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PT MEDCO ENERGI INTERNASIONAL Tbk

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

Investor Document

October 2023

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Overview

We are an energy and natural resources company operating through our core oil and gas exploration and production business and power generation business. We also have a 21.09% interest in a listed copper and gold mining company, PT Amman Mineral Internasional Tbk as of August 31, 2023. 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 January 1, 2023, we have the largest commercial reserves and the highest level of working interest production in Southeast Asia among a selected peer group, consisting of independent exploration and production companies with similar reserves in Southeast Asia, including Harbour Energy, SapuraOMV Upstream, Energi Mega Persada, Hibiscus Petroleum and Neptune Energy. Our core oil and gas activities are primarily in Indonesia. Internationally, we operate a significant producing asset in Thailand and have oil and gas operations in the Middle East, Libya and Tanzania.

In March 2022, we completed the acquisition of Indonesian assets from Corridor, consisting of (i) a 54% working interest in the Corridor PSC and (ii) a 35% interest in Transasia Pipeline Company Pvt. Ltd, which in turn has a 40% interest in PT Transportasi Gas Indonesia, a gas pipeline network supplying customers in Central Sumatra, Batam and Singapore. Corridor PSC has two producing oil fields and seven producing gas fields located onshore South Sumatra, Indonesia, adjacent to our existing operations in South Sumatra. The total consideration for the acquisition was approximately US$1.355 billion, which we financed primarily with the proceeds of the 2028 Notes, a US$450 million amortizing loan and cash on hand. We have completed the integration of the Corridor PSC assets in 2022 and believe Corridor has significant potential, as well as access to reservoirs suitable for carbon capture and storage. Following the completion of the Corridor Acquisition, our proportion of natural gas as a percentage of production has increased from 63.4% in 2021 to approximately 79.4% of production in 2022 (which includes Corridor PSC starting from March 3, 2022), providing, we believe, a path to transition to low carbon energy. We believe that the Corridor Acquisition and its gas shipments through PT Transportasi Gas Indonesia combined with our existing gas shipments from South Natuna Sea Block B and the West Natuna Transportation System pipeline to an onshore receiving facility in Singapore made us the largest Indonesian gas supplier into Singapore in 2022.

As of October 6, 2023, our market capitalization was Rp. 33.7 trillion (US$2,154 million).

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 other countries outside of Indonesia with, among others, interests in key producing assets in Thailand, and interests in other assets in Yemen, Libya, Oman and Tanzania. In Indonesia, the majority of our blocks are held under production sharing arrangements with SKK Migas, Indonesia’s national upstream oil and gas regulator. Our block in Thailand is held under a concession contract, subject to tax and royalty fees.

In 2022 and the six months ended June 30, 2023, our production was 162.5 MBOEPD and 161.8 MBOEPD with oil and gas production split 20.6% oil and 79.4% gas and 19.8% oil and 80.2% gas, respectively (including in each case production under our Oman service contract). Of the gas production, 70.2% and 72.2%, respectively, was sold under fixed price contracts primarily to PGN (a gas and distribution company majority owned by the Government of Indonesia), Pertamina (the national oil company of Indonesia), PUSRI (an Indonesian state-owned company engaged in the production and distribution of fertilizers) and PLN (the Indonesian state-owned electricity generator). Our gas off-takers include blue chip customers with strong credit profiles.

As of June 30, 2023, our estimated gross working interest proved and probable reserves was 457.3 MMBOE. We had proved developed reserves of 197.2 MMBOE, 202.0 MMBOE, 238.1 MMBOE and

212.0 MMBOE, as of December 31 2020, 2021 and 2022, and June 30, 2023, respectively. We produced approximately 32.3 MBOPD, 27.0 MBOPD, 25.8 MBOPD and 24.2 MBOPD of oil and condensate and approximately 281.7 MMSCFD, 280.5 MMSCFD, 633.6 MMSCFD and 633.9 MMSCFD of natural gas in 2020, 2021 and 2022 and the six months ended June 30, 2022 and 2023, respectively. Reserves and production in this paragraph exclude reserves and production under our service contract at our Karim Small Fields.

Overview of Power Business

In addition to our core oil and gas business, we operate in the power generation sector through MPI, 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 clean 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 renewable energy including hydro, solar, and wind power plants. MPI owns and operates twelve power plant assets. Approximately one third of MPI's capacity is from renewable sources. As of June 30, 2023, MPI had gross installed capacity of 2,871 MW combined IPP and O&M power plants. In 2021 and 2022, MPI produced 2,718 GWH and 3,993 GWH of power as an IPP, respectively, and acted as O&M provider for power plants which produced 1,650 MW and 1,925 MW of power.

Copper and Gold

Our copper and gold mining interest consists of our interest in AMI, which is the parent company of AMNT. AMI completed its IPO on the IDX in July 2023, and as of October 6, 2023 had a market capitalization of Rp. 451.3 trillion (US$28,835 million). As of August 31, 2023, we had a 21.09% shareholding in AMI.

Financial Data, History and Registered Office

For the years ended December 31, 2020, 2021 and 2022 and the six months ended June 30, 2022 and 2023, our total revenues were US$1,034.5 million, US$1,252.1 million, US$2,312.2 million, US$1,108.6 million and US$1,116.2 million, respectively, and EBITDA was US$452.1 million, US$667.3 million, US$1,593.1 million, US$779.6 million and US$633.8 million, respectively.

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. 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. On March 3, 2022 we completed the Corridor Acquisition through our subsidiary MEG.

Our registered and principal executive office is located in The Energy Building, floors 53 through 55, 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 2022, we produced oil and gas with average daily production rate of 162.5 MBOEPD. Our scale gives us the largest commercial reserves and the highest level of working interest production in Southeast Asia as of January 1, 2023, according to Wood MacKenzie, among a selected peer group, consisting of independent exploration and production companies with similar reserves in Southeast Asia, including Harbour Energy, SapuraOMV Upstream, Energi Mega Persada, Hibiscus Petroleum and Neptune Energy. As of June 30, 2023, our estimated gross working interest proved and probable reserves were 457.3 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 Corridor, South Natuna Sea Block B, Senoro-Toili, Rimau, South Sumatra, Lematang, Tarakan, Block A, Aceh, Bangkanai, Sampang, Madura Offshore, Simenggaris, North Sokang, West Bangkanai and Beluga blocks, which allows us to control or significantly influence and optimize the pace of exploration, development and the associated capital expenditure at each block.

To provide geographic diversification, we also have interests in oil and gas properties in other countries outside of Indonesia, reducing concentration risk, with interests in key producing assets in Thailand, and interests in other assets in Oman, Tanzania, Yemen and Libya.

In the longer-term, Indonesia's gas market is expected to continue to expand to support the growing economy. Wood Mackenzie expects Indonesia's gas demand to increase at a 2.8% CAGR from 234 MMBOE in 2022 to 384 MMBOE in 2040. This robust long-term growth is supported by their projected consistent GDP increases and corresponding growing demand from the industrial and power sectors.

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. We benefit from five key, structural supports which help to protect us from oil and gas price volatility:

- fixed-price, take-or-pay gas contracts accounted for 54.8% of 2022's production;
- both fixed-domestic and oil price-linked-export GSAs include 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 is contractually required to pay a portion (usually in the range of 80% to 90%) of the total contracted supply for the period;
- cost-recovery mechanism under most of our PSCs which increases our entitlement to allow full recovery of our expenditure before profit oil or gas is split;
- gross split mechanism currently applicable at Rimau and Tarakan PSCs which increases our flexibility in incurring field development costs without the need for Government approval; and
- our current hedging policy to hedge up to 20% of our total annual production to limit downside risk. As of December 31, 2022, we had already hedged approximately 3.5% of our second half 2023 production at approximately US$50.0/bbl.

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 Gas Supply Pte Ltd, each of whom have demonstrated solid payment histories.

Low cost base

We have established a track record as a low-cost oil and gas producer in Indonesia. We believe our significant experience in the operation and management of mature hydrocarbon assets provides us with a competitive advantage in realizing cost efficiencies from such assets. We have implemented cost reduction programs over time, targeting 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. In addition, the Corridor Acquisition (with Corridor PSC being an onshore gas block) helped to further improve our consolidated cash production cost which decreased to US$6.9/BOE in 2022 and US$7.4/BOE in the six months ended June 30, 2023 from US$9.5/BOE in 2021, US$9.1/BOE in 2020, US$9.9/BOE in 2019 and US$8.4/BOE in 2018.

Our cost efficiencies have 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; (iii) we have upgraded or are upgrading our systems to automate certain administrative procedures, such as business planning and consolidation software, Workiva, a platform that enables the use of connected data and automation of reporting across finance, accounting, risk, and compliance; (iv) reassessing all operations to apply “fit-for-purpose” methodologies, such as rescheduling planned maintenance and engine exchanges. Following the Ophir acquisition in 2019, office buildings were closed and we reduced the number of personnel in London, Bangkok and most recently in Jakarta in 2021. In mid-2020, we launched a sustainable performance improvement project, to benchmark our performance against best practices globally, which led to the identification of several new initiatives with respect to maintenance, procurement supply chain management, planning, operations, operating model and code of conduct. In 2021, we also adopted a combined “hot-desking” and “work-from home” approach to the occupancy of our headquarters, and this has allowed the return of three floors to us for rental to third parties. In addition, in connection with the Corridor Acquisition, we identified and have implemented approximately US$50 million of recurring operational, procurement, and commercial recurring synergies with our existing assets.

We are currently committed to maintaining a unit cash production cost per BOE below US$10 for the near future by continuing to implement our cost efficiency measures and benefitting from increased production as demand recovers. 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.

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. With respect to the Corridor Acquisition, which closed in March of 2022, we completed systems integration and organizational integration in 2022 and office integration by April 2023. We also identified and implemented a total of US$50 million of recurring operational, procurement, and commercial recurring synergies with our existing assets. During the integration of Ophir which we acquired in May 2019, we were 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. All 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 an example of our capabilities. This project involved high pressure, high temperature drilling and the construction of a central gas processing facility in a remote area of Indonesia. This project was delivered on time and on budget with production of first gas in August 2018. We also successfully brought phase 4B of oil production at Bualuang online in January 2020, a demonstration of our ability to operate successfully outside of Indonesia. Other recent achievements include, at South Natuna Sea Block B, monetizing our reserves, such as by achieving first gas at the Hiu and Malong fields and Belida extension in 2022, and at the Bronang field in 2023. We are progressing projects to add new producing fields from South Natuna Sea Block B fields from Forel and West Belut by 2024, Terubuk by 2025 and Siput by 2026.

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, we obtained extensions for the Lematang PSC until 2027. Most recently, we were given 20 year extensions for the Rimau PSC until 2043, Tarakan PSC until 2042 and Senoro-Toili PSC until 2047. We also successfully extended our GSA with Gas Supply Pte. Ltd. (Singapore) for the Corridor PSC until 2028 and entered into a new GSA with Sembgas with respect to gas sales into Singapore from South Natuna Sea Block B in 2023.

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.

Organizational and financial capability to realize opportunities from the energy transition with supportive shareholders

There are significant opportunities arising from energy transition toward low carbon energy, including the opportunity to invest in new renewable energy projects in Indonesia and the rest of Southeast Asia.

We have an experienced Board of Commissioners, Board of Directors and senior management team, with extensive experience operating in Indonesia. We also have a track record of raising financing from our lenders and domestic and international capital markets. We are a flat organization with an efficient decision-making process and a clear strategy.

The foregoing has enabled us to quickly orient ourselves to opportunities which arise, and we believe should position us to capture opportunities arising from energy transition.

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, while also pivoting to capture opportunities from the energy transition. 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 are currently developing Senoro Phase II where 2,398 BCF of gross 100% field 2P Reserves were assessed by GCA as of December 31, 2022. The Senoro Phase II Project has started with the South Senoro Development where the Front End Engineering Design and rig tender have been completed. The tender for line pipe and engineering, procurement, construction and installation, or EPCI, are in progress with completion expected in the fourth quarter of 2023, followed by the final investment decision. The South Senoro Development execution is expected to commence in 2024. We have already received gas allocation approval for MPI, and are in the process of obtaining gas allocation approvals for other buyers post 2027 (prior to which, gas sales will be covered under existing GSAs).

We made four commercial discoveries at South Natuna Sea Block B in 2020, and have been monetizing our reserves at the block, such as by achieving first gas at the Hiu and Malong fields and Belida extension in 2022, and at the Bronang field in 2023. We are progressing projects to add to our production from South Natuna Sea Block B fields from Forel and West Belut by 2024, Terubuk by 2025 and Siput by 2026.

Going forward, we expect that a larger percentage of our production will consist of production from Corridor, Senoro-Toili, South Natuna Sea Block B, Block A, Aceh, and Bualuang in Thailand, as certain of our existing blocks, including Rimau PSC and South Sumatra PSC, are in mature stages of production. As of June 30, 2023, our 2P reserve life index was 8.9 years.

Continue to pursue value accretive and credit-enhancing acquisitions, and focus on effective integration

We intend to build on our strong track record of evaluating, closing and integrating successful acquisitions that are EBITDA accretive and within our core oil and gas business. Since 2016, we have made three significant oil and gas acquisitions, the Corridor Acquisition, the Ophir Acquisition and our acquisition of interest in South Natuna Sea Block B, which have substantially increased our production and reserves base. In addition, we are currently in the process of acquiring additional assets in the Middle East as described under "Recent Developments."

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

- Would help to improve our profitability and credit profile, which help us to achieve our objective of net debt over EBITDA of less than 2.5x at mid-cycle prices, that provide current or near-term cash flow and provide synergies with our existing operations;
- Contain manageable risks, including assets where we will act as operator or have a recognized quality operator and where we have existing knowledge of one or more of the asset, its organizational capabilities, subsurface characteristics and markets;

- Have growth potential and upside and which can serve as a platform for further growth and where we believe we can add value; and
- Are consistent with our climate change strategy, such as having renewable or low carbon platforms or access to emerging technology or carbon capture and storage opportunities.

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. We expect merger and acquisition activity to remain elevated in Asia Pacific as (i) international oil companies look to monetize later life assets and pivot capital allocation into 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 are currently reviewing and in discussions with several potential targets, although no definitive agreements have been entered into and there can be no assurances that any acquisition will be completed.

We believe that we are well positioned to acquire interests in assets in the regions in which we operate which may become available for sale. Moreover, we believe our reputation of successful execution, 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. See "Risk Factors — We have in the past, and may again in the future, engage in acquisitions, which would be subject to risks."

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 assets. We intend to implement this strategy primarily by conducting infrastructure-led exploration, development and tie-ins to existing infrastructure on our existing 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. Our average 2P finding and development cost (representing capital expenditures (including acquisitions) divided by reserve additions) for the five year period ending December 31, 2022 was US$7.4/BOE.

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 stated mid-cycle target of Net Debt to EBITDA of below 2.5x. Recently, the strong cashflow generation from our portfolio (particularly given more favorable oil prices) has provided us with the ability to acquire portions of our outstanding U.S. dollar notes through open market purchases and tender offers on our own terms and prices, given on our strategy to de-lever over time, market conditions and our short to medium capital needs. For example, we conducted an any and all tender offer of our then-outstanding 2022 Notes in March 2020, a capped tender offer of up to US$150 million of our 2026 Notes and 2027 Notes in April 2022 and a capped tender offer of up to US$250 million of our 2025 Notes, 2026 Notes and 2027 Notes in October 2022.

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 (approximately US$179.4 million) before deduction of transaction costs, which we used primarily for reducing our leverage. More recently in September 2020, we raised IDR1.8 trillion (equivalent to US$120.9 million) from a rights offering which we used for general corporate purposes including working capital. In August 2021, we received approval from our shareholders for a future equity raise allowing us to issue a maximum of 12.5 billion new shares of the Company in order to increase capital with pre-emptive rights, although we elected not to proceed with the equity raise as we did not require additional capital at the time.

Over the period from 2018 to December 31, 2022 we sold non-core and underperforming assets or interests with total proceeds of US$848 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.

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. In 2021, MPI entered into a strategic alliance with Kansai Electric aimed at developing and operating existing and new gas-fired power plants and expanding their gas-IPP and operation and maintenance businesses in Indonesia through a jointly owned platform, which is majority owned by MPI. AMNT may also form a joint venture with another party or parties to develop its smelter.

Take advantage of Carbon Capture and Storage (CCS) opportunities

We plan to take advantage of CCS technology to unlock the potential to engage in CCS opportunities at our assets. We have assessed the CCS potential at each of our Indonesian producing assets and have set up a division to explore and implement potential opportunities. We believe that certain of our PSCs have the potential to provide CO2 storage and management for our own or adjacent PSC high CO2 gas fields and/or become CO2 storage hubs for CO2 intensive industries including from neighboring countries. We are in the process of conducting feasibility studies with respect to potential projects and have signed MOUs with several third parties for CCS projects. So far, we have identified South Natuna Sea Block B, Corridor, Madura Offshore, Sampang and South Sumatera PSCs as potential storage sites.

Rapidly implement our Energy Transition strategy, while maintaining focus on social and governance issues

Our commitment to environmental, social and governance (“ESG”) initiatives are institutionalized through a thoughtful, comprehensive and forward-thinking ESG strategy. We have sought to adopt industry best practices and target best-in-class environmental standards. We also seek to periodically validate our progress in honoring our ESG commitment and to identify areas for improvement. Our ESG ratings have shown improvement in the past few years as follows:

- Sustainalytics ESG rating of 49.9, 46.9, 42.2 and 36.7 for 2019, 2020, 2021 and 2022, respectively (which represents an improvement to the “high” risk category in 2022 from the “severe” risk category in prior years);
- MSCI’s ESG ratings of B, BB, BB, BBB, A for 2018, 2019, 2020, 2021 and 2022, respectively (with CCC being the lowest and AAA being the highest); and
- CDP’s ESG rating of C in 2021 and B in 2022 (with D being the lowest and A being the highest).

We also remain focused on maintaining high corporate governance standards, which are driven by principles of transparency, accountability, responsibility, independence 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 as a result we 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 conduct. We intend to continue implementing these and other prudent policies to maintain our corporate governance standards and code of conduct.

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 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.

Recent Developments

In August 2023, we signed an agreement to acquire a 20% non-operating interest in producing oil and gas assets in the Middle East from an operator that will continue to hold a majority interest and remain as an operator of the assets. The transaction is subject to certain closing conditions including local regulatory approvals, and if such conditions are satisfied or waived, is expected to close around the end of the year. The approximate consideration payable for our 20% interest is between 25% and 40% of our equity value as of June 30, 2023, which is US$1,871.7 million, and if the transaction closes, we will consolidate the entity which we expect will hold our 20% interest in into our financial statements. We plan to place several of our senior staff in key positions of the operating company. Based on the information made available to us by the seller as part of our due diligence process and subject to warranties of the seller in the asset sale and purchase agreement, these assets, based on our 20% interest, would have contributed approximately 8% (or 13 MBOED) of additional total production for the six months ended June 30, 2023 and would have added approximately 12% (or 56 MMBOE) of 2P reserves as of June 30, 2023. Historically, production from this asset has primarily been oil. More information about this transaction will be publicly announced no later than two business days after closing in accordance with OJK regulations. This transaction is considered a "material transaction" under OJK regulations but does not require an approval from a general meeting of shareholders, as the purchase price is between 20% and 50% of our equity value as of June 30, 2023.

See "Risk Factors — Risk Relating to Our Business and Operations — We face risks associated with our potential acquisition of assets in the Middle East."

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 Gross Split)	South Sumatra	1995	65%	1,103	2043	58-61[5]	48[4]	Medco
South Sumatra Block (PSC Cost Recovery)	South Sumatra	1995	65.00%	4,470	2033	12.50	27.50	Medco
Lematang (PSC Cost Recovery)	South Sumatra	2002	100.00%	409	2027	15.00	29.50	Medco
Tarakan (PSC Gross Split)	North Kalimantan	1992	100.00%	180	2042	58-63[4]	65-67[4]	Medco
Senoro-Toili (PSC-JOB)	Sulawesi	2000	30.00%	451	2047	35.00	40.00	Pertamina-Medco JOB
Block A, Aceh (PSC Cost Recovery)	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 — (PSC Cost Recovery)	Central Kalimantan	2019	70%	1,385	2033	15.00	35.00	Medco
Madura Offshore — (PSC Cost Recovery)	Madura Strait	2019	67.5% (Peluang & Maleo) 77.5% (Meliwis)[5]	849	2027	20.00	35.00	Medco
Sampang — (PSC Cost Recovery)	Madura Strait	2019	45.0%	534	2027	20.00	35.00	Medco
Corridor (PSC Cost Recovery)[6]	South Sumatera	2022	54%	2,106	2043	20.00	35.00	Medco
Development Properties								
Simenggaris (PSC-JOB)	North Kalimantan	1998	62.50%	547	2028	15.00	35.00	Pertamina-Medco JOB
Exploration Properties								
West Bangkanai (PSC Cost Recovery)	Central Kalimantan	2019	70.0%	5,463	2043	25.00	35.00	Medco
North Sokang (PSC Cost Recovery)	Riau Islands	2019	100.00%	1,124	2040	25.00	40.00	Medco
Beluga (PSC Cost Recovery)[8]	Riau Islands	2023	100%	8,472	2053	40	45	Medco
Libya:								
Development Properties								
Area 47 (EPSA IV)	Libya	2005	50.0%	6,182	5 years exploration; 25 years production	6.95	6.89	Nafusah Oil Operation BV[2]

^

Contract Area (Type)	Location	Date of Acquisition	Effective Interest[3]	Gross Area (Km^2)	Contract Expiry Date	Share to Contractor[1] Profit Crude Oil (%)	Share to Contractor[1] Profit Natural Gas (%)	Operator
Oman:								
Producing Properties								
Karim Small Fields (Service Agreement)	The Sultanate of Oman	2006	58.50%	781	2040	12-30	N/A	Medco
Exploration Properties								
Block 56 (PSC)	The Sultanate of Oman	2014	5%	5,808	2023	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)[7]	Nam Con Son Basin, Offshore	2019	31.9%	1,395	2030	40-82.5	40-82.5	Premier Oil
Thailand:								
Producing Properties								
Bualuang (Concession)	Gulf of Thailand	2019	100%	377	2025	N/A	N/A	Medco
Tanzania (LNG):								
Development Properties								
Block 1 (PSA)	Rovuma Basin	2019	20%	8,512	2024	40-60	40-70	Shell
Block 4 (PSA)	Rovuma Basin	2019	20%	3,784	2024	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) Under the gross split regime, the commercial arrangement between the contractor and the Government differs from the cost recovery regime.

(5) One of the partners did not participate in Meliwis field.

(6) PSC gross split post 2023.

(7) Held for sale.

(8) PSC contract Beluga granted as of September 21, 2023, pending execution as of the date of this Document.

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 ("GCA") and DeGolyer and MacNaughton ("D&M"), an independent petroleum engineering consultant for the blocks listed below as of the dates indicated:

Asset	Reserves Date
Corridor	January 1, 2021[(1)]
Block A, Aceh	December 31, 2022
Senoro-Toili	December 31, 2022
South Natuna Sea Block B	December 31, 2020[(2)] and June 30, 2023[(3)]
South Sumatra Block	December 31, 2018
Lematang (Singa Field)	December 31, 2017
Rimau PSC	December 31, 2018
Bangkanai	December 31, 2019
Madura Offshore	December 31, 2019
Sampang	December 31, 2019
Bualuang	December 31, 2020

Notes:

(1) D&M has also more recently estimated our reserves in a report dated October 5, 2023.

(2) Belanak, Belida, Buntal, Kerisi, Hiu, North Belut, South Belut, Bawal, Belida NE, Malong, West Belut, Keong, Tembang, Forel, Bronang, Terubuk, Kaci, Sepat, Kakap – Mumung field.

(3) West Belut, Terubuk and Siput field.

Estimates on reserves for assets that are not listed above which amount to approximately 3% of our gross working interest proved reserves and approximately 4% of our gross working interest proved and probable reserves as of June 30, 2023 are estimated by us based on our own investigations and prior reserve estimates or assessments by reputable international consultants. Investors 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.

The gross working interest values set out in this Document 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 June 30, 2023. 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 June 30, 2023.

