NEWS RELEASE

BHP

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BHP RESULTS AND STRATEGIC UPDATE
GROWING VALUE AND POSITIONING FOR THE FUTURE
FINANCIAL YEAR ENDED 30 JUNE 2021

BHP delivered a strong set of results for the 2021 financial year, with a safe and reliable operational performance and strong financial returns. On the back of these results, the Board has announced a record final dividend of US$2.00 per share, bringing BHP's returns to shareholder to more than US$15 billion for the full year.

Our strategy is to deliver long-term value and returns through the cycle. We aim to do this through owning a portfolio of world class assets with exposure to highly attractive commodities which benefit from the mega-trends playing out in the world around us, by operating them exceptionally well, by maintaining a disciplined approach to capital allocation and through being industry leaders in sustainability and the creation of social value.

As the world continues to evolve, BHP is positioning itself to benefit from the mega-trends and through sustainability leadership.

To this end, today we have announced:

- Investment in the Jansen Stage 1 potash project which is aligned with our strategy of growing our exposure to future facing commodities in world class assets;
- Agreement to pursue a merger of our Petroleum business with Woodside to create a global top 10 independent energy company with a large-scale portfolio of producing, development and exploration assets; and
- Intention to unify our corporate structure under BHP's existing Australian parent company to realise simplification and enhanced strategic flexibility benefits.

BHP Chair, Ken MacKenzie:

"BHP's performance over the past year illustrates the strength of our portfolio, balance sheet, people and performance culture. Including the record dividend announced today of US$2.00 per share, we have returned over US$15 billion to shareholders over the past year.

BHP is in a strong position to manage its future in a time of rapid change. We have a clear strategy and are executing against it. Jansen Stage 1 will give BHP exposure to a commodity with a strong demand outlook and decades of potential growth. The agreement to pursue a merger of BHP's Petroleum business with Woodside will maximise the value of our oil and gas assets through increased operating scale and synergies, with a more diversified product portfolio to support the energy transition. Now is the right time to unify BHP's corporate structure. BHP will be simpler and more efficient, with greater flexibility to shape our portfolio for the future. Our plans announced today will better enable BHP to pursue opportunities in new and existing markets and create value and returns over generations."

BHP Chief Executive Officer, Mike Henry:

"The BHP team has achieved a great set of operational and financial results in the year past. This is thanks to both the outstanding effort of 80,000 people across the company, as well as to the support of BHP's thousands of suppliers and customers, and our host communities and governments. Most importantly, our improved results were achieved safely, with 2021 being our second consecutive full financial year with zero fatalities in BHP operations. We achieved several production records and our four major capital projects were executed on time and on budget. We continue to invest in people and technology, setting BHP up for ongoing improvement in performance.

We continue to actively position our portfolio as well for future returns and growth. We have progressed exploration and development in copper and nickel, commodities which are favourably leveraged to the mega-trends of electrification and decarbonisation. In sanctioning the Jansen Stage 1 project in Canada, we gain access not only to the healthy returns of this project on a stand-alone basis, but to a new front for growth in a future facing commodity in the world's best potash basin and an attractive investment jurisdiction. The merger of our petroleum business with Woodside will create a top 10 global independent energy company, unlocking value for BHP shareholders, including through synergies, and a stronger, more resilient combined business that will be better positioned to continue to grow value as it navigates the energy transition."

BHP Results for the year ended 30 June 2021

Note: All guidance is subject to further potential impacts from COVID-19 during the 2022 financial year.

Keeping our people and communities safe

- There were no fatalities at our operated assets over the last two and a half years. High Potential Injury frequency[(i)] declined by 17% and Total Recordable Injury Frequency[(i)] decreased by 11% during the year.
- Our ongoing focus on safety, health and wellbeing has enabled us to deliver strong safety and operational performance.

Operational excellence: Strong operational performance and free cash flow generation, with a margin of 64%

- Strong underlying operational performance, with record volumes achieved at Western Australia Iron Ore (WAIO), Goonyella and Olympic Dam, and Escondida maintained average concentrator throughput at record levels.
- Profit from operations of US$25.9 billion, up 80%, and Underlying EBITDA[(ii)] of US$37.4 billion at a record[(iii)] margin[(ii)] of 64%.
- Attributable profit of US$11.3 billion (includes an exceptional loss of US$5.8 billion predominantly related to the impairments of our potash and energy coal assets, and the current year impact of the Samarco dam failure). Underlying attributable profit[(ii)] of US$17.1 billion, up 88% from the prior year.
- Net operating cash flow of US$27.2 billion, above US$15 billion for the fifth consecutive year, and record[(iii)] free cash flow[(ii)] of US$19.4 billion, reflects higher iron ore and copper prices, and a strong operational performance.

Disciplined capital allocation: Four major projects delivered and early stage options added

- Capital and exploration expenditure[(ii)] within guidance at US$7.1 billion. Minerals capital and exploration expenditure is expected to be approximately US$6.7 billion for the 2022 financial year (and a further US$2.3 billion for Petroleum).
- Successfully achieved first production at four major development projects, all of which were delivered on or ahead of schedule and on budget. We acquired an additional 28% working interest in Shenzi in November 2020. The Shenzi North development, a two-well subsea tie-in to the Shenzi platform, was approved in August 2021.
- In exploration, we have continued to add to our early stage options in future facing commodities throughout the year, with the recently announced recommended all-cash takeover offer of Noront Resources in Canada, the signing of an agreement for a nickel exploration alliance in Canada and of a farm-in agreement for the Elliott copper project in Australia. At Oak Dam in South Australia, next stage resource definition drilling commenced in May 2021.
- Net debt at US$4.1 billion, compared to US$12.0 billion at 30 June 2020. In light of our announcement to pursue a merger of our Petroleum business with Woodside, we will be reviewing our net debt target and will provide an update with our interim results for the 2022 financial year in February 2022.

Value and returns: Consistently high cash returns, US$15.2 billion of total announced returns to shareholders

- The Board has determined to pay a final dividend of US$2.00 per share or US$10.1 billion, which includes an additional amount of US$0.91 per share (equivalent to US$4.6 billion) above the 50% minimum payout policy. Total dividends announced of US$3.01 per share, equivalent to an 89% payout ratio.
- Underlying return on capital employed[(ii)] strengthened to 32.5%.

Year ended 30 June	2021 US$M	2020 US$M	Change %
Profit from operations	25,906	14,421	80%
Attributable profit	11,304	7,956	42%
Basic earnings per share (cents)	223.5	157.3	42%
Dividend per share (cents)	301.0	120.0	151%
Net operating cash flow	27,234	15,706	73%
Capital and exploration expenditure	7,120	7,640	(7%)
Net debt	4,121	12,044	(66%)
Underlying EBITDA	37,379	22,071	69%
Underlying attributable profit	17,077	9,060	88%
Underlying basic earnings per share (cents)[(ii)]	337.7	179.2	88%

Strategic Update

Investment in the Jansen Stage 1 potash project which is aligned with our strategy of growing our exposure to future facing commodities in world class assets

- BHP approved US$5.7 billion (C$7.5 billion) in capital expenditure for the Jansen Stage 1 (Jansen S1), which includes funding for the required port infrastructure.
- Exposure to potash provides increased leverage to key global mega-trends including rising population, changing diets, decarbonisation and improving environmental stewardship.
- Jansen S1 is expected to produce approximately 4.35 million tonnes of potash per annum[iv].
- First ore is targeted in the 2027 calendar year, with construction expected to take approximately six years, followed by a ramp up period of two years.
- At consensus prices[v], the go-forward investment on Jansen S1 is expected to generate an internal rate of return of 12 to 14%, an expected payback period of seven years from first production and an underlying EBITDA margin of approximately 70%.
- The Jansen project offers significant high returning growth optionality in the world's best potash basin and an attractive investment jurisdiction.
- We have assessed the carrying value of the existing potash asset base as at 30 June 2021 and have recognised a pre-tax impairment charge of US$1.3 billion (US$2.1 billion after-tax).

Agreement to pursue a merger of our Petroleum business with Woodside to create a global top 10 independent energy company with a large-scale portfolio of producing, development and exploration assets

- BHP and Woodside have entered into a merger commitment deed to combine their respective oil and gas portfolios by an all-stock merger. The merger is subject to confirmatory due diligence, negotiation and execution of full form transaction documents, and satisfaction of conditions precedent including shareholder, regulatory and other approvals.
- On completion, it is expected Woodside would be owned approximately 52% and 48% by existing Woodside and BHP shareholders respectively, and will remain listed on the Australian Securities Exchange (ASX) with listings on additional exchanges being considered.
- The proposed merger would create a global top 10 independent energy company by production and would be the largest energy company on the ASX.
- It will give our shareholders greater choice about how to weight their exposure to the different investment propositions of BHP and Petroleum via Woodside.
- It is expected to deliver substantial benefits for our shareholders, including estimated synergies of more than US$400 million per annum.
- With the combination of two high quality asset portfolios, the combined business will have a high margin oil portfolio, long life LNG assets and the financial resilience to help supply the energy needed for global growth and development over the energy transition.

Intention to unify our corporate structure under BHP's existing Australian parent company to drive simplicity and flexibility

- BHP intends to unify its Dual Listed Company (DLC) structure, subject to final Board and other approvals. Unification would result in a corporate structure that is simpler and more efficient, reduce duplication and streamline our governance and internal processes.
- As we position the company for the future operating environment, a unified structure will improve flexibility for portfolio reshaping to maximise value for shareholders over the long-term, including facilitating a simpler separation of Petroleum.
- Following recent changes to our portfolio there has been a significant reduction in earnings contribution from Plc assets, as well as a material reduction in the expected costs of unification of approximately US$1.2 billion, with one-off costs now expected to be US$400 to US$500 million.
- Plc shareholders' shares will be exchanged for Limited shares on a one-for-one basis. BHP's Board, management, dividend policy, ability to distribute fully franked dividends and fundamentals will remain the same.
- It is expected that a unified BHP would have its primary listing on the ASX, a standard listing on the London Stock Exchange (LSE), a secondary listing on the Johannesburg Stock Exchange (JSE), and a sponsored Level II ADR program on the New York Stock Exchange (NYSE).
- If approved, unification is expected to occur in the first half of the 2022 calendar year, with the proposed Petroleum merger with Woodside to follow.

Additional information included on pages 17 to 21.

Delivering strong performance

BHP delivered a strong set of results for the 2021 financial year. We were safe, more reliable and more productive, and we increased our efforts to pursue further improvements in our safety and wellbeing performance. We have now had over two and a half years without a fatality at our operated assets and we have seen a sustained improvement in our key safety performance indicators. High Potential Injury frequency has decreased by 17 per cent during the year and a reduction of 35 per cent since the 2019 financial year. Total Recordable Injury Frequency has continued to decline, down 11 per cent during the year to 3.7[vi], and a reduction of 21 per cent over the last two years. Our two largest assets, Western Australia Iron Ore and our Escondida copper mine have continued to deliver production and throughput respectively at record levels, as did Olympic Dam which achieved the highest annual copper production since BHP acquired the asset in 2005 and the highest gold production ever for the operation. When combined with our strong reliability and disciplined cost control, this has helped us to benefit from record high iron ore and copper prices.

We generated record free cash flow, return on capital employed strengthened to 32.5 per cent and our balance sheet is strong, with net debt finishing the year at US$4.1 billion. On the back of these results, the Board has announced a record final dividend of US$2.00 per share, bringing BHP's returns to shareholder to more than US$15 billion for the full year, and more than US$38 billion over the past three years.

We are continuing to unlock even greater performance from our equipment and infrastructure through enabling our people and investing in capability. We continue to build a more inclusive and diverse workforce to further enhance performance excellence. This includes our aspirational goal of a gender balanced workforce by 2025. We had 48 per cent female external hires during the year, which has resulted in a material increase of female representation[i] in the workforce, up three percentage points to 29.8 per cent. The Executive Leadership Team established last year has 50 per cent female representation.

We are reliably delivering our major growth and sustaining capital projects in copper, iron ore and petroleum, with all major projects during the year executed on time and on budget despite COVID-19 challenges. The Spence Growth Option (SGO) copper project and the South Flank iron ore sustaining project, which will contribute to improved grade and increased lump in our iron ore product suite, both began production and are ramping up. In Petroleum, the Atlantis Phase 3 and Ruby growth projects both started producing over the last 12 months, and we completed the counter-cyclical acquisition of an additional interest in the Shenzi asset. In nickel and copper, we have established further exploration partnerships, acquired new tenements and progressed greenfield exploration.

In addition to strengthening economic growth, in the past year we have seen growing national ambitions and some positive steps towards overcoming the challenge of climate change. This is aligned with, and has reinforced, our perspective on the unfolding mega-trends of decarbonisation, electrification, population growth and the drive for higher living standards in the developing world, which we see becoming key drivers of commodity demand. We expect our diversified portfolio to be resilient under a number of different long-term scenarios, and in fact, that many of our commodities would further benefit from an accelerated decarbonisation pathway[vii]. We continue to pursue opportunities to further strengthen our portfolio and our exposure to these long-term trends.

We have invested through the cycle in high returning growth projects, and in options for future development and value creation in copper, nickel, oil and potash through innovation, exploration, early stage investment and development. Creating and securing more options in future facing commodities remains a priority.

Creating social value

We are committed to creating long-term value for our shareholders and consider social value and financial value in the decisions we make. Social value is our positive contribution to society – to our people, partners, economy, environment and local communities.

Safety and sustainability

The safety, health and wellbeing of our workforce and the communities in which we operate are fundamental to our ability to contribute to social value. We have continued to demonstrate this throughout the COVID-19 pandemic with the ongoing, safe performance of our operated assets. We have provided significant support to local businesses, and regional and Indigenous communities where we operate in response to COVID-19 and have established programs to support the public health response.

At our operated assets, we remain vigilant and will continue with social distancing and hygiene practices, and other additional protocols as appropriate to protect our workforce and communities from COVID-19, in line with guidelines from local and national government bodies and expert health advice in the countries where we operate. Many of these measures remain in place. Our Australian operations have effectively managed the rapidly changing environment relating to interstate travel and border access, however ongoing frequent border restrictions create uncertainty in managing the business. In Chile, the operating environment is expected to continue to be challenging as COVID-19 cases in the country remain elevated, with reductions in our on-site workforce forecast to continue in the 2022 financial year.

Despite the challenges, our people have continued their focus on safety. Our global safety improvement programs are progressing well and our safety leading indicators have continued a strong positive trend underpinning the current safety performance. We have now had over two and a half years without a fatality at our operated assets and we continue to focus on fostering a culture of respect and ensuring our workplace is safe at all times.

Our ambition to minimise our withdrawals of high-quality fresh water[(viii)] and replace them with seawater or low-quality withdrawals where feasible saw a continued reduction in freshwater withdrawals[(i)], which were 11 per cent lower in the 2021 financial year compared to the prior year and are now 27 per cent below the 2017 baseline for our five year target.

Communities remain a critical part of our social value contribution

Our community and social investment commitment (one per cent of pre-tax profit), which began 20 years ago, is aligned with our broader business priorities and contributes to the resilience of the communities and environment where we have a presence. This is one of the critical parts of creating social value.

In response to COVID-19, we have worked closely with local businesses, and regional and Indigenous communities where we operate in both the immediate response to COVID-19 and in the recovery phase. This has included financial support to local and regional health networks, the provision of essential community services including mental health, training and upskilling, enhancing technology and targeted support to remote Indigenous communities. In addition, we secured and donated medical personal protective equipment and other health and sanitation goods to communities and organisations where supply was interrupted.

We also partnered with the communities where we operate, by offering training and apprenticeships on emerging technologies, systems and practices to build future capabilities.

As part of our social value contribution, we also fund the BHP Foundation, which continues to work with partner organisations globally to address some of the world's most critical sustainable development challenges. These efforts are designed to address challenges that are directly relevant to the global resources sector and contribute towards many of the United Nations Sustainable Development Goals focussing on the governance of natural resources, environmental resilience and education equity. The BHP Foundation's global partnership with Transparency International supports governments to identify and address corruption risks in mining licensing processes, and its global programs supporting Indigenous peoples have enabled Indigenous land management activities covering the Ten Deserts of Australia and traditional lands in the Boreal Forests of Canada and the Amazon basin of Peru. Further information can be found at: bhp.com/foundation.

With effect from 1 July 2021, BHP has reduced to seven-day payment terms for all small, local and Indigenous suppliers, getting cash into their hands sooner. This will benefit over 4,000 suppliers globally, including in Australia, Chile, North America and Canada. These include suppliers that are a part of the Local Buying Program in Australia and South America.

Our approach to cultural heritage is driven by the commitments made in our Indigenous Peoples Policy Statement, our Indigenous Peoples Strategy and our Reconciliation Action Plan. During the year, we continued to work with Traditional Owner groups and other Indigenous representative organisations to further strengthen our cultural heritage management practices. We also continue to support efforts to further strengthen the laws, policies and practices that regulate the management of cultural heritage values.

Delivering on our climate change commitments

We have made strong progress on actions required to meet our commitments to reduce operational emissions.

In September 2020, we signed a renewable power purchasing agreement (PPA) to meet half of our electricity needs across our Queensland Coal operations from low emissions sources. We also executed a 15-year contract extension to our power purchase agreement at Nickel West, which provides additional ability to integrate renewable electricity generation. Our four new renewable power contracts for Escondida and Spence commence from the 2022 financial year, as part of our aim to achieve 100 per cent renewable supply at both operations by the mid-2020s. In August 2021, BHP became a founding member of Komatsu's GHG Alliance, providing engineering, technical and mining expertise with the aim of accelerating the path to market of zero-greenhouse gas emissions haul trucks.

In line with the 2030 Scope 3 goals we set in 2020, we have taken actions to contribute to decarbonisation in our value chain. In steelmaking, we have entered into three partnerships that are targeted at the development and deployment of technologies to support a reduction in greenhouse gas emissions in integrated steelmaking for an aggregate investment of up to US$65 million. We signed a Memorandum of Understanding (MoU) with:

- China's HBIS Group Co., Ltd (HBIS), one of the world's largest steelmakers and one of our major iron ore customers, to collaborate on three priority areas: hydrogen-based direct reduction technology, the recycling and reuse of steelmaking slag, and the role of iron ore lump utilisation to help reduce emissions from ironmaking and steelmaking (March 2021).
- JFE Steel, one of Japan's largest steel producers, to study the properties of raw materials, with focus on specific areas such as iron ore pre-treatment, use of enhanced iron ore lump, high quality coke and DRI, required to decrease iron and steelmaking emissions (February 2021).
- World leading steel producer, China Baowu, to collaborate on technical solutions to utilise low carbon fuel sources such as hydrogen injection in the blast furnace, and explore other low emission options (November 2020).

The combined output of these three steelmakers equates to around 10 per cent of global steel production[ix].

In shipping, we have also taken a number of actions to help reduce emissions in our value chain:

- We awarded the world's first LNG-fuelled Newcastlemax bulk carriers contract, since replicated by others, with the aim to reduce CO_2-e emissions by up to 34 per cent per voyage (September 2020).
- We also took part in a successful marine biofuel trial which will support development of a strategy on the supply of biofuels and its use on our key shipping routes (April 2021).
- We announced the signing of a Memorandum of Cooperation to become one of the founding members of Singapore's Global Centre for Maritime Decarbonisation (GCMD). The centre will spearhead the maritime industry's energy transition journey. BHP is the only resources company that is part of the alliance (April 2021).

Building on our leading practice in climate risk management, disclosure and engagement, we plan to put forward a non-binding advisory Say on Climate to shareholders at our 2021 AGMs in the form of a vote with respect to our new Climate Transition Action Plan (CTAP). The CTAP will cover the focus areas of the Climate Action 100+ Net Zero Company Benchmark and in particular, provide further information on our approach to addressing emissions in our value chain (Scope 3 emissions).

Social value: key indicators scorecard[1]

Key indicators	Target	FY21	H2 FY21	H1 FY21	FY20	Comment
Fatalities	Zero work-related fatalities	0	0	0	0	No fatalities at our operated assets for over two and a half years.
High Potential Injury (HPI) frequency[i] (per million hours worked)	Year-on-year improvement in HPI frequency	0.20	0.20	0.20	0.24	17 per cent decrease from FY20.
TRIF[i] (per million hours worked)	Year-on-year improvement in TRIF	3.7	3.7	*3.6*	4.2	11 per cent reduction from FY20.
Operational greenhouse gas (GHG) emissions[i] (Mt CO_2-e)	Maintain FY22 operational GHG emissions at or below FY17 levels[2][3], while we continue to grow our business and reduce emissions by at least 30 per cent from FY20 levels[3] by FY30	16.2	8.0	*8.2*	*15.9*	On track to meet our FY22 and FY30 targets, despite expected increase in FY21, due to reductions in emissions from renewable power contracts in Chile and Australia.
Value chain emissions[i]	Steelmaking: 2030 goal to support industry to develop technologies and pathways capable of 30 per cent emissions intensity reduction in integrated steelmaking, with widespread adoption expected post-2030	✓	✓	✓	-	On track to deliver 2030 goal with three low-carbon partnerships initiated with some of the world's leading steelmakers in FY21: China Baowu, HBIS and JFE.
	Maritime transportation: 2030 goal to support 40 per cent emissions intensity reduction of BHP-chartered shipping of our products	✓	✓	✓	-	On track to deliver 2030 goal with award of a LNG-fuelled bulk carrier tender and LNG supply agreement, completion of a marine biofuel trial and signing of a Memorandum of Cooperation to become a founding member of the Global Centre for Maritime Decarbonisation in FY21.
Freshwater withdrawals[i] (GL)	Reduce FY22 freshwater withdrawals by 15 per cent from FY17 levels[4]	113.5	60.9	52.6	127.0	On track to meet our five-year target with an 11 per cent reduction from FY20 and 27 per cent reduction from FY17 baseline.
Community and social investment (US$M)	No less than one per cent of pre-tax profit (three-year rolling average)	174.8	144.3	*30.5*	149.6	Impacts this year include (i) >12.8M hectares conserved, restored or improved management; (ii) 19,000 people completing training aligned with the future of work, with >1,500 people obtaining paid employment.
Local procurement spend (US$M)	Support the growth of local businesses in the regions where we operate	2,176	1,064	*1,112*	1,922	Over US$4 billion directed to local suppliers in the past two financial years.
Female workforce representation[i] (%)	Aspirational goal for gender balance by the end of FY25	29.8	29.8	27.4	26.5	We have achieved a 12 percentage point increase from FY16, with 48 per cent female external hires in FY21.
Indigenous workforce participation[i] (%)	Australia: aim to achieve 8.0 per cent by the end of FY25	7.2	7.2	6.7	6.5	Continued increase throughout FY21.
	Chile: aim to achieve 10.0 per cent by the end of FY26[5]	7.5	7.5	*6.8*	6.6	Continued increase throughout FY21.
	Canada - Potash: aim to achieve 20.0 per cent by the end of FY27[5]	13.5[6]	13.5[6]	12.8	15.0	Expected to increase slowly throughout project execution but to rise sharply when hiring operational staff begins, predominantly in FY26.

(1) All data points are subject to non-financial assurance reviews. Some previously reported data points have been re-stated as a result of audit and assurance reviews completed subsequent to release of information or due to reclassification. Re-stated figures are shown in italics.

(2) In FY17, our operational GHG emissions were 14.6 Mt CO_2-e (excluding Onshore US).

(3) FY17 and FY20 baselines will be adjusted for any material acquisitions and divestments based on GHG emissions at the time of the transaction. Carbon offsets will be used as required. FY17 baseline is on a continuing operations basis and has been adjusted for divestments.

(4) In FY17, our fresh water withdrawals were 156.1 GL (on an adjusted basis, excluding Onshore US). The FY17 baseline data has been adjusted to account for: the materiality of the strike affecting water withdrawals at Escondida in FY17 and improvements to water balance methodologies at WAIO and Queensland Coal and exclusion of hypersaline, wastewater, entrainment, supplies from desalination and Discontinued operations (Onshore US assets) in FY19 and FY20.

(5) New medium term target established.

(6) Includes data for employees & embedded contractors as at 30 June 2021 and data for service contractors as at 30 April 2021.

Samarco

BHP remains committed to supporting the Renova Foundation and its work to progress the remediation and compensatory programs to restore the environment and re-establish communities affected by the Samarco tragedy. In total, Renova has spent R$14 billion (approximately US$3.3 billion[x]) on remediation and compensation programs to 30 June 2021.

Compensation and financial assistance of approximately R$4.7 billion (approximately US$1.1 billion) has been paid to support approximately 336,000 people affected by the Fundão dam failure up until 30 June 2021[xi]. Resettlement of communities continues to progress despite ongoing challenges, including the implementation of precautionary measures to minimise the spread of COVID-19[xii].

A Framework Agreement was entered into between Samarco, Vale and BHP Brasil and the relevant Brazilian authorities in March 2016 and established the Renova Foundation to develop and implement environmental and socio-economic programs to remediate and provide compensation for damage caused by the Samarco dam failure. Negotiations are ongoing with State and Federal Prosecutors and certain other Brazilian public authorities on the review of the Framework Agreement, seeking a definitive and substantive settlement of claims relating to the dam failure. It is not possible to provide a range of outcomes or a reliable estimate of potential settlement outcomes and there is a risk that a negotiated outcome may be materially higher than amounts currently reflected in the Samarco dam failure provision. Until any revisions to the Programs are agreed, Fundação Renova will continue to implement the Programs in accordance with the terms of the Framework Agreement and the Governance Agreement. The suspended R$155 billion (approximately US$30 billion[x]) Federal Public Prosecution Office claim is under discussion as part of these negotiations.

BHP has reported a total income statement charge of US$1.2 billion (after tax) in relation to the Samarco dam failure for the 2021 financial year. This charge is recognised as an exceptional item. Additional commentary is included on page 53.

Financial performance

Note: All guidance is subject to further potential impacts from COVID-19 during the 2022 financial year

Earnings and margins

- Attributable profit of US$11.3 billion includes an exceptional loss of US$5.8 billion (2020: US$8.0 billion, which includes a US$1.1 billion exceptional loss).
- The exceptional loss of US$5.8 billion (after tax) relates to an impairment charge in relation to potash of US$2.1 billion, an impairment charge in relation our energy coal assets of US$2.2 billion (New South Wales Energy Coal of US$1.7 billion, and Cerrejón of US$0.5 billion), COVID-19 related costs of US$0.4 billion and the current year impact of the Samarco dam failure of US$1.2 billion. The impairment charge against our potash assets reflects an analysis of recent market perspectives and the value that we would now expect a market participant to attribute to our investments to date. The impairment charge for New South Wales Energy Coal (NSWEC) reflects the status of the divestment process and forecast market conditions for thermal coal, the strengthening Australian dollar and changes to the mine plan. The impairment charge for Cerrejón reflects the expected net sale proceeds. The Samarco dam failure exceptional item primarily reflects updates to the Group's assessment of remediation and compensation costs relating to the dam failure, including increased eligibility for compensation programs reflecting the latest judicial rulings and revisions to the resettlement costs for impacted communities.
- Underlying attributable profit of US$17.1 billion (2020: US$9.1 billion) reflects higher commodity prices and strong operational performance.
- Profit from operations of US$25.9 billion (2020: US$14.4 billion) increased as a result of higher commodity prices, strong underlying operational performance, lower deferred stripping depletion at Escondida, lower fuel and energy costs, solid cost performance supported by cost reduction initiatives across our assets and other net movements. This was partially offset by the exceptional charge, unfavourable impacts of a stronger Australian dollar and Chilean peso, copper grade decline, natural field decline in Petroleum, inflation, adverse weather and planned maintenance.
- The total impact from COVID-19 on our operations was US$780 million (pre-tax) (2020: US$348 million). This represents the following impacts: lower volumes at our operated assets of US$234 million (2020: US$112 million) and additional direct costs of US$546 million pre-tax (exceptional item) incurred, such as increased social distancing measures including additional charter flights, accommodation, security and health and hygiene services and also temporary relocation costs due to border restrictions (US$0.2 billion), combined with higher demurrage and other standby charges due to delays caused by COVID-19 (US$0.3 billion).
- Underlying EBITDA of US$37.4 billion (2020: US$22.1 billion), driven by higher iron ore and copper prices, record volumes at WAIO and additional volumes from the Spence Growth Option, higher profit from equity accounted investments, lower deferred stripping depletion at Escondida, lower fuel and energy costs, disciplined cost performance and other net movements. This was partially offset by unfavourable impacts of a stronger Australian dollar and Chilean peso, copper grade decline, natural field decline in Petroleum, inflation, adverse weather and planned maintenance.
- Record[iii] underlying EBITDA margin of 64 per cent (2020: 53 per cent).
- Underlying return on capital employed strengthened to 32.5 per cent (2020: 16.9 per cent).

Operational performance and costs

- Strong underlying performance across the portfolio, including record production at WAIO, Goonyella and Olympic Dam and concentrator throughput at record levels at Escondida, offset by the impacts of overall grade decline at our copper assets, natural field decline in Petroleum, adverse weather and planned maintenance across a number of our assets.
- Disciplined cost performance supported by cost reduction initiatives across our assets offset by higher inventory drawdowns at Olympic Dam and at Nickel West, and additional costs associated with the ramp-up of South Flank.

