COAL Medium-Term Market Report 2014

Market Analysis and Forecasts to 2019

International Energy Agency

COAL
Medium-Term Market Report 2014

Market Analysis and Forecasts to 2019

International Energy Agency

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

IEA member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea (Republic of)
Luxembourg
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Turkey
United Kingdom
United States

International Energy Agency
1974•2014
Secure • Sustainable • Together

The European Commission also participates in the work of the IEA.

International Energy Agency
9 rue de la Fédération
75739 Paris Cedex 15, France

www.iea.org

FOREWORD

Every year in December, before the New Year's break but after the UN Conference of Parties climate negotiations, the International Energy Agency (IEA) publication, *Medium-Term Coal Market Report* (*MCTMR*), brings the latest trends and forecast for the next five years for coal supply, demand and trade.

Despite the public image of a dying industry, coal is still the backbone of electricity generation worldwide – not to mention steel production – and produces more than 40% of power generated worldwide. Coal is abundant and affordable, it is easy to store and transport, and there are no geopolitical issues in the coal supply chain. Pulverised coal is a very well-known and reliable technology, and, with increasing flexibility in new designs, it can complement renewable generation as well as maintain its traditional role as base-load generation.

However, the undeniable positive contribution of coal to energy supply and, thus, to energy security cannot hide the negative environmental implications of coal use, especially on air quality in some places and on climate change globally. Previous *MTCMR*s warned that, as it is used today, coal is simply unsustainable. And things have not improved much since. On average, plants are more efficient and emit fewer pollutants, but this does not mean that we are on track. Many cities in China (but not only there) suffer from pollution caused by NO_x, sulphur and particles from coal burning. While the technology exists to produce cleaner electricity from coal (two-thirds of coal is used in power production), the technical, economic and regulatory reality is often different, and emissions from many coal plants often include unacceptable levels of these pollutants.

This year, we have welcomed the start of the first large-scale carbon capture and storage (CCS) power station project (or CCUS – carbon capture, use and storage – since carbon dioxide (CO_2) is used for enhanced oil recovery) in Boundary Dam (Canada). We acknowledge the project as a milestone, but must also note how far we are from the CCS targets required for broader uptake and deployment. Every year, both coal-related and global CO_2 emissions increase, and, in accordance with the projections presented in this report, this trend will continue until 2019.

Coal consumption follows the current economic and energy growth trends, with a continuous shift to Asia. China, despite having entered a more moderate growth path, will continue to account for the largest share of coal demand growth to 2019. India and the countries comprising the Association of Southeast Asian Nations (ASEAN) countries' growth will be remarkable, and our projections suggest that India will become the largest importer of thermal coal. However, its scale is not comparable with China. For example, the daily 200 MW of coal generation capacity that China has been adding for almost a decade is something unique that will not be duplicated anywhere anytime. Our projections assume that India will add less than one-third of this.

In the OECD area, we see different trends. In the United States, cheap gas, together with stricter environmental legislation, continue to push coal out of the system. In Europe, which is more policy driven, we forecast coal demand declining in the outlook period. However, in OECD Asia, increasing coal-power generation capacity in Japan and Korea together with favourable coal prices compared to gas will give rise to coal demand increases.

Whereas probable export-oriented projects are estimated at 100 Mt, with the potential projects reaching as much as 400 Mt, at current coal prices, there is no incentive for most of these projects to come online. On the other hand, low prices improve coal competitiveness and encourage higher demand mainly at the expense of gas. The million-dollar question is how long markets will be oversupplied, and how long producers can stand at current prices. Market evolution will depend on Chinese dynamics, and hence, producers, consumers, analysts and other stakeholders need to keep an eye on China.

In addition to the projections shown in this *Medium-Term Coal Market Report 2014*, long-term IEA projections suggest that the world will remain dependent on coal until 2050 and beyond. Therefore, the final call of this Foreword is to re-emphasise the need to consume coal in a cleaner, more efficient way and to accelerate the development of carbon capture and storage.

This publication is produced under my authority as Executive Director of the IEA.

Maria van der Hoeven
Executive Director
International Energy Agency

ACKNOWLEDGEMENTS

The *Medium-Term Coal Market Report 2014* was prepared by the Gas, Coal and Power Division (GCP) of the International Energy Agency (IEA), headed by László Varró. The report was managed and co-ordinated by Carlos Fernández Alvarez. Raimund Malischek, Harald Hecking and Carlos Fernández Alvarez are the authors. Keisuke Sadamori, Director of the IEA Energy Markets and Security (EMS) Directorate, provided expert guidance and advice.

We are grateful for the data provided by the IEA Energy Data Centre (EDC). Julian Smith's assistance in aggregating and making the data user-friendly was invaluable. Many colleagues from the IEA provided us with important advice and input: Simon Bennet, Keith Burnard, Farid Hussin, Ellina Levina, Paweł Olejarnik, Rodrigo Pinto Scholtbach, Tristan Stanley, Johannes Trüby, Christelle Verstraeten and Takuro Yamamoto. Rebekah Folsom edited the report. The IEA Communication and Information Office (CIO) also provided editorial and production guidance. Rebecca Gaghen, Muriel Custodio, Angela Gosmann, Astrid Dumond, Therese Walsh and Bertrand Sadin made this publication possible.

Wood MacKenzie provided with invaluable data and information for this report.

Our gratitude goes to the Institute of Energy Economics (EWI) at the University of Cologne for sharing its breadth of coal expertise and coal market models.

The IEA would like to thank the Coal Industry Advisory Board (CIAB) for their support. Special thanks go to the many CIAB associates and analysts who provided the IEA with timely data, information and advice. Nikki Fisher from Anglo American, Jeffrey Phillips from EPRI, J. Gordon Stephens from Joy Global Inc., John Lowell from Arch Coal Inc., Rick Axthelm from Alpha Natural Resources Inc., Peter Morris, from the Minerals Council of Australia, Itaru Nakamura and Naoki Ueda from J-POWER, Svetlana Petrova from the Siberian Coal Energy Company (SUEK), Prach Chongkittisakul from Banpu Public Co. Ltd, Roland Luebke from German Coal Association, Maggi Rademacher from E.On Generation GmbH, Hans-Wilhelm Schiffer from RWE AG, Veronika Kohler, from US National Mining Association as well as Brian Heath, Executive Co-ordinator of the CIAB.

Comments and questions are welcome. Please address to:
Carlos Fernández Alvarez (Carlos.Fernandez@iea.org)

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF MAPS

LIST OF TABLES

LIST OF BOXES

EXECUTIVE SUMMARY

Old times, new times

In 2013, coal added more primary energy than any other fuel and was the fastest-growing fossil fuel. 2013 coal demand grew 2.4% on a tonnage basis, more than oil and gas, enhancing its position as the second-largest primary energy source and closing the gap with oil. This trend, driven by the role of coal as the main provider of electricity, is a *déjà vu* of our annual *Medium-Term Coal Market Reports*. Similarly, the People's Republic of China was once again driving this growth. Growth in China (196 million tonnes [Mt]) was actually larger than global growth (188 Mt). In the United States, 2013 higher gas prices prompted coal demand to recover part of its 2012 decrease. In Europe, low power demand and increasing renewable production squeezed coal power generation, causing an overall coal demand decline of -35 Mt when compared to 2012. In Japan, where the coal fleet fully recovered and two new coal plants commenced commercial operations, coal demand grew +6.4%.

Coal markets show great dynamism. Despite coal's reputation as a 19th-century industry, coal markets are changing at a fast pace. Former parameters age rapidly, and new trends appear. Demand is moving to Asia, and trade flows are following. A great variety of different coal qualities are traded, including low quality high ash coal, triggering new price indices. While long-term contracts still operate, quarterly, monthly and spot purchases become more frequent. There is increasing use of derivatives both in volumes and coal qualities, origin and destinations. Some policy changes – and these are announced frequently – in countries such as China and Indonesia have the potential to impact the global market. Changes are happening at both large and small scale. As one example, Central Appalachia, once the largest producing area in United States, now lags behind both Powder River Basin (PRB) and Illinois Basin.

Coal oversupply keeps pushing prices down

In 2014, coal oversupply persists and very low coal prices continued to dominate. For a few years, the focus of coal producers was to expand production. New capacity was constantly added and demand led by China consumed every additional tonne. However, since 2011, oversupply and low prices have dominated. While US shale gas impacts on international coal prices have often been overstated, domestic Chinese dynamics translated into international markets have been largely overlooked. The domestic oversupply in China – accompanied by price reduction from the major producers to protect their market share – has strongly impacted international markets, which were likewise oversupplied by expansions by all major exporters. Imported European steam coal prices, one of the main reference prices worldwide, were in the USD 70-80/tonne range during 2014, compared to over USD 120/tonne in March 2011. Australian met coal has been in a very narrow band between USD 112/tonne and USD 116/tonne since April 2014, compared to March 2011 when it averaged over USD 320/tonne.

Take-or-pay contracts, financial commitments and better economies of scale pushed prices down. With persistent low prices, the strategy of producers is to reduce costs. However, this is coupled with better efficiencies and economies of scale, putting more coal in the market, increasing oversupply and driving prices even lower. Another way to increase competitiveness is to cut production of unprofitable mines. However, this is not always possible. Take-or-pay contracts for infrastructure use and financial commitments to pay investments make many producers operate with negative margins. Minimised loss is the new target for many, but in the medium term, despite low prices, expansions will happen. There are many projects in different phases of development ready to start or ramp up production, although most of them will not do so at current prices.

OECD: Declining trend with caveats

The coal renaissance in Europe was only a dream. As announced in former *Medium-Term Coal Market Reports*, coal use increase in Europe in recent years was a temporary spike largely due to low coal and carbon dioxide (CO_2) prices, high gas prices, and the partial shutdown of German nuclear plants. However, after 2012, coal demand began to decline due to moderate economic growth, energy efficiency gains, increasing renewable energy sources and coal plant retirements. Nothing new has happened to change our views. Turkey, also grouped with OECD Europe, follows a different trend: high economic and energy demand growth will come with new coal capacity, giving rise to a steady increase of coal consumption. Whether nuclear power plants in Japan are brought back online hardly affects our projections for Japan. The impact, however, may be felt in Europe, as Japanese nuclear power plants could ease liquefied natural gas (LNG) markets and make gas more competitive in Europe, displacing some coal.

Trends in coal demand differ in OECD America and OECD Asia Oceania. While our projections confirm the downward trajectory in US coal consumption, this is far from a dramatic decline. Despite climate plans, environmental regulation and shale gas production, there remains much low-cost coal in the United States and more than 250 gigawatts (GW) of coal capacity will remain at the end of the outlook period. In OECD Asia Oceania, the nuclear shutdown in Japan and high LNG prices make coal very competitive. New coal capacity coming online, foremost in Korea but also in Japan, will lead to a coal demand increase. Given the current high load factor of coal power plants, coal versus gas prices and absence of CO_2 price, we assume coal capacity mostly running flat in the region during the period.

Seaborne trade will largely depend on China, but not only

As arbitrage on the eastern coast of China spreads domestic prices out, Chinese developments will define coal markets. In fact, all developments in China impact coal markets, but there are two key issues to be underlined. Firstly, the fight against pollution is now a driving force of energy policy. But the war on pollution has two sides for coal. On the one hand, the below-mentioned diversification will decrease coal demand. On the other hand, other measures do not decrease coal consumption but can even increase it. In this group we can mention large coal bases linked through ultra-high voltage (UHV) lines to big consumption centres, the coal conversion process to synthetic natural gas or liquid fuels and cleaning equipment in coal power plants. Secondly, 1 billion tonnes are shipped seaborne to the coast of China in a fierce competition between domestic and international supplies. Policy measures (quality restrictions, import taxes, royalties, and so forth), currency rates or other factors could incline the balance towards domestic or international supplies with implications worldwide.

Indonesia is the main unknown among the suppliers, but there are others. Whatever output IEA models produce, there are potential future developments that are out of our control and can change our forecast. Indonesia, the world's largest coal exporter, has accounted for the bulk of coal export growth recently. Indonesia has announced a ban on low calorific coal or a cap on production, and a new export license has been introduced. Our projections show increasing exports from Indonesia, but at a much slower pace than in previous years. In Colombia, a secure supplier with healthy investments in the pipeline, some producers have recently had disruptions for different reasons. There can also be upturn surprises: the Galilee and Surat Basins in Australia and PRB in United States have the potential to oversupply any demand if the appropriate infrastructure is in place. The large, competitive reserves in Mongolia could reach seaborne markets eventually. And Mozambique is uncertain. Finally, geopolitical turmoil or weather disasters can also impact coal trade, given that most thermal exports come from only six countries, even fewer for coking exports.

Peak coal in China? Not yet

At last, coal indicators in China could decrease. China will be the coal giant for many years in the future. We project that coal demand annually grows at 2.6%, more than 100 Mt per year during our outlook period. China will add more coal demand than any other country, but we have entered a new time in which the outstanding growth from the past in all of the coal indicators, such as production, consumption and imports, will not be repeated. Moreover, despite the general increasing trend, we will see temporary declines, for example during a very wet year we could see coal demand for power declining. Imports could also decrease at any time, depending upon prices and/or policy changes. After many years of unbelievable economic and coal demand growth, China has entered a more moderate path. Lower economic growth and also a lower energy intensive economy and higher diversification will curtail coal growth in China in the coming years.

Economic growth in China needs more energy than nuclear, gas, oil and renewables can supply. Diversification efforts, the so-called *anything but coal* policy, will lead to big developments of hydropower, wind, photovoltaic (PV) and nuclear capacity and gas use. Additional non-coal generation in 2019 is assumed to be 1 200 terawatt hours, and gas demand will almost double during the outlook period. Despite such strong assumptions, as well as decreasing energy intensity in the Chinese economy and gross domestic product and power demand growth decoupling notably, additional coal is still needed to meet energy demand. Investments in new coal generation capacity and coal gasification plants also support this growth. Most of diversification investments, such as nuclear, hydro, PV and wind, are capital-intensive with low or very low running costs; therefore, longer-term trends might suggest peak coal in China during the next decade. However, we do not see that peak in the outlook period unless economic growth is much lower than assumed.

There is no other China out there

Annual coal consumption in India will grow 177 million tonnes of coal-equivalent, or over 250 Mt, at 5% annual growth on average, becoming the world's second-largest coal consumer. India, despite problems to ramp up domestic production and to build coal plants at the desired pace, will see a solid increase of coal use and, to a lesser extent, coal production in the outlook period. We project that India will become the second-largest coal consumer, surpassing the United States, and the second-largest coal importer, close to China, as well as the world's largest thermal coal importer. Total coal demand increase of over 250 Mt during the whole outlook period is larger than the current demand of any country except China, United States and India. However, to put this in perspective, growth in China in a single year has often been higher than this during the previous decade.

Over two-thirds of the coal demand growth in India and the Association of Southeast Asian Nations (ASEAN) countries will be for power generation. Although the share of non-power coal demand in Asia is larger than in other regions, power will largely drive the coal demand increase in Asia. Electrification of highly populated areas with poor or no electricity access and power to fuel economic growth will trigger power demand in the region. Driven by investments in coal power plants mainly in India, Indonesia, Viet Nam and Malaysia, coal consumption in the region will increase. Several countries in Asia are building coal power plants, but apart from China and India, the ASEAN countries represent the main area of growth, with over 30 GW of new coal power generation coming online during the outlook period. While this figure might look impressive, China has annually added double this on average since 2005.

1. RECENT TRENDS IN DEMAND AND SUPPLY

Summary

- **Coal remained the fastest-growing fossil fuel in 2013 in both absolute and relative terms, accounting for approximately 30% of global primary energy consumption, second only to oil**.

- **Global coal demand grew by 2.4% (+188 million tonnes [Mt]), from 7 687 Mt in 2012 to an estimated 7 876 Mt in 2013.** Although the 2013 growth rate was higher than the 2.0% in 2012, overall coal demand growth trends in 2013 were slow when compared to the ten-year trend, when the compound average growth rate (CAGR) was 4.6%. Demand growth came from hard coal[1] (+234 Mt), with a decline in lignite[2] (-45 Mt).

- **2013 coal demand growth showed significant geographical differences.** OECD non-member countries' coal demand grew by 3.6% (+201 Mt) to an estimated 5 740 Mt; OECD coal demand in the same period decreased by 0.6% (-12 Mt) to an estimated 2 136 Mt. Coal demand in Asian OECD non-member countries increased by 4.6% (+217 Mt) to an estimated 4 959 Mt; demand in the rest of the world decreased by 1.0% (-29 Mt) to an estimated 2 917 Mt.

- **2013 Chinese coal demand growth again outpaced global coal demand growth.** Incremental Chinese coal demand was 196 Mt reaching 3 894 Mt and maintaining China's market share at greater than 50% of overall global coal demand when measured in energy content.

- **2013 United States' coal demand increased by 2.8% (+23 Mt)[3] to an estimated 843 Mt.** These demand increases were primarily from the power sector, and are attributable to higher gas prices than 2012 (when the mild winter drove gas prices downward).

- **2013 OECD European coal demand decreased (-35 Mt), accounting for most of the decline in the OECD**. This was largely driven by Greece, Spain and the United Kingdom.

- **Global coal supply grew by 0.4% (+28 Mt) from 7 794 Mt in 2012 to an estimated 7 823 Mt in 2013**,[4] the lowest increase since 2000 in both absolute and relative terms. Lignite supply decreased by 49 Mt, while hard coal supply increased by 77 Mt.

- **Incremental hard coal supply volumes were primarily sourced from Indonesia (+45 Mt), Australia (+37 Mt) and China (+28 Mt).** Hard coal supplies in the United States declined by 27 Mt, to reach their lowest supply volume since 1993.

Demand

Coal remained the fastest-growing fossil fuel in 2013 in both absolute and relative terms, accounting for approximately 30% of global primary energy consumption, and second only to oil.

[1] This is largely a statistical distortion due to China, where lignite is not reported, and the entire coal production, except for met coal, is counted as thermal coal. This needs to be taken into account throughout the entire report. Likewise for Indonesia on the supply side, there is no differentiation between lignite and thermal coal, counting all as thermal.
[2] Definitions of coal types and other technical terms can be found in Box 1 of IEA (2011) and Box 1 of IEA (2012).
[3] EIA has revised this figure upward to 4%, but IEA official statistics have not been updated yet.
[4] Supply and production are used interchangeably in this report.

Global coal demand in 2013 increased by an estimated 2.4% to 7 876 Mt (+188 Mt). This is a greater increase than that of 2012 (2.0%), but remains lower than the 4.6% growth averaged over the previous ten years. This can be attributed to slower growth in demand from OECD non-member economies such as China, whose 2013 growth is down by nearly half of the previous ten-year average. While coal demand grew by 3.6% (+201 Mt) in OECD non-member countries, demand in OECD countries decreased by 0.6% (-12 Mt); this decreased the total percentage of OECD countries contributing to the global coal demand to 27.1%.

China remains the world's largest coal market with a 2013 coal demand growth of 5.3% (+196 Mt). Despite this increase over 2012 (4.1%), this growth rate is substantially lower than China's 9.7% ten-year average.

The United States is the world's second-largest coal consumer with a 2013 coal demand growth of 2.8% (+23 Mt), an increase primarily driven by a high power sector coal demand. This apparent 2013 demand growth should be analysed contextually, however, as it is based upon a comparison to 2012, when sustained shale gas production growth and an unusually mild winter drove down gas prices and coal demand.

India's 2013 coal demand growth was 2.1%. This is a decrease from its 7.3% ten-year average growth and from growth of 9.1% in 2012. At this time, it is unclear if this dramatic 2013 decrease might be due to statistical issues.

The European Union and Russia's 2013 coal demand declined significantly. Germany, despite a slight decrease in 2013 coal demand, became the world's fourth-largest coal consumer on a tonnage basis, bypassing Russia, whose demand declined by 7.4%. However, Russian coal consumption is still greater on an energy basis, as Germany's primary coal consumption is lignite.

Total 2013 global hard coal demand increased by 234 Mt to an estimated 7 036 Mt. Hard coal consumption grew by 3.4% on a year-to-year basis; approximately 2 percentage points lower than the ten-year average growth rate. Demand growth was primarily from OECD non-member countries (+216 Mt), specifically China (+196 Mt), with OECD countries accounting for the balance (+18 Mt).

Table 1.1 Coal demand overview

	Total coal demand (Mt) 2012	Total coal demand (Mt) 2013*	Absolute growth (Mt) 2012-13	Relative growth (%) 2012-13	CAGR (% per year) 2003-12	Share (%) 2013
China	3 698	3 894	196	5.3%	9.7%	49.4%
United States	820	843	23	2.8%	-1.7%	10.7%
India	775	791	16	2.1%	7.3%	10.0%
Germany	246	241	-5	-1.9%	0.0%	3.1%
Russia	254	235	-19	-7.4%	1.4%	3.0%
European Union	768	726	-43	-5.6%	-0.4%	9.2%
OECD	2 148	2 136	-12	-0.6%	-0.4%	27.1%
Non-OECD	5 539	5 740	201	3.6%	7.6%	72.9%
World	**7 687**	**7 876**	**188**	**2.4%**	**4.6%**	**100.0%**

Note: differences in totals are due to rounding.

* Estimate.

Global steam coal demand grew by 3.2% (+188 Mt) to an estimated 6 078 Mt. Most of this growth can be attributed to OECD non-member countries (+168 Mt), specifically China (+153 Mt).

Global metallurgical (met) coal demand increased by 5.0% (+46 Mt). This is based upon demand from OECD non-member countries (+48 Mt), of which China again accounted for the majority (+43 Mt). 2013 OECD Europe met coal demand decreased (-5 Mt), and slight increases in OECD Asia Oceania and OECD Americas account for the remainder.

Total 2013 global lignite consumption decreased by approximately 5.1% (-45 Mt). These decreases were divided between OECD non-member (-15 Mt) and OECD member (-30 Mt) countries. However, non-OECD demand decline came from non-OECD Europe and Eurasia (-15 Mt); the majority of OECD country demand decline came from OECD Europe (-19 Mt).

OECD demand trends

Hard coal demand in the OECD grew 1.1% (+18 Mt) to 1 573 Mt in 2013. The OECD's share of global hard coal demand is 22.4%, a slight decrease from 2012 (22.9%) due to stronger increased demand from OECD non-member countries. OECD hard coal consumption increases are primarily from OECD Americas (+27 Mt) and OECD Asia Oceania (+7 Mt), while OECD Europe hard coal demand decreased (-16 Mt).

Table 1.2 Hard coal and lignite consumption in selected OECD member countries (Mt)

Country	Hard coal		Lignite	
	2012	2013*	2012	2013*
Australia	61.1	58.8	71.4	62.6
Austria	3.6	3.6	0.0	0.0
Belgium	4.8	4.1	0.0	0.0
Canada	31.2	32.0	9.4	8.9
Chile	10.9	13.7	0.0	0.0
Czech Republic	7.2	6.6	42.6	39.3
Denmark	4.2	5.4	0.0	0.0
Finland	4.6	5.8	0.0	0.0
France	16.8	18.7	0.1	0.1
Germany	60.4	58.5	185.2	182.5
Greece	0.4	0.3	61.9	53.1
Hungary	1.9	1.6	9.6	9.7
Ireland	2.4	2.1	0.0	0.0
Israel**	14.3	12.1	0.0	0.0
Italy	25.2	21.1	0.0	0.0
Japan	183.8	195.6	0.0	0.0
Korea	126.5	126.4	0.0	0.0
Mexico	17.7	17.2	0.0	0.0
Netherlands	12.8	13.0	0.0	0.0
New Zealand	2.8	2.3	0.3	0.3
Poland	76.1	78.7	64.2	65.8
Portugal	4.9	4.4	0.0	0.0
Slovak Republic	3.9	3.8	2.9	2.7
Spain	28.8	19.5	0.0	0.0
Turkey	32.3	30.8	68.5	63.0
United Kingdom	64.3	60.3	0.0	0.0
United States	748.1	772.4	72.1	70.5

* Estimate.

** The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

In OECD Europe, both thermal coal and met coal demand decreased in 2013, while OECD Americas and OECD Asia Oceania saw increased demand for both coal types. The OECD's thermal coal demand increased by 1.4% in 2013 to 1 388 Mt, which is 88.2% of OECD's hard coal demand; the OECD's met coal demand decreased by 1.1% to 185 Mt.

At a country level: in the United States and Japan, the two largest OECD hard coal consumers, thermal coal demand increased significantly in 2013; Japan and Korea are the two largest OECD met coal consumers, with a slight year-on-year increased met coal demand.

OECD member countries make up 67.0% of the 2013 global lignite demand. However, lignite consumption in OECD countries declined from 593 Mt in 2012 to 563 Mt in 2013. This decline was uniform across all OECD groups. Lignite demand dropped most notably in Australia (-9 Mt) and Greece (-9 Mt), with small increases seen in Poland. Demand in Germany, the largest lignite consumer, dropped by 3 Mt to 183 Mt.

Power sector

Total 2013 coal-fired power generation in OECD member countries grew by 2.2% (+76 terawatt hours [TWh]) over 2012 (3 461 TWh) to an estimated 3 537 TWh. Overall power generation within the OECD, however, showed only fractional growth (+0.1%), from 10 785 TWh in 2012 to 10 798 TWh in 2013. Consequently, coal's share in the electricity mix in OECD member countries rose, from 32.1% in 2012 to 32.8% in 2013.

Following two years of decline, 2013 coal-fired power generation in the United States showed an increase of 74 TWh (+4.5%). This figure is the primary source of the overall coal-fired power generation increase from OECD member countries. However, the United States' 2013 growth should be analysed contextually, as it is based upon a comparison to 2012, when an unusually mild winter drove down coal-fired power generation. Additionally, the United States subsequently experienced an exceptionally cold 2013/14 winter, which increased gas demand for heating and in the power sector.

United States' 2013 gas prices averaged 3.73 USD/million British thermal unit (Mbtu) compared to USD 2.72/Mbtu in 2012. Higher gas prices and increased power demand led to an increase in coal-fired power generation. Despite having some coal plant capacities decommissioned in 2013, the United States showed higher utilisation of their remaining plants, including approximately 1 gigawatt (GW) from Duke Energy's Edwardsport and Dynegy and LS Power's Sandy Creek 1 plants, which started commercial operation.

2013 coal-fired power generation in OECD Asia Oceania increased by 18 TWh to an estimated 774 TWh. Approximately 44% of coal generation came from Japan.

In Japan, coal's share in power generation increased from 29.5% in 2012 to 32.1% in 2013. After the closure of the Ōi plant in September 2013, all Japanese nuclear power plants remain offline. Subsequently, coal-fired power generation increased by 34 TWh, which is primarily attributable to the commissioning of coal plants, Hitachinaka No.2 and Hirono No.6 (with a joint 1.6 GW capacity).

2013 Korean coal-fired power generation stayed constant. Nuclear power capacity was reduced by approximately 25% due to some internal, security-related corruption issues, but these were offset by an increase in output from gas-fired power plants.

2013 Australian coal-fired power generation decreased by 12 TWh. This decrease was largely a result of an increase in output from hydro and renewables.

Box 1.1 Isogo: Making coal cleaner

The *Medium-Term Coal Market Report 2012* included a Box titled, "Can open-pit coal mines be environmentally friendly?" in which reclamation of the As Pontes mine in Spain was shown as an example of good environmental mining practices. Moving from production to use, the Isogo plant in Japan seems to be the most obvious example of a high-efficiency, low-emissions coal-fired plant worldwide.

The Isogo plant is owned by J-POWER and located at the centre of Yokohama, the second-largest city in Japan with a population close to 4 million people. It consists of two ultra-supercritical units of 600 megawatts (MW) each, replacing two old units (2 x 265 MW) built in the same location. New Unit 1 was built while the old units were in operation, which was a challenge on the plant's 12-hectare plot. Build, scrap, and build was the methodology for this unit's construction.

Isogo has a gross thermal efficiency of 45% (referred to lower heating value), using steam conditions of 600 degrees Celsius (°C) for the main steam and 620°C for reheated steam (610°C in the case of Unit 1), as well as pressure of 25 megapascals (MPa). Following internal consumption, net thermal efficiency is 43.5%, which means a 17% emission factor decline when compared with the old units.

In addition to reducing emissions by increasing efficiency, Isogo uses the most advanced systems to improve local air quality and minimise sulphur, NO_x and particles emissions. These advanced systems include passing flue gas through a selective catalytic reduction system where nitrogen oxides are decomposed to water and nitrogen, and then through a desulfuration denitrification system based upon regenerative activated coke technology. From there, multiple pollutants are removed simultaneously with a high yield: 98+% of sulphur, 20% to 80% of NO_x and 90+% of mercury. Dust is also removed using an efficient dry system (>100 times more efficient in reducing water consumption) to lower than 30 milligrammes per normal cubic metre (mg/Nm^3). Finally, flue gas passes through an electrostatic precipitator to further clean the gas of dust before being released by the stack. Following this cleaning process, pollutant concentration surrounding Isogo is extremely low: 1 part per million (ppm) to 6 ppm of sulphur, 10 ppm to 15 ppm of NO_x, 1 mg/Nm^3 to 3 mg/Nm^3 of dust and 0.14 microgrammes per normal cubic metre (µg/Nm^3) to 0.25 µg/Nm^3 of mercury, which are levels more generally expected for gas turbines rather than for coal plants.

The environmentally friendly concept in practice at Isogo goes much further. Both flying and bottom ashes are recycled, and by-products from activated cokes are also passed forward to recycling partners in both the chemical industry (sulphuric acid) and other industries (gypsum). Coal is transported on conveyor belts inside sealed pipes and stored in silos to prevent coal dust dispersion. This makes Isogo an unusual coal plant, as coal is not actually visible in any part of the plant.

In order to avoid accidents and malfunctions, strict control is used throughout the process, such as flue gas monitoring, spilt oil control, coal dust litter control and water pollution control. Additionally, noise pollution is reduced through strategic organisation of noisy equipment indoors and predominant use of low-noise equipment.

Additional environment-friendly elements include carefully planned architectural and landscape designs where the arrangement of buildings and their colour is in harmony with their surroundings. One-fifth of the buildings' surface is dedicated to flowers and trees, including an artificial hill and a Japanese garden. Athletes are delighted to find a tennis court on the roof of one building and a football pitch on the plant plot.

In contrast to other OECD regions, coal-fired power generation decreased in OECD Europe in 2013 (-19 TWh) due to low power demand and an increased renewable production. These decreases were the strongest in the United Kingdom (-14 TWh) and Spain (-14 TWh).

In the United Kingdom this was primarily attributable to the retirement of approximately 5 GW coal capacities since late 2012, due to the Large Plant Combustion Directive and the slight decrease of power demand.