	As of June 30, 2023								
	Gross Working Interest Proved Reserves			Gross Working Interest Proved and Probable Reserves			Gross Working Interest Proved and Probable and Possible Reserves		
	Gas (BCF)	Oil (MMBBLS)	Total (MMBOE)	Gas (BCF)	Oil (MMBBLS)	Total (MMBOE)	Gas (BCF)	Oil (MMBBLS)	Total (MMBOE)
Indonesia:									
Producing Properties									
Rimau	—	3.0	3.0	—	7.8	7.8	—	15.6	15.6
South Sumatra	21.5	2.2	6.4	41.2	3.9	11.8	47.4	7.4	16.5
Lematang	11.4	—	2.0	13.9	—	2.4	13.9	—	2.4
Tarakan	0.7	0.3	0.4	4.3	1.3	2.1	4.3	1.3	2.1
Senoro-Toili (Tiaka Field)	—	0.7	0.7	—	2.2	2.2	—	2.2	2.2
Senoro-Toili (JOB)	604.7	12.6	130.0	702.7	16.0	152.5	709.8	18.0	155.8
South Natuna Sea Block B	79.4	7.6	22.6	173.9	12.7	45.6	235.9	16.5	61.0
Block A, Aceh	113.8	3.5	23.9	117.8	4.3	25.4	122.0	5.3	27.2
Bangkanai	51.3	1.1	10.5	53.5	1.2	11.1	55.5	1.3	11.5
Madura Offshore	7.2	—	1.3	29.5	—	5.2	29.5	—	5.2
Sampang	4.3	0.0	0.8	4.3	0.0	0.8	4.3	0.0	0.8
Corridor	354.4	3.5	67.2	463.3	4.5	87.7	573.2	5.5	108.5
Development Properties									
Simenggaris	6.9	—	1.2	28.1	—	4.9	28.1	—	4.9
Libya:									
Development Properties									
Area 47	35.6	39.1	45.1	56.7	61.1	70.6	172.8	188.0	216.8
Yemen:									
Producing Properties									
Block 9 Malik	—	3.6	3.6	—	9.1	9.1	—	37.7	37.7
Thailand:									
Producing Properties									
Bualuang	—	8.3	8.3	—	14.0	14.0	1.4	3.9	4.2
Vietnam:									
Producing Properties									
Block 12W	0.5	3.3	3.4	1.4	3.9	4.2	1.4	3.9	4.2
Total Reserves	**1,291.7**	**88.8**	**330.4**	**1,690.6**	**142.0**	**457.4**	**1,999.5**	**306.6**	**676.6**
Corridor[(1)]	512.4	3.8	95.8	683.7	4.9	127.8	842.7	6.0	157.4

Notes:

(1) D&M has more recently, in a report dated October 5, 2023, re-estimated our reserves at Corridor which increased our estimates of reserves at the block. The table above shows both our Corridor (i) reserves levels as of June 30, 2023 based on D&M's January 1, 2021 estimation and deducting production as described herein, which is consistent with our recent disclosures and (ii) reserves estimated as of June 30, 2023 by D&M as noted in its October 5, 2023 report.

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 even for blocks where there are recent third-party reserves estimations or assessments, we have not attached these reports to this Document."

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 June 30, 2023 on a gross 100% field basis multiplied by our working interest in each block:

	As of June 30, 2023		
	Oil (MBBLS)	Gas (MMSCF)	Total (MBOE)
Indonesia:			
Producing Properties:			
Rimau	7,500	—	7,500
South Sumatra	1,029	46,828	10,045
Tarakan	1,524	6,370	2,735
Lematang	—	10,295	1,764
Senoro-Toili	3,420	170,100	36,460
South Natuna Sea Block B	15,040	72,544	28,743
Block A, Aceh	11,390	1,047,729	199,672
Bangkanai	3,759	440,300	84,716
Sampang	57	17,617	3,344
Madura Offshore	—	2,675	469
Corridor(1)	3,321	226,187	43,969
Development Properties:			
Simenggaris	—	92,745	16,078
Libya			
Development Properties:			
Area 47	43,522	103,822	60,826
Yemen			
Producing Properties:			
Block 9 Malik	3,327	19,316	6,546
Thailand			
Producing Properties:			
Bualuang	8,900	—	8,900
Vietnam(1)			
Producing Properties:			
Block 12W	473	—	473
Tanzania			
Development Properties:			
Block 1 & 4	—	3,005,800	521,388
Total	**103,262**	**5,262,328**	**1,033,628**
Corridor(2)	5,099	112,900	25,389

Notes:
(1) Held for sale.
(2) Contingent reserves balance based on the latest reserves report.

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 other countries outside of Indonesia, with interests in key producing assets in Thailand and interest in other assets in Yemen, Libya, Oman, 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 Six Months Ended June 30,	
	2020	2021	2022	2022	2023
			BOPD		
Indonesia:					
South Natuna Sea Block B	6,067	5,486	4,104	4,378	4,657
Rimau	4,315	3,901	3,796	3,623	3,910
Senoro-Toili	2,339	2,072	2,350	2,361	2,208
South Sumatera	2,764	2,238	2,017	1,995	1,824
Tarakan	1,185	953	890	899	743
Block A, Aceh	745	860	1,082	1,150	951
Corridor	—	—	2,922	2,365	3,088
Others(1)	403	392	371	378	254
International:					
Bualuang	9,925	7,206	5,637	5,635	4,707
Karim Small Fields	7,424	7,229	7,366	7,445	7,728
Block 12W(3)	4,156	2,845	2,025	2,252	1,932
Block 9 Malik	1,044	1,191	915	960	32
Others(2)	27	25	25	25	7
Total Production	**40,394**	**34,398**	**33,500**	**33,466**	**32,041**

Notes:
(1) Includes Bangkanai and Sampang.
(2) Includes production from Sinphuhorm, which was sold on February 23, 2023.
(3) Held for sale.

Gas Production

	For the Year Ended December 31,			For the Six Months Ended June 30,	
	2020	2021	2022	2022	2023
			MMCFD		
Indonesia Assets					
Senoro-Toili	97,849	87,868	99,711	100,453	94,633
South Natuna Sea Block B	69,190	67,714	70,121	76,991	58,273
Madura Offshore	32,260	31,720	24,331	26,116	18,956
South Sumatra	31,124	34,419	37,909	37,660	39,295
Block A, Aceh	26,498	34,489	40,907	44,028	34,857
Lematang	16,652	15,612	12,033	12,176	26,271
Sampang	15,873	15,211	13,219	13,829	11,626
Bangkanai	13,230	13,892	13,623	13,563	8,312
Corridor(1)	—	—	374,331	308,188	406,417
Others(2)	3,665	4,718	4,501	5,180	4,605
International:					
Sinphuhorm(3)	8,956	8,634	9,238	9,200	2,705
Block 12W PSC(5)	5,678	3,841	2,869	3,154	2,873
Block 9 Malik	1,250	1,547	1,249	1,301	371
Others(4)	51	37	30	29	25
Total Production	**322,276**	**319,702**	**704,072**	**651,868**	**709,219**

Notes:

(1) From March 3, 2022.

(2) Includes Rimau, Tarakan and Simenggaris.

(3) Sold on February 23, 2023.

(4) Includes Bualuang.

(5) Held for sale.

Hydrocarbon Production

	For the Year Ended December 31,			For the Six Months Ended June 30,	
	2020	2021	2022	2022	2023
			BOEPD		
Indonesia Assets					
Senoro-Toili	21,302	19,140	21,718	21,873	20,589
South Natuna Sea Block B	18,976	18,277	17,350	18,922	15,664
South Sumatra	8,761	8,865	9,315	9,245	9,389
Madura	5,655	5,564	4,268	4,581	3,325
Block A, Aceh	5,511	7,063	8,434	9,062	7,215
Rimau	4,793	4,300	4,203	4,023	4,340
Sampang	3,020	2,897	2,517	2,636	2,208
Lematang	2,832	2,673	2,060	2,085	4,502
Corridor(1)	—	—	70,194	57,751	76,126
Others(2)	4,126	4,293	4,118	4,255	2,883
International:					
Bualuang	9,933	7,212	5,642	5,640	4,711
Karim Small Fields	7,424	7,229	7,366	7,445	7,728
Block 12W PSC(4)	5,316	3,603	2,591	2,875	2,499
Block 9 Malik	1,253	1,449	1,124	1,177	94
Others(3)	1,531	1,530	1,635	1,629	478
Total Production	**100,433**	**94,095**	**162,535**	**153,199**	**161,751**

Notes:

(1) From March 3, 2022.

(2) Includes Tarakan and Simenggaris, Bangkanai.

(3) Includes production from Sinphuhorm, which was sold on February 23, 2023

(4) Held for sale

Oil Lifting

	For the Year Ended December 31,			For the Six Months Ended June 30,	
	2020	2021	2022	2022	2023
			MBOPD		
Indonesia Assets					
South Natuna Sea Block B	6.02	5.52	3.95	4.31	4.33
Rimau	4.31	3.91	3.81	3.63	3.92
South Sumatra	2.75	2.23	2.01	1.98	1.82
Senoro-Toili	2.33	2.08	2.35	2.15	2.17
Tarakan	1.20	0.95	0.91	0.83	0.68
Corridor[1]	—	—	2.93	2.39	2.57
Others[2]	0.93	1.04	1.23	1.24	0.95
International:					
Bualuang	9.54	7.25	5.55	4.96	4.61
Karim Small Fields	7.40	7.23	7.37	7.44	7.73
Block 12W[4]	4.16	2.79	2.07	2.11	1.54
Others[3]	0.67	0.60	0.44	0.50	0.00
Total	**39.31**	**33.60**	**32.62**	**31.54**	**30.32**

Notes:

(1) From March 3, 2022.

(2) Includes Sampang, Block A and Bangkanai.

(3) Includes Sinphuhorm, which was sold on February 23, 2023, and Block 9 Malik.

(4) Held for sale.

Gas Sales

	For the Year Ended December 31,			For the Six Months Ended June 30,	
	2020	2021	2022	2022	2023
			BBTUPD		
Indonesia Assets					
Senoro-Toili	104.81	94.43	107.07	107.25	103.32
South Natuna Sea Block B	60.25	58.98	59.86	68.65	55.96
Madura Offshore	30.96	30.38	22.82	24.63	17.27
South Sumatra	29.72	33.44	35.20	35.49	35.02
Block A, Aceh	18.33	26.60	32.93	35.59	27.75
Sampang	16.69	15.95	13.79	14.44	12.08
Bangkanai	14.04	14.23	13.98	14.01	8.52
Lematang	13.96	12.59	8.68	8.91	21.06
Corridor[1]	—	—	360.39	296.58	387.00
Others[2]	0.76	2.29	1.99	2.66	1.93
International:					
Sinphuhorm[3]	8.81	8.49	9.09	9.05	1.53
Block 12W[4]	3.83	2.38	1.30	1.62	1.19
Total	**302.16**	**299.76**	**667.10**	**618.9**	**672.6**

Notes:
(1) From March 3, 2022.
(2) Includes Simenggaris and Tarakan.
(3) sold on February 23, 2023.
(4) Held for sale.

Hydrocarbon Sales

	For the Year Ended December 31,			For the Six Months Ended June 30,	
	2020	2021	2022	2022	2023
			MBOPD		
Indonesia Assets					
Senoro-Toili	20.63	18.54	20.93	20.76	20.09
South Natuna Sea Block B	16.38	15.65	14.33	16.21	14.04
South Sumatra	8.18	8.32	8.12	8.14	7.89
Madura	5.36	5.28	3.96	4.27	3.00
Rimau	4.31	3.91	3.81	3.63	3.92
Block A, Aceh	4.02	5.61	6.81	7.35	5.51
Lematang	2.11	1.96	1.51	1.55	3.65
Corridor(1)	—	—	65.44	53.84	69.69
Others(2)	6.80	6.75	6.20	6.29	4.84
International:					
Bualuang	9.54	7.25	5.55	4.96	4.61
Karim Small Fields	7.40	7.23	7.37	7.44	7.73
Block 12W(5)	4.85	3.21	2.30	2.40	1.75
Sinphuhorm(3)	1.53	1.52	1.60	1.59	0.27
Others(4)	0.64	0.58	0.42	0.48	0.00
Total	**91.75**	**85.81**	**148.35**	**138.91**	**146.99**

Notes:
(1) From March 3, 2022.
(2) Includes Tarakan, Bangkanai and Sampang.
(3) Sold on February 23, 2023.
(4) Includes Block 9, Malik.
(5) Held for sale.

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 eight main business areas. These are our (i) Corridor PSC, (ii) the offshore South Natuna Sea Block B PSC, (iii) the Senoro-Toili JOB, (iv) Block A Aceh, (v) South Sumatra asset (the Rimau PSC, South Sumatra PSC and Lematang PSC), (vi) East Java offshore Madura and Sampang assets, (vii) Bangkanai, Central Kalimantan assets and (viii) East Kalimantan assets (Tarakan PSC and JOB Simenggaris).

Corridor PSC

Medco E&P Grissik Ltd. ("MEPG") is the operator of and holds a 54% working interest in the Corridor Block PSC as a result of an acquisition from ConocoPhillips (Grissik) Ltd. completed in March 2022. Our partners in the Corridor Block are Repsol Corridor SA ("Repsol") which holds a 36% interest and Pertamina Hulu Energi Corridor ("PHEC") which holds a 10% interest. Corridor PSC has one producing oil field (Suban Baru) and seven producing gas fields (Suban, Dayung, Sumpal, Gelam, Letang, Tengah & Rawa) located in onshore South Sumatra, Indonesia, adjacent to MedcoEnergi South Sumatra existing operations.

The existing PSC will expire on December 19, 2023 and MEPG we have received approval for a 20-year extension until December 2043. After December 19, 2023, our Corridor block will change to a gross split regime, and, effective January 1, 2024, our working interest in the block will be 46.0%. In addition the contractors, including the MEPG, will be obliged to offer 10% of their participating interest to the local government.

Corridor PSC is the second-largest gas producer in Indonesia, selling its gas to Indonesian and Singaporean buyers. Through Transasia Pipeline Company Pvt. Ltd., we also hold a minority stake in a gas pipeline network operated by PT Transportasi Gas Indonesia (TGI) that supplies customers in Central Sumatra, Batam, and Singapore.

Corridor PSC has two main gas processing facilities, Suban Gas Plant and Grissik Central Gas Plant with total capacity of 800 MMscfd and 460 MMscfd. Our current gross daily production rate is 801 MMscfd of gas and 5877 BOPD of condensate.

South Natuna Sea Block B

We operate the PSC and the facilities located in the Natuna Sea, which had an average daily gross gas volume production of 175 MMSCFD and oil production of 10,260 BOPD in 2022, in approximately 300 feet of water with 12 offshore platforms, three producing subsea fields and a sophisticated FPSO. 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

A PSC and the working interest holders of Kakap block PSC. We made four commercial discoveries at South Natuna Sea Block B in 2020, and we have successfully produced additional gas from Hiu and first gas at the Malong and Belida extensions in 2022 and at Bronang in 2023. From 2022 to mid-2023, we successfully drilled two subsea wells in the Hiu oil field and ten platform wells in the Malong, Belida, Bronang and Forel oil fields. We plan to follow a continuous drilling campaign until 2025 at the Forel, Bronang, West Belut, Terubuk, Siput oil fields and potential exploration wells. We are in the process of developing the Forel, Bronang, West Belut, Terubuk and Siput oil fields, to increase our production and extend our economic limit beyond current PSC period. We believe we are on track to improve our production from Forel and West Belut by 2024, Terubuk by 2025 and Siput by 2026.

Currently, gas from the South Natuna Sea Block B is sold to Singapore (Sembgas Corp) under a long-term GSA since 2001, and we will start to deliver additional gas under a new GSA commencing in October 2025. Pricing under GSAs are linked to oil prices. We have a crude oil sale and purchase agreement, or COSPA, with Glencore which is valid until December 31, 2025, for the sale of our oil entitlement from this block.

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 before tax is 71.2%. For natural gas, the PSC participants' share before tax is 67.3% and the government's share is 32.7%. A portion of the PSC participants' oil share profits are subject to DMO, but the participant's gas share profits are not subject to DMO.

Senoro-Toili

The block consists of two areas: Senoro (primarily 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 crude oil since 2005 (peak production of 4 MBOPD). Based on the existing PSC, which will expire on December 3, 2047, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares after deduction for the FTP and allowing for cost-recovery. For crude oil, the profit share after tax is 65.0% for the Government and 35.0% for the joint operating body formed by us. For natural gas, the PSC participants' share is 40.0% and the Government's share is 60.0%. 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. A PSC extension was signed by the Minister of Energy and Mineral Resources on April 19, 2022 for a 20 year contract period which will allow the PSC participants to develop the Senoro Phase II project while seeking other potential fields and new resources.

Upstream Sector-Gas

The Senoro field started production in 2014. The production facilities now have a capacity of up to 340 MMSCFD.

JOB-PMEPTS signed several GSAs with its buyers to supply gas until the expiration of the existing PSC in 2027 including a GSA signed with DSLNG in 2009 to supply 250 MMSCFD of gas. In addition, JOB-PMEPTS also entered into an agreement with PT Panca Amara Utama in March 2014, which was amended in 2018, to supply 62 MMSCFD of gas to an ammonia plant for which the price is linked to ammonia prices in the Southeast Asia market. A GSA was signed with PLN in February 2018 to supply 4.5 MMSCFD of gas. Supply of gas to PGN had already commenced in 2020 pursuant to an agreement signed by the parties. Gas allocation has already been granted to MPI in order to supply power to the power plant for AMNT in Sumbawa for its smelter project and currently the relevant GSA is in progress.

On April 19, 2022, the Minister of Energy and Mineral Resources signed the Senoro Toili PSC Extension which was granted to the existing PSC Participants for 20 years. This PSC Extension will allow the PSC participants to develop Senoro Phase II Development project.

We are currently developing Senoro Phase II where 2,398 BCF of gross 100% field 2P Reserves were assessed by GCA as of December 31, 2022. The Senoro Phase II Project started with the South Senoro development. The South Senoro development execution is expected to commence in 2024. We have already received gas allocation approval for MPI, and are in the process of obtaining gas allocation approvals for other buyers after 2027 (prior to which, gas sales will be covered under existing GSAs).

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 1.45 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. CE formed a joint venture (Jera Co. Inc. ("JERA")) with Tokyo Electric Power Company Inc. in 2015, and the existing purchase agreement with DSLNG was novated to JERA in 2015.

In 2022, 42 cargos were sold to three long-term buyers. As of August 31, 2023, a total of 24 cargos have been sold this year.

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%.

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 66.7% and the government's share is 33.3%. 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 of 198 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.

Block A, Aceh contains at least five gas fields, including one producing fields, Alur Siwah. Gas production from Block A through PT. Pertamina Gas Niaga (PTGN) supplies feedgas for an Aceh-based fertilizer company that supplies consumers and farmers throughout Indonesia. Block A is also capable of suppling natural gas, if needed, to the Aceh-Belawan pipeline network and is therefore able to support downstream industries within Sumatra. Block A is in its operational stage, and we believe it has contributed to economic growth in the area improving local manpower skills and education, as well as contributing to the healthcare of surrounding villages.

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

Our South Sumatra asset consists of the South Sumatra PSC, Lematang PSC, and Rimau PSC. The South Sumatera and the Lematang PSC are in a cost recovery regime, while in 2019 Rimau PSC received an extension until 2043 and transitioned to the PSC gross split regime in April 2023. For the South Sumatra PSC and the Lematang PSC, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares after deduction for the FTP and allowing for cost-recovery. Meanwhile at the Rimau PSC, the Government and the PSC participants share the parties profit oil shares and profit gas shares upfront in accordance with the PSC gross split scheme. The initial PSC participant's share prior to the progressive split adjustment based on cumulative hydrocarbon production of oil/gas is 62.5% and the Government's share is 37.5%. For crude oil at the South Sumatra PSC and the Lematang PSC, the PSC participant's share before tax is 19.6% and 23.5%, respectively, and the Government's share is 80.4% and 76.5%, respectively. For natural gas at the South Sumatra PSC and the Lematang PSC, the PSC participant's share before tax is 43.1% and 46.3%, respectively, and the Government's share is 56.9% and 43.7%, respectively. For each of Rimau PSC, South Sumatera PSC and Lematang PSC, a portion of the PSC participants' profit oil share and profit gas share is subject to DMO.

At South Sumatra PSC, we have several fixed price GSAs with various buyers: PT Pupuk Sriwidjaja Palembang, a subsidiary of one of the largest state-owned fertilizer companies in Indonesia, PT Meppogen and Mura Energi as an independent power producer, PLN, PGN and Pertamina for city gas. At Lematang PSC, gas is sold under a fixed-price long-term GSA to PLN, Meppogen through a joint supply contract mechanism with South Sumatera PSC. In 2023, each of Lematang PSC and South Sumatra PSC secured a new GSA with PT Pupuk Sriwidjaja Palembang through a joint supply contract mechanism following successful Singa-1 and Singa-3 acid stimulation in 2022 which we expect will provide an additional 10.7 BCF of sales volume from Lematang PSC.

In 2022 and 2023, we completed operational and facility improvement programs, horizontal well drilling, and production improvements. There was a discovery in 2022 at the Flamboyan-1 well with an estimated 0.56 BSCF which will be developed to supply gas in South Sumatera. A 110 km and 124.5 km 2D seismic acquisition program have been executed in Lematang and South Sumatra PSC without LTI and within budget. Newly acquired 2D seismic data has been utilized and integrates with the exploration opportunity in order to prepare exploration drilling candidates for maintaining gas supply in South Sumatra.

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, Maleo and Meliwis gas fields, 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 the Peluang field since 2014, with output sold to PGN and PLN through the East Java pipeline.

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. We plan to drill one well in the Meliwis field in 2024 to extend the economic life up to the expiration of the PSC in December 2027. For the year ended December 31, 2022, daily gross average gas production from the three fields was 34.09 MMscfd (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 natural gas, the PSC participants' share before tax 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). We plan to develop the Paus Biru field, which is expected to extend the production period beyond the expiration of the PSC in December 2027. Gas from both the Oyong field and Wortel field is sold to PT Indonesia Power (a subsidiary of PT PLN (Persero)) under GSAs. For the year ended December 31, 2022, the daily gross average rate gas production was 29.37 MMSCFD and condensate production was 112.47 BCPD.

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 before tax is 35.7% and the Government's share is 64.3%. For natural gas, the PSC participants' share before tax 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. On June 12, 2023, we received approval on improved PSC terms from the Government to support our development of the Paus Biru field.

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 year ended December 31, 2022, it produced an average daily rate of gas of 19.5 MMscfd (gross) and condensate of 457 Mboepd (gross). For the six months ended June 30, 2023, it produced an average daily rate of gas of 11.9 MMscfd (gross) and condensate of 308 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 before tax is 26.8% and the Government's share is 73.2%. For natural gas, the PSC participants' share before tax 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.

Key International Blocks

Bualuang (Block B8/38), Thailand

We operate and hold 100% of the Bualuang field, located in the B8/38 offshore block in the south-central Gulf of Thailand. The Bualuang field has been in operation since 2008 and consists of three bridge-linked platforms that are connected by an export pipeline to the leased FSO. In 2022, oil production averaged 5,637 BOPD from existing wells. During the first half of 2023, oil production averaged 4,707 BOPD from existing wells. The current Bualuang concessionary contract is set to expire in October 2025. The production period extension for 10 years until 2035 is currently awaiting final approval from the Thai government. We intend to make additional investments to seek to sustain the Bualuang production profile.

Block 12W PSC, Vietnam

The working interest in Block 12W PSC was acquired by Ophir in 2018. Chim Sáo and Dua oil fields (and associated gas fields) are located in the Nam Con Son basin offshore in Vietnamese waters in water depths of approximately 95 meters and contain the Chim Sáo and Dua producing fields. Production at this block is currently expected until 2030. We entered into an agreement for the sale of our interest in the block in December 2022 and it is currently classified as held for sale. The completion of the sale is currently pending government approval.

Oman

In 2006, in partnership with Oman Oil Company S.A.O.C. (referred to as OQ), we entered into a Service Agreement Contract with Petroleum Development Oman (PDO) to develop the Karim Small Fields (KSF) within Block 6 of the Sultanate of Oman's concession area. The collaborative effort between MLLC and OQ was formalized through a Participating and Economic Sharing Agreement (PESA), with us holding a substantial 75% participating interest, while OQ held the remaining 25% participating interest. We became the operator for KSF, becoming the primary point of contact with PDO under the Service Agreement Contract. Medco LLC, the entity through which we entered into the Service Agreement Contract, operates as a joint venture, with local partners, with our stake in Medco LLC being 78%. This arrangement effectively entitles us to a 58.5% operated interest in the KSF Service Contract operations.

In April 2015, KSF and PDO signed an Amendment and Restated Service Contract, extending the contract's term until June 2040. KSF achieved production of approximately 12,600 BOPD per day across 20 fields in 2022. To sustain and enhance production levels, KSF has been actively engaged in infill drilling and fracturing programs. Moreover, KSF has fostered asset growth through robust and successful exploration efforts and enhanced oil recovery thermal activities. Recognizing KSF's performance, PDO recently granted an expansion to the contract area, incorporating an additional four fields and an area spanning 126 square kilometers, in addition to the original 745 square kilometers.

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 14 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 have completed assessing potential exploration of this PSC but have no immediate plans for further expenditure due to surface access issues which may limit the commercial viability of this block. We also have the Simenggaris block, which consists of the Sesayap and South Sembakung gas fields. A GSA with Kayan LNG was signed on May 20, 2020, to supply a mini LNG plant with 22 MMSCFD, located beside the South Sembakung gas plant. Plant construction has been completed and the commissioning process is underway. Commercial production is anticipated to follow commissioning, completion of which is expected in the last quarter of 2023. We seek to supply gas to meet energy needs in the vicinity, especially for the power generation sector of North, East and South Kalimantan.