- Unit costs were 14 per cent higher across our major assets predominantly reflecting unfavourable foreign exchange movements. Unit costs(ii) at Petroleum were better than guidance and reflect the optimisation of maintenance activity. We achieved unit cost guidance (based on exchange rates of AUD/USD 0.70 and USD/CLP 769) at Escondida and WAIO as a result of maintaining average concentrator throughput at record levels, lower deferred stripping costs and higher by-product credits at Escondida, and a strong performance and continued productivity improvements across the supply chain at WAIO. We also achieved revised unit cost guidance at Queensland Coal. WAIO unit costs on a C1 basis excluding third party royalties were higher than the prior year at US$12.98 per tonne (2020: US$11.82 per tonne) due to a stronger Australian dollar.
- Costs related to the impact from COVID-19 that are reported as an exceptional item are not included in unit costs for the 2021 financial year. At our major assets these additional costs were: US$0.91 per tonne at Queensland Coal, US$0.51 per tonne at WAIO, US$0.27 per barrel of oil equivalent at Petroleum and US$0.03 per pound at Escondida.
- Unit cost guidance for the 2022 financial year (based on exchange rates of AUD/USD 0.78 and USD/CLP 727) reflects: the impacts of higher guidance exchange rates and higher expected input costs across the portfolio, higher price-linked costs at Petroleum; costs related to a planned increase in material mined at Escondida due to reduced material movement in the 2021 financial year; continued productivity improvements at WAIO; and increased stripping costs largely offset by productivity uplifts at Queensland Coal. Expected costs related to the impacts from COVID-19 are included in unit cost guidance for the 2022 financial year.
- We will continue to drive performance and unlock value by improving productivity and reliability across the supply chain through implementing maintenance centre of excellence best practices, new technology solutions and ongoing automation.
- Historical costs and guidance for our major assets are summarised below:

	Medium-term guidance(1)	FY22 guidance(1)	FY21(2) at guidance exchange rates(3)	FY21(2) at realised exchange rates(4)	FY20(2)	FY21(2)(4) Vs FY20(2)
Petroleum unit cost (US$/boe)	<13	11 - 12	10.56	10.83	9.74	11%
Escondida unit cost (US$/lb)	<1.10	1.20 - 1.40	0.96	1.00	1.01	(1%)
WAIO unit cost (US$/t)(5)	<16(6)	17.50 - 18.50	13.83	14.82	12.63	17%
Queensland Coal unit cost (US$/t)	-(7)	80 - 90	75.52	81.81	67.59	21%

(1) FY22 and medium-term unit cost guidance includes expected costs related to the impacts from COVID-19 and are based on exchange rates of AUD/USD 0.78 and USD/CLP 727.

(2) FY20 and FY21 unit costs excludes the impact from COVID-19 that was reported as an exceptional item.

(3) FY21 unit costs at guidance exchange rates of AUD/USD 0.70 and USD/CLP 769.

(4) Average exchange rates for FY21 of AUD/USD 0.75 and USD/CLP 746.

(5) WAIO unit costs exclude freight and royalties. The breakdown of C1 unit costs, excluding third party royalties, are detailed on page 33.

(6) WAIO medium-term unit cost guidance has been revised from less than US$13 per tonne predominantly reflecting a number of uncontrollable factors including updated guidance exchange rates (from AUD/USD 0.70 to AUD/USD 0.78), expected higher third party royalties and higher forecast diesel prices.

(7) We remain focused on cost reduction and productivity initiatives, however given the ongoing uncertainty regarding restrictions on coal imports into China we are unable to provide medium-term unit cost guidance for Queensland Coal.

- Production and guidance are summarised below:

Production	Medium-term guidance	FY22 guidance	FY22e vs FY21	FY21	FY20	FY21 vs FY20
Petroleum (MMboe)	~109[(1)]	99 – 106	(4%) – 3%	103	109	(6%)
Copper (kt)		1,590 – 1,760	(3%) – 8%	1,636	1,724	(5%)
Escondida (kt)	~1,200[(2)]	1,000 – 1,080	(6%) – 1%	1,068	1,185	(10%)
Other copper[(3)] (kt)		590 – 680	4% – 20%	568	539	5%
Iron ore (Mt)		249 – 259	(2%) – 2%	254	248	2%
WAIO (Mt)		246 – 255	(2%) – 1%	252	248	1%
WAIO (100% basis) (Mt)	~290[(4)]	278 – 288	(2%) – 1%	284	281	1%
Samarco[(5)] (Mt)		3 – 4	55% – 106%	2	-	100%
Metallurgical coal (Mt)	-[(6)]	39 – 44	(4%) – 8%	41	41	(1%)
Queensland Coal (100% basis) (Mt)		70 – 78	(3%) – 8%	73	73	0%
Energy coal (Mt)		13 – 15	(33%) – (22%)	19	23	(17%)
NSWEC (Mt)		13 – 15	(9%) – 5%	14	16	(11%)
Cerrejón[(7)] (Mt)		n/a	n/a	5	7	(30%)
Nickel (kt)		85 – 95	(4%) – 7%	89	80	11%

(1) Petroleum medium-term production guidance has been revised from approximately 106 MMboe to reflect the approval of the Shenzi North development and the potential sanction of the Scarborough gas development later in the 2021 calendar year.

(2) Represents annual average copper production over the medium term.

(3) Other copper comprises Pampa Norte, Olympic Dam and Antamina.

(4) WAIO's current licenced export capacity is 290 Mtpa.

(5) Samarco restarted operation of one concentrator in December 2020, and had safely produced 1.9Mt (BHP share) by the end of the 2021 financial year.

(6) We remain focused on cost reduction and productivity initiatives, however given the ongoing uncertainty regarding restrictions on coal imports into China we are unable to provide medium-term volume guidance for Queensland Coal.

(7) We will no longer provide production guidance for Cerrejón reflecting the announced divestment of our interest in June 2021 and volumes will be reported separately from 1 July 2021 until transaction completion.

Cash flow and balance sheet

- Net operating cash flows of US$27.2 billion (2020: US$15.7 billion), above US$15 billion for the fifth consecutive year, reflects strong iron ore and copper prices, and strong underlying operating performance across the portfolio. Income tax and royalty-related taxation (petroleum resource rent tax and Chilean mining tax) payments of US$8.0 billion, included within net operating cash flows, are largely based on instalment rates using prior year tax return information. While higher profits resulted in increased tax payments during the current year, approximately US$2.6 billion of tax instalments and final tax payments relating to the 2021 financial year are expected to be made in the 2022 financial year.
- Free cash flow of US$19.4 billion, after capital and exploration expenditure of US$7.1 billion.
- Our balance sheet remains strong with net debt at US$4.1 billion at 30 June 2021 (31 December 2020: US$11.8 billion; 30 June 2020: US$12.0 billion). The decrease of US$7.9 billion in net debt in the year (or US$7.7 billion from December 2020) reflects record[(iii)] free cash flow generation by the operations which more than offset the record ordinary dividends paid to shareholders during the year of US$7.9 billion and US$1.1 billion of lease additions (including SGO).

Year ended 30 June	2021 US$M	2020 US$M
Net debt at the beginning of the period	12,044	9,446
IFRS 16 transition	–	1,778
Lease additions	1,079	363
Free cash flow	(19,389)	(8,090)
Dividends paid	7,901	6,876
Dividends paid to NCI	2,127	1,043
Other movements	359	628
Net debt at the end of the period	**4,121**	**12,044**

- We remain committed to a strong balance sheet through the commodity price cycle. In light of our announcement to pursue a merger of our Petroleum business with Woodside, we will be reviewing our net debt target and will provide an update with our interim results for the 2022 financial year in February 2022.
- Gearing ratio[(ii)] of 6.9 per cent (31 December 2020: 18.1 per cent; 30 June 2020: 18.8 per cent).

Dividends

- The Board has determined to pay a final dividend of US$2.00 per share or US$10.1 billion. This is equivalent to a 92 per cent payout ratio (2020: 72 per cent).
- In total, record dividends of US$15.2 billion (US$3.01 per share) have been determined for the 2021 financial year, including an additional amount of US$6.7 billion above the minimum payout policy.

Capital and exploration

- Capital and exploration expenditure of US$7.1 billion in the 2021 financial year was in line with guidance. This included maintenance expenditure[xiii] of US$2.3 billion and exploration of US$514 million.
- Capital and exploration expenditure of approximately US$6.7 billion for minerals and US$2.3 billion for petroleum is expected for the 2022 financial year. In total, this is US$0.5 billion higher than previous guidance predominantly due to unfavourable impacts of a stronger Australian dollar. Guidance is subject to exchange rate movements.
- This guidance includes a US$800 million exploration program in the 2022 financial year, with approximately US$260 million for our minerals exploration program (additional details on page 37) and approximately US$540 million for petroleum exploration and appraisal program (additional details on page 29).
- Historical capital and exploration expenditure and guidance are summarised below:

	FY22e US$M	FY21 US$M	FY20 US$M
Maintenance[(1)(2)(3)]	3,200	2,336	1,853
Development			
Minerals	3,400	3,353	4,243
Conventional Petroleum[(2)]	1,600	917	804
Capital expenditure (purchases of property, plant and equipment)	**8,200**	**6,606**	**6,900**
Add: exploration expenditure	800	514	740
Capital and exploration expenditure – total operations	**~9,000**	**7,120**	**7,640**

(1) Includes capitalised deferred stripping of US$810 million for FY21 (FY20: US$698 million) and approximately US$800 million for FY22.

(2) Petroleum capital expenditure for FY22 includes US$1.6 billion of development and US$0.1 billion of maintenance.

(3) The increase in maintenance costs of approximately US$0.9 billion in FY22 primarily relates to unfavourable foreign exchange rate impacts, mine and mobile equipment replacements at Escondida and Spence, tailings and waste management at Spence and water infrastructure at WAIO.

- At Olympic Dam, the planned major smelter maintenance campaign and subsequent ramp up is now planned between September 2021 and March 2022 (previously between August 2021 and February 2022). This is due to the ongoing COVID-19 state border restrictions limiting personnel coming to site.
- Average annual sustaining capital expenditure guidance over the medium term, excluding costs associated with our automation programs, has been revised predominantly due to updated guidance exchange rates (from AUD/USD 0.70 to AUD/USD 0.78) and forecast to be approximately:
  - US$4.50 per tonne for WAIO (from US$4 per tonne); and
  - US$10 per tonne for Queensland Coal (from US$9 per tonne).

Projects

- In August 2021, the BHP Board approved two major projects:
  - An investment of US$5.7 billion (C$7.5 billion) for the Jansen Stage 1 potash project in the province of Saskatchewan, Canada (additional details on pages 17 to 18); and
  - An investment of US$544 million for the Shenzi North development in the US Gulf of Mexico, following the successful acquisition of an additional 28 per cent working interest in Shenzi in November 2020 (additional details on page 29). The capital expenditure approved represents a 100 per cent share interest. BHP is operator and holds a 72 per cent share in Shenzi North. Repsol holds the remaining 28 per cent working interest and is expected to make a Final Investment Decision later this calendar year.
- At the end of the 2021 financial year, BHP had two major projects under development, which were Mad Dog Phase 2 in petroleum and Jansen mine shafts in potash. Both of these projects are tracking to plan.

- The Mad Dog Phase 2 project achieved a major milestone in April 2021 as the semi-submersible floating production platform, Argos, arrived in the US from South Korea. First production from Mad Dog Phase 2 is expected in the middle of the 2022 calendar year.
- Engineering work continues to progress at Scarborough, with production licences awarded for WA-1-R (Scarborough) and WA-62-R (North Scarborough) in November 2020. Separate to the merger commitment, BHP and Woodside (the operator) have committed to a plan towards Scarborough Final Investment Decision (FID) by the end of the 2021 calendar year. As part of this plan, BHP and Woodside have agreed an option for BHP to divest its 26.5 per cent interest in the Scarborough Joint Venture (JV) to Woodside and our 50 per cent interest in the Thebe and Jupiter JVs to Woodside if the Scarborough Joint Venture takes a FID by 15 December 2021 (additional details on page 19).
- Major projects are summarised below:

Commodity	Project and ownership	Project scope / capacity[1]	Capital expenditure[1] US$M	Date of initial production	Progress / comments
			Budget	Target	
Projects achieved first production during the 2021 financial year					
Petroleum	Atlantis Phase 3 (US Gulf of Mexico) 44% (non-operator)	New subsea production system that will tie back to the existing Atlantis facility, with capacity to produce up to 38,000 gross barrels of oil equivalent per day.	696	CY20	First production achieved in July 2020, ahead of schedule and on budget.
Copper	Spence Growth Option (Chile) 100%	New 95 ktpd concentrator is expected to increase Spence's payable copper in concentrate production by approximately 185 ktpa in the first 10 years of operation and extend the mining operations by more than 50 years.	2,460	FY21	First copper production achieved in December 2020, on schedule and on budget.
Iron Ore	South Flank (Australia) 85%	Sustaining iron ore mine to replace production from the 80 Mtpa Yandi mine.	3,061	Mid-CY21	First production achieved in May 2021, on schedule and on budget.
Petroleum	Ruby (Trinidad & Tobago) 68.46% (operator)	Five production wells tied back into existing operated processing facilities, with capacity to produce up to 16,000 gross barrels of oil per day and 80 million gross standard cubic feet of natural gas per day.	283	CY21	First production achieved in May 2021, ahead of schedule and on budget.
Projects in execution at 30 June 2021					
Petroleum	Mad Dog Phase 2 (US Gulf of Mexico) 23.9% (non-operator)	New floating production facility with the capacity to produce up to 140,000 gross barrels of crude oil per day.	2,154	Mid-CY22	On schedule and budget. The overall project is 93% complete.
Other projects in progress at 30 June 2021					
Potash[2]	Jansen Potash (Canada) 100%	Investment to finish the excavation and lining of the production and service shafts, and to continue the installation of essential surface infrastructure and utilities.	2,972		The project is 93% complete and expected to be finalised in CY22.

(1) Unless noted otherwise, references to capacity are on a 100 per cent basis, references to capital expenditure from subsidiaries are reported on a 100 per cent basis and references to capital expenditure from joint operations reflects BHP's share.

(2) Capital expenditure of approximately US$100 million (related to the above scope) is expected for FY22.

- Our latent capacity projects are tracking to plan:
  - The Bass Strait West Barracouta project achieved first production in April 2021, on schedule and budget; and
  - WAIO is expected to sustainably achieve supply chain capacity of 290 Mtpa over the medium-term.
- Our licence application to increase capacity at our Port Hedland operations to 330 Mtpa (100 per cent basis) continues to progress, and is expected to be finalised in the September 2021 quarter.

- We have continued to progress with the implementation of autonomous trucks across our Australian iron ore and coal mine sites.
  - At the Newman East (Eastern Ridge) iron ore mine, 22 autonomous trucks deployed in November 2020.
  - At the Goonyella Riverside mine in Queensland, the first coal site to implement autonomous haul trucks, the deployment of 86 autonomous trucks continues in line with the plan and is expected to be completed in the middle of the 2022 calendar year, on schedule and budget.
  - At the Daunia coal mine in Central Queensland, the second coal operation to implement autonomous haul trucks, the first trucks began operating in January 2021. The rollout is expected to be completed in the December 2021 quarter, on schedule and budget.

Operations Services and apprenticeships

In Australia, we have created 3,850 permanent jobs with Operations Services and deployed people across 20 locations in WAIO, Olympic Dam, Queensland Coal and NSWEC. We have provided training to new employees and a mastery program to address the needs of a high-calibre permanent workforce operating in modern mining. Operations Services have successfully accelerated safety and productivity improvements across our operations, including a two per cent increase in availability of haul trucks serviced by Operations Services.

In October 2020, BHP announced a further commitment to the training and funding of 2,500 Australian apprenticeships and training positions over the next five years through our FutureFit Academy. As part of this announcement, BHP also committed to supporting a further 1,000 skills development opportunities across a range of sectors in regional areas. In the last 12 months, the BHP FutureFit academy has welcomed over 400 apprentices and maintenance associates across two locations at Mackay in Queensland and Perth in Western Australia. The first intake of maintenance associates from the FutureFit Academy have been progressively deployed to an Operations Services maintenance team at WAIO and Queensland Coal during the second half of the 2021 financial year.

Capital Allocation Framework

Adherence to our Capital Allocation Framework aims to balance value creation, cash returns to shareholders and balance sheet strength in a transparent and consistent manner.

	FY21 US$B	FY20 US$B
Net operating cash flow – total operations	**27.2**	**15.7**
Our priorities for capital		
Maintenance capital	2.3	1.9
Strong balance sheet	✓	✓
Minimum 50% payout ratio dividend	5.0	5.0
Excess cash(1)	**17.6**	**7.7**
Balance sheet	9.4	0.1
Additional dividends	2.9	1.9
Buy-backs	-	-
Organic development	4.8	5.7
Acquisitions/(Divestments)	0.5	-

(1) Includes total net cash outflow of US$2.3 billion (FY20: US$1.1 billion) which comprises dividends paid to non-controlling interests of US$2.1 billion (FY20: US$1.0 billion); net investment and funding of equity accounted investments of US$0.6 billion (FY20: US$0.6 billion) and an adjustment for exploration expenses of US$(0.4) billion (FY20: US$(0.5) billion) which is classified as organic development in accordance with the Capital Allocation Framework.

Outlook

Economic outlook

We remain positive in our outlook for long-term global economic growth and commodity demand. Population growth, the infrastructure of decarbonisation and rising living standards are all expected to drive demand for energy, metals and fertilisers for decades to come.

The outlook for the short term remains uncertain. While momentum towards recovery remains intact across many key regions, vigilance with respect to COVID-19 risks is still a constant for all.

Inflation trends and exchange rates have been volatile. In our business specifically, many commodity-linked uncontrollable costs have moved higher. For some of our assets, constraints on the free movement of parts of our workforce are creating localised shortages and associated cost increases. While this situation persists, operational risks will be elevated.

Commodities outlook

Global crude **steel** production was unbalanced in the 2020 calendar year, with strong growth in China offset by a steep fall in the rest of the world (ROW). In the 2021 calendar year to date, this has corrected to some degree, with utilisation rates in the ROW back close to normal, on average, even as China continues to produce at very high run-rates. Notwithstanding regulatory uncertainty with respect to periodic output controls, and COVID-19 risks, Chinese steel production is expected to increase by around 5 per cent in the 2021 calendar year. Steel prices and margins have achieved record levels in some key ROW regions as the supply recovery has lagged the rapid improvement in downstream demand. We anticipate a continuation of strong end-use demand conditions in China and ongoing recovery in the rest of world over the course of the 2022 financial year.

Efforts to **decarbonise steel making** are expected to proceed at different rates in different regions, based on availability of lower carbon raw feedstock (including but not exclusively scrap), the age of existing facilities, variable levels of policy support, net trade positions and differential demands for affordable steel. We expect developing nations such as India to deploy principally optimisation and transitional technologies across their steel making fleets in the coming decades. Leading mills in China and in developed regions are already experimenting with transitional and green end-state technology, with commercialisation of hydrogen-based DRI anticipated from the mid-2030s, with Europe at the forefront. Accordingly, we expect that the steel making industry will be a large purchaser of carbon offsets in coming decades even as it positions itself to pursue long run carbon neutrality.

Iron ore prices have been elevated since the Brumadinho tailings dam tragedy in Brazil first disrupted the market in early 2019. Conditions have been particularly tight since the second half of the 2020 calendar year, with new record highs for the 62% Fe index fines and the lump premium established. Forces contributing to price gains over the most recent half have been strong Chinese pig iron production, recovering ROW pig iron production and tight supply of branded fines products. This latter factor was partly due to production coming in towards the lower end of guidance for some of the other major iron ore producers. Other material factors in terms of the supply-demand balance included robust shipments from Port Hedland, Australia, and incremental growth from a high base from price-sensitive sources of supply. The premium for lump product has been very favourable in the most recent half, buoyed by similar factors to fines, in addition to sintering restrictions in parts of China. Medium term, China's demand for iron ore is expected to be lower than it is today as crude steel production plateaus and the scrap-to-steel ratio rises. In the long-term, prices are expected to be determined by high cost production, on a value-in-use adjusted basis, from Australia or Brazil. Quality differentiation is expected to remain a factor in determining iron ore prices.

Metallurgical coal prices faced by Australian producers in the free-on-board (FOB) market were weak for most of the 2021 financial year. Australian FOB prices were able to stage a recovery late in the financial year based on pronounced multi-regional supply constraints, recovering ROW demand and an associated acceleration of trade flow adjustments. Even so, the differential between FOB prices and the China CFR equivalent remains very wide, which represents value leakage for FOB producers. The industry faces a difficult and uncertain period ahead while natural trade flows are impaired. Long term, we believe that a wholesale shift away from blast furnace steel making, which depends on metallurgical coal, is still decades in the future. That assessment is based on our bottom-up analysis of likely regional steel decarbonisation pathways, as discussed above. Demand for seaborne Hard Coking Coals (HCC), or also referred to as high quality metallurgical coals, is expected to expand alongside the growth of the steel industry in HCC importing countries such as India.

Energy coal prices began to recover from their COVID-19 induced lows late in the 2020 calendar year, assisted by a pick-up in demand due to cold weather in North Asia, constrained supply and a bounce in Indian industrial activity. Prices FOB Newcastle rallied again moving into the North Asian summer, with supply disruptions and strengthening demand intersecting. China's policy in respect of energy coal imports remains a key medium-term uncertainty.

Copper prices have been strong, with new record highs established on the LME in the second half of the 2021 financial year. With ROW demand recovering and China's economy continuing to perform well, the short term outlook for demand remains constructive. On the supply side, we note that actual disruption rates have been below both the long-term average and more recent experience in the calendar year to date, despite potential headwinds from COVID-19 outbreaks, political uncertainty and a number of wage negotiations at Chilean mines. Longer term, both demand and supply factors indicate that copper is an attractive avenue for future growth. Regulatory uncertainty is an emerging risk across more than one key supply region, the outcome of which could potentially influence the identity and cost of long-run marginal supply.

Nickel prices have been volatile within an approximate range of US$15,000/t to US$20,000/t on the LME over the second half of the 2021 financial year. Prices have been boosted, at times, by positive sentiment towards pro-growth assets, supply disruptions across multiple regions and a strong demand rebound. Demand improvements have come from both traditional uses and the battery-electric vehicle (EV) complex. Periods of price appreciation have been interspersed with abrupt but ultimately short-lived declines related to prospective developments in upstream or downstream technology. Longer term, we believe that nickel will be a substantial beneficiary of the global electrification mega-trend and that nickel sulphides will be particularly attractive. This is due to their relatively lower cost of production of battery-suitable class-1 nickel than for laterites, as well as the favourable position of integrated sulphide operations on the emission intensity curve.

Potash prices have increased sharply over the last 12 months, despite ongoing excess production capacity. According to CRU, granular spot prices - CFR Brazil and US (New Orleans) FOB barge - increased to around $600 per tonne in July 2021, up more than 150 per cent and 180 per cent from a year ago respectively. Strong demand due to favourable farm economics and constrained supply from presently operating assets have combined to inspire the rally. EU sanctions on certain grades of Belarussian potash exports have amplified the existing upswing. Longer term, potash stands to benefit from the intersection of a number of global mega-trends: rising population, changing diets and the need for the sustainable intensification of agriculture. Our analysis suggests that this latter imperative becomes even more critical under certain decarbonisation pathways. We anticipate trend demand growth will progressively absorb the excess capacity currently present in the industry. That, in turn, is expected to create the need for new greenfield supply by the late 2020s or early 2030s. Canadian greenfield solution mines, which tend to be higher opex and consume more energy and water than conventional mines, are expected to set the industry's long run trend price.

Crude oil prices have recovered to above US$70 per barrel as the 2022 financial year opens. We believe further gains from here are possible given our constructive view of demand tailwinds. However, future developments in price are also expected to rely in large part on the rate at which currently curtailed supply returns, which is highly uncertain. Looking beyond this phase, our bottom-up analysis of demand, allied to systematic field decline rates, points to a long run structural supply-demand gap. Considerable investment in conventional oil is going to be required to fill that gap and maintain market balance. If that investment is not forthcoming in a timely way, the possibility of oil prices increasing aggressively cannot be ruled out.

The Japan-Korea Marker price for **LNG** was extraordinarily volatile across the 2021 financial year. The market balance shifted from heavily over-supplied to extremely tight going into the Northern hemisphere winter. Since that time, prices have remained elevated relative to seasonal norms, with robust demand combined with ongoing supply outages. Longer term, we believe the commodity offers a combination of systematic base decline and an attractive demand trajectory. Within global gas, LNG is expected to gain share due to indigenous supply depletion and/or competitiveness vis-a-vis pipeline imports in some regions. Against this backdrop, assets advantaged by their proximity to existing infrastructure or customers, or both, in addition to competitive emissions intensities, are expected to be attractive.

Further information on BHP's economic and commodity outlook can be found at: bhp.com/prospects

Portfolio

Overview

Our strategy is to deliver long-term value and returns through the cycle. We aim to do this through owning a portfolio of world class assets with exposure to highly attractive commodities which benefit from the mega-trends playing out in the world around us, by operating them exceptionally well, by maintaining a disciplined approach to capital allocation and through being industry leaders in sustainability and the creation of social value.

We regularly review our portfolio to improve our asset base and optimise capital allocation decisions. We have simplified and strengthened our portfolio in recent years. We have invested through the cycle in high returning growth projects and continued to invest in options for future development and value creation in copper, nickel, oil, advantaged gas and potash through exploration, early stage investment and development, and innovation.

As the world continues to evolve, BHP is positioning itself to benefit from the mega-trends and through sustainability leadership.

To this end, today we have announced a major growth investment in the Jansen Stage 1 potash project, which is aligned with our strategy of growing our exposure to future facing commodities in world class assets, as well as our further plans to strengthen our portfolio, improve long-term value, provide choice for shareholders and to streamline our corporate structure, better enabling execution of our strategy.

These decisions will enable a greater allocation of capital in the portfolio to be directed towards future facing commodities and enhanced shareholder returns, as determined under our Capital Allocation Framework.

Approval of Jansen Stage 1 potash project

BHP has today approved US$5.7 billion (C$7.5 billion) in capital expenditure for the Jansen Stage 1 (Jansen S1) potash project in the province of Saskatchewan, Canada. Potash is a future facing commodity and Jansen S1 is aligned with BHP’s strategy of growing our exposure to future facing commodities in world class assets that are large, low cost and expandable.

Jansen S1 includes the design, engineering and construction of an underground potash mine and surface infrastructure including a processing facility, a product storage plant, and a continuous automated rail loading system. It also includes a Remote Operating Centre located in Saskatoon. Jansen S1 product will be shipped to export markets through Westshore, in Delta, British Columbia and the project includes funding for the required port infrastructure.

Jansen S1 was approved following a thorough evaluation of its risk and return metrics under our Capital Allocation Framework and it seeks to create long-term, sustainable value and returns for shareholders. Potash provides BHP with increased leverage to key global mega-trends including rising population, changing diets, decarbonisation and improving environmental stewardship. It will also give BHP diversity of product, customer and operating jurisdiction. The Jansen project also offers significant high returning growth optionality in the world’s best potash basin and an attractive investment jurisdiction.

Jansen S1 is expected to produce approximately 4.35 million tonnes of potash per annum[(iv)]. First ore is targeted in the 2027 calendar year, with construction expected to take approximately six years, followed by a ramp up period of two years. The Jansen S1 development incorporates the latest proven equipment and digital technologies, with a hard-to-replicate design and built in structural advantages. Jansen S1 is designed with a focus on sustainability, including a low carbon footprint and low water intensity embedded in the design.

As the world’s largest undeveloped potash deposit, future expansions at Jansen have been de-risked through the existing shaft capacity. This enables lower capital intensity, shorter execution duration and high-return brownfield expansions, with a basin position that could support a 100-year operation.

At consensus prices[(v)], the go-forward investment on Jansen S1 is expected to generate an internal rate of return of 12 to 14 per cent, an expected payback period of seven years from first production and an underlying EBITDA margin of approximately 70 per cent given its expected first quartile cost position.

We have previously acknowledged the US$4.5 billion (pre-tax) of capital invested to date has resulted in a significant initial outlay and that our approach would be different if considering the project again today. The investment to date includes construction of the shafts and associated infrastructure (US$2.97 billion[xiv] scope of work), as well as engineering and procurement activities, and preparation works related to Jansen S1 underground infrastructure. The construction of two shafts and associated infrastructure at the site is 93 per cent complete and expected to be finalised in the 2022 calendar year. To date approximately 50 per cent of all engineering required for Jansen S1 has also been completed, significantly de-risking the project. If the investment to date were to be included, the full cycle project would yield a much lower internal rate of return.

In addition to the investment approval, we have also assessed the carrying value of the existing potash asset base as at 30 June 2021 and have recognised a pre-tax impairment charge of US$1.3 billion (US$2.1 billion after-tax). The impairment will reduce the carrying value of the potash asset base to approximately US$3.3 billion. The impairment charge against our potash assets reflects analysis of recent market perspectives and the value that we would now expect a market participant to attribute to our investments to date.

Agreement to pursue a merger of Petroleum with Woodside

BHP announced today a merger proposal to combine its Petroleum (Petroleum) business with Woodside Petroleum Ltd (Woodside) (refer joint announcement, 17 August 2021).

BHP and Woodside have entered into a merger commitment deed to combine their respective oil and gas portfolios by an all-stock merger. The merger is subject to confirmatory due diligence, negotiation and execution of full form transaction documents which is targeted for October 2021, and satisfaction of conditions precedent including shareholder, regulatory and other approvals.

The proposed merger would create a global top 10 independent energy company by production, with a global top 10 position in the LNG industry, and would be the largest energy company listed on the ASX. It will give our shareholders greater choice about how to weight their exposure to the different investment propositions of BHP and Petroleum via Woodside.

With the combination of two high quality asset portfolios, the combined business will have a high margin oil portfolio, long life LNG assets and the financial resilience to help supply the energy needed for global growth and development over the energy transition.

The substantial benefits of the proposed merger for BHP’s shareholders is expected to include:

- greater scale and diversity of geographies, products and end markets through an attractive and long-life conventional portfolio;
- resilient, high margin operating cash flows to fund shareholder returns and business evolution to support the energy transition;
- strong growth profile with a plan to achieve targeted Scarborough FID in the 2021 calendar year and capacity to phase the most competitive, high-return options within the portfolio;
- proven management and technical capability from both companies;
- shared values and focus on sustainable operations, carbon management and ESG leadership;
- estimated synergies of more than US$400 million (100 per cent basis, pre-tax) per annum from optimising corporate processes and systems, leveraging combined capabilities and improving capital efficiency on future growth projects and exploration; and
- greater financial resilience, relative to BHP and Woodside’s standalone petroleum businesses.

Under the proposed transaction, Woodside or a wholly owned subsidiary of Woodside, will acquire 100 per cent of the issued share capital of BHP Petroleum International Pty Ltd in exchange for shares in Woodside, which will hold the combined business. The Woodside shares will be immediately distributed to BHP shareholders. On completion, it is expected Woodside would be owned approximately 52 per cent and 48 per cent by existing Woodside and BHP shareholders respectively. Woodside will remain listed on the ASX with listings on additional exchanges being considered. It is intended that the Woodside Board will appoint a current BHP director as a Woodside director on completion.

