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# PT MEDCO ENERGI INTERNASIONAL Tbk

*(incorporated with limited liability under the laws of the Republic of Indonesia)*

## Investor Document

## January 2020

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# BUSINESS

## Overview

We are an integrated energy and natural resources company operating through our core oil and gas exploration and production business, power generation business and investment in mining. We are the largest independent publicly listed oil and gas exploration and production company in Indonesia based on revenue, production and market capitalization. In addition, according to a peer analysis conducted by Wood Mackenzie, as of December 31, 2019, we have the highest level of working interest production in Southeast Asia and North Asia among a selected peer group, consisting of independent exploration and production companies with similar reserves in North and Southeast Asia, including Eni, Repsol, Total, PT Energi Mega Persada Tbk and SapuraOMV. We have historically focused on our activities in Indonesia, and now have significant producing assets in Thailand and Vietnam and also have oil and gas operations in the Middle East, North Africa, Malaysia, Mexico and Tanzania.

On May 22, 2019, through our subsidiary MEG, we completed the Ophir Acquisition. Ophir was an independent upstream oil and gas exploration and production company, with a diversified portfolio of production, development and exploration assets in Indonesia, Thailand, Vietnam, Malaysia, Mexico and Tanzania. Ophir was founded in 2004 and was listed on the London Stock Exchange from 2011 until the completion of the Ophir Acquisition. In September 2018, Ophir had completed the purchase of the Santos Producing Assets in Southeast Asia. Ophir had net proved and probable reserves of 68.8 MMBOE as of December 31, 2018 and average daily production of 29.7 MBOE/d for 2018 (on a pro forma basis including production for the full year 2018 from the Santos Assets). The total consideration for the acquisition was GBP 408.4 million plus transfer taxes, which we financed with the proceeds from our US$650 million offering of the 2026 Notes. Since the closing of the Ophir Acquisition, we have continued to integrate the Ophir Group's assets while disposing of several of the Ophir Group's deep water exploration assets in line with our focus on selective and low-risk exploration and development activities. In the nine months ended September 30, 2019, the Ophir assets (including the period prior to effectiveness of the Ophir Acquisition) produced 7.2 MMBOE.

As of January 8, 2020, our market capitalization was US$1.2 billion.

*Overview of Our Oil & Gas Business*

We currently have interests in 15 oil and gas properties in Indonesia, 11 of which are currently producing. We also have interests in oil and gas properties in eight countries outside of Indonesia with interests in key producing assets in Vietnam and Thailand, and interests in other assets in Yemen, Libya, Oman, Malaysia, Mexico and Tanzania. In Indonesia, our blocks are held under production sharing arrangements with SKK MIGAS, Indonesia's national upstream oil and gas regulator. Under these production sharing arrangements, we are entitled to recover our costs and earn an agreed after-tax share of the production. Our blocks are held under production sharing contracts with PetroVietnam in Vietnam and under concession contracts, subject to tax and royalty, in Thailand.

In the nine months ended September 30, 2019, our production capacity (including the Ophir Group assets from June 1, 2019) was 116.0 Mboepd, and our oil and gas production split was 37.6% oil and 62.4% gas (including production under our Oman service contract). Of the gas production, 53% was sold under fixed price contracts to PLN (the Indonesian state electricity generator), Pertamina (the national oil company of Indonesia) and PGN (the gas and distribution company majority owned by the Government). Currently, our remaining gas production is sold to Sembgas, Petronas, Petro-Vietnam or indirectly pursuant to LNG contracts to KOGAS, Chubu Electric Power Co. Inc and Kyushu Electric Power Co. Inc. Our gas off-takers include blue chip customers with strong credit profiles.

As of September 30, 2019, our estimated gross working interest proved and probable reserves was 332 MMBOE. We had proved developed reserves of 192.6 MMBOE, 180.9 MMBOE, 186.7 MMBOE, 177.2 MMBOE and 189.9 MMBOE as of December 31, 2014, 2015, 2016, 2017 and 2018, respectively. We produced approximately 30.8 MBOPD, 35.1 MBOPD and 32.8 MBOPD of oil and condensate (include Oman KSF) and approximately 205.9 MMSCFD, 278.0 MMSCFD and 279.3 MMSCFD of natural gas in 2016, 2017 and 2018, respectively, and approximately 32.8 MBOPD and 38.2 MBOPD of oil and condensate and approximately 272.3 MMSCFD and 340.9 MMSCFD of natural gas in nine months ended September 30, 2018 and 2019, respectively.

*Overview of Power and Mining Businesses*

In addition to our core oil and gas business, we operate in the power generation sector and have an investment in mining.

Through MPI, which is now a wholly-owned subsidiary, we operate in the power generation sector in Indonesia. MPI is a small to medium sized IPP, developing and operating its own power generation units and O&M provider where it operates and maintains power plants for third parties. MPI promotes a green energy platform and has interests in gas-fired power, geothermal energy and hydro-electricity plants. MPI owns and operates nine power plant assets. As of September 30, 2019, MPI had gross installed capacity of 638 MW as an IPP and acts as O&M provider for gross installed capacity of 2,150 MW (including 330 MW of its own IPP capacity at Sarulla). In 2018 and the nine months ended September 30, 2019, MPI produced 2,704 GW and 1,870 GW of power as an IPP, respectively, and acted as O&M provider for power plants which produced 10,674 GW and 8,874 GW of power (including power produced at its own plant at Sarulla), respectively. As of September 30, 2019, MPI's IPP business had pipeline projects with a capacity of 1,180 MW.

Our copper and gold mining investment consists of our 32.4% effective interest in AMNT. AMNT owns and operates the Batu Hijau Mine, located on the island of Sumbawa, approximately 950 miles east of Jakarta. The mining concession covers an area of 25,000 hectares, which includes the Elang copper and gold resource and several exploration prospects including Lampui, Rinti, Batu Balong, Nangka and Teluk Puna. As of December 31, 2018, AMNT had approximately 4.0 million ounces of proven and probable gold reserves including about 1.0 million ounces of gold stockpiles and 4.2 billion pounds of proven and probable copper reserves including 2.0 billion pounds of copper stockpiles. In 2017, 2018 and the nine months ended September 30, 2019, AMNT had gold sales of 491.9 thousand ounces, 68.1 thousand ounces and 41.9 thousand ounces, respectively and had copper sales of 330.6 million pounds, 130.2 million pounds and 96.3 million pounds, respectively.

*Financial Data, History and Registered Office*

For the years ended December 31, 2016, 2017 and 2018, our total sales and other operating revenues were US$561.9 million, US$905.1 million and US$1,218.3 million, respectively, and EBITDA was US$264.7 million, US$432.9 million and US$585.3 million, respectively. For the nine month periods ended September 30, 2018 and 2019, our total sales and other operating revenues were US$900.6 million and US$1,015.9 million, respectively, and EBITDA was US$441.0 million and US$476.5 million, respectively. Giving effect to the Ophir Acquisition (and related transactions) as if it had occurred as of January 1, 2018, our pro forma EBITDA for the nine months ended September 30, 2019 would have been US$552.4 million. See "Unaudited Pro Forma Combined Consolidated Financial Information."

We were established in 1980 as an Indonesian drilling contractor and have grown substantially in the subsequent forty years. In particular, we expanded our exploration and production activities with the discovery of the Kaji and Semoga oil fields in the Rimau block in 1996 after our acquisition of our interest in the then-considered a maturing Rimau asset in 1995. Since then, we have acquired interests in additional blocks both within and outside Indonesia. In 2004, we entered the power producing business through MPI and entered the copper and gold mining sector through our interest in AMNT in 2016.

Our registered and principal executive office is located on the 53rd floor of The Energy Building, SCBD Lot 11A, Jl. Jend. Sudirman, Jakarta 12190, Indonesia.

## Competitive Strengths

### *A leading regional exploration and production company, positioned for further growth*

We are the largest independent publicly listed oil and gas exploration and production company in Indonesia based on revenue, production and market capitalization. In addition, following the combination of our business and Ophir, we would, as of December 31, 2019, have the highest level of working interest production in Southeast Asia and North Asia among a selected peer group, consisting of independent exploration and production companies with similar reserves in North and Southeast Asia, including Eni, Repsol, Total, PT Energi Mega Persada Tbk and SapuraOMV. As of September 30, 2019, our estimated gross working interest proved and probable reserves were 332 MMBOE.

We believe our large portfolio of blocks in Southeast Asia and beyond offers a diversification of the risks associated with owning and operating exploration and production assets. We currently have interests in 15 oil and gas properties in Indonesia, 11 of which are currently producing. We are either the operator or joint operator of each of our Rimau, South Sumatra, Lematang, Tarakan, Senoro-Toili, South Natuna Sea Block B, Block A, Aceh, Bangkanai, Sampang, Madura Offshore, Simenggaris, Bengara, South Sokang, North Sokang and West Bangkanai blocks, which allows us to control or significantly influence and optimize the pace of exploration, development and the associated capital expenditure at each block.

We also have interests in oil and gas properties in eight countries outside of Indonesia with interests in key producing assets in Vietnam and Thailand, and interests in other assets in Yemen, Libya, Oman, Malaysia, Mexico and Tanzania.

### *Stable cash flows from long-term GSAs with blue-chip customer base*

We have a stable base of producing, relatively low risk assets which are typically under long-term GSAs with blue-chip counterparties.

Our assets typically benefit from long-term GSAs that provide consistent revenue streams and reduce the effects of oil price volatility. For example, gas prices under our Indonesian GSAs are fixed in US$/MMBTU with an application of a relatively small escalation factor (typically 2.5% to 3.0% per annum). In addition, the substantial majority of our GSAs, including both fixed-domestic and oil-linked-export GSAs, have take-or-pay protections, pursuant to which, if a buyer is unable to absorb the agreed supply during a period (typically over twelve months) then the buyer will have to pay a portion (usually in the range of 80% to 90%) of the total contracted supply for the period.

In addition, our gas off-takers include blue chip customers with strong credit profiles, including Indonesian companies such as Pertamina, PGN and PLN, and large international customers such as SembCorp and Petronas each of whom have demonstrated solid payment histories.

### *Low cost base which has improved significantly in recent years*

Through our cost reduction programs, we have significantly improved our organizational cost structure. Our cost reduction programs have targeted both larger scale cost reduction opportunities, such as drilling rig rate reductions, to smaller scale granular opportunities, such as travel budget and streamlining training programs. Our full year unit cash production cost has been significantly reduced to US$8.7/BOE in 2018, US$8.6/BOE in 2017 and US$8.1/BOE in 2016 compared to US$12.3/BOE in 2015 and US$15.4/BOE in 2014. However, our unit cash production cost increased to US$9.5/BOE for the nine months ended September 30, 2019 from US$8.3/BOE for the corresponding period in 2018 primarily due to one-off costs associated with the Ophir Acquisition. We expect to reduce our costs as we continue to integrate Ophir and realize operating synergies.

This cost reduction has been achieved through a number of efficiency initiatives including (i) changing operating models, such as revising crew rotation schedules and outsourcing certain non-core activities such as security services, housekeeping and others; (ii) optimizing existing operations and relationships, such as vendor renegotiations to capture deflation and sharing infrastructure with neighboring operators; and (iii) reassessing all operations to apply “fit-for-purpose” methodologies, such as rescheduling planned maintenance and engine exchanges.

We are committed to maintaining a unit cash production cost per BOE below US$10 through 2021 by continuing to implement our cost efficiency measures and aim to realize synergies across the enlarged portfolio including assets held by the Ophir Group. While cost and efficiency are important, we continue to focus on minimizing risks to employee and contractor safety and promoting production uptime and environmental performance.

We believe that our cost structure assists in extending the economic life of producing blocks and provides stronger operating margins in a given oil price environment, and is particularly beneficial in maturing fields as volumes inevitably decline. A lower cost structure also allows for economic reserve growth and PSC life extension at lower capital cost levels. We plan to leverage this experience following completion of the Acquisition as we integrate Ophir’s assets. We believe that there is significant potential to improve operational efficiencies given our experience in managing mature assets. We have identified recurring cost synergies that we currently estimate at approximately US$50 million annually, which we commenced realization of upon following the Ophir Acquisition in May of 2019, including with respect to: (i) office space and personnel cost savings based on closure of Ophir’s London office and headcount reductions at Ophir; (ii) production and operational savings including from utilization of more favorable Medco rates for services used by Ophir, and achieving a pro forma unit cash cost for the nine months ended September 30, 2019 for Ophir assets which is US$2 less per BOE than Ophir’s pre-acquisition guidance and (iii) taking advantage of business and process synergies including by centralizing certain functions and rationalizing IT systems. We also expect to achieve one-time cost savings from the reduction of capital commitments of approximately US$100 million on assets acquired from Ophir that we disposed of as part of our portfolio rationalization efforts, and, for 2019, we expect our capital expenditure in relation to assets acquired from Ophir to be approximately US$30 million lower than Ophir’s publicly stated capital expenditure guidance for 2019.

***Long-standing track record of successfully executing on our growth strategy***

We have a successful track record of acquiring and integrating assets, demonstrating our ability to both identify acquisition opportunities and effectively integrate acquisitions into our existing business. During the integration of Ophir which we acquired in May 2019, we have been able to realize a number of synergies and cost savings while maintaining our standards for safety. Prior to the Ophir Acquisition, we acquired our interest in, and became the operator of, the South Natuna Sea Block B and the associated West Natuna Transportation System. Both of these transactions realized synergies and cost savings which were substantial and above our estimates prior to transaction close.

Aside from acquisitions, we also have a track record of successfully delivering new projects in oil and gas, power and mining. This has helped us realize value from greenfield projects, and also positions us as an attractive partner for third parties looking for a partner with operating capability.

The completion of the Phase 1 of the Block A gas development in 2019 is the most recent example of our capabilities. This project involved high pressure, high temperature drilling and the construction of a central gas processing facility in an extremely remote area of Indonesia. This project was delivered on time and on budget with first gas in August 2018.

***Reliable partner for foreign companies and state-owned entities***

We believe our extensive experience in Southeast Asia, our operating capability, and our track record of making successful acquisitions positions us as an attractive partner for foreign companies and regional state-owned entities.

Our development of both the Senoro gas field (with Pertamina as the joint operator) and the DSLNG joint venture with Mitsubishi Corporation and KOGAS through their joint venture Sulawesi LNG Development Ltd., and Pertamina through its subsidiary PT Pertamina Hulu Energi are examples of such partnerships. DSLNG is the first project in Indonesia whereby the downstream LNG business is set up as a separate business entity from the upstream business activity, our Senoro gas field. This structure enabled significant savings in procurement and scheduling.

In addition, we have historically been successful in obtaining extensions of our PSCs prior to expiry. For example, most recently in 2016, we obtained extensions for the Lematang PSC until 2027 and the extension of exploration period for the South Sokang PSC until 2020, and prior to that in 2010, we obtained 20-year extensions for the Block A, Aceh and South Sumatra PSCs. Most recently, we were given 20 year extensions for the Rimau and Tarakan PSCs.

We believe that our successful involvement in such projects with both state-owned and foreign companies and our track record in securing extensions of and acquiring interests in PSCs and concessions provide us with a competitive advantage, which will allow us to continue to be the partner of choice for both state-owned and foreign companies.

***Well-positioned to leverage the favorable growth outlook for gas market in Indonesia***

Indonesia's gas market is expected to continue to expand to support the growing economy. Wood Mackenzie expects Indonesia's gas demand to increase by approximately 3.6 BCF/D between 2019 and 2040, corresponding to a CAGR of 3.5%. This robust growth is supported by consistent GDP increases and corresponding growing demand from the industrial and power sectors.

In addition, the Government has introduced policies designed to promote the use of alternative fuels, including domestic natural gas, given the strong economic, environmental and budgetary incentive to do so.

We believe we are well-positioned to capitalize on the prevailing regulations, such as the MEMR Regulation No. 45 of 2017 on the Use of Natural Gas for Power Plant to reduce the regulatory hurdles and time taken to develop IPPs to allow synergies between gas and LNG portfolios.

***Experienced management team with a successful exploration and development record***

We benefit from an experienced board of directors and senior management team with significant experience in oil and gas exploration and production both in and outside of Indonesia. Our management team includes oil and gas professionals with experience at large multi-national corporations such as Premier Oil, Hess, BP, ENI and ConocoPhillips.

In addition, our board of commissioners has significant experience working with regulators and government institutions, which is evidenced by our success with our PSC renewals and our ability to partner with state-owned operators on significant projects or in jointly operating PSCs. Furthermore, we value good corporate governance and our board of commissioners includes two independent commissioners.

**Business Strategies**

Our strategy is to continue to build our operations through our core oil and gas exploration and production business and our investments in power and mining. To that end, the following are our key strategies:

***Continued focus on core business of oil and gas exploration and production by monetizing existing discoveries***

We plan to continue to strengthen our portfolio of producing assets by the phased development and monetization of our existing portfolio of discovered gas assets. We also plan to focus on Senoro-Toili, where in

2018, 1,658 BCF of gross 100% field 1C contingent resources were estimated or assessed by GCA and where we are now evaluating potential development scenarios and preliminary engineering for Senoro-Toili Phase II. The investment decision with respect to the preferred development scenario is expected to be made in the second half of 2020. We received gas allocations in 2019 from the Government to monetize some of the gas from the Senoro-Toili block to supply a 220MW power plant and a regasification plant in Sumbawa which is expected to be built by MPI. The development consists of LNG to power projects for AMNT mining operations and smelter plants with the target commercial operation date of 2023. This development was also listed in the 2019 State Electricity Plan, which also includes several of our other projects. Concurrently, we are in the process of development of Bualuang Phase 4B in Thailand, which started first oil production in December 2019 and is expected to reach peak production by mid-2020 upon the completion of drilling program, and also a gas development project in Meliwis, East Java, Indonesia. Going forward, we expect that a larger percentage of our production will consist of production from Senoro-Toili, South Natuna Sea Block B, Block A, Aceh, Bualang in Thailand and Block 12W in Vietnam, as certain of our existing blocks, including Rimau PSC and South Sumatra PSC, are in mature stages of production. As of September 30, 2019, our reserve life index was 8.9 years.

***Continue to pursue value accretive acquisitions, and focus on effective integration***

We intend to build on our strong track record of evaluating, closing and integrating successful acquisitions in our core oil and gas business. Since 2016, we have made two significant oil and gas acquisitions, the Ophir Acquisition and our acquisition of interest in South Natuna Sea Block B, which have substantially increased our production and reserves base.

We intend to continue to take a disciplined approach in reviewing acquisition opportunities and will focus primarily on:

- High quality assets in the bottom half of the cash cost curve;
- Assets in Southeast Asia, where we have a competitive advantage in operations and stakeholder management;
- Cash flow producing assets, which can support a prudent amount of leverage; and
- Assets where there are synergies with our existing operations.

We believe we can leverage our position as a leading regional oil and gas company to access, review and, if desirable, competitively bid for and acquire both domestic and international blocks. According to WoodMackenzie, merger and acquisition activity is expected to increase in Asia Pacific as (i) international oil companies look to prioritize capital allocation in other markets, leading to divestments in Southeast Asia ; and (ii) Southeast Asia's national oil companies may look to farm-down positions and seek partners for technical and financial support.

We believe that we are well positioned to acquire interests in assets in the region which may become available for sale. Moreover, we believe our reputation, together with our financial and operational strength, allows us to competitively access domestic and international funds through our banking relationships and/or capital markets to fund both project development and, if competitively priced and complementary to our portfolio, suitable future acquisitions.

***Replace and add reserves through selective low-risk exploration and development***

We plan to continue to replace depleting reserves and add reserves through selective low-risk exploration and development on our existing Indonesian PSCs. We intend to implement this strategy primarily by conducting infrastructure-led exploration, development and tie-ins to existing infrastructure on our existing PSCs. Our existing PSCs have cost recovery funded, economic advantages when compared to the contracts offered on new PSCs. While we will continue to assess new block offerings, we intend to continue our disciplined approach to exploration over the next five years. We believe this will help us to economically offset decline in our core PSCs in a continued low oil price environment. Our average 2P finding and development cost (representing capital expenditures (including acquisitions) divided by reserve additions) for the five year periods ending December 31, 2018 and September 30, 2019 was US$11/BOE for both periods.

***Maintain financial flexibility with a prudent capital structure and rigorous financial discipline***

We intend to maintain a prudent capital structure and to retain the flexibility to keep leverage within range of our target of Net Debt to EBITDA of 3.0x.

In the past we have used both equity raises and asset sales in order to reduce our leverage. For example in December 2017, we conducted a rights offering raising proceeds of Rp. 2.6 trillion before deduction of transaction costs, which we used primarily for reducing our leverage.

Over the period from 2017 to 2019 we sold non-core and underperforming assets or interests with total proceeds of US$536 million the proceeds for which assisted in our deleveraging efforts. Similarly in the future we intend to continue rationalizing our portfolio through selective divestments of non-core assets in order to focus our business on productive assets that align with our strategy.

Shareholders that exercised their rights in 2017 were issued detachable warrants which were exercisable between July 2018 and December 2020, with the exercise price for each warrant ranging between Rp. 625 and Rp. 675, with proceeds therefrom potentially up to Rp. 2.9 trillion. Furthermore, we have not declared any dividends in the last four financial years.

In addition, in November 2018, we obtained shareholder approval for a capital increase without preemptive rights for up to 10% of the issued and paid up capital at a minimum price of Rp. 868 per share.

In considering future acquisitions, we plan to continue to be disciplined and target cash flow producing assets, or portfolios with cash producing assets and opportunities, which meet our acquisition criteria and maintain our leverage targets.

***Continue to develop strategic partnerships***

We intend to continue to build strategic alliances through our core oil and gas business and through our investments in power and mining. We have, in the past, successfully collaborated on projects with both foreign and government operators. For example, we were the private Indonesian partner in DSLNG, a joint venture company established in 2007 by a consortium consisting of PT Medco LNG Indonesia (a wholly owned subsidiary of our Group), Mitsubishi Corporation and KOGAS through their joint venture Sulawesi LNG Development Ltd., and Pertamina through its subsidiary PT Pertamina Hulu Energi. AMNT may also form a joint venture with another party or parties to develop its smelter.

***Maintain focus on environmental, social and governance issues***

We are focused on maintaining high corporate governance standards, which are driven by principles of transparency, accountability, responsibility and fairness. We believe that we enjoy a positive reputation within Indonesia, and we believe that implementation of good corporate governance principles is important in sustaining our future growth and aim to execute our business in line with these principles. In addition, we implement and enforce our non-discrimination policies with regard to gender, race and religion and have two externally managed whistleblowing systems in place to enhance oversight of conduct that is not in line with our code of ethics. We intend to continue implementing these and other prudent policies to maintain our corporate governance standards.

We are strongly committed to the goals of sustainability for our business and the environment in which we operate. By relying on the professionalism of our people and adhering to good corporate governance, we aim to achieve long-term sustainability for the benefit of future generations, and we have adopted green principles of managing business sustainably. For example in April 2018, we adopted the MedcoEnergi Sustainability Policy in order to design a sustainability roadmap by reviewing best international practices. The three pillars of our MedcoEnergi Sustainability Policy, which are (i) leadership of and by our employees, (ii) environmental and social development and (iii) sustainable livelihoods and community development, represent the key areas of priority and focus. We aim to become more integrated across our organization with respect to a wide range of areas including health, safety and environment, social development, human capital and governance through these three pillars.

We believe that relationships with local communities around our operations, while a corporate objective, are also important for our business and the security of our operations. We practice CSR policies which foster empowerment and entrepreneurship, and include assisting in the improvement of public welfare and sanitation facilities in local communities, creating economically self-sustaining communities, encouraging local government re-greening and re-forestation programs and supporting social, religious and education activities. We are the only Indonesian listed member of the Business for Social Responsibility NGO and we intend to continue to engage in community development programs encompassing a variety of social and economic areas, including infrastructure, education and sports, medical and health, and religion and culture. For example, we built a hospital near the Block A, Aceh PSC for the use and access of the local community.

### Oil and Gas Exploration and Production Business

Our oil and gas activities are focused in Southeast Asia, where we are involved in upstream activity, exploration, development and production of crude oil and natural gas. We currently have interests in 15 oil and gas properties in Indonesia, 11 of which are currently producing; and in oil and gas properties in four countries outside of Indonesia, three of which are currently producing. Our oil and gas properties that are not currently producing are at various stages of exploration and development.

### Summary of Production Sharing Arrangements and Concessions

The following table summarizes our oil and gas properties including our production sharing arrangements:

| | | | | | | Share to Contractor[1] | | |
|---|---|---|---|---|---|---|---|---|
| **Contract Area (Type)** | **Location** | **Date of Acquisition** | **Effective Interest[2]** | **Gross Area ($Km^2$)** | **Contract Expiry Date** | **Profit Crude Oil (%)** | **Profit Natural Gas (%)** | **Operator** |
| **Indonesia:** | | | | | | | | |
| ***Producing Properties*** | | | | | | | | |
| Rimau (PSC) | South Sumatra | 1995 | 60.00% | 1,103 | 2043 | 15.00[6] | 35.00[6] | Medco |
| South Sumatra Block (PSC) | South Sumatra | 1995 | 65.00% | 4,470 | 2033 | 12.50 | 27.50 | Medco |
| Lematang (PSC) | South Sumatra | 2002 | 100.00% | 409 | 2027 | 15.00 | 29.50 | Medco |
| Tarakan (PSC) | North Kalimantan | 1992 | 100.00% | 180 | 2042 | 15.00[6] | 35.00[6] | Medco |
| Senoro-Toili (PSC-JOB) | Sulawesi | 2000 | 30.00% | 451 | 2027 | 35.00 | 40.00 | Pertamina-Medco JOB |
| Block A, Aceh (PSC) | Aceh, North Sumatra | 2006 | 85.00% | 1,681 | 2031 | 15.00 | 35.00 | Medco |
| South Natuna Sea Block B | Riau Islands | 2016 | 40.00% | 11,155 | 2028 | 15.00 | 35.00 | Medco |
| Bangkanai — Kerendan gas field (PSC) | Central Kalimantan | 2019 | 70% | 1,385 | 2033 | 15.00 | 35.00 | Medco |

| Contract Area (Type) | Location | Date of Acquisition | Effective Interest[2] | Gross Area (Km²) | Contract Expiry Date | Share to Contractor[1] Profit Crude Oil (%) | Share to Contractor[1] Profit Natural Gas (%) | Operator |
|---|---|---|---|---|---|---|---|---|
| Madura Offshore — Peluang and Maleo gas fields (PSC) | East Java Basin | 2019 | 67.5% | 849 | 2027 | 20.00 | 35.00 | Medco |
| Sampang — Wortel and Oyong gas fields (PSC) | East Java Basin | 2019 | 45.0% | 534 | 2027 | 20.00 | 35.00 | Medco |
| ***Development Properties*** | | | | | | | | |
| Simenggaris (PSC-JOB) | North Kalimantan | 1998 | 62.50% | 547 | 2028 | 15.00 | 35.00 | Pertamina-Medco JOB |
| Madura Offshore — Meliwis field (PSC) | East Java Basin | 2019 | 77.5% | 849 | 2027 | 20.00 | 35.00 | Medco |
| ***Exploration Properties*** | | | | | | | | |
| Bengara (PSC) | North Kalimantan | 2001 | 100.00% | 922 | 2029 | 15.00 | 35.00 | Medco |
| South Sokang (PSC) | Riau Islands | 2016 | 100.00% | 998 | 2040 | 35.00 | 40.00 | Medco |
| West Bangkanai (PSC) | Central Kalimantan | 2019 | 70.0% | 5,463 | 2043 | 25.00 | 35.00 | Medco |
| **Libya:** | | | | | | | | |
| ***Development Properties*** | | | | | | | | |
| Area 47 (EPSA IV) | Libya | 2005 | 50.00% | 6,182 | Five years exploration; 25 years production | 6.85 | 6.85 | Nafusah Oil Operation BV[3] |
| **Oman:** | | | | | | | | |
| ***Producing Properties*** | | | | | | | | |
| Karim Small Fields (Service Agreement) | The Sultanate of Oman | 2006 | 58.00% | 781 | 2040 | 12-30 | N/A | Medco |
| ***Exploration Properties*** | | | | | | | | |
| Block 56 (PSC)[8] | The Sultanate of Oman | 2014 | 50.00% | 5,808 | 2020 exploration; 20 years production | 25 | 30 | Medco |
| **Yemen:** | | | | | | | | |
| ***Producing Properties*** | | | | | | | | |
| Block 9 Malik (PSC) | Sayun-Masila Basin | 2008 | 21.25% | 4,728 | 2030[5] | 30 | N/A | Calvalley Petroleum (Cyprus) Ltd |
| **Vietnam:** | | | | | | | | |
| ***Producing Properties*** | | | | | | | | |
| Block 12W (PSC) | Nam Con Son Basin, Offshore | 2019 | 31.9% | 182.26 | 2030 | 40-82.5 | 40-82.5 | PremierOil |
| **Thailand:** | | | | | | | | |
| ***Producing Properties*** | | | | | | | | |
| Bualuang oil field (Concession) | Gulf of Thailand | 2019 | 100% | 377 | 2025 | N/A | N/A | Medco |

| Contract Area (Type) | Location | Date of Acquisition | Effective Interest[2] | Gross Area (Km²) | Contract Expiry Date | Share to Contractor[1] Profit Crude Oil (%) | Share to Contractor[1] Profit Natural Gas (%) | Operator |
|---|---|---|---|---|---|---|---|---|
| Sinphuhorm gas field (Concession) | Northeast Thailand | 2019 | 9.5% | 230 | 2031 | N/A | N/A | PTT Exploration and Production Public Company Ltd |
| **Myanmar:** | | | | | | | | |
| ***Exploration Properties*** | | | | | | | | |
| Block AD-3 | Rakhine Offshore Area | 2019 | 42.0% | 9,898 | 2045 | 15-45 | 10-45 | Medco |
| Block A-5 | Rakhine Offshore Area | 2019 | 42.0% | 10,500 | 2045 | 15-45 | 10-45 | Unocal Myanmar Offshore Co., Ltd. |
| **Mexico:** | | | | | | | | |
| ***Exploration Properties*** | | | | | | | | |
| Block 5 (PSC)[8] | Salina Basin | 2019 | 23.3% | 2,573 | 2052 | N/A[9] | N/A[9] | Murphy |
| Block 10 (PSC) | Mexican Cordilleras | 2019 | 20.0% | 1,999 | 2053 | N/A[9] | N/A[9] | Repsol |
| Block 12 (PSC) | Mexican Cordilleras | 2019 | 20.0% | 3,099 | 2053 | N/A[9] | N/A[9] | PC Carigali |
| **Malaysia:** | | | | | | | | |
| ***Exploration Properties*** | | | | | | | | |
| Block PM-322 (PSC) | Melaka Straits | 2019 | 85.0% | 20,000 | 2040 | 10-70 | 10-80 | Medco |
| **Tanzania (LNG):** | | | | | | | | |
| ***Exploration Properties*** | | | | | | | | |
| Block 1 (PSC) | Rovuma Basin | 2019 | 20% | 8,169 | 2020 | 40-60 | 40-70 | Shell |
| Block 4 (PSC) | Rovuma Basin | 2019 | 20% | 3,806 | 2020 | 40-60 | 40-70 | Shell |

Notes:

(1) Effective post-Government tax and post-cost recovery. Prior to any potential DMO and any local government taxes.

(2) Effective interest is presented net of the participating interests of our partners (if any) but gross of all Government participating interests.

(3) Comprised of the Libya Investment Authority, Medco International Ventures Ltd. and National Oil Corporation.

(4) On March 22, 2019, we exercised our preemption right and signed a Share Sale and Purchase Agreement with KEC Gulf Holdings Limited to increase our interest through our subsidiary, Medco LLC. The Share Sale and Purchase Agreement is expected to close after we receive approval from the Oman government's Ministry of Commerce and Industry. We expect to have an effective 58.5% interest upon completion of the foregoing transactions.

(5) For production over 25,000 BOPD.

(6) Under Gross Split PSC, Profit Share to Contractor is different.

(7) On April 26, 2017, Medco Arabia Limited and Biyaq Oilfield Services LLC signed a Farmout Agreement, whereby Medco Arabia Limited agreed to assign 25% of its participating interest in the Block 56 to Biyaq Oilfield Services LLC. On November 29, 2018, this transaction has been completed with consideration amount of US$1,500,000.

(8) On May 16, 2019, Ophir Mexico Offshore Exploration, S.A. DE C.V., Murphy SUR, S. DE R.L. DE C.V., PC Carigali Mexico Operations, S.A. DE C.V. and Sierra Offshore Explorations, S. DE R.L. DE C.V. signed Asset Sale and Purchase Agreement where Ophir transferred 23.3% participating interest of Block 5 to Murphy, Petronas and Sierra.

(9) On top of Base Royalty and Variable Royalty Rate, contractors need to pay additional Royalty to Government, which was determined during bidding process. Additional royalty for Block 5 is 26.9%, Block 10 is 20.0% and Block 12 is 20.0%.

**Reserves and Resources**

From time to time, we engage independent petroleum engineering consultants to estimate or assess the reserves at certain of our major production blocks.

Estimations or assessments have been prepared by Gaffney, Cline, & Associates, an independent petroleum engineering consultant for the blocks listed below as of the dates indicated:

| Asset | Reserves Date |
|---|---|
| Block A, Aceh | December 31, 2018 |
| Senoro-Toili (Senoro Gas Field) | October 31, 2018 |
| South Natuna Sea Block B | September 30, 2018 |
| South Sumatra Block | December 31, 2018 |
| Lematang (Singa Field) | December 31, 2017 |
| Rimau PSC | December 31, 2018 |

Estimates on reserves for assets that are not listed above (i) which amount to approximately 39.4% of our gross working interest proved reserves and 46.9% of our gross working interest proved and probable reserves as of September 30, 2019 are estimated by us based on our own investigations and prior reserve estimates or assessments by reputable international consultants and (ii) which represent reserves added through the Ophir Acquisition amounting to 17.3% of our gross working interest proved oil and gas reserves and 18.6% of our gross working interest proved and probable reserves as of September 30, 2019 are estimated by us based on prior reserve estimates or assessments by a reputable international consultant as of December 31, 2018. You should note that the above-mentioned estimations or assessments made by us, may differ from the bases of estimation for reserves and resources used by other companies in the industry.

These gross working interest values are calculated based upon our portion of the estimated gross proved reserves and gross proved and probable reserves attributable to our effective working interest, which have been derived from reserves estimations or assessments as of their effective dates and then deducting production, without accounting for reserves appreciation or depreciation, at each production block over the period from the respective estimations or assessments effective date (if a block has been so earlier estimated or assessed) to September 30, 2019. If a recent reserves estimations or assessments for a block is unavailable, the estimates have been derived by our internal technical team based on guidelines promulgated by the Society of Petroleum Engineers in the SPE-PRMS. To the extent that we have presented our gross working interest reserves on the basis of our effective working interest under the applicable contractual arrangement and not in accordance with SPE-PRMS guidelines, we and not our independent petroleum engineering consultants are responsible for such data. However, our independent petroleum engineering consultants are responsible for the reserves data prior to adjustment for the effective working interest. Certain of these reserve estimations or assessments may include projections, forecasts or other forward-looking statements and any such information does not form part of this document.

The following table sets forth the reserves for each of our blocks, excluding our exploration blocks and certain development blocks for which reserves have not yet been estimated, as of September 30, 2019.

| | As of September 30, 2019 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Gross Working Interest Proved Reserves[(1)] | | | Gross Working Interest Proved and Probable Reserves[(1)] | | | Gross Working Interest Proved and Probable and Possible Reserves[(1)] | | |
| | Gas (BCF) | Oil (MMBBLS) | Total (MMBOE) | Gas (BCF) | Oil (MMBBLS) | Total (MMBOE) | Gas (BCF) | Oil (MMBBLS) | Total (MMBOE) |
| **Indonesia:** | | | | | | | | | |
| **Producing Properties** | | | | | | | | | |
| Rimau | — | 12 | 12 | — | 22 | 22 | — | 35 | 35 |
| South Sumatra | 75 | 6 | 21 | 84 | 10 | 26 | 94 | 15 | 33 |
| Lematang | 22 | — | 3 | 26 | — | 4 | 30 | — | 5 |
| Tarakan | 0 | 1 | 1 | 0 | 1 | 1 | 0 | 1 | 1 |
| Senoro-Toili (Tiaka Field) | — | 1 | 1 | — | 2 | 2 | — | 2 | 2 |
| Senoro-Toili (JOB) | 298 | 7 | 64 | 305 | 7 | 66 | 312 | 7 | 68 |
| South Natuna Sea Block B | 29 | 4 | 10 | 43 | 6 | 14 | 69 | 10 | 23 |
| Block A, Aceh | 203 | 5 | 41 | 203 | 7 | 44 | 203 | 10 | 46 |
| Bangkanai | 70 | 0 | 13 | 72 | 1 | 14 | 79 | 1 | 15 |
| Madura Offshore | 12 | — | 2 | 48 | — | 8 | 71 | — | 12 |
| Sampang | 5 | 0 | 1 | 10 | 0 | 2 | 15 | 0 | 3 |
| **Libya:** | | | | | | | | | |
| **Development Properties** | | | | | | | | | |
| Area 47 | 36 | 39 | 45 | 57 | 61 | 71 | 57 | 61 | 71 |
| **Tunisia[(1)]:** | | | | | | | | | |
| **Producing Properties** | | | | | | | | | |
| Bir Ben Tartar Block | — | 3 | 3 | — | 9 | 9 | — | 16 | 16 |
| Adam Block | 1 | 0 | 0 | 2 | 1 | 1 | 2 | 1 | 1 |
| **Yemen:** | | | | | | | | | |
| **Producing Properties** | | | | | | | | | |
| Block 9 Malik | — | 5 | 5 | — | 10 | 10 | — | 14 | 14 |
| **Thailand:** | | | | | | | | | |
| **Producing Properties** | | | | | | | | | |
| Block E5 & EU1 | 29 | 0 | 5 | 32 | 0 | 5 | 33 | 0 | 6 |
| Block B8/38 | — | 16 | 16 | — | 24 | 24 | — | 33 | 33 |
| **Vietnam:** | | | | | | | | | |
| **Producing Properties** | | | | | | | | | |
| Block 12W | 2 | 5 | 6 | 3 | 8 | 9 | 5 | 12 | 13 |
| **Total Reserves** | **782** | **104** | **249** | **885** | **169** | **332** | **970** | **218** | **396** |

Note:

(1) In the fourth quarter of 2019, we disposed of our Tunisia oil and gas assets.

Certain reserve estimates contained in this document (i) which amount to approximately 39.4% of our gross working interest proved oil and gas reserves and 46.9% of our gross working interest proved and probable reserves as of September 30, 2019 are estimated by us based on our own investigations and prior reserve estimates or assessments by reputable international consultants and (ii) which represent reserves added through the Ophir Acquisition amounting to 17.3% of our gross working interest proved oil and gas reserves and 18.6% of our gross working interest proved and probable reserves as of September 30, 2019 are estimated by us based on prior reserve estimates or assessments by a reputable international consultant as of December 31, 2018.

There are numerous uncertainties inherent in estimating natural gas and oil reserves, including many factors beyond the control of the Company. For a description of certain of the risks and uncertainties with respect to the Company's reserve data, see "Risk Factors — The oil and gas reserves data in this document are only estimates and the actual production, revenue and expenditures achievable with respect to our reserves may differ from such estimates; there are no recent reserve estimations or assessments available for a significant portion of our reserves, and the oil and gas reserves data for these blocks are based on our internal estimates. In addition, probable reserves are generally believed to be less likely to be recovered than proved reserves."

**Contingent Resources**

Contingent resources are quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

The contingent resources set forth below are presented based on the "best estimate" scenario of contingent resources, or "2C," meaning that the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts has been assessed to be at least 50%. The following table sets forth the contingent resources regarding our oil and gas assets based on the independent third-party estimations or assessments as of their effective dates and our or the relevant operator's estimates as of September 30, 2019 on a gross 100% field basis multiplied by our working interest in each block:

| | As of September 30, 2019 | | |
|---|---|---|---|
| | Oil (MBBLS) | Gas (MMSCF) | Total (MBOE) |
| **Indonesia:** | | | |
| ***Producing Properties:*** | | | |
| Rimau | 12,500 | — | 12,500 |
| South Sumatra | 1,900 | 91,300 | 19,492 |
| Tarakan | 2,200 | 1,900 | 2,561 |
| Lematang | — | 55,600 | 8,502 |
| Senoro-Toili (JOB) | 17,550 | 818,100 | 176,097 |
| South Natuna Sea Block B | 18,000 | 126,400 | 41,582 |
| Block A, Aceh | 9,775 | 1,121,732 | 211,525 |
| Simenggaris | — | 92,745 | 16,074 |
| Bangkanai | 6,370 | 408,100 | 81,388 |
| **Libya** | | | |
| ***Development Properties:*** | | | |
| Area 47 | 43,522 | 103,822 | 60,826 |
| **Yemen** | | | |
| ***Producing Properties:*** | | | |
| Block 9 Malik | 3,327 | 19,316 | 6,629 |
| **Thailand** | | | |
| ***Producing Properties:*** | | | |
| Block E5 & EU1 | 69 | 19,729 | 3,358 |
| Block B8/38 | 710 | — | 710 |
| **Vietnam** | | | |
| ***Producing Properties:*** | | | |
| Block 12W | 169 | — | 169 |

| | As of September 30, 2019 | | |
|---|---|---|---|
| | Oil (MBBLS) | Gas (MMSCF) | Total (MBOE) |
| **Tanzania** | | | |
| ***Development Properties:*** | | | |
| Block 1 & 4 | — | 3,005,800 | 521,388 |
| **Total** | **104,712** | **4,776,612** | **955,685** |

## Production

Our oil and gas activities are focused on Indonesia, where we focus on upstream activity, exploration, development and production of crude oil and natural gas. We have interests in 15 oil and gas properties in Indonesia, 11 of which are currently producing; and in oil and gas properties in eight countries outside of Indonesia, with interests in key producing assets in Vietnam and Thailand and interests in other assets in Yemen, Libya, Oman, Malaysia, Mexico and Tanzania. Our oil and gas properties that are not currently producing are at various stages of exploration and development. The basis for the oil production numbers are gross 100% field basis multiplied by our working interest in each block:

*Oil Production*

| | For the Year Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| | | | (BOPD) | | |
| **Indonesia:** | | | | | |
| Rimau | 9,826 | 9,041 | 8,233 | 8,315 | 7,659 |
| South Natuna Sea Block B[2] | 617 | 7,162 | 6,777 | 6,841 | 6,404 |
| South Sumatra | 5,198 | 5,468 | 5,244 | 5,209 | 5,340 |
| Senoro-Toili[1] | 2,516 | 2,242 | 2,292 | 2,216 | 2,302 |
| Block A, Aceh | — | — | 146 | 29 | 1,671 |
| Others[4] | 2,576 | 1,779 | 1,561 | 1,462 | 2,096 |
| **International:** | | | | | |
| Karim Small Fields | 8,295 | 7,983 | 7,193 | 7,407 | 7,024 |
| Block B8/38[3] | — | — | — | — | 2,356 |
| Block 12W[3] | — | — | — | — | 2,332 |
| Bir Ben Tartar Block | 1,135 | 858 | 825 | 919 | 627 |
| Others[5] | 620 | 526 | 499 | 446 | 361 |
| **Total Production** | **30,784** | **35,060** | **32,771** | **32,844** | **38,173** |

Notes:

(1) Includes production from both (i) the Senoro-Toili (Senoro Gas Field), which have been estimated by us based on estimates as of October 31, 2018 by Gaffney, Cline & Associates and (ii) the Senoro-Toili, Tiaka field, which is Senoro-Toili's oil field, which have been estimated by us based on other prior estimations or assessments.

(2) From December 1, 2016.

(3) From June 1, 2019.

(4) Includes Tarakan, Bawean in 2016, and Bangkanai and Sampang from June 1, 2019.

(5) Includes Main Pass, Adam, Block 9 Malik and Block E5 & EU1. In February 2019, we sold our Main Pass assets.

*Gas Production*

| | For the Year Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| | | | (MSCFD) | | |
| **Indonesia Assets** | | | | | |
| Senoro-Toili | 95,648 | 88,161 | 91,927 | 88,630 | 93,535 |
| South Natuna Sea Block B[(1)] | 7,596 | 85,153 | 81,158 | 80,126 | 81,249 |
| South Sumatra Extension | 62,197 | 66,501 | 66,792 | 67,986 | 60,174 |
| Lematang | 37,831 | 32,069 | 25,151 | 25,553 | 21,104 |
| Block A, Aceh | — | — | 5,990 | 1,708 | 45,223 |
| Rimau | — | 3,761 | 3,680 | 3,721 | 3,794 |
| Madura Offshore[(2)] | — | — | — | — | 13,137 |
| Sampang[(2)] | — | — | — | — | 9,040 |
| Others[(3)] | 949 | 1,153 | 1,525 | 1,455 | 7,066 |
| **International:** | | | | | |
| Block 12W PSC[(2)] | — | — | — | — | 3,308 |
| Block E5 & EU1[(2)] | — | — | — | — | 2,531 |
| Adam | 1,465 | 1,233 | 1,766 | 1,694 | 1,743 |
| Others[(4)] | 270 | — | 1,326 | 1,433 | 959 |
| **Total Production** | **205,954** | **278,031** | **279,316** | **272,305** | **340,939** |

Notes:

(1) From December 1, 2016.

(2) From June 1, 2019

(3) Includes Tarakan, Simenggaris and Bangkanai.

(4) Includes Bir Ben Tartar Block and Main Pass. In February 2019, we sold our Main Pass assets.

*Hydrocarbon Production*

| | For the Year Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| | | | (BOEPD) | | |
| **Indonesia Assets** | | | | | |
| South Natuna Sea Block B[(1)] | 1,916 | 23,049 | 21,919 | 21,790 | 21,562 |
| Senoro-Toili | 18,866 | 19,328 | 20,108 | 19,392 | 20,429 |
| South Sumatra Extension | 15,830 | 18,281 | 18,113 | 18,309 | 16,934 |
| Block A, Aceh | — | — | 992 | 270 | 9,805 |
| Rimau | 9,826 | 9,684 | 8,862 | 8,951 | 8,308 |
| Lematang | 6,467 | 4,903 | 3,846 | 3,907 | 3,227 |
| Others[(3)] | 2,738 | 1,997 | 1,849 | 1,736 | 7,037 |
| **International:** | | | | | |
| Karim Small Fields | 8,295 | 7,983 | 7,193 | 7,407 | 7,024 |
| Block 12W PSC[(5)] | — | — | — | — | 3,013 |
| Block B8/38[(5)] | — | — | — | — | 2,356 |
| Bir Ben Tartar Block (PSC) | 1,135 | 858 | 1,052 | 1,164 | 791 |
| Others[(4)] | 909 | 737 | 801 | 736 | 1,081 |
| **Total Production** | **65,982** | **86,821** | **84,735** | **83,663** | **101,567** |

Notes:

(1) From December 1, 2016.

(2) In February 2019, we sold our Main Pass assets.
(3) Includes Tarakan, Bawean (in 2016), Simenggaris, Bangkanai[5], Madura Offshore[5] and Sampang[5].
(4) Includes Main Pass, Adam, Block 9 Malik and Block E5 & EU1[5] . In February 2019, we sold our Main Pass assets.
(5) From June 1, 2019.

*Oil Lifting*

| | For the Year Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| | | | (MBOPD) | | |
| **Indonesia Assets** | | | | | |
| Rimau | 9.21 | 8.96 | 8.27 | 8.38 | 7.88 |
| South Natuna Sea Block B[1] | 0.74 | 6.94 | 7.36 | 7.58 | 6.47 |
| South Sumatra | 5.22 | 5.44 | 5.25 | 5.21 | 5.33 |
| Senoro-Toili | 2.51 | 2.25 | 2.31 | 2.26 | 2.30 |
| Others[2] | 2.68 | 1.75 | 1.60 | 1.42 | 3.16 |
| **International:** | | | | | |
| Karim Small Fields | 8.29 | 7.98 | 7.19 | 7.41 | 7.09 |
| Tunisia | 0.75 | 0.48 | 1.36 | 0.80 | 0.35 |
| Block B8/38[3] | — | — | — | — | 2.74 |
| Block 12W[3] | — | — | — | — | 2.39 |
| Others[4] | 0.39 | 0.38 | 0.32 | 0.32 | 0.01 |
| **Total** | **29.79** | **34.19** | **33.67** | **33.36** | **37.73** |

Notes:
(1) From December 1, 2016.
(2) Includes Tarakan, Senoro Tiaka, Block A, Bawean (in 2016), Bangkanai[4] and Sampang[4].
(3) From June 1, 2019.
(4) Includes East Cameron, Main Pass, Block 9 Malik and Block E5 & EU1. In February 2019, we sold our Main Pass assets.

*Gas Sales*

| | For The Year Ended December 31, | | | For The Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| | | BBTUPD | | | |
| **Indonesia Assets** | | | | | |
| Senoro-Toili | 101.65 | 95.03 | 98.73 | 95.12 | 101.01 |
| South Natuna Sea Block B[1] | 7.00 | 81.49 | 70.51 | 69.38 | 72.29 |
| South Sumatra | 63.99 | 68.61 | 71.98 | 72.99 | 57.32 |
| Block A, Aceh | — | — | 3.55 | 0.20 | 38.55 |
| Lematang | 36.77 | 26.14 | 20.22 | 20.65 | 18.07 |
| Madura Offshore[2] | — | — | — | — | 12.63 |
| Others[4] | 0.96 | 0.99 | 1.41 | 1.33 | 14.87 |
| **International:** | | | | | |
| Block E5 & EU1[2] | — | — | — | — | 2.48 |
| Block 12W[2] | — | — | — | — | 2.52 |
| Tunisia | 1.53 | 1.15 | 1.35 | 1.44 | 1.47 |
| Others[4] | 0.26 | — | — | — | — |
| **Total** | **212.15** | **273.41** | **267.75** | **261.10** | **321.21** |

Notes:
(1) From December 1, 2016.
(2) From June 1, 2019.
(3) Includes Tarakan, Simenggaris, Bangkanai(3) and Sampang(3).
(4) Includes Main Pass and Block 9 Malik. In February 2019, we sold our Main Pass assets.