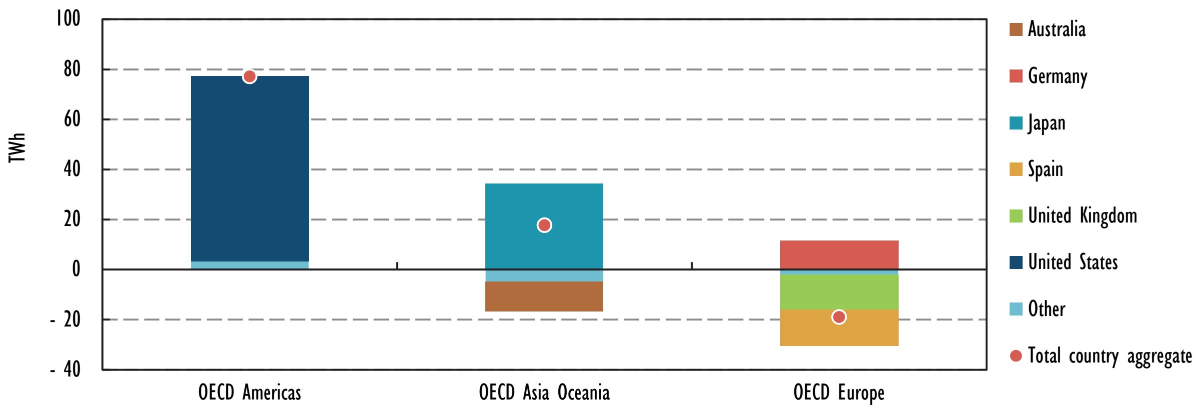
In Spain, increased production from hydro generators combined with lower total power generation impacted Spain's coal consumption: the share of coal's contribution to the electricity mix dropped from 19.1% in 2012 to 14.8% in 2013.

2013 coal-fired power generation in Greece was approximately 4 TWh lower than in 2012, primarily due to higher solar and hydro generation.

Germany, OECD Europe's biggest coal-fired power producer, increased coal power generation by 12 TWh. Low carbon dioxide (CO_2) prices as well as relatively low coal prices, increased coal-fired power generation and further reduced gas power generation.

Coal generation also increased in Poland (+3 TWh) where it accounts for 85.3% of power generation.

Figure 1.1 Coal-based electricity generation in OECD countries: Absolute changes, 2012-13

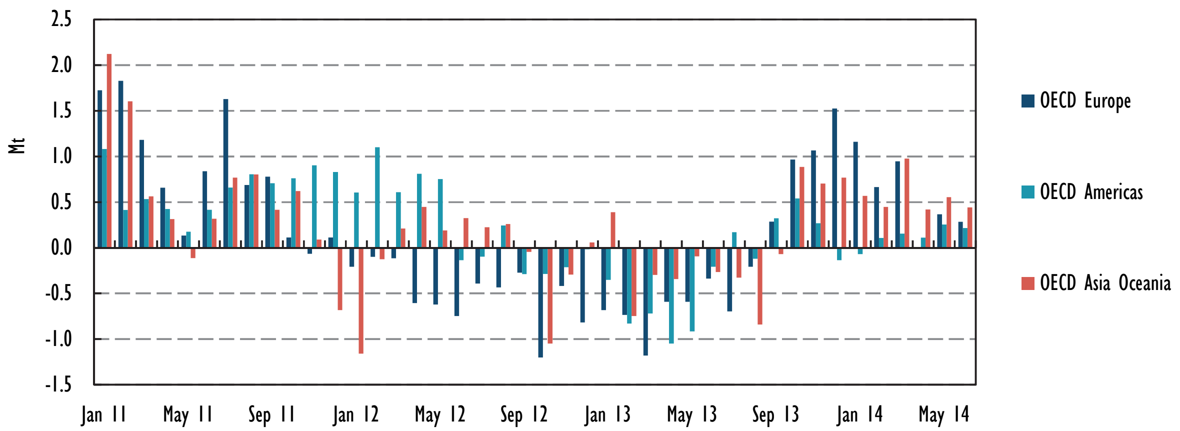


Non-power sector

The estimated 2012 OECD total non-power coal consumption was 285 million tonnes of coal-equivalent (Mtce), down 0.7% (-2 Mtce) from 2011 (287 Mtce). Non-power coal consumption accounts for approximately 20% of all coal consumption in the OECD. The two largest non-power coal consumers were the iron and steel industry, which consumed 159 Mtce, and the cement industry, which consumed 25 Mtce.

Met coal consumption decreased slightly in OECD countries in 2013 (-2 Mt). The trend of declining steel production numbers within the OECD continued from 2012 through the first half of 2013 (see Figure 1.2), but production increased during the second half of 2013.

Figure 1.2 Monthly year-on-year differences in crude steel production in OECD member countries, 2011-14



Source: World Steel Association (various years), *Crude Steel Production*, Brussels, World Steel, www.worldsteel.org/statistics/crude-steel-production.org.

OECD non-member demand trends

OECD non-member countries account for 72.9% of 2013 global coal demand. Coal demand in 2013 increased by 3.6% (+201 Mt) to 5 740 Mt, lower than increases in 2012 (+4.3%) and much lower than the ten-year average increase (+7.6%). Hard coal consumption in OECD non-member countries increased by 4.1% to estimated 5 462 Mt, 85.9% of which was thermal coal and the remainder met coal.

Table 1.3 Hard coal and lignite consumption in selected OECD non-member countries (Mt)

Country	Hard coal		Lignite	
	2012	2013*	2012	2013*
Bosnia and Herzegovina	7.0	7.4	5.7	6.2
Brazil	20.6	22.9	3.0	3.2
Bulgaria	2.2	1.6	33.0	28.5
Chinese Taipei	65.3	68.0	0.0	0.0
Colombia	5.7	7.1	0.0	0.0
DPR of Korea	19.1	15.1	0.0	0.0
India	728.9	746.6	45.9	44.7
Indonesia	56.6	62.5	0.0	0.0
Kazakhstan	79.8	82.4	5.5	5.1
Kosovo	0.1	0.0	8.0	8.2
Malaysia	25.1	25.5	0.0	0.0
Mongolia	0.1	0.1	7.3	7.7
China	3 698.0	3 894.4	0.0	0.0
Philippines	15.3	18.1	0.0	0.0
Romania	1.3	0.9	33.8	24.7
Russia	176.1	161.9	77.6	72.9
Serbia	0.2	0.2	38.6	40.1
South Africa	185.2	187.0	0.0	0.0
Thailand	18.9	14.3	18.7	19.1
Ukraine	73.6	75.9	0.0	0.0
Viet Nam	29.5	28.0	0.0	0.0

* Estimate.

Thermal coal accounts for 77.9% of the 2013 incremental hard coal demand in OECD non-member countries, with an increase of 3.7% (+168 Mt) to 4 690 Mt, primarily from China, the world's largest thermal coal consumer. China's 2013 consumption increased by 4.9% (+153 Mt) to 3 292 Mt.

India, the second-largest OECD non-member thermal coal consumer, showed a thermal coal demand increase of 2.0% (+13 Mt) in 2013. However, India has estimated coal power generation to have increased 8.4% in 2013, and power represents more than 66% of overall coal consumption in India. Both figures (2.0% and 8.4%) do not seem compatible. Reports from India claim that up to 60 Mt per year of coal are stolen from Coal India, the largest coal producer in India, and sold domestically. This report does not judge the veracity of such a claim, but it is included to provide a possible explanation for the data.

OECD non-member countries account for more than 80% of the 2013 global met coal demand, with an increase of 6.6% (+48 Mt) to 773 Mt. This increase is once again led by China, the biggest met coal consumer in the world, whose 2013 met coal consumption increased by 7.7%. Incremental volumes amounted to 43 Mt, which is equivalent to 94.8% of global incremental met coal demand.

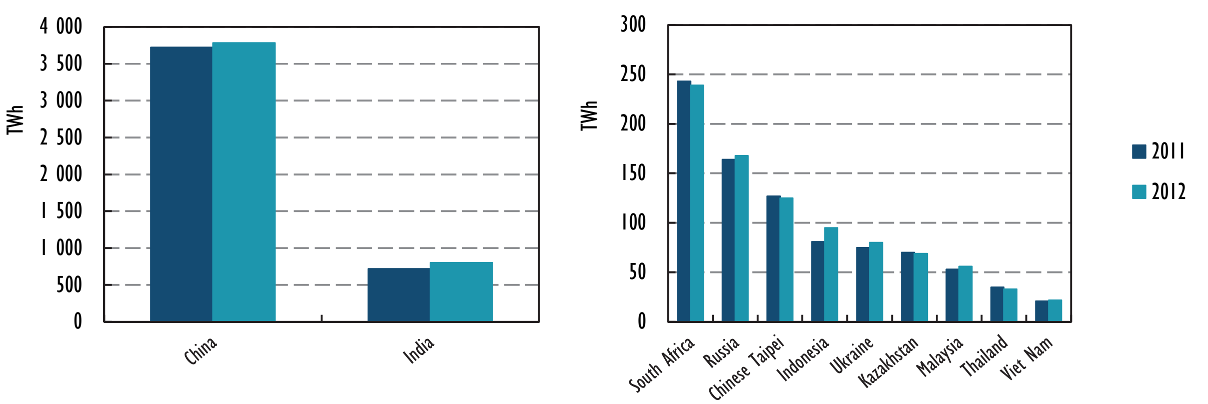
As in OECD countries, lignite consumption in OECD non-member countries decreased strongly in 2013, down 5.2% (-15 Mt) to an estimated 278 Mt. Demand decreases were most notable in Bulgaria, Romania and Russia.

Power sector

Overall 2012 coal-fired power generation in OECD non-member countries was 5 689 TWh, an increase of only 2.9% (+162 TWh) over 2011, which is the lowest growth rate in over ten years. With OECD non-member total power generation growth at 4.6%, coal's share in overall power generation decreased from 48.7% in 2011 to 47.9% in 2012.

China's 2012 coal-fired power generation amounted to 3 812 TWh, making China again the largest producer of coal-fired power in the world. However, growth in China in 2012 was rather weak, with incremental coal-fired power generation at +1.6% (+61 TWh). China's greatest 2012 growth came from hydro generation, which grew by +175 TWh to 863 TWh, as overall power generation grew by 280 TWh, totalling 5 023 TWh in 2012. Consequently, coal's share in overall Chinese power generation dropped from 79.1% to 75.9%.

Figure 1.3 Coal-based electricity generation in selected OECD non-member countries



India is the world's third-largest coal-fired power generator, with a 2012 growth of +11.7% over 2011, the strongest growth shown in over a decade, totalling 801 TWh at the end of 2012. As hydro and gas-fired power generation decreased year-on-year, coal's share in power generation increased from 66.8% to 71.1%.

2012 South African coal-based power generation slightly decreased (-4 TWh or -1.7%) in accordance with a slight drop in total power generation compared to 2011. Development of coal-based power generation in Association of Southeast Asian Nations (ASEAN) countries varied from country to country. For example, while Indonesia (+17.7%), Malaysia (+5.3%), the Philippines (+11.9%) and Viet Nam (+4.8%) increased their coal-fired generation, Thailand's coal-fired production decreased by -4.0%.

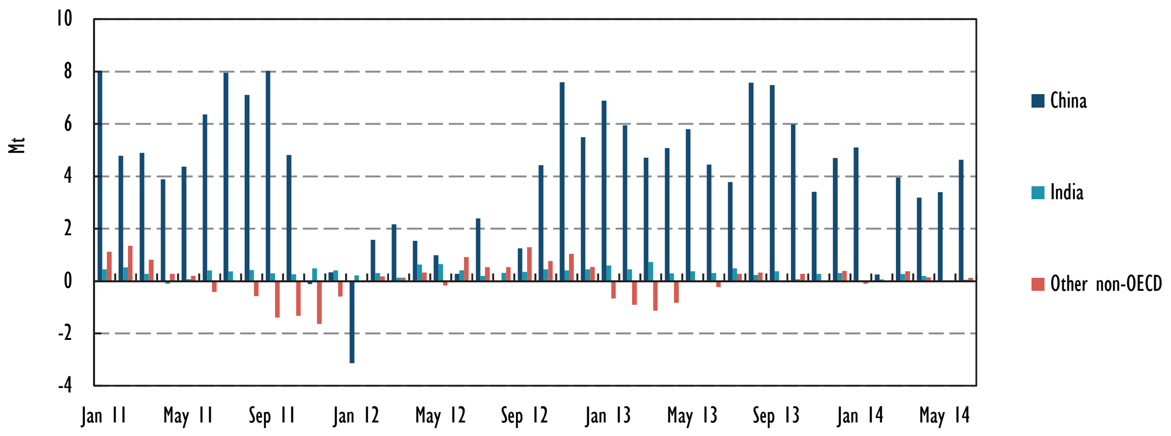
Non-power sector

Non-power coal consumption accounts for approximately 37% of overall coal consumption in OECD non-member countries: this is nearly double the share for that of OECD countries. Non-power sectors consumed around 1 540 Mtce in 2012, slightly up from approximately 1 500 Mtce in 2011. The iron and steel industry is the largest consumer (647 Mtce or 42%), followed by the cement industry (242 Mtce or 16%). Other significant volumes come from the chemical industry (84 Mtce or 5%) and residential coal burn (89 Mtce or 6%).

China accounts for greater than 70% of 2012 non-power coal consumption from OECD non-member countries. This is primarily from China's iron and steel industry (469 Mtce) and cement production (183 Mtce). While China saw only moderate growth below 3% in 2012 in non-power coal consumption, steel production growth in 2013 stood at 9.3% with strong, monthly year-on-year increases, indicating stronger growth for non-power coal consumption (see Figure 1.4).

In 2012 steel production growth in India was 6.2%. Accordingly, coal consumption in the iron and steel industry was strong (70 Mtce), up from 2011 (65 Mtce). Cement production accounts for another 22 Mtce of India's 2012 non-power coal consumption. India's 2013 steel production growth slowed down slightly, however, indicating slower growth in non-power coal consumption.

Figure 1.4 Monthly year-on-year differences in crude steel production in OECD non-member countries, 2011-14



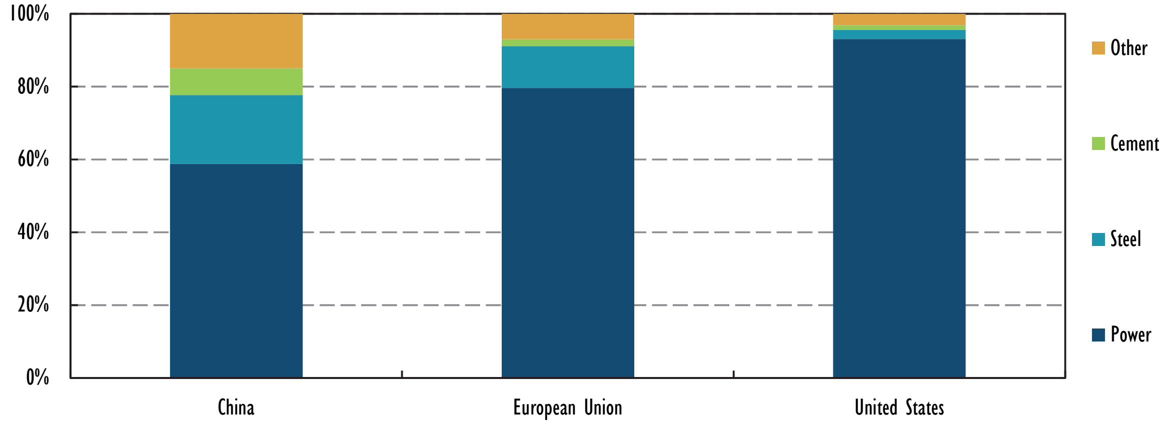
Source: World Steel Association (various years), *Crude Steel Production*, Brussels, World Steel, www.worldsteel.org/statistics/crude-steel-production.org.

Regional focus: China

China remains the largest coal consumer in the world, accounting for more than 50% of global coal consumption when measured in energy content. However, coal consumption in China, with an average growth of 8.7% over the last ten years (when measured in energy content), is not only impressive in magnitude, but shows a distinct consumption footprint when compared to other parts of the world.

Figure 1.5 compares coal consumption by sector between China, the European Union and the United States. China's share of coal consumption for power generation (less than 60%) is lower than that of the European Union (80%) or the United States (93%). On the other hand, coal use in industrial processes like steel, cement and other industries consume a much larger share in China when compared to the European Union or the United States. Steel production in China accounts for approximately 19% of overall coal consumption, and cement and other uses also consume more than 20%. By contrast, the share in coal consumption of all United States' industrial uses is approximately 7% and the European Union's share is approximately 20%.

Figure 1.5 Coal consumption in selected regions by sector, 2012



China saw tremendous growth in power generation over the past ten years, with increases from 1 388 TWh in 2000 to 5 023 TWh in 2012, an annual growth rate of over 10%, and consistent increases in 2013 over 2012 (7.5%). Hydro (15%) and coal-fired (75%-80%) power generation account for the largest shares of Chinese power generation. In 2013, Chinese hydro capacity increased by +12.8% (+32 GW), reaching a total of 282 GW. These 2013 hydro additions, primarily in the Yunnan and Sichuan provinces in southwest China, were roughly the size of all installed hydro capacity in Norway. Comparatively, overall Chinese thermal power capacity in 2013 increased by +4.5% (+37 GW) to 862 GW, a steep decrease from capacity increases in 2012 (+56 GW) and 2011 (+62 GW).

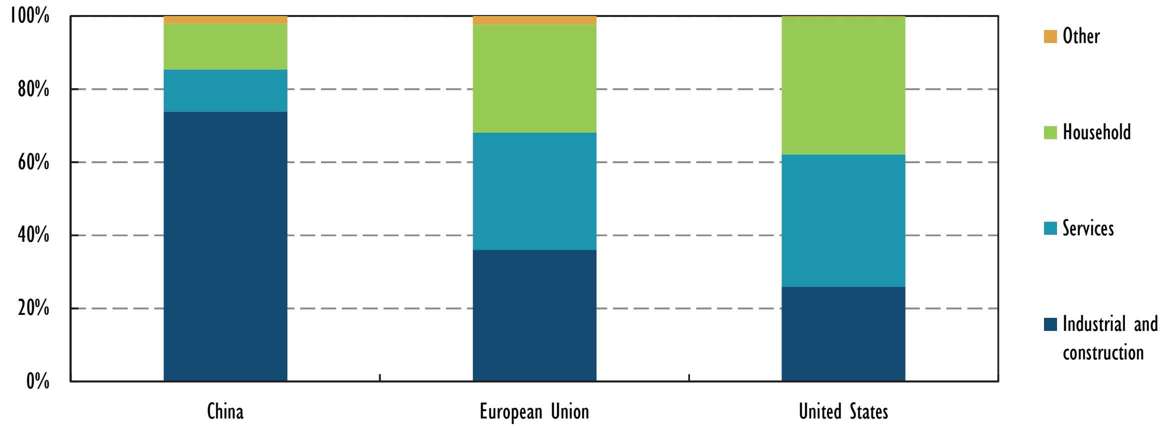
The split in power demand between the different sectors in China is different from patterns in Western countries. As illustrated in Figure 1.6, industrial and construction sectors account for the majority of Chinese power demand (74%). In the European Union and the United States, by comparison, this share is approximately 36% and 26% respectively.

Conversely, the share of Chinese services (11%) is approximately one-third of the share of services in the European Union and the United States. Household power demand accounts for approximately 13% of power demand in China, less than half the share seen in the European Union and the

United States. From 2012 to 2013, relative growth was the strongest in the services (+10.3%) and household (+9.2%) sectors in China, showing a total growth of approximately 160 TWh.

In absolute terms, the bulk of growth in 2013 came from the industrial and construction sectors, which grew by 256 TWh (+7.0%). Overall power consumption increased by 373 TWh (+7.5%) to 5 396 TWh. Jiangsu province in eastern China became the largest power consuming province (496 TWh) in 2013, driven primarily by strong economic performance, and surpassing Guangdong province (483 TWh), which had been the largest consumer for the previous two decades.

Figure 1.6 Power demand in selected regions by sector, 2012



The steel sector accounts for the largest share in non-power coal consumption in China. Steel production increased by approximately 66 Mt (+9.3%) to 775 Mt (Figure 1.7) throughout 2013, strengthening China's position as the world's largest steel producer. Core steel-producing provinces are Hebei (+4%), in the North China region, and Jiangsu (+11%). By the end of 2013, the steel sector faced low steel prices and persisting overcapacities. During the first half of 2014, output in Hebei was lower than in the same period in 2013; however this was offset by higher production from other provinces like Jiangsu and Liaoning. Approximately 10% of Hebei's steel companies are struggling, and their steel capacity will continue to be reduced as the Chinese government attempts to curb growing pollution.

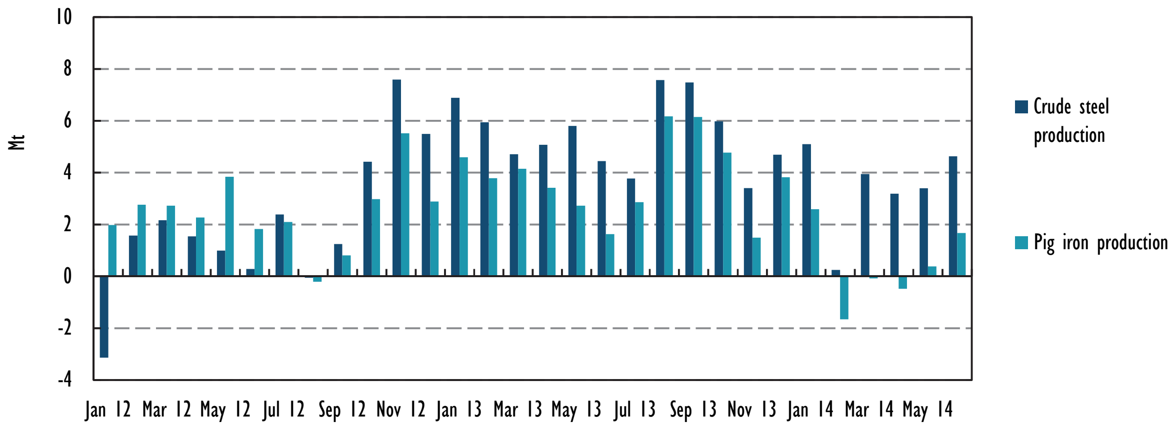
Overall steel demand in China grew by approximately 8% in 2013. The construction sector is the largest user of steel in China, followed by the machinery and automobile sectors. Other users include the energy sector, home appliances and railway construction.

Pig iron production generally followed the same trend as crude steel production, increasing by 6.9% from 2012 (657 Mt) to 2013 (703 Mt). The largest pig iron-producing regions were again Hebei (+3% growth year-on-year) and Jiangsu (+11%).

Coal demand from coal conversion processes is increasing in China, with large investments (see Box 3.2 for a detailed description of coal conversion processes). Some regions in China, such as Inner Mongolia or Xinjiang, have large reserves of stranded coal and host many projects for coal conversion. Previously, coal gasification was used for many purposes: manufactured gas, liquid fuels, fertilisers, and so forth. In 2006, there were more than 8 000 operational gasifiers in China. However, clean, or modern, coal conversion processes refer to larger scale operations, with improved environmental performance and economics. The only operational coal-to-liquid direct liquefaction plant is the Shenhua Group

Corporation's plant in Ordos, with a current capacity of 1.08 million tonnes per annum (Mtpa) and plans to triple this capacity in the coming years. In addition, there are three indirect liquefaction plants in operation with a combined capacity of 0.5 Mtpa, with plans for more. Shenhua maintains coal-to-olefins plants in Baotou (Inner Mongolia) and Ningxia, with a combined capacity of over 1 Mtpa, and Datang Group operates a 0.5 Mtpa coal-to-olefins plant in Duolun (Inner Mongolia). Other coal-to-chemicals plants are in operation, such as Tongliao Jinmei, the first company producing ethylene glycol from coal in Inner Mongolia (0.2 Mtpa capacity).

Figure 1.7 Monthly year-on-year differences in crude steel and pig iron production in China, 2012-14



Source: World Steel Association (various years), *Crude Steel Production*, Brussels, World Steel, www.worldsteel.org/statistics/crude-steel-production.org.

Regional focus: Power sector in India

India is the third-largest coal consumer in the world, accounting for approximately 10% of world coal demand. Thermal coal accounts for approximately 89% of India's 2013 coal demand, the remainder almost evenly divided between lignite and met coal. The power sector accounts for more than two-thirds of India's overall coal demand, with the second- and third-largest sectors being the iron and steel industry (14%) and the cement industry (4%).

70% of India's electricity generation is powered by coal, and as of April 2014, coal generation capacity was approximately 145 GW, around 60% of India's overall capacity. Thermal capacity additions of 17 GW were added between April 2013 and March 2014, and 20 GW during the same period in 2012-13. Despite those additions, it is not likely India's five-year plan target[5] will be met. Not only are capacity additions behind targets, existing capacities are also not operating at maximum despite the prevalence of power shortages. This is due, in part, to an insufficient supply of fuel to the power plants.

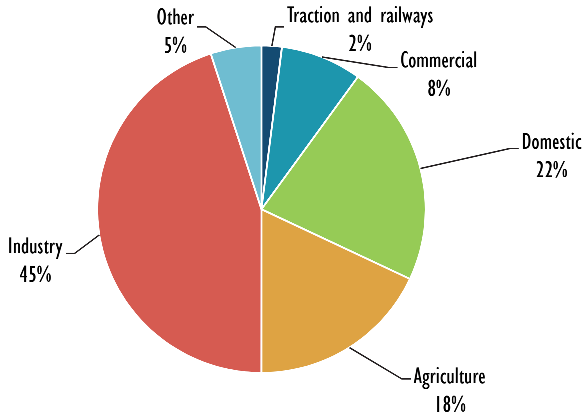
Apart from getting new power plants online and meeting the challenge of supplying fuel to them, India is also struggling to enable power transfer between regions in India, which would open up the possibility to address regional supply-and-demand imbalances. In January 2014, state-run India Power Grid Corp. created a single transmission grid, linking India's Northern, Eastern, North-Eastern and Western grids (interconnected since 2006) to the previously isolated South grid, thereby creating the world's largest power grid. The 765 kV single circuit transmission line between Sholapur, Maharashtra (Western grid) and Raichur, Karnataka (Southern grid) was commissioned five months ahead of schedule. Previously, India's Southern region suffered from severe power shortages, resulting in power prices nearly

[5] India's track record for achieving five-year plans suffers, as generation capacity additions have on average come short 35% compared to the target.

double that of the other grids. Power generators in the Western grid are, in particular, anticipating the benefits of the single grid by increasing generally low full load hours and margins of operations.

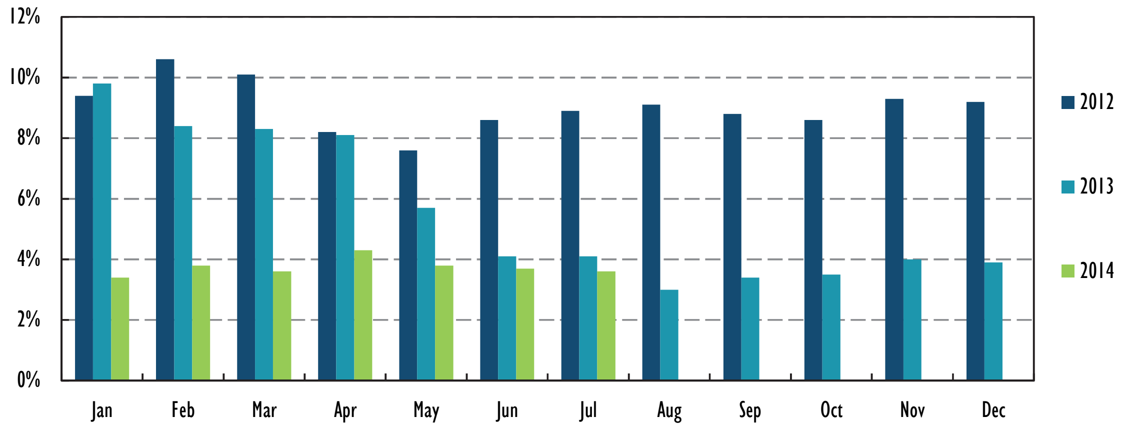
The industry sector is the largest power consumer in India, accounting for approximately 45% of the total. Residential power consumption accounts for approximately 22%, followed by agriculture at 18% and the commercial sector at approximately 8%. These shares have fluctuated as residential and commercial power consumption increases due to increasing electrification, urbanisation and the rise of the service sector, at the expense of a steady reduction in agriculture's share. Additionally, India's sector's share percentages vary region by region, with Southern India traditionally more agricultural. Residential demand is more pronounced in the Northern region, such as in highly populated states like Uttar Pradesh.

Figure 1.8 Power consumption (utilities) by sector in India, 2012-13



Source: Central Statistics Office (2014), *Energy Statistics 2014,* Ministry of Statistics and Programme Implementation, government of India, New Delhi, http://mospi.nic.in/mospi_new/upload/Energy_stats_2014.pdf.

Figure 1.9 Power deficit and seasonality in India, 2012-14



Source: CEA (Central Electricity Authority) (various years), Executive Summary Power Sector, Ministry of Power, government of India, New Delhi.

Indian power demand generally exhibits a seasonal structure. Domestic power demand is usually lower during the monsoon season (June to September), and higher in the hot months preceding the monsoon as well as in winter. This seasonal pattern is seen in power deficits as well, as shown in Figure 1.9, with power deficits[6] highest in winter (8%-10%) and decreasing in monsoon season.

[6] Power deficit is the difference between power demand and supply. Because demand is not met, the power deficit can only be an estimate.

Supply

Global coal supply grew by 0.4% (+28 Mt) from 7 794 Mt in 2012 to an estimated 7 823 Mt in 2013. 2013 coal supply growth was substantially lower than both 2012 (2.2%) and the ten-year average (4.7%). Supply growth in 2013 was particularly weak in China (+0.8%), the world's largest coal producer, and India (+1.5%). Both countries have had much higher coal supply growth in previous years, with ten-year average growth rates above 5%. Supplies from the United States, the world's second-largest coal producer, continued to trend downward, 28 Mt lower in 2013 than in 2012, at an estimated 904 Mt. Although Indonesian supply growth slowed in 2013, down from a +15.8% ten-year average to an estimated +10.1%, Indonesia accounts for the majority of incremental global coal supplies and is now the world's fourth-largest coal producer. Additional global supplies came from producers in Australia, who increased production, thereby increasing Australian output by 6.6% (+29 Mt) to an estimated 459 Mt in 2013.

Thermal coal accounted for 76.9% of 2013 global coal supplies, with met coal accounting for 12.4% and lignite for the balance. Incremental hard coal supply volumes came primarily from thermal coal, which increased by 55 Mt (approximately +0.9% growth), to 6 015 Mt in 2013. Met coal supply grew by 22 Mt (approximately +2.3% growth) to 968 Mt. Lignite supplies declined in 2013 by 49 Mt (-5.5%) compared with 2012. Lignite production dropped in both OECD member countries (-30 Mt) and OECD non-member countries (-19 Mt) to an estimated 840 Mt by the end of 2013.

Table 1.4 Coal supply overview

Country	Total coal supply (Mt) 2012	Total coal supply (Mt) 2013*	Absolute growth (Mt) 2012-13	Relative growth (%) 2012-13	CAGR (% per year) 2003-12	Share (%) 2013
China	3 532	3 561	28	0.8%	8.7%	45.5%
United States	932	904	-28	-3.0%	-0.6%	11.6%
India	604	613	9	1.5%	5.2%	7.8%
Indonesia	444	489	45	10.1%	15.8%	6.2%
Australia	431	459	29	6.6%	2.4%	5.9%
OECD	2 024	1 994	-30	-1.5%	-0.2%	25.5%
Non-OECD	5 770	5 828	58	1.0%	4.7%	74.5%
World	**7 794**	**7 823**	**28**	**0.4%**	**4.7%**	**100.0%**

Note: differences in totals are due to rounding.