Both the BHP and Woodside Boards of directors confirm their support for the proposed merger. The merger is expected to be completed in the second quarter of the 2022 calendar year with an effective date of 1 July 2021.

The merger is subject to confirmatory due diligence, negotiation and execution of full form transaction documents which is targeted for October 2021, and satisfaction of conditions precedent including shareholder, regulatory and other approvals. Under the merger commitment deed, each party has agreed to pursue a merger transaction and agreed to certain exclusivity arrangements and to each pay a reimbursement fee of approximately US$160 million in certain circumstances.

Further information about the proposed merger with Woodside will be provided in due course.

In a separate arrangement, BHP and Woodside have committed to a plan towards Scarborough Final Investment Decision (FID) by the end of the 2021 calendar year, prior to the proposed completion date for the merger. As part of this plan, BHP and Woodside have agreed an option for BHP to divest its 26.5 per cent interest in the Scarborough Joint Venture (JV) to Woodside and its 50 per cent interest in the Thebe and Jupiter JVs to Woodside if the Scarborough JV takes a FID by 15 December 2021. The option is exercisable by BHP in the second half of the 2022 calendar year and if exercised, consideration of US$1 billion is payable to BHP with adjustment from an effective date of 1 July 2021. An additional US$100 million is payable contingent upon a future FID for a Thebe Development.

Intention to unify BHP's Dual Listed Company (DLC) Structure

BHP announced today that it intends to unify its DLC structure, subject to final Board and other approvals.

BHP's DLC structure has two parent companies (BHP Group Limited and BHP Group Plc) operating as a single economic entity and was established with the BHP and Billiton merger in 2001.

The rationale for and efficacy of the DLC structure have been subject to regular evaluation as the attraction of increased simplification has always been clear. Today's announced plans, combined with changes over recent years to our portfolio, a significant reduction in earnings contribution from Plc assets as well as a material reduction in the expected costs of unification, have prompted a renewed assessment of the continued suitability of the DLC structure.

The key benefits of unification comprise:

- a simplified corporate structure which reduces duplication, offers more efficient governance and internal processes and a single measure of value under a unified share register, and
- enhanced strategic flexibility for undertaking future portfolio changes.

A simplified corporate structure with a single unified share register

We have regularly sought to streamline and improve our corporate and governance processes. Unification would further simplify the BHP corporate structure and shareholder registers, reduce duplication and streamline our governance and internal processes.

Unification will enable one market capitalisation and one global pool of liquidity, with the same share trading via the Group's listings on the Australian, London and Johannesburg stock exchanges and its NYSE listed ADR program.

Unification will not change BHP's strong fundamentals. It will not change BHP's underlying assets or operations, workforce, executive leadership team, Board or cash flow generation. It will not change our dividend policy or ability to distribute fully franked dividends.

Enhanced strategic flexibility for undertaking future portfolio changes

As we position the company for the future operating environment, a unified structure will improve flexibility for portfolio reshaping to maximise value for shareholders over the long-term.

Certain equity based acquisitions, demergers and equity raisings will be able to be executed more efficiently. In the near-term, unification of the DLC would facilitate a simpler and more efficient separation of Petroleum.

Earnings contribution from Plc assets have significantly reduced

Plc's earnings have reduced over time relative to Limited's earnings, due to the divestment of assets previously held by Plc and changes in commodity prices. There have also been increases in overall BHP dividend payments. In recent years, Limited has paid significant dividends to Plc through the DLC Dividend Share. Plc has used the earnings generated by the DLC Dividend Share dividends to pay dividends to its shareholders that match the dividends paid to Limited shareholders. If unification does not occur, BHP expects that the ongoing earnings imbalance between Plc and Limited assets will result in Limited continuing to pay significant DLC Dividend Share dividends to Plc. Any DLC Dividend Share dividends paid by Limited must be franked to the same extent as regular Limited dividends and the franking credits that are attached to these dividends cannot be distributed by Plc to BHP shareholders. Unification will remove the DLC-related constraints on dividend arrangements and result in franked distributions being paid directly to all BHP shareholders.

Costs of unification have materially reduced

The expected costs associated with unification have significantly reduced as a result of portfolio and corporate structure changes in recent years, including BHP's settlement of the marketing dispute with the ATO and the recently updated assessment of the likelihood of recovering NSWEC associated tax losses. These changes represent a reduction in unification costs of approximately US$1.2 billion. One-off unification costs are now expected to range between US$400 to US$500 million. In comparison, in 2017 we assessed a loss of value of up to US$3 billion based on a single United Kingdom incorporated company. Under the transaction structure currently contemplated, the most significant component of these expected costs is related to stamp duties levied on Limited as a result of its acquisition of shares in Plc in order to implement unification.

Unification process and timing

Unification is subject to final Board approval, third party consents, regulatory, shareholder and court approvals.

Unification would involve Limited acquiring the shares of Plc and would be implemented by way of an English scheme of arrangement. Unification will require the approval of Plc and Limited shareholders voting separately and UK court approval. If unification is implemented, eligible Plc shareholders would be entitled to receive one Limited share for each Plc share they own. Following unification, both Limited and Plc shareholders would have the equivalent voting and economic interests in BHP as exist under the current DLC structure.

It is expected that a unified BHP would have its primary listing on the ASX, a standard listing on the LSE, a secondary listing on the JSE, and a sponsored Level II ADR program on the NYSE. A unified BHP would retain inclusion in the S&P/ASX indices. We have started engagement with FTSE Russell and understand that, based on their existing indexation methodology, a unified BHP would not qualify for inclusion in the FTSE UK Index Series. BHP's corporate and operational presence in Australia, the UK and other key locations are expected to remain unchanged. Following unification, BHP will retain its ongoing commitment to high corporate governance standards. The Board also intends to continue its practice of holding annual director elections.

If approved, unification is expected to occur in the first half of the 2022 calendar year, with the proposed Petroleum merger with Woodside to follow. Further information about the proposed unification of BHP's DLC structure will be provided in due course.

Update on our non-core coal divestment process

In August 2020, we announced plans to divest our interests in BHP Mitsui Coal[xv] (BMC), NSWEC and Cerrejón in order to focus our coal portfolio on higher quality metallurgical coals used in steelmaking.

In June 2021, we announced the signing of a Sale and Purchase Agreement to divest our 33.3 per cent interest in Cerrejón for US$294 million cash consideration. Subject to the satisfaction of customary competition and regulatory requirements, this is expected to complete in the second half of the 2022 financial year.

The process for BMC and NSWEC is progressing, in line with the two-year timeframe we set last year. We remain open to all options and continue consultation with relevant stakeholders.

A stronger and more competitive BHP

The plans we have announced today will help position BHP for the future. The investment and potential future growth in potash, coupled with the proposed merger of Petroleum with Woodside will result in a portfolio with greater net positive exposure to the mega-trends of decarbonisation and electrification. Copper, potash, nickel, and iron ore all stand to benefit from these trends, as does higher quality metallurgical coal in the near to medium term.

The proposed unification would further simplify the BHP corporate structure with a single share register. It would also improve strategic flexibility for increasing long-term portfolio exposure towards future facing commodities.

Following our investment in Jansen S1, the proposed separation of Petroleum and exit of our non-core coal assets, BHP will be focussed on high quality iron ore and metallurgical coal for the steel that is needed for infrastructure including for renewable energy; copper to support unprecedented demand for renewable energy; nickel for batteries; and potash to make food production and land use more efficient. We will also continue to create and secure further options in future facing commodities

We are a long-term focused company that creates value and returns over generations for our investors, partners and communities. We do this by striving to be excellent operators, by demonstrating industry leadership in sustainability, by maintaining a disciplined approach to capital allocation, and by ensuring exposure to commodities that benefit from the mega-trends playing out in the world around us.

Income statement

Underlying attributable profit and Underlying EBITDA are presented below.

Underlying attributable profit

Year ended 30 June	2021 US$M	2020 US$M
Profit after taxation attributable to BHP shareholders	11,304	7,956
Total exceptional items attributable to BHP shareholders(1)	5,773	1,104
Underlying attributable profit	**17,077**	**9,060**
Weighted basic average number of shares (million)	5,057	5,057
Underlying basic earnings per ordinary share	**337.7**	**179.2**

(1) Refer to page 25 and to note 2 ‘Exceptional items’ and note 8 ‘Significant events – Samarco dam failure’ of the Financial Information for further information.

Underlying EBITDA

Year ended 30 June	2021 US$M	2020 US$M
Profit from operations	25,906	14,421
Exceptional items included in profit from operations(1)	4,385	1,453
Underlying EBIT	**30,291**	**15,874**
Depreciation and amortisation expense	6,824	6,112
Net impairments	2,635	494
Exceptional item included in Depreciation, amortisation and impairments(2)	(2,371)	(409)
Underlying EBITDA	**37,379**	**22,071**

(1) Exceptional items loss of US$4,385 million excludes net finance costs of US$85 million related to the Samarco dam failure. Refer to page 25 and to note 2 ‘Exceptional items’ and note 8 ‘Significant events – Samarco dam failure’ of the Financial Information for further information.
(2) Relates to impairment charges in relation to NSWEC and Potash. Refer to page 25 and to note 2 ‘Exceptional items’.

Underlying EBITDA

The following table and commentary describes the impact of the principal factors(ii) that affected Underlying EBITDA for the 2021 financial year compared with the 2020 financial year:

	US$M	
Year ended 30 June 2020	**22,071**	
Net price impact:		
Change in sales prices	16,965	Higher average realised prices for iron ore, copper, nickel, oil, natural gas and thermal coal, partially offset by lower average realised prices for metallurgical coal and LNG.
Price-linked costs	(870)	Increased royalties reflect higher realised prices for iron ore and higher third party concentrate purchase costs reflect higher nickel prices, partially offset by lower royalties for petroleum and metallurgical coal.
	16,095	
Change in volumes	(312)	Record volumes at WAIO with strong performance across the supply chain, were offset by natural field decline at Petroleum. The expected lower grades at Escondida and Spence more than offset Escondida concentrator throughput maintained at record levels, the new stream of concentrate production from the Spence Growth Option that came online in December 2020 and highest annual copper production achieved at Olympic Dam since our acquisition in 2005. Lower volumes due to adverse weather impacts in the Gulf of Mexico (Petroleum) and NSWEC, combined with dragline maintenance and higher strip ratios at BMC. This was partially offset by the acquisition of the additional 28 per cent working interest at Shenzi and increased volumes at Nickel West following resource transition and major quadrennial maintenance shutdowns in the prior period.
Change in controllable cash costs:		
Operating cash costs	(34)	Higher inventory drawdowns at Olympic Dam due to stronger mill and smelter performance and at Nickel West as volumes increased following planned maintenance shutdowns in the prior period and additional costs associated with the ramp-up of South Flank. This was largely offset by strong cost performance supported by cost reduction initiatives across our assets, lower technology costs and a gain from the optimised outcome from renegotiation of cancelled power contracts at Escondida and Spence.
Exploration and business development	109	Lower exploration expenses due to lower seismic activity in Petroleum.
	75	
Change in other costs:		
Exchange rates	(1,588)	Impact of the stronger Australian dollar and Chilean peso against the US dollar.
Inflation	(286)	Impact of inflation on the Group's cost base.
Fuel and energy	223	Predominantly lower diesel prices at our minerals assets.
Non-Cash	282	Lower deferred stripping depletion at Escondida in line with planned development phase of the mines
One-off items	(122)	Volume loss across our operations due to COVID-19 restrictions, predominantly at our copper operations in Chile.
	(1,491)	
Asset sales	17	
Ceased and sold operations	242	Reflects the divestment of Neptune and a decrease in costs related to the closure and rehabilitation provision for closed mines of US$311 million(1) compared with the prior year.
Other items	682	Other includes higher average realised sales prices received by Antamina.
Year ended 30 June 2021	**37,379**	

(1) Closure and rehabilitation provision for closed mines adjustment charge to the income statement of US$301 million (FY20: US$612 million).

Prices and exchange rates

The average realised prices achieved for our major commodities are summarised below:

Average realised prices[1]	H2 FY21	H1 FY21	FY21	FY20	FY21 vs FY20	H2 FY21 vs H2 FY20	H2 FY21 vs H1 FY21
Oil (crude and condensate) (US$/bbl)	63.05	41.40	52.56	49.53	6%	68%	52%
Natural gas (US$/Mscf)[2]	4.86	3.83	4.34	4.04	7%	29%	27%
LNG (US$/Mscf)	7.04	4.45	5.63	7.26	(22%)	2%	58%
Copper (US$/lb)	4.34	3.32	3.81	2.50	52%	82%	31%
Iron ore (US$/wmt, FOB)	158.17	103.78	130.56	77.36	69%	106%	52%
Metallurgical coal (US$/t)	114.81	97.61	106.64	130.97	(19%)	(5%)	18%
Hard coking coal (HCC) (US$/t)[3]	118.54	106.30	112.72	143.65	(22%)	(11%)	12%
Weak coking coal (WCC) (US$/t)[3]	104.40	73.17	89.62	92.59	(3%)	24%	43%
Thermal coal (US$/t)[4]	70.83	44.35	58.42	57.10	2%	27%	60%
Nickel metal (US$/t)	17,537	15,140	16,250	13,860	17%	41%	16%

(1) Based on provisional, unaudited estimates. Prices exclude sales from equity accounted investments, third party product and internal sales, and represent the weighted average of various sales terms (for example: FOB, CIF and CFR), unless otherwise noted. Includes the impact of provisional pricing and finalisation adjustments.

(2) Includes internal sales.

(3) Hard coking coal (HCC) refers generally to those metallurgical coals with a Coke Strength after Reaction (CSR) of 35 and above, which includes coals across the spectrum from Premium Coking to Semi Hard Coking coals, while weak coking coal (WCC) refers generally to those metallurgical coals with a CSR below 35.

(4) Export sales only; excludes Cerrejón. Includes thermal coal sales from metallurgical coal mines.

In Copper, the provisional pricing and finalisation adjustments increased Underlying EBITDA by US$47 million in the 2021 financial year and are included in the average realised copper price in the above table.

The following exchange rates relative to the US dollar have been applied in the financial information:

	Average Year ended 30 June 2021	Average Year ended 30 June 2020	As at 30 June 2021	As at 30 June 2020	As at 30 June 2019
Australian dollar[1]	0.75	0.67	0.75	0.68	0.70
Chilean peso	746	771	735	816	680

(1) Displayed as US$ to A$1 based on common convention.

Depreciation, amortisation and impairments

Depreciation, amortisation and impairments excluding exceptional items increased by US$891 million to US$7.1 billion. This increase reflected higher depreciation and amortisation at Petroleum following a decrease in estimated remaining reserves at Bass Strait due to underperformance of the reservoir in the Turrum field and lower overall condensate and natural gas liquids (NGL) recovery from the Bass Strait gas fields, higher depreciation at WAIO due to a change in Yandi's life of mine and higher depreciation on right-of-use (lease) assets associated with index-linked freight contracts, including continuous voyage charters (CVCs), as a result of an increase in the prevailing freight index (Baltic C5 index).

Net finance costs

Net finance costs increased by US$394 million to US$1,305 million due to premiums of US$395 million paid as part of the value accretive multi-currency hybrid repurchase programs completed during the year.

Taxation expense

Year ended 30 June	2021 Profit before taxation US$M	2021 Income tax expense US$M	2021 %	2020 Profit before taxation US$M	2020 Income tax expense US$M	2020 %
Statutory effective tax rate	**24,601**	**(11,150)**	**45.3**	**13,510**	**(4,774)**	**35.3**
Adjusted for:						
Exchange rate movements	–	(95)		–	20	
Exceptional items[(1)]	4,470	1,327		1,546	(241)	
Adjusted effective tax rate	**29,071**	**(9,918)**	**34.1**	**15,056**	**(4,995)**	**33.2**

(1) Refer exceptional items below for further details.

The Group's adjusted effective tax rate, which excludes the impact of exchange rate movements and exceptional items, was 34.1 per cent (2020: 33.2 per cent). The adjusted effective tax rate is above 30 per cent and higher than at 30 June 2020 primarily as a result of higher withholding tax on dividends, driven by higher profitability from our Chilean operations, and current period losses which are not recoverable (including NSWEC and certain Petroleum exploration projects). The adjusted effective tax rate is expected to be in the range of 32 to 37 per cent for the 2022 financial year.

Other royalty and excise arrangements which are not profit based are recognised as operating costs within Profit before taxation. These amounted to US$3.2 billion during the period (2020: US$2.4 billion).

Exceptional items

The following table sets out the exceptional items for the 2021 financial year. Additional commentary is included on page 48.

Year ended 30 June 2021	Gross US$M	Tax US$M	Net US$M
Exceptional items by category			
Samarco dam failure	(1,087)	(71)	(1,158)
COVID-19 related costs	(546)	146	(400)
Impairment of Energy coal assets	(1,523)	(651)	(2,174)
Impairment of Potash assets	(1,314)	(751)	(2,065)
Total	**(4,470)**	**(1,327)**	**(5,797)**
Attributable to non-controlling interests	(34)	10	(24)
Attributable to BHP shareholders	(4,436)	(1,337)	(5,773)

Debt management and liquidity

BHP continues to optimise its balance sheet and debt position.

During the 2021 financial year, gross debt decreased by US$6.0 billion to US$21.0 billion at 30 June 2021. A US$2.8 billion reduction was achieved by the completion of two multi-currency hybrid repurchase programs: for US$1.7 billion on 17 September 2020 and US$1.1 billion on 23 November 2020. These programs were funded from surplus cash and were value accretive, with the reduction of future interest costs being higher than the premium paid to repurchase the targeted hybrid notes. An additional US$2.8 billion debt reduction came from the early redemption of hybrid notes including US$1.0 billion of 6.250 per cent hybrid notes on 19 October 2020, US$0.3 billion of 6.750 per cent hybrid notes on 30 December 2020 (the balance following the repurchase programs), and EUR€1.25 billion of 4.750 per cent hybrid notes on 22 April 2021. The redemptions were also completed using surplus cash.

At the subsidiary level, Escondida borrowed US$550 million to refinance maturing long-term debt during the 2021 financial year.

BHP continues to hold a robust liquidity position with US$15.2 billion in cash and cash equivalents. The Group also has a US$5.5 billion commercial paper program backed by a US$5.5 billion revolving credit facility, which expires in October 2025. As at 30 June 2021, the Group had no outstanding commercial paper and no drawn amount under the revolving credit facility.

Dividend

The BHP Board today determined to pay a final dividend of US$2.00 per share (US$10.1 billion). The final dividend to be paid by BHP Group Limited will be fully franked for Australian taxation purposes.

BHP's Dividend Reinvestment Plan (DRP) will operate in respect of the final dividend. Full terms and conditions of the DRP and details about how to participate can be found at: bhp.com

Events in respect of the final dividend	Date
Announcement of currency conversion into RAND	27 August 2021
Last day to trade cum dividend on Johannesburg Stock Exchange Limited (JSE)	31 August 2021
Ex-dividend Date JSE	1 September 2021
Ex-dividend Date (Australian Securities Exchange (ASX), London Stock Exchange (LSE) and New York Stock Exchange (NYSE[(1)]))	2 September 2021
Record Date	3 September 2021
DRP and Currency Election date (including announcement of currency conversion for ASX and LSE)	6 September 2021
Payment Date	21 September 2021
DRP Allocation Date (ASX and LSE) within 10 business days after the payment date	5 October 2021
DRP Allocation Date (JSE), subject to the purchase of shares by the Transfer Secretaries in the open market, Central Securities Depository Participant (CSDP) accounts credited/updated on or about[(2)]	5 October 2021

(1) BHP Group Limited and BHP Group Plc shares are listed in the form of American Depositary Shares (ADSs) and traded as American Depositary Receipts (ADRs) on the NYSE. Each ADS represents two ordinary shares.

(2) Computershare Investor Services (Pty) Limited as the Transfer Secretary will notify Strate and CSDPs when the price and allocation date is known.

BHP Group Plc shareholders registered on the South African section of the register will not be able to dematerialise or rematerialise their shareholdings between the dates of 1 September 2021 and 3 September 2021 (inclusive) and transfers between the UK register and the South African register will not be permitted between the dates of 27 August 2021 and 3 September 2021 (inclusive). Details of the currency exchange rates applicable for the dividend will be announced to the relevant stock exchanges following conversion and will appear on the Group's website.

Any eligible shareholder who wishes to participate in the DRP, or to vary a participation election should do so in accordance with the timetable above, or, in the case of shareholdings on the South African branch register of BHP Group Plc, in accordance with the instructions of your CSDP. The DRP Allocation Price will be calculated in each jurisdiction as an average of the price paid for each share actually purchased to satisfy DRP elections. The Allocation Price applicable to each exchange will made available at: bhp.com/DRP[(xvi)]

Corporate governance

Stefanie Wilkinson was appointed Group Company Secretary of BHP Group Limited and BHP Group Plc, effective from 1 March 2021.

As previously announced in December 2020, Susan Kilsby stepped down as the Chair of BHP's Remuneration Committee, effective 1 March 2021 and intends to retire as a BHP Director during the 2021 calendar year, and no later than the 2021 Annual General Meetings.

The current members of the Board's committees are:

Risk and Audit Committee	Nomination and Governance Committee	Remuneration Committee	Sustainability Committee
Terry Bowen (Chair) Xiaoqun Clever Ian Cockerill Anita Frew Christine O'Reilly	Ken MacKenzie (Chair) Terry Bowen Malcolm Broomhead Gary Goldberg (SID)[(1)] John Mogford Christine O'Reilly	Christine O'Reilly (Chair) Anita Frew Gary Goldberg (SID) Susan Kilsby Dion Weisler	John Mogford (Chair) Malcolm Broomhead Ian Cockerill Gary Goldberg (SID)

(1) Senior Independent Director (SID).

Segment summary[1]

A summary of performance for the 2021 and 2020 financial years is presented below.

Year ended 30 June 2021 US$M	Revenue[2]	Underlying EBITDA[3]	Underlying EBIT[3]	Exceptional items[4]	Net operating assets[3]	Capital expenditure	Exploration gross[5]	Exploration to profit[6]
Petroleum	3,946	2,300	433	(47)	7,964	994	322	382
Copper	15,726	8,489	6,809	(144)	26,928	2,180	53	53
Iron Ore	34,475	26,278	24,294	(1,319)	18,663	2,188	100	55
Coal	5,154	288	(577)	(1,567)	7,512	579	20	7
Group and unallocated items[7]	1,567	24	(668)	(1,308)	3,030	665	19	19
Inter-segment adjustment[8]	(51)	–	–	–	–	–	–	–
Total Group	**60,817**	**37,379**	**30,291**	**(4,385)**	**64,097**	**6,606**	**514**	**516**

Year ended 30 June 2020 (Restated) US$M	Revenue[2]	Underlying EBITDA[3]	Underlying EBIT[3]	Exceptional items	Net operating assets[3][9]	Capital expenditure	Exploration gross[5]	Exploration to profit[6]
Petroleum	4,070	2,207	750	(6)	8,247	909	564	394
Copper	10,666	4,347	2,590	(1,228)	25,357	2,434	54	54
Iron Ore	20,797	14,554	12,924	(614)	18,400	2,328	87	47
Coal	6,242	1,632	811	(18)	9,509	603	22	9
Group and unallocated items[7]	1,219	(669)	(1,201)	413	4,340	626	13	13
Inter-segment adjustment[8]	(63)	–	–	–	–	–	–	–
Total Group	**42,931**	**22,071**	**15,874**	**(1,453)**	**65,853**	**6,900**	**740**	**517**

(1) Group and segment level information is reported on a statutory basis which reflects the application of the equity accounting method in preparing the Group financial statements – in accordance with IFRS. Underlying EBITDA of the Group and the reportable segments, includes depreciation, amortisation and impairments (D&A), net finance costs and taxation expense of US$629 million (FY2020: US$446 million) related to equity accounted investments. It excludes exceptional items loss of US$990 million (FY2020: US$508 million loss) related to share of profit/loss from equity accounted investments, related impairments and expenses.

Group profit before taxation comprised Underlying EBITDA, exceptional items, depreciation, amortisation and impairments of US$11,473 million (FY2020: US$7,650 million) and net finance costs of US$1,305 million (FY2020: US$911 million).

(2) Revenue is based on Group realised prices and includes third party products. Sale of third party products by the Group contributed revenue of US$2,296 million and Underlying EBITDA of US$66 million (FY2020: US$1,171 million and US$32 million).

(3) For more information on the reconciliation of certain alternative performance measures to our statutory measures, reasons for usefulness and calculation methodology, please refer to alternative performance measures set on pages 62 and 72.

(4) Exceptional items loss of US$4,385 million excludes net finance costs of US$85 million included in the total loss before taxation of US$1,087 million related to the Samarco dam failure. Refer to note 2 'Exceptional items' and note 8 'Significant events – Samarco dam failure' of the Financial Information for further information.

(5) Includes US$84 million capitalised exploration (FY2020: US$223 million).

(6) Includes US$86 million of exploration expenditure previously capitalised, written off as impaired (included in depreciation and amortisation) (FY2020: US$ nil).

(7) Group and unallocated items includes functions, other unallocated operations including Potash, Nickel West, legacy assets, and consolidation adjustments. Revenue not attributable to reportable segments comprises the sale of freight and fuel to third parties, as well as revenues from unallocated operations. Exploration and technology activities are recognised within relevant segments.

(8) Comprises revenue of US$51 million generated by Petroleum (FY2020: US$62 million) and US$ nil generated by Coal (FY2020: US$1 million).

(9) Net operating assets has been restated to reflect changes to the Group's accounting policy following a decision by the IFRS Interpretations Committee on IAS 12 'Income Tax', resulting in the retrospective recognition of US$950 million of Goodwill at Olympic Dam. Note, an offsetting increase in Deferred tax liabilities of US$1,021 million which is not included in Net Operating Assets above. Refer to note 1 'Impact of new accounting standards and changes in accounting policies' of the Financial Information for further information.

Year ended 30 June 2021 US$M	Revenue	Underlying EBITDA[3]	D&A	Underlying EBIT[3]	Net operating assets[3]	Capital expenditure	Exploration gross	Exploration to profit
Potash	–	(167)	2	(169)	3,073	268	–	–
Nickel West	1,545	259	110	149	300	286	17	17

Year ended 30 June 2020 US$M	Revenue	Underlying EBITDA[3]	D&A	Underlying EBIT[3]	Net operating assets[3]	Capital expenditure	Exploration gross	Exploration to profit
Potash	–	(127)	3	(130)	4,068	201	–	–
Nickel West	1,189	(37)	71	(108)	60	254	13	13

Petroleum

Underlying EBITDA for Petroleum increased by US$93 million to US$2.3 billion in the 2021 financial year.

	US$M	
Underlying EBITDA for the year ended 30 June 2020	**2,207**	
Net price impact	257	Higher average realised oil and natural gas prices, partially offset by lower average realised LNG prices: Crude and condensate oil US$52.56/bbl (2020: US$49.53/bbl); Natural gas US$4.34/Mscf (2020: US$4.04/Mscf); and LNG US$5.63/Mscf (2020: US$7.26/Mscf).
Change in volumes: growth	(157)	Lower volumes due to natural field decline across the portfolio, impacts from a highly active hurricane season in the Gulf of Mexico and lower gas demand at Bass Strait. This was partially offset by the acquisition of the additional 28 per cent working interest in Shenzi, improved reliability at Bass Strait, stronger performance at North West Shelf, and higher domestic gas sales at Macedon.
Change in controllable cash costs	43	Lower discretionary maintenance activities at our Australian assets due to COVID-19 restrictions, offset by higher workover activity at Atlantis and restructuring costs related to improving future competitiveness. Lower exploration expenses reflects lower seismic activity, partially offset by increased business development activity in Mexico due to Trion progressing into pre-feasibility.
Ceased and sold operations	(62)	Revaluation of closure provisions of US$(110) million and sale of our interest in the Minerva Gas Plant in the prior year, partially offset by the divestment of Neptune.
Change in other costs:		
Exchange rates	29	
Inflation	(10)	
One-off items	(9)	Reflects volume loss related to COVID-19 from shutdown at Atlantis.
Other items	2	Other items include the revaluation of embedded derivatives in Trinidad and Tobago gas contract of US$59 million loss (2020: US$22 million loss), offset by tax barrel adjustments at Trinidad and Tobago and other items.
Underlying EBITDA for the year ended 30 June 2021	**2,300**	

Petroleum unit costs increased by 11 per cent to US$10.83 per barrel of oil equivalent primarily due to lower volumes and unfavourable exchange rate movements, partially offset by a reduction in price-linked costs. Unit costs in the 2022 financial year are expected to be between US$11 and US$12 per barrel (based on an exchange rate of AUD/USD 0.78) reflecting the impact of an increase in exchange rate and forecast higher price-linked costs. In the medium term, we expect an increase in unit costs to be maintained at less than US$13 per barrel (based on an exchange rate of AUD/USD 0.78) primarily as a result of natural field decline.

Petroleum unit costs (US$M)	H2 FY21	H1 FY21	FY21	FY20
Revenue	2,327	1,619	3,946	4,070
Underlying EBITDA	1,511	789	2,300	2,207
Gross costs	816	830	1,646	1,863
Less: exploration expense	115	181	296	394
Less: freight	78	29	107	110
Less: development and evaluation	90	106	196	166
Less: other(1)	(67)	(1)	(68)	131
Net costs	**600**	**515**	**1,115**	**1,062**
Production (MMboe, equity share)	53	50	103	109
Cost per Boe (US$)(2)(3)	**11.32**	**10.30**	**10.83**	**9.74**

(1) Other includes non-cash profit on sales of assets, inventory movements, foreign exchange, provision for onerous lease contracts and the impact from revaluation of embedded derivatives in the Trinidad and Tobago gas contract.

(2) FY21 based on an exchange rate of AUD/USD 0.75.