*Hydrocarbon Sales*

| | For the Year Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| | | MBOPD | | | |
| **Indonesia Assets** | | | | | |
| Senoro-Toili | 20.14 | 18.73 | 19.44 | 18.76 | 19.82 |
| South Natuna Sea Block B(1) | 1.95 | 21.08 | 19.60 | 19.61 | 19.01 |
| South Sumatra | 16.32 | 17.34 | 17.74 | 17.87 | 15.27 |
| Rimau | 9.21 | 8.96 | 8.27 | 8.38 | 7.88 |
| Block A, Aceh | — | — | 0.62 | 0.03 | 7.86 |
| Lematang | 6.38 | 4.53 | 3.51 | 3.58 | 3.13 |
| Others(3) | 2.86 | 1.93 | 1.85 | 1.65 | 6.78 |
| **International:** | | | | | |
| Karim Small Fields | 8.29 | 7.98 | 7.19 | 7.41 | 7.09 |
| Tunisia | 1.01 | 0.68 | 1.59 | 1.04 | 0.60 |
| Block B8/38(2) | — | — | — | — | 2.74 |
| Block 12W(2) | — | — | — | — | 2.85 |
| Others(4) | 0.43 | 0.38 | 0.32 | 0.32 | 0.43 |
| **Total** | **66.58** | **81.62** | **80.11** | **78.64** | **93.45** |

Notes:
(1) From December 1, 2016.
(2) From June 1, 2019.
(3) Includes Tarakan, Senoro Tiaka, Bawean (in 2016), Simenggaris, Bangkanai, Madura Offshore and Sampang.
(4) Includes Main Pass, Block 9 Malik and Block E5 & EU1(3). In 2019, we sold our Main Pass assets.

**Exploration and Development**

We are involved in both exploration (the search for oil and gas) and development (the drilling and development of facilities) to bring oil and gas into production and to market. Our exploration operations include aerial surveys, geological and geophysical studies (such as seismic surveys), drilling of wildcat wells, core testing and well logging.

Seismic surveys involve recording and measuring the rate of transmission of shock waves through the earth with a seismograph. Upon striking rock formations, the waves are reflected back to the seismograph. The time lapse is a measure of the depth of the formation. The rate at which waves are transmitted varies with the medium through which they pass. Seismic surveys may either be 3D or 2D surveys, the former type generally giving a better detailed picture and the latter a better overall picture.

Analysis of the data produced allows us to formulate a picture of the underground strata to enable us to form a view as to whether there are any “leads” or “prospects.” “Leads” are preliminary interpretation of geological and geophysical information that may or may not lead to prospects and “prospects” are geological structures conducive to the production of oil and gas. The actual existence of such oil and gas must be confirmed, usually by the drilling of a wildcat well. If the wildcat well confirms the prospect (that is, is considered “successful”), we may then drill a delineation (or appraisal) well to acquire more detailed data on the reservoir formation. Once the presence of hydrocarbons is proved to be in commercially recoverable quantities, or the delineation well is "successful", development wells may be drilled to prepare for production. An area is considered to be developed when it has a well on it capable of producing oil or gas in paying quantities. We may also "work over" producing wells (wells that produce oil or gas) to restore or increase production and rework producing wells and abandoned wells (wells which are no longer in use) in an effort to begin, restore or increase production from those wells.

**Description of Key Oil and Gas Properties**

**Key Producing Blocks in Indonesia**

Our production blocks in Indonesia are managed in five main business areas. These are our (i) South Sumatra asset (the Rimau PSC, South Sumatra PSC and Lematang PSC), (ii) the offshore South Natuna Sea Block B PSC, (iii) the Senoro-Toili JOB, (iv) Block A Aceh and (v) the Madura Offshore PSC and Sampang PSC. We also manage the smaller Tarakan PSC, Simenggaris PSC and Bangkanai PSC. Going forward, we expect that a larger percentage of our production will consist of production from Senoro-Toili, South Natuna Sea Block B and Block A, Aceh, as certain of our existing blocks, including Rimau PSC, South Sumatra PSC, Madura Offshore PSC, and Sampang PSC are in the mature stage of production.

***Senoro-Toili***

The block consists of two areas: Senoro (onshore), which covers 188 sq. km and contains our largest gas reserves, and Toili (offshore), which covers 263 sq. km and contains the Tiaka field in Toili, which has produced a high quality condensate since 2005 (approximately 1.5 MBOPD). After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 62.5% and the Government's share is 37.5%. For natural gas, the PSC participants' share is 71.4% and the government's share is 28.6%. A portion of the PSC participants' profit oil share is subject to DMO, but the participant's profit gas share is not subject to DMO.

*Upstream Sector-Gas*

The Senoro field started production on time and on budget in August 2015. The production facilities now have a capacity of up to 340 MMSCFD.

JOB-PMEPTS signed a GSA with DSLNG to supply 250 MMSCFD of gas in 2009. In addition, JOB-PMEPTS also entered into an agreement with PT Panca Amara Utama in March 2014 to supply 55 MMSCFD of gas to an ammonia plant for which the price is linked to ammonia prices in the Southeast Asia market.

In 2018, 1,658 BCF of gross 100% field 1C contingent resources were estimated or assessed by an independent third party. The potential development scenarios to monetize these resources are currently being evaluated. Front end engineering and design is ongoing and the final investment decision with respect to the preferred development scenario is expected to be made in the second half of 2020. This Phase II development is planned to begin following the commencement of gas production and sales from our Aceh gas development project. We have entered into a memorandum of understanding for potential GSAs. The Phase II development is expected to increase production from the Senoro field from 2024. A plan of development was submitted in late 2018.

*Downstream Sector-Gas*

Our involvement in the downstream sector is through DSLNG, a joint venture company established in 2007 by a consortium consisting of PT Medco LNG Indonesia (a wholly owned subsidiary of our Group), Mitsubishi

Corporation and KOGAS through their joint venture Sulawesi LNG Development Ltd., and Pertamina through its subsidiary PT Pertamina Hulu Energi. The downstream LNG plant has a capacity of approximately 2.1 million tons per annum located at Banggai Regency, Central Sulawesi. The plant is contracted to take the Phase I 1.44 TCF from the Senoro gas reserves and 0.70 TCF from the Matindok gas field owned by Pertamina.

DSLNG is the first project in Indonesia to use an upstream-downstream LNG structure whereby the downstream LNG business is set up as a separate business entity from the upstream business activity. Within this scheme, DSLNG purchases gas from the upstream sector, operates the LNG plant, and sells LNG to international customers.

More than 1.4 TCF of Senoro's gas is expected to be supplied to the downstream LNG plant, which will then sell to three LNG buyers being, KOGAS, Chubu Electric Power Co. Inc ("CE"), and Kyushu Electric Power Co. Inc. ("QE"). The LNG Sale & Purchase Agreement ("LNG SPA") with KOGAS dated January 2011 has total commitment of 0.7 million ton per annum, the CE LNG SPA dated June 2012 is for the supply of 1.0 million ton of LNG per annum, and QE LNG SPA also dated May 2012 has commitment for the shipment of 0.3 million ton of LNG per annum.

In 2018, 39 cargos were sold to three long-term buyers or otherwise on the spot market. A total of 42 cargos are currently estimated to have been sold in 2019.

***South Natuna Sea Block B***

We operate the PSC and the facilities located in the Natuna Sea, which had the daily gross maximum rate gas production of 235 BBTUPD in 2018, in approximately 300 feet of water with one FPSO, one FSO, four central processing platforms, seven wellhead platforms, four producing subsea fields, and offshore support vessels. The Singapore gas is shipped from the PSC through the 656 kilometer West Natuna Transportation System pipeline to an onshore receiving facility in Singapore. Both the pipeline and the facility are operated by us and the pipeline also serves other working interest holders at two other blocks in the area, including the working interest holders of South Natuna Sea Block A, Aceh PSC, which include Premier Oil, Petronas, Kuwait Foreign Petroleum Exploration Company, Pertamina and PTT Exploration and Production Public Company Limited. The license expires in October 2028.

After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 28.8% and the Government's share is 71.2%. For natural gas, the PSC participants' share is 67.3% and the government's share is 32.7%. A portion of the PSC participants' profit oil share is subject to DMO, but the participants' profit gas share is not subject to DMO. South Natuna Sea Block B, has been selling its gas to two customers in Singapore (Sembgas Corp) and Malaysia (Petronas) under two long-term GSAs since 2001 and 2002, respectively. Pricing under the Sembgas contract and a portion of the Petronas contracts are linked to HSFO. We have a COSPA with Lukoil Asia Pacific Pte Ltd. for the sale of our oil entitlement from this block. Under this agreement, Lukoil is required to make certain prepayments with respect to their off-take obligations.

***Block A, Aceh***

We acquired our participating interests in 2006 (16.67%) and 2007 (25.0%) and became the operator in 2007. In 2016, we acquired a 16.67% participating interest from Japex Block A Ltd. and in 2017 a further 26.67%. In 2016, we also signed an Engineering Procurement and Construction ("EPC") contract with PT JGC Indonesia and PT Encona Inti lndustri for US$240.0 million as well as an EPC for flowline, trunkline, and pipeline construction with PT Kelsri. Total investment costs for the first phase of this block are estimated to be approximately US$540 million. The lump sum nature of the EPC Contract provides us with greater cost certainty for the development of this block. In July 2017, we obtained project financing for the development of this block of US$360.0 million, and do not expect to make further equity contributions for its development.

After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 25.0% and the Government's share is 75.0%. For natural gas, the PSC participants' share is 58.3% and the government's share is 41.7%. A portion of the PSC participants' profit oil share and profit gas share is subject to DMO.

In January 2015, we signed a GSA with Pertamina to sell in a TCQ DF198 TBTU of gas. Gas supply for Phase I of Block A, Aceh, commenced in the first half of 2018 and is expected to continue for a period of 13 years. There are no penalties expected under the GSA with respect to development of the block. However, pursuant to Presidential Regulation No 40 of 2016 on the Determination of Gas Sales Price and MEMR Regulation No. 16 of 2016 on the Procedures in Determining the use and Price of Natural Gas, the Government may require us to reduce the gas sale price under this GSA with Pertamina from US$9.45/MMBTU to US$7.03/MMBTU. We have received legal advice that, under relevant regulations, any such reduction in price should require the Government to absorb any loss to us which would result from such price reduction by compensating us for that loss. In addition, we could reserve our rights under the terms of such GSA. Discussions between the parties have resumed following the appointment of a new Indonesian Ministerial cabinet in late October 2019.

Block A, Aceh contains at least five gas fields, three of which are included in the approved development plan (Alur Siwah, Alur Rambong and Julu Rayeu), which could potentially deliver up to 63 BBTU/D of gas and 1,350 BPD of condensate. Up to three drilling phases and a central processing plant (which is under construction) are located at the Alur Siwah field. Overall project development and the central processing plant are nearly completed. Commissioning work at the Alur Siwah wellsite has been completed, and the first gas sales were conducted in August 2018.

***Kerendan field, Bangkanai PSC***

We acquired our interest in the Kerendan field through our acquisition of Ophir in 2019. The Bangkanai PSC is located in Central Kalimantan. We have a 70% interest in the license and Saka Energi has the remaining 30%. Production from Kerendan gas field commenced in 2016 and ramped up to the full daily contract quantity in 2017. For the nine months ended September 30, 2019, it produced an average daily rate of gas of 16.4 MMscfd (gross) and condensate of 0.4 Mboepd (gross).

After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 26.8% and the Government's share is 73.2%. For natural gas, the PSC participants' share is 62.5% and the government's share is 37.5%. A portion of the PSC participants' profit oil share is subject to DMO, but the participant's profit gas share is not subject to DMO.

Bangkanai PSC has been selling its gas to PT PLN based on GSA that was signed in 2011. Gas pricing and allocations were issued in August 2018. An amendment has been signed with PLN and approval from SKKMigas is pending. We also have a CSPA with PT Kimia Yasa as the buyer, pursuant to which such buyer has agreed to purchase all condensate produced (including both Government and partner entitlement) from the Kerendan field through December 2021. In May 2019, we entered into an agreement with PT Mirah Ganal Energi, pursuant to which PT Mirah Ganal Energi has agreed to purchase un-lifted condensate volume which is not taken by PT Kimia Yasa until 2021 and all condensate produced from Kerendan until expiration of the PSC.

***Madura Offshore PSC***

We acquired our interest in the Madura Offshore PSC through our acquisition of Ophir in 2019. The Madura Offshore PSC, which includes the producing Peluang and Maleo gas fields and the undeveloped Meliwis gas field, is located in the East Java Basin in the Madura Strait with water depths of 48 to 65 meters. The Madura Offshore PSC was acquired by Ophir from Santos Limited in 2018. In the Maleo and Peluang fields, we have a 67.5%

working interest with partners of Petronas Carigali Madura (22.5% interest) and PT Petrogas Pantai Madura (10% interest). The Maleo field has been producing since 2006 and is in decline, with output sold to PGN and PLN through the East Java pipeline. The Peluang field started producing in 2014 and is currently at its production capacity. For the nine months ended September 30 2019, gas production from both fields was 48.2 MMscfd (gross).

Ophir had also invested in the Meliwis field, discovered in 2016, 11 kilometers south of the Maleo field. We have a 77.5% working interest in the Meliwis field. The Meliwis development is planned as a single well well-head platform tie-back to Maleo and would extend the economic field life of the Maleo and Peluang fields. The development plan for the field received regulatory approval in January 2018. A final investment decision was taken for the Meliwis development in February 2019 with the signing of a GSA. First gas from Meliwis field is targeted for the second quarter of 2020.

After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 35.7% and the Government's share is 64.3%. For natural gas, the PSC participants' share is 62.5% and the government's share is 37.5%. A portion of the PSC participants' profit oil share is subject to DMO, but the participant's profit gas share is not subject to DMO.

***Sampang PSC***

We acquired our interest in the Sampang PSC through our acquisition of Ophir in 2019. The working interest in the Sampang PSC was acquired by Ophir from Santos Limited in 2018. The Sampang PSC, which includes the producing Wortel and Oyong gas fields, is located offshore in the East Java Basin in water depths of 48 meters to 65 meters. We have a 45% working interest in the Sampang PSC, and our partners in the PSC are Singapore Petroleum Sampang Ltd (40% interest) and Cue Sampang Pty Ltd (15% interest). For the nine months ended September 30, 2019, production was at an average daily rate of gas of 35.8 MMscfd (gross).

After deduction for FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 35.7% and the Government's share is 64.3%. For natural gas, the PSC participants' share is 62.5% and the government's share is 37.5%. A portion of the PSC participants' profit oil share is subject to DMO, but the participant's profit gas share is not subject to DMO.

Gas from the both the Oyong field and Wortel field is sold to PT Indonesia Power (subsidiary of PT PLN) under GSAs.

**South Sumatra asset (the Rimau PSC, South Sumatra PSC and Lematang PSC)**

Our South Sumatra asset consists of the Rimau PSC, South Sumatra PSC and Lematang PSC. After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil at Rimau PSC, South Sumatra PSC and Lematang PSC, the PSC participants' share is 26.8%, 19.6% and 28.8%, respectively, and the Government's share is 73.2%, 80.% and 71.2%, respectively. For natural gas at Rimau PSC, South Sumatra PSC and Lematang PSC, the PSC participants' share is 62.5%, 43.1% and 57.7%, respectively, and the Government's share is 37.5%, 56.9% and 42.3%, respectively. At Rimau PSC, a portion of the PSC participants' profit oil share is subject to DMO, but the participants' profit gas share is not subject to DMO, and at South Sumatra PSC, each are subject to DMO. At South Sumatra PSC, we have several fixed price GSAs with various buyers: Pertamina, PT Meta Epsi Pejebe Power Generation ("Meppogen"), an independent power producer, PLN and PGN. At Lematang PSC, gas is sold under a fixed-price long-term GSA to PLN.

## Key International Blocks

### *Sinphuhorm field, Thailand*

Production from the Sinphuhorm field commenced in November 2006, and 1,300 BOE/d was produced in 2018 with an average of 79 MMSCF/d (gross). The gas supplies a 710 MW power plant located approximately 3.5 kilometers from the Nam Phong field. The gas and liquids are transported through a 62 km pipeline to a gas processing plant located alongside the Nam Phong power station. At the gas processing plant, the liquids (including water) are removed. The dry gas is sold to PTT under a GSA, and the condensate is sold to PTT under a separate sales agreement. The daily contracted quantity is 108 MMscfd, and the GSA runs until 2021 with the potential to be extended by 10 years by the Government of the Kingdom of Thailand.

### *Bualuang (Block B8/38), Thailand*

The Bualuang field has been on-stream since 2008 and produced over 8,100 bopd in 2018. In the summer of 2018, the next phase of development known as Phase 4, which is split into two parts, began. The objective of Phase 4A was to boost production from the existing facilities, and it was successfully completed, adding three new wells and four workovers. During Phase 4B in 2019, we expect to see the installation of a 12 slot conductor-supported platform, called the Charlie platform, at the Bualuang field. Initial oil production started in December 2019, which was ahead of schedule with production exceeding initial targets.

### *Block 12W PSC, Vietnam*

The working interest in the Block 12W PSC was acquired by Ophir from Santos Limited in 2018. Chim Sáo and Dua oil fields (with some associated gas) are located in the Nam Con Son basin offshore in Vietnamese waters in water depths of approximately 95 meters and contains the Chim Sáo and Dua producing fields. The fields are currently expected to produce until 2030. The operator has begun a field-life extension assessment of all the facilities, most critically the well head platform and main field flow lines which had 10-year design lives (in line with the original development plan). The necessary modifications are expected to be completed in 2020. The operator plans to conduct a series of well interventions that will help offset the natural reservoir decline rates in 2019 and life-extension maintenance projects for the FPSO.

### Oman

In November 2014, our subsidiary, Medco Arabia Ltd, entered into a contract for the exploration and production of Block 56 in Oman with the Government of Oman, and its local partner, Intaj LLC. Block 56 is located in a productive hydrocarbon basin, the Oman Salt Basin. Block 56 is adjacent to Karim Small Fields ("KSF"), with similar geological characteristics. We expect to have operational synergy with KSF going forward, as it is also operated by us. In April 2015, Medco LLC (Oman) signed a new Amendment and Restated Service Contract extending the term of the contract to 2040. In 2016, we completed geological and geophysical studies including 2D seismic reprocessing. Block 56 is estimated to contain up to 370 million barrels of oil. In 2018, we completed the drilling of three exploration wells and the exploration period was extended for two years.

### Libya, Area 47

Due to adverse security conditions there has been no activity at this block since 2014. We have made a force majeure claim to freeze the license period for our exploration areas within this block. In 2016, we finalized the invitation-to-tender package for an engineering procurement construction contract on the development areas within this block. However, due to our assessment of the ongoing security situation, and although front-end engineering design had been completed, we believe that obtaining financing on acceptable terms for the expected scale of our operations would have been impracticable and as a result wrote off our prior expenditure on this block in 2016. In 2018, we, together with the National Oil Company (the "NOC"), continued work on a "Fast Track Production Facilities" project execution plan, which is expected to accelerate oil production with lower initial capital expenditure. We are currently pursuing a strategy of several early production facilities in order to begin small scale oil production. However, the resumption of in-country activity will be dependent on our assessment of developments in the ongoing security situation in Libya. We have obtained the approval of the NOC to begin a sales process for our interest in Area 47 and discussions with approved parties is ongoing.

**Other Oil and Gas Properties**

***Indonesia***

Our other oil and gas properties prior to the acquisition of Ophir in Indonesia included the Tarakan block, which has 21 active oil wells and one active gas well. We have an agreement with Pertamina for the sale of all of our entire net entitlement of oil produced at this block. We have a fixed price GSA with PLN to supply gas for the purpose of electricity generation in the Tarakan area. We are assessing potential exploration of this PSC but have no immediate plans for further expenditure. We also have the Simenggaris block, which consists of the Sesayap and South Sembakung gas fields. We target to supply gas to meet energy needs in the vicinity, especially for the power generation sector of North, East and South Kalimantan. We also have interests in the Bengara and South Sokang blocks.

Through our acquisition of Ophir, we acquired three PSCs in Central Kalimantan, collectively known as Greater Bangkanai. These include the Kerendan gas field development within the Bangkanai PSC and two adjacent exploration licenses, North East Bangkanai and West Bangkanai. The Kerendan gas processing facilities' construction and commissioning have been completed, and production commenced in 2016 with 122 BCF of gas having been commercialized. The first phase of the project commercialized 122 BCF through a 20-year GSA with PLN that is expected to provide for a daily contracted amount of approximately 20 MMSCFD at peak production. In 2015, the GSA was amended to include a 80% take-or-pay and to apply an annual 3% price escalator. This project provides 20 MMscfd of gas to a 155 MW power plant located three kilometers from the field. A 3D seismic program in Bangkanai and West Bangkanai PSC was completed in December 2017 confirming the potential further development of 457 BCF of gas. We have relinquished North East Bangkanai to the Government, and Government approval was received based on the letter dated August 26, 2019 and effective May 14, 2019.

***Yemen, Block 9***

We have a 25.0% participating interest in Block 9. Due to adverse security conditions, there was no activity from 2014 to the fourth quarter of 2018, when activity resumed. As of December 31, 2018, the participating interest of our subsidiary in Block 9 is 21.25%. In 2018, the operator set up an operations office in Cairo and resumed operations on March 1, 2019.

***Mexico***

Through Ophir, we now have a 20% non-operating interest in Blocks 10 and 12 in Mexico, which was awarded to Ophir and its consortium in January 2018 after a series of bidding rounds conducted by the Government of Mexico.

***Malaysia***

We have one license in Malaysia, an 85% operated interest in Block PM-322 acquired through the Ophir Acquisition. Block PM-322 is located in the Melaka Straits on the Malay side of the Central Sumatra Basin, offshore West Coast Peninsular Malaysia.

***Tanzania***

Our interest in Tanzania Blocks, 1 and 4 were acquired through the Ophir Acquisition. The assets have entered the pre-development phase for the Tanzania LNG project. In 2014, the JV partners in Blocks 1 and 4

(Shell and Pavilion Energy) and the partners in Block 2 (Statoil and ExxonMobil) signed an agreement to co-operate on a combined onshore LNG plant. The Block 1 and 4 partners, Block 2 partners and the relevant governmental authorities also signed a memorandum of understanding for the project regarding, among other matters, the site of the LNG plant and the process for acquiring the land and resettlement management. The project is currently in the pre-front end engineering design stage. Engagement with the government of Tanzania on the development of the natural gas discoveries in Blocks 1 and 4 offshore Tanzania continues to focus on establishing key commercial terms for a cost competitive development for the Tanzania Gas and LNG project. The project continues its focus on selecting the optimal integrated upstream and liquefied natural gas project. The Tanzania LNG project is at a stage where detailed planning and multiple agreements need to be agreed between the international gas companies and the government.

***Blocks Relinquished or Divested***

On February 7, 2019, Medco Energi US LLC ("MEUS") entered into an Asset Purchase and Sale Agreement with Sanare Energy Partners LLC and sold its Main Pass assets for US$150,000. As of September 30, 2019, MEUS was contingently liable for an aggregate amount of US$3.3 million for bonds issued on MEUS's behalf to obtain third party guarantees from a surety insurance company with respect to plugging rules and regulations. On November 19, 2019, Medco Energi Global Pte Ltd, a wholly-owned indirect subsidiary of the Company, completed the sale of shares in Medco Tunisia Petroleum Limited to Anglo Tunisian Oil & Gas Limited.

In addition, Ophir signed a sales and purchase agreement on May 16, 2019, relating to its 23.33% interest in Block 5 (Cuenca Salina), offshore Mexico, with the existing partners in the Block 5 exploration license, which was completed in December 2019. The sale was for a cash consideration of $39 million, which accounted for back costs (including its share of the recent well) alongside a cash premium.

The table below sets forth interests in blocks that we divested from or relinquished from January 1, 2016 through September 30, 2019.

| Entity | Divest/ Relinquish | Working interest prior to transaction | Working interest after transaction | Transferee | Date of divestment/ relinquishment |
|---|---|---|---|---|---|
| PSC Bawean (Camar Bawean Petroleum Ltd & Camar Resources Canada Inc.) | Divest | 65% | 0% | Hyoil | June 2016 |
| Medco Cendrawasih VII | Relinquish | 100% | 0% | Government of Republic Indonesia | — |
| Moonbi Energy Ltd (PPL 470) | Divest | 90% | 0% | Moonbi Enterprise Limited | February 2016 |
| PT Medco CBM Lematang (GMB Lematang) | Divest | 55% | 34% | PT Methanindo Energi Resources | February 2016 |
| PT Medcco Energi Madura (previously PT Medco CBM Sekayu) (GMB Sekayu) | Relinquish | 50% | 0% | Government of Republic Indonesia | December 2016 |

While we do incur some costs in relinquishing assets, these costs are typically not material and in certain cases we do not bear costs.

## Sales and Distribution

*Average Realized Sales Prices*

| | For the Years Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| **Average realized sales prices:** | | | | | |
| Oil and condensate (US$ per BBL) | 42.3 | 51.5 | 67.8 | 68.8 | 62.5 |
| Natural gas (US$ per MMBTU) | 4.4 | 5.5 | 6.4 | 6.2 | 6.9 |

### *Crude Oil*

We sell our net oil entitlement from our Indonesian operations to the domestic Indonesian market as well as to the overseas market. In line with the Government regulations, we sell our oil at prices based on ICP. The ICP price is determined by the Government, and is the monthly average of the mean of two publications of independent oil traders and marketers in the Asia Pacific region published by Platts and RIM in the following proportions: 50% Platts and 50% RIM until June 2016. Starting in July 2016, the basis of ICP changed to Dated Brent price plus Alpha and in 2018 was further revised to Dated Brent plus/minus Alpha.

For our oil sold from Thailand, we sell at prices based on Banoco Arab Medium. This crude comes from Bahrain and is similar in quality to Saudi's Arab Medium. Saudi crudes typically do not trade on a spot basis but Banoco Arab Medium can trade spot, priced as a differential to Saudi Aramco's Arab Medium official selling price for Asia. Aramco's official selling price is announced one month forward and is based on the average of front-month Dubai/Oman assessments plus a differential. The equation used to derive Banoco Arab Medium's assessment for barrels loading in May is as follows: Average of May Oman & Dubai derivatives plus existing official selling price differential plus spot differentials plus expected official selling price adjustments.

The following table summarizes the key terms and arrangements of our current material crude oil sales agreements.

| Block | Counterparty | Term | Pricing | Total Gross Volume for Life of Contract |
|---|---|---|---|---|
| **Indonesia:** | | | | |
| Rimau | Lukoil | 2 years | ICP Kaji + premium | whole entitlement |
| South Sumatra | Pertamina[(1)] | — | ICP Kaji Flat | — |
| Tarakan | Pertamina UPV Balikpapan[(2)] | — | ICP Tarakan Flat | — |
| Senoro-Toili (condensate) | Petro Diamond Singapore (2016-2020) | 4 years | ICP Senoro Condensate minus premium | whole entitlement |
| Bangkanai | Kimia Yasa | 5 years | ICP Senipah minus premium | whole entitlement |
| Bangkanai | Mirah Ganal Energi | 14 years | ICP Senipah minus premium | whole entitlement |

Notes:

(1) Swap with Rimau's crude oil.

(2) Domestic market.

### *Natural Gas*

We sell our gas production from our Indonesian onshore operations to buyers including state-owned companies (in the power and fertilizer industries), independent power producers, gas transport companies, and local state and city gas providers. The gas from our Thailand asset is sold to PTTEP and the gas from our non-operated Vietnam asset is sold to Petrovietnam Gas.

We typically enter into GSAs which set the TCQ, DCQ and gas price. While TCQ and DCQ vary between buyers, gas prices are largely fixed using the same structure, in US$/MMBTU with an application of an escalation factor (typically 2.5% to 3.0% per annum). However starting in late 2015 we started commercial gas sales from Senoro-Toili with prices linked to JCC prices. The gas prices for Sembgas from Block B, and prices for gas from Sinphuhorm are linked to HSFO. The GSAs also typically include a “Take-or-pay” mechanism, pursuant to which, if a buyer is unable to absorb the agreed DCQ, the buyer will have to pay a portion (usually in the range of 80.0% to 90.0%) of the DCQ.

The following table summarizes the key terms and arrangements of our current material GSAs for our Indonesian blocks.

| Block | Counterparty | Term | Daily Contract Quantity | Take-or-Pay as a percentage of DCQ |
|---|---|---|---|---|
| **Indonesia:** | | | | |
| South Sumatra ...... | PT Mitra Energi Buana (3rd GSA Amendment) | 2006-December 31, 2027 (on stream on 2007) | 2.5 BBTUD (Mar 2018-Dec 2018) 4 BBTUD (2019) 5 BBTUD (2020) 6 BBTUD (2021-2024) 5 BBTUD (2025) 4.5 BBTUD (2026) 4 BBTUD (2027) | 92% |
| | PT MEPPO-GEN (Amended and Restated) | 2014-March 31, 2027 | 12.5 BBTUD (January 2019-December 2019) 12.4 BBTUD (January 2020-December 2020) 11.6 BBTUD (January 2021-December 2022) 10.8 BBTUD (January 2023-December 2025) 9.7 BBTUD (January 2026-December 2026) 10.4 BBTUD (January 2027-June 2027) | 90% |
| | Perusda Mura Energi (2nd GSA Amendment) | 2009-December 2027 (on stream on 2015) | 1.35 BBTUD-2.10 BBTUD | 90% |
| | Perusda Pertambangan dan Energi (BBG) (Amendment GSA) | 2013-February 7, 2023 (on stream in April 2013) | 0.5 BBTUD | N.A. |
| | Perusda Pertambangan dan Energi (Kelistrikan) | 2011-August 31, 2020 | 3 BBTUD | 90% |
| | PT Medco E&P Rimau | 2016-April 22, 2023 | 0.66 BBTUD increasing to 2.65 BBTUD | 90% |
| | PT Pertamina (Persero) | January 2019-December 8, 2020 | 0.2 BBTUD | N.A. |

| Block | Counterparty | Term | Daily Contract Quantity | Take-or-Pay as a percentage of DCQ |
|---|---|---|---|---|
| | PT PLN (Persero) (South Sumatra Power Plant) | 2017-January 2027 (effective since April 6, 2017) | 20 BBTUD ramp down (Joint supply with Lematang Block) | 90% |
| | PT Perusahaan Gas Negara Tbk | January 1, 2019-December 31, 2021 | 0.3 BBTUD | 90% |
| | PT Pertamina (Persero) | March 8, 2018-July 20, 2027 | 0,25 MMSCFD | N.A. |
| Lematang . . . . . . . . . . | PT PLN (Persero) (South Sumatra Power Plant) | 2017-January 2027 (effective since April 6, 2017) | 20 BBTUD ramp down (Joint supply with South Sumatra Block) | 90% |
| Tarakan . . . . . . . . . . . . | PLN-Gunung Belah (GSA Amendment) | 2010-December 31, 2021 | 0.5 BBTUD | N.A. |
| | PT PGN Tbk | 2016-2020 (five years from MESDM gas allocation approval date) | 0.2 BBTUD | N.A. |
| Block A, Aceh . . . . . . | PT Pertamina (Persero) | 13 years from initial commencement of gas sales | 58 BBTUD | 90% |
| Senoro-Toili . . . . . . . . | Donggi Senoro LNG (GSA Amendment) | 2009-2027 | 252.197 BBTUD | 90% (annually) |
| | PT Panca Amara Utama (GSA Amendment) | 2018-December 3, 2027 (on stream February 14, 2018) | 55 MMSCFD (12 months from first gas in), 62 MMSCFD (after the 12 months until end of GSA) | 80% (year 1) 90% (year 2-end of GSA) |
| | PT PLN (Persero) | From Start Date until December 4, 2027 | 5 BBTUD | 80% (year 1 & 2) 90% (year 3-end of GSA) |
| Simenggaris . . . . . . . . | PT PLN (Persero) | March 2021-February 23, 2028 | 8 BBTUD | a) 60% from the Yearly Contract Quantity (YCQ) for the first 36 months from the start date; and b) 80% from the YCQ for each 12 months until the end of the agreement |
| | PT PLN (Persero) | 2014-five years from starting date | 0.5 MMSCFD | 60% (0.3 MMSC) |
| Simenggaris . . . . . . . . | Perusda Nusa Serambi Persada | 2012-11 years from starting date (not yet on-stream) | 5 MMSCFD | 85% |
| South Natuna Sea Block B . . . . . . . . . . . . | Pertamina | 2001-2032 | 247.0 BBtu in year 1, 337.2 BBtu in year 2, | 85%-90% |

| Block | Counterparty | Term | Daily Contract Quantity | Take-or-Pay as a percentage of DCQ |
|---|---|---|---|---|
| | | | 341.25 BBtu after year 2 and gradually declining to 51.81 BBtu in 2023 | |
| | Pertamina | 1999-2026 | 105.0 BBtu to 263.0 BBtu | 80%-85% |
| Sampang . . . . . . . . . . . | PT Indonesia Power | Sep 2009- 2020 | 15 BBTUD | 95% (Half-Year) |
| | PT Indonesia Power | Feb 2012-2020 | 25 BBTUD | 95% (Annually) |
| Madura Offshore . . . . | PT PGN Tbk. | Sep 2006- 2023 | 25 BBTUD | 95% |
| | PT PLN (Persero) | Mar 2014-Dec 2019 | 25 BBTUD | 90% |
| | PT PGN Tbk. (Gas from Meliwis) | Until 2023 | 20 BBTUD | 95% (Half-Year) |
| Bangkanai . . . . . . . . . . | PT PLN | Jun 2013- 2033 | 16 BBTUD | 91% |
| | PT Perusda | Feb 2015-2033 | 4 BBTUD | 91% |

**Power and Mining**

In addition to our core oil and gas business, we have a significant power generation business and a significant investment in mining.

**Power Business**

Our power business is conducted through MPI, an IPP and O&M service provider. In October 2017, we increased our stake in MPI from 49.0% to an effective interest of 88.6% and in 2019 purchased the remaining stake so that MPI is currently a wholly-owned subsidiary. MPI has interests in gas-fired power, geothermal energy and hydro-electricity plants.

MPI's business is focused on small to medium sized natural gas and geothermal independent power projects and captive power plants in western Indonesia and seeks to maximize its power services operations and synergies with its other businesses.

The table below sets forth certain information about MPI's projects.

| Plant | Fuel Type | Ownership (%) | Commercial Operation Date | Gross (MW) |
|---|---|---|---|---|
| **IPP (in operation)** | | | | |
| MEB Comb. Cycle . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | Gas | 64 | 2004 | 85 |
| DEB Comb. Cycle . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | Gas | 80 | 2006 | 85 |
| ELB Simple Cycle . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | Gas | 70 | 2016 | 76 |
| TM 2500 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | Gas | 100 | 2007 | 20 |
| EPE . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | Gas | 92.5 | 2006 | 12 |
| MPE . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | Gas | 85 | 2008 | 12 |
| Sarulla . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | Geothermal | 19 | 2017-2018 | 330 |
| 2 Mini Hydros . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | Hydro | 70-100 | 2017-2018 | 18 |
| **Subtotal** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | | | | **638** |

| Plant | Fuel Type | Ownership (%) | Commercial Operation Date | Gross (MW) |
|---|---|---|---|---|
| **O&M Services (operating projects)** | | | | |
| Sarulla | Geothermal | 100 | 2017-2018 | 330 |
| CFPP Tanjung Jati | Coal | 80 | 2006 | 1,320 |
| TM2500 | Gas | 64 | 2016 | 500 |
| **Subtotal** | | | | **2,150** |

As of September 30, 2019, MPI's IPP business had pipeline projects with a capacity of 1,180 MW.

**Copper and Gold Mining**

Our copper and gold mining operations are conducted through AMNT, a joint venture in which we and our original joint venture partner, API (an entity in which Mr. Agus Projosasmito is the majority shareholder of record), acquired our interests in November 2016.

We initially, in 2016, acquired a 41.1% economic interest in AMNT. We acquired our interest in AMNT indirectly through our acquisition of a 50% interest in AMIV, a joint venture entity, for a consideration of US$404 million, financed through cash on hand which in turn, through its subsidiary PT Amman Mineral Internasional ("AMI"), acquired 82.2% of AMNT. AMIV's purchase of AMNT was financed through the following sources: (i) Medco Energi provided AMIV with a shareholder loan pursuant to a loan agreement entered into on August 23, 2016 of US$246.0 million; (ii) debt financing obtained by certain of AMIV's subsidiaries which were partially guaranteed by the Medco Energi in proportion to its direct or indirect shareholding in AMI, which was 50% (such debt financing has been repaid and the guarantee discharged). Pursuant to a loan agreement entered into with the prior shareholders of AMNT, PT Pukuafu Indah, an unrelated non-controlling shareholder in AMNT which owns the remaining 17.8% of AMNT, had pledged certain rights in its shares in AMNT to the prior shareholders of AMNT. AMI acquired the pledges of such rights in connection with the acquisition of AMNT and succeeded to certain of those pledged rights and therefore AMI had also acquired the economic benefit of PT Pukuafu Indah's shares in AMNT.

We, API, AMI and a new shareholder, PT Sumber Gemilang Persada (a consortium of Indonesian investors led by Mr. Agus Projosasmito) entered into a transaction pursuant to which we, API and PT Sumber Gemilang Persada now hold our interest in AMNT through AMI, and our and API's shareholding in AMI was, in the first quarter of 2018, reduced to approximately 39.4% each and PT Sumber Gemilang Persada then owned approximately 21.3% of AMI. As part of this transaction, approximately 50% of the amount of the shareholder loan held by us was converted into equity in AMI, and the other 50% of the amount of the shareholder loan converted into a receivable owed to us by API. We novated this receivable to an indirect subsidiary of Medco Energi, PT Medco Services Indonesia ("MSI"), which subsequently converted the receivable to a 5.1% equity interest in AMI. As of December 2018, API's shareholding has been reduced to 18.2% and PT Sumber Gemilang Persada and MSI own 37.4% and 5.1% of AMI's shares, respectively. MSI also purchased an additional 3.7% interest in AMI. On March 29, 2019 we sold our interest (both equity and debt interest) in MSI to a third party, PT Graha Permata Sukses. The total proceeds from such sale was US$251 million. As a result, we currently hold a 39.4% effective interest in AMI.

On December 29, 2017, AMI entered into a facility agreement with PT Bank Mandiri (Persero) Tbk for a US$400 million facility, with the option to upsize to US$1,375 million, primarily for the purpose of funding Phase 7 of the Batu Hijau mine. In the short to medium term, we expect that AMI and/or AMNT will undertake to raise further funding including debt and a domestic-focused initial public offering.

In addition, in connection with the acquisition of AMNT, AMI has agreed to certain contingent consideration payable to the sellers. This contingent consideration consists of: (i) US$225.0 million from Phase 7 of Batu Hijau mine production, 50% of which would be payable after any year end where the London Mercantile Exchange average copper price per pound for such year is US$2.75 or more starting in 2023, (ii) US$229.7 million to be payable if during any quarter commencing after the second quarter after closing of the acquisition, the London Mercantile Exchange average copper price from the Batu Hijau mine exceeds US$3.75 per pound; and (iii) US$203.7 million to be payable by the first anniversary of the first shipment of concentrate (or any other form of saleable copper, gold or silver) from the Elang resource.

AMNT owns and operates the Batu Hijau mine, located on the island of Sumbawa, approximately 950 miles east of Jakarta. The mining concession covers an area of 25,000 hectares that includes the Elang copper and gold resource and several exploration prospects including Lampui, Rinti, Batu Balong, Nangka and Teluk Puna. The Elang copper-gold resource is situated approximately 60 kilometers east of the Batu Hijau mine. AMNT expects to perform feasibility studies on Elang and engage in discussions with the government of Indonesia with a view to developing the mine before the cessation of pit operations at Batu Hijau.

As of December 31, 2018, AMNT had 4.0 million ounces of proven and probable gold reserves including about 1.0 million ounces of gold stockpiles and 4.2 billion pounds of proven and probable copper reserves including 2.0 billion pounds of copper stockpiles.

On January 11, 2017, the Government issued regulations on the export of copper concentrate, namely MEMR Regulation No. 5 of 2017 as amended by MEMR Regulation No. 28 of 2017 on the Amendment of MEMR Regulation No. 5 of 2017 on Increase of Added Value of Minerals through Domestic Mineral Processing and Refinery ("MEMR Regulation No. 5 of 2017"). MEMR Regulation No. 5 of 2017 requires AMNT as COW holder to convert its COW into Special Mining Business License — Operation Production (*Izin Usaha Pertambangan Khusus — Operasi Produksi*, an "IUPK OP") in order to export its copper concentrate. On February 10, 2017, AMNT obtained the IUPK OP from MEMR. The 2017 Regulations also mandate that IUPK OP holders refine their minerals domestically. AMNT continues to work with the government to guarantee investment certainty and operational continuity, including AMNT's commitment to build up in-country smelting and refining as well as export of copper concentrate. For the smelter, AMNT has begun development of the smelter and hired a third party for front end engineering design. AMNT may also form a joint venture with another party to develop the smelter and also plans to maintain majority ownership of the smelter. AMNT expects to contribute access to land, the port and its power plant to the joint venture, with the joint venture partner making capital contributions for the construction of the smelter. AMNT currently is required to complete the smelter by 2022.

In 2018, AMNT and PT Amman Mineral Industri (a subsidiary of AMI) entered into a non-binding heads of agreement for the potential construction of a 300 MW onsite IPP for the smelter and future operations, including Elang mine development.

Current mining at Batu Hijau is focused on stockpile processing and development of Phase 7. Overburden removal for Phase 7 commenced in 2018. This overburden removal is required to access the ore in Phase 7 and is expected to take at least three years to fully complete, though we expect initial mining at Phase 7 to commence in the first half of 2020. During this hiatus in ex-pit ore production, Batu Hijau will raise capital and feed its processing plant from existing long-term stockpiles of lower grade ore resulting in lower metal production during the Phase 7 waste development period in order to generate cash for operating activities.

AMNT generally sells copper in U.S. dollars at the prevailing market price during the month in which the copper is delivered to the buyers. Copper sales are in the form of concentrate that is sold to smelters for further treatment and refining, and copper cathode (raw material for the production of copper rods for the wire and cable industry).

In the nine months ended September 30, 2018 and 2019, AMNT had gold production of 50.3 thousand ounces and 41.9 thousand ounces, sales of 48.0 thousand ounces and 56 thousand ounces and average realized prices of US$1,092 per ounce and US$1,388 per ounce, respectively, and had copper production of 108.6 million pounds and 96.2 million pounds, sales of 98.2 million pounds and 233 million pounds and averaged realized prices of US$2.05 and US$2.68 per pound, respectively.

**The Energy Building**

We, currently have a 49% interest in AMG, which owns The Energy Building, the building in which we and most of our subsidiaries are headquartered. The Energy Building is a modern and intelligent building located in a strategic area of Jakarta, the Sudirman Central Business District ("SCBD"). The building occupies an area of 8,263 square meters, comprising 40 floors for office space and five basement floors for parking. The building was designed by Kohn Pedersen Fox, a prominent architecture firm from New York, USA, The Energy Building was built in 2006 with high-quality specifications and was fully operational by the end of 2008.

We acquired a 49% interest in AMG in 2013 and the remaining 51% in December 2015. In March 2019 we disposed of a 51% interest in AMG to a related party. AMG leases the building to businesses which operate in a number of industries, mostly petroleum, mining, financial institutions and professional services. The building was 95.26% occupied as of September 30, 2019.

**Competition**

We face competition from other oil and gas companies including Pertamina, the Indonesian state-owned national oil and gas company, in all areas of our oil and gas operations, including the acquisition of production sharing arrangements. Our competitors in Indonesia and Southeast Asia include international oil and gas companies, many of which are large, well-established companies with substantially greater capital resources and larger operating staff than we have and many of which have been engaged in the oil and gas business for a longer period than us. Such companies may be able to offer more attractive terms when bidding for concessions for exploratory prospects and secondary operations, to pay more for productive natural gas and oil properties and exploratory prospects, and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical or personnel resources permit. Our ability to acquire production sharing arrangements and to discover, develop and produce reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. However, given the importance of the oil and gas industry to the Indonesian economy, local participation has been actively encouraged by the Government. Being one of the few Indonesian companies involved in the oil and gas exploration and production industry, we believe we have certain advantages when seeking to expand our business in this sector.

Indonesia's independent power sector is fragmented, with multiple IPPs operating in the small-to-medium-sized (< 400 MW capacity) and large-sized segments (> 400 MW). Local Indonesian power players generally operate across multiple segments but are largely focusing on the small-to-medium-sized segments. Indonesia Power and PJB (both state-owned) are the strongest local players as they are well-positioned in the market due to their legacy and relationship with PLN and the government. International power players largely operate in the large sized segment with their main focus being coal and geothermal resources. MPI mainly competes for new projects based on tariff pricing and technical quality location.

AMNT competes with other copper and gold mines, primarily in Asia. AMNT competes based on track record in fulfilling orders, fulfilling customer commitments and ore quality.

**Operating Hazards, Insurance and Uninsured Risks**

Our main operations are subject to hazards and risks inherent in the exploration, production and transportation of natural gas and oil, and through AMNT and MPI, mining and power generation. Such risks and hazards include fires, natural disasters, explosions, encountering formations with abnormal pressures, blowouts, cratering, pipeline ruptures and spills; most of which can result in the loss of hydrocarbons, mineral and power production, environmental pollution, personal injury claims and other damage to our properties. As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. Our coverage includes, but is not limited to, physical damage on certain assets, control of wells, blowouts and certain costs of pollution control, comprehensive general liability including automobile and worker's compensation. In line with what we believe to be industry practice, we do not carry business interruption insurance.

**Safety**

We have extensive safety procedures designed to ensure the safety of our workers, assets, the public and the environment. General safety procedures are available at the corporate level. More specific procedures are developed by each operating subsidiary to manage high risk jobs or tasks. Working procedures must be available, approved and reviewed by authorized person before a high risk job can be undertaken.

It is our policy that in the event of any conflict between the progress of work and safety or environmental concerns, the safety of employees (including third parties) and preservation of the environment are paramount. We also continue to build employee and contractor HSE basic competence. Basic standardized training ensures that all employees and contractors have similar HSE insight and knowledge.

We have implemented an HSE management system known as Performance Integrity of Medco E&P ("PRIME"). PRIME uses a structured approach applied in order to ensure that our business activities fulfill and comply with relevant legal and other requirements relating to HSE. Our management system is aligned with management system models and structures in OHSAS 18001, ISO 9001, ISO 14001, and include the relevant requirements of ISRS 7th. We have also developed our operating systems, guidelines and standard operating procedures to comply with PRIME procedures.

As a result of our robust HSE programs, we recorded a total recordable incident rate of 0.59 in our oil and gas exploration and production domestic operations for 2018, which we believe is in line with top-level performance in the exploration and production industry. In 2016, we received several safety awards from MEMR: the Patra Nirbhaya Karya Madya for Tarakan PSC, Patra Nirbhaya Karya Pratama for Lematang PSC, and Patra Nirbhaya Karya Utama in Senoro-Toili. Patra Nirbhaya awards are awarded in recognition of the success rate of an oil and gas company in ensuring the continuity of safety in oil and gas business activities.

**Employees**

We had 4,342 employees as of September 30, 2019, of which 3,204 were permanent employees and 1,138 were contract employees.

The following table sets forth the number of our regular employees, temporary employees and total employees for the periods indicated below.

| | Permanent Employees | Contract Employees | Total |
|---|---|---|---|
| December 31, 2016 | 2,398 | 1,287 | 3,685 |
| December 31, 2017 | 2,433 | 1,450 | 3,883 |
| December 31, 2018 | 2,533 | 1,533 | 4,066 |
| September 30, 2019 | 3,204 | 1,138 | 4,342 |

Our employees have seven labor unions, and we have signed collective bargaining agreements with a term of two years with a one-year optional extension. As of September 30, 2019, these unions have approximately 1,622 members, or 50.62% of our regular workforce. Our oil and gas business has not been subject to any material strikes or other labor disturbances that have interrupted our operations. AMNT and MPI have been subject to certain labor disturbances. See “Risk Factors — Risks Relating to Our Business and Operations — Our operations could be disrupted by community or labor issues.” We believe we have a good and cooperative relationship with our employees.

**Environmental**

Our operations are primarily currently subject to Indonesian laws and regulations governing the environment or otherwise relating to environmental protection. These laws and regulations require the acquisition of a permit before drilling commences development construction, which restrict the types, quantities and concentration of various substances that can be released into the environment related to drilling and production operation activities, and limit or prohibit drilling activities on certain lands lying within wilderness, natural reserves, wetlands and other protected areas. The regulations also require parameter measurement to prevent pollution resulting from former or recent operations, such as plug abandoned wells, and impose substantial liabilities for pollution resulting from our operations. To some extent, the regulatory system regulates the oil and gas industry such that the cost of doing business increases and consequently affects its profitability. Changes in environmental laws and regulations may result in more stringent and costly waste handling, disposal and clean-up requirements and this could have a significant impact on our operating costs, as well as the oil and gas industry in general. Management believes that we are in compliance with current applicable environmental laws and regulations in all material respects and that continued compliance with existing requirements will not have a material adverse impact on us.

