taken as additional split for the Contractor. • PSCs about to expire but not extended shall automatically be "re-awarded" under the Gross Split scheme.
8.	Others	• The DMO remains at 25% of the Contractor's entitlement/split and paid by the Government at ICP. • Contractors should prioritise the use of local manpower, domestic goods, services, etc (note the potential impact on procurement processes). • Other matters pertaining to Indonesian participation, unitisation, abandonment and reclamation costs, etc should follow prevailing rules.

GR 53/2017 – Tax Rules for Gross Split PSCs

On 28 December 2017, the Government issued GR No.53/2017 (GR 53) providing an initial outline of the tax rules for the "gross split" PSCs. This was an important development, allowing investors to better model the economic outcomes of the gross split PSC. The key tax principles are as follows:

a) that, pursuant to the preamble, GR 53 flows from Article 31D of the Income Tax Law and, perhaps surprisingly, Article 16B of the VAT Law. As expected, there is no reference to GR 79/27 meaning that GR 79/27 is not relevant to gross split PSCs;
b) that, pursuant to Article 18, "Taxable Income" arising from "direct" PSC activities is to be "gross income" less "Operating Costs" (see below) but with a 10 year tax loss carry forward entitlement. This 10 year period is greater than the 5 years available under the general tax law, but a significant reduction from the unlimited carry forward entitlement under conventional PSCs.
c) that, pursuant to Articles 18(4) and (5), Taxable Income in this most general "direct" scenario is to be income relating to liftings, as well as sales of by-products and other "economic gains" (see below). The taxable income is then subject to tax at the general rate applying at the time of signing the PSC in question or the prevailing rate (currently 25%). BPT - currently 20%) is applicable on after tax profits. These rates appear however not to be fixed and so may move with any changes in the general tax law (although the wording of the actual PSC could be important on this point.)

   There is however no apparent prohibition on the utilisation of tax treaty relief, potentially opening the way to BPT reductions where relevant treaty relief is validly available.

   In addition the tax calculation appears to be Contractor-specific rather than following a PSC "cut-back" approach. In other words it appears that individual Contractors could (validly) calculate taxable income outcomes different to that for the PSC as a whole. A range of issues could arise however if this is the case including how individual Contractors will ultimately be tax audited etc in the absence of a "PSC-driven" audit process such as that which currently happens under BPKP and SKK Migas;

d) that, pursuant to Article 14, the gross split taxing point begins at the "point of transfer" of the relevant hydrocarbon to the Contractor. This continues the conventional PSC approach whereby economic value is initially recognised upon the Contractor taking title to their share of hydrocarbons via a lifting entitlement under the PSC rather than (necessarily) via a sale of the hydrocarbons. This should also mean that income from post lifting activity (e.g. trading) should not fall within GR 53;
e) that the value of oil is to be determined using the Indonesian Crude Price (ICP) (Article 15) and that the value of gas is to be determined via the price agreed under the relevant gas sales contract (Article 16). Again this is in line with conventional PSCs;
f) that, pursuant to Article 19(1), income separately arising from "uplifts" is subject to tax at a final rate of 20% of the uplift amount. This is consistent with the taxing outcome under GR 27;
g) that, pursuant to Article 19(2), income arising specifically from PSC transfers is subject to tax at 5% or 7% of transfer income (according to whether the PSC is in exploration or exploitation) and with no further tax due on after tax income. This should mean that no BPT should be due on income from PSC transfers which is also consistent with the revised arrangements under GR 27 for conventional PSCs.

   However, and also similar to GR 27 (and PMK 257) there is no detail on many of the controversial aspects of taxing PSC transfers. This includes what actually constitutes consideration for entity based transfers and the exact circumstances of when such transfers are deemed to occur (e.g. by providing tracing rules on how to appropriately determine underlying changes in ownership). Also absent are any special concessions (say) for inter group re-organisations where the transfer occurs within a particular group. A MoF Regulation dealing with remittance and withholding arrangements on PSC transfers is also still to issue.

Tax Calculation

Key Features include:-

a) that, pursuant to Article 4, a Contractor's "gross income" shall consist of both:-
   i. gross income "directly" from PSC activities; and
   ii. gross income from activities "outside" PSC activities;
b) that gross income from "direct" PSC activities is essentially the Contractor's share of oil/gas realised from liftings, less DMO, plus compensation for DMO, plus/minus lifting price variances;
c) that gross income from "outside" of direct PSC activities constitutes income arising from:-
   i. uplifts;
   ii. transfers of PSCs;
   iii. sales of "secondary" (by-) products arising from upstream activities;
   iv. other amounts resulting in an "economic benefit" (which the elucidation indicates will extend to contractual penalty entitlements, etc.).

   As indicated above, items i) and ii) are subject to specific final tax arrangements whilst items iii) and iv) are simply added to income arising from "direct" PSC activities;

d) that, pursuant to Article 5, “Operating Costs” include:-

i. “Exploration Costs” including those in respect of exploration drilling, general and administrative activities and geological and geophysical activities;
ii. “Exploitation Costs” including those in respect of development drilling, direct production (for oil or gas), processing activities, utilities, general and administrative activities, as well as depreciation and amortisation; and
iii. “Other Costs” including those in respect of the transportation of hydrocarbons, post operational activities and marketing, as well as for reimbursements paid to prior Contractors in the event that a PSC is terminated pursuant to relevant regulations. LNG processing costs, up to the point of LNG transfer, are specifically mentioned in the elucidation; For both exploration and exploitation “general and administrative” activities are to include finance costs as well as “indirect taxes, regional taxes and regional levies”. Interest costs nevertheless remain non deductible (see comments on Article 8 below). Indirect taxes are therefore now also only deductible rather than reimbursable meaning that gross-split PSCs are generally economically inferior to the “assume and discharge” arrangements available under many conventional PSCs.

Limitations on Deductions

Key Features include:-

a. that, pursuant to Article 7, the deductibility of all Operating Costs (outlined above) are still subject to the satisfaction of a series of general criteria. These include:-
   i. that pricing must follow arm's-length principles. This opens the door to more mainstream transfer pricing requirements for related party transactions in the upstream space;
   ii. that oil and gas operations must follow "good" business practices and be in accordance with the relevant work programs. It is however not clear how detailed the residual work program approval process is required to be noting that, if strictly enforced, this could be seen as effectively creating a de facto uniformity principle;
   iii. that depreciation is subject to the asset in question being held by the State. This is similar to conventional PSCs;
   iv. that direct "head office" charges must relate to activities that cannot be "procured locally". This requirement will hopefully be supported by guidelines on how to measure/determine what can or cannot be "procured locally" as this could otherwise be quite subjective in practice.

      In addition, "indirect" head office allocations must be within MoF guidelines and be supported by financial information (e.g. audited financial statements of the relevant head office entity). Interestingly, neither category of head office costs appears to be limited to "Operators" potentially leaving open the possibility for all Contractors to achieve deductions for their individual head offices expenses (where validly connected to PSC activities);

      Indirect head office charges are also exempt from Income Tax and VAT under Article 27;

   v. that the deductibility of spending on a range of other items, e.g. benefits-in-kind, donations, environmental activities and foreign manpower, are to comply with existing regulations.

b. that, pursuant to Article 8, there is no deduction allowed for spending in respect of:-
   i. administrative sanctions, fines, etc.;
   ii. payments of Income Tax;
   iii. incentives, pension contributions, etc. for foreign manpower, etc.;
   iv. the costs of foreign manpower without a work permit;
   v. legal expenses with no direct relationship to upstream activities;
   vi. costs in respect of mergers, acquisitions or PSC transfers.
   vii. spending on consultants, corporate re-branding, management changes, etc.;
   viii. interest costs;
   ix. royalties. The elucidation extends this to payments allowing Contractors access to operational technologies;
   x. third party Income Tax where (effectively) borne by the Contractor;
   xi. Government bonuses.
      Most of these restrictions mirror the restrictions set out at Article 13 of GR 27. This is except for costs for marketing (as indicated above), tax consultants and commercial audits which now seem to be deductible.

Pre-Production/Deferred Spending

Key Features include:-

a) that, pursuant to Article 12, all pre-production spending, including that otherwise constituting an outright deduction or expense, is to be capitalised. Amortization of this capitalised spending is then to commence from the month of commercial production and on a unit of production basis. This deferment measure should temper some of the concerns about the loss of an indefinite tax loss carry forward criteria under the gross split PSCs (see comments above);
b) that, pursuant to Article 9(1), post production spending on amounts creating economic value of less than 1 year should be deductible in the year incurred;
c) that, pursuant to Article 9(2), post production spending on amounts creating economic value of more than 1 year should be depreciable (if relating to tangible assets) or amortisable (if relating to non-tangible assets);
d) that, pursuant to Article 10, depreciation should be on a declining balance basis commencing in the month the relevant asset is "placed into service" and at rates set out in the Attachment to GR 53. The relevant elucidation defines "placed into service" as the time when the assets are utilised and have fulfilled the conditions/requirements set out by SKK Migas. Again, the linkage to SKK Migas criteria could create a question around a de facto uniformity principle;
e) that, pursuant to Article 11, amortisation should be on a unit of production basis commencing from the month the expense is incurred;
f) that, pursuant to Article 13, spending on approved reserves for remediation, etc. is deductible in the year in which the contribution is made to a specifically approved joint bank account with SKKMigas, etc. Any ultimate differences between the reserves and realisation shall be taxable or deductible as the case may be.