(3) FY21 excludes COVID-19 related costs of US$0.27 per barrel of oil equivalent that are reported as exceptional items.

During the 2021 financial year, we maintained our record of strong safety and operational performance while delivering several key milestones and outperforming our production and unit cost targets. We demonstrated capital discipline and strengthened our competitiveness through the counter-cyclical acquisition of an increased working interest in Shenzi, resulting in the addition of high margin barrels to the portfolio. We also accelerated our Shenzi infill drilling program to capture commodity price upside, simplified and restructured our organisational model, and continued to de-risk and improve the competitiveness of our growth options and future opportunities.

We also completed a transaction in May 2021 transferring our ownership interest in the operated Neptune asset in the Gulf of Mexico to EnVen Energy Ventures, LLC.

In the June 2021 quarter, drilling commenced on the second Shenzi infill well. Drilling of the first Shenzi infill well took place in March 2021, with production expected from both infill wells in the 2022 financial year.

On 5 August 2021, the Board approved the funding to develop the Shenzi North project, a two-well subsea tie-in to the Shenzi platform. First production is targeted for the 2024 calendar year. Additional plans for the 2022 financial year include advancing Trion into the Front End Engineering Design (FEED) phase, with competitive risk-weighted returns, and progressing the Calypso appraisal program, with the first appraisal well spud in late July 2021. Further targets include a potential Board decision on investment in the Scarborough gas development by the end of the 2021 calendar year, prior to the proposed completion date for the merger with Woodside, and expected first production from Mad Dog Phase 2 in the middle of the 2022 calendar year. Reflecting these projects, as well as natural field decline, average production is expected to increase to approximately 109 MMboe over the medium term.

Petroleum exploration

Petroleum exploration expenditure for the 2021 financial year was US$322 million, of which US$296 million was expensed. An approximately US$540 million exploration and appraisal program is planned for the 2022 financial year. This is an increase of approximately US$200 million and reflects drilling two Calypso appraisal wells in Trinidad and Tobago, and increased exploration drilling in the Gulf of Mexico.

In Trinidad and Tobago, we fulfilled our drilling commitments in the Southern licences with the drilling of the Broadside-1 exploration well in the first half of the 2021 financial year. The Transocean drilling rig arrived on location in our Northern licences in June 2021 and commenced drilling the first of the two Calypso gas appraisal wells in July 2021.

In Mexico, we commenced an Ocean Bottom Node seismic acquisition[xvii] over the Trion field on 9 November 2020, as part of our ongoing evaluation and analysis. The survey was completed in early January 2021 and the results will be incorporated into the current evaluation of the Trion opportunity. In addition, we received formal approval for a 124-day extension for the evaluation and exploration periods through 1 July 2021 and 1 July 2022 respectively, as a result of the suspension of activities in 2020 due to COVID-19.

In the US Gulf of Mexico, we expanded our acreage position through the acquisition of two blocks in the central regions and three blocks in the western region, aligned with our strategy of growing our Gulf of Mexico heartland.

In Eastern Canada, we have flexibility on timing with our two licences in the Orphan Basin, while evaluating the farm-out opportunities. The technical evaluation to support exploration well planning is ongoing.

Financial information for Petroleum for the 2021 and 2020 financial years is presented below.

Year ended 30 June 2021 US$M	Revenue[1]	Underlying EBITDA	D&A	Underlying EBIT	Net operating assets	Capital expenditure	Exploration gross[2]	Exploration to profit[3]
Australia Production Unit[4]	327	202	186	16	64	23		
Bass Strait	1,066	798	775	23	1,136	70		
North West Shelf	893	761	239	522	1,281	104		
Atlantis	560	401	162	239	1,109	178		
Shenzi	417	309	175	134	970	113		
Mad Dog	231	174	54	120	1,885	308		
Trinidad/Tobago	204	80	44	36	433	152		
Algeria	164	135	–	135	107	2		
Exploration	–	(296)	122	(418)	1,148	–		
Other[5]	85	(262)	113	(375)	(169)	44		
Total Petroleum from Group production	3,947	2,302	1,870	432	7,964	994		
Third party products	11	1	–	1	–	–		
Total Petroleum	3,958	2,303	1,870	433	7,964	994	322	382
Adjustment for equity accounted investments[6]	(12)	(3)	(3)	–	–	–	–	–
Total Petroleum statutory result	**3,946**	**2,300**	**1,867**	**433**	**7,964**	**994**	**322**	**382**

Year ended 30 June 2020 US$M	Revenue[1]	Underlying EBITDA	D&A	Underlying EBIT	Net operating assets	Capital expenditure	Exploration gross[2]	Exploration to profit[3]
Australia Production Unit[4]	361	253	197	56	289	6		
Bass Strait	1,102	761	449	312	1,796	87		
North West Shelf	1,076	731	260	471	1,261	130		
Atlantis	561	431	175	256	1,061	197		
Shenzi	277	174	139	35	550	45		
Mad Dog	216	164	64	100	1,551	375		
Trinidad/Tobago	191	92	46	46	323	46		
Algeria	159	111	12	99	60	16		
Exploration	–	(394)	41	(435)	1,227	(1)		
Other[5]	104	(111)	77	(188)	129	8		
Total Petroleum from Group production	4,047	2,212	1,460	752	8,247	909		
Third party products	39	(2)	–	(2)	–	–		
Total Petroleum	4,086	2,210	1,460	750	8,247	909	564	394
Adjustment for equity accounted investments[6]	(16)	(3)	(3)	–	–	–	–	–
Total Petroleum statutory result	**4,070**	**2,207**	**1,457**	**750**	**8,247**	**909**	**564**	**394**

(1) Total Petroleum statutory result revenue includes: crude oil US$2,013 million (FY2020: US$2,033 million), natural gas US$977 million (FY2020: US$980 million), LNG US$682 million (FY2020: US$774 million), NGL US$212 million (FY2020: US$198 million) and other US$62 million (FY2020: US$85 million) which includes third party products.

(2) Includes US$26 million of capitalised exploration (FY2020: US$170 million).

(3) Includes US$86 million of exploration expenditure previously capitalised, written off as impaired (included in depreciation and amortisation) (FY2020: US$ nil).

(4) Australia Production Unit includes Macedon, Pyrenees and Minerva (divested in December 2019).

(5) Predominantly divisional activities, business development and Neptune (sale finalised in May 2021). Also includes the Caesar oil pipeline and the Cleopatra gas pipeline, which are equity accounted investments. The financial information for the Caesar oil pipeline and the Cleopatra gas pipeline presented above, with the exception of net operating assets, reflects BHP's share.

(6) Total Petroleum statutory result revenue excludes US$12 million (FY2020: US$16 million) revenue related to the Caesar oil pipeline and the Cleopatra gas pipeline. Total Petroleum statutory result Underlying EBITDA includes US$3 million (FY2020: US$3 million) D&A related to the Caesar oil pipeline and the Cleopatra gas pipeline.

Copper

Underlying EBITDA for the 2021 financial year increased by US$4.1 billion to US$8.5 billion.

	US$M	
Underlying EBITDA for the year ended 30 June 2020	**4,347**	
Net price impact	4,336	Higher average realised price: Copper US$3.81/lb (2020: US$2.50/lb)
Change in volumes	(258)	Lower volumes at Escondida as concentrator throughput at record levels was more than offset by lower feed grade for both the concentrators and for stacking. Lower cathode sales at Spence as a result of grade decline and planned maintenance, partially offset by the new stream of concentrate production from the Spence Growth Option that came online in December 2020. Highest annual copper production at Olympic Dam reflected strong performance at the smelter and refinery compared with unplanned downtime at the smelter in the prior period.
Change in controllable cash costs	(106)	Higher inventory drawdowns at Olympic Dam, due to stronger mill and smelter performance compared to the prior period, and at Escondida to offset lower material mined during the period due to a reduced operational workforce. This was partially offset by strong cost performance at Escondida, a US$99 million gain from the optimised outcome from renegotiation of cancelled power contracts at Escondida and Spence, and favourable leach pad inventory movements at Escondida and Spence.
Change in other costs:		
Exchange rates	(477)	
Inflation	(136)	
Non-cash	273	Lower deferred stripping depletion at Escondida, reflecting the planned development phase of the mines.
One-off items	(97)	Copper cathodes volume loss at Escondida due to reduced operational workforce as a result of COVID-19.
Other items	607	Other includes increased profit from Antamina driven by higher realised copper and zinc prices, and favourable impacts from lower fuel and energy prices of US$75 million.
Underlying EBITDA for the year ended 30 June 2021	**8,489**	

Escondida unit costs decreased by one per cent to US$1.00 per pound, reflecting continued strong concentrator throughput, at record levels, as well as lower deferred stripping costs and higher by-product credits. This also reflects a one-off gain from the optimisation of a settlement outcome for the cancellation of power contracts as part of a shift towards 100 per cent renewable energy at Escondida. The strong unit cost result was achieved despite the impact of unfavourable exchange rate movements, a four per cent decline in copper concentrate feed grade and lower cathode volumes as a result of a reduced operational workforce due to COVID-19.

Unit costs in the 2022 financial year are expected to be between US$1.20 and US$1.40 per pound (based on an exchange rate of USD/CLP 727), reflecting expected lower by-product credits, forecast higher costs associated with an approximately 20 per cent increase in material mined required to catch up on mine development due to reduced material movement in the 2021 financial year and study costs to increase optionality at Escondida longer term. This also reflects the inclusion of COVID-19 costs (treated as an exceptional item in the 2021 financial year) and a further decline in concentrator feed grade of approximately two per cent. In the medium term, unit cost guidance remains unchanged at less than US$1.10 per pound (based on an exchange rate of USD/CLP 727).

Escondida unit costs (US$M)	H2 FY21	H1 FY21	FY21	FY20
Revenue	4,954	4,516	9,470	6,719
Underlying EBITDA	3,464	3,019	6,483	3,535
Gross costs	1,490	1,497	2,987	3,184
Less: by-product credits	206	272	478	407
Less: freight	83	79	162	178
Net costs	**1,201**	**1,146**	**2,347**	**2,599**
Sales (kt)	490	576	1,066	1,164
Sales (Mlb)	1,080	1,270	2,350	2,567
Cost per pound (US$)(1)(2)(3)	**1.11**	**0.90**	**1.00**	**1.01**

(1) FY21 based on an average exchange rate USD/CLP 746.

(2) FY21 excludes COVID-19 related costs of US$0.03 per pound that are reported as exceptional items.

(3) FY21 includes a gain from the optimised outcome from renegotiation of cancelled power contracts of US$0.04 per pound.

On 13 August 2021, Escondida successfully completed negotiations for a new collective agreement with the Union Nº1 of Operators and Maintainers, effective for 36 months from 2 August 2021.

The Spence Growth Option achieved first copper concentrate sales in the March 2021 quarter, after delivering first production in December 2020. Ramp-up to full production remains on track and is expected to be completed by December 2021 despite COVID-19 related impacts, including border restrictions preventing key personnel coming to site. Once ramp-up is completed, Spence is expected to average 300 ktpa of production (including cathodes) over the first four years of operation. The expansion will operate with 100 per cent desalinated water, following the commissioning of a new desalinated water plant, with capacity of 1,000 litres per second. In addition, we are looking at options to use 100 per cent desalinated water in our cathode operations. This follows Escondida's investment of more than US$4 billion in desalinated water capacity since 2006, which enabled it in December 2019 to eliminate drawdown of water from aquifers for operational supply, 10 years ahead of target.

In the 2022 financial year, Escondida and Spence will transition to four renewable power contracts to deliver operational flexibility, ensure security of supply and to reduce energy prices at both operations by approximately 20 per cent. We aim to supply Escondida and Spence's energy requirements from 100 per cent renewable energy sources by the mid-2020s.

Financial information for Copper for the 2021 and 2020 financial years is presented below.

Year ended 30 June 2021 US$M	Revenue	Underlying EBITDA	D&A	Underlying EBIT	Net operating assets	Capital expenditure	Exploration gross	Exploration to profit
Escondida(1)	9,470	6,483	969	5,514	11,926	666		
Pampa Norte(2)	1,801	954	390	564	4,510	678		
Antamina(3)	1,627	1,158	142	1,016	1,362	237		
Olympic Dam	2,211	598	313	285	9,045	830		
Other(3)(4)	–	(230)	10	(240)	85	7		
Total Copper from Group production	15,109	8,963	1,824	7,139	26,928	2,418		
Third party products	2,244	64	–	64	–	–		
Total Copper	17,353	9,027	1,824	7,203	26,928	2,418	62	58
Adjustment for equity accounted investments(5)	(1,627)	(538)	(144)	(394)	–	(238)	(9)	(5)
Total Copper statutory result	**15,726**	**8,489**	**1,680**	**6,809**	**26,928**	**2,180**	**53**	**53**

Year ended 30 June 2020 (Restated) US$M	Revenue	Underlying EBITDA	D&A	Underlying EBIT	Net operating assets	Capital expenditure	Exploration gross	Exploration to profit
Escondida(1)	6,719	3,535	1,143	2,392	12,013	919		
Pampa Norte(2)	1,395	599	316	283	3,187	955		
Antamina(3)	832	468	114	354	1,453	205		
Olympic Dam(6)	1,463	212	291	(79)	8,601	538		
Other(3)(4)	–	(202)	58	(260)	103	22		
Total Copper from Group production	10,409	4,612	1,922	2,690	25,357	2,639		
Third party products	1,089	41	–	41	–	–		
Total Copper	11,498	4,653	1,922	2,731	25,357	2,639	62	57
Adjustment for equity accounted investments(5)	(832)	(306)	(165)	(141)	–	(205)	(8)	(3)
Total Copper statutory result	**10,666**	**4,347**	**1,757**	**2,590**	**25,357**	**2,434**	**54**	**54**

(1) Escondida is consolidated under IFRS 10 and reported on a 100 per cent basis.

(2) Includes Spence and Cerro Colorado.

(3) Antamina, SolGold and Resolution are equity accounted investments and their financial information presented above with the exception of net operating assets reflects BHP Group's share.

(4) Predominantly comprises divisional activities, greenfield exploration and business development. Includes Resolution and SolGold.

(5) Total Copper statutory result revenue excludes US$1,627 million (FY2020: US$832 million) revenue related to Antamina. Total Copper statutory result Underlying EBITDA includes US$144 million (FY2020: US$165 million) D&A and US$394 million (FY2020: US$141 million) net finance costs and taxation expense related to Antamina, Resolution and SolGold that are also included in Underlying EBIT. Total Copper Capital expenditure excludes US$237 million (FY2020: US$205 million) related to Antamina and US$1 million (FY2020: US$ nil) related to SolGold. Exploration gross excludes US$9 million (FY2020: US$8 million) related to SolGold of which US$5 million (FY2020: US$3 million) was expensed.

(6) Net operating assets has been restated to reflect changes to the Group's accounting policy following a decision by the IFRS Interpretations Committee on IAS 12 'Income Tax', resulting in the retrospective recognition of US$950 million of Goodwill at Olympic Dam. Note, an offsetting increase in Deferred tax liabilities of US$1,021 million which is not included in Net Operating Assets above. Refer to note 1 'Impact of new accounting standards and changes in accounting policies' of the Financial Information for further information.

Iron Ore

Underlying EBITDA for the 2021 financial year increased by US$11.7 billion to US$26.3 billion.

	US$M	
Underlying EBITDA for the year ended 30 June 2020	**14,554**	
Net price impact:		
Change in sales prices	13,236	Higher average realised price: Iron ore US$130.56/wmt, FOB (2020: US$77.36/wmt, FOB).
Price-linked costs	(1,181)	Higher royalties in line with higher prices.
Change in volumes	148	Record sales volumes reflected record production at Jimblebar and Mining Area C, and strong operational performance across the supply chain, with continued improvements in car dumper performance and reliability and train cycle times.
Change in controllable cash costs	(43)	Incremental costs associated with the ramp up of South Flank, higher labour costs relating to increased planned maintenance and rail track stability activities throughout the year and an increase in the rehabilitation provision related to closed sites. This was partially offset by continuous improvement initiatives and favourable inventory movements.
Change in other costs:		
Exchange rates	(416)	
Inflation	(60)	
One-off items	(16)	Reflects volume loss related to COVID-19.
Other items	56	Other items include favourable impacts from lower fuel and energy prices of US$80 million, partially offset by other items.
Underlying EBITDA for the year ended 30 June 2021	**26,278**	

WAIO unit costs increased by 17 per cent to US$14.82 per tonne (or US$12.98 per tonne on a C1 basis excluding third party royalties(3)), due to the impact of a 12 per cent stronger Australian dollar, higher third party royalties, incremental costs relating to the ramp up of South Flank and higher labour costs relating to increased planned maintenance. This was partially offset by record volumes following strong performance and continued productivity improvements across the supply chain. Costs related to the impact from COVID-19 are reported as an exceptional item and are not included in unit costs. These additional costs were approximately US$0.51 per tonne, bringing WAIO unit costs to a total of US$15.33 per tonne (or US$13.23 per tonne on a C1 basis excluding third party royalties(2)(3)).

Unit costs in the 2022 financial year are expected to be between US$17.50 and US$18.50 per tonne reflecting updated guidance exchange rates (based on an exchange rate of AUD/USD 0.78), forecast costs associated with the ramp up of South Flank and ramp down of Yandi, and elevated third party royalties. This also reflects the inclusion of COVID-19 costs (treated as an exceptional item in the 2021 financial year). In the medium term, unit costs have been revised to less than US$16 per tonne predominantly reflecting a number of uncontrollable factors including updated guidance exchange rates (based on an exchange rate of AUD/USD 0.78), expected higher third party royalties and higher forecast diesel prices.

WAIO unit costs (US$M)	H2 FY21	H1 FY21	FY21	FY20
Revenue	20,345	13,992	34,337	20,663
Underlying EBITDA	16,050	10,220	26,270	14,508
Gross costs	4,295	3,772	8,067	6,155
Less: freight	929	826	1,755	1,459
Less: royalties	1,476	1,101	2,577	1,531
Net costs	**1,890**	**1,845**	**3,735**	**3,165**
Sales (kt, equity share)	123,779	128,273	252,052	250,598
Cost per tonne (US$)(1)(2)	**15.27**	**14.38**	**14.82**	**12.63**
Cost per tonne on a C1 basis excluding third party royalties (US$)(2)(3)	**13.52**	**12.46**	**12.98**	**11.82**

(1) FY21 based on an average exchange rate of AUD/USD 0.75.

(2) FY21 excludes COVID-19 related costs of US$0.51 per tonne (including US$0.25 per tonne relating to operations and US$0.26 per tonne of demurrage) that are reported as exceptional items. An additional US$0.12 per tonne relating to capital projects is also reported as an exceptional item.

(3) Excludes third party royalties of US$2.06 per tonne (FY20: US$1.17 per tonne), net inventory movements US$(1.11) per tonne (FY20: US$(0.61) per tonne), depletion of production stripping US$0.69 per tonne (FY20: US$0.63 per tonne), operational readiness costs relating to South Flank US$0.30 per tonne (FY20: US$0 per tonne), exploration expenses, Marketing purchases, demurrage, exchange rate gains/losses, and other income US$(0.10) per tonne (FY20: US$(0.38) per tonne).

Financial information for Iron Ore for the 2021 and 2020 financial years is presented below.

Year ended 30 June 2021 US$M	Revenue	Underlying EBITDA	D&A	Underlying EBIT	Net operating assets	Capital expenditure	Exploration gross(1)	Exploration to profit
Western Australia Iron Ore	34,337	26,270	1,959	24,311	21,289	2,186		
Samarco(2)	–	–	–	–	(2,794)	–		
Other(3)	120	7	25	(18)	168	2		
Total Iron Ore from Group production	34,457	26,277	1,984	24,293	18,663	2,188		
Third party products(4)	18	1	–	1	–	–		
Total Iron Ore	34,475	26,278	1,984	24,294	18,663	2,188	100	55
Adjustment for equity accounted investments	–	–	–	–	–	–	–	–
Total Iron Ore statutory result	**34,475**	**26,278**	**1,984**	**24,294**	**18,663**	**2,188**	**100**	**55**

Year ended 30 June 2020 US$M	Revenue	Underlying EBITDA	D&A	Underlying EBIT	Net operating assets	Capital expenditure	Exploration gross(1)	Exploration to profit
Western Australia Iron Ore	20,663	14,508	1,606	12,902	20,177	2,326		
Samarco(2)	–	–	–	–	(2,045)	–		
Other(3)	119	53	24	29	268	2		
Total Iron Ore from Group production	20,782	14,561	1,630	12,931	18,400	2,328		
Third party products(4)	15	(7)	–	(7)	–	–		
Total Iron Ore	20,797	14,554	1,630	12,924	18,400	2,328	87	47
Adjustment for equity accounted investments	–	–	–	–	–	–	–	–
Total Iron Ore statutory result	**20,797**	**14,554**	**1,630**	**12,924**	**18,400**	**2,328**	**87**	**47**

(1) Includes US$45 million of capitalised exploration (FY2020: US$40 million).

(2) Samarco is an equity accounted investment and its financial information presented above, with the exception of net operating assets, reflects BHP Billiton Brasil Ltda's share. All financial impacts following the Samarco dam failure have been reported as exceptional items in both reporting periods.

(3) Predominantly comprises divisional activities, towage services, business development and ceased operations.

(4) Includes inter-segment and external sales of contracted gas purchases.

Coal

Underlying EBITDA for the 2021 financial year decreased by US$1.3 billion to US$288 million.

	US$M	
Underlying EBITDA for the year ended 30 June 2020	**1,632**	
Net price impact	(655)	Lower average realised hard and weak coking coal prices, partially offset by slightly higher thermal coal prices: Hard Coking Coal US$112.72/t (2020: US$143.65/t); Weak Coking Coal US$89.62/t (2020: US$92.59/t); and Thermal Coal US$58.42/t (2020: $57.10/t).
Change in volumes	(168)	Lower volumes at NSWEC due to significant weather impacts and an increased proportion of washed coal in response to widening price quality differentials, consistent with our strategy to focus on higher quality products. Lower volumes at Queensland Coal as a result of dragline maintenance, higher strip ratios and lower yields at BMC.
Change in controllable cash costs	(102)	Increased maintenance costs at Queensland Coal (earth moving equipment maintenance and shiploader maintenance at Hay Point port) as well as increased stripping volumes. This was partially offset by cost reduction initiatives at both Queensland Coal and NSWEC.
Change in other costs:		
Exchange rates	(512)	
Inflation	(55)	
Other items	148	Other items include favourable impacts from lower fuel and energy prices of US$69 million and other items (predominantly higher profit from Cerrejón of US$54 million due to higher average realised prices).
Underlying EBITDA for the year ended 30 June 2021	**288**	

Queensland Coal unit costs increased by 21 per cent to US$82 per tonne due to the impact of a 12 per cent stronger Australian dollar, higher planned maintenance in the first half of the year, shiploader maintenance at Hay Point, and lower yields and increased stripping volumes at Poitrel and South Walker Creek. This was partially offset by lower fuel and energy costs, driven by lower diesel prices, and cost reduction initiatives.

Unit costs in the 2022 financial year are expected to be between US$80 and US$90 per tonne (based on an exchange rate of AUD/USD 0.78) as a result of expected higher diesel prices. Mine plan optimisation and efficiency uplifts are forecast to largely offset increased stripping requirements. We remain focused on cost reduction and productivity initiatives, however given the ongoing uncertainty regarding restrictions on coal imports into China we are unable to provide medium-term volume and unit cost guidance. We are preserving low-cost incremental growth optionality in our portfolio and we will continue with our market responsive approach to bringing on new tonnes into the markets.

Queensland Coal unit costs (US$M)	H2 FY21	H1 FY21	FY21	FY20
Revenue	2,459	1,856	4,315	5,357
Underlying EBITDA	534	59	593	1,935
Gross costs	1,925	1,797	3,722	3,422
Less: freight	24	45	69	147
Less: royalties	194	136	330	498
Net costs	**1,707**	**1,616**	**3,323**	**2,777**
Sales (kt, equity share)	21,589	19,030	40,619	41,086
Cost per tonne (US$)(1)(2)	**79.07**	**84.92**	**81.81**	**67.59**

(1) FY21 based on an average exchange rate of AUD/USD 0.75.

(2) FY21 excludes COVID-19 related costs of US$0.91 per tonne that are reported as exceptional items.

NSWEC unit costs increased by 14 per cent to US$64 per tonne due to the impact of a stronger Australian dollar and lower volumes as a result of significant weather impacts, higher strip ratios, an increased proportion of washed coal in response to widening price quality differentials and reduced port capacity following damage to a shiploader at the Newcastle port in November 2020. This was partially offset by lower fuel and energy costs, driven by lower diesel prices, as well as cost reduction initiatives.

Unit costs in the 2022 financial year are expected to be between US$62 and US$70 per tonne (based on an exchange rate of AUD/USD 0.78) reflecting a continued focus on higher quality products, mine plan optimisation, productivity improvements and cost reduction initiatives.

NSWEC unit costs (US$M)	H2 FY21	H1 FY21	FY21	FY20
Revenue	525	314	839	886
Underlying EBITDA	11	(180)	(169)	(79)
Gross costs	514	494	1,008	965
Less: royalties	41	25	66	68
Net costs	**473**	**469**	**942**	**897**
Sales (kt, equity share)	7,518	7,108	14,626	15,868
Cost per tonne (US$)[(1)(2)]	**62.92**	**65.98**	**64.41**	**56.53**

(1) FY21 based on an average exchange rate of AUD/USD 0.75.

(2) FY21 excludes COVID-19 related costs of US$0.40 per tonne that are reported as exceptional items.

Financial information for Coal for the 2021 and 2020 financial years is presented below.

Year ended 30 June 2021 US$M	Revenue	Underlying EBITDA	D&A	Underlying EBIT	Net operating assets	Capital expenditure	Exploration gross	Exploration to profit
Queensland Coal	4,315	593	735	(142)	7,843	512		
New South Wales Energy Coal[(1)]	927	(87)	144	(231)	(289)	50		
Colombia[(1)(5)]	281	74	86	(12)	–	21		
Other[(2)]	–	(122)	14	(136)	(42)	18		
Total Coal from Group production	5,523	458	979	(521)	7,512	601		
Third party products	–	–	–	–	–	–		
Total Coal	5,523	458	979	(521)	7,512	601	20	7
Adjustment for equity accounted investments[(3)(4)]	(369)	(170)	(114)	(56)	–	(22)	–	–
Total Coal statutory result	**5,154**	**288**	**865**	**(577)**	**7,512**	**579**	**20**	**7**

Year ended 30 June 2020 US$M	Revenue	Underlying EBITDA	D&A	Underlying EBIT	Net operating assets	Capital expenditure	Exploration gross	Exploration to profit
Queensland Coal	5,357	1,935	684	1,251	8,168	523		
New South Wales Energy Coal[(1)]	972	(19)	152	(171)	841	73		
Colombia[(1)]	364	69	112	(43)	776	24		
Other[(2)]	–	(155)	11	(166)	(276)	8		
Total Coal from Group production	6,693	1,830	959	871	9,509	628		
Third party products	–	–	–	–	–	–		
Total Coal	6,693	1,830	959	871	9,509	628	22	9
Adjustment for equity accounted investments[(3)(4)]	(451)	(198)	(138)	(60)	–	(25)	–	–
Total Coal statutory result	**6,242**	**1,632**	**821**	**811**	**9,509**	**603**	**22**	**9**

(1) Newcastle Coal Infrastructure Group and Cerrejón are equity accounted investments and their financial information presented above with the exception of net operating assets reflects BHP Group's share.

(2) Predominantly comprises divisional activities and ceased operations.

(3) Total Coal statutory result revenue excludes US$281 million (FY2020: US$364 million) revenue related to Cerrejón. Total Coal statutory result Underlying EBITDA includes US$86 million (FY2020: US$112 million) D&A and US$2 million (FY2020: US$25 million) net finance costs and taxation expense related to Cerrejón, that are also included in Underlying EBIT. Total Coal statutory result Capital expenditure excludes US$21 million (FY2020: US$24 million) related to Cerrejón.

(4) Total Coal statutory result revenue excludes US$88 million (FY2020: US$87 million) revenue related to Newcastle Coal Infrastructure Group. Total Coal statutory result excludes US$82 million (FY2020: US$61 million) Underlying EBITDA, US$28 million (FY2020: US$26 million) D&A and US$54 million (FY2020: US$35 million) Underlying EBIT related to Newcastle Coal Infrastructure Group until future profits exceed accumulated losses. Total Coal Capital expenditure excludes US$1 million (FY2020: US$1 million) related to Newcastle Coal Infrastructure Group.

(5) On 28 June 2021, BHP announced that it had signed a Sale and Purchase Agreement with Glencore to divest its 33.3 per cent interest in Cerrejón. While BHP continued to report its share of profit and loss within the Coal segment and asset tables, the Group's investment of US$284 million in Cerrejón has subsequently been classified as 'Assets held for sale' and therefore excluded from net operating assets.

Greenfield minerals exploration

BHP continued to strengthen its portfolio of options in future facing commodities. During the 2021 financial year, greenfield minerals exploration was undertaken on advancing copper targets in Chile, Ecuador, Mexico, Peru, Canada, Australia and the south-west United States, and nickel targets in Canada and Australia.

Specifically in copper, we are undertaking target drilling in Chile, Ecuador, Peru and the United States, while further drilling is planned in the coming year in Australia and Mexico. BHP exercised its option to sign a farm-in agreement with Encounter Resources for the early-stage Elliott copper project in Australia (May 2021). At Oak Dam in South Australia, next stage resource definition drilling to inform future design commenced in May 2021.

Our nickel optionality has grown substantively over the last 18 months, and drilling is currently underway on our extensive “Seahorse” land package on southern Western Australia. Elsewhere, we signed an agreement for a nickel exploration alliance with Midland Exploration in Canada (August 2020) and we completed the acquisition of the nickel Honeymoon Well tenements and a 50 per cent interest in the Albion Downs North and Jericho exploration joint ventures (September 2020).

In addition, on 27 July 2021, we entered into a definitive Support Agreement with Noront Resources (Noront) to make an all-cash takeover offer for Noront. The Noront Board of Directors has unanimously recommended the offer to Noront shareholders. Noront owns an extensive land package that includes the Eagle’s Nest nickel and copper deposit in the James Bay Lowlands, Ontario, in an emerging metals area known as the Ring of Fire.

