MAXWELL PROJECT (SSD 9526)

Submission to the Independent Planning Commission on greenhouse gas emissions and climate change

22 October 2020

ACKNOWLEDGMENTS

Malabar Resources Limited and Maxwell Ventures (Management) Pty Ltd provided information on the quality characteristics of the Maxwell Project coal.

We acknowledge the contribution that Baker McKenzie made in 2019 in respect of an earlier edition of Part B and Appendix 2 and our reliance on the work of CRU International Limited in respect of Part C and Appendix 3 of this submission.

Mark Brennan (Partner) and Kylie Wilson (Senior Associate)
Ashurst

TABLE OF CONTENTS

GLOSSARY

Abbreviation/Acronym	Meaning
2006 IPCC Guidelines	2006 IPCC Guidelines for National Greenhouse Gas Inventories
2019 IPCC Refinement	2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories
ACA	Australian Coal Alliance
ACARP	Australian Coal Association Research Program
ACCUs	Australian carbon credit units
Applicant	Maxwell Ventures (Management) Pty Ltd
Assessment Report	Department of Planning, Industry and Environment, *Maxwell Underground Coal Mine Project: State Significant Development Assessment SSD 9526* (September 2020)
A-USC	Advanced ultra-supercritical
BAU	Business-as-usual
CCUS	Carbon capture, use and storage
CFI Act	*Carbon Credits (Carbon Farming) Act 2011* (Cth)
CHPP	Coal handling and preparation plant
COP	Conference of the Parties
CO_2-e	Carbon dioxide equivalent
CSR	Coke strength after reaction
CTSCo	Carbon Transport Storage Company
Economic Assessment	Economic Assessment by Deloitte Access Economics Pty Ltd dated 2019, which is Appendix M to the EIS for the Project
EIS	Environmental Impact Statement
EPBC Act	*Environment Protection and Biodiversity Conservation Act 1999* (Cth)
EP&A Act	*Environmental Planning and Assessment Act 1979* (NSW)
ERF	Emissions Reduction Fund
ESD	Ecologically sustainable development
ETS	Emissions trading scheme
Expected Export Countries	The countries to which the Project's coal is expected to be exported: Japan, India, South Korea, China, Taiwan, Vietnam, Brazil, Indonesia and Malaysia

Abbreviation/Acronym	Meaning
Project	The Maxwell Project
GHG	Greenhouse gas
GHG Assessment	Air Quality and Greenhouse Gas Assessment by Todoroski Air Sciences Pty Ltd dated 4 July 2019, which is Appendix J to the EIS for the Project
HCC	Hard coking coal (metallurgical coal)
HELE	High-efficiency, low-emissions
IEA	International Energy Agency
INDC	Intended Nationally Determined Contribution
IPC	Independent Planning Commission
IPCC	Intergovernmental Panel on Climate Change
JCM	Japan's Joint Crediting Mechanism
LGA	Local government area
LULUCF	Land use, land-use change and forestry
Malabar	Malabar Resources Limited, the parent company of the Applicant
Mining SEPP	*State Environmental Planning Policy (Mining, Petroleum Production and Extractive Industries) 2007*
Mt	Million tonnes
Mtce	Million tonnes of coal equivalent
MW	Megawatts
NDC	Nationally Determined Contribution
Net Zero Plan Stage 1	NSW Department of Planning, Industry and Environment's *Net Zero Plan Stage 1: 2020–2030* (March 2020)
NGER Act	*National Greenhouse and Energy Reporting Act 2007* (Cth)
NSW	New South Wales
PAC	Planning Assessment Commission
Roadmap	South Korea's revised roadmap for achieving the 2030 National Greenhouse Gas Reduction Goal in July 2018
Rocky Hill	*Gloucester Resources Limited v Minister for Planning* (2009) 234 LGERA 257
ROM	Run-of-mine

Abbreviation/Acronym	Meaning
SC	Supercritical
SEARs	Secretary's Environmental Assessment Requirements
SSCC	Semi-soft coking coal (metallurgical coal)
Strategic Statement on Coal	NSW Government's *Strategic Statement on Coal Exploration and Mining in NSW* (June 2020)
t	Tonnes
Territorial Limits Bill	The *Environmental Planning and Assessment Amendment (Territorial Limits) Bill 2019* (NSW)
Transparency Framework	Transparency Framework adopted under the Katowice Climate Package
UNFCCC	*United Nations Framework Convention on Climate Change*
USC	Ultra-supercritical
Wallarah 2	*Australian Coal Alliance Inc v Wyong Coal Pty Ltd* [2019] NSWLEC 31
WEO	World Energy Outlook
WEO 2019	World Energy Outlook 2019

SUBMISSION TO THE INDEPENDENT PLANNING COMMISSION

1. INTRODUCTION

1.1 Maxwell Ventures (Management) Pty Ltd (the **Applicant**), a wholly-owned subsidiary of Malabar Resources Limited (**Malabar**), seeks consent to establish and operate an underground coal mine, referred to as the Maxwell Project (the **Project**). The Applicant has applied for consent for the Project under the State significant development provisions of the *Environmental Planning and Assessment Act 1979* (NSW) (**EP&A Act**).

1.2 The Project will involve the extraction of up to 8 Mt of ROM coal per year, with an estimated total extraction of approximately 148 Mt of ROM coal over approximately 26 years. At least 75% of product coal produced by the Project would be capable of being used as semi-soft coking coal (**SSCC**) in the making of steel. The balance would be export thermal coal suitable for new-generation high efficiency, low emissions (**HELE**) power generators.

1.3 Malabar owns the land and the substantial, existing infrastructure within Coal Lease (**CL**) 229, Mining Lease (**ML**) 1531 and CL 395 associated with the former Drayton open cut mine (referred to in the Environmental Impact Statement (**EIS**) for the Project as the "Maxwell Infrastructure"). The Applicant will use the Maxwell Infrastructure for handling, processing and transporting the Project's coal. The Applicant commissioned an Air Quality and Greenhouse Gas Assessment by Todoroski Air Sciences Pty Ltd dated 4 July 2019 (**GHG Assessment**), which is Appendix J to the EIS for the Project.

1.4 The Applicant also commissioned an Economic Assessment by Deloitte Access Economics Pty Ltd dated 2019 (**Economic Assessment**), which is Appendix M to the EIS.

1.5 A number of written objections to the Project have been submitted to the Department of Planning, Industry and Environment regarding the Project's greenhouse gas (**GHG**) emissions and the issue of climate change. Those submissions were considered and addressed in the Applicant's Submissions Report.

1.6 This submission is the Applicant's further response on GHG emissions and climate change issues that are relevant to the IPC's assessment and determination of the development application for the Project.

2. STRUCTURE OF THIS SUBMISSION

2.1 This submission contains the following five parts:

(a) **Part A:** the law regarding the consideration of GHG emissions and climate change in determining development applications under the EP&A Act

(b) **Part B:** international, national and State climate change law and policy that the IPC may consider when determining the development application for the Project

(c) **Part C:** the future demand for coal (including under future climate change policy scenarios), the characteristics of the Project's coal, and the likelihood and consequences of coal market substitution

(d) **Part D:** response to submissions made in respect of GHG emissions and climate change

(e) **Part E:** weighing the benefits of the Project against the consideration of GHG emissions and climate change

3. EXECUTIVE SUMMARY

The law regarding the consideration of GHG emissions and climate change in determining the development application under the EP&A Act

3.1 The following key points are made in **Part A** of this submission:

(a) pursuant to s 4.5(1) of the EP&A Act, the IPC must consider, among other things:

(i) the provisions of the State Environmental Planning Policy (Mining, Petroleum Production and Extractive Industries) 2007 (**Mining SEPP**)**,** including the aims of the Mining SEPP and cl 14;

(ii) the likely impacts of the Project, including environmental impacts on both the natural and built environments, and social and economic impacts in the locality; and

(iii) the public interest;

(b) the aims of the Mining SEPP include: to facilitate the orderly and economic use and development of land containing mineral resources, and to promote the development of significant mineral resources;

(c) clause 14(2) of the Mining SEPP requires a consideration of an assessment of the GHG emissions (including downstream emissions);

(d) the NSW Land and Environment Court has said that the obligation to consider the public interest includes the principles of ESD in cases where issues relevant to those principles arise. The principle of intergenerational equity and the precautionary principle can, in turn, involve the consideration of GHG emissions;

(e) the IPC may take into account:

(i) the *Paris Agreement*;

(ii) Australia's Nationally Determined Contribution (**NDC**) under the *Paris Agreement*;

(iii) the NSW Government's Climate Change Policy Framework and its *Net Zero Plan Stage 1: 2020–2030* (March 2020) (**Net Zero Plan Stage 1**); and

(iv) the NSW Government's *Strategic Statement on Coal Exploration and Mining in NSW* (June 2020) (**Strategic Statement on Coal**);

(f) however, GHG emissions and climate change are not the only considerations that inform the public interest. The public interest is broad and captures not only environmental considerations, but also the social and economic benefits associated with the Project for the wider community and the State;

(g) as recognised by the NSW Court of Appeal, ESD is just one of many objects of the EP&A Act, including:

(i) to promote the social and economic welfare of the community and a better environment by the proper management, development and conservation of the State's natural and other resources, and

(ii) to promote the orderly and economic use of land;[1]

(h) the IPC must consider and determine the development application for the Project on its own merits, taking into account both the positive and negative impacts of the Project and all of the relevant considerations under the EP&A Act;

(i) the IPC is not obliged to consider or follow any part of *Gloucester Resources Limited v Minister for Planning* (2019) 234 LGERA 257 (***Rocky Hill***), in which the NSW Land and Environment Court, exercising administrative power in Class 1 of its jurisdiction, found that the significant and unacceptable planning, visual and social impacts of the proposed project were sufficient reasons alone for refusing consent at [556]; and

(j) there are legal and policy reasons why the IPC should not impose conditions of consent that require the Applicant to offset GHG emissions, or that would restrict the export of the Project's product coal. The Territorial Limits Bill, if enacted, would codify this position.

International, national and NSW climate change law and policy

3.2 The following key points are made in **Part B** of this submission:

(a) almost all of the Project's Scope 3 emissions will be counted under the *Paris Agreement* as the Scope 1 GHG emissions of the Expected Export Countries in which the coal is combusted.[2] Any mitigation in relation to the use of coal in steelmaking or electricity generation within those countries will count towards those countries' Nationally Determined Contributions (**NDCs**) under the *Paris Agreement*;

(b) the Expected Export Countries are parties to the *Paris Agreement* (save for Taiwan which is not a member of the United Nations) and have announced or adopted domestic laws and policies to achieve their targets to reduce their GHG emissions as set out in their NDCs (or Intended Nationally Determined Contribution (**INDC**) in the case of Taiwan);[3]

(c) Australia does not require monitoring or reporting of Scope 3 GHG emissions under the NGER Act and does not count Scope 3 GHG emissions in its national inventory of GHG emissions. This would constitute double counting contrary to the Transparency Framework under the *Paris Agreement.* Consequently, refusing development consent to the Project will not help to achieve Australia's NDC;

(d) the carbon budget approach is not endorsed by the *Paris Agreement* as a method by which allocation or sharing of global mitigation efforts among countries can or should occur. Indeed, the carbon budget approach:

(i) is inconsistent with the approach that has been adopted by the *Paris Agreement* for achieving the goal set under that agreement, namely NDCs;

(ii) its application to Scope 3 GHG emissions results in double counting, which is an outcome that the *Paris Agreement* seeks to avoid;

(e) neither the Australian Government nor the NSW Government have advocated the "carbon budget" approach, or indicated that the development of new coal mines, or

---

[1] EP&A Act, s 1.3(a) and (c); *Minister of Planning v Walker* (2008) 161 LGERA 423 at [52].

[2] Some small quantities of thermal coal may be sold on the domestic market (e.g. to AGL's nearby Liddell or Bayswater power stations).

[3] It should be noted that there may be other countries to which the Project's coal is exported from time-to-time during the Project's life. Nevertheless, the *Paris Agreement* has been adopted almost universally having been ratified by 189 countries, 186 of which have submitted their first NDC.

expansion of existing coal mines, is to be prohibited or restricted in any way for the purpose of achieving Australia's NDC;

(f) the Project's Scope 1 GHG emissions will be regulated under the Safeguard Mechanism of the Australian Government's *National Greenhouse and Energy Reporting Act 2007* (**NGER Act**). Once direct GHG emissions exceed 100,000 tCO_2-e/year, the Clean Energy Regulator will set an emissions baseline based on benchmark emissions intensities (that is, the best, least emissions intensive standard for production),[4] and the Applicant will be required to offset any emissions above its baseline, or otherwise manage compliance, in accordance with the NGER Act; and

(g) it is the NSW Government's policy:

(i) as embodied in the *Mining Act 1992* (NSW) and the Mining SEPP, that mineral resources in NSW continue to be developed in recognition of the significant social and economic benefits to NSW that result from the efficient development of mineral resources. The IPC is required by s 4.15 of the EP&A Act to take into consideration the aims of the Mining SEPP;

(ii) as stated in the Net Zero Plan Stage 1 (at 22):

> New South Wales' $36 billion mining sector is one of our biggest economic contributors, supplying both domestic and export markets with high quality, competitive resources. Mining will continue to be an important part of the economy into the future and it is important that the State's action on climate change does not undermine those businesses and the jobs and communities they support.

and

(iii) to support responsible coal production in areas that are suitable for mining, in line with the Strategic Statement on Coal.

Future demand for coal, the characteristics of the Project's coal, and the likelihood and consequences of coal market substitution

3.3 The following key points are made in **Part C** of this submission:

(a) the International Energy Agency's (**IEA**) *World Energy Outlook 2019* (**WEO 2019**) presents three policy scenarios for projecting global energy demand and energy supply:

(i) the Current Policies Scenario is the business-as-usual scenario and assumes that governments do not implement recently announced climate change or GHG mitigation policies and that no new policies are introduced in the future;

(ii) the Stated Policies Scenario, the WEO 2019's central scenario, incorporates policies and measures that have been announced by governments but where the precise implementation measures have not yet been fully defined; and

(iii) the Sustainable Development Scenario, which incorporates a variety of hypothetical government policies compatible with achieving universal access to electricity while achieving the aim of the *Paris Agreement*;

---

[4] *National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2015* (Cth), cl 38(3); http://www.cleanenergyregulator.gov.au/NGER/The-safeguard-mechanism/Baselines

(b) the Project will produce an estimated 148 Mt of ROM coal (125 Mt of product coal) over approximately 26 years. At least 75% of the product coal produced by the Project would be capable of being used as semi-soft coking coal (**SSCC**) in the making of steel. The balance would be export thermal coal suitable for new-generation high efficiency, low emissions (HELE) power generators.;

(c) the IEA projects that, in the Stated Policies Scenario, primary energy demand grows by approximately 24% from 2018 to 2040, driven by structural trends of population growth, urbanisation and economic growth in developing economies, particularly in the Asia Pacific region;

(d) in relation to coal, the IEA projects that demand for coal in the Stated Policies Scenario will essentially remain flat, falling by approximately 1% or 60 Mtce between 2018 and 2040, ending up in 2040 at around 5400 Mtce. Coal-fired electricity generation plateaus and its share of electricity generation declines from 38% in 2018 to 25% in 2040. However, this varies drastically by region. In advanced economies coal-fired electricity generation will more than halve over the period to 2040 while coal consumption will increase in Southeast Asia, where 40% of the projected rise in the region's electricity demand will be met by coal, and coal plants are currently around 12 years old on average (more than 20 years younger than those in advanced economies);

(e) under all three policy scenarios presented by the IEA (including the Sustainable Development Scenario), there will continue to be a global demand for coal. Without new mines or brownfield expansions, the global production of coal would be approximately 600 Mtce in 2040. Under the Sustainable Development Scenario, global demand for coal would be 2,101 Mtce in 2040 of which 858 Mtce would be for electricity and 1,206 Mtce would be for industrial use, including steelmaking.

(f) currently blast furnace-basic oxygen furnace technology is used for the production of approximately 70% of all steel globally produced, for which metallurgical coals, including hard coking coal (**HCC**) and SSCC are essential inputs. HCC and SSCC are used together to produce coke, which is the primary source of carbon in steelmaking. Coke serves two other functions in steel-making: as a fuel (providing heat) and as a chemical-reducing agent (reducing iron oxides). The proportion of each coal used in the coking process is determined by various factors, including pricing differentials, blast furnace requirements and specific characteristics and qualities of the coals;

(g) the IEA projects that coal use in steelmaking declines in the Stated Policy Scenario by around 30 Mtce by 2040, reflecting efficiency gains and the gradual rise in the use of electricity-based routes for steel production. However, in both the Stated Policies Scenario and the Sustainable Development Scenario, coal remains the backbone of steel manufacturing, as the scope to shift away from coal by making greater use of scrap-based or direct reduction of iron (**DRI**)-based electric arc furnaces is limited by the availability and price of scrap steel and the cost of electricity;

(h) the Applicant engaged CRU International Limited (**CRU**) to undertake a study of global coal demand and supply to 2040, the characteristics of the Project's coal compared to the coal produced by other exporting countries, and the likely GHG consequences of coal market substitution if the Project does not go ahead. CRU's forecasts for global coal demand to 2040 are similar to the IEA's projections for the Stated Policies Scenario. The relevant findings in the CRU study are:

    (i) global demand for thermal coal will remain relatively flat from 2019 to 2040, and coal will remain an important pillar of electricity generation in many regions, including in Southeast Asia, as well as in China and India in 2040;

(ii) high quality thermal coal from Australia (such as that produced by the Project) is, and will continue to be, in high demand to meet the electricity generation needs in these regions;

(iii) as the ability of existing mines to meet the global demand for coal declines over time through depletion of reserves, it will be necessary for the demand to be met by expansion of approved coal mines or the development of new coal mines;

(iv) the Project's thermal coal is higher quality (in terms of calorific value) than the country weighted averages of all other thermal coal exporters, including Australia;

(v) more GHGs are emitted when lower quality coal is used, as more lower quality coal is needed to achieve an equivalent energy output than what would be produced through the combustion of a higher quality coal;

(vi) demand for metallurgical coal is driven by demand for steel which will continue to grow to 2040, as it remains an important material for global development, particularly in Southeast Asia. Blast-furnace technology, which is dependent on HCC and SSCC, will still dominate the steelmaking industry to 2040;

(vii) SSCC's vital role in steel production will continue into the future;

(viii) in 2030, the Project's SSCC is estimated to have:

(A) a medium ash content of 8.9%, similar to the country averages for Australia and Mongolia. This quality parameter improves over the life of mine, as mining progresses down through the seam sequence, the ash content of the Project's product coal will reduce; and

(B) low sulphur content of 0.4% (equal with Russia's average) and lower than the Australian average of 0.5%.

These qualities make the Project's SSCC a very marketable SSCC product globally. Additionally, the Project is very low on the business cost curve making it a highly competitive producer of SSCC.

(i) coal investment and supply conditions in Australia have a limited impact on global market conditions, which means that failure to approve the Project will not affect global demand for coal;

(j) the environmental impacts of substituting the shortfall in supply from the Project with alternative sources of thermal coal would likely be adverse, because the Project's coal is high quality (including compared to the weighted average of Australian mines) in calorific terms and low sulphur;

(k) this means that substitution by other coal sources is likely to result in more coal being mined and combusted to meet the same power needs, resulting in higher Scope 3 GHG emissions and greater sulphur dioxide output;

(l) CRU's analysis found that if the Project is not approved, then the absence of coal supply from the Project is estimated to result in the release of an additional 2.2 million to 84.4 million tonnes of CO_2-e into the atmosphere over the life of mine as the result of substituted inferior coal; and

(m) therefore, the failure to approve the Project would likely result in a net increase in GHG emissions globally due to market substitution of the Project's high quality coal with inferior quality coal.

Response to submissions made in respect of GHG emissions and climate change

3.4 In **Part D** of this submission we have:

(a) identified the key submissions made by opponents of the Project that are based on GHG emissions and climate change; and

(b) identified and critically reviewed five common themes relied upon by opponents of the Project which are related to GHG emissions and climate change. Those five themes which are critically reviewed are:

(i) Theme 1 – anthropogenic climate change is a real phenomenon that is occurring, coal is one of the major sources of human-induced GHG emissions, and the Project will contribute to climate change;

(ii) Theme 2 – in order for the "well below 2°C" goal of the Paris Agreement to be realised, no new fossil fuel developments should be approved;

(iii) Theme 3 – the approval of the Project would be inconsistent with Australia's international commitments and existing climate change laws and policies, particularly Australia's NDC and the NSW Climate Change Policy Framework;

(iv) Theme 4 – in light of the global move towards decarbonisation, the Project will likely become a stranded asset; and

(v) Theme 5 – the IPC should follow *Rocky Hill* and refuse development consent for the Project.

Weighing the benefits of the Project against the consideration of GHG emissions and climate change

3.5 The following key points are made in **Part E** of this submission:

(a) based on the information provided by the Applicant to the IPC, the Applicant considers that there is more than sufficient information before the IPC to comfortably reach a conclusion that the benefits of the Project outweigh its impacts. Those benefits include:

(i) development of the Project solely as an underground mining operation to minimise local environmental impacts while using methods that would maximise resource recovery and mining efficiency;

(ii) the use of the Maxwell Infrastructure for the Project that will result in significantly less disturbance and a lower initial capital cost than would otherwise be required for a greenfield coal mine;

(iii) the continued rehabilitation at the Maxwell Infrastructure including reduction in the volume of the legacy east void through emplacement of reject material generated by coal processing activities for the Project;

(iv) an estimated total net benefit to the NSW economy of $1,010 million in net present value terms, including $342 million (in net present value terms) to the NSW Government royalties, company income tax attributable to NSW of $168 million, plus payroll tax, land taxes and council rates, which will benefit present and future generations; and

(v) approximately 250 jobs during construction and up to 350 new direct, long-term, operational jobs for the region.

4. PART A: THE LAW REGARDING CONSIDERATION OF CLIMATE CHANGE AND GHG EMISSIONS IN DETERMINING A DEVELOPMENT APPLICATION UNDER THE EP&A ACT

4.1 In Part A of the submission, the following is addressed:

(a) the law regarding the consideration of climate change and GHG emissions (particularly Scope 3 emissions) in determining a development application under the EP&A Act;

(b) the type and nature of conditions of consent that may be imposed by the IPC in relation to GHG emissions and climate change; and

(c) relevance of the Territorial Limits Bill to the IPC's assessment and determination of the development application for the Project.

4.2 Each of these will be addressed in turn below.

The law regarding the consideration of climate change and GHG emissions in determining a development application under the EP&A Act

4.3 As a starting point, the exercise of the IPC's discretion under the EP&A Act is governed by the scope and subject matter of the EP&A Act.

4.4 The objects of the EP&A Act relevantly include:

(a) to promote the social and economic welfare of the community and a better environment by the proper management, development and conservation of the State's natural and other resources (s 1.3(a));

(b) to facilitate ecologically sustainable development by integrating relevant economic, environmental and social considerations in decision-making about environmental planning and assessment (s 1.3(b));

(c) to promote the orderly and economic use and development of land (s 1.3(c)); and

(d) to promote the sharing of the responsibility for environmental planning and assessment between the different levels of government in the State (s 1.3(i)).

4.5 In determining a development application, s 4.15 of the EP&A Act requires the consent authority to take into consideration certain matters as are of relevance to the development, including:

(a) the provisions of any relevant environmental planning instrument (s 4.15(1)(a)(i));

(b) "the likely impacts of the development, including environmental impacts on both the natural and built environments, and social and economic impacts in the locality" (s 4.15(1)(b)); and

(c) the public interest (s 4.15(1)(e)).

4.6 The main environmental planning instrument of relevance to the Project is the *State Environmental Planning Policy (Mining, Petroleum Production and Extractive Industries) 2007* (**Mining SEPP**). The aims of the Mining SEPP "in recognition of the importance to New South Wales of mining, petroleum production and extractive industries" include:

(a) to provide for the proper management and development of mineral, petroleum and extractive material resources for the purpose of promoting the social and economic welfare of the State (cl 2(a));

(b) to facilitate the orderly and economic use and development of land containing mineral, petroleum and extractive material resources (cl 2(b));

(c) to promote the development of significant mineral resources (cl 2(b1)); and

(d) to establish appropriate planning controls to encourage ecologically sustainable development through the environmental assessment, and sustainable management, of development of mineral, petroleum and extractive material resources (cl 2(c)).

4.7 Clause 14 of the Mining SEPP relevantly states:

> **14 Natural resource management and environmental management**
>
> (1) Before granting consent for development for the purposes of mining… the consent authority must consider whether or not the consent should be issued subject to conditions aimed at ensuring that the development is undertaken in an environmentally responsible manner, including conditions to ensure the following—
>
> …
>
> (c) that greenhouse gas emissions are minimised to the greatest extent practicable.
>
> (2) Without limiting subclause (1), in determining a development application for development for the purposes of mining… the consent authority must consider an assessment of the greenhouse gas emissions (including downstream emissions) of the development, and must do so having regard to any applicable State or national policies, programs or guidelines concerning greenhouse gas emissions.

4.8 The following things should be noted about s 4.15 of the EP&A Act and cl 14(2) of the Mining SEPP:

(a) statutes are always read as being prima facie restricted in their operation within territorial limits.[5] This principle of interpretation is reflected in s 12(1) of the *Interpretation Act 1987* (NSW) which states that in any Act or instrument "a reference to a locality jurisdiction or other matter or thing is a reference to such a locality, jurisdiction or other matter or thing in and of New South Wales." This applies unless a contrary intention appears in the Act or instrument concerned;[6]

(b) the starting point to interpreting s 4.15 of the EP&A Act is that the impacts of the development (both direct and indirect) that are to be considered are impacts of the development in and of NSW;

(c) in relation to the provisions of any relevant environmental planning instrument, clause 14(2) of the Mining SEPP requires a consideration of an assessment of the GHG emissions (including downstream emissions), being prima facie GHG emissions in and of NSW;[7]

---

[5] *Jumbunna Coal Mine NL v Victorian Coal Miners' Association* (1908) 6 CLR 309, 363 (O'Connor J).

[6] *Interpretation Act 1987* (NSW), s 5(2).

[7] This is supported by the *Guidelines for the economic assessment of mining and coal seam gas proposals* (dated December 2015), in which it appears to be suggested that the assessment of the economic aspects of a given project are to be considered at local, regional and State scale, but not at a higher scale.

(d) the expression "public interest", when used in a statute like the EP&A Act, imports a discretionary value judgment to be made by reference to undefined factual matters and is unconfined except by the scope and subject matter of the EP&A Act;[8]

(e) the public interest is, as a result, broad and captures not only environmental considerations associated with the Project, but also the social and economic benefits associated with the Project for the wider community and the State;

(f) the NSW Land and Environment Court has said that the obligation to consider the public interest under s 4.15(1)(e) of the EP&A Act obliges the consent authority to have regard to the principles of ESD in cases where issues relevant to those principles arise;[9]

(g) as acknowledged by the NSW Court of Appeal, ESD is just one of many objects of the EP&A Act, including:

(i) to promote the social and economic welfare of the community and a better environment by the proper management, development and conservation of the State's natural and other resources, and

(ii) to promote the orderly and economic use of land;[10] and

(h) there is authority that consideration of the public interest and principles of ESD can involve consideration of Scope 3 GHG emissions.[11]

4.9 The Applicant accepts that the IPC may take into account the Paris Agreement, Australia's NDC under the Paris Agreement, the NSW Government's Climate Change Policy Framework, its Net Zero Plan Stage 1 and its Strategic Statement on Coal**.**

4.10 The Applicant accepts that the IPC can consider, as part of the public interest, the GHG emissions of the Project (including Scope 3 emissions), and the Project's contribution to climate change insofar as that contribution is likely to impact NSW. However, the Applicant submits that:

(a) climate change and GHG emissions are not the only considerations that inform the public interest and, certainly, are not to be solely determinative of the Project;[12]

(b) it is for the IPC to determine how much weight is to be attributed to the relevant social, economic and environmental factors associated with the Project (including the climate change impacts and GHG emissions of the Project); and

(c) the IPC's approach to considering and weighting the relevant factors is not prescribed, dictated or restricted by the decision in *Gloucester Resources Limited v Minister for Planning* [2019] NSWLEC 7 (***Rocky Hill***).

---

[8] *The Pilbara Infrastructure Pty Ltd v Australian Competition Tribunal* (2012) 246 CLR 379 at [42] per French CJ, Gummow, Hayne, Crennan, Kiefel and Bell JJ.

[9] *Telstra Corporation Ltd v Hornsby Shire Council* (2006) 67 NSWLR 256 at [121]-[124], cited with agreement in *Minister of Planning v Walker* (2008) 161 LGERA 423 per Hodgson J at [42]-[43]. However, the NSW Court of Appeal has been more circumspect at least in respect of decisions under Part 3A of the EP&A Act, stating that the principles of ESD "are likely to come to be seen as so plainly an element of the public interest, in relation to most if not all decisions, that failure to consider them will become strong evidence of failure to consider the public interest": *Minister of Planning v Walker* (2008) 161 LGERA 423 per Hodgson J at [56].

[10] EP&A Act, s 1.3(a) and (c); *Minister of Planning v Walker* (2008) 161 LGERA 423 at [52].

[11] See, e.g., *Gray v Minister for Planning* (2006) 152 LGERA 258 at [126], [135].

