Oil and Gas in Indonesia

Investment, Taxation and Regulatory Guide

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Contents

Glossary

Term	Definition
AFE	Authorisation for Expenditure
APBN	*Anggaran Pendapatan dan Belanja Negara* (State Budget)
ASC	Accounting Standard Codification
ATIGA	ASEAN Trade in Goods Agreement
BBC	Bare-boat charter
bbl	Barrel
BBTUD	British Thermal Units per Day
Bcm	Billion Cubic Metres
BI	Bank Indonesia
BiK	Benefits in Kind
BKPM	*Badan Koordinasi Penanaman Modal* (Indonesia's Investment Coordinating Board)
BOPD	Barrels of Oil per Day
BP Migas	*Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi* (Oil and Gas Upstream Business Activities Operational Agency), now SKK Migas
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)
BPMA	*Badan Pengelola Migas Aceh* (Special Oil & Gas Regulatory Body of Aceh)
BPR	Branch Profit Remittance
BPT	Branch Profits Tax (i.e. on BPRs)
BSCFD	Billion Standard Cubic Feet per Day
BUMD	*Badan Usaha Milik Daerah* (Regionally Owned Business Enterprise established by the Regional Government)
BUK Migas	*Badan Usaha Khusus Minyak dan Gas Bumi* (Oil and Gas Special Executive Agency)
CBM	Coal Bed Methane
CCS/CCUS	Carbon Capture & Storage/Carbon Capture Utilisation & Storage
CD	Community Development
CITR	Corporate Income Tax Return
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CoD	Certificate of Domicile
COP	Conference of Parties
COVID-19	Coronavirus Disease of 2019
C&D Tax	Corporate and Dividend Tax
DGB	Directorate General of Budget
DGoCE	Directorate General of Customs and Excise
DGOG	Directorate General of Oil and Gas
DGT	Directorate General of Taxes

Term	Definition
DHE	*Devisa Hasil Ekspor* (Foreign Exchange Proceeds from Export)
DMO	Domestic Market Obligation
DPR	*Dewan Perwakilan Rakyat* (House of Representatives)
EIT	Employee Income Tax
EOR	Enhanced Oil Recovery
ESG	Environmental, Social and Governance
E&P	Exploration & Production
FCR	Foreign Exchange Report
FDC	Foreign-owned Drilling Company
FMR	Financial Monthly Report
FMV	Fair Market Value
FPS	Floating Production System
FPSO/FSO	Floating Production Storage and Offload (vessel)/Floating Storage and Offload (vessel)
FPU	Floating Production Unit
FQR	Financial Quarterly Report
FSRU	Floating Storage Regasification Unit
FSU	Floating Storage Unit
FTP	First Tranche Petroleum
FTZ	Free Trade Zone
G&G	Geological and Geophysical
GAAP	Generally Accepted Accounting Principles
GDP	Gross Domestic Product
the Government	Government of Indonesia
GHG	Greenhouse Gas
GR	*Peraturan Pemerintah (*Government Regulation)
GRR	Grass Root Refinery
GS	Gross Split
HPP	*Harmonisasi Peraturan Pajak* (the Harmonisation of Tax Regulations)
HS	Harmonised System
IAS	International Accounting Standards
ICP	Indonesian Crude Price
IDR	Indonesian Rupiah
IFAS	Indonesian Financial Accounting Standards
IFRS	International Financial Reporting Standards
JETP	Just Energy Transition Partnership
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)
Km^2	Square Kilometre
LNG	Liquefied Natural Gas
LST	Luxury-goods Sales Tax

Term	Definition
MBOE	Thousand Barrels of Oil Equivalent
MBOEPD	Thousand Barrels of Oil Equivalent per Day
MBOPD	Thousand Barrels of Oil per Day
MIGAS	*Minyak Bumi dan Gas Alam* (Oil and Natural Gas)
MMBOE	Million Barrels of Oil Equivalent
MMBOPD	Million Barrels of Oil per Day
MMBtu	Million British thermal units
MMSCFD	Million standard cubic feet per day
MoEMR	Ministry of Energy and Mineral Resources
MoF	Ministry of Finance
MRV	Monitoring, Reporting, and Verification
MTPA	Million Tonnes Per Annum
NBV	Net Book Value
NJOP	*Nilai Jual Objek Pajak* (Tax Object Selling Value)
NPWP	*Nomor Pokok Wajib Pajak* (Tax Payer Identification Number)
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of Petroleum Exporting Countries
OSS	Online Single Submission
PBB	*Pajak Bumi dan Bangunan* (Land and Building Tax)
PBI	*Peraturan Bank Indonesia* (Bank Indonesia Regulation)
PCO	Parent Company Overhead
PE	Permanent Establishment
Perppu	*Peraturan Pemerintah Pengganti Undang-Undang*
Pertagas	PT Pertamina Gas
PGN	PT Perusahaan Gas Negara (State Gas Company)
PHR	PT Pertamina Hulu Rokan
PIS	Placed Into Service
PMA	*Penanaman Modal Asing* (Foreign Investment Company)
PMK	*Peraturan Menteri Keuangan Republik Indonesia* (Minister of Finance Regulation)
PoD	Plan of Development
PP&E	Property, Plant & Equipment
PSC	*Kontrak Kerja Sama* - KKS (Production Sharing Contract, one of the types of Joint Cooperation Contracts)
PSN	*Proyek Strategis Nasional* (National Strategic Projects)
PT	*Perseroan Terbatas* (Limited Liability Company)
PTK	*Pedoman Tata Kerja* (Standard Operating Procedure)
PwC	PwC Indonesia, or the PwC global network of firms, as the context requires
RDMP	Refinery Development Master Plan
RPT	Risk Participation Transaction
RPTKA	*Rencana Penggunaan Tenaga Kerja Asing* (Foreign Manpower Employment Plan)
RTO	Regional Tax Office
SA-VAT	Self-assessed VAT
SDA	*Sumber Daya Alam* (Natural Resources)

Term	Definition
SE	*Surat Edaran* (Circular Letter)
SFAS	Statement of Financial Accounting Standards
SKK Migas	*Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi* (Special Taskforce for Upstream Oil and Gas Business Activities)
SKB	*Surat Keterangan Bebas* (Tax Exemption Declaration Letter)
SKFP GS	*Surat Keterangan Fasilitas Perpajakan GS* (GS Tax Facilities Letter)
SKUP	*Surat Kemampuan Usaha Penunjang* (Supporting Business Capacity Certificate)
SOE	*Badan Usaha Milik Negara* - BUMN (State-Owned Enterprise)
SPOP	*Surat Pemberitahuan Objek Pajak* (Notification of PBB Objects)
SPPT	*Surat Pemberitahuan Pajak Terutang* (Official Tax Payable Notification)
SSP	*Surat Setoran Pajak* (Tax Payment Slip)
Tcf	Trillion Cubic Feet
TKDN	*Tingkat Komponen Dalam Negeri* (Local Content Level)
TPAA	Trustee Paying Agent Agreement
TWh	Terawatt hours
UK	United Kingdom
UoP	Units of Production
US	United States
USD	US Dollar
US GAAP	Generally Accepted Accounting Principles (in the United States)
VAT	Value Added Tax
WAP	Weighted Average Price
WHT	Withholding Tax
WP&B	Work Program & Budget

Foreword

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Welcome to the 13th edition of PwC Indonesia’s Oil and Gas in Indonesia—Investment, Taxation and Regulatory Guide. In recent years, we have witnessed a rapid transformation in the macroeconomic landscape, with sustainability taking centre-stage. However, this shift in focus presents a challenge, as many countries still heavily rely on fossil fuels for their energy needs and daily necessities, including petrochemical products. Recognising the need to balance sustainability with energy and petrochemical product demand, the investment climate for oil and gas has become even more crucial. In response, the Indonesian government has implemented alternative solutions, such as the establishment of a carbon credit market to promote emission offsetting. Additionally, there is a growing emphasis on carbon capture & storage (CCS) as a prominent solution, given Indonesia’s immense potential in this area. These initiatives align with the government’s broader focus on energy transition, aiming to strike a balance between energy demand and economic growth, and the country’s commitment to achieving net-zero emissions by 2060.

This edition of the guide focuses on updating readers on the latest tax, regulatory and commercial changes since our previous edition, with an additional focus on the energy transition in Indonesia.

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 of the Indonesian economy.

This publication is organised into chapters that encompass the following overarching subjects:

1. Industry overview;
2. Energy transition;
3. Regulatory framework;
4. (Conventional) upstream sector;
5. Gross Split Production Sharing Contracts;
6. Downstream sector; and
7. Service providers.

As the global energy landscape continues to evolve, Indonesia’s oil and gas industry finds itself at a critical juncture. The world’s shift towards a more sustainable and low-carbon future presents both risks and opportunities for the industry. Balancing the ongoing decline in oil and gas production with the need for more sustainable practices poses a key challenge that requires attention.

To tackle this challenge, SKK Migas has launched a comprehensive Indonesia Oil and Gas Strategic Plan, known as IOG 4.0. This ambitious initiative aims to achieve a production target of one million barrels of oil per day (BOPD) and twelve billion standard cubic feet of gas per day (Bscfd) by 2030. The plan is supported by low-carbon initiatives, including new regulations, energy management, zero flaring, reduction of fugitive emissions, reforestation, and the implementation of CCS and carbon capture, utilisation & storage (CCUS) technologies.

This guide also explores various aspects of the ongoing energy transition, starting from the evolving global energy landscape to the policy frameworks and regulatory measures that are shaping the future of the industry. It also delves into the potential of renewable energy sources, such as solar and wind, and their integration into the existing oil-and-gas infrastructure. Additionally, the guide emphasises the importance of energy efficiency and its role in reducing carbon emissions.

Another area highlighted in this guide is the development of CCS technologies. CCS has emerged as a promising solution for mitigating carbon emissions from fossil fuel-based industries, including oil and gas. By capturing CO_2 emissions and storing them underground, CCS can significantly reduce the industry's carbon footprint and contribute to global efforts to combat climate change.

The Government has shown its support for the implementation of CCS/CCUS activities, through the Ministry of Energy and Mineral Resources (MoEMR) Regulation No. 2/2023 issued in March 2023 and Presidential Regulation No. 14/2024 issued in January 2024. These regulations outline processes for project approval, monitoring, issued in January reporting, and verification. They also allow for carbon credit monetisation to fund these projects.

This publication aims to support investors in navigating the Indonesian oil and gas investment climate, and to support the growth of the industry. Readers should note that the regulatory content in this publication was current as at 31 January 2024. 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. For further guidance on investment opportunities in the Indonesian oil and gas sector, we recommend reaching out to PwC's oil and gas specialists (as listed in Appendix II).

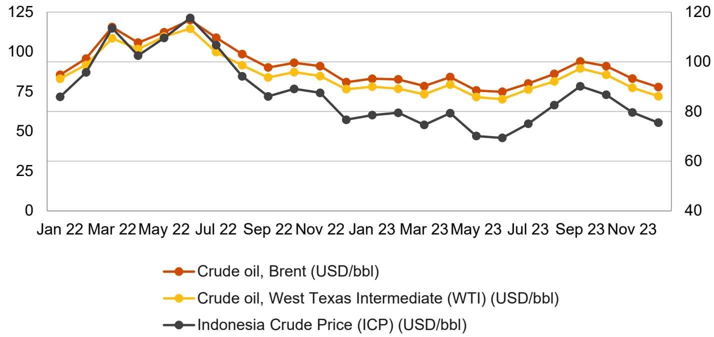
We hope that you find this publication interesting and useful, and we wish all readers success with their endeavours in the Indonesian oil and gas sector.

1 Industry overview

1.1 Global oil and gas overview

As global leaders push for lower carbon emissions and the adoption of new technologies, the oil and gas industry faces economic challenges and geopolitical tensions which have driven price volatility in recent years. The brent crude price averaged USD83 per barrel in 2023 down from USD101 per barrel in 2022. In summary, price volatility in 2023 was influenced by shifting economic growth expectations, tight monetary policies in advanced economies, and production cuts by OPEC+, while geopolitical concerns around the Russia-Ukraine and Middle East conflicts continued to play a part. A summary of oil prices throughout 2022 and 2023 is presented below[1].

Oil Prices 2022 and 2023



Source: MoEMR, World Bank, "Pink Commodity Sheet", 2023

Based on analyses by the International Energy Agency (IEA) and the US Energy Information Administration (EIA), the global oil supply and demand was expected to be around 101-102 million barrels per day (MMBOPD), with an overall excess supply, relatively higher in Q1 2023 compared to Q3 and early Q4 2023. In general, 45% of global oil demand was coming from the non-OECD countries with growth of 2.9 MMBOPD year-on-year. In more detail, the global oil demand growth was led by China (+1.8 MMBOPD) where the September consumption set another all-time record at 17.1 MMBOPD (the fifth in 2023 and fourth in a row, after earlier records in March, June, July and August), driven by China's gradual reopening from stringent COVID-19 measures, ongoing recovery in transportation activity and air travel in China started to recover as tourism picked up[2].

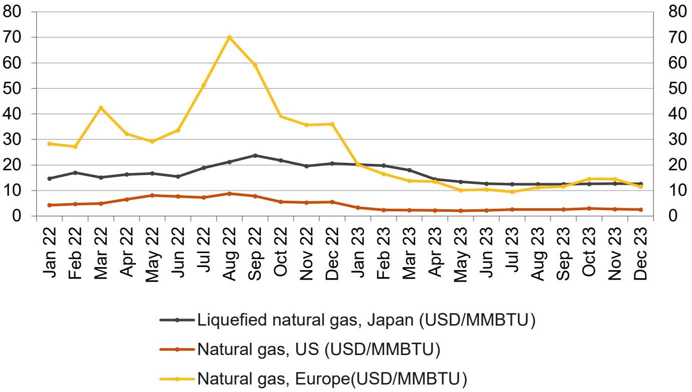
1 PwC Internal Analysis, World Bank, "October 2023 Commodity Markets Outlook: Under the Shadow of Political Risks", Commodity Markets Outlook, October, 2023.
2 World Bank,"April 2023 CMO: Lower Price, Little Relief," CMO, October, 2023.

On the other hand, there was an overall oil demand decline by 130 thousand barrels per day (MBOPD) year-on-year in the OECD, largely due to Europe's sharp deceleration, despite US oil demand rising by 220 MBOPD year-on-year to an average 20.5 MMBOPD for Q3 2023[3].

On the global oil supply side, OPEC+ members agreed to cut oil production by 1.2 MMBOPD until the end of 2023, which was in addition to production cuts already in place. This agreement meant production targets would be 3.66 MMBOPD lower each month relative to actual August 2022 production through the end of 2023[4]. Also, in February 2023, the EU and G7 implemented price caps on Russia's oil exports, alongside an embargo on Russian oil products. These measures aimed to maintain oil flows while reducing Russia's revenue, as its oil prices were significantly lower than Brent crude. Consequently, Russia's oil revenues dropped notably, prompting it to redirect oil to other markets. However, transportation constraints posed challenges to maintaining export volumes. Russia announced a 0.5 MMBOPD reduction in crude oil production from March to June 2023, potentially due to difficulties in exporting oil products[5].

Despite OPEC+'s announcement of a production cut in June, its impact on prices was limited as the reduction was offset by production increases from Iran and the US. While, additional cuts of 1 MMBOPD by Saudi Arabia since July and 0.3 MMBOPD by Russia since October further tightened the balance between supply and demand[6]. Moreover, concerns that the war between Israel and Hamas would escalate into a wider regional conflict, disrupting oil-supply flows, did not materialise. With no significant unforeseen outages, world oil supply was firmly on an upward trajectory, with October output increasing by 320 MBOPD month-on-month. Record output from the United States, Brazil, and Guyana underpinned last year's increase to a record 102 MMBOPD[7]. Production from the world's top three oil producers – the United States, Saudi Arabia and Russia in November 2023 were at 19.8 MMBOPD (roughly 1.2 MMBOPD higher than last year), 10.9 MMBOPD (OPEC+ cuts and sharp voluntary curbs have seen it shut in a massive 1.8 MMBOPD) and 10.9 MMBOPD (down 170 MBOPD year-on-year) respectively.

Gas Prices 2022 and 2023



Source: MoEMR, World Bank, "Pink Commodity Sheet", 2023

3 World Bank, "October 2023 CMO: Under the Shadow of Political Risks," CMO, October, 2023.
4 US Energy Information Administration (EIA), "What is OPEC+ and how is it different from OPEC?," 2023.
5 World Bank, "April 2023 CMO: Lower Price, Little Relief," CMO, April, 2023.
6 World Bank, "October 2023 CMO: Under the Shadow of Political Risks," CMO, October, 2023.
7 IEA, "Oil Market Report - November 2023," November, 2023.

On the other hand, gas prices were heavily affected by the conflict in the Middle East, resulting in increased volatility. In October 2023, European natural gas prices surged to USD 14.60/Million British Thermal Units (MMBTU) following the shutdown of a gas field off the Israeli coast, an explosion at an interconnector in the Baltic Sea, and concerns about escalating conflict in the region. The European benchmark, Netherlands Title Transfer Facility (TTF), continued its decline, reaching USD 11.50/MMBTU by December 2023.

The US benchmark (Henry Hub) also experienced volatility, rising to USD 3.30/MMBTU in January 2023, then dropping to roughly USD 2.20/MMBTU by September 2023. Meanwhile, Japan's Liquefied Natural Gas (LNG) fell to USD 14.40/MMBTU in April 2023 and continued its decline, reaching USD 12.60/MMBTU by December 2023 (see the Gas Prices chart above)[8].

Global gas demand grew by an estimated 20 Billion cubic metres (Bcm) in 2023, but it was not enough to fully recover the losses experienced in 2022, when overall demand had dropped by 60 Bcm. However, global gas demand did return to grow in the second half of 2023, primarily driven by North America and the fast-growing markets of Asia, the Middle East, and Africa, including China's increasing industrial and power sectors by approximately 26 Bcm[9].

Following the gas-supply shock of 2022, natural gas markets gradually rebalanced in 2023 due to timely policy action, market forces, and favourable weather conditions. Despite this, the market remained tight on the supply side. Gas supplies stayed constrained as the increase in global LNG production (up by 13 Bcm) failed to offset the continued decline in Russian piped gas deliveries to Europe (down by 38 Bcm). LNG production growth fell short of previous expectations due to a mix of project delays and feed gas supply issues. Notably, the US contributed 80% of the additional LNG supply and emerged as the world's largest LNG exporter[10].

Meanwhile Russia's gas output declined by a further 8%, after decreasing by 12% in 2022, as increased exports to China and Central Asia did not fully compensate for the drop in pipeline exports to European Union (EU) countries[11]. The decrease in gas supply from Russia was broadly offset by increases in most other regions, particularly in the US, where overall production increased by 5% year-on-year. In the US, gas exports rose to reach 350.1 billion cubic feet (Bcf), with approximately two-thirds of the flows directed to Europe (around 226 Bcf)[12].

Natural gas serves as a transitional energy source in two ways: as a cleaner alternative to more polluting fuels and as a reliable backup for intermittent renewables. A United Nations (UN) study indicates that natural gas has helped renewables by replacing coal and stabilising intermittent energy sources. This is likely to require more long-term investment in gas as renewables become cheaper than coal in much of the United Nations Economic Commission for Europe (UNECE) region. This vulnerability of coal, due to higher carbon emissions and increasing costs, creates opportunities for gas to displace coal, but success depends on factors like cost reductions in renewable energy, technological advancements, and adoption by governments and companies[13].

8 World Bank, "October 2023 Commodity Markets Outlook (CMO): Under the Shadow of Political Risks," Commodity Markets Outlook, October, 2023.
9 IEA (International Energy Agency). "Gas Market Report Q1 2024," January, 2024.
10 IEA (International Energy Agency). "Gas Market Report Q1 2024," January, 2024.
11 World Bank, "October 2023 CMO: Under the Shadow of Political Risks," CMO, October, 2023.
12 World Bank, "October 2023 CMO: Under the Shadow of Political Risks," CMO, October, 2023.
13 "How Natural Gas Can Displace Competing Fuels," UNECE, 2019.

While natural gas emits fewer greenhouse gases than coal, investing in it may divert resources from renewable alternatives, posing long-term challenges to achieving climate goals[14].

The year 2023 also marked a notable moment in the commitment to decarbonisation by the global oil and gas sector. At the 28th United Nations Climate Change Conference (COP28) in Dubai, a historic step towards decarbonisation was taken as National Oil Companies (NOCs) initiated the Oil and Gas Decarbonisation Charter (OGDC). Spearheaded by the COP28 Presidency and Saudi Arabia, this global industry Charter aims to accelerate climate action and achieve significant impact within the oil and gas sectors. Signatory companies, representing over 40% of global oil production, include NOCs accounting for over 60% of the signatories, marking the largest-ever commitment by NOCs to decarbonisation[15]. At the summit, nearly every country agreed to transition away from fossil fuels, marking a landmark agreement after 28 years of international climate negotiations[16]. The power, utility, and energy industry faces a transformative opportunity to shape its cleaner energy future while contributing to broader societal goals. Industry leaders can lead the way in transitioning to cleaner energy by setting net-zero goals and embracing initiatives focused on Environmental, Social, and Governance (ESG) factors. This journey involves driving efficiency in energy use as well as balancing reliability with the intermittency of renewables, embracing innovation while ensuring safety, and managing geopolitical dynamics, all of which are critical aspects. Additionally, retaining skilled workers, keeping costs down, and strategically reinventing business models will be essential for continued relevance in the evolving energy economy[17].

1.2 Indonesian context

Indonesia's rich history in oil and gas, dating back over 130 years, includes a significant legacy since its first discovery in North Sumatra in 1885. In 1912, the inaugural exploration was conducted in South Sumatra, leading to the discovery of the Talang Akar Field, which stood as the largest field before World War II (in 1921). By 1961, the Government signed its first Production Sharing Contract (PSC) in Aceh and Indonesia had become a member of OPEC. However, a prolonged period of declining production prompted Indonesia to suspend its OPEC membership in 2009, rejoining in January 2016 and suspending membership again in November 2016.

In July 2020, the Indonesian Government made a significant policy change, giving investors the choice between the old cost-recovery PSC scheme and the Gross Split (GS) system under MoEMR Regulation No. 12/2020. This sparked more interest in Indonesian blocks. As of 2021, 17 contractors were actively operating under the GS PSC system, marking a noteworthy development in the country's oil and gas landscape. The auction of oil and gas working areas resumed after a pause during the COVID-19 pandemic in 2021. Noteworthy tendered areas included South Coastal Plain and Pekanbaru (CPP), Sumbagsel (South Sumatera), Rangkas, Liman, Merangin III, and North Kangean, encompassing both direct-tender and regular-tender mechanisms. Furthermore, the Rokan PSC, managed by PT Chevron Pacific Indonesia, transitioned to PT Pertamina Hulu Rokan (PHR) in August 2021.

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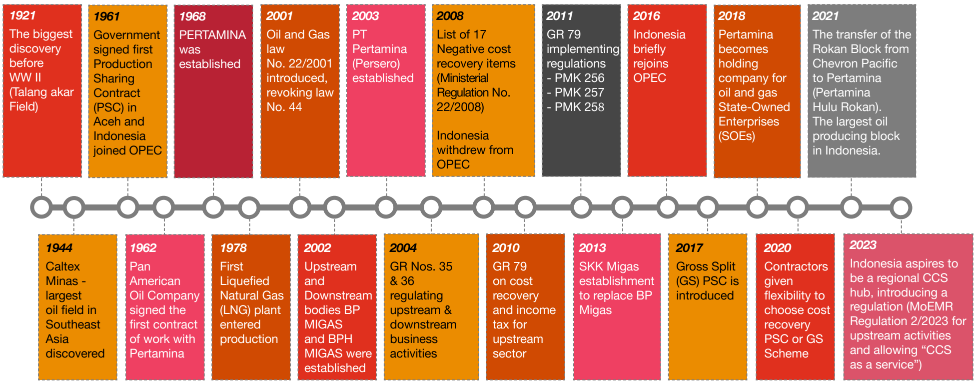
14 C. Gürsan and V. de Gooyert, "The Systemic Impact of a Transition Fuel: Does Natural Gas Help or Hinder the Energy Transition?," Renewable and Sustainable Energy Reviews 138 (March 2021): 110552.
15 "Oil & Gas Decarbonization Charter launched to accelerate climate action," COP28, December, 2023.
16 "COP28: Key Outcomes Agreed at the UN Climate Talks in Dubai," Carbon Brief, January, 2024,
17 PwC, "Fueling Our Future: The Industry's Role in the Transition to Clean and Renewable Energy," PwC, accessed 2024.

On 2 November 2020, Law No. 11/2020 on Job Creation (“Law No. 11/2020”) was promulgated, which amended several provisions of Law No. 3/2020. On 30 December 2022, the Government issued Government Regulation in lieu of Law No. 2 of 2022 regarding Job Creation (“Perppu No. 2/2022”), which revoked Law No. 11/2020 and also amended several provisions of Law No. 3/2020. On 31 March 2023, the Government enacted Law No. 6 of 2023 regarding the stipulation of Perppu No. 2/2022 into Law (“Law No. 6/2023”). Amendments and replacements were made among others, regarding improvements to the investment ecosystem and business activities, employment, ease of doing business, encouragement to research and innovation, land acquisition, and economic zones. With the enactment of Law No. 6/2023, it was confirmed that Law No. 11/2020 has been revoked and is no longer valid.

Significant events in the history of Indonesia’s oil and gas sector



Despite Indonesia’s status as a net oil importer, Indonesia is still a prominent global player in natural-gas production and LNG. Indonesia’s gas lifting in 2023 managed to reach 6,688 MMSCFD, and ranked 14th in terms of global gas production, with a total volume of 59.9 Bcm (equivalent to 2.11 Tcf)[18].

Moreover, significant projects like the Abadi LNG project are progressing towards development, with the operator, Inpex, recently submitting an updated development plan integrating CCS. Later in December 2023, Inpex received approval from the MoEMR for the revised plan of development (PoD) for the Masela Block[19].

Throughout 2023, an additional 13 contract areas were signed. Currently there are 170 working areas in Indonesia (refer to Table 1.4 - Key Indicators - Indonesia’s oil and gas industry)[20]. The upstream oil and gas industry in Indonesia has also made history with significant discoveries of natural-gas potential. These discoveries were Layaran-1 in the South Andaman Block (6 Trillion cubic feet (Tcf)) and Geng North-1 in the North Ganal Block (5 Tcf). Pertamina also discovered two new sources last year, namely East Akasia Cinta (EAC-001) in the PEP Jatibarang Field area, Indramayu Regency, and East Pondok Aren-1 (EPN-001) with a stratigraphic trap in a mature Tambun Field[21].

18 Energy Institute,” Statistical Review of World Energy 2023”, 2023.
19 INPEX, “INPEX Submits Revised Plan of Development for Abadi LNG Project, Masela Block, Indonesia”, INPEX, 2023; INPEX, “INPEX Receives Approval for Revised Plan of Development for Abadi LNG Project, Masela Block, Indonesia”, INPEX, 2023.
20 MoEMR, “Kejar Produksi Migas, Kementerian ESDM Teken 13 WK Migas Sepanjang 2023,” 2024.
21 Pertamina, “Pertamina Temukan 2 Sumber Migas Baru di Jawa Barat”, 2023.

In early 2023, Indonesia's oil and gas sector achieved key milestones, including the approval of strategic development plans for important blocks. On 2 January 2023, Premier Oil Tuna BV, the contractor for the Tuna Field in the Tuna Working Area (WK), received the green light[22]. Shortly after, on 10 January 2023, Petronas Carigali North Madura II Ltd. secured PoD approval for the Hidayah Field in the North Madura II Working Area[23]. The first quarter of 2023 also saw additional PoD approvals for the Asap, Kido, and Merah (AKM) Fields in the Kasuri Block, West Papua, under the operation of Genting Oil Kasuri Pte Ltd. The approval for the AKM project was carried out during the inauguration of the national strategic project (PSN) Jambaran Tiung Biru (JBT) and the MDA and MBH Gas Field Project in East Java[24].

By mid-2023, the Special Task Force for Upstream Oil and Gas Business (SKK Migas) addressed a gas oversupply issue in East Java. Recently, SKK Migas agreed to reduce the peak gas production in the East Java region to anticipate the projected oversupply, estimated to reach 200 MMSCFD from 2024 to 2026[25].

In November 2023, Tangguh Train 3 was inaugurated, boosting the country's LNG production pipeline. Operated by BP Berau Ltd., the Tangguh Train 3 project was constructed at a reported cost of USD4.83 billion[26].

In December 2023, the MoEMR approved contract amendments for PT Medco Energi Internasional Tbk's Corridor Block, transitioning from a gross split PSC to a cost recovery model. The MoEMR also granted approval for new gas allocations and prices from Corridor to several buyers including PT Perusahaan Gas Negara Tbk (PGN), with the gas sales agreements set to be signed soon. The current daily gas deliveries from the Corridor Block amount to 700 MMBTU/day, with a majority (83%) sold domestically and 17% exported to Singapore. The request for a shift to a cost recovery PSC had been in process since ConocoPhillips was the operator. Other fields, including those operated by PT Pertamina Hulu Energi, are seeking the Minister's discretion for contract transition[27].

22 SKK Migas, "Dukung Penegasan Kedaulatan, Pemerintah Setujui POD Pertama Lapangan Tuna", 2023.
23 SKK Migas, "Pemerintah Setujui POD Pertama Lapangan Hidayah", 2023.
24 SKK Migas, "Presiden Resmikan Proyek Tangguh Train 3 dan Ground Breaking Proyek UCC, AKM dan Blue Amonia di Papua Barat," 2023.
25 SKK Migas, Produksi Minyak Jawa Timur 2023 Capai 106 Persen, Lampaui Target Pemerintah," 2023.
26 SKK Migas, "Presiden Resmikan Proyek Tangguh Train 3 dan Ground Breaking Proyek UCC, AKM dan Blue Amonia di Papua.
27 MedcoEnergi, "Pemerintah Setujui Amendemen PSC Blok Corridor", 2023.