The Government has imposed environmental regulations on oil and gas companies operating in Indonesia and in Indonesian waters. Operators are prohibited from allowing oil into the environment and must ensure that the area surrounding any onshore well is restored to its original state after the operator has ceased to operate on the site. Environmental impact study and a Government permit are required before any exploration work can commence. Under the Oil and Gas Law, SKK MIGAS has direct control over operators to ensure that they meet the Government regulations. We are required to provide a report containing an environmental impact analysis to the Indonesian environmental agency on a bi-annual basis.

We believe we have demonstrated our compliance with regulations, particularly in environmental aspects. We have consistently received Blue, Green and Gold (being the highest rating) PROPER awards from the Environmental & Forestry Ministry for certain of our Indonesian assets. While we have generally received Blue, Green and Gold PROPER awards from the Environmental & Forestry Ministry for certain of our Indonesian assets, in 2016, we received a Red rating from Environmental and Forestry Ministry for our Bawean PSC, which we sold in 2017, due among other things to the Government’s request for a wastewater treatment facility to be constructed. A Red rating means that we have made efforts to be in compliance, but are not completely in compliance with regulations. In addition, in 2018, AMNT received Blue PROPER award from Environmental and Forestry Ministry. AMNT’s mining business is also subject to Indonesian environmental regulations.

In 2017, we implemented a new HSE management system which is both corporate and project-based, and which, among other things, improves our ability to monitor and identify risks and assists in compliance with the Equator Principles, which is a risk management framework adopted by financial institutions for determining, assessing and managing environmental and social risk in projects. We established a new division at the Corporate level, Corporate Sustainability and Risk Management, to strengthen our Sustainability and Risk Management agenda in addition to existing organizations that implements our Sustainability programs in the subsidiaries. We published our Sustainability Report (SR) for 2014-2017 in accordance with the 2016 GRI reporting standards in 2018, which include an independent limited assurance statement from Purwantono, Sungkoro & Surja (Ernst & Yang Indonesia) . The SR for 2018 is being finalized for issuance this year. The SRs describes our strategy and progress of implementation with respect to sustainability, health, safety and environmental management, social and security management, including our stakeholder management plan. Our Sustainability Reports can be accessed at the following link: http://www.medcoenergi.com/en/subpagelist/view/36.

We have a strong commitment to participation in reducing the effects of climate change. Energy-related activities contribute around 70% of global greenhouse gas ("GHG") emissions, with oil and gas jointly representing approximately 60% of those energy-related emissions through their extraction, processing and subsequent combustion. While the direct emissions of the oil and gas sector are significant contributors to total global GHG emissions, the bulk of GHG emissions generated through the oil and gas lifecycle are in the consumption and combustion of final products and remain beyond the boundaries of oil and gas companies' operations. Indonesia has ambitious goals to reduce greenhouse gas emissions by 26% away from "business-as-usual" levels by 2020, or by as much as 41% with international support, while at the same time maintaining strong economic growth. As an energy company that mainly does exploration and development in the oil and gas industry, we are highly committed to overcoming the effects of climate change. We conduct efforts to minimize our GHG emissions and to instill good practices in terms of energy and resource efficiency. We minimize our GHG emissions by monthly monitoring of GHG emissions and a reporting process to our board of directors, and we also continuously seek to innovate processes to perform energy efficiency activities. We also report our GHG emission levels to the Ministry of Environment and Forestry on an annual basis. We have also taken measures including converting our operational vehicles from oil fuel-based engines to gas-based engines, pioneering the reduction and utilization of flaring gasses across multiple assets, and applying low-pressure gas emission reductions and utilization with low pressure compressors (gas jack) in asymptotic conditions.

### Corporate Social Responsibility

Our Corporate Social Responsibility ("CSR") program is designed and managed to benefit the stakeholders around our main operating areas and is customized according to each community's primary needs and competencies. In each community, our CSR investments are focused on three policy pillars:

- to foster empowerment and entrepreneurship;
- to manage and mitigate security risks to our operations; and
- to encourage and invest in the development of environmentally friendly renewable energy.

We have CSR programs in operations in East Aceh (Aceh), Anambas (Riau Islands), Banyuasin, Empat Lawang, Lahat, Musi Rawas, Musi Banyuasin, Muara Enim, Penukal Abab and Lematang Ilir (South Sumatra) and Tarakan (North Kalimantan). Such programs have included, among others, promoting sustainable agriculture through organic system of rice intensification and organic rubber cultivation, supporting the cultivation of medicinal herbs and organic vegetables, providing goats and goat farming training, supporting honey bee cultivation, providing electricity to villages, teacher training, a mobile library, village libraries, scholarships, books, student supplies, support for environmental programs such as waste management and school-based environmental programs, support for rehabilitation of social and public facilities, and providing assistance to victims of natural disaster.

### Legal Proceedings

From time to time, we have been and may be a party to various legal proceedings.

We are not currently a party to any pending legal proceedings that we believe will have a material adverse effect on our business, financial condition or results of operations.

## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

*The discussion below should be read together with our consolidated financial statements. Our consolidated financial statements have been prepared in accordance with Indonesian FAS, which differs in certain material respects from U.S. GAAP. See "Risk Factors — Risks Relating to the Company — Indonesian corporate and other disclosure and accounting standards differ from those in the United States, countries in the European Union and other jurisdictions." We have selected the U.S. dollar as our functional currency.*

*This discussion contains forward-looking statements and reflects our current views with respect to future events and financial performance. Actual results may differ materially from those anticipated in these forward-looking statements as a result of certain factors such as those set forth under "Risk Factors," and elsewhere in this document.*

### Overview

We are an integrated energy and natural resources company operating through our core oil and gas exploration and production business, power generation business and investment in mining. We are the largest independent publicly listed oil and gas exploration and production company in Indonesia based on revenue, production and market capitalization. In addition, according to a peer analysis conducted by Wood Mackenzie, as of December 31, 2019, we have the highest level of working interest production in Southeast Asia and North Asia among a selected peer group, consisting of independent exploration and production companies with similar reserves in North and Southeast Asia, including Eni, Repsol, Total, PT Energi Mega Persada Tbk and SapuraOMV. We have historically focused on our activities in Indonesia, and now have significant producing assets in Thailand and Vietnam and also have oil and gas operations in the Middle East, North Africa, Malaysia, Mexico and Tanzania.

On May 22, 2019, through our subsidiary MEG, we completed the Ophir Acquisition. Ophir was an independent upstream oil and gas exploration and production company, with a diversified portfolio of production, development and exploration assets in Indonesia, Thailand, Vietnam, Malaysia, Mexico and Tanzania. Ophir was founded in 2004 and was listed on the London Stock Exchange from 2011 until the completion of the Ophir Acquisition. In September 2018, Ophir had completed the purchase of the Santos Producing Assets in Southeast Asia. Ophir had net proved and probable reserves of 68.8 MMBOE as of December 31, 2018 and average daily production of 29.7 MBOE/d for 2018 (on a pro forma basis including production for the full year 2018 from the Santos Assets). The total consideration for the acquisition was GBP 408.4 million plus transfer taxes, which we financed with the proceeds from our US$650 million offering of the 2026 Notes. Since the closing of the Ophir Acquisition, we have continued to integrate the Ophir Group's assets while disposing of several of the Ophir Group's deep water exploration assets in line with our focus on selective and low-risk exploration and development activities. In the nine months ended September 30, 2019, the Ophir assets (including the period prior to effectiveness of the Ophir Acquisition) produced 7.2 MMBOE.

We currently have interests in 15 oil and gas properties in Indonesia, 11 of which are currently producing. We also have interests in oil and gas properties in eight countries outside of Indonesia with interests in key producing assets in Vietnam and Thailand, and interests in other assets in Yemen, Libya, Oman, Malaysia, Mexico and Tanzania. In Indonesia, our blocks are held under production sharing arrangements with SKK MIGAS, Indonesia's national upstream oil and gas regulator. Under these production sharing arrangements, we are entitled to recover our costs and earn an agreed after-tax share of the production. Our blocks are held under production sharing contracts with PetroVietnam in Vietnam and under concession contracts, subject to tax and royalty, in Thailand.

In the nine months ended September 30, 2019, our production capacity (including the Ophir Group assets from June 1, 2019) was 116.0 Mboepd while total gross production capacity was 1,016.3 BBTU/D, and our oil and gas production split was 37.6% oil and 62.4% gas (including production under our Oman service contract). Of the gas production, 53% was sold under fixed price contracts to PLN (the Indonesian state electricity generator), Pertamina (the national oil company of Indonesia) and PGN (the gas and distribution company majority owned by the Government). Currently, our remaining gas production is sold to Sembgas, Petronas, Petro-Vietnam or indirectly pursuant to LNG contracts to KOGAS, Chubu Electric Power Co. Inc and Kyushu Electric Power Co. Inc. Our gas off-takers include blue chip customers with strong credit profiles.

In addition to our core oil and gas business, we operate in the power generation sector and have an investment in mining.

Through MPI, which is now a wholly-owned subsidiary, we operate in the power generation sector in Indonesia. MPI is a small to medium sized IPP, developing and operating its own power generation units and O&M provider where it operates and maintains power plants for third parties. MPI promotes a green energy platform and has interests in gas-fired power, geothermal energy and hydro-electricity plants. MPI owns and operates nine power plant assets. As of September 30, 2019, MPI had gross installed capacity of 638 MW as an IPP and acts as O&M provider for gross installed capacity of 2,150 MW (including 330 MW of its own IPP capacity at Sarulla). In 2018 and the nine months ended September 30, 2019, MPI produced 2,704 GW and 1,870 GW of power as an IPP, respectively, and acted as O&M provider for power plants which produced 10,674 GW and 8,874 GW of power (including power produced at its own plant at Sarulla), respectively. As of September 30, 2019, MPI's IPP business had pipeline projects with a capacity of 1,180 MW.

Our copper and gold mining investment consists of our 32.4% effective interest in AMNT. AMNT owns and operates the Batu Hijau Mine, located on the island of Sumbawa, approximately 950 miles east of Jakarta. The mining concession covers an area of 25,000 hectares, which includes the Elang copper and gold resource and several exploration prospects including Lampui, Rinti, Batu Balong, Nangka and Teluk Puna. As of December 31, 2018, AMNT had approximately 4.0 million ounces of proven and probable gold reserves including about 1.0 million ounces of gold stockpiles and 4.2 billion pounds of proven and probable copper reserves including 2.0 billion pounds of copper stockpiles. In 2017, 2018 and the nine months ended September 30, 2019, AMNT had gold sales of 491.9 thousand ounces, 68.1 thousand ounces and 41.9 thousand ounces, respectively and had copper sales of 330.6 million pounds, 130.2 million pounds and 96.3 million pounds, respectively.

For the years ended December 31, 2016, 2017 and 2018, our total sales and other operating revenues were US$561.9 million, US$905.1 million and US$1,218.3 million, respectively, and EBITDA was US$264.7 million, US$432.9 million and US$585.3 million, respectively. For the nine month periods ended September 30, 2018 and 2019, our total sales and other operating revenues were US$900.6 million and US$1,015.9 million, respectively, and EBITDA was US$441.0 million and US$476.5 million, respectively. Giving effect to the Ophir Acquisition (and related transactions) as if it had occurred as of January 1, 2018, EBITDA of total Company and Ophir Group consolidated pro forma balances (exclusive of PT Medco Power Internasional and its subsidiaries' historical balances) for the nine months ended September 30, 2019 would have been US$552.4 million. See "Unaudited Pro Forma Combined Consolidated Financial Information."

## Significant Factors Affecting Results of Operations

### *Oil and Gas Prices*

Our net sales, profitability and asset values and financial condition have been and will continue to be significantly affected by movements in oil and gas prices.

#### *Oil Prices*

The international market for crude oil is volatile, and has recently been characterized by significant price fluctuations including significant decreases in the second half of 2014 and in 2015. The monthly average price of

Brent crude oil was US$53.3 as of December 2016, US$64.4 for December 2017, US$57.4 as of December 2018 and US$62.8 as of September 2019.

Oil prices fluctuate due to a number of factors, which include, among others, demand for crude oil, global events and circumstances, political developments and instability in petroleum producing regions, such as the Middle East; the ability of OPEC and other petroleum-producing nations to set and maintain production levels and therefore influence market prices; market prices and supply levels of substitute energy sources, such as natural gas and coal; domestic and foreign government regulations with respect to oil and energy industries in general; the level and scope of activity of oil speculators; weather conditions and seasonality; and overall domestic and regional economic conditions. Our average realized sales prices for oil for the years ended December 31, 2016, 2017 and 2018 and the nine months ended September 2018 and 2019 were US$42.3 per BBL, US$51.5 per BBL, US$67.8 per BBL, US$68.8 per BBL and US$62.5 per BBL, respectively, reflecting the continued decline in crude oil prices globally in 2016 and an increase in crude oil prices globally in 2017, 2018 and 2019. The changes in oil prices have significantly impacted our net oil and gas sales. In addition, fluctuations in oil prices have impacted and may continue to impact our asset values.

We sell most of our net crude oil production through short to medium term off-take contracts which we grant under a competitive tender process. In line with the Government regulations, we sell our Indonesian oil at prices based on ICP. The ICP price is determined by the Government, and was the monthly average of the mean of two publications of independent oil traders and marketers in the Asia Pacific region published by Platts and RIM in the following proportions: 50% Platts and 50% RIM until June 2016. Starting in July 2016, the basis of ICP was changed to Dated Brent price plus Alpha and in 2018 was further revised to Dated Brent plus/minus Alpha. The ICP is published every month. The sales contracts that we enter into are based on the ICP, with certain pre-agreed premiums depending on the quality of the crude oil and provide for the sale of substantially all of our net crude oil production from a given producing block. Increases in ICP therefore increase our net oil sales and have a favorable impact on our results of operations. The cost-recovery portion of net crude entitlement is also calculated based upon ICP prices. Our profitability is significantly affected by the prices of, and demand for, crude oil, and the difference between the prices received for the oil we produce and the costs of exploring for, developing, producing, transporting and selling oil.

The terms of our production sharing contracts at oil-producing blocks require us to effect DMO sales at 10% to 25% of the market price in Indonesia. As a result, we are unable to sell our entire net oil production at the full international market price and consequently our average realized sales price may be lower than the applicable ICP. These prices are also subject to fluctuations which may have a material adverse effect on our revenues and net income and on our business, financial condition and results of operations.

For our oil sold from Thailand, we sell at prices based on Banoco Arab Medium. This crude comes from Bahrain and is similar in quality to Saudi’s Arab Medium. Saudi crudes typically do not trade on a spot basis but Banoco Arab Medium can trade spot, priced as a differential to Saudi Aramco’s Arab Medium official selling price for Asia. Aramco’s official selling price is announced one month forward and is based on the average of front-month Dubai/Oman assessments plus a differential. The equation used to derive Banoco Arab Medium’s assessment for barrels loading in May is as follows: Average of May Oman & Dubai derivatives plus existing official selling price differential plus spot differentials plus expected official selling price adjustments.

*Gas Prices*

We typically enter into GSAs which set the total contracted quantity (“TCQ”), daily contracted quantity (“DCQ”) and gas price. While TCQ and DCQ vary between buyers, gas prices under our domestic gas GSAs are fixed in US$/MMBTU with an application of a relatively small escalation factor (typically 2.5% to 3.0% per annum). Therefore, our revenue from natural gas sales is not subject to as much price volatility as our oil revenues. Some of our export contracts contain pricing linked ultimately to oil prices, such as the Senoro GSA and approximately half of our production under the South Natuna Sea Block B GSA. In particular, as of September 30, 2019, gross working interest volumes from the substantial majority of our 885 BCF of proved and probable gas reserves were commercially committed for sale through long-term contracts (except for Libya, which accounted for 6% of the 885 BCF), with sales through such contracts representing 50% and 46% of our net oil and gas sales in each of 2018 and the nine months ended September 30, 2019, respectively. Of this, for the nine months ended September 30, 2019, gas revenue of approximately 53% was sold through fixed price gas contracts with the remaining gas revenue sold under oil-linked prices. In addition, most of our GSAs, including both fixed-domestic and oil-linked-export GSAs, have take-or-pay protections, pursuant to which, if a buyer is unable to absorb the agreed supply during a period (typically over twelve months) then the buyer will have to pay a portion (usually in the range of 80% to 90%) of the total contracted supply for the period. The revenue contribution from GSAs has increased in recent years. Our average realized sales prices for gas per MMBTU for the years ended December 31, 2016, 2017 and 2018 and the nine months ended September 30, 2018 and 2019 were US$4.4, US$5.5, US$6.4, US$6.2 and US$6.9, respectively, reflecting production primarily from Senoro and South Natuna Sea Block B, which has a GSA with prices linked to movements in oil prices. For a summary description of our gas sales arrangements, see "Business — Sales and Distribution — Natural Gas."

***Acquisitions and Divestments***

Our results of operations and business are significantly affected by acquisitions and divestments. In addition, one of our key strategies is to build on our strong track record of evaluating, closing and integrating successful acquisitions in our core oil and gas business and pursue reserves and production growth in Southeast Asia through strategic acquisitions. Set forth below is a discussion of certain of our recent acquisitions and certain of their effects on our results and financial condition.

*Ophir*

The Ophir Acquisition became effective on May 22, 2019 and we began consolidating Ophir on June 1, 2019, increasing our reserve base and production levels. Prior to Ophir Acquisition, Ophir had a production and development business with net proved and probable reserves of 68.8 MMBOE as of December 31, 2018 (including the Santos Producing Assets) and with average daily production for 2018 of 29.7 MBOE/d (on a pro forma basis including production for the full year 2018 from the Santos Producing Assets). In the nine months ended September 30, 2019, the Ophir assets (including the period prior to effectiveness of the Ophir Acquisition produced 7.2 MMBOE. The larger asset base has also resulted in higher depreciation expenses and costs related to production activities. In addition, we recorded a bargain purchase gain of US$79.5 million in the nine months ended September 30, 2019 in connection with the Ophir Acquisition, reflecting that the purchase price we paid for Ophir was less than our assessment of the fair value of Ophir's assets.

*AMNT*

In November 2016, we entered into the copper and gold mining sector through our acquisition of a joint venture interest in AMNT, the operator of the Batu Hijau copper and gold mine as well as various discovered resources, several exploration prospects and the supporting infrastructure in the same area. This transaction has affected and we expect will continue to affect our results in a number of respects. For example, primarily as a result of the consummation of this transaction, we recorded a bargain purchase gain of US$467.2 million in 2016, reflecting that the purchase price we paid for our share in the joint venture was less than the assessment of the fair value of our share of its assets based on a valuation report from an independent third-party valuer registered with the OJK. In addition, this acquisition affected our balance sheet as our cash balances decreased significantly from the beginning of 2016 to the end of 2016 and our long-term investments increased, primarily due to this acquisition. As part of the transaction, we made a shareholder loan of US$246 million to the joint venture for its acquisition of AMNT and also guaranteed certain indebtedness which was incurred in connection with such acquisition. Such indebtedness has been repaid and such guarantee has since been discharged in full. Through this investment, we now operate in the copper and gold mining industry, and expect our share of the results of our joint venture will be significantly affected by AMNT's operating performance in the future. See "Business — Copper and Gold Mining."

*MPI*

In October 2017, we increased our stake in MPI from 49% to an effective interest of 88.62% by purchasing a 77.68% equity interest in PT Saratoga Power (which has since been renamed PT Medco Power Internasional), which holds a 51% equity interest in MPI, from PT Saratoga Sentra Business and S. Asia III Luxembourg S.A.R.L. for a total consideration of US$129.2 million. Approximately US$85.0 million of the purchase price was financed through a bank loan provided by PT Bank Mandiri (Persero) Tbk and the remainder was financed with cash on hand. In 2019, we purchased the remaining interest in PT Medco Power Internasional for a consideration of US$17.7 million so that MPI is currently a wholly-owned subsidiary. This was financed through cash on hand. Prior to October 3, 2017, we accounted for the results of MPI using the equity method. As a result of our increased interest, starting from October 3, 2017 we began consolidating MPI's results and therefore MPI's results of operations and financial condition now more significantly impact our results of operations and financial condition. In particular, MPI has substantial indebtedness which has been fully reflected in our consolidated financial statements and a significant portion of its indebtedness is associated with projects which are not yet in operation as MPI expands its business. In addition, since the date of consolidation, we have recorded revenue and costs from electric power sales related services. Although the indebtedness of MPI has been fully consolidated in our statement of financial condition as of December 31, 2017, our consolidated statement of profit and loss and cash flows (including revenue, expenses, EBITDA and other items included in, or derived from, our income statement) for the fiscal year ended December 31, 2017 reflects MPI's contribution as a consolidated subsidiary only from the date of acquisition on October 3, 2017 to December 31, 2017. MPI's results of operations are significantly affected by certain factors which include, among others:

- commercial arrangements under its PPAs and O&M agreements, including the duration of agreements and tariffs;
- MPI's power generation capacity and volume and type of O&M services provided;
- with respect to the tendering and tariff regime for future projects, changes in government regulation; and
- currency fluctuations between the U.S. dollar and the Rupiah. Generally, certain of the tariff components under MPI's PPAs contain adjustment provisions based on movements between the U.S. dollar and the Rupiah or the tariffs are U.S. dollar denominated. From a cost perspective, MPI's expenses are mainly denominated in Rupiah and as a result to the extent it earns revenues denominated in U.S. dollars its results are affected by currency fluctuations.

MPI from time to time explores potential capital raising options which could include debt or other forms of financing.

*Oil and Gas Blocks*

From time to time, we acquire and divest from, or increase or decrease our effective interests in, oil and gas blocks. For example, in 2016, we increased our interest in the Lematang PSC, a producing asset, to 100% from 74.1%, increased our interest in Block A, Aceh, a development asset, from 41.7% to 58.3% and acquired a 40.0% interest in South Natuna Sea Block B. We also agreed to divest our entire interest in the Bawean PSC, a producing asset, effective in September 2017. Further in April 2017, we increased our interest in Block A, Aceh from 58.3% to 85.0%. In May 2019, we divested 35% of our participating interest in the Rimau South Sumatera and South Sumatera Block PSCs, and in July 2019, we acquired 100% of North Sokang PSC, which is still in the exploration stage). Furthermore, in the fourth quarter of 2019, we disposed of our Tunisia oil and gas assets and our Mexico Block 5 exploration acreage. The acquisitions of, and divestments from, producing assets affect our production volume, and generally our acquisitions and divestments affect the value of our assets, liabilities and result of operations as we record bargain purchase gains.

*Other Businesses*

From time to time we have entered into certain businesses, including coal, real estate (through our ownership of The Energy Building) and others. Based on our assessment of our business lines, we decided that it may be in our interests to divest from these businesses and therefore we have reclassified them as assets held for sale. Such reclassification has the effect of such businesses being accounted for as discontinued operations on our income statement until we sell or may reclassify such assets. In particular, in 2017 we reclassified our then - subsidiary (now associate) which holds The Energy Building as held for sale, which resulted in a significant decrease in investment properties under our non-current assets and increase in our non-current assets classified as held for sale.

***Cost Efficiencies***

In recent years, in light of oil price volatility, we have carried out an efficiency drive. In 2016, 2017 and 2018, and the nine months ended September 30, 2018 and 2019, our unit cash production cost was US$8.1/BOE, US$8.6/BOE, US$8.7/BOE, US$8.3/BOE and US$9.5/BOE, respectively, compared with US$12.3/BOE in 2015 and US$15.4/BOE in 2014. This reduction was achieved through a number of cost reduction initiatives including (i) changing operating modes, such as revising crew rotation schedules and outsourcing certain non-core activities; (ii) optimizing existing operations and relationships, such as vendor renegotiations to capture deflation and sharing infrastructure with neighboring operators; and (iii) reassessing all operations to apply "fit-for-purpose" methodologies, such as rescheduling planned maintenance and engine exchanges. The cost reduction programs have targeted both larger scale cost reduction opportunities, such as drilling rig rate reductions, to smaller scale granular opportunities, such as travel and training budgets. We currently are committed to maintaining a unit cash production cost per BOE below US$10 through 2021 through, among others, continuing the aforementioned cost-efficiency initiatives and realization of synergies across the enlarged portfolio including assets of the Ophir Group which have had higher unit cash production costs. We will continue to apply our cost reduction programs to the Ophir Group assets with the goal of realizing cost savings. We expect that the structure of our PSCs will begin to change after 2021 with the adoption of the gross split PSC regime as our PSCs are extended. We expect that the structure of the cash flows under the new regime may result in higher operating costs, but that such costs may be offset with lower taxes and potentially higher net profits.

**Commercial Arrangements**

***Indonesia***

Our Indonesian PSCs contain cost recovery provisions which permit us to recover approved costs incurred in capital investment for exploration and development, and production and operating expenses against available revenues generated by the PSC after deduction of FTP, and any applicable investment credits. Generally, under the terms of such PSCs, we and the Government are entitled to take and receive FTP amounting to 20% of the total production of oil and gas each year, split between us and the Government, from our production areas in all of such PSCs, before any deduction for cost recovery, and applicable investment credits. Under the terms of 10 of our PSCs, including 2 JOBs, after we have recovered all approved costs including incentives, the Government is entitled to a 65.0% to 85.0% profit share of the remaining production and we keep the rest as our profit share.

Because our recoverable costs are customarily settled in oil and gas, the exact amount realizable by us out of these cost recoveries varies depending on the market prices of oil and the contracted prices for gas. For example, if oil prices decrease, our cost recovery portion of production will rise and our net entitlement under our commercial arrangements will therefore also rise. However, despite such increase in our net entitlement, a decline in oil prices will lead to a decline in net revenues.

Our share of profits after tax from our PSCs ranges from 27.5% to 40.0% for gas and 12.5% to 35.0% for oil, depending on the PSCs and without taking into account the impact of cost recovery and DMO for oil and gas. After a period of 60 months, commencing from the month of the first delivery of crude oil produced from each new field in a given contract area, the contractor will typically be subject to DMO to sell approximately 3.75% on an after tax basis of the crude oil produced from the contract area at a discounted price, ranging from 10.0% to 25.0% of the market price, depending on the PSC. For the last three years and the nine months ended September 30, 2019, our DMO have accounted for an average of approximately 13.4% on an after tax basis of our crude oil net production. While we are obliged to sell 25% of the gas we produce in the domestic market, we may do so at market price and as we sell the majority of our entire gas net production in the domestic market, in practice, this obligation does not affect our results of operations. There can be no assurance that we will not be subject to increases in our DMO for oil and gas in the future. See "Risk Factors — Risks Relating to our Industries."

In 2018 and 2019 respectively, our Tarakan PSC and Rimau PSC, which were scheduled to expire in 2022 and 2023, respectively, each obtained a 20 years PSC extension from the Government. The terms of the extensions differ from the existing PSC cost recovery format and follow the new gross split PSC regime.

Our business is also subject to commercial arrangements in Thailand and Vietnam.

### *Oil and Gas Production Volume*

Our oil and gas net production volumes are a key factor that affects our sales and profitability and depends primarily on the terms of our production sharing contracts and the level of developed reserves in the fields in which we have an interest. The level of developed reserves is affected by such factors as:

- our exploration success in making discoveries;
- the speed at which successful exploration is approved for development and then brought into production, and the speed at which reserves are depleted through production;
- the extent to which we acquire or divest interests in producing reserves;
- the expiration and extension of the terms of the production sharing arrangements under which we and our partners produce crude oil and gas;
- operational efficiencies in and the infrastructure available for our production processes; and
- managing declining reserves at mature fields.

In addition to our amount of producing reserves, our level of production is affected by:

- market demand; and
- individual terms of the commercial contracts.

## Our Planned Exploration and Development Activities

From January 1, 2016 to September 30, 2019, we incurred US$1,123.0 million in aggregate capital expenditures, which includes acquisition costs for exploration and evaluation assets, and development costs for our oil and gas properties. Our total annual non-debt funded capital expenditures necessary to maintain our production levels are expected to remain below US$300 million per year over the next five years, which should allow for a reduction in gearing. Within this total capital expenditure, we intend to keep expenditures for discretionary exploration and managing declines in production. We plan to do this by phasing expenditures on our developments and making carefully selected investments to offset declines in production. We cap our discretionary exploration capital expenditure and focus on infrastructure-led, low risk targets and we fund this capital expenditure primarily through cash from operations.

We follow PSAK No. 64, Exploration for Evaluation of Mineral Resources, in recording exploration and evaluation assets. Accordingly, all estimated future costs associated with the acquisition and exploration of oil and gas reserves, including directly related overhead costs, are capitalized. All costs arising from production activities are recorded at the time they are incurred. All capitalized costs relating to our oil and gas reserves are depreciated and amortized using the unit of production method.

Investments in unproven reserves and major development projects are not amortized until proved reserves associated with such properties and projects can be determined or until impairments occur. Our depreciation, depletion and amortization costs (including depreciation charged to our operating expenses) for the years ended December 31, 2016, 2017 and 2018 and the nine months ended September 30, 2018 and 2019 were US$107.4 million, US$161.6 million, US$110.4 million, US$73.7 million and US$208.9 million respectively.

We also conduct workover operations, comprising drilling activities, to maintain our current production capacity, which are accounted for as capital expenditure.

***PSC Tax Regime***

Currently all of our Indonesian PSCs are under the cost recovery PSC regime. We expect that the structure of our PSCs will begin to change after 2021 with the adoption of the gross split PSC regime as our PSCs are extended. In 2018 and 2019 respectively, our Tarakan PSC and Rimau PSC, which were scheduled to expire in 2022 and 2023, respectively, each obtained a 20-year PSC extension from the Government. The terms of the extensions, which take effect at the start of the extended period, differ from the existing PSC cost recovery format and follow the new gross split PSC regime.

*Cost Recovery*

The calculation of income tax for cost recovery PSC working interest holders differs from the method generally used in calculating income tax for other Indonesian taxpayers under the general income tax regime. The significant differences between the general income tax regime and the cost recovery PSC income tax regime include:

- under the PSC tax regime, the taxable value of oil liftings is to be referenced to the net entitlement of oil after deduction of cost recovery (calculated based on ICP, as opposed to the actual sales price), while the taxable value of gas liftings is also referenced to the net gas entitlement, but calculated based on actual sales price;
- under the PSC tax regime, the classifications for intangible and capital costs are not necessarily consistent with general Indonesian income tax rules relating to capital spending;
- under the PSC tax regime, the depreciation and amortization rates applying to intangible and capital costs are not necessarily consistent with the depreciation rates available under the general Indonesian income tax rules;
- under the PSC tax regime, interest costs are not recoverable and not tax deductible, whereas interest is usually fully deductible under general Indonesian income tax rules. However, some of our PSCs provide specific allowances (such as investment credit allowance and interest cost recovery) which are calculated based on approved interest rates on remaining capital expenditure balances, allowing our subsidiaries to recover the amount of such allowances. Such allowances are not tax deductible costs;
- under the PSC tax regime prior to the issuance of the Director General of Taxes No. PER-20/PJ/2017 (“PER-20/2017”), regarding Procedures for Calculating and Paying Income Tax on the First Tranche Petroleum (“FTP”) dated November 14, 2017, 20% of the oil and gas production (the number may vary depending on the PSC contract) before any deduction for cost recovery can be deferred from tax until the equity split position is reached, which is not necessarily consistent with how tax is calculated under the general Indonesian income tax rules;

- under PER-20/2017, tax on FTP is deemed to be payable if the balance of accumulative FTP has exceeded the balance of the unrecovered costs;
- the PSC tax regime provides for an unlimited carry forward of prior year unrecovered costs, as opposed to a given year restriction under the general Indonesian income tax rules; and
- no tax deductions will arise under the PSC tax regime until commercial production commences, as opposed to a deduction arising from the date of the expenditure being expensed or accrued under the general Indonesian income tax rules.

Due to the above differences, decreases or increases in current tax expenses may not necessarily be in line with decreases or increases in sales. Deductible costs are accordingly required to be calculated in accordance with the PSC tax regime in order to calculate our taxable income and the related tax expense for a given period.

Indonesian income tax rates on our PSCs currently vary from 25% to 35%, depending on the contract terms for the applicable PSC where revenue is generated and the prevailing tax rates in the year in which the PSC is entered into, and this percentage changes our effective tax rate. Our PSCs are also subject to a PSC dividend tax of 15% to 20%. Our income tax expense is significantly influenced by the fact that PSCs cannot be consolidated for Indonesian income tax purposes, as this prevents us from off-setting losses from one PSC from profits from another PSC. Each PSC is taxed individually and no cross deduction is allowed.

*Gross Split*

The calculation of income tax for gross split PSC working interest holders differs from the method generally used in calculating income tax for other Indonesian taxpayers under the general income tax regime. The significant differences between the general income tax regime and the gross split PSC income tax regime include:

- under the gross split PSC income tax regime, no tax deductions are allowed until commercial production commences, whereas under the general Indonesian income tax rules deductions are allowed on the date of the applicable expenditure being expensed or accrued;
- the gross split PSC income tax regime and the general Indonesian income tax rules differ with respect to (i) classifications of intangible and capital costs; (ii) utilization of the double unit production method to amortize capitalized expenses incurred prior to commercial production period; and (iii) classification of useful life of assets;
- under the gross split PSC income tax regime, interest costs are not tax deductible, whereas under the general Indonesian income tax rules, interest is usually fully tax deductible; and
- the gross split PSC income tax regime provides for historical losses to be carried forward for up to ten years, whereas the general Indonesian income tax rules do not permit losses to be carried forward more than five years.

Under both the gross split PSC regime and the general income tax regime:

- taxable income of a company or a permanent establishment is subject to corporate income tax at the rate of 25% pursuant to Law No. 36 of 2008 regarding Fourth Amendment of Law No. 7 of 1983 regarding Income Tax (ITL-36/2008);
- taxable income of a permanent establishment that results from activities from which corporate income tax has already been deducted is subject to income tax at the rate 20% pursuant to ITL-36/2008 or reduced income tax rate under Tax Treaty; and
- each oil and gas block is taxed on a stand-alone basis, with no allowance for cross deduction of expenses.

### *Political and Security Conditions in the Countries Where we Operate*

While our key producing assets are primarily located in Indonesia, Thailand and Vietnam, we also operate or have historically operated in other countries, including countries with political and security considerations that could impact our operations. In 2016, we recorded impairment losses on our oil and gas properties of US$278.5 million (partially reversed by US$100.0 million in 2017), primarily related to impairments of our assets in Libya and Tunisia resulting from our risk assessment related to political conditions in the North African region, which affected our profitability for the year. In addition, our operations in Tunisia were suspended due to labor protests in connection with a general strike in the country which occurred from April 2017 to June 2017. Operations resumed from June 2017. In Yemen, due to adverse security conditions, there was no activity at our blocks for an extended period of time from 2014 until the fourth quarter of 2018. We continue to monitor and assess the conditions in these countries.

## Overview of Results of Operations

The following table sets forth certain information with respect to our revenues, expenditures and profits, for the years ended December 31, 2016, 2017 and 2018 and the nine months ended September 30, 2018 and 2019.

| | For the Years Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | **2016** | **2017** | **2018** | **2018** | **2019** |
| | **(Restated)[1]** | **(Restated)[1]** | **(Restated)[1]** | **(Unaudited) (Restated)[1]** | |
| | | | **(US$ in millions)** | | |
| **Consolidated Statements of Profit or Loss and Other Comprehensive Income** | | | | | |
| **Sales and Other Operating Revenues** | | | | | |
| Net oil and gas sales | 554.9 | 834.6 | 980.2 | 730.5 | 852.7 |
| Electric power sales and revenue from related services | — | 67.5 | 235.9 | 168.4 | 161.9 |
| Revenues from services | 7.0 | 3.0 | 2.2 | 1.7 | 1.3 |
| **Total Sales and Other Operating Revenues** | **561.9** | **905.1** | **1,218.3** | **900.6** | **1,015.9** |
| **Cost of Sales and Other Direct Costs** | | | | | |
| Production and lifting costs | 190.2 | 192.3 | 203.3 | 135.0 | 211.8 |
| Depreciation, depletion, and amortization | 106.3 | 160.6 | 108.8 | 71.5 | 205.8 |
| Cost of electric power sales and related services | — | 40.6 | 134.3 | 88.6 | 89.4 |
| Cost of crude oil purchases | 13.3 | 80.9 | 125.4 | 109.3 | 43.5 |
| Exploration expenses | 5.9 | 9.9 | 8.6 | 4.3 | 20.7 |
| Cost of services | 0.9 | 5.3 | 5.7 | 4.0 | 5.0 |
| **Total Cost of Sales and Other Direct Costs** | **316.6** | **489.5** | **586.1** | **412.7** | **576.2** |
| **Gross Profit** | **245.2** | **415.6** | **632.2** | **487.9** | **439.7** |
| Selling, general and administrative expenses | (87.9) | (144.3) | (157.3) | (120.5) | (172.1) |
| Finance costs | (99.4) | (140.6) | (189.0) | (146.3) | (188.5) |
| Finance income | 7.6 | 32.3 | 12.7 | 7.4 | 13.0 |
| Bargain purchase | 551.7 | 43.1 | — | — | 79.5 |
| Gain on business combination achieved in stages | — | 16.1 | — | — | — |
| Income from insurance claim | — | 7.7 | — | — | — |
| Loss on assets recognized at fair value less cost to sell | (11.9) | — | — | — | — |
| Loss on impairment of assets | (16.1) | (4.1) | (2.2) | — | — |

| | For the Years Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| | (Restated)[1] | (Restated)[1] | (Restated)[1] | (Unaudited) (Restated)[1] | |
| | | | (US$ in millions) | | |
| Loss on dilution of long-term investment | — | — | (19.1) | (19.1) | — |
| Share of net loss of associates and joint venture | (27.0) | (37.0) | (66.7) | (24.3) | (30.3) |
| Other income | 9.7 | 22.6 | 10.1 | 13.0 | 29.1 |
| Other expenses | (6.4) | (14.4) | (18.6) | (24.9) | (14.1) |
| **Profit Before Income Tax Expense from Continuing Operations** | **565.4** | **197.1** | **202.2** | **173.1** | **156.3** |
| **Income Tax Expense** | **(61.6)** | **(138.1)** | **(196.5)** | **(169.2)** | **(138.5)** |
| **Profit for The Year/Period from Continuing Operations** | **503.8** | **59.0** | **5.7** | **3.8** | **17.8** |
| Profit (loss) after Income Tax Expense from Discontinued Operations | (316.8) | 72.8 | (34.1) | (5.1) | 8.8 |
| **Profit (loss) for The Year/Period** | **187.0** | **131.8** | **(28.4)** | **(1.2)** | **26.6** |
| **Other Comprehensive Income** | | | | | |
| **Other Comprehensive Income That Will Be Reclassified to Profit or Loss** | | | | | |
| Translation adjustments | 1.9 | 26.7 | (5.6) | (4.9) | 0.2 |
| Fair value adjustment on cash flow hedging instruments — net of tax | 26.7 | 24.3 | (7.1) | (7.3) | (14.4) |
| Fair value adjustment on available-for-sale investment | — | 0.7 | 0.4 | — | (0.2) |
| Share of other comprehensive income (loss) of associates and joint venture | (24.2) | 12.4 | 11.7 | 14.7 | (4.3) |
| **Other Comprehensive Income That Will Not Be Reclassified to Profit or Loss** | | | | | |
| Share of other comprehensive income of associates and joint venture | 0.0 | — | — | — | — |
| Remeasurement of defined benefit program | 3.7 | (5.5) | 10.4 | 9.7 | 2.2 |
| Income tax related to the accounts that will not be reclassified to profit or loss | (0.3) | (0.8) | (0.9) | (0.9) | (0.1) |
| **Total Comprehensive Income (Loss) for The Year/Period** | **195.0** | **189.6** | **(19.6)** | **10.0** | **9.9** |
| **Profit (loss) for the Year/Period Attributable to Equity Holders of the Parent Company** | | | | | |
| Profit (loss) for the year/period from continuing operations | 501.5 | 54.3 | (17.2) | (6.0) | 10.4 |
| Profit (loss) for the year/period from discontinued operations | (316.8) | 72.8 | (34.1) | (5.1) | 8.8 |
| Profit (loss) for the year/period attributable to equity holders of the parent company | 184.8 | 127.1 | (51.3) | (11.1) | 19.3 |
| Profit for the year/period attributable to non-controlling interests | 2.3 | 4.7 | 22.9 | 9.9 | 7.3 |
| | 187.0 | 131.8 | (28.4) | (1.2) | 26.6 |

| | For the Years Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| | (Restated)[1] | (Restated)[1] | (Restated)[1] | (Unaudited) (Restated)[1] | |
| | | | (US$ in millions) | | |
| **Total Comprehensive Income (Loss) for the Year/ Period Attributable to Equity Holders of the Parent Company** | | | | | |
| Comprehensive income (loss) for the year/period from continuing operations | 509.4 | 111.7 | (10.8) | 0.2 | 1.2 |
| Comprehensive income (loss) for the year/period from discontinued operations | (316.8) | 72.8 | (34.1) | (5.1) | 8.8 |
| Comprehensive income (loss) for the year/period attributable to equity holders of the parent company | 192.7 | 184.5 | (44.9) | (4.9) | 10.0 |
| Comprehensive income (loss) for the year/period attributable to non-controlling interests | 2.3 | 5.1 | 25.3 | 14.9 | (0.1) |
| | 195.0 | 189.6 | (19.6) | 10.0 | 9.9 |
| **Basic Earnings (Loss) per Share Attributable to Equity Holders of the Parent Company** | **0.01300** | **0.00887** | **(0.00290)** | **(0.00063)** | **0.00108** |
| **Basic Earnings (Loss) per Share From Continuing Operations Attributable to Equity Holders of the Parent Company** | **0.03529** | **0.00379** | **(0.00097)** | **(0.00034)** | **0.00059** |
| **Diluted Earnings (Loss) per Share Attributable to Equity Holders of the Parent Company** | — | **0.00886** | **(0.00266)** | **(0.00057)** | **0.00103** |
| **Diluted Earnings (Loss) per Share From Continuing Operations Attributable to Equity Holders of the Parent Company** | — | **0.00378** | **(0.00089)** | **(0.00031)** | **0.00056** |

Note:

(1) The restated consolidated financial statements resulted from the classification of profit or loss accounts of certain subsidiaries previously included in “Continuing Operations” to “Discontinued Operations”, as further described in note 38 of our consolidated financial statements.

### Description of Certain Principal Comprehensive Income Statement Line Items

*Net Oil and Gas Sales*

Our net oil and gas sales are primarily generated from sales of crude oil and natural gas, which are affected primarily by our net entitlement volume of oil and gas under production sharing arrangements and the prices at which they are sold.

We sell all of our net crude oil entitlement through a competitive tender process, and subject to market conditions, enter into short-term sales contracts with the winning bidder. Crude oil entitlement not sold pursuant to a sales contract is sold in the spot market. Since 2017, substantially all of our net crude entitlement in Indonesia has been sold to customers outside of Indonesia (other than oil sold pursuant to our DMO). We currently sell substantially all of our oil produced in Indonesia at prices based on the ICP, subject to adjustment depending on the quality of the crude oil. The cost recovery portion of net crude entitlement is also calculated based upon ICP prices. Our oil sales from Thailand are not subject to DMO or similar obligations.

In Vietnam, the Law on Petroleum imposes an obligation on foreign contractors to sell their crude oil in Vietnam at an international competitive price upon the Government's request. The Government exercises some discretions in its enforcement of their requirement.

Our natural gas sales contracts are typically long-term fixed price contracts. Most of our gas production in Indonesia, Thailand and Vietnam in 2019 was sold to local customers under long-term GSAs. In Vietnam, the Law on Petroleum imposes an obligation on foreign contractors to sell their natural gas in Vietnam at an agreed price upon the Government's request. For a summary description of our GSAs, see "Business — Sales and Distribution — Natural Gas."

***Electric power sales and revenue from related services***

Our revenue from electric power sales and revenue from related services consists of revenues earned by MPI. MPI's electric power revenue is primarily generated from (i) construction services (which consists of revenue from the Sarulla project based on concession services to PLN), (ii) electric power sales, (iii) concession services (revenue from the Sarulla Geothermal Energy Sales Contract ("ESC") to PLN and PT Medco Ratch Power Riau Power Purchase Agreement ("PPA") to PLN), operation and maintenance services (which consists of operations and maintenance services provided to third parties and the Sarulla project), (iv) rental of power plant, and (v) EPC services. We commenced recording revenue from electric power sales and related services since the consolidation of MPI on October 3, 2017.

***Revenues from services***

Our revenue from services are primarily generated from gas transportation services (onshore and offshore) and gas distribution and other, including labor, services.

***Cost of Sales and Other Direct Costs***

***Production and Lifting Costs***

Production and lifting costs consist primarily of (i) costs for oil and gas contracts, which consist of costs that are directly attributable to oil and gas activities in domestic and international operations, and mainly include manpower and utilities costs; (ii) field operations overhead costs, which consist of several administrative costs such as manpower, equipment rental and utilities costs; and (iii) O&M costs, and to a lesser extent, operational support costs and pipeline and transportation fees.

***Cost of Crude Oil Purchases***

Our costs of crude oil purchases consist of payments for crude oil (outside of our entitlement) purchased from SKK Migas, Tomori E&P Ltd, Camar Resources Canada Inc, and PT Medco Daya Natuna and PT Medco Daya Abadi Lestari, which we then sell to our foreign customers. We settle our lifting position with SKK Migas, Tomori E&P Ltd, Camar Resources Canada Inc, and PT Medco Daya Natuna and PT Medco Daya Abadi Lestari at the end of each year.

***Cost of Electric Power Sales and Related Services***

Our costs of electric power sales and related services consist of MPI's costs directly related to its revenue from electric power sales and related services. Such costs primarily consist of construction expenses, payments for gas purchases, costs related to providing operations and maintenance services, management and technical support expenses, maintenance expenses, and several administrative costs such as manpower, equipment rental and utilities costs.

### *Depreciation, Depletion and Amortization*

Depreciation, depletion and amortization primarily arise from the depletion of capitalized oil and gas exploration and development costs which are calculated using the unit of production method and depreciation of power plants.

### *Exploration Expenses*

Exploration expenses include dry hole costs and exploration overheads. Exploration expenses vary with the level of exploration activities and the success rate of such activities. We use the "successful efforts method" of accounting for oil and gas exploration expenses. Accordingly, the costs related to acquisitions of interests in oil and gas properties, the costs of drilling and equipping exploratory wells that locate or result in proved reserves and the costs of drilling and equipping development wells, including the costs of drilling exploratory-type stratigraphic test wells, are initially capitalized and recorded as part of uncompleted wells, equipment and facilities until the exploration is determined to be unsuccessful. Exploration expenses for dry holes are expensed in the year in which the exploration effort is determined to have been unsuccessful.

### *Cost of Services*

Costs of services represents the costs related to our drilling activities in Oman under our Oman service contract for Karim Small Fields where we operate and provide services for the owner, Petroleum Development Oman LLC, operational activities for our gas transportation and distribution business, and operational activities for our security services.

### *Selling, General and Administrative Expenses*

General and administrative expenses consist of salaries, wages and other employee benefits; professional fees; contract charges; service costs; repairs and maintenance; insurance; office supplies and equipment; depreciation; transportation; education; rental and insurance. Selling expenses include export expenses; business travel; advertising and promotion; and entertainment expenses.

### *Finance Costs*

Finance costs primarily consist of interest expenses on our indebtedness, and accretion of asset abandonment and site restoration obligations.

### *Finance Income*

Finance income primarily consists of interest income on cash deposits at banks.

### *Loss on Impairment of Assets*

Our loss on impairment of assets primarily consists of impairment losses recorded on our oil and gas properties as a result of impairment testing that we perform when circumstances indicate that the carrying value of the asset exceeds its recoverable amount. In 2018, our loss on impairment of assets was primarily due to the recognition of allowance for impairment on property, plant and equipment and advances for MPI mini-hydro projects which had not yet obtained approval for the extension of their construction periods from PT Perusahaan Listrik Negara Distribusi Jawa Barat ("PLNDJB"). In 2017, our loss on impairment of assets was primarily due to the recognition of allowance for impairment on oil and gas properties of Medco Lematang BV as we had increased our stake in Lematang PSC during a period of higher oil prices and revalued the asset after a decrease in oil prices. In 2016, our loss on impairment of assets was primarily because of changes in the recoverable value of our oil and gas properties due to the sharp decrease in oil prices during the year. From time to time, in accordance with Indonesian FAS, we have also made reversals on impairment of assets when relevant circumstances have changed.

### *Bargain Purchase*

We record bargain purchase gains when the value of the consideration paid in an acquisition exceeds the fair value of the net assets acquired. In 2016, we recorded a bargain purchase gain of US$551.7 million, which primarily consisted of gains recorded from the purchase of our interest in AMIV, the acquisition of our interest in South Natuna Sea Block B and the increases in our effective interests in Block A, Aceh and Lematang PSC. In 2017, we recorded bargain purchase gains related to the increase in our effective interests in Block A, Aceh. In addition, we recorded a bargain purchase gain of US$79.5 million in the nine months ended September 30, 2019 in connection with the Ophir Acquisition, reflecting that the purchase price we paid for Ophir was less than our assessment of the fair value of Ophir's assets.

### *Income from insurance claim*

Income from insurance claim consists of proceeds from insurance claims in 2017, resulting from an unintended gas flow incident in the Lagan Deep-1 exploration well at the South Sumatra PSC in 2011.

### *Gain on Business Combination Achieved in Stages*

Gain on business combination achieved in stages in 2017 consists of a US$16.1 million gain that we recognized upon our acquisition of an additional 39.62% effective interest in MPI as a result of our remeasurement of our pre-existing 49% equity interest in MPI at its fair value on the date of such acquisition.