[12] This proposition also gains support generally from Justice Moore's recent decision in *Australian Coal Alliance Incorporated v Wyong Coal Pty Ltd* [2019] NSWLEC 31 at [96] to [105] and from the NSW Court of Appeal's decision in *Minister of Planning v Walker* (2008) 161 LGERA 423.

4.11 The Applicant's position on the relevance of *Rocky Hill* is summarised as follows:

(a) the Court's decision in *Rocky Hill* was the determination of a "merit appeal" whereby the Court "stands in the shoes" of the consent authority and determines the merits of a development application. The Court's decision is, therefore, not a legal precedent that the IPC is obliged to follow;

(b) in contrast, *Australian Coal Alliance Inc v Wyong Coal Pty Ltd* [2019] NSWLEC 31 (***Wallarah 2***), which was decided after *Rocky Hill*, was the determination of judicial review proceedings, with the consequence that this case is a legal precedent and is, in the Applicant's submission, both binding on and instructive to the IPC as to how the issue of climate change and GHG emissions may be addressed by the IPC in determining the development application for the Project;

(c) in *Wallarah 2*, the Court found that there was no legal error in a consent authority approving a new coal mine in circumstances where:

(i) the combustion of the project's coal was predicted to generate Scope 3 emissions significantly greater (by a factor of 7) than those of the Rocky Hill Coal Project;

(ii) there was no proposal to offset those emissions;

(iii) the consent authority considered and accepted the concept of coal market substitution; and

(iv) the consent authority considered that Scope 3 emissions should be dealt with at the location where those emissions are generated or at higher policy levels.

(d) *Rocky Hill* was concerned with the specific facts and circumstances of that proposed mining project, particularly being in the Gloucester Valley, close to the town of Gloucester;

(e) in *Rocky Hill*, climate change impacts and GHG emissions were not the essential reasons for the refusal of the Rocky Hill Coal Project, as the Court made clear at [556] that the significant and unacceptable planning, visual and social impacts of the proposed project were sufficient reasons alone for refusing the development application for the Rocky Hill Coal Project;

(f) the Court in *Rocky Hill* did not adopt the carbon budget approach or the position that, in order to achieve the goal of the *Paris Agreement*, fossil-fuel developments must be refused. Instead the Court stated that the carbon budget approach "admits that some fossil fuel reserves can be exploited and burned" (at [551]) and that the carbon budget approach (at [552]–[553]):

> assume[s] that all existing and approved fossil fuel developments will continue and there will be no reduction in GHG emissions from these sources. It gives priority to existing and approved fossil fuel developments, along the lines of "first in, best dressed". It also frames the decision as a policy decision that no fossil fuel development should ever be approved.
>
> I consider the better approach is to evaluate the merits of the particular fossil fuel development that is the subject of the development application to be determined. Should this fossil fuel development be approved or refused? Answering this question involves consideration of the GHG emissions of the development and their likely contribution to climate change and its consequences, as well as the other impacts of the development. The consideration can be in absolute terms or relative terms.

(g) the IPC is obliged to consider and determine the development application for the Project on its own, individual merits, having regard to the environmental assessment material and information that is before it;

(h) the IPC, in determining the development application for the Project, is not obliged to consider, adopt, distinguish or follow any aspect of the Court's decision in *Rocky Hill*, as the Court's decision in *Wallarah 2* (which is a binding, legal precedent) confirms;

(i) the IPC is required to assess all of the impacts of the Project (both positive and negative) and all of the relevant considerations under the EP&A Act, which involves an "intuitive synthesis of the relevant factors";[13]

(j) as is evident from the judgment in *Wallarah 2*, the fact that a project generates GHG emissions does not mean that the starting position for consideration of a development application is that the Project should be refused, and that fact is also not singularly determinative for the purposes of considering a development application made under the EP&A Act for any type of development, coal mining being only one of many types of development which generate GHG emissions;

(k) there is no government policy or legal principle that dictates the extent to which GHG emissions generated by the Project, or the combustion of the Project's coal by other developments, are to be considered and weighted in determining a development application under the EP&A Act, and there is no prescribed quantitative criteria against which the Project's GHG emissions are to be assessed;

(l) it is for the IPC to determine how much weight it will accord to the climate change impacts and GHG emissions generated by the Project or the combustion of the Project's coal by other developments, compared to all the other relevant considerations under the EP&A Act; and

(m) for the reasons given in Parts C, D and E of this submission, it is submitted that the climate change impacts and GHG emissions generated by the Project or the combustion of the Project's coal by other developments do not outweigh the significant social and economic benefits that the Project will deliver at a local, regional and State level (which are summarised in Part E of this submission and are addressed in other documents already before the IPC, such as the Environmental Impact Statement).

The type and nature of conditions of consent that may be imposed in relation to GHG emissions and climate change

4.12 The case of *Hunter Environment Lobby Inc v Minister for Planning* [2011] NSWLEC 221 is relevant to the type and nature of conditions of consent that may be imposed. Whilst that decision was also in a merit appeal like in *Rocky Hill* (and thus, has no precedent value), the Applicant considers that certain aspects of that decision are worth bringing to the IPC's attention.

4.13 That case was a merit appeal brought in respect of the consolidation and expansion of the Ulan coal mine. At [32] of the judgment, Justice Pain noted that "some of the conditions that [Hunter Environment Lobby] seek to impose are novel, particularly in relation to measures to offset GHG emissions".

4.14 Hunter Environment Lobby sought conditions of consent that would require an offset for Scope 1 and 2 emissions, but not for Scope 3 emissions.

[13] *Bulga Milbrodale Progress Association Inc v Minister for Planning and Infrastructure* (2013) 194 LGERA 347 at [41]–[42].

4.15 Mr Kitto of the then Department of Planning and Environment (**DP&E**) gave evidence in the proceedings. His evidence was that the imposition of conditions on a planning approval requiring offset of GHG emissions would be "inconsistent with the government's policy of not using the development assessment process in the EP&A Act to impose obligations on proponents to offset the GHG emissions of their projects and contrary to the DP&E's practice of at least 5 years of applying this policy to the assessment and regulation of all major projects in NSW" (at [59]).

4.16 Mr Kitto summarised the DP&E's position as being that development approval conditions are unsuitable for implementing a regulatory regime to require proponents to offset some or all of the GHG emissions of their projects. Key reasons given for this position were (at [60]):

(a) such a regime would be inefficient, ineffective and inequitable because conditions could only be imposed on new projects, not existing ones;

(b) no existing mines in NSW are required to offset their GHG emissions (we believe that statement remains true today, to the extent that no existing mine is required by a condition of consent to offset its GHG emissions. Some mines will be subject to the Federal government's Safeguard Mechanism and will need to offset GHGs that are emitted above a certain baseline, as discussed in paragraphs 5.36 to 5.41 below);

(c) imposing a regulatory regime through conditions would make the coal supply from a few mines more expensive and would not drive change across the industry;

(d) in the absence of a national or international scheme for offsetting GHG emissions, the regulatory regime imposed by the conditions would need to rely on a collection of largely voluntary schemes to achieve offsets;

(e) the regime would be inflexible as consents could only be modified at the request of the proponent; and

(f) the regime would be complex to administer as it would not be uniform for all proponents.

4.17 Justice Pain held that it was within power to impose a condition on a planning approval requiring the offset of Scope 1 emissions generated by a project, finding that the fact that "the impact is felt within and also beyond NSW does not suggest that legally a condition should not be imposed under state legislation which seeks to ameliorate one contributor to that impact" (at [93]).

4.18 At [94], her Honour declined to determine whether it would be lawful to impose conditions requiring the offset of Scope 2 emissions, but clearly expressed doubts on the validity of such a condition:

> Scope 2 emissions are different to scope 1 emissions. By contrast scope 2 emissions result from diesel and electricity use at the project and are not emissions which Ulan can control entirely … [W]hile Ulan can minimise electricity and diesel use at the mine it cannot influence how an electricity generator and supplier chooses to generate the electricity Ulan uses … A condition framed to require offsetting of scope 2 emissions would be open to criticism that to the extent that those emissions are under the control of others, the requirement would not fairly relate to the development [one of the three criteria to be satisfied under the *Newbury* test for a valid condition of development consent]. It was not clear from the evidence how identifiable those parts of the scope 2 emissions are which Ulan has the ability to minimise or of any other form of control. The incentive for the electricity generator to reduce the production of GHG will also be removed if Ulan has to offset these, a poor policy outcome as identified in the Respondent's submissions.

4.19 It stands to reason that, if Justice Pain's logic in [94] is accepted (which it should be), it would be invalid to impose conditions of development consent on the SSD consent for the Project which requires offset of Scope 2 or of Scope 3 GHG emissions, which may be even further beyond the control of the Applicant than Scope 2 GHG emissions.

4.20 At [100] et seq, her Honour resolved to impose a condition requiring offset of Scope 1 GHG emissions.

4.21 However, in a later judgment – *Hunter Environment Lobby Inc v Minister for Planning (No 2)* [2012] NSWLEC 40 – Justice Pain departed from the position of imposing a condition requiring offset of Scope 1 GHG emissions generated by the project following the passage of the *Clean Energy Act 2011* (Cth). It appears that the main reason why her Honour did not impose a condition requiring the proponent to offset the project's Scope 1 GHG emissions was that she was satisfied that the Commonwealth scheme as represented by the *Clean Energy Act 2011* (Cth) and related legislation, met "at a practical level the purpose of imposing a condition requiring the offset of Scope 1 GHG emissions" (at [16]).

4.22 In light of Justice Pain's observations in these cases, as well as the information contained in this submission, the Applicant submits that:

(a) the IPC should not impose a condition of consent requiring Scope 1 GHG emissions of the Project to be offset because the Commonwealth Government's Safeguard Mechanism will apply to the Project as described in Part B;

(b) it would be unlawful for a condition of consent to be imposed for the Project requiring offset of Scope 2 and Scope 3 GHG emissions, because it would breach the *Newbury* tests for a valid condition of development consent;

(c) the position in paragraph 4.22(b) above will be codified by the Territorial Limits Bill, which will prohibit conditions of consent imposed for the purpose of achieving objectives relating to the impacts occurring outside Australia as a result of the development, or the impacts occurring in NSW as a result of development carried out outside Australia. The Minister for Planning in his second reading speech for the Bill said that the Bill is "consistent with the well-defined Newbury test for conditions of consent and the development of case law in line with the Newbury Principles";

(d) even if it was lawful to impose a condition of consent requiring the offset of Scope 2 and Scope 3 GHG emissions, there are strong policy reasons why it would be inappropriate for such a condition of development consent to be imposed (see paragraphs 4.15 and 4.16 above); and

(e) there are also strong policy reasons why it would be inappropriate for a condition of development consent to be imposed requiring offset of Scope 1 emissions, in that there are existing Commonwealth laws regulating GHG emissions (as set out in Part B of the submission) which will apply to the Project.

4.23 Although the IPC imposed a condition of consent for the United Wambo Open Cut Coal Mine Project (SSD 7142) that requires the proponent to use all reasonable and feasible measures to ensure that coal is only exported to countries that are signatories to the *Paris Agreement*, the Applicant submits that:

(a) it would be unlawful for an export control condition to be imposed for the Project, including because:

(i) it would breach one or more of the *Newbury* tests for a valid condition of development consent, including for the same reasons as set out in *Hunter Environment Lobby Inc v Minister for Planning* [2011] NSWLEC 221 at [94]. That is, the condition which would be aimed at minimising Scope 3 GHG emissions would not reasonably and fairly relate to the development the subject of the application;[14] and

[14] See *Western Australian Planning Commission v Temwood Holdings Pty Ltd* (2004) 21 CLR 20 per McHugh J at [57].

(ii) the Commonwealth Government has comprehensively regulated the topic of foreign exports and the countries to which certain goods may lawfully be exported by reference to international treaty obligations. This is reflected in the detailed regime of the *Customs Act 1901* (Cth) and other legislation. Therefore, by reason of s 109 of the *Commonwealth Constitution*, s 4.38(1) of the EP&A Act does not authorise the imposition of conditions of consent regulating export permissibility;

(b) the position in paragraph 4.23(a) above will also be codified by the Territorial Limits Bill. The Minister for Planning in his second reading speech for the Bill said that:

> Whilst the United Wambo development consent related to overseas downstream greenhouse gas emissions, conditions like this one highlight a technical and jurisdictional issue with the Environmental Planning and Assessment Act 1979, which does not deal expressly with the extraterritorial impacts of development—that is, impacts of development outside the territorial limits of Australia and therefore outside the territorial capacity of the New South Wales planning system to effectively be involved with the enforcement of such conditions. When the United Wambo conditions were initially proposed, the Government expressed concern that consideration of downstream, or scope 3, greenhouse gas emissions did not automatically mean that those emissions should be controlled by the conditions of a development consent.
>
> …
>
> … As the secretary of the planning department correctly highlighted in his letter to the Independent Planning Commission in relation to the United Wambo proposal, it is not the Government's policy to regulate—either directly or indirectly—matters of international trade. They are matters for the Commonwealth Government… It is therefore important that we clarify the limitations of the New South Wales planning system to control the impacts of development that occurs overseas.

(c) even if it were lawful to impose an export control condition, there are strong practical and policy reasons why it would be inappropriate for such a condition of development consent to be imposed:

(i) it would be inefficient and inequitable to impose export control conditions only on new projects, not existing ones (existing consents could only be modified at the request of the proponent); and

(ii) it is not compatible with the reality of the global coal trade where coal sales are not always made directly to end users, but also to traders, other producers, third parties and customers who operate in multiple jurisdictions, which means that the destination country is not always known to the mine operator and the mine operator does not have control over the on-selling and distribution of coal once it is exported. Coal might be on-sold and blended multiple times before it reaches its final destination.

Relevance of the Territorial Limits Bill to the IPC's assessment and determination of the development application for the Project

4.24 The Territorial Limits Bill was introduced to NSW Parliament on 24 October 2019 following the IPC's decision to grant consent to the United Wambo Open Cut Coal Mine. That consent was granted subject to conditions that require the applicant to use all reasonable and feasible measures to ensure that any coal that is to be exported is only exported to countries that are parties to the *Paris Agreement*.

4.25 The Territorial Limits Bill, if enacted, will amend the EP&A Act and the Mining SEPP by:

(a) inserting a new condition 4.17A into the EP&A Act:

> **4.17A Prohibited conditions**
>
> (1) A condition of a development consent described in this section has no effect despite anything to the contrary in this Act,
>
> (2) A condition imposed for the purpose of achieving outcomes or objectives relating to—
>
> (a) the impacts occurring outside Australia or an external Territory as a result of the development, or
>
> (b) the impacts occurring in the State as a result of any development carried out outside Australia or an external Territory.

(b) Omitting the words "(including downstream emissions)" from clause 14(2) of the Mining SEPP, which is relevantly extracted in paragraph 4.7 above, so that clause 14(2) as amended will require the IPC to consider only an assessment of the greenhouse gas emissions of the development.

4.26 The Territorial Limits Bill, if enacted and in force, will:

(a) render ineffective an export control condition such as that imposed by the IPC on the United Wambo Open Cut SSD consent, if such a condition is purported to be imposed on a new development consent, and

(b) mean that the IPC is no longer required by the Mining SEPP to consider downstream GHG emissions. However, the IPC may still take into account the Scope 3 GHG emissions of the Project and the Project's impact on the climate as part of its consideration of the public interest under s 4.15 of the EP&A Act as discussed above.

5. PART B: INTERNATIONAL, NATIONAL AND STATE CLIMATE CHANGE LAW AND POLICY

5.1 There are a range of climate change laws and policies that may inform, where applicable, the IPC's consideration of climate change and GHG emissions as one of the many matters of relevance to the IPC's decision.

5.2 In Part B of this submission, the Applicant provides commentary on:

(a) the international climate change framework, focussing on the *Paris Agreement*;

(b) the issue of double counting of GHG emissions and how that is addressed in the international and Australian climate change frameworks;

(c) the carbon budget approach and its limited role as a tool in the international and Australian climate change frameworks;

(d) Australia's NDC under the *Paris Agreement*, and the national laws and policies that Australia has adopted to achieve its NDC;

(e) the domestic climate change laws, policies, NDCs and objectives of the countries that are most likely to be the export destinations for the Project's coal; and

(f) the NSW Climate Change Policy Framework and the Net Zero Plan Stage 1.

The international climate change framework

5.3 The international framework that addresses GHG emissions, and more broadly the global response to climate change, comprises:

(a) the *United Nations Framework Convention on Climate Change* (**UNFCCC**);

(b) the *Kyoto Protocol*;

(c) the *Paris Agreement*; and

(d) associated decisions by the Conference of the Parties serving each of the above instruments.

5.4 The UNFCCC was adopted in 1992 and represented the first step by countries to address the issue of climate change. It set an overarching objective of stabilising GHG concentrations in the atmosphere at a level that would prevent "dangerous anthropogenic interference with the climate system". The *Kyoto Protocol* was adopted in 1997 and imposed limits on GHG emissions to be met by developed countries, both individually and collectively, during the first commitment period from 2008 to 2012. The second commitment period of the *Kyoto Protocol* runs from 1 January 2013 to 31 December 2020, but the amendment to the *Kyoto Protocol* that would introduce that second commitment period has not entered into force.

5.5 The *Paris Agreement* builds upon the UNFCCC and, for the first time, requires *all* parties (not just developed countries) to undertake ambitious efforts to combat climate change and adapt to its effects, with enhanced support to assist developing countries to do so. The *Paris Agreement* aims to strengthen the global response to climate change by holding the increase in global average temperatures to "well below 2°C" and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels. To achieve this goal, countries aim to peak and then reduce emissions "as soon as possible" to "achieve a balance between anthropogenic emissions by sources and removals by sinks" in the second half of the century.

5.6 In contrast to the approach of the *Kyoto Protocol*, which imposed limitation or reduction commitments on certain parties, one of the key features of the *Paris Agreement* is the use of NDCs. NDCs are high-level policy plans setting out what approach each country will take to reduce emissions and contribute to the global "well below 2°C" goal. Parties' first NDCs were submitted in 2015 with new or updated NDCs to be submitted every five years. 186 parties to the *Paris Agreement* have submitted their first NDC (or INDC in the case of Taiwan), including Australia and the countries that are expected to be the export destinations for the vast majority of the Project's coal, being Japan, India, South Korea, China, Taiwan, Vietnam, Brazil, Indonesia and Malaysia (**Expected Export Countries**).[15] Parties' updated or second NDCs are due to be submitted to the UNFCCC in 2020. Twelve countries, including Japan and Vietnam, have submitted a second or updated NDC in 2020. The NDCs of Australia and the Expected Export Countries are addressed under separate sub-headings below in this Part B of the submission.

5.7 At the 24th Conference of the Parties in Katowice in December 2018, the Katowice Climate Change Package was adopted. That package contains, among other things, guidance on the features of NDCs, the information each country should provide to facilitate clarity, transparency and understanding of NDCs and accounting for NDCs. In general terms, they establish a common set of elements that each Party will apply, as appropriate, based on the type of its NDC. Importantly, the guidance ensures the avoidance of "double counting" of emissions. The issue of "double counting" is discussed below.

The issue of double counting GHG emissions and how that is addressed in the international and Australian climate change frameworks

5.8 For the purposes of the commentary which follows, it is useful to provide a high level overview of the three scopes of GHG emissions.

5.9 The three scopes of GHG emissions may be defined or described as follows:

(a) **Scope 1:** direct emissions occurring from sources that are owned or controlled by the proponent of the Project (e.g. fuel use of on-site plant and equipment, fugitive emissions). These emissions are emissions over which the Project has a high level of control.

(b) **Scope 2**: indirect emissions from the generation of purchased electricity consumed by the Project.

(c) **Scope 3**: indirect emissions that are a consequence of the activities of the Project, but occur at sources owned or controlled by other entities (e.g. outsourced services). Scope 3 emissions can include emissions generated upstream of the Project by providers of energy, materials and transport. Scope 3 emissions can also include emissions generated downstream of the Project by transport providers and product use (e.g. burning product coal).

5.10 A useful figure that highlights the degree of control the proponent of a mining project has over GHG emissions is produced at **Appendix 1** of this submission.

5.11 Double counting of GHG emissions occurs where the Scope 3 emissions generated by the burning of a mine's coal by other developments, are counted twice in the context of calculating a country's GHG emissions for the purpose of tracking progress towards achievement of its NDC. This can occur in two main circumstances:

[15] It should be noted, of course, that there may well be other countries to which the Project's coal is exported from time-to-time during the Project's life of mine. However, given the broad adoption of NDCs, those countries are highly likely to have also submitted NDCs and be in the process of adopting and implementing laws and policies to achieve their NDCs.

(a) the Scope 3 emissions of a particular development or activity carried out in Country A, are actually generated in Country B as Scope 1 emissions associated with development or activities conducted in Country B, and both Countries A and B count the same GHG emissions towards their NDC; or

(b) the Scope 3 emissions of a particular development or activity carried out in Country A, are actually generated by another development or activity in Country A as Scope 1 emissions generated by that other development or activity, and Country A counts the same GHG emissions towards its NDC.

5.12 The issue of double counting, as arising in the context of the first main circumstance described in paragraph 5.11(a) above, can be illustrated by the example of the Project.

5.13 Almost all of the Project's Scope 3 emissions are generated by the burning or combustion of coal by the end-user of the coal. As the coal from the Project is planned to be exported, the generation of Scope 3 emissions will occur outside of Australia. In this regard, the Scope 3 emissions of the Project would count as Scope 1 emissions in the relevant Expected Export Countries and, if Australia were to count the Scope 3 emissions from the Project in calculating its GHG emissions, this would result in an unacceptable double counting of GHG emissions.

5.14 In relation to the second main circumstance described in paragraph 5.11(b) above, another example can be used to illustrate how double counting can occur in this context. If a coal mine was proposed to be constructed somewhere in Australia, and it was to supply coal to a power station which was also located in Australia and the coal was combusted by that power station, then:

(a) the Scope 1 emissions of the coal mine would need to be accounted for and reported; and

(b) the Scope 1 emissions of the power station would need to be accounted for and reported.

5.15 However, it would be double counting if the Scope 3 emissions of the coal mine were also accounted for and reported because those emissions are the same as the Scope 1 emissions of the power station.

5.16 The importance of avoiding double counting of GHG emissions generally, including in the context of calculating a country's GHG emissions for the purpose of tracking progress towards achievement of its NDC, is well-recognised under the *Paris Agreement* and the NGER Act.

5.17 At an international level:

(a) in respect of overarching obligations, article 4(13) of the *Paris Agreement* requires parties to ensure the avoidance of double counting consistent with the guidance adopted by the COP;

(b) in respect of the use of internationally transferred mitigation outcomes towards NDCs:

(i) article 6(2) of the *Paris Agreement* requires Parties to apply robust accounting to avoid double counting consistent with the guidance adopted by the COP;

(ii) the modalities, procedures and guidelines for the Transparency Framework adopted under the Katowice Climate Package (**Transparency Framework**), requires that each participating Party provide information on how their cooperative approach applies robust accounting to ensure the avoidance of double counting;

(c) in respect of accounting for Parties' NDCs, the guidance adopted by the Parties under the Katowice Climate Package requires that Parties avoid double counting when accounting for anthropogenic emissions and removals corresponding to their NDCs; and

(d) the guiding principles of the Transparency Framework also provide that double counting be avoided.

5.18 The clear intent of the *Paris Agreement* is to ensure a robust approach is taken to accounting of GHG emissions and it would undermine the integrity of that agreement for an approach to be taken to accounting of emissions which involved double counting.

5.19 At the domestic level, the NGER Act in Australia also precludes double counting by imposing reporting obligations upon companies only in respect of Scope 1 and Scope 2 emissions. There is no requirement or obligation imposed on companies under Australian law to report on Scope 3 emissions. The exclusion of Scope 3 emissions from the reporting requirements under Australian law effectively avoids double counting of Scope 3 emissions since the end-user who is responsible for a project's Scope 3 emissions will ultimately account for them as Scope 1 emissions.

5.20 Indeed, a letter from the Commonwealth Minister for Energy and Emissions Reduction to the Hon. Rob Stokes, Minister for Planning and Public Spaces dated 20 November 2019 states that:[16]

> Emissions resulting from overseas actions are already managed through legislative frameworks by the countries where those actions are occurring. Any requirement to consider scope three emissions within a sub-national or state jurisdiction is inconsistent with long-accepted international carbon accounting principles and Australia's international commitments.
>
> …
>
> Any requirement for Australian businesses to report or manage scope three emissions would duplicate existing obligations on third parties, would be impractical to implement and would impose a high regulatory burden for indeterminate benefits.

The carbon budget approach and its limited role as a tool in international and domestic climate change frameworks

5.21 The "carbon budget" approach has been used by some members of the scientific community and non-governmental organisations to estimate the maximum cumulative amount of CO_2 (i.e. the budget of CO_2) that could be released into the atmosphere from human sources globally while limiting global average temperature increases to a desired level above pre-industrialised levels. Once the CO_2 concentration in the atmosphere reaches the estimated maximum amount (i.e. the budget is spent), global emissions of CO_2 must be "net zero" (i.e. the magnitude of emissions to the atmosphere is matched by the magnitude of removals of emissions from the atmosphere).

5.22 While the "carbon budget" approach is sometimes used by scientists and advocates to illustrate generally the global mitigation pathways that may achieve the goals of the *Paris Agreement*, it is not an approach that is required by the *Paris Agreement*, or Australian domestic laws (i.e. federal and NSW legislation) in the context of implementing, or measuring progress towards achievement, of Australia's NDC.

[16] The letter was included as Appendix G2-3 to the Department of Planning, Industry and Environment's *State Significant Development Assessment (SSD 7480): Vickery Extension Project* published in May 2020.

5.23 It would be inappropriate for the IPC to apply the "carbon budget" approach in determining the development application for the Project. The Applicant makes this submission for the following reasons:

(a) the "carbon budget" is a highly-generalised analysis to inform broad, economy-wide or global policy-making. It does not qualitatively assess the impact of a particular project on the environment in terms of its GHG emissions. The "carbon budget" approach does not provide the IPC with any practical assistance in discharging the function it is required to perform (i.e. to determine the development application for the Project), and is a matter that is best left to State, national and international policy makers;

(b) the "carbon budget" approach is inconsistent with the approach that has been adopted by the *Paris Agreement* for achieving the goal set under that agreement, in that:

(i) each country has made a commitment (in the form of a NDC) as to how it will contribute to achieving the goal set by the *Paris Agreement*;

(ii) the *Paris Agreement* does not prescribe the measures or mechanisms by which a particular country is to implement actions to facilitate the achievement of its NDC. Indeed, the *Paris Agreement* enshrines the principle of common but differentiated responsibilities, allowing each party to determine its own contributions taking into account national circumstances; and

(iii) the application of the carbon budget approach results in double counting of GHG emissions, which is an outcome that the *Paris Agreement* seeks to avoid.

(c) the approach suffers from numerous deficiencies, including:

(i) **Uncertainty:** the approach suffers from uncertainties, such as:

(A) the evaluation of an appropriate historic baseline, which is affected by uncertainties in both historical emissions, and in deriving the estimate of globally averaged human-induced warming;[17] and

(B) accounting for non-CO_2 gases (i.e. if non-CO_2 gases are not reduced or reduced more slowly than CO_2, the budget is reduced accordingly). There is also uncertainty in the magnitude and geographical variation of radiative forcing of non-CO_2 climate forcers and the predicted temperature response.[18]

(ii) **Technology:** the approach can be susceptible to ignoring the role that technological advancements can play in reducing CO_2 levels globally (e.g. low emission coal technologies including carbon capture and storage, and HELE projects). Any failure of the carbon budget approach to account for such technological advancements would result in the CO_2 levels being recorded at levels higher than they actually are.

[17] IPCC, Chapter 2: Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development in *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty* (2018) at 96, 107.

[18] Ibid at 96, 101–103 (2.2.1.1), 106 (2.2.2.2).

(iii) **Allocation:** the approach has not been accepted by the international community as a means of sharing global mitigation efforts among countries. The question of the contribution of individual countries in line with an overall carbon budget is rather complex. This is because the transition to a lower-carbon future must be equitably shared so as not to disproportionately damage the economies of countries or undermine the right to sustainable development. For this reason, and as explained above, the approach to allocation adopted under the *Paris Agreement* has been for each country to adopt a NDC and determine, for itself, the measures or mechanisms that will be implemented to achieve that NDC.

5.24 The Court in *Rocky Hill* did not adopt or apply the carbon budget approach. In considering expert opinion about the carbon budget approach, the Court stated that the carbon budget approach "admits that some fossil fuel reserves can be exploited and burned" (at [551]) and that the carbon budget approach (at [552]–[553]):

> assume[s] that all existing and approved fossil fuel developments will continue and there will be no reduction in GHG emissions from these sources. It gives priority to existing and approved fossil fuel developments, along the lines of "first in, best dressed". It also frames the decision as a policy decision that no fossil fuel development should ever be approved.
>
> I consider the better approach is to evaluate the merits of the particular fossil fuel development that is the subject of the development application to be determined. Should this fossil fuel development be approved or refused? Answering this question involves consideration of the GHG emissions of the development and their likely contribution to climate change and its consequences, as well as the other impacts of the development. The consideration can be in absolute terms or relative terms.

Australia's NDC and national climate change laws and policies

5.25 As a starting point, neither the *Paris Agreement* nor Australia's NDC are part of the law of Australia except to the extent that legislation has been passed to give effect to those documents within Australia.

Australia's NDC

5.26 Australia signed the *Paris Agreement* on 22 April 2016, and ratified it on 6 November 2016.

5.27 It is not bound under international law to achieve the emission reduction target in its NDC, although it is to be observed that countries are likely to face international pressure if they fail to meet NDC targets.