Our Metals Exploration and Petroleum Exploration teams are collaborating on a global machine learning initiative that we anticipate will further create new insights on high-potential search spaces. This partnership is unlocking previously unrealised synergies that will further allow BHP to define options in future facing commodities.

Group and unallocated items

Underlying EBITDA for Group and unallocated items increased by US$693 million to US$24 million in the 2021 financial year due to an increase in EBITDA at Nickel West, higher freight rates for consecutive voyage charter (CVC) voyages on-charged to the businesses, lower technology costs reflecting changes to the technology organisational model in the prior year and a decrease in costs related to the closure and rehabilitation provision for closed mines compared with the prior year.

Nickel West’s Underlying EBITDA increased from a loss of US$(37) million to US$259 million for the 2021 financial year, reflecting higher prices and volumes, and lower maintenance costs following the major quadrennial shutdowns in the prior year, as well as lower contractor costs following the transition and ramp up of new mines. This was partially offset by unfavourable exchange rate movements and the adverse impacts of the stronger nickel price on third party concentrate purchase costs.

Commissioning of the Nickel Sulphate plant is now underway, with first production expected in the September 2021 quarter.

The Financial Information set out on pages 41 to 61 for the year ended 30 June 2021 has been prepared on the basis of accounting policies and methods of computation consistent with those applied in the 30 June 2020 financial statements contained within the Annual Report of the Group, with the exception of new accounting standards and interpretations which became effective from 1 July 2020 and other changes in accounting policies applied with effect from 1 July 2020. This news release including the Financial Information is unaudited. Analysis relates to the relative financial and/or production performance of BHP and/or its operations during the 2021 financial year compared with the 2020 financial year, unless otherwise noted. Operations includes operated and non-operated assets, unless otherwise noted. Medium term refers to our five year plan. Numbers presented may not add up precisely to the totals provided due to rounding.

The following abbreviations may have been used throughout this report: barrels (bbl); billion cubic feet (bcf); barrels of oil equivalent (boe); billion tonnes (Bt); cost and freight (CFR); cost, insurance and freight (CIF), carbon dioxide equivalent (CO2-e), dry metric tonne unit (dmtu); free on board (FOB); giga litres (GL); grams per tonne (g/t); kilograms per tonne (kg/t); kilometre (km); metre (m); million barrels of oil equivalent (MMboe); million barrels of oil equivalent per day (MMboe/d); thousand cubic feet equivalent (Mcfe); million cubic feet per day (MMcf/d); million ounces per annum (Mozpa); million pounds (Mlb); million tonnes (Mt); million tonnes per annum (Mtpa); ounces (oz); pounds (lb); thousand barrels of oil equivalent (Mboe); thousand ounces (koz); thousand ounces per annum (kozpa); thousand standard cubic feet (Mscf); thousand tonnes (kt); thousand tonnes per annum (ktpa); thousand tonnes per day (ktpd); tonnes (t); total recordable injury frequency (TRIF); and wet metric tonnes (wmt).

The following footnotes apply to this Results Announcement:

(i) We use various key indicators to reflect our sustainability performance. For further information on the reasons for usefulness and calculation methodology, please refer to “Definition and calculation of Key Indicator terms” set out on pages 73 to 77.

(ii) We use various alternative performance measures to reflect our underlying performance. For further information on the reconciliations of certain alternative performance measures to our statutory measures, reasons for usefulness and calculation methodology, please refer to alternative performance measures set out on pages 62 to 72.

(iii) On a continuing operations basis.

(iv) The Jansen S1 project will convert approximately 20 per cent of the total 5.23 billion tonnes Measured and Indicated Mineral Resources into Ore Reserves (see separate announcement dated 17 August 2021).

(v) Price assumptions reflect average of CRU and Argus prices. Average 2027–2037: US$341/t CRU and US$292/t Argus. IRR = Expected Jansen S1 IRR (across approximately 100 year mine life). Jansen S1 IRR is post tax, nominal and reflects the range of the average CRU and Argus prices and excludes expenditure on shafts and essential services consistent with previous disclosure.

(vi) Per million hours worked, compared to the 2020 financial year.

(vii) Our 1.5°C scenario, described with its assumptions and outputs in our Climate Change Report 2020 (available at bhp.com), is an attractive scenario for us, our shareholders and the global community. However, despite recent progress, all 1.5°C pathways represent a major departure from today’s global trajectory.

(viii) ‘Freshwater’ is defined as waters other than seawater, wastewater from third parties and hypersaline ground water. Freshwater withdrawal also excludes entrained water that would not be available for other uses. These exclusions have been made to align with the target’s intent to reduce the use of freshwater sources of potential value other users or the environment.

(ix) Source: worldsteel.org; BHP analysis

(x) Amounts spent are converted to USD based on actual transactional (historical) exchange rates related to Renova Foundation funding. Amounts yet to be spent are converted to USD based on 30 June 2021 exchange rates.

(xi) This includes more than 17,000 claims settled under the court-mandated “Novel payment” system that was established in August 2020. The system now covers 30 impacted territories (up from 14 territories). More than 10,500 general damages claims have been resolved, in addition to approximately 270,000 claims for temporary interruption to water supplies immediately following the dam failure. The Renova Foundation has continued to assist more than 10,500 families with ongoing financial support.

(xii) Resettlement remains a priority social program for the Renova Foundation and involves ongoing engagement and consultation with many stakeholders. Resettlement works in the municipality of Mariana are continuing with COVID-19 protocols in place. At Bento Rodrigues, civil works and the healthcare facility are complete, while the public school construction is complete and construction of housing is progressing (with 79 houses either complete or under construction). At Paracatu, infrastructure works and the construction of some public buildings and the first houses are underway. At Gesteira, the Renova Foundation is progressing alternatives to urban resettlement, with an option for individual resettlement in which families from the original small community would be able to purchase individual properties.

(xiii) Maintenance capital includes non-discretionary spend for the following purposes: deferred development and production stripping; risk reduction, compliance and asset integrity.

(xiv) The US$2.97 billion current scope of work for Jansen is part of approximately US$4.5 billion that has been invested on the project since 2008 ahead of the sanction decision on Jansen S1. Approximately US$220 million of the US$2.97 billion approved for the current scope of work, expected to be completed in the 2022 calendar year, is not yet spent. Sustaining capital for Jansen S1 is expected to be approximately US$15/t (real) long term average +/- 20 per cent in any given year.

(xv) BHP’s respective interests in BMC.

(xvi) In the case of BHP Group Limited, the allocation price will also be released via the ASX using Appendix 3A.1 in accordance with ASX requirements.

(xvii) Permit: EIA - ASEA/UGI/DGGEERNCM/0122/2018, expedient 28TM2018X0042. CNH Revised Appraisal Plan Approval – Resolucion CNH.14.001/2020.

Forward-looking statements

This release contains forward-looking statements, including statements regarding: trends in commodity prices and currency exchange rates; demand for commodities; production forecasts; operational performance; plans, strategies and objectives of management; closure or divestment of certain assets, operations or facilities (including associated costs); anticipated production or construction commencement dates; capital costs and scheduling; operating costs and shortages of materials and skilled employees; anticipated productive lives of projects, mines and facilities; provisions and contingent liabilities; and tax and regulatory developments.

Forward-looking statements may be identified by the use of terminology, including, but not limited to, ‘guidance’, ‘intend’, ‘aim’, ‘project’, ‘anticipate’, ‘estimate’, ‘plan’, ‘believe’, ‘expect’, ‘may’, ‘should’, ‘will’, ‘would’, ‘continue’, ‘annualised’ or similar words. These statements discuss future expectations concerning the results of assets or financial conditions, or provide other forward-looking information.

These forward-looking statements are based on the information available as at the date of this release and/or the date of the Group's planning processes or scenario analysis processes. There are inherent limitations with scenario analysis and it is difficult to predict which, if any, of the scenarios might eventuate. Scenarios do not constitute definitive outcomes for us. Scenario analysis relies on assumptions that may or may not be, or prove to be, correct and may or may not eventuate, and scenarios may be impacted by additional factors to the assumptions disclosed. Additionally, forward looking statements in this release are not guarantees or predictions of future performance, and involve known and unknown risks, uncertainties and other factors, many of which are beyond our control, and which may cause actual results to differ materially from those expressed in the statements contained in this release. BHP cautions against reliance on any forward-looking statements or guidance, particularly in light of the current economic climate and the significant volatility, uncertainty and disruption arising in connection with COVID-19.

For example, our future revenues from our assets, projects or mines described in this release will be based, in part, upon the market price of the minerals, metals or petroleum produced, which may vary significantly from current levels. These variations, if materially adverse, may affect the timing or the feasibility of the development of a particular project, the expansion of certain facilities or mines, or the continuation of existing assets.

Other factors that may affect the actual construction or production commencement dates, costs or production output and anticipated lives of assets, mines or facilities include our ability to profitably produce and transport the minerals, petroleum and/or metals extracted to applicable markets; the impact of foreign currency exchange rates on the market prices of the minerals, petroleum or metals we produce; activities of government authorities in the countries where we sell our products and in the countries where we are exploring or developing projects, facilities or mines, including increases in taxes; changes in environmental and other regulations, the duration and severity of the COVID-19 pandemic and its impact on our business; political uncertainty; labour unrest; and other factors identified in the risk factors discussed in BHP's filings with the U.S. Securities and Exchange Commission (the 'SEC') (including in Annual Reports on Form 20-F) which are available on the SEC's website at www.sec.gov.

Except as required by applicable regulations or by law, BHP does not undertake to publicly update or review any forward-looking statements, whether as a result of new information or future events.

Past performance cannot be relied on as a guide to future performance.

No offer of securities

Nothing in this release should be construed as either an offer, or a solicitation of an offer, to buy or sell any securities, or a solicitation of any vote or approval, in any jurisdiction, or be treated or relied upon as a recommendation or advice by BHP. No offer of securities shall be made in the United States absent registration under the U.S. Securities Act of 1933, as amended, or pursuant to an exemption from, or in a transaction not subject to, such registration requirements.

Reliance on third party information

The views expressed in this release contain information that has been derived from publicly available sources that have not been independently verified. No representation or warranty is made as to the accuracy, completeness or reliability of the information. This release should not be relied upon as a recommendation or forecast by BHP.

No financial or investment advice – South Africa

BHP does not provide any financial or investment 'advice' as that term is defined in the South African Financial Advisory and Intermediary Services Act, 37 of 2002, and we strongly recommend that you seek professional advice.

BHP and its subsidiaries

In this release, the terms 'BHP', the 'Company, the 'Group', 'BHP Group', 'our business', 'organisation', 'we', 'us', 'our' and ourselves' refer to BHP Group Limited, BHP Group plc and, except where the context otherwise requires, their respective subsidiaries as defined in note 29 'Subsidiaries' in section 5.1 of BHP's 30 June 2020 Annual Report and Form 20-F. Those terms do not include non-operated assets.

This release covers BHP's assets (including those under exploration, projects in development or execution phases, sites and closed operations) that have been wholly owned and/or operated by BHP and that have been owned as a joint venture[(1)] operated by BHP (referred to in this release as 'operated assets' or 'operations') during the period from 1 July 2020 to 30 June 2021. Our functions are also included.

BHP also holds interests in assets that are owned as a joint venture but not operated by BHP (referred to in this release as 'non-operated joint ventures' or 'non-operated assets'). Our non-operated assets include Antamina, Cerrejón, Samarco, Atlantis, Mad Dog, Bass Strait and North West Shelf. Notwithstanding that this release may include production, financial and other information from non-operated assets, non-operated assets are not included in the BHP Group and, as a result, statements regarding our operations, assets and values apply only to our operated assets unless stated otherwise.

(1) References in this release to a 'joint venture' are used for convenience to collectively describe assets that are not wholly owned by BHP. Such references are not intended to characterise the legal relationship between the owners of the asset.

Further information on BHP can be found at **bhp.com**

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BHP Financial Information

Year ended 30 June 2021

Contents

The Financial Information included in this document for the year ended 30 June 2021 is unaudited and has been derived from the draft Financial Report of the Group for the year ended 30 June 2021. The Financial Information does not constitute the Group's full statutory accounts for the year ended 30 June 2021, which will be approved by the Board, reported on by the auditors, and subsequently filed with the UK Registrar of Companies and the Australian Securities and Investments Commission.

The Financial Information set out on pages 41 to 61 for the year ended 30 June 2021 has been prepared on the basis of accounting policies and methods of computation consistent with those applied in the 30 June 2020 Financial Statements contained within the Annual Report of the Group, with the exception of the following:

- Adoption of amendments to existing accounting standards and interpretations which became effective from 1 July 2020;
- Adoption of the revised Conceptual Framework for Financial Reporting which became effective from 1 July 2020;
- Early adoption of amendments to specific International Financial Reporting Standards relating to 'Interest Rate Benchmark (IBOR) Reform – Phase 2;
- Changes to the Group's accounting policy for deferred taxes applied from 1 July 2020.

Note 1 'Impact of new accounting standards and interpretations and changes in accounting policies' describes the impact of the above in this Financial Information.

The comparative figures for the financial years ended 30 June 2020 and 30 June 2019 are not the statutory accounts of the Group for those financial years. Those accounts have been reported on by the company's auditor (at the relevant time) and delivered to the Registrar of Companies. The reports of the auditor were (i) unqualified, (ii) did not include a reference to any matters to which the auditor drew attention by way of emphasis without qualifying the reports and (iii) did not contain a statement under Section 498(2) or (3) of the UK Companies Act 2006.

All amounts are expressed in US dollars unless otherwise noted. The Group's presentation currency and the functional currency of the majority of its operations is US dollars as this is the principal currency of the economic environment in which it operates. Amounts in this Financial Information have, unless otherwise indicated, been rounded to the nearest million dollars.

The Group has made an assessment of its ability to continue as a going concern over the period to 30 September 2022 (the 'going concern' period) and considers it appropriate to adopt the going concern basis of accounting in preparing this Financial Information. Where applicable, comparative periods have been adjusted to disclose them on the same basis as the current period figures.

Consolidated Income Statement for the year ended 30 June 2021

	Notes	2021 US$M	2020 US$M	2019 US$M
Continuing operations				
Revenue		**60,817**	42,931	44,288
Other income		**510**	777	393
Expenses excluding net finance costs		**(34,500)**	(28,775)	(28,022)
Loss from equity accounted investments, related impairments and expenses	3	**(921)**	(512)	(546)
Profit from operations		**25,906**	14,421	16,113
Financial expenses		**(1,378)**	(1,262)	(1,510)
Financial income		**73**	351	446
Net finance costs	4	**(1,305)**	(911)	(1,064)
Profit before taxation		**24,601**	13,510	15,049
Income tax expense		**(10,921)**	(4,708)	(5,335)
Royalty-related taxation (net of income tax benefit)		**(229)**	(66)	(194)
Total taxation expense	5	**(11,150)**	(4,774)	(5,529)
Profit after taxation from Continuing operations		**13,451**	8,736	9,520
Discontinued operations				
Loss after taxation from Discontinued operations		**–**	–	(335)
Profit after taxation from Continuing and Discontinued operations		**13,451**	8,736	9,185
Attributable to non-controlling interests		**2,147**	780	879
Attributable to BHP shareholders		**11,304**	7,956	8,306
Basic earnings per ordinary share (cents)	6	**223.5**	157.3	160.3
Diluted earnings per ordinary share (cents)	6	**223.0**	157.0	159.9
Basic earnings from Continuing operations per ordinary share (cents)	6	**223.5**	157.3	166.9
Diluted earnings from Continuing operations per ordinary share (cents)	6	**223.0**	157.0	166.5

The accompanying notes form part of this Financial Information.

Consolidated Statement of Comprehensive Income for the year ended 30 June 2021

	2021 US$M	2020 US$M	2019 US$M
Profit after taxation from Continuing and Discontinued operations	**13,451**	8,736	9,185
Other comprehensive income			
<u>Items that may be reclassified subsequently to the income statement:</u>			
Hedges:			
Gains/(losses) taken to equity	**863**	(315)	(327)
(Gains)/losses transferred to the income statement	**(837)**	297	299
Exchange fluctuations on translation of foreign operations taken to equity	**5**	1	1
Exchange fluctuations on translation of foreign operations transferred to income statement	**–**	–	(6)
Tax recognised within other comprehensive income	**(8)**	5	8
Total items that may be reclassified subsequently to the income statement	**23**	(12)	(25)
<u>Items that will not be reclassified to the income statement:</u>			
Re-measurement gains/(losses) on pension and medical schemes	**58**	(81)	(20)
Equity investments held at fair value	**(2)**	(2)	1
Tax recognised within other comprehensive income	**(20)**	26	19
Total items that will not be reclassified to the income statement	**36**	(57)	–
Total other comprehensive income/(loss)	**59**	(69)	(25)
Total comprehensive income	**13,510**	8,667	9,160
Attributable to non-controlling interests	**2,158**	769	878
Attributable to BHP shareholders	**11,352**	7,898	8,282

The accompanying notes form part of this Financial Information.

Consolidated Balance Sheet as at 30 June 2021

	Notes	2021 US$M	2020 US$M Restated
ASSETS			
Current assets			
Cash and cash equivalents		**15,246**	13,426
Trade and other receivables		**6,059**	3,364
Other financial assets		**230**	84
Inventories		**4,426**	4,101
Assets held for sale	3	**324**	–
Current tax assets		**279**	366
Other		**129**	130
Total current assets		**26,693**	21,471
Non-current assets			
Trade and other receivables		**337**	267
Other financial assets		**1,610**	2,522
Inventories		**1,358**	1,221
Property, plant and equipment		**73,813**	72,362
Intangible assets	1	**1,437**	1,574
Investments accounted for using the equity method		**1,742**	2,585
Deferred tax assets		**1,912**	3,688
Other		**25**	43
Total non-current assets		**82,234**	84,262
Total assets		**108,927**	105,733
LIABILITIES			
Current liabilities			
Trade and other payables		**7,027**	5,767
Interest bearing liabilities		**2,628**	5,012
Liabilities directly associated with the assets held for sale	3	**17**	–
Other financial liabilities		**130**	225
Current tax payable		**2,800**	913
Provisions		**3,696**	2,810
Deferred income		**105**	97
Total current liabilities		**16,403**	14,824
Non-current liabilities			
Trade and other payables		**–**	1
Interest bearing liabilities		**18,355**	22,036
Other financial liabilities		**1,146**	1,414
Non-current tax payable		**120**	109
Deferred tax liabilities	1	**3,314**	3,779
Provisions		**13,799**	11,185
Deferred income		**185**	210
Total non-current liabilities		**36,919**	38,734
Total liabilities		**53,322**	53,558
Net assets		**55,605**	52,175
EQUITY			
Share capital – BHP Group Limited		**1,111**	1,111
Share capital – BHP Group Plc		**1,057**	1,057
Treasury shares		**(33)**	(5)
Reserves		**2,350**	2,306
Retained earnings	1	**46,779**	43,396
Total equity attributable to BHP shareholders		**51,264**	47,865
Non-controlling interests		**4,341**	4,310
Total equity		**55,605**	52,175

The accompanying notes form part of this Financial Information.

Consolidated Cash Flow Statement for the year ended 30 June 2021

	2021 US$M	2020 US$M	2019 US$M
Operating activities			
Profit before taxation	**24,601**	13,510	15,049
Adjustments for:			
Depreciation and amortisation expense	**6,824**	6,112	5,829
Impairments of property, plant and equipment, financial assets and intangibles	**2,635**	494	264
Net finance costs	**1,305**	911	1,064
Loss from equity accounted investments, related impairments and expenses	**921**	512	546
Other	**348**	720	308
Changes in assets and liabilities:			
Trade and other receivables	**(2,723)**	291	(211)
Inventories	**(447)**	(715)	298
Trade and other payables	**1,201**	(755)	406
Provisions and other assets and liabilities	**501**	1,188	(125)
Cash generated from operations	**35,166**	22,268	23,428
Dividends received	**753**	137	516
Interest received	**97**	385	443
Interest paid	**(771)**	(1,225)	(1,346)
(Settlements)/proceeds of cash management related instruments	**(401)**	85	296
Net income tax and royalty-related taxation refunded	**407**	48	59
Net income tax and royalty-related taxation paid	**(8,017)**	(5,992)	(5,999)
Net operating cash flows from Continuing operations	**27,234**	15,706	17,397
Net operating cash flows from Discontinued operations	**–**	–	474
Net operating cash flows	**27,234**	15,706	17,871
Investing activities			
Purchases of property, plant and equipment	**(6,606)**	(6,900)	(6,250)
Exploration expenditure	**(514)**	(740)	(873)
Exploration expenditure expensed and included in operating cash flows	**430**	517	516
Investment in subsidiaries, operations and joint operations, net of cash	**(480)**	–	–
Net investment and funding of equity accounted investments	**(578)**	(618)	(630)
Proceeds from sale of assets	**197**	265	145
Other investing	**(294)**	(140)	(285)
Net investing cash flows from Continuing operations	**(7,845)**	(7,616)	(7,377)
Net investing cash flows from Discontinued operations	**–**	–	(443)
Proceeds from divestment of Onshore US, net of its cash	**–**	–	10,427
Net investing cash flows	**(7,845)**	(7,616)	2,607
Financing activities			
Proceeds from interest bearing liabilities	**568**	514	250
Proceeds/(settlements) of debt related instruments	**167**	(157)	(160)
Repayment of interest bearing liabilities	**(8,395)**	(2,047)	(2,604)
Purchase of shares by Employee Share Ownership Plan (ESOP) Trusts	**(234)**	(143)	(188)
Share buy-back – BHP Group Limited	**–**	–	(5,220)
Dividends paid	**(7,901)**	(6,876)	(11,395)
Dividends paid to non-controlling interests	**(2,127)**	(1,043)	(1,198)
Net financing cash flows from Continuing operations	**(17,922)**	(9,752)	(20,515)
Net financing cash flows from Discontinued operations	**–**	–	(13)
Net financing cash flows	**(17,922)**	(9,752)	(20,528)
Net increase/(decrease) in cash and cash equivalents from Continuing operations	**1,467**	(1,662)	(10,495)
Net increase/(decrease) in cash and cash equivalents from Discontinued operations	**–**	–	18
Proceeds from divestment of Onshore US, net of its cash	**–**	–	10,427
Cash and cash equivalents, net of overdrafts, at the beginning of the financial year	**13,426**	15,593	15,813
Foreign currency exchange rate changes on cash and cash equivalents	**353**	(505)	(170)
Cash and cash equivalents, net of overdrafts, at the end of the financial year	**15,246**	13,426	15,593

The accompanying notes form part of this Financial Information.

Consolidated Statement of Changes in Equity for the year ended 30 June 2021

US$M	Attributable to BHP shareholders: Share capital: BHP Group Limited	Share capital: BHP Group Plc	Treasury shares: BHP Group Limited	Treasury shares: BHP Group Plc	Reserves	Retained earnings	Total equity attributable to BHP shareholders	Non-controlling interests	Total equity
Balance as at 1 July 2020 (restated)	**1,111**	**1,057**	**(5)**	**–**	**2,306**	**43,396**	**47,865**	**4,310**	**52,175**
Total comprehensive income	**–**	**–**	**–**	**–**	**22**	**11,330**	**11,352**	**2,158**	**13,510**
Transactions with owners:									
Purchase of shares by ESOP Trusts	**–**	**–**	**(229)**	**(5)**	**–**	**–**	**(234)**	**–**	**(234)**
Employee share awards exercised net of employee contributions net of tax	**–**	**–**	**202**	**4**	**(149)**	**(57)**	**–**	**–**	**–**
Vested employee share awards that have lapsed, been cancelled or forfeited	**–**	**–**	**–**	**–**	**(4)**	**4**	**–**	**–**	**–**
Accrued employee entitlement for unexercised awards net of tax	**–**	**–**	**–**	**–**	**175**	**–**	**175**	**–**	**175**
Dividends	**–**	**–**	**–**	**–**	**–**	**(7,894)**	**(7,894)**	**(2,127)**	**(10,021)**
Balance as at 30 June 2021	**1,111**	**1,057**	**(32)**	**(1)**	**2,350**	**46,779**	**51,264**	**4,341**	**55,605**
Balance as at 1 July 2019 (restated)	1,111	1,057	(32)	–	2,285	42,748	47,169	4,584	51,753
Total comprehensive income	–	–	–	–	(12)	7,910	7,898	769	8,667
Transactions with owners:									
Purchase of shares by ESOP Trusts	–	–	(139)	(4)	–	–	(143)	–	(143)
Employee share awards exercised net of employee contributions net of tax	–	–	166	4	(132)	(38)	–	–	–
Vested employee share awards that have lapsed, been cancelled or forfeited	–	–	–	–	(10)	10	–	–	–
Accrued employee entitlement for unexercised awards net of tax	–	–	–	–	175	–	175	–	175
Dividends	–	–	–	–	–	(7,234)	(7,234)	(1,043)	(8,277)
Balance as at 30 June 2020 (restated)	1,111	1,057	(5)	–	2,306	43,396	47,865	4,310	52,175
Balance as at 1 July 2018	1,186	1,057	(5)	–	2,290	51,057	55,585	5,078	60,663
Impact of change in accounting policies (Note 1)	–	–	–	–	–	(71)	(71)	–	(71)
Restated balance as at 1 July 2018	1,186	1,057	(5)	–	2,290	50,986	55,514	5,078	60,592
Total comprehensive income	–	–	–	–	(24)	8,306	8,282	878	9,160
Transactions with owners:									
Purchase of shares by ESOP Trusts	–	–	(182)	(6)	–	–	(188)	–	(188)
Employee share awards exercised net of employee contributions net of tax	–	–	155	6	(100)	(61)	–	–	–
Vested employee share awards that have lapsed, been cancelled or forfeited	–	–	–	–	(18)	18	–	–	–
Accrued employee entitlement for unexercised awards net of tax	–	–	–	–	138	–	138	–	138
Dividends	–	–	–	–	–	(11,302)	(11,302)	(1,205)	(12,507)
BHP Group Limited shares bought back and cancelled	(75)	–	–	–	–	(5,199)	(5,274)	–	(5,274)
Divestment of subsidiaries, operations and joint operations	–	–	–	–	–	–	–	(168)	(168)
Transfer to non-controlling interests	–	–	–	–	(1)	–	(1)	1	–
Balance as at 30 June 2019 (restated)	1,111	1,057	(32)	–	2,285	42,748	47,169	4,584	51,753

The accompanying notes form part of this Financial Information.

Notes to the Financial Information

1. Impact of new accounting standards and interpretation and changes in accounting policies

Amended accounting standards

The adoption of amendments and revisions to accounting pronouncements applicable from 1 July 2020, including the change in definition of a business under the amendments to IFRS 3/AASB 3 'Business Combinations' and revisions to the Conceptual Framework for Financial Reporting, did not have a significant impact on the Group's Financial Statements.

The Group has early adopted 'Interest Rate Benchmark (IBOR) Reform – Phase 2 (Amendments to IFRS 9/AASB 9 'Financial Instruments', IAS 39/AASB139 'Financial Instruments: Recognition and Measurement'; IFRS 7/AASB 7 'Financial Instruments: Disclosures'; IFRS 4/AASB 4 'Insurance Contracts' and IFRS 16/AASB 16 'Leases'). These amendments address the financial reporting impacts from IBOR reform and supplement the IBOR Reform Phase 1 amendments to IFRS 7 and IFRS 9 which were early adopted by the Group in the financial year ended 30 June 2020.

The amendments provide relief from applying specific hedge accounting requirements to hedging arrangements directly impacted by IBOR reform. In particular, where changes to the Group's instruments arise solely as a result of these reforms and do not change the economic substance of the Group's arrangements, the Group is able to maintain its existing hedge relationships and accounting, resulting in no impact on the Group's hedge accounting. Upon transition to alternative risk-free rates, the Group will seek to apply relief available in IFRS 9 and continue to apply hedge accounting to its hedging arrangements.

Changes in accounting policies

On 29 April 2020, the IFRS Interpretations Committee issued a decision on the application of IAS 12 'Income Taxes' when the recovery of the carrying amount of an asset gives rise to multiple tax consequences, concluding that an entity must account for distinct tax consequences separately. As a result, the Group has changed its accounting policy for assets that have no deductible or depreciable amount for income tax purposes, but do have a deductible amount for capital gains tax (CGT) when determining deferred tax. The Group's policy had been to use only the amount deductible for CGT purposes whereas the Group will now account for the distinct income tax and CGT consequences arising from the expected manner of recovery. The assets impacted by the change predominately relate to mineral rights.

Retrospective application of the accounting policy change has resulted in the following adjustments:

Consolidated Balance Sheet

The consolidated balance sheet as at 1 July 2019 has been updated for the following:

	US$M
Increase in Deferred tax liabilities	1,021
Increase in Goodwill (included within Intangible assets)	950
Decrease in Retained earnings	(71)

The goodwill recognised as a result of the change in accounting policy relates to Olympic Dam and has been tested for impairment in the period, with no impairment charge being required. The comparative balance sheet as at 30 June 2020 has been restated to reflect these amounts.

Consolidated Statement of Changes in Equity

The consolidated statement of changes in equity as at 1 July 2018 and 1 July 2019 have been updated to reflect the reduction in retained earnings of US$71 million.

Consolidated Income Statement, Consolidated Statement of Comprehensive Income

The impact of the accounting policy change on the consolidated income statement and consolidated statement of comprehensive income is de minimus and therefore the comparative information has not been restated.

Consolidated Cash Flow Statement

The change in accounting policy has no impact on the consolidated cash flow statement.

2. Exceptional items

Exceptional items are those gains or losses where their nature, including the expected frequency of the events giving rise to them, and impact is considered material to the Financial Statements. Such items included within the Group's profit for the year are detailed below.