* Estimate.

OECD supply trends

OECD coal production decreased by 1.5% (-30 Mt) in 2013, to 1 994 Mt. This drop in coal supplies can mainly be attributed to lignite production, which dropped by 5.1% (-30 Mt). Thermal coal supplies in OECD countries dropped 0.8% (-9 Mt). However, thermal coal supplies varied significantly between OECD regions. While OECD Asia Oceania production grew by 11.7% (+26 Mt) in 2013, primarily due to increased production in Australia, OECD Europe and OECD Americas' production declined by 12.7% (-14 Mt) and 2.6% (-21 Mt) respectively. 2013 met coal supplies increased by 3.1% (+9 Mt) over 2012, mainly due to increases in OECD Asia Oceania.

The majority of incremental OECD hard coal production came from Australia, which increased production by 37 Mt. Incremental supplies in Australia came from both steam coal (+26 Mt) and met coal (+11 Mt). Australian producers are increasingly trying to generate economy of scale by increasing production as well as continuing to produce even during unfavourable international coal pricing due to take-or-pay contract obligations.

The United States' hard coal supplies decreased by 26 Mt despite increasing coal demand from the power sector. Apart from lower exports, stock changes served increasing demand (see Table 1.5).

Production in OECD Europe declined in 2013 due to both mine closures, such as the Daw Mill mine in the United Kingdom, which closed in March 2013 following a fire, and competition with other coal producers exacerbated by low coal prices.

Table 1.5 Hard coal supply-and-demand balance for the United States (Mt)

	2010	2011	2012	2013*
Production	925	932	861	834
Imports	17	12	8	8
Exports	74	97	114	107
Stock changes	13	-1	-7	37
Demand	881	846	748	772

* Estimate.

Lignite supplies decreased significantly from 2012 to 2013. In OECD Europe, Greece and Turkey saw the strongest lignite supply decline due to lower lignite-fired power generation. Lignite production in Germany, the largest lignite producer in the world, remained stable in 2013 at 183 Mt. Lignite production in Australia decreased by 9 Mt to 63 Mt, a decline driven mainly by the carbon tax.

Table 1.6 Hard coal and lignite production among selected OECD member countries (Mt)

Country	Hard coal		Lignite	
	2012	2013*	2012	2013*
Australia	359	397	71	63
Canada	57	60	9	9
Czech Republic	12	9	44	40
Germany	12	8	185	183
Greece	0	0	63	54
Hungary	0	0	9	10
Korea	2	2	0	0
Mexico	15	15	0	0
New Zealand	5	4	0	0
Norway	1	2	0	0
Poland	80	77	64	66
Slovak Republic	0	0	2	2
Spain	6	4	0	0
Turkey	3	3	68	63
United Kingdom	17	13	0	0
United States	861	834	72	70

* Estimate.

Regional focus: United States

The United States (US) is the second-largest coal producer in the world, with the world's largest recoverable coal reserves (224 Gt of hard coal). United States' coal production peaked in 2008 at 1 076 Mt and decreased since then to its 2013 level of 904 Mt. Approximately 756 Mt of US coal production is thermal coal, 78 Mt is met coal and another 70 Mt lignite.

Although US coal is mined in more than 20 states, about 70% of total United States' coal comes from mines in Illinois, Kentucky, Pennsylvania, West Virginia and Wyoming. The majority of thermal coal is produced in mines in the Powder River Basin (PRB), the Illinois Basin and the Appalachian Basin. Virtually all met coal is mined in the Appalachia region, mostly in Central Appalachia, which was once the largest coal producing area in the United States. Currently, however, the largest producers are the PRB and the Illinois Basin.

Approximately 34% of US coal is mined in underground operations, with the remaining 66% in surface operations. However, this split varies widely between regions. In the eastern mining regions, 32% of coal is produced underground and 68% in surface mines. In western regions, surface mining accounts for 91% and only 9% is underground. Consequently, underground mining is prevalent in the Central Appalachian, Northern Appalachian and Illinois basins, while surface mining is prevalent in the PRB. Currently, around 1 200 mines are operating in the United States with average annual production below 1 Mt. In 2012, the ten largest mines in the United States had an average annual production of approximately 65 Mt and accounted for more than 70% of overall coal production. The 50 largest mines had an average production of around 86%.

The two largest mines in the United States are both located in the Powder River Basin: Peabody's North Antelope Rochelle Mine, which produced approximately 100 Mt of coal in 2013 and currently holds the largest coal reserves in the world (2.2 Gt), and Arch Coal's Black Thunder mine, which produced approximately 91 Mt in 2013.

Table 1.7 Capital expenditure, historical and anticipated, for major US coal producers, 2012-14, in USD million

	2012	2013	2014*
Peabody Energy	990	330	250-300
Arch Coal	395	297	180-190
Alpha Natural Resources	498	258	225-275
Cloud Peak Energy	104	57	40-60
Consol Energy**	663	459	390
Alliance Resource Partners	425	329	320-350
Walter Energy	392	154	130

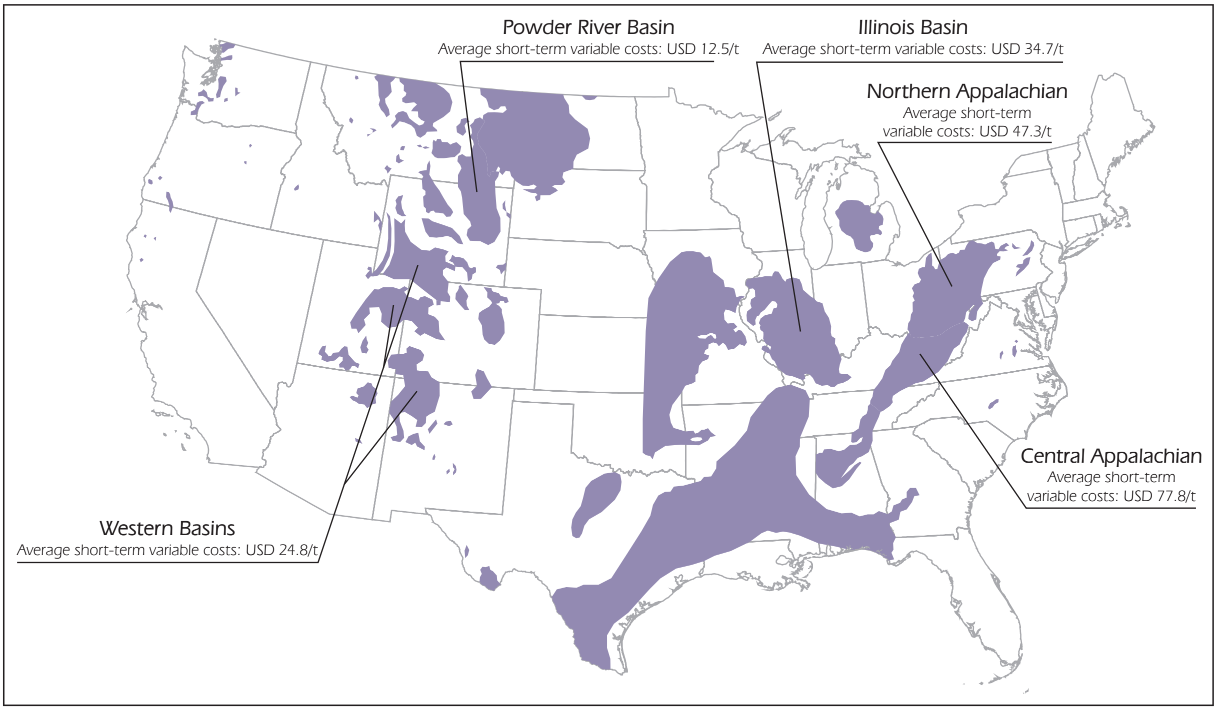
* Estimate.

** Consol Energy is engaged in both coal and gas related businesses. The capital expenditures reported here refer only to coal. Moreover, in 2013, several mines were sold to Murray, which became fifth-largest US coal producer.

Half of US coal production comes from four producers: Peabody Energy, Arch Coal, Alpha Natural Resources and Cloud Peak Energy. In order to remain profitable in a low-price market, US producers continue to reduce costs. This includes mine idling, selling non-core assets and mine closures (see Chapter 2 for an overview of cost reduction measures). Subsequently, the number of total US mines has been reduced, from over 1 400 mines in 2010 to 1 325 mines in 2011 and 1 229 mines in 2012 (EIA, 2013). Reported capital expenditures also decreased, with overall 2013 capital expenditures over 30% lower than those from 2012. This current attempt to reduce cost continues, and the announced 2014 capital expenditures from the major producers are again significantly lower than those from 2013 (see Table 1.7).

Map 1.1 shows that average short-term variable costs for thermal coal vary strongly between the different coal basins in United States, with average costs lowest in the PRB at USD 12.5/tonne (t). Coal from the Western Basin (comprising the Uinta Basin, the Green River Basin and the San Juan River Basin among others) are also on the low side of the US supply curve, with costs of USD 24.8/t. Coal from the Illinois Basin and Northern Appalachia are in the middle of the supply curve, with costs averaging at USD 34.7/t and USD 47.3/t respectively. Central Appalachian coal, at USD 77.8/t, is on the upper side of the supply curve. When adjusting costs by energy content, the cost picture does not change significantly. Coal from the PRB is typically of lower calorific value, with standardised contracts based on a calorific value of approximately 4 650 kilocalories per kilogramme (kcal/kg). Coal from Northern and Central Appalachia ranks between 6 600 kcal/kg and 6 870 kcal/kg. The calorific value of coal from the Illinois Basin is somewhat lower, with standardised products settled around 6 240 kcal/kg. Sulphur content of Illinois Basin coal is rather high at around 3%.

Map 1.1 Short-term variable costs for thermal coal in the United States by region, 2013



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

* Short-term variable costs include mining costs, costs for coal preparation, overhead as well as royalties and taxes. Not included are transport costs and port fees.

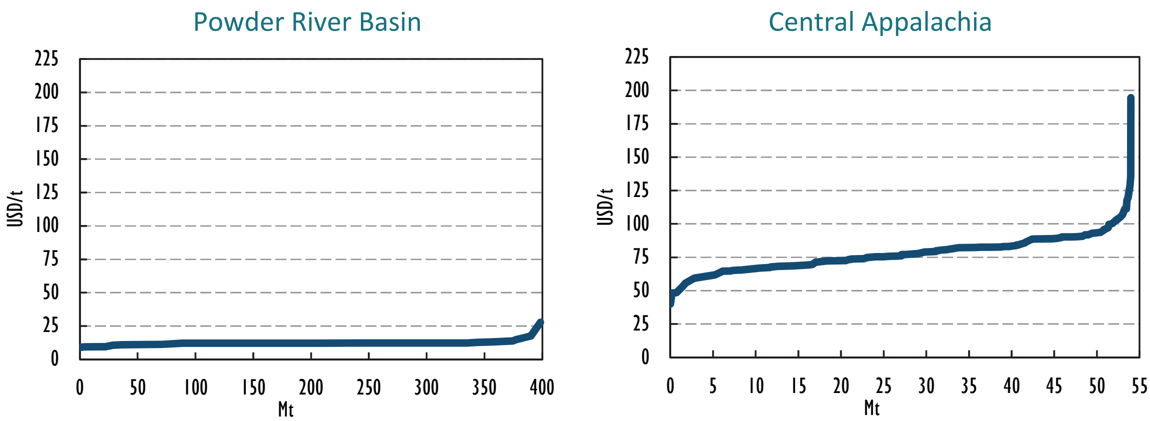
Source: IEA analysis from Wood MacKenzie (2014).

Transport distance and cost differences can be significant in the United States: PRB coal travels an average of almost 2 000 kilometres (km) by rail, compared to a distance of approximately 500 km to 700 km for coal from the Illinois Basin. Varying costs of mining and transport are also reflected in varying average sales prices of coal in the different states. Sales prices in the United States averaged

USD 73/t for bituminous coal in 2012. Illinois is below average at USD 59/t, Kentucky at USD 70/t, Pennsylvania at USD 81/t and West Virginia at USD 91/t, which are all on the upper side. Bituminous coal in Virginia sells for an average price of USD 122/t (EIA, 2013).

Apart from notable regional cost differences between the basins displayed in Map 1.1, there are also cost differences within each basin. Figure 1.10 lists short-term variable cost curves for the PRB and Central Appalachia. As shown, the majority of coal in the PRB is mined for short-term variable costs between USD 10/t to USD 15/t (average USD 12.5/t, and an average strip ratio between 3 and 4). Average costs in Central Appalachia are higher than costs in the PRB, and the variance of costs in Central Appalachia is higher than the variance in costs in the PRB, where the majority of US coal is mined. Central Appalachian costs are in the rather large bandwidth of USD 50/t and USD 100/t. Comparatively, the average strip ratio of Central Appalachian surface mines is approximately 11.

Figure 1.10 Short-term variable cost curves for thermal coal and different coal basins in the United States, 2013



Source: IEA analysis from Wood MacKenzie (2014).

OECD non-member supply trends

Coal production in OECD non-member countries grew by 1.0% (+58 Mt) in 2013, the lowest growth rate since 2000. 2013 total coal output was 5 828 Mt, up from 5 770 Mt in 2012. Supply growth was weak for thermal coal (+1.3% or 64 Mt) and coking coal (+2.0% or 13 Mt), with lignite 2013 supply decreasing by -6.3% (from 296 Mt to 277 Mt).

Supply from China, the world's largest hard coal producer, was approximately 3 561 Mt, a 28 Mt (+0.8%) increase over 2012. Incremental coal volumes came from both thermal coal (+17 Mt) and met coal (+11 Mt). When compared to last year's growth rate of 3.3% and the ten-year average growth rate of 8.7%, growth is slowing in China.

India, the third-largest hard coal producer in the world, saw 2013 hard coal production increases of 1.9% (+11 Mt) to an estimated 568 Mt, much lower than the ten-year average growth of 5.1%. Thermal coal production increased by 1.2% to an estimated 562 Mt. Met coal production almost tripled in 2013 to an estimated 6 Mt. However, Indian production figures require scrutiny, as a reported 60 Mt of coal is stolen annually in India, almost 10% of overall Indian coal production. While such estimates might be excessive, the magnitude of this reported figure is significant.

Indonesia, the fourth-largest hard coal producer in the world, saw production increase by 10.1% (+45 Mt) in 2013 to an estimated 489 Mt, lower than the Indonesian ten-year average growth of 15.8%.

Following a strong increase in output from 2011 to 2012, hard coal production in Russia and Kazakhstan has remained close to their 2012 levels.

Output in 2013 fell in Colombia (-4.1%, totalling 85 Mt) and South Africa (-1.1%, totalling 256 Mt), mainly due to supply disruptions.

Lignite production in OECD non-member countries decreased significantly (-6.3%) in 2013. This development is mainly driven by a strong decline in production of lignite from non-OECD Europe, primarily production decreases in Bulgaria (-5 Mt) and Romania (-9 Mt). Russia (73 Mt), India (45 Mt), Thailand (18 Mt) and Mongolia (8 Mt) are further major lignite suppliers among OECD non-member countries.

Table 1.8 Hard coal and lignite production among selected OECD non-member countries (Mt)

Country	Hard coal		Lignite	
	2012	2013*	2012	2013*
Bulgaria	0	0	33	29
Colombia	89	85	0	0
India	557	568	46	45
Indonesia**	444	489	0	0
Kazakhstan	113	115	8	5
China	3 532	3 561	0	0
Romania	0	0	34	25
Russia	278	274	77	73
Serbia	0	0	38	40
South Africa	259	256	0	0
Ukraine	68	66	0	0
Viet Nam	42	40	0	0

* Estimate.

** Actually, part of that coal is lignite.

Regional focus: Indonesia

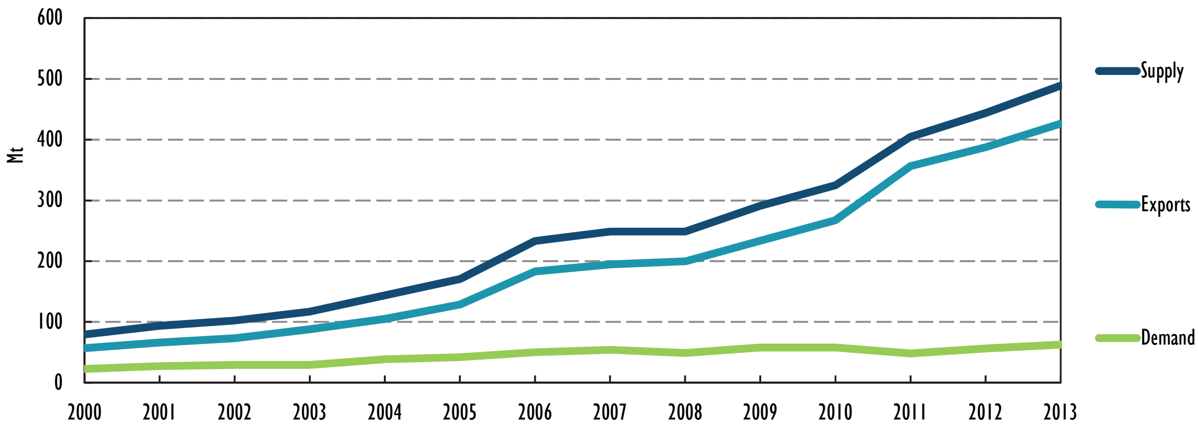
Although Indonesia has only 1.8% (14 Gt) of the world's proven hard coal reserves and a 6.2% share of global coal production, it is the world's largest coal exporter, accounting for approximately 1/3 of overall world coal exports. Indonesia is in a geographically advantageous location to serve the growing Asian market, has comparatively low production and transportation costs, coal mines in close proximity to the coast and comparatively few environmental restrictions. These have contributed to Indonesia's impressive export growth from approximately 57 Mt in 2000 to 426 Mt in 2013 (see Figure 1.11). The share of exports in overall production rose from approximately 72% in 2000 to 88% in 2013, as domestic coal demand grew (+8.1% per year) at approximately half the pace of production (+15.0%) and exports (+16.8%).

The vast majority (99%) of Indonesian coal production is thermal coal,[7] although it also produces coking coal. Indonesian coal quality tends to have lower calorific value and higher moisture content, as high calorific value coal reserves in Indonesia are limited. The five largest companies, PT Adaro

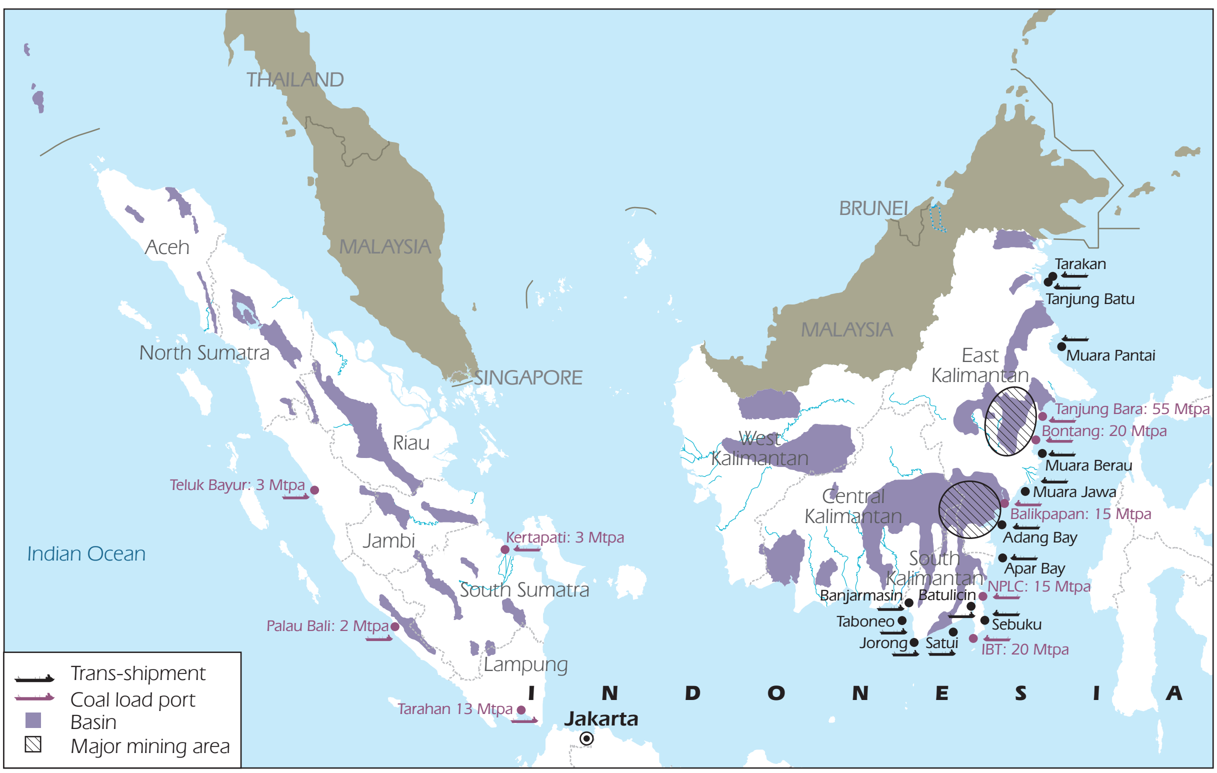
[7] As mentioned in Footnote 1 of Chapter 1, Indonesian thermal coal is actually bituminous and sub-bituminous coal as well as lignite.

Indonesia (2013: 52 Mt), PT Kaltim Prima Coal (Bumi) (2013: 45 Mt), PT Kideco Jaya Agung (2013: 37 Mt), PT Indotambang Raya Megah (2013: 30 Mt) and PT Arutmin Indonesia (Bumi) (2013: 29 Mt) account for almost 40% of Indonesian coal production. PT Asmin Coalindo Tuhup (AKT) is the largest met coal producer in Indonesia, with an output target of approximately 3 Mt in 2013.

Figure 1.11 Supply, demand and coal exports in Indonesia, 2000-13



Map 1.2 Indonesia coal infrastructure map



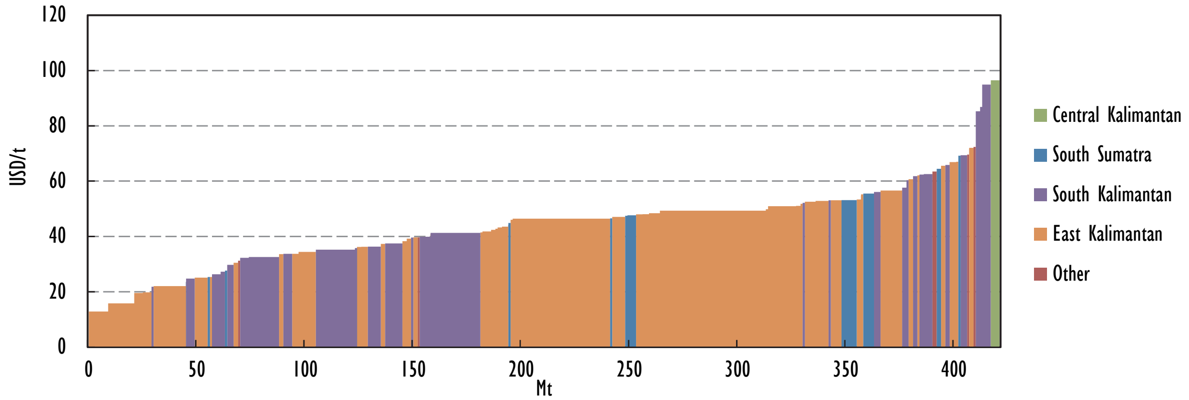
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

The bulk of Indonesian production comes from Kalimantan, where approximately 91% of Indonesian coal is produced (57% East Kalimantan, 31% South Kalimantan and approximately 3% from Central Kalimantan). South Sumatra accounts for 7% of Indonesian production, with the remaining production from smaller mining areas (see Map 1.2). There are more than 150 mines operating in Indonesia, with an average 2013 production per mine of approximately 2.8 Mt. By comparison, an average mine in Queensland (Australia) produced 4.5 Mt of saleable coal in 2013, an average mine in the United States less than 1 Mt.

Almost all Indonesian coal mines are surface mines using truck and shovel mining methods. Mining costs, which make up the largest part in free-on-board (FOB) costs in Indonesia, are very sensitive to movement in diesel prices. The average strip ratio of Indonesian mines is 8.

Overall weighted 2013 Indonesian coal mine FOB costs decreased by approximately 5% in 2013 to an average of USD 45/t. As indicated in Figure 1.12, costs vary between Indonesian basins and also within each basin. Low-cost mines in East Kalimantan produce coal at a cost below USD 20/t; South Kalimantan, below USD 40/t. However, despite being at the lower end of the global supply curve, many of Indonesia's smaller producers struggle to survive in the marketplace due to low international coal prices, resulting in mine closures and job cuts. For example, approximately 2 000 miners are reported to have lost their jobs in 2013 in the East Kutai region of East Kalimantan.

Figure 1.12 Indicative FOB cost curve for Indonesia

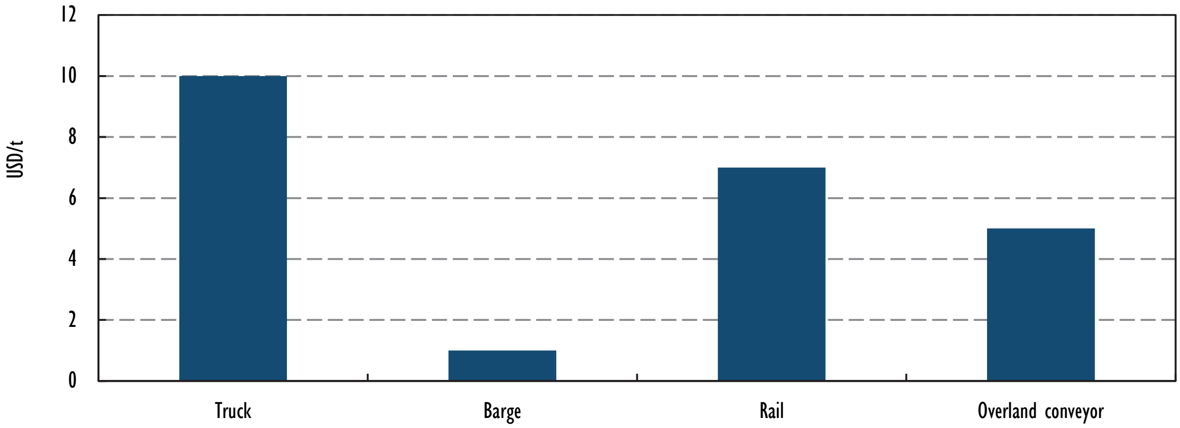


Source: IEA analysis from Wood MacKenzie (2014).

Although it occupies a smaller share in overall costs (approximately 15%) when compared to other parts of the world, transport costs are still an important cost component in Indonesia. There are generally four methods of coal transportation in Indonesia: truck, barge, rail and overland conveyor. Average transport costs vary by a factor of ten, with transport by truck at USD 0.10 per tonne-kilometre (USD/tkm) and barge at USD 0.01/tkm. Railway costs in Indonesia are approximately USD 0.07/tkm and overland conveyor costs are USD 0.05/tkm (see Figure 1.13).

Trucks are generally used to transport coal from mines to river ports, from where it is further barged. Both transport by truck and barging relies heavily on diesel and transport costs, and is therefore sensitive to fluctuations in diesel prices. Nevertheless, transport costs in Indonesia are relatively low when compared to other exporting countries, as coal can be transported by barge on rivers in Kalimantan to anchorage or coal terminals. Typical transport distances for coal barging range between short distances (10 km to 20 km) to larger distances (400 km to 700 km). Road transport is typically lower than 40 km. Despite not being commonplace, train transport distance ranges between 200 km and 450 km.

Figure 1.13 Typical cost for 100 km inland transportation in Indonesia



Overall Indonesian coal transport and load port capacity exceeds 430 Mtpa, and is currently not a source of bottleneck for coal exports. Kalimantan load port capacity exceeds 120 Mtpa, with PT Kaltim Prima Coal's Tanjung Bara (55 Mtpa) the largest coal-loading port. Load ports in Kalimantan can accept vessel sizes between 80 000 and 200 000 deadweight tonnage (dwt). Loading ports in Sumatra are smaller, with vessel sizes ranging between 20 000 dwt and 65 000 dwt. Combined load port capacity in Sumatra exceeds 20 Mtpa, with PTBA's Tarahan one of the largest (12.5 Mtpa). Off-shore and barge loading capacity is dependent upon the number of floating cranes/platforms installed, but may exceed 290 Mtpa, and is easily extendable.

References

Central Statistics Office (2014), *Energy Statistics 2014,* Ministry of Statistics and Programme Implementation, government of India, New Delhi, http://mospi.nic.in/mospi_new/upload/Energy_stats_2014.pdf.

CEA (Central Electricity Authority) (various years), *Executive Summary Power Sector*, Ministry of Power, government of India, New Delhi.

EIA (US Energy Information Administration) (2013), *Annual Coal Report 2012*, EIA, Washington, D.C.

IEA (International Energy Agency) (2012), *Medium-Term Coal Market Report 2012*, OECD/IEA, Paris.

IEA (2011), *Medium-Term Coal Market Report 2011*, OECD/IEA, Paris.

McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

Wood MacKenzie (2014), *Coal* (private database), accessed April 2014.

World Steel Association (various years), *Crude Steel Production*, Brussels, World Steel, www.worldsteel.org/statistics/crude-steel-production.html.

2. RECENT TRENDS IN INTERNATIONAL COAL TRADING

Summary

- **2013 international coal trade grew 4.2% (+54 million tonnes [Mt]), to an estimated 1 333 Mt.** This is a 2.5 percentage point decrease from 2012 growth, and is the sum of thermal coal (5.0% increase to 1 028 Mt); met coal trade (2.4% increase to 301 Mt); and a small amount of traded lignite.[1]

- **Seaborne trade, approximately 90% of international coal trade, grew 4.9% (+56 Mt) in 2013, to an estimated 1 204 Mt.[2]** This is a 2.6 percentage point decrease from 2012 growth. This slowdown in growth can be attributed to the seaborne thermal coal trade, which grew by only 3.1% to 923 Mt, more than a 5 percentage point decrease compared to 2012 growth. Seaborne met coal trade increased by 4.7%, to 265 Mt.

- **China and Indonesia remain the dominant importer and exporter respectively in the international coal trade.** China accounted for the bulk of incremental imports, with an import increase of 13.2% (+40 Mt) over 2012 to 341 Mt. Indonesia remains the world's leading coal exporter in terms of both energy content and volume in 2013, with a coal export growth of 10.0% (+39 Mt) to 426 Mt.