5.28 Australia has obligations under the *Paris Agreement* to:

(a) prepare, communicate and maintain an NDC that it intends to achieve (Article 4(2));

(b) pursue domestic mitigation measures, with the aim of achieving the objectives of its NDC (Article 4(2));

(c) communicate an NDC every 5 years (Article 4(3), (9)); and

(d) account for its NDC and, in the process, ensure the avoidance of double counting in accordance with the methodologies and common metrics assessed by the IPCC and adopted by the Katowice Climate Package (Article 4(13)).

5.29 With respect to the specifics of Australia's NDC, it is to be noted that Australia's NDC communicates an unconditional economy-wide target to reduce GHG emissions by 26-28% below 2005 levels by 2030. Australia's emissions reduction target represents a 50-52% reduction in emissions per capita and a 64-65% reduction in the emissions intensity of the economy between 2005 and 2030. Australia's NDC is summarised in the following table.

Summary of Australia's NDC	
Emissions reduction target	Economy-wide target to reduce greenhouse gas emissions by 26 to 28 per cent below 2005 levels by 2030
Coverage	Economy-wide
Scope	- Energy - Industrial processes and product use - Agriculture - Land-use, land-use change and forestry - Waste
Gases	CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, NF_3

Mechanisms by which Australia's NDC is to be achieved

5.30 The policy document supporting Australia's NDC communicates that Australia will achieve its 2030 target through the Direct Action policy suite. The key component of the Direct Action policy suite is the Emissions Reduction Fund (**ERF**), which is complemented by the Safeguard Mechanism, the Renewable Energy Target (which requires 33,000 Gwh of electricity generation (or approximately 23.5% of total generation) to be produced from renewable resources by 2020), improvements in energy efficiency under the National Energy Productivity Plan, phasing out of synthetic GHGs and direct support for investment in low emissions technologies and practices.

5.31 Importantly, the Australian Government has not – in any climate change policy or law – indicated that the development of new coal mines, or expansions of existing coal mines, is to be prohibited or restricted in any way for the purpose of achieving Australia's NDC. As a corollary, it must follow that the Australian Government considers that Australia's NDC can still be achieved in circumstances where new coal mines, or expansions of existing coal mines, are approved.

5.32 It is also to be noted that the Federal climate change policy of the Australian Labor Party does not contain any measures that could constitute a prohibition on new coal mines or coal mining. Indeed, Labor leader Anthony Albanese recently stated that demand for coal around the world would not change if Australia stopped its exports, which meant that a ban on new coal mines would have no impact on emissions and that:

> We've got to consider what the actual outcome is from any proposal, and the proposal that we immediately stop exporting coal would damage our economy and would not have any environmental benefit.[19]

5.33 For present purposes, the most relevant mechanisms in the suite of existing law and policy are:

(a) the ERF; and

(b) the Safeguard Mechanism.

[19] David Crowe, 'Albanese says Australia should continue to export coal' *Sydney Morning Herald* 9 December 2019, available at: https://www.smh.com.au/politics/federal/albanese-says-australia-should-continue-to-export-coal-20191208-p53hyp.html

5.34 First, the ERF is a $2.55bn fund which purchases least cost emission reductions and abatement through a Commonwealth government procurement process, which includes reverse auctions. It is underpinned by the *Carbon Credits (Carbon Farming) Act 2011* (**CFI Act**) which creates a legislative framework for the development of offset projects and the creation of Australian carbon credit units (**ACCUs**). The CFI Act was initially enacted to support activities in the land sector but has been amended to now support a wider range of projects related to energy, transport and industry.

5.35 Separate from, but related to the ERF, it should be acknowledged that in February 2019 the Australian Government announced the Climate Solutions Package, which is a $3.5 billion plan to deliver Australia's 2030 emissions reduction target. As part of the package, a Climate Solutions Fund has been established to continue the work of the ERF with an additional $2 billion investment over 10 years. Approximately $200 million per year over ten years is expected to be allocated to abatement purchases through the ERF. The Climate Solutions Fund is also designed to be a fund that will partner with businesses, local communities and farmers in emissions reduction programs. The Package, and the ERF specifically, has been promoted as a key policy to contribute to the national 26% emissions reduction target by 2030.

5.36 Secondly, the Safeguard Mechanism, established under Part 3H of the *National Greenhouse and Energy Reporting Act 2007* (**NGER Act**), aims to ensure that emission reductions purchased by the Government through the ERF are not undermined by increases in emissions in other areas of the economy.

5.37 The Safeguard Mechanism sets a baseline on emissions for facilities that emit over 100,000 tonnes CO_2-e per year. When the Safeguard Mechanism was implemented, baselines were set for existing facilities using data reported under the NGER Act. For most facilities, baselines were the highest level of report emissions for a facility over the historical period 2009-10 to 2013-4. These baselines could be adjusted to accommodate economic growth, natural resource variability and other circumstances where historical baselines do not represent future business-as-usual emissions. Baselines for new facilities are based on an audited emissions forecast provided by the facility operator, with a reconciliation of the estimate against the actual performance of the facility at the end of the forecast period.

5.38 In 2019, the *National Greenhouse and Energy Reporting (Safeguard Mechanism Rule 2015* (Cth) was amended so that, for new facilities completed after 1 July 2020 (or existing facilities with new investments), baselines would be set to encourage facilities to achieve and maintain best practice in emissions intensity (known as benchmark baselines).[20] Baselines for existing facilities would also be brought up-to-date by transitioning all facilities to calculated baselines over 2018-19 and 2019-20. The amendments also allow baselines to be updated annually for annual production (known as a production-adjusted baseline), but facilities transitioning from a benchmark baseline must use the same emissions intensity that was used in the benchmark baseline.[21]

5.39 Due to Covid-19, the introduction of benchmark baselines for new facilities has been delayed to 1 July 2021, and the complete transition of existing facilities to calculated baselines will be delayed to 1 July 2021.

---

[20] Australian Government (2018) Consultation on amendments to the National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2017, available at: https://publications.industry.gov.au/publications/climate-change/climate-change/government/emissions-reduction-fund/consultation/safeguard-mechanism-legislative-amendments-2018.html

[21] See: http://www.cleanenergyregulator.gov.au/NGER/The-safeguard-mechanism/Baselines/Production-adjusted-baseline

5.40 If a facility exceeds its baseline, it is generally required to surrender a number of ACCUs equivalent to the exceedance to the Clean Energy Regulator. There are other mechanisms by which a facility can manage baseline exceedance, including applying for multi-year monitoring periods and exemptions for exceptional circumstances (i.e. natural disasters or criminal activity unrelated to the liable entity).

5.41 For example, if a facility has a baseline of 1,000,000 tonnes CO_2-e and reported emissions of 1,500,000, the company with operational control of that facility would have to surrender 500,000 ACCUs, or be liable to the penalty under section 22XF of the NGER Act.

5.42 In its first year of operation (FY2016/17), 203 facilities were covered by the Safeguard Mechanism with combined emissions of 131.3 $MtCO_2$-e. Sixteen facilities exceeded their emissions limits and purchased and retired a total of 448,097 ACCUs to clear their liabilities.

5.43 The GHG Assessment for the Project estimates that the total Scope 1 emissions of the Project will exceed 100,000 $tCO_{2\text{-}e}$ in its first year. As the Project's Scope 1 emissions will likely not exceed 100,000 $tCO_{2\text{-}e}$ until after 1 July 2021, the baseline emissions number for the Project to be set by the Clean Energy Regulator under the Safeguard Mechanism will not be based on reported emissions or on an audited emissions forecast, but will be based on benchmark emissions intensities (that is, the best, least emissions intensive standard for production).[22] The Applicant will be required to offset any emissions above its baseline, or otherwise manage compliance, in accordance with the NGER Act.

NGER Act

5.44 The NGER Act is a national system for reporting GHG emissions, energy production and consumption by corporations. The data gathered under the NGER Act assists with compiling Australia's national GHG inventory in order to meet Australia's reporting obligations under the UNFCCC.

5.45 Corporations that have operational control of facilities that emit more than a specified amount must report on the type of the source of their emissions, the methods used to estimate emissions and the amount of GHG emitted (in CO_2-e). The reporting requirements under the NGER Act apply to:

(a) an individual facility that emits 25kt or more of CO_2-e or produces or consumes 100tJ or more of energy; or

(b) an individual facility and other facilities under the operational control of the same corporate group that together emit 50kt or more of CO_2-e or produce or consume 200tJ or more of energy.

5.46 Failure to comply with these reporting obligations is a breach of the legislation and can result in the imposition of civil penalties on companies and executive officers.

5.47 The NGER Act covers each of the six classes of Kyoto Protocol gases:

- CO_2;
- CH_4;
- N_2O;
- SF_6;

[22] *National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2015* (Cth), cl 38(3); http://www.cleanenergyregulator.gov.au/NGER/The-safeguard-mechanism/Baselines

- certain specified HFCs; and
- certain specified PFCs.

5.48 Reporting requirements cover both Scope 1 and Scope 2 emissions. The NGER Act does not cover Scope 3 emissions.

5.49 The parent company of the Applicant, Malabar, will submit NGERs reports for the years during which facilities over which it or a member of its corporate group has operational control reach the relevant reporting threshold. Typically these reports will include Scope 1 emissions related to fugitive emissions of CO_2 and CH_4, emissions from the combustion of diesel, LPG and other gaseous fuels for stationary and transport uses, and Scope 2 emissions related to electricity consumption.

5.50 Australia's GHG Inventory is prepared centrally by the Department of the Environment using the Australian Greenhouse Emissions Information System, including data reported under the NGER Act. Australia's National Greenhouse Accounts conform to the UNFCCC Reporting Guidelines on Annual Inventories and the supplementary reporting requirements under the Kyoto Protocol to prepare its national inventories. These guidelines establish standardised reporting formats and require detailed information on all aspects of each party's national inventory system, including measurement systems, data collection systems, estimation methodologies, reporting and data management.

5.51 Currently, emission estimates are compiled in accordance with the IPCC 2006 Guidelines for National Greenhouse Gas Inventories (**2006 IPCC Guidelines**), the 2013 Revised Supplementary Methods and Good Practice Guidance Arising from the Kyoto Protocol, and now the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (**2019 IPCC Refinement**). Parties may also use country-specific methodologies where these are consistent with the IPCC guidelines and improve the accuracy of emissions estimates. Australia predominantly uses country-specific methodologies and emissions factors, described in detail in its National Inventory Report.

5.52 The National Greenhouse Gas Inventory is reviewed annually by a team of international experts through the UNFCCC review process.

5.53 Notably, neither the 2006 IPCC Guidelines, the Revised Supplementary Methods, nor the 2019 IPCC Refinement require emissions data to be collected and reported or estimates to be made for Scope 3 emissions.

5.54 The NGER Act also does not provide any methodology for accounting for and reporting on Scope 3 emissions.

The NSW Climate Change Policy Framework, Net Zero Plan Stage 1, and Strategic Statement on Coal

5.55 The NSW Climate Change Policy Framework (October 2016) seeks to provide aspirational goals and broad policy directions to attain NSW's objective of achieving net-zero emissions by 2050 and ensuring that NSW is more resilient and responsive to climate change. Its other aspirational objectives include the implementation of policies consistent with the Commonwealth's plan for long-term emissions savings, to reduce emissions in government operations, and to advocate for Commonwealth, COAG and international action consistent with the *Paris Agreement*.

5.56 Under the NSW Climate Change Policy Framework, NSW has committed to both follow the *Paris Agreement* and to work to complement national action. The key policy directions under the NSW Climate Change Policy Framework and their rationales are summarised in the table below:

Policy Direction	Rationale/Goals
Creating an investment environment that manages the emissions reduction transition	Energy will be transformed and investment/job opportunities will be created in emerging industries of advanced energy, transport and carbon farming and environmental services
Boost energy productivity and put downward pressure on energy bills	Boosting energy and resource productivity will help reduce prices and the cost of transitions to net-zero emissions
Grow new industries and capitalise on competitive advantages	Capitalising on the competitive advantage and growth of industries in professional services, advanced energy technology, property management and financial services
Reduce risks and damage to public and private assets arising from climate change	Embed climate change considerations into asset and risk management as well as support the private sector by providing information and supportive regulatory frameworks for adaptation
Reduce climate change impacts on health and wellbeing	Recognise the increased demand for health and emergency services due to climate change and identify ways to better support more vulnerable communities to health impacts
Manage impacts on natural resources and communities	Coordinate efforts to increase resilience of primary industries and rural communities as climate change impacts water availability, water quality, habitats, weeds and air pollution

5.57 The Policy Framework is being delivered through:

(a) the Climate Change Fund;

(b) the development of a value for emissions savings that will be applied consistently in government economic appraisals;

(c) embedding climate change mitigation and adaptation across government operations including service delivery, infrastructure, purchasing decisions and regulatory frameworks;

(d) building on NSW's expansion of renewable energy; and

(e) developing action plans and strategies, including on advanced energy, energy efficiency, climate change adaptation, energy productivity, fugitive emissions, primary industry emissions and adaptation and health and wellbeing.

5.58 In March 2020, the Department of Planning, Industry and Environment published the Net Zero Plan Stage 1, which sets out how the NSW Government will deliver on its objective of achieving net zero emissions by 2050 over the next decade to 2030. The Net Zero Plan sets out GHG emission mitigation measures in relation to electricity generation, transport, agriculture, stationary energy (excluding electricity generation), fugitive emissions from mining, industrial processes, waste, and land use.

5.59 Significantly, for the IPC's consideration of the Project, the Net Zero Plan Stage 1 states (at 22) (underline added):

> New South Wales' $36 billion mining sector is one of our biggest economic contributors, supplying both domestic and export markets with high quality, competitive resources. Mining will continue to be an important part of the economy into the future and it is important that the State's action on climate change does not undermine those businesses and the jobs and communities they support.

5.60 In June 2020, the NSW Government published its Strategic Statement on Coal which, in light of the fact that the NSW coal industry provided over 22,000 direct jobs, around 89,000 indirect jobs and approximately $2 billion in royalties in 2018-19, sets out:

> how the NSW Government is taking a responsible approach to the global transition to a low carbon future, consistent with Australia's ambition under the Paris Agreement, and is planning to manage the impact for coal-reliant communities.

5.61 The Strategic Statement states that the NSW Government will act in four areas:

(a) improving certainty about where coal mining should not occur;

(b) supporting responsible coal production in areas deemed suitable for mining, including by:

(i) prohibiting conditions on the grant of development consents that relate to coal exports;

(ii) continuing to consider responsible applications to extend the life of current coal mines; and

(iii) streamlining the process for exploring new areas and areas adjacent to current mining operations to deliver a better economic return to NSW;

(c) addressing community concerns about the impacts of coal mining; and

(d) supporting diversification of coal-reliant regional economies to assist with the phase-out of thermal coal mining.

The NDCs and climate change laws and policies of the Expected Export Countries

5.62 It is to be noted that of the Expected Export Countries, all except Taiwan are parties to the *Paris Agreement* and either have or are in the process of adopting domestic laws, policies, and measures to implement and achieve their NDC targets. Taiwan is not recognised as an independent sovereign nation and therefore is not a member of the United Nations and consequently cannot be a party to the Paris Agreement. Nonetheless, it has put forward an INDC and is also implementing measures to achieve its INDC. Each Expected Export Country's domestic efforts to achieve their NDC (or INDC) targets are summarised in the table below and set out in detail in **Appendix 2** to this submission.

Country	Summary of the domestic climate change framework in the likely export customer countries for the Project
Japan	• has highlighted carbon pricing and the use of CCUS technologies as key to achieving its emissions reductions NDC of 26% below 2013 levels by 2030; • Japan's second/updated NDC submitted to the UNFCCC on 31 March 2020 states that Japan "will strive to achieve a 'decarbonized society' as close as possible to 2050 with disruptive innovations, such as artificial photosynthesis and other CCUS technologies"; • made significant progress with several CCUS projects; • has imposed import taxes for coal and LNG; • aims to pursue high efficiency in thermal power generation using high-efficiency technologies such as ultra-supercritical and advanced ultra-supercritical; and • is on track to halve its emissions by 2050 according to the IEA (WEO 2019, p 97).

Country	Summary of the domestic climate change framework in the likely export customer countries for the Project
India	• has imposed a coal tax on all domestic and imported coal since 2010 (which has been increased three times since its inception), though its NDC indicates that coal (from both domestic and imported sources) will continue to dominate power generation into the future and India has included constructing coal-fuelled power plants with higher efficiency.
South Korea	• is looking to increase the share of renewable energy to 20% by 2030 and natural gas while decreasing the share of coal as a key measure for achieving its NDC of 37% below business-as-usual (**BAU**) levels by 2030; and • has imposed import taxes for coal and LNG which act as a carbon tax and seeks to encourage a transition away from coal to renewables and LNG
China	• has introduced several policies to limit emissions (including policies to shut down coal-fired power plants, increase the efficiency of its coal generation fleet and place caps on the annual production capacity of coal), and to promote the development of commercially-viable CCUS technology in order to achieve its NDC of lowering carbon intensity by 60% to 65% from 2005 levels by 2030; and • is in the process of implementing a nation-wide carbon price, building on eight state-based carbon price schemes that are already operational.
Taiwan	• has legislated toward reducing reliance on both domestic and imported sources of coal, with plans to increase reliance on renewable energy and impose tax mechanisms on imported fossil fuels as a part of its plan to achieving emissions reductions of 50% below BAU levels by 2030 per its INDC.
Vietnam	• has targeted an increase in reliance on renewable energy, while not discounting the continued use of coal, in its plans to reach its NDC of emissions reductions of 9% below BAU by 2030.
Brazil	• Brazil's first NDC sets out a variety of measures to achieve its 2030 emissions reduction target of 43% reduction below 2005 levels by 2030, including improving energy efficiency in the industrial sector; and • provides a commitment to preserve and restore the Amazon as a carbon sink through restoring and reforesting 12 million hectares of forest by 2030.
Indonesia	• has committed to achieving almost a quarter of its energy supply from renewable sources by 2025; and • has committed the state-owned electricity company to prioritise low carbon technologies when developing new power plants.
Malaysia	• has set a renewable energy target of 20% by 2025 as a key mechanism for achieving its NDC of reducing emissions by 45% by 2030 relative to 2005 levels.

Uptake of HELE and CCUS in the Expected Export Countries

5.63 It is also important to understand that increasing the efficiency of coal-fuelled power plants is a well-understood approach to reducing CO_2 emissions. Under the *Paris Agreement*, it is the responsibility of each party to indicate how it will meet emissions reduction targets. Numerous countries that are major coal users (e.g. China, India and Japan) and customers of Australian coal have indicated a role for high-efficiency coal fired power stations in their NDCs under the *Paris Agreement*.

5.64 High-efficiency, low-emissions (**HELE**) power plants have lower GHG emissions of all types per unit of power produced, including CO_2. Subcritical coal-fuelled power plants are not considered HELE, while supercritical (SC) and ultra-supercritical (USC) coal-fuelled plants with advanced emissions controls are considered to meet the HELE technology classification.

Advanced ultra-supercritical (A-USC) coal-fuelled power plants are nearing commercial status and will be the most efficient plants once they are fully available.

5.65 Many coal-importing countries are leaders in the deployment of higher efficiency coal-fuelled power plants simply because power plants with higher efficiency require less coal per unit of electricity and reduce the fuel costs associated with electricity production.

5.66 Importantly, the higher efficiency plants result in lower CO_2 emissions per unit of electricity. According to the International Energy Agency Clean Coal Centre, "if a power producer decides to build a new SC or USC unit, it involves 13% and 19% fewer CO_2 emissions than a brand new subcritical unit respectively; and up to 40% fewer CO_2 emissions if the HELE unit is replacing an older plant."

5.67 The IEA's Clean Coal Centre estimates that the installed capacity of HELE coal-fired power plants in South East Asia will increase to 2040 as shown in the following figure extracted from the IEA's report.[23]

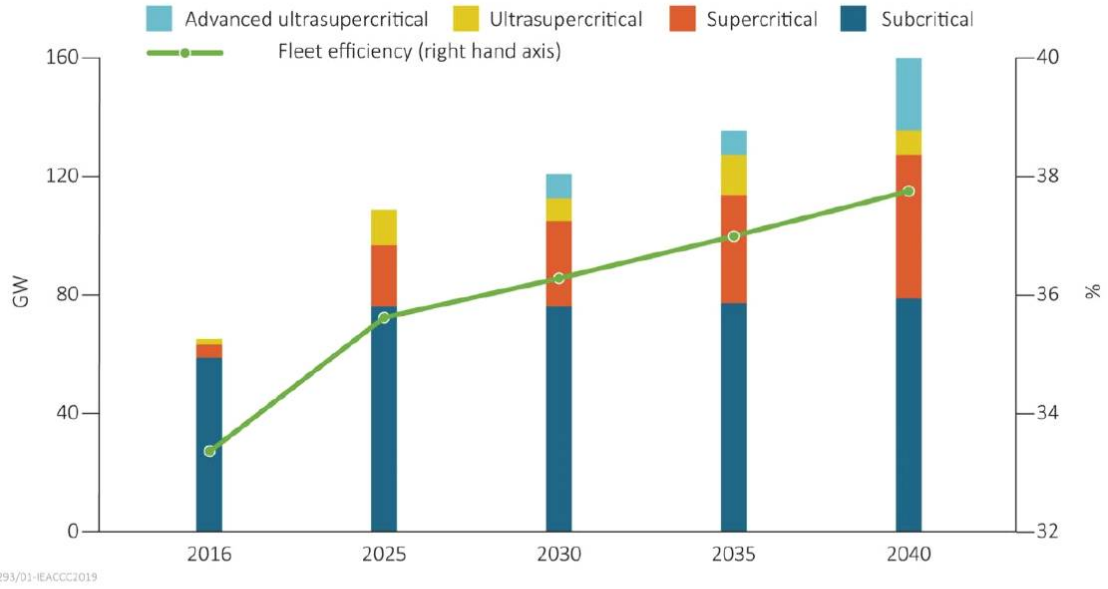


Figure 1 Installed and planned coal-fired capacity by technology and average fleet efficiency in South East Asia in the IEA's New Policies Scenario (Apportionment of ultrasupercritical (USC) and advanced ultrasupercritical (AUSC) plant author's estimates based on Barnes (2018)); (IEA, 2017a)

Source: IEA

5.68 Additionally, if carbon capture, use and storage (**CCUS**) is applied to a contemporary power plant, it may prevent 90% or even more of CO_2 emissions from entering the atmosphere compared to power plants without CCUS.

5.69 The Applicant has summarised some of the main initiatives that have been implemented by these countries in relation to low emission coal technologies in the following table.[24]

---

[23] I Barnes, 'HELE Technologies and Outreach in Japan and South Korea' (International Energy Agency Clean Coal Centre, March 2019), https://www.iea-coal.org/hele-technologies-in-japan-and-south-korea-2/.

[24] The content referred to in the table immediately below has been informed by the following sources: S&P Global Platts World Electric Power Plants Database, December 2018; M Wiatros-Motyka, 'An overview of HELE technology deployment in the coal power plant fleets of China, EU, Japan and USA' (December 2016); I Barnes, 'HELE Perspectives for Selected Asian Countries' (International Energy Agency Clean Coal Centre, May 2018); Global CCS Institute's Global Status Reports of 2018 and 2019: https://www.globalccsinstitute.com/resources/global-status-report/; I Barnes, 'HELE

Country	Implementation of HELE, CCUS and other similar technologies

Japan	• A global leader in the application of HELE coal-fueled power plants and built its first USC plant in 1993.
	• 95% of the country's plants are HELE plants.
	• Included high-efficiency coal as part of its contributions to the *Paris Agreement*.
	• Japan's Fifth Strategic Energy Plan to 2050 recognises coal as an important fuel for baseload power generation. It is the stated policy of Japan to promote the conversion of its coal fleet to HELE technologies.
	• The 'Rational Use of Energy' Policy provides that State approval for new coal-fired power stations will only be considered if state-of-the-art technologies are adopted (ultrasupercritical). Every electric power company is required to have an average power generation efficiency of 44.3% or higher for all thermal power generation plants by 2030. This policy also required the power sector to agree on a GHG emissions cap consistent with Japan's 2030 energy mix and emissions targets.
	• As at March 2019, a number of new USC coal-fired power projects were at various stages of development. Japan has long been at the forefront of newer integrated gasification combined cycle (**IGCC**) technology development. The 543 MW IGCC unit at the Nakoso Power Plant is scheduled for completion in 2020 and the 543 MW Hirono Power Plant is due to be completed in 2021. IGCC is said to be capable of reducing CO_2 emissions by approximately 15% compared to USC systems.
	• Long-term Low-carbon Vision, published in March 2017, refers to CCUS as a means of achieving emission reductions in the energy sector, as well as centralised/distributed energy management.
	• Long-term Strategy under the Paris Agreement was adopted on 11 June 2019 states that the Government will work to reduce CO_2 emissions from thermal power generation, including by accelerating "the efforts of a wide range of stakeholders, aiming to establish its first commercial scale CCU technology by 2023 as a trigger for wider usage in view of full social adoption in 2030 and thereafter."
	• Roadmap for Carbon Recycling Technologies published 7 June 2019 sets out specific goals for improving the competitiveness of CCUS; aiming to reduce the costs of CCUS to JPY 1000-2000/tCO_2 by 2030 and to JPY 1000/tCO_2 or lower by 2050.
	• Japan's second/updated NDC submitted to the UNFCCC on 31 March 2020 states that Japan "will strive to achieve a 'decarbonized society' as close as possible to 2050 with disruptive innovations, such as artificial photosynthesis and other CCUS technologies".
	• According to the Global CCS Institute's Global Status Reports of 2018 and 2019, Japan has achieved the following major milestones:
	  ○ commenced CO_2 injections at the Tomakomai CCUS facility by Japan CCUS with the Ministry of Economy, Trade and Industry's full support – this is Asia's first full-cycle CCUS hydrogen plant, which will capture more than 300,000 tonnes of CO_2 by 2020. In 2019, it reached a capture milestone of 300,000 tonnes of CO_2, and continued intensive monitoring of storages;
	  ○ retrofitted the Toshiba Corporation 49MW Mikawa power plant in Omuta (Fukuoka Prefecture) to accept biomass (in addition to coal) with a carbon capture facility. Completion is expected in 2021;

Technologies and Outreach in Japan and South Korea' (International Energy Agency Clean Coal Centre, March 2019); International Energy Agency Clean Coal Centre, 'Who's "Environmentally Backward"? Japan is Developing these New Energy Technologies' 26 February 2020: https://www.iea-coal.org/whos-environmentally-backward-japan-is-developing-these-new-energy-technologies/.

Country	Implementation of HELE, CCUS and other similar technologies
	○ launched JPOWER and Chugoku Electric Power Company's Osaki CoolGen facility, a 166 MW oxygen-blown IGCC (integrated gasification combined cycle) plant in Osakikamijima (Hiroshima Prefecture), which started demonstration tests to separate and capture CO_2 from February 2020; ○ completed construction of Toshiba's carbon capture and utilisation system at the Saga City Waste Incineration Plant (on Japan's Kyushu Island), using captured CO2 for algae culture; and ○ commencement of construction of the gasifier for the Hydrogen Energy Supply Chain project that plans to gasify Australian brown coal in Victoria's Latrobe Valley and transport it by ship to Japan for future decarbonised hydrogen developments. This project being developed by Kawasaki Heavy Industries (KHI), Electric Power Development Co. (J-Power), Iwatani Corporation, Marubeni Corporation, Sumitomo Corporation and AGL, with the support of the Governments of Japan, Australia and the State of Victoria. First hydrogen production is expected by 2021.
India	• India's first NDC pointed out the essential role of coal in providing a secure energy supply into the future. India is therefore seeking to improve the efficiency of coal-based power, including by: ○ importing high quality coal; ○ requiring all new, large coal-based generating stations to use highly efficient supercritical technology; ○ renovation and modernisation of existing old power stations; ○ prescribing mandatory targets for improving energy efficiency at approximately 144 thermal coal plants; and ○ investigating the viability of USC technology. • As of December 2018, 21% of India's coal-fuelled generation capacity was HELE, but at least 83% of planned and under construction capacity is HELE. In the 5 years to 2023, at least 53 GW of HELE generating capacity is expected to come online in India.
South Korea	• As of December 2018, 83% of South Korea's coal-fuelled generation capacity was HELE and at least 90% of planned and under construction capacity is HELE. In the 5 years to 2023, at least 7 GW of HELE generating capacity is expected to come online in South Korea. • The South Korean coal fleet has one of the world's largest shares of SC or USC coal-fired power generation in a single country. • South Korea shares similarities with Japan in having a relatively young, high efficiency coal fleet in place. • South Korea has one of only seven commercial IGCC projects worldwide with an installed capacity of 346.3 MW, which commenced operation in August 2016. There are plans to improve and commercialise the technology to a wider customer base. • South Korea's NDC indicated that it would subsequently develop a detailed plan to implement its mitigation target. To this end, South Korea released a revised roadmap for achieving the 2030 National Greenhouse Gas Reduction Goal in July 2018 (the **Roadmap**). The Roadmap sets out sectoral targets, including emission reductions of 24 million tons in the energy conversion sector (power generation, group energy) through policies to reduce fine dust and promote the use of eco-friendly energy.

Country	Implementation of HELE, CCUS and other similar technologies
	• National CCS Comprehensive Plan announced in July 2011 to promote research and development on CCUS with a view to commercialising the technology by 2020.[25] • Final draft Integrated CCS Act published in 2018 will require yearly CCUS implementation plans.