In 2024, SKK Migas identified 15 upstream oil and gas projects that will begin operations in 2024, including CNG initiatives.

Table 1.1 - List of oil and gas projects for 2024

Gas Projects					
No	Name	Production Capacity (MMSCFD)	Company	Onstream	Cost (USD)
1	West Belut	50	Medco Natuna	August 2024	84,045,295
2	Dayung Facility Optimisation	40	Medco Grissik	July 2024	12,781,045
3	Compressor Facility South Sembakung	22.5	JOB PMEP Simenggaris	May 2024	12,781,045
4	Peciko 8B	16	Pertamina Hulu Mahakam	March 2024	29,496,786
5	Bekapai Artificial Lift	12	Pertamina Hulu Mahakam	March 2024	17,553,051
6	SWPG Debottlenecking	8	Pertamina Hulu Mahakam	March 2024	4,587,248
7	Akatara Gas Plant	25	Jadestone Energy	April 2024	86,327,705
8	Merbau Compressor	8	Pertamina EP	November 2024	10,565,948
9	Karang Baru Field	5	Pertamina EP	April 2024	7,805,008
Oil Projects					
No	Name	Production Capacity (MMBOPD)	Company	Onstream	Cost (USD)
1	SP Puspa Asri	0.6	Pertamina EP	October 2024	6,399,708
2	Flowline ASDJ-116X	0.094	PHE Ogan Kemering	April 2024	10,222,836
3	OPL E-Main	0.128	PHE ONWJ	June 2024	3,555,980

Source: SKK Migas, "Press Conference - Upstream Oil and Gas Performance Achievements of Year 2023 and Targets 2024", Broadcast January 2024 on Youtube, SKK Migas, 2024

Table 1.2 - List of oil and gas projects for 2023 which carry forward for 2024

Gas Projects				
No	Name	Production Capacity (MMSCFD)	Company	Onstream
1	AFCP	117	Premier Oil	May 2024
2	Mako	120	West Natuna Exploration Ltd.	Q4 2025
Oil Projects				
No	Name	Production Capacity (MMBOPD)	Company	Onstream
1	Forel Bronang	10	Medco Natuna	June 2024
2	Banyu Urip Infill Clastic	30	ExxonMobil Cepu Ltd.	July 2024
3	Hidayah	25.276	Petronas Carigali Madura II Ltd.	Q1 2027

Source: SKK Migas, "Press Conference - Upstream Oil and Gas Performance Achievements of Year 2023 and Targets 2024", Broadcast January 2024 on Youtube, SKK Migas, 2024

Table 1.3 - List of Compressed Natural Gas (CNG) initiatives of 2024

No	Name	Production Capacity	Company
1	CNG Mother Station Grobokan	1.8 MMSCFD	PT Energasindo Heksa Karya (EHK)
2	Biomethane CNG (Bio-CNG)	387,000 cubic metres	PT United Kingdom Indonesia Plantation (AEP Group)

Source: PT Rukun Raharja, "PT Rukun Raharja, Tbk (RAJA) Subsidiary Inaugurates New Compressed Natural Gas (CNG) Mother Station in Grobogan, Central Java", 2024; Denis Meilanova, "Pabrik Bio-CNG Komersial Pertama di Indonesia Resmi Beroperasi", 2024

Indonesia aims to become a regional hub for CCS by implementing MoEMR Regulation 2/2023, encompassing cooperation in upstream oil and gas activities, introducing a "CCS as a service" business model and potential multi-user CCS hubs, pending further implementing regulations. The framework outlines procedures for the capture, utilisation, and storage of carbon emissions, including specific requirements for contractors, monitoring, and closure of CCS activities. Economically, it addresses treating CCS costs as operational expenses, exploring monetisation through carbon trading or reimbursement, and underscores the importance of downstream business entities holding specific licences for monetising injection and storage services. A preliminary analysis on the impact to the regulations and processes within the oil and gas industry as well as the relevant Presidential Regulation 14/2024 are discussed further in Chapter 3.

1.3 Resources, reserves and production

Out of 128 basins across Indonesia, 20 have entered to production stage, 8 have been drilled but not yet entered production, 19 basins indicated hydrocarbons, and 13 basins were dry holes, while 68 basins have not been explored[28]. Approximately 75% of exploration and production activities are in Western Indonesia. In summary, there are 4 oil-producing regions, which are Sumatra, the Java Sea, East Kalimantan and Natuna, and 6 main gas-producing regions: East Kalimantan, South Sumatra, Aceh, North Sumatra, South Natuna Sea and West Papua.

In 2023, notable upstream activities in Indonesia included drilling 38 exploration wells, making 14 discoveries, with 12 wells still ongoing[29]. Indonesia saw the addition of several resources in 2023, including the four carried over PSNs from 2022, the Abadi Masela Project in the Arafura Sea, Maluku, the Tangguh Train-3 Project in Bintuni, West Papua, the Jambaran Tiung Biru Project in Bojonegoro, East Java, and the Indonesia Deepwater Development (IDD) Project in the Makassar Straits, East Kalimantan[30].

Inpex Masela Ltd., the operator of the Abadi Project, aims to onstream production by 2030. The estimated investment costs for the LNG Abadi project in the Masela Block total USD20,946 million (not including sunk costs)[31]. Inpex's timeline includes initiating front-end engineering and design in 2024, site preparation in 2025, and drilling preparation in 2026. The Masela Block contract, with a 30-year term and a recent 20-year extension, is set to conclude on 15 November 2055. Current participating interest (PI) holders include Inpex Masela Ltd (65%), PT Pertamina Hulu Energi Masela (20%), and Petronas Masela Sdn. Bhd (15%). The Abadi Masela project is targeted to come onstream in 2030[32].

The IDD Project operator aimed to finalise the transfer of PI and operatorship by the first quarter of 2023[33]. On 25 July 2023, the Eni Group, officially acquired Chevron's 62% interest, becoming the operator of the IDD Phase II project. The IDD project has a production capacity of 844 MMSCFD for natural gas and 27,000 BOPD for crude oil. The project is considered crucial for Indonesia's goal of boosting gas production to 12,000 MMSCFD by 2030[34].

28 MoEMR, "20 Cekungan Migas Indonesia Simpan Potensi Besar Penyimpanan Karbon", 2023.
29 SKK Migas, "Press Conference - Upstream Oil and Gas Performance Achievements of Year 2023 and Targets 2024", Broadcast January 2024 on Youtube, SKK Migas, 2024.
30 SKK Migas, "Press Conference - Upstream Oil and Gas Performance Achievements of Year 2023 and Targets 2024", Broadcast January 2024 on Youtube, SKK Migas, 2024.
31 MoEMR, "Pengembangan Blok Masela Dukung Ketahanan Energi Nasional dan Pencapaian NZE", 2023.
32 MoEMR, "Pengembangan Blok Masela Dukung Ketahanan Energi Nasional dan Pencapaian NZE", 2023.
33 SKK Migas, SKK Migas Annual Report 2022, 2022.
34 Eni, "Eni acquires Chevron's Assets in Indonesia," 2023.

Tangguh Train-3, came online in 2023, elevating Tangguh LNG's annual production capacity to 11.4 million tonnes and significantly contributing to the 2030 gas production target[35]. The Tangguh Train-3 project, an extension of the Train-1 and Train-2 projects, is designed to allocate approximately 75% of its LNG volume to satisfy the domestic electricity sector's requirements. A durable commitment from SKK Migas and BP (Berau) Ltd. is demonstrated through a long-term contract with PT PLN (Persero) for an annual volume of 60 cargoes, underscoring their commitment to prioritising domestic energy needs[36].

Additionally, the government is expediting several upstream oil and gas projects in Papua, including the completion of Tangguh Train 3, with three additional projects underway: CCUS Ubadari project, Blue Ammonia downstream project, and the Asap Kido Merah gas field. The Ubadari CCUS project (UCC) is a crucial component of Tangguh's expansion and aims to establish Indonesia's first CCS Hub, injecting around 30 million tonnes of CO_2 by 2035[37]. The UCC is part of the PSN for 2023, with an anticipated peak production capacity of 476 MMSCFD and a CCS capacity of 1.8 gigatonnes. The integrated project is projected to require an investment of approximately USD3.84 billion[38]. Moving forward, the next project in the pipeline involves the downstream processing of natural gas into low carbon ammonia. With a planned production of 875 thousand tonnes per annum of Blue Ammonia, this product will find applications in co-firing at power plants and in steel factories[39].

In 2023, Indonesia made two significant discoveries, i.e. Geng North and Layaran. Eni unveiled the Geng North discovery on 2 October 2023, marking a noteworthy find in deep waters. Geng North-1 was drilled to a depth of 5,025 metres, revealing a 50-metre gas column in Miocene sandstone. Preliminary estimates for Geng North indicated a total gas volume of 5 Tcf with up to 400 million barrels of condensate. This discovery was located adjacent to the IDD area, which includes several untapped discoveries in the Rapak and Ganal PSC blocks. Eni recently acquired Chevron's interests in these blocks, increasing its ownership and assuming operatorship. Combining these areas was expected to offer significant benefits for gas development opportunities[40].

SKK Migas and Mubadala Energy jointly announced a significant gas discovery in the Layaran-1 Exploration Well in the South Andaman Block, situated approximately 100 kilometres off the northern coast of Sumatra. The well, drilled to a depth of 4,208 metres in 1,207 metres of water depth, revealed an extensive gas column exceeding 230 metres in the Oligocene sandstone reservoir. Comprehensive data acquisition, including wireline, coring, sampling, and Drill Stem Test (DST), has been successfully completed. The well demonstrated the flow of high-quality gas at a rate of 30 MMSCFD[41].

35 SKK Migas, "Presiden Resmikan Proyek Tangguh Train 3 dan Groundbreaking Proyek UCC, AKM dan Blue Amonia di Papua Barat," 2023.
36 SKK Migas, SKK Migas Annual Report 2022, 2022.
37 SKK Migas, "Presiden Resmikan Proyek Tangguh Train 3 dan Groundbreaking Proyek UCC, AKM dan Blue Amonia di Papua Barat," 2023.
38 SKK Migas, "Press Conference - Upstream Oil and Gas Performance Achievements of Year 2023 and Targets 2024", Broadcast January 2024 on Youtube, SKK Migas, 2024.
39 SKK Migas, "Presiden Resmikan Proyek Tangguh Train 3 dan Groundbreaking Proyek UCC, AKM dan Blue Amonia di Papua Barat," 2023.
40 Eni, "Eni announces a significant gas discovery in the Kutei Basin in Indonesia," 2023.
41 SKK Migas, "SKK Migas dan Mubadala Energy Mengumumkan Penemuan Gas Besar di South Andaman, Indonesia", 2023.

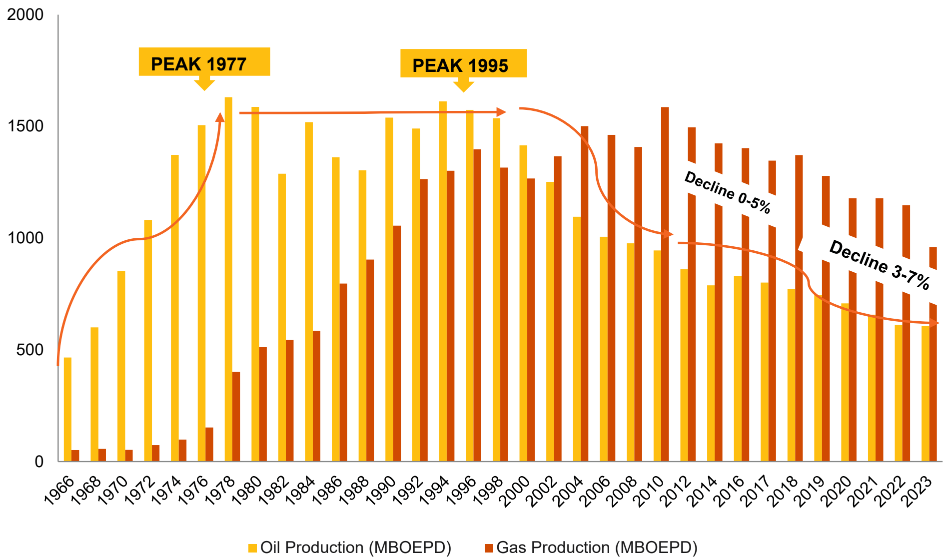
Another important project is the AKM gas field, which is a component of the 2023 PSN[42] and is under the operation of Genting Oil Kasuri Pte Ltd, as noted above. AKM is anticipated to have a daily gas in place of 2,673.7 BSCFD, while the potential reserves are estimated at 2,244.45 billion standard cubic feet[43]. The estimated production is 330 MMSCFD, with an investment of USD3.37 billion, and the project is expected to be onstream by Q4 2025[44].

SKK Migas has proposed two oil and gas projects, namely the North Ganal project (Geng North) in East Kalimantan and AKM project in Teluk Bintuni, West Papua, to be designated as national strategic projects (PSN)[45].

In terms of reserves, Indonesia, holding substantial reserves from west to east, reported 2.27 million stock tank barrels (MMSTB) for oil and 36.34 Tscf for natural gas in 2022[46]. While in 2023, MoEMR reported oil proven reserves reached 2.41 MMBOPD, while proven reserves of gas reached 35.3 TCF[47].

SKK Migas reported a successful increase in reserves by 599.08 million barrels of oil equivalent (MMBOE) and a 104.5% Reserves Replacement Ratio (RRR) up to November 2023 and updated the RRR to 123.5% throughout 2023. This achievement stems from 33 approved plans of development, with a commitment of around USD 10.769 billion[48]. There were 40 development plan proposals in 2023 accounting for an overall potential increase in oil and gas reserves of about 788.29 MMBOE[49].

Indonesian oil and gas production profile



Source: SKK Migas Annual Report 2022; MoEMR, "Kinerja Sektor ESDM 2023: Perluas Akses Energi, Prioritaskan Kebutuhan Domestik, Dan Jaga Daya Saing Lewat Transisi Energi", 2023.

42 SKK Migas, "Press Conference - Upstream Oil and Gas Performance Achievements of Year 2023 and Targets 2024", Broadcast January 2024 on Youtube, SKK Migas, 2024.
43 SKK Migas, "Presiden Resmikan Proyek Tangguh Train 3 dan Groundbreaking Proyek UCC, AKM dan Blue Amonia di Papua Barat," 2023.
44 SKK Migas, "Press Conference - Upstream Oil and Gas Performance Achievements of Year 2023 and Targets 2024", Broadcast January 2024 on Youtube, SKK Migas, 2024.
45 Aditya Perdana, "Proyek Strategis Nasional Gas Bumi Bisa Bantu Pembangunan IKN", 2023.
46 SKK Migas, SKK Migas Annual Report 2022, 2023.
47 MoEMR, "Peluang Investasi Migas Indonesia Masih Menjanjikan", 2023.
48 SKK Migas, "SKK Migas Berhasil Tambah Cadangan 599,08 MMBOE Dan Capaian RRR 104,5%", 2023.
49 SKK Migas, "SKK Migas Minta Pimpinan KKKS Berkomitmen Laksanakan Program Kerja 2024", 2024.

As Indonesia's oil and gas fields matured over the last two decades with no significant new reserves found, managing the natural decline in production has posed an increasing challenge. In 2022, the realisation of oil lifting was 612 MBOPD, accounting for 87.1% of the target, while gas production reached 6,490 MMSCFD, exceeding the target at 110%. In 2023, oil lifting reached 606 MBOPD, slightly below the target of 660 MBOPD (refer to Table 1.4 - Key Indicators - Indonesia's oil and gas industry below). Moreover, Pertamina also succeeded in increasing oil lifting through the Rokan Block, which contributes 26.8% of national production and operates under the Gross Split model for 20 years, achieving a level of oil and gas lifting of over 59 million barrels in 2023. This marked an increase of 1.7 million barrels compared to the previous achievement of 57.3 million barrels in 2022[50].

Meanwhile, Indonesia's gas lifting in 2023 managed to reach 6,688 MMSCFD, surpassing the target of 6,160 MMSCFD. Indonesia managed to rank 14th, the same rank as 2022 in terms of global gas production, with a total volume of 59.9 Bcm (equivalent to 2.11 Tcf). At the same time, in terms of global consumption, Indonesia ranked 26th with a total volume of 38.78 Bcm (equivalent to 1.34 Tcf). In terms of reserves, Indonesia was still ranked 26th globally (with proved reserves of 44.2 Tcf) and fourth in the Asia Pacific region (behind China, Australia, and India), according to BP's Statistical Review of World Energy (refer to the figure Share World of Gas 2023 - Rank Based on 2023 Production[51]).

Table 1.4

Key indicators - Indonesia's oil and gas industry

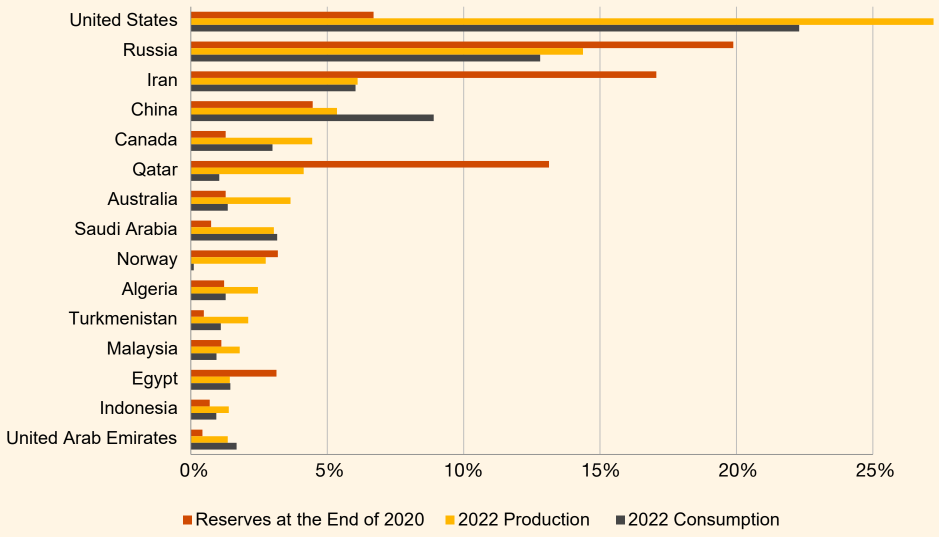
Indicator	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Reserves												
Oil (Million Barrels)	7,410	7,550	7,370	7,305	7,251	7,535	7,512	3,770	4,170	3,950	4,171	4,703
Proven	3,740	3,690	3,620	3,603	3,307	3,171	3,154	2,480	2,440	2,245	2,271	2,413
Potential	3,670	3,860	3,750	3,702	3,944	4,364	4,358	1,290	1,730	1,700	1,900	2,290
Gas (Tcf)	150.70	150.39	149.30	151.33	144.80	143.70	135.55	77.29	62.39	60.61	54.83	54.76
Proven	103.35	101.54	100.26	97.99	102.00	101.40	96.06	49.74	43.57	41.62	36.34	35.30
Potential	47.35	48.85	49.04	53.34	42.80	42.30	39.49	27.55	18.82	18.99	18.49	19.46
Production												
Crude oil (MBOPD)	918	825	789	786	831	804	772	745	708	659	612	606
Natural gas (MMSCFD)	8,149	8,130	8,218	8,078	7,938	7,620	7,764	7,235	6,665	6,662	6,490	6,688
New contracts signed	39	14	7	12	2	0	11	6	0	2	5	13

Source:
Reserves of oil and gas are obtained from DGOG, MoEMR
2012-2023 Crude Oil Production: Perfomance Report Directorate of Oil and Gas 2023
2012 - 2022 Gas Production: SKK Migas Annual Report 2022
2023 Gas Production: SKK Migas Site
New Contracts Signed 2021: MoEMR, Statistik Migas 2021
New Contracts Signed 2022: MoEMR, Statistik Migas 2022
New Contracts Signed 2023: Press Conference - Performance of the Energy and Mineral Resources Sector in 2023

50 "Jadi Produsen Minyak Terbesar Di Indonesia, Lifting PHR Tembus 59 Juta Barel Selama 2023," Energia, 2024.
51 Production & Consumption: BMI (Fitch Solution), "BMI Data Tools - Production & Consumption", 2024; Reserves: The Energy Institute, "Statistical Review of World Energy 2023," 2023.

To pursue the lifting target, SKK Migas, together with the PSC contractors in the upstream oil and gas sector, undertook various efforts to boost production. One of them was completing the construction of several oil and gas projects. For instance, the Jambaran Tiung Biru gas field. Furthermore, it also optimised oil and gas fields that could provide additional condensate. One of them was the development of Tangguh Train-3, which is now in operation and capable of producing LNG[52].

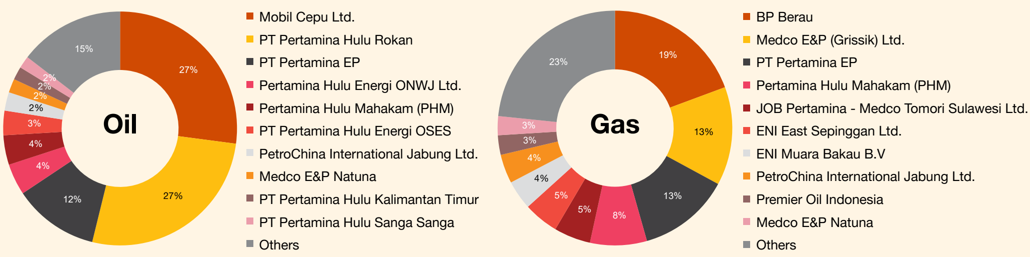
Share of World Gas 2023 - Rank Based on 2023 Production



Source: Production & Consumption : BMI (Fitch Solution), BMI Data Tools - Production & Consumption, 2024; Reserves: The Energy Institute, Statistical Review of World Energy 2023 2023, PwC Internal Analysis

Pertamina entities contributed roughly 50% of Indonesia's oil and gas production (see the pie chart below). The major crude oil and natural gas producers (as PSC operators) as of 2023 were as follows:

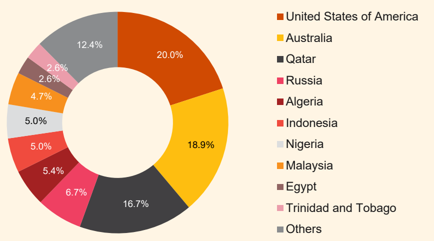
Indonesia's Major oil and gas producers 2023



Source: SKK, "Lifting Minyak & Kondensat 15 KKS Besar", 2023;SKK, "STATISTIK MIGAS 2022", 2023

52 Dwitri Waluyo, "Mengejar Target Produksi Minyak Bumi," Indonesia.go.id, 2023.

World's top LNG exporters 2023



Source: Global Energy Monitor (GEM), 2023

Indonesia's relevance in seaborne LNG is critical to maintain its reserves and production level. Indonesia managed to maintain its position as the sixth largest exporter of LNG in 2023, with a capacity of 23.3 million tonnes per annum (MMTPA), behind the US, Australia, Qatar, Russia and Algeria (Figure World's Top LNG Exporters 2023). Indonesia's LNG liquefaction and regasification capacities are presented below.

Table 1.5 - List of Indonesian LNG liquefaction terminals

Location	Project	Capacity (MMTPA) 2023	Operator
East Kalimantan	Bontang	22.5	PT Badak LNG
West Papua	Tangguh	11.4	BP Tangguh
Central Sulawesi	Donggi Senoro	2	PT Donggi Senoro LNG
Maluku	Abadi LNG	9.5 (planned)	Inpex
South Sulawesi	Sengkang	2 (planned)	PT Energi Sengkang

Table 1.6 - List of Indonesian LNG regasification terminals

Location	Project	Capacity (MMSCFD) 2023	Operator
West Java	Nusantara Regas Satu	500	PT Nusantara Regas
North Sumatera	Arun Regas	405	PT Perta Arun Gas
South Sumatera	Lampung LNG	240	PT PGN LNG
Bali	Tanjung Benoa LNG	50	PT Pelindo Energi Logistik
West Java	Jawa-1	300	PT Jawa Satu Power
North Sulawesi	Sulawesi Regas Satu	24	PT Sulawesi Regas Satu

There was a gradual recovery in upstream activities in 2022, and this positive trend continued to gain momentum in 2023. Exploration activities also showed an upward trajectory, increasing from 30 to 38 wells in 2022. In 2023, Indonesia achieved the highest number of wells drilled since 2017, 38 wells.

In addition, more development wells were developed in 2023, from 260 to 799 wells. The Full Tensor Gravity (FTG) Survey hit 2023's target 129,305 square kilometres (Km^2). The Tensor Gravity Survey was first introduced in 2021, with the realisation at 101,920 Km^2. Although more exploration wells were drilled and surveys showed positive result, there was a setback in 3D Seismic operations. The survey declined from 3,790 to 1,432 Km^2 in 2023. The exploration and exploitation activities in 2023 are constrained by well drilling for development due to safety stand down, rig availability, labour force, and flooding at the location[53].

Table 1.7

Key indicators - Indonesia's oil and gas industry exploration activities

		2022 Realisation	2023 Target	2023 Realisation	% 2023 vs 2022	% of 2023 Target
2D Seismic	Km	1,950	934	25	1.3%	3%
Survey Full Tensor Gravity Gradiometry (FTG)	Km^2	18,814	129,305	129,305	687%	100%
3D Seismic	Km^2	3,790	2,282	1,432	38%	63%
Development Wells	Wells	760	919	799	105%	87%
Exploration Wells Drilling	Wells	30	57	38	127%	67%
Workover Wells	Wells	639	834	834	131%	100%
Well Service Activity	Activity	30,229	33,182	33,412	110.5%	101%

Source: SKK Migas, "Press Conference - Upstream Oil and Gas Performance Achievements of Year 2023 and Targets 2024", Broadcast January 2024 on Youtube, SKK Migas, 2024.

In response to increasing energy demands, Indonesia developed the Long-Term Plan (LTP) Target for 2030. The goal was to achieve a production level of 1 MMBPOD and 12 BSCFD by 2030, requiring increased investment and collaboration among stakeholders. SKK Migas then developed the Indonesia Oil & Gas (IOG) 4.0 strategic plan to enhance production, national capabilities, sustainability, and environmental continuity through various initiatives.

One notable IOG initiative focused on the transformation from resources to production. As part of this strategy, the drilling of the Gulamo exploration well for Unconventional Oil (NUO) commenced in the Rokan Block managed by PHR. Additionally, the MoEMR announced plans for a second NUO Exploration Well in the Rokan Block, named the Kelok Well, slated for November 2023. The potential of these two wells alone is estimated to be at least 80 million barrels of oil, while the oil potential in place in the Rokan Block itself is about 1.26 billion barrels[54].

53 SKK Migas, "Press Conference - Upstream Oil and Gas Performance Achievements of Year 2023 and Targets 2024", Broadcast January 2024 on Youtube, SKK Migas, 2024.
54 MoEMR, "Pengeboran Sumur MNK di Rokan Jadi Showcase Investor Migas Dunia", 2023.

Another pivotal IOG initiative focused on the implementation of Enhanced Oil Recovery (EOR) techniques to bolster oil production. Recent years saw extensive studies conducted to ensure the effectiveness of EOR methods and formulas. Notably, the waterflood method was explored in the Rokan contract area at the Minas Field (PHR) and in the Mahakam contract area at the Handil Field (Pertamina Hulu Mahakam)[55]. In December 2023, SKK Migas approved two projects in the Rokan working area with a total investment of IDR 5.18 trillion. These projects encompass the Chemical EOR (CEOR) at Minas Field Phase-1 and Steam Flood EOR at Rantaubais Field Phase-1. The adoption of CEOR at Minas Field on a commercial scale, utilising Alkali-Surfactant-Polymer (ASP) injection chemicals, marked a historic milestone. The Phase-1 CEOR development at Minas Field added 2.24 million barrels of oil reserves and achieved peak production of 1,566 BOPD[56].

Furthermore, the government aimed to reduce emissions and increase production through CCS/CCUS[57] (discussed further in the Energy Transition chapter). CCUS, especially in conjunction with EOR through CO_2-EOR, offers potential for permanent CO_2 storage. While Indonesia's oil fields show promise, detailed studies are necessary to assess economic feasibility and identify CO_2 sources. Initial research in South Sumatra indicates viable CO_2-EOR injection options. However, CCUS projects remain in the pilot phase due to high costs, leaving considerable potential for CO_2 injection untapped[58].

In addition, Pertamina, through PT Pertamina EP (PEP) Regional Java Subholding Upstream Pertamina, successfully confirmed additional hydrocarbon reserves with two exploration wells in West Java Province. The first, East Akasia Cinta (EAC)-001 in PEP Jatibarang Field, Indramayu Regency, yielded oil at 30 BOPD, gas at 2.08 MMSCFD, and condensate equivalent to 15.05 BCPD. The second, East Pondok Aren (EPN)-001 in PEP Tambun Field, Bekasi Regency, flowed oil at 402 BOPD and gas at 1.09 MMSCFD. These efforts were part of Pertamina's aggressive exploration strategy, showcasing a new concept involving stratigraphic traps[59].

As for Coal Bed Methane (CBM), Indonesia holds 6% of the global reserve, estimated at 453 Tcf, surpassing natural gas reserves. Commercialising CBM is a challenge and no block has yet entered production.

In 2023, despite the government's termination of 50 cooperation blocks for oil and gas contracts, including 11 non-conventional blocks like Shale Gas or CBM[60], NuEnergy Gas Limited's unit, Dart Energy (Tanjung Enim) Pte. Ltd, obtained the environmental permit for Indonesia's Tanjung Enim plan of development between September and October 2023. This could lead to the country's first CBM development. On 10 February 2023, NuEnergy signed a heads of agreement with Laras Energy, later extended on 10 August 2023, outlining the supply and sale commitment by NuEnergy and the purchase commitment by Laras Energy for CBM produced from Tanjung Enim's POD 1.