Photo source: PwC

Administration

That, pursuant to Article 22, all Contractors are required to:-

a) register for tax;
b) file annual tax returns;
c) perform tax payments including making monthly tax instalments based on each Contractor's liftings of each prior month;
d) report any PSC transfers to both MoEMR and MoF.

That, pursuant to Article 23, all Operators are required to:-

a) deal with the WHT obligations of the PSC itself. These obligations presumably extend only to all jointly incurred costs. A question however arises on remittance for any individual Contractor-only spending;
b) to manage the bookkeeping of the PSC itself. These obligations extend to the keeping of the general financial records including traditional financial statement which (presumably) will now also become the key fiscal documentation. This is noting that PSC specific record may no longer exist (e.g. FQRs).

Incentives

That, pursuant to Article 25, for the pre-production period (i.e. exploration and development) these incentives include:-

a) an exemption from Import Duty on goods used in relation to oil and gas operations. It is however, technically curious how this can be provided without a general reference or reliance on the Custom's Law;
b) the non-collection of VAT on the import or local procurement of goods and services used in operations. This is obviously a wide ranging incentive which, in relation to in-country procurement at least, is potentially superior to that under conventional PSCs;
c) an exemption from Article 22 on the import of goods entitled to an Import Duty exemption outlined in a) above;
d) a 100% reduction in PBB.

These incentives are subject to further regulation by the MoF and so any qualifying criteria within these rules will be of critical importance.

There are however, no incentives being offered for post-production activities (presumably) meaning that all such taxes should simply be deductible (although there is a view that alternative protection may be offered within the PSC itself).

In addition, pursuant to Article 26, where during the post-production period excess capacity associated with certain upstream assets is made available to other Contractors on a cost sharing basis then the cost sharing receipts shall be exempt from Income Tax and VAT where a number of conditions are met.

Photo source: PT Pertamina (Persero)

Conclusion

GR 53 provides only the initial fiscal framework for gross split PSCs with a number of implementing regulations still to issue. While at this stage the general fiscal framework appears broadly in line with that for conventional PSCs further regulations will be required before Contractors can draw more definitive conclusions.

Nevertheless an early analysis is that the key fiscal differentiators under the gross split PSC include:-

a) that Contractor-specific tax calculations are applicable rather than each Contractor following a PSC “cut-back” approach;
b) that, from the drafting of GR 53, there is an intention to formulate the tax calculation as a contract area-based tax calculation (rather than PoD based tax calculation). This is however not certain;
c) that a 10 year tax loss carry forward restriction applies (albeit with an automatic deferment during pre-production) rather than the indefinite period under traditional PSCs;
d) that there are no apparent prohibitions around treaty use leaving open the possibility to leverage treaty reductions particularly in relation to BPT;
e) that there is an apparent loss of the “assume and discharge” entitlement meaning essentially that all (deductible) spending will need to be determined at its after tax cost;
f) that there is a likely exemption of all “non-Income Tax” taxes during pre-production but less certainty of any incentives during the post-production period;
g) that there is potentially greater certainty on the treatment of certain post-production costs such as for marketing and processing.

5 Downstream Sector

This chapter covers the following topics:

5.1 Downstream Regulations

Law No.22 formally liberalised the downstream market by opening the sector (processing, transportation, storage and trading) to direct foreign investment and ending the former monopoly of state-owned oil and gas company PT Pertamina (Persero). Whilst the distribution of downstream products and blending of lubricants had previously been conducted by multinationals in Indonesia, since Law No.22 was enacted many domestic and multinational companies have established themselves in the more capital intensive areas of the downstream sector. These areas include:

a. Tank farms/storage facilities for bulk liquids and LPG;
b. The distribution of gas by way of pipelines (Citigas and long distance pipelines);
c. Proposed refineries and downstream LNG;
d. LNG regasification terminals; and
e. The retailing of fuel (both subsidised and non-subsidised).

We present below a summary of the key section of the downstream regulations as provided for in Law No.22 and its implementing regulations GR 36/2004 (as last amended by GR 30/2009).

Photo source: PwC

5.1.1 Operation and Supervision of Downstream Business

Downstream businesses are required to operate through an Indonesian incorporated entity (hereafter referred to as a PT Company) and to have obtained a business licence (issued by the MoEMR/the Government, with input from BPH Migas). As indicated in Chapter 2, BPH Migas is responsible for regulating, developing and supervising the operation of the downstream industry.

5.1.2 Business Licences

A separate business licence is required for each of the following downstream activities (except where the activity is the continuation of an upstream activity, in which case a licence is not required):

a. Processing (excluding field processing);
b. Transportation;
c. Storage; and
d. Trading (two types of business licences are required – a wholesale trading business licence; and a trading business licence).

It is permissible for one PT Company to hold multiple business licences.

Each business licence, managed by MoEMR with input from BPH Migas, stipulates obligations and technical requirements that the licensee must abide by.

To obtain a business licence, a PT Company must submit an application to the MoEMR by enclosing administrative and technical requirements which contain, at a minimum, the:

a. Name of operator;
b. Line of business proposed;
c. Undertaking to comply with operational procedures; and
d. Detailed plan and technical requirements relating to the business.

The business licences are issued in two stages:

a. A temporary licence for a maximum period of five years during which the PT Company prepares the facilities and infrastructure of the business; and
b. A permanent operating licence once the PT Company is ready for operation.

5.1.3 Processing

A PT Company holding a processing business licence must submit to the MoEMR and BPH Migas operational reports, an annual plan, monthly realisations, and other reports.

The processing of oil, gas and/or processing output to produce lubricants and petrochemicals are to be stipulated and operated jointly by the MoEMR and the Ministry of Trade (MoT).

Non-integrated Gas Supply Chain

Processing of gas into Liquefied Natural Gas (LNG), Liquefied Petroleum Gas (LPG), and Gas To Liquids (GTL) is classified as a downstream business activity as long as it is intended to realise a profit and is not secondary to an upstream development.

This technically allows for a non-integrated LNG/LPG supply chain concept by virtue of:

a. Enabling PSC Contractors to be the appointed seller of gas (including Government share) to be further processed by a separate entity;
b. Shorter LNG supply arrangements; and
c. The possible use of an onshore project company sponsored by a shareholder agreement which receives initial funds for the development and operation of a LNG processing plant.

In practice, downstream LNG and mini LNG refineries have been impacted by a multitude of regulatory issues, including a change in the VAT treatment of LNG, and concerns over the adequacy of domestic gas supply.

5.1.4 Transportation

Transportation of gas by pipelines via a transmission segment or a distribution network area is permitted only with the approval of BPH Migas, with licences being granted only for specific pipelines/commercial regions.

A PT Company with a transportation business licence is required to:
a. Submit monthly operational reports to the MoEMR and BPH Migas;
b. Prioritise the use of transportation facilities owned by cooperatives, small enterprises and national private enterprises when using land transportation;
c. Provide an opportunity to other parties to share utilisation of its pipelines and other facilities used for the transportation of gas; and
d. Comply with the Masterplan for a National Gas Transmission and Distribution Network.

BPH Migas has the authority to:
a. Regulate, designate, and supervise tariffs after considering the economic considerations of the PT Company, users and consumers; and
b. Grant permits for the transportation of gas by pipelines to a PT Company based on the Masterplan for a National Gas Transmission and Distribution Network.

A PT Company may increase the capacity of its facilities and means of transportation after obtaining special permission.

5.1.5 Storage

A PT Company is required to:

a. Submit its operational reports to the MoEMR each quarter or as and when requested by BPH Migas;
b. Provide an opportunity to another party to share in its storage facilities;
c. Share storage facilities in remote areas; and
d. Have a licence to store LNG.

A PT Company can increase the capacity of its storage and related facilities after obtaining permission from BPH Migas.

Transportation or storage activities that are intended to make a profit, or be used jointly with another party by collecting fees or lease rentals, are construed as downstream business activities and require the appropriate downstream business licence and permits.

5.1.6 Trading

A PT Company must guarantee the following when operating a trading business:

a. The constant availability of fuels and processing output in its trade distribution network;
b. The constant availability of gas through pipelines in its trade distribution network;
c. The selling prices of fuels and processing output at a fair rate;
d. The availability of adequate trade facilities;
e. The standard and quality of fuels and processing output as determined by the MoEMR;
f. The accuracy of the measurement system used; and
g. The use of qualifying technology.

A PT Company is required to:

a. Submit monthly operational reports to the MoEMR or at any time as required by BPH Migas;
b. Maintain facilities and means of storage and security of supply from domestic and foreign sources;
c. Distribute fuels through a distributor, to small-scale users under the Company's authorised trademark;
d. Prioritise cooperatives, small enterprises and national private enterprises when appointing a distributor; and
e. Submit operational reports to the MoEMR and BPH Migas regarding appointment of distributors.

A PT Company holding a wholesale trading licence can operate a trading business to serve certain consumers (e.g. large consumers). The MoEMR, along with BPH Migas, may determine the minimum capacity limit of a storage facility or facilities of a PT Company. The PT Company may start its trading business after fulfilling the required minimum capacity.

A direct user who has a seaport or receiving terminal may import fuel oil, gas, other fuels, and process the output directly for its own use, but not for resale, after obtaining specific approval from the MoEMR.

A PT Company operating an LPG trading business is required to:

a. Control facilities and means for the storage and bottling of LPG;
b. Have a registered trademark; and
c. Be responsible for maintaining a high standard and quality of LPG, LPG bottling, and LPG facilities.

PT Companies operating in the business of gas trading may include those with a gas distribution network facility and those without. The former should only operate after obtaining a licence to trade gas and special permission for a Distribution Network Area. The latter may only be implemented through a distribution network facility of a PT Company that has obtained access to a Distribution Network Area and after obtaining a licence to trade gas.