China	• Included high-efficiency coal in its first NDC under the *Paris Agreement*.
	• Given the young age of China's coal infrastructure and predicted further dependence on coal into the future, China has been engaged in CCUS technology research and demonstration since the early 2000s.
	• Several commercial CCUS demonstration programs are ongoing including:
	  ○ Jilin Oil Field enhanced oil recovery (**EOR**) Demonstration has been researching and conducting CO_2-enhanced oil recovery operations since 2006. The site has a 350,000 tonnes per annum of CO_2 capacity.
	  ○ The Shenhua Group Ordos CCS Demonstration operated from 2011-2014 as a dedicated geological site storage facility injecting around 100,000 tonnes per annum of CO_2.
	  ○ Guohua Jinjie CCS Full Chain Demonstration commenced in 2019 and has a 150 000 tonnes per annum capacity into geological storage.
	• China also has several pipeline projects in the construction or development phase, including Yanchang Integrated CCS (the first large-scale facility in Asia), and the Sinopec Qilu Petrochemical CCS.

Taiwan	• HELE technology is included in Taiwan's INDC. • As of December 2018, 31% of Taiwan's coal-fuelled generation capacity was HELE and 2.4 GW of planned and under construction capacity is USC HELE. • Taiwan's EPA established a national CCUS strategic alliance in 2011. This alliance brings together domestic experts from government, academia and industry, for the purpose of developing the technology and regulatory framework required for the commercial use of CCUS technology, with the ultimate goal of achieving widespread use of CCUS technology by 2020. Through the alliance, the Taiwan Cement Corporation (in partnership with the Industrial Technology Research Institute) commissioned the world's first CCUS pilot project in the cement industry in 2013, with the two entities agreeing in 2016 to extend their cooperation on the project.
Vietnam	• HELE technologies are being adopted in order to reduce CO_2 emissions from the ongoing demand for coal in Vietnam. Long Phu 1 is one of the first coal-fired power plants in Vietnam to use supercritical technology for higher efficiency energy production.
Brazil	• Much of Brazil's energy is from hydroelectricity, which means that GHG emissions from industry are a focus of Brazil's NDC, which identifies certain targeted measures for emissions mitigation for industry including "new standards of clean technology; enhance energy efficiency measures and low carbon infrastructure".
Indonesia	• A study completed for the Indonesian Ministry of Finance in 2015, considered the pros and cons of pursuing deployment of CCUS technology in Indonesia. • Indonesia's domestic supply of crude oil has created national interest in developed enhanced oil recovery through the injection of carbon dioxide (CO_2-EOR) scheme.

[25] Moonhyun Koh, Eunhae Shin and Woongchan Seo, 'Outline of Korean Integrated CCS Act Draft and Its Implication' *Energy Procedia* 154 (2018) 15-21.

Country	Implementation of HELE, CCUS and other similar technologies
Malaysia	• In 2015, Manjung 4 commenced operation. It is Southeast Asia's first and largest ultra-supercritical coal-fired power plant with a 1,010 MW output, enough to power nearly 2 million households. It is approximately 10% more efficient than the global average for coal fired power plants. • In 2017, Manjung 5 commenced operation. It is another 1,000 MW USC coal-fired power plant, and the second in Southeast Asia. • In 2019, a further 2, 1,000 MW ultra-supercritical plants were commissioned in Port Dixon.

5.70 For the purposes of the Project, the key points for the IPC to appreciate in relation to the material produced in this submission on climate change laws, policies and initiatives in the Expected Export Countries are:

(a) the likely countries where the Project's coal will ultimately be burned or combusted have numerous domestic laws and policies in place for how each respective country intends to achieve its NDC (or INDC in the case of Taiwan);

(b) it is both appropriate, and consistent with the overarching international climate change framework, for the Project's Scope 3 emissions to be accounted for, regulated and reported by the respective Expected Export Countries as Scope 1 emissions generated in those countries; and

(c) the uptake of HELE and CCUS technologies over time will reduce the CO_2 emissions associated with the use of coal.

6. PART C: FUTURE DEMAND FOR COAL, THE CHARACTERISTICS OF THE PROJECT'S COAL, AND THE CONSEQUENCES OF COAL MARKET SUBSTITUTION

Overview

6.1 It is important to recognise that there is, and will remain for the foreseeable future, a demand for coal (both coking and thermal coal) as a reliable, affordable and efficient resource to meet the basic needs of human populations throughout the world. That demand for coal will remain irrespective of whether the IPC approves the Project or not and, if the Project is not approved, the demand will simply be met by coal sourced from elsewhere. In this regard, there is a real likelihood that the coal sourced from elsewhere will:

(a) be of inferior quality (in terms of calorific value, and sulphur content) than the coal that will be produced by the Project; and

(b) result in a higher level of GHG emissions than if the Project is approved.

6.2 In this Part C of the submission, the Applicant will provide evidence for the points made in the paragraph immediately above and will:

(a) demonstrate that under all three policy scenarios presented by the IEA in WEO 2019 (including the Sustainable Development Scenario), there will continue to be a global demand for coal that will need to be met by brownfield expansion coal mines or the development of new coal mines;

(b) provide commentary on the:

(i) Project's coal and cost of operations, having regard to the Project's coal's qualities and tonnage profile;

(ii) relative importance of Australian coal exports in terms of meeting projected demand for thermal and coking coal;

(iii) likelihood of market substitution if the Project is not approved; and

(iv) consequences that would likely follow from substitution of the Project's coal with product coal from alternative sources, particularly in respect of GHG emissions.

6.3 Ashurst, on behalf of the Applicant, retained CRU to undertake an independent study of global coal demand and supply and the coal market to 2040, in the context of the Project. For reasons relating to confidentiality and intellectual property, the Applicant only has CRU's permission to publicly disclose a letter summarising the main findings of CRU's report. However, CRU has advised that it is prepared to give permission for its study to be disclosed to the IPC, if the IPC makes a direction under clause 5 of Schedule 2 to the EP&A Act that the study is not to be published.

6.4 A copy of the summary letter is produced at **Appendix 3** of this submission.

Global demand for coal to 2040

6.5 The global demand for coal to 2040 is addressed in detail by the IEA, an entity related to the Organisation for Economic Co-operation and Development (**OECD**), in its annually published reports known as the WEO. The IEA does analysis work for both the Intergovernmental Panel on Climate Change (**IPCC**) and under the UNFCCC.

6.6 At the time of preparing this submission, the most recent report published by the IEA is the WEO 2019, which was published in November 2019.

6.7 The purpose of the WEO is to provide a framework for thinking about the future of global energy. It does not make predictions about or forecast the future. Instead, it sets out what the future could look like on the basis of different scenarios or pathways, with the aim of providing insights to inform decision makers as they design new policies or consider new investments.[26]

6.8 The WEO 2019 presents three policy scenarios for assessing global energy demand and energy sources. Those three policy scenarios are described in the WEO 2019 (at 29 and 30) as follows (footnotes omitted):

> The aim of the **Stated Policies Scenario** (STEPS), which occupies a central position in the *WEO* analysis, is to hold up a mirror to the actions and intentions of today's policy makers, and to provide a candid assessment of their implications for energy markets, energy security and emissions. The scenario reflects:
>
> - The impact of energy-related policies that governments have already implemented.
> - An assessment of the likely effects of announced policies, as expressed in official targets and plans.
> - A dynamic evolution of the cost of energy technologies, reflecting gains from deployment and learning-by-doing.
>
> The Stated Policies Scenario, previously called the New Policies Scenario, is not an IEA forecast. It takes into account policies that have already been announced ("stated"), but does not speculate on how these might evolve in the future. The new name of this scenario in *WEO-2019* has been chosen with the aim of avoiding misunderstanding on this point.
>
> Policies announced by governments include some far-reaching commitments, including aspirations to achieve full energy access in a few years, to reform pricing regimes and, more recently, to reach net zero emissions in some countries and sectors. These ambitions are not automatically incorporated into the scenario: full implementation cannot be taken for granted, so the prospects and timing for their realisation are based upon our assessment of the relevant regulatory, market, infrastructure and financial constraints. Nonetheless, these targets and plans move the projections away from a business-as-usual trajectory, as a comparison with the **Current Policies Scenario**, in which such announcements are not considered, makes clear.
>
> The time horizon of the Stated Policies Scenario is to 2040. The design of this scenario, which relies on detailed bottom-up consideration of the impact of today's policies and plans, does not lend itself to very long-term horizons.
>
> The **Sustainable Development Scenario** (SDS) is an essential counterpart to the Stated Policies Scenario. It sets out the major changes that would be required to reach the key energy-related goals of the United Nations Sustainable Development Agenda. These are:
>
> - An early peak and rapid subsequent reductions in emissions, in line with the Paris Agreement (Sustainable Development Goal [SDG] 13).
> - Universal access to modern energy by 2030, including electricity and clean cooking (SDG 7).
> - A dramatic reduction in energy-related air pollution and the associated impacts on public health (SDG 3.9).

[26] WEO 2019 at 29.

> The trajectory for emissions in the Sustainable Development Scenario is consistent with reaching global "net zero" carbon dioxide (CO_2) emissions in 2070. If net emissions stay at zero after this point, this would mean a 66% chance of limiting the global average temperature rise to 1.8 degrees Celsius (°C) above pre-industrial levels (or a 50% chance of a 1.65°C stabilisation). In the light of the *Intergovernmental Panel on Climate Change Special Report on 1.5°C*, we also explore what even more ambitious pathways might look like for the energy sector, either via "net negative" emissions post-2070 or by reaching the "net zero" point even earlier.

6.9 It must be recognised that:

(a) the WEO is not, and never has been, a forecast of what will happen;[27]

(b) the IEA does not endorse any particular scenario in WEO 2019; and

(c) the Stated Policies Scenario is the central scenario in WEO 2019.[28]

6.10 Coal is generally characterised into two types – thermal coal which is used in the production of electricity, and metallurgical coal which is used for steelmaking.

6.11 The Project will produce approximately 125 Mt of product coal comprising semi-soft coking coal (**SSCC**), a type of metallurgical coal, and thermal coal. The indicative life of mine average proportion of SSCC to thermal coal will be 75:25. The following paragraphs therefore consider the predicted demand for thermal coal and SSCC.

Projected global demand for thermal coal

6.12 The IEA projects the global demand for thermal coal under the three policy scenarios. Table 1.1 of the WEO 2019 (p 38), which is reproduced below, sets out the global demand for all energy sources under the three policy scenarios. The entries for "coal" in **Table 1.1** are in respect of thermal coal.

[27] WEO 2019 at 3, 23, 29 and 751.

[28] WEO 2019 at 29 to 30.

Table 1.1 ▻ World primary energy demand by fuel and scenario (Mtoe)

			Stated Policies		Sustainable Development		Current Policies	
	2000	2018	2030	2040	2030	2040	2030	2040
Coal	2 317	3 821	3 848	3 779	2 430	1 470	4 154	4 479
Oil	3 665	4 501	4 872	4 921	3 995	3 041	5 174	5 626
Natural gas	2 083	3 273	3 889	4 445	3 513	3 162	4 070	4 847
Nuclear	675	709	801	906	895	1 149	811	937
Renewables	659	1 391	2 287	3 127	2 776	4 381	2 138	2 741
Hydro	225	361	452	524	489	596	445	509
Modern bioenergy	374	737	1 058	1 282	1 179	1 554	1 013	1 190
Other	60	293	777	1 320	1 109	2 231	681	1 042
Solid biomass	638	620	613	546	140	75	613	546
Total	**10 037**	**14 314**	**16 311**	**17 723**	**13 750**	**13 279**	**16 960**	**19 177**
Fossil fuel share	*80%*	*81%*	*77%*	*74%*	*72%*	*58%*	*79%*	*78%*
CO_2 emissions (Gt)	**23.1**	**33.2**	**34.9**	**35.6**	**25.2**	**15.8**	**37.4**	**41.3**

Notes: Mtoe = million tonnes of oil equivalent; Gt = gigatonnes. Other includes wind, solar PV, geothermal, concentrating solar power and marine. Solid biomass includes its traditional use in three-stone fires and in improved cookstoves.

Source: WEO 2019

6.13 The relevant commentary on the data for the three policy scenarios, as outlined in Table 1.1 of the WEO 2019, is in Chapter 1 at pp 38–39 of the WEO 2019. The following relevant observations from that commentary are extracted below:

> Global primary energy demand grew by 2.3% in 2018, its largest annual increase since 2010. China, the United States and India accounted for 70% of the total energy demand growth. Despite the fact that growth in renewables has outpaced growth in all other forms of energy since 2010, the share of fossil fuels in global primary energy demand remains above 80% (Table 1.1).
>
> The energy debate is often focussed on the pace of change, but the forces of continuity in the energy sector should not be discounted. The **Current Policies Scenario** provides just such a "business as usual" picture, although 1.3% average annual growth in energy demand to 2040 is well below the rate seen in 2018. Growth in line with this scenario would mean greater consumption of all fuels and technologies, leading to a continuous rise in energy-related emissions and increasing strains on almost all aspects of energy security.
>
> In the **Stated Policies Scenario**, primary energy demand grows by one-quarter to 2040; the 1% annual average growth represents a slowdown compared with the 2% average seen since 2000. The global economy and the demand for energy move on diverging pathways due to structural shifts towards less energy-intensive output, energy efficient gains and saturation effects, particularly in terms of vehicle use.
>
> Low-carbon sources meet well over half of the increase in demand to 2040 in the Stated Policies Scenario, compared with 30% in 2017-2018. This is led by the power sector, where renewables dominate investment and capacity additions (Figure 1.2). However, demand for all sources of energy, except coal, continues to increase.
>
> After rising strongly in the medium term, growth in oil demand slows markedly post-2025 in the Stated Policies Scenario before flattening in the 2030s. Oil use in passenger cars peaks in the late-2020s, despite the number of cars on the road increasing by 70% between 2018 and 2040. Coal demand in 2040 is slightly below today's level, and its share in the primary mix is overtaken by gas around 2030. Gas demand rises by 30%, with industrial use of gas increasing at more than twice the pace of gas in power generation.

In the **Sustainable Development Scenario**, a relentless focus on improving efficiency and a shift away from combustion for power generation (reduces losses from waste heat) means that the projected increase in the size of the global economy and population (the same in all scenarios) is accommodated without any rise in primary demand, With no overall increase in demand, the rise of low-carbon sources comes at the expense of coal and oil.

Global oil demand peaks within the next few years in the Sustainable Development Scenario. Much greater fuel efficiency and fuel switching, with almost half the global car fleet powered by near-zero carbon electricity, means that in 2040 oil use in transport is 40% lower than today; only the (non-combustion) use of oil, mostly as a feedstock for chemicals production, shows any increase. Natural gas use grows to 2030 and then falls back. Coal demand is hit hard in this scenario, declining at more than 4% per year.

6.14 It is important to understand the structural trends that determine the increased energy demand. They are primarily population growth, urbanisation and economic growth in developing economies, particularly those in the Asia Pacific region. This is illustrated by **Table 6.2** from the WEO 2019, which is reproduced below.

Table 6.2 ▷ Electricity demand by region and scenario (TWh)

			Stated Policies		Sustainable Development		Change 2018-2040	
	2000	2018	2030	2040	2030	2040	STEPS	SDS
North America	4 260	4 786	5 160	5 626	4 966	5 602	840	816
United States	3 589	4 011	4 226	4 517	4 099	4 573	506	563
Central & South America	660	1 081	1 445	1 837	1 331	1 660	757	579
Brazil	327	517	675	845	619	745	328	228
Europe	3 114	3 631	3 975	4 346	3 926	4 724	715	1 093
European Union	2 604	2 884	3 045	3 243	3 050	3 645	359	761
Africa	380	703	1 086	1 653	1 073	1 696	950	993
South Africa	190	211	252	319	210	249	108	38
Middle East	361	954	1 309	1 817	1 189	1 621	863	667
Eurasia	809	1 084	1 302	1 474	1 132	1 220	390	137
Russia	677	893	1 043	1 149	916	971	256	77
Asia Pacific	3 569	10 792	15 662	19 699	14 474	18 038	8 907	7 246
China	1 174	6 330	9 127	10 912	8 415	10 052	4 582	3 723
India	376	1 243	2 417	3 718	2 254	3 263	2 475	2 020
Japan	962	994	980	989	926	942	-4	-52
Southeast Asia	323	935	1 510	2 091	1 346	1 888	1 156	953
World	**13 152**	**23 031**	**29 939**	**36 453**	**28 090**	**34 562**	**13 422**	**11 531**

Note: TWh=terawatt-hour; STEPS = Stated Policies Scenario; SDS = Sustainable Development Scenario.
Source: WEO 2019

6.15 The Sustainable Development Scenario for electricity demand at 2040 in the WEO 2019 is predicated on achieving universal access to both electricity and clean cooking facilities in circumstances of strong population growth, such that an additional 1 billion people would have access to electricity by 2030, and more than 2.5 billion people would move away from the traditional use of biomass for cooking by the same date (at 86).

6.16 **Table 5.1** of the WEO 2019 (p 222) sets out the global coal demand, production and trade by scenario for each of thermal coal (i.e. steam coal) and metallurgical coal (i.e. coking coal).

Table 5.1 ▷ Global coal demand, production and trade by scenario (Mtce)

			Stated Policies		Sustainable Development		Current Policies	
	2000	2018	2030	2040	2030	2040	2030	2040
Power	2 233	3 500	3 470	3 395	1 872	858	3 789	4 156
Industrial use	869	1 680	1 852	1 903	1 461	1 206	1 926	2 075
Other sectors	207	279	175	100	137	36	220	168
World coal demand	**3 309**	**5 458**	**5 498**	**5 398**	**3 471**	**2 101**	**5 934**	**6 399**
Asia Pacific share	*47%*	*75%*	*81%*	*83%*	*86%*	*84%*	*79%*	*81%*
Steam coal	2 504	4 342	4 393	4 394	2 672	1 515	4 753	5 266
Coking coal	449	955	857	790	676	497	885	854
Lignite and peat	302	270	247	214	123	89	297	280
World coal production	**3 255**	**5 566**	**5 498**	**5 398**	**3 471**	**2 101**	**5 934**	**6 399**
Asia Pacific share	*48%*	*73%*	*78%*	*79%*	*80%*	*83%*	*77%*	*78%*
Steam coal	310	859	733	726	381	197	888	964
Coking coal	175	319	314	371	258	247	332	404
World coal trade	**471**	**1 169**	**1 039**	**1 087**	**633**	**413**	**1 206**	**1 355**
Trade as share of production	*14%*	*21%*	*19%*	*20%*	*18%*	*20%*	*20%*	*21%*
Coastal China steam coal price ($2018/tonne adjusted to 6 000 kcal/kg)	**34**	**106**	**89**	**92**	**74**	**76**	**98**	**105**

Notes: Mtce = million tonnes of coal equivalent; kcal/kg = kilocalories per kilogramme. Unless otherwise stated, industrial use in this chapter reflects volumes also consumed in own use and transformation in blast furnaces and coke ovens, petrochemical feedstocks, coal-to-liquids and coal-to-gas plants. Historical supply and demand volumes differ due to changes in stocks. World trade reflects volumes traded between regions modelled in the *WEO* and therefore does not include intra-regional trade. See Annex C for definitions.

Source: WEO 2019

6.17 The relevant commentary on the projections for the three policy scenarios, as outlined in Table 5.1 of the WEO 2019, is at pp 222-223 of the WEO 2019. The following relevant observations from that commentary are extracted below:

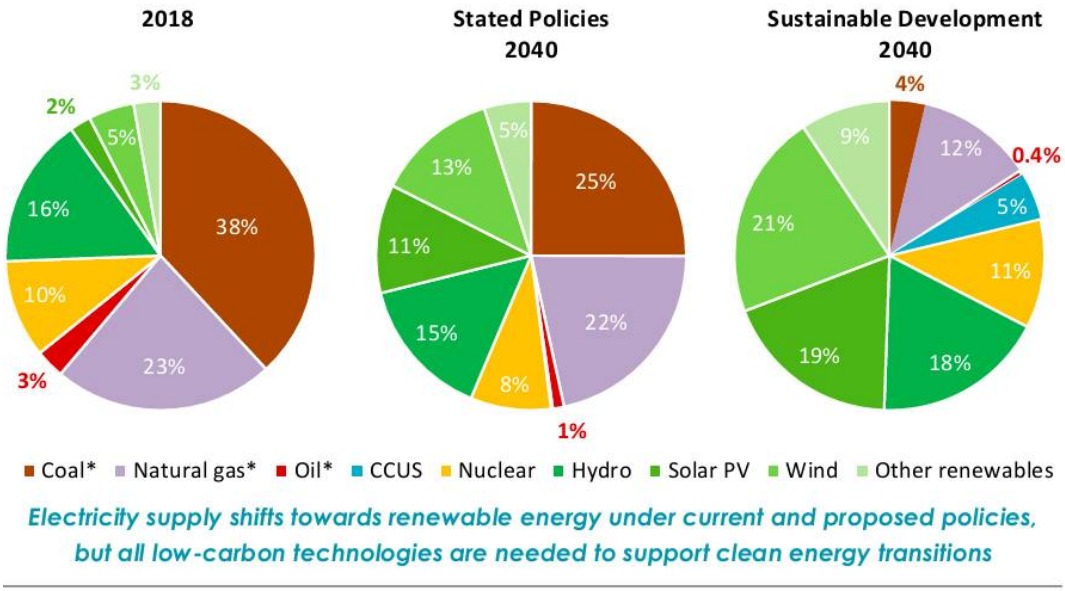
> Coal demand is essentially flat in the **Stated Policies Scenario**, ending up in 2040 at around 5400 Mtce, some 60 Mtce below where it is today (Table 5.1). This represents a slight downward revision compared with the World Energy Outlook (WEO)-2018 (IEA, 2018). Flat demand in an expanding energy system means that the share of coal in the global energy mix declines from 27% in 2018 to 21% in 2040, falling behind natural gas in the process.
>
> The strength of the economic and policy headwinds facing coal vary widely by scenario and, within each scenario, across different countries and sectors. The net effect in the Stated Policies Scenario is that global coal use in power generation decreases slightly, while its industrial use grows modestly. The **Current Policies Scenario**, in which energy demand is stronger and policy pressure on coal is weaker, sees coal use rise in both areas.
>
> …
>
> The outlook for coal is very different in the **Sustainable Development Scenario**. With a much more stringent focus on reducing emissions, coal use decreases steeply at an annual rate of 4.2%. By 2040, world coal use is 60% lower than in the Stated Policies Scenario and coal's share in the primary energy mix falls towards 10%.

Until the early 2010s, coal demand was aligned with economic growth. That is not the case in the future in either the Stated Policies or Sustainable Development scenarios (Figure 5.2). In advanced economies, e.g. European Union, United States, Japan, the trend in coal demand becomes detached from the overall economic outlook. By contrast, strong growth in incomes and energy needs in parts of developing Asia continues to go hand-in-hand with higher coal demand. China's position moves progressively closer to that of the advanced economy group, exerting a strong influence on the global decoupling of coal demand from economic growth.

With coal demand growth levelling off, CO_2 emissions from coal combustion flatten in the Stated Policies Scenario, but they do not reduce significantly. In the Sustainable Development Scenario, the deployment of CCUS and improvements in plant efficiencies result in coal-related CO_2 emissions falling faster than coal demand. By 2040, almost 160 gigawatts (GW) of coal-fired plants are equipped with CCUS, accounting for 40% of the electricity generated from coal, although today's policies fall far short of those which could stimulate needed investment in CCUS.

6.18 In the Stated Policies Scenario, coal-fired electricity generation plateaus and its share declines from 38% today to 25% in 2040 (as shown in **Figure 6.4** extracted below from p 265). However, this varies drastically by region. In advanced economies, coal-fired electricity generation will more than halve over the period to 2040 while coal consumption will increase in Southeast Asia, where 40% of the projected rise in the region's electricity demand will be met by coal (WEO 2019, pp 224, 225, 253, 256).

Figure 6.4 ▷ Global electricity generation mix by scenario



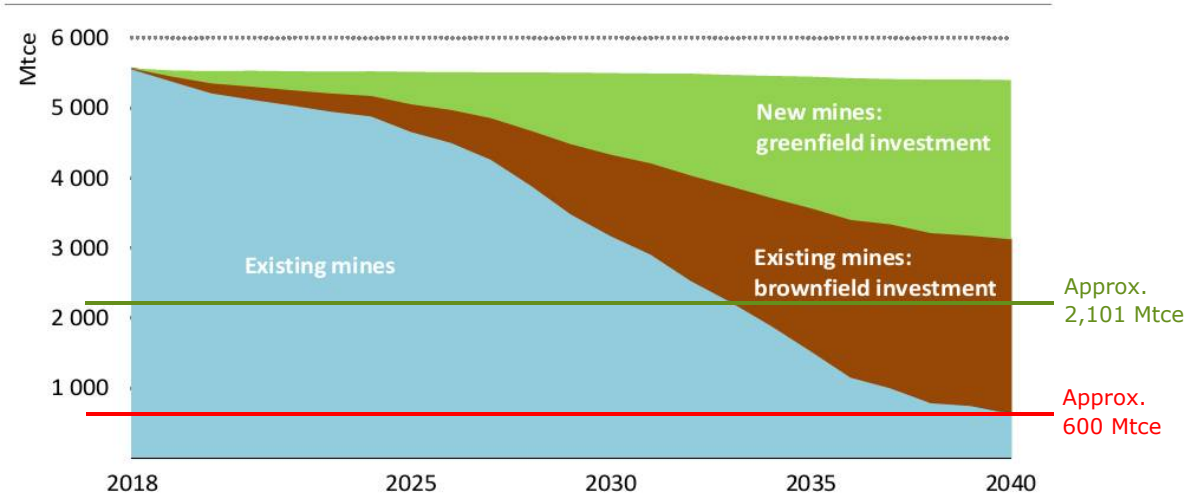
* Excludes capacity equipped with CCUS.

Source: WEO 2019

6.19 In 2018, around 70% of global coal power capacity and coal-based electricity generation was in Asia where electricity demand is rising fast and coal plants are around 12 years old on average, more than two decades younger than those in North America and Europe. In 2018, coal use rose for the second straight year in China, India and South East Asian countries. However, China would see a modest reduction in consumption of 0.4% per year on average from 2018 to 2040 due in large part to a strong policy push to improve air quality, but will remain the largest consumer of coal worldwide. China has a stock of more than 1000 GW of coal-fired capacity, much of it recently commissioned and highly efficient (WEO 2019, pp 220, 221, 224, 238).

6.20 It is evident that under all three policy scenarios presented by the IEA (including the Sustainable Development Scenario), there will continue to be a global demand for coal. Figure 5.13 (from WEO 2019, p 244) is reproduced below. In the absence of new mines or brownfield expansions, the global production of coal would be approximately 600 Mtce in 2040. We have drawn a red line on **Figure 5.13** to illustrate that. Table 5.1 from the WEO 209 (p 222) reproduced above projects that even under the Sustainable Development Scenario, global demand for coal would be 2,101 Mtce in 2040 (which we have indicated with a green line on Figure 5.13) of which 858 Mtce would be for electricity and 1,206 Mtce would be for industrial use, including steelmaking.

Figure 5.13 ▹ Global coal production by type in the Stated Policies Scenario



Source: WEO 2019

6.21 The independent modelling undertaken by CRU (which aligns generally with IEA's Stated Policies Scenario) (see **Appendix 3**), forecasts that:

(a) coal will, in 2040, remain an important pillar of electricity generation in many of the world's regions, including in Southeast Asia, as well as in China and India;

(b) high quality coal from Australia (such as that produced by the Project) is, and will continue to be, in demand to meet the electricity generation needs in these regions in particular (as many of these countries have little to no domestic supply), as well as global demand more generally; and

(c) as the ability of existing mines to service global demand for coal declines (e.g. as a result of exhausting their environmentally recoverable reserves), it will be necessary for the coal demand to be met by expansions of approved coal mines or the development of new coal mines.

Projected global demand for metallurgical coal

6.22 SSCC is classified as metallurgical coal, along with hard coking coal (**HCC**).[29] Metallurgical coals are essential inputs for blast furnace-based steelmaking. HCC and SSCC are both used in the production of coke, a vital component of blast furnace feed. The proportion of each coal used in the coking process is determined by various factors, including price, blast furnace requirements and specific characteristics and qualities of the coal.

[29] Pulverised coal for injection (PCI) is also used in steelmaking but, unlike HCC and SSCC, is injected directly into the blast furnace.

6.23 As shown in Table 5.1 of the WEO 2019 extracted above, the IEA has projected that industrial coal use which today accounts for around one-third of coal consumption, increases by some 225 Mtce to 2040 in the Stated Policies Scenario, as coal remains the backbone of steel and cement manufacturing. In the Sustainable Development Scenario, overall use drops significantly, but coal remains important to several industrial processes, reflecting the difficulty and expense of finding substitutes for coal in these processes (WEO 2019, p 220, 225, 230).

6.24 The WEO 2019 states that 70% of global crude steel is produced through the blast furnace-basic oxygen furnace (BF-BOF) route which is heavily dependent on coking coal (SSCC and HCC) for the production of coke. The scope to shift away from coal by making greater use of scrap-based or direct reduction of iron (DRI)-based electric arc furnaces is limited by the availability and cost of scrap steel, as well as the cost competitiveness of electricity. Coal use in the iron and steel industry declines in the Stated Policy Scenario by around 30 Mtce by 2040, reflecting efficiency gains and the gradual rise in the use of electricity-based routes for steel production (WEO 2019, 231, 233).