### *Loss on Assets Recognized at Fair Value less Costs to Sell*

Our impairment loss on assets recognized at fair value less costs to sell consists of impairment of net assets that are classified as held for sale, which in 2016 was related to the classification of Bawean PSC as held for sale.

### *Loss on Dilution of Long-Term Investment*

In the first quarter of 2018, we, API, AMI (the holding company which directly holds our and API's shares in AMNT) and a new shareholder, PT Sumber Gemilang Persada entered into a transaction pursuant to which (i) we, API and PT Sumber Gemilang Persada began to hold our respective interests in AMNT through AMI, and (ii) our and API's respective shareholding at the time in AMI was reduced to 39.4% each while PT Sumber Gemilang Persada at the time held the remaining 21.3%. We recorded a US$19.1 million dilution loss from this transaction, which we believe represents the effect of changes in our rights to the net assets of AMI from such transaction. See "Business — Copper and Gold Mining" for further information about subsequent transactions with respect to AMI.

### *Share of Net Loss of Associates and Joint Venture*

Our share of net income (loss) of associates and joint venture primarily consists of our share of the net losses and net income from (i) AMNT, which we currently hold through our interest in AMI (previously AMIV), (ii) prior to October 2017, MPI, which historically had been accounted for using equity accounting prior to us obtaining a majority interest, (iii) from October 2017, AMG (which previously had been consolidated) and (iv) from May 22, 2019, APICO LLC in which we acquired a 27.2% interest through the Ophir Acquisition.

### *Other Income*

In the nine months ended September 30, 2019, other income mainly represented gain on fair value adjustment of associates of US$5.8 million. In 2017 and 2018, other income mainly represented overhead fees we received from the other working interest holders at South Natuna Sea Block B as operator of the block under our Joint Operating Agreement and from the DMO fee income recognized from the Government. In 2016, other income mainly consisted of cash receipts from VAT reimbursements amounting to US$5.7 million.

### *Other Expenses*

In the nine months ended September 30, 2019, other expenses primarily consisted of certain other expenses incurred in connection with the Ophir Acquisition. In 2018, other expenses primarily consisted of foreign exchange losses related to receivables recorded in Rupiah of US$13.1 million and marketing fee expenses, net of US$5.1 million. In 2017, other expenses primarily consisted of foreign exchange losses related to tax receivables recorded in Rupiah and penalty from taxes payable on First Tranche Petroleum. In 2016, other expenses primarily consisted of foreign exchange losses related to receivables recorded in Rupiah.

### *Income Tax Expense*

Income tax expenses primarily consist of our current tax expense net of the deferred tax benefit available or deferred tax expense which is determined in accordance with Statement of Financial Accounting Standards (PSAK) No. 46, "Accounting for Income Taxes." Our current tax expenses are generally determined based on the following: (i) subsidiaries involved in the oil and gas exploration and production are subject to Indonesian corporate income tax at a rate which varies from 25% to 35% and dividend tax which varies from 15% to 20%. Dividend tax is computed from taxable profit after Indonesia corporate income tax; and (ii) the Company and its subsidiaries are subject to corporate tax which varies from 17% to 25%.

Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases.

### *Loss After Income Tax Expense from Discontinued Operations*

Loss after income tax expense from discontinued operations represents losses generated by our investment properties, coal mining business, certain oil and gas blocks and certain other operations, including drilling services, and chemicals production which are either held for sale or categorized as discontinued operations.

## Comparison of The Nine Months Ended September 30, 2019 and 2018

### *Net Oil and Gas Sales*

Our net oil and gas sales increased by 16.7% to US$852.7 million for the nine months ended September 30, 2019 from US$730.5 million for the nine months ended September 30, 2018. The increase was primarily due to the Ophir Acquisition in May 2019, commercialization of Block A, Aceh in March 2019 and an increase in gas prices. Our average realized prices for oil decreased to US$62.5/barrel in the nine months ended September 30, 2019 from US$68.8/barrel in the nine months ended September 30, 2018. Our gas sales increased to 321.21 BBTUPD for the nine months ended September 30, 2019 from 261.1 BBTUPD for the same period in 2018. Our average realized prices for natural gas increased to US$6.9/MMBTU for the nine months ended September 30, 2019 from US$6.2/MMBTU for the corresponding period in 2018, primarily due to the commercialization of Block A, Aceh in March 2019. Our oil sales increased to 30.6 MBOPD for the nine months ended September 30, 2019 from 26.0 MBOPD for the same period in 2018.

### *Electric Power Sales and Revenue from Related Services*

Sales from electric power decreased to US$161.9 million in the nine months ended September 30, 2019 compared to US$168.4 million in the corresponding period in 2018. The decrease was primarily due to the offsetting effect between amortization of concession assets and its associated electric power sales revenue which started from December 31, 2018.

### *Revenue from services*

Our revenues from services decreased slightly to US$1.3 million for the nine months ended September 30, 2019 compared to US$1.7 million for the nine months ended September 30, 2018.

### *Production and Lifting Costs*

Production and lifting costs increased by 56.9% to US$211.8 million for the nine months ended September 30, 2019 from US$135.0 million for the nine months ended September 30, 2018. The increase was inline with the increase in revenue from net oil and gas sales, which was primarily due to the Ophir Acquisition in May 2019 and commercialization of Block A, Aceh in March 2019.

### *Depreciation, Depletion and Amortization*

Depreciation, depletion and amortization increased by 187.8% to US$205.8 million for the nine months ended September 30, 2019 from US$71.5 million for the nine months ended September 30, 2018, primarily due to the Ophir Acquisition in May 2019 which increased our assets and the commercialization of Block A, Aceh in 2019.

### *Cost of Crude Oil Purchases*

Cost of crude oil purchases decreased by 60.2% to US$43.5 million for the nine months ended September 30, 2019 from US$109.3 million for the nine months ended September 30, 2018, primarily due to significant decrease in purchases by our trading unit, Far East Energy Trading which in certain cases purchases and re-sell oil from our partners' entitlements at certain blocks.

### *Cost of Electric Power Sales and Related Services*

Our cost of electric power sales and related services were relatively stable at US$89.4 million for the nine months ended September 30, 2019 compared to US$88.6 million for the nine months ended September 30, 2018.

### *Exploration Expenses*

Exploration expenses increased by 378.8% to US$20.7 million for the nine months ended September 30, 2019 from US$4.3 million for the nine months ended September 30, 2018, primarily due to higher dry hole expenses incurred in Indonesia at South Natuna Sea Block B in 2019.

### *Cost of Services*

Cost of services increased by 25% to US$5.0 million for the nine months ended September 30, 2019 from US$4.0 million for the nine months ended September 30, 2018.

### *Total Cost of Sales and Other Direct Costs*

As a result of the foregoing, total cost of sales and other direct costs increased by 39.6% to US$576.2 million for the nine months ended September 30, 2019 from US$412.7 million for the nine months ended September 30, 2018.

### *Gross Profit*

Gross profit decreased by 9.9% to US$439.7 million for the nine months ended September 30, 2019 from US$487.9 million for the nine months ended September 30, 2018. Gross profit margin decreased to 43.3% for the nine months ended September 30, 2019 from 54.2% for the nine months ended September 30, 2018, primarily due to the early stage of commercialization at Block A, Aceh in March 2019, during which time margins are lower. Gross profit margin is derived by dividing gross profit over total sales and other operating revenues.

### *Selling, General And Administrative Expenses*

Selling, general and administrative expenses increased by 42.7% to US$172.1 million for the nine months ended September 30, 2019 from US$120.5 million for the nine months ended September 30, 2018. This increase was primarily due to costs related to executing the Ophir Acquisition of US$35.2 million, operating expenses from Block A Aceh's commercialization starting in March 2019, and the contribution of the Ophir Group's operating expenses starting from its date of consolidation.

***Finance Costs***

Finance costs increased by 28.8% to US$188.5 million for the nine months ended September 30, 2019 from US$146.3 million for the nine months ended September 30, 2018, primarily due to increases in debt issuance costs and in our average amount of indebtedness in 2019 compared to 2018.

***Finance Income***

Finance income increased by 76.8% to US$13.0 million for the nine months ended September 30, 2019 from US$7.4 million for the nine months ended September 30, 2018, primarily due to interest income on restricted cash held in escrow accounts.

***Bargain Purchase***

Bargain purchase was US$79.5 million for the nine months ended September 30, 2019, representing a bargain purchase gain on the Ophir Acquisition.

***Share of Net Loss Of Associates and Joint Venture***

For the nine months ended September 30, 2019, our share of net loss of associates and joint venture was US$30.3 million compared to our share of net loss of associates and joint venture of US$24.3 million for the nine months ended September 30, 2018. The increase in share of net losses in the nine months ended September 30, 2019 was primarily due to expenses at AMNT as it accelerated the development of Phase 7 at the Batu Hijau mine.

***Other Income***

Other income increased by 122.9% to US$29.1 million for the nine months ended September 30, 2019 from US$13.0 million for the nine months ended September 30, 2018, which was primarily due to gain on fair value adjustments on our remaining 49% share in AMG, which owns The Energy Building, and foreign exchange gains (mainly at MPI) as the Rupiah strengthened.

***Other Expenses***

Other expenses decreased by 43.3% to US$14.1 million for the nine months ended September 30, 2019 from US$24.9 million for the nine months ended September 30, 2018, primarily due to an increase in foreign exchange gains in 2018 related to receivables recorded in Rupiah.

***Profit before Income Tax Expense from Continuing Operations***

As a result of the foregoing, our profit before income tax expense from continuing operations decreased to US$156.3 million for the nine months ended September 30, 2019 from US$173.1 million for the nine months ended September 30, 2018.

***Income Tax Expense***

Income tax expense from continuing operations decreased by 18.1% to US$138.5 million for the nine months ended September 30, 2019 from US$169.2 million for the nine months ended September 30, 2018, primarily due to recognition of deferred tax expenses at PT Medco E&P Tomori Sulawesi (Senoro) and PT Medco E&P Natuna (South Natuna Sea Block B) due to a decrease in depreciation expenses resulting from an update in reserves valuations of those blocks in 2018.

### *Profit for the Period from Continuing Operations*

As a result of the foregoing, we recorded profit from continuing operations US$17.8 million for the nine months ended September 30, 2019 compared to profit from continuing operations of US$3.8 million for the corresponding period in 2018.

### *Profit (Loss) After Income Tax Expense From Discontinued Operations*

We recorded profit after income tax expense from discontinued operations US$8.8 million for the nine months ended September 30, 2019 due to gains on disposal of subsidiaries classified as held for sale as compared to loss after income tax expense from discontinued operations of US$5.1 million for the corresponding period in 2018.

### *Profit (Loss) For the Period*

As a result of the foregoing, we recorded profit for the period of US$26.6 million for the nine months ended September 30, 2019 compared to loss for the period of US$1.2 million for the nine months ended September 30, 2018.

### *Total Comprehensive Income (Loss) For the Period*

For the nine months ended September 30, 2019, we recorded total comprehensive income for the period of US$9.9 million, compared to total comprehensive income for the period of US$10.0 million for the nine months ended September 30, 2018.

## Comparison of 2018 and 2017

### *Net Oil and Gas Sales*

Our net oil and gas sales increased by 17.4% to US$980.2 million for the year ended December 31, 2018 from US$834.6 million for the year ended December 31, 2017. The increase was primarily due to an increase in our average realized prices as the result of higher oil prices. Our average realized prices for oil increased to US$67.8/barrel in 2018 from US$51.5/barrel for in 2017. Our gas sales decreased to 267.8 BBTUPD for the year ended December 31, 2018 from 273.4 BBTUPD for the same period in 2017. Our average realized prices for natural gas increased to US$6.4/MMBTU for the year ended December 31, 2018 from US$5.5/MMBTU for the corresponding period in 2017, primarily due to the increase in oil prices which impacted the portion of our GSAs which are linked to oil prices. Our crude oil sales increased to 26.5 MBOPD for the year ended December 31, 2018 from 26.2 MBOPD for 2017.

### *Electric Power Sales and Revenue from Related Services*

Sales from electric power increased by 249.4%, to US$235.9 million in 2018 from US$67.5 million in 2017. The increase primarily reflected a full year of consolidation of MPI’s revenues compared to 2017 when we consolidated MPI’s revenues from October 3, 2017.

### *Revenue from services*

Our revenues from services decreased by 25.2% to US$2.2 million for the year ended December 31, 2018, from US$3.0 million for the year ended December 31, 2017. The decrease was primarily due to decreased pipeline fee tariffs by PLN.

### *Production and Lifting Costs*

Production and lifting costs were reasonably stable at US$203.3 million and US$192.3 million for the years ended December 31, 2018 and 2017, respectively. The increase was primarily due to routine parts replacement for production equipment at South Natuna Sea Block B.

### *Depreciation, Depletion and Amortization*

Depreciation, depletion and amortization decreased by 32.2% to US$108.8 million for the year ended December 31, 2018 from US$160.6 million for the year ended December 31, 2017, primarily due to a reserve adjustment at South Natuna Sea Block B based on a new GCA certification report issued in November 2018. The increase in reserves was mostly attributable to producing fields. Actual production performance from the end of 2016 through September 2018 was better than originally forecasted, justifying an increase in reserves.

### *Cost of Crude Oil Purchases*

Cost of crude oil purchases increased by 55.0% to US$125.4 million for the year ended December 31, 2018 from US$80.9 million for the year ended December 31, 2017, primarily due to additional crude oil purchases from our affiliate PT Medco Daya Abadi Lestari (in 2017, crude oil purchases were from Medco South Natuna Sea Pte Ltd).

### *Cost of Electric Power Sales and Related Services*

In the year ended December 31, 2018, we recorded costs from electric power sales and related services of US$134.3 million, which is an increase of 231.2% from US$40.6 million in 2017. The increase was primarily due to the full year consolidation of MPI in 2018.

### *Exploration Expenses*

Exploration expenses decreased by 13.6% to US$8.6 million for the year ended December 31, 2018 from US$9.9 million for the year ended December 31, 2017, primarily due to higher dry hole expenses recorded in 2017.

### *Cost of Services*

Cost of services increased by 7.4% to US$5.7 million for the year ended December 31, 2018 from US$5.3 million for the year ended December 31, 2017, primarily due to higher operational activities from our security services company.

### *Total Cost of Sales and Other Direct Costs*

As a result of the foregoing, total cost of sales and other direct costs increased by 19.7% to US$586.1 million for the year ended December 31, 2018 from US$489.5 million for the year ended December 31, 2017.

### *Gross Profit*

Gross profit increased by 52.1% to US$632.2 million for the year ended December 31, 2018 from US$415.6 million for the year ended December 31, 2017. Gross profit margin increased to 51.9% for the year ended December 31, 2018 from 45.9% for the year ended December 31, 2017, primarily due to higher average oil and gas prices in 2018, MPI's 2018 full year contribution from electric power sales, and lower depreciation recognized in 2018. Gross profit margin is derived by dividing gross profit over total sales and other operating revenues.

### *Selling, General And Administrative Expenses*

Selling, general and administrative expenses increased by 9.0% to US$157.3 million for the year ended December 31, 2018 from US$144.3 million for the year ended December 31, 2017. This increase was primarily due to the full year consolidation of MPI in 2018, while in 2017 MPI's results were consolidated from October 3, 2017.

### *Finance Costs*

Finance costs increased by 34.5% to US$189.0 million for the year ended December 31, 2018 from US$140.6 million for the year ended December 31, 2017, primarily due to an increase in the average amount of indebtedness in 2018 as compared to 2017 and the full year consolidation of MPI's finance costs in 2018.

### *Finance Income*

Finance income decreased by 60.7% to US$12.7 million for the year ended December 31, 2018 from US$32.3 million for the year ended December 31, 2017, primarily due to there being no interest income earned from the shareholder's loan to AMIV earned in 2018, since the loan was converted in the beginning of 2018. In January 2018, approximately 50% of the shareholder loan was converted into equity in AMI, while the other 50% was converted into a non-interest bearing receivable from API.

### *Bargain Purchase*

In 2017, we recorded a bargain purchase gain of US$43.1 million, which was primarily due to the purchase of additional participating interest in Block A, Aceh. We did not record any bargain purchase in 2018.

### *Gain on Business Combination Achieved in Stages*

In 2017, we recorded gain on business combination achieved in stages of US$16.1 million as a result of remeasurement of our previous 49% equity interest in MPI at the fair value on the date of our acquisition of an additional 39.62% effective interest in MPI. We did not record any gain on business combination achieved in stages in 2018.

### *Income from Insurance Claim*

In 2017, we recorded income from cash receipt on an insurance claim of US$7.7 million. This claim was related to a 2011 gas flow incident where unintended gas flow occurred at the Lagan Deep-1 exploration well at the South Sumatera PSC. There was no insurance claim for the year ended 2018.

### *Share of Net Loss Of Associates and Joint Venture*

For the year ended December 31, 2018, our share of net loss of associates and joint venture was US$66.7 million compared to our share of net loss of associates and joint venture of US$37.0 million for the year ended December 31, 2017. The share of net losses in 2018 was primarily due to expenses at AMNT, as it accelerated the development of Phase 7. The share of net losses in 2017 was primarily due to our share of net losses of AMIV due to termination costs of hedging arrangements.

### *Loss on Impairment of Assets*

In 2018, we recorded loss of impairment of assets of US$2.2 million as compared to loss of impairment of assets of US$4.1 million for the corresponding period in 2017. In 2018, our loss on impairment of assets was primarily due to the recognition of allowance for impairment on property, plant and equipment and advances for MPI mini-hydro projects which had not yet obtained approval for the extension of their construction periods from PT Negara PLNDJB. In 2017, our loss on impairment of assets was primarily due to the recognition of allowance for impairment on oil and gas properties of Medco Lematang BV as we had increased our stake in Lematang PSC during a period of higher oil prices and revalued the asset after a decrease in oil prices.

### *Other Income*

Other income decreased by 55.1% to US$10.1 million for the year ended December 31, 2018 from US$22.6 million for the year ended December 31, 2017, which was primarily due to reversal of the previous year over-accrued liability of US$5.1 million and a decrease of management fees recognized from South Natuna Sea Block B.

### *Other Expenses*

Other expenses increased by 29.1% to US$18.6 million for the year ended December 31, 2018 from US$14.4 million for the year ended December 31, 2017, primarily due to an increase in foreign exchange losses related to receivables recorded in Rupiah.

### *Profit before Income Tax Expense from Continuing Operations*

As a result of the foregoing, our profit before income tax expense from continuing operations increased by 2.6% to US$202.2 million for the year ended December 31, 2018 from US$197.1 million for the year ended December 31, 2017.

### *Income Tax Expense*

Income tax expense from continuing operations increased by 42.3% to US$196.5 million for the year ended December 31, 2018 from US$138.1 million for the year ended December 31, 2017, primarily due to increases in deferred tax expense from PT Medco E&P Tomori Sulawesi (Senoro) and PT Medco E&P Natuna (South Natuna Sea Block B); which were caused by higher depreciation expenses recognized in the fiscal book compared with the commercial book, due to the difference in depreciation calculation method used for the PSC accounting regime (mostly using the double declining method) and the GAAP accounting regime (using unit of production method), and also an increase in deferred tax expense from MPI due to commercialization of Sarulla Project.

### *Profit for the year from Continuing Operations*

As a result of the foregoing, profit for the year from continuing operations decreased by 90.3%, to US$5.7 million for the year ended December 31, 2018 from US$59.0 million for the year ended December 31, 2017.

### *Loss After Income Tax Expense From Discontinued Operations*

In 2018, we recorded loss after income tax expense from discontinued operations of US$34.1 million compared to profit after income tax expense from discontinued operations of US$72.8 million for the corresponding period in 2017. In 2018, our loss after income tax expense from discontinued operations was primarily due to the recognition of loss on impairment of assets and loss on assets recognized at fair value less cost to sell from our divestment plan with respect to our United States blocks in 2018. In 2017, our profit after income tax expense from discontinued operations was primarily due to our recognition of the reversal of the prior year's provision for impairment of oil and gas properties of US$100.0 million related to our assets in Libya because of favorable changes in cost estimates of developing the oil and gas assets.

### *Profit (Loss) For the Year*

As a result of the foregoing, we recorded loss for the year of US$28.4 million for the year ended December 31, 2018, compared to profit for the year of US$131.8 million for the year ended December 31, 2017.

### *Total Comprehensive Income (Loss) For the Year*

For the year ended December 31, 2018, we recorded total comprehensive loss for the year of US$19.6 million, compared to total comprehensive income of US$189.6 million for the year ended December 31, 2017.

**Comparison of 2017 and 2016**

***Net Oil and Gas Sales***

Our net oil and gas sales increased by 50.4% to US$834.6 million for the year ended December 31, 2017 from US$554.9 million for the year ended December 31, 2016. The increase in net oil and gas sales was primarily due to increased sales volume, primarily due to the full year effect of our acquisition of interest in South Natuna Sea Block B in November 2016 and an increase in our average realized prices due to higher oil and gas prices. Our crude oil sales increased to 26.2 MBOPD for the year ended December 31, 2017 from 21.5 MBOPD for the same period in 2016. Our average realized prices for oil increased to US$51.5/barrel for the year ended December 31, 2017 from US$42.3/barrel for in 2016. Our gas sales increased to 273.4 BBTUPD for the year ended December 31, 2017 from 212.2 BBTUPD for the same period in 2016. Our average realized prices for natural gas increased to US$5.5/MMBTU for the year ended December 31, 2017 from US$4.4/MMBTU for the corresponding period in 2016, primarily due to the increase in oil prices which impacted the portion of our GSAs which are linked to oil prices.

***Electric Power Sales and Revenue from Related Services***

In 2017, we recorded sales from electric power sales and revenue from related services of US$67.5 million from MPI, which we began consolidating on October 3, 2017.

***Revenue from services***

Our revenues from services decreased by 57.2% to US$3.0 million for the year ended December 31, 2017 from US$7.0 million for the year ended December 31, 2016. The decrease was primarily due to a decrease in pipeline fee tariffs by PLN.

***Production and Lifting Costs***

Production and lifting costs were relatively stable with a slight increase at US$192.3 million and US$190.2 million for the years ended December 31, 2017 and 2016, respectively. The slight increase was mainly due to an increase in production and lifting costs from South Natuna Sea Block B, which we acquired in November 2016 which was partially offset by a decrease in operations and maintenance expenses and pipeline and transportation fees resulting from the implementation of cost efficiency measures.

***Depreciation, Depletion and Amortization***

Depreciation, depletion and amortization increased by 51.0% to US$160.6 million for the year ended December 31, 2017 from US$106.3 million for the year ended December 31, 2016, primarily due to depreciation of oil and gas assets from South Natuna Sea Block B, which we acquired in November 2016.

***Cost of Crude Oil Purchases***

Cost of crude oil purchases increased by 507.8% to US$80.9 million for the year ended December 31, 2017 from US$13.3 million for the year ended December 31, 2016, primarily due to additional crude oil purchases at South Natuna Sea Block B, which we acquired in November 2016.

***Cost of Electric Power Sales and Related Services***

For the year ended December 31, 2017, we recorded cost of electric power sales and related services of US$40.6 million from MPI, which we began consolidating on October 3, 2017.

### *Exploration Expenses*

Exploration costs increased by 67.4% to US$9.9 million for the year ended December 31, 2017 from US$5.9 million for the year ended December 31, 2016, primarily due to significantly higher dry hole expenses recognized in 2017.

### *Cost of Services*

Cost of services increased by 492.8% to US$5.3 million for the year ended December 31, 2017 from US$0.9 million for the year ended December 31, 2016, primarily due to increase in security services.

### *Total Cost of Sales and Other Direct Costs*

As a result of the foregoing, total cost of sales and other direct costs increased by 54.6% to US$489.5 million for the year ended December 31, 2017 from US$316.6 million for the year ended December 31, 2016.

### *Gross Profit*

Gross profit increased by 69.5% to US$415.6 million for the year ended December 31, 2017 from US$245.2 million for the year ended December 31, 2016. Gross profit margin increased to 45.9% for the year ended December 31, 2017 from 43.6% for the year ended December 31, 2016, primarily due to our increased revenues, particularly from South Natuna Sea Block B, which as a mature block carries higher margins, and higher oil prices. Gross profit margin is derived by dividing gross profit over total sales and other operating revenues.

### *Selling, General And Administrative Expenses*

Selling, general and administrative expenses increased by 64.2% to US$144.3 million for the year ended December 31, 2017 from US$87.9 million for the year ended December 31, 2016. This increase was primarily due to, among others, increased expenses for rental expenses, manpower supply, export expenses, salaries, wages and other employee benefits mostly relating to South Natuna Sea Block B, which we acquired in 2016, expenses under our Oman contract, which had a higher contribution to our revenue in 2017 compared with 2016, and expenses from the consolidation of MPI with effect from October 3, 2017.

### *Finance Costs*

Finance costs increased by 41.4% to US$140.6 million for the year ended December 31, 2017 from US$99.4 million for the year ended December 31, 2016, primarily due to our higher average amount of indebtedness in 2017 as compared to 2016.

### *Finance Income*

Finance income increased by 327.5% to US$32.3 million for the year ended December 31, 2017 from US$7.6 million for the year ended December 31, 2016, primarily due to interest income from the shareholder's loan to AMIV made in connection with the acquisition of our interest in AMNT.

### *Bargain Purchase*

For the year ended December 31, 2017, we recorded a bargain purchase gain of US$43.1 million, which primarily consisted of gains recorded from the purchase of our interest in Block A, Aceh. For the year ended December 31, 2016, we recorded a bargain purchase gain of US$551.7 million, which primarily consisted of

US$467.2 million gains recorded from the purchase of our interest in AMIV, while the others are gain from the acquisition of our interest in South Natuna Sea Block B and the acquisition of additional effective interests in Block A, Aceh and Lematang PSC.

***Gain on Business Combination Achieved in Stages***

In the year ended December 31, 2017, we recorded gain on business combination achieved in stages of US$16.1 million as a result of remeasurement of our pre-existing 49% equity interest in MPI at the fair value of the date of our acquisition of additional 39.62% effective interest in MPI. We did not record any gain on business combination achieved in stages in 2016.

***Income from Insurance Claim***

For the year ended December 31, 2017, we recorded income from cash receipt on an insurance claim of US$7.7 million. This claim was related to a 2011 gas flow incident where unintended gas flow occurred at the Lagan Deep-1 exploration well at the South Sumatera PSC. There was no insurance claim for the year ended 2018.

***Loss on assets recognized at fair value less cost to sell***

Loss on assets recognized at fair value less cost to sell for the year ended December 31, 2016 was US$11.9 million which related to our classification of the Bawean PSC as an asset held for sale. We did not record any loss on assets recognized at fair value less cost to sell in 2017.

***Share of Net Loss Of Associates and Joint Venture***

For the year ended December 31, 2017, our share of net loss of associates and joint venture was US$37.0 million compared to our share of net loss of associates and joint venture of US$27.0 million for the year ended December 31, 2016. The share of net losses in 2017 was primarily due to our share of net losses in AMIV from the cost of termination of hedging arrangements. The share of net losses in 2016 was primarily due to our share of net losses in AMIV acquisition costs of AMNT. This loss in 2016 was partially offset by our share of net income in MPI.

***Loss on Impairment of Assets***

For the year ended December 31, 2017, we recorded loss of impairment of assets of US$4.1 million as compared to a loss on impairment of assets of US$16.1 million for the year ended December 31, 2016. In 2016, our loss on impairment of assets was primarily because of changes in the recoverable value of our oil and gas properties due to the sharp decrease in oil prices during the year. In 2017, our loss on impairment of assets was primarily due to the recognition of allowance for impairment on oil and gas properties of Medco Lematang BV.

***Other Income***

Other income increased by 131.7% to US$22.6 million for the year ended December 31, 2017 from US$9.7 million for the year ended December 31, 2016, which was primarily due to a full year of management fees recognized from South Natuna Sea Block B, which we acquired in November 2016. For the year ended December 31, 2016, other income mainly consisted of cash receipts from VAT reimbursements of US$5.7 million.

***Other Expenses***

Other expenses increased by 124.2% to US$14.4 million for the year ended December 31, 2017 from US$6.4 million for the year ended December 31, 2016, primarily due to increase in foreign exchange losses.

*Profit before Income Tax Expense from Continuing Operations*

Our profit before income tax expense from continuing operations decreased to US$197.1 million for the year ended December 31, 2017 from US$565.4 million for the year ended December 31, 2016. The decrease was primarily due recognition of higher bargain purchase in 2016 and increase in finance cost in 2017, which were partially offset by our recognition of gain on business combination achieved in stages and increased gross profit in 2017.

*Income Tax Expense*

Income tax expense from continuing operations increased by 124.3% to US$138.1 million for the year ended December 31, 2017 from US$61.6 million for the year ended December 31, 2016, primarily due to the recognition of tax expenses from South Natuna Sea Block B.

*Profit for the year from Continuing Operations*

As a result of the foregoing, profit for the year from continuing operations decreased by 88.3%, to US$59.0 million for the year ended December 31, 2017 from US$503.8 million for the year ended December 31, 2016.

*Profit (Loss) After Income Tax Expense From Discontinued Operations*

In 2017, we recorded profit after income tax expense from discontinued operations of US$72.8 million compared to loss after income tax expense from discontinued operations of US$316.8 million for the corresponding period in 2016. In 2017, our profit after income tax expense from discontinued operations was primarily due to our recognition of the reversal of the prior year's provision for impairment of oil and gas properties of US$100.0 million related to our assets in Libya because of favorable changes in cost estimates of developing the oil and gas assets. In 2016, our loss after income tax expense from discontinued operation was primarily due to goodwill impairment and loss on impairment of our Tunisia and Libya assets recorded in 2016 with respect to assets held for sale.

*Profit For the Year*

As a result of the foregoing, we recorded a 29.5% decrease in profit for the year from US$131.8 million for the year ended December 31, 2017 to US$187.0 million for the year ended December 31, 2016.

*Total Comprehensive Income For the Year*

Total comprehensive income for the year decreased by 2.7% to US$189.6 million for the year ended December 31, 2017 from US$195.0 million for the year ended December 31, 2016.

**Liquidity and Capital Resources**

Our operations, capital expenditures and working capital requirements are primarily funded from cash generated from operations and from borrowings, both short-term and long-term, including banking facilities and bonds. As of September 30, 2019, we had available banking facilities of US$958.7 million, of which US$505.2 million was unutilized. Of these facilities, US$435 million represents financing for Block A, Aceh and Senoro development, of which US$96.0 million was unutilized as of September 30, 2019.

As of September 30, 2019, we had cash and cash equivalents of US$313.8 million (including US$51.6 million of MPI's cash and cash equivalents), which comprised cash and time deposits with maturity dates of not more than three months and which are not used as collateral and short term investments of

US$25.8 million. We also had restricted time deposits and cash in banks (current and non-current portion) of US$261.0 million (including US$24.8 million from MPI), which include US$226.4 million in escrow accounts and interest reserve account in Standard Chartered Bank — Singapore Branch and DBS Bank Ltd, which consisted of proceeds from the offering of US$400.0 million, US$500.0 million and US$650.0 million aggregate principal amount of guaranteed senior notes due in 2022, 2025 and 2026 by our subsidiaries, Medco Straits Services Pte. Ltd., Medco Platinum Road Pte. Ltd. and Medco Oak Tree Pte. Ltd., which has been used to repay debt, primarily consisting amounts owed under the IDR Shelf-Registered Bonds II Phases I, II, and III which matured in July, September and December 2019, respectively, and MTN V Phase I of 2016 which matured in November 2019 as well as pay for the Ophir Acquisition.

The following table presents our cash flow data for the years ended December 31, 2016, 2017 and 2018 and the nine months ended September 30, 2018 and 2019.

***Cash Flow Data***

| | For the Years Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | **2016** | **2017** | **2018** | **2018** | **2019** |
| | **(Restated)[1]** | **(Restated)[1]** | **(Restated)[1]** | **(Unaudited) (Restated)[1]** | |
| | | | **(US$ in millions)** | | |
| **Consolidated Statements of Cash Flows** | | | | | |
| Net Cash Provided by Operating Activities . . . . | 11.9 | 444.1 | 361.7 | 166.9 | 200.9 |
| Net Cash Used in Investing Activities . . . . . . . . | (567.3) | (242.9) | (266.7) | (210.9) | (245.5) |
| Net Cash Provided by (Used in) Financing Activities . . . . . . . . . . . . . . . . . . . . . . . . . . . . | 259.8 | 121.0 | (41.6) | (25.5) | (76.3) |

Note:

(1) The restated consolidated financial statements resulted from the classification of profit or loss accounts of certain subsidiaries previously included in "Continuing Operations" to "Discontinued Operations".

***Net Cash Provided by Operating Activities***

Nine Months ended September 30, 2019. Our net cash provided by operating activities was US$200.9 million primarily which comprise of cash receipts from customers of US$958.9 million, partially offset by cash paid to suppliers and employees of US$604.0 million and income tax paid of US$154.0 million.

Nine Months ended September 30, 2018. Our net cash provided by operating activities was US$166.9 million primarily which comprise of cash receipts from customers of US$810.1 million, partially offset by cash paid to suppliers and employees of US$515.5 million and income tax paid of US$127.8 million.

Year ended December 31, 2018. Our net cash provided by operating activities was US$361.7 million primarily which comprise of cash receipts from customers of US$1,220.1 million, partially offset by cash paid to suppliers and employees of US$689.6 million and income tax paid of US$168.8 million.

Year ended December 31, 2017. Our net cash provided by operating activities was US$444.1 million, primarily which comprise of cash receipts from customers of US$1,070.4 million, partially offset by cash paid to suppliers and employees of US$459.3 million and income tax paid of US$167.0 million.

Year ended December 31, 2016. Our net cash provided by operating activities was US$11.9 million, primarily which comprise of cash receipts from customers of US$493.4 million, partially offset by cash paid to suppliers and employees of US$461.2 million and income tax paid of US$20.3 million. Net cash provided by operating activities in 2016 reflects a significant year on year increase in trade receivables, which primarily relate to sales from the South Natuna Sea Block B, which we acquired in November 2016.

### *Net Cash Used in Investing Activities*

Nine Months ended September 30, 2019. Our net cash used in investing activities was US$245.5 million, which was primarily due to the acquisition of subsidiaries for US$297.1 million, which represents Ophir and additional interests in MPI and Oman and additions to oil and gas properties of US$83.1 million mostly consisting of additions in Block A, Aceh. These were partially offset by, among others, proceeds from disposal of subsidiaries of US$83.5 million and receipt of other receivables of US$136.2 million.

Nine Months ended September 30, 2018. Our net cash used in investing activities was US$210.9 million, which was primarily due to additions to oil and gas properties of US$147.4 million for Block A, Aceh and South Natuna Sea Block B development drilling and additions to concession financial assets of US$41.7 million. These were partially offset by, among others, interest received during the period of US$8.0 million.

Year ended December 31, 2018. Our net cash used in investing activities was US$266.7 million, which was primarily due to additions to oil and gas properties of US$228.5 million for Block A, Aceh and South Natuna Sea Block B development drilling; additions to exploration and evaluation assets of US$13.0 million which represent exploration spending for Block A; and additions to concession financial assets of US$56.8 million. These were partially offset by, among others, proceeds from disposal of subsidiaries of US$16.9 million and interest received during the year of US$14.0 million.

Year ended December 31, 2017. Our net cash used in investing activities was US$242.9 million in 2017, which was primarily due to additions to oil and gas properties of US$183.8 million for South Natuna Sea Block B and Block A, Aceh development drilling and the acquisition of business net of cash acquired of US$93.2 million for PT Saratoga Power (now PT Medco Power Internasional) of US$66.8 million and KrisEnergy of US$26.4 million. These were partially offset by, among others, proceeds from redemption of short term investments of US$43.0 million, which was previously managed by banks.

Year ended December 31, 2016. Our net cash used in investing activities was US$567.3 million, which was primarily due to: (i) investments in joint ventures of US$404.0 million for the acquisition of our interest in AMIV; (ii) US$261.5 million for acquisition of subsidiaries, holding interests in South Natuna Sea Block B and the WNTS, and for subsidiaries holding interests in Lematang PSC, South Sokang PSC, and Cendrawasih VII; and (iii) additions to oil and gas properties of US$77.0 million consisting of additions to oil and gas properties for South Natuna Sea Block B and Block A, Aceh development drilling. These were partially offset by, among others, proceeds from redemption of short term investments of US$218.9 million previously managed by banks.

### *Net Cash Flow Provided by (Used in) Financing Activities*

Nine Months Ended September 30, 2019. Our net cash used in financing activities was US$76.3 million, which primarily consisted of: (i) US$794.6 million repayment of bank loans, (ii) US$174.5 million payment of financing charges, (iii) US$173.2 million repayment of other long-term debt (primarily for payment of Bonds of Salamander Energy plc and Rupiah Shelf Registered Bonds II Phase I and II) and (iv) US$5.4 million placement of restricted time deposits and cash in bank. These were partially offset by: (i) US$378.0 million proceeds from additional bank loans and (ii) US$696.2 million proceeds from other long-term debt (primarily from the 2026 Notes).

Nine Months Ended September 30, 2018. Our net cash used in financing activities was US$25.5 million, which primarily consisted of: (i) US$636.2 million repayment of bank loans, (ii) US$148.3 million payment of financing charges, (iii) US$148.1 million repayment of other long-term debt (primarily for payment of Rupiah Shelf Registered Bonds I Phase II) and (iv) US$46.5 million settlement of derivative liability due to settlement of hedging arrangements with respect to our IDR bonds. These were partially offset by: (i) US$300.7 million proceeds from additional bank loans and (ii) US$684.5 million proceeds from other long-term debt (primarily from the 2025 Notes).

Year ended December 31, 2018. Our net cash used in financing activities was US$41.6 million, which primarily consist of: (i) US$839.3 million repayment of bank loans, (ii) US$180.8 million payment of financing charges, (iii) US$214.1 million repayment of other long-term debt (primarily for payment of Rupiah Shelf Registered Bonds I Phase II), (iv) US$62.3 million settlement of derivative liability due to settlement of hedging arrangements with respect to our IDR bonds, (v) US$57.8 million placement of restricted time deposits and cash in bank. These were partially offset by: (i) US$546.9 million proceeds from additional bank loans, and (ii) US$763.3 million proceeds from other long-term debt (primarily from the 2025 Notes).

Year ended December 31, 2017. Our net cash provided by financing activities was US$121.0 million, which was primarily due to (i) US$370.6 million proceeds from additional bank loans, (ii) US$567.1 million proceeds of other long-term debt from 2022 Notes, and (iii) US$191.6 million proceeds from share issuance. These were partially offset by: (i) US$468.2 million repayment of bank loans, (ii) US$240.7 million repayment of other long-term debt, (iii) US$124.7 million payment of financing charges, (iv) US$120.0 million increases in restricted time deposits and cash in bank mainly coming from DBS Bank Ltd related to 2022 Notes, and (v) US$60.0 million settlement of derivative liability of hedging arrangements with respect to our IDR and SGD bonds.

Year ended December 31, 2016. Our net cash provided by financing activities was US$259.8 million, which was primarily due to: (i) US$330.0 million proceeds from additional bank loans, and (ii) US$267.1 million proceeds of other long-term debt from Rupiah Shelf Registered Bonds II Phases I, II and III. These were partially offset by (i) US$168.4 million repayment of bank loans, (ii) US$86.5 million payment of financing charges and (iii) US$79.9 million repayment of other long-term debt.

***Indebtedness***

The following table shows the amount of the Company's total consolidated short-term and long-term debt outstanding as of December 31, 2016, 2017 and 2018 and September 30, 2018 and 2019:

| | As of December 31, | | | As of September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| | (US$ in millions) | | | | |
| **Short-term debt** | | | | | |
| Short-term bank loans | 16.0 | 42.0 | 40.0 | 70.0 | 70.0 |
| Current maturities of long-term bank loans and obligation | 395.0 | 365.3 | 362.5 | 338.7 | 259.4 |
| **Long-term debt (net of current maturities)** | | | | | |
| Bank loans | 1,009.6 | 1,367.2 | 1,012.3 | 956.5 | 934.0 |
| Loan from non-bank financial institutions | — | 27.3 | 10.9 | 10.6 | — |
| Rupiah bond[(1)] | 316.9 | 348.6 | 447.6 | 451.2 | 472.7 |
| US Dollar bond | — | 384.7 | 867.8 | 866.4 | 1,503.9 |
| Singapore Dollar bond | 68.3 | — | — | — | — |
| Medium-term notes | 127.5 | 54.0 | 66.5 | 54.4 | 66.8 |
| **Total debt** | **1,933.3** | **2,589.1** | **2,807.5** | **2,747.8** | **3,306.8** |

Note:

(1) Rupiah amounts were converted to U.S. dollars at an exchange rate: of 0.000074 US$ per Rupiah, 0.000074 US$ per Rupiah, 0.000069 US$ per Rupiah and 0.000071 US$ per Rupiah for amounts as of December 31, 2016, 2017 and 2018 and September 30, 2019, respectively.

Our long-term debt outstanding as of December 31, 2016, 2017 and 2018 and September 30, 2018 and 2019 consisted of both local and foreign currency obligations. Under the terms and conditions of these long-term obligations, we are subject to various restrictive covenants, which restrict us from undertaking certain actions without prior approval of lenders.

### Contractual Obligations, Including Long-term Debt

The following table discloses our contractual and other obligations, excluding contingent liabilities, that were outstanding as of September 30, 2019 and the effect such obligations are expected to have on liquidity and cash flow in future periods.

| | Payments Due By Period | | | | |
|---|---|---|---|---|---|
| | Total | 2019 | 2020 | 2021 | After 2021 |
| | (US$ in millions) | | | | |
| Bank Loans | 1,170.0 | 70 | 142.5 | 334.5 | 622.7 |
| Loan from a non-bank financial institution | 11.2 | — | 11.2 | — | — |
| Long-term Debt Obligations (Bonds) | 2,088.2 | 17.4 | 45.8 | 276.1 | 1,748.9 |
| Long-term Debt Obligations (Medium-term notes) | 122.2 | 55.0 | — | 67.2 | — |
| **Total** | **3,391.4** | **142.4** | **199.5** | **677.8** | **2,371.6** |

Note: Amounts outstanding are presented excluding unamortized discounts, and the amounts due in 2019 represent amounts due in the last three months of 2019.

In addition, remaining proceeds from the 2025 Notes and 2026 Notes have been earmarked for the repayment of some of our debt listed above.

### Capital Expenditures

The following table sets forth the Company's capital expenditures for the years ended December 31, 2016, 2017 and 2018 and the nine months ended September 30, 2018 and 2019.

| | For the Years Ended December 31, | | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2018 | 2019 |
| | (US$ in millions) | | | | |
| Maintenance Capex | 159.1 | 25.2 | 46.1 | 23.9 | 42.9 |
| Development Drilling | 68.0 | 51.3 | 22.3 | 17.5 | 31.4 |
| Major Projects | 109.8 | 165.2 | 163.9 | 129.5 | 19.8 |
| Exploration Program | 9.1 | 18.4 | 35.9 | 27.9 | 13.3 |
| Others | 0.1 | 5.5 | 60.5 | 4.1 | 75.2 |
| **Total** | **346.1** | **265.5** | **328.7** | **202.8** | **182.7** |

Note: The amounts shown represents our expenditure based on our working interest in the project.

Development and exploration drilling accounts for a majority of the capital expenditure for exploration and development activities.

We intend to fund our capital expenditure through a combination of cash generated from the cost recovery portion of our oil and gas sales pursuant to the terms of our PSCs, cash on hand, and equity and debt financing.

The cost recovery mechanism in each of our producing Indonesian PSCs allows us to recover capital expenditure within a relatively short period of time. Our capital expenditure for maintenance of equipment and facilities and for drilling is fully recoverable through the cost recovery mechanism under our PSCs. Our capital expenditure at major projects is expected in the short to medium term to be funded primarily through debt and cash from operations. Our capital expenditure for major projects will primarily be focused on the development of Bualuang Phase 4B, Meliwis and at South Natuna Sea Block B (Buntal and infill drilling). Our total annual non-debt funded capital expenditures necessary to maintain our production levels are expected to remain below US$300 million per year over the next five years, which should allow for a reduction in gearing. Within this total capital expenditure, we intend to keep expenditures for discretionary exploration and managing declines in production at an average of US$60 million per year. We plan to do this by phasing expenditures on our developments and making carefully selected investments to offset declines in production. We cap our discretionary exploration capital expenditure and focus on infrastructure-led, low risk targets and we fund this capital expenditure primarily through cash from operations.

Our ability to obtain adequate financing to satisfy our capital expenditure and debt service requirements may be limited by our financial condition, results of operations and the liquidity of international and domestic financial markets. We may make additional capital expenditures as opportunities or needs arise. In addition, we may increase, reduce or suspend planned capital expenditures or change the timing and use of capital expenditures from what is currently planned in response to market conditions or for other reasons. The above budgeted amounts do not include any investments we may make in acquisitions of oil and gas properties or other downstream projects, if any.

Our ability to maintain and grow our revenues, net income and cash flows depends upon continued capital spending. Our capital expenditure plans are subject to a number of risks, contingencies and other factors, such as oil and gas prices, geological factors, market demand, acquisition opportunities and the success of our drilling program, some of which are beyond our control. We adjust our capital expenditure plans and investment budget periodically, based on factors deemed relevant by us. Therefore our actual future capital expenditures and investments are likely to be different from its current planned amounts, and such differences may be significant.

**Off-Balance Sheet Arrangements**

We have various contractual obligations, some of which are required to be recorded as liabilities in our consolidated financial statements, including long-term and short-term loans. We have certain additional commitments and contingencies that are not recorded on our consolidated balance sheet but may result in future cash requirements. These off-balance sheet arrangements are not generally required to be recognized as liabilities on our balance sheet.

*Production Sharing Arrangements*

| | | | | PSA | |
|---|---|---|---|---|---|
| **Subsidiary** | **Block Ownership** | **Country** | **Term** | **Local Government** | **Subsidiary** |
| Medco Oman LLC. | Karim Small Fields | Oman | 25 years | 88% of profit from total production | 12% of profit from total production; |
| Medco International Venture Ltd. | Area 47 | Libya | 30 years | 86.3% of profit from total production | 13.7% of profit from total production |
| Medco Arabia Ltd | Block 56 | Oman | 3 years exploration period | 75% of profit from total production for oil and 70% for gas | 25% of profit from total production for oil and 30% for gas |
| Medco Yemen Malik Ltd. | Block 9 | Yemen | 25 years | 70%-80% range of profit oil (for production of 25,000 up to 100,000 BOPD) | 20%-30% of profit oil (for production of 25,000 up to BOPD) |

| Subsidiary | Block Ownership | Country | Term | PSA | |
|---|---|---|---|---|---|
| | | | | Local Government | Subsidiary |
| Medco Ventures International (Barbados) Limited | Block Bir Ben Tartar | Tunisia | 30 years | 65% of profit from total production | 35% of profit from total production |
| Medco Ventures International (Barbados) Limited | Block Cosmos | Tunisia | 50 years | 20% of profit from total production | 80% of profit from total production |
| Medco Ventures International (Barbados) Limited | Block Yasmin | Tunisia | 30 years | 20% of profit from total production | 80% of profit from total production |
| Medco Ventures International (Barbados) Limited | Block Sud Remada | Tunisia | 13 years | 65% of profit oil (shareable) | 35% of profit oil (shareable) |
| Medco Ventures International (Barbados) Limited | Block Jenein | Tunisia | 14 years | 70% of profit oil (shareable) | 30% of profit oil (shareable) |
| Medco Sahara Limited | Block Adam | Tunisia | 30 years | 50% of profit from total production | 50% of profit from total production |
| Medco Sahara Limited | Block Borj El Khadra | Tunisia | 25 years | 50% of profit from total production | 50% of profit from total production |
| Salamander Energy (Malaysia) Limited | Block PM-322 | Malaysia | 27 years (1 year study + 3 years exploration + 3 years extended exploration + 20 years development & production) | **Oil** : 30%-70% pre-cumulative threshold volume (30 mmbls per oil field) and 60%-90% after-cumulative threshold volume (30 mmbls per oil field)<br><br>**Gas :** 20%-70% pre-cumulative threshold volume (750 bcf per gas field) and 60%-90% after-cumulative | **Oil** : 30%-70% pre-cumulative threshold volume (30 mmbls per oil field) and 10%-40% after-cumulative threshold volume (30 mmbls per oil field)<br><br>**Gas :** 30%-80% pre-cumulative threshold volume (750 bcf per gas field) and 10%-40% after-cumulative |

| Subsidiary | Block Ownership | Country | Term | PSA: Local Government | PSA: Subsidiary |
|---|---|---|---|---|---|
| | | | | threshold volume (750 bcf per gas field) | threshold volume (750 bcf per gas field) |
| Ophir Tanzania (Block 1) Limited . . . . . . | Block 1 | Tanzania | 11 years for the current Exploration License (4 years initial exploration period + 4 years first extension + 3 years second extension) with additional 25 years once the Development License is obtained | **Oil :** 40%-60% of profit oil depending on increments of daily total production rate<br>**Gas :** To be determined once there is a commercial discovery of non-associated natural gas | **Oil :** 40%-60% of profit oil depending on increments of daily total production rate<br>**Gas :** To be determined once there is a commercial discovery of non-associated natural gas |
| Ophir Tanzania (Block 1) Limited . . . . . . | Block 4 | Tanzania | 11 years for the current Exploration License (4 years initial exploration period + 4 years first extension + 3 years second extension) with additional 25 years once the Development License is obtained | **Oil :** 42.5%-62.5% of profit oil depending on increments of daily total production rate<br>**Gas :** To be determined once there is a commercial discovery of non-associated natural gas | **Oil :** 37.5%-57.5% of profit oil depending on increments of daily total production rate<br>**Gas :** To be determined once there is a commercial discovery of non-associated natural gas |

| Subsidiary | Block Ownership | Country | Term | PSA |
|---|---|---|---|---|
| Ophir Mexico Offshore Exploration, S.A. DE C.V. . . . . . . . . . . . . . . . . . . . . | Block 5 | Mexico | 35 years | - Contract fee during exploration phase<br>- Royalty determined for each type of hydrocarbon which percentage is calculated based on a specific formula<br>- 26.91% total production |
| Ophir Mexico Operations, S.A. DE C.V. . . . . . . . . . . . . . . . . . . . . . . . . . . | Block 10 | Mexico | 35 years | - Contract fee during exploration phase |

| Subsidiary | Block Ownership | Country | Term | PSA |
|---|---|---|---|---|
| | | | | - Royalty determined for each type of hydrocarbon which percentage is calculated based on a specific formula<br>- 20.00% total production |
| Ophir Mexico Operations, S.A. DE C.V. . . . . . . . . . . . . . . . . . . . . . . . . . . . | Block 12 | Mexico | 35 years | - Contract fee during exploration phase<br>- Royalty determined for each type of hydrocarbon which percentage is calculated based on a specific formula<br>- 20.00% total production |
| Ophir Myanmar (Block AD-3) Limited . . . . . . . . . . . . . . . . . . . . . . . . | Block A5 | Myanmar | 27 years (1 year study + 3 years exploration + 3 years extended exploration + 20 years development & production) | - 55%-90% of profit both for oil and gas depending on production daily rate and water depth<br>- 12.5% royalty from total net production |
| Ophir Myanmar (Block AD-3) Limited . . . . . . . . . . . . . . . . . . . . . . . . | Block AD-3 | Myanmar | 28 years (2 year study + 3 years exploration + 3 years extended exploration + 20 years development & production) | - 55%-85% of profit both for oil and gas depending on production daily rate and water depth<br>- 55%-85% of profit for gas depending on production daily rate and water depth<br>- 12.5% royalty from total net production |
| Medco Energi (Thailand) Bualuang Limited . . . . . . . . . . . . . . . . . . . . . . . . | Block B8/38 | Thailand | 20 years from production start (October 23, 2005) | - 5%-15% royalty based on monthly gross sale and disposal volume |
| Medco Energi (Thailand) E&P Limited | | | | - Special remuneration benefit (windfall tax) |

| Subsidiary | Block Ownership | Country | Term | PSA |
|---|---|---|---|---|
| Santos Petroleum B.V. . . . . . . . . . . . . . . | Block 12W | Vietnam | 25 years for oil and 30 years for gas | **Oil:**<br>- 4%-20% royalty of net oil production depending on net daily production rate<br>- 4% export duty<br>- 10%-60% of profit oil depending on quarterly average net oil production by incremental tranches in barrels per day<br><br>**Gas:**<br>- 0%-6% royalty of net gas production depending on net daily production rate<br>- 0% export duty<br>- 10%-60% of profit gas depending on quarterly average net gas production by incremental tranches in barrels per day with conversion rate of 6,000 SCF as 1 barrel equivalent |

The total remaining commitment for exploration expenditures relating to the above contracts as of September 30, 2019 is US$75.8 million.