- **Both thermal and met coal prices continued to decline during 2013 and 2014 due to an oversupplied market.** In China, domestic coal producers cut coal prices to secure market share, which exerted significant downward pressure on international coal prices. Imported European steam coal prices were traded between USD 70 per tonne (USD/t) to USD 80/t throughout 2014, which is approximately USD 40/t to USD 50/t less than in March 2011. Australian met coal prices traded between USD 112/t and USD 116/t since April 2014, compared to USD 320/t in March 2011.

- **Coal producers continued to reduce supply costs in 2013.** Measures taken to improve competitiveness include labour cost reductions, increases in productivity and renegotiating take-or-pay contracts. In addition, many producers focused on increased production that benefited from economies of scale. However, despite these efforts, many producers continue to operate at a loss due to current low coal prices.

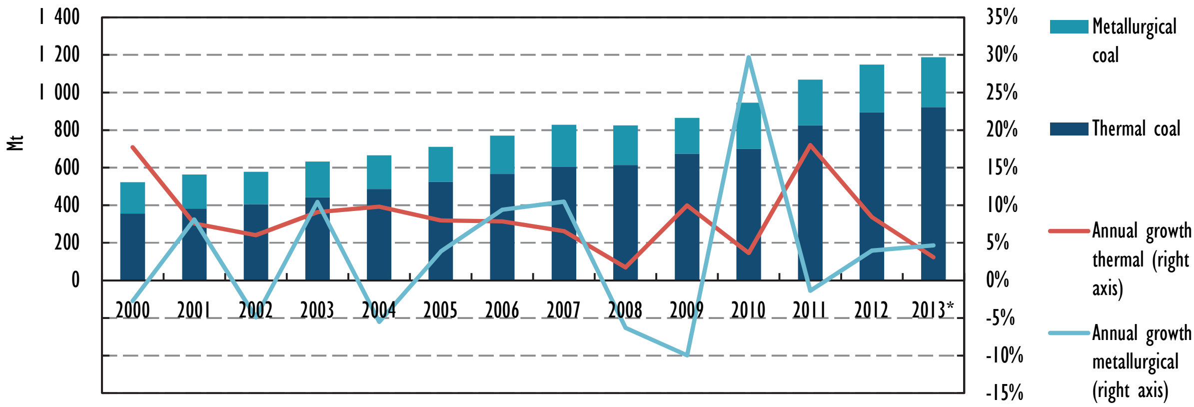
The international coal market

In 2013, international coal trade growth was 2.5 percentage points lower than that of 2012, at 4.2% or an increase of 54 Mt to 1 333 Mt. Approximately 91% (49 Mt) of incremental volumes came from thermal coal trade (1 028 Mt); met coal trade increased by 7 Mt to 301 Mt, and small quantities of lignite account for the balance.

Around 90% of internationally traded coal is seaborne, whose growth slowed from +7.4% in 2012 to +4.9% in 2013. This can be attributed to a slowdown in seaborne thermal coal trade growth (+3.1%, more than 5 percentage points lower than 2012), although seaborne thermal coal trade (923 Mt) still provided the largest share in 2013 overall seaborne coal trade. Seaborne met coal trade increased during this period by 4.7% to 265 Mt.

[1] Indonesian thermal coal exports include lignite in this report.
[2] Due to some statistical differences, total coal trade does not exactly match seaborne trade plus inland trade.

Figure 2.1 Development of the seaborne thermal and met coal markets, 2000-13

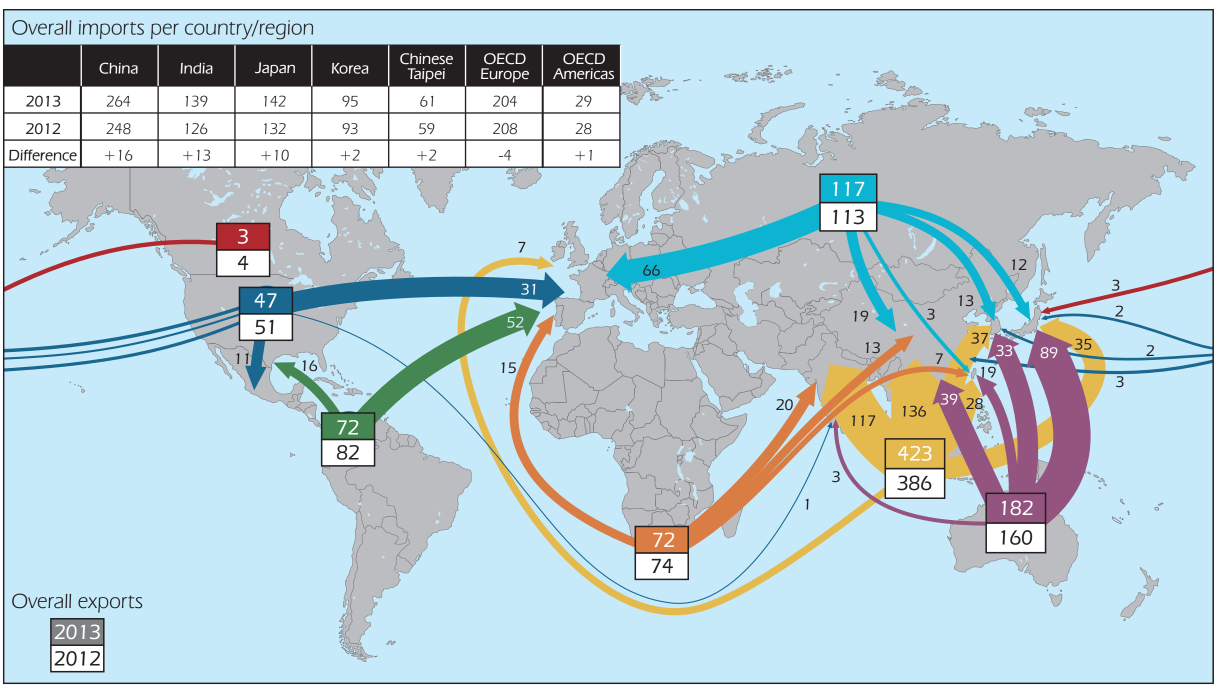


* Estimate.

International thermal coal trade

Although its share has increased by approximately 4 percentage points since 2000, international thermal coal trade still accounts for only a moderate share of total thermal coal demand (17%). The remainder is produced domestically. Approximately 90% of the international thermal coal trade is seaborne.

Map 2.1 Major trade flows in the thermal coal market, 2013



	China	India	Japan	Korea	Chinese Taipei	OECD Europe	OECD Americas
2013	264	139	142	95	61	204	29
2012	248	126	132	93	59	208	28
Difference	+16	+13	+10	+2	+2	-4	+1

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Note: Given that minor flows have not been represented in the map, and some statistical differences, imports and exports flows do not match exactly. This figure must therefore be regarded as indicative.

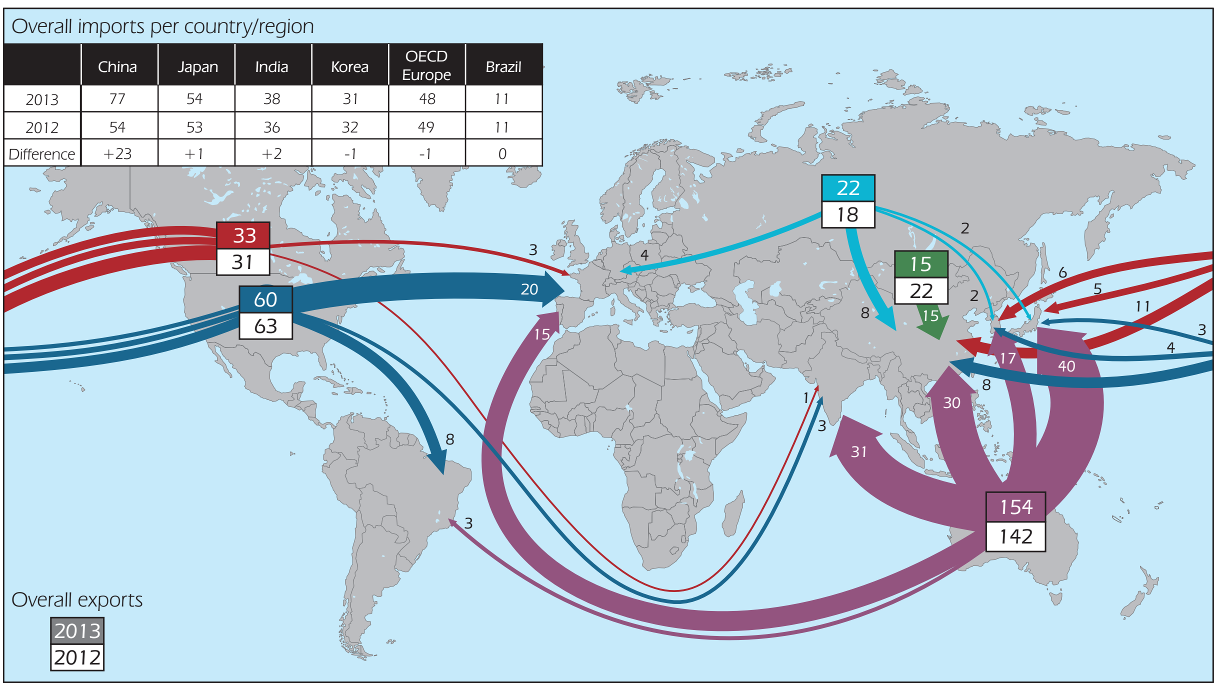
Map 2.1 illustrates major thermal coal trade flows in 2013, from the largest seven producing countries/ country groups to the primary demand centres. 2013 seaborne trade flows saw further increases in the Pacific Basin,[3] where the world's largest exporters and importers are located. Exports from Indonesia, the largest coal exporter in the world, increased by 9.6% in 2013 to 423 Mt. Exports from Australia saw the strongest relative increases (+14.4%) to 182 Mt. Chinese imports grew by 6.6% to 264 Mt, maintaining China's position as the largest coal importer, followed by Japan and India.

International met coal trade

Approximately 31% of met coal demand is traded internationally, with 88% of that trade seaborne. In relative terms, therefore, met coal is a more internationally traded product than thermal coal.

Australia is the primary met coal exporter, accounting for greater than 50% of the total met coal trade in 2013 (see Map 2.2). Along with the next three largest exporters, the United States, Canada and Russia, they account for approximately 90% of all internationally traded met coal. In addition, Mongolia provides significant volumes of met coal to China overland annually. The main demand centres for met coal are in the Pacific Basin, where China, Japan, Korea and India are the four largest importers. These four countries accounted for approximately two-thirds of all 2013 met coal imports, and further significant volumes are exported to OECD Europe and Brazil.

Map 2.2 Major trade flows in the met coal market, 2013



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Note: Given that minor flows have not been represented in the map, some statistical differences and roundings, imports and exports flows do not match exactly. This figure must therefore be regarded as indicative.

Regional analysis

The following section provides an overview of recent trends in international coal trade for the main exporting and importing countries.

[3] The seaborne coal market can generally be divided into two geographical regions, the Atlantic and the Pacific Basin. The Pacific Basin comprises the west coast of North and South America, all Asian countries and Australia. The Atlantic Basin comprises the remaining countries.

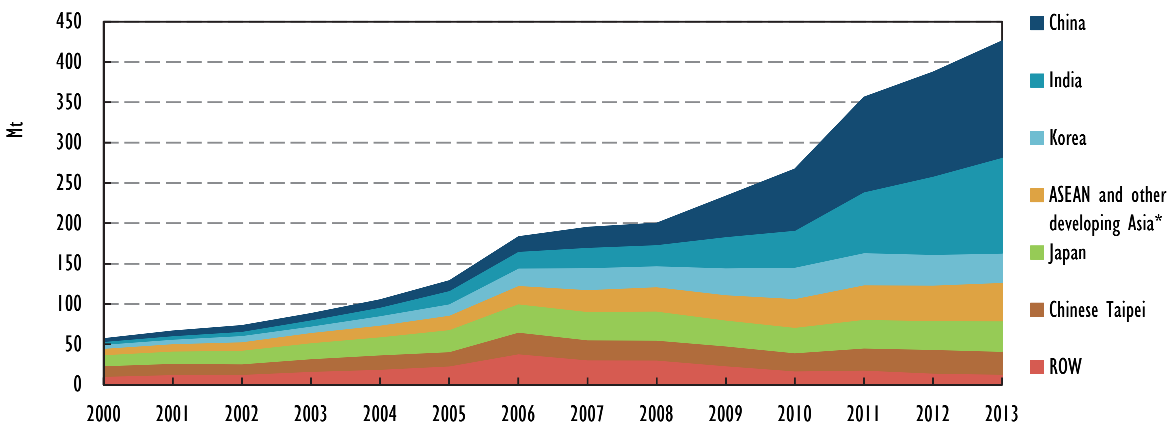
Exporters

Indonesia

Indonesia was again the largest coal exporter in 2013, both on the basis of tonnage and energy content. While it is only the fourth-largest thermal coal producer, with 8.1% of global production, Indonesia accounted for more than 40% of the global thermal coal trade in 2013. 2013 Indonesian coal exports grew by 10.0% to 426 Mt, or approximately 87% of Indonesian production. As shown in Figure 2.2, Indonesian exports have shown large-scale growth since 2000 (+16.8% per year), and contribute to approximately 60% of the incremental thermal coal trade during that period.

China and India remain the primary export destinations in Asia, as low-quality coal exports to these two countries grew in 2013. China accounted for 33% of Indonesian coal exports; India for 28%. Further export destinations are Japan and Korea, accounting for approximately 8% each of Indonesian exports.

Figure 2.2 Development of Indonesian export destinations, 2000-13



* Excludes Chinese Taipei. ASEAN = Association of Southeast Asian Nations.

Source: McCloskey (2014), *McCloskey Coal Reports 2000-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

Indonesian coal is typically of low calorific value and high moisture content. Different coal qualities and prices leave opportunities for players in the market to look for quality arbitrage (see the discussion in the section entitled "Prices" in this chapter). Indonesian producers have increased output in order to benefit from economies of scale given persistently low market prices. However, low prices for coal have rendered the operations of several small mining companies unprofitable, and slowing demand growth in China impacts Indonesian export growth.

When observing production and export statistics for Indonesia, it is important to remember that it includes illegal mining, amounting to an estimated 74 Mt in 2013. In early 2014, Indonesia enforced a 2011 regulation concerning enhanced cargo documentation, which hampered illegal mining and led to delays in exports from South Kalimantan. Indonesian authorities are currently discussing further measures to curb illegal mining such as the construction of as many as 14 state-owned coal terminals, which will facilitate tracking coal exports and production.

Australia

2013 Australian coal exports increased by 11.5% (+35 Mt) over 2012, to their highest level of 336 Mt. Approximately 73.2% of Australia's 2013 production was exported, making it the second-largest thermal coal and the largest met coal exporter in the world. Incremental export volumes were significant for both thermal (+23 Mt) and met coal (+12 Mt). 2013 met coal exports totalled 154 Mt, almost matching Australia's 2010 record high (157 Mt).

In 2013, Japan and China remained the primary export destinations for Australian coal. Most incremental coal export volumes were directed to China, which increased its imports of low quality and high ash coal from Australia. Thermal coal exports to Korea also increased year-over-year. Despite increasing export volumes and an easing Australian dollar, export revenues from coal decreased in the fiscal year 2012 to 2013 (July to June). Overall Australian coal exports generated revenues of USD 38 billion, approximately 60% of which came from met coal.

Russia

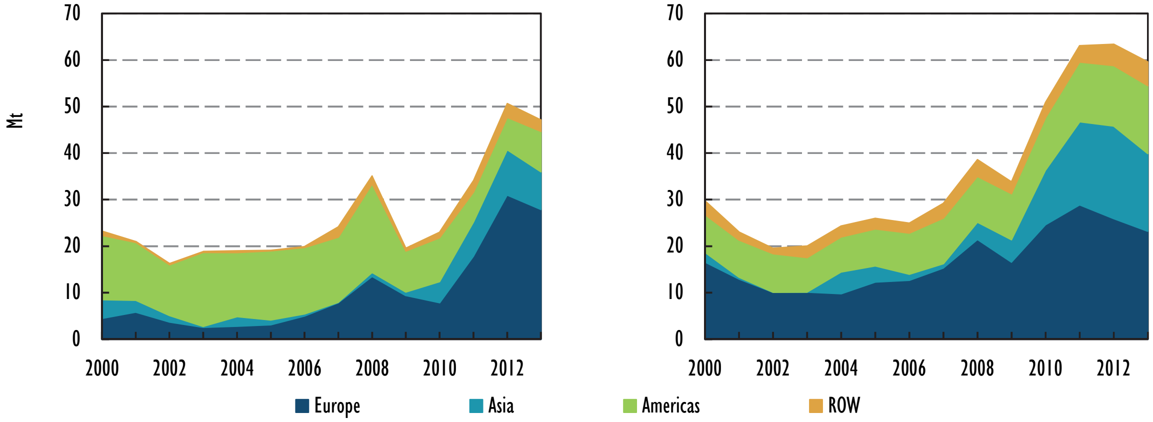
Russia remained the world's third-largest overall coal exporter in 2013. While 2013 Russian coal production decreased by 2.4% as domestic coal consumption fell, exports increased by 6.9% (+9.1 Mt) to 141 Mt. Approximately 118 Mt of the country's exports came from thermal coal, making Russia the world's third-largest thermal coal exporter. 2013 met coal exports also increased by 4 Mt (+21.4%), to 22 Mt, causing Russia to surpass Mongolia as the world's fourth-largest met coal exporter.

Russian coal is primarily exported to OECD Europe. Exports increased to 70 Mt, up from 64 Mt in 2012. Russia's seaborne exports to the Atlantic Basin are shipped through ports in the Baltic Sea (such as Ventpils/Latvia or Ust-Luga/Russia), in the Black Sea (such as Tuapse/Russia or Mariupol/Ukraine) or in the Barents Sea (Murmansk/Russia). Attracted by higher Asian prices, Russian exports to Asian markets are increasing. A new export infrastructure in Russia's Far East has helped spur exports to the Pacific Basin, and a further portion of Russian exports reach non-OECD Europe/Eurasia overland.

United States

Exports from the United States decreased in 2013 by 6.4% (-7 Mt), to 107 Mt. While thermal coal exports remained relatively strong at 47 Mt, this was a decrease from 51 Mt in 2012 (see Table 1.5). Revenues from thermal coal exports decreased by 15% to USD 3.4 billion in 2013 from USD 4.1 billion in 2012. Met coal exports from the United States, the second-largest met coal exporter in the world, decreased by 6.0% (-4 Mt) to 60 Mt following decreasing domestic production. Revenues from met coal exports decreased by 29% to USD 7.6 billion in 2013 from USD 10.6 billion in 2012.

Figure 2.3 Development of thermal (left) and met coal (right) exports from the United States, 2000-13



Source: McCloskey (2014), *McCloskey Coal Reports 2000-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

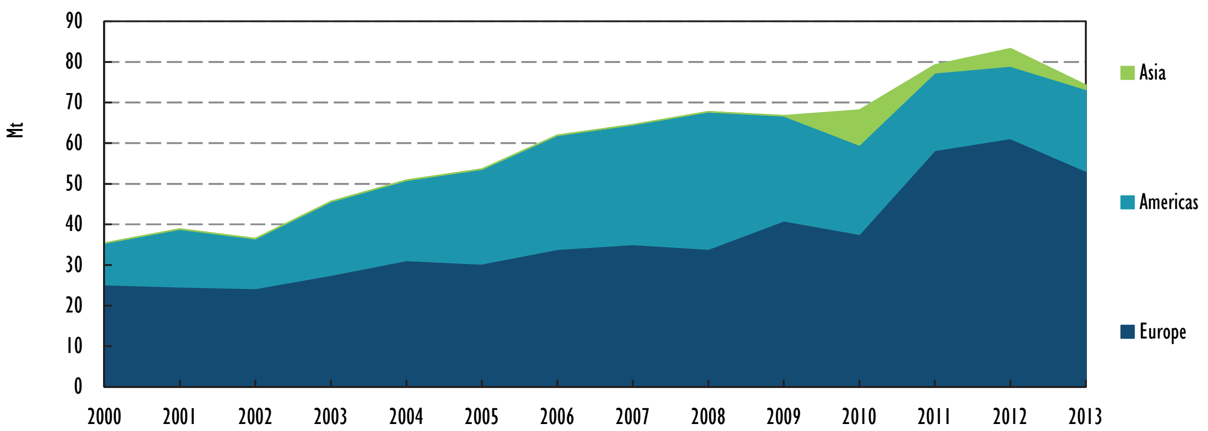
United States' thermal coal exports to Europe have been rising since 2010, which has since been their primary thermal coal export destination. Their 2013 exports to Europe declined slightly, while exports to Asia and other Americas remained stable. Similarly, United States' met coal exports to Europe declined again in 2013, while exports to Asia have increased in significance since 2009 (see Figure 2.3).

Colombia

2013 Columbian coal exports decreased by 9 Mt (-10.8% year-over-year) to 74 Mt. Nearly all Colombian coal exports are thermal, making it the world's fourth-largest thermal coal exporter. Columbia saw a significant drop in 2013 exports due to a 52-day strike between July and September (affecting United States-based mining company, Drummond), a month long strike in February at the Cerrejon mine (owned jointly by BHP Billiton, Anglo American and Glencore) and a suspension of coal loadings by Drummond in February. Rebel attacks on the railway infrastructure serving the Cerrejon mine also led to disruptions in 2013 coal deliveries. Additionally, Colombian Natural Resources' (CNR) La Francia mine halted operations for almost all of 2013 following allegations from former contractor Consorcio Minero del Cesar concerning back payments. Operations at Puerto Drummond were halted in the first quarter of 2014 due to a delay in the installation of a compulsory direct loading system. Despite this initial setback, 2014 exports are expected to increase significantly compared to 2013.

Colombia traditionally exports coal to Europe and the Americas. In 2013, more than 70% of Colombian exports were to Europe and 27% to the Americas. While 2013 exports to Europe decreased, exports to the Americas increased year-on-year; exports to Asian markets remained low.

Figure 2.4 Development of Colombian export destinations, 2000-13



Source: McCloskey (2014), *McCloskey Coal Reports 2000-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

South Africa

South Africa, the world's fifth-largest thermal coal exporter, exported approximately 72 Mt (-3 Mt compared to 2012) in 2013, nearly all of which is thermal coal. Once primarily an exporter only to the European market, South Africa now supplies both the Atlantic and Pacific markets due to its geographic location. The percentage of South Africa's total coal exports sent to the Pacific has grown from less than 10% in 2003 to approximately 50% in 2009 and over 75% in 2013. Larger demand in China and India, and competitive suppliers to Europe from Colombia and the United States, made it more profitable for South Africa to focus their coal exports on Asia, where prices are higher. Additionally, the Asian marketplace (particularly India and China) is generally more tolerant of

5 500 kcal/kg grades or less. Although South Africa previously exported only 6 000 kcal/kg, the lower-grade coal market is increasingly better-suited to South Africa's remaining lower-grade reserves and resources. Currently, a significant portion of South Africa's lower-grade coal goes to the Indian market.

Canada

Canadian 2013 coal exports grew by 5.1%, from 35 Mt in 2012 to 37 Mt. The majority of Canadian exports come from met coal (+7.7% to 33 Mt), making Canada the world's third-largest met coal exporter. Canadian coal exports are mainly destined for Asian markets, with the majority of 2013 exports shipped through major ports such as the Westshore Terminals or the Neptune Bulk Terminals.

Other countries

Exports from **Poland**, OECD Europe's largest coal exporter, increased by 53% year-on-year, to 11 Mt in 2013, 9 Mt of which is mostly thermal coal destined largely for the European market. Despite an uncompetitive Polish mining sector, and large stockpiles during the past year, a few mines, such as Bogdanka in Lublin Basin, have been able to export in a competitive way. As of mid-2014, several mines were temporarily idled in order to reduce production and costs.

Exports from the **Czech Republic**, the second-largest coal exporter in OECD Europe behind Poland, decreased slightly to 6 Mt in 2013.

Coal exports from **Mongolia**, primarily destined for China, dropped nearly -30% from 2012 to 18 Mt. Met coal exports, which comprise the bulk of Mongolian coal exports, fell to 15 Mt. With no railway infrastructure, and production regions near the Chinese border, all Mongolian coal exports are transported by truck to China.

In **Viet Nam**, the state-owned coal producer Vinacomin exported almost 20% less coal in 2013 than in 2012. The company is under pressure from the Vietnamese government to curtail coal exports, as a way to preserve domestic resources to meet internal demand. Overall 2013 exports, which are typically anthracite rank, dropped by 21.1% to 12 Mt. These exports primarily went to China, and to a lesser extent, to Japan and Korea.

Mozambique, once identified as the world's next major coal exporter, exported 4 Mt in 2013, up 1 Mt from 2012, their first year of notable exporting. Mozambican exports face important challenges, as coal deposits are far from the ports, rail is not properly developed and the Mozambican government has prohibited barging coal on the Zambezi River due to environmental concerns. Moreover, Rio Tinto has sold its Mozambican assets.

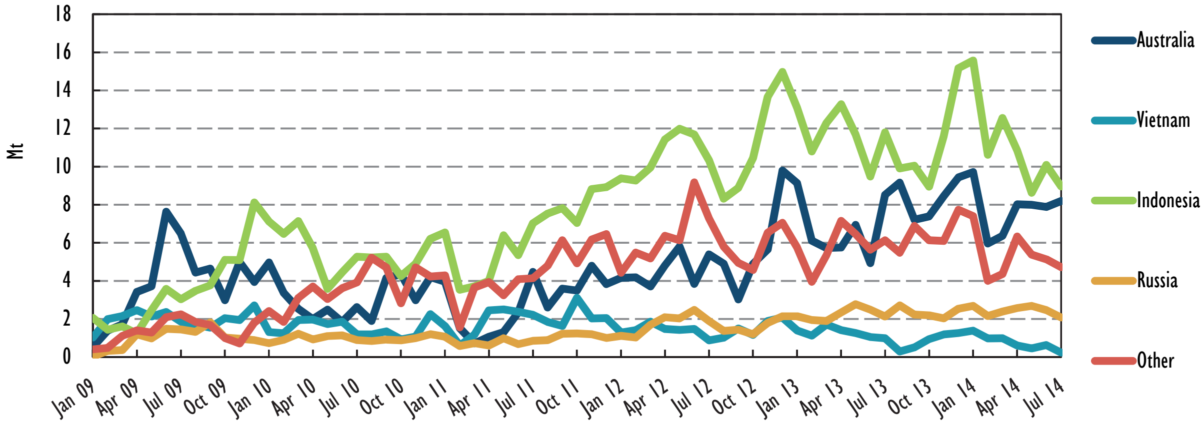
Importers

China

Chinese 2013 coal imports grew by 13.2% to 341 Mt, making China again the world's largest coal importer. Incremental import volumes to China were 40 Mt, more than 55% of total 2013 global incremental imports. Chinese met coal imports grew by a notable 43.7% to 77 Mt; thermal coal imports grew by 6.6% to 264 Mt, which is approximately 77% of total Chinese coal imports.

Since 2011, Indonesia has been the primary supplier of Chinese coal (see Figure 2.5). However, China has recently favoured importing higher-quality coal, benefitting Australian suppliers. Australia, the primary supplier (40%) of China's met coal imports, had a significant 7 Mt increase (to 30 Mt) of 2013 met coal exports to China. Mongolia's overland met coal exports to China have decreased year-on-year to 15 Mt, although Mongolia remains China's second-largest met coal supplier.

Figure 2.5 Evolution of monthly Chinese coal imports, 2009-14



Source: McCloskey (2014), *McCloskey Coal Reports 2000-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

Japan

Without significant domestic coal resources, Japan is dependent upon imports to meet its coal demand. Japan is the second-largest coal importer in the world behind China, and was, until it was surpassed by China in 2013, the world's largest seaborne met coal importer. Overall Japanese imports totalled 196 Mt, up 12 Mt from 2012, divided between thermal coal (142 Mt) and met coal (54 Mt). 2013 Japanese thermal coal imports increased by 7.7% due to higher coal-fired power generation, and met coal imports increased by 3.1%, returning to 2011 levels.

Australia is Japan's biggest supplier for met and thermal coal, accounting for over 65% of Japan's total coal imports. Australian exporters have an advantage over Indonesian suppliers (the second-largest exporter to Japan), as Japanese power plants typically prefer coal with high calorific value.

India

Indian coal imports increased strongly in 2013, up by 10.1% to 180 Mt, and divided between thermal (80%) and met coal (20%). In relative terms, import growth has been almost equally strong for both coal types. Indonesia remains the primary supplier for Indian thermal coal imports; Australia is the primary supplier (82%) for Indian met coal imports.

Indian import increases are based upon a higher domestic demand than domestic production can match. Their import growth slowed, however, in the second half of 2013 as the Indian rupee depreciated against the US dollar, increasing the cost of coal imports, while power plants continued to reduce their stockpiles. Strong hydropower generation further reduced the Indian power sector's demand for coal.

Korea

Korea's 2013 coal imports increased by 2 Mt over 2012 to 127 Mt, divided between thermal coal (95 Mt) and met coal (31 Mt). Similar to Japan, Korea is mostly dependent upon imports to meet its coal demand. Korea's 2013 met coal imports were slightly lower than in 2012. Australia supplies the largest amount of Korea's coal imports, followed by Indonesia and Russia.

In 2014, a new Korean coal tax will probably shift coal importers towards higher calorific value coal. Korean utilities are typically designed for 5700 kcal/kg coal, which favours Australian coal. However, Korea has begun blending Australian and Indonesian coal (see the section entitled "Prices" in this chapter for a discussion on quality arbitrage).

Europe

Overall coal imports by OECD Europe slightly decreased (-1.9%) in 2013 to 253 Mt. Comparing import data country-by-country, however, shows rather diverse statistics. Low carbon emission prices benefit German and United Kingdom coal imports, while strong hydropower generation has reduced Spain and Italy's coal-fired power generation and import needs. Coal imports to the **Netherlands** and **France** increased in 2013.

Germany is the largest coal importer in OECD Europe, with 2013 import increases of 2.9% to 51 Mt, driven by thermal coal (+3 Mt to 43 Mt) while met coal imports decreased (-2 Mt to 8 Mt). Russia, Colombia and the United States are the primary suppliers of German overall coal imports; Poland provides Germany with significant thermal coal supplies; and in 2013, Australia became Germany's primary met coal supplier, surpassing the United States.

The **United Kingdom** is the second-largest coal importer in OECD Europe, with 2013 imports growth of 10.2% to 49 Mt. The UK showed a 2013 increase in both thermal and met coal imports, as domestic production decreased due to mine closures and unfavourable mining conditions at the remaining mines.

Coal imports to **Spain** and **Italy** decreased strongly in 2013. Imports to Spain were down by nearly 40% (-9 Mt), and imports to Italy decreased by almost 18% (-4 Mt). While decreases in Spanish thermal coal imports accounted for their entire decline, in Italy both thermal and met coal imports declined strongly.

Turkey's 2013 coal imports decreased by 4.8% (-1 Mt) to 28 Mt, caused by decreased thermal coal imports while met coal imports increased by 1 Mt to 6 Mt.