6.25 As Table 5.1 from the WEO 2019 (reproduced above) shows, demand for coking coal in 2040 under the IEA's Stated Policies Scenario will be 790 Mtce.[30]

6.26 The IEA's projections of demand for metallurgical coal are supported by the NSW Government's Strategic Statement on Coal, which states (at 6) that "[t]he use of coal in the manufacture of steel (coking coal) is likely to be sustained longer [than thermal coal] as there are currently limited practical substitutes available."

6.27 The IEA's projections in relation to metallurgical coal align with the independent modelling undertaken by CRU, which forecast that:

(a) steel will remain an important material for global development, particularly in South East Asia;

(b) annual global demand for carbon crude steel (crude steel, excluding stainless steel) is expected to grow to 2.3 billion tonnes in 2040, up by 501 Mt per annum from its 2019 level. This will be driven by economic development and rising steel intensity per capita in the developing economies, particularly in India and Southeast Asia;

(c) despite the share of steel produced by blast furnace-basic oxygen furnace declining in the long term, as electric arc furnace steelmaking grows, there will continue to be a significant requirement for new iron units from coal (produced by blast furnace-basic oxygen furnaces as opposed to iron from recycled steel which is used in electric arc furnace steelmaking);

(d) given the relatively young age of the installed capacity of blast furnace-basic oxygen furnaces in Asia, much of the future demand for steel is forecast to be met by this existing capacity, which requires coking coal;

(e) by 2040, the blast furnace-basic oxygen furnace process will still account for approximately 58% of global steel production (compared to 73% currently), remaining the dominant steelmaking process and supporting demand for metallurgical coal; and

[30] Table 5.1 is titled "Global coal demand, production and trade by scenario". The projected world coal production in Table 5.1 is the same as world coal demand. However, as Figure 5.13 of WEO 2019 shows, global coal production will not meet demand. Therefore, it is clear that "world coal production" in Table 5.1 is to be interpreted as a breakdown of the projected demand for different types of coal under the IEA's three scenarios.

(f) while demand for SSCC is expected to decline in China and developed economies in Europe, North America, Japan, Korea, Singapore, Hong Kong and Taiwan, demand for SSCC is expected to rise in emerging economies in India and Southeast Asia due to the commissioning of new blast furnace-basic oxygen furnace capacity to meet increasing demand for steel.

Evaluating the Project's coal and cost of operations: coal qualities, tonnage profile and duration of the Project

6.28 The Project will involve the extraction of approximately 148 Mt of ROM coal over approximately 26 years, with the total production of 125 Mt of product coal, the large majority (if not all) of which will be exported.

6.29 Coal produced by the Project will be one of two coal categories:

(a) semi-soft coking coal (**SSCC**) (metallurgical coal); and

(b) thermal.

At least 75% of the product coal for the life of mine would be capable of being used as SSCC.

6.30 Coal is not a standardised, homogeneous commodity, as the quality produced by different mines varies considerably. This is a critically important factor to recognise when comparing the environmental consequences of the production and use of coal.

6.31 In order to appreciate the likely consequences of the substitution of the Project's coal with product coal from alternative sources, it is essential to first acknowledge the quality of the Project's coal. This is because the quality of the Project's coal, compared to alternative markets and projects, is key for assessing the potential environmental impacts of any supply substitution that may arise.

6.32 There are three particular measures by which the Project's coal can be evaluated. They are:

(a) calorific value (unit: kcal/kg);[31]

(b) ash content (unit: %);[32] and

(c) sulphur content (unit: %).[33]

6.33 The qualities of the Project's coal products (averaged over the life of mine) are presented in the following table.

	Unit	Life of Mine Average (air dried)
Semi-soft Coking Coal		
Calorific Value	kcal/kg	7,340
Ash	%	8.7
Sulphur	%	0.35

[31] The energy density of different coal sub product is a key driver of the volume of coal that is needed to be burned to attain a given level of power demand.

[32] This refers to the non-combustible residue left after the coal is burnt; it is a key driver of costs as it impacts power plant maintenance costs via equipment wear and ash-handling requirements.

[33] This contaminant impacts the level of atmospheric oxides which are emitted (a key local air pollutant and contributor to acid rain).

	Unit	Life of Mine Average (air dried)
Thermal Coal		
Calorific Value	kcal/kg	6,900
Ash	%	12.3
Sulphur	%	0.36

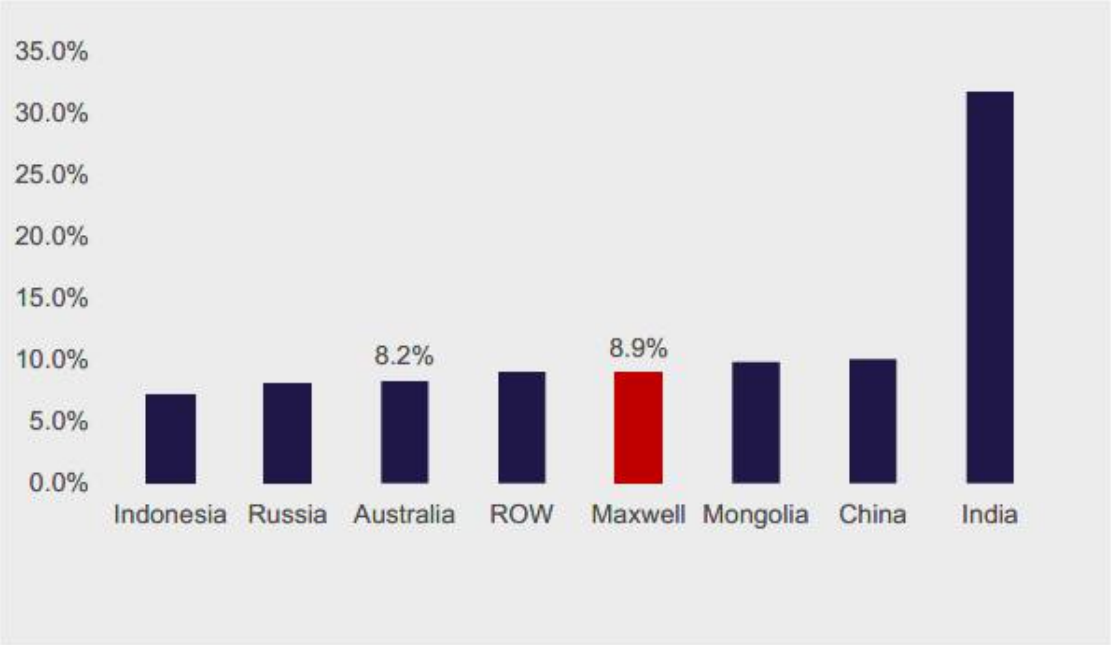
SSCC coal quality

6.34 SSCC and HCC are essential inputs for steelmaking using blast furnace-basic oxygen furnace technology. HCC and SSCC are both used in the production of coke a vital component of blast furnace feed. The proportions of each coal used in the coking process are determined by various factors, including pricing differentials, blast furnace requirements and specific characteristics and qualities of the coal.

6.35 One of SSCC's key contributions to the coke blend is its lower impurities such as ash and sulphur, as well as being lower cost compared to HCC. Sulphur is a local air pollutant and contributor to acid rain (or increases operating cost if flue gas desulphurisation is used). Ash is the non-combustible residue left after the coal is burnt – a waste which increases operating costs (due to equipment wear and ash-handling requirements).

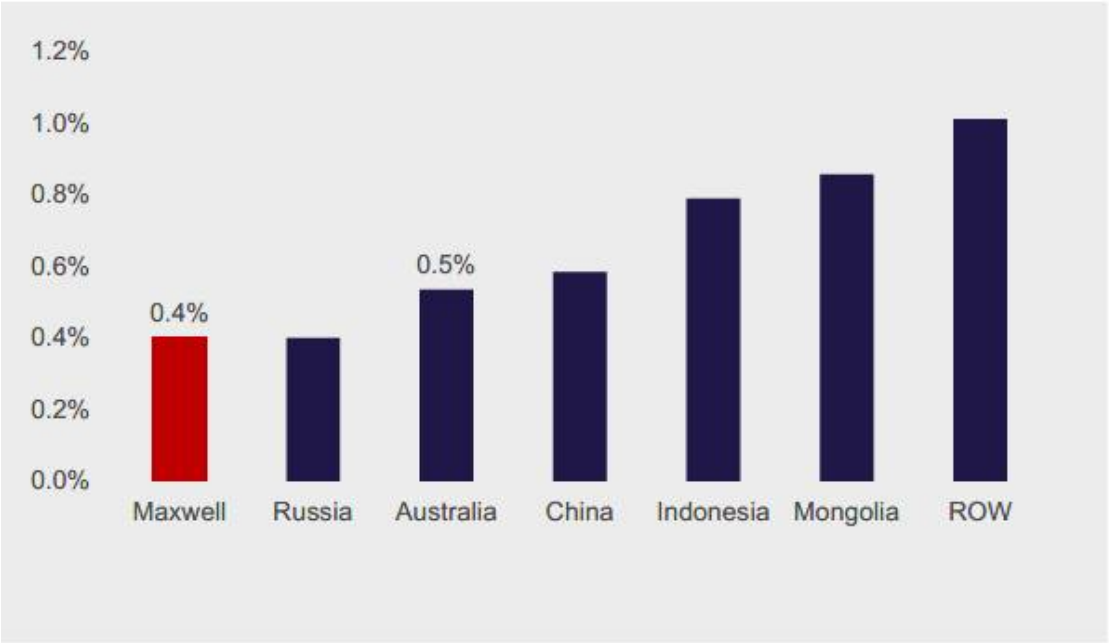
6.36 **Figures 18 and 19** extracted from CRU's study below, show the ash and sulphur content of the Project's SSCC compared to the country weighted averages of other major seaborne suppliers of SSCC in 2030.

Figure 18: SSCC quality comparison (ash content, %) between the Maxwell Project and country weighted average of seaborne mines and projects in 2030 (weighted: 2030 production), %



Source: CRU, Malabar.
Source: CRU

Figure 19: SSCC quality comparison (sulphur content, %) between the Maxwell Project and country weighted average of seaborne mines and projects in 2030 (weighted: 2030 production), %



Source: CRU, Malabar. Note: We have removed India's sulphur content from this chart given our low confidence of the reported data.

Source: CRU

6.37 In 2030, the Project's SSCC is expected to have a medium ash content of 8.9%, similar to the country averages for Australia and Mongolia. Over the life of mine, however, as mining progresses down through the seam sequence, the ash content of the Project's product coal will decrease.

6.38 In 2030, the Project's SSCC is expected to have a low sulphur content of 0.4% (equal with Russia's average) and lower than the Australian average (0.5%).

6.39 CRU has assessed the Project as:

(a) being in the ninth percentile (lowest quartile) on the business cost curve for all metallurgical coal producers in 2030;

(b) being in the eighteenth percentile (lowest quartile) on the business cost curve for seaborne metallurgical coal suppliers in 2030; and

(c) having the lowest business cost compared to other SSCC existing operations and potential projects in 2030.

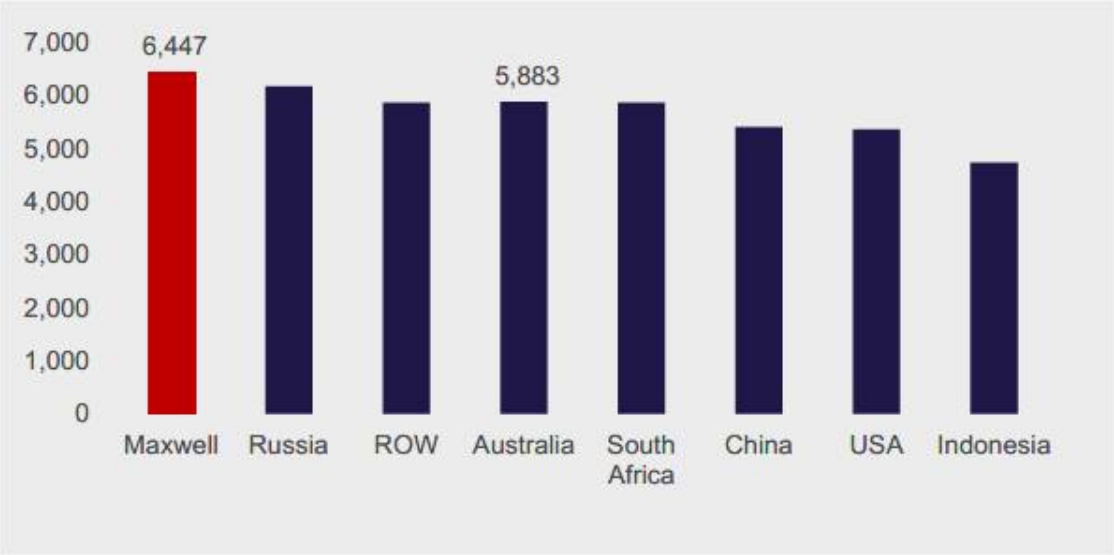
This means that the Project's SSCC is highly competitive.

Thermal coal quality

6.40 The classification of thermal coal is dependent on the calorific value of the product. The term "calorific value" refers to the energy density of the coal and determines the volume of coal that needs to be combusted to generate a given level of energy. That is, the higher the calorific value of the coal, the less coal needs to be burned to generate a unit of electricity. The less coal burned, the less CO_2 is released into the atmosphere. Therefore, the use of high quality coal for electricity generation can reduce the amount of CO_2 that is released into the atmosphere per unit of electricity produced, compared to coal of an inferior quality. Associated ash and suphur content also play a role in the quality of and environmental impacts associated with burning coal to produce electricity.

6.41 **Figure 26** extracted from the CRU study below shows that, in 2030, the Project's thermal coal will have a higher calorific value than the country weighted averages of all major seaborne thermal coal suppliers, including Australia.

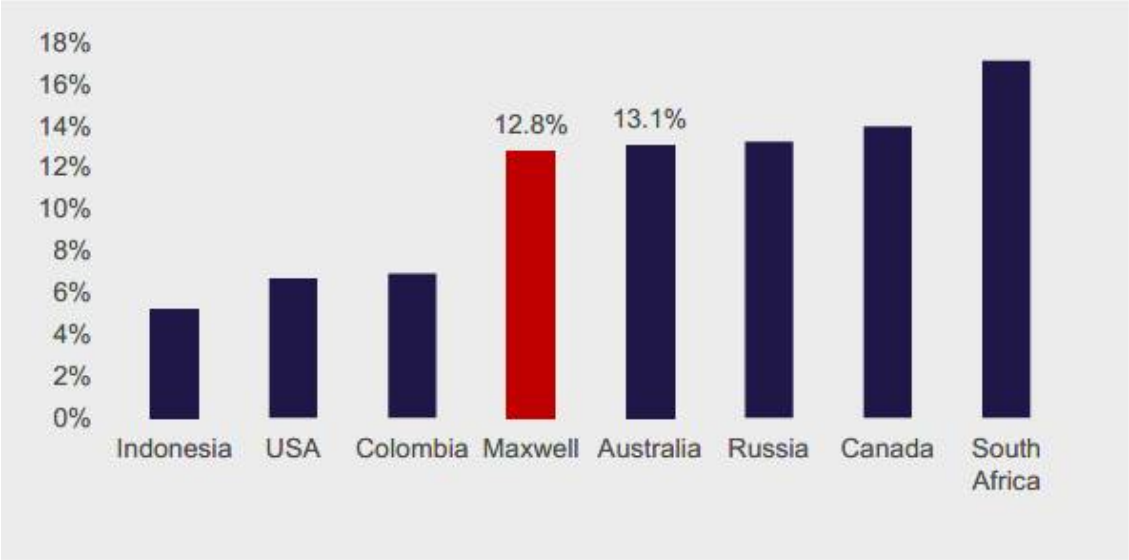
Figure 26: Thermal coal quality comparison (calorific value, CV) between Maxwell and the country weighted average of mines and projects in 2030 (weighted: 2030 production), kcal/kg GAR



Source: CRU.
Source: CRU

6.42 **Figure 27** extracted from the CRU study below shows that, in 2030, the Project's thermal coal will have a lower ash content than the country weighted average of Australia and other major seaborne thermal coal suppliers.

Figure 27: Thermal coal quality comparison (ash content, %) between Maxwell and the country weighted average of mines and projects in 2030 (weighted: 2030 production), %

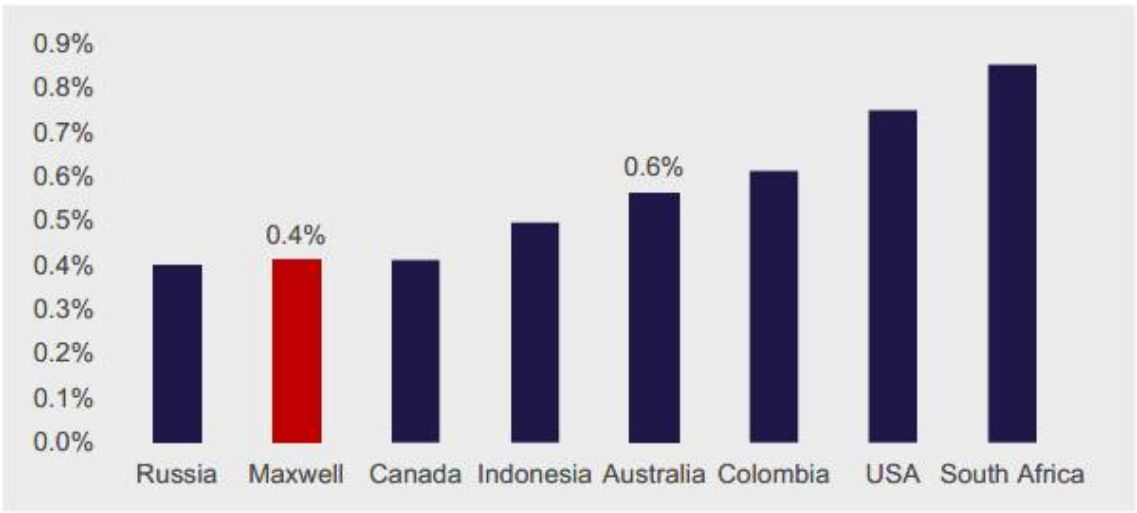


Source: CRU.

Source: CRU

6.43 **Figure 28** extracted from the CRU study below shows that, in 2030, the Project's thermal coal will have a sulphur content equal to the country weighted averages of Russia and Canada and lower than the country weighted average of all other seaborne thermal coal suppliers.

Figure 28: Thermal coal quality comparison (sulphur content, %) between Maxwell and country weighted average of mines and projects in 2030 (weighted: 2030 production), %



Source: CRU.

Source: CRU

6.44 CRU has assessed the Project's premium thermal coal product as being in the first percentile of the global thermal coal business cost curve and in the sixth percentile of the global seaborne thermal coal business cost curve in 2030. It is a quality premium thermal coal which is very cost competitive.

The relative importance of Australian coal exports in terms of meeting projected demand for coking and thermal coal

6.45 While Australia is the world's largest exporter of coal, it should be acknowledged that coal investment and supply conditions in Australia have a limited impact on the global demand for coal for several reasons:

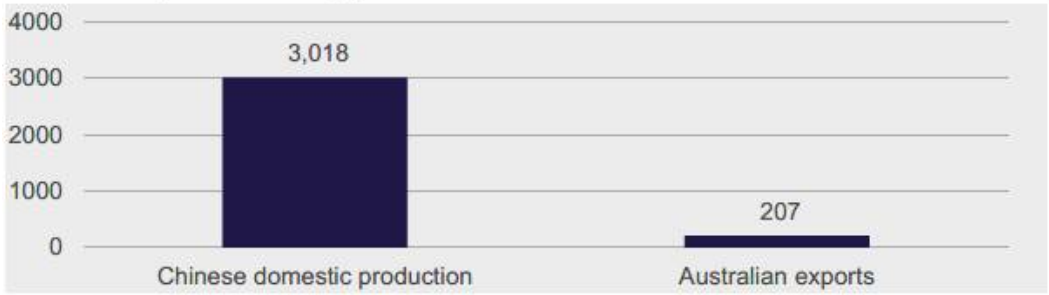
(a) as a low-cost producer of coal, it does not affect the global price of thermal (which is determined by the marginal – typically Chinese coal producers);

(b) Australian coal supplies are small relative to domestic industries in the major importing countries: Chinese domestic coal production alone is more than 14 times larger than total Australian exports (see **Figure 45** extracted from the CRU study below);

(c) the Strategic Statement on Coal acknowledges that although NSW is an important coal producer, exports of coal from NSW represent only around 3% of global coal consumption; and

(d) there is a high degree of flexibility in the coal industries of major Asian demand centres, rendering it likely that any change in Australian exports would be offset by expansion in these domestic supplies. The WEO 2019 (p 227) recognises that Indonesia is a swing producer that is able to quickly increase production in response to price signals from international markets.

Figure 45: Size comparison between China domestic market and Australian exports for thermal coal (2014-19 average), Mt



Source: CRU.
Source: CRU

Likelihood of market substitution

6.46 For its market substitution analysis, CRU considered the hypothetical scenario where the Project is not approved and treated all of the Project's product coal as thermal coal for this purpose.

6.47 It should be noted that the analysis of the impacts of market substitution has been informed by various technical factors, including:

(a) the requisite coal volumes evaluated on an energy-equivalent basis;

(b) the relative average regional boiler efficiencies;

(c) the average fuel consumption and fuel emission intensity (Scope 1 GHG emissions) for coal mines by region;

(d) low and high fugitive emissions rates (Scope 1 GHG emissions) for underground and surface mines (see further explanation below);

(e) average power consumption of coal mines (Scope 2 GHG emissions) and average emissions intensity of grid power by region;

(f) the average distance coal is transported by rail by region (Scope 3 GHG emissions); and

(g) the Project's product-specific energy content factor that ranges from 27.1 to 28.5 GJ/t of product coal over the life of mine and the calculation of Scope 3 GHG emissions associated with energy production.

6.48 There will remain a global demand for high quality Australian coal irrespective of whether the Project is approved, as is evident from discussion of the three policy scenarios posited in the IEA's WEO 2019 discussed above. CRU considered that, if the Project is not approved, demand for the Project's SSCC would likely be satisfied by other major SSCC producing countries including China, Russia and Indonesia, and demand for the Project's thermal coal would likely be satisfied by other major thermal coal producers, including in Australia, China, India, Russia and Indonesia.

Consequences of substitution of the Project's coal with coal from alternative mines, particularly in respect of GHG emissions

6.49 The high quality of the Project's thermal and SSCC product coal (as explained above), means that it performs at a higher level of boiler efficiency when burned at power stations, compared with alternative supply sources. This has important consequences for the purpose of calculating the GHG emissions that would occur if the Project were to proceed compared to if the Project were refused.

6.50 As mentioned in paragraph 6.46 above, for the purpose of assessing the GHG emissions if the Project is not approved, the Project's product coal has been treated as a single thermal coal product.

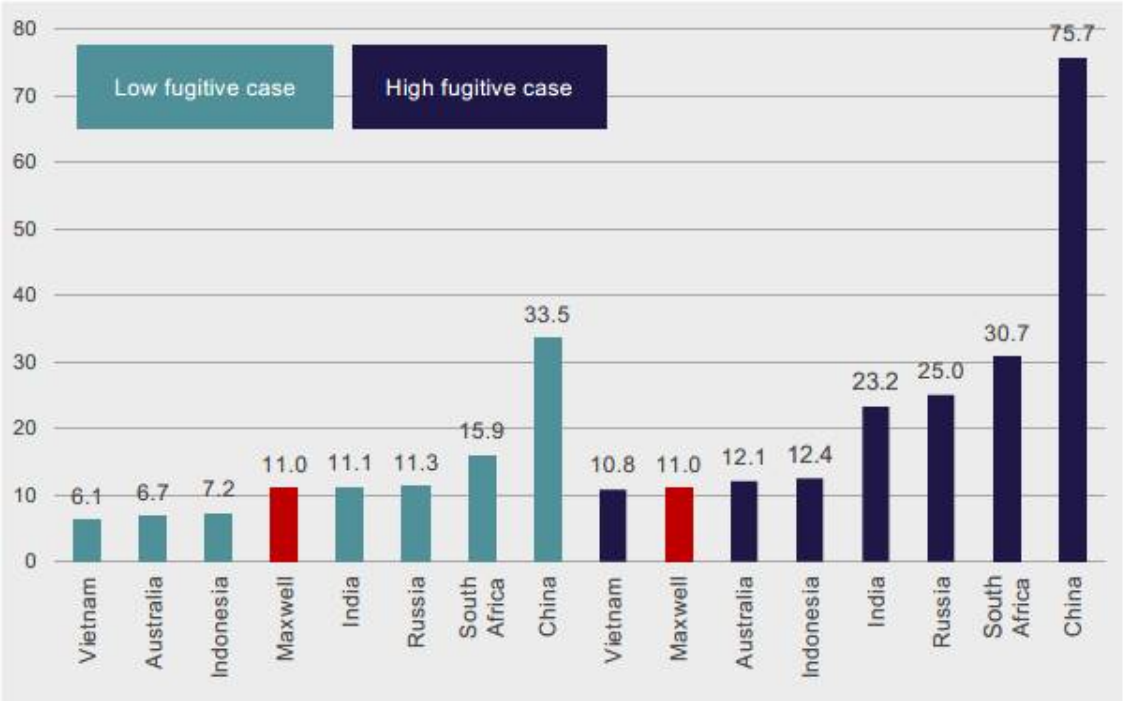
6.51 The Project is expected to produce 0.066 t CO_2-e of fugitive emissions per tonne of ROM coal. As a result of the absence of detailed estimates of fugitive emissions from a defined alternative supply source, a low and high fugitive emissions case needed to be adopted. The selection of the low and high cases was informed by the IPCC's estimates of fugitive methane emissions from coal mining, which range from 0.164 to 0.410 t CO_2-e per tonne of coal in the case of underground mining, and 0.005 to 0.033 t CO_2-e per tonne of coal in the case of surface mining. Underground mines typically have higher fugitive emissions than open cut (surface) mines. A range boundary of 0.005 to 0.164 t $CO_{2\text{-}e}$ per tonne of coal was applied to alternative coal sources for the low fugitive emissions case, and 0.033 to 0.410 t CO_2-e per tonne of coal for the high fugitive emissions case. It is important to note, therefore, that in both the low and high fugitive emissions cases, the Project's estimated fugitive emissions (which are below the lower-bound of the IPCC's estimated range for underground mining) were compared to the estimated average fugitive emissions of countries that have a mix of underground and surface mines.

6.52 It should also be noted that the Department of Planning, Industry and Environment's Assessment Report for the Project dated September 2020 (the **Assessment Report**) acknowledges (at 124) that the Project's fugitive emissions "conservatively assume that no greenhouse abatement, such as flaring or beneficial use, occurs for the Project".

6.53 In the low fugitive emissions case, the Project is expected to produce more Scope 1 and 2 GHG emissions compared to the average Scope 1 and 2 GHG emissions of replacement sources in Vietnam, Australia and Indonesia. However, sources in India, Russia, South Africa and China would on average produce an additional 0.1 to 22.5 Mt CO_2-e over the life of mine of the Project.

6.54 In the high fugitive emissions case, the Project is expected to produce the second lowest volume of Scope 1 and 2 GHG emissions compared to replacement sources. Alternate sources of coal in Russia, Australia, Indonesia, India, South Africa and China would on average produce an additional 1.1 to 64.7 Mt CO_2-e over the life of the Project (see **Figure 50** extracted from the CRU study below).

Figure 50: Scope 1 & 2 emissions from the Maxwell Project and alternative supply sources for both fugitive emission cases over the LOM, Mt CO2-e



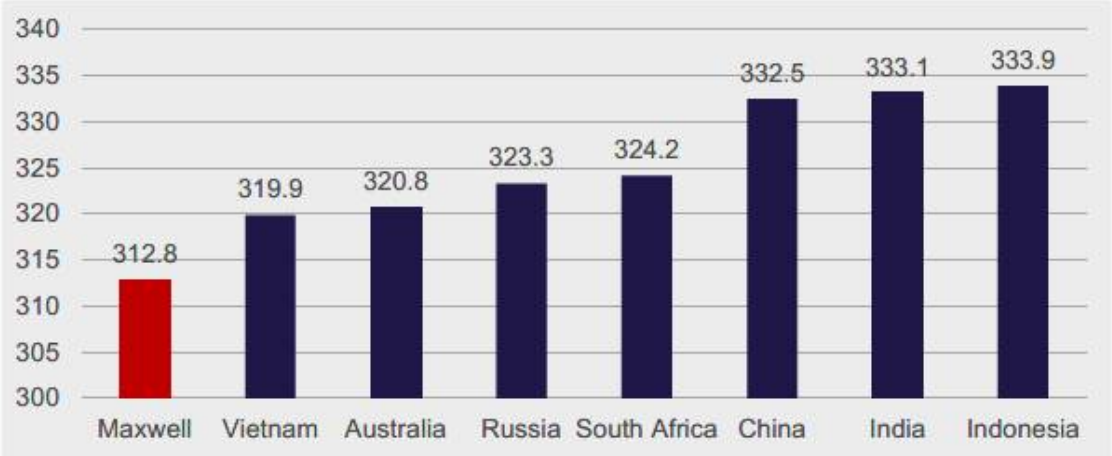
Source: CRU, Malabar.
Source: CRU

6.55 Scope 1 and 2 emissions also account for approximately 3% of all direct and indirect GHG emissions calculated for the Project. Therefore, direct mining activity by the Applicant is responsible for only a small fraction of emissions of the coal value chain.