*Gas Supply Agreements*

Our significant GSAs as of September 30, 2019, are as follows.

| Company / Counter-party | Date of Agreement | Commitment | Contract Year |
|---|---|---|---|
| **PT Medco E&P Indonesia** | | | |
| PT Perusahaan Gas Negara (Persero) Tbk | January 1, 2019 as lastly amended on July 11, 2019 | To supply gas of 30 BBTUD ramp down to 20 BBTUD (joint contract with PT Medco E&P Lematang) in Sumatera and Java Region with total contract quantity of 10,960 BBTU from South Sumatera PSC (Total joint supply contract quantity 27,400 BBTU) | Approximately 3 years since the gas in the date or until the total contract quantity of joint supply has been fully supplied, whichever occurs first. |
| PT Pertamina (Persero) | January 1, 2019 through Mutual Agreement dated December 21, 2018 | To supply gas of 0.20 MMSCFD with total contract quantity of 123.40 MMSCF | September 8, 2020 or until the total contract quantity has been fully supplied, whichever occurs first |
| PT Pupuk Sriwidjaja Palembang | August 7, 2007, last amended by the dated February 23, 2018 | To supply gas at an average of 45 BBTUD. | The GSA expires on the earlier of January 1, 2019 or until total contract quantity has been fully supplied. |
| PT Mitra Energi Buana | July 24, 2006, last amended on June 8, 2018 | To supply gas with total gas contract quantity amounted to 30,119 BBTU. | The GSA expires on the earlier of December 31, 2027 or until the total contracted quantity has been fully supplied. |
| PT MEPPO-GEN | October 17, 2014, amended on November 13, 2018 | To supply 10-16 BBTUD of gas with total gas contract quantity amounting to 35,246 BBTU. | The GSA expires on the earlier of December 31, 2027 or until total contract quantity has been fully supplied. |
| Perusahaan Daerah Pertambangan dan Energi for electricity | August 10, 2011, as amended on December 4, 2012 | To supply and sell 3 BBTUD of gas. | Expires on August 31, 2020 or until the total contract quantity has been fully supplied, whichever occurs first. |
| PT Sarana Pembangunan Palembang Jaya (SP2J) | April 13, 2010, last amended on November 25, 2015 | To supply gas with total contract quantity of 450.93 BBTU. | The GSA expired on January 1, 2019 or until such quantity has been fully supplied, whichever occurs first. |

| Company / Counter-party | Date of Agreement | Commitment | Contract Year |
|---|---|---|---|
| PT Pertamina (Persero) | July 31, 2019 | To supply and sell 0.2 BBTUD | The GSA expires on December 8, 2026 |
| PT PLN Tarakan for Electricity in Gunung Belah Tarakan | May 12, 2010, last amended on January 16, 2018 | To supply and sell gas with total contract quantity of 10,134 BBTU. | Expires on December 31, 2021 or when the total contract quantity has been fully supplied, whichever occurs first. On January 1, 2017, this commitment was transferred to PT Perushaan Listrik Negara (Persero). |
| Perusahaan Daerah Pertambangan dan Energi for Gas Fuel in South Sumatra | August 4, 2009, last amended on July 4, 2019. | To supply and sell 0.5 BBTUD of gas, with a total contract quantity of 1,606.5 BBTU. | Expires on the earlier of February 7, 2023 and the date on which the total contract quantity has been fully supplied. |
| Perusahaan Daerah Mura Energi | August 4, 2009, last amended August 9, 2018 | To supply 1.35-2.1 BBTUD of gas with total contract quantity of 6,039 BBTU of gas. | Expires on December 31, 2027 or until the total contract quantity has been fully supplied, whichever occurs first. |
| Perusahaan Daerah Kota Tarakan (assigned to PT PGN (Persero) Tbk) | October 30, 2018 (assigned to PGN from Perusahaan Daerah Kota Tarakan effective since January 8, 2016) | To supply gas to meet the needs of households in Tarakan of 0.2 BBTUD. | Five years from effective assignment date (January 8, 2016). |
| PT Perusahaan Gas Negara (Persero) Tbk | May 4, 2018 | To supply gas to meet the needs of households in Kabupaten Musi Banyuasin of 0.25 BBTUD with total contract quantity of 871 BBTU. | The GSA expires on the earlier of July 20, 2027 or until the total contract quantity has been fully supplied whichever occurs first. |
| PT Pertamina (Persero) | Mutual Agreement (Kesepakatan Bersama) dated January 30, 2018 | To supply and sell gas of 0.25 MMSCFD, with a total contract quantity of 864.25 MMSCF. | The GSA expires on July 20, 2027 or until the total contract quantity has been fully supplied, whichever occurs first. |

| Company / Counter-party | Date of Agreement | Commitment | Contract Year |
|---|---|---|---|
| PD Petrogas Ogan Ilir | May 25, 2016 last amendment of agreement dated November 6, 2017. This agreement has been terminated on July 26, 2018 | To supply gas with total gas contract quantity of 1,148 BBTU of gas | December 31, 2019 or until the quantity of the contract has been fully supplied, whichever occurs first. |
| PT Perusahaan Listrik Negara (Persero) | September 19, 2017 | To supply and sell gas of 20-25 BBTUD (joint supply with MEPL) total contract quantity of 50,932.8 BBTU from South Sumatera PSC. (Total joint supply quantity 70,260 BBTU). | January 31, 2027 or until such quantity has been fully supplied, whichever occurs first. |
| **PT Medco E&P Lematang** | | | |
| PT Perusahaan Listrik Negara (Persero) | March 21, 2017, as last amended on September 19, 2017 | To supply and sell gas of 8-25 BBTUD (joint supply with MEPI), with a total contract quantity of 19,327.2 BBTU from Lematang PSC and 50,932.80 BBTU from South Sumatra PSC. | Expires on January 31, 2027 or when the total contract quantity has been fully supplied, whichever occurs first. |
| PT MEPPO-GEN | November 13, 2018 | To supply 10-16 BBTUD of gas with total gas contract quantity amounting to 12,805.3 BBTU. | December 31, 2027 or until total contract quantity has been fully supplied, whichever occurs first. |
| PT Perusahaan Gas Negara (Persero) Tbk | January 1, 2019 through Mutual Agreement dated December 27, 2018; last amendment through Gas Sales Purchase dated July 11, 2019 | To supply gas of 30 BBTUD ramp down to 20 BBTUD (joint contract with PT Medco E & P Indonesia (MEPI)) in Sumatera and Java Region with total contract quantity of 16,440 BBTU from Lematang PSC. (Total joint supply contract quantity 27,400 BBTU). | Approximately 3 (three) years since the gas in date or until the total contract quantity of joint supply has been fully supplied, whichever occurs first |
| PT Pupuk Sriwidjaja Palembang | April 2, 2018 through mutual agreement | To supply and sell gas of 5 BBTUD with total contract quantity of 1,375 BBTU. | This agreement has ended on December 31, 2018. |

| Company / Counter-party | Date of Agreement | Commitment | Contract Year |
|---|---|---|---|
| **PT Medco E&P Malaka** | | | |
| PT Pertamina (Persero) | January 27, 2015 | To supply 58 BBTUD of gas with a total volume of 198 TBTU. | Expires up to 13 years from the date of first gas delivery, or upon the earliest of fulfillment of the total amount of the contract, the gas no longer having any economic value, or the expiration of Block A, Aceh PSC. |
| **PT Medco E&P Tomori** | | | |
| PT Donggi Senoro LNG | January 22, 2009, as amended on December 13, 2010 | Supply 277.8 BBTUD (equivalent to 250 MMSCFD) of gas. | Expires upon the earlier of 15 years following the commencement of commercial operations of the LNG plant, or total contract quantity has been delivered, or expiry of the Senoro-Toili PSC. |
| PT Panca Amara Utama | March 13, 2014, last amended on January 11, 2018 | To supply 248,200 MMSCF of gas. | Expires when such quantity in the agreement has been fully supplied or upon the termination of the Senoro-Toili PSC (December 3, 2027), whichever occurs first. |
| PT Perusahaan Listrik Negara (Persero) | February 6, 2018 | To supply and sell gas, with a total contract quantity of 15.63 TBTU. | The GSA expires on the earlier of December 4, 2027 or when the total contract quantity has been fully supplied, whichever occurs first. |
| **PT Medco E&P Simenggaris** | | | |
| PT Perusahaan Listrik Negara (Persero) | October 17, 2014 | To supply gas at 0.5 MMSCFD with total Contracts value of 805 MMSCF. | Expires five years following the first gas date or upon the fulfillment of the total contract quantity, whichever occurs first. |
| PT Perusahaan Listrik Negara (Persero) | February 6, 2018 | To supply 8 BBTUD of gas with total contract commitment of 21.6 TBTU | At the time when total contract quantity in the agreement has been fully supplied or until the expiration of the right of utilization of the contract area, |

| Company / Counter-party | Date of Agreement | Commitment | Contract Year |
|---|---|---|---|
| | | | February 23, 2028, whichever occurs first. |
| **Medco E&P Natuna Ltd** | | | |
| PT Pertamina (Persero) | January 15, 1999 | To supply gas with PT Pertamina (Persero) for SembCorp Gas Pte Ltd with the total contract quantities 2,625 TBTU. | Expires 27 years following the Start Date or upon the fulfillment of the total amount of the contract, whichever occurs first |
| PT Pertamina (Persero) | March 28, 2001 amended on May 8, 2012 | To supply gas to PT Pertamina (Persero) for Petroliam Nasional Berhad (Petronas) with the total contract quantities 1,648 TBTU. | Expires 20 years or whichever occurs first as stated in the agreement. |
| **Ophir Indonesia (Sampang) Pty Ltd** | | | |
| PT Indonesia Power | July 19, 2003 | To supply gas from Oyong Field (Sampang Block PSC) to PT Indonesia Power with quantity of 13.9 BBTUD. | Until December 31, 2020 |
| PT Indonesia Power | November 26, 2010 | To supply gas from Wortel Field (Sampang Block PSC) to PT Indonesia Power with quantity of 24-15 BBTUD. | Until December 31, 2020 |
| **Ophir Indonesia (Madura Offshore) Pty Ltd** | | | |
| PT Perusahaan gas negara | May 31, 2005 | To supply gas from Maleo Field (Madura Offshore Block PSC) to PGN with quantity of 23.3 BBTUD. | Until August 2023 |
| PT PLN (Persero) | May 15, 2013 | To supply gas from Peluang Block to PT PLN (Persero) with quantity of 23.8 BBTUD. | Until December 2019 (3rd amendment under negotiation) |
| **Ophir Indonesia Bangkanai Limited** | | | |
| PT PLN (Persero) | June 28, 2011 | To supply gas to PT PLN (Persero) with quantity of 20,327 BBTUD and total volume of 130 TBTU. | Until TCQ delivered or until PSC expired, whichever occurs first. |

**Contingent Liabilities**

As of December 31, 2018, Medco Energi US LLC was contingently liable in the amount of US$13.8 million for bonds issued on Medco Energi US LLC's behalf to the United States Bureau of Energy Management and previous sellers of the assets. On February 7, 2019, Medco Energi US LLC entered into an Asset Purchase and Sale Agreement with Sanare Energy Partners LLC to sell its Main Pass assets for US$150,000. As part of Medco

Energi US LLC's sale of its Main Pass assets, Sanare Energy Partners LLC has replaced the foregoing surety obligations and the United States Bureau of Ocean Energy Management is in the process of administratively changing the surety obligations to reflect the replacement.

### Inflation

The Indonesia rate of inflation was 3.0% in 2016, 3.6% in 2017 and 3.1% in 2018 based on the consumer price index. Inflation in Indonesia has not significantly impacted the Company's results of operations in recent years.

### Seasonality

Indonesia's wet and dry seasons do not have a material impact on the demand and prices for crude oil and natural gas. During the annual rainy season, typhoons and heavy rain can temporarily limit our ability to continue our oil and gas development activities and reduce AMNT's mine production.

### Quantitative and Qualitative Disclosure About Market Risks

Our primary market risk exposures are to fluctuations in oil and gas prices.

#### *Commodity Price Risk*

We are exposed to fluctuations in prices of crude oil which is a commodity whose price is determined by reference to international market prices. International oil prices are volatile and this volatility has a significant effect on our revenues and asset values. Due to the cost recovery provided to us in our production sharing arrangements, previously we did not materially hedge market risk resulting from fluctuations in oil and gas prices. Currently, our policy is to hedge a maximum of 15% of production, with up to 7% in put structures and the remainder in collar structures. See "Risk Factors — Risks Relating to our Industries — The volatility of prices for crude oil could adversely affect the Group's financial condition and results of operations." AMNT's business is subject to fluctuations in market prices for gold and copper.

#### *Operating Risks*

We are exposed to operating risks, including reservoir risk, risk of loss of oil and gas and natural calamities risk in respect of all its installations and facilities. We have, however, insured our installations and facilities. We do not have insurance coverage for lost profits. See "Business — Operating Hazards, Insurance and Uninsured Risks" and "Risk Factors — Risks Relating to our Industries — Our operations are subject to significant operating hazards."

#### *Foreign Exchange Rate Risk*

Most of the major contracts entered into by us have historically been denominated in U.S. dollars, and it is anticipated that this will continue to be the case. Such contracts include PSCs, JOBs, agreements with joint venture partners, major construction contracts, drilling leases, service contracts, oil and gas sales contracts and transportation agreements. Consequently, substantially all of our revenues are denominated in U.S. dollars, and a majority of our cash expenses are also denominated in U.S. dollars. Certain expenses comprising the salaries of Indonesian employees, local vendors, local rentals and interest income/expense are normally paid in Rupiah. Given the relatively small currency mismatch, we believe that our exposure to the currency risk of an appreciation of the Rupiah is limited. However, since MPI currently reports its results in Rupiah, fluctuations of the Rupiah against the U.S. dollar affect our accounting for MPI's net income.

We are also exposed to foreign exchange rate risk resulting from fluctuations in exchange rates in the translation of Rupiah-denominated loans and U.S. dollar-denominated purchases of diesel, which is later sold in

Rupiah-denominated sales. As of September 30, 2019, we had U.S. dollar denominated loans of US$2.8 billion and Rupiah-denominated loans of Rp. 7.8 trillion (equivalent to US$549.4 million), and of such Rupiah-denominated loans, Rp. 5.5 trillion are subject to U.S. dollar swaps (US$409.8). For the nine months ended September 30, 2019, 89.8% of revenue were U.S. dollar-denominated and 44.8% of our expenditures were denominated in non-U.S. dollars (primarily denominated in Rupiah, Vietnam dong and Thai Baht).

Our policy for foreign exchange management, swap and hedging was designed to minimize currency risk and maintain cost effectiveness and has the following objectives: ensure that all transactions in currencies other than U.S. dollars (being our functional currency) are sufficiently covered on a timely basis; ensure that we are not adversely affected by foreign exchange, commodity price, interest rate and general market movement in a way that might seriously threaten our viability or undermine the confidence of our customers, staff or debt and equity holders; reduce the actual or anticipated cost of financing; and optimize swap and hedging transactions by maintaining cost effectiveness of such activities and to fairly weigh the cost of risk with possible saving in going unhedged or by engaging in natural hedging.

### *Interest Rate Risk*

We are exposed to interest rate risk resulting from fluctuations in interest rates on our short-term and long-term indebtedness. Upward fluctuations in interest rates increase the cost of new borrowings and the interest cost of our outstanding floating rate indebtedness. As of September 30, 2019, 11.6% of our long-term indebtedness have interest at floating rates which, in the case of U.S. dollar debts, principally are determined in reference to LIBOR and, in the case of Rupiah debts, in reference to the banks' prime lending rate. It is part of our policy to protect any risks related to foreign currency, interest rate, and commodity price using financial hedging instruments. In addition to obtaining cash flow certainty, we enter into cross currency swap transactions to mitigate foreign currency risk for any non-U.S. dollar debts, and interest rates swap to fixed any floating interest rates exposures. We apply hedge accounting to any hedging transactions that meet the criteria for hedge accounting to minimize the volatility of marked-to-market movement on income. Under this policy, we are allowed to enter into hedging transactions for up to 50% of underlying exposures, with special approval required for larger exposures. We monitor the positions through marked to market report distributed by the hedge counterparties.

## Critical Accounting Policies and Practices

Our critical accounting policies and practices are those that we believe are the most important to the portrayal of our financial condition and results of operations and that require subjective judgment on behalf of management. In many cases, the accounting treatment of a particular transaction is specifically dictated by generally accepted accounting principles. However, in the preparation of the consolidated financial statements we use judgment to make certain estimates, assumptions and decisions regarding accounting treatments. We believe the policies and practices described below are its critical accounting policies and practices.

### *Purchase Price Allocation and Goodwill Impairment*

Acquisition accounting requires extensive use of accounting estimates to allocate the purchase price to the reliable fair market values of the assets and liabilities purchased, including intangible assets. Under PSAK No. 48 (Revised 2014), "Impairment of Assets", goodwill is not amortized and is subject to an annual impairment testing. Impairment testing is performed when certain impairment indicators are present. In case of goodwill, such asset is subject to annual impairment test and whenever there is an indication that an asset may be impaired; management uses its judgment in estimating the recoverable value and determining the amount of impairment.

### *Bargain Purchase*

Bargain purchase represents the excess of the estimated fair value of the net assets acquired over the cash paid to acquire the assets. The difference is recognized directly in the income statement. Primarily as a result of the acquisition of our interest in AMIV in 2016, we recorded a bargain purchase gain of US$467.2 million in 2016, reflecting that the purchase price we paid for our share in AMIV was less than the assessment of the fair value of our share of AMIV's assets based on a valuation report from an independent third-party valuer registered with the OJK. In addition, we recorded a bargain purchase gain of US$79.5 million in the nine months ended September 30, 2019 in connection with the Ophir Acquisition, reflecting that the purchase price we paid for Ophir was less than our assessment of the fair value of Ophir's assets.

***Impairment of Non-Financial Assets***

Assets that have an indefinite useful life are not subject to amortization but tested annually for impairment, or more frequently if events or changes in circumstances indicate that the carrying amount may not be recoverable based on the fair value assessment using the cash flow projection method that we conduct on a regular basis. When value in use calculations are undertaken, management must estimate the expected future cash flows from the asset or cash-generating unit and choose a suitable discount rate in order to calculate the present value of those cash flows. For the purpose of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows.

Proved reserves represent quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations. Reserves in undeveloped locations may be classified as "proved reserves" provided that (a) the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive; and (b) interpretation of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled proved locations.

Our historical impairment of oil and gas properties were made where we estimated the recoverable amount of reserves based on value in use using cash flow projections. The calculation of value in use for oil and gas properties cash generating units is mostly sensitive to the following assumptions: (a) lifting, (b) prices, (c) discount rates, and (d) operating and capital expenses. Changes to the assumptions used by the management to determine the recoverable amount, in particular the discount rate, can have significant impact on the result of the impairment assessment.

***Reserve Estimates***

The accuracy of proved reserve estimates depends on a number of factors, assumptions and variables such as: the quality of available geological, technical and economic data, results of drilling, testing and production after the date of the estimates, the production performance of the reservoirs, production techniques, projecting future rates of production, the anticipated cost and timing of development expenditures, the availability for commercial market, anticipated commodity prices and exchange rates.

As the economic assumptions used to estimate reserves change from year to year, and additional geological data are generated during the course of operations, estimates of reserves may change from year to year. Changes in reported reserves may affect the Group's financial results and financial position in a number of ways, including:

- Depreciation and amortization which are determined on a unit of production basis, or where the useful economic lives of assets change.
- Decommissioning, site restoration and environmental provision may change where changes in estimated reserves affect expectations about the timing or cost of these activities.
- The carrying value of deferred tax assets/liabilities may change due to changes in estimates of the likely recovery of the tax benefits.

### *Asset Abandonment and Site Restoration Obligations*

We have recognized provisions for asset abandonment and site restoration obligations associated with our oil and gas wells, facilities and infrastructure. In determining the amount of the provision, assumptions and estimates are required in relation to discount rates and the expected cost to dismantle and remove all the structures from the site and restore the site. We intend to fulfill these obligations in accordance with the terms of our PSCs or contract areas.

## RISK FACTORS

*Our business, financial condition and results of operations could be materially and adversely affected by any of these risks.*

### RISKS RELATING TO OUR BUSINESS AND OPERATIONS

**We are dependent on our ability to produce from and/or develop existing reserves, replace existing reserves and find and develop additional reserves for our core oil and gas business.**

We must explore for, find, develop or acquire new reserves to replace those depleted or sold in order to grow or maintain our current levels of production. We face challenges in sustaining production growth due to the maturation and depletion of oil and gas properties. Revenue from Rimau, South Sumatra, Lematang and the South Natuna Sea Block B PSCs, each of which is entering a mature stage with economic lives of five to 10 years, contributed 10%, 12%, 3% and 28% of our net oil and gas sales for the year ended December 30, 2018, respectively and 8%, 10%, 1% and 23% of our net oil and gas sales for the nine month period ended September 30, 2019, respectively. In addition, through the Ophir Acquisition we acquired interests in fields in production decline, including the Chim Sáo field under the Block 12W PSC, which is a mid-life field at the early stages of production decline and the Madura Offshore PSC and the Sampang PSC in Indonesia which are in decline.

We cannot assure the success of our current or future exploration and development activities or that we will be successful in acquiring new reserves. The decision to explore or develop a property will depend in part on geophysical and geological analyzes and engineering studies, the results of which may be inconclusive or subject to varying interpretations. Exploration activities are subject to numerous risks, including the risk that no commercially viable oil or natural gas accumulations will be discovered. Furthermore, if we are unable to find or acquire additional reserves, we would not be able to sustain total production nor grow our core business, and this could have material and adverse effect on our business, prospects, financial condition and results of operations.

The cost of drilling, completing and operating wells is also uncertain. Drilling may be curtailed, delayed or canceled as a result of many factors, including weather conditions, government requirements and contractual conditions, shortages of or delays in obtaining equipment, reductions in product prices and limitations in the market for products. Geological uncertainties and unusual or unexpected formations and pressures may result in dry wells. Our exploration and production activities may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or the recovery of drilling, completion or operating costs. In addition, we face substantial competition in the discovery and acquisition of reserves, which requires substantial investment.

Production in the Madura Offshore PSC and the Sampang PSC is in decline. The development of the Meliwis gas field and other exploration prospects is key to extending economic production from these Indonesian assets. The final investment decision for the Meliwis gas field development, along with the signing of a gas sale and purchase agreement, was taken in February 2019. A gas sale and purchase agreement (replacing the current gas sale and purchase agreement) for the Maleo gas field which is also located within the Madura Offshore PSC, which resulted in increased prices from mid-2019, received SKK Migas approval in November 2019 and is targeted to sign in 2020. In addition, for the Sampang PSC, the Oyong gas sale and purchase agreement will expire in December 2020 and can be extended until 2022 or until the period reflecting production of proven, probable and possible natural gas reserve of Oyong field with Government and SKK Migas approval. The Wortel gas sale and purchase agreement is expected to expire in November 2020, but may extend beyond 2020 depending on delivery of gas above the TCQ. Although the Paus Biru development in the Sampang PSC drilled in 2018 resulted in gas discovery and we are currently preparing a plan of development for submission to the regulator, the 2027 license expiry increases the risk related to the currently planned Paus Biru development due to a potentially insufficient remaining license term.

***Our indebtedness could adversely affect our financial condition.***

We have substantial indebtedness and expect to incur further indebtedness. Covenants in agreements governing debt that we may incur in the future may materially restrict our operations, including our ability to incur debt, pay dividends, make certain investments and payments, and encumber or dispose of assets. Our high degree of leverage and ability to incur additional debt may have important consequences to prospective investors, including the following:

- we may have difficulty satisfying our obligations under indebtedness and, if we fail to comply with these requirements, an event of default could result;
- we may be required to dedicate a substantial portion of our cash flow from operations to required payments on indebtedness, thereby reducing the availability of cash flow for working capital, capital expenditures and other general corporate activities;
- covenants relating to indebtedness may limit our ability to obtain additional financing for working capital, capital expenditures and other general corporate activities;
- covenants relating to indebtedness may limit our flexibility in planning for, or reacting to, changes in our business and the industries;
- we may be more vulnerable than our competitors to the impact of economic downturns and adverse developments in our business; and
- we may be placed at a competitive disadvantage against any less leveraged competitors.

Any of these factors could have a material adverse effect on our business, financial condition, results of operations, prospects and ability to satisfy our debt obligations.

***We face risks related to third parties with whom we partner, with respect to certain of our assets.***

We have a significant minority interest in AMNT, which operates a copper and gold mine in Sumbawa. Because we do not control AMNT, we do not control decisions relating to its operations and strategy, which could adversely affect our ability to obtain benefits from our investment. There can be no assurance that the other shareholders in AMNT will not take actions collectively or otherwise that are detrimental to our interests.

In addition, a number of our oil and gas blocks have other interest holders, including government entities and a number of our power projects have other interest holders. These types of relationships involve special risks associated with the possibility that partner(s) may have economic or business interests or goals that are inconsistent with ours; take or omit to take actions contrary to our instructions, requests, policies or objectives, good corporate governance practices or the law; be unable or unwilling to fulfill their obligations under the relevant agreements; have disputes with us as to the scope of their responsibilities; and/or have financial difficulties. For example, our involvement in the downstream sector is through PT Donggi Senoro LNG (“DSLNG”), a joint venture company established in 2007 by a consortium consisting of PT Medco LNG Indonesia (a wholly owned subsidiary of our Group), Mitsubishi Corporation and KOGAS through their joint venture Sulawesi LNG Development Ltd., and Pertamina through its subsidiary PT Pertamina Hulu Energi. Within this scheme, DSLNG purchases gas, operates the LNG processing plant, and markets LNG to international customers. We have an 11.1% interest in DSLNG. DSLNG has certain banking facilities that require certain of its shareholders to fulfill certain requirements or reach certain milestones by August 28, 2020 (subject to extension as provided under applicable agreements relating to DSLNG) (the “Completion Longstop Date”). Although we have complied with our obligations under the agreement to date, we understand that one of our partners anticipated being unable to meet certain requirements and that DSLNG was able to obtain an extension of Completion Longstop Date from DSLNG’s lenders to August 2020. However, there can be no assurance that our partners will meet their obligations in the future, and if our partners do not meet their obligations, DSLNG may be considered in default on its indebtedness, which could materially and adversely affect our downstream operations and upstream operations at the Senoro gas field. We have provided a completion guarantee with respect to such indebtedness in proportion to our 11.1% ownership in DSLNG, and we cannot assure you that we will not be liable pursuant to such guarantee up to the DSLNG completion date.

***Our business is subject to significant government regulation.***

Oil and gas companies operating in Indonesia are highly regulated. The key terms and conditions applicable to us under Indonesian regulations include cost recovery arrangements and the DMO. For every barrel produced, an oil and gas company that operates under a PSC is entitled to recover costs pertaining to the exploration and production activities carried out during the year. The cost recovery portion of the annual net entitlement varies with the level of cost incurred, including capital investment for exploration, development and production, annual operating expenses and the realized prices of oil and gas. The DMO specifies the amount of production that must be sold domestically, which can be at lower prices than could be obtained from selling elsewhere.

In addition, oil and gas companies are subject to regulation by governments throughout the world. These regulations typically include the requirement to obtain permits to export products. Compliance with government regulations is required to ensure that these permits are, for example, granted, renewed or extended. In the case of exporting pipeline gas, for example, a quarterly permit renewal is required in Indonesia. An inability to obtain the necessary permits may affect exploration and production interests, the costs of safety and health and environmental controls and restrictions on drilling and production. We are also subject to the risk of nationalization, expropriation or cancelation of contract rights by governments. We operate in several countries and are therefore exposed to risks associated with the laws and regulations of each of these countries. Furthermore, through the Ophir Acquisition, we have acquired oil and gas assets in Thailand, Vietnam, Malaysia, Mexico and Tanzania. Our operations in these countries are subject to significant regulations and we may not be as successful at complying with such regulations or managing relationships with regulators in new jurisdictions as we have been in Indonesia.

AMNT's copper and gold mining is subject to significant regulation. In 2014, the Government issued new regulations pertaining to the export of copper concentrate that contain potentially restrictive conditions in respect of obtaining an export permit and impose a new export duty (the "2014 Regulations").

The Batu Hijau mine was temporarily shut down from June 2014 through September 2014 due to an inability to export copper concentrate, and AMNT's predecessor and its majority shareholder filed claims against the Government at the International Centre for Settlement of Investment Disputes in July 2014. However, AMNT's predecessor withdrew its case in August 2014, and following the withdrawal, AMNT's predecessor and the government entered into a Memorandum of Understanding in September 2014 in which, among other things, AMNT's predecessor agreed to pay higher royalties and certain export duties and the government agreed to issue permits to allow it to export and sell copper concentrates. The government then issued several six-month export permits commencing in September 2014, March 2015 and November 2015.

In 2017, the Government through MEMR issued MEMR Regulation No. 5 of 2017 as amended by MEMR Regulation No. 28 of 2017 on the Amendment to the MEMR Regulation No. 5 of 2017 on the Increasing Value Added Minerals Through domestic Mineral Refinery and Purification Activities (the "MEMR 5/2017") which removed a provision in the previous government regulation that allowed contract of work ("COW") holders to export processed minerals, and also mandates that COW holders convert their COW to a Special Mining Business License (*Izin Usaha Pertambangan Khusus*, or "IUPK") and refine their minerals domestically. Further, in February 2017, under its new ownership, AMNT adopted the Government's IUPK mining permit, which has preserved all economic conditions in the original COW. In February 2017, the Government issued a twelve-month export permit to AMNT. Future export permits will be subject to the government's assessment of progress on AMNT's commitments to comply with MEMR 5/2017, which include the requirement to build an in-country smelter no later than five years after the issuance of MEMR 5/2017. AMNT is currently developing a smelter and has appointed a third party to conduct front-end engineering design. In 2018, the MEMR issued MEMR Regulation No. 25 of 2018 on Mining of Minerals and Coal, as lastly amended by MEMR Regulation No. 11 of 2019 (the "MEMR 25/2018") which revoked the MEMR 5/2017. The MEMR 25/2018 include among other, provisions requiring that a minimum of 90% of the proposed work plan be designated for the construction of smelters and progress evaluations every six months. If the evaluation results state that the progress of the smelter does not reach the minimum, the export permit will be revoked. In addition, an administrative fine of 20% of the cumulative value of offshore mineral sales can be imposed.

The Government's regulations pertaining to the export of copper concentrate could, notwithstanding the accommodations made by AMNT, result in an inability of AMNT to export copper concentrate or to incur additional financial obligations, which could adversely impact our future operating and financial results. In addition, AMNT is required to apply for renewals of certain other key permits related to Batu Hijau (such as wastewater permit and explosion utilization permit). If AMNT is unable to renew its permits, including the export permit or other key permits, then such failure could result in an adverse impact on AMNT's Batu Hijau operations and may adversely impact our business, prospects, financial condition and results of operations.

The power business in Indonesia is highly regulated and certain regulations restrict the price that can be charged for power as well as place other restrictions on the sale of power, which can limit our ability to earn revenue. Regulations also affect the tendering process for new projects and any changes in the future to such regulations could affect our ability to tender for new projects. Furthermore, the business is influenced by factors beyond our or our partner's control, such as the entrance into the market by new market participants, prices, the supply gas, and operating risks inherent in the industry. Any reduction in the prices received for power could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***The oil and gas reserves data in this document are only estimates and the actual production, revenue and expenditures achievable with respect to our reserves may differ from such estimates; there are no recent reserve estimations or assessments available for a significant portion of our reserves; and even for blocks where there are recent third-party reserves estimations or assessments, we have not attached these reports to this document.***

This document includes estimates of certain of our proved reserves, proved and probable reserves and proved and probable and possible reserves. There are no recent estimations or assessments or no available estimations or assessments for the Senoro-Toili (Tiaka field, which is Senoro-Toili's oil field), the Tarakan PSC and for our international blocks, and the reserves estimations have been derived based on prior reserves estimations or assessments which are not recent. Certain reserves figures presented in this document are derived based on reserves estimations or assessments by GCA as of December 31, 2017 for the Lematang PSC (Singa field); as of September 30, 2018 for South Natuna Sea Block B; as of December 31, 2018 for Rimau PSC, South Sumatra PSC and for Block A, Aceh, as of October 31, 2018 for the Senoro Toili (Senoro Gas Field). We have not previously sought or otherwise obtained their consent for other disclosures, including in our annual reports. Our estimates of reserves at our blocks as at any date which is more recent than the date of the most recent reserve estimations or assessments for the applicable block have been derived by deducting production at the block, without accounting for any reserves appreciation or depreciation, since the dates of the respective estimations or assessments. However, there can be no assurance that a more recent reserves estimation or assessment conducted would result in estimates of the available reserves at these blocks which are consistent with our internal estimates of such reserves.

Even with respect to reserves figures presented in this document that are derived based on independent third-party reserves estimations or assessments (namely, the reports of GCA as of December 31, 2017 for the Lematang PSC (Singa field); as of September 30, 2018 for South Natuna Sea Block B; as of December 31, 2018 for Block A, Aceh, Rimau PSC and South Sumatra PSC, and as of October 31, 2018 for the Senoro Toili (Senoro Gas Field), we have not attached the reports relating thereto to this document. Accordingly, investors will not have access to such reports provided by these independent consultants, which reports include additional information that may be useful in evaluating the reserves information relating to these blocks.

On August 2, 2019, the MEMR issued the MEMR Regulation No. 7 of 2019 on Management and Use of Oil and Gas Data (the "MEMR 7/2019"). MEMR 7/2019 replaced the procedures relating to the management and utilization of oil and gas data which was previously addressed under the MEMR Regulation No. 27 of 2006 on Management and Use of Data Obtained from General Survey, Exploration and Exploitation of Oil and Gas as amended by The Ministry of Energy and Mineral Regulation No. 29 of 2017 on the Licenses for Oil and Gas Business Activities. MEMR 7/2019 requires any person that discloses any "data" (as defined therein) relating to oil and gas reserves to obtain consent from the MEMR. The MEMR Regulation does not specify the type of reserves data or information, or reserves report, disclosure that requires consent from the MEMR. Failure to comply with this requirement to obtain consent from the MEMR could result in sanctions of up to one year of imprisonment or fines of up to Rp. 10 billion. As a public company, under the OJK and IDX Regulations, Medco Energi is required to release its audited financial statements and an annual report as well as other material information. These documents include or may include reserves data and information relating to our operations. In compliance with the OJK and IDX Regulations, Medco Energi has disclosed reserves data and information from time to time in its audited financial statements and annual reports and other disclosures. In relation to this requirement, Medco Energi has received consent from the Director General of Oil and Gas to disclose reserves data in its annual reports, financial statements and offering documents. Medco Energi's financial statements as of September 30, 2019 have been disclosed on the IDX website and been made publicly available on January 6, 2020. For the purposes of this document, we have included reserves data and information consistent with disclosures in Medco Energi's financial statements as of September 30, 2019 that have been publicly released in accordance with IDX requirements. Although such information has been made public, MEMR may take the view that the inclusion of reserves data in this document requires a separate consent and has been made without obtaining their consent as may be required under the MEMR Regulation and impose penalties or sanctions on us, which could have an adverse effect on us.

***Determining estimates of reserves is an inexact activity and, accordingly, there can be no assurance that our reserves data accurately reflects actual reserves or will not change. In addition, the basis on which we estimate our reserves differs from SPE-PRMS guidelines.***

Determination of reserves estimates is an inexact interpretive activity generally based upon SPE-PRMS guidelines and definitions which require estimators to make uncertain forecasts of future production and to analyze incomplete technical and commercial data. There often exist professional interpretive differences of SPE-PRMS guidelines and reserves classification between companies, independent petroleum engineering consultants and operators. This is often evidenced by different reported reserves between consortium members of the same exploration or producing block. Such differences may include assigning volumes to the categories of proved, probable or possible reserves, based on interpretation of guidelines or on views of the commercial viability of a given oil or gas reserve, at a particular point in time.

There is no assurance that we, independent petroleum engineering consultants or other operators will not change our or their views or interpretations of such guidelines or change our or their interpretation on the commercial viability of given reserves, thus causing such reserves to be reclassified into another category under SPE-PRMS guidelines or other similar guidelines. Accordingly, there can also be no assurance that the reserves estimates that we have recorded at these blocks accurately reflect the currently available reserves at these blocks.

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. The reserves data set forth in this document represent estimates determined by independent petroleum engineering consultants according to current industry practice (where reserves estimations or assessments are applicable), or our own internal review. In general, estimates of economically recoverable oil and gas reserves are based upon a number of variable factors and assumptions, such as geological and geophysical characteristics of the reservoirs, historical production performance from the properties, the quality and quantity of technical and economic data, prevailing oil and gas prices applicable to a company's production, extensive engineering judgments, the assumed effects of regulation by Government agencies and future operating costs. All such estimates involve uncertainties, and classifications of reserves are only attempts to define the degree of likelihood that the reserves will result in revenue for us. For those reasons, estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. In addition, such estimates can and will be subsequently revised as additional pertinent data becomes available prompting revision. Actual reserves may vary significantly from such estimates. To the extent that actual production is lower than the estimated reserves, our business, prospects, financial condition and results of operations are likely to be materially and adversely affected.

The estimates of gross working interest reserves set out in this document, with respect to our reserves, reflect reserves attributable to our effective working interest under the applicable contractual arrangement before consideration of PSC or concession terms. This is a different approach to the method stipulated under SPE-PRMS guidelines, which state that a producer's net entitlement to reserves should be estimated on the basis of the applicable contract terms taking into account project costs and profits. We believe that our approach reflects a common practice in our industry in Indonesia. Our approach may result in higher gross working interest reserves compared to such reserves as estimated under SPE-PRMS guidelines. Estimates of gross working interest reserves are also significantly affected by many factors, including (but not limited to) sales prices, production rates and capital and operating expenses prevailing as of the time such reserves are determined, as well as cost recovery provisions affecting the Government's share of such reserves and the portion of Government take payable to the Government as owner of the reserves. Such estimates may change materially from period to period even in the absence of any new geological information.

***Estimates of proven and probable gold and copper reserves are uncertain and the volume and grade of ore actually recovered may vary from estimates.***

The reserves stated in this document represent the amount of gold and copper that are estimated at December 31, 2018 that could be economically and legally extracted or produced at the time of the reserve determination. Such reserves are calculated based on a competent persons report as of December 31, 2018 prepared by a reputable third party consultant. We have not attached the competent persons report to this document. Accordingly, investors will not have access to such report, which report includes additional information that may be useful in evaluating the gold and copper reserves information in this document. Estimates of proved and probable reserves are subject to considerable uncertainty. Such estimates are, to a large extent, based on the prices of gold and copper and interpretations of geologic data obtained from drill holes and other exploration techniques, which data may not necessarily be indicative of future results. Producers use feasibility studies to derive estimates of capital and operating costs based upon anticipated tonnage and grades of ore to be mined and processed, the predicted configuration of the ore body, expected recovery rates or metals from the ore, the costs of comparable facilities, the costs of operating and processing equipment and other factors. Actual operating and capital cost and economic returns on projects may differ significantly from original estimates. Further, it may take many years from the initial phases of exploration until commencement of production, during which time, the economic feasibility of production may change.

In addition, if the price of gold or copper declines from recent levels, if production costs increase or recovery rates decrease, or if applicable laws and regulations are adversely changed, we can offer no assurance that the indicated levels of recovery will be realized or that mineral reserves can be profitably mined or processed. If AMNT determines that certain of its ore reserves have become uneconomic, this may ultimately lead to a reduction in aggregate reported reserves. The foregoing could cause AMNT to revise its business plans or make asset impairments. Consequently, if AMNT's actual mineral reserves are less than current estimates, AMNT's results would be materially and adversely affected, which in turn would materially and adversely affect our business, prospects, financial condition and results of operations, which could in turn affect its ability to pay dividends to us.

***Failure or delay by SKK MIGAS, our counterparties or us to comply with the terms of PSCs or other contracts under which we hold our working interests, and the failure to receive SKK MIGAS and other government approvals on a timely basis, could adversely affect us.***

SKK MIGAS currently regulates Indonesia’s petroleum resources on behalf of the Government. SKK MIGAS enters (and prior to it, BP MIGAS had entered) into production sharing contracts and other forms of cooperation contracts with private sector energy companies, such as us (or in respect of pre-existing production sharing contracts, as the Government contract counterparty of private sector energy companies) whereby such companies explore, develop and market oil and gas in specified areas in exchange for a percentage interest in the production from the blocks in the applicable contract area. To the best of our knowledge, as of the date of this document, we believe we and our partners have been in compliance with the terms of our PSCs.

Most of our reserves are attributable to PSCs. The PSCs in Indonesia to which we are a party contain requirements regarding quality of service, capital expenditures, legal status of the contractors, restrictions on transfer and encumbrance of assets and other restrictions. While there is no specific regulation under Indonesian law which requires the enforcement of a pledge of interests in oil and gas companies that control, directly or indirectly, interests in a PSC, to be approved by SKK MIGAS, we believe that such enforcement and transfer of interests will, as a matter of policy and market practice, require the approval of SKK MIGAS. Any failure by us or any private counterparty to comply with the terms of our PSCs could result, under certain circumstances, in the revocation or termination of such arrangements. Such an action by SKK MIGAS or Pertamina against us could have a material adverse effect on us. Furthermore, SKK MIGAS may fail to comply with the terms of PSCs. In addition, we must obtain approval from SKK MIGAS for substantially all material activities undertaken with respect to our PSCs, including acquisitions, divestments, exploration, development, production, drilling and other operations, sale of oil or natural gas and the hiring or termination of personnel. The failure to obtain such approvals or delays in obtaining such approvals, or conditions imposed in connection with the grant of such approvals, would have an adverse impact on us. As part of these PSCs, we finance such activities and facilities and equipment and recover our costs from the sales of the production, if there is successful production, in accordance with the terms of the PSCs. Our business and results of operations are substantially dependent on our relationship with SKK MIGAS and our counterparties, and any adverse change to these relationships may have a material adverse effect on our business, prospects, financial condition and results of operations.

Furthermore, our oil and gas operations outside of Indonesia including Vietnam and Thailand are subject to significant regulation and we and our partners need to comply with the terms of the PSCs or other arrangements under which we hold our working interests. A number of our major assets outside of Indonesia are operated by joint venture partners or have joint venture partners with veto rights over certain decisions. Our ability to influence these operating (and non-operating) partners may be limited. A failure by us or our partners to comply with the terms of PSCs or other arrangements under which we hold our working interests could materially and adversely affect our or our investments’ business, prospects, financial condition and results of operations.

***The price paid to us under the GSA for Block A, Aceh may be lowered by the Government.***

Pursuant to Presidential Regulation No 40 of 2016 on the Determination of Gas Sales Price and MEMR Regulation No. 16 of 2016 on the Procedures in Determining the use and Price of Natural Gas, the Government may require us to reduce the gas sale price under our GSA with PT Pertamina (Persero) for the supply of gas from Block A, Aceh, from US$9.45/MMBTU to US$7.03/MMBTU. We have received legal advice that, under relevant regulations, any such reduction in price should require the Government to absorb any loss to us which would result from such price reduction by compensating us for that loss. In addition, we could reserve our rights under the terms of such GSA. Discussions between the parties have resumed following the appointment of a new Indonesian Ministerial cabinet in late October 2019; however, the outcome of such discussions is uncertain, and if the gas sale price is adjusted and the Government ultimately refuses or fails to absorb any such losses, the uncompensated reduction of the gas sale price under such GSA may have a material adverse effect on our business, results of operations and financial condition.

***We have in the past, and may again in the future, engage in acquisitions, which would be subject to risks.***

We have in the past, and may in the future, continue to pursue strategic acquisitions that will expand our oil and gas business and our activity in the oil and gas industry generally, including transactions such as the Ophir Acquisition, or in our other lines of business, such as power and mining. We may not be able to identify opportunities or complete acquisitions or may be unable to obtain financing on acceptable terms or at all, or if we consummate acquisitions, we may not realize any anticipated benefits from such acquisitions. For international acquisitions in jurisdictions where we do not operate, we may face new and different regulatory regimes, environmental requirements and other regulations with which we need to comply. In addition, we are required to comply with covenants under certain of our existing funding agreements which may require written notification to and/or prior consent from the lenders in the event that we would like to consummate any acquisitions should such acquisition fall within the criteria for the covenants. The process of integrating acquired operations into our existing operations may result in unforeseen issues and may require financial resources that would otherwise be available for the ongoing development or expansion of our existing operations. Future acquisitions could result in the incurrence of additional debt, contingent liabilities and increased capital expenditures, interest and other costs, any of which could have a material adverse effect on our business, prospects, financial condition and results of operations by reducing our net profit or increasing our total liabilities, or both.

In addition, we have in the past recorded bargain purchase gains on certain of our acquisitions and in the future may recognize bargain purchase gains or acquisition of goodwill. For example, we recorded a bargain purchase gain of US$467.2 million in 2016 with respect to our investment in PT Amman Mineral Investama ("AMIV"), reflecting that the purchase price we paid for our share in AMIV was less than the assessment of the fair value of our share of AMIV's assets based on a valuation report from an independent third-party valuer registered with the OJK. We have also recognized bargain purchase gains from the acquisition of our interest in South Natuna Sea Block B and the increases in our effective interests in Block A, Aceh and Lematang PSC. In addition, we recorded a bargain purchase gain of US$79.5 million in the nine months ended September 30, 2019 in connection with the Ophir Acquisition, reflecting that the purchase price we paid for Ophir was less than the assessment of the fair value of Ophir's assets. Bargain purchase gains and goodwill that we acquire are subject to impairment testing with respect to whether the value of the asset is recoverable, and therefore to the extent such assets decrease in value, we could record impairment losses in the future.

***We may experience difficulties in expanding into new businesses and geographic areas.***

We have already expanded, and may in the future again expand, our operations or invest in new businesses. For instance, in 2016, we acquired our interest in AMNT, which operates a copper and gold mine in Sumbawa. In addition, we have in the past expanded into jurisdictions outside of Indonesia, including among others, Thailand, Vietnam, Oman, Libya, Tunisia, and Yemen. We are also expanding our O&M business activities in the power sector. Prior to making our investment in AMNT, neither we nor our joint venture partner had experience in the gold and copper mining sector. We have also entered into different businesses from time to time which we have subsequently exited or otherwise hold for sale for portfolio rationalization, such as The Energy Building. We may have limited or no prior investment or operational experience in areas into which we expand in the future, and there can be no assurance that we will be successful in investing or operating in such areas, or that such activities will not detract the financial and personnel resources from our core business.