The MoEMR has the authority to determine and set technical standards for gas, and also minimum technical standards for distribution and facilities.

5.1.7 National Fuel Oil Reserve

The MoEMR is responsible for setting policy regarding the quantity and type of national fuel oil reserve and may appoint a PT Company to contribute to building this reserve. The national fuel oil reserve is determined and supervised by BPH Migas. The reserve can only be used when there is a scarcity of fuel oil, and once the scarcity is resolved, the reserve must be returned to its original position.

5.1.8 Standard and Quality

The MoEMR sets the type, standard and quality of fuel oil, gas, other fuels, and certain processed products that are marketed domestically. In determining the quality standards, the MoEMR reviews the technology to be applied, the capacity of the producer, the consumer's financial position, safety, health, and environmental standards.

A PT Company operating as a processing business must have an accredited laboratory to perform tests on the quality of the processing output. Likewise, a PT Company operating a storage business which carries out blending to produce fuel oil must provide a testing facility on the quality of the blending output. If the PT Company is unable to provide a self-owned laboratory, it is allowed to use an accredited laboratory facility owned by another party.

Fuel oil, gas, and processing output in the form of finished products which are imported or directly marketed domestically must comply with the quality standards determined by the MoEMR. For fuels and processing output that are exported, a producer may determine the standard and quality based on the buyer's request. Fuels and processing output specially requested must report their determined standard and quality to the MoEMR.

5.1.9 Availability and Distribution of Certain Types of Fuel Oil

To guarantee the availability and distribution of certain types of fuel oil, trading businesses are not currently able to operate in a fully fair and transparent market.

The MoEMR has the authority to designate areas of trading certain types of fuel oil domestically. This may include trading fuel oil where:

a. The market mechanism has been effective;
b. The market mechanism has been ineffective; or
c. The market is located in a remote area.

BPH Migas has the authority to:

a. Designate a trade distribution area for certain types of fuel oil for corporate bodies holding a trading business licence; and
b. Determine joint usage of transportation and storage facilities, particularly in areas where the market mechanism is not yet fully effective or in remote areas.
c. If necessary, the Government, with input from BPH Migas, may determine the retail price for certain types of fuel oil by calculating its economic value.

A PT Company holding a wholesale trading business licence that sells certain types of fuel oil to transportation users or trades kerosene for household and small enterprises, must provide opportunities to the local distributor appointed. The distributors includes cooperatives, small enterprises, and/or national private enterprises contracted with the PT Company. The distributor may only distribute the trademark fuel oil of the corporate body. The PT Company must report to BPH Migas and the MoEMR the names of its distributors.

5.1.10 Occupational Health and Safety, Environmental Management, and Development of the Local Community

PT Companies operating with a downstream business licence must comply with provisions relating to occupational health and safety, the environment, and the development of local communities. This responsibility includes developing and utilising the local community through, amongst other things, local employment. Such development must be implemented in coordination with the regional government and priority given around the area of operation.

5.1.11 Utilisation of Local Goods, Services, Engineering and Design Capacity and Workforce

PT Companies operating with a downstream business licence must prioritise the utilisation of local goods, tools, services, technology, and engineering and design capacity.

In fulfilling labour requirements, a downstream PT Company must prioritise the employment of Indonesian workers according to the required competency standards. Where Indonesian workers do not meet the required standards of competence and occupational qualifications, the PT Company must arrange for training and development programs to improve those workers' capacity.

5.1.12 Sanctions

BPH Migas has the power to determine and impose sanctions relating to a PT Company's breach of its business licence. Sanctions increase during the time the breach remains unremedied and can include a written reminder, suspension of the business, freezing of the business, and finally, annulment of the business licence. All damages arising out of any sanction must be borne by the respective corporate bodies.

Any person or company who operates a business without a licence will be penalised. Duplication or falsification of fuels or processing output; or any misuse of transportation or trading of subsidised fuel carries with it a maximum penalty of six years' imprisonment and a Rp 60 billion fine.

5.2 *Downstream Accounting*

Unlike the upstream sector, there are not many specific accounting standards promulgated for the downstream oil and gas businesses. Instead, generally accepted accounting standards usually apply. The table below shows some of the key standards and differences specifically relating to downstream oil and gas companies under US GAAP and IFRS. Currently, Indonesian Financial Accounting Standards do not significantly differ from IFRS.

Accounting in Downstream Oil and Gas		
A general comparison between US GAAP and IFRS		
Area	**US GAAP**	**IFRS**
Property, Plant and Equipment	US GAAP utilises the historical cost and prohibits revaluations. US GAAP generally does not require the use of the component approach for depreciation. While it would generally be expected that the appropriateness of significant assumptions within the financial statements would be reassessed at the end of each reporting period, there is no explicit requirement for an annual review of the residual values.	Historical cost is the primary basis of accounting. However, IFRS permits the revaluation to fair value of property, plant and equipment. IFRS requires that separate significant components of property, plant, and equipment with different economic lives be recorded and depreciated separately. The guidance includes a requirement to review the residual values and useful lives at each balance sheet date.
Asset retirement obligations (ARO)	ARO is recorded at fair value, and is based upon the legal obligation that arises as a result of an acquisition, construction, or development of a long-lived asset.	IFRS requires that management's best estimate of the costs of dismantling and removing the item or restoring the site on which it is located be recorded at the time when an obligation exists. The estimate is to be based on the present obligation (legal or constructive) that arises as a result of the acquisition, construction or development of a long-lived asset.

Accounting in Downstream Oil and Gas		
A general comparison between US GAAP and IFRS		
Area	**US GAAP**	**IFRS**
Asset retirement obligations (ARO) *continued*	The use of a credit-adjusted, risk-free rate is required for discounting purposes when an expected present-value technique is used for estimating the fair value of the liability. The guidance also requires an entity to measure changes in the liability for an ARO due to the passage of time by applying an interest method of allocation to the amount of the liability at the beginning of the period. The interest rate used for measuring that change would be the credit-adjusted, risk-free rate that existed when the liability, or portion thereof, was initially measured. In addition, changes to the undiscounted cash flows are recognised as an increase or a decrease in both the liability for an ARO and the related asset retirement cost. Upward revisions are discounted using the current credit-adjusted, risk-free rate. Downward revisions are discounted by using the credit- adjusted, risk-free rate that existed when the original liability was recognised. If an entity cannot identify the prior period to which the downward revision relates, it may use a weighted-average, credit-adjusted, risk-free rate to discount the downward revision to estimated future cash flow.	If it is not clear whether a present obligation exists, the entity may evaluate the evidence on the basis of a more-likely-than-not threshold. This threshold is evaluated in relation to the likelihood of settling the obligation. The guidance uses a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the liability. Changes in the measurement of an existing decommissioning, restoration or similar liability that result from changes in the estimated timing or amount of the cash outflows or other resources or a change in the discount rate adjust the carrying value of the related asset under the cost model. Adjustments may not increase the carrying amount of an asset beyond its recoverable amount or reduce it to a negative value. The periodic unwinding of the discount is recognised in profit or loss as a finance cost as it occurs.
Base inventory/line fill – cushion gas and line pack gas	Similar to IFRS	The cost of cushion gas and line pack gas are capitalised and depreciated over the useful life of the PP&E, as they meet the definition of PP&E.
Inventory	Carried at the lower of cost or market value. Market value is the current replacement cost; however, the replacement cost cannot be greater than the net realisable value or less than the net realisable value reduced by a normal sales margin. The use of Last In, First Out (LIFO) is permitted. Reversal of write-down is prohibited.	Carry at lower of cost and net realisable value. The use of First In, First Out (FIFO) or the weighted average method to determine cost. LIFO prohibited. Reversal is required for subsequent increase in value of previous write-downs limited to the amount of the original write-downs.

Accounting in Downstream Oil and Gas		
A general comparison between US GAAP and IFRS		
Area	**US GAAP**	**IFRS**
Revenue recognition - General	Revenue recognition guidance is extensive and includes a significant volume of literature issued by various US standard setters. Generally, the guidance focuses on revenue being: (1) either realised or realisable, and (2) earned. Revenue recognition is considered to involve an exchange transaction; that is, revenue should not be recognised until an exchange transaction has occurred.	Two primary revenue standards capture all revenue transactions within one of four broad categories: • Sale of goods • Rendering of services • Others' use of an entity's assets (yielding interest, royalties, etc.) • Construction contracts Revenue recognition criteria for each of these categories include the probability that the economic benefits associated with the transaction will flow to the entity and that the revenue and costs can be measured reliably. Additional recognition criteria apply within each broad category. The principles laid out within each of the categories are generally to be applied without significant further rules and/or exceptions.
Take-or-pay arrangement	Similar to IFRS	These arrangements are often entered into save transportation costs by exchanging a quantity of product A in location X for a quantity of product A in location Y. The nature of the exchange will determine whether it is a like-for-like exchange or an exchange of dissimilar goods. A like-for-like exchange does not give rise to revenue recognition or gains. An exchange of dissimilar goods results in revenue recognition and gains or losses.
Producer gas imbalances	US GAAP permits a choice of the sales/lifting method or the entitlement methods for revenue recognition	Revenue is recognised in cases of imbalance on an entitlement basis.
Buy-sell arrangement	Similar to IFRS	Expense
Derivatives	Similar to IFRS, however, differences can arise in the detailed application.	Derivatives not qualifying for hedge accounting are measured at fair value with changes in fair value recognised in the income statement. Hedge accounting is permitted provided that certain stringent qualifying criteria are met.