55 SKK Migas, SKK Migas Annual Report 2022, 2023.
56 SKK Migas, "Jelang Tutup Tahun 2023, Dua Proyek EOR (Enhanced Oil Recovery) di Wilayah Kerja Rokan Dengan Investasi Rp 5,18 Triliun Disetujui SKK Migas", 2023.
57 Ministry of Industry,"POTENSI TEKNOLOGI CCS, CCUS DAN EMISI GRK DI INDONESIA", accessed 2024.
58 Sugihardjo, "CCUS-Aksi Mitigasi Gas Rumah Kaca Dan Peningkatan Pengurasan Minyak CO_2-Eor," Lembaran Publikasi Minyak Dan Gas Bumi 56, no. 1 (April 1, 2022): 21-35.
59 Pertamina, "Pertamina Temukan 2 Sumber Migas Baru di Jawa Barat", 2023.
60 MoEMR, "11 Blok Migas Terminasi Simpan Potensi MNK", 2023.

1.4 Downstream sector

Indonesia once again recorded a significant demand for crude oil. This is evident from the import of crude oil and natural gas which reached 15,263.4 tonnes in 2022[61] and increased to 52,144.1 tonnes in 2023[62]. Despite that, Bank Indonesia (BI) reported that the trade deficit balance for oil and gas declined to USD1.89 billion (5,011.4 thousand tonnes) in December 2023, in line with the decrease in oil and gas imports amid an increase in exports[63]. Indonesia is also actively working to optimise the use of its domestic natural-gas resources. In 2023, the share of domestic gas utilisation increased slightly to 3,745 Billion British Thermal Units per Day (BBTUD), compared to the 2022 level of 3,683 BBTUD. Notably, the industrial sector remains a major consumer, accounting for a significant portion of the demand at 1,515.8 BBTUD[64].

While Indonesia is considered an attractive market for downstream investors, Pertamina holds a significant position in the refining industry, operating six out of the nation's seven refineries. The seventh refinery is owned by the Research & Development (R&D) Agency of the Ministry of Energy and Mineral Resources (MoEMR). Combined, these refineries had an installed capacity of 1.031 MMBOPD in 2021. In response to increased oil consumption in 2022, Pertamina boosted its existing refinery capacity to 1.058 MMBOPD.

Pertamina aims to increase its refining capacity from 1.15 to 2.0 MMBOPD. This expansion plan is facilitated through the Refinery Development Master Plan (RDMP), which focuses on upgrading and expanding existing capacities and Grass Root Refineries (GRR). Pertamina's RDMP encompasses Cilacap, Dumai, Balongan, Balikpapan, and the GRRs will be located in Tuban and Bontang[65]. Finding the right partners for Tuban and Bontang GRRs continues to be a challenge for Pertamina[66].

Pertamina also has a majority share in the PT Trans-Pacific Petrochemical Indotama (TPPI) Tuban refinery[67]. The Government aims to reduce gasoline subsidies by restricting distribution in certain areas and promoting non-subsidised fuels such as Pertalite, Pertamax, and Pertamina Dex. The Government also allows investments from multinational giants such as Shell, ExxonMobil, Total, and BP in the non-subsidised fuel distribution market.

In the industrial fuels sector, Pertamina continues to be a major player, yet foreign and local competitors have made significant strides in expanding their market share through fuel imports. Compounded by Indonesia's burgeoning economy, the demand for fuel consistently outpaces the country's refinery capacity and its crude oil/natural gas production.

61 The Indonesian national statistics agency (BPS - Badan Pusat Statistik), "Volume Ekspor dan Impor Migas (Berat bersih: ribu ton) 1996-2022", 2023.
62 BPS, "Volume Impor Migas-NonMigas (Ribu Ton)", 2023.
63 BI, "SURPLUS NERACA PERDAGANGAN BERLANJUT", 2024.
64 MoEMR, "Kinerja Sektor ESDM 2023: Perluas Akses Energi, Prioritaskan Kebutuhan Domestik, Dan Jaga Daya Saing Lewat Transisi Energi", 2023.
65 PT Pertamina (Persero), Pertamina Annual Report 2022, June 12, 2023.
66 BMI (Fitch Solution), "Indonesia Oil and Gas Report Q1 2024", 2023.
67 Indonesia Oil and Gas Report Q1 2024 (Fitch Solution, 2023).

1.5 Contribution to the economy

Indonesia's heavy reliance on imported fuels and crude oil poses risks to energy security due to fluctuating global prices. In 2022, rising fossil fuel prices led to significantly higher energy subsidies than budgeted[68]. The energy subsidy saw a substantial increase from IDR152.5 trillion to IDR502.3 trillion, culminating in a realisation of IDR551.2 trillion in 2022. By August 2022, the Ministry of Finance signalled that nearly the entire gasoline subsidy allocation had been utilised, raising concerns about potential fuel-price hikes. In response to the escalating energy subsidy costs, the president implemented an average 30% increase in fuel prices in September 2022[69]. The trend in energy subsidies reversed in 2023. The MoEMR reported that Indonesia's energy subsidy realisation in 2023 reached IDR159.6 trillion, surpassing the set target of IDR145.3 trillion, but much lower than 2022. The energy subsidy covers various components, including fuel oil (BBM) for diesel and kerosene, Liquefied Petroleum Gas (LPG), and electricity. The 2024 target for energy subsidies is set at IDR186.9 trillion, with BBM and LPG subsidies at IDR113.3 trillion and electricity subsidies at IDR73.6 trillion[70].

The Ministry of Finance (MoF) also reported a reduction in subsidies for fuel and 3 kg LPG, amounting to IDR95.6 trillion, marking a 17.3% decrease. The decline in energy subsidies, particularly for fuel and LPG, is attributed to various policies. Notably, the targeted distribution transformation for LPG initiated on 1 March 2023, played a significant role. Furthermore, measures such as customer registration through MyPertamina and restrictions on subsidised fuel purchases also contributed to the decline[71].

As Indonesia seeks to diversify away from fossil fuels, it is expected that the fuel demand in the long term will slow. Demand for transport fuels also showed slower growth rates due to the government's ongoing efforts to cut fuel subsidies. Fitch forecasted that Indonesia's fuel consumption will grow 1.4% annually between 2023 and 2032, with total volumes staying below or around 2.1 MMBOPD in 2032. The decarbonisation target for fuel switching in the road transport sector is ambitious and will bring about major reductions in fuel consumption. The national objective is to reach carbon neutrality by 2060, which will require emissions reduction measures to be introduced in most fuel-intensive sectors[72].

The rapid global growth of electric vehicles (EVs) is causing a potential disruption to the traditional oil market, with more countries and consumers embracing EVs and shifting from oil to electricity as the primary energy source[73]. While the EV market is projected to expand in Indonesia due to increasing consumer awareness and government incentives, as well as the government's plans for Indonesia to become a battery and EV hub for the region, given Indonesia's significant reserves of critical minerals needed for batteries, such as nickel, cobalt, copper and others, the EV adoption in Indonesia currently lags behind global markets. Nevertheless, industry leaders and policymakers are preparing for a future where EVs could have a significant market presence, driving a shift towards sustainability and technological advancements[74].

68 Institute for Essential Service Reform (IESR), "Indonesia Electric Vehicle Outlook 2023", 2023.
69 MoEMR Strategic Study, "Realisasi Subsidi Dan Kompensasi Energi 2022 Melesat Tiga Kali", Laporan Harian KESDM, January 4, 2023; The Economist Intelligence Unit (EIU), Energy Report Indonesia Q4 2022, June 1, 2022.
70 MoEMR, "Jaga Daya Beli, Menteri ESDM Targetkan Alokasi Subsidi Energi 2024 Rp186,9 Triliun", 2024.
71 Ministry of Finance (MoF), "Press Conference - Performance and Realisation of State Budget 2023", Broadcast January 2024 on Youtube, MoF, 2024.
72 BMI (Fitch Solution), "Indonesia Seeking To Slow Down Fuel Demand Growth And Cut Imports", 2023.
73 World Economic Forum (WEForum), "Electric vehicles: an analysis of adoption and the future of oil demand", 2023.
74 PwC, "Key drivers and future expectations for electric vehicles in the Indonesia market", 2023.


Photo source: PT Pertamina (Persero)

In 2021, Indonesia's government Non-Tax State Revenue (PNBP - *Penerimaan Negara Bukan Pajak*) from the oil and gas sector rebounded to IDR95 trillion, surpassing the target by 26.67%, largely due to high oil prices driven by global geopolitical factors. Entering 2022, following more stability in oil and gas prices, the oil and gas revenue reached a level of IDR148.7 trillion from a target of IDR139 trillion[75]. In 2023, the realisation of Non-Tax State Revenue in the oil and gas sub-sector reached IDR117 trillion, indicating a decrease from 2022, but still 113% of the target set of IDR103.6 trillion[76].

The export revenue from oil and gas grew to 4.35% of total exports in 2021 but experienced a decline to 3.75% in 2022 and 2023, marking the lowest level in the past decade (refer to figure Oil and Gas exports as a % of total Indonesian exports). Concurrently, the contribution of the oil and gas industry to Gross Domestic Product (GDP) saw a decline from 3.46% in 2021 to 3% in 2022 and 2.49% in 2023 (refer to Oil and Gas products as a % of total Indonesian GDP).

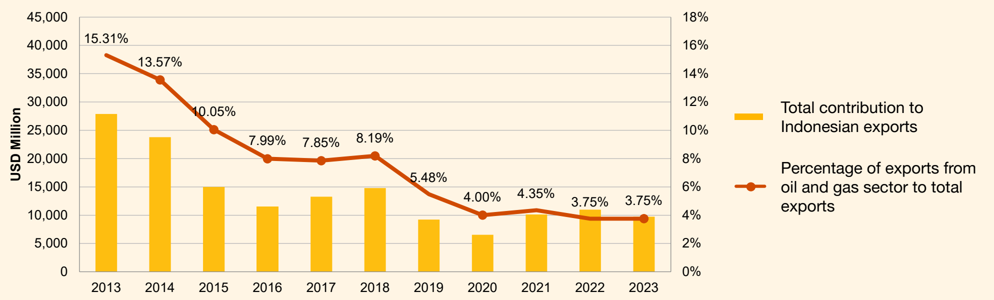
Table 1.8 - State budget

Year	Total State Revenue (IDR Trillion)	Oil and Gas Revenue (IDR Trillion)	% of Contribution from Oil & Gas
2013	1,438	204	14.19%
2014	1,551	217	13.99%
2015	1,505	78	5.18%
2016	1,555	44	2.84%
2017	1,666	82	4.91%
2018	1,942	143	7.38%
2019	1,959	127	6.49%
2020	1,699	69	4.07%
2021	1,736	95	5.47%
2022	1,846	149	8.05%
2023	2,462	117	4.75%

Source: MoF, "APBN Kita December 2023", 2023; MoEMR, "Capaian Kinerja Sektor 2023", 2024

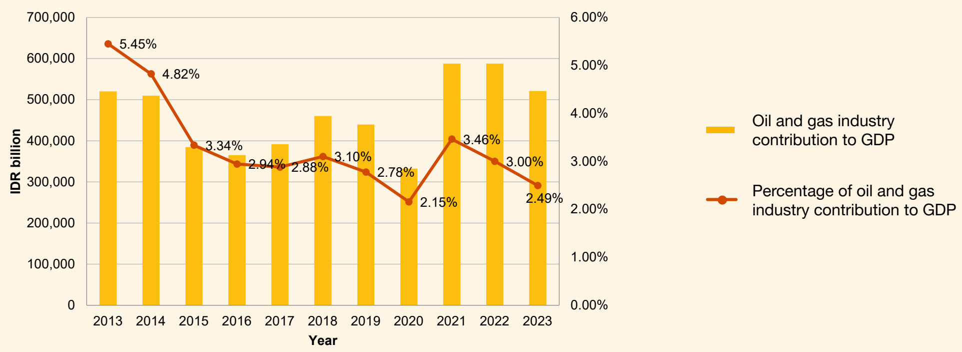
75 MoEMR Strategic Study, "Realisasi Subsidi Dan Kompensasi Energi 2022 Melesat Tiga Kali", Laporan Harian KESDM, January 4, 2023; The Economist Intelligence Unit (EIU), Energy Report Indonesia Q4 2022, June 1, 2022.
76 MoEMR, "PNBP Migas Sumbang Rp 117 Triliun ke Kas Negara", 2024.

Oil and gas exports as a % of total Indonesian exports



Source: Bank Indonesia (BI)

Oil and gas products as a % of total Indonesian GDP



Source: Bank Indonesia (BI)

Investment in Indonesia's upstream oil and gas sector showed improvement. In 2023, there was a 12% increase from 2022, reaching USD13.7 billion (refer to Table 1.9 - Upstream Oil & Gas Investment). Oil and gas operations in Indonesia also contribute significantly to the job markets. According to SKK Migas, in 2022, the number of Indonesian Workers (TKIs) employed in upstream oil and gas activities stood at 18,924, with 145 expatriate employees.

The utilisation of Indonesia's workforce experienced a decline from 2015 to 2021 due to factors such as falling oil prices and the impact of the COVID-19 pandemic (refer to the figure Indonesian Workers and Expatriates Headcount in Oil and Gas). This decline was also brought about by efficiency programmes by PSC Contractors and the completion of various oil and gas projects. Consequently, recruitment for vacant positions was generally delayed, prompting contractors to focus on enhancing the development of Indonesian workers through more efficient methods like in-house training and online modules[77].

77 SKK Migas, SKK Migas Annual Report 2022, 2023.

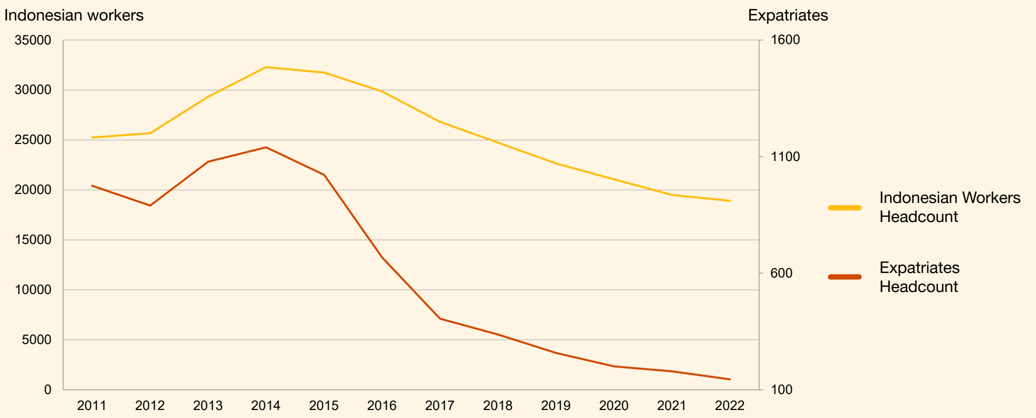
Table 1.9

Upstream oil and gas investment (in million USD)

Type of operation	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Exploration	1,877	1,735	1,345	1,078	565	546	600	578	600	700	900
Administration	1,199	1,157	1,286	702	944	873	700	643	800	800	600
Development	4,306	4,048	2,116	1,322	705	1,310	1,700	1,680	1,400	2,600	2,800
Production	11,960	12,336	10,883	8,156	8,053	8,189	8,700	7,600	8,100	8,100	9,400
Total Expenditure	19,342	19,276	15,630	11,258	10,267	10,918	11,700	10,501	10,900	12,200	13,700

Source:
2009 - 2021: Calculated by PwC based on BP Migas/SKK Migas Annual Reports 2022: BUMI Buletin SKK Migas January 2023 Edition.
2023: SKK Migas, "Press Conference - Upstream Oil and Gas Performance Achievements of Year 2023 and Targets 2024", Broadcast January 2024 on Youtube, SKK Migas, 2024.

Indonesian workers and expatriates headcount in oil and gas



Source: SKK Migas Annual Report 2022 (released on 2023)

2 Energy transition

2.1 The need for energy transition and challenges

Energy is a crucial input to all economic activity, and a secure and affordable energy supply has been a key enabling factor for global economic growth that has lifted millions out of poverty. Over the period from 1900 to 2022, global per capita Gross Domestic Product (GDP) has increased from ca. USD 2,200 to ca. USD 12,800[78]. Over the same period, global primary energy consumption increased from ca. 12,000 TWh to ca. 167,788 TWh[79], with the proportion of fossil fuels in the primary energy supply at ca. 82% in 2022[80]. About three-quarters of global greenhouse gas emissions come from energy use, with around 74% being carbon dioxide (CO_2) and the remainder from gases like methane (CH4), nitrous oxide (N2O), and F-gases. The climate science, coordinated under the aegis of the Intergovernmental Panel on Climate Change, is unequivocal in its conclusion that anthropogenic GHG emissions are responsible for global warming and climate change.

The Paris Agreement at Conference of Parties 21 (COP21) calls for keeping global warming to well below 2°C above pre-industrial levels and pursuing all efforts to limit it to 1.5°C above pre-industrial levels recognising that this would significantly reduce the risks and impacts of climate change. The Glasgow Climate Pact, agreed at COP26, emphasised the urgent need to address global warming and climate change. It reiterated the goals set in COP21 to limit global warming to well below 2°C above pre-industrial levels and pursue efforts to limit it to 1.5°C. This includes rapid reductions in global CO_2 emissions by 45% by 2030 compared to 2010 levels, aiming for net zero emissions by around mid-century, and reducing other greenhouse gases[81]. Most countries worldwide have agreed to transition away from fossil fuels, the primary cause of climate change.

This requires significantly accelerated action in this decade itself, considering that with all committed policies and actions, we are estimated to be on track for ca. 2.7°C[82], while even considering all current pledges and targets, which are yet to be fully translated into policies and action, we are estimated to hit ca. 2.1°C of warming.

78 World Bank, "October 2021 Commodity Markets Outlook: Urbanization and Commodity Demand", Commodity Markets Outlook, October, 2022; Natasha Turak, "OPEC+ agrees to stick to oil production plan, defying U.S. pressure", CNBC, 2021.
79 World Bank, "April 2022 Commodity Markets Outlook: The Impact of the War in Ukraine on Commodity Markets", Commodity Markets Outlook, 2022.
80 Max Roser et al., “Economic Growth”, Our World in Data, 2023.
81 COP28: Key outcomes agreed at the UN climate talks in Dubai", Carbon Brief, January, 2024; COP 28: What Was Achieved and What Happens Next?", United Nation Climate Change (UNCC), 2023.
82 https://climateactiontracker.org/publications/no-change-to-warming-as-fossil-fuel-endgame-brings-focus-onto-false-solutions/

At the same time, energy security continues to be a major concern across the globe. While the energy transition is key to averting catastrophic global warming and climate change, this cannot be to the detriment of the unfinished development agenda in the developing countries of the world which are historically and currently below developed countries, and even global averages, in terms of per capita incomes, energy consumption and emissions. It is essential to ensure that the transition doesn't reverse decades of progress in economic and social development. If not, the loss of social and political license for the many difficult decisions that have to be implemented for a rapid and deep energy transition, will derail the transition.

The B20 Energy, Sustainability & Climate (ESC) Task Force, for which PwC Indonesia was the knowledge partner, highlighted the key areas of focus if a just energy transition is to be achieved, in its policy paper submitted to the G20 in 2022. These are summarised in Table 2.1 below.

Tabel 2.1 - B20 ESC TF policy recommendations

Policy recommendation	Policy Action No	Policy Action
Enhance global cooperation on accelerating the transition to sustainable energy use by reducing carbon intensity of energy use through multiple pathways	1.1	Enhance the pace of energy efficiency improvement across the transport, buildings, and industrial sectors
	1.2	Progressively reduce the carbon intensity of electricity by reducing emissions from coal fired generation and accelerating renewable energy deployment, according to national circumstances
	1.3	Accelerate the mitigation of carbon emissions from hard-to-abate sectors
	1.4	Progressively enhance the quantum, predictability & ease of financing flows to developing countries
	1.5	Support climate technology innovation by supporting start-ups, and research universities with technology, financing, skilled manpower, knowledge & facilities sharing
Enhance global cooperation on ensuring a just, orderly, and affordable transition to sustainable energy use across developed and developing countries	2.1	Ensure an orderly transition in primary energy sources
	2.2	Ensure MSMEs participation in energy transition activities with financing and capacity building
	2.3	Assist transition readiness by ensuring human capital ability to accommodate change (e.g., transfer knowledge, upskilling & workshop)
	2.4	Ensure sustainable practices for mining of essential minerals for energy technologies
Enhance global cooperation on enhancing consumer level access and ability to consume clean, modern energy	3.1	Accelerate deployment of integrated electricity access solutions, including off grid with community participation and grid-based electrification to expand energy access and enhance economic prosperity
	3.2	Facilitate adoption of technology by households and MSMEs for efficient, clean, modern energy usage
	3.3	Ensure broad basing of the transition by addressing affordability barriers in developing countries

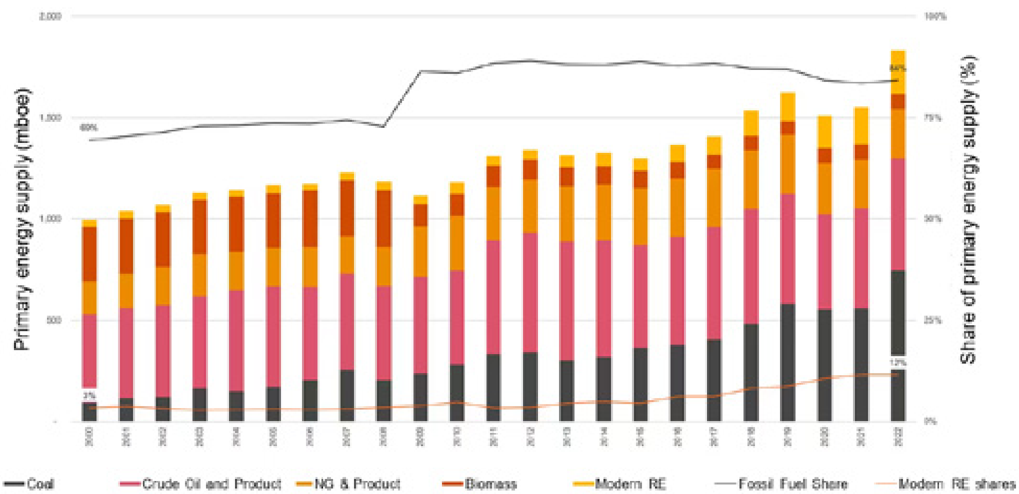
Source: B20 Energy, Sustainability & Climate Task Force ESC TF) , "B20 Summit Indonesia 2022 : Energy, Sustainability & Climate Task Force Policy Recommendation", Broadcast November 2022 on Youtube, Kemkominfo, 2022

2.2 Energy transition in Indonesia

Indonesia has demonstrated strong and consistent economic growth over this century, with GDP at constant 2010 prices increasing from IDR 4,122 trillion in 2000 to IDR 11,710 trillion in 2022, supported by primary energy-supply expansion of 836 MBOE. 78% (652 MBOE) of this expansion was from coal, reflecting natural-resource endowment and a national policy stance favouring domestic-resource exploitation for economic development and job creation. This strong and consistent growth has resulted in a more than tenfold increase of per capita GDP over the same period from ca. USD 770 (IDR 6.5 million)[83] to ca. USD 4,788 (IDR 71 million)[84]. However, this also indicates how much further Indonesia has to go in its ambition to become a developed economy.

In pursuit of the required growth, the primary energy supply will have to be expanded, but if the expansion continues to be from fossil fuels, the consequent greenhouse gas emissions growth will lead to Indonesia failing to achieve its international treaty obligations under the Paris Agreement and failing to secure the international support promised for its transition under the Indonesia – Just Energy Transition Partnership.

Primary energy supply mix



Source: PwC, "The Energy Transition," PwC, accessed 2024.

83 Based on average exchange rate of USD/IDR in 2000 of 8,421
84 Based on average exchange rate of USD/IDR in 2022 of 14,849

The scale of Indonesia's challenge in planning and implementing its energy transition can be seen from the two graphs below which show the dependence on fossil fuels in the final energy consumption basket.

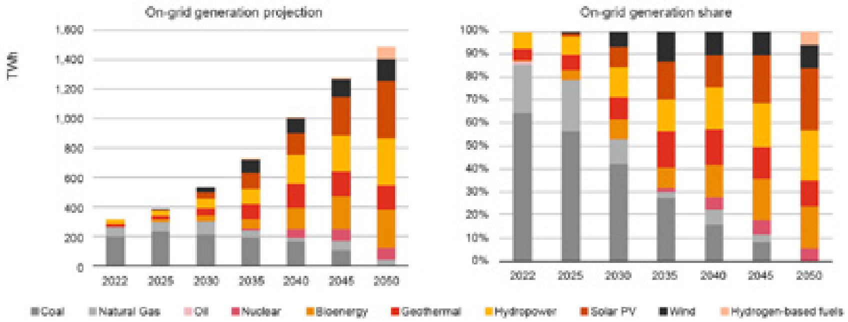
Fossil Fuel Dependence in FEC (2022) and Sectoral Fossil Fuel Dependence (2022)

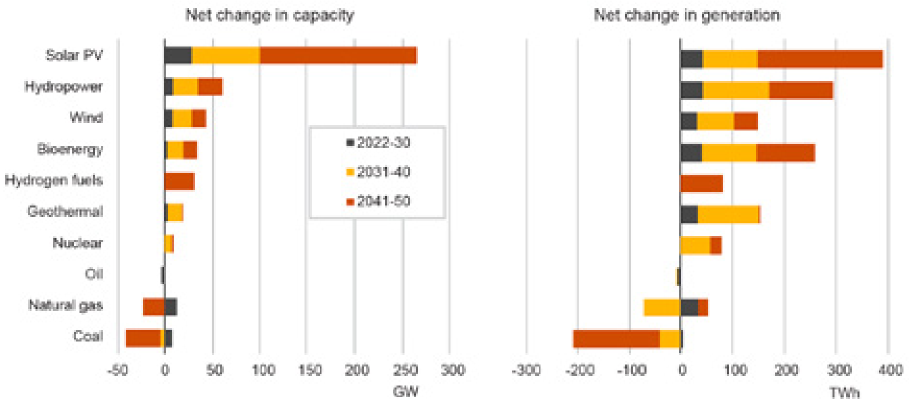
Source: PwC, "The Energy Transition," PwC, accessed 2024.

Indonesia will have to simultaneously transition its final energy consumption and primary energy supply mix by applying the four levers of transition – energy efficiency, electrification of the economy, decarbonising electricity generation and replacing residual fossil-molecule demand with alternative fuels. The Just Energy Transition Partnership (JETP) scenario that has been finalised in the recently released Comprehensive Investment Policy and Plan considers energy efficiency (minimum energy performance standards for appliances and machinery across households, industry and commercial sectors), electrification of the economy (Internal Combustion Engine (ICE) vehicles to Electric Vehicles (EVs) in transport, process heat in industries and electrification of cooking), and decarbonising electricity (significant shift to baseload and variable RE (Renewable Energy), biomass co-firing).

The JETP was established in Indonesia during the G20 Summit in Bali on 15 November 2022, with a catalytic USD 20 billion funding agreement between the government, the International Partners Group (IPG) and the Glasgow Financial Alliance for Net Zero (GFANZ) to transition Indonesia's electricity sector. In Indonesia, JETP has developed the Comprehensive Investment and Policy Plan (CIPP) to guide power sector planning and policymaking.

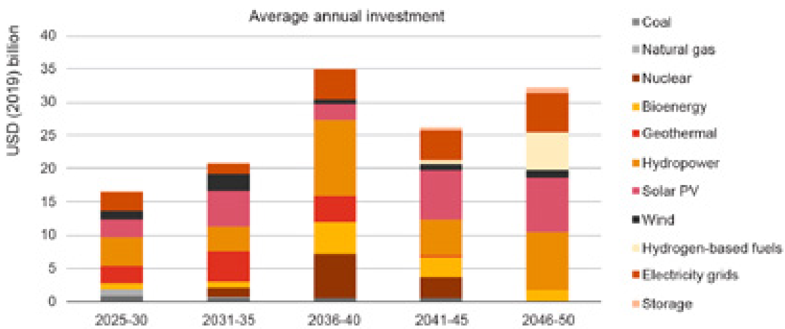
The CIPP outlines a potential pathway for the on-grid system (JETP Scenario) with an emissions target of no more than 250 MT CO_2 in 2030; a renewable energy generation share of 44% by 2030; and achievement of net zero emissions in the power sector by 2050. On-grid generation and net capacity changes for each technology can be seen below.





Source: Just Energy Transition Partnership (JETP) Secretariat and Working Groups, "Just Energy Transition Partnership for Indonesia (JETP Indonesia) Comprehensive Investment and Policy Plan," 2023

In terms of investment costs, at least USD97.1 billion between 2023-2030 and USD580.3 billion between 2023-2050 is required to realise the JETP Scenario, excluding the full extent of just transition assessments and interventions, projected to cost at least USD0.2 billion by 2030. Average annual investment for respective technologies can be seen below.



Source: Just Energy Transition Partnership (JETP) Secretariat and Working Groups, "Just Energy Transition Partnership for Indonesia (JETP Indonesia) Comprehensive Investment and Policy Plan," 2023

To support the power sector, around 6,000 km of transmission lines are needed by 2030, increasing to around 15,000 km by 2040. For transmission, around USD42 billion of cumulative capital investment is projected by 2040, and USD9 billion is needed for distribution network investment.

Specifically for dispatchable renewables: Hydropower is expected to make up 12% of the energy mix by 2030, with an expansion driven by the addition of 8 GW of new plants, reaching a capacity of 65 GW by 2050. Geothermal capacity is set to expand by 3 GW by 2030 and nearly 22 GW by 2050. Bioenergy is projected to constitute 7% of the total coal generation mix by 2030, increasing to 9% beyond 2040 as retired coal plants are repurposed. Investment requirements for dispatchable renewable power total almost USD197 billion cumulatively by 2040, with hydropower alone needing at least USD100 billion.