***A majority of our oil and gas assets and operations is concentrated in Indonesia, all of MPI's operations are in Indonesia and AMNT's copper and gold mining operations are located within one contract area, which geographically exposes us to risks and hazards in those areas.***

The concentration of our operations within Indonesia exposes us to the possibility that events could adversely affect the development or production of oil and/or gas, power generation or mining operations in limited geographic areas. Adverse developments with respect to the areas in which we or AMNT operate could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***The development and expansion of our projects under development involve construction and financing risks that could lead to increased expenses and a loss of opportunities.***

As part of our ongoing business, we participate in development projects. Such development projects involve many risks, including:

- the breakdown or failure of plant equipment or processes;
- the inability to obtain required governmental permits and approvals in time;
- work stoppages and other industrial actions by employees or contractors;
- opposition from local communities and special-interest groups;
- engineering and environmental problems;
- construction delays;
- inability to obtain working capital; and
- unanticipated cost overruns.

If we experience any of these or other problems, we may not be able to derive income and cash flows from the projects and investments in a timely manner, in the amounts expected or at all.

Furthermore, the projects we are developing and in which we invest require substantial capital outlay and a long gestation period before we realize any benefits or returns on investments. For example, with respect to our investment in Senoro-Toili, first gas discoveries were made at Senoro-Toili in 1999, we signed a GSA in 2009, the final investment decision was made in 2011, and gas deliveries began in 2014. More recently, in July 2017, we entered into a facility agreement for up to US$360 million for the development of Block A, Aceh (which has subsequently been refinanced), where first gas production and gas deliveries have begun in 2018. We also plan to focus on Senoro-Toili, where in 2018, 1,658 BCF of gross 100% field 1C contingent resources were estimated or assessed by GCA and where we are now evaluating potential development scenarios and preliminary engineering for Senoro-Toili Phase II and the investment decision with respect to the preferred development scenario is expected to be made in the second half of 2020. Concurrently, we are continuing with the development of the Ophir Group's projects under development, including Bualuang Phase IV in Thailand and Meliwis in Indonesia. Development of Senoro-Toili Phase II and these Ophir blocks will require additional financing. We cannot assure you that we will be able to obtain such financing on acceptable terms or at all.

In addition, the time and some of the costs required in completing a project may be subject to substantial increases due to factors including shortages, or increased competition or market prices, for materials, equipment, skilled personnel and labor; adverse weather conditions; natural disasters; labor disputes with contractors; accidents; changes in government priorities and policies; changes in market conditions; delays in obtaining the requisite licenses, permits and approvals from the relevant authorities; and other unforeseeable problems and circumstances. We cannot assure you that our projects will be completed on time, within budget or at all, or that their development period will not be affected by any or all of these factors. Any of the foregoing could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***We are engaged in the power generation and gold and copper mining business through MPI and AMI, respectively, which have required capital contributions and have substantial indebtedness.***

Through MPI, we are engaged in the power generation sector in Indonesia. Through our current 39.4% interest in AMI, which controls and has an economic interest in all of the shares in AMNT, we have an investment in a copper and gold mine in Sumbawa. AMI is accounted for using the equity method.

MPI and AMI and their respective subsidiaries have substantial indebtedness. In order to receive cash flows from these entities, we rely on dividends and there can be no assurance that we will receive dividends from MPI or AMI.

We currently do not expect make capital injections into AMI; however there can be no assurance that we will not do so in the future. We are working to ensure that MPI is self-financing. However, AMI and MPI have required capital contributions in the past and there can be no assurance that these entities will be self-financing in the future in line with our strategies.

***We may suffer uninsured losses or experience losses exceeding our insurance limits.***

Our projects could suffer physical damage from fire or other causes, resulting in losses which may not be fully compensated by insurance. The proceeds of any insurance claim may be insufficient to cover rebuilding costs as a result of inflation, changes in building regulations, environmental issues as well as other factors. In addition, there are certain types of losses, such as those due to earthquakes, floods, hurricanes, other natural disasters, terrorism or acts of war, which may be uninsurable or are not insurable at a reasonable premium. We may not carry coverage for timely completion of our projects under development, loss of rent or profit, defects in the quality of materials used, public liability insurance and comprehensive general liability insurance. Should an uninsured loss or a loss in excess of insured limits occur, we may lose the capital invested in and the anticipated revenue from the affected property. We could also remain liable for any debt or other financial obligation related to that property. In addition, any payments we make to cover any uninsured loss may be significant. We may bear the costs associated with any damage suffered by us in respect of these uninsured events. Any of the foregoing could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Our business is capital intensive, and if we are unable to obtain financing on terms acceptable to us to fund the substantial capital expenditure we expect to incur, we may not be able to implement our development plans.***

We require, and will continue to require, substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves and, through MPI, we require and will continue to require substantial capital expenditures for the development of power projects. If certain oil and gas projects currently under development do not increase our production as quickly as expected or, if following such increases, our revenues subsequently decline, we may be constrained in our ability to secure the capital necessary to undertake or to complete future drilling or other programs. Our ability to obtain required capital on acceptable terms or at all is subject to a variety of uncertainties, including: limitations on our ability to incur additional debt, including as a result of prospective lenders' evaluations of our creditworthiness and pursuant to restrictions on incurrence of debt in our existing and anticipated credit facilities; whether it is necessary to provide credit support or other assurances from our shareholders on terms and conditions and in amounts that are commercially acceptable to them; limitations on our ability to raise capital in the capital markets and conditions of the various capital markets in which we may seek to raise funds; and our future results of operations, financial condition and cash flows. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet our requirements or, if debt or equity financing or loans are available, that it will be on acceptable terms. In addition, with respect to MPI,, our ability to make capital contributions or advances to, or enter into transactions with, MPI is limited under certain of our indentures with respect to our notes.

To the extent we raise additional debt in order to fund our planned capital expenditures, this may pose additional risks and place restrictions on us which may, among other things:

- increase our vulnerability to general adverse economic and industry conditions;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the availability of our cash flow to fund capital expenditure, working capital requirements and other general corporate purposes; and/or
- limit our flexibility in planning for, or reacting to, changes in our business and our industry, either through the imposition of restrictive financial or operational covenants or otherwise.

Any inability to access financing on acceptable terms and conditions could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Increases in interest rates may materially impact our financial condition.***

We have entered into certain facility agreements pursuant to which we have indebtedness which is subject to floating rate interest payments. The outstanding indebtedness which is subject to floating interest rate represents 11.6% of our total outstanding indebtedness (Bank loans, loans from non-bank financial institutions, Rupiah Bonds, US Dollar Bonds, Singapore Dollar Bonds and medium term notes) as of September 30, 2019. Under such facility agreements, we are exposed to interest rate risk in the future depending on the nature of our financing cash flows. We may from time to time enter into interest or other hedging contracts or financial arrangements in the future to minimize our exposure to interest rate fluctuations. These hedging contracts are designed to reduce the risk of exposure to variable interest rates. However, we cannot assure you that we will be able to do so on commercially reasonable terms or that any such agreements we enter into will protect us fully against these risks. Any increase in interest expense of our loan servicing obligations could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Changes to Indonesian FAS standards for lease accounting may adversely affect our financial results and position.***

The International Accounting Standards Board ("IASB") released a new standard ("IFRS 16") on lease accounting, which replaced International Accounting Standards ("IAS") 17 Leases and which was effective for financial reporting periods beginning on or after January 1, 2019. The corresponding standard we will follow is PSAK 73 which became effective for financial reporting periods beginning on or after January 1, 2020. The application of PSAK 73 is expected to have a significant impact on our consolidated financial statements, since under PSAK 73 operating leases will be treated the same as finance leases with an asset being recorded on the balance sheet along with a corresponding liability. On the income statement, operating lease payments will be recognized as interest expense and depreciation. This and any other changes to PSAK standards (or IFRS implemented by corresponding PSAK standards) that may be proposed in the future could have a material adverse effect on our results of operations or financial condition.

Although we are still in the process of analyzing the detailed consequences of PSAK 73's application, we currently believe that had PSAK 73 been applicable as at and for the year ended December 31, 2018, the estimated impact on our consolidated financial statements would have been as follows: (a) a significant increase in our consolidated assets; (b) a significant increase in our consolidated liabilities; (c) an increase in our consolidated depreciation expense; (d) an increase in our consolidated interest expense; and (e) a decrease in our consolidated lease expense. PSAK 73 will not have any impact on calculations we are required to make under the Indenture for the purposes of ensuring compliance therewith, as those will continue to be made in accordance with the PSAK standards in effect as at the date of the document, although (i) it will have effect on the calculations we are required to make and the operation of our certain of our covenants under the indentures for our 2022 Notes and 2025 Notes unless we are able to amend those indentures; and (ii) it is likely to lead to certain divergence between some financial metrics that we report on a regular basis (including Adjusted EBITDA of continuing operations) and related or similarly titled metrics under indentures and for covenant purposes.

***We rely on equipment provided by third parties.***

We compete with other oil and gas companies for equipment and human resources such as drilling rigs, supply vessels and helicopters, which are a limited resource given the competitive market in the Indonesian oil and gas sector. While the current situation is such that there is an excess availability and capacity for oil and gas equipment and services, there is no assurance that this situation will continue. If we are unable to obtain the equipment that we need to carry out our development plans and operations, we may have to delay or restructure our development plans or curtail selected operations, which may have an adverse effect on our ability to commercialize our oil and gas reserves on a timely basis. Further, depending on the complexity of our development projects, the competitive dynamics of the market, and the availability and prices of our contractors and equipment, we may have to pay more than we currently anticipate to implement our development plans. In addition, both MPI and AMNT also compete with third parties for infrastructure and equipment for their respective businesses.

In the event of a disruption or delay in the availability of equipment provided by third parties, we and AMNT would be unable to sell our respective products until the problem is corrected or until we or they find alternative means to deliver our or their products to our or their customers. Such alternative means, if available, may result in increased costs, and could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil and gas.***

Seismic data is a method used to determine the depth, orientation and configuration of subsurface rock formations. Seismic data is generated by applying a source of energy, from explosives or vibrations, to the surface of the ground and capturing the reflected sound waves to create two-dimensional ("2D") "lines" or three-dimensional ("3D") grids, the latter of which provides a more accurate subsurface understanding (which includes subsurface maps). Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in interpreting subsurface structures and potential hydrocarbon occurrences and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures or the amount of hydrocarbons. We employ 3D seismic technology to reduce the uncertainty of our projects. However, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies. This could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in its returns. Moreover, our drilling activities may not be successful or economical, and our overall drilling success rate, or our drilling success rate for activities in a particular area, could decline.

***We are dependent on key personnel as well as the availability of qualified technical personnel.***

We are dependent on senior management employees and other key personnel. If we lose the services of any of our key executive officers, it could be time consuming to find, relocate and integrate adequate replacement personnel into our operations, which could harm our operations and the growth of our business. We are also dependent on attracting and retaining qualified technical employees to provide services in relation to certain of our oil and gas operations. If we are unable to retain our current workforce or hire qualified technical personnel in the future, it could have a material adverse effect on our business, prospects, financial condition and results of operations.

***From time to time, we may be involved in legal, regulatory and other proceedings arising out of our operations, and may incur substantial costs arising therefrom.***

From time to time we have been, and in the future may continue to be, involved in legal disputes. These disputes may cause us to incur substantial costs, delays in our development schedule, and the diversion of resources and management's attention, regardless of the outcome. If we were to fail to win these disputes, we could incur substantial losses and face significant liabilities. Further, even if we were to win these disputes, we may incur substantial costs in mounting our defense. We may also be subject to regulatory action in the course of our operations, which may subject us to administrative proceedings and unfavorable decisions that could result in penalties and/or delayed construction of new logistics facilities. Any of the foregoing could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***We may not be able to renew our production sharing or concession arrangements on the same or attractive terms or at all.***

Although in the past we have been able to renegotiate economic extensions for our previous expiring Indonesian PSCs, there can be no assurance that we will be able to negotiate new PSCs with SKK MIGAS, or concessions or other arrangements with other authorities, when existing arrangements expire, or that any new arrangements will be on terms that are satisfactory to us. In addition, as we acquire additional assets outside of Indonesia, we may be less familiar with the local regulations or requirements and may face new and unforeseen challenges in renewing PSCs or similar licenses. With respect to Ophir, prior to completion of the Ophir Acquisition, Ophir recorded a US$613.7 million impairment of non-current assets held for sale in 2018, relating to the non-renewal of the Block R license in Equatorial Guinea (containing the Fortuna discovery) which expired at the end of 2018. The asset was classified as a non-current asset held for sale and has been fully recorded as an impairment. In addition, the Madura Offshore PSC, Sampang PSC, Senoro-Toili PSC and Lematang PSC, will expire in 2027. Any new arrangements could, among other things, reduce our production sharing entitlement, royalty or other payments or place other restrictions on our ability to realize economic value from our production entitlement. We also face risks in this regard because new contracts can be less attractive than existing PSCs and so we have increased our focus on older PSCs, which are more likely to require that we obtain extensions thereof. Failure to successfully negotiate any such extensions on favorable terms or at all could result in impairment losses and the loss of our ability to carry out activities on the applicable blocks, our inability to grow or maintain production levels and could therefore materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Due to the limited natural gas transmission and distribution infrastructure, failure by us to develop markets for the sale of our natural gas would have an adverse effect on our results of operations.***

The limited natural gas transmission and distribution infrastructure within Indonesia and between Indonesia and other countries, including Singapore, has restricted the access to and consumption of Indonesian natural gas. There can be no assurance as to when or if a significant natural gas transmission and distribution system will be constructed. Construction of transmission and distribution pipelines and other infrastructure depends on many factors, many of which are beyond our control, such as government funding, costs of land acquisition, national and local government approvals and timely completion of construction.

Our natural gas is primarily transported through pipelines to the off-taker. Due to the limited natural gas delivery infrastructure, we must sell our natural gas to off-takers who are within close geographical proximity to our operations or find other means of monetizing such resources. We must seek to maximize utilization of our natural gas reserves by entering into working alliances as a gas supplier to obtain and secure long-term gas contracts with power plants and industrial users, among others, as new users of natural gas, or by investing interests in or acquiring power plants. Our ability to sustain the planned expansion of our natural gas exploration and production business by continuously finding, developing and maintaining markets for the sale of our natural gas will be subject to many factors, including our ability to obtain funding, regulatory approvals, competition from other regional and international gas producers, downstream market reforms such as reductions of fuel subsidies that could trigger public opposition, environmental regulations, and other operating or commercial risks, some of which are beyond our control. Any failure by us to find, develop and maintain markets for the sale of our natural gas would have a material adverse effect on our natural gas business and therefore could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Fluctuations in the value of the Indonesian Rupiah against foreign currencies may have an adverse effect on our results of operations.***

While Medco Energi reports its consolidated results in U.S. dollars, a substantial portion of our costs are generated in Rupiah, and we also incur costs in certain other currencies, including primarily Thai Baht and Vietnamese Dong. Revenues earned by us (excluding MPI) and AMNT are earned in U.S. dollars, and MPI's revenue is earned in Rupiah. Many of our and AMNT's operating costs, such as salaries and employee expenses, are denominated in Rupiah, and we also have costs in Thai Baht and Vietnamese Dong, as well as other currencies. Accordingly, we are exposed to fluctuations in the value of the Rupiah or other currencies, against the U.S. dollar. In addition, since MPI currently reports its results in Rupiah, fluctuations of the Rupiah against the U.S. dollar affect our accounting for MPI's financial statements. All of our borrowings are either in U.S. dollars or have been swapped to U.S. dollars, except in the case of MPI, which has some U.S. dollar and non-U.S. dollar borrowings not swapped to U.S. dollars, although, in the future, if we earn revenues or dividends from our investments in Rupiah, or have debt exposure in Rupiah or other currencies, fluctuations in the value of the Rupiah or other currencies against the U.S. dollar will affect the U.S. dollar cost to us of servicing and repaying these borrowings. We enter into currency hedging contracts to reduce the exposure to this risk. However, we cannot assure you that we will be able to do so on commercially reasonable terms or that any such agreements we enter into will protect us fully against these risks. Future fluctuations in the value of the Rupiah against foreign currencies, including but not limited to the U.S. dollar, could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***AMNT may be unable to replace gold and copper reserves as they become depleted.***

Our gold and copper mining operations are carried out by our joint venture, AMNT. AMNT plans to continue the development of its Batu Hijau mine, and to engage in further appraisal on other discovered resources, including at Elang, which is its largest discovered resource. AMNT also plans further exploration activities in the future. There can be no assurance that AMNT's development plans will be successful or that its appraisal and exploration activities will result in the discovery or development of mineable reserves. With respect to exploration activities, if a viable commercial deposit is discovered, it can take several years and substantial capital expenditures from the initial phases of exploration until production commences during which time the capital cost and economic feasibility may change. Furthermore, actual results upon production may differ from those anticipated at the time of discovery. In order to maintain gold and copper production beyond the life of AMNT's current proved and probable gold and copper reserves, additional gold and copper reserves must be appraised and developed. AMNT's appraisal and exploration programs may not result in the replacement of such gold and copper reserves or result in new commercial mining operations, which outcome could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

Current mining at Batu Hijau is focused on stockpile processing and development of Phase 7. Overburden removal for Phase 7 commenced in 2018. This overburden removal is required to access the ore in Phase 7 and is expected to take at least three years to fully complete, though we expect initial mining at Phase 7 to commence in the first half of 2020. As such, AMNT has been loss-making since 2018, and there is no certainty that AMNT will return to profitability within the time frames we expect. During this hiatus in ex-pit ore production, Batu Hijau will feed its processing plant from existing long-term stockpiles of lower grade ore resulting in lower metal production during the Phase 7 overburden removal period. Predominantly low to medium grade ore has been accumulated in stockpiles since the start of operations in 2000 until the present day. AMNT believes that grade control from blast hole sampling and the precise spatial tracking of the placement of each truckload of this material on the stockpile have resulted in an accurate physical geo-model of the stockpile. However, these stockpiles have been classified as a probable mineral reserve in order to reflect some uncertainty regarding the degree of oxidation of the copper minerals over time, which affects metal recovery. In addition, Phase 7 could also experience unexpected problems and delays during development arising from such factors as unseasonal or exceptional wet weather and localized pit wall disturbance as well as other project and operational risks.

***The interests of our controlling shareholders may differ from those of our Group.***

PT Medco Duta, PT Medco Daya Abadi Lestari ("MDAL"), and PT Multifabrindo Gemilang are beneficially owned by, and/or held for the benefit of, Mr. Arifin Panigoro, a member of Mr. Hilmi Panigoro's family, our President Director. The interests beneficially owned by, and/or held for the benefit of, Mr. Arifin Panigoro, a member of Mr. Hilmi Panigoro's family, our President Director, through PT Medco Duta, PT Multifabrindo Gemilang, and PT Medco Daya Abadi Lestari, represent 50.29% of our total outstanding Shares as of December 31, 2019. As a result, these shareholders have the power to significantly influence the management and policies of Medco Energi. Under Indonesian regulations, an affiliate transaction is a transaction entered into between a company and its affiliates or affiliates of a member of the board of directors of a company, a member of the board of commissioners or a substantial shareholder who owns at least 20% of the total issued and paid up capital of such company. An affiliate transaction does not require prior approval by a company's independent shareholders. Subject to certain exemptions, the company must publicly disclose the transaction, including providing a fairness opinion from an independent appraiser. An affiliate transaction may, however, be a conflict of interest transaction if such transaction could raise a conflict between the economic interests of the company and the personal economic interests of a member of the board of directors or board of commissioners or substantial shareholder or any of their affiliates, which may be detrimental to us. If the transaction is considered to be a conflict of interest transaction, it will be subject to the approval of Medco Energi's independent shareholders, which could affect our ability to enter into such transactions even if such a transaction may be in our interests.

The interests of Medco Energi's controlling shareholders may differ from ours, and such shareholders may vote their shares in a way which prioritizes their interests over ours. Resulting transactions may be adverse to us. To the extent that we enter into affiliate transactions without public disclosure and providing the fairness opinion or enter into conflict of interest transactions without independent shareholder approval, Medco Energi may be subject to administrative sanctions under OJK Regulations, such as written notices, fines, restrictions of business activity, ceasing business activity, revocation of license, cancelation of approval and/or cancelation of registration. In addition, MDAL may be subject to certain covenants and restrictions with respect to its shareholding in Medco Energi pursuant to financing arrangements with its lenders, including having to provide a pledge over its shares in Medco Energi. The interests of MDAL's lenders may also differ from ours and the exercise of certain rights by these lenders may be adverse to ours.

***Indonesian law contains provisions which may cause us to forego transactions that are in our best interests.***

In order to provide more legal certainty and protection to shareholders, in particular the independent shareholders, in connection with affiliated party transactions or conflict of interest transactions conducted by an issuer or an Indonesian public company, in November 2009, Bapepam-LK issued Rule No. IX.E.1 on Affiliated Party Transaction and Conflict of Interest of Certain Transaction which replaced the previous rule issued in 2008 ("Rule No. IX.E.1").

Rule No. IX.E.1 requires the issuer or the Indonesian public company to disclose information to the public or to submit a report to OJK of its affiliated party transaction by the end of the second working day following such a transaction and further stipulates that any conflict of interest transaction conducted by Indonesian public companies would require prior independent shareholders' approval of the issuer or the said Indonesian public company, unless such affiliated party transaction or conflict of interest transaction meets certain exemptions stipulated under this rule.

Transactions between us and other persons could constitute an affiliated party transaction or conflict of interest transaction under Rule No. IX.E.1. If such a transaction falls under the conflict of interest transaction, the approval of holders of a majority of shares owned by the independent shareholders would have to be obtained prior to conducting such a transaction. OJK has the power to enforce this rule and our shareholders may also be entitled to seek enforcement or bring enforcement actions based on Rule No. IX.E.1.

The approval of independent shareholders is designed to be a control to stop abuse by controlling shareholders. However the requirement to obtain independent shareholder approval could be burdensome to us in terms of time and expense and could cause us to forego entering into certain transactions which we might otherwise consider to be in our best interests. Moreover, we cannot assure you that approval of the independent shareholders would be obtained if sought.

***Indonesian corporate and other disclosure and accounting standards differ from those in other jurisdictions, such as the United States and countries in the European Union.***

There may be less publicly available information about Indonesian public companies, such as Medco Energi, than is regularly made available by public companies in the United States, the European Union and other countries. In addition, our financial statements have been prepared in accordance with Indonesian FAS, which differs in certain material respects from U.S. GAAP. Further, although we are required to comply with the requirements of OJK with respect to corporate governance standards, these standards may differ materially from those applicable in other jurisdictions, such as the United States or the European Union.

***Political and social instability in the countries where we operate could adversely affect us.***

While our assets are primarily located in Indonesia, we also have significant producing assets in Thailand and Vietnam and assets or operations in Oman, Yemen, Libya, Tanzania, Mexico and Malaysia. Exploration and development activities in these countries may require protracted negotiations with host governments, national oil companies and third parties and may be subject to economic and political considerations, such as the risks of war, actions by terrorist or insurgent groups, community disturbances, renegotiation, forced change or nullification of existing contracts or royalty rates, unenforceability of contractual rights, changing taxation policies or interpretations, adverse changes to laws (whether of general application or otherwise) or the interpretation thereof, foreign exchange restrictions, inflation, changing political conditions, the death or incapacitation of political leaders, local currency devaluation, currency controls, and governmental regulations that favor or require awarding contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. Any of the factors detailed above or similar factors or the occurrence of any of the foregoing events in Indonesia or the other countries where we operate could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

In 2016, we recorded impairment losses on our oil and gas properties of US$278.5 million (of which US$100 million with respect to Libya was reversed in 2017), primarily related to impairments of our assets in Libya and Tunisia partly resulting from our risk assessment related to political conditions in the North African region. Due to political conditions in Libya and Yemen, we have reduced activities at, and in the case of Yemen, relinquished our rights to, certain of our oil and gas blocks in these countries. In addition, exploration activities in Libya are currently suspended under force majeure. There can be no assurance that our rights to these blocks will not be impaired or terminated as a result, including, for example, because we are deemed not to have fulfilled our development or other obligations relating thereto.

If a dispute arises in connection with our operations, it may be subject to the exclusive jurisdiction of courts in those countries or arbitration tribunals or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to more favorable jurisdictions. Further, we may also be adversely affected by increased action by non-governmental organizations opposed to the oil and gas exploration and production industry.

Political and related social developments in the countries where we operate have been unpredictable in the past and there can be no assurance that social and civil disturbances will not occur in the future and on a wider scale, or that any such disturbances will not, directly or indirectly, have a material adverse effect on our business, financial condition, result of operations and prospects.

***Our operations could be disrupted by community or labor issues.***

We are subject to risks associated with community and workforce unrest. For example, AMNT's Batu Hijau operations faced demonstrations, including protests and roadblocks by the local community in 2011 and again in 2015 relating to a worker recruitment process by AMNT. The local community believed that AMNT conducted an unfair recruitment process by accepting the workers from families of the local village and sub-district officials. The Batu Hijau mine also faced temporary work stoppages in 2011 and 2012. In addition, development of the geothermal facility at Sarulla, which is not operated by us, was also impacted by social unrest, including riots, which delayed commercial operation of the first facility there. In addition, our operations in Tunisia were suspended due to labor protests in connection with a general strike in the country from April to June 2017. We cannot predict whether similar or more significant incidents will occur and the recurrence of significant opposition from the local community could disrupt exploration, development or operational activities and, thereby, adversely affect our assets and operations or our other operations. Indonesia has seen greater worker and union activism in recent times, and a strike or other labor disputes could adversely affect our operations and assets. Strikes and labor disputes can have various causes, including disagreements on wages, benefits, work conditions and job security, as well as layoffs, which can result from, among other things, reduced labor needs during the lifecycle of our projects. Any of the foregoing could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Oil and gas facility and pipeline, mine closure and remediation costs and abandonment costs and environmental liabilities may exceed the provisions we have made therefor.***

Natural resource extractive companies are required to close their operations and rehabilitate the lands that they mine in accordance with a variety of environmental laws and regulations in accordance with the obligations in their PSCs, contracts of work, or IUPK, and a variety of implementing environmental laws and regulations, as applicable. Under the Indonesian mining law (the "Mining Law"), mining companies are required to submit reclamation plans and post-mining activity plans to the Directorate General of Minerals, Coal and Geothermal ("DGMCG"). Mining companies are also required to provide reclamation and post-mining guarantees as a commitment to implement the reclamation and post-mining activities as stipulated in the plan. The amount of guarantee itself is determined by the DGMCG based on its assessment and valuation of the plan submitted by the mining company. Estimates of the total ultimate closure and rehabilitation costs may be significant and based principally on current legal and regulatory requirements and closure plans that may change materially. Any underestimated or unanticipated rehabilitation costs could materially affect our or AMNT's business and prospects. The laws and regulations governing oil and gas facilities and pipelines, mine closure and remediation are subject to review at any time and may be amended to impose additional requirements and conditions which may cause our or AMNT's provisions for environmental liabilities to be underestimated and could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations. In Thailand, similar facilities' removal, rehabilitation, and related reporting and guarantee obligations apply, and these may have a material impact on petroleum operations and closure costs.

In Vietnam, the Block 12W FPSO was designed with a 15-year design life ending on October 14, 2026. The joint venture partners in the Block 12W PSC (including us) may be liable to pay for repair and maintenance costs in relation to the Block 12W FPSO in order to allow production under the Block 12W PSC to continue and the amount of such costs are uncertain. There are ongoing commercial discussions between the joint venture partners and the owner of the FPSO is order to determine the future operating strategy of the FPSO.

***The exploration, development, and operation of the Sarulla geothermal power project is subject to geological risks and uncertainties.***

The Sarulla geothermal power project, in which MPI owns an 18.6% interest, is subject to various uncertainties, such as potential dry holes, flow-constrained wells and uncontrolled releases of pressure and temperature decline. In addition, the high temperature and high pressure in geothermal energy resources requires special resource management and monitoring. Because geothermal resources are complex geological structures, there can be no assurance that MPI's estimates of their geographic area are accurate. The viability of geothermal projects depends on different factors directly related to the geothermal resource, such as the heat content (the relevant composition of temperature, acidity and pressure) of the geothermal resource, the useful life (commercially exploitable life) of the resource and operational factors relating to the extraction of geothermal fluids. Although MPI believes its geothermal resources will be fully renewable if managed appropriately, the geothermal resources that MPI intends to exploit may not be sufficient for sustained generation of the anticipated electrical power capacity over time. Further, MPI's geothermal resources may suffer an unexpected decline in capacity. Any of these factors could adversely affect MPI's development of the Sarulla geothermal power project and, in turn, could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***The historical financial information for Ophir and the pro forma financial information included in this document may not be representative of our results as a combined company in the future.***

The pro forma financial information included in this document is based upon the historical audited consolidated financial statements for the year ended December 31, 2018 of each of the Company and Ophir (reclassified as described under "Unaudited Pro Forma Combined Consolidated Financial Information") / in each case subject to the adjustments set forth under "Unaudited Pro Forma Combined Consolidated Financial Information" and the audited consolidated financial statements for the nine months ended September 30, 2019 of the Company and the audited consolidated financial statements of Ophir for the nine months ended September 30, 2019. The unaudited pro forma combined consolidated profit or loss and other comprehensive income for the year ended December 31, 2018 and the nine months ended September 30, 2019 give effect to the Ophir Acquisition as if it had occurred on January 1, 2018. Neither the underlying pro forma adjustments nor the resulting pro forma financial information have been audited in accordance with Indonesian FAS. Solely for the purpose of preparing the pro forma financial information, the historical audited consolidated financial statements of Ophir for the year ended December 31, 2018 have been reclassified in accordance with Indonesian FAS, although originally prepared in accordance with EU IFRS.

The pro forma financial information included in this document has been prepared to illustrate the effects of, among other things, (i) consummation of the Ophir Acquisition; (ii) repayment of Ophir indebtedness; and (iii) additional indebtedness incurred in connection with the Ophir Acquisition. The unaudited pro forma financial information presented in this document is based in part on certain assumptions regarding Ophir, the Ophir Acquisition and intercompany eliminations. We cannot assure you that our assumptions will prove to be accurate over time. The unaudited pro forma financial information included in this document is not necessarily indicative of the results that we would have achieved had we actually completed the Acquisition as of January 1, 2018.

Furthermore, the unaudited pro forma combined consolidated statement of profit or loss and other comprehensive income does not take into account the effects on income tax expenses of the pro forma adjustments set forth in Note 3 Unaudited Pro Forma Combined Consolidated Financial Information assuming the Ophir Acquisition had occurred as of January 1, 2018. Given the unaudited pro forma combined consolidated statement of profit or loss and other comprehensive income does not take account of the foregoing expenses that, although the amounts are not definitively determined, would have been incurred or not incurred (as applicable) had the Ophir Acquisition taken place on January 1, 2018, the unaudited pro forma combined consolidated loss for the year of the Company set forth herein would have been higher by the amount of the impact of such items had they been accounted for.

***The due diligence undertaken in connection with the Ophir Acquisition may not have revealed all relevant considerations or liabilities of the Ophir Group, and the Ophir Acquisition also generally subjects us to the liabilities of the Ophir Group, and such liabilities could have a material adverse effect on our financial condition or results of operations.***

We completed the Ophir Acquisition on May 22, 2019. Although we have been integrating Ophir's business with our own, given that the Ophir Acquisition was only recently completed, there can be no assurance that the due diligence undertaken by us in connection with the Ophir Acquisition has revealed all relevant facts that may be necessary to evaluate the Ophir Acquisition. Furthermore, the information provided during due diligence may have been incomplete or inadequate. As part of the due diligence process, we have also made subjective judgments regarding the results of operations, financial condition and prospects of Ophir. If the due diligence investigation has failed to correctly identify material issues and liabilities that may be present in Ophir, or if we consider any identified material risks to be commercially acceptable relative to the opportunity, we may incur substantial impairment charges or other losses following the Acquisition.

As part of the Ophir Acquisition, we acquired the Ophir Group and assumed all of its assets and liabilities. Additional information about the Ophir Group that we are currently not aware of (including previously undisclosed liabilities of Ophir that were not identified during due diligence or in the period following completion of the Ophir Acquisition) and that could adversely affect us, such as unknown or contingent liabilities and issues relating to compliance with applicable laws, could increase our costs and expenses due to exposure to such unanticipated liabilities and therefore could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

In addition, in recent years Ophir has been engaged in downsizing and redundancy-related activities, including in relation to management and employees. Such activities involve costs and could also face disputes and litigation relating thereto, and may be subject to greater attrition.

***Business growth opportunities, cost savings and synergies achieved through the Ophir Acquisition may differ from those anticipated and the challenges and/or costs of integration may be higher than expected.***

As we continue to integrate the operations and assets of the Ophir Group, we may encounter challenges. The business growth opportunities, cost savings and other synergies we anticipated in making the Ophir Acquisition are based on management estimates and may not be achieved as expected, or at all, or may be materially delayed. The incurrence of increases in integration costs or us achieving lower synergy benefits than expected could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations. In particular, with respect to the $50 million recurring cost synergies identified by us, there can be no assurance that such synergies can be maintained or will actually be achievable. In addition, although we have achieved one-time cost savings from the reduction of capital commitments of approximately US$100 million on assets acquired from Ophir that we disposed of as part of our portfolio rationalization efforts, and, for 2019, we expect our capital expenditure in relation to assets acquired from Ophir to be approximately US$30 million lower than Ophir's publicly stated capital expenditure guidance for 2019, such savings are one-time cost savings and may not be indicative of our future performance and our estimates of our capital expenditures may ultimately be lower than actual capital expenditures for 2019.

***The Ophir Acquisition may expose us to tax liabilities in Tanzania.***

In 2014, the Ophir Group sold a 20% interest in Tanzania Blocks 1, 3 and 4 for US$1.3 billion for which it paid US$222.4 million in Tanzanian capital gains taxes on the related gains. At present, we now hold a 20% interest in Tanzania Blocks 1 and 4. In the meantime, in 2015, Royal Dutch Shell ("Shell") acquired British Gas, which held a 60% interest Blocks 1, 3 and 4. The Tanzanian Revenue Authority assessed a very significant capital gains tax on Royal Dutch Shell Tanzania in connection with the British Gas acquisition given the indirect transfer of British Gas's interest in the Tanzanian blocks. Shell has disputed this assessment and the dispute currently remains unresolved.

In connection with our acquisition of Ophir, we believe that the Ophir companies in Tanzania ("Ophir Tanzania") should not be subject to a material capital gains tax obligation given that we have assessed a low value for the Tanzanian blocks held by Ophir Tanzania on the acquisition date of Ophir. However, the tax authorities in Tanzania may take the view that Ophir Tanzania is subject to capital gains tax based on, among other things, different valuation methodologies and the taxes previously paid by Ophir in the context of its 2014 disposal and/or the ongoing dispute with Shell. If Ophir Tanzania is assessed a capital gains tax liability which exceeds our current estimate of the tax due, we will assess our options and may decide, as a commercial matter, to contest the assessment or pursue other alternatives.

## RISKS RELATING TO OUR INDUSTRIES

***The volatility of prices for crude oil could adversely affect the Group's financial condition and results of operations.***

Our future revenues will be highly dependent upon the prices of, and demand for, oil and natural gas. Our profitability is determined in large part by the difference between the prices received for the oil and natural gas and the costs of exploring for, developing, producing and selling these products. We currently sell most of our oil at prices based on the ICP. Currently, we sell all of our natural gas under long-term contracts. Some of our contracts, which represented approximately 55% of gas sales volume in 2018, contain pricing linked to oil prices, such as the Senoro GSA and one of the South Natuna Sea Block B GSAs. The remaining 45% was sold domestically within Indonesia under fixed price or inflation linked long-term contracts with no linkage to oil price, and accordingly, our revenue from natural gas sales is not subject to as much price volatility as with sales of oil.

There have recently been significant fluctuations in the prices of crude oil, with oil prices having dropped significantly in 2015. In 2015, our average realized crude oil price was US$49.29 per BBL, representing a 49.6% decline from our average realized crude oil price in 2014 of US$97.83 per BBL, which impacted our revenues and profitability and impacted the value of our assets as we recorded asset impairments. The average monthly ICP ranged from US$54.81 per BBL to US$77.56 per BBL from January 2018 to September 2019 and, more recently, the average monthly ICP decreased from US$67.47 per BBL in 2018 to US$62.03 per BBL for the period between January and September of 2019.

The market prices of crude oil are subject to a variety of factors beyond our control. These factors, among others, include:

- international events and circumstances, as well as political developments and instability in petroleum producing regions, such as the Middle East (particularly the Persian Gulf, Iraq and Iran), Latin America and Western Africa;
- the ability of the Organization of Petroleum Exporting Countries ("OPEC") and other petroleum-producing nations to set and maintain production levels and therefore influence market prices;
- market prices and supply levels of substitute energy sources, such as coal;
- domestic and foreign government regulations with respect to oil and energy industries in general;
- the level and scope of activity of oil speculators;
- weather conditions and seasonality; and
- overall global economic conditions.

In the event of sustained low oil prices, we attempt to reduce our cost of production and curtail exploration activities. In the event that the price of oil falls below the cost of production, we may reduce oil production to a level where we can produce oil economically. These circumstances could lead to further decreases in our revenues, net income and cash flows. We do not materially hedge our exposure to movements in oil prices and any significant decreases in the price of oil and gas could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***A substantial or extended decline in gold or copper prices would have a material adverse effect on AMNT.***

AMNT's business is dependent on the prices of gold and copper, which fluctuate on a daily basis and are affected by numerous factors beyond our control. Factors tending to influence prices include:

- gold sales, purchases or leasing by governments and central banks;
- speculative short positions taken by significant investors or traders in gold or copper;

- the relative strength of the U.S. dollar;
- the monetary policies employed by the world's major central banks;
- the fiscal policies employed by the world's major industrialized economies;
- expectations of the future rate of inflation;
- interest rates;
- recession or reduced economic activity in the United States, China, India and other industrialized or developing countries;
- decreased industrial, jewelry or investment demand;
- increased import and export taxes;
- increased supply from production, disinvestment and scrap;
- forward sales by producers in hedging or similar transactions; and
- availability of cheaper substitute materials.

Any decline in AMNT's realized gold or copper price could adversely impact our net income. In addition, sustained lower gold or copper prices can:

- reduce revenues further through production declines due to cessation of the mining of deposits, or portions of deposits, that have become uneconomic at sustained lower gold or copper prices;
- reduce or eliminate the profit that we currently expect from ore stockpiles and ore on leach pads and increase the likelihood and amount that AMNT might be required to record as an impairment charge related to the carrying value of its stockpiles;
- halt or delay the development of new projects;
- reduce funds available for exploration and advanced projects with the result that depleted reserves may not be replaced; and
- reduce existing reserves by removing ores from reserves that can no longer be economically processed at prevailing prices.

***Our operations are subject to significant operating hazards.***

Our oil and gas exploration, development and production operations are subject to significant risks normally associated with such activities, including drilling blowouts, pipeline ruptures, explosions, oil spills and fires. Any of these risks could result in environmental pollution, damage to or destruction of wells, production facilities or other property, or injury to persons or fatalities. While we aim to prepare for, and train our personnel to deal with, such emergencies, if we are unable to quickly fix the damage resulting from such accidents, our financial condition and results of operation could be materially and adversely impacted. In addition, drilling hazards or environmental damage could increase the cost of operations, and various field operating conditions may adversely affect our production levels from successful wells. These conditions include delays in obtaining government approvals or consents, shut-in of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to materially and adversely affect revenue and cash flow to varying degrees. Offshore production facilities are subject to hazards inherent in marine operations, such as capsizing, sinking, grounding, collision and damage from severe weather or tidal conditions. These hazards can cause substantial damage to facilities and interrupt production. Offshore oil activities can also be affected by ocean conditions arising from occurrences such as typhoons and tsunamis.

In addition, the exploration and development of natural resources and the development and production of oil and gas, mining or power operations are activities that involve a high level of uncertainty. These can be difficult to predict and are often affected by risks and hazards outside of our control. These factors include, but are not limited to:

- environmental hazards, including discharge of metals, concentrates, pollutants or hazardous chemicals;
- industrial accidents, including in connection with the operation of mining transportation equipment, milling equipment and/or conveyor systems and accidents associated with the preparation and ignition of large-scale blasting operations, milling, processing and transportation of chemicals, explosives or other materials;
- surface or underground fires or floods;
- unexpected geological formations or conditions (whether in mineral or gaseous form);
- ground and water conditions;
- fall-of-ground accidents in underground operations;
- failure of mining pit slopes and tailings dam walls;
- seismic activity; and
- other natural phenomena, such as lightning, cyclonic or tropical storms, floods or other inclement weather conditions.

The occurrence of one or more of these events in connection with our businesses or investments may result in the death of, or personal injury to, employees, other personnel or third parties, the loss of equipment, damage to or destruction of properties or production facilities, monetary losses, deferral or unanticipated fluctuations in production, environmental damage and potential legal or regulatory actions or liabilities, all of which may adversely affect our reputation, business, prospects, results of operations and financial position. In November 2017, there was an employee fatality at MPI's Cibalapulang mini hydro power generating plants, and in each of December 2017 and March 2019, there was a fatality at the Sarulla geothermal power project. In 2018, there was one fatality at the Block A, Aceh assets involving employees of third party contractors. These incidents have been reviewed internally through a series of accident investigations, which resulted in corrective action to improve our health, safety and environment ("HSE") culture with a view to avoiding similar accidents in the future.

***The mining industry faces continued geotechnical challenges.***

The mining industry and AMNT's mining operations are facing continued geotechnical challenges due to the aging of mines and a trend toward mining deeper pits and more complex deposits. This leads to higher pit walls and increased exposure to geotechnical instability and hydrological impacts. As AMNT's operations are maturing, open pits get deeper and AMNT has experienced certain geotechnical failures at the Batu Hijau mine in the past. In addition, the pit design for Phase 7 was developed based on the same geotechnical and hydrological strategies that have been developed over the 20-year life of the Batu Hijau operation to date. The pit walls will be depressurized with horizontal drainage holes and pre-split blasting will be used to maximize wall competency but, based on experience at Batu Hijau, the pit walls are still anticipated to fail on a localized scale. The operation is well-practiced in monitoring and managing such confined failures and there is no reason to expect the additional depth in Phase 7 will present any additional issues to what the mine has experienced in the past.

No assurances can be given that unanticipated adverse geotechnical and hydrological conditions, such as landslides and pit wall failures, will not occur in the future or that such events will be detected in advance. Geotechnical instabilities can be difficult to predict and are often affected by risks and hazards outside of

AMNT's control, such as severe weather and considerable rainfall, which may lead to periodic floods, mudslides, wall instability and seismic activity, which may result in slippage of material. Geotechnical failures could result in limited or restricted access to mine sites, suspension of operations, government investigations, increased monitoring costs, remediation costs, loss of ore and other impacts, which could cause mining operations to be less profitable than currently anticipated and could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***We operate in a competitive environment.***

The Indonesian oil and gas, mining and power industries are highly competitive. Key areas in which we face competition include the acquisition, renewal and negotiation of licenses, evaluating, bidding for and acquiring assets, and securing the resources necessary for our operations as well as selling our products. Many of our competitors have greater financial and personnel resources available to them than we do. The size, infrastructure, wide-ranging experience and close relationships with the Government of some state-owned, international, or other energy companies may provide them with competitive advantages over other companies operating in Indonesia or the other countries where we operate, including us. Our ability to develop our business will depend upon our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

***Our business operations may be adversely affected by current and future environmental regulations.***

Our business is subject to certain laws and regulations on environmental and safety matters relating to the exploration for, and development and production of, oil and gas, conducting mining operations and power generation, which may have a material adverse effect on our financial condition and results of operations. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities which may require us to incur costs to remedy such discharge and pay penalties or fines. Any change in relevant laws and regulations applicable to us, including environmental laws and regulations and increased governmental enforcement of environmental laws or other similar developments in the future may require us to make additional capital expenditure or incur additional operating expenses in order to maintain our current production, development, exploration and other operations activities, curtail our production activities or take other actions that could materially and adversely affect us.

On October 3, 2009, the Government enacted Law No. 32 of 2009 regarding Environmental Protection and Management (the "Environmental Law"), in place of the previous Law No. 23 of 1997, which required that all current environmental management licenses be integrated into the environmental permit issued pursuant to the Environmental Law and introduced more stringent penalties for breaches of environmental laws and regulations. As an implementation of the Environmental Law, the Government enacted Government Regulation No. 27 of 2012 on Environmental License, dated February 23, 2012 ("Regulation No. 27") and State Minister of Environmental Affairs Regulation No. 5 of 2012 on Types of Planned Businesses and/or Activities Subject to Mandatory Environmental Impact Analysis which requires that in addition to an environmental impact analysis (*Analisa Mengenai Dampak Lingkungan*) ("AMDAL") approval, an environmental management effort plan (*Upaya Pengelolaan Lingkungan*) ("UKL") or an environmental monitoring effort plan (*Upaya Pemantauan Lingkungan*) ("UPL"), an environmental permit from the State Ministry of Environmental Affairs or governor or mayor/head of regent of their respective areas would need to be obtained. However, all environmental documents (AMDAL, UKL and UPL) obtained before the implementation of Regulation No. 27 would be accepted as valid environmental permits. The Environmental Law requires us to obtain environmental licenses (*Izin Lingkungan*) ("Environmental Licenses") as a pre-requisite to obtaining the relevant business licenses, and if obligations in the AMDAL approval, UKL or UPL are not met, one of the sanctions that could be imposed is the revocation of our environmental permit. Revocation of Environmental Licenses may lead to nullification or termination of the corresponding business license, which may require us to cease certain operations and may have a material adverse effect on us. In addition to Environmental Licenses, under Law No. 32/2009, each holder of an Environmental License is required to effect a cash deposit in a designated state-owned bank; however, no government regulation has been issued which stipulates the amount of such cash deposit, and accordingly we have not made any such deposit as of the date of this document. If, in the future, government regulations are issued which stipulate the amount of the cash deposit, we would be required to make such a deposit in order to comply with Law No. 32/2009. The enactment of further implementing regulations relating to the Environmental Law could cause us to incur significant additional costs or delay in the completion of our projects under development in order to comply with such new regulations. See "Business — Environmental."

While we have generally received Blue, Green and Gold (being the highest rating) PROPER awards from the Environmental & Forestry Ministry for certain of our Indonesian assets, in 2016, we received a Red rating from the Environmental & Forestry Ministry for our Bawean PSC (which we sold in June 2017), due, among other things, to the Government's request for a wastewater treatment facility to be constructed. A Red rating means that although the facility was making efforts to be in compliance with relevant regulations, such facility is not in full compliance.

We operate the South Natuna Sea Block B PSC as well as the WNTS pipeline to an onshore receiving facility in Singapore through which we distribute approximately 30% of our total gas sales. It has been reported that the Singapore government may consider implementing regulations aimed at limiting the amount of mercury in gas supplied to Singapore. There can be no assurance regarding the extent or effect of such regulations, which have not yet been promulgated. While a mercury removal unit has been implemented at the South Natuna Sea Block B PSC, which we believe would allow us to be in compliance with such prospective regulations, the actual implementation of such regulations in a manner different from our expectations could have an adverse effect on our business, prospects, results of operations and financial condition if we are not in compliance.

In addition, certain discoveries on our blocks, such as Block A, Aceh, have high carbon dioxide levels. The future developments of such resources will need to be considered, designed and managed by us in light of prevailing regulations. Given the possibility of unanticipated regulatory or other developments, including more stringent environmental laws and regulations, the amount and timing of future environmental compliance expenditures could vary substantially from their current levels. These changes could limit the availability of our funds for other purposes.

Any of the foregoing could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Shortages of critical parts and equipment may adversely affect us.***

The industries in which we operate and invest have been impacted, from time to time, by increased demand for critical resources such as input commodities, drilling equipment, trucks, shovels and tires. These shortages have, at times, impacted the efficiency of operations, and resulted in cost increases and delays in production and construction of projects, thereby impacting operating costs, capital expenditures and production and construction schedules.

## RISKS RELATING TO INDONESIA AND CERTAIN OTHER COUNTRIES WHERE WE OPERATE

Medco Energi is incorporated in Indonesia and most of its commissioners and directors are based in Indonesia. A substantial majority of our operations and assets are also located in Indonesia. As a result, future political, economic, legal and social conditions in Indonesia, as well as certain actions and policies the Government may take or adopt, or omit to take or adopt, could have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, we now have key assets in new jurisdictions including Thailand and Vietnam and our business will be subject to political, economic, legal, social and other factors in such jurisdictions.

***Political and social instability in Indonesia may adversely affect us.***

Following the collapse of President Soeharto's regime in 1998, Indonesia experienced a process of democratic change. Despite Indonesia having successfully conducted its first free elections for parliament and president in 1999, as a new democratic country, Indonesia continues to face various socio-political issues and has, from time to time, experienced political instability and social and civil unrest.