Accounting in Downstream Oil and Gas		
A general comparison between US GAAP and IFRS		
Area	**US GAAP**	**IFRS**
Determination of functional currency	There is no hierarchy of indicators to determine the functional currency of an entity. In those instances in which the indicators are mixed and the functional currency is not obvious, management's judgment is required in order to determine the currency that most faithfully portrays the primary economic environment of the entity's operations.	Primary and secondary indicators should be considered in the determination of the functional currency of an entity. If indicators are mixed and the functional currency is not obvious, management should use its judgment to determine the functional currency that most faithfully represents the economic results of the entity's operations by focusing on the currency of the economy that determines the pricing of transactions (not the currency in which the transactions are denominated).
Joint Arrangement/ Joint Venture	The use of the equity method is required except in specific circumstances. Proportionate consolidation is generally not permitted except for unincorporated entities operating in certain industries.	IFRS reduces the types of joint arrangements to joint operations and joint ventures, and prohibits the use of proportional consolidation.

Chapter 3.3.1 describe more detail on applicability of SFAS 66/IFRS 11 in downstream sectors.

5.3 *Taxation and Customs*

5.3.1 General Overview

Goods and services supplied by downstream operators, Contractors and their businesses are generally subject to taxes under the general tax law. Please see our annual publication, the PwC Pocket Tax Guide, which can be found at http://www.pwc.com/id, for more detail. Most downstream entities pay taxes in accordance with the prevailing law, although some activities can be subject to different withholding tax arrangements and a final tax arrangement.

Practical tax issues to be considered before making any significant investment include the following:

a. Whether any tax incentives are available for the proposed investment;
b. Whether a PE exists in Indonesia either as part of the proposed investment or prior to the new investment;
c. The import taxes obligations especially within the transportation and storage industry;
d. The Income Tax treatment of the revenue stream noting that there could be a different Income Tax treatment according to the nature of the transaction;
e. Ensuring that contracts specifically cater for the imposition of WHT and VAT, i.e. the use of net versus gross contracts;
f. Structuring inter-group transactions and agreements to accommodate the WHT and VAT implications and any transfer pricing issues that may arise (for example, inventory supplies and/or offtake, management fees, financing, etc.); and
g. structuring certain contracts to minimise VAT and WHT implications.

From a customs perspective issues include the following:

a. Royalties – Customs (the Directorate General of Customs and Excise (DGoCE)) pursuing duty on royalty payments during customs' audits;
b. Transfer pricing adjustments - multinationals making year-end adjustments. The DGoCE could charge duty on any additional payments, and ignore any credits received by the importer;
c. Arrangements with no sale to the importer – examples include leased goods, warranty replacement, imports by branches, ship to A/sell to B. At best, there is a compliance burden in determining the alternative basis of customs value. At worst, the duty liability may increase significantly;
d. Inventory control in Customs Facilities - Companies using customs facilities may have problems in accounting for the physical inventory as compared to the bookkeeping records; and
e. Transfers of fixed assets under Customs Facilities - the exempted duties may have to be paid, where the company does not follow the proper procedures.

Thin Capitalisation

On 9 September 2015 the MoF issued Regulation No. 169/2015 ("PMK 169") which introduced a general debt and equity ratio (DER) limitation of 4 to 1 for Income Tax purposes. PMK 169 first applies from 1 January 2016. Where debt exceeds equity by a factor of 4 (determined on a monthly basis) the interest attaching to the "excessive debt" is non-deductible. There are debt and equity definitions provided. MoF 169 does however provide an exemption from the DER rules for certain industries including infrastructure (which is not defined). Most downstream activities are likely to be subject to this 4:1 DER limitation.

On 28 November 2017, the DGT issued PER-25 with additional implementing guidelines on the DER calculation and filing arrangements. PER-25 also introduced a general requirement to file an "offshore" loans report. These rules apply firstly for the 2017 annual returns.

5.3.2 Tax Incentives

Tax incentives may be available to certain investors in the following downstream sectors:

Tax Holiday for Pioneer Investors

On 4 April 2018 the MoF issued new regulation No. 35/PMK.010/2018 as an amendment to the previous PMK 103. PMK 35 provides an Income Tax reduction of 100% for 5-20 years depending on the investment value .The taxpayer can enjoy a 50% CIT reduction for the next two years after the concession period ended. The application process is centralised through the BKPM and ends on 3 April 2023.

Qualifying criteria include:

a. that the business is in a "pioneer industry". Within the energy sector this includes oil refineries or industries and oil refinery infrastructure, including those using the Cooperation of Government and Business Entity (*Kerjasama Pemerintah dan Badan Usaha* or KPBU) scheme as well as base organic chemicals sourced from oil and gas;
b. that the applicant involves a new capital investment plan;
c. that the project involves a capital investment of at least Rp 500 billion;
d. that the project is carried out through an Indonesian legal entity ;
e. that the applicant has never had its Tax Holiday application granted or rejected by the MoF;
f. that the taxpayer satisfies the DER stipulated in a separate MoF regulation (see above).

Under the new PMK 35, domestic shareholders of the applicant must obtain a tax clearance letter issued by the DGT.

Tax Allowances

Pursuant to Investment Law No.25/2007 the Government can provide incentives to qualifying investments.

Pursuant of Government Regulation No.1/2007 (GR No.1) the tax incentives proposed by Law No.25 consitute:

a. An "investment credit" equal to 30% of qualifying spending deductable at 5% p.a over 6 years;
b. Accelerated tax depreciation/ amortisation;
c. Reduced withholding tax rates on payable dividend to non-resident; and
d. An extended tax loss carried forward period of up to 10 years.

The incentives must be applied for through the BKPM and will involve Tax Office recommendations.

GR No.1 was amended by GR 62/2008 (effective 23 September 2008) by expanding the qualifying industries to certain gas to LNG/LPG processing activities and hydrocarbon refining activities.

GR 62/2008 was then amended GR 52/2011 to covers LNG regasification using a Floating, Storage and Regasification Units and certain refining activities.

GR 52/2011 was then amended by GR 18/2015 and GR 9/2016 with the following tables outlining the energy related sectors now eligible:

Business Field	Scope of Products	Requirements
Natural Oil Refinery Industry	Refinering of natural oil to produces gas/LPG, avtur, avigas, naphtha, diesel fuel, kerosene, diesel oil, fuel oil, lubricant, waz, solvent, residue and asphalt	Priority to meet local demands
Natural Gas Refinery and Processing Industry	Refining and processing of natural gas into LNG and LPG	None
Lubricant Manufacturing Industry	All products included within the relevant Lubricants business code (KBLI)	None
Oil, Natural Gas and Coal Originated Organic Base Chemical Industry	• Olefin upstream group: ethylene, propylene, crylic acid butadien, buthane, butane-1, Ethyl Tert Buthyl Ether, ethylene dichloride, vinyl chloride monomer, raffinate, pyrolisis gasoline, crude c-4 • Aromatic upstream group: purified, terephthalic acid (PTA), paraxylene, benzene, toluene, orthoxylene • C1 upstream group: methanol, ammonia • Others: black carbon	None
Natural and Artificial Gas Supply	Regasification of LNG into gas using a Floating Storage Regasification Unit (FSRU) Coalbed Methane (Non PSC), shale gas, tight gas sand and methane hydrate	None

Special Economic Zones (*Kawasan Ekonomi Khusus*/KEK)

On 28 December 2015, the Government issued Regulation (GR) 96/2015 that provides facilities for those who invest in a KEK. The facilities cover Income Tax, VAT, Luxury-goods Sales Tax (LST), Import Duty, and excise.

At the time of writing there are eleven areas designated as KEKs.

Free Trade Zone (FTZ) in Batam, Bintan and Karimun

Goods entering a Free Trade Zone/FTZ (*Kawasan Perdagangan Bebas*/KPB) may enjoy tax facilities such as Import Duty and excise exemptions. In addition, other import taxes (i.e., VAT, LST, and Article 22 Income Tax) are not collected.

Bonded Zones

A bonded zone (*Kawasan Berikat*/KB) allows companies producing finished goods mainly for export an Import Duty etc. exemption on imports of capital equipment and raw materials.

5.3.3 Taxation on the Sale of Fuel, Gas and Lubricants by Importers and Manufacturer

The taxation on the sale of fuel, gas and lubricants by importers and manufacturers are regulated under MoF Regulation No. 34/PMK.010/2017 (“PMK 34”). PMK 34 requires importers and manufacturers to collect Article 22 WHT from the sale of fuel, gas and lubricants as follows:

Definition	Rate	Sale to	
		Agent/Distributor	Non-Agent/Non-Distributor
Fuel			
Sale by Pertamina and its subsidiaries to Gas Station	0.25%	Final	Non-Final
Sale by non - Pertamina to Gas Station	0.3%	Final	Non-Final
Sale other than the above	0.3%	Final	Non-Final
Gas	0.3%	Final	Non-Final
Lubricants	0.3%	Final	Non-Final

VAT on Commercial Sales

The producer/importer is regarded as a taxable entrepreneur with the general VAT rules being applicable. The sale is therefore subject to a 10% VAT. Generally, the producer/importer adds VAT to its sales which is then creditable to the purchaser. Onward sales would be subject to VAT.

5.3.4 Import Duties

Import Duty on Petroleum

Crude oils are classified under HS 27.09 (which covers Petroleum oils and oils obtained from bituminous minerals, crude). Both the general Import Duty rate and the ASEAN Trade in Goods Agreement (ATIGA) rate for crude oil is 0%.