Other countries

Imports by **Chinese Taipei** grew by 5.3% (+3 Mt) to 68 Mt in 2013, making it the fifth-largest coal importer in the world. The bulk of its imports come from thermal coal (+2 Mt to 61 Mt). Indonesia and Australia are the primary suppliers of Chinese Taipei's thermal coal, while their met coal supplies (+1 Mt to 7 Mt) are entirely provided by Australia.

Russian coal imports decreased by 4 Mt to 26 Mt in 2013. These are thermal coal imports from Kazakhstan, a legacy from the Soviet times.

Malaysia imported 23 Mt of thermal coal in 2013, up 1 Mt from 2012. All Malaysian imports come from thermal coal (for more recent trends and an outlook on Malaysia see Box 3.4).

Brazil's overall coal imports increased by 2 Mt to 18 Mt in 2013. Their met coal imports, supplied primarily by the United States, remained at 11 Mt, while their thermal coal imports, supplied by Colombia, Russia and Canada, increased to 7 Mt.

Coal trading

Coal markets are very dynamic with changing trends in terms of 1) the quality of seaborne traded coal, 2) the traded flows, and 3) how coal is traded and priced. The *Medium-Term Coal Market Report 2011* mentioned a new trend of significant international trading in low calorific coal. Now that this trend has consolidated, there are new price indices such as API3 (FOB price for exports from South Africa), API5 (FOB price for exports from Australia) and API8 (CFR price for imports to China) for 5 500 kcal/kg coal, compared with the traditional API2 (cost insurance freight [CIF] price for imports to Europe), API4 (FOB price for exports from South Africa) and API6 (FOB price for exports from Australia) price indices for 6 000 kcal/kg coal. Indonesian exports are mostly low calorific coal. Argus assessments for Indonesian coal are ICI1 (6 200 kcal/kg), ICI2 (5 500 kcal/kg), ICI3 (4 600 kcal/kg), ICI4 (3 800 kcal/kg) and ICI5 (3 000 kcal/kg).

China is a primary destination for low calorific coal, but other countries, such as India and Korea, also consume it. For a number of years there has been talk of potential bans upon both the export of low calorific Indonesian coal and upon the import of low quality (including low calorific, high ash and high sulphur) coal to China. After so many rumours, the Chinese government has decided to address this issue (see the section on China in Chapter 4).

Another proof of coal market dynamism is found in Poland, where the Industrial Development Agency and the Polish Power Exchange started publishing domestic steam coal price indices in October 2014. Poland, a large producer and consumer of coal, has a substantial domestic market in which prices are linked to international indices. However, the link is weak due to the differences in quality when comparing variations in Polish hard coal, including very high calorific value (destined for export), high calorific value (imported hard coal and domestic coal for the industrial and residential sectors), and lower calorific value (domestic coal for power generation). And of course, all prices are influenced by the coal's sulphur content. Therefore, improved transparency in price formation is needed in the domestic sector. This is why Poland launched two indices, one for steam coal for power plants and the second for steam coal for industrial consumers, including specifications for quality and delivery terms.

Changes to how coal is contracted are occurring most notably in China, but it is important to take a look at other, primary regions since *MTCMR 2013* did not address this topic. In the Pacific market, Japan, and to a lesser extent, Korea and Chinese Taipei rely on term-based contracts, typically yearly, for most steam coal procurement with the balance purchased on a spot basis.

In Europe, where the 1996 liberalisation of electricity prohibited the passing of costs through to consumers, spot deals are in the majority, with wide use of derivatives and hedging options. Poland, where domestic supply is still dominant, is an exception, with long-term contracts still playing an important role. Of course, lignite follows a different pattern, as most of it is both mined and consumed by integrated companies, generally utilities such as RWE, Vattenfall or E.On in Germany or PGE in Poland.

In the United States, domestic coal sales in a market of over 800 Mt have historically been settled on longer-term agreements. Recently there has been a trend towards shorter-term sales, particularly steam coal. This shift, as noted in last year's report, could be attributed to multiple factors, but low natural gas prices and lower or uncertain demand for coal is likely a contributing factor. Notably, during some periods of 2013 more than 12% of procurements were on a spot basis, more than double the levels from 2011. This is seen most in the Central Appalachian region. In the Powder River Basin and North Appalachian regions, where coal is competitive even with low natural gas prices, contracts are still in excess of one year. Met coal tends to be sold to US steelmakers under contracts with a one-year term, while export deals tend to be either on spot, monthly or quarterly. Despite this shift, over 80 % of coal used in US power generation is purchased under multiyear contracts.

30% of South African exports are on long-term contracts, although this percentage has been declining for a number of years. Short-term contracts and spot sales make up the balance in equal proportions. The domestic South African market is quite different, as Eskom is seeking to secure its supply and avoid short-term and spot market deals. Occasionally, however, they can procure coal destined for export, at which time Eskom consumes raw coal rather than washed and pays an export parity price, adjusted for yields, for processing and transport costs. On average, South African domestic coal is approximately 4 600 kcal/kg, much lower than that of 6 000 kcal/kg exported coal, thus limiting price linkage.

In Russia, pricing in the domestic market for steam coal varies for lignite, hard steam coal and high-grade coal. Prices for lignite are based upon the level of competition between providers in selected markets rather than the export prices. The prices for hard coal are similar to the level of export netback with recalculation of calorific value. All contracts involving more than 1 million tonnes must be reported to one of the commodity exchanges.

In India most coal is supplied by public companies, primarily Coal India Limited, through Fuel Supply Agreements (FSA), a type of long-term contract with prices decided by the government based upon coal quality. However, other options include non-FSA for small quantities; captive blocks, in which private and public coal-consuming companies such as power, iron and steel, and cement producers, as well as more recently, coal gasification projects, can produce coal for their own consumption; e-auctions, that improve transparency and price discovery, and help create a market; and imported coal that comes through contract and spot purchases.

In China, after the full liberalisation of the coal sector in January 2013, coal trade has changed radically. In order to promote competition and improve market working, the government settled 31 coal trading hubs, most with the support of regional authorities. There are, however, a number of difficulties facing those centres: many cannot offer essential services such as rail; Shenhua set up its own trading platform, which sold more than 90 Mt from June to December 2013, thus lowering volumes traded in the coal hub in Ordos, Inner Mongolia, where Shenhua is its largest producer; in Shanxi, regional authorities have requested coal companies to join the China Taiyuan Coal Transactions Centre and use that platform for their trades. Despite full liberalisation, state- and province-owned companies are dominant, maintaining the government involvement in the sector. Recently, rumours of a new policy to cut domestic coal production and orders to state-owned producers to do so demonstrate the continued involvement of the Chinese government.

Coal derivatives

After the big drop in 2011 followed by modest increases in 2012, the volume of coal derivatives is estimated to have surpassed the 3 billion tonnes level for the first time in 2013. Futures make up the majority, although options are increasing their share, from almost nothing a couple of years ago to more than 10% in 2013. API2 contracts, which were more than 2 billion tonnes, again accounted for the bulk of contracts. API4 continues to be the second-largest used index, with contracts close to 0.5 billion tonnes. In the United States, coal derivatives trade increased, probably linked to increasing spot deals and exports to Europe, where API2 liquidity creates a favourable trade environment.

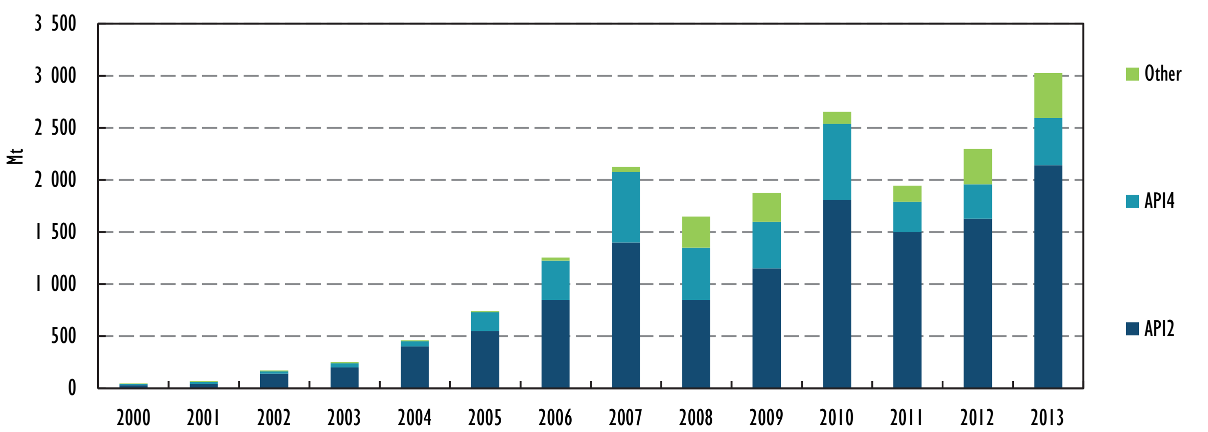
Despite the current small size of the coal derivatives market in Asia, there is tremendous potential. This is based firstly upon the size of Asian markets as compared to Europe, and beyond that upon the opening of the China market, encouraging many Chinese participants to use financial instruments for risk management and hedging. As the churn ratio (derivatives trade volume divided by physical trade volume) in the European market is over 10, if one applies that ratio to the imports to China and India the result is near 5 billion tonnes. Moreover, the size of domestic markets in China and India is 5 billion tonnes of physical trade, and this shows a great potential in these countries. However, derivatives are unlikely to be used at large scale in the near term. Nevertheless, there are some indications about future interest in these markets. On 4 August, yuan-denominated coal swaps linked to the government-run Bohai Rim index debuted in the Shangai Exchange market. Some of the largest state-owned companies, such as Shenhua, Yanzhou or China Coal, which had not participated in derivative trading in China previously, began to do so this year.

The recent increase in coal derivatives in Asia is largely based upon API8 linked swaps, hence referred to coal of 5 500 kcal/kg. This calorific value is more adequate to hedge coal traded in Asia than assessments made based upon 6 000 kcal/kg indices, such as API2 or API4. Derivatives based upon API3 and API5, other 5 500 kcal/kg indices, can be also traded in different markets.

While new, available indices are increasing, it is unclear whether most of them can support derivatives development, as these require transparent markets and liquidity, or, conversely, the bulk of derivatives might be linked to very few indices because there is not enough volume to keep liquidity in so many indices.

Coking coal derivatives are still very new and they need time to mature. For example, the Chicago Mercantile Exchange announced that the volume of coking coal swaps it cleared in January 2014 was larger than those it cleared in all of 2013. With more deals made on spot basis and increasing volatility, producers might try to hedge their production. Moreover, the need to hedge the entire chain of steel production, including iron ore, coking coal and freights, will develop coking coal derivatives. In fact, traded volumes are increasing and some other exchange houses have announced plans to launch coking coal futures. Developments on iron ore swaps are also important in furthering the development of the coking coal derivatives trade.

Figure 2.6 Development of trade volumes for coal derivatives, 2000-13

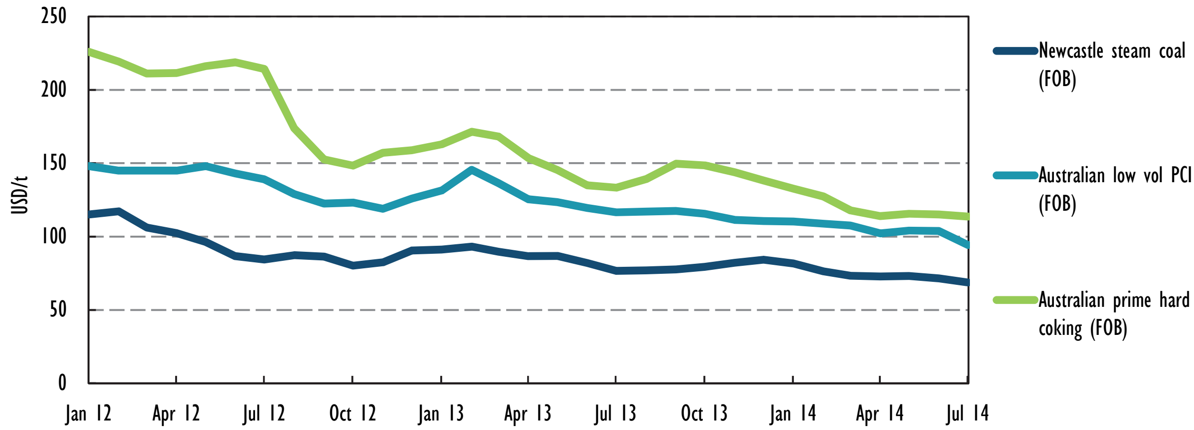


Note: API = Argus McCloskey's Coal Price Index.

Prices

As explained in past issues of the *Medium-Term Coal Market Report*, coal is a heterogeneous product with a wide variety of coal types and classifications. There are a number of coal markets and coal prices. Figure 2.7 illustrates the development of three Australian coal export price markers between 2012 and 2014. Each price marker represents a different coal product, such as steam coal, low volatile PCI coal and prime hard coking coal. Since each product is different, different market dynamics drive their prices. What all price curves have in common, however, is that their downward trend has remained steady since 2011, irrespective of coal type, as the market for coal has generally remained oversupplied.

Figure 2.7 Development of coal marker prices for different types of coal, 2012-14



Source: McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

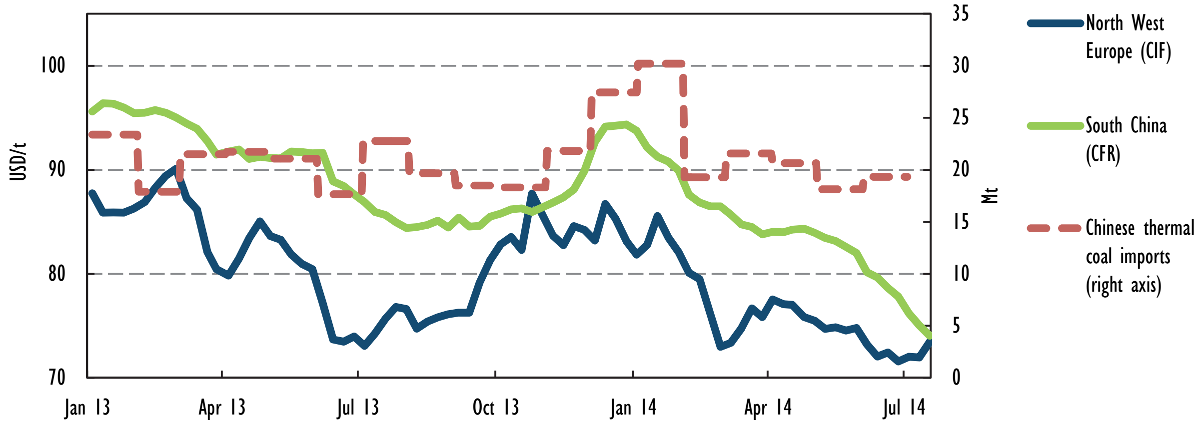
Australian prime hard coking coal price, for example, at USD 114/t as of July 2014, is only one-third its price from March 2011, and only half the price from January 2012. The price decrease for Australian low volatile PCI from USD 148/t to USD 94/t is not as dramatic as for prime hard coking coal, but nonetheless significant. The Newcastle steam coal free-on-board (FOB) price has decreased additionally, from USD 93/t in February 2013 to USD 69/t in July 2014, a five-year low.

Seaborne thermal coal prices, regional and quality arbitrage

International prices for seaborne traded thermal coal have remained weak through July 2014 (see Figure 2.8). The Cost Freight (CFR) price marker for South China had been declining in 2013, from USD 97/t in January to USD 84/t in August as Chinese producers cut coal prices to protect their market share, thus influencing international coal prices. Following a temporary upswing in winter 2013/14 to USD 94/t, led by leading Chinese coal producers who increased their coal prices ahead of annual contract negotiations between major coal consumers and suppliers, prices dropped below USD 75/t in July 2014. European coal prices moved similarly but at a generally lower level. The Amsterdam Rotterdam Antwerp (ARA) cost, insurance and freight (CIF) price, which had already declined by USD 52/t to USD 73/t between September 2011 and July 2013, dropped to USD 71/t in July 2014. Coal in Europe has not been this inexpensive since the economic crisis in autumn of 2009.

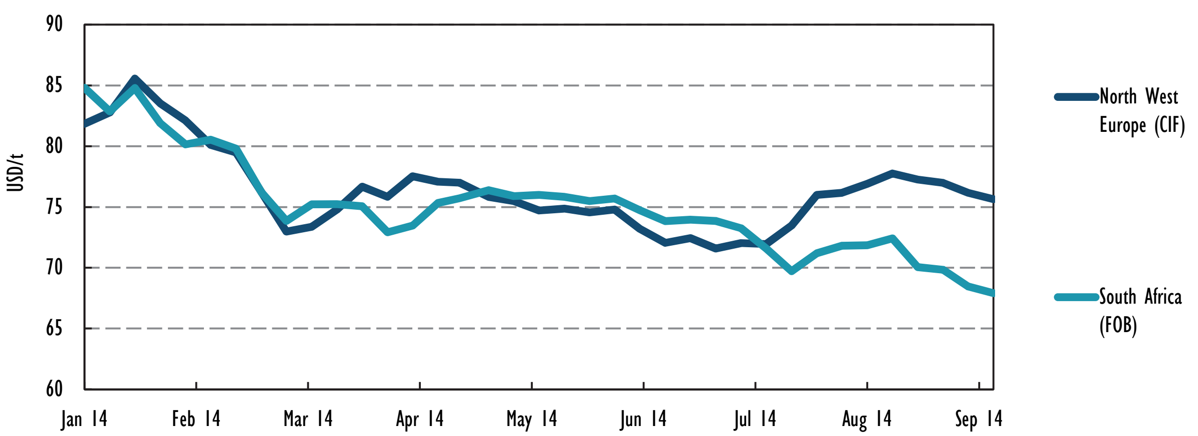
As of August 2014, the ARA CIF price began to increase following a trend shift in European coal buyer's behaviour away from Russian coal and towards other import sources, and as South African coal increasingly reached Europe. Spreads between the ARA CIF and South African coal prices increased, nearing the freight cost level for coal from South Africa, which is similar to the time when South African coal set European coal prices, which were prices at South African FOB price plus freight cost from Richards Bay/South Africa to Europe.

Figure 2.8 Thermal coal price markers in Europe and Asia, 2013-14, and monthly Chinese imports



Source: McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

Figure 2.9 Thermal coal price markers in Europe and South Africa, 2014



Source: McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

The fundamentals of demand and supply have not changed qualitatively within the past three years. Although demand for seaborne thermal coal imports continues to grow, there is no upward trend in price. This indicates market oversupply. Comparing thermal coal exports between 2011 and 2013, Australia has increased exports by 38 Mt, Indonesia by 70 Mt, the United States by 13 Mt, Russia by 8 Mt and South Africa by 5 Mt. Even lower than expected Colombian exports in 2013 due to strikes, transport disruptions and terrorist attacks did not alter the picture substantially.

It seems clear that international seaborne thermal coal trade is currently characterized by oversupply. However, short-term and region-specific events can cause upward and downward price reactions. One example from Europe: in winter 2013/14 ARA CIF coal prices started to increase, reaching levels above USD 85/t. At this time, the market reflected concerns regarding Colombian supply disruptions expected for Q1 2014. And in fact, the Colombian government halted coal exports by Drummond at the beginning of 2014 after the company had failed to complete building a direct ship loading facility in order to reduce coal dust emissions. Consequently, the market had to attract, on short term, 6.5 Mt of missing supplies with higher prices. When opening of Drummond's new port in April 2014 approached, market prices began to soften.

Another example from China: Chinese utilities act as arbitrageurs. Depending upon price levels, either domestic or international coal is demanded more. Given its size (approximately 1 billion tonnes of domestic and foreign coal are shipped to the east coast of China), both domestic and international prices are sensitive to this arbitrage. The red dashed line in Figure 2.8 shows China's monthly thermal coal imports. Import demand had been extraordinarily strong in December 2013 and January 2014, with total monthly imports of 28 and 30 Mt respectively. Figure 2.8 suggests that this increased import demand pushed prices up and broke the downward price trend temporarily. When imports fell back to previous levels, prices started to decrease.

Except for certain specific demand or supply events, Figure 2.8 confirms that Chinese and European prices exhibit a long-term relationship. Both markets are connected via coal exporters, foremost South Africa and Russia, but also Colombia, whose geographical location and rather low FOB costs enable arbitraging between Asia and Europe.

Arbitrage opportunities are illustrated in Figures 2.10 and 2.11.[4] Figure 2.10 shows North West European (ARA) CIF prices as well as the costs of Colombian, South African and Russian coal supplied to Europe, assessed as their respective FOB prices plus sea freight costs. Figure 2.11 depicts the Qinhuangdao FOB price plus sea freight along the Chinese coast and Value Added Tax (VAT), serving as a price indicator for South China. Additionally, Figure 2.11 shows costs for Colombian, South African and Australian coal supplied to South China, assessed as their respective FOB prices plus freight costs plus import tax.

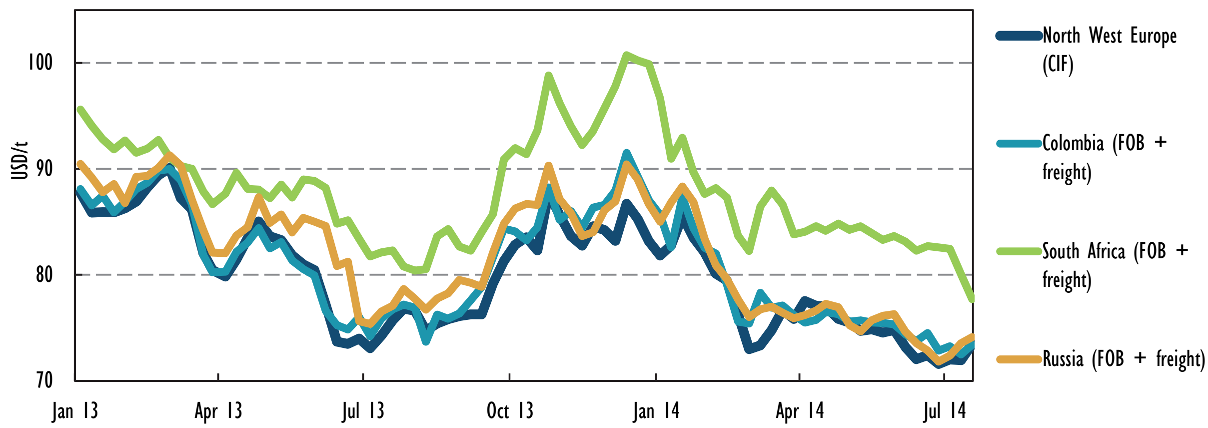
Figure 2.10 shows how the cost of Colombian and Russian coal in Europe is similar, and close to ARA CIF price. As Colombian coal is more competitive than Russian in Europe, the latter is the marginal supplier to Europe and sets prices, irrespective of Colombia's importance for European prices as the largest supplier to Europe. As suggested by Figure 2.11 regarding the period surrounding July 2013, Colombia sometimes also trades competitively in the South Chinese market, leading to an upward trend in European prices and a downward trend in Chinese prices. The main players and price drivers in the South Chinese market are South Africa and Australia along with domestic Chinese producers. Being able to deliver coal competitively to Europe and sometimes also to South China, Colombia provides a further connection between the Asian and European coal market, aside from the connection provided by South Africa and Russia, swing suppliers to both markets due to their geographical position.

In Figure 2.11, the costs of Colombian coal in South China (and therefore indirectly the Colombian FOB price) seems to adapt to whichever coal has the higher costs in South China. This movement was particularly apparent in both the first half of 2013, when Colombian coal seemed to follow Australian coal, and the first half of 2014, when Colombian coal seemed to follow South African coal. One explanation for this finding could be that Colombian coal exporters are able to obtain prices in Europe slightly higher than the market price in China. Thus, when Chinese coal prices decrease, Colombian FOB prices (and thus the cost of Colombian coal in Europe) follow that descent. In other words, Colombian

4 Not all arbitrage opportunities shown materialize in physical trade flows as the figures abstract from contractual obligations and quality restrictions in the markets.

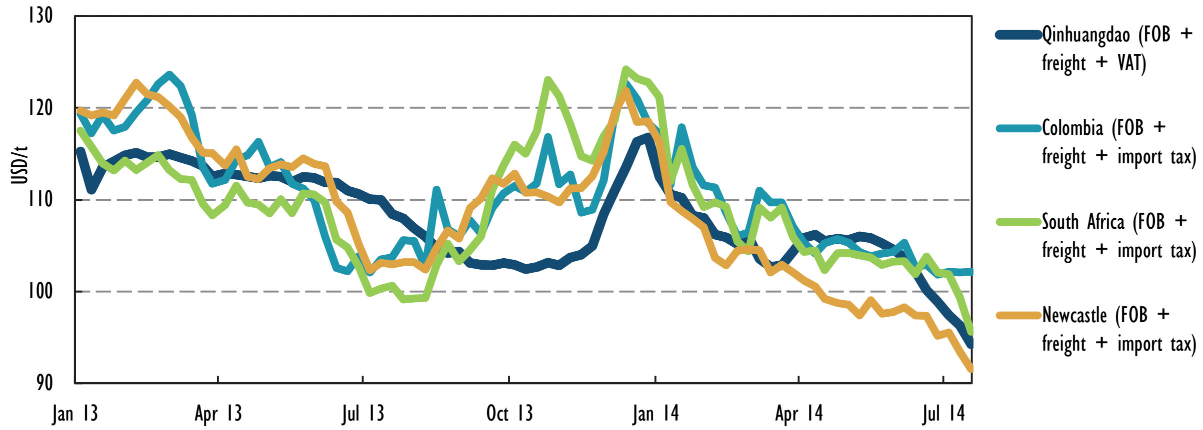
exporters include the opportunity costs of delivering coal to China into their prices – so that the Colombian arbitrage opportunity to China connects the Asian and the European coal market (see Box 2.1).

Figure 2.10 European coal prices, 2013-14



Source: McCloskey (2014), McCloskey Coal Reports 2010-2014, McCloskey's, London, http://cr.mccloskeycoal.com.

Figure 2.11 South China price markers (FOB plus freight plus taxes), 2013-14



Source: McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

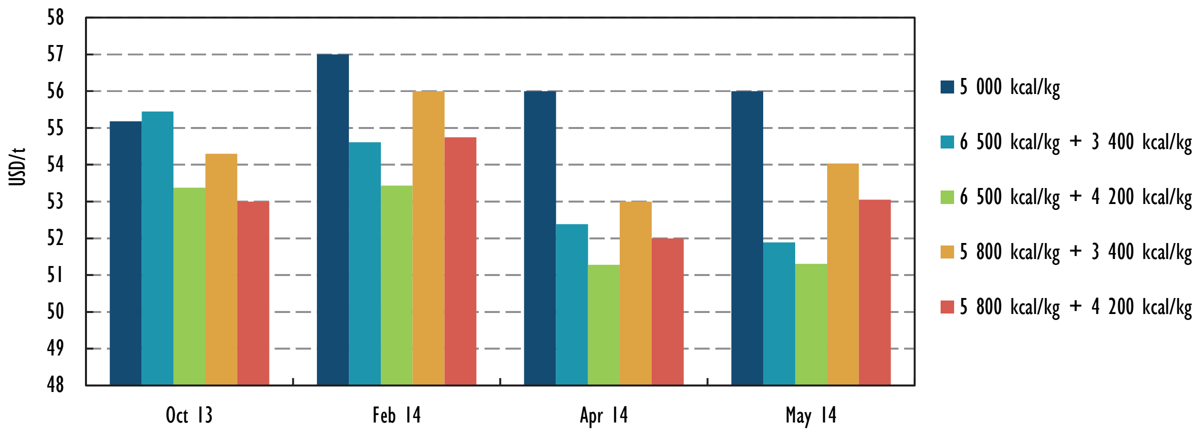
South Africa is the primary connection between the Asian and the European coal markets. Figure 2.11 shows that the cost of South African coal in South China (and therefore the South African FOB price) is driven by competition between Australian and Chinese coal. Since coal prices in Asia are higher than in Europe, and freight costs from South Africa to Europe and Asia are similar, the cost of South African coal in Europe is higher than the European price. Figure 2.10 illustrates that since 2013, the difference between the two was between USD 7/t and USD 10/t. Despite that difference, South African coal prices influence European prices. In March 2013, for example, the cost of South African coal in Europe was similar to that of Russian and Colombian coal. Subsequently, the European price and the costs of Russian and Colombian coal in Europe declined. Similar situations could be observed in May 2013 and February 2014. These examples and the similar movement of South African coal and the ARA CIF price illustrate the regional arbitrage potential of South African producers.

Although the cost of South African coal in Europe is well above European prices, South Africa exports significant coal volumes to Europe. In 2013, South Africa exported more than an average 1.5 Mt per month to Europe. Coal market players occasionally see trading opportunities for South African coal in Europe, for example in the case of supply shortages such as the aforementioned case of Colombian coal exporter Drummond. Other explanations might be: contracted coal with negotiated prices, coal that has been purchased through forward trading or issues concerning coal quality.

Apart from regional arbitrage, there is also arbitrage between coal qualities; however, this is not well-developed, partially due to difficulties in blending. Figure 2.12 illustrates the arbitrage opportunity from blending coal of different calorific values in Indonesia: the price for a tonne of coal, which has a calorific value of 5 000 kcal/kg, serves as a reference. The other bars in the figure show the costs for coal required as an input to produce 1 t of 5 000er coal by blending coal of different calorific values. The green bar, for example, represents the coal costs of mixing 6 500 kcal/kg coal with coal of 3 400 kcal/kg at proportions to get 1 t of 5 000er coal. This figure does not consider blending costs, but shows how different coal quality prices move independently, generating arbitrage opportunities. Of course, besides coal costs, the blending itself creates costs. The lower these costs, the higher the potential arbitrage is between coal qualities.

For example, if the price difference between 3 400er coal and 5 000er coal becomes too great, coal blending using 3 400er coal and another higher calorific coal becomes economical. Thus, demand for 3 400er coal would increase while the price gap for the 5 000er coal would decrease. As Figure 2.12 shows, the non-blended 5 000er coal exhibits the highest prices; the coal input costs for blended 5 000er coal costs least. If the difference is greater than the cost of blending, arbitrage between blended and non-blended coal is economical.