Since 2000, thousands of Indonesians have participated in demonstrations in Jakarta and other Indonesian cities both for and against former President Wahid, former President Megawati, former President Yudhoyono and current President Widodo as well as in response to specific issues, including fuel subsidy reductions, privatization of state assets, anti-corruption measures, decentralization and provincial autonomy and the American-led military campaigns in the middle-east. In and shortly after October 2016, thousands of Indonesians marched in a series of demonstrations in Jakarta and other cities either in support of or in opposition to the then Governor of Jakarta, Basuki Tjahja Purnama (commonly known as "Ahok") in connection with blasphemy allegations against him, in the period preceding the Jakarta gubernatorial election in early 2017. Mr. Purnama was convicted of the blasphemy charges in May 2017. Anies Baswedan (of the same party as the losing candidate of the 2014 presidential election) had been elected as governor of Jakarta in April 2017. Although these demonstrations were generally peaceful, some turned violent, including one on November 4, 2016, in which thousands of Indonesians marched in Jakarta demanding legal action against then Governor of Jakarta Purnama Basuki in connection with the blasphemy allegations against him. Clashes with police injured hundreds and left one dead. On April 17, 2019, Indonesia held its first general election, where the president and vice president, members of people's consultative assembly (*Majelis Permusyawaratan Rakyat*) and members of regional people's representative assembly were elected on the same day. On May 21, 2019, the General Elections Commission (***Komisi Pemilihan Umum***) has officially announced that the incumbent President Joko Widodo had won the 2019 Presidential election. Following the official announcement of the election results, protests and riots erupted in various area in Jakarta over two days and authorities officially stated that nine people were dead, more than two hundred were injured and more than three hundred were arrested. Political and related social developments in Indonesia, including immediately after the announcement of the 2019 general election official results, could result in civil disturbances that could directly or indirectly, materially and adversely affect our businesses, financial condition and results of operations.

Political and related social developments in Indonesia have been unpredictable in the past. There can be no assurance that this situation or future sources of discontent will not lead to further political and social instability. Social and civil disturbances could directly or indirectly, materially and adversely affect our business, financial condition, results of operations and prospects. In addition, as a significant oil producer and consumer market of great potential, Indonesia remains a key investment location, though corruption, policy drift and collapsing infrastructure, as well as insecurity in the region, present risks to business operations in that country.

***Increased scope of regulation by Government agencies may have a material adverse effect on our business, financial condition and results of operations.***

The evolving roles of SKK MIGAS and the Ministry of Energy and Mineral Resources, coupled with political changes in Indonesia, have allowed other Government agencies to increase their roles in administering and regulating the oil and gas industry in Indonesia.

BP MIGAS (currently known as SKK MIGAS), pursuant to a letter dated June 10, 2009 in relation to the Regulation of the Minister of Energy and Mineral Resources No. 22 Year 2008 on "Type of Activities Cost of Business Upstream Oil and Gas which cannot be recovered to Contractor of Production Sharing Contract" (*Kontraktor Kontrak Kerja Sama*) and Government Regulation of Republic of Indonesia No. 27 of 2017 regarding Amendment of Government Regulation of Republic Indonesia No. 79 of 2010 on "Cost Recovery and Income Tax Treatment in the Upstream Oil and Natural Gas Business Sector," added to the categories of costs that could not be recovered under cost recovery PSC.

Further, for PSCs under the gross split PSC regime, the Government has enacted Government Regulation No. 53 of 2017 regarding the Tax Treatment of Upstream Business Activity in A Gross Split Production Sharing Contract on December 27, 2017 (GR-53/2017), which regulates categories of costs that are not deductible under the gross split PSC regime.

Also, the Indonesian tax authorities have recently initiated additional tax audits and implemented measures to increase tax revenues from the oil and gas industry. Further, the treatment of taxation under the new tax laws may conflict with the approach currently adopted for PSCs. Continued expansion of the role of these governmental agencies may have a material adverse effect on companies operating in the oil and gas industry, including us.

***The interpretation and application of laws and regulations in Indonesia involves uncertainty.***

The courts in Indonesia may offer less certainty as to the judicial outcome or a more protracted judicial process than is the case in more established economies. Businesses can become involved in lengthy court cases over simple issues when rulings are not clearly defined, and the poor drafting of laws and excessive delays in the legal process for resolving issues or disputes compound such problems. Accordingly, we could face risks such as: (1) effective legal redress in the courts of such jurisdictions being more difficult to obtain, whether in respect of a breach of law or regulation, or in an ownership dispute, (2) a higher degree of discretion on the part of governmental authorities and therefore less certainty, (3) the lack of judicial or administrative guidance on interpreting applicable rules and regulations, (4) inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions, or (5) relative inexperience or unpredictability of the judiciary and courts in such matters.

Enforcement of laws in Indonesia may depend on and be subject to the interpretation placed upon such laws by the relevant local authority, and such authority may adopt an interpretation of an aspect of local law which differs from the advice that has been given to us by local lawyers or even previously by the relevant local authority itself. Furthermore, there is limited or no relevant case law providing guidance on how courts would interpret such laws and the application of such laws to its concessions, joint operations, licenses, license applications or other arrangements.

For example, on November 13, 2012, the Indonesian Constitutional Court (*Mahkamah Konstitusi*) (“MK”) handed down Decision No. 36/PUU-X/2012 (“MK Decision 36/2012”), which declared several articles in the Oil and Gas Law pertaining to the establishment and functions of BP MIGAS to be unconstitutional and unenforceable. In its considerations, the MK elaborates its views on the meaning of Article 33 of the Constitution of Indonesia, concluding that the Government should directly manage oil and gas resources, as opposed to only performing supervisory duties through BP MIGAS.

Upon the announcement of MK Decision 36/2012, certain provisions of the Oil and Gas Law, amongst others, relating to the establishment and functions of BP MIGAS ceased to have any binding force, and BP MIGAS therefore ceased to exist. However, in order to avoid legal uncertainty with respect to ongoing oil and gas business activities, the MK made clear, in MK Decision 36/2012, that pending the promulgation of further regulations and amendments to the Oil and Gas Law, the functions and duties formerly held by BP MIGAS would be taken over by the Government, represented by the MEMR. The MK also stated that all PSCs signed by BP MIGAS would remain valid until their respective expiration dates or as agreed by the parties. This follows a line of constitutional precedent regarding the non-retroactivity of MK decisions. Since the issuance of MK Decision 36/2012, the Government has authorized SKK MIGAS, pursuant to PR 9/2013, to take over the former functions and duties of BP MIGAS.

There can be no assurance, however, that PR 9/2013, the establishment of SKK MIGAS, or any future amendments to the Oil and Gas Law or its implementing regulations, will not be the subject of further challenges before the MK.

In addition, the Oil and Gas Law requires upstream oil and gas operators to provide at least 25.0% of production to fulfill domestic needs. As the DMO is implemented on a case-by-case basis, there is no certainty as to the proportion that will be allocated in the event we enter into new concessions. Moreover, in Indonesia, regional autonomy is a sensitive political subject. Laws and regulations have changed the regulatory environment by decentralizing certain regulatory and other authority from the Government to regional (i.e., provincial and/or local) governments. The process of devolving authority to regional governments is ongoing, and while the regulations on regional autonomy, as well as various sector-specific laws (including the Oil and Gas Law), have set out the divisions of authority between the Government and the regional governments, the implementation of such regulations has been erratic, causing the scope of devolved authority to be uncertain. Although the central Government has made efforts in the regulatory sector to curb overreaching by regional governments, jurisdictional uncertainty is expected to continue for the foreseeable future. One consequence of this uncertainty is that the powers of the licensing authorities in Indonesia are not completely transparent or clearly delineated. Under these regional autonomy laws, regional autonomy was expected to give the regional governments greater powers and responsibilities over the use of "national assets" and to create a balanced and equitable financial relationship between central and regional governments. However, under the pretext of regional autonomy, certain regional governments have put in place various restrictions, taxes and levies which may differ from restrictions, taxes and levies put in by other regional governments and/or are in addition to restrictions, taxes and levies stipulated by the central government. It is unclear whether the rights granted by the Government at the central, provincial and local levels conflict with each other, or that the application of regulatory powers will be consistent.

In addition, Indonesia's Law No. 17 of 2008 on Shipping includes a cabotage rule. The cabotage rule specifically reserves domestic sea transportation activities to domestic shipping companies using Indonesian-flagged vessels and Indonesian crews. The Government has interpreted the cabotage requirement broadly to apply not only to vessels engaged in the transportation of goods and passengers, but also to offshore platforms, construction and drilling vessels, FPSO and other specialized equipment used in the offshore oil and gas industry. For the time being, the Indonesian Ministry of Transportation has exempted specific specialized oil and gas vessels, including vessels conducting oil and gas survey activities, drilling, offshore construction, offshore supporting activities, dredging and salvage and sub-sea work, from flying the Indonesian flag, as many vessels used for oil and gas activities are high-tech specialized vessels, expensive, and currently not available from Indonesian shipbuilders. The exemptions will apply temporarily as long as Indonesian-flagged vessels are not yet available for such specific activities (such as oil and gas survey activities, drilling, offshore construction, offshore supporting activities, dredging and salvage and sub-sea work) There can be no assurance that Indonesian-flagged vessels will be available on terms that we find acceptable, or at all, once the exemptions are no longer applicable due to revocation. If the exemptions are revoked, it is likely that the supply of such rigs and vessels for use in our Indonesian operations will be reduced as there is no certainty that international oil services companies will re-flag their rigs and vessels. This could potentially increase our costs of operations and delay exploration and/or development within our Indonesian contract areas, which could materially and adversely affect our growth, business, results of operations, financial condition and prospects.

Unfavorable interpretation or application of the laws in the jurisdictions in which we operate may adversely affect our concessions, joint operations, licenses, license applications or other legal arrangements. In Indonesia, the commitment of local businesses, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be less certain and more susceptible to revision or cancelation, and legal redress may be uncertain or delayed. If the existing body of laws and regulations in Indonesia are interpreted or applied, or relevant discretions exercised, in an inconsistent manner by the courts or applicable regulatory bodies, the foregoing could result in ambiguities, inconsistencies and anomalies in the enforcement of such laws and regulations, which in turn could hinder our long-term planning efforts and may create uncertainties in our operating environment.

***Increased regulation by governments and governmental agencies may increase the cost of regulatory compliance and limit our access to new exploration properties.***

The oil and gas industry is generally subject to regulation and intervention by governments throughout the world in such matters as the award of exploration and production interests, the imposition of specific drilling obligations, environmental, health and safety controls, controls over the development and decommissioning of a field (including restrictions on production) and possibly, nationalization, expropriation, cancelation or non-renewal of contract rights.

Within Indonesia, where our operations are primarily located, the evolving roles of SKK MIGAS and the Ministry of Energy and Mineral Resources, coupled with political changes in Indonesia, have allowed other Government agencies such as the Ministry of Trade, BKPM and the Ministry of Environment and Forestry, to increase their roles in administering and regulating the oil and gas industry in Indonesia. The continued expansion of the roles of governmental agencies may result in the adoption of new regulations, legislation and practices that we would be required to comply with.

In addition, new regulations, legislation and practices may be adopted by the Government and other governments or governmental agencies in countries in which we have operations in response to evolving practices or specific incidents, such as the Gulf of Mexico oil spill, which may result in more stringent regulation of oil and gas activities in the United States and elsewhere, particularly relating to environmental, health and safety controls and oversight of drilling operations, as well as access to new areas. Any new regulations, legislation and practices could increase the cost of compliance and may require changes to our drilling operations, exploration, development and decommissioning plans and could impact our ability to capitalize on our assets and limit our access to new exploration properties or operatorships.

The oil and gas industry is also subject to the payment of royalties and taxation, which tend to be high compared with those payable in respect of other commercial activities, and we operate in certain tax jurisdictions that have a degree of uncertainty relating to the interpretation of, and changes to, tax law. As a result of new laws and regulations or other factors, we could be required to curtail or cease certain operations, or we could incur additional costs.

***Indonesia is subject to significant geological risk that could lead to natural disasters and economic loss.***

Because of its location in a geologically active part of the world, Indonesia is subject to various forms of natural disasters. These include earthquakes, tsunamis, volcanic eruptions, floods, tropical weather conditions and landslides that can result in major losses of life and property, such as the 2018 earthquake just off the central island of Sulawesi and the 2018 eruption and partial collapse of the Anak Krakatau volcano followed by a tsunami. Recently, heavy rain caused massive flooding in the capital and the Greater Jakarta region and several other regions, including Aceh from December 31, 2019 until January 1, 2020. These types of events may cause significant disruptions and can therefore have significant economic and developmental effects. For example, gas production at Block A, Aceh was recently temporarily suspended due to the impact of heavy rain.

If the Government is unable to timely deliver foreign aid to affected communities, political and social unrest could result. Any such failure on the part of the Government, or declaration by it of a moratorium on its sovereign debt, could trigger an event of default under numerous private-sector borrowings including ours, thereby materially and adversely affecting our business, financial condition, results of operations and prospects.

In addition, the future geological or meteorological occurrences may significantly harm the Indonesian economy. A significant earthquake or other geological disturbance or weather-related natural disasters in any of Indonesia's more populated cities and financial centers could severely disrupt the Indonesian economy and thereby could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Terrorist attacks and terrorist activities and certain destabilizing events have led to substantial and continuing economic and social volatility in Indonesia, which may materially and adversely affect our business.***

Terrorist attacks and associated military responses have resulted in substantial and continuing economic volatility and social unrest in the world. In Indonesia during the last several years and as recently as May 2017, there have been various terrorist attacks directed towards the Government, foreign governments and public and commercial buildings frequented by foreigners, which have killed and injured a number of people. For example, in May 2018, terrorist bombings at three churches in Surabaya, Java resulted in the death of at least 13 people and injuries to more than 40 people.

There can be no assurance that further terrorist acts will not occur in the future. Any of the foregoing events, including damage to our infrastructure or that of our suppliers and customers, could materially and adversely affect international financial markets and the Indonesian economy, interrupt parts of our business and therefore could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Political conditions in Thailand could impact our business.***

We hold interests in the Bualuang and Sinphuhorm fields in Thailand. As a result, we would be subject to the risk that our business may be impacted by the ongoing political situation in Thailand, which has been unstable from time to time. On May 22, 2014, Thailand's Army Commander-in-Chief Gen. Prayuth Chan-ocha declared a coup. The National Council for Peace and Order was then established, comprised of leaders from the army, navy, air force and police. The 2007 constitution was abrogated and replaced with a new constitution in August 2016. A general election was held in March 2019 and the leadership of the new government, as well as the new government's stance on the regulation of the oil and gas industry as well as any potential actions related to its oil and gas industry, remain uncertain. There can be no assurance that there will be no further political disruptions in the future or that the new government will continue the policies of the previous government with respect to the oil and gas industry. Prolonged political instability in Thailand or changes in policies related to the oil and gas industry could have a material adverse effect on the economic and legal conditions in Thailand as well as our current interests in Thailand, which in turn could have a material adverse effect our business, financial condition, results of operations and prospects.

***Any outbreak of infectious disease, or fear of an outbreak, or any other serious public health concerns in Indonesia or elsewhere may have an adverse effect on the Indonesian economy and may adversely affect us.***

An outbreak of infectious diseases (including avian flu, SARS, swine flu, the H7N9 virus) or another contagious disease or the measures taken by the governments of affected countries, including Indonesia, against such potential outbreaks, could seriously interrupt our operations or the services or operations of our suppliers and customers, which could have a material adverse effect on our business, financial condition, results of operations and prospects. The perception that an outbreak of infectious diseases or another contagious disease may occur may also have an adverse effect on the economic conditions of countries in Asia, including Indonesia.

***Regional or global economic challenges may materially and adversely affect the Indonesian economy and our business.***

The economic crisis which affected South East Asia, including Indonesia, from mid-1997 was characterized in Indonesia by, among other events, currency depreciation, a significant decline in real gross domestic product, high interest rates, social unrest and extraordinary political developments. As a result of the economic crisis in 1997, the Government has had to rely on the support of international agencies and governments to prevent sovereign debt defaults. The economic difficulties Indonesia faced during the Asian economic crisis that began in 1997 resulted in, among other things, significant volatility in interest rates, which had a material adverse impact on the ability of many Indonesian companies to service their existing indebtedness.

Indonesia's economy remains significantly affected by economic conditions which resulted in a decrease in Indonesia's real GDP growth from 6.2% in 2012, to 5.8% in 2013, 5.0% in 2014, 4.8% in 2015, a slight increase in 2016 to 5.0%, to 5.1% in 2017 and to 5.2% in 2018. These conditions had a material adverse effect on Indonesian businesses. The global financial markets have experienced, and may continue to experience, significant turbulence originating from the liquidity shortfalls in the U.S. credit and sub-prime residential mortgage markets since 2008, which have caused liquidity problems resulting in bankruptcy for many institutions, and resulted in major government bailout packages for banks and other institutions. The global economic crisis has also resulted in a shortage in the availability of credit, a reduction in foreign direct investment, the failure of global financial institutions, a drop in the value of global stock markets, a slowdown in global economic growth and a drop in demand for certain commodities. The global financial markets have also recently experienced volatility as a result of concerns over the debt crisis in the Eurozone. Uncertainty over the outcome of the Eurozone governments' financial support programs and worries about sovereign finances generally are ongoing.

The Government continues to have a modest fiscal deficit and a high level of sovereign debt, its foreign currency reserves are modest, the Rupiah continues to be volatile and has poor liquidity and the banking sector is weak and suffers from high levels of non-performing loans. The inflation rate (measured by the year on year change in the consumer price index) remains volatile. The Indonesia rate of inflation was 3.0% in 2016, 3.0% in 2017 and 3.1% in 2018 based on the consumer price index. Interest rates in Indonesia have also been volatile in recent years, which have had a material adverse impact on the ability of many Indonesian companies to service their existing indebtedness.

The current global economic situation could further deteriorate or have a greater impact on Indonesia and our business. Any of the foregoing could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***We are subject to corporate disclosure and reporting requirements that differ from those in other countries.***

We are subject to corporate governance and reporting requirements in Indonesia that differ, in significant respects, from those applicable to companies in certain other countries. The amount of information made publicly available by issuers in Indonesia may be less than that made publicly available by comparable companies in certain more developed countries, and certain statistical and financial information of a type typically published by companies in certain more developed countries may not be available. As a result, investors may not have access to the same level and type of disclosure as that available in other countries, and comparisons with other companies in other countries may not be possible in all respects.

***Downgrades of the credit ratings of Indonesia and Indonesian companies could materially and adversely affect us.***

As of the date of this document, Indonesia's sovereign foreign currency long-term debt is rated "Baa2/Stable" by Moody's, "BBB/Stable" by Standard & Poor's and "BBB/Stable" by Fitch. These ratings reflect an assessment of the Government's overall financial capacity to pay its obligations and its ability or willingness to meet its financial commitments as they become due.

Any downgrade to credit ratings of Indonesia or Indonesian companies could have an adverse impact on liquidity in the Indonesian financial markets, the ability of the Government and Indonesian companies, including us, to raise additional financing and the interest rates and other commercial terms at which such additional financing is available and could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***We may be subject to changes in taxation.***

Our subsidiaries engaged in oil and gas operations in Indonesia are subject to taxation and are faced with increasingly complex tax laws. The amount of tax we pay could increase substantially as a result of changes in, or new interpretations of, these laws, which could have a material adverse effect on our liquidity and results of operations. Taxes have increased or been imposed in the past and may increase or be imposed again in the future. In addition, taxing authorities could review and question our tax returns leading to additional taxes and penalties which could be material.

We have participating interests in a number of PSCs in Indonesian with a different regime. Certain recent changes to Indonesian tax laws may adversely affect us:

*Cost recovery PSC regime*

On December 20, 2010, the Government enacted Government Regulation 79/2010 ("GR 79/2010"), which changes the regime governing cost recovery under PSCs and the taxation of oil and gas activities. GR 79/2010 generally applies to PSCs entered into or extended after December 20, 2010. PSCs entered into or extended before December 20, 2010 will continue to be governed by the regulations prevailing at the time such PSCs were executed, unless it is determined that such PSCs have not expressly or sufficiently provided for the areas mentioned in the list below, in which case the provisions of GR 79/2010 will apply and such PSCs must be adjusted within three months of the effective date of GR 79/2010 (being December 20, 2010). It is not yet clear who will make such determinations or how they will be made.

The transitional provisions in GR 79/2010 list eight areas that makes GR 79/2010 applicable to PSCs entered into before December 20, 2010 including:

- government share;
- requirements for cost recovery and the norms for claiming operating non-allowable costs;
- non-recoverable operating costs;
- the appointment of independent third parties to carry out financial and technical verifications;
- the issuance of income tax assessments;
- the exemption of customs duty and import tax on the importation of goods used during exploitation and exploration activities;
- contractor's tax in the form of oil and gas from the contractor's share; and
- income from outside the PSC in the form of uplifts and/or the transfer of PSC interests.

On June 15, 2017, the Government enacted Government Regulation No. 27 of 2017 regarding the Amendment of Government Regulation No. 79 of 2010 regarding Operating Costs that may be Recovered and Income Tax Treatment for Upstream Oil and Gas Activities ("GR 27/2017"), which was put into effect on June 19, 2017. PSCs entered into or extended: (i) prior to the enactment of Oil and Gas Law; (ii) after the enactment of Oil and Gas Law and prior to enactment of GR 79/2010; and/or (iii) after the enactment of GR 79/2010, will continue to be governed by the regulations prevailing at the time such PSCs were executed, unless it is determined that such PSCs have not expressly or sufficiently provided for the eight areas mentioned in the transitional provisions of GR 27/2017, which are the same as the eight areas mentioned in the transitional provisions of GR 79/2010 above.

GR 27/2017 introduced new tax facilities which previously were not available in GR 79/2010, as described below:

- domestic purchase of certain goods on which VAT is applicable and utilization of certain intangible goods and services from overseas during exploitation and exploration period are exempted from VAT.

These VAT exemption facilities available during the exploitation period can be granted by the Ministry of Finance upon consideration of the economics of the project;

- 100% reduction of land and building tax during exploration period as stated in the Tax Payable Notification Letter. The same facilities also apply to activities during the exploitation period for sub-surface parts, but are granted only by the Ministry of Finance upon consideration of the economics of the project;
- facility cost sharing and parent company overhead charges are exempted from withholding tax and VAT; and
- income from outside the PSC in the form of uplifts and/or the transfer of PSC interests after deduction of final income tax, is from branch profit tax.

PSCs entered into or extended prior to enactment of GR 27/2017 which aim to utilize benefits from GR 27/2017 may choose to adjust the PSCs in full with the terms of GR 27/2017 within a period of no more than six months after the effective date of GR 27/2017 (being June 19, 2017). It is not yet clear who will make such determinations or how they will be made.

Further changes to the taxation and tax laws that may result in higher taxes and operating costs in Indonesia could have a material adverse effect on our business, results of operations, financial condition and prospects.

*Gross split PSC regime*

On January 16, 2017, the MEMR introduced the gross split PSC regime, along with the existing cost recovery PSC regime, through the Ministry of Energy and Mineral Resources Regulation No. 8 Year 2017 ("EMR Reg-8/2017"), as amended on August 27, 2017 by Ministry of Energy and Mineral Resources Regulation No. 52 Year 2017. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant Factors Affecting Results of Operations — Gross Split PSC Tax Regime."

On December 28, 2017, the Government enacted GR-53/2017, which regulates the taxation of oil and gas activities under a gross split PSC regime. Any PSC entered into or extended after January 16, 2017 has been or will be arranged under a gross split PSC.

The taxation of gross income derived from gross split PSC activities generally follows the prevailing general corporate income tax rate, which is equal to 25% of taxable income. Gross income derived by a permanent establishment from gross split PSC activities, is subject to a branch profit tax of 20% of net after tax profits or such lower income tax rate as is applicable under an applicable Tax Treaty. The taxable income arising from PSC activities comprises "gross income" less the deductible "operating costs", which may be carried forward for up to 10 years. Under general Indonesian tax law, tax losses are not permitted to be carried forward more than five years. While the traditional cost recovery regime permits tax losses to be carried forward indefinitely, the gross split PSC tax regime does not provide for a cost recovery mechanism, such that only operating costs may be deducted from gross income.

The tax benefits available to a gross split PSC under GR-53/2017 are as follows:

(1) during the exploration and development period prior to commencement of production:

  - goods used in relation to oil and gas operations are exempt from import duty;
  - VAT is not collected on the local procurement and import of goods (whether tangible or intangible) and services used in operations;
  - the import of goods that have the benefit of the import duty exemption described above is exempt from withholding tax; and
  - 100% of land and buildings tax may be deducted for income tax purposes.

(2) facility cost sharing and parent company overhead charges that are exempted from withholding tax and VAT; and

(3) income from outside the PSC in the form of uplifts and/or the transfer of PSC interests after deduction of final income tax, is not subject to branch profit tax.

However, the procedures to be undertaken in order to obtain these tax benefits are to be governed by regulations of the Ministry of Finance, which have not yet been issued. Furthermore, if an existing PSC that benefits from the cost recovery regime and is already in commercial production is extended into a gross split PSC, the foregoing tax benefits that apply only during the pre-production period would not be available. Any of the foregoing could have a material adverse impact on our business, results of operations, financial condition and prospects.

In 2018 and 2019 respectively, our Tarakan PSC and Rimau PSC, which were scheduled to expire in 2022 and 2023, respectively, each obtained a 20-year PSC extension from the Government. The terms of the extensions differ from the existing PSC cost recovery format and follow the new gross split PSC regime.

***We are exposed to the risk of adverse sovereign action.***

The oil and gas industry is a significant contributor to the Indonesian economy and the economies of the other countries where we operate and is therefore a key government focus. Potential future changes in government policy, regulations or PSC fiscal regimes and taxes could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations. In addition, there are unresolved sovereign boundary disputes involving Vietnam, China and other countries in the East Sea (South China Sea) that involve risk to operations.

***Our assets may be subject to sovereign immunity risk.***

Indonesia has a constitution and laws which entrench and vest all of the rights over its natural resources in the state, including oil and gas resources, which are regarded as sovereign state assets. Indonesia has also established a state-owned agency which enters into commercial contracts with oil and gas exploration and production companies in relation to the exploration, development and production of oil and gas resources. Accordingly, the natural resources discovered within a contract area are ultimately owned by the state and the exploration and production agency only has contractual rights of exploration, development and production. As our contracts in Indonesia are with a state-owned agency, in the event of a dispute, it is uncertain if the state-owned agency will be able to invoke the principles of sovereign immunity. We are subject to similar risks with respect to our international operations. The invocation of such immunity may limit our ability to enforce our rights, which in turn could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

***Labor laws and regulations in Indonesia or other countries where we operate as well as labor unrest may materially adversely affect our results of operations.***

Laws and regulations which facilitate the forming of labor unions, combined with weak economic conditions, have resulted and may continue to result in labor unrest and activism in Indonesia. In 2000, the Government issued Law No. 21 of 2000 regarding Labor Unions (the "Labor Union Law"). The Labor Union Law permits employees to form unions without intervention from an employer, the government, a political party or any other party. On March 25, 2003, President Megawati enacted Law No. 13 of 2003 regarding Employment (the "Labor Law") which, among other things, increased the amount of severance, pension, medical coverage, life insurance, service and compensation payments payable to employees upon termination of employment. The Labor Law requires further implementation of regulations that may substantively affect labor relations in Indonesia. The Labor Law requires companies with 50 or more employees to establish bipartite forums with participation from employers and employees. The Labor Law also requires a labor union to have participation of more than half of the employees of a company in order for a collective labor agreement to be negotiated and creates procedures that are more permissive to the staging of strikes. Following the enactment, several labor unions urged the Indonesian Constitutional Court to declare certain provisions of the Labor Law unconstitutional and order the Government to revoke those provisions. The Indonesian Constitutional Court declared the Labor Law valid except for certain provisions, including relating to the right of an employer to terminate its employee who committed a serious mistake and criminal sanctions against an employee who instigates or participates in an illegal labor strike. Our international operations are also subject to the labor laws in the jurisdictions where we operate, and our international operations are affected by such laws.

Labor unrest and activism in Indonesia could disrupt our operations, our suppliers or contractors and could affect the financial condition of Indonesian companies in general, depressing the prices of Indonesian securities on the Jakarta or other stock exchanges and the value of the Rupiah relative to other currencies. Labor disruptions outside of Indonesia in the markets in which we operate have affected and could in the future affect our operations. For example, our operations in Tunisia were suspended due to labor protests in connection with a general strike in the country from April 2017 to June 2017. Such events could materially and adversely affect our business, financial condition, results of operations and prospects.

## UNAUDITED PRO FORMA COMBINED CONSOLIDATED FINANCIAL INFORMATION

The following tables present the unaudited pro forma combined consolidated financial information of the Company for the year ended December 31, 2018 and the nine-month period ended September 30, 2019, which consists of: (i) the unaudited pro forma combined consolidated statement of profit or loss and other comprehensive income for the year ended December 31, 2018, (ii) the unaudited pro forma combined consolidated statement of profit or loss and other comprehensive income for the nine-month period ended September 30, 2019, and (iii) the notes to the unaudited pro forma combined consolidated financial information for the year ended December 31, 2018 and the nine-month period ended September 30, 2019 (collectively referred to as the "Unaudited Pro Forma Financial Information").

Effective from May 22, 2019 (the "Acquisition Date"), the Company has acquired Ophir, and accordingly, Ophir's results have been reflected in the historical audited consolidated financial statements of the Company from the Acquisition Date. Since the Ophir Acquisition has been reflected in the historical audited consolidated statements of financial position of the Company as of September 30, 2019, Medco Energi did not present the unaudited pro forma combined consolidated statement of financial position of the Company as of September 30, 2019.

The unaudited pro forma combined consolidated statement of profit or loss and other comprehensive income for the year ended December 31, 2018 and the nine-month period ended September 30, 2019 gives effect to the Ophir Acquisition as if it had occurred on January 1, 2018.

The unaudited pro forma combined consolidated statement of profit or loss and other comprehensive income for the year ended December 31, 2018 was prepared based on: (i) the historical audited consolidated financial statements of the Company as of December 31, 2018 and for the year then ended prepared by Medco Energi's management in accordance with IFAS and presented in U.S. Dollars (the "2018 IFAS Audited Financial Statements of the Company"), and (ii) the historical unaudited consolidated financial statements of the Ophir Group as of December 31, 2018 and for the year then ended prepared by Medco Energi's management in accordance with IFAS and presented in U.S. dollars (the "2018 IFAS Unaudited Financial Statements of the Ophir Group"). The 2018 IFAS Unaudited Financial Statements of the Ophir Group were prepared by the Medco Energi's management by converting the historical audited consolidated financial statements of the Ophir Group as of December 31, 2018 and for the year then ended prepared by the Ophir's management in accordance with International Financial Reporting Standards as adopted by the European Union ("EU IFRS") and presented in U.S. dollars (the "2018 EU IFRS Audited Financial Statements of the Ophir Group") to IFAS after considering: (i) the relevant significant differences between EU IFRS and IFAS, and (ii) the alignment of the financial statements presentation in conformity with the 2018 Audited Financial Statements of the Company through certain reclassification journal entries.

The unaudited pro forma combined consolidated statement of profit or loss and other comprehensive income for the nine-month period ended September 30, 2019 was prepared based on: (i) the historical audited consolidated financial statements of the Company as of September 30, 2019 and for the nine-month period then ended prepared by Medco Energi's management in accordance with IFAS and presented in U.S. Dollars (the "2019 IFAS Audited Financial Statements of the Company"), and (ii) the historical audited consolidated financial statements of the Ophir Group as of September 30, 2019 and for the nine-month then ended prepared by Medco Energi in accordance with IFAS and presented in U.S. dollars (the "2019 IFAS Audited Financial Statements of the Ophir Group") and adjusted as described below.

The 2019 IFAS Audited Financial Statements of the Company and the 2018 IFAS Audited Financial Statements of the Company have been audited by KAP Purwantono, Sungkoro & Surja (the Indonesian member firm of Ernst & Young Global Limited), independent public accountants, in accordance with Standards on Auditing established by the Indonesian Institute of Certified Public Accountants ("IICPA"), whose audit report is included therein.

The 2019 IFAS Audited Financial Statements of Ophir, have been audited by KAP Purwantono, Sungkoro & Surja, the Indonesian member firm of Ernst & Young Global Limited), independent public accountants, in accordance with Standards on Auditing established by the IICPA.

The 2018 EU IFRS Audited Financial Statements of the Ophir Group have been audited by Ernst & Young LLP, London, United Kingdom, independent public accountants, in accordance with International Standards on Auditing (UK), whose audit report is included therein.

The 2018 IFAS Unaudited Financial Statements of the Ophir Group, are neither audited nor reviewed in accordance with any generally accepted auditing or review standards.

We have derived the 2018 Unaudited Pro Forma Financial Information presented in the tables below through the following mechanism:

(a) First, the accounts in the audited historical consolidated statement of profit or loss and other comprehensive income of Ophir Group for the year ended December 31, 2018 prepared under EU IFRS have been reclassified ("Reclassification Adjustments") to conform to the presentation of the audited historical consolidated statement of profit or loss and other comprehensive income for the year then ended. Further, Medco Energi presented "IFAS Adjustments" which pertain to adjustments to reflect (i) the adjustments to convert Ophir's EU IFRS balances to IFAS balances; and (ii) adjustments to conform the Ophir Group's significant accounting policies to the Company's significant accounting policies and IFAS balances. However, for purposes of the Unaudited Pro Forma Consolidated Financial Information, Medco Energi used certain assumptions. For further details on Medco Energi's key assumptions and estimates on these IFAS adjustments, see "Notes on IFAS Adjustments".

(b) Lastly, Medco Energi recorded "Pro forma Adjustments" based on certain estimates and assumptions. For further details on Medco Energi's key assumptions and estimates underlying the pro forma adjustments, see "Notes on Pro forma Adjustments".

We have derived the 2019 Unaudited Pro Forma Financial Information presented in the tables below through the following mechanism:

(a) First, the accounts in the audited historical consolidated statement of profit or loss and other comprehensive income of Medco Energi for the nine-month period ended September 30, 2019 prepared under IFAS are combined with the audited historical consolidated statement of profit or loss and other comprehensive income for the nine-month period ended of Ophir Group prepared under IFAS.

(b) Lastly, the Company recorded "Pro forma Adjustments" to exclude Ophir's historical operating results which have been included in the Company's historical consolidated financial statements from the Acquisition Date until September 30, 2019, and to reclassify certain accounts to conform with Medco Energi's presentation and additional pro forma adjustments based on estimates and assumptions. For further details on the Company's key assumptions and estimates underlying the pro forma adjustments, see "Notes on Pro forma Adjustments".

The Unaudited Pro Forma Combined Consolidated Financial Information included in this document is provided for illustrative purposes only. Because of its nature, the Unaudited Pro Forma Combined Consolidated Financial Information included in this document addresses a hypothetical situation and, therefore, does not represent the Company's actual results of operations for the year ended December 31, 2018 and the nine-month period ended September 30, 2019. In addition, the Unaudited Pro Forma Combined Consolidated Financial Information included in this document does not represent what the Company's financial condition or results of operations actually would have been if the Ophir Acquisition had in fact occurred on January 1, 2018 and is not representative of and should not be relied upon as indicative of the results of operations for any future periods.

The unaudited pro forma combined consolidated statement of profit or loss and other comprehensive income set forth below does not take into account: (i) the effects on income tax expenses of the pro forma adjustments set forth in Note 3 Unaudited Pro Forma Combined Consolidated Financial Information assuming the Acquisition had occurred as of January 1, 2018. See "Risk Factors — Risks Relating to Our Business and Operations — The historical financial information for Ophir and the pro forma financial information included in this document may not be representative of our results as a combined company in the future."

*You should read the summary pro forma combined consolidated financial information presented in the tables below in conjunction with our consolidated financial statements, Ophir's EU IFRS financial statements, related notes to such financial statements, and other financial information, included elsewhere in this document and the sections of this document entitled "Summary Financial, Operation and Reserve Data," "Risk Factors — Risks Relating to Our Business and Operations — The historical financial information for Ophir and the pro forma financial information included in this document may not be representative of our results as a combined company in the future" and "Management's Discussion and Analysis of Financial Condition and Results of Operations."*

**Ophir Energy plc**
**Historical Consolidated Income Statement and Statement of Other Comprehensive Income**
**Prepared in accordance with EU IFRS**
**For the year ended December 31, 2018**
**(Expressed in Millions of United States Dollars)**

| | Ophir Group Historical Consolidated Balances (EU IFRS) (Before Reclassification) (Audited) | Reclassification (Unaudited) | Ophir Group Historical Consolidated Balances (EU IFRS) (After Reclassification) (Unaudited) |
|---|---|---|---|
| Revenue | 298.2 | (298.2) | — |
| Cost of sales | (199.2) | 199.2 | — |
| **Gross profit** | **99.0** | **(99.0)** | **—** |
| Share of profit of investments accounted for using the equity method | 4.9 | (4.9) | — |
| Impairment (losses)/reversal of oil and gas properties | (13.5) | 13.5 | — |
| Impairment of investments accounted for using the equity method | (45.0) | 45.0 | — |
| Impairment of non-current assets held for sale | (613.7) | 613.7 | — |
| Exploration expenses | (130.4) | 130.4 | — |
| General and administration expenses | (10.9) | 10.9 | — |
| Gain on bargain purchase | 57.5 | (57.5) | — |
| Other operating expenses | (40.8) | 40.8 | — |
| **Operating loss** | **(692.7)** | **692.7** | **—** |
| Net-finance expense | (27.2) | 27.2 | — |
| Other financial gains | 0.2 | (0.2) | — |
| **Loss from continuing operations before taxation** | **(719.8)** | **719.8** | **—** |
| Taxation expense | (61.9) | 61.9 | — |
| **Loss from continuing operations for the year** | **(781.7)** | **781.7** | — |
| **Attributable to:** | | | |
| Equity holders of the Company | (781.7) | 781.7 | — |
| | **(781.7)** | **781.7** | **—** |
| **Consolidated statement of other comprehensive income** | | | |
| **Loss from continuing operations for the year** | **(781.7)** | **781.7** | **—** |
| Other comprehensive income/(loss) | | | |
| Other comprehensive income/(loss) to be reclassified to profit or loss in subsequent period: | | | |
| Exchange differences on retranslation of foreign operations, net of tax | 0.0 | 0.0 | — |
| Cash flow hedges marked to market | 5.6 | (5.6) | — |
| Cash flow hedges reclassified to the income statement | 8.0 | (8.0) | — |
| **Other comprehensive income/(loss) for the year, net of tax** | **13.5** | **(13.5)** | **—** |
| **Total comprehensive loss for the year, net of tax:** | **(768.1)** | **768.1** | **—** |
| **Attributable to:** | | | |
| Equity holders of the Company | (768.1) | 768.1 | — |
| | **(768.1)** | **768.1** | **—** |

**Ophir Energy plc**
**Unaudited Consolidated Income Statement and Statement of Other Comprehensive Income — As reclassified and Adjusted**
**Prepared in accordance with IFAS**
**For the year ended December 31, 2018**
**(Expressed in Millions of United States Dollars)**

| | Ophir Group Historical Consolidated Balances (EU IFRS) (Before Reclassification) (Unaudited) | Reclassification (Unaudited) | Ophir Group Historical Consolidated Balances (EU IFRS) (After Reclassification) (Unaudited) |
|---|---|---|---|
| **Continuing Operations** | | | |
| **Sales and Other Operating Revenues** | | | |
| Net oil and gas sales | — | 298.2 | 298.2 |
| **Total Sales and Other Operating Revenues** | **—** | **298.2** | **298.2** |
| **Cost of Sales and Other Direct Costs** | | | |
| Production and lifting cost | — | (92.1) | (92.1) |
| Cost of crude oil purchase | — | (0.1) | (0.1) |
| Depreciation, depletion and amortization | — | (107) | (107) |
| Exploration expenses | — | (130.4) | (130.4) |
| **Total Cost of Sales and Other Direct Costs** | **—** | **(329.6)** | **(329.6)** |
| **Gross Profit (Loss)** | **—** | **(31.4)** | **(31.4)** |
| Selling, general and administrative expenses | — | (10.9)<br>(0.2) [1a] | (11.1) |
| Finance costs | — | (30.1) [1b] | (30.1) |
| Finance income | — | 2.9 [1b] | 2.9 |
| Bargain purchase | — | 57.5 | 57.5 |
| Reversal of (Loss on) impairment of assets | — | (13.5) | (13.5) |
| Share of net gain (loss) of associated entities — net | — | 4.9 | 4.9 |
| Impairment of investments accounted for using the equity method | — | (45.0) | (45.0) |
| Impairment of non-current assets held for sale | — | (613.7) | (613.7) |
| Other income | — | 0.2 | 0.2 |
| Other expenses | — | (40.8)<br>0.2 [1a] | (40.5) |
| **Profit (loss) before tax expense from continuing operations** | **—** | **(719.8)** | **(719.8)** |
| Income tax benefit (expense) | — | (61.9) | (61.9) |
| **Profit (loss) for the year from continuing operations** | **—** | **(781.7)** | **(781.7)** |
| **Profit (loss) for the year from discontinued operations** | **—** | **—** | **—** |
| **Profit (loss) for the year** | **—** | **(781.7)** | **(781.7)** |

**Ophir Energy plc**
**Unaudited Consolidated Income Statement and Statement of Other Comprehensive Income — As reclassified and Adjusted**
**Prepared in accordance with IFAS**
**For the year ended December 31, 2018**
**(Expressed in Millions of United States Dollars)**

| | Ophir Group Historical Consolidated Balances (EU IFRS) (Before Reclassification) (Unaudited) | Reclassification (Unaudited) | Ophir Group Historical Consolidated Balances (EU IFRS) (After Reclassification) (Unaudited) |
|---|---|---|---|
| **Other Comprehensive Income that will be will be reclassified to profit and loss** | | | |
| Translation adjustment | — | — | — |
| Fair value adjustments on cashflow hedging instruments | — | 13.6 | 13.6 |
| Fair value adjustment from available for-sale investment | — | — | — |
| Share of OCI of associates | — | — | — |
| **Other Comprehensive Income that will note be will be reclassified to profit and loss** | | | |
| Share of OCI of associates | — | — | — |
| Remeasurement of defined benefit program | — | — | — |
| Income tax related to account which is not being reclassified | — | — | — |
| **Total Comprehensive Income For the Year** | **—** | **(768.1)** | **(768.1)** |
| **PROFIT (LOSS) ATTRIBUTABLE TO** | | | |
| Equity holders of the parent company | | | |
| Profit (loss) for the year from continuing operations | — | (781.7) | (781.7) |
| Profit (loss) for the year from discontinued operation | — | — | — |
| **Profit (loss) for the year attributable to owners of the parent company** | **—** | **(781.7)** | **(781.7)** |
| **Profit for the year from continuing operations attributable to non-controlling interests** | **—** | **—** | **—** |
| | **—** | **(781.7)** | **(781.7)** |
| **TOTAL COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO** | | | |
| Equity holders of the parent company | | | |
| Comprehensive income (loss) for the year from continuing operations | — | (768.1) | (768.1) |
| Comprehensive income (loss) for the year from discontinued operations | — | — | — |
| Comprehensive income (loss) for the year attributable to owners of the parent company | — | (768.1) | (768.1) |
| Total comprehensive income for the year from continuing operations attributable to non-controlling interests | — | — | — |
| | **—** | **(768.1)** | **(768.1)** |

**Ophir Energy plc**
**Unaudited Consolidated Income Statement and Statement of Other Comprehensive Income —**
**As reclassified and Adjusted**
**Prepared in accordance with IFAS**
**For the year ended December 31, 2018**
**(Expressed in Millions of United States Dollars)**

| | Ophir Group Historical Consolidated Balances (EU IFRS) (After Reclassification) (Unaudited) | IFAS Adjustments (Unaudited) | Ophir Group Historical Consolidated Balances (IFAS) (Unaudited) |
|---|---|---|---|
| **Continuing Operations** | | | |
| **Sales and Other Operating Revenues** | | | |
| Net oil and gas sales | 298.2 | — | 298.2 |
| **Total Sales and Other Operating Revenues** | **298.2** | **—** | **298.2** |
| **Cost of Sales and Other Direct Costs** | | | |
| Production and lifting cost | (92.1) | — | (92.1) |
| Cost of crude oil purchase | (0.1) | — | (0.1) |
| Depreciation, depletion and amortization | (107.0) | (41.3) [2a] | (148.3) |
| Exploration expenses | (130.4) | — | (130.4) |
| **Total Cost of Sales and Other Direct Costs** | **(329.6)** | **(41.3)** | **(370.9)** |
| **Gross Profit (Loss)** | **(31.4)** | **(41.3)** | **(72.7)** |
| Selling, general and administrative expenses | (11.1) | — | (11.1) |
| Finance costs | (30.1) | — | (30.1) |
| Finance income | 2.9 | — | 2.9 |
| Bargain purchase | 57.5 | — | 57.5 |
| Reversal of (Loss on) impairment of assets | (13.5) | — | (13.5) |
| Share of net gain (loss) of associated entities — net | 4.9 | — | 4.9 |
| Impairment of investments accounted for using the equity method | (45.0) | — | (45.0) |
| Impairment of non-current assets held for sale | (613.7) | — | (613.7) |
| Other income | 0.2 | — | 0.2 |
| Other expenses | (40.5) | — | (40.5) |
| **Profit (loss) before tax expense from continuing operations** | **(719.8)** | **(41.3)** | **(761.1)** |
| Income tax benefit (expense) | (61.9) | 21.3 [2b] | (40.6) |
| **Profit (loss) for the year from continuing operations** | **(781.7)** | **(20.0)** | **(801.7)** |
| **Profit (loss) for the year from discontinued operations** | **—** | **—** | **—** |
| **Profit (loss) for the year** | **(781.7)** | **(20.0)** | **(801.7)** |

**Ophir Energy plc**
**Unaudited Consolidated Income Statement and Statement of Other Comprehensive Income — As reclassified and Adjusted**
**Prepared in accordance with IFAS**
**For the year ended December 31, 2018**
**(Expressed in Millions of United States Dollars)**

| | Ophir Group Historical Consolidated Balances (EU IFRS) (After Reclassification) (Unaudited) | IFAS Adjustments (Unaudited) | Ophir Group Historical Consolidated Balances (IFAS) (Unaudited) |
|---|---|---|---|
| **Other Comprehensive Income that will be will be reclassified to profit and loss** | | | |
| Translation adjustment | — | — | — |
| Fair value adjustments on cashflow hedging instruments | 13.6 | — | 13.6 |
| Fair value adjustment from available for-sale investment | — | — | — |
| Share of OCI of associates | — | — | — |
| **Other Comprehensive Income that will note be will be reclassified to profit and loss** | | | |
| Share of OCI of associates | — | — | — |
| Remeasurement of defined benefit program | — | — | — |
| Income tax related to account which is not being reclassified | — | — | — |
| **Total Comprehensive Income For the Year** | **(768.1)** | **(20.0)** | **(788.1)** |
| **PROFIT (LOSS) ATTRIBUTABLE TO** | | | |
| Equity holders of the parent company | | | |
| Profit (loss) for the year from continuing operations | (781.7) | (20.0) | (801.7) |
| Profit (loss) for the year from discontinued operation | — | — | — |
| **Profit (loss) for the year attributable to owners of the parent company** | **(781.7)** | **(20.0)** | **(801.7)** |
| **Profit for the year from continuing operations attributable to non-controlling interests** | — | — | — |
| | **(781.7)** | **(20.0)** | **(801.7)** |
| **TOTAL COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO** | | | |
| Equity holders of the parent company | | | |
| Comprehensive income (loss) for the year from continuing operations | (768.1) | (20.0) | (788.1) |
| Comprehensive income (loss) for the year from discontinued operations | — | — | — |
| Comprehensive income (loss) for the year attributable to owners of the parent company | (768.1) | (20.0) | (788.1) |
| Total comprehensive income for the year from continuing operations attributable to non-controlling interests | — | — | — |
| | **(768.1)** | **(20.0)** | **(788.1)** |

**PT Medco Energi Internasional Tbk.**
**Unaudited Pro Forma Combined Consolidated Statement of Profit or Loss and Other Comprehensive Income**
**Prepared in accordance with IFAS**
**For the year ended December 31, 2018**
**(Expressed in Millions of United States Dollars)**

| | Company Historical Consolidated Balances IFAS (Audited) | Ophir Group Historical Consolidated Balances (IFAS) (Unaudited) | Total Combined Company and Ophir Group Balances (IFAS) (Unaudited) | Pro Forma Adjustments (Unaudited) | Company and Ophir Group Consolidated Pro Forma Balances (Unaudited) |
|---|---|---|---|---|---|
| **Continuing Operations** | | | | | |
| Sales and Other Operating Revenues | 1,218.3 | 298.2 | 1,516.5 | — | 1,516.5 |
| Cost of Sales and Other Direct Costs | (586.1) | (370.9) | (957.0) | 44.2 [3b] | (912.9) |
| **Gross Profit (Loss)** | **632.2** | **(72.7)** | **559.5** | **44.2** | **603.6** |
| Selling, general and administrative expenses | (157.3) | (11.1) | (168.4) | — | (168.4) |
| Finance costs | (189.0) | (30.1) | (219.1) | (24.0) [3g] | (243.1) |
| Finance income | 12.7 | 2.9 | 15.6 | — | 15.6 |
| Bargain purchase | — | 57.5 | 57.5 | — | 57.5 |
| Reversal of (Loss on) impairment of assets | (2.2) | (13.5) | (15.7) | — | (15.7) |
| Loss on dilution of investment | (19.1) | — | (19.1) | — | (19.1) |
| Share of net gain (loss) of associated entities — net | (66.7) | 4.9 | (61.8) | — | (61.8) |
| Impairment of investments accounted for using the equity method | — | (45.0) | (45.0) | — | (45.0) |
| Impairment of non-current assets held for sale | — | (613.7) | (613.7) | — | (613.7) |
| Other income | 10.1 | 0.2 | 10.3 | — | 10.3 |
| Other expenses | (18.6) | (40.5) | (59.1) | — | (59.0) |
| **Profit (loss) before tax expense from continuing operations** | **202.2** | **(761.1)** | **(558.9)** | **20.2** | **(538.7)** |
| Income tax benefit (expense) | (196.5) | (40.6) | (237.1) | (22.3) [3c] | (259.4) |
| **Profit (loss) for the year from continuing operations** | **5.7** | **(801.7)** | **(796.0)** | **(2.1)** | **(798.1)** |
| **Profit (loss) for the year from discontinued operations** | **(34.1)** | **—** | **(34.1)** | **—** | **(34.1)** |
| **Profit (loss) for the year** | **(28.4)** | **(801.7)** | **(830.1)** | **(2.1)** | **(832.2)** |
| **Other Comprehensive Income that will be will be reclassified to profit and loss** | | | | | |
| Translation adjustment | (5.6) | — | (5.6) | — | (5.6) |
| Fair value adjustments on cashflow hedging instruments | (7.1) | 13.6 | 6.5 | — | 6.5 |
| Fair value adjustment from available for-sale investment | 0.4 | — | 0.4 | — | 0.4 |
| Share of OCI of associates | 11.7 | — | 11.7 | — | 11.7 |