Refined oil products are potentially classifiable under HS 27.10 which covers

> *"Petroleum oils and oils obtained from bituminous minerals, other than crude; preparations not elsewhere specified or included, containing by weight 70% or more of petroleum oils or of oils obtained from bituminous minerals, these oils being the basic constituents of the preparations; waste oils".*

The general Import Duty rate ranges from 0% to 5% depending on the specific product. The ATIGA duty rate is 0%.

Natural gas is classifiable under HS 27.11 which covers "Petroleum gases and other gaseous hydrocarbons". The general Import Duty rate ranges from 0% to 5%. The ATIGA rate is 0%.

Import Duty on Fuel

For Import Duty on fuel, this should refer to the 2012 Indonesian Customs tariff book under MoF Regulation No. 06/PMK.010/2017. The HS codes are:

a. 2710.12 which has a 0% Import Duty in general and for the ATIGA duty rate;
b. 2710.19 which has a general Import Duty rate in the range of 0% to 5% and 0% for ATIGA.

In addition the import of fuel is subject to a 2.5% or 7.5% Article 22 Income tax and a 10% import VAT.

Photo source: PwC

5.3.5 Royalty on Fuel Oil Supply and Distribution and Transmission of Natural Gas through Pipelines.

General

A PT Company must pay a royalty to BPH Migas where:
a. It carries out the supply and distribution of fuel oil and/or transmission of natural gas through pipeline; or
b. It owns a Natural Gas Distribution network facilities operating at the Distribution Network Area and/or Transmission Section.

The Natural Gas Distribution Area/Transmission Section is defined as an area/section of the Natural Gas Distribution Network/Transmission Pipeline which is part of the Masterplan of the National Natural Gas Transmission and Distribution Network.

Companies that must pay a royalty on the supply and distribution of fuel oil are:
a. PT Companies holding a fuel oil wholesale trading business licence;
b. PT Companies holding a fuel oil limited trading business licence; and
c. PT Companies holding a processing business licence that produces the fuel oil and supplies and distributes the fuel oil and/or trades fuel oil as an extension of the processing business.

Companies that must pay a royalty on transmitting Natural Gas are:
a. PT Companies holding the Natural Gas Transmission through Pipeline business licence at the Transmission Section and/or Distribution Network Area that has owned the special right; and
b. PT Companies holding the Natural Gas Trading business licence that own the special rights and distribution network facilities at the distribution network area.

Sanctions

Any late payment of royalties is subject to a 2% penalty.

Tariff

The royalty must be settled on a monthly basis and is calculated as follows (pursuant to Government Regulation No.1/2006):

Volume Level per Annum	Percentage Amount
Fuel Oil Sales Up to 25 million kilolitres 25 million - 50 million kilolitres > 50 million kilolitres	 0.3% of the selling price 0.2% of the selling price 0.1% of the selling price
Gas Transmission Up to 100 billion Standard Cubic Feet > 100 billion Standard Cubic Feet	 3% transmission tariff per one thousand Standard Cubic Feet 2% transmission tariff per one thousand Standard Cubic Feet

5.4 *Commercial Considerations*

When reviewing a potential downstream asset investors should consider the following issues:

Topics	Issues
Land rights	• The land where a pipeline is located may not be acquired/owned. • The process of land registration is time consuming and subject to Government regulation. • Land ownership may be disputed and/or overlap with Government protected forest area or with other businesses' concession rights (e.g. timber, plantation or mining). • Any land and building right transfer attracts a duty of 5% of the land value.
Valuation of underlying fixed assets and inventory	• Asset costs may be subject to mark-up. • Equipment may not be in good condition and hence the net book value may not reflect its market value. • The underlying assets may not have been formally verified. Lack of fixed asset and physical inventory verification increases the risk of non-existence. • Special accounting rules apply for turnaround costs. • There could be contractual or legal obligations for Asset Retirement. • Asset validity (including any assets pledged as collateral) may need to be verified. • The deductibility of shareholders' expenditure (e.g. feasibility study, etc.) incurred before the establishment of the project company may be scrutinised by the DGT. • Unutilised tax depreciation expenses for fixed assets may exist if the project life is less than the tax useful life.
Underlying regulations and permits	• Some of the downstream related regulations, especially those relating to the rights of access, taxation and tariff structure are in a transitional stage. • There are no customs regulations supporting storage activities. There could be import taxes and duties leakage especially for liquid products. • The requirement to share storage facilities needs to be defined in more detail. • A guarantee by a trading business to have a product constantly available to the distribution network needs to be defined to ensure optimal inventory management. • The requirement to supply to remote areas needs to be clarified.
Stand-by Letters of Credit	• There is a potential exposure to non-payment by a customer if there are no stand-by letters of credit or other credit protection in place.
Contractual Commitments	• Investors need to assess the impact of the following on their deals: - Gas Sales and Supply Agreements. - Gas Transportation Agreements. - Take-or-Pay obligations. - Ship-or-Pay Arrangements (including the deferred revenue impact and the correct taxation treatment). - Potential liquidated damages and other exposures (upsides and downsides). - The cash waterfall mechanism. - Avenues for recourse against Contractors. - Line-pack gas - treatment, exposures and accounting. - Make-up gas - treatment. - Guaranteed product supply (contract, other arrangements, etc.). - Related party transactions.

Topics	Issues
Government relationship	• The Government may intend to control refineries as has been the case in the past. • Restrictions on the further issue of capital/transfers of shares for a certain period of time. • The Government usually keeps the right for first refusal, as well as "tag along" rights, on any future sale. • The requirement to pledge a shareholding to the Government to secure performance may need to be considered. • The form and content of reports to be filed with the MoEMR and regulatory bodies needs to be understood. • Further guidance is needed on how private investors will work with the Government in maintaining national strategic oil and fuel oil reserves. • Further guidance is required on how investors may set pricing and how any subsidy will be paid to investors until such time that the Government fuel subsidy is fully removed. • The designation of trading areas and the requirement to market product in remote areas needs further elaboration. • The requirement to distribute to remote areas needs to be further defined. • Expectations of the Regulator's and the Government's role in the short, medium and long term needs to be understood. • Product pricing restrictions may be applicable in some areas based on the prevailing GRs.
Associated Products	• Later generation PSCs promote Contractors developing associated products from its petroleum operations. Questions remain as to whether earnings from the sale of the associated products will be creditable to operating costs (treated as by-products under GR 79 and credited against cost recovery) or treated as profit oil and gas. The commercial feasibility and profitability of additional product development is subject to a proper review and analysis.
Profitability	• Future operations could be subject to volatility in the supply and prices of key inputs (other than feedstock), e.g. electricity, water, etc. • There may be significant volatility in storage and transportation costs of feed stock and finished product. • Exposures to commodity price movements need to be considered. • Counterparty performance assessments need to be undertaken. • Demand forecasting must be considered. • Operational performance assessment may be needed. • Distortion of trading performance through related party transactions and other undisclosed arrangements is possible. • Controls and reporting processes need to be undertaken. • A review of the cost structure and impact on overall economics may be required.

Topics	Issues
Technology	• The licensing arrangements for technology may not have been formalised. • The operators' technical expertise/credit strength may be questionable. • There is a general restriction on the tax deductibility of Research and Development (R&D) expenditure when the R&D activities are not conducted in Indonesia. • Royalty payments to offshore counterparts may attract Duty.
Product mix	• The ability to change the product mix and associated costs may be limited. • The contractual commitments associated with the product mix may be significant.
Supply Chain	• The continuous availability of feedstock to the refining process is sometimes not secure.
Environmental Issues	• Compliance with existing and future environmental regulations (including remediation/abandonment exposures) may be lacking. • Remediation costs for the previous activities of the refinery may be significant. • The environmental impact may need to be considered.
Strategic Value enhancement opportunities	• There may be opportunities to improve crude procurement and inbound logistics costs. • There may be opportunities to improve refinery utilisation. • There may be opportunities to enhance retail outlet throughput may be limited. • Branding and value capture opportunities need to be identified.
Competition	• Prioritisation of cooperatives, small enterprises and national companies to own/operate transportation and distribution facilities may hinder development in the short-term due to lack of operational experience and understanding of the industry as well as potential capital or financing constraints. • Overall market growth and product specific demand supply need to be considered. • Emerging competition in retail market due to liberalisation needs to be assessed.
Other potential taxation issues	• The imposition of WHT on the hire of pipelines. • The imposition of WHT on the hire of oil/gas tanking. • The adoption of a split contract for Engineering, Procurement, and Construction (EPC) contracts can be contested. • The VATable status of LNG – now clarified in chapter 3. • Any related party transactions (where transactions with a counterparty exceed Rp 10 billion in a year) should be supported by transfer pricing documentation which includes an explanation of the nature of transactions, pricing policy, characteristic of the property/services, functional analysis, pricing methodology applied and the rationale for the methodology selected, and benchmarking.

5.5 *Gas Market Developments in Indonesia*

5.5.1 Gas pipeline infrastructure

Despite a decline in oil reserves status, there is a rise in Indonesia's natural gas reserves. Most research reveals that gas will be Indonesia's fuel for the future. This is also supported by the fact that the natural gas market in Indonesia grew tremendously during the past decade and will keep rising in the coming years. Completion of LNG plant, arrival of FSRUs, and the increasing demand for gas in power generation and transportation, has doubled Indonesia's consumption and it is predicted to keep growing in the future. Resources availability and government eagerness to utilise more natural gas will lead Indonesia to become one of the major gas consumers in future years.