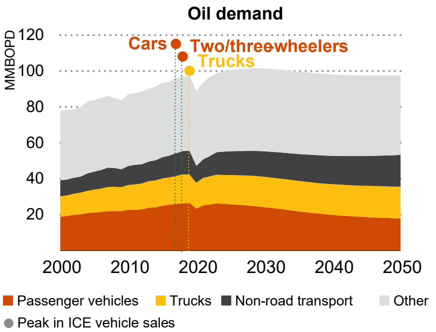
Beyond 2030, minimal investment is directed towards new **on-grid fossil-fuel plants**, but up to USD10 billion is projected for repurposing coal power plants to enhance flexibility. Repurposing coal and gas plants for bioenergy or hydrogen requires an average annual investment exceeding USD7 billion during 2046–2050.

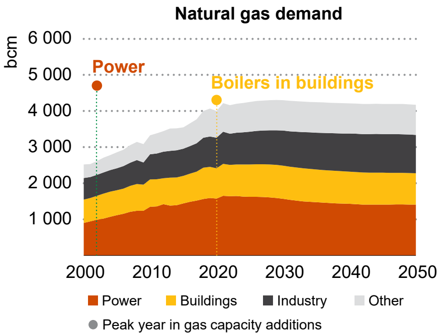
Meanwhile, variable renewable energy (VRE) comprises 60% of power-capacity additions through 2040, led by the growth of solar PV to 100 GW by 2040 and close to 265 GW by 2050. Wind power complements this growth, also accelerating to nearly 30 GW in 2040 and almost 45 GW in 2050, even though its expansion is limited due to resource availability. Achieving these levels of installed capacity requires nearly USD25 billion cumulative investment in solar PV and wind by 2030 and almost USD80 billion by 2040.

It is noted that the success of this pathway is conditional upon integration measures and investments to expand and upgrade transmission grids, system flexibility to integrate variable renewables and policy enhancements, among others.

The combined effect of this planned transition is expected to peak and then reduce the demand for all three major fossil fuel sources – coal, oil and gas. Oil and gas demand as feedstock for industrial processes will likely continue or grow.

Primary energy supply mix





Source: IEA, "World Energy Outlook 2023", 2023

However, these use cases and transition consumption of fossil fuels will likely have to be abated to minimise their GHG emissions and environmental impact.

2.3 Oil and gas demand

The demand for oil and gas in Indonesia is significant, with the country's oil and gas market expected to grow. The Indonesia Oil and Gas Market is projected to reach 635.23 thousand barrels per day in 2024 and grow at a Compound Annual Growth Rate (CAGR) of 1.60% to reach 687.70 thousand barrels per day by 2029[85]. Indonesia has one of the largest proven oil reserves among Southeast Asian countries, and the country is seeing rapid economic growth, which is expected to drive up the demand for petroleum and petroleum-derived products in the future. The country's gasoline consumption is also on the rise, with demand expected to reach a record high of 670,000 barrels per day in 2023, up from 635,000 barrels per day in 2022[86]. Additionally, Indonesia produced 2.2 trillion cubic feet of dry natural gas in 2020, mostly from offshore fields not associated with crude-oil production. Despite some challenges and disruptions, Indonesia's oil and gas market is poised for growth, presenting significant opportunities for industry players[87]. However, it is important to note that Indonesia's oil consumption has experienced fluctuations over the years, influenced by various factors such as economic growth, government policies, and global oil prices. The country's oil demand is expected to evolve in response to these factors[88].

In Indonesia, both gasoline and petrochemicals are significant in the energy and industrial sectors. The country's reliance on fossil fuels, including gasoline, is evident in its energy consumption, with petroleum accounting for a notable share. Additionally, the petrochemical industry in Indonesia is a vital part of the economy, with a promising market due to the large population and the demand for petrochemical products. The government has expressed ambitions to reduce the import of petrochemical products and develop the domestic petrochemical industry to meet the growing demand. Therefore, while gasoline is primarily used as a fuel, petrochemicals play a crucial role in various industrial and consumer products, making them both important in the Indonesian context.

The Indonesian petrochemicals market is significant, as the country's demand for petrochemical products is consistently proportional to its large population. The government aims to reduce the import of petrochemical products and develop the domestic petrochemical industry to meet the growing demand. Indonesia's reliance on fossil fuels, including gasoline, is evident in its energy consumption, with petroleum accounting for a notable share. The Indonesian government aims to be totally self-sufficient in petrochemicals by 2027, indicating a significant focus on the development of the petrochemical industry in the country. While the demand for gasoline is driven by the transportation sector, the increasing demand for petrochemicals is fueled by various industrial and consumer applications, reflecting the diverse usage of petrochemical products in the Indonesian economy.

85 Mordor Intelligence. "Oil and Gas Industry in Indonesia Size & Share Analysis - Growth Trends & Forecasts (2024 - 2029)", 2023.
86 Mohi Narayan, "Indonesia 2023 gasoline demand, imports likely to exceed 2022 records," 2023.
87 Mohi Narayan, "Indonesia's 2024 oil and gas lifting estimated below targets - upstream regulator," 2023.
88 IEA, "Country Analysis - Indonesia", accessed in 2024.

Photo source: PT Medco Energi Internasional Tbk

2.4 Role of CCS/CCUS in transition

In the wake of global efforts to combat climate change, nations worldwide are exploring innovative solutions to reduce greenhouse gas emissions. Indonesia, a country rich in natural resources, faces the challenge of balancing economic development with environmental sustainability. It is well acknowledged that Indonesia has enormous potential for geological formations that can be used to store carbon emissions. With technology in carbon capture & storage (CCS) as well as carbon capture, utilisation & storage (CCUS) activities, it is hoped that Indonesia can find the right balance and achieve its global commitments being pledged pursuant to the Paris Agreement. The idea of CCS and CCUS is novel to the public, but their technological history extends a century back. However, the application of these technologies is not risk-free. The risks could manifest into harm, damage, and injuries in early periods and at periods much later. Having said that, it is without a doubt that effective and clear legal standards and frameworks must be in place not only to facilitate the creation of incentives but also to efficiently protect the community from any foreseeable risks.

In 2024, there is significant momentum for the implementation of CCUS in Asia. Several developments and initiatives are underway in various Asian countries to promote CCUS technology:

- Japan and China: The Japanese Government has launched the Asia CCUS Network to support capacity development and promote collaborative projects in the region. China has included large-scale CCUS demonstration projects in its 14th Five-Year Plan[89];
- Asian Development Bank (ADB): The ADB has been working with its developing member countries to identify new opportunities in CCUS, prepare regulatory frameworks, and grow a research network to create opportunities for low-carbon development[90];
- Southeast Asia: Interest in CCUS in Southeast Asia has been growing, with plans for several potential projects in countries such as Indonesia, Malaysia, Singapore, and Timor-Leste. Singapore has identified a key role for CCUS in its long-term emissions-reduction strategy[91].

89 CCS Knowledge, "Momentum of Large-Scale CCUS in Asia," 2022.
90 Asian Development Bank (ADB), "Enabling CCUS Implementation in Asia," 2024.
91 IEA, "Carbon capture, utilisation and storage: the opportunity in Southeast Asia," 2021.
Global CCS Institute, "2024 Australia and Southeast Asia Forum on Carbon Capture and Storage" 2024.

In this context, the Indonesian government has introduced a legal framework to regulate CCS and CCUS activities particularly within the oil and gas sector. It was started by the issuance of the MoEMR Regulation No. 2 of 2023 (MoEMR Regulation No. 2/2023) which is aiming to provide general guidelines for CCS/CCUS projects. This regulation aligns with Indonesia's commitment to the Paris Agreement and aims to facilitate the country's energy transition while also encouraging an increase in oil and natural-gas production.

At the outset, MoEMR Regulation No. 2/2023 regulates the implementation of both CCS and CCUS activities which preceded by obtaining approval from the government authorities. The approval process itself requires contractors[92] to submit detailed proposals covering technical, economic, safety, and environmental aspects, either to:

(i) MoEMR through SKK Migas or the Aceh Oil and Gas Management Agency (*Badan Pengelola Migas Aceh* or BPMA), if the CCS/CCUS is part of the first field development plan; or
(ii) SKK Migas or BPMA, if CCS/CCUS is part of the next field development plan(s).

Based on the evaluation of the proposal, MoEMR or SKK Migas/BPMA (according to their respective authorities) may approve or reject the CCS/CCUS plan submitted by the contractors. The cooperation contract[93] will be amended to reflect the approved proposal. Furthermore, the regulation mandates monitoring, reporting, and verification (MRV) of CCS/CCUS activities to ensure compliance with standards and good practices. It also outlines closure conditions, emphasising safety and environmental considerations.

In addition to this, the newly issued Presidential Regulation No. 14 of 2024 (PR No. 14/2024) focuses on the implementation of CCS activities, recognising yet reemphasising Indonesia's potential as a carbon storage hub. It offers two schemes for CCS activities: 1) integration into oil and gas operations and requires cooperation contract amendments for CCS inclusion, and 2) exploration and storage operation permits for designated non-working areas. PR No. 14/2024 further outlines a more detailed process for CCS implementation plans, including evaluation by SKK Migas and approval by the MoEMR. It also addresses carbon-storage licenses which are not being a pre-requisite for implementing CCS under MoEMR Reg No.2/2023, prioritising domestic storage capacity and international cooperation.

Moreover, the regulation introduces carbon transportation licensing and emphasises tax incentives to encourage investment in CCS projects. PR No. 14/2024 is elaborative enough for businesses to start considering the development of CCS projects and complements MoEMR Reg No. 2/2023 perfectly. However, challenges persist regarding international carbon trading and regulatory enforcement as there are still requirements that need to be fulfilled for international carbon trading to be conducted.

92 Business entities or permanent establishments that are stipulated to carry out exploration and exploitation in a work area based on a cooperation agreement with SKK Migas or BPMA.

93 Cooperation contract means a production sharing contract or other forms of cooperation contract in exploration and exploitation activities which is more profitable for the state and the results of which are used for the greatest prosperity of the people.

SKK Migas Work Procedure Guidelines No. PTK-070/SKKIA0000/2024/09 (PTK 070) provides a comprehensive technical framework for CCS/CCUS activities. It emphasises health, safety, and environmental protection, along with compliance with national and international standards. PTK 070 outlines the responsibilities of SKK Migas and contractors, emphasising risk management and MRV throughout the project lifecycle. It also addresses data collection, geological studies, and integrity evaluations for CCS/CCUS facilities. Additionally, PTK 070 highlights monetisation strategies for CCS/CCUS implementation and the classification of goods and equipment used in these activities.

In conclusion, Indonesia's current legal framework for CCS/CCUS activities reflects its commitment to environmental sustainability and economic development. As in many parts of the world, the implementation of CCS/CCUS in Indonesia could enable continued fossil fuel consumption with responsibility while reducing CO_2 emissions. As elaborated above, while regulations provide more clarity and guidance on the implementation of CCS/CCUS activities, challenges such as:

a) whether risk allocation of the development of CCS/CCUS projects has been distributed and managed fairly since the timeline of potential damages/injuries may extend multiple millennia beyond the lifetime of humans or even corporate entities. Addressing this, it is important to ensure that the legal framework strikes the right balance between potential liability issues and the related issue of compensation for CCS related damages and the economic value of the CCS/CCUS projects from the contractors' point of view.

   In this context, the questions might specifically be whether at the end of the verification of plans to close CCS/CCUS projects, releasing contractors' obligations is the best option and whether the 10 years of monitoring that has been set by the regulations is sufficient to guarantee the possibility of CCS related damages. The current legal framework on CCS/CCUS implies the application of rules of negligence instead of strict liability;

b) whether the Indonesia government provides sufficient incentives for contractors and investors (as applicable) to run CCS/CCUS projects and does monetisation of projects provide a profitable return on investment to attract more investors to participate in the projects. From a carbon trading perspective alone, the contractors or investors may see insufficient domestic market price for carbon. Not to mention limited insurance providers for insuring the CCS/CCUS projects which therefore increases the project costs;

c) whether in its implementation, regulatory requirements and enforcement as set forth in the relevant legal framework are carried out by parties with full responsibility. The devil will be in the details, especially in the approval and MRV processes, which will be crucial for the development of CCS/CCUS projects. While it is recognised that the risks of CCS/CCUS activities are foreseeable considering the advanced technologies, for developing countries like Indonesia regulators should be equipped with sufficient technical knowledge and power to enforce sanctions (as applicable) and to take decisions in a timely manner so as not to delay investment.

Moving forward, stakeholders must collaborate to address these challenges and unlock the full potential of CCS/CCUS technologies. By fostering innovation, promoting investment, and ensuring regulatory compliance, Indonesia can pave the way for a sustainable future while contributing to global climate-action efforts. Furthermore, Indonesia's legal framework for CCS/CCUS activities lays the foundation for a transition towards a low-carbon economy. As the country navigates this path, it must continue to prioritise environmental stewardship while fostering economic growth and energy security.

As the first country in Asia to enact a legal framework for CCS, and the regulations may provide opportunities for investors to participate in CCS or CCUS projects in Indonesia. The country has also been proactive in promoting energy transition in Southeast Asia through the development of these regulations, which are seen as a catalyst for neighbouring countries in the region[94].

MoEMR and SKK Migas' efforts to promote CCS and CCUS investments are notable. They has taken the lead in promulgating regulations to support the development of these technologies[95]. The regulations in Indonesia address key aspects such as the establishment of legal and regulatory frameworks, monitoring, reporting and verification requirements, and the creation of a carbon credit scheme and carbon trading market.

Indonesia's proactive approach and the comprehensive nature of its regulations demonstrate its commitment to advancing CCS and CCUS technologies, which could have a significant impact on the region's energy transition and climate change mitigation efforts. As a closing remark, the journey towards widespread CCS/CCUS implementation in Indonesia is multifaceted and requires the concerted efforts of government, industry, and civil society. By leveraging legal frameworks, promoting technological innovation, and fostering international collaboration, Indonesia can play a pivotal role in global efforts to mitigate climate change while ensuring sustainable development for the future[96].

94 Morgan et al., "Indonesia's New Regulation on CCS and CCUS: A Step Rather than a Leap?," Lexology, 2023.
95 "Indonesia's New CCS/CCUS Regulations: Promoting Energy Transition in Southeast Asia," Indonesia's New CCS/CCUS Regulations: Promoting Energy Transition in Southeast Asia, 2023.
96 Arma-Law, "Indonesia introduces CCS and CCUS regulations", 2024.


Photo source: PwC

Photo source: PwC

3 Regulatory framework

3.1 Oil and Gas Law No. 22/2001

Law No. 6 of 2023 on the Stipulation of Government Regulation in Lieu of Law No. 2 of 2022 on Job Creation

On 30 December 2022, the President of the Republic of Indonesia signed Government Regulation in Lieu of Law No. 2 of 2022 on Job Creation (Perppu No. 2). Perppu No. 2 revoked and completely replaced Law No. 11 of 2020 concerning Job Creation (Law No. 11/2020) that was previously declared legally defective and conditionally unconstitutional by the Indonesia Constitutional Court based on the Constitutional Court Decision No. 91/PUU-XVIII/2020 (MK-91 Decision) since it was issued without a proper formality process. On 31 March 2023, Indonesia's House of Representatives approved into law the Perppu No. 2 as Law No. 6/2023 (the Job Creation Law).

In general, the provisions stipulated in the Job Creation Law are not substantially different from those stipulated in Law No. 11/2020. The Job Creation Law essentially amends several laws, one of which is the oil and gas law, namely Law No. 22 dated 23 November 2001 (Law No. 22). The laws that are amended by the Job Creation Law relating to the oil and gas sector and mentioned in this guide are:

1. Law No. 22;
2. Investment Law No. 25/2007 (Law No. 25/2007);
3. Company Law No. 40/2007 (Law No. 40/2007);
4. Environment Law No. 32/2009 (Law No. 32);
5. Forestry Law No. 41/1999, as amended by Law No. 1/2004 and Law No. 18/2013 (Law No. 41);
6. Shipping Law No. 17/2008.

For ease of reference, the above-mentioned regulations will be referenced throughout this guide with the intention that they have been amended by the Job Creation Law.

The law regulating oil and gas activities is Law No. 22. The objectives of Law No. 22 (Article 3) are to:

a. Guarantee effective, efficient, highly competitive and sustainable exploration and exploitation of oil and gas;
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 Constitutional Court decision in 2012 to disband the upstream regulator (BP Migas - *Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi*), there has been an expectation that Law No. 22 will be amended. A draft amendment to Law No. 22 became available in 2023.

The draft law reaffirms that Indonesia's oil and gas resources are national assets under State control. The Central Government is to act as the holder of all mining authority and to establish a “special executive agency”, which will be a state- owned enterprise (BUK Migas - *Badan Usaha Khusus Minyak dan Gas Bumi*). BUK Migas will be granted authority by the State to do business activities in the upstream (independently and/or through a cooperation with contractor(s)) and downstream sectors. Whilst Law No. 22 requires a maximum of 25% Domestic Market Obligation (DMO) for both oil and gas, the draft law also contains the same DMO percentage.

The draft law, while obviously still subject to further review, appears to focus on locking-down State control over oil and gas resources. Although not a significant shift, there seems to be a stronger emphasis on this outcome. Practically, these changes, especially the relaxation of contractual terms, may raise concerns among investors. Obviously progress of the draft law should be monitored.

3.1.1 Control of upstream and downstream activities

According to Law No. 22, the Government regulates upstream oil and gas activities (generally via a PSC) as the grantor of the relevant concession. Law No. 22 differentiates upstream business activities (between exploration and exploitation) and downstream business activities (processing, transport, storage and commerce) and stipulates that upstream activities are controlled through ”Joint Cooperation Contract (JCCs)” (predominantly PSCs) between the Business Entity/Permanent Establishment (PE) and the executing agency (SKK Migas) (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 thereby 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 SOEs, regional administration-owned companies, cooperatives, small-scale businesses or private-business entities. Upstream business activities can include branches of foreign incorporated enterprises as a 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).

3.1.2 GR-79 as amended by GR-27 on cost recovery and income tax for the oil and gas sector

GR No. 79 (GR-79), issued on 20 December 2010, introduced the initial framework for cost recovery and tax arrangements in the upstream sector. Many implementing regulations have been issued, although some regulations are still pending. For more on this, see Chapter 4.4.2.

Addressing concerns raised by the upstream industry with regard to the application of GR-79, the Government enacted GR No. 27 (GR-27) on 19 June 2017 as lastly amended by GR No. 93 (GR-93) on 31 August 2021. The key provisions of GR-27 are discussed in Chapter 4.4.2.

3.1.3 MoEMR Regulation No. 8/2017 as lastly amended by MoEMR Regulation No. 12/2020 and GR- 93 on GS PSCs

With the stated aim of incentivising exploration and exploitation activities, the Government since 2017 has introduced a "gross production split" model for how upstream business activities should be conducted going forward. We elaborate this model further in Chapter 5.

3.1.4 Restrictions on foreign workers

Currently, by the revocation of Regulation No. 31/2013 by the enactment of MoEMR Regulation No. 6/2018, there is no particular position that is closed to expatriates, unless such activities are restricted under general manpower regulations (e.g. human resource director, occupational safety specialist, job analyst, etc.).

3.1.5 Local content requirements

Law No. 22 mandates that the Business Entity or PE carrying out Oil and Natural Gas business activities must give priority to use of local manpower, domestic goods, services, as well as engineering and design capabilities in a transparent and competitive manner.

As the implementing regulation of Law No. 22, the MoEMR issued Regulation No. 15/2013 on the Use of Domestic Products for Upstream Business of Oil and Natural Gas. The regulation further stipulates that any procurement activity must be in accordance with the Domestic Product Appreciation Book (APDN Book) published by the MoEMR, which lists, among other things, the goods and/or services that are categorised as mandatory, maximised or empowered for use of domestic products.

The method of calculation of the Local Content (TKDN - *Tingkat Komponen Dalam Negeri*) is as follows:

a. Goods will be calculated based on the ratio of domestic components in the goods and the entire costs of finished goods;
b. Services will be calculated based on the ratio between the service cost of domestic components in the services and the total costs of services; and
c. Combination of Goods and Services will be the ratio of entire domestic components costs in the combined goods and services against the entire combined costs of goods and services.

In addition, the status of the goods and/or services' provider will also determine the TKDN value. The MoEMR divides the status as follows: (i) a Domestic Company (owned at least 50% by an Indonesian entity(s)); (ii) a National Company (owned 50% or more by foreign entities); and (iii) a Foreign Company.

Furthermore, the requirement on TKDN is regulated under SKK Migas Work Guidelines (PTK - *Pedoman Tata Kerja*) No. PTK 007 concerning Procurement Guidelines for Goods or Services.

3.1.6 Licences

Business licensing in the oil and gas sector is regulated in GR No. 5/2021 (GR-5) which is the implementing regulation of Law No. 22/2001 (as amended by the Job Creation Law). GR-5 recognises Risk-Based Business Licensing, which is a business license based on the level of risk of business activities, and the level of risk determines the type of business license. The government has mapped the risk level according to business fields or Indonesian Standard Industry Classification (KBLI - *Klasifikasi Baku Lapangan Usaha Indonesia*), which has been implemented in the Risk-Based Online Single Submission (OSS) System.

The Online Single Submission Risk Based Approach (OSS RBA) accommodates licensing in various business sectors based on the level of risk and scale of business activities. This system integrates all business licensing services under the authority of the minister/agency head, governor, or regent/mayor. The requirements and obligations for obtaining a business license of each KBLI are regulated in the attachment of GR-5 and the technical ministry regulation (this refers to MoEMR Regulation). For more of this, see section 6.1.2.

3.2 Other relevant laws

3.2.1 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 - *Dewan Energi Nasional*) 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

GR No. 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 energy-resource mix at 2025 and 2050 target dates as follows:

Table 3.1

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%

Source: PR 22/2017

DEN is chaired by the President and Vice- President with the MoEMR 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 (two from academia; two from industry; one technology representative; one environment representative; and two from consumer groups).

3.2.2 Investment Law No. 25/2007 and Company Law No. 40/2007

Form of business

Under Law No. 22, foreign investors can enter the upstream oil and gas sector through two avenues: either by establishing a branch of a foreign company (referred to as a PE) or by incorporating a limited-liability company in Indonesia (known as PT - Perseroan Terbatas).

The "ring-fencing" principle, outlined in Article 13 of Law No. 22, dictates that only one Production Sharing Contract (PSC) can be granted per PE or PT, necessitating separate entities for each operational area. For instance, following the enactment of Law No. 22, Pertamina had to create subsidiaries and form PSC agreements with SKK Migas for each operational area.

Investment Law No. 25/2007 (Law No. 25) dated 26 April 2007 applies to PTs operating in the downstream sector (including foreign investment companies (PMA – *Penanaman Modal Asing*).

Law No. 25 allows investors to repatriate profits and pay interest and dividends in foreign currencies 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.

Please also note that the authority to issue certain licences is now delegated from MoEMR to Indonesia’s Investment Coordinating Board (BKPM - *Badan Koordinasi Penanaman Modal*), including for trading, refineries, storage, general surveys and various support services.

Positive investment list

On 2 February 2021, a positive investment list was issued through Presidential Decree No. 10/2021 (as amended by Presidential Decree No. 49/2021).

The regulation has three appendices that consist of a business activities priority list, cooperatives and small enterprises business activities list, and business activities with certain requirements list.

As a rule of thumb, any business activities that are not included in the positive investment list are open for foreign investment.

As per Presidential Decree No. 10/2021, restrictions on foreign ownership apply only to National and/or International Sea freight for specific goods business activity within Indonesia's oil and gas sector, with a maximum foreign shareholding capped at 49%.

Legislative responsibilities: environment and others

Law No. 40/2007 imposes corporate social responsibility and environmental obligations on 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. On 4 April 2012, the Government issued GR No. 47/2012 providing explanation of this responsibilities, but it has not been regulated in more detail. Investment Law No. 25 outlines requirements for PT companies, such as giving priority to Indonesian manpower, 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 responsibility (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).

3.2.3 Environment Law No. 32/2009 and Forestry Law No. 41/1999

Environment law

In October 2009, Law No. 32 was issued and entities are required to comply with standard environmental quality requirements and to secure environmental approval before beginning operations. Sanctions can include the cancellation of operating permits, fines, and/or imprisonment.

Forestry law

Law No. 41 prohibits oil and gas activities from being conducted in protected forest areas except where a Government permit is obtained. GR No. 23/2021 allows projects, including for oil and gas activities, to take place in protected forests where they are deemed strategically important.

Under GR No. 23/2021 the utilisation of forestry areas for non-forestry activities is permitted in both production forests and protected forests subject to obtaining an PPKH (*Persetujuan Penggunaan Kawasan Hutan*) from the Ministry of Forestry. The PPKH 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 PPKH 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.

3.2.4 Regulating export proceeds and foreign exchange

BI has issued regulations in 2023 concerning export proceeds and foreign exchange, namely Bank Indonesia Regulation (PBI - *Peraturan Bank Indonesia*) PBI No. 7/2023.

PBI No. 7/2023 stipulate that exporters of natural resources that have a Foreign Exchange Proceeds from Exports from Natural Resources Exported Goods (DHE SDA) with an export value of equal or more than USD250,000 (or its equivalent) in their Export Customs Declarations (PPE - *Pemberitahuan Pabean Ekspor*) must deposit at least 30% of its DHE SDA in the Indonesian financial system, for a minimum period of three months since the placement of the deposit.

The DHE SDA deposit can be placed in one of the following instruments:

a. A special account opened at the Indonesian Export Financing Agency (LPEI - *Lembaga Pembiayaan Ekspor Indonesia*) or at a foreign exchange bank;
b. Banking instruments, e.g., foreign exchange time deposit;
c. Financial instruments issued by LPEI, i.e, promissory note in foreign exchange; and/or
d. Financial instruments issued by BI, i.e, conventional open market operation term deposit in foreign exchange in BI.

Pursuant to BI Regulation 7/2023, DHE SDA deposited in the above banking and financial instruments have several benefits for the exporters, among other things, for funds deposited into a special account, it could be used for a forex swap transaction between the exporters and the banks and such instruments may also be used by the exporters as a loan security (in Rupiah currency). Furthermore, according to GR 36/2023, DHE SDA deposited in the special account may be used by exporters for the payment of export duty and other levies in export sector, loan, import, profits/dividends, and/or other needs for investment (e.g. transfer of DHE SDA to another party).

Administrative sanctions, in the form of suspension of export services/facilities, will be imposed to the exporters of natural resources for non-compliance of the following obligations:

a. Failure to deposit DHE SDA on special accounts;
b. Failure to deposit DHE SDA of at least 30% of their export proceeds and below 3 months; and/or
c. Failure to create an escrow account on or transfer overseas escrow account to LPEI and/or certain banks conducting activities in foreign exchanges.

GR 36/2023 introduces heavier penalties than GR 1/2019 on exporters failing to comply with the regulation. The requirement for the exporters to deposit at least 30% of their DHE SDA for a minimum of three months may cause concerns for the exporters (including Indonesian mining companies) in managing their cash flows.

For the oil and gas sector concerns with the PBIs 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. The cost of minimum periods of deposit and/or mandatory conversions into Rupiah.

3.2.5 Mandatory use of Indonesian Rupiah

On 31 March 2015, Central Bank of Indonesia (BI) issued Regulation No. 17 (17/3/PBI/2015) as implementing guidance for Law No. 7/2011 regarding the mandatory use of the Rupiah for cash and non-cash transactions in Indonesia. Circular Letter (SE - *Surat Edaran*) No. 17/11/ DKSP17) 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 systems; and
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 ten-year period.

The MoEMR and BI have formed a task force to set guidelines and procedures for the implementation of PBI No. 17/3/PBI/2015, especially for Category 3 types of transactions.

3.3 Key stakeholders

3.3.1 The MoEMR

The 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. Presidential Decree No. 97/2021 stipulates the functions of the MoEMR, which include:

a. Formulating and determining the development, control, and supervision policies of oil and gas;
b. Implementing policies in the field of development, control, and supervising oil and gas;
c. Implementing of technical guidance and supervising the implementation of policies in the field of guidance, control, and supervision of oil and gas;
d. Implementing research and development in the field of energy and mineral resources.

3.3.2 Special Task Force for Upstream Oil and Gas Business Activities (SKK Migas)

SKK Migas controls upstream activities and manages oil and gas contractors on behalf of the Government through JCCs. 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.

Based on MoEMR Regulation No. 2/2022, SKK Migas has the following roles:

a. To provide advice to the MoEMR with regard to the preparation and offering of work areas and JCCs;
b. To act as a party to JCCs;
c. To assess first field development plans in a given work area and to submit evaluations to the MoEMR for 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 JCCs; and
g. To appoint sellers of the State's portion of petroleum and/or natural gas to the Government's best advantage.


Photo source: PT Pertamina (Persero)

3.3.3 Downstream Oil and Gas Regulatory Agency (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' regulatory, development and supervisory roles are set out in the following table:

Table 3.2 - Regulatory, development and supervisory roles

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 (CD) • 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 CD • 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.

Table 3.3 - Supervision of fuel distribution and transportation of gas

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 outlined a plan to auction concessions for the construction of gas pipelines 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.

3.3.4 House of representatives (DPR - *Dewan Perwakilan Rakyat*) and regional governments

Commission VII of the 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 (APBN) and control of related Government policy. It also advises the Government of the oil and gas sector's contributions to the APBN.

Regional Governments are involved in the approval of PoD through the issuance of local permits and land rights. In addition, the Regional Governments have the right to be offered a 10% participating interest of a PSC. For more detail on this, please see Chapter 4.1.8.

3.3.5 PT Pertamina (Persero)

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 (JOs) within 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.

With the issuance of GR No. 6/2018, the Government formalised the establishment of a National State-Owned Enterprise (SOE/BUMN - *Badan Usaha Milik Negara*) holding company in the oil and gas sector, combining the business of PGN with Pertamina and appointing Pertamina as the holding company of SOEs serving the oil and gas industry. In February 2018, Pertamina became the major shareholder of PGN, by acquiring the Government's controlling 56.97% stake while PGN continues to be a publicly listed company.