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 first quarter of 2019. When activity resumed, the operator set up an operations office in Cairo and resumed operations on March 1, 2019. The operator started mobilizing a drilling rig and 3D seismic crew to begin developing drilling and exploration programs in early 2021. Production continued until November 2022 when the oil terminal was blocked due to external security threats. Prior to this stoppage, production reached 5.0 MMSCFD of gas (gross) and 3.7 MBPOD of oil (gross) for the year ended December 31, 2022.

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. All firm commitments in both blocks were fulfilled and the relinquishment process is currently underway with respect to each of Block 10 and Block 12.

Malaysia

We had 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. Full tensor gravity survey operations were completed on June 30, 2021, and this block was relinquished in 2022.

Tanzania

Medco Energi has a 20% interest in Tanzania Blocks 1 and 4, which are offshore deepwater blocks. These blocks were awarded in 2005 and 2006, respectively, and natural gas discoveries have been made with estimated natural gas reserves of at least 12 TCF. The operator of the blocks is Shell with a 60% working interest. Pavilion Energy, a Singapore-based energy company, holds a 20% interest.

Adjacent to deepwater Blocks 1 and 4 is the deepwater Block 2, which has discovered natural gas reserves of at least 13 TCF. This block is operated by Equinor, which holds a 65% working interest, and Exxon holds the remaining 35%.

The two operators, Shell and Equinor, have been negotiating enabling agreements with the Government of Tanzania to facilitate the launch of a major LNG project. The target is for the LNG project to produce 15 MTPA of LNG and also supply natural gas to the domestic market. The LNG liquification plant will be located onshore in the Lindi region of Tanzania.

The enabling agreements, including a host government agreement and an amended production sharing agreement, covering Blocks 1, 2 and 4, have been agreed between the Government of Tanzania and the respective joint ventures for Blocks 1, 2 and 4. Finalization of the agreements and execution by the parties is expected to take place shortly.

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 June 30, 2023, MEUS was contingently liable for an aggregate amount of US$3.0 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, MEG, 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 December 2022, we signed a sale agreements in respect of our interest in Block 12W, Vietnam with closing of the transaction expected to be at the end of the first half of 2024. In February 2023, we divested our share ownership in APICO which held our interest in the Sinphuhorm, Thailand, gas field.

The table below sets forth interests in blocks that we divested from or relinquished from January 1, 2020 through the date of this Document.

Entity	Divest/ Relinquish	Working interest prior to transaction	Working interest after transaction	Transferee	Date of divestment/ relinquishment
Ophir Energy Indonesia (West Papua IV) 1 Limited	Divest	100%	0%	Repsol Exploracion West Papua IV, S.L.	January 2020
Ophir Indonesia (West Papua IV) 2 LLC	Divest	100%	0%	Repsol Exploracion West Papua IV, S.L.	January 2020
Ophir Energy Indonesia (Aru) Limited	Divest	100%	0%	Repsol Exploracion Aru, S.L.	April 2020
Ophir Indonesia (S.E. Sangatta) Limited (South East Sangatta Block)	Relinquish	100%	0%	Government of the Republic of Indonesia	July 2020
Medco Arabia Limited	Divest	45%	5%	Tethys Oil Oman Onshore Limited	October 2020
PT Medco E & P Bengara (Bengara-1)	Relinquish	100%	0%	Government of the Republic of Indonesia	December 2021
Salamander Energy (S.E. Asia) Limited	Divest	10%	0%	Jadestone Energy Plc	February 2023
Ophir Jaguar 2 Ltd	Divest	100%	0%	Bitexo Energy Ltd	Expected by end 2023
Salamander Energy (Malaysia) Limited (Block PM322)	Relinquish	100%	0%	Government of Malaysia	Expected by end 2023
Ophir Mexico Operations, S.A. DE C.V. (Block 10 and Block 12)	Relinquish	20%	0%	Government of Mexico	Expected by end 2023
Medco South Sokang BV Belanda/Netherlands	Relinquish	100%	0%	Government of the Netherlands	December 2022

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 Six Months Ended June 30,

Average realized sales prices:	**2020**	**2021**	**2022**	**2022**	**2023**
Oil and condensate (US$ per BBL)	40.3	68.0	96.2	104.4	75.2
Natural gas (US$ per MMBTU)	5.2	6.5	8.2	8.5	7.2

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 generally calculated as Dated Brent plus/minus Alpha. In Thailand we sell our oil at prevailing market prices in accordance with prevailing benchmarks for crude oil in the Asia Pacific region.

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	Pertamina	1 year	ICP Kaji Flat	whole entitlement
South Sumatra	Pertamina	1 year	ICP Jene Flat & ICP Matra Flat	whole entitlement
Tarakan	Pertamina	1 year	ICP Tarakan Flat	whole entitlement
Senoro-Toili (condensate)	Glencore Singapore Pte. Ltd.	3 years	ICP Senoro + premium	whole entitlement
Arun (condensate)	Saras Trading	3 years	ICP Arun + premium	whole entitlement
Bangkanai	Kimia Yasa	1 year	Provisional ICP Kerendan Condensate	whole entitlement
Belanak	Glencore Singapore Pte. Ltd.	3 years	ICP Belanak + premium	whole entitlement
Belida.	Glencore Singapore Pte. Ltd.	3 years	ICP Belida + premium	whole entitlement
Grissik Mix	BCP Trading Pte. LTd.	3 years	Provisional ICP Grissik Mix + premium	whole entitlement
Sampang	PT Multi Colour Indonesia	1 year	ICP Sampang Condensate	whole entitlement

Natural Gas

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

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. However, starting in late 2015 we started commercial gas sales from Senoro-Toili with prices linked to JCC prices. The existing gas prices for Sembgas from Block B is linked to HSFO whereas the gas prices for the GSA commencing in the fourth quarter of 2024 are linked to the price of oil. 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 (4th GSA Amendment)	July 24, 2006-December 31, 2027 (on stream on 2007)	2.5 BBTUD (Mar 2018-Dec 2018) 4 BBTUD (2019) 5 BBTUD (2020) 3.5 BBTUD (2021) 3.65 BBTUD (2022) 4 BBTUD (2023-2027)	70% (2021) 92% (2022-2027)
	PT MEPPO-GEN* (4th GSA Amendment)	October 24, 2014-December 31, 2027	14.2 BBTUD (Oct-Dec 2018) 12.5 BBTUD (2019) 12.4 BBTUD (2020) 11.6 BBTUD (2021-2022), 10.8 BBTUD (2023-2025), 9.7 BBTUD (2026), 10.4 BBTUD (2027)	90%
	Perusahaan Daerah Mura Energi (4th GSA Amendment)	August 4, 2009-December 31, 2027 (on stream on 2015)	1.35 BBTUD 2.65 BBTUD (Nov-Dec 2019)	90%
	PT Medco E&P Rimau (1st GSA Amendment)	January 18, 2016-December 31, 2027	2 BBTUD (2020-2027)	90%
	PT Perusahaan Listrik Negara (Persero)*	April 6, 2017-January 31, 2027	20 BBTUD ramp down	90%
	PT Pertamina (Persero)	November 15, 2019-July 20, 2027 (start date January 30, 2018)	0.25 MMSCFD	N.A
	PT Perusahaan Gas Negara Tbk	May 4, 2018- July 20, 2027 (start date September 29, 2017)	0.25 BBTUD	N.A
	PT Perusahaan Gas Negara Tbk	September 8, 2020-November 27, 2033	0.40 MMSCFD	N.A
	PT Pupuk Sriwidjaja Palembang (1st GSA Amendment)	December 1, 2021-November 27, 2033	15 BBTUD (Aug 2021-Dec 2024) 10 BBTUD (2025-2029) 8 BBTUD (2030) 5 BBTUD (2031-2033)	85%

Block	Counterparty	Term	Daily Contract Quantity	Take-or-Pay as a percentage of DCQ

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	upuk Sriwidjaja Palembang*	January 1, 2023- November 27, 2033	7 BBTUD (2023) 9 BBTUD (2024) 7 BBTUD (2025) 5 BBTUD (2026) 7 BBTUD (2027) 17.63 BBTUD (2028) 14 BBTUD (2029) 13.36 BBTUD (2030-2031) 12.05 BBTUD (2032) 9.09 BBTUD (2033)	85%
Lematang	PT Pupuk Sriwidjaja Palembang	January 1, 2023- April 5, 2027	7 BBTUD (2023) 9 BBTUD (2024) 7 BBTUD (2025) 5 BBTUD (2026) 7 BBTUD (2027) 17.63 BBTUD (2028) 14 BBTUD (2029) 13.36 BBTUD (2030-2031) 12.05 BBTUD (2032) 9.09 BBTUD (2033) (joint supply with South Sumatra Block)	85%
Tarakan	PT Perusahaan Listrik Negara (Persero)-Gunung Belah	January 1, 2022- December 31, 2025	2.10-3.00 BBTUD (2022-2023) 3 BBTUD (2024-2025)	70%
	PT PGN Tbk	January 14, 2022- September 7, 2030	0.3 MMSCFD	N.A
Block A, Aceh	PT Pertagas Niaga (2nd GSA Amendment)	June 1, 2020- August 31, 2031	54 BBTUD	90%
Senoro-Toili	Donggi Senoro LNG (GSA Amendment)	January 22, 2009- December 3, 2027	227.5 BBTUD	90% (annually)
	PT Panca Amara Utama (GSA Amendment)	February 14, 2018- December 3, 2027	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 Perusahaan Listrik Negara (Persero)	February 6, 2018- December 3, 2027	5 BBTUD	80% (year 1 & 2) 90% (year 3-end of GSA)
	PT PGN Tbk	December 20, 2019- December 3, 2027	0.22 BBTUD	N.A

Block	Counterparty	Term	Daily Contract Quantity	Take-or-Pay as a percentage of DCQ
Simenggaris	PT Perusahaan Listrik Negara (Persero)			

	PT Kayan LNG Nusantara	March 1, 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
		December 31, 2021- February 23, 2028	12-22 MMSCF	85%
South Natuna Sea Block B	SembCorp Gas Singapore	January 15, 1999- July 15, 2028	135 BBTUD	90%
Sampang	PT Indonesia Power	July 19, 2003- December 31, 2031	30 BBTUD (2023) 25 BBTUD (2024-2027) 23 BBTUD (2028) 15 BBTUD (2029) 9 BBTUD (2030) 6 BBTUD (2031)	95% (Annually)
	PT Indonesia Power	November 26, 2010- December 31, 2031	13.9 BBTUD	95% (Annually)
Madura Offshore	PT PGN Tbk.	May 31, 2005- December 31, 2023	13 BBTUD (2023) 8.5 BBTUD (2024) 8.5 BBTUD (2025) 5 BBTUD (2026)	95% (Annually)
Bangkanai	PT Perusahaan Listrik Negara (Persero)	June 28, 2011- December 29, 2033	20 BBTUD	91% (Annually)
Corridor	Gas Supply Pte. Ltd	February 12, 2001- December 31, 2028	221 BBTUD (2021) 93 BBTUD (2022) 48 BBTUD (2023)	94%
	PGN Batam 3	November 12, 2018- December 19, 2023	33 BBTUD (2021) 20 BBTUD (2022-2023)	70%
	PGN RU Dumai	November 3, 2017- December 19, 2023	40 BBTUD	90%
	PGN BBG Jargas	October 14, 2021- December 19, 2023	8.42 MMSCFD (2023)	N.A
	PGN Central Sumatera	May 31, 2010- December 19, 2023	12.5 BBTUD	90%

Block	Counterparty	Term	Daily Contract Quantity	Take-or-Pay as a percentage of DCQ
	PT Pertamina Hulu Rokan	August 6, 2021-December 31, 2026	31.5 BBTUD (2021) 105 BBTUD (2022) 60 BBTUD (2023) 50 BBTUD (2024) 50 BBTUD (2025) 65 BBTUD (2026)	70%
	Energasindo	October 30, 2007-December 19, 2023	20 BBTUD (2022) 14 BBTUD (2023)	90%
	PT Perusahaan Listrik Negara (Persero) PT	May 4, 2015-December 19, 2023	3 BBTUD	70%
	Pupuk Sriwidjaja Palembang	May 25, 2016-December 19, 2023	73 BBTUD	90%
	PGN West Java	February 1, 2007-December 31, 2023	175 DCQ (2007) 237 DCQ (2008) 309 DCQ (2009) 360 DCQ (2010) 386 DCQ (2011) 412 (2012 - 2023)	90%

Note:
* These agreements also apply to the Lematang Block.

Power

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. MPI is currently a wholly-owned subsidiary through our 49% direct stake and 51% indirect ownership through PT Medco Power Internasional. MPI has interests in gas-fired power, geothermal energy and renewable energy including hydro, solar, and wind power plants.

In February 2022, MPI and its partner reached COD for a 275 MW combined-cycle power plant in Riau, Sumatera. In March 2022, each of PT Medco Solar Bali Barat and PT Medcosolar Bali Timur signed a Power Purchase Agreement with PLN for the development of 25 megawatt peak (“MWp”) Solar PV power plant in Bali, respectively.

In the renewables sector, we currently operate two mini-hydro assets in West Java, and a geothermal operation in Sarulla, North Sumatra. We are expanding our renewables business, particularly in geothermal and solar photovoltaics (“Solar PVs”). In 2022, we completed construction of the Sumbawa solar PV (26 MWp) power plant in Indonesia, which supports the PT AMNT Batu Hijau mine. In September 2023, MPI’s subsidiaries and partners were presented with a conditional award by the Energy Market Authority of Singapore for a 600 MW solar project at Bulan. This project will install over 2,000 MWp of Solar PV and 500 MW of battery storage and is expected to be completed by 2028.

With respect to our geothermal assets, as of June 30, 2023, we have completed exploration activities at Ijen and the final investment decision for phase 1 of the project (34.3 MW), with commercial operations expected to commence in the first quarter of 2025. When operational, Ijen will be the first geothermal power plant in East Java.

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

	Fuel Type	Ownership (%)	Commercial Operation Date	Gross (MW)
Power Generation				
Operating				
MEB Batam	Gas	42	2004	85
DEB Batam	Gas	48	2006	85
ELB Batam	Gas	43	2016	76
Singa	Gas	100	2015	7
TM2500	Gas	100	2017	20
EPE — South Sumatera	Gas	56	2006	12
MPE — South Sumatera	Gas	51	2008	12
Sarulla	Geothermal	19	2017-2018	330
2 Mini Hydros — West Java	Hydro	70-100	2017-2018	18
Riau CCPP — Sumatera	Gas	51	2022	275
Sumbawa	Solar PV	50	2022	26
Total Operating				**946**
Under Construction				
Ijen (construction phase 1)	Geothermal	51	2024	110
Bali Barat	Solar PV	51	2024	25
Bali Timur	Solar PV	51	2024	25
Total under Construction				**160**
Development				
ELB Add on	Gas	43	2025	39
Bonjol PSPE (PSPE stage — MEMR)*	Geothermal	51	2028	60
Total Development				**99**
Total Power Generation				**1,205**
O&M Services				
Operating				
TJBPS — Central Java	Coal	50	2006	1,320
MGS — North Sumatera	Geothermal	62	2017	330
Riau — Sumatera	Gas	62	2022	275
Total Operating				**1,925**
Under Construction				
Sulut-1	Coal	60	2023	100
Timor-1	Coal	60	2024	100
Ijen (phase 1)	Geothermal	51	2024	110
Total Under Construction				**310**
Total O&M Services				**2,235**

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, with 40 floors for office space and five basement floors for parking, and it has also obtained the Green Building Certification from the Indonesian Green Building Council for its energy efficiency and environmental procedures.

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.

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 and asset 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 competence. A systematic and structured standardized training and certification helps to ensure that all employees and contractors have similar HSE insight and knowledge.

We have implemented an HSE Management System (HSEMS) in order to ensure that our business activities fulfill and comply with relevant legal and other requirements relating to HSE. Our HSEMS is aligned with management system models and structures in OHSAS 18001, ISO 9001, and ISO 14001. We have also developed our operating systems, guidelines and standard operating procedures to ensure consistency and implementation of comprehensive HSE aspects within our business.

Our 202w personnel and process safety result improved as a result of continuing efforts to reinforce safety culture, process safety and work hazard identification. We aim to continue to improve our performance on an ongoing basis. Our total recordable incident rate improved from 0.56 in 2019 to 0.34 in 2020, to 0.29 in 2021 and 0.21 in 2022. In 2022, there were no Tier-1 or Tier-2 Process Safety Events in Block A, Aceh, Lematang PSC, Bangkanai PSC, Tarakan PSC, Rimau PSC, South Sumatra Block PSC, Block B Natuna PSC, Sampang PSC, Madura PSC, Oman and Bualuang field. We also continue our efforts to reduce Process Safety Events Tier-3, mainly in South Sumatra Region related with corrosion in mature facilities.

In 2023, we received several safety awards from MEMR: the *Patra Nirbhaya* (given in recognition of zero fatality, significant property damage and oil spill) for South Natuna Sea Block B PSC, Block A, Aceh, Lematang PSC, Bangkanai PSC and Madura Offshore PSC.

Employees

We had 4,908 employees as of June 30, 2023, of which 3,373 were permanent employees and 1,535 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, 2020	2,916	1,069	3,985
December 31, 2021	3,404	2,285	5,689
December 31, 2022	3,339	1,345	4,684
June 30, 2023	3,373	1,535	4,908

In Indonesia (Corporate Office and E&P), our employees have eleven (11) labor unions, and we have signed collective bargaining agreements with a term of two years with a one-year optional extension. As of June 30, 2023, these unions have approximately 2,103 members, or 90.3% 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. We believe we have a good and cooperative relationship with our employees.

Environmental

Environmental stewardship is an integral part of our HSE policy. We are committed to targeting zero incidents, injuries, and illness in all our activities and to protect our employees and stakeholders as well as the environment where we operate.

Two key objectives to meet our goals are:

1. Comply with all applicable laws and regulations and align our HSE Management System with industry best practices and relevant international standards.
2. Manage non-hazardous & hazardous waste, air emissions and the utilization of energy and resources in order to minimize impact on the environment and protect the ecosystem and biodiversity.

Our operations are primarily subject to Indonesian laws and other host countries' government 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 unless specified by the Government under specific mechanism and approval. 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, clean-up, and emission handling 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 and development work can commence. Under the Oil and Gas Law, the Special Task Force for Upstream Oil and Gas Business Activities (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 management and monitoring implementation plan 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 received 'Blue', 'Green', and 'Gold' (being the highest rating) PROPER awards from the Environmental & Forestry Ministry for our participating Indonesian assets. In 2020, we received 'Gold' rating for our non-operated assets, JOB Tomori and Tanjung Jati B Power Station. This demonstrates the best of beyond compliance efforts. In 2021, we also received 'Gold' rating for JOB Tomori and Tanjung Jati B Power Station. We also received 'Green' rating for South Natuna Sea Block B. In 2022, we received 'Gold' rating for Tanjung Jati B Power Station, 'Green' rating for JOB Tomori and South Natuna Sea Block B, acknowledging our efforts of going beyond compliance. The rest of our participating domestic assets received Blue PROPER, demonstrating our regulatory compliance. In addition, AMNT mining business consistently received 'Blue' category PROPER in the last three years.

We have implemented a HSE management system which 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. Environmental stewardship is a key part of our HSE Management System and Risk Management.

We published our Sustainability Report for 2022 in accordance with the 2021 GRI reporting standards which includes an independent limited assurance statement from a reputable third party.

Sustainability Policy

We aim to provide value for our shareholders and stakeholders in a sustainable manner. This means maintaining technical excellence and operational efficiency, and conducting our affairs transparently and with integrity so that we are able to maintain our social license to operate.

We are committed to operating in an ethical, sustainable manner, protecting the health and safety of our employees, safeguarding the environment, and listening and acting in response to the needs of stakeholders, including local communities, business partners, and regulatory authorities, and from each of these parties to the extent applicable we expect comparable standards.

We are implementing a 2023-2027 sustainability roadmap with new sets of sustainability goals and key performance indicators. Our three pillars of sustainability are (1) Leadership of and by Our Employees: We are committed to maintaining a healthy, safe workplace built upon a culture of mutual respect, rewarding good performance and expecting accountability and providing clear expectations, (2) Environmental and Social Development: Among other things, we are committed to complying with applicable laws and regulations, applying best practices and international standards to environmental, health and safety matters, and (3) Local Community Empowerment: we aim for empowerment through among other things, regular and transparent engagement with local stakeholders and assistance in creating self-reliant communities aligned with UN sustainable development goals.

We have implemented programs and initiatives to embed sustainability as part of our DNA through socialization, advocacy and capacity building activities. We have integrated environmental, social and governance aspects across our operations and projects.

Climate Change Strategy

We have a strong commitment to participation in reducing the effects of climate change. As an energy company that mainly engages in exploration and development in the oil and gas industry, we are committed to overcoming the effects of climate change. We improved our emissions inventory and accounting methodology by implementing corporate standardized air and GHG emissions accounting guidelines across all operating assets in 2020. The improvement includes addition of international references in the methodology and inclusion of more accurate quantification methods in several emissions sources. Our GHG emission inventory has now covered all applicable Scope 1 and Scope 2 emissions sources. We produce an annual sustainability report assured by a reputable third party which does not form a part of this Document). We became a reporting member of CDP (a global disclosure system to manage environmental impact) in May 2021 and have submitted our climate related data annually.

We undertake efforts to minimize our GHG emissions and to instill good practices in terms of energy and resource efficiency. We seek energy efficiency improvement on an ongoing basis and aim to improve GHG emissions reduction initiatives and integrate these into business planning and budgeting processes. The GHG emissions are reported and monitored on a monthly basis from asset management teams up to the board of directors level. We also report our GHG emissions to the Indonesian Ministry of Environment and Forestry on an annual basis. In addition, we conduct energy audits at selected assets, and emissions benchmarking with peers to support a company-wide climate change strategy.

Our aspiration is to deliver our Net Zero commitment for Scope 1 and Scope 2 greenhouse gas emissions by 2050 and Scope 3 emissions by 2060, and our strategy consists of three pillars: GHG emissions reduction, with, supporting transition towards low-carbon Energy (focus areas on gas as a transition energy source and expanding our renewable portfolio; managing physical climate risks, with the focus areas on climate adaptation and climate design).

In 2022, we established interim targets for 2025 and 2030 to reduce the Scope 1 and 2 GHG emissions by 20% by 2025 and 30% by 2030 from 2019 levels and to reduce methane emissions by 25% by 2025 and 37% by 2030 also from 2019 levels for our oil and gas operations. The target for our power business is to provide 26% of our installed capacity from renewable energy in 2025 and 30% in 2030.

Corporate Social Responsibility

Our corporate social responsibility ("CSR") programs are 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 pillars of our community development policy, being natural resources and local wisdom, where programs are developed based on natural resources and local wisdom within local communities to foster sustainable growth, empowerment, where we aim to improve the ability of communities to become more environmentally self-reliant, and stakeholder engagement, where we engage with various stakeholders to operate and implement our initiatives. We have CSR programs in operation 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) Barito Utara (Central Kalimantan), Sampang, Sumenep and Pemkasan (East Java), Oman and Thailand, as well as areas surrounding MPI's assets. 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 disasters.

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. For a description of the legal proceedings, see Note 50 to our consolidated financial statements.

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 other jurisdictions, such as the United States and countries in the European Union." 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 energy and natural resources company operating through our core oil and gas exploration and production business and power generation business. We also have a 21.09% interest in a listed copper and gold mining company, PT Amman Mineral Internasional Tbk as of August 31, 2023. 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 January 1, 2023, we have the largest commercial reserves and the highest level of working interest production in Southeast Asia among a selected peer group, consisting of independent exploration and production companies with similar reserves in Southeast Asia, including Harbour Energy, SapuraOMV Upstream, Energi Mega Persada, Hibiscus Petroleum and Neptune Energy. Our core oil and gas activities are primarily in Indonesia. Internationally, we operate a significant producing asset in Thailand and have oil and gas operations in the Middle East, Libya and Tanzania.

In March 2022, we completed the acquisition of Indonesian assets from Corridor, consisting of (i) a 54% working interest in the Corridor PSC and (ii) a 35% interest in Transasia Pipeline Company Pvt. Ltd, which in turn has a 40% interest in PT Transportasi Gas Indonesia, a gas pipeline network supplying customers in Central Sumatra, Batam and Singapore. Corridor PSC has two producing oil fields and seven producing gas fields located onshore South Sumatra, Indonesia, adjacent to our existing operations in South Sumatra. The total consideration for the acquisition was approximately US$1.355 billion, which we financed primarily with the proceeds of the 2028 Notes, a US$450 million amortizing loan and cash on hand. We have completed the integration of the Corridor PSC assets in 2022 and believe Corridor has significant potential, as well as access to reservoirs suitable for carbon capture and storage. Following the completion of the Corridor Acquisition, our proportion of natural gas as a percentage of production has increased from 63.4% in 2021 to approximately 79.4% of production in 2022 (which includes Corridor PSC starting from March 3, 2022), providing, we believe, a path to transition to low carbon energy. We believe that the Corridor Acquisition and its gas shipments through PT Transportasi Gas Indonesia combined with our existing gas shipments from South Natuna Sea Block B and the West Natuna Transportation System pipeline to an onshore receiving facility in Singapore made us the largest Indonesian gas supplier into Singapore in 2022.