6.56 In relation to Scope 3 GHG emissions, the substitution of the Project's product coal with coal from alternate sources would on average increase Scope 3 GHG emissions by an estimated 7.0 to 21.1 Mt of CO_2-e for the life of mine (between 2021 and 2046) (see **Figure 51** extracted from the CRU study below).

6.57 Scope 3 emissions account for 97% of all direct and indirect GHG emissions associated with the Project. Therefore, the use of the Project's product coal by third parties is responsible for almost all the emissions of the coal value chain.

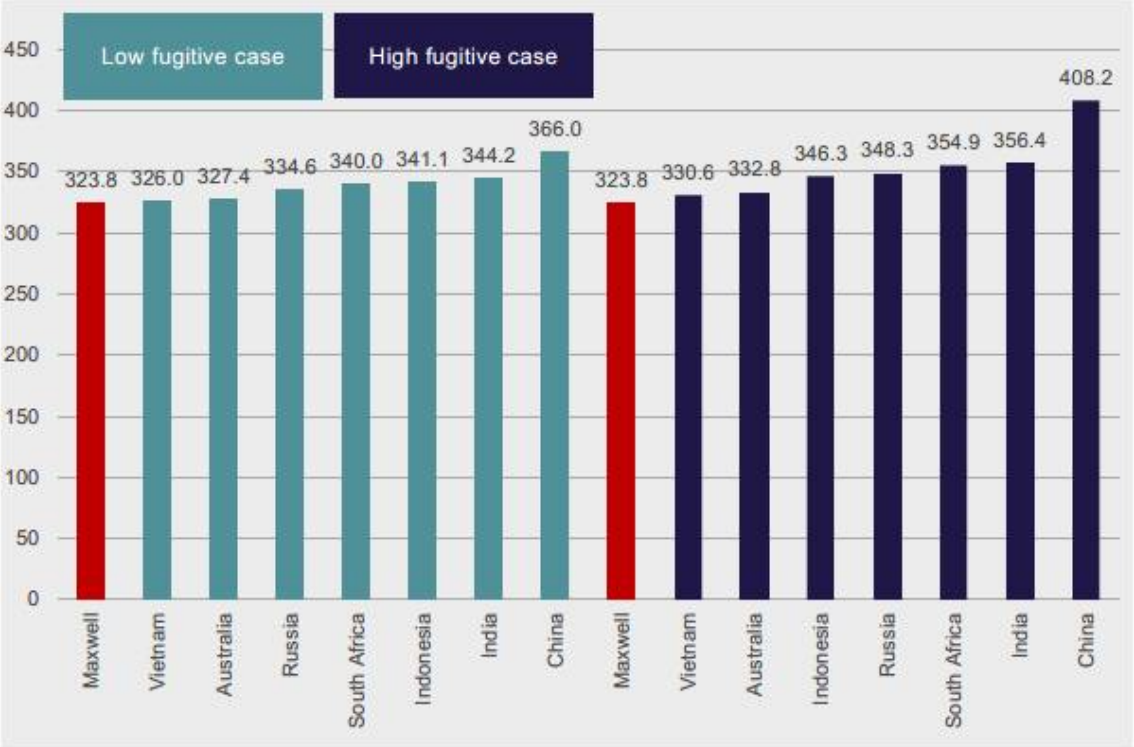
Figure 51: Scope 3 emissions from the Maxwell Project and alternative supply sources over the LOM, Mt CO2-e



Source: CRU, Malabar.
Source: CRU

6.58 When combining Scope 1, 2 and 3 GHG emissions, Scope 3 emissions are the main driver of GHG emissions and are much larger than Scope 1 and 2 emissions. Overall, CRU estimated that the Project would have the lowest total GHG emissions compared to the average GHG emissions of alternate sources and that market substitution of the Project's coal would release between 2.2 to 84.4 Mt CO_2-e into the atmosphere over the life of mine (see **Figure 52** extracted from the CRU study below).

Figure 52: Scope 1, 2 & 3 emissions from the Maxwell Project and alternative supply sources, over the LOM, Mt CO2-e



Source: CRU, Malabar.
Source: CRU

7. PART D: RESPONSE TO SUBMISSIONS MADE IN RESPECT OF GHG EMISSIONS, CLIMATE CHANGE, AND COAL DEMAND

Overview

7.1 As set out in the Submissions Report, 15 submissions on the EIS objected to the Project on the basis of GHG emissions and climate change issues.

7.2 Rather than address each submission individually, this Part D addresses the common themes or elements of those submissions.

Common themes raised by public submissions regarding GHG emissions, climate change and demand for coal

7.3 The following common themes or elements were contained in the public submissions that object to the Project:

(a) Theme 1: anthropogenic climate change is a real phenomenon that is occurring, coal is a major source of human-induced GHG emissions, and the Project will contribute to climate change;

(b) Theme 2: in order for the "well below 2°C" goal of the *Paris Agreement* to be realised, no new fossil fuel developments should be approved;

(c) Theme 3: the approval of the Project would be inconsistent with Australia's international commitments and existing climate change laws and policies, particularly Australia's NDC and the NSW Climate Change Policy Framework; and

(d) Theme 4: in light of the global move towards decarbonisation, the Project will likely become a stranded asset; and

(e) Theme 5: the IPC should follow *Rocky Hill* and refuse development consent for the Project.

7.4 Each of these themes will be addressed in turn below.

Theme 1: anthropogenic climate change is a real phenomenon that is occurring, coal is a major source of human-induced GHG emissions, and the Project will contribute to climate change

7.5 Most of the 15 objections mention, at a high level, the science of climate change and the impacts that can be caused to the world's and Australia's climate and environments as a result of anthropogenic climate change.

7.6 The Applicant does not contest that climate change is real and happening and that global GHG emissions must be reduced.

7.7 The Applicant considers that comments about the effects of anthropogenic climate change generally, which are not tied or made referrable to the determination of the development application for the Project, are of little to no assistance to the IPC's consideration of the impacts of the Project.

7.8 The relevant impact to be assessed is the impact of the Project. That involves considering the difference to the environment if the Project goes ahead and if it does not. In that regard, the Applicant submits that:

(a) its total contribution of Scope 1 emissions will be 0.3% of total GHG emissions in NSW and 0.07% of total GHG emissions for Australia from 2016, as set out in the GHG Assessment;

(b) the life of the Project will be completed before 2050, which is the target date for NSW achieving net zero emissions;

(c) to the extent that the total Scope 1 emissions for the Project will exceed 100,000 tCO_{2-e} in a year (which they are likely to in the first year of the Project), then the Applicant must comply with the Federal government's Safeguard Mechanism by offsetting its emissions above a baseline set by the Clean Energy Regulator or otherwise managing compliance; and

(d) if the Project does not proceed there will be no corresponding reduction in global GHG emissions in the atmosphere because the global demand for coal will be satisfied by other sources. Indeed, refusal of consent would likely result in a net increase in GHG emissions globally due to market substitution of the Project's high quality coal with inferior quality coal (lower calorific value and higher ash and sulphur content), as discussed in **Part C** of this submission.

7.9 The Applicant readily acknowledges that coal mining projects, like other forms of development, generate GHG emissions. However, coal is currently, and will continue to be for several decades, vital to the provision of affordable, reliable energy particularly to countries in the Asia-Pacific region. It is the world's demand for coal-fired electricity generation that is the main cause of Scope 3 GHG emissions.

7.10 This point was recognised by Member Smith of the Queensland Land Court, in the context of considering the Alpha coal mine, in the decision of *Hancock Coal Pty Ltd v Kelly & Ors and Department of Environment and Heritage Protection (No 4)* [2014] QLC 12, where he relevantly observed:

> [230] … [I]t is the demand for electricity to the extent that it is met by coal-fired generators that causes the Scope 3 emissions, and the facts as set out in this case clearly show that Alpha is but one of a myriad of suppliers, both local and around the world, who will seek to meet this existing demand.
>
> [231] … I must on the evidence of this case determine that it is the demand for coal-fired electricity, and not the supply of coal from coal mines, which is at the heart of the problem.
>
> [232] … the clear and unambiguous facts of this case show that there will be no reduction of GHGs if the Alpha mine is refused, and, indeed, depending on the source of replacement coal, such replacement coal may well, on the evidence, result in an increase in GHG emissions.

7.11 Additionally, the 97% of Scope 3 GHG emissions of the Project that are generated by the use of the product coal, will be subject to the NDCs (or INDC in the case of Taiwan) and the various laws, policies and initiatives adopted by the Expected Export Countries to achieve their commitments under the Paris Agreement. While the Applicant does make the point in its EIS that its contribution to Australia's GHG emissions "would be relatively small", the Applicant does not suggest that the GHG emissions that are generated by the Project do not matter or are irrelevant. The Applicant takes the GHG emissions generated by the Project seriously, which is why the Applicant has committed to implementing the following measures to mitigate its Scope 1 and 2 GHG emissions:

(a) gas collected from underground mining would be managed through the following hierarchy:

(i) where practical, storing gas underground in the goaf;

(ii) where there is sufficient methane content in the deeper coal seams, a small gas-powered plant (less than 5 MW) may be installed to generate power from gas drained in the underground workings (as set out in section 3.5.6 of the EIS);

(iii) if a gas-powered plant is not installed, drained gas would be flared (to reduce methane levels); or

(iv) drained gas would be vented to the atmosphere if the gas is too low in methane content for flaring (or other operational reasons, such as the gas content being too variable);

(b) selecting and designing equipment and processes to optimise efficiency and reduce energy consumption; and

(c) maintaining plant and equipment;

(d) monitoring fuel and electricity consumption; and

(e) sourcing electricity from renewable resources where available and economically reasonable and feasible.

7.12 The GHG Assessment for the Project assessed GHG emissions conservatively, assuming no GHG abatement (i.e. venting as opposed to flaring or power generation).

7.13 Additionally, as a separate project, on 19 August 2020 Malabar received Development Consent for a solar farm, known as the Maxwell Solar Project (SSD 18_9820). The solar panels would be located on areas of previous open cut mining disturbance.

7.14 The proposed capacity of the Maxwell Solar Project would power approximately 10,000 homes, which is equivalent to the towns of Muswellbrook and Singleton combined.

7.15 The Maxwell Solar Project would allow for beneficial use of an area previously subject to open cut mining. The location would be adjacent to a major electricity generating hub in NSW (Liddell and Bayswater Power Stations), and in proximity to high voltage power lines.

Theme 2: in order for the "well below 2°C" goal of the Paris Agreement to be realised, no new fossil fuel developments should be approved

7.16 The Applicant does not dispute that action needs to be taken to reduce GHG emissions globally in order for the "well below 2°C" goal of the *Paris Agreement* to be realised.

7.17 However, in circumstances where:

(a) the *Paris Agreement* has not been enacted as part of the law of Australia, and parties to the *Paris Agreement* individually determine their national contribution to its goal in the form of an NDC;

(b) the development of new coal mines, or the continuation of existing coal mines, is not prohibited by the operation of international, Australian or NSW law or policy;

(c) the prohibition of new coal mines is not one of the many measures that Australia has adopted as part of its NDC under the *Paris Agreement*;

(d) indeed, to the contrary, NSW law or policy:

(i) aims to "foster the significant social and economic benefits" to NSW "that result from the efficient development of mineral resources";[34] and

(ii) permits the carrying out of coal mining projects with development consent under the Mining SEPP; and

[34] *Mining Act 1992* (NSW), s 3A.

(iii) prescribes that the State's action on climate change will not undermine the NSW's $36 billion mining sector and the jobs and communities it supports;[35]

(e) the IPC must have regard to the objects of the Mining SEPP, which include:

(i) to facilitate the orderly and economic use and development of land containing mineral resources (such as coal); and

(ii) to promote the development of significant mineral resources;

(f) the material produced in Part C of this submission demonstrates that the failure to approve the Project would likely result in a net increase in GHG emissions (particularly Scope 3 emissions) due to market substitution of the Project's high quality coal with inferior quality coal; and

(g) the Applicant considers that any suggestion that the refusal of the development application would demonstrate a commitment on the IPC's part to take action to achieve the goal of the *Paris Agreement* is misconceived, at risk of giving rise to a legal error on the part of the IPC, and places at risk the realisation of the significant social and economic benefits that the Project will deliver at a local, regional and State level.

7.18 The Assessment Report for the Project states (at 125):

> It is important to note that the established national and State policy frameworks do not seek to restrict private development in order to meet Australia's commitments under the Paris Agreement. Nor do these frameworks impose any prescriptive emissions criteria which can be applied in development assessments.

7.19 The simplistic assertion that coal mines should be refused on the ground that they are inconsistent with the *Paris Agreement*, is flawed on legal and merit grounds.

7.20 Legally, the assertion is problematic because NSW planning laws do not prohibit or restrict (as distinct from regulate, pursuant to development consent conditions) the carrying out of fossil fuel development, including coal mines (nor, for that matter, does any other climate change law or policy considered in Part B of this submission). More specifically, the carrying out of the Project here is permissible with development consent under the Mining SEPP. The objects of the Mining SEPP include:

(a) to facilitate the orderly and economic use and development of land containing mineral resources (such as coal); and

(b) to promote the development of significant mineral resources.

7.21 If the approach of no new fossil fuel development is adopted by the IPC as a decision-making practice, it would mean that all development applications for fossil fuel developments would be rejected without being assessed on their own merits and such decisions would almost certainly be invalid in that:

(a) the EP&A Act, the Mining SEPP and the *Mining Act 1992* (NSW) all contemplate that fossil fuel developments may be carried out with lawful authority in NSW; and

(b) a failure to entertain a development application for such fossil fuel development on its merits would amount in numerous legal errors rendering the IPC's decision invalid, including:

---

[35] *Net Zero Plan Stage 1: 2020–2030* (March 2020) at 22.

(i) a failure to have regard to all relevant considerations set out in s 4.15 of the EP&A Act;

(ii) a failure to accord the proponent of the proposed project with procedural fairness;

(iii) a constructive failure to exercise its decision-making power or jurisdiction; and

(iv) rigid adoption and application of a decision-making practice or policy without due regard to the circumstances or merits of the development application before it.

7.22 Indeed, the Court in *Rocky Hill* did not go so far as to accept expert opinion that the development should be refused on the basis that it was inconsistent with achieving the aim of the *Paris Agreement*. In *Rocky Hill*, the Court remarked that such a position:

> [552] … It gives priority to existing and approved fossil fuel developments, along the lines of "first in, best dressed". It also frames the decision as a policy decision that no fossil fuel development should ever be approved.
>
> [553] I consider the better approach is to evaluate the merits of the particular fossil fuel development that is the subject of the development application to be determined. Should this fossil fuel development be approved or refused? Answering this question involves consideration of the GHG emissions of the development and their likely contribution to climate change and its consequences, as well as the other impacts of the development …

7.23 Thus, the Applicant suggests that the position of some of the objectors is fundamentally at odds with the decision-making framework of NSW planning laws.

7.24 Further, the position that no new fossil-fuel developments should be approved also has practical problems. If the approach is to be adopted that any form of development – new or existing – that will be reliant on fossil fuels (either directly or indirectly) should be refused, then this could have crippling and devastating consequences for human populations that rely on fossil fuels as a reliable, affordable and efficient means for energy or electricity. It could result in many different forms of development, such as schools and hospitals, being without electricity, which would, in turn, have flow-on effects for human development globally. Such consequences would give rise to distributive injustice to different populations and undermine the achievement of intra-generational equity, which is one of the principles of ecologically sustainable development. Moreover, as the Department of Planning recognised in its Addendum Report on the Wallarah 2 Coal Project in considering the principle of inter-generational equity:

> [The Department] recognises that there remains for the foreseeable future a clear need to continue to mine coal deposits to meet society's basic energy needs … The Department also acknowledges that the downstream energy and other socio-economic benefits generated by the amended project would benefit future generations, particularly through the provision of international energy needs.

7.25 Furthermore, if the position were to be applied equitably to all development applications, then consent authorities should also refuse all other types of development whose Scope 1, 2 and 3 emissions contribute to climate change. For example, all new commercial buildings and residential developments that are not carbon neutral should be refused, as the construction industry accounts for almost 20% of Australia's GHG emissions.[36] So many sectors of the Australian economy contribute to GHG emissions that applying the approach advocated by some of the objectors to planning decisions would virtually halt all major development in NSW.

---

[36] See Man Yu, Thomas Wiedmann, Robert Crawford and Catriona Tait 'The Carbon Footprint of Australia's Construction Sector' (2017) 180 *Procedia Engineering* 211-220;

Theme 3: Approval of the Project would be inconsistent with Australia's international commitments and existing climate change laws and policies

7.26 This theme has already been addressed in the context of discussing Theme 2 above. As pointed out there, and in Parts A and B of this submission:

(a) there is nothing in existing climate change laws and policies which prohibits the approval of new coal mining development; and

(b) the prohibition of new coal mines is not one of the specific mechanisms or measures that Australia has adopted for the specific purpose of meeting its NDC under the *Paris Agreement*;

(c) indeed, to the contrary,

(i) the Federal government's Safeguard Mechanism which will apply to the Project when its GHG emissions exceed 100,000 tCO_2-e is one of the measures that Australia has adopted to meet its NDC under the *Paris Agreement;*

(ii) NSW planning laws recognise that the carrying out of coal mining projects is permitted with development consent; and

(iii) NSW's Net Zero Plan Stage 1 states that it is important that the State's action on climate change does not undermine the State's mining businesses and the jobs and communities they support; and

(d) the objects of the Mining SEPP include:

(i) to facilitate the orderly and economic use and development of land containing mineral resources (such as coal); and

(ii) to promote the development of significant mineral resources.

Theme 4: in light of the global move towards decarbonisation, the Project will likely become a stranded asset

7.27 One objection asserted that given the global move towards decarbonisation, the Project "will likely end up as a stranded asset". Similarly, the Assessment Report for the Project dated September 2020 acknowledged that some submitters questioned the future demand profile for coking coal.

7.28 However, as Part C of this submission demonstrates, there is a clear global demand for thermal and coking coal into the future that will not be met by existing mines. Even in the IEA's Sustainable Development Scenario, there will be continued demand for coal that will not be met in 2040 by existing mines. Accordingly, any assertion that demand for coal will fall so as to make the Project unviable, is not supported by the evidence.

7.29 Indeed policy announcements and any trends regarding the uptake of renewable energy, that are often cited in support of a stranded asset argument, are already captured by the Stated Policies Scenario of the WEO 2019, which recognises the increasing share of electricity generated by renewable sources but nevertheless projected a continuing demand (although declining share) for coal-fired power (as set out in Part C of this submission). These projections are supported by CRU's forecasts.

7.30 Secondly, although some institutions are divesting from coal projects, the WEO 2019 states that financing restrictions for coal projects based on the preferences of lenders and their shareholders is not yet an issue affecting projects in China and India, and that financing restrictions in developed economies could provide an opening for Russian and Indonesian coal producers to increase their market share (at 220, 227, 244–245).

7.31 Thirdly, coal is a commodity and potential future coal prices (taking into account all the factors that may cause fluctuation including competing sources of energy and climate change policy) have already been considered in the Applicant's decisions and indeed in the Economic Assessment for the Project at Appendix J to the EIS. That Economic Assessment included a coal price sensitivity analysis to account for potential fluctuations in coal prices, including due to potential future climate change policies.[37]

7.32 In any event, it is for the Applicant to make its own assessment of the economic viability of the Project and then decide whether it wishes to proceed to seek development consent for the Project. The Applicant has undertaken that course of action in lodging the development application for the Project.

7.33 Lastly, it should be noted that 75% of the Project's product coal will be capable of being used as SSCC. As set out in **Part C**:

(a) steel will remain an important material for global development, particularly in South East Asia;

(b) approximately 70% of global crude steel is produced through the blast furnace-basic oxygen furnace route which is heavily dependent on coking coal (SSCC and HCC);

(c) global demand for carbon crude steel (crude steel, excluding stainless steel) is expected to grow to 2.3 billion tonnes in 2040, up by 501 Mt from its 2019 level;

(d) the IEA projects that industrial coal use which today accounts for around one-third of coal consumption, increases by some 225 Mtce to 2040 in the Stated Policies Scenario, as coal remains the backbone of steel and cement manufacturing;

(e) the scope to shift away from coal by making greater use of scrap-based or direct reduction of iron (DRI)-based electric arc furnaces is limited by the availability and cost of scrap steel, as well as the cost competitiveness of electricity;

(f) despite the share of steel produced by blast furnace-basic oxygen furnace declining in the long term, as electric arc furnace steelmaking grows, there will continue to be a significant requirement for new iron units from coal produced by blast furnace-basic oxygen furnaces (as opposed to iron from recycled steel which is used in electric arc furnace steelmaking);

(g) given the relatively young age of the installed capacity of blast furnace-basic oxygen furnaces in Asia, much of the future demand for steel is forecast to be met by this existing capacity;

(h) in 2040, the blast furnace-basic oxygen furnace process will still account for approximately 58% of global steel production; and

(i) the Project is a low-cost producer of SSCC that is low in sulphur which makes it one of the most marketable and competitive SSCC products globally.

[37] The sensitivity analysis in the Economic Assessment included a scenario where export coal prices reduce by 25%. See also, the Assessment Report for the Project at 126 and 151.

Theme 5: the IPC should follow *Rocky Hill* and refuse development consent for the Project

7.34 Opponents of the Project argue that the IPC should follow the decision in *Rocky Hill* having regard to the GHG emissions of the Project.

7.35 Consistency in administrative decision-making would not require the same outcome for the Project as that which occurred in *Rocky Hill*. For consistency in administrative decision-making to be achieved, like cases need to be treated alike. The Project and the Rocky Hill Coal Project are very different developments. The Rocky Hill Project was proposed to be developed in the Gloucester Valley, close to the town of Gloucester; a location that was considered to be incompatible with other land uses in the vicinity of the development, contrary to cl 12 of the Mining SEPP. The Department of Planning's assessment report recommended that development consent to the Rocky Hill Coal Project be refused. The Court found that the mine would have significant adverse impacts on the visual amenity and rural and scenic character of the valley, significant adverse social impacts on the community and particular demographic groups in the area, and significant impacts on the existing, approved and likely preferred uses of land in the vicinity of the mine. The Court also found that (at [421]):

> although the [Rocky Hill Coal Project] has the potential to generate some positive social benefits, including from the local economy and employment, these benefits will be outweighed by the significant negative social impacts that the Project will cause.

7.36 The purpose of this submission is not to describe all the differences between the Project and the Rocky Hill Coal Project because, in determining the development application for the Project, the IPC is not required to refer to *Rocky Hill*, distinguish *Rocky Hill* on its facts, or otherwise opine that the decision in *Rocky Hill* was wrong.[38] The differences set out in paragraph 7.35 above are not exhaustive. They merely illustrate that the Project is different to the Rocky Hill Coal Project such that following *Rocky Hill* would not achieve consistency in administrative decision-making.

7.37 The IPC is required to consider the merits of the Project itself, taking into consideration the matters set out in s 4.15 of the EP&A Act as are of relevance to the Project. This is the best way to achieve consistency in planning decisions. Indeed, the NSW Court of Appeal has acknowledged that applying ministerial policy, such as the Mining SEPP, is one of the most useful aids in achieving consistency with other decisions in comparable cases.[39]

[38] *Segal v Waverley Council* (2005) 64 NSWLR 177 at [56].

[39] *Segal v Waverley Council* (2005) 64 NSWLR 177 at [52].

8. PART E: WEIGHING THE BENEFITS OF THE PROJECT AGAINST GHG EMISSIONS AND CLIMATE CHANGE CONSIDERATIONS

8.1 It is not intended, in this submission, to repeat the impact assessment material that is before the IPC. Rather, in this Part E of the submission, we only provide a brief summary of some of the benefits of the Project that weigh against climate change considerations and, therefore, to assure the IPC that there is more than sufficient material before it to grant development consent to the Project. Those benefits include:

(a) development of the Project solely as an underground mining operation to minimise local environmental impacts while using methods that would maximise resource recovery and mining efficiency;

(b) the use of the Maxwell Infrastructure for the Project will result in significantly less disturbance and a lower initial capital cost that would otherwise be required for a greenfield coal mine. The Assessment Report for the Project dated September 2020 states that (at xii):

> The Project represents a logical 'brownfield' extension of the existing Drayton coal mine, enabling not only the economic and beneficial reuse of existing infrastructure, but improved rehabilitation outcomes and post-mining land uses for the existing mine site

(c) additionally, the Project will support continued rehabilitation at the Maxwell Infrastructure including reduction in the volume of the legacy east void through emplacement of reject material generated by coal processing activities for the Project;

(d) the Economic Assessment indicates that the Project will generate an estimated total net benefit to the NSW economy of $1,010 million in net present value terms, including $342 million (in net present value terms) to the NSW Government in royalties, company income tax attributable to NSW of $168 million, plus payroll tax, land taxes and council rates, which will benefit present and future generations; and

(e) the generation of approximately 250 jobs during construction and up to 350 new direct, long-term, operational jobs for the region.

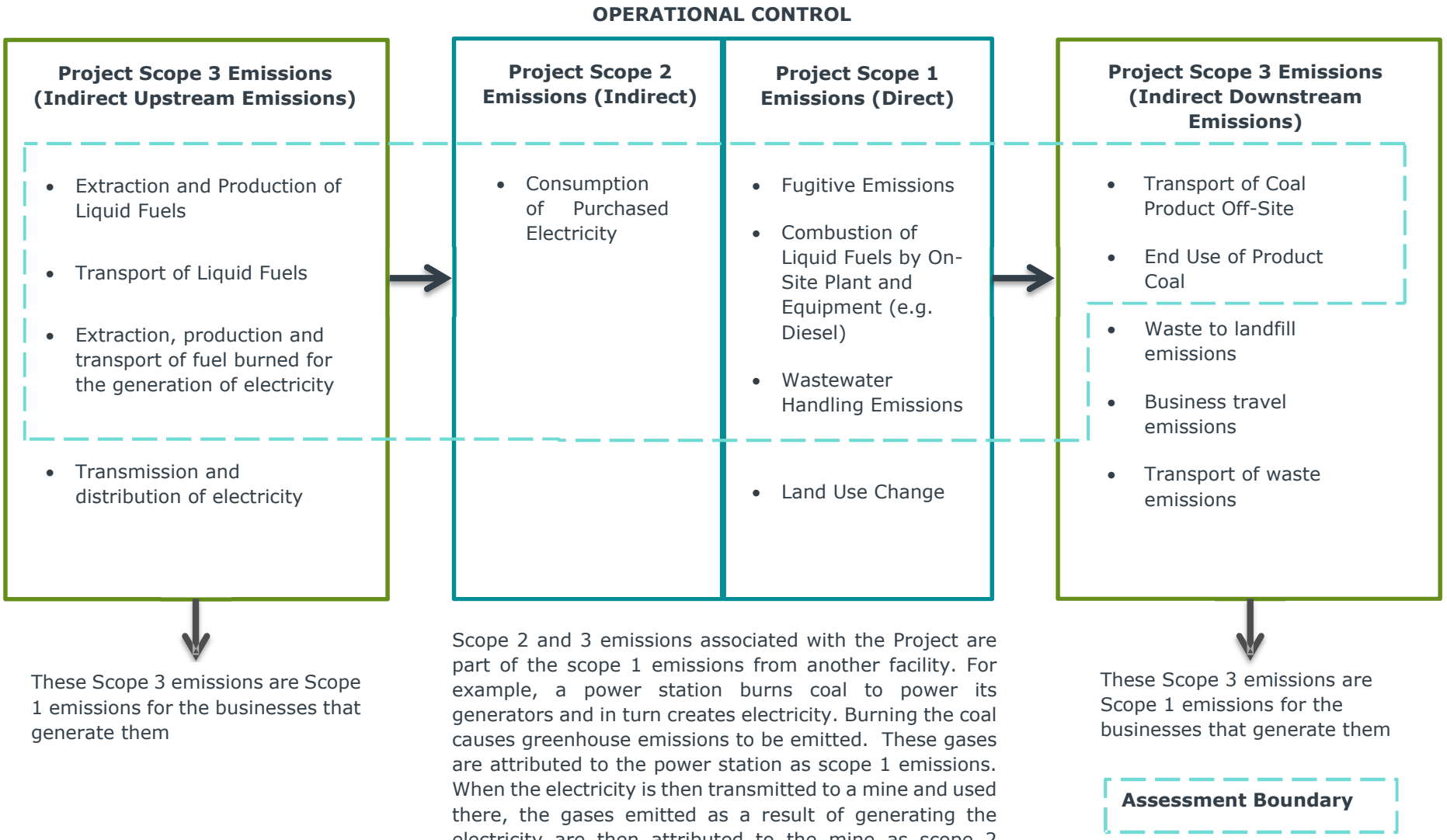
Conclusion

8.2 As noted in Part A of this submission, it is for the IPC to engage in an "intuitive synthesis" of weighing all of the various positive and negative impacts associated with the Project. Climate change impacts and GHG emissions are just one of many different factors that the IPC may take into account. Certainly, climate change impacts and GHG emissions should not be the single determinative consideration for the IPC in making a decision in respect of the development application for the Project.

8.3 The Applicant considers that, in light of the benefits of the Project summarised above and as detailed elsewhere in the material before the IPC, the positive aspects associated with the Project clearly outweigh the negative aspects associated with the Project, and that the Project should be approved.

8.4 Not proceeding with the Project would result in a failure to realise these significant benefits for the local, regional and State economy.