Following the acquisition, Pertamina and PGN integrated and streamlined the gas distribution business previously held by PGN and PT Pertamina Gas (Pertagas), a wholly-owned subsidiary of Pertamina. In December 2018, PGN acquired Pertamina's 51% controlling interest in Pertagas, and became the sub-holding entity for gas operations.

3.3.6. Notable 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 mission is to be the voice of the upstream oil and gas industry in Indonesia and to work collaboratively with all stakeholders to promote the industry for the benefit of government, investors, communities, employees, customers and the environment.

Other industry associations include drilling company associations (APMI – *Asosiasi Perusahaan Pemboran Minyak, Gas dan Panas Bumi Indonesia*), national oil and gas company association (ASPERMIGAS - *Asosiasi Perusahaan Minyak dan Gas*), oil and gas entrepreneurs association (HISWANA MIGAS - *Himpunan Wiraswasta Nasional Minyak dan Gas Bumi*) and KADIN.

Photo source: PT Pertamina (Persero)

4 (Conventional) Upstream sector

As previously mentioned, the government introduced the Gross Split (GS) Production Sharing Contract (PSC) model for upstream business activities, intended to be implemented for new PSCs from 2017/2018 onwards. However, it's worth noting the flexibility introduced in 2020, as discussed in Section 1.2.

The GS PSC regime has significantly altered the fundamental principles and regulatory framework of the conventional cost recovery model in the upstream sector, which had been established for over 40 years. The GS system is discussed in Chapter 5. This chapter covers the traditional, or conventional, cost recovery PSC system, which is still the main system in force in the Indonesian upstream oil and gas sector.

4.1 Upstream regulations

Activities in the oil and gas upstream sector are regulated by Law No. 22, its implementing regulation GR No. 35/2004 (GR-35), and the amending GR No. 34/2005 (GR-34), as well as GR No. 55/2009 (GR-55), GR-27 (as an amendment to GR-79), and GR-93. A summary of Law No. 22's key sections is set out below.

4.1.1 Work areas

Upstream business activities, including exploration and exploitation, are conducted within designated regions known as "work areas". These areas are formalized following approval by the Ministry of Energy and Mineral Resources (MoEMR), in consultation with SKK Migas and relevant local government authorities, and are specified in a Joint Cooperation Contract (JCC).

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

Following the issuance of MoEMR Regulation No. 08/2017 (Regulation-08) regarding GS PSCs in January 2017, direct offers or tenders for new acreage must be awarded under the GS mechanism. However, on 15 July 2020, the MoEMR issued Regulation No.12/2020 (Regulation-12), which constitutes the third amendment to Regulation-08, providing an option for oil and gas investors to choose either a conventional cost recovery PSC or a GS PSC. Hence, this provides legal certainty and flexibility for oil and gas investors.

The key features of a GS PSC can be found in Chapter 5.

Photo source: PT Pertamina (Persero)

Each business entity or Permanent Establishment (Contractor) is permitted to hold only one work area, adhering to the "ring-fencing" principle. The Contractor must return the work area, either in stages or in full, as commitments are fulfilled according to the JCC. Once returned, the work area becomes open for allocation.

4.1.2 Awarding of contracts – direct offers or tenders for new acreage

Direct offers for new acreage

Under 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 during 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 has been relinquished.

MoEMR Regulation No. 23/2021 regulates that expiring PSCs can be managed by either:

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


Photo source: ENI Muara Bakau B.V

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 USD5,000, and is non-refundable;
b. Purchase an official government data package for the particular block being tendered to support the technical evaluation and the proposed exploration program to be submitted together 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 complete bid documents by the tender closing date;
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); and
f. The winner of the tender is determined by the DGOG after a recommendation from the Tender Team.

Table 4.1 - Tender document checklist

No.	Subject	Remark
1.	Application Form	A completed application form.
2.	Work Programme and Budget (WP&B)	A proposed WP&B for six years of exploration activities (a sample WP&B for a tender is provided below).
3.	Technical Report and Montage	The geological and technical justification for the proposed exploration programme, 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 of its parent company.
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 projections of the participant for the next three years. A statement letter from a bank confirming the participant's ability to finance all work programme 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 parent 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.

4.1.3 General surveys and oil and gas data

In order to delineate work areas effectively, a general survey Geological and Geophysical (G&G) is a prerequisite. However, any survey undertaken by a business entity must be at its own expense and risk, and only after obtaining permission from the MoEMR.

Data obtained from general surveys and exploration and exploitation activities automatically become the property of the State. Therefore, any utilisation, transmission, surrender, or transfer of this data, whether within or outside Indonesia, requires explicit permission from the MoEMR. Furthermore, data resulting from exploration and exploitation activities must be surrendered to the MoEMR (via SKK Migas) within three months of collection, processing, and interpretation.

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

4.1.4 JCC

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

The JCC contains provisions stipulating as follows (Article 6):

a. That ownership of the oil and gas remains with the Government until the point of delivery;
b. That ultimate control over operational management remains with SKK Migas; and
c. That all capital and risks shall be 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 programmes;
d. Expenditure commitments;
e. Transfer of ownership of the results of the production of oil and gas;
f. The period and conditions for the extension of the contract;
g. The mechanism for the settlement of any disputes;
h. Any domestic supply obligations (a maximum of 25% of production is generally earmarked to meet domestic demand) (Article 22);
i. Post-mining operation obligations;
j. Workplace 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 for 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 investors in return for investing, in cooperation with the Government, in oil and gas exploration and exploitation (i.e. PSCs; TACs; and Enhanced Oil Recovery (EOR) Contracts). The second category referred to the agreements entered into by participants in a PSC, TAC or EOR regarding how they will conduct petroleum operations, such as JOAs and Joint Operation Bodies (JOBs). Since the passing of Law No. 22, most new contracts have been in the form of PSCs.

4.1.5 Activity, expenditure and bonus commitments

Contractors are required to begin their activities within six months of the effective start 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 meeting all financing requirements, and bears full risk if exploration is not successful. This financing is expected to be denominated in USD. Any costs incurred by Contractors are subject to recovery from the Government.

Annual exploration expenditure requirements are outlined in the Production Sharing Contract (PSC) for both the initial six years and any extensions. While the annual commitment is stipulated in the PSC, specifics must be endorsed by SKK Migas through annual work programmes and associated budgets (for PSCs with cost recovery mechanisms). Additionally, the Government usually mandates the Contractor to obtain a performance bond to cover the initial three contract years of activity. Any excess expenditure can be carried forward, but under-expenditure requires consent from SKK Migas for adjustment.

Failure to carry out the required obligation may lead to the termination of the JCC, and any under-expenditure may need to be paid to the Government along with the forfeiture 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 USD 1 million – USD 15 million.
b. Production Bonuses – payable if production exceeds a specified number of barrels per day, e.g. USD 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 by the Contractor and SKK Migas before signing the PSC.

4.1.6 Contract period

Joint Cooperation Contracts (JCCs) are valid for a maximum of thirty years from the date of approval. Upon reaching this limit, the Contractor has the option to request an extension from the MoEMR for a maximum period of twenty years per extension (as per Article 14). Extension requests can be submitted no earlier than ten years and no later than two years before the JCC expiration date.

The maximum thirty-year period encompasses both the exploration and exploitation phases. Typically, the exploration phase lasts for six years and can be extended for an additional four years at most (as outlined in Article 15). If no commercial discoveries are made during the exploration phase, the JCC is terminated. Upon expiration of the contract period, the Contractor is required to return the remaining work area to the MoEMR.

4.1.7 Amendments to a JCC

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.

4.1.8 Participating interests-transfers

A contractor has the option to transfer part or all of its participating interest, subject to prior approval from the Ministry of Energy and Mineral Resources (MoEMR) and/or SKK Migas, depending on the terms outlined in its Production Sharing Contract (PSC). However, the transfer of a majority participating interest to a non-affiliate is prohibited during the first three years of the exploration period. The taxation issues associated with PSC transfers are discussed in Chapter 4.5, including under GR-79, as amended by GR-27.

Upon making a commercial discovery, the Contractor is obligated to offer a 10% participating interest (at the Net Book Value of the expenditure incurred up to that date) to a Regionally Owned Business Entity (BUMD - Badan Usaha Milik Daerah). This requirement was established by MoEMR Regulation No. 37 of 2016. Under this regulation, the Contractor must bear the financial obligations associated with the 10% participating interest of the BUMD and recoup the investment through oil and gas production without any uplift.

If the offer is not taken up by the BUMD, the Contractor is required to offer the interest to a nationally-owned company. The offer is declared closed if the nationally-owned 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.

4.1.9 Occupational health and safety, environmental management, and CD

Contractors must adhere to relevant laws and regulations concerning occupational health and safety, environmental management, and community development (CD). For PSC contracts signed on or after 2008, the Contractor is explicitly tasked with implementing CD programmes throughout the PSC's duration.

Contractors can contribute to CD through various means, including providing physical facilities, empowering local enterprises and the workforce, and conducting community-focused activities. These CD efforts should be done in consultation with the Local Government, with priority given to communities nearest to the work area. Additionally, Contractors are responsible for funding 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 (non-CR) according to GR-79, becomes cost-recoverable under GR-27 (see comments on GR 27 in Chapter 4.4).

4.1.10 Reservoir extension and unitisation

When a reservoir extends into another Contractor’s work area, an open area, or the territory/continental shelf of another country, it must be reported to the MoEMR or SKK Migas. Unitisation arrangements may be formalised in these cases. If the reservoir extends into an open area that later becomes a work area, unitisation must be formalised. However, if the open area remains unchanged for five years, a proportionate extension of a contract’s work area can be requested. All unitisation requests require approval from the MoEMR.

4.1.11 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’s approval has been obtained, and the activities are not aimed at making a profit. If such facilities are used jointly with the objective of making a profit, these will represent downstream activities, and will require the establishment of a separate business entity under a downstream business permit.

4.1.12 Share of production to meet domestic needs

Contractors are responsible for meeting domestic demand for crude oil and/or natural gas. According to regulations GR-35 and GR-27 (amendment of GR-79), the Contractor's share of production earmarked for domestic demand is capped at a maximum of 25%. Additionally, GR-27 introduces a DMO (Domestic Market Obligation) holiday incentive for oil, which can be issued by the MoEMR with approval from the MoF.

4.1.13 Land title (Articles 33-37 of Law No. 22 and Section VII of GR-35)

Rights to working areas are a “right to the sub-surface part” and do not cover land surface rights. Land-rights acquisitions can be obtained after offering a settlement to the owners and occupiers in accordance with the prevailing laws (Article 34).
A consideration for land is based upon the prevailing market rate. Where a settlement is offered, land titleholders 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 has been granted 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 a condition for the granting of any consent. Section VII of GR-35 sets out detailed provisions regarding the procedures for resettlement.

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

4.1.14 Use of domestic goods, service, technology, engineering and design capabilities

Under the cost-recovery scheme, all goods and equipment purchased by Contractors become the property of the Government. Importation of goods requires approvals from the Ministry of Energy and Mineral Resources (MoEMR), Ministry of Finance (MoF), and other relevant ministries. Imports are permitted only if the required products are not domestically available at the necessary quality, efficiency, guaranteed delivery time, and after-sales service standards.

Management of goods and equipment falls under the jurisdiction of SKK Migas. Surplus goods and equipment may be transferred to other Contractors with government approval, ensuring responsible use of cost recovery funds. Surplus inventory resulting from poor planning is not eligible for cost recovery, aligning with GR-79 as amended by GR-27.

This position is supported by GR-79, as amended by GR-27.

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 a recommendation from 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 (PP&E); and tendering for goods and services, please refer to these respective titles in Chapter 4.2.4.


Photo source: PT Pertamina (Persero)

4.1.15 Manpower and control of employee costs and benefits

Contractors are encouraged to prioritise hiring local manpower, but they may employ foreign workers for specialised expertise not readily available among Indonesian personnel. The number of expatriate positions is regulated by SKK Migas and undergoes annual review. The current manpower laws and regulations applying to the employees of a Contractor are dealt with in Chapter 3.1.4 above. Contractors are required to provide development, education and training programs for Indonesian workers.

During the annual work plan and budget review, SKK Migas evaluates training programmes, salary and benefit costs, and plans for localising expatriate positions. Contractors must submit annual manpower or organisational charts for both national and expatriate workers (RPTK and RPTKA) for SKK Migas' approval. SKK Migas controls the salaries and benefits which can be paid and the costs which can be 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 retirement, or severance payments for general terminations (referred to as the *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 their years of service.

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

Some PSC operators have opted to manage their pension plans by funding them using bank time deposits, with the interest earned reinvested and used to reduce the future funding. All pension schemes require PSC operators to prepare an actuarial assessment of the fair value of the 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.

4.1.16 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 the relevant provisions on occupational health and safety and environmental protection, and using EOR technology, as appropriate.

4.1.17 Dispute mechanism-arbitration

SKK Migas has established a special dispute resolution mechanism, PTK 051, for PSC cost recovery disputes. This mechanism guides SKK Migas and Contractors in deferring cost recovery based on audit findings, Financial Quarterly Report (FQR) analysis, Authorisation for Expenditure (AFE) audits, and questioned expenditures.

Prior to the deferral of cost recovery, discussions shall be held with successive tiers of management of 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.

Photo source: PwC

4.2 Production Sharing Contracts (PSCs)

4.2.1 General overview and commercial terms

Production Sharing Contracts (PSCs) are the predominant agreements used in Indonesia's upstream sector. In a conventional PSC, the Government and the Contractor agree to split production revenue based on predetermined percentages. Operating costs are recovered from production through Contractor Cost oil formulas defined in the PSC. Additionally, the Contractor has the right to separately dispose of its share of oil and gas, with ownership passing at the point of export or delivery.

Regulation-08 introduces a PSC scheme based upon the sharing of a "Gross Production Split" without a cost recovery mechanism, later amended by MoEMR Regulation No. 52/2017, MoEMR Regulation No. 20/2019 and MoEMR Regulation No. 12/2020 (refer to Chapter 5 for more detail).

Generations of conventional PSCs

PSCs have evolved through five "generations", with the main variations between them relating to 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 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 that region (fourth generation). In 2008, a fifth generation of PSCs with a cost recovery mechanism was introduced. While the after-tax equity split is negotiable, the latest model limits the spending available for cost recovery (via a "negative list" regulated under GR-79 as amended by 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 4.2.2.

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

a. Rather than a fixed after-tax share, recent PSCs have introduced 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 in the contracts 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 for 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 the MoEMR and/or SKK Migas' approval; and
    - Where the Contractor has retained a majority interest and operatorship for three years after signing.

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.

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 a PSC is that the Contractor bears all the risks and costs of exploration. If production does not proceed, these costs are not recoverable, but 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.

The 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" with 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 programme with a minimum exploration expenditure over a certain number of years;
e. All equipment, machinery, inventory, materials and supplies purchased by the Contractor becomes the property of the State once landed in Indonesia. The Contractor has a right to use and retain custody during operations. The Contractor has access to exploration, exploitation and G&G 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 the 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. Recent 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 the current-year depreciation charges) and non-capital costs;
b. Prior years' unrecovered capital and non-capital costs;
c. Inventory costs;
d. Head office overheads charged to operations; and
e. Insurance premiums and receipts from insurance claims.

Over time, several principles and regulations have been developed by entities like SKK Migas/BP Migas/Pertamina and the Indonesian Tax Office (ITO). For instance, PSC Contractors typically receive an after-tax equity share of 15% from oil production. However, this share is subject to meeting the Domestic Market Obligation (DMO), leading to a reduced return for Contractors. Additionally, Field Development Plans (FTPs) allow the Government to claim a share of production before full cost recovery by Contractors.

Since 1995, PSCs have mandated that Contractors are responsible for site restoration, including clearing, cleaning, and restoring sites upon completion of work. Funds allocated for abandonment and site restoration are recoverable once spent or funded, with unused funds retained in a joint account, and are not refundable to the Contractor.

In 2017, the MoEMR issued Regulation No. 26/2017 (as later amended by MoEMR Regulation No. 47/2017, No. 24/2018, and No. 46/2018) stipulating the mechanism for PSC Contractors to recover (unrecovered) "Investment Costs" upon the expiration of the PSC. Investment costs are referred to as capital expenditure incurred over the PSC term by PSC Contractors with the objective of maintaining an equitable level of production for a maximum of five years before PSC expiration, subject to SKK Migas approval.

In summary, MoEMR Regulation 26 stipulates that; for (conventional) PSC, an unrecovered investment costs can be carried forward to the extended (conventional) PSC.

PSC accounting principles

The PSC outlines the accounting principles to be applied by the Contractor. Under relevant clauses of the PSC, 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) and Indonesian Financial Accounting Standards (IFAS). Most companies, however, do not prepare financial statements compliant with IFAS, and instead prepare PSC statements adjusted at the head office level to comply with GAAP. SKK Migas issued PTK 059 as general guidance on PSC accounting. However, detailed PSC accounting must make reference to the specific PSC agreement.

4.2.2 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 delayed generation of income inherent in the exploration process, a credit ranging from 17% to 55% of the capital costs of development, transport and production facilities has historically been available. Second-generation PSCs allowed a rate of up to 20% for fields that commenced commercial operations after 1976.

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

Under 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 specified in GR-79/27.

Cost oil

The expenses which are 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 head office overheads (typically capped at a maximum of 2% of current year costs) provided the cost methodology is applied consistently, is disclosed in quarterly reports and is approved by SKK Migas (see further guidance below under Management and Head Office Overheads);


Photo source: PwC

b. Depreciation of capital costs calculated at the beginning of the year during which the asset is Placed Into Service (PIS) (although for recent PSCs only monthly depreciation is allowed in the initial year). The permitted depreciation methods are either the declining balance or double declining balance method, 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. Unrecouped operating and depreciation costs from previous years. If production is not sufficient to recoup costs, these may be carried forward to subsequent years with no time limit.

In December 2010, GR-79 increased the number of non-CR items to 24. However, the list of non-items CR was then revised under GR-27 to 22 items effective from 19 June 2017. The list of non-CR items under GR-27 is as follows:

a. Costs 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 implementing regulations, as well as claims or fines resulting from the Contractor's actions;
e. Depreciation of assets which do not belong to the Government;
f. Incentives, payments of pension contributions and insurance premiums for foreign manpower, management and shareholders and/or their family members;
g. Expatriate manpower costs which do not comply with the procedures of the RPTKA or Expatriate Manpower Permits (IMTA - *Izin Mempekerjakan Tenaga Asing*);
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 accompanied by a nominative list and the relevant tax ID number (NPWP - *Nomor Pokok Wajib Pajak*);
l. Training costs for expatriate manpower;
m. Merger and acquisition costs or Participating Interest costs;
n. Interest expenses on loans;
o. Employee Income Tax (EIT) borne by the Contractor, except when paid as a tax allowance, or third party EIT which is borne by the 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 by the MoEMR;
q. Surplus materials purchased due to poor planning;
r. Costs incurred due to the negligent operation of Place Into Service (PIS) facilities;
s. Transactions which are written off, contrary to the terms of the tender process or against the law;
t. Bonuses paid to the Government;
u. Costs incurred prior to the signing of the relevant cooperation contract; and
v. Commercial audit costs.

Sharing of production oil

Crude production in excess of the amounts received for FTP, cost recovery and investment credits is allocated to the Government and 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 4.5 for further discussion.

GS PSCs have a slightly different approach regarding the charging of direct and indirect head office expenditure to PSC operations. See further discussion in Chapter 5.

FTP

Under pre-2002 contracts, Contractors and the Government were both entitled to claim FTP, and received petroleum equal to 20% of the production before any deduction for operating costs. The 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%) without sharing with the Contractor.

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

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 grandfathered rates (i.e. the tax rates in effect when the PSC was signed). This is summarised as follows:

Table 4.2 - Summary of after tax oil splits

	Post 2002 PSC (%)	1995 Eastern Province PSC (%)	1995 PSC (%)	1985 - 1994 PSC (%)	Pre-1984 PSC (%)
Tax rate	42.4/40/37.6*	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:	Varies				
35/(100-44)		62.50			
15/(100-44)			26.79		
15/(100-48)				28.85	
15/(100-56)					34.09

** The general combined Corporate and Dividend (C&D) tax rate fell to 42.4% in 2009, 40% in 2010 and 37.6% in 2020.*

Sources: GR-79/2010 as amended by GR-27/2017, Pre-1984 PSC, 1985 - 1994 PSC, 1995 PSC, 1995 Eastern Province PSC, 2002 - 2023 PSC.

DMO

According to the PSC, after the commencement of commercial production 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 25% of the total oil production to the domestic market out of its equity share of production. The oil DMO is to be 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, SKK Migas pays the Contractor the full ICP value for its oil DMO. This is reduced to 10% or 25% of that price for subsequent years (depending upon the generation of PSC). The price used is the Weighted Average Price (WAP).

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

In July 2021, the MoEMR issued regulation No.18/2021 prioritising the use of crude oil for domestic needs. The issuance of this regulation was in line with the Government's broader policy objective of reducing crude oil imports.

In summary, MoEMR Regulation No. 18/2021 requires Pertamina to prioritise the procurement of crude oil from domestic sources over importing. In this regard, PSC contractors are obliged to offer or include Pertamina in tenders for their portion of crude oil before exporting, pursuant to business-to-business negotiations (presumably meaning that the crude need not be sold at below "market" value). It is also stipulated that the negotiations must be conducted within 20 days.

The tax implications of MoEMR Regulation No. 18/2021 include that crude sales at market price could lead to a gain or loss for PSC Contractors based on any variation between the negotiated price (with Pertamina) and the ICP. Any gains generated could be subject to the prevailing Income Tax rates (including Branch Profits Tax (BPT) - if applicable).

Valuation of oil

For the purpose of calculating a share of production, and for tax purposes, oil is valued using a price reference known as the ICP. Under a PSC, the Contractor receives oil or in-kind products in settlement of its costs and its share of equity. This makes it necessary to determine a price to convert oil into USD in order to calculate cost recovery, taxes and other fiscal items such as under/over lifting. The ICP is determined monthly by the MoEMR based on the average daily prices of international indices from the preceding month.

The monthly tax calculations are based on the ICP and on actual Contractor lifting. 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.


Photo source: bp Indonesia

4.2.3 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 the relevant production costs will be allocated against each according to the proportion of production in value terms in the year or some other 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:

Table 4.3 - Summary of after tax gas splits

	Post 2002 PSC (%)	1995 Eastern Province PSC (%)	1995 PSC (%)	1985 - 1994 PSC (%)	Pre-1984 PSC (%)
Tax rate	40/37.6*	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:	Varies				
40/(100-44)		71.43			
30/(100-44)			53.57		
30/(100-48)				57.69	
30/(100-56)					68.18

** The general combined C&D tax rate fell to 42.4% in 2009, 40% in 2010 and 37.6% in 2020.*

Sources: GR-79/2010 as amended by GR-27/2017, Pre-1984 PSC, 1985 - 1994 PSC, 1995 PSC, 1995, Eastern Province PSC, 2002 - 2023 PSC.

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.

Table 4.4

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 =	USD 60		
C&D tax =	56%		
Description	Formula used	Year to date	
		bbls	USD
Lifting:			
- SKK Migas	USD [a1] = bbls x WAP	2,500	150,000
- Contractors	USD [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 USD : WAP	4,000	240,000
- Investment credit	Cost in bbls = cost in USD : 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

Note: SKK Migas on behalf of the Government

Table 4.5

Illustrative calculation of C&D taxes for Contractor's entitlement in old PSC			
Description	USD		
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		= C&D tax/ Contractor's taxable income
C&D tax (56%)	14,268		= 14,268/25,479
			= 56%
Contractor's net income	11,211		
* DMO comprised of two items :	Quantity in barrels	USD	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 :	USD		
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 FQR format

Description	USD
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
Contractor's 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 Contractor's share	**251,211**

Domestic gas pricing

Gas pricing in domestic supply contracts is determined through negotiations on a field-by-field basis between 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 in turn then sold the gas to the end-user. Prices were fixed for a designated level of supply for the duration of the contract.

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

Take-or-pay arrangements have been negotiated in some circumstances. Although this concept has long been accepted, the policy regarding 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.

MoEMR issued Regulation No. 15/2022 and Regulation No. 10/2020 stipulating a maximum gas price of USD6/MMBTU at the plant gate for gas buyers in certain industries. Industries covered by Regulation No. 8/2020 include the fertiliser, petrochemical, oleochemical, steel, ceramic, glass and rubber glove industries, and this was expanded under Regulation No. 10/2020 to the power generation sector (including PT PLN (Persero) as gas buyer). The MoEMR will determine the necessary adjustments to the gas purchase price from the gas producer and/or to the related distribution costs, including liquefaction, compression, pipeline transmission and distribution, and transportation based on recommendations from SKK Migas or the Special Oil & Gas Regulatory Body of Aceh (BPMA - *Badan Pengelola Migas Aceh*) and the supervisory body for gas distribution.

Further, Regulations No. 15/2022 and No. 10/2020 clarify that the adjustments to the gas price will not affect the gas producer's entitlement to proceeds based on existing gas purchase agreements with gas buyers. Instead, these adjustments will be accounted for as a reductions in the Government entitlement when performing the current year equity split calculation. Detailed provisions regarding the calculation of the entitlement to gas price adjustments will be further regulated through technical guidance from SKK Migas or BPMA.

Over/(under) lifting

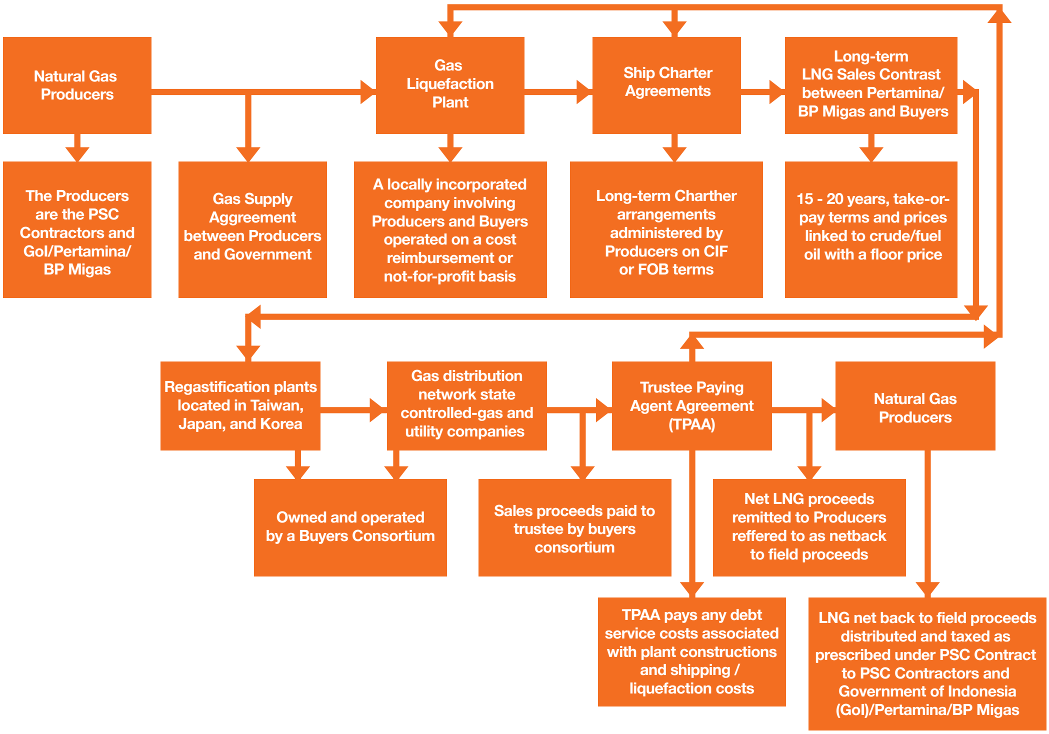
Lifting variances will occur each year between the Contractor and the Government. These under-/over-lifting amounts are settled with the Government in cash or from production and can be considered as sales/purchases of oil or gas respectively. The individual members of the PSC may in turn have under-/over-lifting balances 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. 118/PMK/02/2019 as lastly amended with MoF Regulation No. 51/2023 any under-lifting position between the Contractor and the Government should be settled in cash within 17 days (subject to the time taken for the 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 FQR is finalised in March of the subsequent year.

Integrated LNG supply projects

Indonesia currently has three operating LNG facilities, namely PT Badak LNG, BP Tangguh LNG, and PT Donggi Senoro LNG.

Historically, Indonesia has utilised a traditional integrated LNG seller/buyer supply chain structure. The LNG supply chain is generally structured as follows:



For Bontang, PT Badak NGL was established as a continuation of the upstream operations of 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 at minimum prices in order to reduce the 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.

The Bontang and Tangguh LNG projects were effectively project-financed with an implied Government guarantee which enabled lower financing costs. A trustee-paying agent arrangement was also established to service this debt and the related O&M costs. These processing and financing costs are first netted off against LNG proceeds with the net proceeds then released back to the PSC entitlement calculation (i.e. under the so-called “net back to field” approach). The Tangguh LNG facility uses a similar concept to Bontang, and is operated by BP Tangguh on behalf of the gas producers, but without a separate gas processing entity.

Non-integrated LNG projects

Non-integrated projects involve the legal/investor separation of 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. Under a non-integrated LNG model the investors in the LNG plant separately require a designated rate of return on their investment in order to service project finance etc. (i.e. unlike the “net back to field” approach outlined above for integrated projects which effectively allows 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 (WHT), VAT, tax rate differentials (and associated transfer pricing) and PE issues need to be considered. In addition, any offshore project company would need to consider its 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 Corporation, Kogas and Pertamina, but Mitsubishi does not have a participating interest in the two PSCs that supply gas to the LNG plant.

4.2.4 Other PSC conditions and considerations

The procurement of goods and services

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

Guidance No.PTK-007/SKKIA0000/2023/S9 (PTK-007) on the Management Framework for the Supply Chain for Cooperation Contracts (*Pedoman Tata Kerja Pengelolaan Rantai Suplai Kontraktor Kontrak Kerja Sama*) is the current referred guidance on procurement of goods and services.