As of October 6, 2023, our market capitalization was Rp. 33.7 trillion (US$2,154 million).

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 other countries outside of Indonesia with, among others, interests in key producing assets in Thailand, and interests in other assets in Yemen, Libya, Oman and Tanzania. In Indonesia, the majority of our blocks are held under production sharing arrangements with SKK Migas, Indonesia's national upstream oil and gas regulator. Our block in Thailand is held under a concession contract, subject to tax and royalty fees.

In 2022 and the six months ended June 30, 2023, our production was 162.5 MBOEPD and 161.8 MBOEPD with oil and gas production split 20.6% oil and 79.4% gas and 19.8% oil and 80.2% gas, respectively (including in each case production under our Oman service contract). Of the gas production, 70.2% and 72.2%, respectively, was sold under fixed price contracts primarily to PGN (a gas and distribution company majority owned by the Government of Indonesia), Pertamina (the national oil company of Indonesia), PUSRI (an Indonesian state-owned company engaged in the production and distribution of fertilizers) and PLN (the Indonesian state-owned electricity generator). Our gas off-takers include blue chip customers with strong credit profiles.

As of June 30, 2023, our estimated gross working interest proved and probable reserves was 457.3 MMBOE. We had proved developed reserves of 197.2 MMBOE, 202.0 MMBOE, 238.1 MMBOE and 212.0 MMBOE, as of December 31 2020, 2021 and 2022, and June 30, 2023, respectively. We produced approximately 32.3 MBOPD, 27.0 MBOPD, 25.8 MBOPD and 24.2 MBOPD of oil and condensate and approximately 281.7 MMSCFD, 280.5 MMSCFD, 633.6 MMSCFD and 633.9 MMSCFD of natural gas in 2020, 2021 and 2022 and the six months ended June 30, 2022 and 2023, respectively**.** Reserves and production in this paragraph exclude reserves and production under our service contract at our Karim Small Fields.

Overview of Power Business

In addition to our core oil and gas business, we operate in the power generation sector through MPI, 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 clean 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 renewable energy including hydro, solar, and wind power plants. MPI owns and operates twelve power plant assets. Approximately one third of MPI's capacity is from renewable sources. As of June 30, 2023, MPI had gross installed capacity of 2,871 MW combined IPP and O&M power plants. In 2021 and 2022, MPI produced 2,718 GWH and 3,993 GWH of power as an IPP, respectively, and acted as O&M provider for power plants which produced 1,650 MW and 1,925 MW of power.

Copper and Gold

Our copper and gold mining interest consists of our interest in AMI, which is the parent company of AMNT. AMI completed its IPO on the IDX in July 2023, and as of October 6, 2023 had a market capitalization of Rp. 451.3 trillion (US$28,835 million). As of August 31, 2023, we had a 21.09% shareholding in AMI.

For the years ended December 31, 2020, 2021 and 2022 and the six months ended June 30, 2022 and 2023, our total revenues were US$1,034.5 million, US$1,252.1 million, US$2,312.2 million, US$1,108.6 million and US$1,116.2 million, respectively, and EBITDA was US$452.1 million, US$667.3 million, US$1,593.1 million, US$779.6 million and US$633.8 million, respectively.

Our consolidated financial statements as of and for the six months ended June 30, 2022 and for the year ended December 31, 2020 have been restated for comparative purposes in accordance with PSAK 58 primarily to reflect the following: (i) the reclassification of Block 12W in Vietnam as held for sale, following our entry into an agreement for the sale of our interest in the block in December 2022, (ii) the reclassification of our investment in APICO LLC, which held our interest in the Sinphuhorm block in Thailand which we had acquired as part of the Ophir Acquisition, as held for sale, as we sold off our interest in February 2023. See note 39 of our consolidated financial statements.

Significant Factors Affecting Results of Operations

Oil and Gas Prices

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

The table below sets forth our revenue from exploration and production of oil and gas and trading for the periods indicated.

	For the Years Ended December 31,			For the Six Months Ended June 30,	
	2020	2021	2022	2022	2023
	(Restated)			(Unaudited) (Restated)(1)	
	(US$ in millions)				
Revenue from exploration and production of oil and gas and trading:					
Fixed price contracts	242.9	304.8	949.6	463.1	434.0
Oil linked and others	645.2	810.7	1,240.2	582.7	508.8
Total	888.0	1,115.5	2,189.8	1,045.8	942.8

Oil Prices

The international market for crude oil is volatile, and has historically been characterized by significant price fluctuations including for example significant decreases in 2020 resulting from the impact of the COVID-19 pandemic on global demand for crude oil and significant increases in demand as economic activity has increased as COVID-19 measures have been eased. The annual average price of Brent crude oil was US$41.60 in 2020 and US$70.63 in 2021 and US$100.97 in 2022. The monthly average price of Brent crude oil was US$79.78 for the month of June in 2023.

Oil prices fluctuate due to a number of factors, which include, among others, demand for crude oil, global events and circumstances such as the COVID-19 pandemic, 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, 2020, 2021 and 2022 were US$40.3 per BBL, US$68.0 per BBL and US$96.2 per BBL respectively, with the lower realized price in 2020 reflecting the impact of the COVID-19 pandemic and were US$104.4 per BBL and US$75.2 per BBL, respectively in the six months ended June 30, 2022 and 2023. The changes in oil prices have significantly impacted our total revenue from exploration for and production of oil and gas and trading. In addition, fluctuations in oil prices have impacted and may continue to impact our results of operations and asset values generally.

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 Indonesian Government regulations, we sell our oil at prices based on the Indonesian Crude Price, or ICP. The ICP price is determined by the Government. 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 for cost recovery PSCs (but not gross split PSCs), gross split PSCs require us to effect DMO Sales at 100% of the market price. 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.

In Thailand we sell our oil at prevailing market prices in accordance with local practice.

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 the majority of our domestic gas GSAs are fixed in US$/MMBTU. 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, the South Natuna Sea Block B GSA and a portion of the gas from Corridor GSA. In particular, as of June 30, 2023, gross working interest volumes from the substantial majority of our 1,690.5 BCF of proved and probable gas reserves were commercially committed for sale through long-term contracts (except for Libya of 3.4% of the 1,690.5 BCF), with sales through such contracts representing 69.3**%** of our total revenue from exploration for and production of oil and gas and trading in June 30, 2023. Of this, gas revenue of approximately 66.4**%** 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 over time as we have become more gas than oil focused. Our average realized sales prices for gas per MMBTU for the years ended December 31 2020, 2021 and 2022 and the six months ended June 30, 2022 and 2023 were US$5.2, US$6.5, US$8.2, US$8.5 and US$7.2, respectively, reflecting production primarily from Corridor, Senoro and South Natuna Sea Block B, which has a GSA with prices linked to movements in oil prices. Gas prices were impacted significantly by the COVID-19 pandemic in 2020. For a summary description of our gas sales arrangements, see “Business — Sales and Distribution — Natural Gas.”

Acquisitions and Divestments

One of our key strategies has been and continues to be 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. As a result, our results of operations and business are significantly affected by acquisitions and divestments. For example, the Corridor Acquisition became effective on March 3, 2022 and we began consolidating Corridor thereafter. We also completed the Ophir Acquisition in 2019. These acquisitions increased our reserve base and production levels. The larger asset base has also resulted in higher depreciation expenses and costs related to production activities. We have also been able to realize value through these acquisitions through synergies and cost savings once integrated.

From time to time, we have also acquired and divested from, or increased or decreased our effective interests in, other oil and gas blocks. For example, in December 2022, we entered into an agreement to sell our interest in Block 12W, Vietnam, which is still in the process of obtaining requisite approvals for closing and on February 23, 2023, sold our share ownership in APICO LLC, the entity which held our interest in the Sinphuhorm gas field in Thailand.

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, result of operations and income as we record bargain purchase gains.

Cost Efficiencies

In light of oil price volatility, we have focused on maintaining strong cost efficiencies. In 2020, 2021 and 2022, our unit cash production cost was US$9.1/BOE, US$9.5/BOE and US$6.9/BOE, respectively and US$6.2/BOE and US$7.4/BOE in the six months ended June 30, 2022 and 2023, respectively. We had initially achieved these efficiencies 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 targeted both larger scale cost reduction opportunities, such as drilling rig rate reductions, to smaller scale granular opportunities, such as travel and training budgets. In mid-2020, we launched a sustainable performance improvement project, facilitated by a reputable consulting firm, to benchmark our performance against best practices globally, which led to the identification of several new initiatives with respect to maintenance, procurement supply chain management, planning, operations, operating model and code of conduct. In 2021, we also adopted a combined "hot-desking" and "work-from home" approach to the occupancy of our headquarters, and this has allowed the return several floors to the landlord for rental to third parties. We have also been able to take advantage of synergies when integrating acquisitions including following the Ophir Acquisition and the Corridor Acquisition. For example, in connection with the Corridor Acquisition, we identified and implemented US$50 million of recurring operational, procurement, and commercial recurring synergies with our existing assets.

Commercial Arrangements

Currently the majority of our Indonesian PSCs are cost recovery PSCs which 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 15%-20% of the total production of oil and gas each year, to be 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 two JOBs, after we have recovered all approved costs including incentives, the Government is entitled to a 60.0% to 87.5% profit share of the remaining production and we keep the rest as our profit share. As our recoverable costs are customarily settled in oil and gas, the exact amount realizable by us from these cost recoveries varies depending on the market prices of oil and the contracted prices of gas. For example, if oil prices decrease, our cost recovery portion of production will rise and consequently, our net entitlement percentage under our commercial arrangements will also rise. However, despite such increase in our net entitlement percentage, a decline in oil prices will lead to a decline in net revenues.

The gross split scheme was introduced as a new type of PSC in 2017. Under the gross split PSC regime, gross revenue from a PSC is directly split between the contractor and the Government with the contractor bearing its own costs without any deduction of FTP. Such expenses are deductible only through the contractor's share of gross revenue or as a deduction to the contractor share of taxable revenue. The split includes a base split, variable split, and progressive split and in general, the base splits for contractor are 43% for oil fields and 48% for gas. Variable splits may differ for each PSC depending on the risk profile of the PSC (e.g., field status, field location, reservoir type, local content, etc.), while the progressive split depends on the actual oil and gas price, and cumulative production volume. In addition, the Government may determine an additional split based on negotiation on special circumstances.

Our share of profits after tax from our cost recovery 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 3.12% to 8.75% 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% for PSC cost recovery of the market price, depending on the PSC.

The quantity of crude oil determined in respect of the DMO obligation shall be the maximum quantity to be supplied by the contractor. In the event that the recoverable operating costs exceed the difference of total sales proceeds from crude oil produced and saved, minus the first tranche petroleum and investment credit, the relevant contractor shall be relieved from this supply obligation for such year. While we are obliged to sell 25% of the gas we produce in the domestic market, we may do so at market price and we sell the majority of our entire gas net production in the domestic market. See "Risk Factors — Risks Relating to our Industries."

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

In 2022, we incurred US$280.4 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$300.0 million per year, assuming mid-cycle commodity prices, over the next five years. However, we intend to retain flexibility to adjust planned capital expenditures depending on movements in commodity prices. 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. In addition, to respond to the significant drop in energy demand due to the impact of the COVID-19 pandemic, we reduced both capital and operating budgets in order to maintain liquidity, which impacted our exploration and development activities. Although we were able to realize cost savings, such reduced capital expenditure impacted our exploration and development activity, impacting production and/or reserves levels. We have subsequently increased our capital expenditures along with oil price recovery as the effects of the pandemic subsided.

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, based on the total estimated proved reserves, as detailed in Note 2.n to our consolidated financial statements as of and for the year ended December 31, 2022.

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, 2020, 2021 and 2022 and the six months ended June 30, 2022 and 2023 were US$286.9 million, US$278.0 million, US$567.3 million, US$250.1 million and US$281.6 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 the majority of our Indonesian PSCs are under the cost recovery PSC regime. The Rimau and Tarakan PSCs are under the gross split PSC regime and our Corridor PSC is currently expected to be under the gross split regime starting from late December 2023.

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, 15% or 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 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 corporate 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 or the PSC becomes effective, 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 pursuant to income tax law and its implementing regulations applicable to the gross split PSC in fiscal year of the signing date or the effective date of the gross split PSC, as the case maybe, which is 22% for fiscal year 2020 onwards. The relevant corporate income tax rate will continue to be applicable to relevant gross split PSC until the expiration date of the contract;
- taxable income of a permanent establishment that results from gross split PSC activities from which corporate income tax has already been deducted is subject to branch profits tax at the rate 20% pursuant to ITL-36/2008 or reduced branch profits 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.

Key Factors Impacting our Power Business

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;
- factors impacting demand for power in Indonesia, including the COVID-19 pandemic;
- MPI's power generation capacity and volume and type of O&M services provided;
- geopolitical and other factors which impact raw material and other costs;
- 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.

Recovery from the COVID-19 Pandemic

In 2020 and 2021, the COVID-19 pandemic significantly affected Indonesia and the oil and gas industry globally. In the early stages of the COVID-19 pandemic, oil prices fell to near historic lows due to a combination of a severely reduced demand for crude oil, gasoline, jet fuel, diesel fuel, and other refined products resulting, among other things, from government-mandated travel restrictions and a curtailment of economic activity. In order to respond to the significant drop in energy demand due to the impact of the COVID-19 pandemic, we reduced both capital and operating budgets in order to maintain liquidity, which impacted our exploration and development activities. As governments have lifted pandemic-related restrictions, including travel and other restrictions, the oil and gas market has experienced recovery. We also took measures to protect the safety of our employees during the height of the pandemic. See also "Risk Factors — Risks Relating to the Company — Our business have been and may continue to be materially and adversely affected by the COVID-19 pandemic."

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, 2022, 2021 and 2020 and the six months ended June 30, 2023 and 2022.

	For the Years Ended December 31,			For the Six Months Ended June 30,	
	2020	2021	2022	2022	2023
	(Restated)[1]			(Unaudited)	
	(US$ in millions)				
CONSOLIDATED STATEMENTS OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME					
Continuing Operations					
Revenues					
Revenue from contracts with customers	1,002.4	1,212.2	2,269.7	1,087.3	1,094.1
Finance income	32.1	39.9	42.6	21.4	22.1
Total Revenues	**1,034.5**	**1,252.1**	**2,312.2**	**1,108.6**	**1,116.2**
Cost of Revenues and Other Direct Costs					
Depreciation, depletion, and amortization	282.6	272.6	561.5	247.1	278.9
Production and lifting costs	247.9	257.3	334.5	146.3	174.0
Cost of electric power sales and related services	74.0	59.0	44.9	20.7	122.7
Cost of crude oil purchases	70.0	79.7	94.3	57.7	54.4
Cost of services	17.8	15.5	18.0	8.7	12.0
Exploration expenses	23.2	17.3	13.0	7.8	4.2
Total Cost of Revenues and Other Direct Costs	**715.5**	**701.5**	**1,066.2**	**488.2**	**646.2**
Gross Profit	**319.0**	**550.6**	**1,246.0**	**620.5**	**470.0**
Selling, general and administrative expenses	(153.8)	(161.4)	(220.2)	(91.0)	(117.8)
Finance costs	(278.2)	(222.5)	(259.4)	(126.6)	(132.7)
Dividend income	—	—	28.1	28.1	31.8
Share of net profit of associates and joint venture	28.1	61.9	232.9	119.9	21.5
Interest income	18.5	9.1	39.6	13.3	21.3
Gain/(loss) on derivative transactions	9.5	(11.5)	(36.9)	(18.8)	—
Bargain purchase	—	—	49.0	46.1	—
Loss on disposal of long-term investment	(2.2)	—	—	—	—
Loss on dilution of long-term investment	(19.0)	—	—	—	—
Loss on impairment of assets	(60.1)	(35.5)	(2.3)	(1.8)	—
Gain/(loss) on fair value adjustment of financial assets	31.1	80.5	(0.5)	(1.8)	(20.8)
Other expenses	(25.5)	(20.3)	(73.1)	(23.7)	(9.1)
Other income	35.7	18.4	42.3	7.8	9.6
Profit (Loss) Before Income Tax Expense from Continuing Operations	**(96.9)**	**269.4**	**1,045.6**	**572.1**	**273.8**
Income Tax Expense	**(67.2)**	**(222.8)**	**(508.0)**	**(270.0)**	**(150.1)**
Profit/(Loss) for the Period/Year from Continuing Operations	**(164.1)**	**46.5**	**537.6**	**302.0**	**123.7**
Discontinued Operations					
Profit/(Loss) after income tax expense from discontinued operations	(17.1)	16.1	13.8	12.2	6.6
Profit/(Loss) for the Period/Year	**(181.2)**	**62.6**	**551.4**	**314.2**	**130.3**

	For the Years Ended December 31,	For the Six Months Ended June 30,
Other Comprehensive Income		

Other Comprehensive Income That Will Be Reclassified to Profit or Loss	**2020**	**2021**	**2022**	**2022**	**2023**
	(Restated)[1]			**(Unaudited)**	
			(US$ in millions)		
Translation adjustments	(4.6)	(5.6)	(15.4)	(12.1)	25.1
Fair value adjustment on cash flow hedging instruments — net of tax	(35.5)	19.1	31.7	(30.9)	4.0
Fair value adjustment on available-for-sale investment	(0.8)	—	—	—	—
Share of other comprehensive income (loss) of associates and joint venture	(10.3)	6.5	24.0	14.0	(0.1)
Other Comprehensive Income That Will Not Be Reclassified to Profit or Loss					
Remeasurement of defined benefit program	1.9	2.0	(2.4)	7.2	(1.2)
Income tax related to the accounts that will not be reclassified to profit or loss	2.8	0.3	(0.8)	(2.6)	1.0
Total Comprehensive Income/(Loss) for the Period/Year	**(227.6)**	**84.8**	**588.5**	**289.8**	**159.2**
Profit/(Loss) for the Period/Year Attributable to Equity Holders of the Parent Company					
Profit (Loss) for the period/year from continuing operations	(175.8)	31.0	517.1	290.9	112.9
Profit for the period/year from discontinued operations	(17.1)	16.1	13.8	12.2	6.6
Profit (Loss) for the period/year attributable to equity holders of the parent company	(192.8)	47.0	530.9	303.1	119.5
Profit for the period/year attributable to non-controlling interests	11.7	15.6	20.5	11.2	10.8
	(181.2)	**62.6**	**551.4**	**314.2**	**130.3**
Total Comprehensive Income/(Loss) for the Period/Year Attributable to Equity Holders of the Parent Company					
Comprehensive income (loss) for the period/year from continuing operations	(211.9)	53.4	527.5	254.2	137.4
Comprehensive income (loss) for the period/year from discontinued operations	(17.1)	16.1	13.8	12.2	6.6
Comprehensive income (loss) for the period/year attributable to equity holders of the parent company	(229.0)	69.4	541.3	266.4	144.0
Comprehensive income for the period/year attributable to non-controlling interests	1.3	15.4	47.3	23.4	15.2
	(227.6)	**84.8**	**588.5**	**289.8**	**159.2**

Notes:

(1) The restated consolidated financial statements resulted from the re-classification of profit or loss accounts of certain subsidiaries previously included in “Continuing Operations” to “Assets Held for Sale and Discontinued Operations” as further described in note 39 of our consolidated financial statements.

(2) As presented in the Company’s Consolidated Financial Statements.

Description of Certain Principal Comprehensive Income Statement Line Items

Total Revenues

Our total revenues mainly consist of revenues from contracts with customers and to a lesser extent finance income.

We have four operating segments for the purposes of our financial information, which are exploration for and production of oil and gas, trading, service and power. Our exploration for and production of oil and gas segment primarily consists of our oil and gas being sold domestically while our trading business primarily consists of oil we produce and which is sold through our subsidiary MEG for export. Given that both of these segments primarily consist of sales of our oil and gas, in the period on period discussions below we have combined the two segments into a single line item. Set forth below is a breakdown of our total revenue by segment. See note 44 of our consolidated financial statements.

	For the Years Ended December 31,			For the Six Months Ended June 30,	
	2020	2021	2022	2022	2023
	(Restated)[1]			(Unaudited)	
	(US$ in millions)				
Exploration for and production of oil and gas	836.6	1,019.7	2,051.4	971.3	797.6
Trading	51.4	95.7	138.4	74.5	145.2
Service	10.2	14.3	8.0	5.5	8.9
Power	136.2	122.3	114.4	57.3	164.5
Total Revenue	**1,034.5**	**1,252.1**	**2,312.2**	**1,108.6**	**1,116.2**

Note:

(1) The restated consolidated financial statements resulted from the re-classification of profit or loss accounts of certain subsidiaries previously included in "Continuing Operations" to "Assets Held for Sale and Discontinued Operations" as further described in note 39 of our consolidated financial statements.

Exploration For and Production of Oil and Gas and Trading

Our revenues from our oil and gas business 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. Our total revenue from exploration for and production of oil and gas and from trading consists of (i) revenue from sales to external parties from oil and gas sold from our entitlement at our blocks, plus (ii) revenue from oil and gas trading, which currently primarily comprises revenue we earn from our international sales of oil and gas from our entitlement at our blocks sold through our trading arm to external parties, and revenue earned from purchasing oil and gas from external parties, primarily our partners in the blocks that we operate or from SKK Migas's entitlement, which we then sell as exports to external parties. Prior to the enactment of MEMR No. 42 dated September 16, 2018, we were generally able to sell oil and gas from our entitlement internationally. Following the enactment of such legislation, Pertamina had priority to purchase oil and gas sold from our Indonesian blocks. However, such legislation was replaced by MEMR No. 18 dated July 9, 2021, which instead requires that oil and gas from our Indonesian blocks be sold through a tender process whether sold domestically or internationally.

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. 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.

Our natural gas sales contracts are typically long-term fixed price contracts. Most of our gas production in Indonesia, Thailand and Vietnam is 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."

Power

Our revenue from power consists of revenues earned by MPI. MPI's electric power revenue is primarily generated from (i) construction revenue it earns from constructing power plants regulated by PLN as the public sector body in charge of selling electricity to end users in Indonesia, (ii) electric power sales, (iii) interest income from the outstanding initial investment of constructing power plants (finance income from service concession), (iv) operation and maintenance services (which consists of operations and maintenance services provided to third parties and the Sarulla project) and (v) lease of power plant.

Service

Our revenue from services are primarily generated from gas transportation services, rig rental and gas distribution and other, including labor, services.

Cost of Revenues and Other Direct Costs

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization primarily arise from the depletion of capitalized oil and gas exploration and development costs and depreciation of power plants. In addition, we also record depreciation expense related to capitalization of certain operating leases as right of use assets.

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 Electric Power Sales and Related Services

Our cost of electric power sales and related services consists 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.

Cost of Crude Oil Purchases

Our cost of crude oil purchases consists of payments for crude oil (outside of our entitlement) purchased from SKK Migas and our other joint venture partners in the PSC that we operate, which we then sell to our foreign customers. We settle our lifting position with SKK Migas and our other partners at the end of each year.

Cost of Services

Costs of services represent the costs related to our gas transportation and distribution business, and operational activities for our rig rental and security services.

Exploration Expenses

Exploration expenses include dry hole costs, in the event that the exploration activities are unsuccessful, and exploration overheads. Exploration expenses vary with the level of exploration activities and the success rate of such activities. We follow PSAK 64 in 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 result is determined to be unsuccessful, in which case, such expenses are recorded in the year of such determination. Exploration overhead is expensed in the period incurred.

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 expense on our indebtedness, accretion of asset abandonment and site restoration obligations and interest expense on lease liabilities.

Share of Net Profit (Loss) of Associates and Joint Ventures

Our share of net profit (loss) of associates and joint ventures primarily consists of our share of the net profit or net losses of AMI.

Gain/(loss) on Fair Value Adjustment of Financial Assets

Gain or loss on fair value adjustment of financial assets consists of gains or losses on fair value adjustments related to our equity investment other than interest in subsidiaries, associates and joint venture which are accounted for using either consolidation or equity method. In accordance with Indonesian FAS, as we hold a minority interest and have determined that we do not hold significant influence over such equity investment, we hold our interest at fair value through profit or loss and reevaluate the value of our interest at the end of each reporting period and as a result, record fair value gains or losses depending on the movement in valuation during the period.

Loss on Impairment of Assets

Our loss on impairment of assets primarily consists of impairment losses recorded on our oil and gas properties; property, plant and equipment; and long-term investment in shares of our associates and joint ventures as a result of impairment testing that we perform when circumstances indicate that the carrying value of the asset exceeds its recoverable amount.