Year ended 30 June 2021	Gross US$M	Tax US$M	Net US$M
Exceptional items by category			
Samarco dam failure	(1,087)	(71)	(1,158)
COVID-19 related costs	(546)	146	(400)
Impairment of Energy coal assets	(1,523)	(651)	(2,174)
Impairment of Potash assets	(1,314)	(751)	(2,065)
Total	**(4,470)**	**(1,327)**	**(5,797)**
Attributable to non-controlling interests	(34)	10	(24)
Attributable to BHP shareholders	(4,436)	(1,337)	(5,773)

Samarco Mineração SA (Samarco) dam failure

The loss of US$1,158 million (after tax) related to the Samarco dam failure in November 2015 comprises the following:

Year ended 30 June 2021	US$M
Other income	34
Expenses excluding net finance costs:	
Costs incurred directly by BHP Brasil and other BHP entities in relation to the Samarco dam failure	(46)
Loss from equity accounted investments, related impairments and expenses:	
Samarco impairment expense	(111)
Samarco Germano dam decommissioning	(15)
Samarco dam failure provision	(1,000)
Fair value change on forward exchange derivatives	136
Net finance costs	(85)
Income tax expense	(71)
Total[(1)]	**(1,158)**

(1) Refer to note 8 'Significant events – Samarco dam failure' for further information.

COVID-19 related costs

COVID-19 is considered a single protracted globally pervasive event with financial impacts being experienced over a number of reporting periods. The exceptional item reflects the directly attributable COVID-19 pandemic related additional costs for the Group for the year ended 30 June 2021, including costs associated with the increased provision of health and hygiene services, the impacts of maintaining social distancing requirements and demurrage and other standby charges related to delays caused by COVID-19.

Impairment of Energy coal assets

The Group recognised an impairment charge of US$1,704 million (after tax) in relation to NSWEC reflecting the status of the divestment process and forecast market conditions for thermal coal, the strengthening Australian dollar and changes to the mine plan. In addition, the Group recognised an impairment charge of US$470 million (after tax) for Cerrejón, reflecting the expected net sale proceeds. Refer to note 9 'Impairment of non-current assets' for further information on the pre-tax impairments.

Impairment of Potash assets

The Group recognised an impairment charge of US$2,065 million (after tax) in relation to Potash. The impairment charge reflects an analysis of recent market perspectives and the value that we would now expect a market participant to attribute to our investments to date. Refer to note 9 'Impairment of non-current assets' for further information on the pre-tax impairments.

2. Exceptional items (continued)

The exceptional items relating to the year ended 30 June 2020 and the year ended 30 June 2019 are detailed below.

Year ended 30 June 2020	Gross US$M	Tax US$M	Net US$M
Exceptional items by category			
Samarco dam failure	(176)	–	(176)
Cancellation of power contracts	(778)	271	(507)
COVID-19 related costs	(183)	53	(130)
Cerro Colorado impairment	(409)	(83)	(492)
Total	(1,546)	241	(1,305)
Attributable to non-controlling interests	(291)	90	(201)
Attributable to BHP shareholders	(1,255)	151	(1,104)

Year ended 30 June 2019	Gross US$M	Tax US$M	Net US$M
Exceptional items by category			
Samarco dam failure	(1,060)	–	(1,060)
Global taxation matters	–	242	242
Total	(1,060)	242	(818)
Attributable to non-controlling interests	–	–	–
Attributable to BHP shareholders	(1,060)	242	(818)

3. Interests in associates and joint venture entities

The Group's major shareholdings in associates and joint venture entities, including their profit/(loss), are listed below:

	Ownership interest at the Group's reporting date			Loss from equity accounted investments, related impairments and expenses		
	2021 %	2020 %	2019 %	2021 US$M	2020 US$M	2019 US$M
Share of profit/(loss) of equity accounted investments:						
Cerrejón	**33.33**	33.33	33.33	**(14)**	(68)	103
Compañia Minera Antamina SA	**33.75**	33.75	33.75	**623**	212	394
Samarco Mineração SA[(1)]	**50.00**	50.00	50.00	**–**	–	–
Other				**(74)**	(148)	(98)
Share of profit/(loss) of equity accounted investments				**535**	(4)	399
Samarco impairment expense[(1)]				**(111)**	(95)	(96)
Samarco dam failure provision[(1)]				**(1,000)**	(459)	(586)
Samarco Germano dam decommissioning[(1)]				**(15)**	46	(263)
Fair value change on forward exchange derivatives[(1)]				**136**	–	–
Cerrejón impairment expense[(2)]				**(466)**	–	–
Loss from equity accounted investments, related impairments and expenses				**(921)**	(512)	(546)

(1) Refer to note 8 'Significant events – Samarco dam failure' for further information.

(2) Refer to note 9 'Impairment of non-current assets' for further information.

On 28 June 2021, the Group announced the divestment of its 33.3 per cent interest in Cerrejón to Glencore, for US$294 million cash consideration. The transaction has an effective economic date of 31 December 2020. The purchase price is subject to adjustments at transaction completion, which may include an adjustment for any dividends paid by Cerrejón to the Group during the period from signing to completion. An impairment charge of US$466 million (before tax) was recognised in the year ended 30 June 2021 reducing the carrying value of the Group's investment in Cerrejón at 30 June 2021 to US$284 million, being the agreed sale proceeds of US$294 million adjusted for expected transaction costs.

At 30 June 2021, the Group's investment of US$284 million in Cerrejón along with a loan due from Cerrejón of US$40 million, has been classified as 'Assets held for sale'. Payables owed to Cerrejón of US$17 million have been classified as 'Liabilities directly associated with the assets held for sale'. Subject to the satisfaction of customary competition and regulatory requirements, the transaction is expected to be completed within 12 months from the balance sheet date.

4. Net finance costs

	Year ended 30 June 2021 US$M	Year ended 30 June 2020 US$M	Year ended 30 June 2019 US$M
Financial expenses			
Interest expense using the effective interest rate method:			
Interest on bank loans, overdrafts and all other borrowings	**610**	1,099	1,296
Interest capitalised at 2.83% (2020: 4.14%; 2019: 4.96%)(1)	**(248)**	(308)	(248)
Interest on lease liabilities	**109**	90	47
Discounting on provisions and other liabilities	**467**	452	470
Other gains and losses:			
Fair value change on hedged loans	**(779)**	721	729
Fair value change on hedging derivatives	**704**	(788)	(809)
Loss on bond repurchase(2)	**395**	–	–
Exchange variations on net debt	**99**	(18)	6
Other	**21**	14	19
Total financial expenses	**1,378**	1,262	1,510
Financial income			
Interest income	**(73)**	(351)	(446)
Net finance costs	**1,305**	911	1,064

(1) Interest has been capitalised at the rate of interest applicable to the specific borrowings financing the assets under construction or, where financed through general borrowings, at a capitalisation rate representing the average interest rate on such borrowings. Tax relief for capitalised interest is approximately US$74 million (2020: US$92 million; 2019: US$74 million).

(2) Relates to the additional cost on settlement of two multi-currency hybrid debt repurchase programs and the unwind of the associated hedges, included in a total cash payment of US$3,402 million disclosed in repayment of interest bearing liabilities in the Consolidated Cash Flow Statement.

5. Income tax expense

	Year ended 30 June 2021 US$M	Year ended 30 June 2020 US$M	Year ended 30 June 2019 US$M
Total taxation expense comprises:			
Current tax expense	**9,825**	5,109	5,408
Deferred tax expense/(benefit)	**1,325**	(335)	121
	11,150	4,774	5,529

	Year ended 30 June 2021 US$M	Year ended 30 June 2020 US$M	Year ended 30 June 2019 US$M
Factors affecting income tax expense for the year			
Income tax expense differs to the standard rate of corporation tax as follows:			
Profit before taxation	**24,601**	13,510	15,049
Tax on profit at Australian prima facie tax rate of 30 per cent	**7,380**	4,053	4,515
Non-tax effected operating losses and capital gains(1)	**3,112**	707	742
Tax on remitted and unremitted foreign earnings	**485**	225	283
Tax effect of loss from equity accounted investments, related impairments and expenses(2)	**317**	154	164
Investment and development allowance	**–**	(99)	(94)
Tax rate changes	**(1)**	(8)	6
Amounts (over)/under provided in prior years	**(11)**	64	(21)
Recognition of previously unrecognised tax assets	**(28)**	(30)	(10)
Foreign exchange adjustments	**(95)**	20	(25)
Impact of tax rates applicable outside of Australia	**(603)**	(167)	(312)
Other	**365**	(211)	87
Income tax expense	**10,921**	4,708	5,335
Royalty-related taxation (net of income tax benefit)	**229**	66	194
Total taxation expense	**11,150**	4,774	5,529

(1) Includes the tax impacts related to the exceptional impairments of NSWEC and Potash in the year ended 30 June 2021 and Cerro Colorado in the year ended 30 June 2020, as presented in note 2 'exceptional items'. There were no exceptional impairments in the year ended 30 June 2019.

(2) The loss from equity accounted investments, related impairments and expenses is net of income tax, with the exception of the Samarco forward exchange derivatives described in note 8 'Significant events – Samarco dam failure'. This item removes the prima facie tax effect on such loss, related impairments and expenses, excluding the impact of the Samarco forward exchange derivatives which are taxable.

6. Earnings per share

	Year ended 30 June 2021	Year ended 30 June 2020	Year ended 30 June 2019
Earnings attributable to BHP shareholders (US$M)(1)			
- Continuing operations	**11,304**	7,956	8,648
- Total	**11,304**	7,956	8,306
Weighted average number of shares (Million)			
- Basic(2)	**5,057**	5,057	5,180
- Diluted(3)	**5,068**	5,069	5,193
Basic earnings per ordinary share (US cents)(4)			
- Continuing operations	**223.5**	157.3	166.9
- Total	**223.5**	157.3	160.3
Diluted earnings per ordinary share (US cents)(4)			
- Continuing operations	**223.0**	157.0	166.5
- Total	**223.0**	157.0	159.9
Headline earnings per ordinary share (US cents)(5)			
- Basic	**284.8**	171.1	164.9
- Diluted	**284.2**	170.7	164.5

(1) Diluted earnings attributable to BHP shareholders are equal to earnings attributable to BHP shareholders.

(2) The calculation of the number of ordinary shares used in the computation of basic earnings per share is the aggregate of the weighted average number of ordinary shares of BHP Group Limited and BHP Group Plc outstanding during the period after deduction of the number of shares held by the Billiton Employee Share Ownership Trust and the BHP Billiton Limited Employee Equity Trust.

(3) For the purposes of calculating diluted earnings per share, the effect of 11 million of dilutive shares has been taken into account for the year ended 30 June 2021 (2020: 12 million shares; 2019: 13 million shares). The Group's only potential dilutive ordinary shares are share awards granted under employee share ownership plans. Diluted earnings per share calculation excludes instruments which are considered antidilutive.

At 30 June 2021, there are no instruments which are considered antidilutive (2020: nil, 2019: nil).

(4) Each American Depositary Share represents twice the earnings for BHP ordinary shares.

(5) Headline earnings is a Johannesburg Stock Exchange defined performance measure and is reconciled from earnings attributable to ordinary shareholders as follows:

	Year ended 30 June 2021	Year ended 30 June 2020	Year ended 30 June 2019
Earnings attributable to BHP shareholders	**11,304**	7,956	8,306
Adjusted for:			
(Gain)/loss on sales of PP&E, Investments and Operations(i)	**(50)**	4	(52)
Impairments of property, plant and equipment, financial assets and intangibles	**2,633**	494	264
Samarco impairment expense	**111**	95	96
Cerrejón impairment expense	**466**	–	–
Other(ii)	**–**	48	–
Recycling of re-measurements from equity to the income statement	**–**	–	(6)
Tax effect of above adjustments	**(60)**	54	(64)
Subtotal of adjustments	**3,100**	695	238
Headline earnings	**14,404**	8,651	8,544
Diluted headline earnings	**14,404**	8,651	8,544

(i) Included in other income.

(ii) Mainly represent BHP share of impairment embedded in the statutory income statement of the Group's equity accounted investments.

7. Dividends

	Year ended 30 June 2021		Year ended 30 June 2020		Year ended 30 June 2019	
	Per share US cents	Total US$M	Per share US cents	Total US$M	Per share US cents	Total US$M
Dividends paid during the period[1]						
Prior year final dividend	**55.0**	**2,779**	78.0	3,946	63.0	3,356
Interim dividend	**101.0**	**5,115**	65.0	3,288	55.0	2,788
Special dividend	**–**	**–**	–	–	102.0	5,158
	156.0	**7,894**	143.0	7,234	220.0	11,302

(1) 5.5 per cent dividend on 50,000 preference shares of £1 each determined and paid annually (2020: 5.5 per cent; 2019: 5.5 per cent).

Dividends paid during the period differs from the amount of dividends paid in the Consolidated Cash Flow Statement as a result of foreign exchange gains and losses relating to the timing of equity distributions between the record date and the payment date. Additional derivative proceeds of US$8 million was received as part of the funding of the interim dividend and is disclosed in (Settlements)/proceeds of cash management related instruments in the Consolidated Cash Flow Statement.

The Dual Listed Company merger terms require that ordinary shareholders of BHP Group Limited and BHP Group Plc are paid equal cash dividends on a per share basis. Each American Depositary Share (ADS) represents two ordinary shares of BHP Group Limited or BHP Group Plc. Dividends determined on each ADS represent twice the dividend determined on BHP ordinary shares.

Dividends are determined after period-end and contained within the announcement of the results for the period. Interim dividends are determined in February and paid in March. Final dividends are determined in August and paid in September. Dividends determined are not recorded as a liability at the end of the period to which they relate. Subsequent to the year end, on 17 August 2021, BHP Group Limited and BHP Group Plc determined a final dividend of 200 US cents per share (US$ 10,114 million), which will be paid on 21 September 2021 (2020: final dividend of 55 US cents per share – US$2,782 million; 2019: final dividend of 78 US cents per share – US$3,944 million).

At 30 June 2021, BHP Group Limited had 2,945 million ordinary shares on issue and held by the public and BHP Group Plc had 2,112 million ordinary shares on issue and held by the public. No shares in BHP Group Limited were held by BHP Group Plc at 30 June 2021 (2020: nil; 2019: nil).

BHP Group Limited dividends for all periods presented are, or will be, fully franked based on a tax rate of 30 per cent.

	2021 US$M	2020 US$M	2019 US$M
Franking credits as at 30 June	**14,302**	10,980	8,681
Franking credits arising from the payment of current tax	**1,799**	471	1,194
Total franking credits available[1]	**16,101**	11,451	9,875

(1) The payment of the final 2021 dividend determined after 30 June 2021 will reduce the franking account balance by US$2,525 million.

8. Significant events – Samarco dam failure

On 5 November 2015, the Samarco Mineração S.A. (Samarco) iron ore operation in Minas Gerais, Brazil, experienced a tailings dam failure that resulted in a release of mine tailings, flooding the communities of Bento Rodrigues, Gesteira and Paracatu and impacting other communities downstream (the Samarco dam failure).

Samarco is jointly owned by BHP Billiton Brasil Ltda (BHP Brasil) and Vale S.A. (Vale). BHP Brasil's 50 per cent interest is accounted for as an equity accounted joint venture investment. BHP Brasil does not separately recognise its share of the underlying assets and liabilities of Samarco, but instead records the investment as one line on the balance sheet. Each period, BHP Brasil recognises its 50 per cent share of Samarco's profit or loss and adjusts the carrying value of the investment in Samarco accordingly. Such adjustment continues until the investment carrying value is reduced to US$ nil, with any additional share of Samarco losses only recognised to the extent that BHP Brasil has an obligation to fund the losses. After applying equity accounting, any remaining carrying value of the investment is tested for impairment.

Any charges relating to the Samarco dam failure incurred directly by BHP Brasil or other BHP entities are recognised 100 per cent in the Group's results.

The financial impacts of the Samarco dam failure on the Group's income statement, balance sheet and cash flow statement for the year ended 30 June 2021 are shown in the table below and have been treated as an exceptional item.

Financial impacts of Samarco dam failure	Year ended 30 June 2021 US$M	Year ended 30 June 2020 US$M	Year ended 30 June 2019 US$M
Income statement			
Other income[1]	**34**	489	50
Expenses excluding net finance costs:			
Costs incurred directly by BHP Brasil and other BHP entities in relation to the Samarco dam failure[2]	**(46)**	(64)	(57)
Loss from equity accounted investments, related impairments and expenses:			
Samarco impairment expense[3]	**(111)**	(95)	(96)
Samarco Germano dam decommissioning[4]	**(15)**	46	(263)
Samarco dam failure provision[5]	**(1,000)**	(459)	(586)
Fair value change on forward exchange derivatives[6]	**136**	–	–
Loss from operations	**(1,002)**	(83)	(952)
Net finance costs[7]	**(85)**	(93)	(108)
Loss before taxation	**(1,087)**	(176)	(1,060)
Income tax expense[8]	**(71)**	–	–
Loss after taxation	**(1,158)**	(176)	(1,060)
Balance sheet movement			
Trade and other payables	**(5)**	(5)	4
Derivatives	**136**	–	–
Tax liabilities	**(71)**	–	–
Provisions	**(741)**	(137)	(629)
Net liabilities	**(681)**	(142)	(625)

8. Significant events – Samarco dam failure (continued)

		Year ended 30 June 2021 US$M		Year ended 30 June 2020 US$M		Year ended 30 June 2019 US$M
Cash flow statement						
Loss before taxation		**(1,087)**		(176)		(1,060)
Adjustments for:						
Samarco impairment expense(3)	**111**		95		96	
Samarco Germano dam decommissioning(4)	**15**		(46)		263	
Samarco dam failure provision(5)	**1,000**		459		586	
Fair value change on forward exchange derivatives(6)	**(136)**		–		–	
Net finance costs(7)	**85**		93		108	
Changes in assets and liabilities:						
Trade and other payables	**5**		5		(4)	
Net operating cash flows		**(7)**		430		(11)
Net investment and funding of equity accounted investments(9)		**(470)**		(464)		(424)
Net investing cash flows		**(470)**		(464)		(424)
Net decrease in cash and cash equivalents		**(477)**		(34)		(435)

(1) Proceeds from insurance settlements.

(2) Includes legal and advisor costs incurred.

(3) Impairment expense from working capital funding provided during the period.

(4) US$(6) million change in estimate and US$21 million exchange translation.

(5) US$842 million change in estimate and US$158 million exchange translation.

(6) During the period the Group entered into forward exchange contracts to limit the Brazilian reais exposure on the dam failure provisions. While not applying hedge accounting, the fair value changes in the forward exchange instruments are recorded within Loss from equity accounted investments, related impairments and expenses in the Income Statement.

(7) Amortisation of discounting of provision.

(8) Includes tax on forward exchange derivatives and other taxes incurred during the period.

(9) Includes US$(111) million funding provided during the period, US$(351) million utilisation of the Samarco dam failure provision, and US$(8) million utilisation of the Samarco Germano decommissioning provision.

Equity accounted investment in Samarco

BHP Brasil's investment in Samarco remains at US$ nil. BHP Brasil provided US$111 million funding under a working capital facility during the period and recognised impairment losses of US$111 million. No dividends have been received by BHP Brasil from Samarco during the period and Samarco currently does not have profits available for distribution.

Provisions related to the Samarco dam failure

		30 June 2021 US$M		30 June 2020 US$M
At the beginning of the financial year		**2,051**		1,914
Movement in provisions		**741**		137
Comprising:				
Utilised	**(359)**		(369)	
Adjustments charged to the income statement:				
Change in estimate - Samarco dam failure provision	**842**		916	
Change in estimate - Samarco Germano dam decommissioning	**(6)**		37	
Amortisation of discounting impacting net finance costs	**85**		93	
Exchange translation	**179**		(540)	
At the end of the financial year		**2,792**		2,051
Comprising:				
Current		**1,206**		896
Non-current		**1,586**		1,155
At the end of the financial year		**2,792**		2,051
Comprising:				
Samarco dam failure provision		**2,560**		1,824
Samarco Germano dam decommissioning provision		**232**		227

Samarco dam failure provisions and contingencies

As at 30 June 2021, BHP Brasil has identified provisions and contingent liabilities arising as a consequence of the Samarco dam failure as follows:

8. Significant events – Samarco dam failure (continued)

Provision for Samarco dam failure

On 2 March 2016, BHP Brasil, Samarco and Vale, entered into a Framework Agreement with the Federal Government of Brazil, the states of Espírito Santo and Minas Gerais and certain other public authorities to establish a foundation (Fundação Renova) that is developing and executing environmental and socio-economic programs (Programs) to remediate and provide compensation for damage caused by the Samarco dam failure. Key Programs include those for financial assistance and compensation of impacted persons, including fisherfolk impacted by the dam failure, and those for remediation of impacted areas and resettlement of impacted communities. A committee (Interfederative Committee) comprising representatives from the Brazilian Federal and State Governments, local municipalities, environmental agencies, impacted communities and Public Defence Office oversees the activities of the Fundação Renova in order to monitor, guide and assess the progress of actions agreed in the Framework Agreement. In addition, the 12th Federal Court is supervising the work of the Fundação Renova and the Court's decisions have been considered in the Samarco dam failure provision change in estimate. Any future decisions will be analysed for impacts on the provision at the time of any decision.

The term of the Framework Agreement is 15 years, renewable for periods of one year successively until all obligations under the Framework Agreement have been performed. Under the Framework Agreement, Samarco has primary responsibility for funding Fundação Renova's annual calendar year budget for the duration of the Framework Agreement. The funding amounts for each calendar year will be dependent on the remediation and compensation projects to be undertaken in a particular year. Annual contributions may be reviewed under the Framework Agreement. To the extent that Samarco does not meet its funding obligations, each of BHP Brasil and Vale have secondary funding obligations under the Framework Agreement in proportion to its 50 per cent shareholding in Samarco.

Samarco began to gradually recommence operations in December 2020, however, there remains significant uncertainty regarding Samarco's long term cash flow generation. In light of these uncertainties and based on currently available information, BHP Brasil's provision for its obligations under the Framework Agreement Programs is US$2.6 billion before tax and after discounting at 30 June 2021 (30 June 2020: US$1.8 billion).

Under a Governance Agreement ratified on 8 August 2018, BHP Brasil, Samarco and Vale were to establish a process to renegotiate the Programs over two years to progress settlement of the R$155 billion (approximately US$30 billion) Federal Public Prosecution Office claim (described below). Pre-requisites established in the Governance Agreement, for re-negotiation of the Framework Agreement were not implemented during the two year period and on 30 September 2020, Brazilian Federal and State prosecutors and public defenders filed a request for the immediate resumption of the R$155 billion (approximately US$30 billion) claim, which has been suspended from the date of ratification of the Governance Agreement. The claim remains suspended after the parties to the claim agreed to continue the suspension on 19 March 2021. BHP Brasil, Samarco, Vale and Federal and State prosecutors have been engaging in negotiations to seek a definitive and substantive settlement of the obligations under the Framework Agreement and the R$155 billion (approximately US$30 billion) Federal Public Prosecution Office claim. It is not possible to provide a range of outcomes or a reliable estimate of potential settlement outcomes and there is a risk that a negotiated outcome may be materially higher than amounts currently reflected in the Samarco dam failure provision. Until any revisions to the Programs are agreed, Fundação Renova will continue to implement the Programs in accordance with the terms of the Framework Agreement and the Governance Agreement.

BHP Brasil, Samarco and Vale are required to maintain security of an amount equal to the Fundação Renova's annual budget up to a limit of R$2.2 billion (approximately US$440 million). The security currently comprises R$1.3 billion (approximately US$260 million) in insurance bonds and a charge of R$800 million (approximately US$160 million) over Samarco's assets. A further R$100 million (approximately US$20 million) in liquid assets previously maintained as security was released for COVID-19 related response efforts in Brazil.

Samarco Germano dam decommissioning

Samarco is currently progressing plans for the accelerated decommissioning of its upstream tailings dams (the Germano dam complex). Given the significant uncertainties surrounding Samarco's long term cash flow generation, BHP Brasil's provision for a 50 per cent share of the expected Germano decommissioning costs is US$232 million (30 June 2020: US$227 million). The decommissioning is at an early stage and as a result, further engineering work and required validation by Brazilian authorities could lead to changes to estimates in future reporting periods.

8. Significant events – Samarco dam failure (continued)

Key judgements and estimates

Judgements

The outcomes of litigation are inherently difficult to predict and significant judgement has been applied in assessing the likely outcome of legal claims and determining which legal claims require recognition of a provision or disclosure of a contingent liability. The facts and circumstances relating to these cases are regularly evaluated in determining whether a provision for any specific claim is required.

Management has determined that a provision can only be recognised for obligations under the Framework Agreement and Samarco Germano dam decommissioning as at 30 June 2021. It is not yet possible to provide a range of possible outcomes or a reliable estimate of potential future exposures to BHP in connection to the contingent liabilities noted below, given their status.

Estimates

The provisions for Samarco dam failure and Samarco Germano dam decommissioning currently reflect the estimated remaining costs to complete Programs under the Framework Agreement and estimated costs to complete the Germano dam decommissioning and require the use of significant judgements, estimates and assumptions. Based on current estimates, it is expected that approximately 85 per cent of remaining costs for Programs under the Framework Agreement will be incurred by December 2023.

While the provisions have been measured based on latest information available, likely changes in facts and circumstances in future reporting periods may lead to material revisions to these estimates. However, it is currently not possible to determine what facts and circumstances may change, therefore revisions in future reporting periods due to the key estimates and factors outlined below cannot be reliably measured.

The key estimates that may have a material impact upon the provisions in the next and future reporting periods include:

- number of people eligible for financial assistance and compensation and the corresponding amount of expected compensation; and
- costs to complete key infrastructure programs, including resettlement of the Bento Rodrigues, Gesteira and Paracatu communities.

The provisions may also be affected by factors including but not limited to:

- resolution of existing and potential legal claims in Brazil and other jurisdictions, including the impact of ongoing settlement negotiations and outcome of the United Kingdom group action complaint;
- potential changes in scope of work and funding amounts required under the Framework Agreement including the impact of the decisions of the Interfederative Committee along with further technical analysis, community participation required under the Governance Agreement and rulings made by the 12th Federal Court;
- the outcome of ongoing negotiations with State and Federal Prosecutors, including review of Fundação Renova's Programs as provided in the Governance Agreement;
- actual costs incurred;
- resolution of uncertainty in respect of the nature and extent of Samarco's long term cash generation;
- costs to complete the Germano dam decommissioning;
- updates to discount and foreign exchange rates; and
- the outcomes of Samarco's judicial restructuring (defined below).

Given these factors, future actual expenditures may differ from the amounts currently provided and changes to key assumptions and estimates could result in a material impact to the provision in the next and future reporting periods.

8. Significant events – Samarco dam failure (continued)

Contingent liabilities

The following matters are disclosed as contingent liabilities and given the status of proceedings it is not possible to provide a range of possible outcomes or a reliable estimate of potential future exposures for BHP, unless otherwise stated. Ultimately, all the legal matters disclosed as contingent liabilities could have a material adverse impact on BHP's business, competitive position, cash flows, prospects, liquidity and shareholder returns.

Federal Public Prosecution Office claim

BHP Brasil is among the defendants named in a claim brought by the Federal Public Prosecution Office on 3 May 2016, seeking R$155 billion (approximately US$30 billion) for reparation, compensation and moral damages in relation to the Samarco dam failure.

The 12th Federal Court previously suspended the Federal Public Prosecution Office claim, including a R$7.7 billion (approximately US$1.5 billion) injunction request. On 30 September 2020, Brazilian Federal and State prosecutors and public defenders filed a request for the immediate resumption of the R$155 billion (approximately US$30 billion) claim, which has been suspended since the date of ratification of the Governance Agreement. The claim remains suspended after the parties to the claim agreed to continue the suspension on 19 March 2021.

BHP Brasil, Samarco, Vale and Federal and State prosecutors have been engaging in negotiations to seek a definitive and substantive settlement of the obligations under the Framework Agreement and the R$155 billion (approximately US$30 billion) Federal Public Prosecution Office claim. It is not possible to provide a range of outcomes or a reliable estimate of potential settlement outcomes and there is a risk that a negotiated outcome may be materially higher than amounts currently reflected in the Samarco dam failure provision.

United States class action complaint – Samarco bond holders

On 14 November 2016, a putative class action complaint (Bondholder Complaint) was filed in the U.S. District Court for the Southern District of New York on behalf of purchasers of Samarco's ten-year bond notes due 2022-2024 between 31 October 2012 and 30 November 2015. The Bondholder Complaint was initially filed against Samarco and the former chief executive officer of Samarco.

The Bondholder Complaint was subsequently amended to include BHP Group Ltd, BHP Group Plc, BHP Brasil, Vale and officers of Samarco, including four of Vale and BHP Brasil's nominees to the Samarco Board. On 5 April 2017, the plaintiff discontinued its claims against the individual defendants.

The complaint, along with a second amended complaint, had previously been dismissed by the court. The plaintiff filed a motion for reconsideration, or leave to file a third amended complaint, which was denied by the court on 30 October 2019. The plaintiff appealed this decision, which was affirmed by the court of appeals in March 2021.

Australian class action complaint

BHP Group Ltd is named as a defendant in a shareholder class action filed in the Federal Court of Australia on behalf of persons who acquired shares in BHP Group Ltd on the Australian Securities Exchange or shares in BHP Group Plc on the London Stock Exchange and Johannesburg Stock Exchange in periods prior to the Samarco dam failure. The amount of damages sought is unspecified.

United Kingdom group action complaint

BHP Group Plc and BHP Group Ltd were named as defendants in group action claims for damages filed in the courts of England. These claims were filed on behalf of certain individuals, governments, businesses and communities in Brazil allegedly impacted by the Samarco dam failure. The amount of damages sought in these claims is unspecified. The complaint and a subsequent application for permission to appeal have been dismissed by the court, however an application by the claimants to reopen the proceedings was granted in July 2021, allowing the claimants to appeal previous dismissals of the claim.

8. Significant events – Samarco dam failure (continued)

Criminal charges

The Federal Prosecutors' Office has filed criminal charges against BHP Brasil, Samarco and Vale and certain employees and former employees of BHP Brasil (Affected Individuals) in the Federal Court of Ponte Nova, Minas Gerais. On 3 March 2017, BHP Brasil filed its preliminary defences. The Federal Court terminated the charges against eight of the Affected Individuals. The Federal Prosecutors' Office has appealed seven of those decisions with hearings of the appeals still pending. BHP Brasil rejects outright the charges against the company and the Affected Individuals and will defend the charges and fully support each of the Affected Individuals in their defence of the charges.