In general, all purchases are done by either tender or direct appointment (with certain requirements) and only vendors with Oil and Gas Support Business Capability Certificate (SKUP - *Surat Kemampuan Usaha Penunjang Migas*) and (SPDA - *Sertifikat Pengganti Dokumen Administrasi*) are considered qualified and able to bid. A PSC Contractor can procure goods and services by itself but require SKK Migas approval at the preparation of procurement list and planning stage if the package is worth over IDR50 billion or USD5 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 carried out through approval by SKK Migas and where the overruns exceed 10% of the initial contract or above IDR200 billion or USD20 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 IDR200 billion or USD20 million.

All equipment purchased by PSC Contractors is considered the property of the Government from the time when it enters Indonesia. Oil and gas equipment may enter duty free if used for operational purposes (please see further discussion in Chapter 4.4.8 below). Imported equipment used by service companies on a permanent basis is assessed for Import Duty unless this is 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 4.4.8.

Inventory

Under the PSC, spare parts inventory is separated into capital and non-capital. Non-capital inventory is charged to cost recovery immediately upon purchase or landing in Indonesia. A counter-entry account is usually maintained to track the physical movements and use of non-capital inventory. For later generation PSCs, however, inventory is 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 surplus materials 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, or held by the Contractor on behalf of SKK Migas.


Photo source: PT Pertamina (Persero)

PP&E

Under the PSC framework, PP&E, including land rights, purchased or acquired in Indonesia, become the property of the Government. However, the Contractor retains the right to use these assets until approved for abandonment by SKK Migas.

The NBV 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 they are 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 from the time when the asset is 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 PIS 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. PIS approval should be submitted together with the AFE Close-out Report in order for the final depreciable project cost to be agreed. Exhibit C to the PSC describes the category method, and useful life for the purposes of PSC depreciation.

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 PSCs signed from 2008 onwards any cash funds set aside in a non-refundable joint account for abandonment and site restoration are cost-recoverable. Any unused funds will be transferred to SKK Migas. According to 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 costs 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.

Based on MoEMR Regulation No. 15/2018 regarding the post-operation of oil and gas upstream activities, Contractors are obligated to conduct post-operation activities using post-operation activity funds and to 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 bank account of SKK Migas and the Contractors, in accordance with the estimated post-operation activity costs (referred to as the "Abandonment and Site Restoration" or "ASR" fund).

4.3 Upstream accounting

The table below shows some of the key standards relating to upstream oil and gas companies under PSC accounting, GAAP in the United States (US GAAP) and IFRS.

Table 4.6

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***
Depreciation of capital costs	Accelerated depreciation with a full year's depreciation in the year of acquisition	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 Standards (IAS) 12 treatment
Contingent liabilities	Recognised when settled or approved by SKK Migas	ASC 450	IAS 37 treatment
Severance and retirement benefits	Recognised when paid or funded	ASC 715	IAS 19 (Revised) treatment
Decommissioning and restoration obligation	Recorded and recovered on a cash basis, if specifically provided for in the PSC	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	Expensed
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, IFAS do not significantly differ from IFRS, except for the effective date of the application of new standards as they are issued.*
*** New PSCs signed from 2011 capitalise intangible costs*

4.3.1 Statement of Financial Accounting Standards (SFAS) 66/IFRS 11 – joint arrangements

Oil and gas companies often use joint arrangements to spread risks, share costs, or bring specialised skills to projects. These arrangements can take various legal forms, such as formal joint-venture contracts or governance arrangements outlined in company formation documents. What distinguishes joint arrangements is the presence of joint control.

Unanimous consent is generally required 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, for unincorporated JOs, participants must account for their interest in a JO as a share of assets, liabilities, revenue and costs. A joint venture participant uses the equity method to account for its investment in a joint venture.

In Indonesia's oil and gas industry, upstream joint working arrangements typically take the form of joint arrangements. While some companies establish JOs through separate vehicles, such instances are rare and generally fall under SFAS 66/IFRS 11. Midstream and downstream joint-working arrangements usually involve separate vehicles and incorporated entities.

Photo source: PwC

4.4 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 addressed, however (please see our annual PwC Pocket Tax Guide for discussion of this area). Issues around the taxation of GS PSCs are outlined in Chapter 5.

4.4.1 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 SOEs. Law No. 44 did, however, allow for SOEs to appoint other parties as Contractors.

Pertamina, established as a State Enterprise through GR No. 27 of 1968 and Law No. 8/1971, gained authority over appointing private enterprises, including overseas entities, as Contractors under oil and gas mining arrangements. This marked the start of PSC and similar contractual setups.

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 1970s, this changed to a "gross of tax" basis to comply with US foreign tax credit rules. Consequently, PSC entities became responsible for calculating taxable income and paying Income Tax directly. Despite this shift, there was an expectation that PSC entities would maintain a "net of tax" entitlement.

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-27 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 Gas Sales Agreement 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 as long as within a 4:1 debt equity ratio to the five year restriction under the general Income Tax rules;
e. That there is an unlimited carry forward of prior year unrecovered costs; 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.

4.4.2 GR-79, as amended by GR-27 and GR-93 (GR-79/27/93)

GR-79 was the first dedicated regulation dealing with both the cost recovery and tax arrangements for this important industry. Notwithstanding the issuance of a number of implementing regulations for GR-79, many issues remain unclear. The table below summarises the issues which remain unclear, as well as the status of the respective regulations etc.

Table 4.7

Article	Unclear Area	Regulation Pending	Guidance Pending
Article 3, Article 5, Article 12	Definition of the principle of effectiveness, efficiency and fairness, as well as good business and engineering practices		
Article 7	Ring fencing by field or well		
Article 8	Minimum Government Share of a Work Area		Yes, per Article 8(2) - from the Minister
Article 10	FTP amount and share		
	Investment incentives (form/ extent)		
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		
Article 14	Income from by-products (sulphur/electricity)		
Article 17	The use of reserve funds for abandonment and site restoration	Yes, per Article 17(4)	
Article 18	Severance for permanent employees paid to the undertaker of employee severance funds	Yes, per Article 18(2) - procedures for the administration of employee severance	Yes, per Article 18(1) Minister to determine

Article	Unclear Area	Regulation Pending	Guidance Pending
Article 19 (See also Article 7)	Deferment of cost recovery until a field is produced - Ring fencing by field		
	Policy with regard to the PoD to secure State Revenue		Yes, per Article 19(2) – Minister to determine policy
Article 22	Procedures to determine the methodology and formula for Indonesia's crude oil price	Yes, per Article 22(2)	
Article 24	DMO fee for delivery of crude oil and gas	Issued as MoF Reg. No. 137/2013	Yes, per Article 24(9), to be determined by Minister
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, per 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, per Article 32(1)
Article 33	Procedures to calculate and deliver government share in the event of tax payment in kind	Yes, per Article 33(3) PMK-70/2015 (see below)	
Article 34	Standard and norms of costs utilised in petroleum operations		Yes, per Article 34(2)
Article 36	Independent third party appointment to perform financial and technical verification		
Article 38	Transitional rules and adjustment to the GR		

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”.


Photo source: PwC

Amendment of GR-79 (i.e. GR-27 and GR-93)

GR-27

On 19 June 2017, the President signed GR-27, which amended GR-79. The main changes were as follow:

a) **Article 10 in regard to State Revenue including Government Share and FTP**
This Article was 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 these 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 targets the incentives embedded in historical PSCs such as investment credits and DMO holidays. This will not extend to general tax concessions.

   These amendments also included a new Article 10(a) to allow for a "sliding scale" equity split to be determined by the MoEMR. 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 regarding to recoverable costs**
This Article has been amended to positively confirm the recoverability of LNG processing costs.

c) **Article 13 regarding non-recoverable costs**
This Article has been amended to remove a number of items from the list of non-CR spending being:
   i) Tax allowances related to EIT (which appears to be EIT where remitted on a grossed up basis);
   ii) Interest formally approved for cost recovery; and
   iii) CD 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 would 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 from a tax audit are to be issued within 12 months of the receipt of a "complete" tax return (previously there was no formal timeline except in the case of a tax refund).

      The intent/impact is not clear, particularly noting the joint-audit framework with the Financial and Development Supervision Agency (BPKP - *Badan Pengawasan Keuangan dan Pembangunan*) and SKK Migas. It is possible, however, that this amendment will mean less of a role for the DGT in its Income Tax related audits; and
   ii) New Articles 25(12) and (13), which provide that Income Tax on FTP is to be due when the "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 the exhaustion of all unrecovered costs (and thus 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 follow:
   i) "duty/import tax exemption" in relation to physical imports by PSCs during both the exploration and exploitation phases;
   ii) Reductions in Land and Building Tax (PBB - *Pajak Bumi dan Bangunan*) of 100% (during the exploration phase) and up to 100% (during the exploitation phase); Note that MoF approval is required for these import-related and PBB incentives during exploitation (the incentives during the exploration phase appear to be automatic);
   iii) Income arising from charges from the shared use of assets by PSCs is to be exempt from WHT and VAT. Interestingly, the amendment does not formally provide that the income itself is otherwise exempt; and
   iv) "Indirect head office allocations" do not constitute Income Tax "objects" or VAT-able "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 Participating Interest 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 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 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 BPT on the after-tax income from PSC transfers, presumably in both direct and indirect transfer scenarios.

It should also be noted 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 anticipated that a complementary amendment to PMK-257 may be issued to ensure complete clarity on this matter. Timing of issuance is however unclear.

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 GR-79 reporting only took place 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 to follow the provisions of the relevant PSC (i.e. exclusive of any GR-27 adjustments); or

- “Adjust” their PSC 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 selection mechanism);

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

The most likely interpretation of these transitional provisions is that GR-27 operates to “immediately” amend GR-79 on all matters outlined 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 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 effective 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).

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.

GR-93

On 31 August 2021, the Government of Indonesia issued GR No. 9 (GR-9), which provides updated guidance on the Income Tax treatment on transfers of PSC participating interests (PIs) in both direct and indirect transfers. GR-93 came into effect on the same date (i.e. 31 August 2021) and revoked several articles in GR-79/27 and GR-53. Other provisions of GR-79/27 and GR-53 remain operational.

Key highlights are as follows:

- GR-93 covers transfers of PSCs falling under either the cost recovery or GS framework;
- GR-93 provides some clarity on a number of long-standing issues, especially on the “tracing rules” in the case of transfers via share sales (i.e. “indirect” transfers); and
- GR-93 also provides clarity on certain transactions that are exempt from PSC transfer tax (particularly in indirect transfers);

Please refer to the PSC transfer section below for more details.

Photo source: PwC

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 BPT (i.e. the so-called Corporate and Dividend (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; and
f. If requested, the C&D Tax must be paid “in-kind” based on the ICP (for oil) or the WAP (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 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 BI). The payment/remittance is still in USD 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. DGT Regulation No.25/PJ/2011 provides different tax payment codes for Petroleum Income Tax, Natural Gas Income Tax and BPT; and

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 (*Surat Setoran Pajak*) 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; and

   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 – 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 the following requirements:

   i) Operators must 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); and

   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.

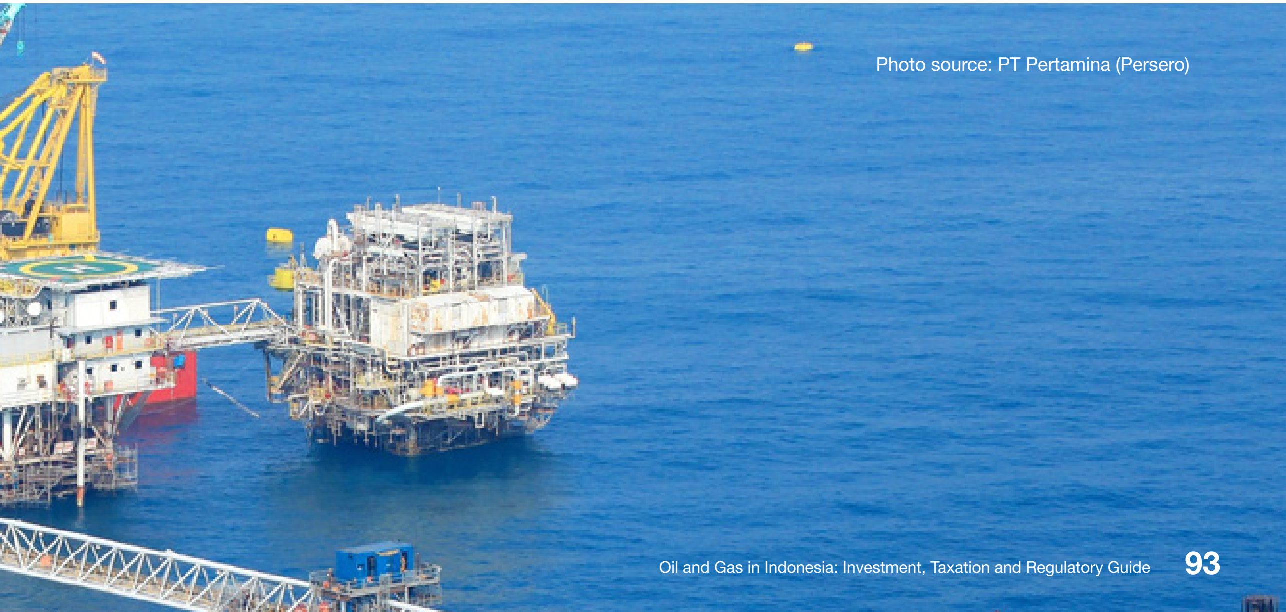


Photo source: PT Pertamina (Persero)

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 WP&B.

GR-79/27 also outlines two items of spending that are not allowed for cost recovery. For this list please refer Chapter 4.4.2 above.

Indirect taxes

Indirect taxes, regional taxes and regional levies are stated as cost recoverable. Indirect taxes include VAT, Import Duty, PBB, regional taxes and regional levies. These PBB and regional taxes/levies have generally been exempt (or at least 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 also generally exempt (see below).

PBB for Post GR-79-PSCs

On 12 April 2013, the MoF issued Regulation No.76/PMK.03/2013 (PMK-76) on PBB for the oil and gas sector, replacing Regulation No. 15/PMK.03/2012 (PMK-15). The effective date of PMK-76 was 12 May 2013. PMK-76 has led to a major change in the PBB regulatory framework for PSCs. PMK-76 has gone through several amendments, most recently by MoF Regulation No. 234/PMK.03/2022 (PMK-234).

General PBB regime

Pursuant to Article 5 of PBB 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 Tax Object Selling Value (NJOP - *Nilai Jual Objek Pajak*)). 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 - *Surat Pemberitahuan Pajak Terutang*). 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 directly to "assess" post-GR-79 PSCs.

On 30 September 2013, the DGT issued SE-46 to provide further clarification on the completion of the Notification of PBB Objects (SPOP - *Surat Pemberitahuan Objek Pajak*) for the "offshore" components of these 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.

This outcome left post-GR-79 PSCs exposed to PBB liabilities.

On 10 December 2019, the MoF issued PMK-186, which became effective on 1 January 2020, and introduced the following changes:
a. An updated classification of "Tax Objects"; and
b. New procedures to determine the Sales Value of these NJOP.

PMK-186 applies to PBB Objects in, among others, the oil and gas sector and other sectors which are:
a. Located within Indonesian waters; and
b. Not PBB Objects of a Village or Town.

PBB objects

For "Other Sectors", the definition of "land" has now been clarified to include Indonesian waters used for storage and processing facilities, and thereby extends to the various categories of vessels used on these waters.

The definition of "buildings" has now also been clarified to include technical constructions planted or attached permanently on "land" within Indonesian waters. This includes pipelines, and storage and processing facilities such as Floating Storage Offload (FSO), Floating Production System (FPS), Floating Production Unit (FPU), Floating Storage Unit (FSU), Floating Production Storage and Offload (FPSO), and Floating Storage Regasification Unit (FSRU). Please refer to our comments in Chapter 7 (Service Providers to the Upstream Sector) for more details on the development of PBB issues pertaining to FSRU/FPSO/FSO, etc.

Further, this clarification confirms the recent DGT position during tax audits that PBB should now cover these assets.

NJOP calculation

PMK-186 sets out the procedures to calculate the NJOP for assets falling into the above sectors. For land, the NJOP varies according to the characteristics of use (e.g. productive, not yet productive, non-productive, onshore/offshore etc.). This is obviously relevant for oil and gas.

For buildings, the NJOP for all sectors is based on the "New Acquisition Price". This is defined as all costs incurred to acquire the Tax Object at the time of assessment, less depreciation based on the physical condition of the Tax Object.

PBB reduction for post-GR-79 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 from 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. A SPOP (notification of PBB objects) has been submitted to the DGT; and
c. A recommendation letter has been provided by the MoEMR which stipulates that the PBB object is still at the 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).

On 27 August 2019, the MoF issued Regulation No. 122/PMK.03/2019 (PMK-122) which provides incentives including a PBB reduction of up to 100% (effectively a PBB exemption). These incentives apply during both the exploration and exploitation periods, although their application during the exploitation period is subject to an approval from the MoF after reviewing the project's economics.

From an administrative perspective, the incentive requires a "confirmation letter for the tax facilities" for both the exploration and exploitation phases. Such a confirmation letter should be issued by the Head of the Regional Tax Office (RTO).

Bookkeeping and tax registration

A PSC entity is automatically entitled to maintain its books, and calculate its Income Tax liability, in English and using USD. 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 USD are to be converted into USD using the exchange rate as the date of the transactions.

VAT and WHT continue to be calculated in Rupiah irrespective of any USD 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 JOB 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 the exploration stage, a final tax of 5% of the gross proceeds will be levied. However, the transfer will be exempted if it was 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 any transfer to a "national company" as stipulated in the JCC (i.e. Indonesian participation).

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

As briefly mentioned above, GR-93, which was issued on 31 August 2021, provides some further clarity on the long-standing issues pertaining to the PSC transfer tax:

a. GR-93 now looks to define a PSC interest as "immovable property". This "immovable property" concept is more consistent with international tax law suggesting (perhaps) greater recognition of the applicability of tax treaty protections for indirect transfers. However, the definition goes beyond most treaties to include shares in the entities which hold the immovable property;
b. Notwithstanding a), GR-93 more clearly distinguishes between "direct" and "indirect" transfer scenarios. Note in particular the new annual remittance mechanism for indirect transfers, i.e. on the 10th of the following month of the end of fiscal year (e.g. for a fiscal year ending 31 December, the remittance takes place on 10 January);
c. In terms of indirect transfers, GR-93 makes it clear that the Transfer Tax can apply on an "unlimited" tracing basis (including multi-tier share ownership) and so goes beyond the "in substance" indirect transfer guidelines that currently exist. However, there is no specific relief on "day-to-day" share trading, leaving the scope of taxation via on-market share trading activity unclear;
d. GR-93 now provides that the transfer consideration in indirect-transfer scenarios will be set as a percentage of the transferred ownership (%) multiplied by the fair market value (FMV) of the Indonesian PSC assets. There is, however, no guidance on how to determine the FMV in this case. Perhaps most surprisingly, this FMV default appears to apply even to arm's-length transfers;
e. GR-93 provides a number of new Transfer Tax exemptions, as follow:
   i. For transfers taking place pursuant to approved "book-value" business restructuring transactions (e.g. mergers, spinoffs, takeovers, etc). This suggests that PSC transfers falling within the recently issued Minister of Finance Decision No.56/2021 covering SOE business restructuring transactions are now protected;
   ii. For transfers taking place pursuant to any other "restructuring" provided that the restructuring is:
      a) Not "profit-oriented"; and
      b) Does not lead to a change in the ultimate "parent entity"

      This exemption appears to be available for multinational corporations (MNCs). However, requirements that the MNCs must also satisfy, include the filing of various approvals and financial statements;

   iii. For transfers made as part of "local transactions", such as share sales between Indonesian entities subject to 0.1% final tax, where any Income Tax outcome otherwise falls within the "ordinary" tax rules

f. GR-93 indicates that a new MoF Decision will be issued and provide further guidance in a number of areas. Therefore, until this occurs, PMK- 257 will remain in force to the extent that it is consistent with GR-93.

   Overall, the issuance of GR-93 provides some clarity around the areas of contention regarding indirect transfers, but arguably still without the level of precision that this area warrants. GR-93 however now provides some "welcome" exemptions, especially for local oil and gas investors.

Head office costs

Head Office costs are recoverable subject to:

a. The cost-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 could be either the rate which prevailed at the time of signing, or the rate that prevails from time to time (i.e. may be subject to changes based on the changes in the Tax Law). 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.

Table 4.8

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 EIT withholding obligation is subject to the prevailing income tax law meaning the Article 21/26 WHT is based on the actual payment.

4.4.3 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.

For entities holding an interest in a PSC signed before 1984, the applicable Income Tax rate should be 45%. This rate was reduced to 35% in 1984, and then to 30% in 1995 up to 2008. Further reductions occurred to 28% in 2009, and to 25% starting in 2010 based on the new Income Tax Law No. 36/2008, effective from 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%).

To maintain a consistent after-tax take, adjustments to the gross-of-tax share have been made over the years in response to changes in Indonesia’s general Income Tax rate. Additionally, in certain PSC bidding rounds, the net-of-tax Contractor take has increased to (up to) 25% for oil and 40% for gas, resulting in variations in the gross production-sharing rates. These calculations can be summarised as follows:

Table 4.9 - Historical income tax rates and the after tax split calculation

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%	0.3409	15%	0.6818	30%
1984-1994	35%	20%	48%	0.2885	15%	0.5769	30%
1995-2007	30%	20%	44%	0.2679	15%	0.5357	30%
2008	30%	20%	44%	0.4464	25%	0.7143	40%
2009	28%	20%	42.4%	0.6250	36%	0.7140	41.142%
2010	25%	20%	40%	0.6000	36%	0.6850	41.143%
2013-2016*	25%	20%	40%	0.5830	35%	0.6670	40%

**GS PSCs from 1 January 2017*
Sources: Pre-1984 PSC, 1984 - 1994 PS, 1995 - 2007 PSC, 2008 PSC, 2009 PSC, 2010 PSC, 2013 - 2016 PSC

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 United Kingdom (UK), Malaysia, and Singapore – although there are others) the BPT reduction in a tax treaty does not apply to PSC activities.

A decrease in the BPT rate might translate into a higher after-tax production share for a PSC entity. Consequently, Indonesian government authorities pertinent to the matter have historically contested a PSC entity's right to avail itself of treaty benefits. This contention led to the termination of the Netherlands' treaty in the late 1990s, although subsequent negotiations have taken place. Similarly, there were discussions about canceling other treaties, including the one with the UK. In 1999, the MoF mandated an increase in the Government's production share to offset any advantages derived from treaty concessions by PSC entities.

Over the last 15 years, PSCs have aimed to address these concerns by incorporating contractual provisions to nullify the use of treaties. These provisions typically involve adjusting production shares in accordance with the aforementioned MoF directive. 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.**"*

Some older PSC Contractors that are not subject to a "re-balancing" of their production-sharing entitlement from treaty relief have contested their position with the Indonesian tax authorities. In the first quarter of 2019, the Supreme Court issued series of decisions under which it was found, in a majority of cases (but not all), that treaty relief was available to reduce the BPT in these limited circumstances. That is there was no commercial basis for an implied after-tax production share. It seems that the Supreme Court's focus was on the actual contractual position under the PSCs in question and the individual taxpayer's entitlement to the treaty relief.

Readers should note of course that Indonesia's rules of jurisprudence do not typically result in binding precedents. Consequently, none of the decisions will necessarily bind the assessing behaviour of the tax authorities (other than in respect of the assessments being litigated). It should be noted also that the Tax Court decisions in question, and even (arguably) the Supreme Court decisions, could still be challenged by the DGT (particularly if there are two or more "conflicting" Supreme Court decisions on the same/similar dispute). On this basis these decisions may not represent "settled" law even for the disputes in question.

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 however, can 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) WHT 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 dividends are distributed via statutory or legal procedures (e.g. the general shareholders meeting, etc.).

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 the contract is 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 the **GOVERNMENT'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.**"*

4.4.4 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 EIT returns (for each interest holder – noting that generally for a non-operator this will be a nil return);
e. Filing of monthly VAT reports (please refer to our detailed explanation in the VAT section); and
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. BPT/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; and
f. Details of Changes in the Participating Interests.

Since April 2012, the DGT attempted to consolidate all PSC Contractors into 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, 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 in 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 FQR.
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.

MoF issued Regulation No. 34/PMK.03/2018 (MoF-34) which stipulates procedures and guidance for the implementation of Joint Audits conducted by SKK Migas, BPKP and DGT. MoF-34 probably was issued to accommodate the industry concern over the lack of coordination amongst the three institutions in performing audits on PSC Contractors. In late 2023, MoF issued MoF Regulation No. 94/2023 (MoF-94) as the amendment to MoF-34. Whilst most of the changes stipulated in MoF-94 are mainly related to the administrative procedures of the joint audit process, one of the notable changes introduced in MoF-94 is it seems to provide more room for the DGT to conduct a tax audit separately apart from the joint audit process. Under MoF-34, a separate tax audit may be carried out under three conditions, i.e. i) if the Contractor files an overpayment tax return; ii) if the tax return submitted by the Contractor shows a different tax calculation compared to the FQR; and/or iii) the Contractor does not file the tax return. These three conditions are removed under MoF-94.

Ring fencing

Pursuant to MoF Regulation SE No. 75/190, 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 narrows even further the focus of the ring fencing principle.

4.4.5 EIT

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 "BiK". 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 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.

4.4.6 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 often remitted by the driller (see Chapter 7.3 below)).

4.4.7 VAT

General

The sale of hydrocarbons taken directly from source has historically been exempt from VAT. PSC entities had therefore never constituted taxable firms for VAT purposes, and were not registered for VAT purposes.

Law No. 7/2021 regarding the Harmonisation of Tax Regulations (HPP Law - *Harmonisasi Peraturan Pajak*) was signed by the President of the Republic of Indonesia on 29 October 2021 and came into effect on the same date.

The HPP Law has made significant changes to the VAT rules, including the foundational features which have been in place for decades. These changes include the VAT rate and the status of several non-taxable objects. The new VAT provisions were effective from 1 April 2022.

Article 4A paragraph 2 of the Law No. 42/2009 regarding VAT ("VAT Law") has now been amended by the HPP Law to exclude the "mining or drilling products taken directly from the source" from non-VAT-able goods. This means that, by default, crude oil and natural gas are regarded as VAT-able goods, and hence any "delivery" of these goods could be subject to VAT.

On 12 December 2022, the Government issued Regulation No. 49/2022 (GR-49) which provides further confirmation of the VAT-exempt status of certain deliveries of goods. GR-49 now confirms that, whilst still regarded as VAT-able Goods, deliveries of crude oil and natural gas (among others) are exempt from VAT. The VAT exemption is automatically granted (i.e. there is no requirement to obtain the Tax Exemption Declaration Letter (SKB - *Surat Keterangan Bebas*)).

From a VAT administration perspective, the PSC entities making the above VAT-exempt deliveries will still be required to register as a VAT-able Firm and issue VAT Invoices (with "exempt" status) on each relevant delivery.

In addition to the above "raw" mining products, GR-49 also confirms the VAT-exempt status of the following types of gas derivatives:

1) LNG (no change from the existing treatment); and
2) Compressed Natural Gas (CNG).

Input VAT side

The VAT Law stipulates that any input VAT related to the delivery of exempted VAT-able goods will not be creditable. The impact should arguably be no different compared to the pre-HPP Law conditions.

Irrespective of the above, in our view there should be room to argue that the pre-existing input VAT recoverability mechanism under the PSC (i.e. either reimbursement or cost recovery) could still prevail due to the "*lex specialis*" status of the PSC.

Changes in the VAT rate

The impact of any change in VAT status also needs to take into account the proposed increase in the VAT rate (i.e. to 11% in 2022 and to 12% by 2025).

The increase in the VAT rate may commercially impact post GR-79 PSCs (which mostly adopt VAT treatment as cost recovery) as it may to an extent disturb the portion of hydrocarbon entitlement between the Government and Contractors.

In summary, the changes to the VAT treatment for hydrocarbons still leaves some areas unclear, and may add to the tax administration burden on the oil and gas business in Indonesia. If such tax administration is not carefully managed, it may lead to significant tax penalties, sanctions, etc. (e.g. failure to issue a VAT invoice may lead to a 1% tax penalty on the tax base).

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 payment of the Government Share (when the VAT was then reimbursed - see VAT Reimbursement section). This arrangement effectively eliminated all but a small cash-flow exposure to VAT charged in these scenarios.

However, in 1995, an amendment to the VAT Law aimed to end all VAT deferments by 31 December 1999. The Indonesian tax authorities interpreted this amendment as terminating the deferment available to Production Sharing Contract (PSC) entities. Consequently, assessments for all deferred VAT up to this date were issued in January 2000. Approximately 30 taxpayers challenged these assessments through the Indonesian Court system, resulting in mixed outcomes.

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 the Government Share is achieved (and if permitted under the PSC).

Imports – VAT exemption

See Import Taxes below in Chapter 4.4.8.

VAT reimbursement (pre-GR-79)

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.......*
> *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".*

In the past, protection from non-income taxes in PSCs has generally fallen into two categories. Firstly, certain taxes were directly covered by SKK Migas, such as the Property and Building Tax (PBB). Secondly, some taxes were initially paid by the Contractor, such as Value Added Tax (VAT), which were then 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 satisfying high standards of documentation (original VAT invoices, etc.). Where VAT is not reimbursed for a documentation related to the concern SKK Migas had, on occasions, allowed VAT to be charged to cost recovery.

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

On 16 August 2019, the MoF issued Regulation No. 119/2019 (PMK-119) which stipulates updated VAT reimbursement procedures. PMK-119 cancelled the previous MoF Regulation Nos. 218/2014 and 158/2016 and is effective from the above issuance date.

While most key features are similar to the previous regulations (i.e. points a) to d)), PMK-119 provides more clarity on several aspects of reimbursement as outlined in points e) and f) below.