From time to time, in accordance with Indonesian FAS, we have also made reversals on impairment of assets when relevant circumstances have changed.

Interest Income

Interest income primarily consists of interest income on cash deposits at banks and interest recorded on a shareholder's loan made to Transasia Pipeline Company Pvt Ltd, in which we acquired an interest as part of the Corridor Acquisition in March 2022.

Bargain Purchase

We record bargain purchase gains when the value of the consideration paid in an acquisition is less than the fair value of the net assets acquired.

Gain/(loss) on derivative transactions

Gain/(loss) on derivative transactions primarily consists of gains or losses related to commodity hedging.

Dividend income

We record dividend income from our equity investments recorded under the fair value method, where we hold a minority interest and have determined that we do not hold significant influence over such equity investment, which primarily consists of dividends paid to us from DSLNG.

Loss on Disposal of Long-Term Investment

Loss on disposal of long-term investment represents losses recorded when we sold 10% of our share ownership interest in AMI in 2020.

Loss on Dilution of Long-Term Investment

Loss on dilution of long-term investment represents losses recorded when our share ownership interest in an associate or joint venture is reduced, whether directly or indirectly, either through new shares issuance or restructuring, diluting our shareholding.

Other Expenses

Other expenses primarily consist of loss from currency swap derivative settlements, receivables written off, marketing fees and foreign exchange losses.

Other Income

Other income mainly represents management fees related to the Joint Operating Agreement of Medco E&P Natuna Ltd, gain from currency swap derivative settlement, and foreign exchange gains.

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 22%.

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.

Profit/(Loss) After Income Tax Expense from Discontinued Operations

Profit or loss after income tax expense from discontinued operations primarily represents profits or losses generated by our assets which were either held for sale or categorized as discontinued operations, being primarily Block 12W in Vietnam.

Comparison of The Six Months Ended June 30, 2023 and 2022

Total Revenue

Our total revenue increased by 0.7% to US$1,116.2 million for the six months ended June 30, 2023 compared to US$1,108.6 million for the six months ended June 30, 2022, primarily due to an increase in revenue from power, partially offset by lower revenue from the exploration for and production of oil and gas and trading, which primarily resulted from lower oil and gas prices.

Exploration for and Production of Oil and Gas and from Trading

Our total revenue from exploration for and production of oil and gas and from trading decreased by 9.8% to US$942.8 million for the six months ended June 30, 2023 from US$1,045.8 million for the six months ended June 30, 2022. The decrease was primarily due to a decrease in both oil and gas prices, partially offset by increases in gas sales volume as a result of the Corridor Acquisition which became effective on March 3, 2022. Our average realized prices for oil decreased to US$75.2/barrel in the six months ended June 30, 2023 from US$104.4/barrel in the six months ended June 30, 2022. Our average realized prices for natural gas decreased to US$7.2/MMBTU for the six months ended June 30, 2023 from US$8.5/MMBTU for the corresponding period in 2022. Our oil sales volume decreased to 28.8 MBOPD for the six months ended June 30, 2023 from 29.4 MBOPD for the six months ended June 30, 2022. Our gas sales volume increased to 671.4 BBTUPD for the six months ended June 30, 2023 from 617.3 BBTUPD for the same period in 2022, primarily due to Corridor PSC's consolidation for the full six month period ended June 30, 2023 as compared to consolidation of only a portion of the six month period ended June 30, 2022 as we consolidated Corridor PSC from March 3, 2022.

Power

Revenue from power increased by 187.1% to US$164.5 million in the six months ended June 30, 2023 compared to US$57.3 million in the corresponding period in 2022. The increase was primarily due to construction revenue from the Ijen Geothermal Project which commenced its construction phase in February 2023.

Services

Our revenues from services increased by 61.7% to US$8.9 million for the six months ended June 30, 2023 compared to US$5.5 million for the six months ended June 30, 2022.

Costs of Revenues and Other Direct Costs

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by 12.9% to US$278.9 million for the six months ended June 30, 2023 from US$247.1 million for the six months ended June 30, 2022 primarily due to the Corridor Acquisition which completed on March 3, 2022, and which increased our asset base subject to depreciation, depletion and amortization.

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Production and Lifting Costs

Production and lifting costs increased by 18.9% to US$174.0 million for the six months ended June 30, 2023 from US$146.3 million for the six months ended June 30, 2022. The increase was primarily due to the effect of the Corridor Acquisition and the costs associated with field operations overhead at Corridor PSC and costs recognized with respect to oil inventories sold from Thailand.

Cost of Electric Power Sales and Related Services

Our cost of electric power sales and related services increased by 493.5% to US$122.7 million for the six months ended June 30, 2023 from US$20.7 million for the six months ended June 30, 2022, primarily due to the Ijen Geothermal Project entering its construction phase, increasing both construction revenue and the related costs.

Cost of Crude Oil Purchases

Cost of crude oil purchases decreased by 5.7% to US$54.4 million for the six months ended June 30, 2023 from US$57.7 million for the six months ended June 30, 2022, primarily due to a decreased price of crude oil purchases.

Cost of Services

Cost of services increased by 38.3% to US$12.0 million for the six months ended June 30, 2023 from US$8.7 million for the six months ended June 30, 2022, as our subsidiary engaged in security services increased headcount in connection with a new contract it obtained.

Exploration Expenses

Exploration expenses decreased by 45.6% to US$4.2 million for the six months ended June 30, 2023 from US$7.8 million for the six months ended June 30, 2022, primarily because we recognized certain dry hole expenses in relation to exploration activities in Mexico in the six months ended June 30, 2022.

Total Cost of Revenues and Other Direct Costs

As a result of the foregoing, total cost of revenues and other direct costs increased by 32.4% to US$646.2 million for the six months ended June 30, 2023 from US$488.2 million for the six months ended June 30, 2022.

Gross Profit

Gross profit decreased by 24.2% to US$470.0 million for the six months ended June 30, 2023 from US$620.5 million for the six months ended June 30, 2022. Gross profit margin decreased to 42.1% for the six months ended June 30, 2023 from 56.0% for the six months ended June 30, 2022, primarily due to the decrease in oil and gas 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 29.5% to US$117.8 million for the six months ended June 30, 2023 from US$91.0 million for the six months ended June 30, 2022, primarily due to annual incremental salary increases for our employees as well as the impact of Corridor Acquisition in March 2022 which increased our headcount.

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Finance Costs

Finance costs increased by 4.9% to US$132.7 million for the six months ended June 30, 2023 from US$126.6 million for the six months ended June 30, 2022, primarily due to increases in debt and interest rates.

Share of Net Profit Of Associates and Joint Venture

Our share of net profit of associates and joint venture decreased by 82.1% to US$21.5 million for the six months ended June 30, 2023 from US$119.9 million for the six months ended June 30, 2022, primarily reflecting our share in the results of AMI. The significant decrease was primarily the result of heavy rainfall at the Batu Hijau mine between October 2022 to April 2023, delaying AMNT's ability to extract ore from Phase 7 and export restrictions restricting AMNT's ability to export copper concentrate from March 31, 2023 until its new permit was granted in July 2023.

Loss on Fair Value Adjustment of Financial Assets

Loss on fair value adjustment of financial assets increased to US$20.8 million for the six months ended June 30, 2023 from US$1.8 million for the six months ended June 30, 2022. The increase was primarily the result of fair value adjustments of our investment in DSLNG, which was due to, among other factors, realization of a dividend for the fiscal year 2022.

Loss on Impairment of Assets

For the six months ended June 30, 2022, we recorded loss on impairment of assets of US$1.8 million. We did not record a loss on impairment of assets for the six months ended June 30, 2023.

Interest Income

Interest income increased by 60.2% to US$21.3 million for the six months ended June 30, 2023 from US$13.3 million for the six months ended June 30, 2022 primarily due to increased interest recorded on a shareholder's loan made to Transasia Pipeline Company Pvt Ltd, in which we acquired an interest as part of the Corridor Acquisition in March 2022.

Bargain Purchase

In the six months ended June 30, 2022, we recorded a bargain purchase gain of US$46.1 million, which was primarily due to the fair value of the assets acquired in connection with the Corridor Acquisition in March 2022 exceeding the consideration paid. We did not record a bargain purchase gain or loss for the six months ended June 30, 2023.

Gain/(Loss) on derivative transactions

For the six months ended June 30, 2022 we recorded loss on derivative transactions of US$18.8 million related to oil hedging. We did not record a loss on derivative transactions for the six months ended June 30, 2023.

Dividend income

Dividend income increased by 13.1% to US$31.8 million in the six months ended June 30, 2023 from US$28.1 million for the six months ended June 30, 2022 primarily due to increased cash dividend payments received from DSLNG.

Other Expenses

Other expenses decreased by 61.5% to US$9.1 million for the six months ended June 30, 2023 from US$23.7 million for the six months ended June 30, 2022, primarily due to penalties charged in 2022 related to the unfulfilled drilling commitments in Mexico.

Other Income

Other income increased by 23.3% to US$9.6 million for the six months ended June 30, 2023 from US$7.8 million for the six months ended June 30, 2022, primarily due to certain compensation payments received from PLN at MPI, partially offset by a decrease in foreign exchange gains.

Profit before Income Tax Expense from Continuing Operations

As a result of the foregoing, profit before income tax expense from continuing operations decreased by 52.1% to US$273.8 million for the six month ended June 30, 2023 from US$572.1 million for the six months ended June 30, 2022.

Income Tax Expense

Income tax expense from continuing operations decreased by 44.4% to US$150.1 million for the six months ended June 30, 2023 from US$270.0 million for the six months ended June 30, 2022, primarily as a result of lower profit before income tax expense due to among other things, lower oil and gas prices in 2023.

Profit for the Period from Continuing Operations

As a result of the foregoing, profit for the period from continuing operations decreased by 59.0% to US$123.7 million for the six months ended June 30, 2023 from US$302.0 million for the six months ended June 30, 2022.

Profit After Income Tax Expense From Discontinued Operations

Profit after income tax expense from discontinued operations decreased by 45.8% to US$6.6 million for the six months ended June 30, 2023 from US$12.2 million for the six months ended June 30, 2022.

Profit For the Period

As a result of the foregoing, profit for the period decreased by 58.5% to US$130.3 million for the six months ended June 30, 2023 from US$314.2 million for the six months ended June 30, 2022.

Total Comprehensive Income For the Period

Total comprehensive income for the period decreased by 45.1% to US$159.2 million for the six months ended June 30, 2023 from US$289.8 million for the six months ended June 30, 2022.

Comparison of 2021 and 2022

Total Revenue

Our total revenue increased by 84.7% to US$2,312.2 million in 2022 compared to US$1,252.1 million in 2021, primarily due to the Corridor Acquisition which became effective as of March 3, 2022 and to higher average oil and gas prices.

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Exploration for and Production of Oil and Gas and from Trading

Our total revenue from exploration for and production of oil and gas and from trading increased by 96.3% to US$2,189.8 million for the year ended December 31, 2022 from US$1,115.5 million for the year ended December 31, 2021. The increase was primarily due to the Corridor Acquisition which became effective as of March 3, 2022 and contributed to a significant increase in gas sales volume and to an increase in both oil and gas prices, partially offset by a decrease in oil sales volume. Our average realized prices for oil increased to US$96.2/barrel in 2022 from US$68.0/barrel in 2021. Our average realized prices for natural gas increased to US$8.2/MMBTU in 2022 from US$6.5/MMBTU in 2021. Our oil sales volume decreased to 30.6 MBOPD in 2022 from 30.8 MBOPD in 2021. Our gas sales volume increased to 665.8 BBTUPD in 2022 from 297.4 BBTUPD in 2021.

Power

Revenue from power decreased by 6.5% to US$114.4 million in 2022 from US$122.3 million in 2021. The decrease was primarily due to lower construction revenue from the Riau Power Project as the project was entering its commissioning phase.

Services

Our revenues from services decreased by 43.7% to US$8.0 million in 2022 compared to US$14.3 million in 2021, primarily due to lower revenue from drilling services.

Costs of Revenues and Other Direct Costs

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by 106.0% to US$561.5 million in 2022 from US$272.6 million in 2021. The increase was primarily due to the Corridor Acquisition which completed on March 3, 2022, and which increased our asset base subject to depreciation, depletion and amortization.

Production and Lifting Costs

Production and lifting costs increased by 30.0% to US$334.5 million in 2022 from US$257.3 million in 2021. The increase was primarily due to the effect of the Corridor Acquisition and our consolidation of its production and lifting costs from March 3, 2022.

Cost of Electric Power Sales and Related Services

Our cost of electric power sales and related services decreased by 24.0% to US$44.9 million in 2022 from US$59.0 million in 2021, primarily due to the Riau Power Project entering its commissioning phase, reducing both construction revenue and costs.

Cost of Crude Oil Purchases

Cost of crude oil purchases increased by 18.3% to US$94.3 million in 2022 from US$79.7 million in 2021, primarily due to higher crude oil purchases at our blocks from certain partners partially offset by an underlifting position in 2022.

Cost of Services

Cost of services increased by 16.6% to US$18.0 million in 2022 from US$15.5 million in 2021, as our subsidiary engaged in security services increased headcount in connection with a new contract it obtained.

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__Exploration Expenses__

Exploration expenses decreased by 24.8% to US$13.0 million in 2022 from US$17.3 million in 2021, primarily because we recognized certain dry hole expenses at Mexico Block 12 in 2021.

__Total Cost of Revenues and Other Direct Costs__

As a result of the foregoing, total cost of revenues and other direct costs increased by 52.0% to US$1,066.2 million in 2022 from US$701.5 million in 2021.

__Gross Profit__

Gross profit increased by 126.3% to US$1,246.0 million in 2022 from US$550.6 million in 2021. Gross profit margin increased to 53.9% in 2022 from 44.0% in 2021, primarily due to the increase in oil and gas 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 36.4% to US$220.2 million in 2022 from US$161.4 million in 2021, primarily due to the Corridor Acquisition in March 2022, which increased, among others, salaries, wages and other employee benefits as we took on additional employees in connection with the acquisition and professional fees, primarily related to the acquisition.

__Finance Costs__

Finance costs increased by 16.6% to US$259.4 million in 2022 from US$222.5 million in 2021, primarily due to indebtedness incurred in connection with the financing of the Corridor Acquisition in 2022.

__Share of Net Profit Of Associates and Joint Venture__

Our share of net profit of associates and joint venture increased by 276.3% to US$232.9 million in 2022 from US$61.9 million in 2021, primarily reflecting the improved results of AMI, and which was primarily due to higher sales volume of copper and gold from Phase 7 of the Batu Hijau mine.

__Gain (loss) on Fair Value Adjustment of Financial Assets__

In 2022 we recorded a loss on fair value adjustment of financial assets of US$0.5 million compared to a gain of US$80.5 million in 2021. This change was primarily the result of: (i) in 2021 we recorded a gain on fair value re-measurement of investments amounting to US$47.2 million on our investment in MGEOPS. Prior to March 2021, we held a 51% interest in MGEOPS and in March 2021 we sold a 2% interest to our shareholder, MDAL. Following the sale, we remeasured the fair value of the remaining 49% and as a result of the remeasured value being higher than the carrying value of the asset on our balance sheet, we recorded the fair value gain, (ii) we recorded gain on fair value adjustment of financial assets from our investment in DSLNG of US$25.0 million in 2021 compared to loss on fair value adjustment of US$5.1 million in 2022, primarily due to, among other factors, higher LNG prices, leading to an increase in value of the investment in 2021 and then a decrease in the value of the investment in 2022 due to DSLNG’s dividend and pro rata share buyback and (iii) a gain on fair value adjustment of financial assets from our investment in SMCN of US$8.3 million in 2021 compared to US$4.1 million in 2022.

__Loss on Impairment of Assets__

Loss on impairment of assets decreased by 93.6% to US$2.3 million in 2022 from US$35.5 million in 2021, primarily related to our 2021 impairment of our investment in AMG which owns a 49% interest in The Energy

Building as the commercial real estate market in Jakarta was impacted by the COVID-19 pandemic and to impairment of assets in Mexico in 2021 in relation to our intention to exit from those assets.

Interest Income

Interest income increased by 334.5% to US$39.6 million in 2022 from US$9.1 million in 2021. The increase primarily due to interest recorded on a shareholder's loan made to Transasia Pipeline Company Pvt Ltd, in which we acquired an interest as part of the Corridor Acquisition in March 2022.

Bargain Purchase

In 2022, we recorded a bargain purchase gain of US$49.0 million, which was primarily due to the fair value of the assets acquired in connection with the Corridor Acquisition in March 2022 exceeding the consideration paid. We did not record a bargain purchase gain or loss in 2021.

Loss on derivative transactions

Loss on derivatives transactions increased by 219.9% to US$36.9 million in 2022 from US$11.5 million in 2021 mainly due to oil prices having increased above the price at which we hedged in our hedging arrangements.

Dividend income

We recorded dividend income of US$28.1 million in 2022, consisting of cash dividend payments received from DSLNG. We did not record dividend income in 2021.

Other Expenses

Other expenses increased by 260.7% to US$73.1 million in 2022 from US$20.3 million in 2021. In 2022, other expenses mainly represented losses on the fair value less costs to sell of our investment APICO LLC, which held our interest in the Sinphuhorm block in Thailand which we had acquired as part of the Ophir Acquisition, settlement of taxes in Tanzania, and provision for a penalty at Block 10 Mexico due to an uncompleted drilling commitment, as well VAT write-offs, while in 2021, other expenses mainly represented VAT write-off.

Other Income

Other income increased by 129.3% to US$42.3 million for the year ended December 31, 2022 from US$18.4 million for the year ended December 31, 2021, primarily due to higher gains on foreign exchange in 2022 compared to 2021 partially offset by lower management fees under the Joint Operating Agreement of Medco E&P Natuna Ltd in 2021.

Profit before Income Tax Expense from Continuing Operations

As a result of the foregoing, profit before income tax expense from continuing operations increased by 288.2% to US$1,045.6 million in 2022 from US$269.4 million in 2021

Income Tax Expense

Income tax expense from continuing operations increased by 128.0% to US$508.0 million in 2022 from US$222.8 million in 2021, primarily as a result of higher profit before income tax expense from continuing operations in 2022.

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Profit for the Year from Continuing Operations

As a result of the foregoing, profit for the year from continuing operations increased to US$537.6 million in 2022 from US$46.5 million in 2021.

Profit After Income Tax Expense From Discontinued Operations

Profit after income tax expense from discontinued operations decreased to US$13.8 million in 2022 from US$16.1 million in 2021.

Profit For the Year

As a result of the foregoing, profit for the year increased to US$551.4 million in 2022 from US$62.6 million for the year ended December 31, 2021.

Total Comprehensive Income For the Year

For the year ended December 31, 2022, we recorded total comprehensive income for the year of US$588.5 million, compared to total comprehensive loss for the year of US$84.8 million for the year ended December 31, 2021.

Comparison of 2020 and 2021

Total Revenue

Our total revenue increased by 21.0% to US$1,252.1 million in 2021 from US$1,034.5 million in 2020, primarily due to a increase in revenue from exploration for and production of oil and gas.

Exploration for and Production of Oil and Gas and from Trading

Our total revenue from exploration for and production of oil and gas and trading increased by 25.6% to US$1,115.5 million in 2021 from US$888.0 million in 2020. The increase was primarily due to higher oil and gas prices in 2021 due to the impact of COVID-19 in 2020, which severely impacted oil prices. Our crude oil sales decreased to 30.8 MBOPD in 2021 from 35.1 MBOPD in 2020, primarily due to a temporary shutdown for maintenance at our block in Vietnam and natural decline in production from Bualuang in Thailand. Average realized oil prices increased to US$68.0/barrel in 2021 from US$40.3/barrel in 2020. Our gas sales volume decreased slightly to 297.4 BBTUPD in 2021 from 298.4 BBTUPD in 2020. Our average realized prices for natural gas increased from US$5.2/MMBTU in 2020 to US$6.5/MMBTU in 2021.

Power

Power revenue decreased by 10.2% to US$122.3 million in 2021 from US$136.2 million in 2020. The decrease was primarily due to the Riau Power Project shifting from the procurement phase to installation phase of construction in the first quarter of 2020, which reduced both revenue and costs related to its construction.

Services

Our revenue from services increased by 40.4% to US$14.3 million in 2021 from US$10.2 million in 2020.

Costs of Revenues and Other Direct Costs

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization decreased by 3.5% to US$272.6 million in 2021 from US$282.6 million in 2020 primarily due to the decrease in production from 2020 to 2021.

Production and Lifting Costs

Production and lifting costs slightly increased by 3.8% to US$257.3 million in 2021 from US$247.9 million in 2020, primarily due to the increase in production from 2020 to 2021.

Cost of Electric Power Sales and Related Services

Cost of electric power sales and related services decreased by 20.2% to US$59.0 million in 2021 from US$74.0 million in 2020, primarily due to the Riau Power Project shifting from procurement phase to installation phase of construction in the first quarter of 2020, which reduced both revenue and costs related to its construction.

Cost of Crude Oil Purchases

Cost of crude oil purchases increased by 13.8% to US$79.7 million in 2021 from US$70.0 million in 2020, primarily due to our overlifting of oil and gas position for the year.

Cost of Services

Cost of services decreased by 13.2% to US$15.5 million in 2021 from US$17.8 million in 2020.

Exploration Expenses

Exploration expenses decreased by 25.1% to US$17.3 million in 2021 from US$23.2 million in 2020 primarily due to a dry hole expenses recognized during 2021 following unsuccessful drilling results at our Mexico Block.

Total Cost of Revenues and Other Direct Costs

As a result of the foregoing, total cost of sales and other direct costs slightly decreased by 2.0% to US$701.5 million in 2021 from US$715.5 million in 2020.

Gross Profit

Gross profit increased by 72.6% to US$550.6 million in 2021 from US$319.0 million in 2020. Gross profit margin increased to 44.0% in 2021 from 30.8% in 2020, primarily due to significant increase in average realized prices as a result of higher oil and gas prices in 2021. 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 4.9% to US$161.4 million in 2021 from US$153.8 million in 2020, primarily due to, among others, increased general and administrative expenses such as salaries, wages and other employee benefits, provisions for credit losses and repairs and maintenance, partially offset by, among others, decreases in professional fees, rental expenses and selling expenses.

Finance Costs

Finance costs decreased by 20.0% to US$222.5 million in 2021 from US$278.2 million in 2020. The decrease was primarily due to lower debt resulting from our repayment of 2022 Notes and Rupiah shelf-registered II and III, partially offset by, among others, the issuance of the 2028 Notes in 2021.

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Share of Net Profit/(Loss) Of Associates and Joint Venture

Our share of net profit of associates and joint venture increased by 120.6% to US$61.9 million in 2021 from US$28.1 million in 2020, primarily reflecting the improved results of AMI, and which was primarily due to higher sales volume of copper and gold from Phase 7 of the Batu Hijau mine.

Gain on Fair Value Adjustment of Financial Assets

In 2021, we recorded a gain on fair value adjustment of financial assets of US$80.5 million compared to a gain of US$31.1 million in 2020. In 2021, we recorded a gain on fair value of US$47.2 million on our investment in MGEOPS. Prior to March 2021, we held a 51% interest in MGEOPS and in March 2021 we sold a 2% interest to our shareholder, MDAL. Following the sale, we remeasured the fair value of the remaining 49% and as a result of the remeasured value being higher than the carrying value of the asset on our balance sheet, we recorded the fair value. In addition, in 2021 we recorded gains on fair value on DSLNG and SMCN. In 2020, the gain was primarily due to the implementation of PSAK 71 with effect from January 1, 2020, which caused us to record our investment in DSLNG at fair value rather than at cost.

Loss on Impairment of Assets

Loss on impairment of assets decreased by 40.9% to US$35.5 million in 2021 from US$60.1 million in 2020, primarily due to our decreased impairment of our investment in AMG (which owns a 49% interest in The Energy Building) as the commercial real estate market in Jakarta was impacted by the COVID-19 pandemic, impairments related to certain legacy Ophir assets, including Bangkanai PSC, as the recoverable value was less than the fair value recognized from the allocation of purchase price paid in connection with the Ophir Acquisition and to an impairment at our hydro business where certain power purchase agreements were terminated.

Interest Income

Interest income decreased by 50.7% to US$9.1 million in 2021 from US$18.5 million in 2020, primarily due to interest income on a receivable related to our disposal of assets in Tunisia and lower interest income from MDAL on amounts owed to us for crude oil purchases.

Gain/(Loss) on derivative transactions

We recorded a loss on derivative transactions of US$11.5 million in 2021 mainly due to our hedged commodity price being lower than actual prices, compared to gain of US$9.5 million in 2020 as a result of our hedged commodity price being higher than actual prices.

Loss on Dilution of Long-term Investments

In December 2020, AMI issued new shares to new shareholders, which resulted in the dilution of our interest in AMI from 29.35% to 23.13%. We recorded a dilution loss of US$19.0 million to reflect the reduction in the value of our shareholding from such transaction. In 2021, we did not recognize any loss on dilution of long-term investments.