**PT Medco Energi Internasional Tbk.**
**Unaudited Pro Forma Combined Consolidated Statement of Profit or Loss and Other Comprehensive Income—(Continued)**
**Prepared in accordance with IFAS**
**For the year ended December 31, 2018**
**(Expressed in Millions of United States Dollars)**

| | Company Historical Consolidated Balances IFAS (Audited) | Ophir Group Historical Consolidated Balances (IFAS) (Unaudited) | Total Combined Company and Ophir Group Balances (IFAS) (Unaudited) | Pro Forma Adjustments (Unaudited) | Company and Ophir Group Consolidated Pro Forma Balances (Unaudited) |
|---|---|---|---|---|---|
| **Other Comprehensive Income that will note be will be reclassified to profit and loss** | | | | | |
| Remeasurement of defined benefit program | 10.4 | — | 10.4 | — | 10.4 |
| Income tax related to account which is not being reclassified to profit or loss | (0.9) | — | (0.9) | — | (0.9) |
| **Total Comprehensive Income For The Year** | **(19.5)** | **(788.1)** | **(807.6)** | **(2.1)** | **(809.7)** |
| **PROFIT (LOSS) ATTRIBUTABLE TO** | | | | | |
| Equity holders of the parent company | | | | | |
| Profit (loss) for the year from continuing operations | (17.2) | (801.7) | (818.9) | (2.1) | (821.0) |
| Profit (loss) for the year from discontinued operation | (34.1) | — | (34.1) | — | (34.1) |
| **Profit (loss) for the year attributable to owners of the parent company** | **(51.3)** | **(801.7)** | **(853.0)** | **(2.1)** | **(855.1)** |
| **Profit for the year from continuing operations attributable to non-controlling interests** | **22.9** | **—** | **22.9** | **—** | **22.9** |
| | **(28.4)** | **(801.7)** | **(830.1)** | **(2.1)** | **(832.2)** |
| **TOTAL COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO** | | | | | |
| Equity holders of the parent company | | | | | |
| Comprehensive income (loss) for the year from continuing operations | (14.1) | (788.1) | (802.2) | (2.1) | (804.3) |
| Comprehensive income (loss) for the year from discontinued operations | (30.7) | — | (30.7) | — | (30.7) |
| **Comprehensive income (loss) for the year attributable to owners of the parent company** | **(44.8)** | **(788.1)** | **(832.9)** | **(2.1)** | **(835.0)** |
| **Total comprehensive income for the year from continuing operations attributable to non-controlling interests** | **25.3** | **—** | **25.3** | **—** | **25.3** |
| | **(19.5)** | **(788.1)** | **(807.6)** | **(2.1)** | **(809.7)** |

## PT Medco Energi Internasional Tbk.
## Unaudited Pro Forma Combined Consolidated Statement of Profit or Loss and Other Comprehensive Income
## Prepared in accordance with IFAS
## For the nine-month period ended September 30, 2019
## (Expressed in Millions of United States Dollars)

| | Company Historical Consolidated Balances (IFAS) (Audited) | Ophir Group Historical Consolidated Balances (IFAS) (Audited) | Total Combined Company and Ophir Group Balances (IFAS) (Unaudited) | Pro Forma Adjustments | | Company and Ophir Group Consolidated Pro Forma Balances (Unaudited) |
|---|---|---|---|---|---|---|
| | | | | Adjustment 1 | Adjustment 2 | |
| **Continuing Operation** | | | | | | |
| Sales and Other Operating Revenues | 1,015.9 | 290.5 | 1,306.4 | (118.7) [3a] | — | 1,187.7 |
| Cost of Sales and Other Direct Costs | (576.2) | (218.1) | (794.3) | 70.8 [3a] | (12.9) [3b] | (736.4) |
| **Gross Profit** | **439.7** | **72.5** | **512.2** | **(47.9)** | **(12.9)** | **451.4** |
| Selling, general & administrative expenses | (172.1) | (17.6) | (189.7) | (0.8) [3a] | 35.2 [3d] | (155.3) |
| Exploration expenses | — | (5.5) | (5.5) | 5.5 [3a] | — | — |
| Finance costs | (188.5) | (24.4) | (212.9) | 1.5 [3a] | (2.0) [3g] | (213.4) |
| Finance income | 13.0 | 4.4 | 17.4 | — | — | 17.4 |
| Bargain purchase | 79.5 | — | 79.5 | — | (79.5) [3f] | — |
| Share of net gain (loss) of associated entities — net | (30.3) | 3.8 | (26.5) | (2.1) [3a] | — | (28.6) |
| Other income | 29.1 | 17.6 | 46.7 | (1.8) [3a] | — | 44.9 |
| Other expenses | (14.1) | (41.6) | (55.7) | — | 32.4 [3e] | (23.3) |
| **Income before tax expense from continuing operations** | **156.3** | **9.2** | **165.5** | **(45.6)** | **(26.9)** | **93.1** |
| Income tax benefit (expense) | (138.5) | (50.5) | (189.0) | 21.7 [3a] | (7.4) [3c] | (174.7) |
| **Profit (loss) for the period from continuing operations** | **17.8** | **(41.3)** | **(23.6)** | **(23.8)** | **(34.2)** | **(81.6)** |
| **Profit (loss) for the period from discontinued operations** | **8.8** | **—** | **8.8** | **—** | **—** | **8.8** |
| **Profit (loss) for the period** | **26.6** | **(41.3)** | **(14.7)** | **(23.8)** | **(34.2)** | **(72.8)** |
| **Other Comprehensive Income that will be will be reclassified to profit and loss** | | | | | | |
| Translation adjustment | 0.2 | — | 0.2 | — | — | 0.2 |
| Fair value adjustments on cashflow hedging instruments | (14.4) | — | (14.4) | — | — | (14.4) |
| Fair value adjustment from available for-sale investment | (0.2) | — | (0.2) | — | — | (0.2) |
| Share of OCI of associates | (4.3) | — | (4.3) | — | — | (4.3) |
| Cash flow hedges reclassified to the income statement | — | (10.0) | (10.0) | — | — | (10.0) |
| **Other Comprehensive Income that will note be will be reclassified to profit and loss** | | | | | | |
| Remeasurement of defined benefit program | 2.2 | — | 2.2 | — | — | 2.2 |
| Income tax related to account which is not being reclassified | (0.1) | — | (0.1) | — | — | (0.1) |
| **Total Comprehensive Income For The Period** | **9.9** | **(51.3)** | **(41.4)** | **(23.8)** | **(34.2)** | **(99.4)** |

**PT Medco Energi Internasional Tbk.**
**Unaudited Pro Forma Combined Consolidated Statement of Profit or Loss and Other Comprehensive Income—(Continued)**
**Prepared in accordance with IFAS**
**For the nine-month period ended September 30, 2019**
**(Expressed in Millions of United States Dollars)**

| | Company Historical Consolidated Balances (IFAS) (Audited) | Ophir Group Historical Consolidated Balances (IFAS) (Audited) | Total Combined Company and Ophir Group Balances (IFAS) (Unaudited) | Pro Forma Adjustments | | Company and Ophir Group Consolidated Pro Forma Balances (Unaudited) |
|---|---|---|---|---|---|---|
| | | | | Adjustment 1 | Adjustment 2 | |
| **PROFIT (LOSS) ATTRIBUTABLE TO** | | | | | | |
| **Equity holders of the parent company** | | | | | | |
| Profit (loss) for the period from continuing operations | 10.4 | (41.3) | (30.9) | (23.8) | (34.2) | (88.9) |
| Profit (loss) for the period from discontinued operation | 8.8 | — | 8.8 | — | — | 8.8 |
| Profit (loss) for the period attributable to Equity holders of the parent company | 19.3 | (41.3) | (22.0) | (23.8) | (34.2) | (80.0) |
| Profit for the period from continuing operations attributable to Equity holders of the parent company | 7.3 | — | 7.3 | — | — | 7.3 |
| | **26.6** | **(41.3)** | **(14.7)** | **(23.8)** | **(34.2)** | **(72.8)** |
| **TOTAL COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO** | | | | | | |
| **Equity holders of the parent company** | | | | | | |
| Comprehensive income (loss) for the period from continuing operations | 1.2 | (51.3) | (50.1) | (23.8) | (34.2) | (108.1) |
| Comprehensive income (loss) for the period from discontinued operations | 8.8 | — | 8.8 | — | — | 8.8 |
| Comprehensive income (loss) for the period attributable to Equity holders of the parent company | 10.0 | (51.3) | (41.3) | (23.8) | (34.2) | (99.3) |
| Total comprehensive income for the period from continuing operations attributable | (0.1) | — | (0.1) | — | — | (0.1) |
| | **9.9** | **(51.3)** | **(41.4)** | **(23.8)** | **(34.2)** | **(99.4)** |

**Notes to the Unaudited Pro Forma Financial Information**

**Footnotes relating to the columns "Ophir Group Historical Consolidated Balances (EU IFRS) (After Reclassification) (Unaudited)" and "IFAS Adjustments (Unaudited)" referring to the key assumptions and estimates used by Medco Energi in the preparation of these adjustments on the Ophir Groups' historical consolidated EU IFRS balances**

1. **Ophir Group Historical Consolidated Balances (After Reclassification)** *(amounts in millions of United States Dollars)*

   In general, the reclassified historical consolidated balances column is to re-present the Ophir Group's consolidated statement of income statement and other comprehensive income accounts as reflected in the 2018 EU IFRS Audited Financial Statements of the Ophir Group to the accounts naming convention and accounts presentation of the Company.

   In addition to the above general reclassification, certain accounts below have been identified to have different grouping or different accounts mapping, therefore, there are certain amounts that have been reclassified on these accounts to conform to the specific accounts grouping or accounts mapping of the Company. These amounts have been already incorporated in the "Ophir Group Historical Consolidated Balances (After Reclassification)" column.

   a. **Reclassification adjustment — Other operating expenses**

      The Company reclassified US$0.2 representing depreciation of other property, plant, and equipment from "Other operating expenses" balance of Ophir Group to "Selling, general, & administrative expenses" account.

   b. **Reclassification adjustment — Net finance expense**

      The Company reclassified US$27.2 representing the "Net finance expense" balance of Ophir Group to the following accounts: (i) "Finance costs" account amounting to US$30.1, and (ii) to "Finance income" account amounting to US$2.9.

2. **Indonesian Financial Accounting Standards (IFAS) Adjustments** *(amounts in millions of United States Dollars, unless otherwise stated)*

   The IFAS adjustments refer to (i) the adjustments of the Ophir's EU IFRS balances for the year ended December 31, 2018 as reflected in the 2018 EU IFRS Audited Financial Statements of the Ophir Group to convert to IFAS; and (ii) the adjustments to conform to the significant accounting policies and IFAS balances of the Company.

   a. **IFAS adjustments — Oil and gas properties**

      The Company noted a difference in the method of calculation of depreciation/depletion of oil and gas properties and related decommissioning assets. Due to the difference in the reserves base used by Ophir in calculating depreciation/depletion expense, the Company recalculated the Ophir's depreciation/depletion expense as follows:

      - Wells, facilities and decommissioning assets: Beginning balance of Net Book Value (NBV) plus future costs multiplied by the production volume divided by the beginning balance of proved (P1) reserves.
      - Excess cost over book value allocated to oil and gas assets from Santos acquisition: Beginning balance of Net Book Value (NBV) multiplied by the production volume divided by 90% of P1 reserves beginning balance + 50% proved and probable (P2) reserves beginning balance.

      The effect of the recalculation to conform with the Company's depreciation/depletion method resulted to additional depreciation/depletion expense amounting to US$41.3.

**b. IFAS adjustments — Deferred Tax Assets, Deferred Tax Liabilities, and Deferred Tax Income/ Expenses**

The Company adjusted the deferred tax assets/liabilities, and recognized the related deferred income tax impact. For the deferred income tax adjustment, this is pertaining to temporary difference arising from the difference in depreciation/depletion expense calculation as stated in Note 2a, and unwinding of the discount effect (accretion expense) from their decommissioning liabilities, with total adjustment of US$21.3 million

**Footnotes relating to the column "Pro forma adjustments" referring to the key assumptions and estimates used by the Company in the preparation of the pro forma adjustments**

**Basis of Acquisition Transaction** *(Expressed in millions of United States Dollars, unless otherwise stated)*

Medco Energi, through its wholly-owned subsidiary, MEG, acquired 100% of the issued and outstanding shares of Ophir for total cash consideration of US$579.5 (including related transaction costs of US$35.2), wherein such amount was based on the "Increased Recommended Final Cash Offer for Ophir Energy plc" by MEG, after converting from GBP to US$ using the applicable forward rate and average spot exchange rate.

Medco Energi financed the Ophir Acquisition with a portion of the net proceeds of the offering of the 2026 Notes.

Related to the Ophir Acquisition, and its would-be impact on the change of control on Ophir, the following financing transactions are also considered in the pro forma adjustments.

Ophir had existing debt on Reserves Based Lending (RBL) facility amounting to US$251.4 (including US$5.7 of unamortized cost and fair value adjustment at initial recognition) which is subject to interest rate between 4% and 4.5% plus LIBOR depending on the maturity of the RBLF, whereby, one of the covenants of the RBLF was that all outstanding amounts will be immediately due and demandable if there is a change in control in Ophir as the Original Borrower. The Acquisition would have triggered a change in control in Ophir as the Original Borrower of the RBLF, so the outstanding amounts of the RBLF would be immediately due and payable and Ophir used its available cash and cash equivalents to pay the outstanding debt on the RBLF amounting to US$253.2 (current portion of US$103.2; Non-Current portion of US$142.5; unamortized cost of US$7.5). The RBLF outstanding amount was settled in May 2019.

Ophir had outstanding 2013 Bonds payable amounting to US$104.8 (US$106.7 less fair value adjustment at initial recognition of US$1.9). The 2013 bonds payable of Ophir include a provision that the bondholders will have a right of prepayment of its bonds upon occurrence of change of control. Medco Energi used its internally available cash and cash equivalents to top up Ophir's own cash and cash equivalents and settle in full the Ophir's outstanding 2013 bonds payable. The 2013 bonds payable was settled in June 2019.

**Provisional Purchase Price Allocation**

The following table summarizes the preliminary purchase price allocation using provisional fair values as of Acquisition Date (May 22, 2019):

| | |
|---|---|
| Ophir Energy plc consolidated total assets | US$ 1,618.9 |
| Ophir Energy plc consolidated total liabilities | (995.1) |
| Total identifiable net assets at fair values | 623.8 |
| Bargain purchase | (79.5) |
| Purchase price consideration transferred | US$ 544.3 |

The Ophir Group's consolidated total assets and liabilities amounts above are the preliminary "provisional value" of Ophir's identifiable assets and liabilities assumed upon acquisition by Medco

Energi. These preliminary estimates of the provisional value will likely differ from the final amounts the Company will calculate after completing a detailed valuation analysis, and the difference could have a material effect on the unaudited pro forma combined consolidated financial information. The final purchase price allocation will be determined when the Company has completed the detailed valuations and necessary calculations and all information needed to perform detailed assessment are available to the Company.

Further, the Company has eliminated all of Ophir's equity accounts which are derived from "Ophir Group IFAS Consolidated Balances (Unaudited)" with the Company's investment cost to acquire 100%-ownership in Ophir.

The unaudited pro forma combined consolidated statement of profit or loss and other comprehensive income for the year ended December 31, 2018 and the nine-month period ended September 30, 2019 give effect to the Ophir Acquisition as if it had occurred on January 1, 2018.

The key assumptions and estimates underlying the "Pro forma adjustments" column to the unaudited pro forma consolidated financial information are described in the below footnotes, which should be read together with the unaudited pro forma combined consolidated financial information.

## 3. Pro Forma Adjustments

The pro forma adjustments are based on Medco Energi's estimates and assumptions that are subject to change. The following adjustments have been reflected in the unaudited pro forma consolidated financial information.

### a. Pro forma adjustments — Exclusion of Ophir's historical operating results

Amounts presented in the adjustment 1 column of the Pro Forma Adjustments in the Unaudited Pro Forma Combined Consolidated Statement of Profit or Loss and Other Comprehensive Income for the nine-month period ended September 30, 2019 represent adjustments to exclude Ophir's historical operating results which have been consolidated to the Company's historical consolidated balances from the Acquisition Date until September 30, 2019. Also, this includes general reclassification of certain profit or loss accounts to conform with Medco Energi's presentation.

### b. Pro forma adjustment — Depreciation expenses

This represents the adjustment to depreciation expense as a result of the adjustment on Ophir's historical oil and gas properties assets to their estimated fair value. As part of the preliminary purchase price allocation valuation analysis, Medco Energi estimated the fair value of Ophir oil and gas properties based on economic valuations of third party appraisals.

The Company calculated the depreciation/depletion expense as follows:

- Wells: Beginning balance of Net Book Value (NBV) multiplied by the production volume divided by the beginning balance of proved develop (P1D) reserves.
- Facilities: Beginning balance of Net Book Value (NBV) multiplied by the production volume divided by the beginning balance of proved develop and undeveloped (P1D+P1UD) reserves.

### c. Pro forma adjustment — Deferred tax

This represents the adjustment to reverse the deferred tax posted by Ophir in 2019 and record the deferred tax on depreciation/depletion using the new cost of Ophir's oil and gas properties based on the preliminary purchase price allocation at Acquisition Date of Ophir as stated in Note 3b.

Further, this also represents the deferred income tax adjustment pertaining to temporary differences arising from the difference in depreciation/depletion expense calculation based on commercial books, and the depreciation/depletion expense per production sharing contracts (tax books) of the oil and gas properties.

**d. Pro forma adjustment — Transaction costs**

This represents the elimination of nonrecurring transaction costs incurred during the nine-month period ended September 30, 2019 of US$35.2 that are directly related to the acquisition of Ophir.

**e. Pro forma adjustment — Penalty expenses on disposal of Santos assets**

This represents the elimination of penalty compensation payment for Santos assets, which was recorded as penalty expenses in the 2019 IFAS Audited Financial Statements of Ophir. In September 2018, Ophir acquired oil and gas blocks from Santos which includes blocks that were subject to various approvals by the government authorities where the blocks are located. Since the conditions precedent are not likely to be met, the acquisition transaction was terminated and the penalty was paid. Such penalty is considered as assumed liability in the purchase price allocation of Medco Energi at Acquisition Date. This penalty expenses are considered as a non-recurring item.

**f. Pro forma adjustment — Bargain purchase**

This represents elimination of preliminary bargain purchase gain calculated at the Acquisition Date which have been recorded in the 2019 IFAS Audited Financial Statements of the Company. The preliminary bargain purchase gain is considered as a non-recurring item and that is directly related to the acquisition.

**g. Pro forma adjustment — Finance costs**

This represents the effect of interest expenses from the issuance of the Company's 2026 Notes, and the settlement of the Ophir's RBLF and 2013 bonds payable assuming the transactions had occurred on January 1, 2018. The adjustment includes also the following assumptions:

1. Exclude interest expense from RBLF and 2013 bonds payable recognized in the December 31, 2018 Ophir Group consolidated balances, and include interest expense calculated from principal amount of the 2026 Notes multiplied with the effective interest rate, assuming the bonds issuance occurred on January 1, 2018.
2. Exclude profit or loss effect (e.g. unamortized cost) from the settlement of RBLF and 2013 bonds payable in the Ophir Group historical balances for the nine-month period ended September 30, 2019 and its related interest expense, and include interest expense calculated from the 2026 Notes starting from January 1, 2019 until May 31, 2019.

**h. Other pro forma assumptions**

The Company has not taken into account the effect to the unaudited pro forma combined consolidated statement of profit or loss and other comprehensive income.

a. Effect on the income tax expenses of the above pro forma adjustments assuming the Ophir Acquisition transaction had occurred on January 1, 2018.

## 4. Additional Information

The Company calculates for its pro forma depreciation, depletion and amortization expenses, which are included in the Cost of Sales and Other Direct Costs balances and in the Selling, general and administrative expenses balance as presented in the Unaudited Pro Forma Combined Consolidated Statement of Profit or Loss and Other Comprehensive Income Prepared in Accordance with IFAS, for the nine-month period ended September 30, 2019 as follows:

| | Company Historical Consolidated Balances (IFAS) (Audited) | Ophir Group Historical Consolidated Balances (IFAS) (Audited) | Total Combined Company and Ophir Group Balances (IFAS) (Unaudited) | Pro Forma Adjustments | | Company and Ophir Group Consolidated Pro Forma Balances (IFAS) (Unaudited) |
|---|---|---|---|---|---|---|
| | | | | **Adjustment 1** | **Adjustment 2** | |
| **Depreciation, depletion and amortization charged to:** | | | | | | |
| **Cost of Sales and Other Direct Costs** | | | | | | |
| Depreciation, Depletion and Amortization | (205.8) | (109.3) | (315.1) | 22.5 [3a] | (12.9) [3b] | (305.5) |
| **Selling, general and administrative expenses** | | | | | | |
| Depreciation, Depletion and Amortization | (3.1) | (0.1) | (3.2) | 0.2 [3a] | — | (3.0) |
| **Total** | **(208.9)** | **(109.4)** | **(318.3)** | **22.7** | **(12.9)** | **(308.5)** |

## GLOSSARY

### Certain Defined Terms

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| "1C" | means with respect to contingent resources, in the "low estimate" scenario of contingent resources, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 90%. |
| "AFS" | means available-for-sale. |
| "Alpha" | means adjustment to the Dated Brent price to accommodate crude quality, international oil price, and national energy security. |
| "AMDAL" | means an environmental impact analysis (Analisa Mengenai Dampak Lingkungan) required under the Environmental Law. |
| "AMG" | means PT Api Metra Graha. |
| "AMI" | means PT Amman Mineral Internasional. |
| "AMIV" | means PT Amman Mineral Investama. |
| "AMNT" | means PT Amman Mineral Nusa Tenggara. |
| "API" | means PT AP Investment. |
| "ASC" | means the Accounting Standard Codification. |
| "ASR" | means abandonment and site restoration for upstream oil and gas business activities. |
| "B/G" | means a bank guarantee facility in the form of uncommitted bank guarantee. |
| "Bapepam-LK" | means Badan Pengawas Pasar Modal dan Lembaga Keuangan (or Capital Market Supervisory Agency). |
| "BJI" | means PT Bio Jatropha Indonesia. |
| "BKPM" | means the Coordinating Investment Board (Badan Koordinasi Penanaman Modal) of the Government. |
| "Block A, Aceh PSC" | means the PSC between Pertamina and Asamera Oil (Indonesia) Ltd. dated July 6, 1989, which expired on August 31, 1991, and the amended and restated PSC between Pertamina, PT Medco EP Malaka, Premier Oil Sumatra (North) BV. and Japex Block A Ltd. dated October 28, 2010 that became effective as of September 1, 2011, as may be amended from time to time. |
| "BPD" | means barrels per day. |

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| "BP MIGAS" . . . . . . . . . . . . . . . . . . . . . . . . . | means Badan Pelaksana Kegiatan Usaha Hulu Minyak Dan Gas Bumi, the non-profit Government-owned operating board that is succeeding to Pertamina's role as regulator of upstream oil and gas activities under the Oil and Gas Law. |
| "BPH MIGAS" . . . . . . . . . . . . . . . . . . . . . . . . | means Badan Pengatur Hilir Minyak Dan Gas Bumi, the non-profit Government-owned operating board that is succeeding to Pertamina's role as regulator of downstream oil and gas activities under the Oil and Gas Law. |
| "BPJS" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means the national healthcare and employment social security schemes. |
| "Brent price" . . . . . . . . . . . . . . . . . . . . . . . . . | means Brent crude oil price. |
| "BSM" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means PT Bank Syariah Mandiri. |
| "BUMD" . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means a regional government-owned enterprise (Badan Usaha Milik Daerah). |
| "BUMN" . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means a state-owned enterprise (Badan Usaha Milik Negara). |
| "CAGR" . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means compounded annual growth rate. |
| "CCPP" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means a combined cycle power plant. |
| "CE" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Chubu Electric Power Co. Inc. |
| "CGU" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means a cash generating unit. |
| "Chubu" . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Chubu Electric Power Co, Inc. |
| "CoD" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means a certificate of domicile. |
| "COD" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means commercial operation date, which is the date as of which a project commences commercial operations. |
| "Company" . . . . . . . . . . . . . . . . . . . . . . . . . . | means Medco Energi and its consolidated subsidiaries. |
| "ConocoPhillips" . . . . . . . . . . . . . . . . . . . . . . | means ConocoPhillips Indonesia. |
| "Consortium" . . . . . . . . . . . . . . . . . . . . . . . . . | means a consortium of MPI and PT Dalle Engineering Construction. |
| "contract area" . . . . . . . . . . . . . . . . . . . . . . . . | means a specified geographic area that is the subject of a production sharing arrangement pursuant to which an operator and its partners provide financing and technical expertise to conduct exploration, development and production operations. |
| "COSPA" . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Crude Oil Sale and Purchase Agreement. |
| "COW" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means contract of work. |

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| "CPI" | means Consumer Price Index. |
| "Curator PKLC" | means the Curator Team of PT Panghegar Kana Legacy. |
| "custodian" | has the same meaning as set forth in the Indonesian Regulation PER-10/PJ/2017. |
| "Dated Brent" | means a benchmark assessment of the price of physical, light North Sea crude oil of physical cargoes of crude oil in the North Sea that have been assigned specific delivery dates. |
| "DBS" | means PT Bank DBS Indonesia. |
| "DCQ" | means daily contracted quantity. |
| "DE" | means PT Dago Endah. |
| "DEB" | means PT Dalle Energy Batam. |
| "delineation well" or "appraisal well" | means a well drilled in a newly discovered or known discovery to gain further information. |
| "development well" | means a well that is drilled to exploit the hydrocarbon accumulation defined by an appraisal or delineation well. |
| "DGMCG" | means the Directorate General of Minerals, Coal and Geothermal of Indonesia. |
| "DGOG" | means the Directorate General of Oil and Gas of Indonesia. |
| "DGT" | means the Directorate General of Tax of Indonesia. |
| "DMO" | means Domestic Market Obligations. |
| "DPR" | means the House of Representatives (Dewan Perwakilan Rakyat) of Indonesia. |
| "dry well" or "dry hole" | is an exploratory, development or appraisal well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. |
| "DSLNG" | means PT Donggi Senoro LNG, a joint venture company established in 2007 by a consortium consisting of PT Medco LNG Indonesia (a wholly owned subsidiary of our Group), Mitsubishi Corporation and KOGAS through their joint venture Sulawesi LNG Development Ltd., and Pertamina through its subsidiary PT Pertamina Hulu Energi. |
| "ELB" | means PT Energi Listrik Batam. |
| "EMR" | means Energy and Mineral Resources. |

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| "Encore" . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Encore Energy Pte Ltd. |
| "Energi Sengkang" . . . . . . . . . . . . . . . . . . . . | means PT Energi Sengkang. |
| "Environmental Law" . . . . . . . . . . . . . . . . . . . | means he Government enacted Law No. 32 of 2009 regarding Environmental Protection and Management. |
| "Environmental License" . . . . . . . . . . . . . . . . | means an Environmental License (Izin Lingkungan) from the Ministry of the Environment. |
| "EPC" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means engineering, procurement and construction. |
| "EPE" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means PT Energi Prima Elektrika. |
| "EPSA" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Exploration and Production Sharing Agreement. |
| "ESC" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Energy Sales Contract. |
| "ET-Batubara" . . . . . . . . . . . . . . . . . . . . . . . . | means a Registered Coal Exporter (Eksportir Terdaftar Batubara). |
| "exploration well" . . . . . . . . . . . . . . . . . . . . . . | means a well that is designed to test the validity of a seismic interpretation and to confirm the presence of hydrocarbons in an undrilled formation. |
| "Explosive Regulations" . . . . . . . . . . . . . . . . . | mean the Decree of Minister of Mining and Energy No. 555.K/26/M.PE/1995 on General Mining Occupational Safety and Health and the Regulation of Head of National Police No. 2 of 2008 on Supervision, Control and Safety of Commercial Explosive Materials. |
| "FID" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means the final investment decision. |
| "Financial Sector Incentive" . . . . . . . . . . . . . | has the same meaning as set forth in the Indonesian Regulation PER-10/PJ/2017. |
| "Forestry Law" . . . . . . . . . . . . . . . . . . . . . . . | means the Law No. 41 of 1999 on Forestry, as amended by Government Regulation as Substitute of Law No. 1 of 2004. |
| "FPSO" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means the Floating Production Storage and Offloading facilities. |
| "FRS" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means the Singapore Financial Reporting Standard. |
| "FSI-BM Companies" . . . . . . . . . . . . . . . . . . . | mean Financial Sector Incentive (Bond Market) Companies (as defined in the ITA). |
| "FSI-CM Companies" . . . . . . . . . . . . . . . . . . . | mean Financial Sector Incentive (Capital Market) Companies (as defined in the ITA). |
| "FSI-ST Companies" . . . . . . . . . . . . . . . . . . . | mean Financial Sector Incentive (Standard Tier) Companies (as defined in the ITA). |

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| "FSO" | means floating storage and offloading vessel. |
| "FTP" | means first tranche petroleum. |
| "GCA" | refers to Gaffney, Cline & Associates. |
| "Geothermal Law" | means the Law No. 21 of 2014 on the Geothermal Resources. |
| "GHG" | means global greenhouse gas. |
| "Government Benchmark Price" | means the Coal Benchmark Price or Mineral Benchmark Price (Harga Patokan Batubara atau Harga Patokan Mineral Logam) that is determined each month by the DGMCG. |
| "Government" | means the Government of Indonesia. |
| "GR" | means Government Regulations enacted by the Government. |
| "gross working interest production" | represents the sum of the oil and gas production from each of the Company's blocks multiplied by the effective interest in such block. |
| "gross working interest reserves" | represents reserves attributable to the Company's effective interest prior to deduction of Government take payable to the Government as owner of the reserves under the applicable contractual arrangement. |
| "GSA" | means Gas Sale Agreements. |
| "HOAs" | means binding heads of agreements. |
| "HSE" | means the health, safety and environment. |
| "HSFO" | means High Sulfur Fuel Oil 180 CST. |
| "HTM" | means held-to-maturity. |
| "ICP" | means the Indonesia Crude Price, which is a benchmark oil price that is currently based on the Brent benchmark oil price plus Alpha. |
| "ICP-SLC" | means the Indonesian Crude Price-Sumatra Light Crude/Minas, a reference price calculated using a formula determined by the Government. |
| "IDP" | means a Company Registration Certificate (Tanda Daftar Perusahaan). |
| "IDR" | means Indonesian Rupiah. |
| "IDS Shelf Bonds" | means Rupiah-Denominated Shelf Bonds. |

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| "IDX" ...... | means the Indonesia Stock Exchange (formerly known as the Jakarta Stock Exchange or JSX). |
| "IIF" ...... | means PT Indonesia Infrastructure Finance. |
| "Indonesia Income Tax" ...... | has the same meaning as set forth in the Indonesian Regulation PER-10/PJ/2017. |
| "Indonesia" ...... | means the Republic of Indonesia. |
| "Indonesian Bankruptcy Law" ...... | means the Law No. 37 of 2004 regarding Bankruptcy and Suspension of Obligation for Payment of Debts. |
| "Indonesian FAS" ...... | means Indonesian Financial Accounting Standards. |
| "Indonesian participant" ...... | means an Indonesian entity which must be offered a certain specified percentage undivided interest in the total rights and obligations under a production sharing arrangement. |
| "ING" ...... | means ING Bank N.V., Singapore Branch. |
| "IO" ...... | means an Operation License (Izin Operasi) for the purpose of supplying electricity for private use. |
| "IPB" ...... | means a Geothermal License (Izin Panas Bumi). |
| "IPP" ...... | means Independent Power Producer. |
| "IPPKH" ...... | means a Borrow-Use Forestry Permit (Izin Pinjam Pakai Kawasan Hutan) issued by the Minister of Environment and Forestry. |
| "IPR" ...... | means a People's Mining License (Ijin Pertambangan Rakyat). |
| "ISO" ...... | means International Organization for Standardization. |
| "ISRS" ...... | means International Stereotactic Radiosurgery Society. |
| "ITA" ...... | means the Income Tax Act, Chapter 134 of Singapore. |
| "Itochu" ...... | means Itochu Petroleum Co., (Singapore) Pte. Ltd. |
| "IUKS" ...... | means an Electricity Business License for Self-Use (Izin Usaha Ketenagalistrikan Untuk Kepentingan Sendiri). |
| "IUKU" ...... | means an Electricity Business License for Public Use (Izin Usaha Ketenagalistrikan Untuk Kepentingan Umum). |
| "IUP" ...... | means a Mining Business License (Ijin Usaha Pertambangan). |
| "IUPK" ...... | means a Special Mining Business License (Izin Usaha Pertambangan Khusus). |

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| "IUPK OP" . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Special Mining Business License—Operation Production (Izin Usaha Pertambangan Khusus—Operasi Produksi). |
| "IUPTL" . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means an Electricity Supply Business License (Izin Usaha Penyediaan Tenaga Listrik). |
| "JCC" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Japan Crude Cocktail. |
| "JOB(s)" . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Joint Operating Body/Bodies. |
| "JOB-PMEPTS" . . . . . . . . . . . . . . . . . . . . . . . . | means JOB Pertamina-Medco E&P Tomori Sulawesi. |
| "KOGAS" . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Korea Gas Corporation. |
| "KP" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means mining authorizations (Kuasa Pertambangan). |
| "KPPK Report" . . . . . . . . . . . . . . . . . . . . . . . . | refers to the prudential principle implementation activity report. |
| "KSF" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means Karim Small Fields. |
| "KSOs" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | mean Operation Cooperation Agreements. |
| "Labor Law" . . . . . . . . . . . . . . . . . . . . . . . . . . | means the Law No. 13 of 2003 regarding employment enacted on March 25, 2003. |
| "Labor Union Law" . . . . . . . . . . . . . . . . . . . . | means the Law No. 21 of 2000 regarding Labor Unions enacted on August 4, 2000. |
| "lead" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means preliminary interpretation of geological and geophysical information that may or may not lead to prospects. |
| "Lematang PSC" . . . . . . . . . . . . . . . . . . . . . . . | is the production sharing contract between Pertamina and Enim Oil Company Ltd dated April 6, 1987, and the amended and restated PSC between SKK Migas, PT Medco EP Lematang, Lundin lematang BV. and Lematang E&P Ltd. dated June 28, 2016, as may be amended from time to time. |
| "LIA" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means the Libyan Investment Authority. |
| "LIBOR" . . . . . . . . . . . . . . . . . . . . . . . . . . . . | refers to the London Interbank Offering Rate. |
| "lifting cost" or "production cost" . . . . . . . . . | means, for a given period, cost incurred to operate and maintain wells and related equipment and facilities. |
| "LNG SPA" . . . . . . . . . . . . . . . . . . . . . . . . . . | means the LNG Sale & Purchase Agreement with KOGAS dated January 2011, which has the total commitment of 0.7 million ton of LNG per annum. |
| "LNG" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means liquefied natural gas. |
| "LPG" . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | means liquefied petroleum gas. |

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| "Mandiri" | means PT Bank Mandiri (Persero) Tbk. |
| "MAS" | means the Monetary Authority of Singapore. |
| "MCG" | means PT Medco Cahaya Geothermal. |
| "MDAL" | means PT Medco Daya Abadi Lestari. |
| "MDS" | means PT Medco Daya Sentosa. |
| "MEB" | means PT Mitra Energi Batam. |
| "Medco E&P Indonesia" | means PT Medco E&P Indonesia (formerly PT Exspan Nusantara). |
| "Medco Energi" | means PT Medco Energi Internasional Tbk. |
| "Medco Madura" | means Medco Madura Pty Limited, a subsidiary of Medco Energi. |
| "Medco Simenggaris" | means Medco Simenggaris Pty Ltd., a subsidiary of Medco Energi. |
| "MEGS" | means PT Mitra Energi Gas Sumatra. |
| "MEM" | means PT Medco Energi Menamas. |
| "MEMR Regulation" | refers to the Ministry of Energy and Mineral Regulation No. 29 of 2017 on the Licenses for Oil and Gas Business Activities. |
| "MEMR" | means the Ministry of Energy and Mineral Resources. |
| "Menamas" | means PT Menamas. |
| "MEPL" | means PT Medco E&P Lematang. |
| "Meppogen" | means PT Meta Epsi Pejebe Power Generation. |
| "MGI" | means PT Medco Gas Indonesia. |
| "MGS" | means PT Medco Geothermal Sarulla. |
| "MIGAS" | refers to the Directorate General of Oil & Gas (Direktorat Jenderal Minyak dan Gas Bumi), of the Ministry of Energy and Mineral Resources of the Republic of Indonesia. |
| "Ministry" | means Ministry of Energy and Natural Resources, Indonesia. |
| "MIV" | means Medco International Ventures Ltd. |
| "MK" | means the Indonesian Constitutional Court (Mahkamah Konstitusi). |

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| "MoF" | means the Ministry of Finance of Indonesia. |
| "MOTR" | means the Ministry of Trade. |
| "MP" | means mining authorizations (Kuasa Pertambangan). |
| "MPR" | means Medco Platinum Road Pte. Ltd. |
| "MSS" | means Medco Strait Services Pte. Ltd. |
| "MTN" | means medium term notes. |
| "NCD" | means Negotiable Certificate Deposit. |
| "net production" or "net entitlement" | represents the Company's share of gross working interest production after deducting the share payable to the Government pursuant to the terms of the relevant production sharing arrangement. |
| "Net reserves" | represents reserves attributable to the Company's effective interest, after deduction of Government take payable to the Government as owner of the reserves under the applicable contractual arrangement. |
| "NIB" | means a Business Identification Number (Nomor Induk Berusaha). |
| "NIL" | means the Namora I Langit reservoir (under the JOC Sarulla Operations Ltd). |
| "Non-Bank Corporations" | has the same meaning as set forth in the No. 16/22/PBI/2014 regarding the Reporting of Foreign Exchange Activity and Reporting of Application of Prudential Principles in Relation to an Offshore Loan Management for Non-Bank Corporation. |
| "O&M" | means Operations and maintenance. |
| "OCBC" | means Overseas-Chinese Banking Corporation. |
| "Offshore Debt Plan" | has the same meaning as set forth in the No. 16/22/PBI/2014 regarding the Reporting of Foreign Exchange Activity and Reporting of Application of Prudential Principles in Relation to an Offshore Loan Management for Non-Bank Corporation. |
| "OHSAS" | means Occupational Health and Safety Assessment Series. |
| "Oil and Gas Law" | refers to the oil and gas law as set forth in Law No. 22 of 2001 enacted on November 23, 2001 by the Government. |
| "OJK Regulation" | refers to the OJK Regulation No. 29/POJK.04/2016 on Annual Report of Issuer or Public Companies as implemented by OJK Circular Letter No. 30/SEOJK.04/2016 on Format and Content |

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| | of Annual Report of Issuer or Public Companies to periodically submit financial reports, including annual financial statements and semi-annual financial statements pursuant to Bapepam-LK Regulation No. X.K.2 on Obligation to Submit Periodic Financial Statements. |
| "OJK" | means the Indonesian Financial Services Authority (Otoritas Jasa Keuangan). |
| "Oman Oil" | means Oman Oil Company S.A.O.C. |
| "OPEC" | means the Organization of Petroleum Exporting Countries. |
| "PADG" | means Governor of Bank Indonesia Regulation. |
| "PBI" | means Bank Indonesia Regulation. |
| "PDCL" | means Petro Diamond Co. Ltd. |
| "PDO" | means Petroleum Development Oman LLC. |
| "PDS" | means Petro Diamond Singapore Pte. Ltd. |
| "Persero" | means PT Pertamina (Persero). |
| "Pertamina" | means Perusahaan Pertambangan Minyak Dan Gas Bumi Negara, the Indonesian state-owned oil and gas company. |
| "PESA" | means Participating and Economic Sharing Agreement. |
| "Petronas" | means Petroliam Nasional Berhad. |
| "PGN" | means PT Perusahaan Gas Negara (Persero) Tbk. |
| "PJB" | means PT Pembangkitan Jawa-Bali. |
| "PKPU" | means a suspension of payment obligations under the Indonesian Bankruptcy Law. |
| "PKUK" | means the exclusive Holders of the Electricity Business Authority (Pemegang Kuasa Usaha Ketenagalistrikan) that supplies electricity in Indonesia—PLN. |
| "Platts" | means S&P Global Platts. |
| "PLN DJB" | means PLN West Java Distribution. |
| "PLN WS2JB" | means PT PLN (Persero) Wilayah Sumetera Selatan Jambi dan Bengkulu. |
| "PLN" | means PT Perusahaan Listrik Negara (Persero). |
| "PLN-E" | means PT Prima Layanan Nasional Enjiniring. |
| "possible reserves" | are those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than probable reserves. |

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| "PPA" | means Power Purchase Agreement. |
| "PPPSRS" | means the Residents of Condominium of Condotel Dago (Penghuni Satuan Rumah Susun Condotel Dago). |
| "PR" | means Presidential Regulation. |
| "PRIME" | means an HSE management system known as Performance Integrity of Medco E&P. |
| "probable reserves" | are those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. |
| "prospects" | mean geological structures conducive to the production of oil and gas. |
| "proved and probable and possible reserves" | are proved and probable reserves and possible reserves. |
| "proved and probable reserves" | are proved reserves and probable reserves. |
| "proved reserves" | represents those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations. |
| "PSAK" | means the Indonesian Statement of Financial Accounting Standards (Pernyataan Standar Akuntansi Keuangan). |
| "PSC(s)" | means Production Sharing Contract(s). |
| "QDS" | means qualifying debt securities under the ITA. |
| "QE" | means Kyushu Electric Power Co. Inc. |
| "Reserves" | are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. |
| "RIM" | means RIM Intelligence Co. |
| "Rimau PSC" | means the PSC between Pertamina and PT Stanvac Indonesia dated April 23, 1973, as may be amended from time to time, and the renewal and extension PSC between Pertamina, Exspand Airsenda Inc. and Exspan Airlimau Inc. dated December 7, 2001 that became effective as of April 23, 2003, and amended and restated production sharing contract between SKK Migas, PT Medco EP Rimau, and Perusahaan Daerah Pertambangan dan Energi dated February 14, 2019 that will become effective on April 23, 2023, as may be amended from time to time. |

“RMC” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . means the Risk Management Committee.

“Rp.” or “Rupiah” . . . . . . . . . . . . . . . . . . . . . . means Indonesian Rupiah.

“RPR” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . means PT Medco Ratch Power Riau.

“Rule No. IX.E.1” . . . . . . . . . . . . . . . . . . . . . . refers to the Rule No. IX.E.1 on Affiliated Party Transaction and Conflict of Interest of Certain Transaction which replaced the previous rule issued in 2008.

“SCB” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . means Standard Chartered Bank.

“SCBD” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . means the Sudirman Central Business District in Jakarta.

“SCPP” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . means a simple cycle power plant.

“SembCorp” . . . . . . . . . . . . . . . . . . . . . . . . . . means SembCorp Industries.

“Sembgas” . . . . . . . . . . . . . . . . . . . . . . . . . . . means SembCorp Gas Pty. Ltd.

“Senoro-Toili JOB-PSC” . . . . . . . . . . . . . . . . means the PSC between Pertamina and Union Texas Tomori, Inc dated December 4, 1997, and Amendment to Production Sharing Contract of Contract Area: Tomori Block between BPH Migas, PT Pertamina (Persero), PT Pertamina Hulu Energi Tomori Sulawesi and PT Medco EP Tomori Sulawesi dated September 14, 2009, as may be amended from time to time.

“SIBOR” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . means the Singapore Interbank Offering Rate.

“SIL” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . means the Silangkitang reservoir (under the JOC Sarulla Operations Ltd).

“Simenggaris JOB-PSC” . . . . . . . . . . . . . . . . means the PSC between Pertamina and Genindo Western Petroleum Pty. Ltd. dated February 24, 1998, as may be amended from time to time.

“SKBDN” . . . . . . . . . . . . . . . . . . . . . . . . . . . means bank guarantee facilities in the form of issuance of uncommitted usance local letter of credit (surat kredit berdokumen dalam negeri).

“SKK MIGAS” . . . . . . . . . . . . . . . . . . . . . . . . refers to the Government’s Special Task Force for Upstream Oil and Gas Activities (Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak Dan Gas Bumi), which came into existence upon the issuance of PR 9/2013 to take over the former functions and duties of BP MIGAS.

“SKUP” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . means an Oil and Gas Supporting Business Competency Certificate (Surat Kemampuan Usaha Penunjang Minyak dan Gas Bumi).

“South Natuna Sea Block B PSC” . . . . . . . . . means the PSC between Pertamina and Conoco Indonesia Inc., Texaco Block B South Natuna Sea Inc, Chevron International

Ltd. and Inpex Natuna Ltd. dated August 3, 1990, signed on October 16, 1968, as may be amended from time to time, and the renewal and extension PSC between Pertamina and Conoco Indonesia Inc., Texaco Block B South Natuna Sea Inc, and Inpex Natuna Ltd. dated January 15, 1999 that became effective as of October 16, 2018 as may be amended from time to time.

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| "South Sokang PSC" | means the PSC between BP MIGAS and Medco South Sokang BV dated December 17, 2010, as may be amended from time to time. |
| "South Sumatra Block PSC" | means the PSC between Pertamina and PT Stanvac Indonesia dated July 6, 1989 that became effective as of November 28, 1993, as may be amended from time to time, and the renewal and extension PSC between BP MIGAS and PT Medco E&P Indonesia dated October 28, 2010, as may be amended from time to time. |
| "SPE-PRMS" | means the Society of Petroleum Engineers-Petroleum Resources Management System. |
| "SPOP" | means the Tax Object Notification Form / Surat Pemberitahuan Objek Pajak in Indonesia. |
| "sq. km." | means square kilometers. |
| "TAC" | means Technical Assistance Contract. |
| "Tarakan PSC" | means the production sharing contract between Pertamina and Tesoro Tarakan dated January 14, 1982, as may be amended from time to time, and the renewal and extension production sharing contract between Pertamina and PT Medco E&P Tarakan (formerly PT Exspan Tarakan) dated December 7, 2001, and amended and restated production sharing contract between SKK Migas and PT Medco EP Tarakan dated November 29, 2018 that will become effective on January 14, 2022, as may be amended from time to time. |
| "TCQ" | means total contracted quantity. |
| "U.S. GAAP" | means generally accepted accounting principles in the United States, which is the accounting standards adopted by the United States Securities and Exchange Commission. |
| "U.S." or "United States" | means the United States of America. |
| "UKL" | means an environmental management effort plan (Upaya Pengelolaan Lingkungan) required under the Environmental Law. |
| "UKL-UPL" | means an Environmental Management Effort- Environmental Monitoring Effort document. |
| "UPL" | means an environmental monitoring effort plan (Upaya Pemantauan Lingkungan) under the Environmental Law. |

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| "Upstream Regulation" | refers to the Government Regulation No. 35 of 2004 on October 14, 2004 with respect to Upstream Oil and Gas Business Activities. |
| "US$" | means United States dollars. |
| "VAT" | means value-added tax. |
| "VIEs" | mean variable interest entities. |
| "Warrants" | means the warrants issued by the Company in December 2017. |
| "WIUP" | means a Mining Business License operational area (Wilayah Izin Usaha Pertambangan). |
| "WIUPK" | means a special mining operation area (Wilayah Usaha Pertambangan Khusus). |
| "WNTS" | means the West Natuna Transportation System. |
| "Wood Mackenzie" | means Wood MacKenzie Ltd., an international energy research and consulting company. |
| "WPR" | means a people's mining area (Wilayah Pertambangan Rakyat). |
| "WUP" | means a mining operational area (Wilayah Usaha Pertambangan). |

**Units of Measurement**

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| "BBLS" | means barrels. |
| "BBTU" | means billion BTU. |
| "BBTUPD" | means billion BTU per day. |
| "BCF" | means billion cubic feet. |
| "BOE" | means barrels of oil equivalent; natural gas is converted to BOE using the ratio of one Bbls of crude oil in the range of 5.19—6.54 Mcf of natural gas. |
| "BOPD" | means barrels of oil production. |
| "BTU" | means British Thermal Unit, the standard measure of the heating value of natural gas. |
| "GW" | means gigawatt. |
| "GWh" | means gigawatt hour. |
| "KWh" | means kilowatt hour. |
| "MBBLS/d" | means thousand barrels per day. |
| "MBOE/d" | means thousand barrels of oil equivalent per day. |

“MBOPD” . . . . . . . . . . . . . . . . . . . . . . . . . . . . means million barrels gross oil production.

“MBTU” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . means thousand BTU.

“Mcf” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . means thousand cubic feet.