APPENDIX 1: FIGURE SHOWING OPERATIONAL CONTROL THE PROPONENT OF A COAL MINING PROJECT HAS OVER GHG EMISSIONS



APPENDIX 2: DOMESTIC LAWS, POLICIES AND MEASURES OF EXPECTED EXPORT COUNTRIES DIRECTED TOWARDS CLIMATE CHANGE IMPACTS, GHG EMISSIONS AND ACHIEVEMENT OF THE COUNTRY'S NDC

<table>
<tr><th>Country</th><th>Summary</th></tr>
<tr><td>Japan</td><td>
Paris Agreement and NDC

Japan signed the Paris Agreement on 22 April 2016 and ratified it on 8 November 2016. The Paris Agreement entered into force for Japan on 8 December 2016. Japan's first NDC includes an emissions reduction target of 26% below 2013 levels in 2030. This equates to emissions of approximately 1.042 billion tCO_2-e in 2030.

Japan submitted its second/updated NDC on 31 March 2020. That NDC re-affirms Japan's commitment to reducing its greenhouse gas emissions by 26% by 2030 from 2013 levels and states that Japan "will strive to achieve a 'decarbonized society' as close as possible to 2050 with disruptive innovations, such as artificial photosynthesis and other CCUS technologies".

The table below sets out further information relating to Japan's First NDC:
<table>
<tr><td>Emissions reduction target</td><td>Emission reductions of 26% below 2013 levels in 2030.</td></tr>
<tr><td>Total emissions in 2030</td><td>Approximately 1.042 billion tCO_2e in 2030.</td></tr>
<tr><td>Coverage</td><td>100% (economy-wide)</td></tr>
<tr><td>Scope</td><td>• All sectors, including:
• energy;
• industrial processes and product use;
• agriculture;
• Land Use, Land-Use Change and Forestry (LULUCF); and
• waste.</td></tr>
<tr><td>Gases</td><td>CO_2, CH4, N2O, HFCs, PFCs, SF6 and NF3.</td></tr>
<tr><td>Sectoral targets</td><td>• Japan has sector-specific emissions reduction targets.
Relevantly, Japan's target for:
• the industry sector is to reduce emissions from 429 $MtCO_2$ in 2013 to 401 $MtCO_2$ in 2030; and
• the energy conversion sector is to reduce emissions from 101 $MtCO_2$ in 2013 to 73 $MtCO_2$ in 2030.
• Japan also has a "removals target" for the LULUCF sector, of removing 37 $MtCO_2$ from the atmosphere by 2030. Japan did not provide a base year figure.</td></tr>
</table>
Japan's First NDC sets out a variety of measures to achieve its 2030 emissions reduction target. Relevantly, measures in the energy conversion sector include:
• expanding renewable energy introduction to the maximum extent possible;
• utilizing nuclear power generation whose safety is confirmed; and
</td></tr>
</table>

Country	Summary
	• pursuit of high efficiency in thermal power generation, including coal-fuelled technologies such as USC, A-USC, integrated gasification and combined cycle, etc. Measures in the industry sector are classified as measures which relate to the iron and steel industry, the chemical industry, the ceramics, stone and clay products industry, factory energy management and cross-sectoral/other. Measures in the iron and steel industry include: • efficiency improvement of electricity-consuming facilities; • increased chemical recycling of waste plastic at steel plants; • introduction of a next-generation coke making process (SCOPE21); • improvement of power generation efficiency; • enhanced energy efficiency and conservation facilities; • introduction of an innovative ironmaking process (Ferro Coke); and • introduction of an environmentally harmonized steelmaking process (COURSE50). Japan's second/updated NDC does not include a detailed set of further measures to meet its commitment but specifically mentions artificial photosynthesis, other CCUS technologies, and hydrogen. **Current policies** Plan for Global Warming Countermeasures The **Plan for Global Warming Countermeasures** was adopted by the Cabinet of Japan on 13 May 2016. The Plan incorporates the emissions reduction target in Japan's NDC of 26% below 2013 levels in 2030. The Plan also sets out strategic actions towards Japan's long-term goal of an 80% reduction by 2050. The base year of this long-term goal is not specified. The Plan incorporates the sectoral targets and measures set out in Japan's NDC (see above). The Plan also emphasises the key role of innovative technology, which the Government is promoting though its "Environmental and Energy Technology Innovation Plan" and its "National Energy and Environment Strategy for Technological Innovation towards 2050". The Plan will be revised every three years as necessary. Long-term Low-Carbon Vision Japan's **Long-term Low-carbon Vision**, published in March 2017, establishes that Japan's long-term goal of reducing emissions by 80% in 2050 will be met through energy efficiency, low-carbon energy supply and a switch to end-use low-carbon energies. This will be achieved through existing technologies and the development and deployment of new technologies. Carbon pricing is highlighted as a key policy direction. Relevantly, Japan's vision refers to CCUS as a means of achieving emission reductions in the energy sector, as well as centralised/distributed energy management. The Vision sets out that "now" is the time to act, and refers to concepts including: • the carbon budget, which is set in accordance with the total amount of cumulative emissions that can be emitted in order to allow Japan to achieve its 2°C target; • the avoidance of "lock-in" through introducing city structures and large-scale facilities; and • key principles of environmental policy including prevention, the precautionary principle and the polluter pays principle.

Country	Summary
	Long-term Strategy under the Paris Agreement The **Long-term Strategy under the Paris Agreement** was adopted by the Cabinet of Japan on 11 June 2019. The Strategy covers the period 2018 to 2050 and outlines the country's intention to reduce its GHG emissions by 80% by 2050. In relation to energy, the Strategy sets out a "future vision" in which renewable energy will become an "economically self-sustained and decarbonised main power source" and in which all options and innovations will be explored, including renewable energy, energy efficiency, storage batteries, hydrogen, and CCUS. Specifically, with respect to thermal power, the Strategy states that the Government will: • "work to reduce reliance on coal-fired power generation as much as possible by fadeout inefficient coal-fired thermal power generation" (footnote omitted); • work to reduce CO_2 emissions from thermal power generation, including by accelerating "the efforts of a wide range of stakeholders, aiming to establish its first commercial scale CCU technology by 2023 as a trigger for wider usage in view of full social adoption in 2030 and thereafter." Tax for Climate Change Mitigation Japan implemented a **Tax for Climate Change Mitigation** (a carbon tax) on 1 October 2012. It currently has a value of JPY289/tCO_2e (US$3/t$CO_2$e). The tax covers all fossil fuels, which comprise 68% of Japan's emissions. Revenues earned from the tax are applied to bolstering mitigation activities, such as encouraging energy savings and increasing utilisation of renewable energy. Tokyo also has a cap and trade scheme and Saitama has an emissions trading system - these schemes are bilaterally linked and cover an additional 2% of Japan's emissions. In 2015, Tokyo's cap and trade scheme had reduced emissions by 26% compared to emissions in 2000, and Saitama's ETS had achieved a 27% reduction in emissions below 2005 levels. Both Tokyo's cap and trade scheme and Saitama's ETS cover large-scale facilities in all commercial and industrial sectors which consume more than 1,500KL of crude oil equivalent in energy per year. Joint Crediting Mechanism Japan has introduced a Joint Crediting Mechanism (**JCM**), through which Japan will cooperate with developing countries to achieve a reduction in greenhouse gas emissions through the diffusion of low-carbon technologies. The JCM's partnership document has been signed by 17 developing countries. Credits generated from emission reductions under the JCM will be allocated according to agreed terms between the participating countries. Development of CCUS technologies Japan is actively engaged in the **development of CCUS technologies**, including under its **Roadmap for Carbon Recycling Technologies** published 7 June 2019. According to the Global CCS Institute's Global Status Reports of 2018 and 2019, Japan: • commenced of CO_2 injections at the Tomakomai CCUS facility by Japan CCUS with the Ministry of Economy, Trade and Industry's full support – this is Asia's first full-cycle CCUS hydrogen plant, which will capture more than 300,000 tonnes of CO_2 by 2020. In 2019, it reached a capture milestone of 300,000 tonnes of CO_2, and continued intensive monitoring of storages;

Country	Summary
	• retrofitted the Toshiba Corporation 49MW Mikawa power plant in Omuta (Fukuoka Prefecture) to accept biomass (in addition to coal) with a carbon capture facility. • launched JPOWER and Chugoku Electric Power Company's Osaki CoolGen facility, a 166 MW oxygen-blown IGCC (integrated gasification combined cycle) demonstration plant in Osakikamijima (Hiroshima Prefecture), which will separate and capture CO_2 from the end of 2019; • completed construction of Toshiba's carbon capture and utilisation system at the Saga City Waste Incineration Plant (on Japan's Kyushu Island), using captured CO_2 for algae culture; and • commencement of construction of the gasifier for the Hydrogen Energy Supply Chain project that plans to gasify Australian brown coal in Victoria's Latrobe Valley and transport it by ship to Japan for future decarbonised hydrogen developments. This project being developed by Kawasaki Heavy Industries (KHI), Electric Power Development Co. (J-Power), Iwatani Corporation, Marubeni Corporation, Sumitomo Corporation and AGL, with the support of the Governments of Japan, Australia and the State of Victoria. First hydrogen production is expected by 2021.
India	**Paris Agreement and NDC** India signed the Paris Agreement on 22 April 2016, and ratified it on 2 October 2016. India's NDC includes the following targets: • to reduce the emissions intensity of its GDP by 33-35% percent by 2030 from 2005 levels; • to achieve about 40% cumulative electric power installed capacity from non-fossil fuel based energy resources by 2030 with the help of transfer of technology and low cost international finance including from the Green Climate Fund (**GCF**); and • to create an additional carbon sink of 2.5 to 3 billion tonnes of CO_2-e through additional forest and tree cover by 2030. Priority areas for emission reductions include: • introducing new, more efficient and cleaner technologies in thermal power generation (noting that most thermal power generation in India is coal-fuelled); • promoting renewable energy generation and increasing the share of alternative fuels in the overall fuel mix; • reducing emissions from transportation sector; • promoting energy efficiency in the economy, notably in industry, transportation, buildings and appliances; • reducing emissions from waste; • developing climate resilient infrastructure; • fully implementing the Green India Mission and other programmes of afforestation; and • planning and implementing actions to enhance climate resilience and reduce vulnerability to climate change.

Country	Summary
	Current policies Perform, Achieve, Trade Scheme India has a Perform, Achieve, Trade Scheme, introduced in 2008, which reduces energy consumption in energy intensive industries. The scheme involves the trading of energy saving certificates and operates as a market based mechanism. National Action Plan on Climate Change India's National Action Plan on Climate Change (NAPCC), introduced in 2008, outlines priorities for mitigating and adapting to climate change. It established "missions" relating to solar energy and enhanced energy efficiency, among others. Clean Environment Cess Since 2010, the Indian Government has imposed a coal cess (i.e. a coal tax), the Clean Environment Cess, on all domestic and imported coal (in all forms). The Clean Environment Cess has been increased three times since its establishment, now reaching 400 rupees per tonne of coal. The revenues from the coal tax feed into the National Clean Environment Fund, which provides finance to renewable energy projects. National Electricity Plan In April 2018, India released its National Electricity Plan (NEP), which is valid to financial year 2026/27. The NEP provides electricity demand forecasts for the period 2017-2026/27, calculates installed capacities from conventional and renewable energy sources needed to meet that demand and describes relevant policies. During the period 2017-22, no additional capacity of coal will be added (except for the coal power plants currently under construction). Demand growth will be met by additional installed capacities in gas, hydro, nuclear and renewables. A share of 56.5% of installed capacity is expected to come from non-fossil sources by 2027. In 2027 the country aims to have 275GW installed capacity of solar and wind, 72GW of hydro and 15GW of nuclear. The Central Electricity authority estimates that this means that no additional coal capacity is needed until at least 2027. Draft National Energy Policy According to India's **Draft National Energy Policy**, published in 2017, coal based power generation capacity is likely to go up to more than 330-441GW by 2040 (from 192GW in FY 2017). The Draft Policy indicates India's preference for demand to be met by domestic coal, however the percentage of coal that is imported is likely to remain high unless domestic production increases rapidly. According to India's NDC, coal will continue to dominate power generation in the future. The Government has introduced the following initiatives to improve the efficiency of coal-fired power plants: • all new, large coal-based generating stations have been required to use highly efficient supercritical technology; • R&M and LE of existing old power stations is being undertaken in a phased manner; and approximately 144 old thermal stations have been assigned mandatory targets for improving energy efficiency.

<table>
<tr><th>Country</th><th>Summary</th></tr>
<tr><td>South Korea</td><td>
Paris Agreement and NDC

South Korea signed the Paris Agreement on 22 April 2016, and ratified it on 3 November 2016. The Paris Agreement entered into force for South Korea on 3 December 2016. South Korea's NDC has proposes an economy-wide target to reduce GHG emissions by 37% below BAU emissions of 850.6 $MtCO_2e$/year in 2030. The table below sets out key information relating to South Korea's NDC:
<table>
<tr><td>Emissions reduction target</td><td>37% below BAU by 2030. BAU emissions in 2030 are projected at 850.6 MtCO2e.</td></tr>
<tr><td>Coverage</td><td>Economy-wide</td></tr>
<tr><td>Scope</td><td>100% (economy-wide)</td></tr>
<tr><td>Scope</td><td>• Energy;
• industrial processes and product use;
• agriculture; and
• waste
(A decision on whether to include land use, land-use change and forestry (LULUCF) will be made at a later stage.)</td></tr>
<tr><td>Gases</td><td>CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6</td></tr>
</table>
South Korea's NDC indicated that it would subsequently develop a detailed plan to implement its mitigation target. To this end, South Korea released a revised roadmap for achieving the 2030 National Greenhouse Gas Reduction Goal in July 2018 (the Roadmap). The Roadmap sets out sectoral targets, including:

• emission reductions of 24 million tons in the energy conversion sector (power generation, group energy) through policies to reduce fine dust and promote the use of eco-friendly energy. The sector will create a detailed plan to reduce another 34 million tons before submitting the revised NDC in 2020 by establishing a third basic energy plan, revising the energy tax framework, and enhancing the dispatch of environmental power; and
• emission reductions of 99 million tons in the industry sector through the revision of industrial processes, energy use reduction, and sharing of emission reductions technologies.

The Roadmap indicates that South Korea intends to achieve a 32.5% reduction on BAU emissions domestically, and the remaining 4.5% through international market mechanisms.

Current Policies

<u>Act on the Allocation and Trading of Greenhouse Gas Emission Permits</u>

South Korea enacted the Act on the Allocation and Trading of Greenhouse Gas Emission Permits in 2012 and launched an ETS on 1 January 2015. It currently has a price of approximately US$20/$tCO_2e$. The ETS covers 68% of Korea's emissions, including emissions from the industry, power, aviation, building and waste sectors. Liable emitters comprise companies and factories in the relevant sectors which produce over 125,000 tons of CO_2 per year and 25,000 tons of CO_2 per year (respectively). This represents approximately 600 companies, including 5 domestic airlines.
</td></tr>
</table>

Country	Summary
	During the first phase of the scheme (2015-2017), only domestic offset credits could be used for compliance. Certified Emission Reductions (CERs) generated from domestic Clean Development Mechanism (CDM) projects and credits from domestically certified projects (Korean Offset Credits) were allowed. These credits had to be converted to Korean Credit Units (KCUs) before being used for compliance. Offsets could only be used for up to 10% of each entity's compliance obligation. During the second phase of the scheme (2018-2020), CERs generated from international CDM projects developed by domestic companies can be used for compliance (up to 5% of each entity's emission volume). During the third phase of the scheme (2021-2025), credits of up to 10% of each entity's compliance obligation with a maximum of 5% coming from international offsets will be allowed. Framework Act on Low Carbon Green Growth South Korea enacted a **Framework Act on Low Carbon Green Growth** on 6 June 2016. Article 25 of the Act incorporates the 2030 emissions reduction target in South Korea's NDC. Article 4 of the Act requires the Government to establish a five-year National Strategy for Low Carbon Green Growth every five years. Article 39 of the Act requires the Government to gradually reduce the use of fossil fuels such as petroleum and coal. Third Energy Master Plan In June 2019, the government announced its **Third Energy Master Plan** which aims to increase the share of renewable energy to 20% by 2030 and 30 to 35% by 2040. Eighth Plan for Electricity Supply and Demand In December 2017, the government released its **Eighth Plan for Electricity Supply and Demand** which sets targets for increased electricity supply from renewables and natural gas, and decreases supply from coal and nuclear. The Plan sets an objective of 20% share of electricity production obtained from renewables by 2030, while natural gas would reach 18.8%, and both coal and nuclear decreasing to 36.1% and 23.9% respectively. These targets are intended to be achieved through the addition of 4.3GW in new LNG and pumped-storage hydroelectric generation facilities and an increase in the installed capacity of renewable energy (to be comprised mainly of wind and solar projects) from 11.3GW to 58.5GW, by 2030. The South Korean Government published a draft Ninth Basic Plan for Electricity Supply and Demand in 2020. The draft Plan covers the period of 2020–2034 and sets a renewable source target for installed power capacity of 40% by 2034. The draft Plan is set against the background of the Democratic party's victory in elections that took place in April 2020. One key election platform included the Party’s pledge to reach net zero emissions by 2050.

Country	Summary
China	**Paris Agreement and NDC** China signed the Paris Agreement on 22 April 2016 and ratified it on 3 September 2016. China's NDC has the following goals: • to peak carbon dioxide emissions around 2030 and make best efforts to peak early; • to lower carbon intensity (carbon dioxide emissions per unit of GDP) by 60% to 65% from the 2005 level by 2030; • to increase the share of non-fossil fuels in primary energy consumption to around 20%; and • to increase the forest stock volume by around 4.5 billion cubic meters compared to the 2005 level. Through achieving these goals, China aims to limit emissions to approximately 1.042 billion tCO_2-e in 2030. China's NDC sets out policies and measures to implement enhanced action on climate change. Measures relating to energy include to: • control total coal consumption; • enhance the clean use of coal; • increase the share of concentrated and highly-efficient electricity generation from coal; • lower coal consumption of electricity generation from newly built coal-fired power plants to around 300 grams coal equivalent per kilowatt-hour; • expand the use of natural gas by 2020 by achieving more than 10% share of natural gas consumption in the primary energy consumption and making efforts to reach 30 billion cubic meters of coal-bed methane production; • proactively promote the development of hydro power, on the premise of ecological and environmental protection and inhabitant resettlement; • develop nuclear power in a safe and efficient manner; • scale up the development of wind power; • accelerate the development of solar power; • proactively develop geothermal energy, bio-energy and maritime energy; • achieve 200GW installed capacity of wind power, 100GW installed capacity of solar power and the utilization of thermal energy to 50 million tons coal equivalent by 2020; • enhance the recovery and utilization of vent gas and oilfield-associated gas; and • scale up distributed energy and strengthen the construction of smart grid. Measures relating to industry include to: • strictly control the total expansion of industries with extensive energy consumption and emissions, accelerate the elimination of outdated production capacity and promote the development of service industry and strategic emerging industries; • promote low-carbon development of industrial sectors, implement the Action Plan of Industries Addressing Climate Change (2012-2020) and

Country	Summary
	formulating carbon emission control targets and action plans in key industries; • research and formulate greenhouse gas emission standards for key industries; • effectively control emissions from key sectors including power, iron and steel, nonferrous metal, building materials and chemical industries through energy conservation and efficiency improvement; • strengthen the management of carbon emissions for new projects and to actively control greenhouse gas emissions originating from the industrial production process; and • construct a recycling-based industrial system, promoting recycling restructur in industrial parks, increasing the recycling and utilization of renewable resources and improving the production rate of resource. Measures relating to enhancing support for science and technology include strengthening research and development and commercializing demonstration for low-carbon technologies, such as energy conservation, renewable energy, advanced nuclear power technologies and carbon capture, utilization and storage and promoting the technologies of utilizing carbon dioxide to enhance oil recovery and coal-bed methane recovery. Measures relating to emissions trading include to: • build on carbon emission trading pilots, steadily implement a nationwide carbon emission trading system and gradually establish the carbon emission trading mechanism so as to make the market play the decisive role in resource allocation; and • develop mechanisms for the reporting, verifying and certificating of carbon emissions and to improve rules and regulations for carbon emission trading to ensure openness, fairness and justice in the operation of the carbon emission trading market. On 22 September 2020, China announced that it would aim be "carbon neutral" by 2060. It is expected that China's updated or second NDC under the Paris Agreement and its upcoming 14th five-year plan will reflect this aim. **Current policies** <u>National emissions trading scheme</u> In December 2017, China launched its national emissions trading scheme (**ETS**) building on its pilot schemes since 2013. It is expected that the ETS will be implemented in 2021. It will initially only cover companies in the power sector. This will cover more than three billion tons of CO_2-e, which accounts for 26% of China's emissions. The national ETS will also gradually be expanded to include another seven sectors: aviation, building materials, chemicals, iron and steel, non-ferrous metals, pulp and paper, and petrochemicals. The National Carbon Emissions Trading Market Construction Plan (Power Generation Industry) set out the targets and roadmap for developing the ETS. While it has not yet been decided whether offsets will be available to be used in the ETS, it is expected that domestic offsets that have been used in China's existing regional ETS pilots will be able to be used. China has eight multiple regional pilot ETSs which have operated as pilot markets since 2013, including the:

Country	Summary
	• Beijing (Pilot) Emissions Trading System; • Chongqing (Pilot) Emissions Trading System; • Fujian (Pilot) Emissions Trading System; • Guangdong (Pilot) Emissions Trading System; • Hubei (Pilot) Emissions Trading System; • Shanghai (Pilot) Emissions Trading System; • Shenzhen (Pilot) Emissions Trading System; and • Tianjin (Pilot) Emissions Trading System. These pilots have adopted different approaches to sectoral coverage, allocation methods, use of offsets and other design elements to test various approaches. <u>Five-year plan to save energy and cut emissions</u> China issued a **five-year plan to save energy and cut emissions** (2016-2020) on 5 January 2017. The Plan aims to cut energy consumption by 15% in 2020 based on 2015 levels. It also sets a target of a 58% maximum share of coal in national energy consumption by 2020. Coal consumption will be controlled in key areas that are suffering from heavy air pollution, and gas is encouraged as a replacement for coal. <u>Action Plan on the Efficient Use of Coal</u> In 2015, MIIT and Finance Ministry released a 2015-2020 **Action Plan on the Efficient Use of Coal**. The action plan sets out how fiscal and financial policies will support cuts in coal consumption. Through the Action Plan on the Efficient Use of Coal, China intends to decrease coal consumption by 160 million tonnes over the next five years. Policies under this action plan included the closure of multiple coal-fired power plants, a ban on the construction of new coal-fired power plants until 2018, and now include a cap on the annual production capacity of coal to 700Mtce (approximately 15% of total coal production capacity). China supports CCUS and has recently implemented multiple measures to accelerate the deployment of CCUS. These include: • widely promoting low-carbon technologies, with an emphasis on CCUS; • supporting CCUS pilots and Near Zero Carbon Emissions pilots; • providing grant funding for CCUS research projects promoted by the Ministry of Science and Technology; • amending the Environmental Impact Assessment Guidelines to better address CCUS projects; and • establishing a CCUS capacity building project for government officials and researchers directly involved in CCUS. A significant focus for China is the application of CCUS for EOR. China has over 20 CCUS for EOR projects at various stages of development. A number of these EOR projects have been, or will be, linked to facilities that capture the CO_2 generated by coal-fired power plants. For example, the Sinopec Shengli Power Plant, located near the Shengli oilfield in the Shangdong province (the second largest oil field in China), currently possesses an integrated CCUS pilot plant which captures 40,000 tons of CO_2 per annum, with a second phase of the CCUS plant currently under construction and intended to capture up to 1 million tons of CO_2 per annum. Once the second phase of the CCUS plant is complete, all captured CO_2 will be used for EOR to increase oil recovery by 10-15%.

<table>
<tr><th>Country</th><th>Summary</th></tr>
<tr><td>Taiwan</td><td>
Paris Agreement and NDC

Taiwan is not a party to the UNFCCC or the Paris Agreement. Nevertheless, Taiwan's Cabinet put forward an Intended Nationally Determined Contribution (INDC) on 17 September 2015. Taiwan's INDC has an emissions reduction target of 50% from the BAU level by 2030. The BAU level is 428 $MtCO_2e$ and the 2030 target is 214 $MtCO_2$-e by 2030. The table below sets out key information relating to Taiwan's INDC:

<table>
<tr><td>Emissions reduction target</td><td>Emission reductions of 50% below BAU levels by 2030.</td></tr>
<tr><td>Total emissions in 2030</td><td>Approximately 214 $MtCO_2e$ in 2030.</td></tr>
<tr><td>Coverage</td><td>Economy-wide</td></tr>
<tr><td>Scope</td><td>All sectors, including:
energy;
industrial processes and product use;
agriculture;
Land Use, Land-Use Change and Forestry (LULUCF); and
waste.</td></tr>
<tr><td>Gases</td><td>CO_2, CH_4, N_2O, HFCs, PFCs, SF_6 and NF_3.</td></tr>
</table>
Taiwan's INDC sets out measures for achieving sectoral mitigation measures. Relevantly, in relation to energy, the government will:

reduce energy demand by introducing energy conservation measures;
raise the renewable energy development target to 17,250MW in 2030;
continue to phase out nuclear power plants;
increase the use of natural gas;
replace old power plants with the "best feasible technology";
promote the construction of smart grids; and
use low-carbon fuel and energy-efficient technologies in the refining sector.

Emissions reductions will be achieved in the industrial sector through:

industrial structure adjustment;
technical advice service of energy conservation and carbon reduction;
integrated utilization of energy and resources in industrial zones;
regulation of energy efficiency standards;
alternative fuels;
heat recovery; and
a renewal of facilities.

Current policies

<u>Greenhouse Gas Reduction and Management Act 2015</u>

Taiwan enacted its Greenhouse Gas Reduction and Management Act on 1 July 2015. Key features of the Act are:
</td></tr>
</table>

Country	Summary
	• Article 4 of the Act sets a goal to reduce GHG emissions to no more than 50% of 2005 emissions by 2050; • Article 5(1) requires the Government to draft mid- to long-term strategies for gradually reducing dependence on fossil fuels, with a mid-to long-term aim of improving renewable energy policies, and the gradual realization of a nuclear-free homeland; • Article 5(3)-(4) recommends that the Government implement tax mechanisms on imported fossil fuels based on their CO_2-e emissions, and actively help traditional industries achieve energy conservation and carbon reduction or transition, develop green technology and green industry, create new employment opportunities and green economies, and promote a low-carbon, green growth plan for Taiwan's infrastructure; • Article 8 requires relevant government agencies to promote GHG reduction and climate change adaptation through, relevantly, development of renewable energy and energy technology, reduction in GHG emissions by industrial sectors, establishment of GHG cap-and-trade scheme and facilitation of international emission reduction cooperation mechanism, and research, development and implementation of GHG reduction technologies; and • Article 18 requires Taiwan's Environmental Protection Administration (EPA) to implement a domestic cap and trade scheme, and Article 20 outlines matters to be considered in the development of the scheme, including trade intensities of various sectors, avoiding carbon leakage and overall national competitiveness. <u>National Climate Change Action Guideline/GHG Reduction Action Plan</u> The Act also required the Government to develop the **National Climate Change Action Guideline** (which was approved on 23 February 2017) and a **GHG Reduction Action Plan**.[40] The National Climate Change Action Guideline is to include periodic regulatory goals, implementation timetables, implementation strategies and an evaluation mechanism.[41] Under the GHG Reduction Action Plan, the authorities responsible for the Taiwan's energy, manufacturing, transportation, residential, commercial, and agriculture sectors are required to formulate GHG Emission Control Action Programs. These Action Programs must include GHG emissions targets, timetables and economic incentive measures. These Action Programs are to be regularly reviewed and revised and are to propose improvement plans if sectors are failing to meet their emission targets. Multiple subsidiary regulations have been introduced, including the: • Regulations Governing Incentives for Landfill Sites to Reduce Greenhouse Gas Emissions (announced 25 December 2015). • Regulations Governing Greenhouse Gases Offset Program Management (announced 31 December 2015). • Management Regulations Governing Greenhouse Gas Emission Inventories and Registration (announce 5 January 2016). • Greenhouse Gas Reduction and Management Enforcement Rules (announced 6 January 2016).

[40] Taiwan, *Greenhouse Gas Reduction and Management Act*, Article 9.

[41] Taiwan, *Greenhouse Gas Reduction and Management Act*, Article 9.