Other Expenses

Other expenses decreased by 20.5% to US$20.3 million for the year ended December 31, 2021 from US$25.5 million for the year ended December 31, 2020, primarily due to receivables written off at Block A, Aceh in 2020 as its pricing under a GSA was reduced with retroactive effect as well as to expenses for machinery maintenance for MPI and its subsidiaries that were recorded in year 2020.

Other Income

Other income decreased by 48.4% to US$18.4 million for the year ended December 31, 2021 from US$35.7 million for the year ended December 31, 2020 primarily due to gains on foreign exchange in 2020.

Profit/(Loss) before Income Tax Expense from Continuing Operations

As a result of the foregoing, our profit before income tax expense from continuing operations was US$269.4 million for the year ended December 31, 2021 as compared to our loss before income tax expense from continuing operations of US$96.9 million for the year ended December 31, 2020.

Income Tax Expense

Income tax expense from continuing operations increased by 231.5% to US$222.8 million for the year ended December 31, 2021, from US$67.2 million for the year ended December 31, 2020. This was primarily due to an increase in net oil and gas revenue.

Profit/(Loss) for The Year from Continuing Operations

As a result of the foregoing, we recorded a profit for the year from continuing operations of US$46.5 million for the year ended December 31, 2021 compared to a loss of US$164.1 million for the year ended December 31, 2020.

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

In 2021, we recorded profit after income tax expense from discontinued operations of US$16.1 million, compared to a loss after income tax expense from discontinued operations of US$17.1 million for the year ended December 31, 2020.

Profit/(Loss) For the Year

As a result of the foregoing, we recorded a profit for the year of US$62.6 million for the year ended December 31, 2021, compared to a loss for the year of US$181.2 million for the year ended December 31, 2020.

Total Comprehensive Income/(Loss) For the Year

For the year ended December 31, 2021, we recorded total comprehensive income for the year of US$84.8 million, compared to total comprehensive loss for the year of US$227.6 million for the year ended December 31, 2020.

Liquidity and Capital Resources

Our operations, capital expenditures and working capital requirements are primarily funded by cash generated from operations, borrowings (both short-term and long-term including banking facilities) and bonds. As of June 30, 2023, our total debt was US$3,070.1 million, and we had US$597.4 million of unutilized banking facilities.

As of June 30, 2023, we had cash and cash equivalents of US$466.1 million (including US$161.9 million of Unrestricted Subsidiaries’ 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$11.0 million. We also had restricted time deposits and cash in banks (current and non-current portion) of

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US$138.1 million (including US$3.2 million from Unrestricted Subsidiaries), which include US$87.8 million in escrow accounts and interest reserve accounts.

The following table presents our cash flow data for the years ended December 31, 2020, 2021 and 2022 and the six months ended June 30, 2022 and 2023.

Cash Flow Data

	For the Years Ended December 31,			For the Six Months Ended June 30,	
	2020	2021	2022	2022	2023
	(Restated)[1]			(Unaudited)	
	(US$ in millions)				
Components of Consolidated Statements Cash Flows					
Net Cash Provided by Operating Activities	443.6	439.7	1,116.4	381.3	179.1
Net Cash Provided by (Used in) Investing Activities	(292.7)	82.9	(1,063.0)	(872.6)	34.1
Net Cash Provided by (Used in) Financing Activities	(301.1)	(335.6)	64.4	369.1	(352.7)

Note:

(1) The restated consolidated financial statements resulted from the re-classification of accounts of certain subsidiaries previously included in “Continuing Operations” to “Assets Held for Sale and Discontinued Operations” as further described in note 39 of our consolidated financial statements.

Net Cash Provided by Operating Activities

Six months ended June 30, 2023. Our net cash provided by operating activities was US$179.1 million primarily which comprises cash receipts from customers of US$908.5 million. This was partially offset by cash paid to suppliers and employees of US$427.1 million and income tax paid of US$302.3 million.

Six months ended June 30, 2022. Our net cash provided by operating activities was US$381.3 million primarily which comprises cash receipts from customers of US$964.9 million. This was partially offset by cash paid to suppliers and employees of US$254.5 million and income tax paid of US$329.1 million.

Year Ended December 31, 2022. Our net cash provided by operating activities was US$1,116.4 million primarily which comprises cash receipts from customers of US$2,376.9 million. This was partially offset by cash paid to suppliers and employees of US$747.2 million and income tax paid of US$513.3 million.

Year Ended December 31, 2021. Our net cash provided by operating activities was US$439.7 million primarily which comprises cash receipts from customers of US$1,067.9 million. This was partially offset by cash paid to suppliers and employees of US$436.4 million and income tax paid of US$191.8 million.

Year ended December 31, 2020. Our net cash provided by operating activities for the year ended December 31, 2020 was US$443.6 million primarily which comprises cash receipts from customers of US$1,101.0 million, partially offset by cash paid to suppliers and employees of US$522.9 million and income tax paid of US$134.5 million.

Net Cash Provided by (Used in) Investing Activities

Six months ended June 30, 2023. Our net cash provided by investing activities was US$34.1 million, which was primarily due to receipts from other receivables of US$121.1 million, primarily comprising receipt of final settlement of funds from SMCN related to our 2020 sale of an interest in AMI to SMCN as described under “Related Party Transactions,” cash dividends from DSLNG of US$31.8 million, and cash received from DSLNG related to its pro-rata share buyback of US$10.5 million. These were partially offset by, among others, addition of long-term investments of US$33.0 million comprising an additional investment in SMCN, additions to concession financial assets of US$27.8 million primarily comprising additions to our Ijen Geothermal Project concession asset, acquisitions of property, plant and equipment of US$16.1 million and additions to oil and gas properties of US$83.4 million primarily comprising additions to South Natuna Block B and Bualuang.

Six months ended June 30, 2022. Our net cash used in investing activities was US$872.6 million, which was primarily due to cash paid for the Corridor Acquisition of US$846.8 million and additions to oil and gas properties of US$96.3 million primarily comprising additions to South Natuna Block B and Bualuang. These were partially offset by, among others, proceeds from other receivables of US$39.8 million, primarily comprising receipt of partial settlement of funds from SMCN related to our 2020 sale of an interest in AMI to SMCN as described under “Related Party Transactions,” cash dividends received from DSLNG of US$28.1 million and proceeds from redemption of short-term investments of US$19.8 million.

Year Ended December 31, 2022. Our net cash used in investing activities was US$1,063.0 million, which was primarily due to cash paid for the Corridor Acquisition of US$846.8 million, additions to oil and gas properties of US$218.2 million primarily comprising additions to South Natuna Block B and Bualuang, additions of other receivables of US$60.7 million comprising receivables from MDAL in relation to its interest at South Natuna Sea Block B consisting of ordinary course payments made to us as operator of the block, acquisitions of property, plant and equipment of US$34.7 million, additions to concession financial assets of US$11.9 million, additions to exploration and evaluation assets of US$15.6 million. These were partially offset by, among others, proceeds from other receivables of US$39.8 million primarily comprising receipt of partial settlement of funds from SMCN related to our 2020 sale of an interest in AMI to SMCN as described under “Related Party Transactions,” cash dividends received from associates of US$28.1 million mainly from DSLNG, proceeds from redemption of short-term investments of US$19.8 million, and interest received of US$15.6 million.

Year ended December 31, 2021. Our net cash provided by investing activities was US$82.9 million, which was primarily due to proceeds from disposal of subsidiaries or associates of US$110.9 million comprising cash received by MPI in relation to its partnership with Kansai, proceeds from other receivables of US$99.3 million mainly comprising receipt of partial settlement of funds from SMCN related to our 2020 sale of an interest in AMI to SMCN as described under “Related Party Transactions,” and final settlement of receivables from DSLNG pertaining to a shareholder loan which was extended to finance its LNG project, cash dividends received of US$5.6 million and interest received of US$8.4 million. These were partially offset by, among others, additions to oil and gas properties of US$59.8 million primarily comprising additions at South Natuna Sea Block B, additions to concession financial assets of US$31.5 million primarily at the Riau Power Project, additions to exploration and evaluation assets of US$35.0 million primarily comprising exploration drilling at the Ijen Geothermal Project and additions to property, plant and equipment of US$16.4 million.

Year ended December 31, 2020. Our net cash used in investing activities was US$292.7 million in 2020 primarily which comprises (i) additions to exploration and evaluation assets as well as oil and gas properties of US$187.5 million primarily comprising additions at South Natuna Sea Block B and exploration drilling at the Riau Power Project , (ii) addition of concession financial assets of US$75.8 million with respect to Medco Ratch Power Riau, (iii) addition of property, plant and equipment of US$4.0 million, (iv) addition of investment in joint venture of US$1.1 million, (v) other receivables addition from related parties of US$17.7 million, (vi) addition of short-term investment of US$25.0 million and (vii) other asset additions of US$15.2 million. These were partially offset by, among others, (i) receipt of short-term investments disbursement of US$14.2 million and (ii) receipts from disposal of subsidiaries or associates of US$10.0 million, primarily comprising receipt of partial settlement of funds from SMCN related to our 2020 sale of an interest in AMI to SMCN as described under “Related Party Transactions”.

Net Cash Flow Provided by (Used in) Financing Activities

Six months ended June 30, 2023. Our net cash used in financing activities was US$352.7 million, which primarily consists of: (i) US$293.5 million of repayment of bank loans primarily comprising repayment of short-term bank loans and syndicated loans, (ii) US$83.4 million of repayment of other long-term debt comprising Rupiah shelf-registered bonds III Phase I and III (iii) US$117.4 million payment of financing charges consisting primarily of interest payments in relation to indebtedness, (iv) US$59.6 million of repayment of lease liabilities comprising payments under operating leases, (v) dividend payments of US$40.0 million and (vi) US$15.8 million of purchases of bonds (vii) US$9.0 million of settlements of derivative liabilities due to settlement of hedging arrangements with respect to our IDR bonds. These were partially offset by US$271.5 million of proceeds from additional bank loans.

Six months ended June 30, 2022. Our net cash provided by financing activities was US$369.1 million, which primarily consists of: (i) US$822.7 million of proceeds from additional bank loans primarily comprising of proceeds from short-term bank loan and syndicated loans, (ii) US$302.4 million of withdrawal of restricted time deposits and cash in banks. These were partially offset by: (i) US$271.6 million of repayment of bank loans primarily comprising repayment of short-term bank loans and syndicated loans, (ii) US$118.3 million of payment of financing charges consisting primarily of interest payments in relation to indebtedness, (iii) US$273.3 million of repayment of other long-term debt comprising repayments of 2025 Notes, 2026 Notes and 2027 Notes in connection with a tender offer and repayments of Rupiah bonds, (iv) US$53.1 million repayment of lease liabilities comprising payments under operating leases, and (v) US$23.2 million in settlements of derivative liability, and (vi) US$14.9 million of purchases of bonds.

Year Ended December 31, 2022. Our net cash provided by financing activities was US$64.4 million, which primarily consists of: (i) US$1,041.8 million of proceeds from additional bank loans primarily comprising proceeds from short-term bank loans and syndicated loans, (ii) US$270.0 million of proceeds from other long-term debt comprising Rupiah shelf-registered bonds IV Phase III and Rupiah Sukuk Wakalah I, (iii) US$314.9 million of withdrawals of restricted time deposits and cash in banks. These were partially offset by: (i) US$536.2 million in repayment of bank loans primarily comprising repayments of short-term bank loans and syndicated loans, (ii) US$235.5 million of payments of financing charges consisting primarily of interest payments in relation to indebtedness, (iii) US$528.5 million repayment of other long-term debt comprising repayments of 2025 Notes, 2026 Notes and 2027 Notes in connection with a tender offer, (iv) US$121.5 million of repayment of lease liabilities comprising payments under operating leases, (v) US$60.0 million dividend payment, (vi) US$36.2 million settlement of derivative liability, (vii) US$32.5 million of purchases of bonds and (viii) US$11.9 million dividend payments to non-controlling interests by subsidiaries.

Year ended December 31, 2021. Our net cash used in financing activities was US$335.6 million, which primarily consists of: (i) US$246.7 million repayment of bank loans comprising repayments of bank loans and syndicated loans, (ii) US$192.9 million payment of financing charges primarily in relation to interest payments in relation to indebtedness and charges in relation to our issuance of the 2028 Notes, (iii) US$163.6 million repayment of other long-term debt comprising repayments of Medium Term Notes VI, Rupiah shelf-registered bonds II Phase II and III, Rupiah shelf-registered III Phase I, and Rupiah Sukuk Wakalah I, (iv) US$94.3 million repayment of lease liabilities comprising payments under operating leases, (v) US$302.7 million of deposits of restricted time deposits and cash in banks and (vi) US$16.7 million settlement of derivative liabilities. These were partially offset by: (i) US$145.7 million in proceeds from additional bank loans, (ii) US$521.6 million of proceeds from other long-term debt comprising proceeds from Rupiah shelf-registered bonds IV Phase I and II and the 2028 Notes, and (iii) US$23.3 million of capital injections from non-controlling interests.

Year ended December 31, 2020. Our net cash used in financing activities was US$301.1 million in 2020 which was primarily due to (i) proceeds from other long-term loans of US$759.2 million which was primarily from US Dollar Bonds and IDR Bonds III Phase III, (ii) proceeds from bank loans of US$208.9 million comprising short-term bank loans and syndicated loans, (iii) additional paid-in capital from the issuance of shares

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of US$119.9 million, and (iv) additional paid-in capital from non-controlling interest of US$28.9 million, which were partially offset by (i) repayment of bank loans of US$391.0 million comprising repayment of short-term bank loans and syndicated loans, (ii) repayment of other long-term debt of US$623.7 million which was primarily the repayment of US Dollar Bonds, IDR Bonds II (phase I, phase IV, phase V, and phase VI), and IDR Bonds III phase II, (iii) payment of finance costs of US$283.5 million comprising interest payments in relation to indebtedness and charges in relation to our issuance of the 2027 Notes, (iv) payment of lease liabilities of US$76.9 million comprising payments under operating leases, (v) placement of time deposits and restricted bank accounts of US$32.3 million, (vi) purchases of bonds of US$16.0 million.

Indebtedness

The following table shows the amount of the Company's total consolidated short-term and long-term debt and the Restricted Group's total debt outstanding as of December 31, 2020, 2021 and 2022 and June 30, 2022 and 2023:

	As of December 31,			As of June 30,	
	2020	2021	2022	2022	2023
				(Unaudited)	
			(US$ in millions)		
Company:					
Short-term debt					
Short-term bank loans	22.9	—	35.0	80.0	105.0
Current maturities of long-term debts(2)	301.5	315.5	401.0	407.1	348.4
Long-term liabilities (net of current maturities)					
Bank loans	366.5	231.5	562.0	561.9	456.0
Loan from non-bank financial institutions	—	1.3	16.5	4.3	15.6
Rupiah bond(1)	302.8	317.5	436.8	221.7	456.7
US Dollar bond	1,733.7	2,123.5	1,699.9	1,962.0	1,688.4
Total debt	**2,727.5**	**2,989.2**	**3,151.2**	**3,237.0**	**3,070.1**
Restricted Group's total debt	2,319.7	2,614.1	2,712.4	2,841.9	2,601.6

Note:

(1) Rupiah amounts were converted to U.S. dollars at an exchange rate: of 0.000071 US$ per Rupiah, 0.000070 US$ per Rupiah, 0.000064 US$ per Rupiah, 0.000067 US$ per Rupiah and 0.000067 US$ per Rupiah for amounts as of December 31, 2020, 2021 and 2022 and June 30, 2022 and 2023, respectively.

(2) Represents current maturities of long term bank loans, loan from non-bank financial institutions, Rupiah bonds, US Dollar bonds and for December 31, 2020 including medium-term notes.

Our long-term debt outstanding as of December 31, 2020, 2021 and 2022 and June 30, 2022 and 2023 consisted of both local and foreign currency obligations. Our consolidated debt outstanding as of December 31, 2018 and 2019 and June 30, 2019 and 2020 was US$2,807.5 million, US$3,195.0 million and US$3,508.2 million and US$3,044.4 million, respectively. Restricted Group debt outstanding as of December 31, 2018 and 2019 and June 30, 2019 and 2020 was US$2,215.2 million, US$2,471.0 million, US$2,885.2 million and US$2,666.0 million, respectively. 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.

Of the US$2.6 billion of Restricted Group indebtedness outstanding as of June 30, 2023, we plan to repay up to US$400 million of such indebtedness, consisting of amortizing loans including the Mandiri Term Loan I, Medco Energi Global Pte. Ltd.'s syndicated loan, PT Medco E&P Tomori Sulawesi and PT Medco E&P Malaka senior secured term loan facility agreements, and certain of ours short term facility agreements with PT Bank DBS Indonesia, PT Bank HSBC Indonesia, PT Bank Permata Tbk using additional cash on hand for early repayment by the end of 2023.

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Contractual Obligations, Including Long-term Debt

The following table discloses our contractual and other obligations, excluding contingent liabilities, that were outstanding as of June 30, 2023 and the effect such obligations are expected to have on liquidity and cash flow in future periods.

	Payments Due By Period				
	Total	2023	2024	2025	After 2026
	(US$ in millions)				
Bank Loans	925.1	271.1	229.3	52.4	372.5
Long-term Debt Obligations (Bonds)	2,230.4	33.8	95.2	466.2	1,635.3
Total	**3,155.5**	**304.9**	**255.4**	**518.5**	**2,007.7**

Note: Amounts outstanding are presented excluding unamortized discounts.

Capital Expenditures

The following table sets forth the Company's capital expenditures for the years ended December 31, 2020, 2021 and 2022 and for the six months ended June 30, 2022 and 2023.

	For the Years Ended December 31,			For the Six Months Ended June 30,	
	2020	2021	2022	2022	2023
	(US$ in millions)				
Capital Expenditures Based on Activities:					
Oil and Gas:					
Facilities and Maintenance	41.4	42.8	115.8	55.5	32.4
Development Drilling	67.5	20.7	106.0	40.8	51.2
Exploration Program	35.0	19.8	9.6	1.1	0.8
Power (Gross)	123.4	59.4	49.1	20.4	43.8
Total (Oil and Gas and Power)	267.3	142.7	280.4	117.9	128.1
Capital Expenditures Based on Segment:					
Oil and Gas	143.9	83.3	231.4	97.5	84.4
Power (Net)[1]	63.5	29.6	32.7	15.2	27.4
Total (Oil and Gas and Power) (Net)	207.3	112.9	264.1	112.7	111.8

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

(1) Capital expenditures for power (net) are calculated by multiplying the capital expenditures for joint projects for power (Riau IPP and Ijen Geothermal) by the relevant respective ownership percentages.

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

Our budgeted capital expenditure for the full year ended December 31, 2023 is US$330 million (US$250.0 million for oil and gas and US$80.0 million for power (net)). 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 several fields at South Natuna Sea Block B (Forel, Bronang, West Belut, Terubuk and Siput) further field development through the Accelerated Corridor Development program, Block A and Senoro phase 2, Madura Offshore PSC and Paus Biru field at Sampang PSC. Our total annual non-debt funded capital expenditures necessary to maintain our production levels are expected to remain below US$300 million per year, assuming mid-cycle commodity prices. However, we intend to retain flexibility to adjust planned capital expenditures depending on movements in commodity prices. 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. To respond to the significant drop in energy demand brought on by the COVID-19 pandemic, we reduced both capital and operating budgets in order to maintain liquidity. Although we were able to realize cost savings, our resulting reduced capital expenditure may impact our exploration and development activity, negatively impacting future production and/or reserves levels.

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 expenditure. 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 our 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

				PSA	
Subsidiary	**Block Ownership**	**Country**	**Term**	**Local Government**	**Subsidiary**
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 100,000 BOPD)
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 **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 **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 **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 **Gas :** To be determined once there is a commercial discovery of non-associated natural gas

Subsidiary	**Block Ownership**	**Country**	**Term**	**PSA**
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
Ophir Vietnam Block 12W B.V.	Block 12W	Vietnam	25 years for oil and 30 years for gas	**Oil**: - 4%-20% royalty of net oil production depending on net daily production rate - 4% export duty - 10%-60% of profit oil depending on quarterly average net oil production by incremental tranches in barrels per day **Gas**: - 0%-6% royalty of net gas production depending on net daily production rate - 0% export duty - 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 June 30, 2023 is US$20.3 million.

Gas Supply Agreements

Our significant GSAs as of June 30, 2023, are as follows.

Company / Counter-party	Date of Agreement	Commitment	Contract Year
PT Medco E&P Indonesia			
PT Perusahaan Gas Negara (Persero) Tbk	GSA signed on March 15, 2022	To supply gas of 0.40 MMSCFD.	November 27, 2033 or until end of gas production whichever occurs first.
PT Mitra Energi Buana	July 24, 2006, last amended on December 24, 2021	To supply gas with total gas contract quantity amounted to 26,172 BBTU.	The GSA expires on the earlier of December 31, 2027 or until the total contracted quantity has been fully supplied.
PT MEPPO-GEN	November 13, 2018, amended on October 17, 2019	To supply 14.2-9.7 BBTUD (SS Block) and 11.6-10.8 BBTUD (Lematang Block) with total gas contract quantity of 8,051.3 BBTU.	The GSA expires on the earlier of December 31, 2027 or until total contract quantity has been fully supplied.

Company / Counter-party	Date of Agreement	Commitment	Contract Year
Perusahaan Daerah Mura Energi	August 4, 2009, last amended March 25, 2022	To supply 1.35 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.
PT Perusahaan Gas Negara (Persero) Tbk	May 4, 2018	To supply gas of 871 BBTU total contract quantity of gas to meet the needs of households in Kabupaten Musi Banyuasin of 0.25 BBTUD.	The GSA expires on July 20, 2027 or until the end of production of natural gas from the Supplier's working area, whichever occurs first.
PT Pertamina (Persero)	November 15, 2019, effective date on March 8, 2018	To supply and sell gas of 0.25 MMSCFD.	The GSA expires on July 20, 2027 or until the end of production of natural gas from the Supplier's working area, whichever occurs first.
PT Perusahaan Listrik Negara (Persero)	September 19, 2017	To supply and sell gas of 20 BBTUD (joint supply with MEPL) total contract quantity of 50,932.8 BBTU from South Sumatera PSC and Lematang 19,327.2 BBTU (Total joint supply quantity 70,260 BBTU).	Expires on January 31, 2027 or until such quantity has been fully supplied, whichever occurs first.
PT Medco E&P Rimau	January 18, 2016, as amended on December 2, 2020	To supply 2 BBTUD of gas with total gas contract quantity of 9,015 BBTU.	Expires on December 31, 2027
PT Pupuk Sriwidjaja Palembang	September 20, 2023	To supply and sell gas (joint supply with MEPL) with total contract quantity of 31,150 BBTU from South Sumatera PSC and Lematang 10,679 BBTU (Total joint supply quantity 41,829 BBTU).	Expires on November 27, 2033
PT Medco E&P Bangkanai			
PT Perusahaan Listrik Negara (Persero)	June 28, 2011, last amended on December 20, 2019	To supply gas to PLN of DCQ at 20 BBTUD with total Contract Quantity of 130,000 BBTU.	Expires on December 29, 2033 or until Contract Quantity has been fully supplied, whichever occurs first.

Company / Counter-party	Date of Agreement	Commitment	Contract Year
PT Medco E&P Lematang			
PT Perusahaan Listrik Negara (Persero)	September 19, 2017	To supply and sell gas of 20BBTUD total contract quantity of 50,932.8 BBTU from South Sumatera PSC and Lematang 19,327.20 BBTU (Total joint supply quantity 70,260 BBTU).	Expires on January 31, 2027 or when the total contract quantity has been fully supplied, whichever occurs first.
PT Pupuk Sriwidjaja Palembang	September 20, 2023	To supply and sell gas (joint supply with MEPI) with total contract quantity of 31,150 BBTU from South Sumatera PSC and Lematang 10,679 BBTU (Total joint supply quantity 41,829 BBTU).	Expires on November 27, 2033
PT Medco E&P Malaka			
PT Pertagas Niaga	January 27, 2015 last amended on October 2, 2020	To supply 54 BBTUD of gas with a total volume of 198 TBTU.	Expires on August 31, 2031 or up to when the total amount of the contract has been fully supplied, or 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, last amended on August 19, 2021	Supply 277.8 BBTUD (equivalent to 250 MMSCFD) of gas and with Total Contract Quantity of 1,307.508 TBTU.	Expires upon the earlier of 15 years following the commencement of commercial operations of the LNG plant (December 3, 2027), 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, with DCQ of 62 MMSCFD.	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.