Figure 2.12 Costs of coal for different varieties of coal blendings of 5 000 kcal/kg

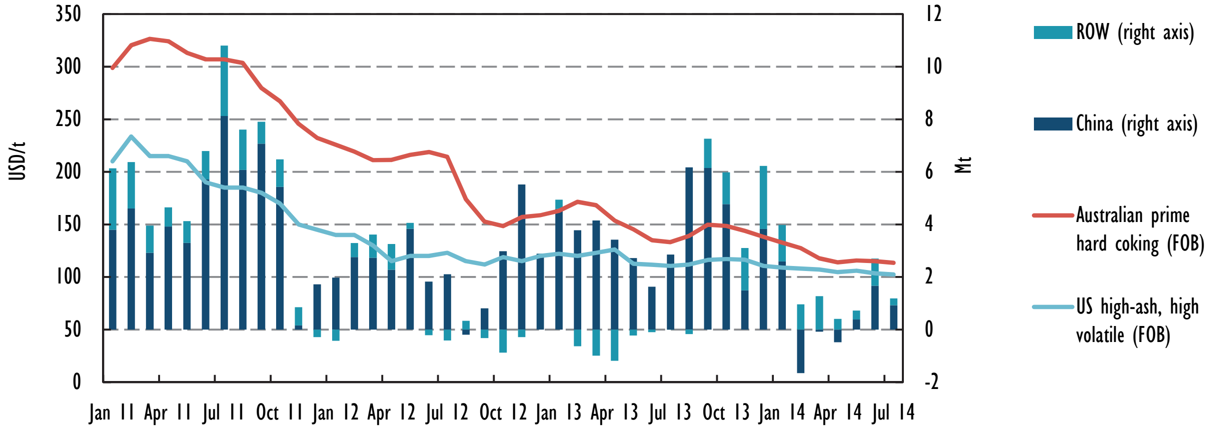


Seaborne met coal prices

The trend of falling met coal prices that began in 2011 continued through 2013/14, as illustrated in Figure 2.13. The price of Australian prime hard coking coal was at a record high in March 2011 at USD 330/t, and then plummeted. In March 2012, the marker price stood at USD 211/t, USD 148/t in October 2012 and USD 133/t in July 2013. Since then, the price of Australian prime hard coking coal has lost another USD 20/t within 12 months. The United States' high ash, high volatile coking coal price has also declined, but not as strongly, since their prices decreased by only USD 8 between

July 2013 and July 2014. Notably, the price premium for Australian prime hard coking coal over US high ash, high volatile coal has almost disappeared.

Figure 2.13 Development of met coal prices and monthly year-on-year differences in BFI production, 2011-14



Note: "BFI": blast furnace iron; "ROW"= rest of world.

Source: World Steel Association (various years), *Crude Steel Production*, Brussels, World Steel, www.worldsteel.org/statistics/BFI-production.html; McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

Box 2.1 Cheap coal in Europe: Is China pushing prices down?

Since 2012, Europe has experienced comparably bearish steam coal import prices. A common explanation for the low coal price level is increasing United States coal exports as a consequence of the shale gas revolution in the United States. However, taking into account that other coal-exporting countries can perform arbitrage between the European and the Chinese market, analysis suggests that the Chinese market drives steam coal prices in Europe more than US coal exports.

The standard argument for low coal prices in Europe includes the following: the shale gas boom has caused gas prices in the United States to plummet. These low gas prices increase gas-fired power generation, whereas coal-fired power plants run at lower utilisation rates implying a lower US coal demand. The coal which is not consumed in the United States is exported to Europe and higher US coal exports flood the European coal market and push European coal prices down.

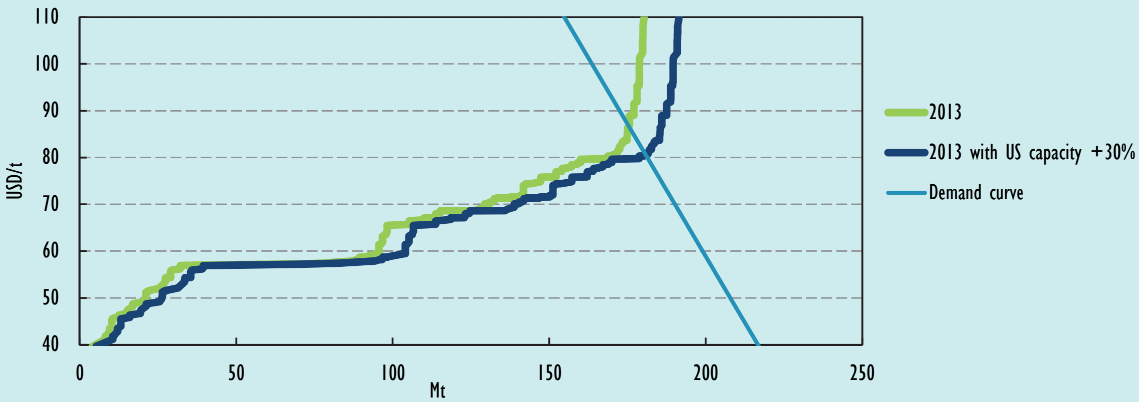
Figure 2.14 illustrates this argument using the example of two CIF* cost curves for coal imports to Europe and a stylised coal demand curve for Europe. The green line shows the cost curve of actual coal suppliers to Europe for the year 2013. The dark blue line also represents the situation in 2013, but assumes a hypothetical increase of US export capacity by 30%. Increasing US coal exports shift the supply cost curve to the right such that the European import price decreases from USD 87/t to USD 80/t. This analysis would reflect the market dynamics correctly if the European coal market was isolated and had no interaction with other coal markets such as the Chinese coal market.

However, coal markets interact: since coal is a bulk good, exporters can ship coal flexibly to other destinations. Thus, if the coal price in Europe is low and higher in Asia, exporters have an incentive to sell their coal in Asia. Given the high arbitrage potential between markets, exporters will optimise their sales by accounting for different sales alternatives. In a simple example, Figure 2.15 illustrates the sales decision of an exporter given regionally separated demand regions.

Box 2.1 Cheap coal in Europe: Is China pushing prices down? (continued)

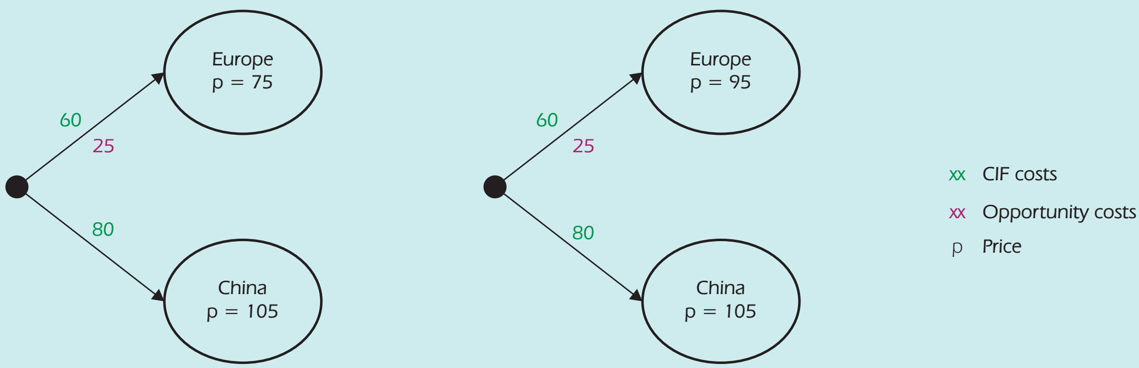
In the first situation, an exporter has CIF costs of USD 60/t to Europe where the coal price is assumed to be USD 75/t. Therefore, each tonne of coal sold would imply a margin of USD 15. Selling coal to China would incur costs of USD 80/t. Assuming a price of USD 105/t in China, the exporter would earn a margin of USD 25/t. Given that the exporter's capacity is limited (either because of rail or port infrastructure or mining capacity), each tonne of coal sold in Europe could not be sold in China. Thus, when earning the USD 15/t margin in Europe, the exporter could not realise the USD 25/t margin in China. When accounting for these so-called opportunity costs, total costs of coal sales to Europe would be USD 85/t and would therefore exceed the market price. Thus, coal would be shipped to China. The second situation shows the opposite: the coal price in Europe would be USD 95/t. When including opportunity costs, coal sales to Europe would incur costs of USD 85/t and hence would be profitable, causing the exporter to sell its coal to Europe.

Figure 2.14 Coal supply costs (CIF) of exporters and import coal demand in Europe



Source: IEA analysis from Wood MacKenzie (2014).

Figure 2.15 A stylised example of a coal exporter's sales decision in a spatial market

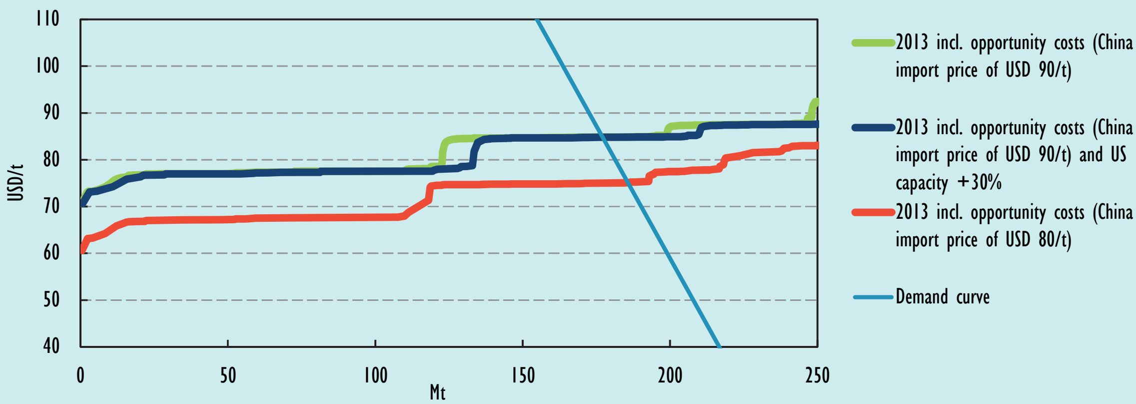


The concept of opportunity costs is next applied to European coal supply cost curves shown in Figure 2.14. Figure 2.16 shows the CIF cost curves (green and dark blue lines), which now include opportunity costs for coal sales to China. Opportunity costs are derived for the 2013 annual average Chinese coal price of approximately USD 90/t. As the figure reveals, a 30% increase of US coal exports again shifts the supply curve to the right, but the price effect would be negligible. The reason for this rather surprising result is that additional US coal exports increase European coal supplies but at the same time crowd out sales of other coal exporters. Given the currently low transport costs, these exporters have the almost equally profitable alternative of selling coal to China, and exports to Europe incur rather high opportunity costs.

Box 2.1 Cheap coal in Europe: Is China pushing prices down? (continued)

If, for example, an additional 20 Mt of US steam coal come to the European market, a similar amount of coal is pushed out of the market towards China. China, which produced and imported approximately 3 300 Mt of steam coal in 2013, faces a comfortable supply situation currently. It is difficult to believe that 20 Mt of additional imports can cause a substantial price reaction. Since increasing US exports do not affect the Chinese coal price, they neither impact European coal supply costs (including opportunity costs) nor European coal prices due to arbitrage.

Figure 2.16 Coal supply costs (CIF) in Europe, including opportunity costs for selling coal to China



Note: The green line always lies above the dark blue line. However, due to formatting issues this is hardly visibly in Figure 2.16.

Source: IEA analysis from Wood MacKenzie (2014).

If, however, the price level in China decreased (for example due to further overcapacities of mines, productivity gains or currency appreciation of the renminbi against the US dollar), the effect on European prices would be much more significant. The red line in Figure 2.16 shows the European coal supply curve (including opportunity costs) given a Chinese coal import price of USD 80/t. The lower price in China decreases opportunity costs for coal suppliers to Europe, which has an immediate impact on European coal supply costs and prices.

Clearly, coal markets in reality are far more complex because of varying coal qualities, long-term supply contracts or market imperfections. Additionally, this analysis aggregates the market dynamics for an entire year, whereas demand and supply vary within a year. Nonetheless, the analysis reveals that limited capacities, opportunity costs and comparably low transport costs connect the European and Chinese coal markets. Therefore, as long as freight costs remain low, additional US coal exports have only a small impact on prices whereas Chinese coal market dynamics influence the European coal price substantially.

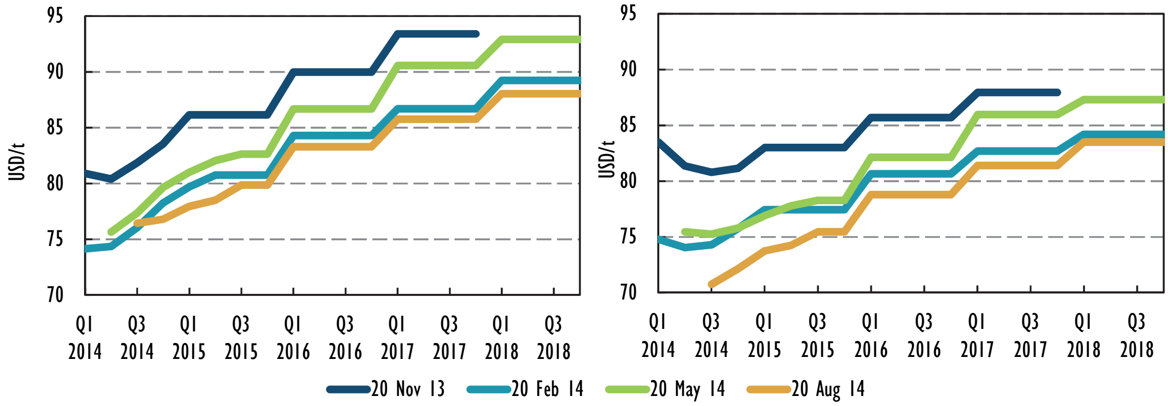
* Costs comprise mining and preparation costs, inland transport costs, port handling costs, royalties and freight costs to Europe. Costs are standardised with respect to an energy content of 6 000 kcal/kg.

Met coal prices in 2013 continued to decrease despite production of BFI, the primary end use of metallurgical coal, increasing between 2012 and 2013. In China, BFI production increased by 46 Mt (+6.9%) while in the rest of the world it increased by 3 Mt (+0.7%). In the second half of 2013 in particular, increasing BFI production induced a temporary upswing in price. Demand growth has been outperformed by the growth in global met coal supply capacity, triggered by high met coal prices in 2011. The intense competition of met coal exporters worldwide in addition to Chinese domestic producers has made prices plummet. Early numbers for 2014 indicate a significant slowdown of BFI production growth. This development has pushed met coal prices further downward.

Coal forward prices

Figure 2.17 shows the evolution of forward curves of API2 and API4 indices between November 2013 and August 2014. As mentioned in the "Coal derivatives" section, derivatives linked to API2 and API4 account for most of the global trade. If we compare with charts in former *Medium-Term Coal Market Reports*, we see same trends, such as the spread between API2 and API4 is widening, as it goes from USD 3/t in 2015 to more than USD 5/t in 2018. We also observe, similar to former years, a general contango in the curves, representing generally well-supplied markets. However, during the last months of 2013 and first months of 2014, the market was in backwardation. The explanation lies in the turmoil in Colombia, where Drummonds mining company was banned from exporting from Puerto Drummond in addition to issues in Cerrejón and other producers. Once Colombian exports recover normal levels, the forward curve got back to the usual contango.

Figure 2.17 Forward curves of API2 (left) and API4 (right), 2013-14



Source: McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

Coal supply costs

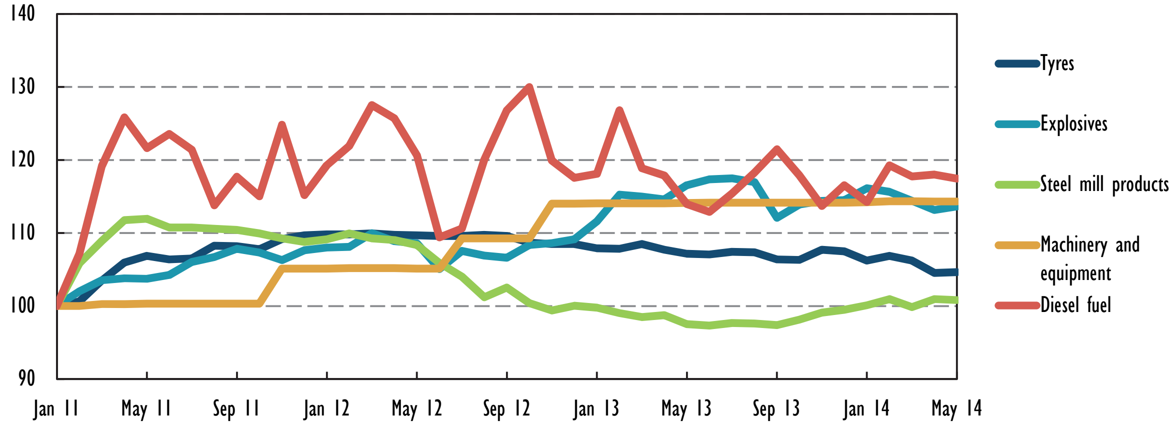
Unlike oil and gas extraction, which are more capital-intensive, the cost focus in coal mining is on variable costs rather than investment costs. The variable costs of coal supply comprise costs of mining, costs for inland transportation, port fees, seaborne transport costs in addition to taxes and royalties. Further, currency exchange rates and their development play a crucial part in determining relative cost competitiveness of coal producers and therefore have a strong influence on the international coal trade.

Development of input factor prices

Variable costs, often referred to as mining cash costs, comprise costs for material, costs of labour and other costs such as royalties or costs for outside services. Mining costs account for the largest share in coal supply costs in most coal-exporting countries. The breakdown of costs depends upon the country as well as the geological conditions and the mining methods applied. Costs for material generally account for more than 50% of a mine's cash costs. In countries with particularly low labour costs, such as Indonesia or Colombia, this share might rise to approximately 75%. Internationally traded inputs to coal mining such as diesel fuel, steel mill products, explosives, tyres and machinery mostly follow global price trends, even though local distortions (for example fuel subsidies) may exist. Other inputs used in coal mining, such as electricity or water, adhere to national price trends.

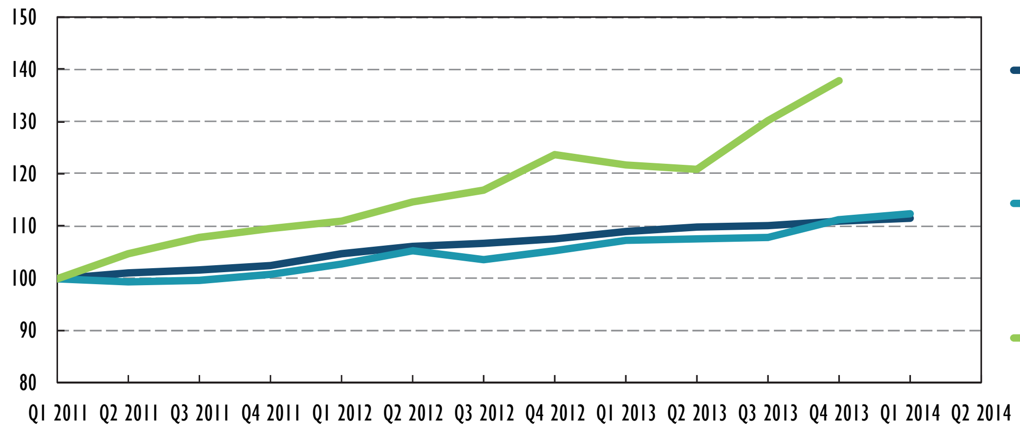
Figure 2.18 shows the indexed price development of selected inputs used in coal mining, which mostly follow international price trends. Prices for diesel fuel are more volatile than other input prices. However, average annual diesel prices have stayed rather stable over the past three years. Average prices for explosives and machinery increased strongly from 2011 to 2013, by more than ten index points each. Prices for tyres and steel mill products, however, decreased over 2013 with a decrease in steel mill products being more pronounced. The average price for steel mill products in 2013 was approximately 11 index points below its 2011 level.

Figure 2.18 Indexed price development of selected commodities used in coal mining



Source: US Bureau of Labor Statistics (2013a), *Producer Price Data Commodity and Industry*, United States Department of Labor, Washington D.C., www.bls.gov/data/.

Figure 2.19 Indexed labour cost development (in local currency) in selected countries

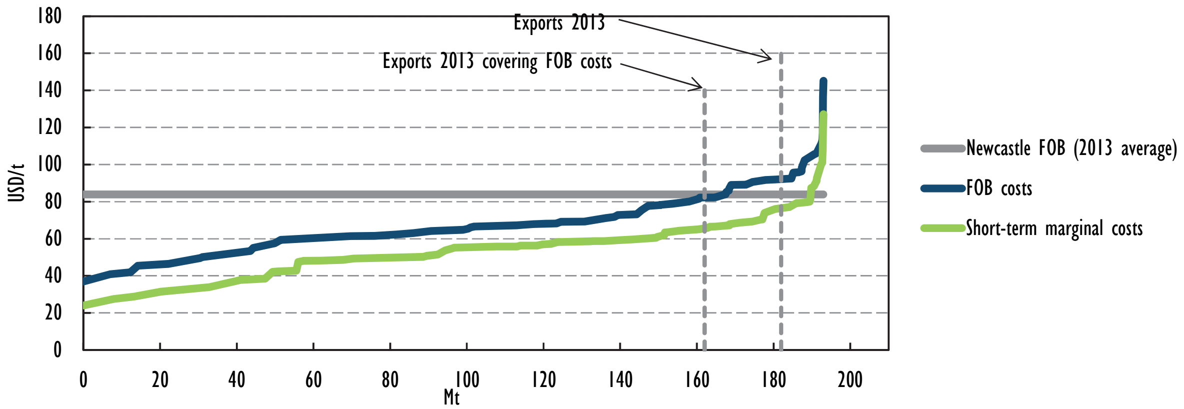


Sources: US Bureau of Labor Statistics (2013b), *Employment, Hours, and Earnings from the Current Employment Statistics survey (National), Industry: Coal Mining (average hourly earnings of all employees)*, United States Department of Labor, Washington, D.C., www.bls.gov/data/; Statistics South Africa (2014), *Quarterly Employment Statistic (QES),* June 2014, Statistics South Africa, Johannesburg, www.statssa.gov.za/publications/P0277/P0277June2014.pdf; Australian Bureau of Statistics (2014), *6345.0 Wage Price Index*, Australia, June 2014, Australian Bureau of Statistics, Canberra, www.abs.gov.au/ausstats/abs@.nsf/mf/6345.0/.

Besides materials, labour costs form one of the largest components in mining costs. Varying between countries and the applied mining technique, labour costs can comprise between 20% and 50% of overall mining cash costs. Labour costs are typically higher in Australia, the United States and Canada when compared to Colombia, Indonesia or South Africa. However, labour productivity is typically higher in the former countries, which at least partially offsets higher labour costs. Labour costs increased most significantly in South Africa in 2013 (+9.6%), whereas growth in the United States (+4.0%) and Australia (+3.5%) was less pronounced.

Cost pressure for Australian coal producers has been widely discussed in previous years. Figure 2.20 suggests that the supply costs of approximately 20 Mt of the 182 Mt steam coal exported from Australia in 2013 were below the 2013 average Newcastle FOB price, so that producers were operating at a loss. Figure 2.20 is a simplified model of reality as time varying FOB prices, coal qualities and contractual details are not mapped. However, there are also economic reasons for producers to sell below FOB prices. Producers are often engaged in take-or-pay contracts, obliging them to pay port fees or to pay for railway transport infrastructure irrespective of usage. Therefore, these cost components should be considered stranded and not part of the short-term marginal costs (green line in Figure 2.20). Another limitation of this model is that not all producers are engaged in take-or-pay contracts. Further, one could argue that labour and machinery costs are also part of stranded costs.

Figure 2.20 Australian steam coal supply cost curves, export volumes and price levels, 2013



Notes: coal volumes, prices and costs are based upon a calorific value of 6 000 kcal/kg. Short-term marginal costs comprise variable production costs, processing, overburden removal and royalties. For simplification, this analysis assumes that port usage and inland transportation are based solely on long-term contracts and are therefore not part of the short-term marginal costs. FOB costs comprise short-term marginal costs and the costs of inland transportation and port usage. Royalties are assumed to increase proportionally with the production output.

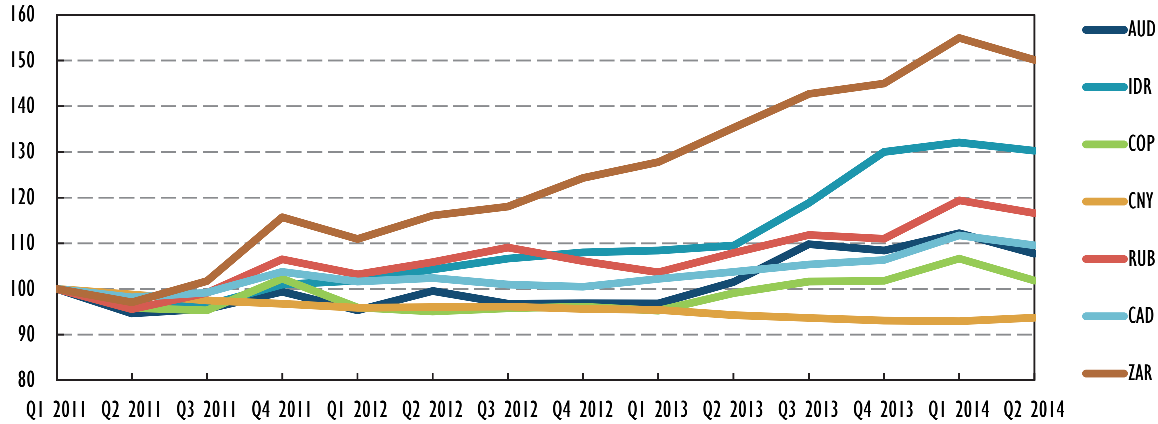
Source: IEA analysis from Wood MacKenzie (2014); McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

Currency exchange rates

Currency exchange rate developments have a direct impact on supply costs for coal and therefore strongly influence the competitiveness of coal suppliers (both exporters and local suppliers). Most international coal trade is settled in USD and thus also generates a revenue stream in USD for coal suppliers. Since costs such as labour and railway costs are settled in local currency, a depreciation of the local currency against the USD directly translates into a supply cost decrease for domestic producers. Analogously, an appreciation of the local currency results in a supply cost increase for domestic producers. Buyers of coal are affected by exchange rate fluctuations as well: a depreciation of the local currency translates into higher costs. It should be noted however, that the influence of exchange rate fluctuations is mitigated through numerous hedging instruments, which allows coal suppliers (and buyers) to hedge against currency exchange risks.

Figure 2.21 shows the indexed development of the USD against currencies of selected coal-exporting countries. When looking at the timeframe from 2011 until the end of 2013, most currencies depreciated against the USD, with the strongest depreciation in 2013 by the Indonesian rupiah (IDR). This resulted in currency-based cost decreases, thereby strengthening exports even at declining (USD-based) coal prices. Starting in 2014, most currencies began to appreciate against the US dollar.

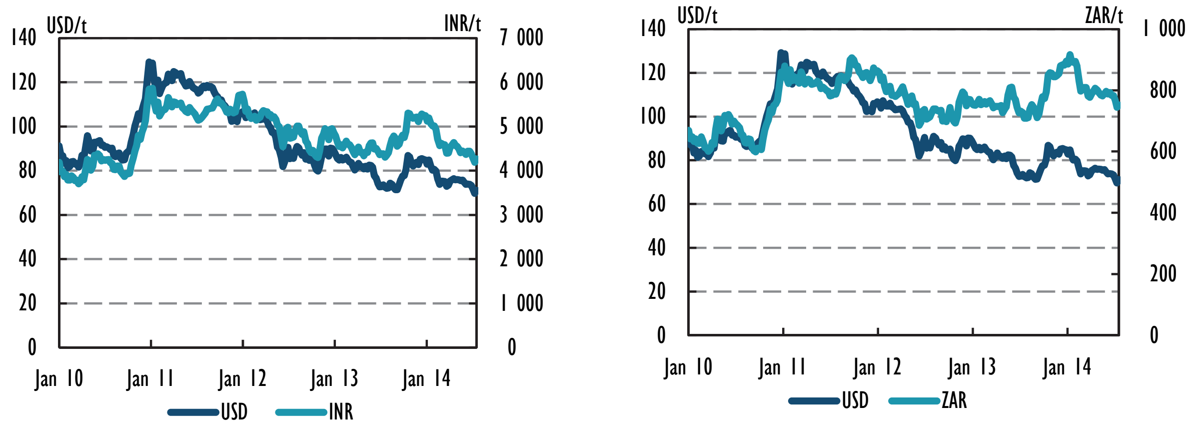
Figure 2.21 Indexed development of the US dollar against selected currencies



Note: AUD = Australian dollar; COP = Colombian peso; CNY = Chinese renminbi; RUB = Russian ruble; CAD = Canadian dollar; ZAR = South African rand). The graph shows the indexed (Q1 2011 = 100) development of the US dollar against selected currencies, expressed as USD/domestic currency (for example USD/AUD). Therefore a devaluation of the USD (1 USD buys less units of another currency) results in a decline in the index.

Figure 2.22 illustrates the effects described above. The left chart shows the development of the Richards Bay FOB price in USD and South African rand (ZAR). When expressed in USD, the FOB price decreased by 19% between January and September 2013. The depreciation of the ZAR in the same period has however at least partially offset this deterioration; the price in ZAR decreased by only 6%. The right chart illustrates the effect of exchange rate developments on importers showing the Richards Bay FOB price in USD and Indian rupee (INR). The INR depreciated against the USD over most of the first half of 2013. Consequently, compared to the 19% decrease of the price marker in USD, when expressed in INR the price marker decreased by only 10%.

Figure 2.22 FOB steam coal prices in USD and local currency (left: ZAR; right: INR)



Note: ZAR/t = South African rand per tonne; INR/t = Indian rupee per tonne.

Source: McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

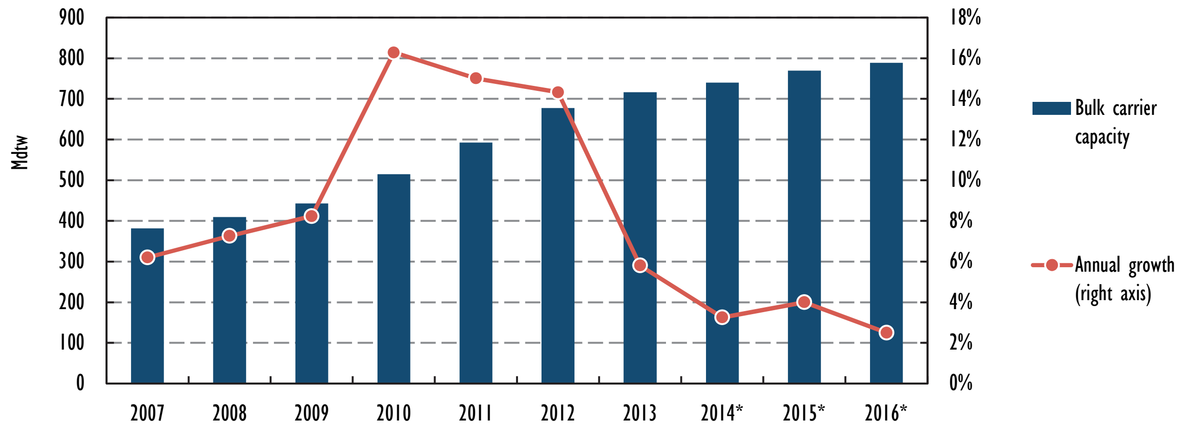
Dry bulk shipping market

Approximately 90% of internationally traded coal was transported by ship in 2013. The seaborne dry bulk shipping market constitutes an important part of the coal supply chain. Dry bulk freight vessels are typically categorized by their deadweight tonnage (dwt), which is the weight that they can carry. Four main vessel types transporting coal exist: Handysize (10 000 dwt to 35 000 dwt), Handymax/Supramax

(35 000 dwt to 60 000 dwt), Panamax (60 000 dwt to 80 000 dwt) and Capesize (over 80 000 dwt). Panamax and Capesize vessel types dominate the international trade of coal.