Although Indonesia has large potential in the natural gas sector, it needs a lot of investment to develop infrastructure on the downstream side. It is indeed challenging for ventures to build receiving facilities, pipelines and other kinds of distribution infrastructure for the country, which has an archipelagic shape and land issue matters, but the opportunities are promising because the Government wants to encourage households and industries to utilise more natural gas. If natural gas is being pushed up, infrastructure will be prioritised. As of now, the construction of a natural gas pipeline for households is included in strategic national projects, and is planned to begin operating in this year.

Previously, there were two major gas pipeline companies: PT Pertamina Gas and PT PGN. However, following the issuance of GR 6/2018, PT PGN will be converted into a subsidiary of PT Pertamina after it became a holding company for state-owned enterprises in the oil and gas industry. Meanwhile, PGN is planned to be the national sub-holding gas company, although the merger scheme between PT Pertamina Gas and PGN was not yet clear at the date of writing.

1. PT Pertamina Gas

PT Pertamina Gas is a subsidiary of PT Pertamina (Persero) which focuses on midstream sector and gas marketing in Indonesia. This company has a role in gas trading, gas transportation, gas process and gas distribution and other business which is related with natural gas and associated products.

PT Pertamina Gas was established in February 2007 as a result of implementation of Oil and Gas Law No. 22/2001 and also to respond the increasing demand for natural gas. As of the end of 2016, PT Pertamina Gas's areas of operation are classified into five areas with a total length of 2,015 km:

a. Transmission pipeline East Java
b. Transmission pipeline Kalimantan
c. Transmission pipeline Southern Sumatra
d. Transmission pipeline West Java
e. Transmission pipeline Northern Sumatera

PT Pertamina Gas built three more gas pipelines in 2017, with a total length of 513 km:

a. Transmission pipeline Grissik – Pusri (176 km)
b. Transmission pipeline Gresik – Petrokimia Gresik loop (70 km)
c. Transmission pipeline Gresik - Semarang (267 km)

Aside from the projects above, PT Pertamina Gas also formed a joint venture with PT PGN to build a gas transmission pipeline between Duri and Dumai, which was started in November 2016, with the gas distribution pipeline under construction since June 2017.

2. PT Perusahaan Gas Negara (Persero) Tbk (PGN)

PGN was originally a Dutch-based gas company called Firma L.I. Eindhoven & Co. In 1958, the firm was nationalised and became Perusahaan Negara Gas, changing its name to PT. Perusahaan Gas Negara in 1965. In 2003, PGN began trading on the Jakarta and Surabaya Stock Exchanges. PGN is 57% owned by the Government of Indonesia, but after GR 6/2018 was issued on 28th February 2018, PGN will become a subsidiary of PT Pertamina, as a national oil and gas holding company.

PGN operates natural gas distribution and transmission pipeline networks. Its subsidiaries and affiliated companies are engaged in upstream activities (Saka Energi Indonesia which operates the Pangkah PSC and has participating interests in various PSCs, including Bangkanai, Ketapang, Muriah, Sanga Sanga, and South East Sumatra PSCs), gas pipelines, regasification terminals and other support services. Along with its subsidiaries, PGN has constructed around 7,278 km of gas pipeline in total.

Other gas pipeline companies are privately owned and their pipelines usually tie in to PGN's or Pertagas's main pipelines.

5.5.2 Open Access to Gas Pipelines and Gas allocation, Utilisation and Price

The Government of Indonesia recognises the need to expand its pipeline network to raise gas penetration rates and reduce oil dependency. However, gas marketing development in Indonesia is hampered by slow infrastructure development, limited access to distribution and transmission pipelines, and multiple layers of traders, resulting in high gas prices to end users.

BPH Migas have said that they will auction the construction of gas pipeline infrastructure in the distribution lines of Natuna (Riau) to Kalimantan and across Kalimantan on the basis of open (third party) access. Although there have been BPH Migas rules supporting open access since 2008 (Rule No.12/BPH Migas/II/2008 on Special Right Auction of Gas Pipeline, Rule No. 16/P/BPH Migas/VII/2008 on Toll Fee (Tariff) of Gas Pipeline, Rule No.15/P/BPH Migas/VII/2008 on Open Access of Gas Pipeline) and a MoEMR regulation (10/2009 on Piped Natural Gas Business Activities) stipulating that owners of gas pipes in the country must allow their lines to be accessed by third parties, PGN has been reluctant to open access to its pipelines.

By auctioning new open access gas pipelines, BPH Migas hopes to pave the way for the entire distribution network to adopt open access in due course.

In 25 January 2018, the Minister of Energy and Mineral Resources (Minister of EMR) issued PerMen No. 4/2018 regarding natural gas businesses in downstream oil and gas business activities. This regulation replaced the previous regulation, i.e. PerMen No. 19/2009. This regulation amends the Master Plan for the National Gas Transmission and Distribution Network and authorises BPH Migas to put gas transmission sections to tender. The tender winner will have a contract for 30 years, while the existing business entities in the distribution network that do not win the tender have the opportunity to continue their business for 15 years, with BPH Migas and MoEMR to monitor the feasibility and the economy of the transmission section results.

The other section of PerMen No. 4/2018 abolishes the distribution area system based on the downstream dedicated system in the form of private gas pipes utilised by business entities to transmit their own gas, and sets out provisions on licensing required for engaging in natural gas transmission business activities by pipelines or by using facilities other than pipelines (in form of CNG or LNG) in certain transmission segments or distribution network areas, as well as natural gas storage business activities. The holders of special rights on certain distribution network areas are obligated to develop and provide natural gas infrastructure in the form of natural gas pipeline networks, and there is also a procedure for natural gas customers to obtain permission to develop and operate natural gas pipelines and supporting facilities for their own interest.

Meanwhile, the provisions and procedures on determination of allocation and utilisation as well as price of natural gas are regulated in PerMen No. 6/2016:

	PerMen No. 6/2016 (new)
Order of priorities for gas allocation and utilisation	a. Support government's program to supply natural gas for transportation, households ($\leq$50m^3/month) and small customers ($\leq$100m^3/month). b. Increase national oil and gas production c. Fertilizers d. Natural gas-based industry e. Electricity f. Industries which uses gas as fuels
Buyer	a. State owned enterprise (BUMN); b. BUMD; c. Gas fired – power/electricity company; d. Companies holding *Izin Usaha Niaga Gas Bumi*; e. LPG Companies; f. End - user
Gas Price	Gas price to be approved by the MoEMR through SKK Migas

Documents to be Submitted by the Oil and Gas Contractors to Obtain Allocation:

1. The Contractor applies for the allocation and utilisation of natural gas for domestic demand to the Minister of EMR through SKK Migas.
2. For domestic sales, documents to be included are:
   - a plan of Development and supporting documents; or
   - if a PoD not yet obtained, a reserves report and production profile, the results of production tests, any production facility, gas deliverability, estimation of production split; and
   - other documents explaining the potential gas buyers, gas volume, infrastructure for the distribution.
3. For exports, documents to be included should explain potential buyers, volumes, infrastructure or delivery methods, timeline for deliveries.
4. For new allocations, SKK Migas must submit to the Minister 60 days before delivery time.
5. For extensions, the Contractor or gas buyer, through SKK Migas, needs to propose the new gas allocation and utilisation to the Minister of EMR at least six months before the end of the existing GSA.
6. For increases in volume, the Contractor or gas buyer needs to submit a proposal/request to the Minister of EMR as per regulation.

The Contractor needs to propose a new gas price at least three months before the termination date of the existing gas sales agreement. If the Contractor wants to propose an additional gas allocation and utilisation, the Contractor needs to submit a proposal to the Minister of EMR as per regulation. The gas price which is used in the contract is determined by the Minister of EMR. In addition, the gas purchase contract must include an additional clause regarding the price review.

Requirement for Contractor to propose a gas price to the Minister of EMR:

1. Propose price of gas and the price formula justification
2. Economic value of gas
3. Gas resources, distribution and delivery principle, volume in the contract, delivery place per contract, period of distribution, estimation volume daily gas distributed.
4. Copy of approval Minister of EMR on allocation and utilisation of gas
5. Copy of approval Plan of Development and supporting documents
6. Statistic domestic and international gas price
7. Copy of negotiation on price of gas document
8. Copy of contract to purchase and sell gas

Photo source: PwC

6 Service Providers to the Upstream Sector

6.1 *Equipment and Services – General*

As discussed in Chapters 2, 3 and 4, the Government and SKK Migas set the guidelines and make the final decision on large purchases of most equipment and services provided to the upstream sector.

Purchases by JCCs are effectively Government expenditure and generally must be provided from a local limited liability company. Foreign companies wishing to sell upstream equipment or services must therefore comply with the strict procurement rules set out under SKK Migas Guidance No.007/PTK as last revised in 2017, and the oil and gas services activities guidance under the MoEMR Regulation 14/2018, which revoked the previous regulation in MoEMR Regulation 27/2008, on 23 February 2018.

MoEMR Reg 14/2018 requires oil and gas supporting business to conduct registration to obtain an oil and gas supporting business capacity certificate (Surat Kemampuan Usaha Penunjang/SKUP) for oil and gas supporting business capacity development and improvement. The SKUP is classified into oil and gas construction services, oil and gas non-construction services, and oil and gas supporting industry. The previous Registration Certificate is abolished by MoEMR, while the issuance of SKUP that previously required 10 days is shortened to 3 days. The documents required to obtain SKUP can be found on the attachment of MoEMR Regulation 14/2018.