Company / Counter-party	Date of Agreement	Commitment	Contract Year
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 3, 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 last amended on November 30, 2020 through Mutual Agreement	To supply gas at 0.5 BBTUD with total Contracts 805 MMSCF.	Expires five years since November 30, 2020 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 BCF.	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, February 23, 2028, whichever occurs first.
PT Kayan LNG Nusantara	May 20, 2020	To supply 12-22 BBTUD of gas with total contract commitment of 47,091 MMSCF.	Expired on February 23, 2028 or upon the fulfillment of the total contract quantity, whichever occurs first.
Medco E&P Natuna Ltd			
SembCorp Gas Singapore	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 (July 15, 2028) or upon the fulfillment of the total amount of the contract, whichever occurs first.
Medco Energi Sampang Pty Ltd			
PT Indonesia Power (“IP”)	July 19, 2003, last amended on October 27, 2022	Commitment to supply all gas from Oyong field.	Until December 31, 2031
PT Indonesia Power (“IP”)	November 26, 2010 amended on April 9, 2021	Commitment to supply all gas from Wortel field with total maximum contract quantity of 129.5 TBTU.	Until December 31, 2031.

Company / Counter-party	Date of Agreement	Commitment	Contract Year
Ophir Indonesia (Madura Offshore) Pty Ltd			
PT Perusahaan Gas Negara (Persero) Tbk (“PGN”)	May 31, 2005 last amended on May 29, 2023 through Mutual Agreement	To supply gas from Maleo field until total cumulative gas supply reach 27.040 BBTU.	Until December 31, 2023 or until total cumulative gas supply fulfilled whichever occurs first.
PT Medco E&P Tarakan			
PT Perusahaan Listrik Negara (Persero) Tbk (“PLN”)	January 5, 2022	To supply 3 BBTUD of gas with total gas contract quantity of 4,367.7 BBTU.	Expires December 31, 2025
PT Perusahaan Gas Negara (Persero) Tbk (“PGN”)	February 21, 2022	To supply 0.3 MMSCFD of gas with total gas contract quantity of 947.7 MMSCF.	Expires September 7, 2030
Medco E&P Grissik Ltd.			
Gas Supply Pte. Ltd.	February 12, 2001, last amended on November 4, 2022	To supply gas with total contract quantity of 2,380 TBTU	Until August 11, 2023
PGN Batam 3	November 12, 2018, last amended on July 25, 2019	To supply 20 BBTUD gas with total contract quantity of 49 TBTU	Until December 19, 2023 or until the total contract quantity has been fully supplied, whichever occurs first
PGN RU Dumai	November 3, 2017, last amended on January 1, 2022	To supply 40 BBTUD gas with total contract quantity of 65 TBTU	Until December 19, 2023 or until the total contract quantity has been fully supplied, whichever occurs first
PGN Dumai	May 17, 2017, last amended on January 1, 2022	To supply 37 BBTUD gas with total contract quantity of 57 TBTU	Until December 19, 2023 or until the contract quantity has been fully supplied, whichever occurs first
PGN BBG Jargas	October 14, 2021, last amended on January 27, 2022	To supply at 5.82 BBTUD gas with total contract quantity of 7.5 TBTU	Until December 19, 2023 or until the total contract quantity has been fully supplied, whichever occurs first
PGN ARGSPA	May 31, 2010, last amended on May 30, 2015	To supply at 12.5 BBTUD gas with total contract quantity of 34 TBTU	Until December 19, 2023 or until the total contract quantity has been fully supplied, whichever occurs first
Pertamina Hulu Rokan	August 6, 2021	To supply gas with total contract quantity of 133.1 TBTU	Until December 31, 2026 or until the aggregate quantity of gas delivered equals the contract quantity, whichever occurs first

Company / Counter-party	Date of Agreement	Commitment	Contract Year
Energasindo	October 30, 2007, last amended on December 1, 2021	To supply gas with total contract quantity of 107.4 TBTU	Until December 19, 2023 or until the aggregate quantity of gas delivered equals the contract quantity, whichever occurs first
PLN	May 4, 2015, last amended on November 25, 2019	To supply gas with total contract quantity of 6.6-35.7 TBTU	Until December 19, 2023 or until the aggregate quantity of gas delivered equals the contract quantity, whichever occurs first
PT Pupuk Sriwidjaja Palembang	May 25, 2016, last amended on July 10, 2020	To supply gas with total contract quantity of 133.2 TBTU	Until December 19, 2023 or until the aggregate quantity of gas delivered equals the contract quantity, whichever occurs first

Inflation

The Indonesia rate of inflation was 1.7% in 2020, 1.9% in 2021 and 5.5% in 2022 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 and gas which is a commodity whose price is determined by reference to international market prices. International oil and gas prices are volatile and this volatility has a significant effect on our revenues and asset values. Currently, our policy is to hedge a maximum of 20% of production. See "— Overview" and "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 denominated in non U.S. dollars (primarily denominated in Rupiah, but also in Euro, Australian Dollar, Singapore Dollar, Great Britain Pound Sterling, Thai Baht, and Vietnam Dong). Certain expenses comprising the salaries of Indonesian employees, local vendors, local rentals and interest income/expense are normally paid in Rupiah. 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 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 June 30, 2023 we had U.S. dollar denominated loans of US$2.4 billion and Rupiah-denominated loans of Rp. 10.6 trillion (equivalent to US$704.5 million), and of such Rupiah-denominated loans, Rp. 6.8 trillion (equivalent to US$454.5 million) are subject to U.S. dollar swaps. For the six months ended June 30, 2023, 85.8% of revenue were U.S. dollar-denominated and 46.5% of our expenditures were denominated in non-U.S. dollars.

Our policy for foreign exchange management, swap and hedging is 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 June 30, 2023, 20.0% of our long-term indebtedness has interest at floating rates which, in the case of U.S. dollar debts, principally are determined in reference to SOFR and, in the case of Rupiah debts, in reference to the banks' prime lending rate. Out of these long-term indebtedness with interest at floating rates, 10.3% is not hedged. 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 our 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.

Fair Value of Financial Assets

In accordance with PSAK 71 on Financial Instruments (equivalent to IFRS 9), which is effective starting from January 1, 2020, financial instruments such as non-trade receivables, derivatives, short term investment, equity investment without significant influence or joint control are now measured at fair value at each reporting date.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either:

- In the principal market for the asset or liability; or
- In the absence of a principal market, in the most advantageous market for the asset or liability.

Assuming that the company has access to such market and the market participants act in their economic best interest.

We use valuation techniques that are appropriate for each type of financial instruments in the circumstances and for which sufficient data are available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs; such as interest free rates. We also used independent appraisers to perform valuation of significant assets such as our investment in DSLNG.

Impairment of Financial Assets

In accordance with PSAK 71 on Financial Instruments (equivalent to IFRS 9), which is effective starting from January 1, 2020, we recognize an allowance for expected credit losses (“ECL”) for all debt instruments which are held for the purpose of collecting contractual cash flows which are solely consist of payments of principal and interest. The amount recognized as ECL is the difference between the amount contractual cash flows due and the amount we expect to receive, discounted at an approximation of the original effective interest rate.

In determining of the amount expected to be received, assumptions and estimates are required in relation to the discount rate used, the determination of the probability of default for each customer, and the recovery rate in case default event happens based on historical data as well as forward looking estimate such as macroeconomics conditions in the future.

Rights of Use Assets and Lease Liabilities

In accordance with PSAK 73 on Leases (equivalent to IFRS 16), which is effective starting from January 1, 2020, we assess each service contract at its inception date to determine if it contains a lease. The assessment involves management judgement in terms of determining if the contract contains an identified asset, if the company has the right to control such asset, the period of time such asset is used, the consideration paid for such asset and the interest rate applicable to the company should it use external source of funds to finance the contract. Those factors will influence if a right of use asset and the respective lease liability should be recognized as well as the amount of each, and the interest expense to be recognized related with lease liabilities.

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. We recorded a bargain purchase gain of US$49.0 million in 2022 in connection with the Corridor Acquisition, reflecting that the purchase price we paid for Corridor was less than our assessment of the fair value of Corridor's assets. For more information, see note 48 of our consolidated financial statements.

	Final Fair Value
	(US$ in millions)
Assets	
Cash and cash equivalents	173.4
Trade receivables	157.7
Other receivables	31.6
Inventory	5.4
Prepaid expenses	1.3
Long-term other receivables	1.8
Long-term investments	118.4
Oil and gas properties	1,295.9
Right-of-use assets	40.7
Sub-total	1,826.3
Liabilities	
Trade payables	106.1
Taxes payables	71.8
Other payables	17.3
Accrued expenses	28.5
Lease liabilities	40.7
Deferred tax liabilities — net	409.1
Long-term payables	49.5
Long-term employee benefit liabilities	5.7
Asset abandonment and site restoration obligations and other provision	28.4
Sub-total	757.1
Total identifiable net assets at fair values	**1,069.2**
Bargain purchase	(49.0)
Purchase consideration transferred	**1,020.2**
Net cash of the acquired subsidiary	**(173.4)**
Acquisition of a subsidiary, net of cash acquired	**846.8**

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.

Our business, financial condition and results of operations could be materially and adversely affected byany 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. Revenue from Rimau, South Sumatra, Lematang, the South Natuna Sea Block B and Tarakan PSCs, and Oman each of which is entering a mature stage with economic lives of five years, contributed in the aggregate 24.6% of our total revenue from exploration for and production of oil and gas and trading for the six months ended June 30, 2023.

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. If we are not successful in developing and replacing our oil and gas reserves, our business, prospects, financial condition and results of operations will be materially and adversely affected.

Our indebtedness could adversely affect our financial condition.

As of June 30, 2023, we had 3,070.1 million of total long-term debt outstanding. Covenants in agreements governing our existing debt and
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 and results of operations.

Our business is subject to significant government regulation.

Oil and gas companies operating in Indonesia are highly regulated, including with respect to, among others, costs and DMO obligations, impacting both our costs and revenues, licenses and permits, health, safety and the environment and tax matters and are subject to audit in various respects by the Government. Maintaining compliance with regulations requires significant resources and is an ongoing part of our operations. Any failure to comply with regulations could adversely impact us, including leading to the non-renewal of licenses or permits. For example, in the case of exporting pipeline gas, 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. We have in the past acquired assets in new markets and may do so again in the future. Our operations in these markets 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.

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 from independent third-parties for the Senoro-Toili (Tiaka field, which is Senoro-Toili’s oil field) and for our international blocks (other than Bualuang), 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 Lematang PSC (Singa field); as of December 31, 2018 for Rimau PSC and South Sumatra PSC; as of December 31, 2019 for Bangkanai PSC, Madura Offshore PSC and Sampang PSC; as of December 31, 2020 for South Natuna Sea Block B (excluding West Belut, Terubuk and Siput field) and Bualuang; as of December 31, 2022 for Block A, Aceh and Senoro Toili (Senoro Gas Field); and as of June 30, 2023 for West Belut, Terubuk and Siput field and D&M as of January 1, 2021 or June 30, 2023 for Corridor Block PSC. In addition, while we have obtained consent from each of GCA and DeGolyer and MacNaughton to name it in this Document, 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. Approximately 3% of our gross working interest proved reserves and approximately 4% of our gross working interest proved and probable reserves as of December 31, 2022 are estimated by us based on our own investigations and prior reserve estimates or assessments by reputable international consultants. 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 Lematang PSC (Singa field); as of December 31, 2018 for Rimau PSC and South Sumatra PSC; as of December 31, 2019 for Bangkanai PSC, Madura Offshore PSC and Sampang PSC; as of December 31, 2020 for South Natuna Sea Block B (excluding West Belut, Terubuk and Siput field) and Bualuang; as of December 31, 2022 for Block A, Aceh and Senoro Toili (Senoro Gas Field); and as of June 30, 2023 for West Belut, Terubuk and Siput field and D&M as of January 1, 2021 or June 30, 2023 for Corridor Block PSC, 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 as amended by MEMR Regulation No. 1 of 2022 on the Amendment of MEMR Regulation No. 7 of 2019 on Management and Use of Oil and Gas Data (the "MEMR 7/2019"). The 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. The 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 7/2019 does not specify the type of reserves data or information, reserves report, or disclosure that requires consent from the MEMR. Failure to comply with this requirement to obtain consent from the MEMR may result in sanctions of up to one year of imprisonment or fines of up to IDR 10 billion. As a public company, pursuant to the OJK and IDX Regulations, we are 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, we have disclosed reserves data and information from time to time in our audited financial statements and annual reports and other disclosures. In relation to this requirement, we have, through our subsidiaries, received consent from the Director General of Oil and Gas to disclose reserves data in our annual reports, financial statements and offering documents, including this Document, up to March 17, 2024. Our financial statements as of June 30, 2023 have been disclosed on the IDX website and been made publicly available on October 2, 2023. For the purposes of this Document, we have included reserves data and information consistent with disclosures in our unaudited financial statements as of June 30, 2023 that have been publicly released in accordance with IDX requirements. Although such information has been made public and we have obtained the consent to disclose the reserves data in our annual reports, financial statements and offering documents, including this Document, there is no assurance that we will be able to secure the consent in the future and failure to obtain such consent could result us imposed by penalties or sanctions, 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.

We face risks associated with our potential acquisition of assets in the Middle East.

In August 2023, we signed an agreement to acquire a 20% non-operating interest in producing oil and gas assets in the Middle East from an operator that will continue to hold a majority interest and remain as the operator of the asset (the “Potential Acquisition”). There can be no assurance that the evaluation and due diligence undertaken by us in connection with the Potential Acquisition revealed all relevant facts and circumstances that may be relevant for purposes of evaluating the acquisition, including the opportunities and risks, costs, benefits and prospects, acquired assets and operations including production and reserves, operator and other counterparties, regulatory framework and numerous other relevant considerations. 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 the relevant assets and operations. If the due diligence investigation has failed to correctly identify material issues and liabilities that may be present or the prospects of the relevant assets and operations, or if we incorrectly considered any identified material risks to be commercially acceptable relative to the opportunity, we may incur substantial impairment charges or other losses following closing of the Potential Acquisition. We may also incur unforeseen liabilities, such as unknown or contingent liabilities and issues relating to compliance with applicable laws, which could increase our costs and expenses due to exposure to such liabilities. Any of the foregoing could materially and adversely affect our business, prospects, financial condition and results of operations.

We face numerous other risks in connection with the Potential Acquisition, including the possibility that the expected benefits from the acquisition will not be realized or will not be realized within the expected time period; disruption to our business and distraction of management’s time and attention as a result of the transaction; negative effects of the announcement or consummation of the acquisition, including on the market price of our shares and/or operating results; significant transaction costs; unknown liabilities; unexpected costs or delays; the risk of regulatory challenges or scrutiny in connection with to the acquisition; other business effects and uncertainties, including the effects of industry, market, business, economic, political or regulatory conditions; future exchange and interest rates; changes in tax and other laws, regulations and policies; uncertainties regarding the commercial success of the assets and operations being acquired; uncertainties inherent in exploration and development, including the ability to meet anticipated objectives, in respect of the assets and operations being acquired; as well as numerous other risks that could materially and adversely affect our business, prospects, financial condition and results of operations.

Furthermore, the Potential Acquisition is not complete and is subject to certain closing conditions and other uncertainties, including corporate, local regulatory and other approvals. While the transaction is currently targeted to close around the end of the year, we cannot predict with any certainty whether and when any of the remaining required conditions will be satisfied or if other uncertainties may arise. As a result, there can be no assurance that the Potential Acquisition will close on the terms or in the manner in which we currently anticipate, or on schedule or at all. If the Potential Acquisition does not receive, or timely receive, the required local regulatory approvals, or if another event occurs that delays or prevents the completion of the Potential Acquisition, such delay or failure to complete the Potential Acquisition and the acquisition process may cause uncertainty or other negative consequences that may materially and adversely affect our business, financial condition and results of operations.

In addition, the Potential Acquisition is being funded from cash and debt and may increase our leverage and reduce our financial flexibility. Consequently, the Potential Acquisition will increase our overall indebtedness, which will result in increased repayment commitments and borrowing costs.

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We face risks related to third party partners or shareholders, with respect to certain of our assets and investments.

We have a significant minority interest in AMI, the holding company of AMNT, which operates a copper and gold mine in Sumbawa. AMI completed its initial public offering in July 2023 and as a result is now a publicly traded company. We also have a minority interest in PT Donggi Senoro LNG ("DSLNG"), a joint venture company involved in the downstream oil and gas sector. Because we do not control AMI or DSLNG, we do not control decisions relating to their respective operations and strategy, which could adversely affect our ability to obtain benefits from our investments. There can be no assurance that the other shareholders in such businesses will not take actions collectively or otherwise that are detrimental to our interests.

In addition, AMI has from time to time raised funds in order to fund AMNT through the issuance of shares to new investors, including through its July 2023 initial public offering, which has diluted our interest in AMI. We have in the past recorded losses in relation to dilution of our interest in AMI and cannot assure that we will not incur such losses again in the future if our interest is subject to further dilution. Furthermore, although AMI's share price has risen significantly since its IPO in July 2023, as a publicly listed company AMI's share price, and as a consequence, the market value of our investment, will be affected by many factors, including its business performance and market factors which are outside of our control, and such share price and value could be subject to volatility or negative pressure in the future. Furthermore, such share price may not be reflective of the price which we could achieve for sale of a large block of AMI shares, such as our 21.09% equity interest.

A number of our oil and gas blocks also have other interest holders, including government entities and a number of our power projects have other interest holders. We are also expanding our O&M business activities in the power sector and partnering with Kansai Electric to develop our gas IPP and O&M business. 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. In addition, we may face disputes with other partners and co-shareholders, an inability to finance certain developments, limits on the ability to recoup investments and limits on financial flexibility.

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

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 (or in the case of Aceh province, *Badan Pengelola Migas Aceh*, or BPMA). SKK Migas enters (and prior to it, BP Migas had entered or in the case of Block A, Aceh BPMA enters) 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 or BPMA as applicable, we believe that such enforcement and transfer of interests will, as a matter of policy and market practice, require the approval of SKK Migas or BPMA. 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 against us could have a material adverse effect on us. Furthermore, SKK Migas or BPMA may fail to comply with the terms of PSCs. In addition, we must obtain approval from SKK Migas or BPMA, as applicable, 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, BPMA 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 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.

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 Potential Acquisition, Corridor Acquisition and Ophir Acquisition, or in our other lines of business, such as power and mining. Although we are currently reviewing and in discussions with other potential targets, no definitive agreements have been entered into and there can be no assurances that any acquisition will be completed. 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. In the past, we have made significant acquisitions, and we may do so again in the future. For more information, see "Business — Business Strategies — Continue to pursue value accretive and credit-enhancing acquisitions, and focus on effective integration." 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 in 2022 in connection with the Corridor Acquisition, reflecting that the purchase price we paid was less than the assessment of the fair value of the acquired assets. Fair value of the assets and goodwill are subject to impairment testing with respect to whether they are recoverable, and therefore to the extent such assets decrease in value, we could record impairment losses in the future.

We have already expanded, and may in the future again expand, our operations or invest in new businesses and jurisdictions. We have also entered into different businesses from time to time which we have subsequently exited or otherwise hold for sale for portfolio rationalization. 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.

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Our business have been and may continue to be materially and adversely affected by the COVID-19 pandemic.

The rapid drop in energy demand during the first and second quarters of 2020 as a result of the COVID-19 pandemic negatively impacted, the oil and gas industry. In the early stages of the COVID-19 pandemic, oil prices fell to near historic lows due to a combination of a severely reduced demand for crude oil, gasoline, jet fuel, diesel fuel, and other refined products resulting, among other things, from government-mandated travel restrictions and a curtailment of economic activity. Our sales of oil are sold at market prices and while prices were lower in 2020 we continued to sell oil, but at significantly reduced prices. Our business also experienced other negative effects such as the impairment of our investment in The Energy Building and one of our gas offtake customers temporarily shutting down its operations for pandemic-related health and safety reasons. Although this customer continued to honor the take-or-pay provisions in its contract with us, similar events in the future could put a strain on our customers' financial resources and impact their ability to meet their obligations to us. Although conditions in our industry have improved significantly, the COVID-19 pandemic may evolve, and any resurgence of the COVID-19 or any other pandemic, including as a result of new variants or other viruses or events outside of our control, could precipitate or aggravate the other risk factors, which in turn could further materially and adversely affect our business, financial condition, results of operations and prospects.

Furthermore, an outbreak of other infectious diseases in the future (including avian flu, SARS, swine flu, the H7N9 virus) or another contagious disease or the measures taken by the governments of affected countries 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.

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 in Indonesia, 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 develop and in which we invest often require substantial capital outlay and a long gestation period before we realize any benefits or returns on investments.

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 business through MPI and have an investment in the gold and copper mining business through AMI, which have required capital contributions and have substantial indebtedness.

Through MPI, we are engaged in the power generation sector in Indonesia. Through our interest in AMI we have an interest in a copper and gold mine in Sumbawa.

MPI and AMI and/or 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 to make capital injections into AMI or MPI; however there can be no assurance that we will not do so in the future. 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.

Concerns over climate change could materially impact our operating results, access to capital and strategy.

Concerns over the risk of climate change have increased the focus by regional, national and local regulators on GHG emissions and on transitioning away from hydrocarbon fuels towards renewable sources of energy. A number of countries and local authorities have adopted, or are considering the adoption of, regulatory frameworks to reduce, and to improve transparency of reporting and pricing of, greenhouse gas emissions. These regulatory measures may include, among others, adoption of cap and trade regimes, carbon taxes, increased efficiency standards and incentives or mandates for battery-powered automobiles and/or wind, solar or other forms of alternative energy. More stringent environmental regulations can result in the imposition of costs associated with greenhouse gas emissions, either through environmental agency requirements relating to mitigation initiatives or through other regulatory measures such as carbon pricing taxation limitations on greenhouse gas emissions, which have the potential to increase our operating costs and reduce production. For example, the Minister of Environment and Forestry promulgated on May 24, 2021 Regulation of the Minister of Environment and Forestry No. 11 of 2021 on Emissions Quality Standards for Internal Combustion Engines that set a higher air emission threshold for the operation of internal combustion engines or generators which has been in effect since May 1, 2022. As a result of the new air emission thresholds, we are required to adjust our existing operations which may require additional costs. Furthermore, to obtain financing, we may be required to fulfill international standards with higher thresholds than those set out by the Minister of Environment and Forestry, which could materially affect our operations and limit our financing options.

In addition, we may be required to install new emission controls, acquire allowances or pay taxes related to their greenhouse gas emissions, or otherwise incur costs to administer and manage a GHG emissions program. Additionally, we could incur reputational risk tied to changing customer or community perceptions of our or our customers contribution to, or detraction from, the transition to a lower-carbon economy. These changing perceptions could lower demand for oil and gas products, resulting in lower prices and lower revenues as consumers avoid carbon-intensive industries, and could also pressure banks and investment managers to shift investments and reduce lending and other financing. In addition, environmental laws that may be implemented in the future could increase litigation risks and compliance costs and have a material adverse effect on us.

Separately, banks and other financial institutions, including investors, are increasingly adopting policies that restrict or prohibit investment in, or otherwise funding, us based on climate change-related concerns, which could affect our access to capital for refinancing and capital investment.

Approaches to climate change and transition to a lower-carbon economy, including government regulation, company policies, and consumer behavior, are continuously evolving. At this time we cannot predict how such approaches may develop or otherwise reasonably or reliably estimate their impact on our financial condition, results of operations and ability to compete. However, any long-term material adverse effect on the oil and gas industry may adversely affect our financial condition, results of operations and cash flows. For instance, the OJK has introduced carbon exchange through OJK Regulation No. 14 of 2023 on Carbon Trading through Carbon Exchange and OJK Circular Letter No. 12/SEOJK.04/2023 on the Procedures for Organising Carbon Trading through Carbon Exchange. Under the current framework, we will be forced to purchase other party’s (including our competitors) carbon units if we exceed our determined carbon emissions limit. The carbon trading regulations are evolving rapidly and there can be no assurance that any carbon related regulations or policies implemented in the future will not increase our compliance costs or require us to purchase carbon units of our main competitors, thereby having a material adverse effect on us.

Furthermore, our onshore and offshore assets are located in areas that may experience catastrophic weather and other natural events from time to time. To the extent that significant changes in the climate occur, we may experience extreme weather and changes in precipitation and temperature and rising sea levels, all of which may result in physical damage to our assets or disruptions in our production in these areas.

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 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 and granting liens and other security interests in our existing and anticipated credit facilities and other indebtedness; 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.

Our existing indebtedness and future indebtedness we may raise 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 20% of our total outstanding indebtedness (which is comprised of bank loans, loans from non-bank financial institutions, Rupiah Bonds, US Dollar Bonds and medium term notes) as of June 30, 2023. 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. In addition, increases in interest rates could materially increase the cost of refinancing our existing debt (increasing our existing fixed rate debt). 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.

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. 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 (including MPI) 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 and power operations, including resources for energy transition and renewable energy projects. 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. The Madura Offshore PSC, Sampang PSC and Lematang PSC will expire in 2027. However, we cannot assure you that the PSC extensions or renewals will be completed before the expiration of the relevant PSCs. In addition, the South Natuna Sea Block B PSC and Simenggaris PSC will expire in 2028. 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 we reports our consolidated results in U.S. dollars, a substantial portion of our costs are incurred in Rupiah, and we also incur costs in certain other currencies, including primarily Thai Baht and historically 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. 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. 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 at all or that any such agreements we enter into will protect us fully against these risks. Future fluctuations in the value of the Rupiah and other currencies 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.