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 SKK Migas may offset a reimbursement entitlement against any Contractor "overliftings" (previously over-liftings were settled in cash);
c. That there is no timeframe for obtaining the full verification on the reimbursement request from SKK Migas;
d. That reimbursement entitlement excludes input VAT arising from LNG processing, unless the PSC stipulates otherwise;
e. That a reimbursement is to be subject to confirmation from the DGT via a "Tax Clearance Document". Under the previous MoF Regulations, the availability of an original Tax Clearance Document was compulsory. PMK-119 however provides a more relaxed requirement on this point as the term "original" was deleted and there is no requirement for SKK Migas to verify the validity of the Tax Clearance Document;
f. That whenever reimbursement is specifically regulated under the PSC, the mechanism should follow the provisions under that PSC (rather than PMK-119). This seems to be an acknowledgement of the "*lex specialis*" status of the PSC including perhaps to accommodate unique VAT reimbursement provisions in some early 2000's PSCs;
g. That, following the issuance of GR No. 23/2015 regarding the management of oil and gas resources in Aceh province, any VAT reimbursement related to oil and gas concessions in Aceh province should now be administered by the BPMA rather than by SKK Migas; and
h. That the authorised officials (within SKK Migas/BPMA) who can provide recommendations to the MoF (i.e. DGB) for the payment of VAT reimbursement is expanded to include, not only the Head of SKK Migas/BPMA, but also the Deputy of SKK Migas/BPMA.

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

VAT cost recovery (post GR-79)

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).

4.4.8 Import taxes

On 31 December 2019, the MoF issued two regulations to synchronise a number of existing import facility regulations applicable to PSC Contractors. These can be summarised as follows:

Table 4.10 - Summary of import taxes facilities regulations

No	Regulation	Effective Date	Replaces/Amends
1.	MoF Regulation No. 217/ PMK.04/2019 (PMK-217) – for import taxes facility (Import Duty, VAT and income tax). Specific to the oil and gas sector.	1 March 2020	• MoF Regulation No. 20/ PMK.010/2005 (import taxes facility for pre-2001 PSCs) • MoF Regulation No. 177/ PMK.011/2007 ((only) Import Duty exemption for post 2001 PSCs)
2.	MoF Regulation No. 198/ PMK.010/2019 (PMK-198) – specific to import VAT facilities. Applicable to all sectors including the oil and gas sector.	23 December 2019	MoF Decree No. 231/KMK.03/2001 as most recently amended by MoF Regulation No. 137/PMK.010/2018 (import VAT facility)

Sources: MoF-217/2019, MoF-198/2019, MoF-20/2005, MoF-177/2007, MoF Decree-231/2001 (as amended by MoF-137/2018)

Some of the key features are as follow:

1) PMK-217

Historically the import facilities applicable to PSCs were scattered across various regulations. With the enactment of PMK-217, the MoF attempted to “pool” the arrangements under a single regulation which applies to all generations of PSCs (including GS PSCs).

A summary of the import facilities (which are ultimately unchanged) applied to each generation of PSC can be outlined as follows:

Table 4.11 - Summary of import tax facilities applicable to Production Sharing Contracts (PSC)

Incentives	Cost Recovery PSCs - Generations		GS PSCs
	Fully adjusted to GR-271)	Not adjusted with Fully GR-272)	
Import Duty (exempt)	(a)	(b)	(c)
VAT (not collected)	(a)	(b)	(c)
Article 22 Income Tax (not collected)	(a)	(b)	(c)

Source: MoF-217/2019, GR-27/2017

Note:
1) Fully adjusted to GR-27, but can be classified as pre-2001 PSCs, pre-GR-79 PSCs (2001-2010), post-GR-79 but pre-GR-27 PSCs (2010-2017), and post-GR-27 PSCs (post 2017)

2) Predominantly pre-2001 PSCs, for which:
   (a) Facilities apply during exploration only (i.e. up to PoD). Incentives during exploitation apply according to project economics
   (b) Facilities apply during the entire contract period
   (c) Facilities apply during exploration and up to the commencement of commercial production

Other important features of PMK-217 include:

a. Type of goods: applies to imported goods which:
   (i) Are not produced locally; or
   (ii) Are produced locally but do not meet the required specifications; or
   (iii) Are produced locally but in insufficient quantity.
b. Validity period: the validity of the facility is 12 months from approval.
c. "Extended" facility for vendors/suppliers: PMK-217 seems to have extended the import facility beyond the "project owner" (as the importer of record) to the relevant suppliers/vendors, provided that the vendor is stated in the application and the relevant procurement contract is attached to the application.
d. No claw back: goods covered under this facility can be reexported, transferred to other PSC Contractors or moved to other PSC work areas without triggering any claw back. This is subject to SKK Migas approval, and a notification should be sent to the Tax Office.

2) PMK-198

PMK-198 is an updated regulation which confirms the "non-collection" of import VAT for goods which are also exempt from Import Duty. This is a generic regulation applicable to all industries, including goods imported in the PSC sector.

Furthermore, confusingly, PSC imports during the exploitation phase still do not appear to be granted a VAT facility via PMK-198, as no underlying Import Duty exemption exists.

4.4.9 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 make a decision on an objection within twelve months. Failure to decide within this timeframe means that the objection is deemed to be accepted. A taxpayer should pay at least the amount agreed during the tax audit closing conference before filing an objection. If the objection is rejected, any underpayment is subject to a surcharge of 30%. This underpaid tax and surcharge is not due if the taxpayer files an appeal with the Tax Court regarding the decision objected to.

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 Indonesian;
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 the agreed amount of the tax due on the underlying assessment should be settled before filing an Appeal. However, this payment requirement now contradicts 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 a Tax Court decision is subject to a surcharge of 60%.

Request for reconsideration

For Tax Court decisions delivered after 12 April 2002, taxpayers are entitled to file "reconsideration requests" to the Supreme Court. The Reconsideration Request must be submitted within three months of receipt of the Tax Court Decision (for the Appeal).

Interest penalties/compensation

Late payments of tax are subject to interest penalties at varying rates based on the Ministry of Finance interest rates (MIR) issued on a monthly basis. Tax refunds attract a similar interest rate using the following formula: MIR/12. The interest penalty and compensation are capped at 24 months.


Photo source: PwC

4.5 Commercial considerations

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

Table 4.12

Topics	Issues
Abandonment Costs	• SKK Migas has 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. • To be recoverable (and tax deductible), funds should be physically remitted into a joint bank account between SKK Migas and Contractor. 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-35 introduced a DMO obligation on a Contractor's share of natural gas. • Recent PSCs have also included the DMO obligation requirement for gas, whose impact should be carefully observed.
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%, in which the uplift should be taxable (at 20% final tax from gross amount).
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 phase 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.
Associated products	• Later-generation PSCs promote contractors developing associated products from their 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 from oil and gas. The commercial feasibility and profitability of additional product development is subject to a proper review and analysis.

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.
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 and onwards for many PSC holders.

Topics	Issues
"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
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). • GR79/27 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 4.4.2 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.

Topics	Issues
	• 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 (at least for pre-GR-27 transfer) 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)? • In the first quarter of 2019, the Tax Courts have issued several decisions on some outstanding cases and found: - *transfer consideration*: that transfer consideration relevant to a PSC transfer, in an entity sale scenario at least, should only extend to amounts paid for the shares in the PSC-holding entity (or higher up the holding structure – this tracing aspect remains unclear). In other words transfer consideration should not extend to amounts received for the transfer of a receivable due from a PSC entity even where carried out as part of the transfer; - *BPT*: that PMK-257, as the implementing regulation to GR-79, was technically incorrect in applying a 20% BPT on the transfer of a PSC interest (in an entity sale scenario at least). This was because the Transfer Tax component under GR 79 represented a final tax meaning that no further tax (including BPT) should be due. The Tax Court felt this position was supported by the GR-27 amendments to GR-79 where the BPT exposure for PSC transfers was formally eliminated; and - *treaty protection*: that, in an entity sale scenario at least, treaty relief should be accepted to the extent that a treaty operates to prevent/mitigate the operation of GR-79 (subject to satisfying Indonesia's treaty use rules). The tax treaty relevant to the operation of GR-79 should also be that applicable to the vendor of the shares (in a context of an entity sale scenario). As the above outcomes relate to Tax Court decisions it is possible that the DGT may file appeals to the Supreme Court, so these positions could still change. There are also some arguable contradictions within the decisions themselves. These include that in some decisions treaty relief was recognised according to the legal form of the transaction whilst other decisions appeared to indicate that the GR-79/27 liability arose at the asset level irrespective of the legal form of the transaction. Overall, caution should therefore still be exercised in analysing the impact of these decisions with regard to any individual tax positions. That aside, in regard to PSC transfer, GR-79/27 has now been amended by GR-93 on 31 August 2021. Please refer to the PSC Transfer section above for a more detailed explanation.
Domestic gas pricing for certain industries	Following the issuance of Regulation No. 15/2022 and No. 10/2020, the current gas producers shall negotiate with gas buyers (for gas prices and transportation tariffs) and with SKK Migas on potential adjustments to the production split calculation to neutralise the impact of price adjustments on gas producers' entitlement. For potential gas investors, the new gas pricing regulation shall be considered for overall project economics prior to the submission of a PoD if the gas output might be marketed to certain industries as stipulated in the above regulations.

4.6 Documentation for planning and reporting

4.6.1 PoD (Articles 90-98 of GR-35)

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. Health, Security, and Environment (HSE) & CD;
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.

4.6.2 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's approval is required if budgeted expenditure is equal to or greater than USD500,000.
An AFE should include the following Information:

a. Project information in sufficient detail to allow for BP Migas's 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%.

4.6.3 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 and geological survey, drilling and G&G study), lead and prospect, and exploration commitment;
b. Production and an effort to maintain its continuity:
    1. Development plan;
    2. Intermittent drilling;
    3. Production operations and workovers;
    4. Maintaining production; and
    5. EOR projects (Secondary Recovery and Tertiary Recovery).
c. The costs allocated for those programmes are as:
    1. Exploration;
    2. Development drilling and production facilities;
    3. Production and operations; and General administration, exploration administration and overheads.
d. An estimation of:
    1. Entitlement share;
    2. Gross Revenue, Oil and Gas Price, Cost Recovery, Indonesia Share, Contractor Share;
    3. Unit cost (USD/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 and 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 No. 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.

4.6.4 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.

4.6.5 Foreign Exchange Report (FCR) and offshore borrowing

Foreign exchange Report including the offshore loan report to BI

Law No. 24 of 1999 on Currency Flow and Exchange Rate System and its implementation regulation, being PBI No. 21/2/PBI/2019 on Foreign Exchange Activity Report and PBI No. 21/1/PBI/2019 on Bank Foreign Debts and Other Bank Liabilities in Foreign Exchange require non-financial institution companies (including oil and gas companies) to submit a report of their foreign-exchange activities in Indonesia every month to BI.

The foreign exchange report should include the information about the following:

a. Transaction on the trading of goods, services, and other transactions;
b. The principal data of the off-shore borrowing and/or Risk Participation Transaction (RPT);
c. Plan on withdrawal and/or payment of off-shore borrowing and RPT;
d. Realisation of withdrawal and/or payment of off-shore borrowing and RPT;
e. Foreign financial liabilities position and amendments; and
f. Plan on new offshore loans and their amendments.

In practice, the above report must be submitted online through the borrower's reporting account in BI's system. Failure to submit this report will subject to an administrative sanction in the form of a written warning by the BI.

Reporting obligation in relation to offshore borrowing

- Report to MoF

  In relation to offshore borrowing and in addition to the BI reporting, a borrower (including an Indonesian oil and gas company) is also required to submit a report to the MoF starting on the effective date of each of facility agreement and each subsequent three-month period. In practice, this report is submitted concurrently with the reporting obligation to the BI, which is no later than the 15th day of the month following the date of the facility agreement. However, the regulation is silent on the sanctions for noncompliance with this requirement.

In addition to the above, SKK Migas, under PTK 007, mandates that PSC Contractors must use a state-owned bank for both the vendor and payer's accounts with respect to payments for goods and services. Please see Chapter 4.2.4 above for further details.

4.6.5.1 Prudential principle on offshore borrowing for non-bank corporations

PBI No. 16/21/PBI/2014 (as amended by PBI No. 18/4/2016) and SE 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 foreign-exchange assets and current foreign-exchange 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 foreign-exchange assets and current foreign-exchange liabilities which will be due within three months of the end of the reporting quarter; and
c. a minimum credit rating of BB- or its equivalent from credit ratings agencies approved by the Indonesian Financial Services Authority.


Photo source: PwC

5 Gross Split Production Sharing Contracts

5.1 Regulation-08 (as amended by Regulation-52, Regulation-20 and Regulation-12) - GS PSC features

In 2017, the Ministry of Energy and Mineral Resources (MoEMR) issued Regulation-08 (as amended by Regulation-52, Regulation-20 and Regulation-12) introducing a PSC scheme based on the “Gross Production Split” methodology. This represented a landmark change to Indonesia’s PSC arrangement, moving away from the cost-recovery mechanism that has been in place for nearly 50 years.

On 15 July 2020, the MoEMR issued Regulation-12 as the third amendment to Regulation-08. The amendments reflect a gradual shift away from the emphasis on GS PSCs, arguably in response to the lukewarm response to the GS PSC format from a number of industry players.

Regulation-12 gives the MoEMR the authority to choose the contract type for PSC Working Areas, whether this be in a GS or traditional cost-recovery format. This discretion is applicable to all new PSCs and to all extensions of existing PSCs.

At this stage, there are no further details on the extent to which investors will have the opportunity to negotiate the type of contract with the MoEMR. As noted earlier, there are some examples of transition from GS contracts to cost recovery PSCs already having occurred.

The key features of Regulation-08 (as most recently amended by Regulation-52, Regulation-20 and Regulation-12) are summarised below:

Photo source: PwC

Table 5.1 - GS PSC features

No.	Items	Description
1.	Key Features	• A sharing concept based on a gross production and without regard to a cost recovery mechanism. • 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 GS PSC should stipulate at least 17 items, including (but not limited to) government take, financing obligations, contract term, settlement of disputes, Domestic Market Obligatio (DMO), contract termination, etc.
2.	GS Mechanism	• This can be illustrated as follows: Contractor Take = Base Split +/- Variable Components +/- Progressive Components Government Take = Government share + bonuses + Contractor's Income Tax • The Base Split shall constitute the baseline in determining the production split during the 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, the features of the 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. • Experience to date indicates that the production split could be quite flexible in practice as it is generally subject to commercial negotiation with MoEMR and SKK Migas.
3.	SKK Migas' Role	• This is limited to control and monitoring of GS PSCs. • Control means to formulate policies on Work Program and Budget (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 means to supervise the realisation of exploration and exploitation activities according to the approved work program. The role of SKK Migas is 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 from the PSC shall belong to the State (as per existing PSCs).
5.	Taxation	• The income tax treatment of Contractors follows specific tax rules for upstream activities. This is stipulated under GR No. 53/2017 (see below). • Because relief for costs occurs via tax deductions rather than cost recovery, the key agency for oversight of this area is the ITO.
6.	Procurement	• Only the goods and equipment which are directly used in the upstream business will become the property of the Government. • GS contractors are obliged to follow the provisions of PTK 007 to the extent specifically stipulated in PTK-007. If it is not specifically regulated in PTK 007, then the mechanism follows the provisions in the contract.

No.	Items	Description
7.	Transitional Provisions	• The operation of existing PSCs continues until expiry. However, Contractors may unilaterally change the GS scheme. • An option to change is also available for extended PSCs (if initially signed based on cost recovery arrangements). We understand that, for extended PSCs, the option to continue with the existing cost recovery arrangements requires approval from the MoEMR. • If the PSC format is changed, any unrecovered costs may be taken as an additional split for the Contractor. • Under Regulation-12, a PSC that is about to expire but has not been extended is not automatically "re-awarded" under the GS 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 follow prevailing rules.
9.	Unrecovered Costs	Unrecovered investment costs shall be taken into account as an additional split/ take for the existing contractor: • If a new Contractor joins the PSC, such new contractor should proportionately bear the unrecovered costs, and the existing Contractor shall deduct that same portion from its share. • The reimbursement is included in the new Contractor's operating costs, as specifically regulated under GR No. 53/2017. • The settlement of such unrecovered costs should be formalised in a written agreement between the existing Contractor and the new Contractor. • The new Contractor shall reimburse the investment costs to the existing Contractor at least seven days prior to the signing date of the extension or the new PSC. • Any late reimbursement will be subject to a penalty of 2.5% per day at a maximum.

5.2 GR-53 – Tax rules for GS PSCs

On 28 December 2017, the Government issued GR-53 providing an initial outline of the tax rules for the GS PSCs. The key tax principles are as follow:

a. Pursuant to the preamble, GR-53 flows from Article 31D of the Income Tax Law and, perhaps surprisingly, from Article 16B of the Value-Added Tax (VAT) Law. As expected, there is no reference to GR-79/27, meaning that GR-79/27 (as discussed in Chapter 3) is not relevant to GS PSCs;

b. Pursuant to Article 18, the "Taxable Income" arising from "direct" PSC activities is calculated as "gross income" less "operating costs" (see below) but with an entitlement to ten-year tax-loss carry-forward. This ten year period is greater than the five years available under the general tax law, but represents a significant reduction on the unlimited carry forward entitlement under conventional PSCs;

c. Pursuant to Articles 18(4) and (5), Taxable Income for "direct" activities is income relating to the lifting as well as the sale of by-products and other "economic gains" (see below). The taxable income is taxed at the prevailing rate at the time of signing the PSC, which is currently 22%. BPT (currently due at 20%) is applicable to after-tax profits. These rates however are not 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).

However, there is no apparent prohibition on the utilisation of tax-treaty relief potentially opening the way to BPT reductions where relevant treaty relief is validly available (but see below for more detailed comments).

Tax calculations are specific to each contractor, differing from the traditional PSC approach. In other words, individual Contractors could validly calculate taxable income outcomes different to that derived for the PSC as a whole. However, a range of issues may arise in such a 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 takes place under Financial and Development Supervisory Agency (BPKP) and Special Task Force for Upstream Oil and Gas Business Activities (SKK Migas);

d. According to Article 14, taxes are applied when the contractor receives the hydrocarbons. 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 the sale of the hydrocarbons. This should also mean that income from post-lifting activity (e.g. trading) should not fall within GR-53;

e. The value of oil is determined using the Inductively Coupled Plasma (ICP) (Article 15), while the value of gas is determined via the price agreed under the relevant gas sales contract (Article 16). Again this is in line with conventional PSCs;

f. 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; and

g. Pursuant to Article 19(2), income arising specifically from PSC transfers is subject to tax at 5% or 7% of the transfer income (according to whether the PSC is in exploration or exploitation) with no further tax due on after-tax income. This means 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. Refer to our explanation of GR-93 in Chapter 4 (Upstream Sector) for more details of the PSC transfer tax imposition and exemption conditions.

In summary, GR-53 provides only the initial fiscal framework for GS PSCs, with a number of implementing regulations still to be issued. While the general fiscal framework appears broadly in line with that for conventional PSCs, further regulations are still required before Contractors can draw more definitive conclusions.

Nevertheless, the key fiscal differentiators for GS PSCs include:

a. Contractor-specific tax calculations are applicable, rather than each Contractor following a PSC "cut-back" approach;

b. In GS PSCs, the production split is based on gross production, unlike traditional PSCs where it occurs after cost recovery, except for FTP;

c. The Contractor's GS revenue is subject to deductions (under GR-53 and the ITL) rather than cost recovery;

d. There is likely to be an exemption from all "non-Income Tax" taxes during pre-production, no incentive during the post-production period. This means that essentially Contractors will bear non-income tax spending (during the post-production period) at its after-tax cost;

e. A ten-year tax-loss carry-forward restriction applies (albeit with an automatic deferral during pre-production) rather than the indefinite period under traditional (cost recovery) PSCs;

f. There is no apparent "lock-down" entitlement to a tax rate applicable to lifting income; although a number of existing GS PSCs have defined the ITL as that in place as at the "Effective Date" of the PSC in question, and thus "locking-down" the Income Tax rate to the PSC signing date is apparently possible; and
g. There are no apparent prohibitions around treaty use leaving open the possibility of leveraging treaty reductions particularly in relation to BPT (but see below).

5.2.1 GS tax calculation

Key features of the GS tax calculation include:

a. Similarly to existing PSCs, pursuant to Article 4, a Contractor's "gross income" shall consist of both:
   i) Gross income "directly" derived from PSC activities; and
   ii) Gross income arising from activities "outside" of PSC activities;

b. Gross income from "direct" PSC activities is essentially the Contractor's share of oil/gas realised from lifting, less a DMO, plus compensation for the DMO, plus/minus lifting price variances;
c. Gross income from activities "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; and
   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 the income arising from "direct" PSC activities;

d. Pursuant to Article 5, "Operating Costs" include:
   i) "Exploration Costs" including those arising from exploration drilling, general and administrative activities and Geological & Geophysical (G&G) activities;
   ii) "Exploitation Costs" including those arising from 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 arising from 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 the 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 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 GS PSCs are generally economically inferior to the "assume and discharge" arrangements available under many conventional PSCs.

   Although reimbursements for unrecovered capital costs paid to prior Contractors are generally treated as operating costs, some spending may actually constitute reimbursements of capital expenditure, and therefore would be subject to amortisation (whereas the nature of the costs being reimbursed is capital expenditure incurred by the prior Contractor).

Limitations on deductions

Key features include:

a. that, pursuant to Article 7, the deductibility of all Operating Costs (outlined above) are 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. This is 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). 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. BiK, donations, environmental activities and foreign manpower, must comply with existing regulations.

b. that, pursuant to Article 8, there is no deduction 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; and
   - xi) Government bonuses.

   Most of these restrictions mirror those 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 are as follow:

a. Similarly to existing PSCs, pursuant to Article 12, all pre-production spending, including that otherwise constituting an outright deduction or expense is still capitalised. Amortisation of this capitalised spending then commences from the month of commercial production, on a Units of Production (UoP) basis. This deferment measure helps address concerns about losing the ability to carry forward tax losses indefinitely under GS PSCs (see comments above);

b. Pursuant to Article 9(1), post-production spending on amounts creating economic value of less than one year is deductible in the year in which the expenses are incurred;

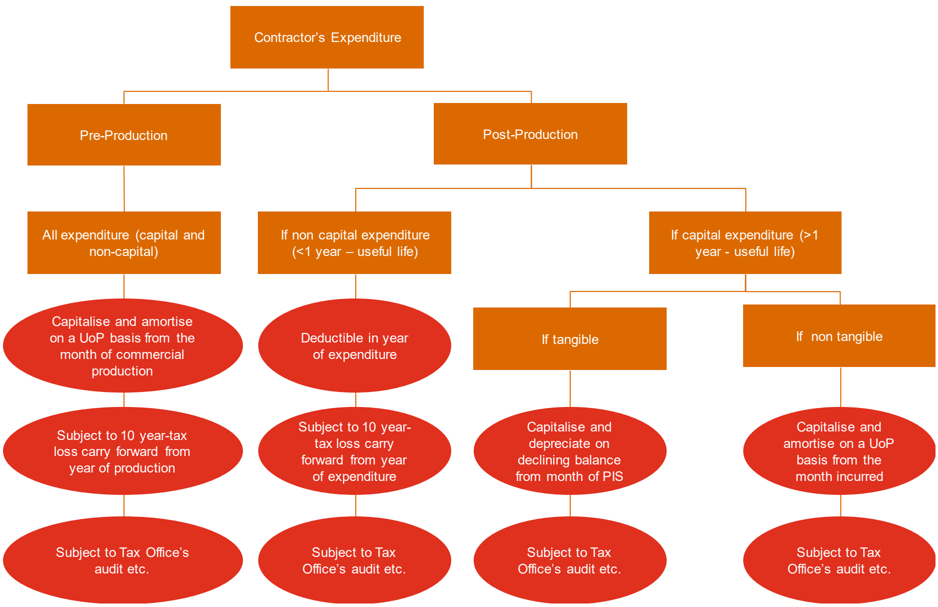
c. Pursuant to Article 9(2), post-production spending on amounts creating economic value for more than one year is depreciable (if relating to tangible assets) or amortisable (if relating to intangible assets);

d. Pursuant to Article 10, depreciation is on a declining balance basis commencing in the month in which the relevant asset is PIS, and at rates set out in the Attachment to GR-53. The relevant elucidation defines PIS as the time when the assets are utilised and have fulfilled the conditions/requirements set out by SKK Migas. Again, the reference to SKK Migas criteria gives rise to questions around a de-facto uniformity principle;

e. Pursuant to Article 11, amortisation should be on a UoP basis, commencing from the month in which the expense is incurred; and

f. 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 SKK Migas, etc. Any ultimate differences between the reserves and realisation shall be taxable or deductible, as the case may be.

The tax treatment of a Contractors' expenditure in the context of a GS PSC can be summarised as follows:



Administration

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

a. Register for tax;
b. File annual tax returns;
c. Remit tax payments, including monthly tax instalments based on each Contractor's lifting for the prior month; and
d. Report any PSC transfers to both the MoEMR and the MoF.

That, pursuant to Article 23, 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 regarding remittances for any individual Contractor-only spending; and
b. Manage the bookkeeping of the PSC itself. These obligations extend to the keeping of the general financial records, including traditional financial statements which (presumably) will now also become key fiscal documentation.

Incentives

Pre-production period

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

a. An exemption from Import Duty on goods used for oil and gas operations. However, it is still unclear how this can be provided without a general reference, or without placing reliance on the Customs 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 superior to that under conventional PSCs;
c. An exemption from Article 22 on imports of goods on which the Contractor is entitled to an Import Duty exemption as outlined in a) above; and
d. A 100% reduction in PBB.

On 15 June 2020, the MoF issued Regulation No. 67/PMK.03/2020 (PMK-67), which provides guidelines on the granting of VAT and PBB facilities for GS PSCs during the pre-production period. PMK-67 serves as the implementing regulation of GR-53, and is effective from 15 July 2020.

In order to obtain such facilities, the operator needs to submit an application to the RTO (via the Tax Office where the operator is registered) enclosing the following documents:

a. A confirmation letter from the MoEMR stating that the Contractor is in the pre-production stage, and providing the following information:
    i. Name of the Working Area;
    ii. List of Contractors;
    iii. Names of the operators; and
    iv. Effective date of the GS PSC or approval of conversion (from a traditional cost recovery PSC);
b. A copy of the GS PSC.

The RTO will then issue the GS Tax Facilities Letter ((SKFP - *Surat Keterangan Fasilitas Perpajakan*) GS) within seven working days of the application being submitted, which will be effective from:

a. The effective date of GS PSC (for PSCs signed post-GR-53);
b. The approval date of PSC conversion into GS format (for converted PSC); or
c. The effective date of GR-53 (for PSCs signed pre-GR-53).

The SKFP GS is considered to be invalid in the event that the contract expires, is terminated or commences commercial production.

VAT not collected facility mechanism

The operator needs to provide local vendors with a copy of the SKFP GS and show them the original prior to the delivery of VAT-able goods/services. Local vendors will then issue their VAT invoices with the statement “VAT NOT COLLECTED IN ACCORDANCE WITH GR-53”.

The operator (as a VAT collector) is therefore:

a. Not obliged to collect and pay the VAT on local procurement of goods and/or services;
b. Not required to pay the self-assessed VAT (SA-VAT), in regard to SA-VAT, as the VAT facility will be stated on the SKFP.

PBB reduction mechanism

The Contractor needs to submit:

a. The SPOP; and
b. A copy of the SKFP GS to the Tax Office where the PBB object is administered.

The DGT would then issue an SPPT based on the relevant SPOP, which would also enclose the PBB (100%) reduction amount based on the SKFP GS.

In the event that the SKFP GS is submitted after the issuance of an SPPT, the Contractor will still be eligible for the PBB reduction facility.

VAT and PBB clawback

VAT and PBB clawback may apply, along with the associated late-payment penalty, in the event that such a facility is used not in the context of oil operations and/or the utilisation of an invalid SKFP GS.

There are no incentives offered for post-production activities, meaning that all such taxes should simply be deductible.

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

5.3 Other tax considerations/issues

Whilst not an exhaustive list, below are a number of tax considerations relevant to GS PSCs which are not dealt with in GR-53. Specific advice should be sought where relevant.

Table 5.2 - Summary of other tax considerations/issues not dealt in GR-53

Topics	Tax Consideration / Issues
Conversion of Conventional PSCs to GS PSCs.	**A. Unrecovered Costs** • Pursuant to Article 32(c) of GR-53 and Article 25(d) of Regulation-08 (as amended by Regulation-52), any unrecovered costs on conversion to GS shall be <u>converted</u> to additional split (i.e. additional Contractor's take provided as compensation for the unrecovered costs). • Applies whenever a Contractor voluntarily converts to a GS PSC. • SKK Migas can audit these costs as part of the conversion process. • Once the additional split is agreed, then the unrecovered costs are no longer recognised and cannot be brought into the (new) GS PSC. This is consistent with Article 8(5) of GR-53 which indicates that any costs incurred prior to signing of a GS PSC are not deductible. • Currently, there is no specific formula mandated to calculate the "additional split". In practice this has been based on negotiations with the MoEMR and/or SKK Migas. • Notwithstanding the above, some Contractors have agreed a carried-forward cost entitlement (via deductibility) with SKK Migas (presumably without any additional split). • Should the costs be forfeited as per GR-53, then a question arises on the accounting treatment. The carrying value may need to be impaired if the costs cannot be fully recovered over the life of the operations of the GS PSC. **B. Outstanding VAT Reimbursement** • For post GR-79 PSCs, VAT is generally recovered through cost recovery, meaning that VAT is treated similar to other unrecovered costs (refer to above). • However, for a pre GR-79 PSC, VAT may be recovered via reimbursement which has a greater value than recoverable costs (i.e. effectively a 100% refund to the contractor). • GR-53 and the MoEMR Regulations are silent on any special compensation for outstanding VAT reimbursements if a pre GR-79 PSC is converted to GS. • We expect that this issue would be subject to separate negotiations with SKK Migas.
PSC Holding Structure Options (PE vs PT)	• A PSC entity holding structure, as either a PE or PT, is essentially tax neutral in respect of revenue and/or deduction recognition. • Under a PT structure profit repatriation is via dividends where there are positive Retained Earnings (R/E). Positive R/E takes into account past losses. • Under a PE structure, profit repatriation is via a deemed BPR arising simultaneously with the corporate tax liability (unless reinvested into an Indonesian PT). The deeming approach ignores past losses.