Photo source: PT Chevron Pacific Indonesia

6.2 Tax Considerations – General

Goods and services supplied to PSC Contractors are subject to taxes identical to those under the general Indonesian tax law (please refer to the PwC Pocket Tax Guide published annually and available at http://www.pwc.com/id). There have been some exceptions for oil field service providers with regard to import taxes (Article 22 Income Tax, VAT and Import Duty). Historically, service providers were able to take advantage of a PSC client's Master List (ML) facility. Please refer to our comments in Chapter 3.4.8, for details of the ML Facility.

There has been increased tax audit activity in relation to service providers in the last few years culminating in the creation of Oil & Gas tax service office. This is where PSC taxpayers and many oilfield service providers are now registered.

Transfer pricing is also becoming an area of close scrutiny for the oilfield service providers resulting in regular annual tax audits.

Where the service providers operate in a form of an Indonesian entity, a debt to equity limitation of 4:1 (refer to the previous Chapter 4.3) shall apply.

6.3 Taxation of Drilling Services

On 24 April 2014 a new negative investment list was issued as Presidential Decree No. 44/2016, which replaces Presidential Decree No. 39/2014. This restricts foreign investment companies (PMA entities) involved in both offshore and onshore drilling as follows:

- PMA entities can no longer engage in onshore drilling (this is now restricted to domestic companies only). This is consistent with previous Presidential Decree No.39/2014.
- The maximum foreign shareholding for PMA entities which engage in offshore drilling is 75%. Previously, wholly owned foreign companies could engage in offshore drilling in eastern Indonesia and the maximum foreign shareholding was 95% for all other offshore drilling.

The 2016 Negative Investment List does not apply to investments approved prior to its issue unless the terms are more favourable to the relevant investor. The List also does not apply to indirect investments or to portfolio investments transacting through domestic capital markets.

For further investment restrictions in the oil and gas industry see Chapter 2.2.2.

6.3.1 Foreign-owned Drilling Companies

Foreign-owned drilling companies (FDCs), historically carried out their drilling activities in Indonesia via a branch or PE for Indonesian tax purposes. The taxation regime that applies to Foreign-owned Drilling Company (FDC) PEs is outlined below:

a. The PE of a FDC is subject to a general Corporate Income Tax rate based on a deemed profit percentage of 15% of drilling income (hence an effective corporate income tax rate of 3.75% assuming a 25% tax rate), plus a 20% BPT.
b. The 20% BPT rate may be reduced under a relevant tax treaty. A Certificate of Domicile (CoD) is required to claim the benefit of any tax treaty (refer to the new CoD form and the requirements of DGT Regulation No. 10 of 19 June 2017).
c. Drilling income is generally accepted as meaning the FDCs "day rate" income received. Reimbursements and handling charges (including mobilisation and demobilisation) may not be taxable income, depending on whether a de minimis threshold test is exceeded. The test is generally applied on an annual rather than a contractual basis.
d. Other non-drilling income, for example interest, is subject to tax at normal rates.
e. Since MoEMR Reg 27, it is unclear how FDCs can continue to provide drilling services once any existing licence expires.

Since MoEMR Reg 27, it is unclear how FDCs can continue to provide drilling services once any existing licence expires.

6.3.2 Indonesian Drilling Companies

Unlike a FDC, Indonesian and PMA drilling companies are taxed on actual revenues and costs, and are subject to an Income Tax rate of 25%. The drilling services they provide also currently attract WHT at 2%, which represents a prepayment of their tax. Any imports of consumables or equipment by the drilling companies will generally attract Article 22 tax at 2.5%, which represents a further prepayment of their annual income tax bill.

6.3.3 VAT and WHT

The provision of drilling services is subject to VAT with PSC companies acting as the VAT collectors (i.e. with the output VAT of the drilling service entity remitted directly to the Tax Office). This means that many service providers will be in a perpetual VAT refund position. This VAT is technically refundable but only after a Tax Office audit.

6.3.4 Labour taxes

Foreign nationals (who become residents for tax purposes) of an FDC are generally subject to Article 21 – Employer WHT on a deemed salary basis as published by the ITO (at least for a branch). Individual tax returns should still however be filed on the basis of an individual's actual earnings.

For rotators or non-resident expatriate staff it may be possible to file an Article 26 WHT return (i.e. as a non-resident of Indonesia) in relation to tax withheld from their salary. This would effectively result in a tax rate of 20%.

The lodging of a monthly Article 21 Tax Return in relation to staff does not remove the individual's obligation to register for an Indonesian NPWP (tax payer identification number) and to file an Indonesian individual tax return.

6.4 *Shipping/FPSO & FSO Services*

Large crude carriers/tankers are engaged to ship oil from Indonesian territorial waters to overseas markets. Similarly, LNG carriers carry LNG cargo from the Bontang and Tangguh plants. Converted tankers are also used as Floating Production Storage & Offload (FPSO) or Floating Storage Offload (FSO) vessels.

The shipping industry is heavily regulated. Both local and international shipping are open to foreign investment through a PMA company in a joint venture with a maximum foreign shareholding of 49%, which is confirmed in the Negative Investment List issued on 18 May 2016 in Presidential Regulation 44/2016. A revision to the Negative Investment List is being discussed in the coordinating ministry of economy to be reviewed and discussed with the related ministry or institution.

Indonesian Shipping Law No. 17/2008 adopted the cabotage principles that were first introduced by Ministry of Transportation Regulation No.71/2005 of 18 November 2005. These oblige the use of Indonesian flagged vessels for local shipping from 1 January 2011. Foreign-flagged vessels for specific types of activities can obtain permission in form of a permit to use foreign vessels (*Izin Penggunaan Kapal Asing*/IPKA) issued by a holder of a Shipping Company Business Licence (*Surat Izin Usaha Perusahaan Angkutan Laut*/SIUPAL). These exempted activities include oil and gas survey, drilling, offshore construction and operational support, dredging, and salvage and underwater work. Exempted ships are jack-up rigs, jack-up barges, self-elevating drilling units, semi-submersible rigs, and deepwater drill ships. The permit for the aforementioned ships can be obtained by satisfying the requirements set out in Ministry of Transportation Regulation No. PM 100/2016.

PM 100/2016 renders offshore drilling rig activities to be valid up to and including the end of December 2017. On 15 December 2017, PM 115/2017, as an amendment to the previous regulation, came into effect extending the dispensation to the cabotage principle until the end of December 2018. This extension is given due to the current evaluation that there is an insufficient number of the specified types of ship in Indonesia. PM 100/2016 and PM 115/2017 also allow for foreign-flagged vessels not included in the list of ships mentioned to obtain permits at the discretion of the Ministry of Transportation.

The current Negative List does not specifically regulate FPSO/FSO operations. However, the Department of Sea Transportations views this as a shipping activity which requires a shipping licence. In this regard, licensing as a shipping company creates investment and ownership issues. Note that the Shipping Law No.17/2008 stipulates that only a company majority owned by an Indonesian party can register an Indonesian flagged vessel. Therefore, a holding of a 95% interest by a foreign shareholder would not allow the company to register as an owner of an Indonesian flagged vessel and consequently to obtain a shipping licence to operate the FPSO/FSO.

6.4.1 Taxation of Shipping/FPSO/FSO Service Providers

Export cargos

Shipping involves the provision of services and is subject to a WHT on the fees generated. The relevant WHT rates are generally:

a. Domestic (Indonesian incorporated) shipping companies – taxed at 1.2% of gross revenue.
b. Foreign shipping companies - taxed (final) at 2.64% of gross revenue.

In this regard:

a. The above WHT rates are only applicable to gross revenue from the "transportation of passengers and/or cargo" loaded from one port to another and, in the case of a foreign shipping company, from the Indonesian port to a foreign port (not vice versa);
b. The 2.64% regime presumes that the foreign shipping company has a PE in Indonesia;
c. It may not be possible to take advantage of a tax treaty to reduce BPR rates;
d. It is unclear whether this (final) WHT rate can be reduced to reflect the recently reduced corporate tax rate (i.e. 28% for 2009, 25% for 2010 and onward);
e. Tax treaties have specific shipping articles – which may be relevant;
f. Bare-boat charter (BBC) rentals (i.e. with no service component) might instead be subject to 20% WHT (before tax treaty relief); and
g. BBC payments may alternatively be characterised as royalties.

With regard to the VAT:

a. Shipping services which include an element of Indonesian "performance" (i.e. being performed within the Indonesian Customs Area) are technically subject to VAT. This is the case irrespective of whether the shipping company has a PE, and irrespective of whether the client is an Indonesian based entity, or an offshore entity;
b. A VAT exemption may be available if it can be argued that the services involve only a small proportion of Indonesian presence/performance and should thus be viewed as entirely ex-Indonesia (i.e. as entirely International); and
c. Shipping services provided entirely outside of Indonesia (say under a separate international contract) may avoid VAT on a "performance" basis. However, VAT could still arise on a self-assessment basis where the services are "utilised" within Indonesia. Whilst "utilised" is not well defined, in practice the ITO deems this to occur where the shipping costs are charged to Indonesia.

FPSO/FSO services

Traditionally many PSC entities have treated their FPSO/FSO service providers as shipping companies (and thus as fitting into the 1.2%/2.64% tax regime). The current and better view is that such services do not constitute transportation or shipping services and regard should be paid to the general tax law provisions.

About PwC

The firms of the PwC global network (www.pwc.com) provide industry-focused assurance, tax, legal, advisory and consulting services for public and private companies. More than 236,000 people in 158 countries connect their thinking, experience and solutions to build trust and enhance value for clients and their stakeholders.