Other claims

Civil public actions filed by State Prosecutors in Minas Gerais (claiming damages of approximately R$7.5 billion, US$1.5 billion), State Prosecutors in Espírito Santo (claiming damages of approximately R$2 billion, US$400 million), and public defenders in Minas Gerais (claiming damages of approximately R$10 billion, US$2 billion), have been consolidated before the 12th Federal Court and suspended. The Governance Agreement provides for a process to review whether these civil public claims should be terminated or suspended.

BHP Brasil is among the companies named as defendants in a number of legal proceedings initiated by individuals, non-governmental organisations, corporations and governmental entities in Brazilian Federal and State courts following the Samarco dam failure. The other defendants include Vale, Samarco and Fundação Renova. The lawsuits include claims for compensation, environmental rehabilitation and violations of Brazilian environmental and other laws, among other matters. The lawsuits seek various remedies including rehabilitation costs, compensation to injured individuals and families of the deceased, recovery of personal and property losses, moral damages and injunctive relief. In addition, government inquiries and investigations relating to the Samarco dam failure have been commenced by numerous agencies of the Brazilian government and are ongoing.

Additional lawsuits and government investigations relating to the Samarco dam failure could be brought against BHP Brasil and possibly other BHP entities in Brazil or other jurisdictions.

BHP insurance

BHP has various third party general liability and directors and officers insurances for claims related to the Samarco dam failure made directly against BHP Brasil or other BHP entities, their directors and officers, including class actions. External insurers have been notified of the Samarco dam failure along with the third party claims and class actions referred to above. In the period since the dam failure to 30 June 2021, the Group has recognised US$573 million other income from general liability insurance proceeds relating to the dam failure. Recoveries related to general liability insurance are now considered complete.

As at 30 June 2021, an insurance receivable has not been recognised for any potential recoveries in respect of ongoing matters.

Commitments

Under the terms of the Samarco joint venture agreement, BHP Brasil does not have an existing obligation to fund Samarco.

BHP has agreed to fund a total of up to US$765 million for the Fundação Renova programs and Samarco's working capital during calendar year 2021. This comprises up to US$725 million relating to Fundação Renova programs until 31 December 2021, which will be offset against the Group's provision for the Samarco dam failure, and a short-term working capital facility of up to US$40 million to be made available to Samarco until 31 December 2021. Amounts related to Fundação Renova and Samarco working capital incurred in the six months to 30 June 2021 have been reflected in the utilisation of the provision and impairment expense respectively disclosed above. Any additional requests for funding or future investment provided would be subject to a future decision by BHP, accounted for at that time.

8. Significant events – Samarco dam failure (continued)

Samarco judicial reorganisation

Samarco filed for judicial reorganisation (JR) in April 2021, with the Commercial Courts of Belo Horizonte, State of Minas Gerais, Brazil (JR Court), after multiple enforcement actions taken by certain creditors of Samarco. Samarco's JR filing followed unsuccessful attempts to negotiate a debt restructure with certain financial creditors and multiple legal actions filed by those creditors which threatened Samarco's operations. The JR is an insolvency proceeding with a means for Samarco to seek to restructure its financial debts and establish a sustainable financial position that allows Samarco to continue to rebuild its operations and strengthen its ability to meet its Fundação Renova funding obligations. Samarco's operations are expected to continue during the JR and restructure process. The JR is not expected to affect Samarco's obligation or commitment to make full redress for the 2015 Fundão dam failure, and is not expected to impact Renova Foundation's ability to undertake that remediation and compensation. It is not possible to determine the outcomes of the JR or estimate any impact that the reorganisation may have for BHP Brasil, including its share of the Samarco dam failure provisions.

9. Impairment of non-current assets

		Year ended 30 June 2021			
Cash generating unit	Segment	Property, plant and equipment US$M	Goodwill and other intangibles US$M	Equity-accounted investment US$M	Total US$M
New South Wales Energy Coal	Coal	**1,025**	**32**	**–**	**1,057**
Cerrejón	Coal	**–**	**–**	**466**	**466**
Potash	G&U	**1,314**	**–**	**–**	**1,314**
Other	Various	**244**	**20**	**–**	**264**
Total impairment of non-current assets		**2,583**	**52**	**466**	**3,101**
Reversal of impairment		**–**	**–**	**–**	**–**
Net impairment of non-current assets		**2,583**	**52**	**466**	**3,101**

		Year ended 30 June 2020			
Cash generating unit	Segment	Property, plant and equipment US$M	Goodwill and other intangibles US$M	Equity-accounted investment US$M	Total US$M
Cerro Colorado	Copper	409	–	–	409
Other	Various	85	–	–	85
Total impairment of non-current assets		494	–	–	494
Reversal of impairment		–	–	–	–
Net impairment of non-current assets		494	–	–	494

Impairment testing requirements

Impairment tests for all assets are performed when there is an indication of impairment, although goodwill is tested at least annually. If the carrying amount of the asset exceeds its recoverable amount, the asset is impaired and an impairment loss is charged to the income statement so as to reduce the carrying amount in the balance sheet to its recoverable amount.

Previously impaired assets (excluding goodwill) are reviewed for possible reversal of previous impairment at each reporting date. Impairment reversal cannot exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognised for the asset or cash generating units (CGUs). There were no reversals of impairment in the current or prior year.

How recoverable amount is calculated

The recoverable amount is the higher of an asset's fair value less costs of disposal (FVLCD) and its value in use (VIU). For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows.

9. Impairment of non-current assets (continued)

Impairment of non-current assets

The Group recognised the following impairments to non-current assets during the year:

Year ended 30 June 2021	NSWEC	Cerrejón	Potash
What has been recognised?	At 30 June 2021, the Group determined the overall recoverable amount of the CGU to be negative US$300 million, resulting in an aggregate impairment of property, plant and equipment and intangibles of US$1,057 million for FY2021.	At 30 June 2021, the Group determined the recoverable amount to be US$284 million, being the agreed sale proceeds of US$294 million adjusted for expected transaction costs, resulting in an aggregate impairment of US$466 million for FY2021.	At 30 June 2021, the Group determined the recoverable amount for Potash to be US$3.3 billion resulting in an impairment charge of US$1.3 billion against property, plant and equipment.
What were the drivers of impairment?	The impairment charges reflect the status of the divestment process and the forecast market conditions for Australian thermal coal, the strengthening Australian dollar and changes to the mine plan.	On 28 June 2021, the Group announced that it had signed a Sale and Purchase Agreement with Glencore to divest its interest in Cerrejón.	The impairment charge against the Group's Potash assets reflects an analysis of recent market perspectives and the value that the Group would now expect a market participant to attribute to the Group's investments to date.
How were the valuations calculated?	The 30 June 2021 valuation represents VIU, applying discounted cash flow (DCF) techniques.	The 30 June 2021 recoverable amount reflects the expected net sale proceeds of US$284 million.	The 30 June 2021 valuation was determined using FVLCD methodology, applying DCF techniques.
What were the significant assumptions and estimates used in the valuations?	The valuation for NSWEC using DCF techniques is most sensitive to changes in energy coal prices, estimated future production volumes and discount rates. The valuation for Potash is most sensitive to changes in the long-term potash price outlook and the risking applied to the future development phases of the potash resource.		

10. Business combination

In October 2020, the Group signed a Membership Interest Purchase and Sale Agreement with Hess Corporation (Hess) to acquire an additional 28 per cent working interest in Shenzi, a six-lease development in the deepwater Gulf of Mexico. The transaction was completed on 6 November 2020 for a purchase price of US$480 million after customary post-closing adjustments.

The transaction increased the Group's working interest from 44 per cent to 72 per cent. Shenzi continues to be accounted for as a joint operation because BHP continues to have joint decision-making rights with the other joint venture partner (Repsol). The assets and liabilities related to the acquired interests have been accounted for in line with the principles of IFRS 3/ AASB 3 'Business Combinations' with no remeasurement of the Group's previously held interest. The acquisition resulted in increases to property plant and equipment of US$642 million, inventory of US$17 million and closure and rehabilitation liabilities of US$179 million.

Fair value of the identifiable assets acquired and liabilities assumed, approximate the consideration paid to Hess and therefore no goodwill or bargain purchase gain has been recognised for the acquisition.

There were no other significant acquisitions during the year ended 30 June 2021, year ended 30 June 2020 or year ended 30 June 2019.

11. Subsequent events

On 27 July 2021, BHP entered into a definitive Support Agreement with Noront Resources (Noront) to make an all-cash takeover offer for Noront.

On 17 August 2021, BHP announced a major growth investment in the Jansen Stage 1 potash project, which is aligned with our strategy of growing our exposure to future facing commodities in world class assets.

On 17 August 2021, BHP announced an agreement to pursue a merger of our Petroleum business with Woodside to create a global top 10 independent energy company with a large-scale portfolio of producing, development and exploration assets.

On 17 August 2021, BHP announced its intention to realise simplification and enhanced strategic flexibility benefits through unifying our corporate structure under BHP's existing Australian parent company.

Other than the matters outlined above or elsewhere in this financial information, no matters or circumstances have arisen since the end of the financial year that have significantly affected, or may significantly affect, the operations, results of operations or state of affairs of the Group in subsequent accounting periods.

BHP

Alternative Performance Measures

Year ended 30 June 2021

Alternative Performance Measures

We use various Alternative Performance Measures (APMs) to reflect our underlying financial performance.

These APMs are not defined or specified under the requirements of IFRS, but are derived from the Group's draft Consolidated Financial Statements for the year ended 30 June 2021 prepared in accordance with IFRS. The APMs and below reconciliations included in this document for the year ended 30 June 2021 and comparative periods are unaudited. The APMs are consistent with how management review financial performance of the Group with the Board and the investment community.

We consider Underlying attributable profit to be a key measure that allows for the comparability of underlying financial performance by excluding the impacts of exceptional items. It is also the basis on which our dividend payout ratio policy is applied.

Underlying EBITDA is a key APM that management uses internally to assess the performance of the Group's segments and make decisions on the allocation of resources. In the Group's view, this is a relevant measure for capital intensive industries with long-life assets. Underlying EBITDA and Underlying EBIT are included in the Group's draft Consolidated Financial Statements, as required by IFRS 8 'Operating Segments'.

The "Definition and calculation of alternative performance measures" section outlines why we believe the APMs are useful and the calculation methodology. We believe these APMs provide useful information, but they should not be considered as an indication of, or as a substitute for, statutory measures as an indicator of actual operating performance (such as profit or net operating cash flow) or any other measure of financial performance or position presented in accordance with IFRS, or as a measure of a company's profitability, liquidity or financial position.

The following tables provide reconciliations between the APMs and their nearest respective IFRS measure.

Exceptional items

To improve the comparability of underlying financial performance between reporting periods some of our APMs adjust the relevant IFRS measures for exceptional items. Refer to the Group's 30 June 2021 Financial Information for further information on exceptional items.

Exceptional items are those gains or losses where their nature, including the expected frequency of the events giving rise to them, and impact is considered material to the Group's Consolidated Financial Statements. The exceptional items included within the Group's profit for the period are detailed below.

Year ended 30 June	2021 US$M	2020 US$M
Revenue	–	–
Other income	34	489
Expenses excluding net finance costs, depreciation, amortisation and impairments	(592)	(1,025)
Depreciation and amortisation	–	–
Net impairments	(2,371)	(409)
Loss from equity accounted investments, related impairments and expenses	(1,456)	(508)
Profit/(loss) from operations	**(4,385)**	**(1,453)**
Financial expenses	(85)	(93)
Financial income	–	–
Net finance costs	**(85)**	**(93)**
Profit/(loss) before taxation	**(4,470)**	**(1,546)**
Income tax (expense)/benefit	(1,327)	241
Royalty-related taxation (net of income tax benefit)	–	–
Total taxation (expense)/benefit	**(1,327)**	**241**
Profit/(loss) after taxation from Continuing and Discontinued operations	**(5,797)**	**(1,305)**
Total exceptional items attributable to non-controlling interests	(24)	(201)
Total exceptional items attributable to BHP shareholders	(5,773)	(1,104)
Exceptional items attributable to BHP shareholders per share (US cents)	(114.2)	(21.9)
Weighted basic average number of shares (Million)	5,057	5,057

APMs derived from Consolidated Income Statement

Underlying attributable profit

Year ended 30 June	2021 US$M	2020 US$M
Profit after taxation from Continuing and Discontinued operations attributable to BHP shareholders	11,304	7,956
Total exceptional items attributable to BHP shareholders[1]	5,773	1,104
Underlying attributable profit	**17,077**	**9,060**

(1) Refer to Exceptional items for further information.

Underlying basic earnings per share

Year ended 30 June	2021 US cents	2020 US cents
Basic earnings per ordinary share	223.5	157.3
Exceptional items attributable to BHP shareholders per share[1]	114.2	21.9
Underlying basic earnings per ordinary share	**337.7**	**179.2**

(1) Refer to Exceptional items for further information.

Underlying EBITDA

Year ended 30 June	2021 US$M	2020 US$M
Profit from operations	25,906	14,421
Exceptional items included in profit from operations[1]	4,385	1,453
Underlying EBIT	**30,291**	**15,874**
Depreciation and amortisation expense	6,824	6,112
Net impairments	2,635	494
Exceptional item included in Depreciation, amortisation and impairments[1]	(2,371)	(409)
Underlying EBITDA	**37,379**	**22,071**

(1) Refer to Exceptional items for further information.

Underlying EBITDA margin

Year ended 30 June 2021 US$M	Petroleum	Copper	Iron Ore	Coal	Group and unallocated items/ eliminations[4]	Total Group
Revenue – Group production	3,935	13,482	34,457	5,154	1,493	58,521
Revenue – Third party products	11	2,244	18	–	23	2,296
Revenue	**3,946**	**15,726**	**34,475**	**5,154**	**1,516**	**60,817**
Underlying EBITDA – Group production	2,299	8,425	26,277	288	24	37,313
Underlying EBITDA – Third party products	1	64	1	–	–	66
Underlying EBITDA[1]	**2,300**	**8,489**	**26,278**	**288**	**24**	**37,379**
Segment contribution to the Group's Underlying EBITDA[2]	6%	23%	70%	1%		100%
Underlying EBITDA margin[3]	58%	62%	76%	6%		64%

Year ended 30 June 2020 US$M	Petroleum	Copper	Iron Ore	Coal	Group and unallocated items/ eliminations[4]	Total Group
Revenue – Group production	4,031	9,577	20,782	6,242	1,128	41,760
Revenue – Third party products	39	1,089	15	–	28	1,171
Revenue	**4,070**	**10,666**	**20,797**	**6,242**	**1,156**	**42,931**
Underlying EBITDA – Group production	2,209	4,306	14,561	1,632	(669)	22,039
Underlying EBITDA – Third party products	(2)	41	(7)	–	–	32
Underlying EBITDA[1]	**2,207**	**4,347**	**14,554**	**1,632**	**(669)**	**22,071**
Segment contribution to the Group's Underlying EBITDA[2]	10%	19%	64%	7%		100%
Underlying EBITDA margin[3]	55%	45%	70%	26%		53%

(1) Refer to Underlying EBITDA for further information.

(2) Percentage contribution to Group Underlying EBITDA, excluding Group and unallocated items.

(3) Underlying EBITDA margin excludes Third party products.

(4) Group and unallocated items includes functions, other unallocated operations including Potash, Nickel West, legacy assets and consolidation adjustments.

APMs derived from Consolidated Cash Flow Statement

Capital and exploration expenditure

Year ended 30 June	2021 US$M	2020 US$M
Capital expenditure (purchases of property, plant and equipment)	6,606	6,900
Add: Exploration expenditure	514	740
Capital and exploration expenditure (cash basis)	**7,120**	**7,640**

Free cash flow

Year ended 30 June	2021 US$M	2020 US$M
Net operating cash flows	27,234	15,706
Net investing cash flows	(7,845)	(7,616)
Free cash flow	**19,389**	**8,090**

APMs derived from Consolidated Balance Sheet

Net debt and gearing ratio

Year ended 30 June	2021 US$M	2020 US$M Restated	2019 US$M Restated
Interest bearing liabilities – Current	2,628	5,012	1,661
Interest bearing liabilities – Non current	18,355	22,036	23,167
Total interest bearing liabilities	**20,983**	**27,048**	**24,828**
Comprising:			
Borrowing	17,087	23,605	24,113
Lease liabilities	3,896	3,443	715
Less: Lease liability associated with index-linked freight contracts	**1,025**	**1,160**	**–**
Less: Cash and cash equivalents	**15,246**	**13,426**	**15,613**
Less: Net debt management related instruments[(1)]	557	433	(204)
Less: Net cash management related instruments[(2)]	34	(15)	(27)
Less: Total derivatives included in net debt	**591**	**418**	**(231)**
Net debt	**4,121**	**12,044**	**9,446**
Net assets[(3)]	55,605	52,175	51,753
Gearing	**6.9%**	**18.8%**	**15.4%**

(1) Represents the net cross currency and interest rate swaps included within current and non-current other financial assets and liabilities.

(2) Represents the net forward exchange contracts related to cash management included within current and non-current other financial assets and liabilities.

(3) 30 June 2020 and 30 June 2019 net assets have been restated to reflect changes to Group's accounting policy following a decision by the IFRS Interpretations Committee on IAS 12 'Income Tax' resulting in a retrospective decrease of US$71 million . Refer to note 1 'Impact of new accounting standards and interpretations and changes in accounting policies'.

Net debt waterfall

Year ended 30 June	2021 US$M	2020 US$M
Net debt at the beginning of the period	**(12,044)**	**(9,446)**
Net operating cash flows	27,234	15,706
Net investing cash flows	(7,845)	(7,616)
Net financing cash flows	(17,922)	(9,752)
Net increase/(decrease) in cash and cash equivalents from Continuing and Discontinued operations	**1,467**	**(1,662)**
Carrying value of interest bearing liability repayments	**7,433**	**1,533**
Carrying value of debt related instruments (proceeds)/settlements	**(167)**	**157**
Carrying value of cash management related instruments settlements/(proceeds)	**403**	**(451)**
Fair value adjustment on debt (including debt related instruments)	58	88
Foreign exchange impacts on cash (including cash management related instruments)	(1)	(26)
IFRS 16 leases taken on at 1 July 2019	–	(1,778)
Lease additions	(1,079)	(363)
Other	(191)	(96)
Non-cash movements	**(1,213)**	**(2,175)**
Net debt at the end of the period	**(4,121)**	**(12,044)**

Net operating assets

Year ended 30 June	2021 US$M	2020 US$M Restated
Net assets[(1)]	**55,605**	**52,175**
Less: Non-operating assets		
Cash and cash equivalents	(15,246)	(13,426)
Trade and other receivables[(2)]	(280)	(194)
Other financial assets[(3)]	(1,516)	(2,425)
Current tax assets	(279)	(366)
Deferred tax assets	(1,912)	(3,688)
Assets held for sale	(324)	–
Add: Non-operating liabilities		
Trade and other payables[(4)]	227	310
Interest bearing liabilities	20,983	27,048
Other financial liabilities[(5)]	588	1,618
Current tax payable	2,800	913
Non-current tax payable	120	109
Deferred tax liabilities	3,314	3,779
Liabilities directly associated with the assets held for sale	17	–
Net operating assets	**64,097**	**65,853**

(1) 30 June 2020 balance sheet has been restated to reflect changes to Group's accounting policy following a decision by the IFRS Interpretations Committee on IAS 12 'Income Tax'. Refer to note 1 'Impact of new accounting standards and interpretations and changes in accounting policies'.

(2) Represents loans to associates, external finance receivable and accrued interest receivable included within other receivables.

(3) Represents cross currency and interest rate swaps, forward exchange contracts related to cash management and investment in shares and other investments.

(4) Represents accrued interest payable included within other payables.

(5) Represents cross currency and interest rate swaps and forward exchange contracts related to cash management.

Other APMs

Principal factors that affect Revenue, Profit from operations and Underlying EBITDA

The following table describes the impact of the principal factors that affected Revenue, Profit from operations and Underlying EBITDA for the year ended 30 June 2021 and relates them back to our Consolidated Income Statement.

	Revenue US$M	Total expenses, Other income and Loss from equity accounted investments US$M	Profit from operations US$M	Depreciation, amortisation and impairments and Exceptional Items US$M	Underlying EBITDA US$M
Year ended 30 June 2020					
Revenue	**42,931**				
Other income		**777**			
Expenses excluding net finance costs		**(28,775)**			
Loss from equity accounted investments, related impairments and expenses		**(512)**			
Total other income, expenses excluding net finance costs and Loss from equity accounted investments, related impairments and expenses		**(28,510)**			
Profit from operations			**14,421**		
Depreciation, amortisation and impairments				**6,606**	
Exceptional item included in Depreciation, amortisation and impairments				**(409)**	
Exceptional items				**1,453**	
Underlying EBITDA					**22,071**
Change in sales prices	17,186	(221)	**16,965**	–	**16,965**
Price-linked costs	–	(870)	**(870)**	–	**(870)**
Net price impact	17,186	(1,091)	**16,095**	–	**16,095**
Change in volumes	(371)	59	**(312)**	–	**(312)**
Operating cash costs	–	(34)	**(34)**	–	**(34)**
Exploration and business development	–	109	**109**	–	**109**
Change in controllable cash costs	–	75	**75**	–	**75**
Exchange rates	104	(1,692)	**(1,588)**	–	**(1,588)**
Inflation on costs	–	(286)	**(286)**	–	**(286)**
Fuel and energy	–	223	**223**	–	**223**
Non-cash	–	282	**282**	–	**282**
One-off items	(142)	20	**(122)**	–	**(122)**
Change in other costs	(38)	(1,453)	**(1,491)**	–	**(1,491)**
Asset sales	–	17	**17**	–	**17**
Ceased and sold operations	(22)	264	**242**	–	**242**
Other	1,131	(449)	**682**	–	**682**
Depreciation, amortisation and impairments	–	(891)	**(891)**	891	**–**
Exceptional items	–	(2,932)	**(2,932)**	2,932	**–**
Year ended 30 June 2021					
Revenue	**60,817**				
Other income		**510**			
Expenses excluding net finance costs		**(34,500)**			
Loss from equity accounted investments, related impairments and expenses		**(921)**			
Total other income, expenses excluding net finance costs and Loss from equity accounted investments, related impairments and expenses		**(34,911)**			
Profit from operations			**25,906**		
Depreciation, amortisation and impairments				**9,459**	
Exceptional item included in Depreciation, amortisation and impairments				**(2,371)**	
Exceptional items				**4,385**	
Underlying EBITDA					**37,379**

Underlying return on capital employed (ROCE)

Year ended 30 June	2021 US$M	2020 US$M Restated
Profit after taxation from Continuing and Discontinued operations	13,451	8,736
Exceptional items[1]	5,797	1,305
Subtotal	**19,248**	**10,041**
Adjusted for:		
Net finance costs	1,305	911
Exceptional items included within net finance costs[1]	(85)	(93)
Income tax expense on net finance costs	(337)	(267)
Profit after taxation excluding net finance costs and exceptional items	**20,131**	**10,592**
Net assets at the beginning of the period[2]	52,175	51,753
Net debt at the beginning of the period	12,044	9,446
Capital employed at the beginning of the period	**64,219**	**61,199**
Net assets at the end of the period[2]	55,605	52,175
Net debt at the end of the period	4,121	12,044
Capital employed at the end of the period	**59,726**	**64,219**
Average capital employed	61,973	62,709
Underlying Return on Capital Employed	**32.5%**	**16.9%**

(1) Refer to Exceptional items for further information.

(2) The Underlying ROCE calculation uses the restated net assets for the comparative period.

Underlying return on capital employed (ROCE) by segment

Year ended 30 June 2021 US$M	Petroleum	Copper	Iron Ore	Coal	Group and unallocated items/ eliminations[1]	Total Group
Profit after taxation excluding net finance costs and exceptional items	109	4,191	16,640	(454)	(355)	20,131
Average capital employed	9,471	23,710	16,042	8,262	4,488	61,973
Underlying Return on Capital Employed	**1%**	**18%**	**104%**	**(5%)**	**–**	**32.5%**

Year ended 30 June 2020 US$M Restated[2]	Petroleum	Copper	Iron Ore	Coal	Group and unallocated items/ eliminations[1]	Total Group
Profit after taxation excluding net finance costs and exceptional items	90	1,705	9,105	373	(681)	10,592
Average capital employed	9,161	23,118	16,227	8,786	5,417	62,709
Underlying Return on Capital Employed	**1%**	**7%**	**56%**	**4%**	**–**	**16.9%**

(1) Group and unallocated items includes functions, other unallocated operations including Potash, Nickel West, legacy assets and consolidation adjustments.

(2) The Underlying ROCE calculation uses the restated net assets for the comparative period.

Underlying return on capital employed (ROCE) by asset

Year ended 30 June 2021 US$M	Western Australia Iron Ore	Antamina	Escondida	Pampa Norte	Petroleum[1]	Olympic Dam	Potash	Queensland Coal	Cerrejón	New South Wales Energy Coal	Other	Total Group
Profit after taxation excluding net finance costs and exceptional items	16,665	593	3,281	302	464	214	5	(103)	(13)	(203)	(1,074)	20,131
Average capital employed	18,661	1,353	10,353	3,760	8,283	8,021	3,710	7,475	483	269	(395)	61,973
Underlying Return on Capital Employed	**89%**	**44%**	**32%**	**8%**	**6%**	**3%**	**0%**	**(1%)**	**(3%)**	**(75%)**	**–**	**32.5%**

Year ended 30 June 2020 US$M Restated[2]	Western Australia Iron Ore	Antamina	Escondida	Pampa Norte	Petroleum[1]	Olympic Dam	Potash	Queensland Coal	Cerrejón	New South Wales Energy Coal	Other	Total Group
Profit after taxation excluding net finance costs and exceptional items	9,106	200	1,656	161	459	(83)	(132)	862	(97)	(204)	(1,336)	10,592
Average capital employed	18,351	1,346	11,053	3,040	8,028	7,520	4,197	7,172	781	826	395	62,709
Underlying Return on Capital Employed	**50%**	**15%**	**15%**	**5%**	**6%**	**(1%)**	**(3%)**	**12%**	**(12%)**	**(25%)**	**–**	**16.9%**

(1) Excludes Exploration.

(2) The Underlying ROCE calculation uses the restated net assets for the comparative period.

Definition and calculation of alternative performance measures

Alternative Performance Measures (APMs)	Reasons why we believe the APMs are useful	Calculation methodology
Underlying attributable profit	Allows the comparability of underlying financial performance by excluding the impacts of exceptional items and is also the basis on which our dividend payout ratio policy is applied.	Profit after taxation attributable to BHP shareholders excluding any exceptional items attributable to BHP shareholders.
Underlying basic earnings per share	On a per share basis, allows the comparability of underlying financial performance by excluding the impacts of exceptional items.	Underlying attributable profit divided by the weighted basic average number of shares.
Underlying EBITDA	Used to help assess current operational profitability excluding the impacts of sunk costs (i.e. depreciation from initial investment). Each is a measure that management uses internally to assess the performance of the Group's segments and make decisions on the allocation of resources.	Earnings before net finance costs, depreciation, amortisation and impairments, taxation expense, discontinued operations and exceptional items. Underlying EBITDA includes BHP's share of profit/(loss) from investments accounted for using the equity method including net finance costs, depreciation, amortisation and impairments and taxation expense/(benefit).
Underlying EBITDA margin		Underlying EBITDA excluding third party product EBITDA, divided by revenue excluding third party product revenue.
Underlying EBIT	Used to help assess current operational profitability excluding net finance costs and taxation expense (each of which are managed at the Group level) as well as discontinued operations and any exceptional items.	Earnings before net finance costs, taxation expense, discontinued operations and any exceptional items. Underlying EBIT includes BHP's share of profit/(loss) from investments accounted for using the equity method including net finance costs and taxation expense/(benefit).
Profit from operations		Earnings before net finance costs, taxation expense and discontinued operations. Profit from operations includes Revenue, Other income, Expenses excluding net finance costs and BHP's share of profit/(loss) from investments accounted for using the equity method including net finance costs and taxation expense/(benefit).
Capital and exploration expenditure	Used as part of our Capital Allocation Framework to assess efficient deployment of capital. Represents the total outflows of our operational investing expenditure.	Purchases of property, plant and equipment and exploration expenditure.
Free cash flow	It is a key measure used as part of our Capital Allocation Framework. Reflects our operational cash performance inclusive of investment expenditure, which helps to highlight how much cash was generated in the period to be available for the servicing of debt and distribution to shareholders.	Net operating cash flows less net investing cash flows.
Net debt	Net debt shows the position of gross debt less index-linked freight contracts offset by cash immediately available to pay debt if required and any associated derivative financial instruments. Liability associated with index-linked freight contracts, which are required to be remeasured to the prevailing freight index at each reporting date, are excluded from the net debt calculation due to the short-term volatility of the index they relate to not aligning with how the Group uses net debt for decision making in relation to the Capital Allocation Framework. Net debt includes the fair value of derivative financial instruments used to hedge cash and borrowings to reflect the Group's risk management strategy of reducing the volatility of net debt caused by fluctuations in foreign exchange and interest rates. Net debt, along with the gearing ratio, is used to monitor the Group's capital management by relating net debt relative to equity from shareholders.	Interest bearing liabilities less liability associated with index-linked freight contracts less cash and cash equivalents less net cross currency and interest rate swaps less net cash management related instruments for the Group at the reporting date.
Gearing ratio		Ratio of Net debt to Net debt plus Net assets.
Net operating assets	Enables a clearer view of the assets deployed to generate earnings by highlighting the net operating assets of the business separate from the financing and tax balances. This measure helps provide an indicator of the underlying performance of our assets and enhances comparability between them.	Operating assets net of operating liabilities, including the carrying value of equity accounted investments and predominantly excludes cash balances, loans to associates, interest bearing liabilities, derivatives hedging our net debt, assets held for sale, liabilities directly associated with assets held for sale and tax balances.