Topics	Tax Consideration / Issues
Reduced BPT rate entitlement	**A. Domestic rules** • Article 18(5) of GR-53 indicates that net taxable income (i.e. after Income Tax) is subject to further "income tax" pursuant to the prevailing tax regulations (i.e. a BPT)). • This potentially acknowledge a Contractor's obligation to pay BPT but only in accordance with relevant tax laws including those set out under tax treaties. • This is consistent with the fiscal framework of the GS PSC (under GR-53) moving towards the general tax rules. **B. Indonesia's Tax Treaties** • Indonesia has concluded approximately 67 tax treaties. Most of the treaties provide a general reduced BPT rate. However, the following should be noted: a. Some treaties provide no restrictions around the application of reduced BPT rates for Indonesian PSCs. This means that a reduced BPT rate should be available; b. Other treaties include restrictions and "non-discrimination" provisions in respect of a reduced BPT rate for Indonesian PSCs. For example the protocol to Indonesia/Japan tax treaty provides: *"5(a) …. But such [BPT] shall not exceed **10%** of the amount of such earnings, **except where such earnings are those derived by such company under its oil or natural gas PSCs with the Government of the Republic of Indonesia or the relevant state oil company of Indonesia**"* *"5(b) The above-mentioned tax in respect of the earnings of a company being a resident of Japan which has a PE in Indonesia derived under its oil or natural gas PSCs with the Government of the Republic of Indonesia or the relevant state oil company of Indonesia **shall not be less favourably** levied in Indonesia of any third state which has a PE in Indonesia derived under its oil or natural gas PSCs with the Government of the Republic of Indonesia or the relevant state oil company of Indonesia"*

Sources: GR-53/2017, Regulation-08, GR-79/2010, Indonesia's tax treaties

5.4 GS PSC accounting - PTK-066/2019

In April 2019, SKK Migas issued guidelines for reporting upstream oil and gas business activities under GS arrangements, known as PTK-066/2019. These guidelines are applicable to the preparation and submission of the WP&B, FQR and the Financial Monthly Report (FMR) to SKK Migas by Contractors. The guidelines cover various topics, including:

a. The procedures for the preparation, submission and revision of the WP&B;
b. The accounting policies and descriptions of line items in the WP&B, FQR and FMR for a GS PSC; and
c. Asset management arrangements.

The guidelines also make clear that the GS PSC should follow the prevailing tax laws and regulations, which are currently regulated under GR-53. The guidelines will be adjusted automatically to follow the tax regulations.

6 Downstream sector

6.1 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 the 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 sections of the downstream regulations, as provided in Law No. 22 and its implementing regulations GR No. 36/2004 (as last amended by GR No. 30/2009).

6.1.1 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 OSS with the approval and assessment from the Ministry of Energy and Mineral Resources (MoEMR) and/or government agencies) through a one-door integrated system. As indicated in Chapter 3, Investment Coordinating Board (BKPM) and Downstream Oil and Gas Regulatory Agency (BPH Migas) are responsible for regulating, developing and supervising the operation of the downstream industry.

6.1.2 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).

Photo source: PwC

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

To obtain a business licence, a PT company must apply for a Risk-Based Licensing (*Perizinan Berbasis Risiko*) approach, conducted through the OSS platform, which is integrated with government agencies (e.g. MoEMR and BPH Migas) by enclosing administrative and technical requirements which contain, at a minimum, the following:

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 (i.e. three years, plus two years of extension), 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.

6.1.3 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).

The Oil and Gas Processing Business License is valid for a maximum of 30 years and may be extended for a maximum of 20 years at a time.

Non-integrated gas supply chain

The processing of gas into Liquefied Natural Gas (LNG), Liquid 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 the Government's 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 miniature 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.

6.1.4 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.

The Oil and Gas Transportation Business License shall be valid for a maximum of 20 years, and may be extended for a maximum of 10 years at a time.

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.

6.1.5 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 to 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.

6.1.6 Trading

A PT company must guarantee the following when operating a trading business:
a. The constant availability of fuels and processing outputs 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 outputs at a fair rate;
d. The availability of adequate trade facilities;
e. The standard and quality of fuels and processing outputs, 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 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, and 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 only after obtaining a licence to trade gas.

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

6.1.7 National fuel oil reserve

The MoEMR is responsible for setting policy regarding the quantity and type of the 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.

6.1.8 Standard and quality

The MoEMR establishes and regulates the type, standard, and quality of fuel oil, gas, other fuels, and certain processed products for the domestic market. These standards are determined by considering factors such as the technology used, producer capacity, consumer financial capability, and adherence to 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 outputs 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 outputs that are exported, a producer may determine the standard and quality based on the buyer’s request. Fuels and processing outputs specially requested must have their determined standard and quality reported to the MoEMR.

6.1.9 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 prices for certain types of fuel oil by calculating their economic value.

A PT company holding a wholesale trading business licence that sells certain types of fuel oil to transportation users, or that trades kerosene for household and small enterprises, must provide opportunities to the appointed local distributor. The distributors include 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 the names of its distributors to BPH Migas and the MoEMR.

6.1.10 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, with priority given around the area of operation.

6.1.11 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' capacities.

6.1.12 Sanctions

BPH Migas has the authority 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 who commits:

a. Processing without a Processing Business License shall be punished with a maximum imprisonment of five years and a maximum fine of IDR 50,000,000,000.00 (fifty billion rupiah);
b. Transportation as without a Transportation Business License shall be punished with a maximum imprisonment of four years and a maximum fine of IDR 40,000,000,000.00 (forty billion rupiah);
c. Storage without a Storage Business License shall be punished with a maximum imprisonment of three years and a maximum fine of IDR 30,000,000,000.00 (thirty billion rupiah);
d. Trading without a Trading Business License shall be punished with imprisonment of up to a maximum of three years and a maximum fine of IDR 30,000,000,000.00 (thirty billion rupiah).

6.2 Taxation and customs

6.2.1 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 details. Most downstream entities pay taxes in accordance with the prevailing law, although some activities can be subject to different WHT 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 tax 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 the 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 has not followed the proper procedures.

Thin capitalisation

On 9 September 2015, the MoF issued Regulation No. 169/PMK.010/2015 (PMK-169), establishing a general Debt to Equity ratio (DER) limitation of four to one for Income Tax purposes. PMK-169 became effective on 1 January 2016. According to this regulation, if debt exceeds equity by a factor of four on a monthly basis, the interest on the "excessive debt" is non-deductible. MoF 169 provides exemptions from the DER rules for certain industries, including infrastructure, although the definition of infrastructure is not provided. Most downstream activities are likely subject to the 4:1 DER limitation.

On 28 November 2017, the DGT issued PER-25/PJ/2017 (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 starting from the 2017 annual returns.

On 7 October 2021, the Indonesian Parliament passed the HPP Law, expanding the methods to determine the limitation on financing costs deductibility. In addition to the DER method, the HPP Law allows other internationally accepted methods such as using a percentage of Earnings Before Interest, Taxes, Depreciation, and Amortisation (EBITDA). However, the implementing regulations for the HPP Law have not been issued to date.

6.2.2 Tax incentives

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

Tax holiday for pioneer investors

On 24 September 2020, the MoF issued Regulation No. 130/PMK.010/2020 (PMK-130), which revokes the previous MoF Regulation (i.e. PMK-150) related to the Tax Holiday facility. PMK 130 was effective from 9 October 2020.

Under PMK-130, the benefits of the Tax Holiday facility remain largely the same, whereby taxpayers may enjoy the Income Tax facility in the form of a Corporate Income Tax (CIT) reduction of 50-100% for 5-20 years, depending on the investment value. The taxpayer can also enjoy a 50% or 25% CIT reduction for the next two years after the concession period ends (depending on the initial investment value).

The key highlights under PMK-130 are as follows:

A. General eligibility

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 (KPBU - *Kerjasama Pemerintah dan Badan Usaha*) scheme, as well as base organic chemicals sourced from oil and gas;
b. That the applicant is an Indonesian legal entity;
c. That the applicant involves a new capital investment plan;
d. That the project involves a capital investment of at least IDR 100 billion;
e. That the project is carried out through an Indonesian legal entity;
f. That the applicant has never had its Tax Holiday application granted or rejected by the MoF;
g. That the applicant has never been granted with other tax facilities i.e. Tax Allowance, additional deduction on labour intensive industry, and Special Economic Zones (KEK - *Kawasan Ekonomi Khusus*);
h. That the taxpayer satisfies the DER requirement; and
i. That the taxpayer is committed to start realising the investment plan at the latest one year after the issuance of the Tax Holiday approval.

B. Avenue for companies not listed as pioneer industries

Companies that are not listed as being in a pioneer industry may also apply for the Tax Holiday facility. In this regard, PMK-130 now stipulates that the applicant can make a self-assessment to justify why they should be considered as a pioneer industry in accordance with the form attached to PMK-130.

The self-assessment form contains criteria in the following categories:

a. Possessing a broad local connection (e.g. using main raw materials produced domestically, production products used domestically etc.);
b. Having added value or high externalities (e.g. hiring a large number of workers, investment locations etc.);
c. Introducing new technology (e.g. using environmentally friendly technology); and
d. Being a priority industry on a national scale (e.g. supporting national strategic projects, building infrastructure facilities independently).

In addition, the self-assessment form also sets out a quantitative scoring system. The taxpayer must obtain a score of at least 80 in the quantitative criteria assessment form. An assessment will be carried out to evaluate the quantitative criteria self-assessment.

C. National Strategic Project (PSN – *Proyek Strategis Nasional*)

There are some beneficial provisions relating to investors that carry out a PSN business expansion/additional investment through a “spin-off”. Under a spin-off scheme, the capital investment that is counted (and can enjoy benefits) for the Tax Holiday will include the value of the investment resulting from the spin-off, in addition to the newly invested capital.
The investment value amount to be used to determine the concession period of the tax holiday will be either:

a. All of the investment value (i.e. the new investment value and investment value resulting from the spin-off) – if the new investment value is higher than the investment value resulting from the spin-off; or
b. The new investment value – if the new investment value is lower than the investment value resulting from the spin-off.

D. Other administrative and procedural matters

Once the application is granted, the taxpayer is required to submit annual investment and production realisation reports. PMK-130 now stipulates that if a taxpayer fails to do so in a timely manner (within 30 days of the year’s end), the DGT will issue a warning letter that may eventually lead to a tax audit.

It should be noted that Tax Holiday applications from OSS system to the MoF under PMK-130 now may only be submitted up to four years after the effective date of PMK-130, i.e. until 8 October 2024.

As with PMK-130, domestic shareholders of the applicant must obtain a tax clearance letter issued by the DGT.

The decision on the start date of utilisation of a Tax Holiday is determined based on the field audit, which is intended to verify the conformity of the realisation of the investment plan and the initial main business activity plan. Adjustment on the entitlement of the Tax Holiday facility may occur as a result of this audit.

PMK-130 now provides a time limit of this audit, i.e. at most 45 working days after the audit notification letter has been delivered to the taxpayer.

Tax allowances

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

On 12 November 2019, the Government issued Regulation No. 78 Year 2019 (GR-78/2019), which constitutes an amendment to the regulations on the tax allowances available for companies that invest in certain business sectors and/or regions.

GR-78/2019 is effective from 13 December 2019, and revokes a series of previous GR (i.e. GR-18/2015, as amended by GR-9/2016).

The principal tax facilities remain the same, with the following updated features:

a. An "investment credit" equal to 30% of qualifying spending, deductible at 5% p.a over six years, provided that the assets invested in are not being misused or transferred out within a certain period, except to be replaced with new assets.
   The fixed assets should now satisfy the following conditions under GR-78:
   a. that they be new, unless originating from a complete relocation from another country;
   b. that they be listed in the new business license as the basis for obtaining a tax allowance facility; and
   c. that they be owned directly by the taxpayer (not through a lease) and utilised for the main business activity.

b. Accelerated tax depreciation/amortisation;
c. Reduced WHT rates on payable dividends to non-residents; and
d. An extended tax loss carried forward period, of up to ten years.

The application is made through the OSS system prior to the start of commercial production.

The following tables outline the energy-related sectors that are eligible for this incentive:

Table 6.1 - Summary of oil and gas sectors eligible for tax allowance facility

Business Field	Scope of Products
Lubricant Manufacturing Industry	All products included within the relevant Lubricants business code Lubricant Business Code KBLI
Oil, Natural Gas and Coal Originated Organic Base Chemical Industry	All products included within the relevant business code (KBLI), except for products which have been covered for the tax holiday facility as regulated under PMK-130
Natural and Artificial Gas Supply	• Regasification of LNG into gas using a FSRU • Coalbed Methane (Non-PSC), shale gas, tight gas sand and methane hydrate • Refining and/or processing of natural gas into LNG and/or LPG • Provision and/or processing of artificial gas resulting from coal gasification

Sources: Investment Law No. 25/2007, GR-78/2019


Photo source: PT Pertamina (Persero)

KEK

On 28 December 2015, the Government issued Regulation No. 96/2015, which was since revoked by Regulation No. 40/2021 (GR-40) 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.

There have been twenty areas designated as KEKs.

Free Trade Zone (FTZ - *Kawasan Perdagangan Bebas*) in Batam, Bintan and Karimun

Goods entering an FTZ 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 zone

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

6.2.3 Taxation on the sale of fuel, gas and lubricants by importers and manufacturers

The taxation on the sale of fuel, gas and lubricants by importers and manufacturers are regulated under MoF Regulation No. 34/PMK.010/2017, which has been amended by MoF Regulation No. 110/PMK.010/2018 (PMK-34/110). PMK-34/110 requires importers and manufacturers to collect Article 22 WHT from the sale of fuel, gas and lubricants, as follows:

Table 6.2

Definition	Rate	Sale to	
		Agent/Distributor	Non-Agent/Non-Distributor
Fuel			
Sale by Pertamina and its subsidiaries to gas stations	0.25%	Final	Non-Final
Sale by non-Pertamina to gas stations	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

On 26 December 2019, the MoF issued Regulation No. 199/PMK.010/2019, which further amends certain clauses in PMK-34/110. The amendments do not, however, have a significant impact on the tax-related areas being discussed in this section.

VAT on commercial sales

Producers or importers are considered taxable entrepreneurs, so general VAT rules apply to their sales, making them subject to VAT. Typically, producers or importers add VAT to their sales, which can be credited by the purchaser. Subsequent sales also incur VAT.

The introduction of HPP Law increased the VAT rate to 11% (since 1 April 2022), and 12% starting 1 January 2025.

Furthermore, the HPP Law now also excludes “mining or drilling products taken directly from the source” from the list of non-VAT-able goods (negative list). This means that by default, crude oil and natural gas are regarded as VAT-able goods and hence, any delivery of these goods could be subject to VAT.

GR No. 49/2022 (GR-49) confirms that although crude oil and natural gas are considered VAT-able goods, they are exempt from VAT upon delivery. This exemption is automatic, eliminating the need for a Tax Exemption Declaration Letter (SKB). However, from an input VAT perspective, any input VAT incurred for these VAT-exempt goods will not be creditable, similar to the previous treatment.

From the VAT administration perspective, the trading companies making the above VAT-exempt deliveries will still be required to register as VAT-able firms, and to issue VAT invoices (with "exempt" status) on each relevant delivery.

6.2.4 Import duties

Import duty on petroleum

Crude oils are classified under Harmonised System (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, one 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; and
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

6.2.5 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 pipelines; or
b. It owns 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, where the company produces fuel oil, and supplies and distributes fuel oil and/or trades fuel oil as an extension of its 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;
b. PT companies holding a fuel oil limited trading business licence; and
c. PT companies holding a processing business licence, where the company produces fuel oil, and supplies and distributes fuel oil and/or trades fuel oil as an extension of its processing business.

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 GR No. 48/2019):

Table 6.3

Volume level per Annum	Percentage amount
Fuel Oil Sales Up to 25 million kilolitres 25 million – 50 million kilolitres Over 50 million kilolitres	 0.25% of the selling price 0.175% of the selling price 0.075% of the selling price
Gas Transmission Up to 100 billion Standard Cubic Feet Over 100 billion Standard Cubic Feet	 2.5% transmission tariff per one thousand Standard Cubic Feet 1.5% transmission tariff per one thousand Standard Cubic Feet

Photo source: PT Pertamina (Persero)

6.3 Commercial considerations

When reviewing a potential downstream asset, investors should consider a number of commercial considerations, including the following:

Table 6.4

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 GR. • Land ownership may be disputed and/or overlap with Government-protected forest areas, or with other businesses' concession rights (e.g. timber, plantation or mining). • Any transfer of land and building rights 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 NBV 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 measures 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 terms needs to be understood. • Product pricing restrictions may be applicable in some areas, based on the prevailing GRs.
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.
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 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. • The opportunities to enhance retail outlet throughput may be limited. • Branding and value capture opportunities need to be identified.

Topics	Issues
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 and 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 VAT-able status of LNG (now clarified in chapter 4). • Any related-party transactions (where transactions with a counterparty exceed IDR 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, as well as benchmarking.

6.4 Market developments in Indonesia

6.4.1 Gas pipeline infrastructure

Despite a decline in the status of oil reserves, 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 plants, 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.

Although Indonesia has a large amount of potential in the natural gas sector, it needs a lot of investment to develop infrastructure on the downstream side. It is 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 this year.

There used to be two major gas pipeline companies: PT Pertamina Gas and PGN. Following the issuance of GR No. 6/2018 and the designation of PT Pertamina (Persero) as the state-owned holding company for oil and gas, the Government's ownership in PGN was transferred to PT Pertamina (Persero) in April 2018. Subsequently, PGN acquired 51% of PT Pertamina Gas shares from PT Pertamina (Persero) in December 2018.

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

6.4.2 Open access to gas pipelines and gas allocation, utilisation and price

The Government 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.

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.

On 25 January 2018, the MoEMR issued Regulation No. 4/2018 (as amended by MoEMR Regulation No. 19/2021), regarding natural gas businesses in downstream oil and gas business activities. This regulation replaced the previous regulation, i.e. MoEMR Regulation No. 19/2009. This regulation amends the Masterplan for the National Gas Transmission and Distribution Network, and authorises BPH Migas to put gas transmission sections to a tender process. 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 MoEMR Regulation 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 interests.

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

Table 6.5

	PerMen No. 6/2016
Order of priorities for gas allocation and utilisation	a. Support the Government's programme to supply natural gas for transportation, households (≤50m^3/month) and small customers (≤100m^3/month); b. Increase national oil and gas production; c. Fertilisers; d. Natural-gas-based industry; e. Electricity; and f. Industries which uses gas as fuels.
Buyer	a. SOE; b. BUMD; c. Gas-fired power/electricity companies; d. Companies holding Izin Usaha Niaga Gas Bumi; e. LPG companies; and f. End-users.
Gas Price	Gas price to be approved by the MoEMR through SKK Migas

On 29 December 2017, the MoEMR issued Regulation No. 58/2017 whereby the MoEMR determines gas prices for power plants and households based on three components consisting of gas price, gas infrastructure maintenance costs, and commercial costs (7% of gas price) based on proposals from gas producers. Furthermore, on September 20, 2019, the MoEMR issued Regulation No. 14/2019, amending Regulation No. 58/2017, which stipulates that the project economic life assumption for gas infrastructure maintenance cost is 30 years from the first gas price determination. The change may impact the overall economic assessment of the project, as the assumption of a longer useful life may reduce the overall gas price calculation.

The provisions and procedures on determination of allocation and utilisation, as well as the price of flare gas, are regulated under MoEMR Regulation No. 30/2021. According to the regulation, the utilisation of flare gas can be carried out by: (i) business entities which hold a processing business licence and/or natural gas commercial business license; or (ii) government institutions.

The offering of flare gas to the business entities is carried out by SKK Migas, by considering the following requirements and criteria:

a. Offering price;
b. Investment commitment;
c. Onstream period;
d. Implementation guarantee (amounting to 1% of the investment value);
e. Annual tax payment receipt; and
f. An application letter.

Furthermore, MoEMR Regulation No. 30/2021 provides that the MoEMR will determine the sales price of flare gas for the business entities in accordance with the proposal from SKK Migas. On the other hand, if the flare gas will be sold to government institutions, the maximum sale price is USD 0.35/MMBTU.


Photo source: PwC

Documents to be submitted by the oil and gas contractors to obtain allocation:

Referring to Chapter V of MoEMR Regulation 6/2016, there are certain summarised requirements that must be met, as follows:

1. The contractor applies for the allocation and utilisation of natural gas for domestic demand to the Minister of Energy and Mineral Resources, through SKK Migas.
2. For domestic sales, documents to be included are:
   - a PoD and supporting documents; or
   - if a PoD is 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, and a timeline for deliveries.
4. For new allocations, SKK Migas must submit the application 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 MoEMR at least six months before the end of the existing gas sales agreement.
6. For increases in volume, the contractor or gas buyer needs to submit a proposal/ request to the MoEMR, 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 agreement, the contractor needs to submit a proposal to the MoEMR, as per regulation. The gas price which is used in the contract is determined by the MoEMR. In addition, the gas purchase contract must include an additional clause regarding the price review.

Requirements for the contractor to propose a gas price to the MoEMR:
1. Proposed 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, estimated volume of gas distributed daily.
4. Copy of approval from the MoEMR on allocation and utilisation of gas.
5. Copy of approval PoD and supporting documents.
6. Statistics regarding domestic and international gas prices.
7. Copy of the negotiation on price of gas document.
8. Copy of the contract to purchase and sell gas.

7 Service providers to the upstream sector

7.1 Equipment and services – general

As discussed in Chapters 4, 5 and 6, 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 (except for GS PSCs) 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 Work Procedure Guidelines (PTK 007) on Goods and Services Procurement Guidelines as lastly amended in 2018, and the oil and gas services activities guidance under the MoEMR Regulation 14/2018. However, the recent SKK Migas Guidance PTK 066 regarding Gross Split (GS) may imply that PTK 007 only applies to the conventional Production Sharing Contract (PSC), while the procurement activities for GS PSC will be self-managed.

MoEMR Regulation No. 14/2018 requires oil and gas supporting businesses to conduct registration to obtain an oil and gas supporting business capacity certificate Supporting Business Capability Letter (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 has been abolished by MoEMR, while the issuance of SKUP that previously required ten days is shortened to three days after all documentations and requirements are fulfilled (the issuance process may take more days in practice). The documents required to obtain SKUP can be found in the attachment of MoEMR Regulation 14/2018.

7.2 Tax considerations – general

Goods and services provided to PSC contractors are taxed according to Indonesian tax laws, similar to those applicable in the broader context (refer to the PwC Pocket Tax Guide published annually and accessible at http://www.pwc.com/id). Some exemptions exist for oil field service providers concerning import taxes (Article 22 Income Tax, VAT, and Import Duty).

Photo source: PT Pertamina (Persero)

In the past, service providers benefited from a PSC client's master list facility. Please see our discussion in Chapter 4.4.8 for an explanation of the master list facility.

Tax audits on service providers have intensified in recent years, leading to the establishment of the Oil and Gas Tax Office. This office is now the registration point for PSC taxpayers and numerous oilfield service providers.

Transfer pricing is increasingly under scrutiny for oilfield service providers, leading to frequent annual tax audits.

If service providers operate as Indonesian entities, a debt-to-equity limitation of 4:1 (see Chapter 5.3 for reference) applies.

7.3 Taxation of drilling services

A positive investment list (previously known as negative investment list) is provided under Presidential Regulation (PR) 10/2021 (as lastly amended by PR 49/2021). In relation to drilling services, PMA entities have no certain restrictions upon maximum foreign shareholding.

For further investment restrictions in the oil and gas industry see Chapter 3.2.2.

7.3.1 Foreign-Owned Drilling Companies (FDCs)

FDCs, historically carried out their drilling activities in Indonesia via a branch or Permanent Establishment (PE) for Indonesian tax purposes. The taxation regime that applies to FDCs PEs is outlined below:

a. The PE of an 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 3.3% assuming a 22% 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. 25 of 21 November 2018).
c. Drilling income is generally accepted as meaning the FDC "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.

7.3.2 Indonesian drilling companies

Unlike an FDC, Indonesian and PMA drilling companies are taxed on actual revenues and costs, and are subject to an income tax rate of 22%. 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.

7.3.3 VAT and WHT

The provision of drilling services is subject to VAT, with PSC companies acting as the VAT collectors. This implies that the output VAT of the drilling service entity is directly remitted to the Tax Office by the PSC companies. Consequently, many service providers may find themselves in a perpetual VAT refund position. However, it's important to note that this VAT is technically refundable only after a Tax Office audit.

7.3.4 Labour taxes

Foreign nationals working for a Foreign-Owned Drilling Company (FDC) and becoming residents for tax purposes are generally subject to Article 21 – Employer Withholding Tax (WHT) on a deemed salary basis, as published by the Indonesian Tax Office (ITO). However, individual tax returns should still be filed based on the 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) regarding tax withheld from their salary, resulting in a tax rate of 20%.

Note that lodging a monthly Article 21 Tax Return for staff does not exempt individuals from registering for an Indonesian Taxpayer Identification Number (NPWP) and filing an Indonesian individual tax return.

7.4 Shipping/ Floating Production Storage and Offloading (FPSO) & Floating Storage and Offloading (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 FPSO or FSO vessels.

The shipping industry is heavily regulated. Both local and international shipping is open to foreign investment through a PMA company with a maximum foreign shareholding of 49%, which is confirmed in the Positive Investment List Indonesian Shipping Law No. 17/2008 (as lastly amended by the Job Creation Law) generally adopted the cabotage principles that were first introduced by Ministry of Transportation Regulation No.71/2005 (as amended by Ministry of Transportation Regulation No. 73/2010).

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 Permit to Use Foreign Ships (IPKA) issued for a by a holder of a Shipping Company Business Licence Sea Transportation Company Business License (SIUPAL). Exempted activities include oil and gas surveys, drilling, offshore construction and operational support, dredging, and salvage and underwater work. Exempted ships for drilling are jack-up rigs, jack-up barges, self-elevating drilling units, semi-submersible rigs, deepwater drill ships, and tender assist rigs. Ships for oil and gas geophysical, geotechnical, and seismic (with electromagnetic or broadband triple source) survey activities are also exempted based on this regulation. The permit for the aforementioned ships can be obtained by satisfying the requirements set out in Ministry of Transportation Regulation

Although the current Positive Investment List does not specifically regulate FPSO/ FSO operations, the Department of Sea Transportation considers these operations as shipping activities, requiring a shipping license. Licensing as a shipping company presents investment and ownership challenges. Note that Shipping Law No. 17/2008, lastly amended by the Job Creation Law, mandates that only a company majority-owned by an Indonesian entity can register an Indonesian-flagged vessel. Therefore, a foreign shareholder holding a 95% interest would not be eligible to register as an owner of an Indonesian-flagged vessel and consequently obtain a shipping license to operate the FPSO/FSO.

7.4.1 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 - 2019 and 22% for 2020 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 that 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 Indonesia-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 in cases where the shipping costs are charged to Indonesia.

FPSO/FSO/Floating Storage and Regasification Unit (FSRU), etc. services

Traditionally, many Production Sharing Contract (PSC) entities have classified their FPSO/FSO service providers as shipping companies, allowing them to fall under the 1.2%/2.64% tax regime. However, the current perspective suggests that such services do not qualify as transportation or shipping services and should instead be subject to the general tax law provisions.

Further in regard to the Land and Building Tax (PBB), on 10 December 2019 the MoF issued MoF Regulation No. 186/PMK.03/2019 (PMK-186), which includes an updated classification of “Tax Objects” for the imposition of Land & Building Tax (PBB). PMK-186 became effective on 1 January 2020.

Under PMK-186, the definition of “land” now is clarified to include Indonesian waters used for storage and processing facilities, and thereby extends to the various categories of vessels used on the waters. Furthermore, the definition of “buildings” is also clarified to include technical construction planted or attached permanently on “land” within Indonesian waters. This includes, among other things, the processing facilities such as FSO, FPS, FPU, FSU, FPSO and FSRU.

PMK-186 has therefore formally confirmed the imposition of PBB on typical vessels such as those used for FSO, FPU, FSRU, etc., which is consistent with the DGT’s position during past tax audits.

Despite the issuance of PMK-186, tax disputes persist with the DGT, as taxpayers argue that these vessels should not be subject to PBB, considering their nature as vessels rather than "buildings." PMK-186 remains in effect as of the current writing, with no amendments or revocations to date.

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Appendices

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- Our Energy, Utilities and Resources (EU&R) practice in Indonesia comprises over 550 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&R network which includes more than 25,700 people focused on serving energy, power and mining clients.
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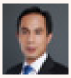

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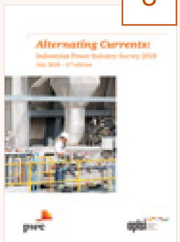

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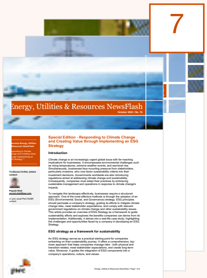

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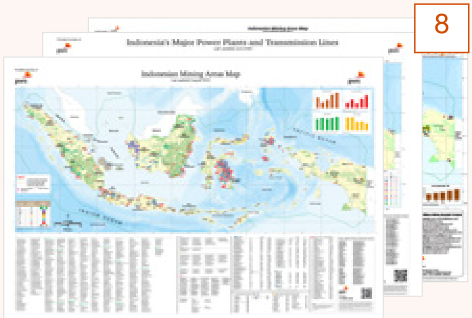

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