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.

Mining at Batu Hijau is focused on stockpile processing and development of Phase 7 and advancing the development of Phase 8. Overburden removal for Phase 7 commenced in 2018. AMNT began processing production ore in April 2020, and this expected to continue until beyond 2024. AMNT also commenced Phase 8 development and is expected to produce ore starting from 2024. However, Phase 8 development may experience unexpected problems including issues with funding and delays during development. In addition, AMNT through its subsidiary PT Amman Mineral Industri ("AMIN") is in the process of constructing a 900 ktpa (dry basis) copper concentrate smelter and precious metals refinery near the Benete Port, and AMIN expects mechanical completion in 2024. However, we cannot assure you that AMIN will be able to continue to maintain its permits, ever commence production or have sufficient funds from its internal cash and/or from other sources of financing to achieve its target schedule.

AMI's copper and gold mining business is subject to significant regulation, including with respect to, among others, restrictions on export, and health, safety and the environment matters and since July 2023 AMI has been a public company listed on the IDX, subjecting it to the rules applicable to public companies in Indonesia.

In 2023, the Government through the Minister of Trade ("MOT") issued Minister of Trade Regulation No. 08 of 2023 on the Procedures for Determination of Export Benchmark Prices for Mining Products which is Subjected to Export Duty (the "MOT 08/2023") that sets out the procedures in determining export benchmark price (*Harga Patokan Ekspor* "HPE"). Meanwhile, the HPE itself is currently set out under MOT Decree No. 1703 of 2023 on the Export Benchmark Prices for Mining Products which is subjected to Export Duty ("MOT Decree 1703/2023") which is valid until October 31, 2023. In the event that no HPE is determined after October 31, 2023, the HPE stipulated under MOT Decree 1703/2023 will remain valid pursuant to MOT 08/2023.

Since August 2023, upon the promulgation of Government Regulation No. 36 of 2023 on Export Proceeds from Natural Resources Business Activities, Management, and/or Processing ("GR 36/2023"), exporters of natural resource products, namely those generated from the mining, plantation, forestry, and fishery sectors, must place at least 30% of the proceeds generated by them from the export of natural resource products (these proceeds are referred to as *Devisa Hasil Ekspor dari Barang Ekspor Sumber Daya Alam* or "DHE SDA") in Indonesia's financial system. Pursuant to GR 36/2023, at least 30% of DHE SDA must be placed in the country's financial system through an account referred to as a special DHE SDA account in GR 36/2023. Such 30% portion of the DHE SDA must remain in the DHE SDA account for at least three months from the initial date of placement.

Further, in February 2017, AMNT was granted the Government's IUPK mining permit, which has preserved all economic conditions in the original COW. In February 2017, the Government issued a 12-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, among others, MOT 08/2023 and its implementing regulations. In 2018, the MEMR issued MEMR Regulation No. 25 of 2018 on Mining of Minerals and Coal, as lastly amended by MEMR Regulation No. 17 of 2020 (the "MEMR 25/2018"). 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 that progress evaluations are conducted every six months. If the evaluation results state that the progress of the smelter does not reach the minimum required, the export permit will be revoked. In addition, an administrative fine of 20% of the cumulative value of offshore mineral sales may be imposed.

In July 2023, MOT issued an approval for the export of copper concentrate by AMNT, which is valid until May 31, 2024. Such approval was issued upon recommendation from the MEMR.

As such, the Government's regulations pertaining to the export of copper concentrate could result in AMNT becoming unable to export copper concentrate or the incurrence of additional financial obligations, which could adversely impact our share of AMI's results and its value. In addition, AMNT is required to apply for renewals of certain other key permits related to Batu Hijau (including a wastewater permit and an explosive 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 interests of our controlling shareholders may differ from those of our Group.

PT Medco Duta, PT Medco Daya Abadi Lestari ("MDAL"), and PT Kalibiru Lestari Bersama are beneficially owned by Mr. Hilmi Panigoro, and/or held for the benefit of, the family of Mr. Arifin Panigoro, who was a family member of Mr. Hilmi Panigoro, our President Director, and Mr. Hilmi Panigoro. Mr. Arifin Panigoro passed away in February 2022, and his shares are currently held by his heirs, namely Mrs. Raisis Panigoro (wife), Mrs. Maera (daughter) and Mr. Yaser Raimi A. Panigoro (son), and beneficiaries, Mr. Hilmi Panigoro and one of his family members, and Mr. Sudjiono Timan and one of his family members. (i) Mr. Hilmi Panigoro and one of his family members (through PT Medco Daya Abadi Lestari, PT Kalibiru Lestari Bersama and PT Medco Duta), (ii) the heirs of Mr. Arifin Panigoro (through PT Medco Daya Abadi Lestari and PT Medco Duta), and (iii) Mr. Sudjiono Timan and one of his family members (through an indirect minority interest in PT Medco Daya Abadi Lestari) hold a direct and indirect effective interest in Medco Energi of 18.17%, 20.60% and 15.36%, respectively. Mr. Hilmi Panigoro and other members of the Panigoro family through PT Medco Daya Abadi Lestari, PT Kalibiru Lestari Bersama and PT Medco Duta) hold a combined direct and indirect effective interest in Medco Energi of 38.77% and beneficially own 54.25% of the total outstanding shares of Medco Energi as of September 30, 2023. As a result, these shareholders have the power to significantly influence our management and policies. Under OJK Regulations, an affiliate transaction is an activity and/or a transaction entered into between a public company and its affiliates or affiliates of a member of the board of directors of a public 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 public company. An affiliate transaction does not require prior approval by a public company's independent shareholders, save for an affiliate transaction which also constitutes a material transaction that requires a general meeting of shareholders' approval. 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. Furthermore under OJK regulations, a transaction between a publicly listed company (or one of its controlled entities) and an affiliated party or a third party that has any conflicts of interest are considered to be a conflict of interest transaction. If the transaction is considered to be a conflict of interest transaction, it will be subject to the approval of our 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 our 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. Furthermore, MDAL has a number of non-operated oil and gas assets investments Indonesia and other active and passive investments in other Southeast Asian businesses. 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, we 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 us pursuant to financing arrangements with its lenders, including having to provide a pledge over its shares in us. 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 July 2020, OJK issued Regulation No. 42/POJK.04/2020 on Affiliated Party Transaction and Conflict of Interest Transaction which replaced the previous rule issued in 2009 ("POJK No. 42 of 2020").

POJK No. 42 of 2020 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 POJK No. 42 of 2020. 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 POJK No. 42 of 2020.

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 us, 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 currently still hold our Vietnam producing asset which we are in the process of selling) and assets or operations in Oman, Yemen, Libya, Tanzania and Mexico. 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 significant impairment losses on our oil and gas properties (which were partially reversed), 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. Our oil production in Yemen stopped in November 2022 due to a blockage at the oil terminal due to external threats, and was not re-commenced. 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, in April 2021, there were complaints about unpleasant odor during an acid fracturing program at Block A from local residents. Upon receiving such complaints, we ceased all flaring activity, shut down the well and conducted a toxic gas sweeping in the village. Although no toxic gas was found, we are subject to the risk that similar incidents could occur in the future, resulting in shut-downs or interruptions to our operations. We have also received various other complaints from local residents which have not been disruptive to our activities, but there can be no assurance that our activities will not be disrupted by local community-related issues in the future. In addition, AMNT’s Batu Hijau mine has experienced temporary work stoppages in the past. 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.

Our business could be negatively affected by security threats, including cybersecurity threats, destructive forms of protest and opposition by activists and other disruptions.

We face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information, to misappropriate financial assets or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure; and threats from terrorist acts. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs, and there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of financial assets, sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows.

Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability. In addition, destructive forms of protest and opposition by activists and other disruptions, including acts of sabotage or eco-terrorism, against oil and gas production and activities could potentially result in damage or injury to people, property or the environment or lead to extended interruptions of our operations, adversely affecting our 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, or IUPK (in the case of AMNT) 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 and Coal (“DGMC”). 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 DGMC 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 AMNT’s business and prospects impacting our investment in AMI. 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 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 (where we are currently in the process of selling), 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 as well as risks related to third parties with whom we partner.

The Sarulla geothermal power project, in which MPI owns an 18.07% 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.

Furthermore, we divested 2% of our ownership in PT Medco Geopower Sarulla ("MGEOPS"), the entity through which we hold our interest in the Sarulla geothermal power project (which previously was consolidated), to our shareholder, MDAL, in March 2021. As such, we no longer have a majority interest in MGEOPS, and are therefore subject to more risks associated with third parties with whom we partner. There had been a default under a loan facility for Sarulla geothermal power project beginning in 2020 and continuing in 2021 due to the debt service coverage ratio falling below the required ratio value. Although the lenders have not declared the remaining outstanding amounts under such loan to be due and payable, and Sarulla has previously requested a waiver, the lenders have not granted a waiver of the event of default. Accordingly, we could be required to inject additional capital into Sarulla in case the credit agreement is not extended by the lenders.

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 ICPG. Currently, we sell all of our natural gas under long-term contracts. Some of our contracts, which represented approximately 33.6% of gas sales volume in the first half of 2023, contain pricing linked to oil prices, such as the Corridor GSPL GSA and the Senoro GSA and one of the South Natuna Sea Block B GSAs. The remaining 66.4% 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 been significant fluctuations in the prices of crude oil in recent years, with oil prices having dropped significantly in 2020 as a result of the COVID-19 pandemic. The average price of Brent crude oil was US$41.6 in 2020, US$70.63 in 2021, US$100.97 in 2022 and US$79.78 for the month of June 2023. The market prices of crude oil are subject to a variety of factors beyond our control. These factors, among others, include:

- economic conditions and the demand for crude oil;
- 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, Western Africa and Russia;
- 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 and environmental laws and policies including relating to ESG, climate change and greenhouse gasses;
- 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 AMI.

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 share of AMI's results or its value. 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 2018, there was one fatality at the Block A, Aceh assets involving an employee of a third party contractor. In 2019, there were four fatalities involving contractors working for our subsidiaries or associates. There was an employee fatality at MPI during the construction of the Riau IPP facilities, a fatality at our Lematang PSC during a fire, a fatality at the Sarulla geothermal power project and a fatality at AMNT's operations. A fatality also occurred at MPI in 2020 involving a contractor during the demobilization of our Ijen Geothermal drilling operations. 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.

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. For example, the Batu Hijau mine experienced approximately 4,100 mm of rainfall between October 2022 and the first week of April 2023, and as a result of such heavy rainfall, AMNT experienced significant disruptions to its mining activities impacting its sales volume. Similarly, 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 as amended by the Job Creation Law (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 and the issuance of the Job Creation Law, the Government enacted Government Regulation No. 22 of 2021 on the Implementation of Environmental Protection and Management dated February 2, 2021 ("GR 22/2021"), which revokes the Government Regulation 27 of 2012 on Environmental License, dated February 23, 2012 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 GR 22/2021 would be accepted as valid environmental permits. The Environmental Law requires us to obtain environmental approval (Persetujuan Lingkungan) ("Environmental Approval") 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 Approval 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. Due to the enactment of Law No. 11 of 2020 on Job Creation (the "2020 Job Creation Law") on November 2, 2020 and the implementation of GR 22/2021 in 2021, the Indonesian government is planning to simplify such environmental licensing policy by, among other things integrating the environmental approval into the business license (*perizinan berusaha*) which is now administered through the Online Single Submission ("OSS") system. The OSS system is, an electronic licensing platform managed by the OSS Body, which is part of the Indonesia Investment Coordinating Board (*Badan Koordinasi Penanaman Modal*). However, there are no assurances that this simplification will occur or we will be able to obtain or retain the licenses we require.

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.

Increasing scrutiny and changing expectations from our investors, customers and employees with respect to ESG practices may impose additional costs on us or expose us to new or additional risks.

Investors, customers, employees, regulators and other stakeholders have expressed increasing interest in ESG practices. Such practices may be taken into consideration by investors in making their investment decisions, and such investors may not invest in us if they believe that our ESG practices are inadequate or may invest in our competitors if our ESG practices are perceived to be less robust than those of our competitors. The criteria by which companies ESG practices are assessed are subject to change. We may be subject to heightened scrutiny from stakeholders and other third parties in respect of our ESG performance, and we may be required to undertake costly initiatives to maintain a positive ESG outlook or to satisfy any new criteria. Our reputation may be adversely affected if we fail to meet applicable ESG standards or fail to maintain our ESG rating. In addition, our competitors may achieve similar or better ratings than us in the future.

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

We are 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. Such instances of unrest have highlighted the unpredictable nature of Indonesia's changing political landscape. Indonesia also has many political parties, with no political party winning a clear electoral majority to date. These events have resulted in political instability, as well as general social and civil unrest on certain occasions in recent years.

Indonesia also has a history of demonstrations and social protests concerning Indonesian politics as well as in response to specific issues, including fuel subsidy reductions, privatization of state assets, anticorruption measures, minimum wage, decentralization and provincial autonomy, actions of former Government officials and their family members, potential increases in electricity tariffs, human rights violations and international geopolitical events, such as past U.S. led military campaigns in Afghanistan and Iraq. Although these demonstrations have generally been peaceful, some have turned violent. There can be no assurance demonstrations or protests will not occur in the future or that such events will not adversely affect our business or operations.

Separatist movements and clashes between religious and ethnic groups have resulted in social and civil unrest in parts of Indonesia. Should these events occur in the vicinity of our facilities or transport routes, our business and operations may be adversely affected. Political and social unrest may occur if the results of future elections are disputed or unpopular. Political and social developments in Indonesia have been unpredictable in the past and, as a result, confidence in the Indonesian economy has remained low. Any resurgence of political instability could lead to extended disruptions in our operations and/or adversely affect the Indonesian economy, which could adversely affect our business.

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 (or in the case of Aceh province, BPMA) 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) which has been revoked by MEMR Regulation No. 6 of 2018 regarding the revocation of Minister of Energy and Mineral Resources Regulation, Minister of Mining and Energy Regulation, and Minister of Energy and Mineral Resources Decree regarding business activities of oil and gas 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 later amended by Government Regulation No. 93 of 2021 on the Income Tax Treatments for Transfers of Participating Interest in Offshore Oil and Gas Business Activities ("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. See Note 23 to our consolidated financial statements for information on our tax assessment letters.

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 "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 as amended by the Job Creation Law 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 revoked. 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, BPMA 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.

Furthermore, we are subject to the risk that governments may discontinue granting new contracts or licenses for the exploration and/or production of oil and gas.

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.

Indonesia is subject to various forms of natural disasters, because of its location in a geologically active part of the world. 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. 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 temporarily suspended in December 2019 due to the impact of heavy rain when a landslide occurred. Immediately after the landslide, we covered the area with tarpaulin and completed temporary draining. We then developed an engineering design for additional pipe support and conducted soil investigation as a mid-term plan. Block A, Aceh resumed normal operations in March 2020. However, we lost approximately four months of operations at Block A, Aceh.

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 March 2021, there have been various terrorist attacks directed towards the Government, religious sites, foreign governments and public and commercial buildings frequented by foreigners, which have killed and injured a number of people. For example, in March 2021, terrorist bombings at a Cathedral in Makassar, South Sulawesi leaving at least 20 people wounded.

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 an interest in the Bualuang field 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.

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

Indonesia's economy was significantly impacted by the Asian financial crisis of 1997. The crisis 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 generally and was impacted by, among other things, the 2008 global financial crisis and the COVID-19 pandemic.

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 1.7% in 2020, 1.9% in 2021 and 5.5% in 2022 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.

Indonesian accounting standards differ from those in other jurisdictions.

We prepare our financial statements in accordance with Indonesian FAS, which differs from U.S. GAAP. As a result, our financial statements and reported earnings could be significantly different from those that would be reported under U.S. GAAP. This Document does not contain a reconciliation of our financial statements to U.S. GAAP, and there can be no assurance that such reconciliation would not reveal material differences.

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 Business 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 tax benefits 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 benefits 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 benefits 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 after deduction of final income tax, is not subject to branch profits tax.

On August 31, 2021, the Government enacted Government Regulation No. 93 of 2021 regarding Income Tax Treatments on Participating Interest Transfer in Offshore Oil and Gas Business Activities ("GR 93/2021") that provides tax benefits in the form of income from transfer of participating interest in cost recovery PSC after deduction of final income tax is not subject to income 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 ("MEMR 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 — 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.

On March 31, 2020, the Government enacted Government Regulation in lieu of Law No. 1 of 2020 regarding State Financial Policy and Financial System Stability Policy for Managing The Corona Virus Disease (COVID-19) Pandemic and/or in Dealing with Threats that are Potentially Harmful to The National Economy and/or Financial System Stability ("Perppu-1/2020"), which adjusted corporate income tax rate for domestic company and permanent establishment to 22% for fiscal year 2020 and 2021, and 20% for fiscal year 2022 onwards (prior to such adjustment, the applicable corporate income tax was 25%). Perppu-1/2020 has become a law on May 18, 2020 through the enactment of Law No. 2 of 2020 regarding Determination of Government Regulation in lieu of Law No. 1 of 2020 regarding State Financial and Financial System Stability Policies for Managing The Corona Virus Disease (COVID-19) Pandemic.

Profits derived from gross split PSC activities generally are subject to corporate income tax rates that vary depending on the signing or effective date of the relevant gross split PSC (25% for those signed or effective prior to fiscal year 2020, 22% for fiscal years 2020 and 2021 and 20% for fiscal year 2022 onwards).

The relevant corporate income tax rate will continue to be applicable to relevant gross split PSC until the expiration date of the contract. Profits derived by a permanent establishment from gross split PSC activities after deduction of corporate income tax, is subject to a branch profits tax of 20% or such lower branch profits 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 after deduction of final income tax, is not subject to branch profits 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, as of this Document, 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.

GR 93/2021 with reference to GR 53/2017 provides that tax benefits in form of income from transfer of participating interest in gross split PSC after deduction of final income tax is not subject to branch profits tax.

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. In addition, the Corridor

PSC is scheduled to switch to the gross split regime in late December 2023, unless approved to remain under the cost recovery regime. The terms of the extensions differ from the existing PSC cost recovery format and follow the new gross split PSC regime. See "Management's Discussion and Analysis of Results of Operation and Financial Condition — PSC Tax Regime — Gross Split."

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 (as amended by the Job Creation Law, 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 Supreme Constitutional Courts / Mahkamah Konstitusi ("MK") to declare certain provisions of the Labor Law unconstitutional and order the Government to revoke those provisions. The MK 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

On November 2, 2020, the 2020 Job Creation Law was enacted. The 2020 Job Creation Law represents effort from the Government to comprehensively amend or revoke numerous sectoral laws and regulations with the goal to create job opportunities and improve Indonesia's investment eco-system. The changes amend several provisions in the Labor Law on the termination of employment and the amount of severance pay. As implementation of the 2020 Job Creation Law, the Government recently issued Government Regulation No. 35 of 2021 on Fixed Term Employment Agreement, Outsourcing, Working Hours and Time-off and Termination of Employment ("GR No. 35 of 2021") as the implementation regulation of the 2020 Job Creation Law, which regulates further on the compensation made for the termination on the Fixed-Term Employment Agreement. Based on GR No. 35 of 2021, the employer must pay compensation when a Fixed-Term Employment Agreement expires.

In October and November 2020, there were numerous protests across the country against the newly issued 2020 Job Creation Law. Protesters claim that the 2020 Job Creation Law would generally undermine existing labor laws and weakens environmental protections. The constitutionality of the 2020 Job Creation Law was challenged before the MK through several submissions.

Most recently, in November 2021, the court in one of those submissions declared the law to be "conditionally unconstitutional" due to non-compliance with the requisite formalities during the process in which the Government and the House of Representatives created the law (e.g., lack of public participation and an "omnibus" format is not recognized under Indonesian law). The court ruled that: (i) the law remains valid, but the Government and the House of Representatives must redraft the law within a two-year period to satisfy the required formality and follow the good legislation principles as mandated by the constitution; and (ii) the Government must hold any further action derived therefrom and refrain from issuing new implementing rules or strategic policies that have significant impact on society. Since the court's verdict was handed down, various stakeholders, including the general public, hold varying interpretations of the verdict. This has led to political instability and while the Government claims that the law remains valid, many scholars and groups (e.g., labor activists and NGOs) claim that the law and its implementing rules are unconstitutional and can no longer be referred to, thereby re-enacting the old law. In response, on December 30, 2022, the Indonesian Government enacted the Job Creation Law which revokes and replaces the 2020 Job Creation Law.

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. Such events could materially and adversely affect our business, financial condition, results of operations and prospects.

Certain Defined Terms

"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.
"AMNT"	means PT Amman Mineral Nusa Tenggara.
"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, the amended and restated PSC between Pertamina, PT Medco E&P Malaka, Premier Oil Sumatra (North) BV. and Japex Block A Ltd. dated October 28, 2010 that became effective as of September 1, 2011, and the amendment of the PSC between Badan Pengelola Migas Aceh, PT Medco E&P Malaka and PT Medco Daya Energi Nusantara dated October 2, 2020, as may be amended from time to time.

"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.
"CAGR"	means compounded annual growth rate.
"CCPP"	means a combined cycle power plant.
"CE"	means Chubu Electric Power Co. Inc.
"Chubu"	means Chubu Electric Power Co, Inc.
"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.

“custodian”	has the same meaning as set forth in the Law No. 8 of 1995 on the Capital Market as amended by Law No. 4 of 2023 on Development and Strengthening of Financial Sectors.
“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.
“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.
“DGMC”	means the Directorate General of Minerals, Coal and Geothermal of Indonesia.
“DMO”	means Domestic Market Obligations.
“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.
“Environmental Approval”	means an Environmental Approval (Persetujuan Lingkungan)

"Environmental Law"	means the Law No. 32 of 2009 regarding Environmental Protection and Management as amended by the Job Creation Law.
"EPE"	means PT Energi Prima Elektrika.
"EPSA"	means Exploration and Production Sharing Agreement.
"ESC"	means Energy Sales Contract.
"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.
"FPSO"	means the Floating Production Storage and Offloading facilities.
"FRS"	means the Singapore Financial Reporting Standard.
"FTP"	means first tranche petroleum.
"GCA"	refers to Gaffney, Cline & Associates.
"GHG"	means global greenhouse gas.

"Government"	means the Government of Indonesia.
"GR"	means Government Regulations enacted by the Government.
"HSE"	means the health, safety and environment.
"HSFO"	means High Sulfur Fuel Oil 180 CST.
"ICP"	means the Indonesia Crude Price, which is a benchmark oil price that is currently based on the Brent benchmark oil price plus Alpha.
"IDR"	means Indonesian Rupiah.
"IDS Shelf Bonds"	means Rupiah-Denominated Shelf Bonds.
"IDX"	means the Indonesia Stock Exchange (formerly known as the Jakarta Stock Exchange or JSX).
"Indonesia Income Tax"	has the same meaning as set forth in the Indonesian Regulation PER-25/PJ/2018.
"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, as partially revoked by Law No. 40 of 2014 on Insurance.
"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).
"ISRS"	means International Stereotactic Radiosurgery Society.
"ITA"	means the Income Tax Act 1947 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).
"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 Creation Law"	means the Law No. 6 of 2023 on the Stipulation of Government Regulation in Lieu of Law No. 2 of 2022.
"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, as amended by the Job Creation Law.
"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.
"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).
“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.
“MRPR”	means PT Medco Ratch Power Riau.
“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, as partially revoked by Bank Indonesia Regulation No. 21/2/PBI/2019 regarding the Reporting of Foreign Exchange Activities.
“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, as partially revoked by Bank Indonesia Regulation No. 21/2/PBI/2019 regarding the Reporting of Foreign Exchange Activities.

“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, as amended by the Job Creation Law.

“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. 16/SEOJK.04/2021 on Format and Content of Annual Report of Issuer or Public Companies to periodically submit financial reports, including annual financial statements and semi-annual financial statements pursuant to OJK Regulation No. 14/POJK.04/2022 on submission of Periodic Financial Statements of Issuers or Public Companies.

“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.

“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.
"PPA"	means Power Purchase Agreement.
"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 as defined in 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 which became effective on April 23, 2023, as may be amended from time to time.
"Rp." or "Rupiah"	means Indonesian Rupiah.
"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.
"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.
"Upstream Regulation"	refers to the Government Regulation No. 35 of 2004 on October 14, 2004 with respect to Upstream Oil and Gas Business Activities, as amended by Government Regulation No. 55 of 2009 and Government Regulation No. 34 of 2005.
"US$"	means United States dollars.
"VAT"	means value-added tax.
"VIEs"	mean variable interest entities.

"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.
"WPR"	means a people's mining area (Wilayah Pertambangan Rakyat).
"WUP"	means a mining operational area (Wilayah Usaha Pertambangan).

Units of Measurement

"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.