Alternative Performance Measures (APMs)	Reasons why we believe the APMs are useful	Calculation methodology
Underlying return on capital employed (ROCE)	Indicator of the Group's capital efficiency and is provided on an underlying basis to allow comparability of underlying financial performance by excluding the impacts of exceptional items.	Profit after taxation excluding exceptional items and net finance costs (after taxation) divided by average capital employed. Profit after taxation excluding exceptional items and net finance costs (after taxation) is profit after taxation from Continuing and Discontinued operations excluding exceptional items, net finance costs and the estimated taxation impact of net finance costs. These are annualised for a half year end reporting period. The estimated tax impact is calculated using a prima facie taxation rate on net finance costs (excluding any foreign exchange impact). Average capital employed is calculated as the average of net assets less net debt for the last two reporting periods.
Adjusted effective tax rate	Provides an underlying tax basis to allow comparability of underlying financial performance by excluding the impacts of exceptional items.	Total taxation expense/(benefit) excluding exceptional items and exchange rate movements included in taxation expense/(benefit) divided by Profit before taxation and exceptional items.
Unit cost	Used to assess the controllable financial performance of the Group's assets for each unit of production. Unit costs are adjusted for site specific non-controllable factors to enhance comparability between the Group's assets.	Ratio of net costs of the assets to the equity share of sales tonnage. Net costs is defined as revenue less Underlying EBITDA and excludes freight and other costs, depending on the nature of each asset. Freight is excluded as the Group believes it provides a similar basis of comparison to our peer group. Petroleum unit costs exclude: • exploration, development and evaluation expense as these costs do not represent our cost performance in relation to current production and the Group believes it provides a similar basis of comparison to our peer group; • other costs that do not represent underlying cost performance of the business. Escondida unit costs exclude: • by-product credits being the favourable impact of by-products (such as gold or silver) to determine the directly attributable costs of copper production. WAIO, Queensland Coal and NSWEC unit costs exclude: • royalties as these are costs that are not deemed to be under the Group's control, and the Group believes exclusion provides a similar basis of comparison to our peer group.

Definition and calculation of principal factors

The method of calculation of the principal factors that affect the period on period movements of Revenue, Profit from operations and Underlying EBITDA are as follows:

Principal factor	Method of calculation
Change in sales prices	Change in average realised price for each operation from the prior period to the current period, multiplied by current period sales volumes.
Price-linked costs	Change in price-linked costs (mainly royalties) for each operation from the prior period to the current period, multiplied by current period sales volumes.
Change in volumes	Change in sales volumes for each operation multiplied by the prior year average realised price less variable unit cost.
Controllable cash costs	Total of operating cash costs and exploration and business development costs.
Operating cash costs	Change in total costs, other than price-linked costs, exchange rates, inflation on costs, fuel and energy costs, non-cash costs and one-off items as defined below for each operation from the prior period to the current period.
Exploration and business development	Exploration and business development expense in the current period minus exploration and business development expense in the prior period.
Exchange rates	Change in exchange rate multiplied by current period local currency revenue and expenses.
Inflation on costs	Change in inflation rate applied to expenses, other than depreciation and amortisation, price-linked costs, exploration and business development expenses, expenses in ceased and sold operations and expenses in new and acquired operations.
Fuel and energy	Fuel and energy expense in the current period minus fuel and energy expense in the prior period.
Non-cash	Change in net impact of capitalisation and depletion of deferred stripping from the prior period to the current period.
One-off items	Change in costs exceeding a pre-determined threshold associated with an unexpected event that had not occurred in the last two years and is not reasonably likely to occur within the next two years.
Asset sales	Profit/(loss) on the sale of assets or operations in the current period minus profit/(loss) on sale of assets or operations in the prior period.
Ceased and sold operations	Underlying EBITDA for operations that ceased or were sold in the current period minus Underlying EBITDA for operations that ceased or were sold in the prior period.
Share of profit/(loss) from equity accounted investments	Share of profit/(loss) from equity accounted investments for the current period minus share of profit/(loss) from equity accounted investments in the prior period.
Other	Variances not explained by the above factors.

Definition and calculation of Key Indicator terms

We use various Key Indicators to reflect our sustainability performance.

Management uses these Key Indicators to evaluate BHP's performance against both positive and negative impacts of operational activities and our progress against our sustainability commitments and targets.

This section outlines why we believe the Key Indicators are useful to the Board, management, investors and other stakeholders, and the methodology behind the metrics. A definition and explanation of each of the Key Indicators are provided in the tables below.

Health and safety-related metrics

Our highest priority is the safety of our people and the communities in which we operate. This is why are focussed on introducing more reliable and effective controls across our safety risk profile and improving human and organisational performance, enabling our people to work safely each day. Our work in fatality elimination is underpinned by our field leadership program, ensuring our leaders are spending quality time in field engaging with our workforce. The health and safety Key Indicators allow the Board, management, investors and other stakeholders to measure and track health and safety performance at our operated assets.

Key Indicator	Calculation methodology
High Potential Injury (HPI)	High potential injury frequency (HPIF) is an indicator which measures the number of injuries with fatal potential per million hours. HPIFR equals the sum of (lost time cases + restricted work cases + medical treatment cases + first aid cases) x 1,000,000 ÷ total hours worked. High potential injuries remain a primary focus to assess progress against our most important safety objective: to eliminate fatalities. The basis of calculation for high potential injuries was revised in FY2020 from event count to injury count as part of a safety reporting methodology improvement. In some events, multiple people are injured. This methodology has been prepared in accordance with GRI standard 403-9.
Total Recordable Injury Frequency (TRIF)	Total recordable injury frequency (TRIF) is an indicator which measures the number of recordable injuries per million hours. TRIF equals the sum of (fatalities + lost-time cases + restricted work cases + medical treatment cases) x 1,000,000 ÷ total hours worked total exposure hours. BHP adopts the US Government Occupational Safety and Health Administration (OSHA) guidelines for the recording and reporting of occupational injury and illnesses. TRIF statistics exclude non-operated assets. Year-on-year improvement of TRIF is one of our five-year sustainability targets and is one of the indicators used to assess our safety performance. This methodology has been prepared in accordance with GRI standard 403-9 and OSHA guidelines.

Climate change-related metrics

We recognise the impacts of climate change may impact BHP in a range of areas. Climate-related risks include the potential physical impacts of acute and chronic risks, and transition impacts arising from the transition to a lower carbon economy. Our climate change Key Indicators help us monitor our climate change commitments to mitigate the risks and potential impacts associated with climate change to BHP, as well as fulfil our regulatory reporting obligations. The Key Indicators allow the Board, management, investors and other stakeholders to measure BHP's performance against these commitments.

Key Indicator	Calculation methodology

Operational greenhouse gas emissions

Definition

Scope 1 greenhouse gas emissions are direct emissions from operations that are owned or controlled by BHP, primarily emissions from fuel consumed by haul trucks at our operated assets, as well as fugitive methane emissions from coal and petroleum production at our operated assets. Scope 1 refers to direct GHG emissions from our operated assets.

Scope 2 greenhouse gas emissions are indirect emissions from the generation of purchased or acquired electricity, steam, heat or cooling that is consumed by operations that are owned or controlled by BHP. Our Scope 2 emissions have been calculated using the market-based method using supplier-specific emission factors unless otherwise specified. A residual mix is currently unavailable to account for voluntary purchases and this may result in double counting between electricity consumers.

Scope 1 and 2 emissions have been calculated on an operational control basis in accordance with mandatory minimum performance requirements for HSEC reporting, which are in line with the Greenhouse Gas Protocol definitions and are measured in tonnes of carbon dioxide equivalent, and in line with the Greenhouse Gas Protocol Corporate Accounting and Reporting Standard and the Greenhouse Gas Protocol Scope 2 Guidance.

Calculation methodology

The emissions figures are calculated using the activity data collected at our operated assets. Activity data is multiplied by an energy content (where necessary) and emission factors to derive the energy consumption and GHG emissions associated with a process or an operation. Examples of activity data include kilowatt-hours of electricity used or quantity of fuel used.

Energy and Scope 1 emissions for facilities already reporting to mandatory local regulatory programs are required to use the same emission factors and methodologies for reporting under BHP's operational control boundary. This ensures a single emissions and energy inventory is maintained for consistency and efficiency. Local regulatory programs were applicable to the majority of BHP's Scope 1 emissions inventory in FY2020 (operational control boundary), as listed in the table below. A local regulatory program in this context refers to any scheme requiring emissions to be calculated using mandated references (e.g. the Green Tax legislation in Chile, which requires emissions to be calculated using the Intergovernmental Panel on Climate Change (IPCC) factors) or mandated emission factors (e.g. the Australian National Greenhouse and Energy Reporting (NGER) Scheme or US EPA GHG reporting program, which publish factors specific to the programs). In the absence of local mandatory regulations, the Australian NGER (Measurement) Determination has been set as the default source for emission factors and methodologies for consistency with the majority of the emissions inventory.

Asset	Location	Local regulations
BMA, BMC, NSW Energy Coal, Olympic Dam, Nickel West, WA Iron ore, Petroleum – Australia	Australia	National Greenhouse and Energy Reporting Scheme
Escondida, Pampa Norte	Chile	Green Tax legislation (referencing IPCC factors)
Petroleum – Gulf of Mexico	USA	US EPA GHG reporting program
Potash – Canada	Canada	Canadian Greenhouse Gas Reporting Program (referencin IPCC factors)
Petroleum – Trinidad	Trinidad	None

Scope 2 emissions totals are reported using the market-based method (default calculation approach unless otherwise stated) and the location-based method, as recommended by the GHG Protocol Scope 2 Guidance. Definitions of location and market-based reporting used in BHP's accounting are consistent with the Greenhouse Gas Protocol terminology as follows:

- Market-based reporting: Scope 2 GHG emissions based on the generators (and therefore the generation fuel mix from which the reporter contractually purchases electricity and/or is directly provided electricity via a direct line transfer).
- Location-based reporting: Scope 2 GHG emissions based on average energy generation emission factors for defined geographic locations, including local, subnational or national boundaries (i.e. grid factors). In the case of a direct line transfer, the location-based emissions are equivalent to the market-based emissions.

For facilities where market-based reporting is required, electricity emission factors are sourced directly from the supplier in the first instance. An emission factor in the public domain, which is specific to the generation plant supplying the facility, is considered equivalent to a supplier-specific factor in this context.

Where supplier-specific factors are not available, a default emission factor for off-grid electricity is used

Key Indicator	Calculation methodology
	instead, as published in local regulations or industry frameworks (or the default off-grid electricity emission factor from the Australian NGER (Measurement) Determination) in the case where no local default is available. The location-based method is applied using electricity emission factors for the relevant grid network, as sourced from local regulations, industry frameworks or publications from the local grid administrator. These methodologies have been prepared in accordance with GRI standard 305-1 and GRI standard 305-2. More information on the calculation methodologies for other reported categories, boundaries assumptions and key references used in the preparation of our Scope 1 and Scope 2 emissions data can be found in the BHP Scope 1, 2 and 3 Emissions Calculation Methodology, available at bhp.com/climate.
Value chain emissions	Scope 3 emissions have been calculated on a carbon dioxide equivalent basis using methodologies consistent with the Greenhouse Gas Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard (Scope 3 Standard). Scope 3 emissions refers to all other indirect emissions (not included in Scope 2) that occur in BHP's value chain, primarily emissions resulting from our customers using the fossil fuel commodities and processing the non-fossil fuel commodities we sell, as well as upstream emissions associated with the extraction, production and transportation of the goods, services, fuels and energy we purchase for use at our operated assets; emissions resulting from the transportation and distribution of our products; and operational emissions (on an equity basis) from our non-operated joint ventures. Scope 3 emissions reporting necessarily requires a degree of overlap in reporting boundaries due to our involvement at multiple points in the life cycle of the commodities we produce and consume. A significant example of this is that Scope 3 emissions reported under Category 10: 'Processing of sold products' include the processing of our iron ore to steel. This third party activity also consumes metallurgical coal as an input, a portion of which is produced by us. For reporting purposes, we account for Scope 3 emissions from combustion of metallurgical coal with all other fossil fuels under the Category 11: 'Use of sold products', such that a portion of metallurgical coal emissions is accounted for under two categories. This is an expected outcome of emissions reporting between the different scopes defined under the standard GHG accounting practices and is not considered to detract from the overall value of our Scope 3 emissions disclosure. This double counting means that the emissions reported under each category should not be added up, as to do so would give an inflated total figure. For this reason, we do not report a total Scope 3 emissions figure. The below methodology describes the emissions from Category 10: Processing of sold products and Category 11: Use of sold products. These categories are the most material Scope 3 emission categories and together account for almost 95 per cent of Scope 3 emissions. **Category 10: Processing of sold products** Emissions from the processing of intermediate products sold in the reporting year by downstream companies (e.g. manufacturers) subsequent to sale by the reporting company. **Calculation methodology** The average-data method as described in the Greenhouse Gas Protocol Technical Guidance for Calculating Scope 3 Emissions (Scope 3 Guidance) is used to calculate these emissions, with industry-average emission factors applied to production volumes (on an equity basis) for each commodity to calculate an overall emissions estimate for this category. **Assumptions** • To estimate emissions from the processing of iron ore, all iron ore production is assumed to be processed to steel. To estimate the higher-end estimate, the crude steel emission factor is applied to the volume of crude steel produced from BHP's iron ore. • To estimate the lower-end emissions number from the processing of iron ore, it is assumed that the crude steel emission factor already takes into account emissions from both iron ore and metallurgical coal. Therefore, the crude steel emission factor is apportioned based on the ratio of iron ore and metallurgical coal input to produce 1,000 kilograms of crude steel (based on World Steel Association's integrated blast furnace and basic oxygen furnace route). The crude steel emission factor is split to estimate the emissions from iron ore and metallurgical coal (calculated in Category 11: Use of sold products). The split factor is applied to the volume of crude steel produced from BHP's iron ore. The estimated crude steel produced with BHP's iron ore is significantly higher than with BHP's metallurgical coal (due to higher iron ore production). Therefore, this approach does not capture third party metallurgical coal emissions in the steelmaking process. • To estimate emissions from the processing of copper, we apply an emission factor for the processing of copper to copper wire (rather than alternative products such as tubes or sheets), as this is the most emissions-intensive process and therefore the most 'conservative' assumption.

Key Indicator	Calculation methodology
	Category 11: Use of sold products Emissions from the end use of goods and services sold by the reporting company in the reporting year. **Calculation methodology** The method recommended in the Scope 3 Guidance for 'direct use-phase' emissions calculations for 'Fuels and feedstocks' is used to calculate these emissions, with industry-average emission factors applied to production volumes (on an equity basis) for each commodity to calculate an overall emissions estimate for this category. For the lower-end estimate emissions from metallurgical coal, the average-data method as described in the Scope 3 Guidance is used to calculate these emissions, with industry-average emission factors applied to production volumes (on an equity basis) for metallurgical coal to calculate an overall emissions estimate for this category. **Assumptions** • All metallurgical coal (higher end estimate), energy coal, natural gas and petroleum products are assumed to be combusted. • In practice, metallurgical coal is primarily used in steelmaking and a portion of the carbon content remains embedded in the final steel product and is not released to the atmosphere; the quantities involved vary according to the feedstocks, processing technologies and output specifications of the process route used. • To estimate the lower-end emissions number from the use of metallurgical coal, it is assumed that crude steel emission factor already takes into account emissions from both iron ore and metallurgical coal. Therefore, the crude steel emission factor is apportioned based on the ratio of iron ore and metallurgical coal input to produce 1,000 kilograms of crude steel (based on World Steel Association's integrated blast furnace and basic oxygen furnace route). The crude steel emission factor is split to estimate the emissions from metallurgical coal and iron ore (calculated in Category 10: Processing of sold products). The split factor is applied to the volume of crude steel produced from BHP's metallurgical coal. It should be noted that in reality, BHP's metallurgical coal may not end up with the same customer as our iron ore. • All energy coal is assumed to be bituminous, which has a mid-range energy content among the three sub-categories of black coal (the others being sub-bituminous coal and anthracite) listed in the NGER Measurement Determination published by the Australian Government (Australian NGER Determination), from which these emission factors are sourced. • All crude oil and condensates are assumed to be refined and combusted as diesel (rather than alternative products such as gasoline) as the most emissions-intensive, therefore the most conservative assumption. The energy content of the crude oil and condensate volumes is used to estimate the corresponding quantity of diesel that would be produced, assuming that no fuel is 'lost' during the refining process. • Emissions from LPG and ethane volumes are included in emissions reported for 'natural gas liquids' (NGL) production and are assumed to be combusted with the same NGL emission factors. This assumption has minimal impact on estimated emissions due to the small volumes involved. This methodology has been prepared in accordance with GRI standard 305-3. More information on the calculation methodologies for other reported categories, boundaries assumptions and key references used in the preparation of our Scope 3 emissions data can be found in the associated BHP Scope 1, 2 and 3 Emissions Calculation Methodology, available at bhp.com/climate.

Fresh water withdrawals

We acknowledge the nature of our operations can have significant environmental impacts. Our water withdrawal metrics allow the Board and management to manage and monitor the inherent risks relating to, and any adverse impacts our operations may have on, water resources. They also allow the Board, management, investors and other stakeholders to measure and track our performance towards our water-use commitments. Water withdrawal metrics assist the Board and management in understanding the significance of our water resource use, collectively for the Group and by individual operated assets, and to assess trends over time. It also helps inform investment in infrastructure to reduce water withdrawals and improve efficiency of water use.

Key Indicator	Calculation methodology
Fresh water withdrawals	The volume of freshwater, in megalitres (ML), received and intended for use within the reporting period by the operated asset from the water environment and/or a third party supplier. Fresh water is defined as waters other than seawater, wastewater from third parties and hypersaline groundwater. Freshwater withdrawal also excludes entrained water that would not be available for other uses. These exclusions have been made to align with the target's intent to reduce the use of freshwater sources subject to competition from other users or the environment.

People-related metrics

Our global workforce is the foundation of our business and we believe that supporting the wellbeing of our people and promoting an inclusive and diverse culture are vital for maintaining a competitive advantage. The proportion of the workforce that are female or Indigenous workers are key indicators, which allow the Board, management, investors and other stakeholders to measure and track our near and long-term progress.

Key Indicator	Calculation methodology
Female workforce representation (%)	The number of female employees as a proportion of the total workforce on the last day of the respective reporting period, used in internal management reporting for the purposes of monitoring progress against our goals.
Indigenous workforce participation (%)	The number of Indigenous employees as a proportion of the total workforce in the relevant countries on the last day of the respective reporting period, used in internal management reporting for the purposes of monitoring progress against our goals. There is no significant seasonal variation in employment numbers. These methodologies have been prepared in accordance with GRI standard 102-8 and GRI standard 405-1.

Petroleum reserves and resources, producing assets and project information

Year ended 30 June 2021

Statement of petroleum resources

The estimates of Petroleum Reserves and Contingent Resources contained in this presentation are based on, and fairly represent, information and supporting documentation prepared under the supervision of Mr. A. G. Gadgil, who is employed by BHP. Mr. Gadgil is a member of the Society of Petroleum Engineers and has the required qualifications and experience to act as a qualified Petroleum Reserves and Resources evaluator under the ASX Listing Rules. This presentation is issued with the prior written consent of Mr. Gadgil who agrees with the form and context in which the Petroleum Reserves and Contingent Resources are presented. Reserves and Contingent Resources are net of royalties owned by others and have been estimated using deterministic methodology. Aggregates of Reserves and Contingent Resources estimates contained in this presentation have been calculated by arithmetic summation of field/project estimates by category with the exception of the North West Shelf (NWS) Gas Project in Australia. Probabilistic methodology has been utilised to aggregate the NWS Reserves and Contingent Resources for the reservoirs dedicated to the gas project only and represents an incremental 6 MMboe of Proved Reserves. The barrel of oil equivalent conversion is based on 6000 scf of natural gas equals 1 boe. The Reserves and Contingent Resources contained in this presentation are inclusive of fuel required for operations. The respective amounts of fuel for each category are provided by the following table. Production volumes exclude fuel. The custody transfer point(s)/point(s) of sale applicable for each field or project are the reference point for Reserves and Contingent Resources. Reserves and Contingent Resources estimates have not been adjusted for risk. Unless noted otherwise, Reserves and Contingent Resources are as of 30 June 2021. Where used in this presentation, the term Resources represents the sum of 2P reserves and 2C Contingent Resources. BHP estimates Proved Reserve volumes according to SEC disclosure regulations and files these in our annual 20-F report with the SEC. All Unproved volumes are estimated using SPE-PRMS guidelines, which among other things, allow escalations to prices and costs, and as such, would be on a different basis than that prescribed by the SEC, and are therefore excluded from our SEC filings. All Resources and other Unproved volumes may differ from and may not be comparable to the same or similarly-named measures used by other companies. Non-proved estimates are inherently more uncertain than proved.

Net BHP Petroleum Reserves and Contingent Resources (MMboe) as of 30 June 2021

	Australia						United States					Trinidad & Tobago		Mexico	Algeria	Other Assets	BHP Total
	Bass Strait	NWS	Pyrenees	Macedon	Scarborough	Thebe+ Jupiter	Shenzi	Shenzi North	Wildling	Atlantis	Mad Dog	Angostura + Ruby	Calypso	Trion	ROD		
1P	**107**	**151**	**12**	**43**	**0**	**0**	**74**	**0**	**0**	**79**	**137**	**52**	**0**	**0**	**9**	**0**	**665**
2P	**179**	**186**	**21**	**54**	**0**	**0**	**105**	**0**	**0**	**175**	**192**	**86**	**0**	**0**	**13**	**0**	**1011**
2C	**209**	**35**	**16**	**18**	**390**	**142**	**94**	**31**	**64**	**223**	**173**	**34**	**409**	**275**	**33**	**50**	**2195**
2P+2C	**387**	**222**	**36**	**72**	**390**	**142**	**199**	**31**	**64**	**398**	**365**	**120**	**409**	**275**	**45**	**50**	**3206**
Fuel Included Above																	
1P	9.5	21.4	0.2	2.8	0.0	0.0	2.9	0.0	0.0	4.0	4.2	1.4	0.0	0.0	0.8	0.0	47.3
2P	11.4	26.3	0.2	5.4	0.0	0.0	3.2	0.0	0.0	7.0	6.1	2.3	0.0	0.0	0.8	0.0	62.6
2C	6.8	0.1	0.0	1.5	43.9	18.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	71.1
2P+2C	18.2	26.5	0.2	6.9	43.9	18.5	3.2	0.0	0.0	7.0	6.1	2.3	0.0	0.0	0.8	0.2	133.7

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only Proved, Probable and Possible Reserves, and only when such Reserves have been determined in accordance with SEC guidelines. We use certain terms in this presentation such as “Resources,” “Contingent Resources,” “2C Contingent Resources” and similar terms not determined in accordance with the SEC’s guidelines, all of which measures we are strictly prohibited from including in filings with the SEC. These measures include Reserves and Resources with substantially less certainty than Proved Reserves. US investors are urged to consider closely the disclosure in our Form 20-F for the fiscal year ended 30 June 2021, File No. 001-09526 and in our other filings with the SEC, available from us at http://www.bhp.com/. These forms can also be obtained from the SEC as described above.

Petroleum portfolio | Producing assets and growth projects

Asset	Description	Operator	BHP ownership	FY21 Production (MMboe)	End of field life	1P[3] (MMboe)	2P[3] (MMboe)	2P+2C[3] (MMboe)
Producing assets[1]								
Shenzi[2]	Oil asset located in the US Gulf of Mexico with TLP (tension leg platform) development operated by BHP.	BHP	72%	8.1	2030s	74	105	294
Atlantis	One of the largest fields in the US Gulf of Mexico, with field production average of ~93,000 bopd over last 5 years and base decline offset via infill drilling and successful workovers.	BP	44%	12.1	2040s	79	175	398
North West Shelf	Integrated LNG project with material remaining resource position. Five LNG trains allowing transition towards a third party gas tolling facility extending operations for decades to come.	Woodside	12.5% – 16.67% across 9 separate joint venture agreements	24.8	2040s	151	186	222
Mad Dog	Original development with a Truss Spar host (A-Spar): Dry trees, floating spar hull, with integrated drilling and production capabilities of ~4,400 of water depth.	BP	23.9%	4.8	2040s	137	192	365
ROD Integrated Development	The Rhourde Ouled Djemma (ROD) Integrated Development, which consists of the ROD, Sif Fatima – Sif Fatima North East (SF SFNE) and four satellite oil fields.	Joint Sonatrach/ ENI	29.3% effective interest in the ROD Integrated Development	3.1	2020s	9	13	45
Bass Strait	Major integrated asset consisting of offshore facilities, onshore plants and associated pipeline infrastructure. Advantaged gas position with modest investable opportunities.	Exxon	Gippsland Basin Joint Venture (GBJV): 50.0% Kipper Unit Joint Venture (KUJV): 32.5%	28.5	2030s	107	179	387
Pyrenees	Subsea oil development in 200m water depth tied back to FPSO.	BHP	WA-42-L permit: 71.43% WA-43-L permit: 39.999%	3.0	2030s	12	21	36
Macedon	Subsea gas development in 200m water depth tied back to onshore domestic gas plant.	BHP	71.43%	8.4	2030s	43	54	72
Trinidad and Tobago (Angostura and Ruby)	**Angostura:** Discovered by BHP in 1999, phase 2 included a new gas export platform and two pipelines with gas sales to Trinidad & Tobago commencing in 2011. **Ruby:** Developed through a wellhead program, tied back to the Angostura infrastructure. Offsets declining production from Angostura.	BHP	45.0% Block 2(c) 68.46% effective interest in Block 3(a) Project Ruby	9.3	2030s	52	86	120

Asset	Description	Operator	BHP ownership	Potential execution timing (FID)	Potential first production	FY22 – FY30 Capex (BHP share, nominal US$bn)	1P[3] (MMboe)	2P[3] (MMboe)	2P+2C[3] (MMboe)
Growth projects									
Scarborough	Large offshore gas development exporting gas from a floating production unit to Pluto LNG facility for onshore processing.	Woodside	26.5%	CY21	CY26	~2 bn	-	-	532
Trion	Large greenfield development in the deepwater Mexico GoM. Resource uncertainty reduced with recent successful appraisal drilling of 2DEL and 3DEL wells. Recently moved into FEED phase.	BHP	60%	CY22	CY26	<5 bn	-	-	275
Calypso	Operated deepwater advantaged gas discovery in Trinidad & Tobago, well positioned to existing regional infrastructure and with low CO_2 content / low greenhouse gas intensity. Multiple development concepts under evaluation.	BHP	70%	CY26	CY27-28	~3 bn	-	-	409

1. Includes all sanctioned and brownfield projects; Breakeven basis.
2. Includes Shenzi North & Wildling.
3. Based on FY21; includes Shenzi WI acquisition. Scarborough estimates include Thebe & Jupiter.

Petroleum portfolio | Embedded growth within producing assets

Asset	Description	Operator	BHP ownership	Potential first production	Estimated peak production capacity	FY22 – FY30 Capex (BHP share, nominal US$bn)
Sanctioned Projects (in execution)						
Shenzi SSMPP	Shenzi Subsea Multi-Phase Pumping (SSMPP); subsea pumping to increase production rates from existing wells.	BHP	72%	CY22	6.5 kbpd in CY22	<0.25bn
Mad Dog A Spar	3-4 infill wells tied to Mad Dog A Spar.	BP	24%	CY23	18 kbpd in CY26	<0.25bn
Mad Dog Phase 2	Semi-submersible platform with 22 subsea wells (14 producing wells and 8 water injection wells).	BP	24%	CY22	140 kbpd in CY23	~0.75bn
Atlantis Phase 3	8-well subsea tieback achieved first production in CY20.	BP	44%	CY20	35 kbpd in CY24	<0.5bn
Pyrenees Phase 4	Well re-entry program comprising infill drilling and water shut off operation.	BHP	71.43%	CY23	9-10 kbpd (net) in CY23	<0.25bn
NWS Lambert Deep & GWF 3	4-well subsea tieback to existing infrastructure	Woodside	17%	CY22	110 MMscfd (net) in CY22	<0.25bn
Shenzi North	2-well subsea tieback to Shenzi TLP. IRR of over 35%[1], a breakeven of ~$25/bbl and a payback of <2 years.	BHP	72%	CY24	30 kbpd in CY24	<0.5bn

Asset	Description	Operator	BHP ownership	Potential execution timing (FID)	Potential first production	FY22 – FY30 Capex (BHP share, nominal US$bn)
Unsanctioned projects						
Wildling	2-well subsea tieback to Shenzi TLP via Shenzi North.	BHP	100%	CY22 – 23	CY24 – 25	<0.75bn
Shenzi growth opportunities	Additional infill opportunities to increase production with 3 producing and 2 water injection wells tied back to Shenzi TLP.	BHP	72%	CY22 – 25	CY24 – 26	~0.5bn
Atlantis growth opportunities	Additional development opportunities for 12 infill producing wells and 6 additional water injection wells. Opportunity to increase production via Subsea Multi-Phase Pumping (SSMPP) and topside modification.	BP	44%	CY23 – 28	CY25 – 29	~2bn
Mad Dog Phase 2 growth opportunities	Additional opportunities to increase the Mad Dog Phase 2 production beyond the initial investment scope with 9 new wells tied back to existing facility.	BP	24%	CY25 – 26	CY26 – 28	~0.5bn
Mad Dog WI expansion	Two water injector wells providing water from Mad Dog Phase 2 facility to increase production at existing A Spar facility.	BP	24%	CY24	CY25	<0.25bn
NWS growth opportunities	Low risk investment opportunity to maximize Karratha Gas Plant value through processing other resource owner gas; benefits through tolling fees, cost recovery and life extension.	Woodside	17%	CY24 – 26	CY26 – 28	<0.25bn
Bass Strait growth opportunities	Kipper expansion (additional Phase 1B well & compression) for acceleration and incremental resource capture from the Kipper field.	Exxon	GBJV: 50.0% KUJV: 32.5%	CY24 – 27	CY27 – 28	~0.5bn

1. At consensus pricing, 10% nominal discount rate.