PwC is organised into lines of service staffed by highly qualified and experienced professionals who are leaders in their fields, providing:

Assurance Services provide assurance over any system, process or controls and over any set of information to the highest PwC quality. These services include:

- Risk Assurance
- Financial Audit
- Capital Market Services
- Accounting Advisory Services

Tax Services optimise tax efficiency and contribute to overall corporate strategy through the formulation of effective tax strategies and ensuring general compliance. Some of our services include advice on:

- Corporate tax
- International tax
- Transfer pricing (TP)
- Mergers and acquisitions (M&A)
- VAT
- Tax disputes
- International assignments
- Customs
- Investment and corporate services

Advisory services involve an integrated suite of solutions covering deals and transaction support from deal strategy through to execution and post-deal services. These services include:

- Business Recovery Services
- Capital Projects & Infrastructure
- Corporate Finance
- Corporate Value Advisory
- Deal Strategy
- Delivering Deal Value
- Transaction Services

Consulting Services help organisations to work smarter and grow faster. We consult with our clients to build effective organisations, innovate and grow, reduce costs, manage risk and regulations, and leverage talent. Our aim is to support you in designing, managing and executing lasting beneficial change. These services include:

- Management Consulting
- Risk Consulting
- Technology Consulting
- Strategy Consulting

Legal Services provide responsive high value services through the provision of cutting edge legal solutions to support and facilitate legal developments in Indonesia. We work with you to understand your commercial objectives, express our advice in commercial terms and offer you seamless end-to-end service across the life cycle of your project. We structure and manage transactions from start to finish. While technical excellence is at the core of what we do, the breadth of our business and market insight differentiates us from traditional law firms to deliver an unparalleled, focused, integrated service. Our core value is providing excellent legal services, putting client needs and priorities first, continuously improving and doing business ethically. These services include:

- Mergers and Acquisitions
- Capital Markets and Securities
- Corporate Advisory
- Finance
- Employment
- Litigation & Dispute Resolution

For companies operating in the Indonesian oil and gas sector there are some compelling reasons to choose PwC Indonesia as your professional services firm, as outlined below:

The PwC network is the leading adviser to the oil and gas industry, both globally and in Indonesia, working with more explorers, producers and related service providers than any other professional services firm. We have operated in Indonesia since 1971 and have over 2,100 professional staff, including 54 partners and technical advisors, specialised in providing assurance, advisory, tax and legal services to Indonesian and international companies.

Our Energy, Utilities and Mining (EU&M) practice in Indonesia comprises over 350 dedicated professionals across our lines of service. This body of professionals brings deep local industry knowledge and experience with international industry expertise and provides us with the largest group of industry specialists in the Indonesian professional services market. We also draw on the PwC global EU&M network which includes more than 13,500 people focused on serving energy, power and mining clients.

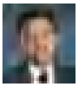
Our commitment to the oil and gas industry is unmatched and demonstrated by our active participation in industry associations around the world and our thought leadership on the issues affecting the industry. This includes our involvement with the Indonesian Petroleum Association. Overall, we believe we are helping to shape the future of the industry.

Our client service approach involves learning about your organisation's issues and seeking ways to add value to every task we perform. Detailed industry knowledge and experience ensures that we have the background and understanding of industry issues and can provide sharper, more sophisticated solutions that help clients accomplish their strategic objectives.

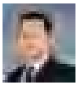
PwC Oil & Gas Contacts

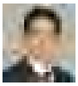
Assurance

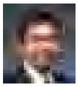

Sacha Winzenried
sacha.winzenried@id.pwc.com
T: +62 21 528 90968

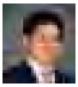

Yusron Fauzan
yusron.fauzan@id.pwc.com
T: +62 21 528 91072

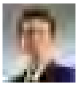

Gopinath Menon
gopinath.menon@id.pwc.com
T: +62 21 528 75772

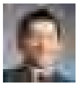

Yanto Kamarudin
yanto.kamarudin@id.pwc.com
T: +62 21 528 91053

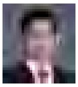

Daniel Kohar
daniel.kohar@id.pwc.com
T: +62 21 528 90962

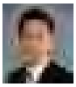

Toto Harsono
toto.harsono@id.pwc.com
T: +62 21 528 91205

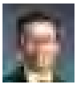

Firman Sababalat
firman.sababalat@id.pwc.com
T: +62 21 528 90785


Dodi Putra
putra.dodi@id.pwc.com
T: +62 21 528 90347

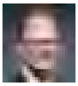

Heryanto Wong
heryanto.wong@id.pwc.com
T: +62 21 528 91030

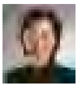

Dedy Lesmana
dedy.lesmana@id.pwc.com
T: +62 21 528 91337


Tody Sasongko
tody.sasongko@id.pwc.com
T: +62 21 528 90588

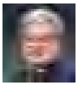

Irwan Lau
irwan.lau@id.pwc.com
T: +62 21 528 91016

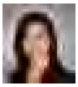
Tax

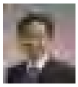

Tim Watson
tim.robert.watson@id.pwc.com
T: +62 21 528 90370


Suyanti Halim
suyanti.halim@id.pwc.com
T: +62 21 528 76004

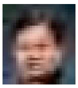

Antonius Sanyojaya
antonius.sanyojaya@id.pwc.com
T: +62 21 528 9097

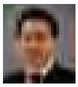

Turino Suyatman
turino.suyatman@id.pwc.com
T: +62 21 528 75375


Gadis Nurhidayah
gadis.nurhidayah@id.pwc.com
T: +62 21 528 90765

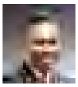

Tjen She Siung
tjen.she.siung@id.pwc.com
T: +62 21 528 90520


Alexander Lukito
alexander.lukito@id.pwc.com
T: +62 21 528 75618

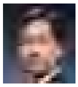

Otto Sumaryoto
otto.sumaryoto@id.pwc.com
T: +62 21 528 75328

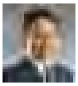

Raemon Utama
raemon.utama@id.pwc.com
T: +62 21 528 90560

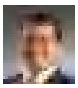
Advisory

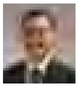

Mirza Diran
mirza.diran@id.pwc.com
T: +62 21 521 2901


Joshua Wahyudi
joshua.r.wahyudi@id.pwc.com
T: +62 21 528 90833

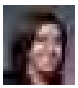

Michael Goenawan
michael.goenawan@id.pwc.com
T: +62 21 528 90340

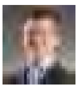

Agung Wiryawan
agung.wiryawan@id.pwc.com
T: +62 21 528 90666


Hafidsyah Mochtar
hafidsyah.mochtar@id.pwc.com
T: +62 21 528 90774

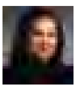

Ripa Yustisiadi
ripa.yustisiadi@id.pwc.com
T: +62 21 528 90947

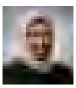
Consulting


Lenita Tobing
lenita.tobing@id.pwc.com
T: +62 21 528 75608


Paul van der Aa
paul.vanderaa@id.pwc.com
T: +62 21 528 91091

Legal


Melli Darsa
melli.darsa@id.pwc.com
T: +62 21 521 2901 ext. 72710


Nurul Setyorini
nurul.setyorini@id.pwc.com
T: +62 21 521 2901 ext. 90437

Acknowledgements

We would like to convey our sincere thanks to all the contributors for their efforts in supporting the preparation of this publication.

Photographic contributions:

PT Pertamina (Persero)
PT Chevron Pacific Indonesia

Project team

Sacha Winzenried
Daniel Kohar
Tim Watson
Alexander Lukito
Nurul Setyorini
Fitri Budiman
Laksmana Hanif
Jeremiah Pranajaya

PwC Indonesia (www.pwc.com/id)
Telp: +62 21 5212901
Fax: +62 21 5290 5555/5290 5050

PwC Indonesia **@PwC_ Indonesia**

More Insights

Visit www.pwc.com/id to download or order hardcopies of reports

1. Power in Indonesia: Investment and Taxation Guide
2. Indonesian Power Industry Survey
3. Energy, Utilities and Mining NewsFlash
4. mineIndonesia – survey of trends in the Indonesian mining sector
5. Mining in Indonesia: Investment and Taxation Guide
6. Investor survey of the Indonesian oil and gas industry
7. Indonesian Mining Areas, Indonesia Oil & Gas Concessions & Major Infrastructure, and Indonesia's Major Power Plants and Transmission Lines Maps
8. We need to talk – About the future of mining
9. Financial Reporting in the Oil & Gas Industry
10. Indonesian Pocket Tax Book
11. On the Road to IPO: Stop, Look and Leap
12. Exploring Alternative Solutions to Infrastructure Financing

1

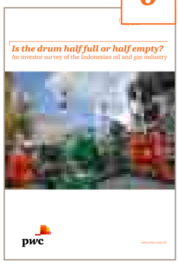
2

3

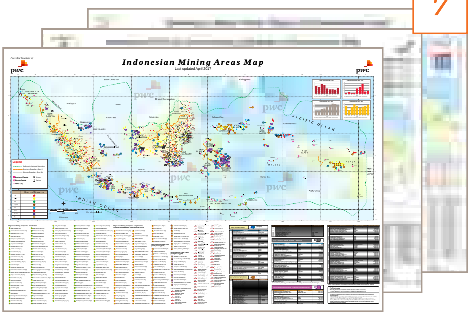
4

5

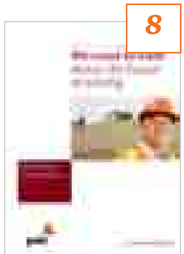
6



7



8



9

10

11

12

Indonesian Oil and Gas Concessions and Major Infrastructure Map