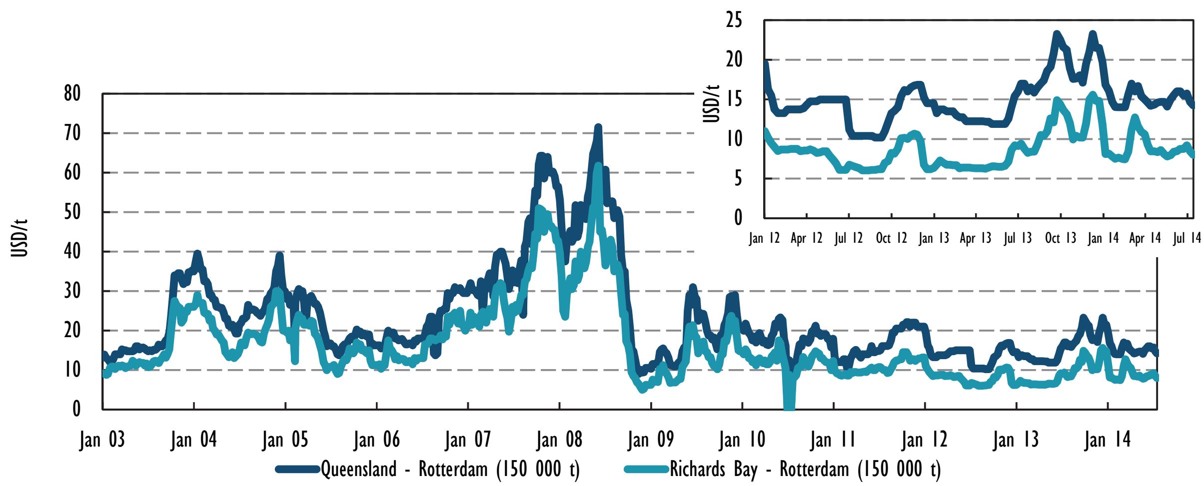
As the construction of new bulk carriers takes approximately one to two years, and as shipyards typically have limited excess capacity (because of limited number of assembly docks), the supply of bulk carrier capacity is somewhat inflexible and hence predictable. As shown in Figure 2.23, the annual growth of the dry bulk carrier exceeded 7% in each year between 2008 and 2012. 2013 saw a slower growth rate of the bulk carrier fleet by approximately 6%, and growth is projected to further decrease and remain at the decreased rate through at least 2015. New building orders are now primarily focused on Supramax vessels, which have been increasingly popular for cargoes from Indonesia to India, as Handysize orders are decreasing.

Figure 2.23 Development of the bulk carrier fleet, 2007-16



* Estimate.

Figure 2.24 Development of selected freight rates, 2003-14



Source: McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

Sea freight rates increased slightly in 2013 with average freight rates from Richards Bay to Rotterdam at USD 9/t and from Queensland to Rotterdam at USD 16/t. Compared to 2012, this is an increase by USD 1/t and USD 2/t respectively. Most of this was driven by a strong increase in freight rates in the second half of 2013 caused by growth of iron ore imports to China and strong grain exports from the

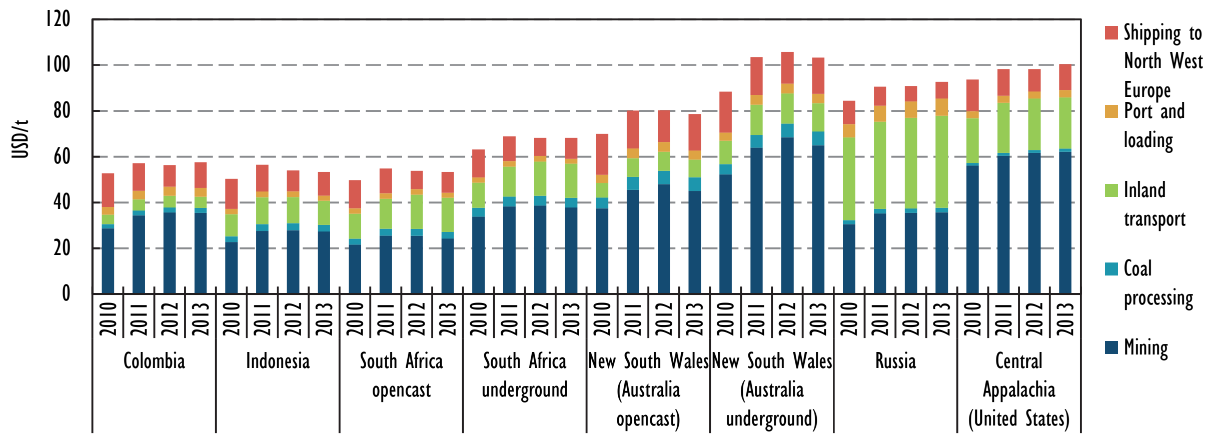
United States. However, at the beginning of 2014, prices fell back again to lower levels. In the first half of 2014, freight rates from Richards Bay to Rotterdam ranged between USD 8/t and USD 12/t and from Queensland to Rotterdam between USD 14/t and USD 20/t.

Development of coal supply costs

Coal supply costs have increased in all coal producing countries since 2010. However, coal supply costs have increased at a slower speed or even began to decrease since 2011. Three key factors contributed to this development. First, companies have taken great efforts to reduce mining and labour costs. Second, most currencies stopped appreciating against the US dollar in late 2011 and even started to depreciate. Third, several input factor prices for mining such as diesel fuel or steel mill products did not increase further or even decreased. Factors having a bullish impact on coal supply costs can also be observed. First, currencies began to appreciate again against the US dollar in 2014, thereby driving up international supply costs. Second, labour costs continued to increase while productivity decreased in several exporting countries. Third, after having decreased in 2012, average freight rates to Europe increased again in 2013.

Figure 2.25 illustrates these developments, showing indicative steam coal supply costs to northwest Europe (ARA ports) for selected coal exporters. In order to allow for a comparison between the regions, royalties and taxes are not included in the figure.

Figure 2.25 Indicative steam coal supply costs to North West Europe by supply chain component and by country, 2010-13

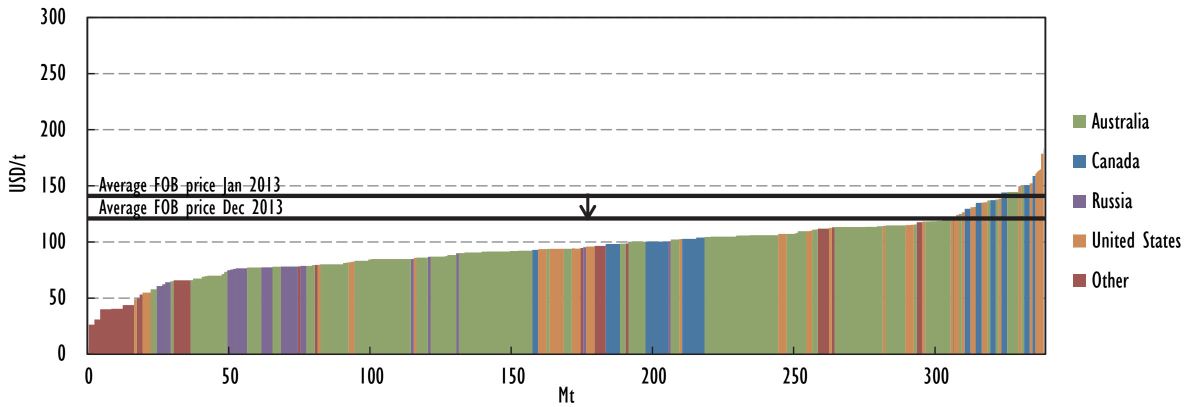


Note: Indicative supply costs shown in this figure do not include taxes and royalties.

In absolute terms, supply costs have increased most strongly in Australia since 2010, and several Australian producers are incurring losses at current price levels. However, average mining costs in Australia decreased in 2013 compared to 2012, as producers have taken strong measures to reduce mining and labour costs. Measures that resulted in cost savings include increased labour productivity through increased production per person due to fewer roles and contractors, as well as gains in truck utilisation with fewer trucks moving the same quantity of material. Parts substitution, condition-based replacement, the use of alternative suppliers and price renegotiation resulted in savings in consumables. Furthermore, producers have opted for procurement outsourcing, including off-shoring, higher feed rates and increased run hours have led to increases in coal preparation plant production. Producers are also increasingly trying to renegotiate take-or-pay contracts with railway and port operators. These contracts often date back to the high price period.

Investment activity in met coal production capacity has been strong in recent years, triggered by a pronounced high price period with met coal prices peaking above USD 320/t in 2011. However, met coal prices have decreased strongly since 2011. Prices for met coal were between USD 110/t and USD 140/t (depending on coal quality) in December 2013, a decrease from when it ranged between USD 120/t and USD 170/t in January 2013. Even though producers have taken great efforts to reduce costs, oversupply to the market persists and, in consequence, leave the operations of many met coal producers at the upper end of the supply curve unprofitable at current low price levels (see Figure 2.26).

Figure 2.26 Indicative met coal FOB cost curve and FOB price levels, 2013



Notes: FOB price levels are monthly averages derived from different price indices, such as Australian prime hard coking coal, Australian low volatile PCI, US high ash, high volatile and US low volatile. Price levels of certain met coal types can deviate from these indicative figures. FOB costs comprise variable production costs, processing, overburden removal, royalties, port usage and inland transportation.

Source: IEA analysis from Wood MacKenzie (2014); McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

References

Australian Bureau of Statistics (2014), *6345.0 Wage Price Index*, Australia, June 2014, Australian Bureau of Statistics, Canberra, www.abs.gov.au/ausstats.

McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com.

Statistics South Africa (2014), *Quarterly Employment Statistic (QES),* June 2014, Statistics South Africa, Johannesburg, www.statssa.gov.za/publications.

US Bureau of Labor Statistics (2013a), *Producer Price Data Commodity and Industry*, United States Department of Labor, Washington D.C., www.bls.gov/data/.

US Bureau of Labor Statistics (2013b), *Employment, Hours, and Earnings from the Current Employment Statistics survey (National), Industry: Coal Mining (average hourly earnings of all employees)*, United States Department of Labor, Washington, D.C., www.bls.gov/data/.

World Steel Association (various years), *Crude Steel Production*, Brussels, World Steel, www.worldsteel.org/statistics.

3. MEDIUM-TERM FORECAST OF DEMAND AND SUPPLY

Summary

- **Global coal demand grows on average +2.1% per year over the outlook period, from 5 690 million tonnes of coal-equivalent (Mtce) in 2013, to 6 462 Mtce by 2019. This is slightly slower than the 2.3% annual growth rate from last year's report.** Coal will therefore be the fastest-growing fossil fuel until 2019 in absolute terms. Gas will grow at a slightly slower pace, on average by 2.2% per year.

- **Non-OECD countries will continue to dominate global coal demand growth.** Coal demand in non-OECD countries will grow on average +3.0% per year from 4 239 Mtce in 2013 to 5 060 Mtce in 2019. The fastest-growing non-OECD country groups in relative terms are the Association of Southeast Asian Nations (ASEAN) countries (+8.3% per year) and Latin America (+6.2% per year, from very low levels). Most incremental demand volumes are projected for China (+471 Mtce) and India (+177 Mtce), enabling India to surpass the United States and become the second-largest coal consumer in the world by 2019.

- **Demand in China will continue to grow on average by +2.5% per year over the outlook period, however at a significantly slower rate than over the previous ten years (approximately 10% per year, on average).** Thermal coal and lignite will grow by 2.6% per year, thereby providing most incremental volumes (+402 Mtce), and met coal by 2.0% (+69 Mtce).

- **Demand in OECD countries is projected to decrease on average by 0.6% per year from 1 451 Mtce in 2013 to 1 402 Mtce in 2019.** Demand growth decline is not evenly distributed among OECD countries. While coal demand decreases in OECD Europe and OECD Americas, it increases in OECD Asia Oceania. Coal demand in the United States is projected to decrease by as much as 1.7% on average per year.

- **The picture is similar when looking at the different coal types.** Both thermal coal (+2.3% per year) and metallurgical (met) coal demand (+1.8% per year) are forecast to grow until 2019 with the bulk of growth coming from non-OECD countries.

- **Global coal supply is forecast to increase by 752 Mtce (+2.1% per year), from 5 709 Mtce in 2013 to 6 462 Mtce in 2019**. Incremental coal volumes in non-OECD countries amount to 686 Mtce (+2.5% per year) until 2019 – approximately 65% of which comes from China. Coal supplies in OECD countries will grow by 67 Mtce (+0.8% per year), mostly due to increasing production in Australia.

Methodology

The demand forecast in this section is subdivided into thermal coal and lignite demand and metallurgical (met) coal demand. This market-oriented approach reflects that met coal is priced and traded differently than thermal coal and lignite. As with the previous editions of this report, the International Energy Agency (IEA) provides forecasts for both OECD member countries and OECD non-member countries. This report additionally features forecasts for the ASEAN country group, thus taking into account their importance to the international coal markets.

Coal usage is driven by factors such as the relative prices of coal and its substitutes (particularly for power generation and industry), economic and population growth and electrification rates. However, similar growth rates of the gross domestic product (GDP) in two countries may result in different growth rates for coal demand, depending on the country's average per capita income (used as a measure of its development level), resource endowment and energy policy, among others. To account for these diverse influences, demand forecasts are based upon country-specific econometric estimations, for example the elasticity of thermal coal demand to GDP or population growth. Using assumptions about various relevant parameters (such as GDP and population growth forecasts provided by the International Monetary Fund [IMF], fuel prices and development of average efficiency coal-fired power plants in the various countries) allows us to derive demand projections specific to the country and coal type. Drawing on the broad expertise of the IEA on primary energy markets enables consistent demand estimates that account for development in the other primary energy markets, such as natural gas, renewable energies or crude oil.

In addition to the demand and trade forecast presented in this and the next chapter, two separate demand and trade analyses are presented in Boxes 3.3 and 4.4. Box 3.3 analyses how Chinese coal demand could peak in the outlook period, showing that only very strong assumptions would lead to peak coal in China before 2019. Box 4.4 analyses the effect of a cap on production in Indonesia on global coal trade.

Assumptions

GDP growth is an important driver for future coal consumption. Our demand forecast is based upon the April 2014 IMF GDP forecast. In its April 2014 forecast the IMF revised its projections downward compared to the April 2013 forecast which was used in last year's *Medium-Term Coal Market Report* (IEA, 2013): for the period 2013-18, the compound average growth rate (CAGR) is almost 0.5 percentage points lower. Global GDP is projected to grow on average by 3.8% per year from 2014 to 2019. In line with previous IMF forecasts, GDP growth is stronger in non-OECD economies than in OECD economies. Non-OECD economies are projected to grow by 5.4% per year from 2014 to 2019; OECD economies will grow on average by 2.3% per year.

OECD Europe will grow at an average 1.9% per year from 2014 to 2019 with growth gradually increasing over the outlook horizon. OECD Americas are projected to grow by 2.8% per year driven by strong economic development in the United States in the beginning of the outlook period. GDP in OECD Asia Oceania will grow at 2.0% per year. Strong growth mostly stems from Korea, which is expected to grow by 3.8% per year over 2014-19.

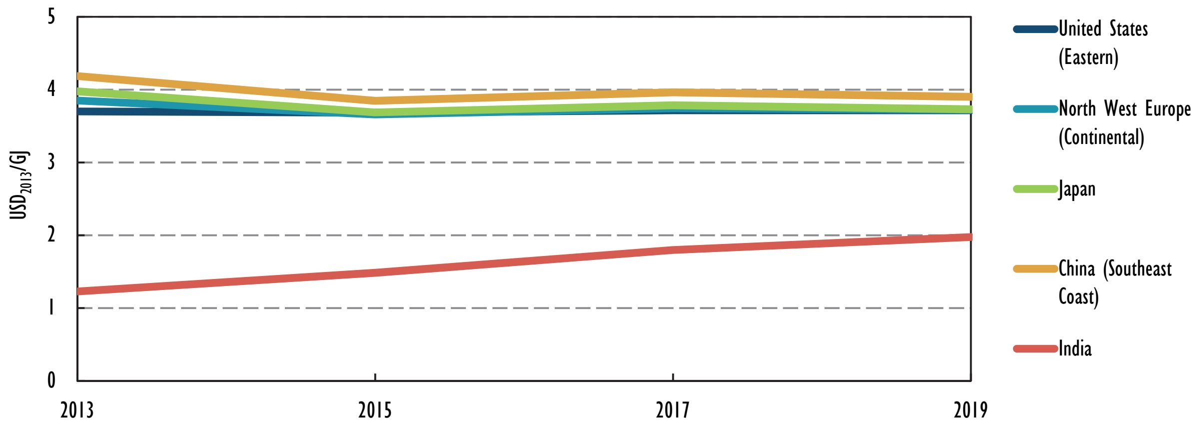
Non-OECD economies in Asia will maintain strong growth rates between 2014 and 2019. However, growth is less strong than projected in the April 2013 forecast: China will grow at an average 7.0% per year, a downward revision of more than one percentage point compared to the April 2013 projections. Growth projections for India and Indonesia have been revised slightly downwards with India projected to grow by 6.4% per year and Indonesia by 5.9%. ASEAN and other developing Asian and African economies maintain overall strong growth rates (exceeding 5% per year), which are similar to those set out in the IMF projections of April 2013. Latin America's GDP will increase by 3.1% per year and GDP in the Middle East by 4.1%. Projected growth for non-OECD Europe/Eurasia has been revised downwards to 2.7%.[1]

[1] In April 2014, the IMF did not publish a forecast for GDP growth in the Ukraine. For the demand forecast, we assumed an annual GDP growth rate of 0% in the Ukraine over the outlook period.

Apart from GDP development, the evolution of fuel prices is a major factor when determining future coal demand. The price paths for oil, gas and coal are consistent with IEA (2014a), IEA (2014b) and IEA (2014c). The *Medium-Term Reports* use forward curves as an input to price forecasts, however these prices do not in any manner represent IEA forecasts.

Nominal IEA average oil import prices are expected to follow a continuous trend from the current levels to over USD 90/bbl in 2019. The natural gas market is projected to continue to lack sufficient interregional arbitrage (due, among other things, to higher seaborne transportation costs, infrastructure constraints and oil-price-indexed long-term contracts). Regional gas price divergence among the United States, Europe and Asia is therefore assumed to persist over the outlook period, rendering coal-to-gas competition in Asian economies very favourable to coal. Average Henry Hub gas prices are expected to cross the USD 4/million British thermal unit (MBtu) threshold in 2014, increasing progressively to USD 4.6/MBtu by 2019. Continental Europe will continue to see a mix of spot and oil indexation. The average USD 10.4/MBtu import price over the forecast horizon will be slightly higher than for British gas users (USD 10.1/MBtu). Gas prices in OECD Asia Oceania (represented by Japan) are expected to remain well above US gas prices. The gap will narrow from USD 12.6/MBtu in 2013 to USD 8.6/MBtu in 2019 due to a progressive decrease in oil prices pushing contract prices downward.

Figure 3.1 Regional (real) steam coal price assumptions, 2013-19, delivered to the power plant



Notes: USD_{2013}/GJ = 2013 USD per gigajoule.

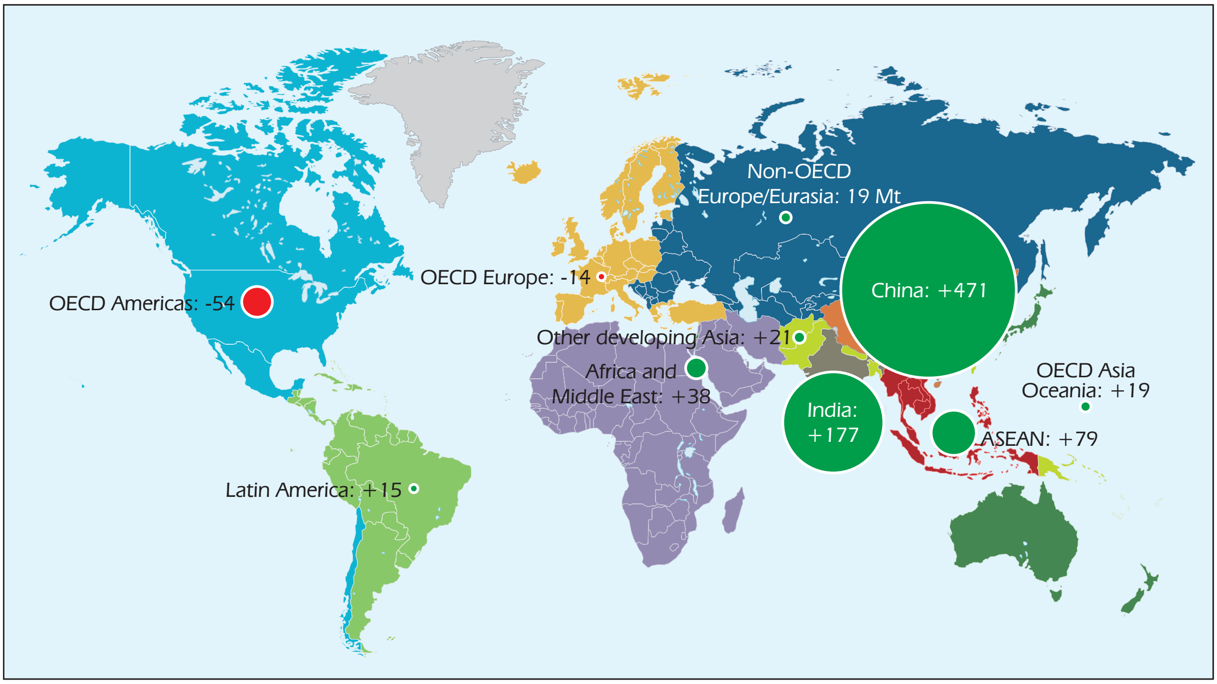
Regional coal prices in this report are based upon forward curves subject to individual adjustments, for example for transport and handling costs. Prices for coal delivered to power plants in the United States (eastern), North West Europe (Continental) and Japan are generally assumed to slightly decrease in the short term until 2015, picking up again thereafter and converging at approximately USD 3.7 per gigajoule (GJ) in 2019. Prices for the South East Coast of China are projected to decrease from USD 4.2 per GJ to USD 3.9 per GJ in 2019. Coal prices in India will diverge: average delivery prices to power plants are assumed to almost double until 2019 (to USD 2 per GJ) due to an expected increase in thermal coal imports and a slow-to-moderate rise of domestic coal prices. Nevertheless, delivery prices in India are expected to range between approximately USD 1.3 and USD 1.9 per GJ lower than prices in the other regions depicted in Figure 3.1.

Global coal demand forecast

Global coal demand is forecast to grow by 772 Mtce (+2.1% per year on average), from 5 690 Mtce in 2013 to 6 462 Mtce in 2019. Thus, considering the average annual growth rate of 4.8% over the last ten years, coal demand growth is projected to more than halve. Non-OECD economies clearly drive global coal use, with an average annual growth rate of 3.0% during the outlook period. By 2019, coal consumption in non-OECD economies accounts for 78.3% of global coal use, up from 74.5% in 2013. Even though coal demand growth in China is slowing, from an average of almost 10% per year over the last ten years to on average 2.5% per year over the outlook period, the bulk of incremental coal demand can still be attributed to China (+471 Mtce). In relative terms, the ASEAN country group leads other countries (+8.3% average growth per year), followed by Latin America (+6.2%) and India (+5.0%).

While coal demand growth among non-OECD economies is expected to continue, coal use in OECD economies will decline on average by 0.6% per year over the outlook period. Coal demand will decrease by 49 Mtce, from 1 451 Mtce in 2013 to 1 402 Mtce in 2019. Coal demand growth will experience pronounced geographical differences among OECD regions. Coal demand decreases in both OECD Europe (-0.6% per year) and OECD Americas (-1.4% per year). The bulk of this decline can be attributed to the United States, where coal demand decreases by on average 1.7% per year (-62 Mtce). The decline in the United States is slightly counterbalanced by growth in other OECD Americas economies, resulting in an overall decrease in coal demand by 54 Mtce. Coal demand in OECD Asia Oceania is projected to increase by 19 Mtce, equivalent to an annual growth rate of 0.9%.

Map 3.1 Forecast of incremental global coal demand 2013-19 (Mtce)



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

OECD coal demand forecast, 2014-19

Thermal coal and lignite

Thermal coal and lignite consumption accounts for approximately 87% of overall coal consumption in OECD countries. It is projected to decrease by 54 Mtce (-0.7% on average per year) from 1 269 Mtce in 2013 to 1 214 Mtce in 2019, despite slight growth to 1 276 Mtce in 2015. Thermal coal and lignite is mainly consumed within the power sector (88%) and is the main source of power generation in OECD countries (32.8% in 2013). Other uses include district heating as well as the cement and iron and steel industries.

Box 3.1 MATS, Clean Power Plan and US coal

The United States has enacted new regulations over the past years aiming at reducing emissions of toxic air pollutants from a range of different sectors, such as Mercury and Air Toxics Standards (MATS), Regional Haze Rules and Cross-State Air Pollution Rule. Some of these target the power sector, more specifically power generated from coal-fired power plants. But recently the focus of attention has been the "Clean Power Plan", released in June 2014.

The US Environmental Protection Agency (EPA) estimates that the power sector accounts for 32% of total greenhouse gas (GHG) emissions of the United States (measured in carbon dioxide [CO_2] equivalent) while coal is accountable for 25% of total GHG emissions in the United States. As part of the new regulatory requirements, the coal generation sector will have to reduce emissions of mercury, particulate matter (PM), sulphur dioxide (SO_2), acid gases and other individual metals, but also to comply with the new targets set in the "Clean Power Plan" and look at reducing GHG emissions from the fossil fuel power generation sector by 30% from 2005 levels by 2030. The Clean Power Plan will be implemented through a state-federal partnership where the EPA has proposed GHG emissions reduction goals by state, allowing them the initiative to take dedicated actions with the help of EPA guidelines made to assist states in developing plans to meet those goals. In this framework, states can determine their generation mix based upon installed capacity, fuel diversity and demand forecast. States are also allowed to join existing or launch new multi-state programs.

In order to continue assisting states, the EPA will prepare new regulatory standards (Best System of Emission Reduction – BSER) by mid-2015 to assess emissions from existing power plants. These new standards will be based upon efficiency improvements for existing coal power plants and for natural gas-fired plants, increasing the generation from renewable power and nuclear, improving end-user efficiency. States will then have to submit their action plan by end of June 2016, which could become regulation by 2019. Numerous lawsuits have been filed against the rule, and hence, the timeline could be affected.

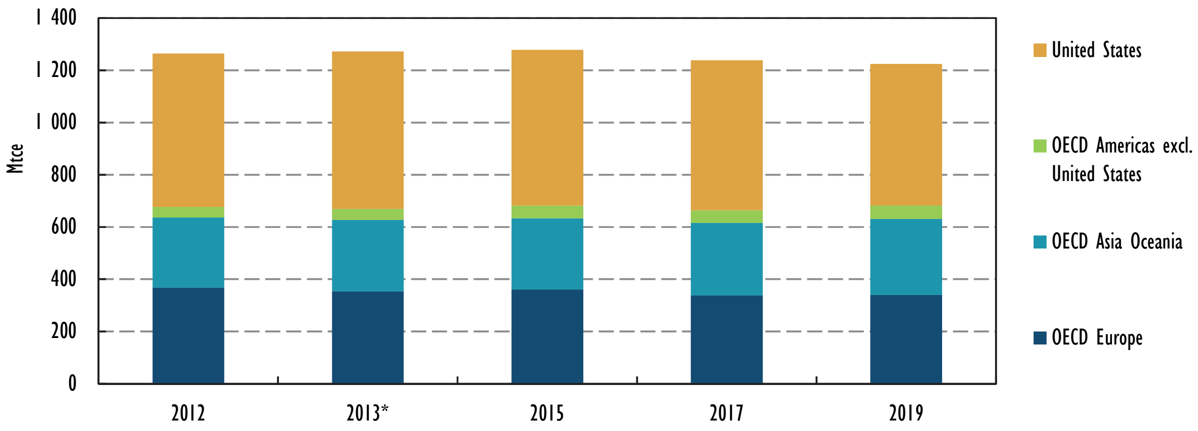
As the power generation sector will have to integrate these new regulatory parameters as well as adjust to current low gas prices, some impacts can be expected on profitability in the coal generation sector, while power supply reliability and final electricity prices for consumers will have to be monitored. As an example, PJM, for whom coal generation represented 44% of the electricity generated in 2013, announced that over 20 gigawatts (GW) of coal capacity generation (out of 182 GW total capacity) would be retired by 2016 as part of retirement plans mainly due to MATS regulation. The system operator is working at replacing this capacity with more environmentally friendly technologies, but is also pointing at increasing the share of demand response particularly for peak timing. The share of coal capacity foreseen in PJM for 2016 is about 32% compared to 39% today. The electricity generation sector will therefore increase its exposure to gas price variation due to a higher share of gas-fired generation in the mix. This increased share of gas in the power generation will also impact the local demand for gas, which could result in higher gas prices. The final cost of electricity will therefore have to include new capital expenditure costs as well as possible higher fuel (gas) prices. Financing capital will have to be secured in order to invest in new infrastructure while new capacity will have to ensure some form of protection against gas spikes such as coal previously did.

New environmental regulation will certainly impact the market model for energy production in the United States, but fuel prices and capital cost will also drive new generation investment and possibly require for system operators to readjust their generation adequacy balance.

Thermal coal and lignite demand in the United States accounted for 48% of overall OECD consumption in 2013. However, regulations regarding coal-fired power plant utilisation (such as the EPA's MATS) in combination with an ageing coal power plant fleet will lead to the decommissioning of approximately

45 GW to 50 GW of existing coal-fired power plant capacity until 2019 (around 15% of existing coal capacity). This decommissioning forecast is slightly higher than in last year's *Medium-Term Coal Market Report* due to an update regarding recent EPA regulations (see Box 3.1). Even though small amounts of liquefied natural gas (LNG) exports are expected to be shipped from the United States by the end of the outlook horizon, gas prices in the United States are expected to stay low. Hence, given the current regulatory environment regarding new coal plants and strong coal-to-gas competition, large investment activity in coal-fired power plants is unlikely. However, despite climate plans, environmental regulation and shale gas production, there is a tremendous amount of cheap coal in the United States and more than 250 GW of coal capacity will remain by the end of the outlook period. Overall, thermal coal and lignite consumption in the United States is projected to decrease from 603 Mtce in 2013 to 543 Mtce in 2019 (-1.7% per year). The decline in the United States is, to a certain extent, counterbalanced by growth in other OECD Americas countries, such as Chile. Thermal coal and lignite demand in OECD Americas is projected to decrease by 52 Mtce to 594 Mtce in 2019 (-1.4% per year).

Figure 3.2 Forecast of thermal coal and lignite demand for OECD member countries



* Estimate.