Country	Summary
	• First Batch of Emission Sources Required to Report Greenhouse Gas Emission Inventory and Registration (announced 7 January 2016). • Greenhouse Gas Management Fund Revenues and Expenditures, Safekeeping, and Utilization Regulations (announced 30 January 2016). <u>Electricity Act 2017</u> Taiwan passed the Electricity Act in January 2017. The objects of the Act outlined in Article 1 relevantly include: • developing effectively managing the national electric power resources; • regulating electricity supply; • facilitating the transformation of energy production; • reducing carbon emissions; and • promoting the supply diversification of the electricity industry. <u>Annual Emission Reports</u> Since 1 January 2012, Taiwan's EPA has been, in batches, requesting major enterprises to submit annual emission reports. As of the end of 2015, the EPA had added 269 firms to the list, and the reporting rate has been 100%. These enterprises account for approximately 80% of CO_2 emissions from industry and fossil-fuel energy generation in Taiwan. <u>National CCUS Strategic Alliance</u> Taiwan's EPA established a national CCUS strategic alliance in 2011. This alliance brings together domestic experts from government, academia and industry, for the purpose of developing the technology and regulatory framework required for the commercial use of CCUS technology, with the ultimate goal of achieving widespread use of CCUS technology by 2020. Through the alliance, the Taiwan Cement Corporation (in partnership with the Industrial Technology Research Institute) commissioned the world's first CCUS pilot project in the cement industry in 2013, with the two entities agreeing in 2016 to extend their cooperation on the project.
Vietnam	**Paris Agreement and NDC** Vietnam signed the Paris Agreement on 22 April 2016, and "approved" it on 3 November 2016. In its first NDC, Vietnam set out an unconditional emissions reduction target of reducing GHG emissions by 8% compared to the BAU projection for 2030 by 2030, or a total of approximately 724 Mt CO_2-e in 2030. This was to be achieved by reducing emissions intensity per unit of GDP by 20% compared to 2010 levels, and increasing forest cover to 45%. If sufficient international support is received, the target of reducing GHG emissions by 8% compared to BAU by 2030 could be increased to 25%, or a total of approximately 591 Mt CO_2-e in 2030. Vietnam submitted an updated NDC in September 2020, which set out an updated target of 9% reduction below BAU for 2030 with an updated BAU projection for 2030 based on a 2014 base year (the year with the latest national GHG inventory results) from which BAU emissions are projected (instead of 2010 under the first NDC). This represents a further reduction of 21.2 Mt CO_2-e (from 62.7 Mt CO_2-e under the first NDC to 83.9 Mt CO_2-e in the updated NDC), or by 1%. This target can be increased to 27% with international support.

Country	Summary	
	Emissions reduction target	Unconditional target of reducing GHG emissions by 9% compared to BAU by 2030. BAU emissions were 284 Mt CO_2-e in 2014 (compared with 246.8 Mt CO_2-e in 2010), and are projected to be 528.4 Mt CO_2-e in 2020 and 927.9 Mt CO_2-e (compared to 474.1 Mt CO_2-e in 2020 and 787.4 Mt CO_2e in 2030 under the first NDC). Conditional target of reducing GHG emissions by 27% compared to BAU by 2030.
	Coverage	Economy-wide
	Scope	• Energy • Agriculture • Land Use, Land-Use Change and Forestry (LULUCF) • Waste
	Gases	CO_2, CH_4, N_2O, HFCs, PFCs and SF_6.
	Vietnam will exert efforts in implementing a range of measures to achieve its NDC, including: • investment in energy efficiency in industry, production and manufacturing, including in vehicles, equipment, machinery, lighting and energy consumption; • restructuring the freight transportation market; • shifting to public transport; • reducing clinker content and implementing other measures to reduce GHG emissions in cement production, including by using blast furnace slag to replace clinker in cement production; • increasing carbon sequestration in forests; and • developing waste management technology. **Current Policies** <u>Resolution No 55NQ/TW on the orientation of the National Energy Development Strategy of Vietnam to 2030</u> On 11 February 2020, this Resolution established the **National Energy Development Strategy**. The Resolution focuses on incentivising renewables in the energy mix with a goal of 15-20% proportion of renewables in the energy mix by 2030, reaching 25-30% by 2045. This is related to a requirement to reduce greenhouse gas emissions by 15%. This goal is supported by preferencing large-capacity and high-efficiency coal-fired thermal power generating units, including USC technology. Where technological upgrades of power producers are not completed or not possible, retirement of those plants will occur. <u>National Energy Efficiency Program 2019-2030 (VNEEP3)</u> In 2018, the Vietnamese Government adopted the third VNEEP. The first VNEEP was developed in 2006. By 2015 energy supply required in Vietnam grew from 29.171 to 70.588 million of tonnes of oil equivalent (Mtoe) when compared to 2000. Supply of coal as an energy source has grown eight times across that same period. Forecasts for the period covered by the VNEEP3 expect an average increase of 8.7% per year.	

<table>
<tr><th>Country</th><th>Summary</th></tr>
<tr><td></td><td>the VNEEP 3 forecasts an average increase in total power demand domestically of 8.7% per year to 2030.

The focus on energy efficiency by the Vietnamese Government is due to the high potential for economic and emissions savings. For example, the efficiency of coal power plants is 10% below the standard performance of developed countries. The VNEEP3 sets out specific objectives to achieve energy efficiency.

<u>The National Climate Change Strategy and Green Growth Strategy</u>

Developed in 2011, and designed to be a "living" document, the National Climate Change Strategy has broad objectives linked to sustainable development and GHG mitigation. The National Climate Change Strategy had an immediate focus on the period 2011-2015, however also sets plans for 2016–2025 as well as objectives for 2050, with a vision to 2100 which are economy-wide including advanced energy technologies, improved energy efficiency.

Vietnam’s Green Growth Strategy was introduced in 2012 and aims to work with the National Climate Change Strategy. Key to the Strategy is the access to new and "green technology" and improving energy efficiency through the introduction of market-based instruments. Vietnam is considering developing pilot crediting programs for the steel and waste sectors, which could start after 2020.</td></tr>
<tr><td>Brazil</td><td>Paris Agreement and NDC

Brazil signed the Paris Agreement on 22 April 2016 and ratified it on 21 September 2016. Brazil's first NDC includes an emissions reduction target of 43% below 2005 levels in 2030. This equates to emissions of approximately 1.2 $GtCO_2$-e in 2030.

The table below sets out further information relating to Brazil's First NDC:

<table>
<tr><td>Emissions reduction target</td><td>Emission reductions of 43% below 2005 levels in 2030.</td></tr>
<tr><td>Total emissions in 2030</td><td>Approximately 1.2 $GtCO_2$-e in 2030.</td></tr>
<tr><td>Coverage</td><td>100% (economy-wide)</td></tr>
<tr><td>Scope</td><td>All sectors, including:
energy;
industrial processes and product use;
agriculture;
Land Use, Land-Use Change and Forestry; and
waste.</td></tr>
<tr><td>Gases</td><td>CO_2, CH_4, N_2O, HFCs, PFCs and SF_6.</td></tr>
<tr><td>Sectoral targets</td><td>Brazil has sector-specific emissions reduction targets. Relevantly, Brazil's target for the energy sector is to achieve 45% renewables in the energy mix by 2030.

Increase the share of sustainable biofuels in the Brazilian energy mix to approximately 18% by 2030.

Brazil also has a "removals target" for the LULUCF sector, by restoring and reforesting 12 million hectares of forests by 2030, for multiple purposes.</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th>Country</th><th>Summary</th></tr>
<tr><td></td><td>Brazil's first NDC sets out a variety of measures to achieve its 2030 emissions reduction target, including:
expanding renewable energy beyond hydropower;
improving energy efficiency in the energy conversion sector by 10%;
new standards of "clean technology" in the industrial sector;
further enhance energy efficiency measures in the industrial sector; and
low carbon infrastructure.
Current policies
National Policy on Climate Change (Law 12.187/2009)
The Law 12.187 is regulated by Decree 9578/2018 and has a broad scope which establishes policy areas or plans covering the climate mitigation and adaptation, conservation and deforestation, energy expansion, sustainable agriculture, and reduction of carbon emissions from the steel industry. Brazil's National Policy notes a reduction of GHG up to 37% by 2025 with 45% of all energy generation to be renewable.
CONAMA Resolution No. 382/2006
This Resolution requires reporting of air pollution by industry and sets emission standards for industrial stationary sources.
Ten-Year Plan for Energy Expansion (2019-2029)
The Plan sets out the decade-long vision of the Brazilian Government in regard to energy sources. It is revised annually. The most recent revision was released in June 2020.</td></tr>
<tr><td>Indonesia</td><td>Paris Agreement and NDC
Indonesia signed the Paris Agreement on 22 April 2016 and ratified it on 31 October 2016.
Indonesia's first NDC set a target to reduce (unconditionally) its GHG emissions 26% against BAU by 2020 and to reduce (unconditionally) its GHG emissions by 29% against BAU by 2030. With international assistance (i.e. technology transfer, payments and capacity building), Indonesia has a conditional emissions reduction target of 41% by 2030.
The table below sets out further information relating to Indonesia's First NDC:<table><tr><td>Emissions reduction target</td><td>Emission reductions of 29% below BAU in 2030</td></tr><tr><td>Total emissions in 2030</td><td>Approximately 2 037 $MtCO_2e$ in 2030</td></tr><tr><td>Coverage</td><td>100% (economy-wide)</td></tr><tr><td>Scope</td><td>All sectors, including:
energy;
industrial processes and product use;
agriculture;
Land Use, Land-Use Change and Forestry (LULUCF); and</td></tr></table></td></tr>
</table>

Country	Summary
	<table><tr><td></td><td>• waste.</td></tr><tr><td>Gases</td><td>CO_2, CH4 and N2O.</td></tr></table> India's first NDC sets out key mitigation measures in the energy sector, including expanding "new and renewable energy" to at least 23% in 2025 and 31% in 2050. One relevant mitigation measure in the industry sector is the requirement of the steel industry to implement CO_2 "recovery, improvement process in smelter and scrap utilization". **Current policies** Presidential Regulation (PERPRES) No. 61/2011 Codifies the National Action Plan to achieve the quantified emission reduction target of 26% in 2020 is 0.767 Gt CO_2-e, and of 41% is 1.189 Gt CO_2-e. National Energy Policy Government Regulation No. 79/2014 (KEN) This National Energy Policy establishes the energy mix in Indonesia out to 2050 as follows: • renewable energy at least 23% in 2025 and at least 31% in 2050; • oil less than 25% in 2025 and less than 20% in 2050; • coal should be minimum 30% in 2025 and minimum 25% in 2050; and • gas should be minimum 22% in 2025 and minimum 24% in 2050. Electricity Supply Business Plan 2019-2028 (RUPTL) To achieve the quantitative targets set out in the National Energy Policy, the Indonesian Government regularly prepares and revises the national Electricity Supply Business Plan. This Plan, released in February 2019, presents the electricity development plan for the specified decade by projecting expected demand, and necessary infrastructure to supply this demand. The forecasts establish the share of power to be supplied by state owned energy companies, and independent power producers. Coal remains the largest power source due to low costs associated with construction and operation. The state-owned electricity company PLN has prioritised low carbon technology such as supercritical and ultra-supercritical technologies when developing new large scale coal-fired power plants. For example, the PLN will proceed with the development of the 1,000 MW class ultra-super critical coal-fired plant for the Java-Bali system.

<table>
<tr><th>Country</th><th>Summary</th></tr>
<tr><td>Malaysia</td><td>
Paris Agreement and NDC

Malaysia signed the Paris Agreement on 22 April 2016, and ratified it on 16 November 2016.

Malaysia's NDC has a target to reduce its GHG emissions intensity of GDP by 45% by 2030 relative to the emissions intensity of GDP in 2005. This comprises a 35% reduction on an unconditional basis and a further 10% conditional reduction based upon receipt of climate finance, technology transfer and capacity building from developed countries. The table below sets out key information relating to Malaysia's NDC:
<table>
<tr><td>Emissions reduction target</td><td>Reduce GHG emissions intensity of GDP by 45% by 2030 relative to the emissions intensity of GDP in 2005. Emissions intensity in 2005 was Emissions intensity of GDP in the base year: 0.531 tons CO_2-e per thousand RM.</td></tr>
<tr><td>Coverage</td><td>Economy-wide</td></tr>
<tr><td>Scope</td><td>• Energy
• Industrial processes
• Waste
• Agriculture
• Land Use, Land-Use Change and Forestry (LULUCF)</td></tr>
<tr><td>Gases</td><td>CO_2, CH_4, N_2O</td></tr>
</table>
Current policies

<u>Energy Efficiency and Conservation Act</u>

The Malaysian government has set a renewable energy target of 20% (equivalent to 3,991MW) by 2025. Currently the country only sources 2% of its energy from renewable sources. However, it is intended for the target to be met through various policies and frameworks under the recently introduced Energy Efficiency and Conservation Act.

<u>Eleventh Malaysia Plan</u>

The government will continue to pursue the green growth goal under the Eleventh Malaysia Plan (2016-2020) and will further focus on pursuing green growth for sustainability and resilience. The Plan includes strategies to enable green growth, adopt sustainable consumption and production methods, conserve natural resources and strengthen resilience against climate change and natural disasters. These actions will further reduce Malaysia's carbon footprint.

<u>A Roadmap of Emissions Intensity Reduction in Malaysia in 2014</u>

Malaysia developed A Roadmap of Emissions Intensity Reduction in Malaysia in 2014. The study indicated that Malaysia has opportunities across various sectors to meet the emissions intensity reduction target of 40% of GDP. However, while these opportunities exist, considerable efforts would be required to realise these emissions reductions in light of the challenges and barriers described below.
</td></tr>
</table>

APPENDIX 3: CRU'S SUMMARY LETTER

THE INDEPENDENT AUTHORITY
MINING | METALS | FERTILIZERS

Sydney Office

Suite 1002
99 Mount Street
North Sydney
NSW 2060
Australia

Tel +61 2 8412 2800
Fax+61 2 8412 2810

www.crugroup.com

18th September 2020

Mark Brennan
Partner, Ashurst Australia
Level 11, 5 Martin Place
Sydney, NSW 2000

A study of coal market substitution for the Maxwell Project

Dear Mr Brennan,

Maxwell Ventures (Management) Pty Ltd, a wholly owned subsidiary of Malabar Resources Limited (“Malabar”), is seeking consent to develop an underground coal mining operation, referred to as the Maxwell Project (“the Project” or “Maxwell”). The proposed Maxwell Project is expected to extract ~148 Mt of run of mine (“ROM”) coal over a production life of 26 years. An average of approximately 5.7 Mt of ROM would be extracted annually, yielding an average of ~4.8 Mt of product coal. The total measured, indicated and inferred coal resource within EL 5460 is ~770 Mt. At least 75% of coal produced over the life of the Project would be semi-soft coking coal (“SSCC”) and 25% would be thermal coal.

CRU Consulting ("CRU") has prepared a report in response to a request from Ashurst, on behalf of Malabar and Maxwell Ventures (Management) Pty Ltd to carry out an independent study on coal market substitution over the long term ("CRU Report").

The purpose of this letter is to provide a summary of the main findings we have made in the CRU Report. This letter is permitted to be shared with the New South Wales Independent Planning Commission (“IPC”) and placed in the public domain.

We note that, for reasons relating to commercial sensitivity and intellectual property, CRU grants permission to Ashurst, Malabar and Maxwell Ventures (Management) Pty Ltd to disclose the CRU Report to the NSW Independent Planning Commission ("IPC") only if the IPC makes a direction under clause 5 of Schedule 2 to the Environmental Planning & Assessment Act 1979 (NSW) ("EP&A Act") that the CRU Report is not to be published.

Structure of the CRU Report

The CRU report is comprised of four main components:

(Unless otherwise stated, long term forecasts are provided to 2040; cost comparisons are provided for 2030).

1. CRU's forecast of the long term demand and seaborne supply for steelmaking coal, with a focus on semi-soft coking coal ("SSCC") which will be produced by the Maxwell Project. The Maxwell Project's positions (SSCC quality) in relation to the global market.

2. CRU's forecast of the long term demand and seaborne supply for thermal coal, explaining the forecasting methodology, key drivers of trends and the positions of the Maxwell Project (thermal coal quality) in relation to the global market.

3. CRU's analysis of the cost competitiveness of the Maxwell Project and other competing supply sources, for both thermal coal and SSCC.

4. CRU's assessment of alternative SSCC and thermal coal supply, assuming the Maxwell Project is not approved. Finally, we will provide CRU's assessment of coal supply substitution scenario where the Maxwell Project is not approved and the consequent impact on greenhouse gas ("GHG") emissions.

Summary of key findings of CRU Report

First Component: long-term demand and supply of steelmaking coal:

- **Overall, there is a sufficient demand for Maxwell's SSCC production of typically 3.6 Mt per annum over the forecast period.**

- Although CRU forecasts **demand** for the steelmaking coal to be produced by the Maxwell Project, namely, seaborne SSCC, to fall from 60 Mt per annum in 2019 to 53 Mt per annum in 2040 (-0.6% compound annual growth rate ("CAGR")), our long term base case[1] **supply** into the seaborne SSCC market is forecast to fluctuate over the next 5 years reaching 75 Mt in 2026, then declining to 44 Mt per annum by 2040. Hence our conclusion above.

By way of background:

1. Demand for steelmaking coal (hard coking coal ("HCC") and semi-soft coking coal ("SSCC") combined) is driven by underlying steel demand trends and the choice of steelmaking technology. Currently around 73% of steel globally is produced via the blast furnace-basic oxygen furnace ("BF-BOF") route, with the remainder from non-coal consuming technologies such as the scrap-electric arc furnace ("scrap-EAF") or natural gas-direct reduced iron-EAF ("NG-DRI-EAF") routes;

2. Metallurgical coals are essential inputs for 73% of all steel currently produced globally. HCC and SSCC are used together to produce coke, which is the primary source of carbon in steelmaking. The proportion of each

[1] Please note our base case includes existing operating mines, committed projects and probable projects. The CRU Report shows the supply profile of possible projects, however, possible projects are excluded from our base case.

coal used in the coking process is determined by various factors, including price, blast furnace requirements and the specific characteristics and qualities of the coal. SSCC's contributions to the coke blend are often through lower impurities such as ash and sulphur, as well as being lower cost compared to HCC;

3. Carbon crude steel (crude steel, excluding stainless) demand is expected to grow to 2.3 Bn t in 2040, increasing by 501 Mt from its 2019 level. This is driven by economic development and rising steel intensity per capita in the developing economies, particularly India and Southeast Asia. With an increasing focus on lowering emissions and with rising scrap availability in developed economies (including China), there will be a greater utilisation of scrap-EAF steelmaking in the future. As a result, the BF-BOF share will fall to 58% in 2040 compared to 73% in 2019;

4. Over the forecast period from 2019 to 2040, global hot metal production from blast furnaces is expected to decrease marginally from 1,372 Mt to 1,338 Mt. Consistent with the increased use of EAF in China, global demand for steelmaking coal is forecast to fall from 954 Mt in 2019 to 820 Mt in 2040 (-0.7% CAGR);

5. Although the share of BF-BOF route in steel production will fall from 73% in 2019 to 58% in 2040, it will remain the dominant steelmaking process, supporting global metallurgical coal demand;

6. It is expected that the steelmaking industry will increase its consumption of HCC as a proportion of total steelmaking coal consumption, however the percentage of HCC used in a coke blend can only increase to a certain point and will not entirely replace SSCC;

7. While SSCC demand is expected to decline in China and developed economies in Europe, Asia-Pacific Advanced[2] ("APAC Advanced") and North America, SSCC demand in emerging economies such as India and Asia-Pacific Developing[3] ("APAC Developing") are expected to rise due to increasing steel demand and commissioning of new BF capacity in these regions. Economic development along with population growth will remain the core drivers of steel demand and hence SSCC demand;

8. Australia and Canada are expected to be the primary contributors to the growing seaborne SSCC supply in the period to 2040. Along with Indonesia and Russia, these countries account for the majority of the global seaborne supply;

9. The Maxwell Project will account for ~6% and ~8% of global SSCC seaborne supply in 2030 and 2040, respectively;

10. Understanding the quality of the Maxwell Project's SSCC, relative to alternative markets and projects, is key for assessing the marketability of the product:

    a) In 2030, the Project's SSCC is expected to have a medium ash content of 8.9% within the seaborne SSCC supplying countries, similar to the country averages for Australia and Mongolia. As mining progresses down through the seam sequence the product ash decreases.

[2] Australia, New Zealand, Japan, Korea, Singapore, Hong Kong and Taiwan.

[3] Other countries in Asia (excluding China, India and APAC Advanced), other Indian and Pacific Ocean islands

b) In 2030, the sulphur content of Maxwell's SSCC is expected to be the lowest in the world at 0.4% (equal with Russia's average). Maxwell's SSCC is lower in sulphur than the Australian average of 0.5%.

These qualities make Maxwell's SSCC competitive when compared to the other seaborne SSCC suppliers.

Second Component: long-term demand and supply of thermal coal:

- **CRU forecasts that global thermal coal demand is expected to remain relatively flat at around 4,000 Mt between 2019 and 2040, with a CAGR of -0.03% over the period.**

- **Seaborne thermal coal supply is expected to fall by 190 Mt between 2019 and 2040.**

- **Based on the current global supply landscape, new projects will be required in the long term to satisfy demand – these are expected to come from producers with higher quality coals and established infrastructure, notably Australia and Russia.**

By way of background:

1. CRU's forecasts for primary energy demand and demand for thermal coal are broadly aligned with International Energy Agency's (IEA's) projections for the Stated Policies Scenario in the World Energy Outlook 2019.

2. From 2019 to 2040, the fastest contractions in thermal coal demand will be seen in developed economies in Europe, North America and APAC Advanced, where thermal coal demand for electricity generation is expected to decline at CAGRs of -5.3%, -1.7% and -3.4% respectively. However, electricity's increasing share of primary energy demand in developing countries, driven by population growth and economic development, almost entirely offsets the decline in coal's share of electricity generation globally.

3. The fall in seaborne thermal coal supply over the forecast period is mainly driven by increased domestic usage, mine depletion and a lack of investment in new projects. Most notably, seaborne supply is expected to decline by ~246 Mt per annum from Indonesia over the forecast period, as Indonesia's domestic demand is expected to rise considerably.

4. Understanding the quality of the Maxwell Project's thermal coal, relative to alternative markets and projects, is key for assessing the potential environmental impacts of any supply substitution arising from a given investment decision:

    a) In 2030, the average calorific value for Maxwell's thermal coal product (6,447 kcal/kg GAR) is greater than the 6,000 kcal/kg benchmark (a typical calorific value of many traded coal products in the region).

    b) In 2030, the calorific value for Maxwell's thermal coal product is higher than the country averages for Australia and all other major seaborne thermal coal suppliers such as Russia, South Africa and Indonesia.

c) In 2030, Maxwell's thermal coal has a moderate ash content of 12.8% compared to other major thermal coal supplying countries, similar to the country averages for Australia and Russia.

d) In 2030, Maxwell's thermal coal has the lowest sulphur content globally of 0.40% (equal to the average sulphur content of Russian and Canadian thermal coal). Maxwell is also lower than Australia's average (0.6%).

Third Component: cost competitiveness of the Maxwell Project:

- **Maxwell has the lowest business cost when compared to other SSCC existing operations and potential projects globally in 2030[4].**

By way of background:

1. Based on the cost information provided by Malabar and analysis by CRU, we find that the Maxwell project sits at around the 9th percentile on the total metallurgical coal business cost curve and the 18th percentile on the total metallurgical coal seaborne cost curve.

2. CRU's proprietary methodology – the Value Based Costing (VBC)™ system – takes differences in quality and their impacts on producers (and, indirectly, consumers) of coal into account in analysing the business performance and competitive position of individual production facilities in the extractive industries. In the case of coking coal, the key 'benchmark' is the premium HCC grade (FOB Australia);

3. Considering the small proportion of thermal coal amongst Maxwell's products, the cost benchmark analysis was focused on metallurgical coal production costs.

Fourth Component: carbon leakage and scenario analysis

- **Under the scenario where the Maxwell Project is not approved, CRU expects that the likely substitutions to Maxwell's SSCC will come from the major producing countries including China, Russia and Indonesia.**

- **Regarding Maxwell's thermal coal, replacement projects will most likely come from the other major producing countries within the Pacific Basin including Australia, China, India, Russia and Indonesia. This is due to the low volumes of Maxwell's thermal coal that would be substituted, in comparison with traded volumes globally.**

- **The environmental impacts of substituting the supply shortfall from the Maxwell Project's coal with alternative supply sources would be adverse, because Australian coal (including the Maxwell Project's thermal coal) is high quality (in calorific terms) and low in negative attributes (such as sulphur). This means that substitution by other coal supply sources is likely to result in more physical coal being mined and combusted to meet the same power needs, resulting in higher Scope 3 emissions and concentrations of ash and sulphur globally.**

[4] CRU's long term prices are set in one reference year over the long term. We used 2030 as the reference year to set our long term prices. As such, cost benchmarking is also conducted for 2030.

- **Overall, these results confirm the material increase in total GHG emissions that is likely to arise if the Maxwell Project is not approved. The consequences of coal market substitution for Scope 1, 2 and 3 GHG emissions, as well as total emissions, are set out in Table 1 below.**

By way of background:

1. In evaluating a scenario where the Maxwell Project is not approved, we start by understanding the potential alternative SSCC and thermal coal supply sources. We consider the competitive environment and analyse the cost position to understand the probable replacement projects;

2. For the purpose of analysing coal supply substitution and carbon leakage, all GHG emission calculations were based on the assumption that all Maxwell products are being used for electricity generation (Maxwell intends to produce 25% thermal coal with the remaining 75% being SSCC);

3. In order to measure the GHG emissions associated with the coal value chain, CRU uses definitions consistent with the GHG Protocol Corporate Accounting and Reporting Standard. Fugitive methane emissions are highly variable and depend on the characteristics of each coal orebody. The IPCC estimates methane emissions from coal mining are in the range of 0.164-0.410 t CO_2-e / coal tonne (or 10-25 m^3/tonne) for underground mining and 0.005-0.033 t CO_2-e / coal tonne (or 0.3-2.0 m^3/tonne) for surface mining. In the absence of detailed estimates of fugitive emissions from a defined alternative supply source, we apply these ranges in order to evaluate low and high cases:

    a) In relation to Scope 1 (direct) emissions, for each alternative coal supplier, two GHG emission values are supplied, representing low and high fugitive cases (low and high fugitive emission rates); fuel use has also been included;

    b) In relation to Scope 2 (indirect) emissions, Australian coal mining consumes less power compared to many other regions;

    c) In relation to Scope 3 (indirect) emissions, this focusses on the downstream impacts of coal substitution from the alternate countries.

4. The key findings for the scenario analysis in which the Maxwell Project is not approved and is replaced by alternative supply sources is summarised below[5]:

    a) **Scope 1 and 2 emissions:**

    In this analysis, we compared Maxwell's GHG emissions against the country averages which included both underground and surface mines. It is important to note the proportion of underground mines and surface mines vary from country to country.

    In the **low fugitive emissions case**, because Maxwell is an underground mine (and is being compared to the lowest end of the range of fugitive emissions for both underground and surface mines), Maxwell is expected to produce more GHG emissions compared to some alternative suppliers over the LOM (2021-46), particularly those suppliers that have a number of surface mines and whose country average fugitive

[5] Note that the ranges provided below are differences between Maxwell's emissions and emissions from any given alternative supplying country if this country substitutes Maxwell's coal production. For any given country, emissions are modelled based on various country specific factors including the shares of underground/open pit mines. (See calculations in Appendix C of the CRU Report).

emissions are therefore expected to be lower compared to an underground mine. India, Russia, South Africa and China are each expected to produce additional emissions of between **0.1 to 22.5 Mt CO_2-e** over the LOM.

In the **high fugitive emissions case**, the Maxwell Project is expected to emit the second lowest GHG emissions among the alternative suppliers, with only Vietnam having lower GHG emissions. Other alternative supply sources, including Russia, Australia, Indonesia, India, South Africa and China, are expected to produce an additional **1.1 to 64.7 Mt CO_2-e** over the LOM period.

b) **Scope 3 emissions:**

Substituting the Maxwell Project's output by coal from the alternative suppliers will increase Scope 3 emissions by **7.0 to 21.1 Mt CO_2-e** between 2021 and 2046 (LOM period).

c) **Total GHG emissions**:

Our calculations indicate that the substitution of Maxwell's coal by coal from alternative suppliers will result in additional GHG emissions of between:

Low fugitive case: **2.2 to 42.2 Mt CO2-e** into the atmosphere over the LOM (2021-2046).

High fugitive case: **6.8 to 84.4 Mt CO2-e** into the atmosphere over the LOM (2021-2046).

Table 1: Summary of scenario analysis results (Unit: Mt CO2-e).

	Scope 1 & 2	Scope 1 & 2	Scope 3	Total emissions	
Fugitive emissions	***Low case***	***High case***	***n/a***	***Low case***	***High case***
Maxwell	11.0	11.0	312.8	323.8	323.8
Alternative suppliers	6.1-33.5	10.8-75.7	319.9-333.9	326.0-366.0	330.6-408.2
*Additional emissions**	*-4.9 to +22.5*	*-0.2 to +64.7*	*+7.0 to +21.1*	*+2.2 to +42.2*	*+6.8 to +84.4*

Note: * Additional emissions calculated from the difference between Maxwell & alternative suppliers. Negative number indicates lower GHG emissions compared to the Maxwell Project.

Totals may not align with total of emission ranges due to rounding of numbers.

The lower and upper range of emissions from the low/high case for Scenarios 1 & 2 is due to potential coal substitution in a number of alternative supply countries.

Note that the Air Quality and Greenhouse Gas Assessment prepared by Todoroski Air Sciences (TAS) dated 4 July 2019 estimated the total Scope 1, 2 and 3 GHG emission associated with the Project to be 337.0 Mt CO_2-e, which is different from CRU's estimated total emissions of 323.8 Mt CO_2-e. This is due to the fact that CRU has modelled the GHG emissions from the Maxwell Project based on the assumption that all Maxwell products are consumed as thermal coal products, while TAS has modelled Maxwell's GHG emissions from thermal coal and SSCC separately.

If you wish to discuss any aspect of this letter, or require further information, please do not hesitate to contact me.

Yours sincerely,

Alex Tonks
Head of CRU Australia & New Zealand