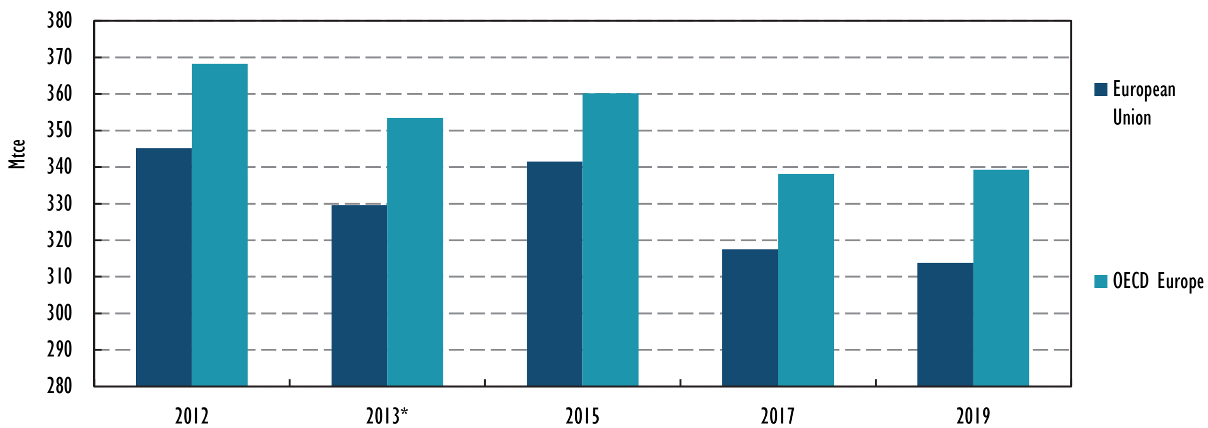
Despite a slight increase from 353 Mtce in 2013 to 360 Mtce until 2015, thermal coal and lignite demand in OECD Europe is projected to decrease by on average 0.7% per year over the outlook horizon, totalling 339 Mtce in 2019. Increasing generation from renewable energy sources and measures to increase energy efficiency as well as only moderate economic growth will curb future coal use in power generation in most parts of Europe. Older coal-fired power plants are additionally affected by the European Union's Large Combustion Plant Directive (LCPD). Despite continuing low prices for carbon emission allowances and mostly favourable gas-to-coal spreads for coal, no significant coal investment activity is expected over the outlook horizon. Exceptions are Germany and the Netherlands. In Germany, approximately 6 GW of coal-fired power plant capacities are commissioned over the outlook horizon. However, as illustrated in Table 3.1, the final investment decisions for these plants were made no later than 2008, dating back as far as 2006 for the plants in Hamm, Karlsruhe and Datteln. Commercial operations at the plants in Karlsruhe and Hamm started in mid-2014 and the remaining plants (with the exception of Datteln) are expected to commence commercial operations by 2015. In Turkey, there are approximately 30 GW of coal-fired power plants applying for a permit, but the capacity coming online will be significantly lower. In Greece, a new unit, capable of carbon capture and storage (CCS), has been proposed for the coal-fired plant at Ptolemaida. This CCS-ready unit will burn lignite of approximately 1 500 kcal/kg at a net efficiency of 41.5%.

Table 3.1 Coal-fired power plant projects in Germany

Project/location	Fuel	Net generating capacity (MW)	Final invest decision	Start of construction	Probable start-up
Hamm	Thermal	765/765	2006	2008	2014/15
Karlsruhe	Thermal	842	2006	2008	2014
Moorburg	Thermal	830	2007	2007	2014
Wilhelmshaven	Thermal	731	2008	2008	2014
Moorburg	Thermal	830	2007	2007	2015
Mannheim	Thermal	843	2007	2010	2015
Datteln	Thermal	1 055	2006	2007	x

Demand growth in the European Union follows a similar pattern as in OECD Europe (see Figure 3.3). However, decreases over the outlook period in OECD Europe (-0.7% per year) will be slightly less pronounced than in the European Union (-0.8% per year), due to increasing energy needs in growing non-European Union member economies such as Turkey.

Figure 3.3 Thermal coal and lignite demand forecast for OECD Europe and the European Union



* Estimate.

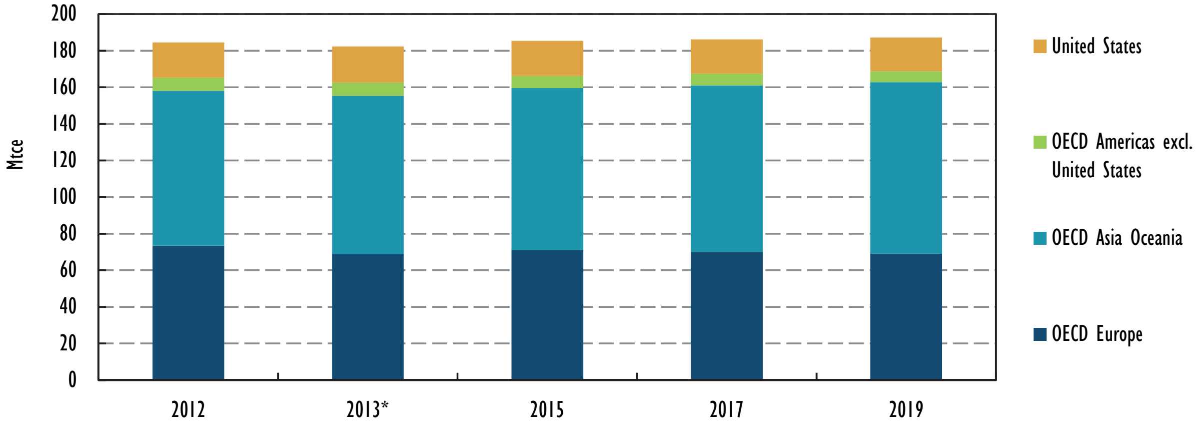
In OECD Asia Oceania, thermal coal and lignite demand is forecast to increase by 0.7% per year, from 269 Mtce in 2013 to 281 Mtce in 2019. This development is mostly driven by moderate economic growth in Japan and Korea. In Japan, 1.6 GW of coal-fired capacity commenced commercial operations in 2013 and the Osaki plant (170 megawatts [MW]) is scheduled to start operations in 2017. Furthermore, new coal-fired power plants by Japan's independent power producers will also come online during the outlook period, totalling over 500 MW of new capacity. In Korea, increasing power demand in previous years has triggered strong investment activity in new coal-fired power plants and approximately 10 GW will come online by 2019. In an effort to reduce electricity demand and increase the use of gas, a tax on coal was introduced in July 2014 and tax rates for LNG in power generation were lowered. The coal tax will be USD 16.2/t for coals below 5 000 kcal/kg (net as received), and USD 18.1/t for coals above. These tax changes will likely shift buyers' behaviour more towards higher calorific coal within each of the two categories.

Met coal

OECD met coal consumption is forecast to grow at 0.4% per year, from 182 Mtce in 2013 to 187 Mtce at the end of the outlook period. While met coal consumption will increase in OECD Asia Oceania, consumption in OECD Europe remains flat, and is projected to decrease in OECD Americas.

Met coal demand in the United States, which accounts for approximately 73% of met coal demand in OECD Americas, is projected to decrease by 2 Mtce (-1.0% per year) to 18 Mtce in 2019. This downward revision compared to IEA (2013a) mostly stems from a less optimistic economic outlook by the IMF in April 2014 compared to April 2013. Met coal demand in OECD Americas is projected to decrease further, by 1.5% on average per year to 25 Mtce in 2019.

Figure 3.4 Forecast of met coal demand for OECD member countries



* Estimate.

Met coal use in OECD Europe is projected to remain mostly flat over the outlook period. Increases in growing economies (for example in Turkey, which raised steel production by approximately 19% between 2010 and 2013) are offset by decreases in more mature economies (such as Poland or the United Kingdom) due to reductions in industrial output or efficiency gains.

OECD Asia Oceania is projected to increase met coal demand by 1.3% per year (+7 Mtce). Growth is led by developments in Japan (+6 Mtce), the second-largest met coal importer in the world. Korea, which has a large steel industry, will increase demand by 2 Mtce. Both countries are projected to benefit from economic growth over the outlook period.

Non-OECD coal demand forecast, 2014-19

Thermal coal and lignite

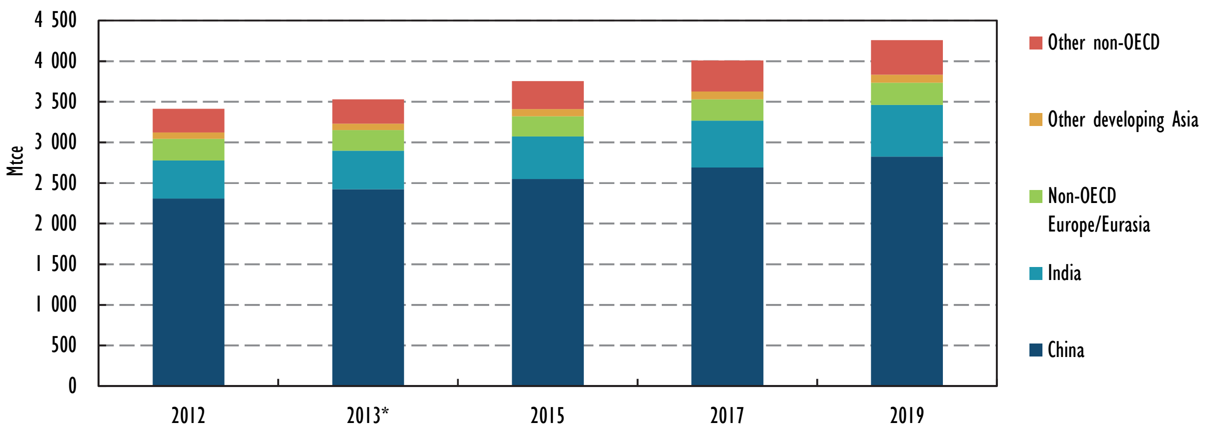
Thermal coal and lignite use in non-OECD countries will grow by 3.2% per year over the outlook horizon, from 3 531 Mtce in 2013 to 4 258 Mtce in 2019. Incremental thermal coal and lignite demand thus amounts to 727 Mtce, approximately 1.2 times the current demand in the United States.

Although power generation accounts for approximately 64% of thermal coal and lignite demand in non-OECD countries, significantly lower than in OECD economies (88%), power will largely drive coal demand increase in Asia and thereby non-OECD countries. Over two-thirds of the coal demand growth in India and the ASEAN countries will be for power generation. Other uses of coal include heating and cement and iron and steel industries.

Chinese thermal coal and lignite demand, which accounts for 68.6% of non-OECD demand in 2013, is projected to grow by 402 Mtce (+2.6% per year) to 2 824 Mtce by 2019. Growth will therefore slow significantly compared to the average growth of approximately 9% per year over the past ten years.

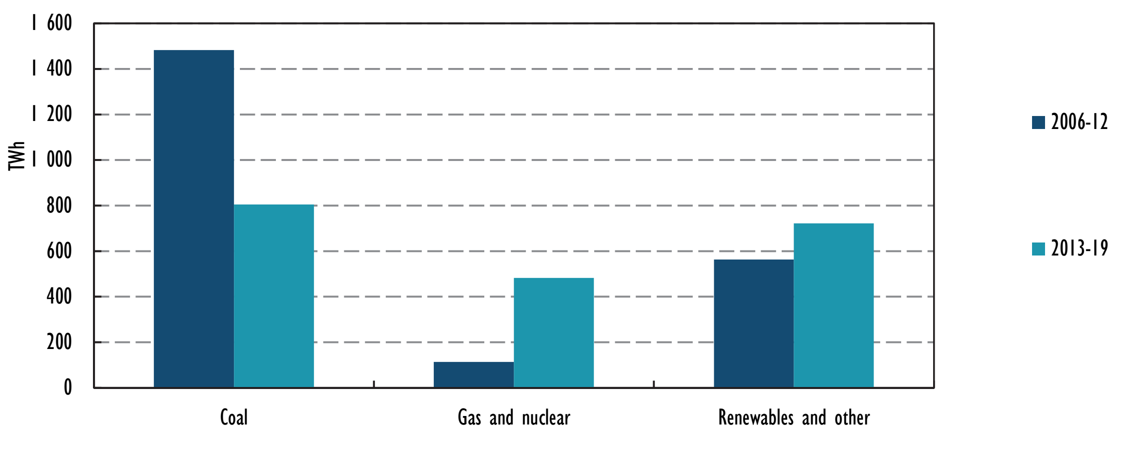
There are numerous reasons for this slowdown. Slowing economic growth – with China's economy projected to grow 7% per year – and a less energy intensive economy lead to a reduction in coal demand growth. In addition, Chinese energy policy is pushing for a diversification of its energy mix. Figure 3.6 illustrates this effort for diversification showing growth in electricity generation by fuel for the period 2006 to 2012 and the assumed growth for the outlook period of 2013 to 2019. Whereas growth in generation from coal will be significantly lower during the forecast period, growth in renewable energy, hydropower and nuclear/gas power generation will gain momentum. Additional non-coal generation in 2019 is assumed to be 1 200 TWh and gas demand to almost double during the outlook period.

Figure 3.5 Forecast of thermal coal and lignite demand for OECD non-member economies



* Estimate.

Figure 3.6 Electricity generation growth in China by fuel



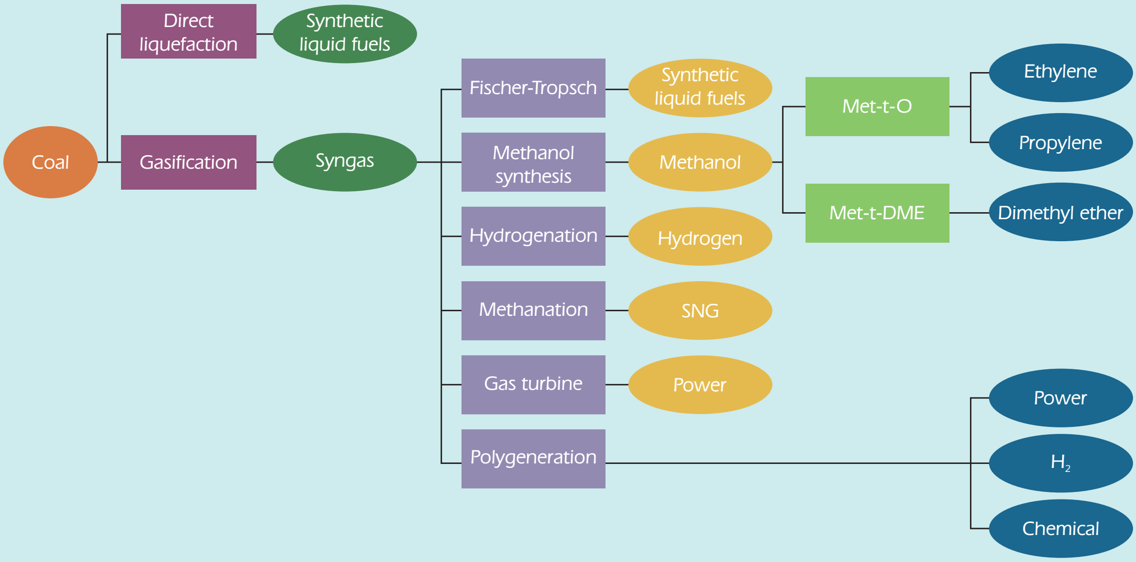
Further coal policies and infrastructure investments in China, which are intended to fight the problem of growing pollution, might not lead to a decrease but could lead to an increase in coal demand. Examples are new-built ultra-high voltage lines linking large coal bases to large consumption centres (in which additional consumption is required to compensate transmission losses), the increased use of cleaning equipment (such as desulphurisation) in power plants or the potential role played by the coal conversion process to produce synthetic natural gas and liquid fuels.

Box 3.2 Coal conversion processes

While coal gasification has been used in China for years to produce fertilisers and other chemicals, modern coal conversion includes a series of processes such as coal-to-chemicals, coal-to-gas, coal-to-liquids and other terms typically used to refer to the various processes shown in Figure 3.7 at a larger scale and in a cleaner way than it used to be. Most of these processes include coal gasification to obtain syngas, which can be used to produce electricity in a turbine (or combined cycle if another steam turbine is added) or to be transformed in a variety of products such as synthetic liquid fuels, hydrogen, synthetic natural gas, methanol and, of course, fertilisers, also an important application of coal gasification technology. Methanol can also be used directly or used to produce dimethyl ether, glycol and olefins, such as ethylene and propylene, intermediate products which can be inputs to produce plastic, fibres, and so forth. Therefore, coal conversion is extremely versatile, as the final product can be the syngas itself, synthetic natural gas (mostly methane), synthetic liquid fuels, or a great variety of chemicals, which can be further treated, or a combination of different outputs, which can include electricity. In the direct liquefaction process, however, synthetic liquid fuels are obtained directly without using syngas as intermediate product.

The two key factors to understand the economics of coal conversion are the concept of stranded coal and the evolution of competing fuel (oil and gas) prices. Stranded coal refers to coal with difficulties to be marketed due to high transportation costs, low quality or both. If stranded coal is low or very low in cost, such as for example in certain regions in China, it is perfectly suitable to be used as feedstock for coal conversion.

Figure 3.7 Coal conversion processes



Given that coal conversion produces materials otherwise coming from oil and gas (or even directly substituting natural gas), the prices of oil and gas are as important for coal conversion competitiveness as coal cost. Pre-feasibility studies for the first coal-to-liquid project in China were made in 1997, when oil price was below USD 20/bbl. Then, the break-even oil price of USD 40/bbl to USD 50/bbl seemed to make coal-to-liquid unfeasible. Today, profitability of coal conversion looks much brighter with current oil and gas prices.

Box 3.2 Coal conversion processes (continued)

Another economic factor to be considered is capital. Upfront investments in coal conversion plants are significant. Investments depend upon the process, technology, design, capacity of the plant, and so forth, but a very simple rule of thumb is to consider USD $1/m^3$ of synthetic natural gas (SNG) for coal-based natural gas and USD 2/kg to USD 3/kg of synthetic liquid fuel. In addition to the capital costs, this is important because availability of financing can be an issue. Moreover, the length of time required to build the plant adds risk and financial cost to the projects.

Further, the process is water intensive. First, any output has more hydrogen than coal, and water combines with the hydrogen for the process. In addition, most reactions are exothermic and use water for cooling. Finally, water is required for auxiliary purposes, such as cleaning, human use in the plant, and so forth. Although dry cooling and recycling can minimise requirements, water is absolutely necessary for the reaction to provide with the needed hydrogen. Depending on the process and design, it can require four, seven or more times the amount of water than the final output.

Modern coal conversion is sometimes considered a clean process, and this is true in terms of local pollutants, which are captured in the gasification process and cleaned. However, without CCS, CO_2 produced in the process and released to the environment can be a few times higher than using oil from a refinery or natural gas from a conventional field. On the other hand, the CO_2 stream is relatively pure, so costs of capture are reduced if applied to coal conversion processes.

Finally, some technical problems have been reported. Although gasification is not a new process, experience is limited, nothing comparable, for example, with accumulated experience in design, building and operation of pulverised coal plants.

Coal-to-liquids

Coal-to-liquids refer to the process in which synthetic diesel and gasoline are obtained from coal. They are based upon two different processes. Direct liquefaction is a process in which coal is dissolved in a solvent at high temperature and pressure followed by a catalysed hydrocracking of the dissolved coal with hydrogen gas.

The indirect liquefaction is based upon Fischer-Tropsch synthesis of syngas produced by coal gasification. The process was first developed by Germans in the early decades of the last century and then improved by Sasol in South Africa.

Coal-to-gas

To produce SNG (methane), syngas produced by coal gasification is subject to a water gas shift reaction in order to adjust the proportion of CO and hydrogen and then to the methanation reaction. Great Plains Synfuels plant in North Dakota is producing natural gas from lignite gasification at large scale.

Coal-to-chemicals

Coal-to-chemicals comprises a few processes which start with coal gasification to obtain syngas and after the methanol synthesis, methanol, which will be used for various purposes. Coal-to-olefins refer to the process to obtain ethylene and propylene, used to obtain polyethylene and polypropylene, inputs to produce many of the elements we use in the daily modern life, such as cables, synthetic fibres, diapers, films, carpets, plastic bottles, and so forth. Glycol and dimethyl ether are other chemicals that can be produced.

The *Medium-Term Coal Market Report 2013* emphasised that a growing driver of future coal demand in China will be coal conversion, as use of coal as a feedstock to produce synthetic fuels, SNG and chemicals will significantly increase in the coming years. The great potential of coal conversion and the currently ongoing activities (see "Regional Focus: China" in Chapter 1) oblige us to follow developments thoroughly.

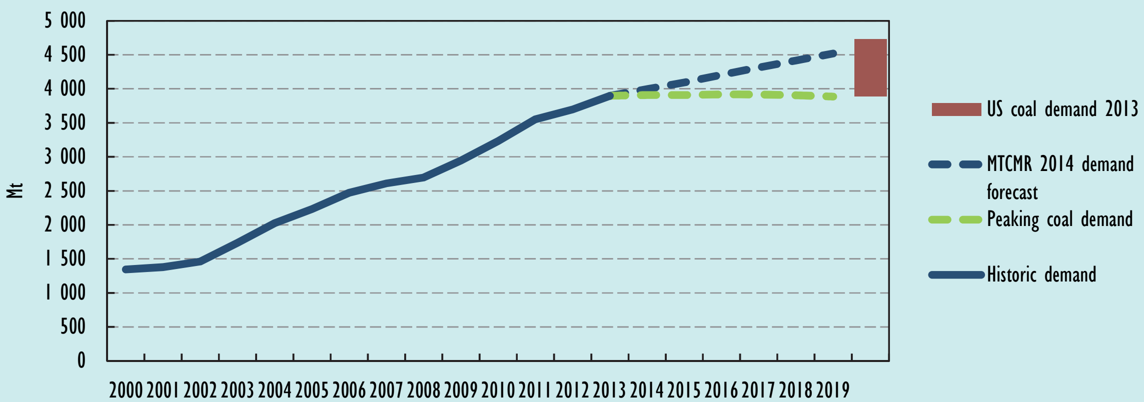
Given the call to reduce pollution in large Chinese cities and the lack of conventional resources in China, coal-to-gas developments can be an important element of the Chinese energy strategy. There are four plants that are expected to be operational by the end of the year, with a combined capacity of 14 bcm, although the first phase of these projects includes output of approximately 5 bcm, with expansions coming later.

However, given the uncertainties and challenges surrounding coal conversion -such as water,[2] technology, CO_2, capital; (see Box 3.2 for a discussion)-, forecast must be done cautiously. Back in the early years of this century, forecasts of annual 70 GW of new coal capacity in China seemed unbelievable based on the Western experience. However, those projections became true. Of course, coal conversion faces different and bigger challenges than coal power generation, but the magnitude of the plans obliges us to look at them closely. The list of projects planned, designed or under construction implies 1 billion tonnes of coal per year to be converted. This figure represents the potential ceiling as of today. But in order to make a realistic forecast we need to consider that some of the projects will be delayed, postponed or cancelled. After a meticulous analysis of individual projects, estimated growth of annual coal demand for conversion by 2019 is 225 Mt, of which almost half are projects to produce SNG (≈ 40 bcm), with close to 50 Mtpa to replace oil (≈ 10 Mt) and the balance for coal-to-chemicals. As noted last year, this figure is likely to be significantly revised in the future.

Box 3.3 Peak coal in China? Not yet

For decades, Chinese coal consumption has had only one direction: upwards. During the last 30 years, annual coal use in China decreased only twice, most recently in 1997. Given the orientation of Chinese policy to diversify the power system beyond coal and the current emphasis on air quality, the question is whether the trend will stop soon, resulting in a peak or at least a plateau in coal demand during the outlook period.

Figure 3.8 Forecasted coal demand in China, 2013-19, and peak coal scenario



The basis of the outlook for Chinese coal demand is an annual GDP growth averaging 7%. But GDP decouples from, or outpaces, electricity growth by 1.4 percentage points per year. At the same time, demand rises 2.3% per year in the non-power sector and gas use nearly doubles. The outlook also counts on 1 200 terawatt hours (TWh) of new non-coal power generation from gas, nuclear and renewable energy through 2019 – thus assuming 110 GW of new hydro capacity, or approximately one Three Gorges Dam per year; 110 GW of new wind, about the currently installed capacity in Europe; and 80 GW of new solar photovoltaic (PV), more than Europe's present installed capacity.

[2] Water is a curtailing factor in some arid areas in China and also, if water is priced, economics might change.

Box 3.3 Peak coal in China? Not yet (continued)

But can coal peak within the 2019 horizon? We find that it is possible, but only if one of the circumstances below happens:

- GDP growth slows to 3% from 2015 onwards, less than half of the assumed 7% per year. Since 1978, the lowest growth rate in China was 3.8% in 1990; or
- GDP and electricity growth decouple by 4.5 percentage points per year. But from 1980 to 2010 the maximum five-year annual average for this rate was 1.4 points in Japan. In China the annual average over the last five years was 0.4 points; or
- China produces 2 500 TWh of additional power generation from gas, nuclear or renewable power. This extra output is equivalent to four times global wind generation or 18 times global solar PV generation in 2013. To generate 2 500 TWh with modern gas power plants, China would have to raise natural gas consumption by 250%. Alternatively, China would have to commission 300 nuclear reactors in addition to the about 30 already expected over the outlook period; or
- China cuts non-power coal demand at a 2.9% annual rate. This would be equivalent to reducing non-power coal demand in 2019 by 360 Mt from 2013 and does not consider China's plans to expand its coal-to-gas conversion programme. Substituting natural gas for 360 Mt of coal would more than double current Chinese gas demand.

Of course, a combination of more moderate versions of these scenarios would also produce peak coal. For instance:

- Either non-power coal demand remains constant but China adds 1 900 TWh of additional power generation from gas, nuclear or renewable power; or
- GDP and electricity growth decouple by three percentage points per year with an additional 1 900 TWh of power generation from gas, nuclear or renewable power; or
- GDP grows 5% per year from 2015 combined with constant non-power coal demand, while GDP and electricity growth decouple by a 1.7% annual rate; or
- 5% GDP growth from 2015 combines instead with an additional 1 500 TWh of power generation from gas, nuclear or renewable power – and GDP and electricity growth decouple by 2.5 percentage points per year.

Because this calculation is a static analysis, it does not consider the effect of variations on other factors – which makes the prerequisites for coal demand to peak in China even harder to achieve. If, for example, GDP growth were to decrease significantly, it is not clear whether the assumed primary energy diversification of power generation through renewable power, nuclear or gas would still be achieved. Experience in Europe shows that in a crisis, subsidies to renewable power are among the choices for cuts in spending.

This exercise shows that peaking coal demand in China within this decade necessitates either a significantly lower GDP growth or dramatic changes concerning power generation or energy intensity in the economy. While past performance is no guarantee of future results, neither development has been observed, -nothing even close-, in recent history.

Power generation in India

The power sector is the key driver for thermal coal and lignite demand in India. It accounts for approximately 78% of Indian thermal coal and lignite demand. Approximately 70% of power generated in India came from coal in 2012. Annual GDP growth of 6.4% over the outlook period and the electrification of highly populated areas with poor or no electricity access at all and power to fuel economic growth will trigger increased power demand. Even though India's Planning Commission targets a diversification of the power supply mix, coal will remain the primary fuel for power generation in India. According to the 12th Five-Year-Plan (FYP), 63 GW of new coal-fired power plants are to be built until 2017, at least 50% of which will be supercritical. Table 3.2 lists India's 16 Ultra Mega Power Projects (UMPPs). Under this plan, India aspires to build 16 supercritical coal-fired power plants, each with a capacity of approximately 4 GW. Four of these plants have been awarded to developers in the first phase of the programme and another two projects are currently in the bid evaluation stage. However, in line with previous difficulties in realising previous energy policy targets, India's UMPP projects have faced delays despite attempts to fasten approvals.

Therefore, taking into account India's poor track record in realising its energy policy targets, improved fuel efficiency and that some of the new plants will substitute older coal-fired power plants, Indian thermal coal and lignite demand in the power sector is projected to grow by 4.7% per year, from 372 Mtce in 2013 to 491 Mtce in 2019. Overall thermal coal and lignite demand in India is forecast to grow by 4.9% per year, from 477 Mtce in 2013 to 635 Mtce in 2019. India will thereby surpass the United States as the second-largest thermal coal and lignite consumer in the world.

Table 3.2 UMPP projects in India

State	Project name	Owner	Capacity (MW)	Coal source	Status
Gujarat	Mundra UMPP	Tata Power	4 000	Imported	Units 1 and 5 in operation
Madhya Pradesh	Sasan UMPP	Reliance Power	3 960	Domestic	Unit1 to 6 in operation
Andhra Pradesh	Krishnapattnam UMPP	Reliance Power	3 960	Imported	Delayed, tariff issue
Jharkhand	Tilaiya UMPP	Reliance Power	3 960	Domestic	Land acquisition, initial civil work
Orissa	Sundargarh UMPP	Not awarded	4 000	Domestic	Bid evaluation
Tamil Nadu	Cheyyur UMPP	Not awarded	4 000	Imported	Bid evaluation
Andhra Pradesh	Nayunipalli UMPP	Not awarded	4 000	Imported	Pre-RFQ stage
Karnataka	Kamataka UMPP	Not awarded	4 000	Imported	Deferred, site not finalised
Maharashtra	Sindhudurg UMPP	Not awarded	4 000	Imported	Deferred, site not finalised
Jharkhand	Deoghar UMPP	Not awarded	4 000	Domestic	Proposed
Orissa	Sakhigopal UMPP	Not awarded	4 000	Imported	Proposed
Orissa	Ghogarpalli UMPP	Not awarded	4 000	Domestic	Proposed
Bihar	Bihar UMPP	Not awarded	4 000	Domestic	Location not finalised
Tamil Nadu	Tamil Nadu UMPP 2	Not awarded	4 000	Not finalised	Location not finalised
Gujarat	Gujarat UMPP 2	Not awarded	4 000	Not finalised	Location Not finalised
Chhattisgarh	Surguja UMPP	Not awarded	4 000	Domestic	Scrapped – forest, land issue

Source: Salva Report India (2014), *Salva Report India,* accessed February 2014, https://salvareport.com/.

In ASEAN countries, thermal coal and lignite demand is expected to grow by 79 Mtce, making it the fastest-growing country group (+8.3% per year) as increasing electrification will spur power demand in the region. Increasing power generation from coal prevails in all countries and over 30 GW of new coal-fired power plant capacities are projected to be commissioned (see also Box 3.4 for an in depth view on the developments in Malaysia). The forecasted demand growth in other developing Asian markets is comparably more moderate at 3.9% per year.

Demand in Africa and the Middle East as well as in Latin America will grow at approximately 4% per year, equivalent to a combined increase in the two regions by 43 Mtce. South Africa is the main driver for developments in Africa and the Middle East. Eskom, the local electric public utility is building coal-fired power plants in Kusile and Medupi with a combined capacity of 9.6 GW. Both plants are expected to be operational by the end of the outlook horizon, thereby raising South Africa's coal demand. The first 800 MW of the Medupi power plant are projected to start operations in late 2014 and, once completely finished, Medupi is expected to be the largest dry-cooled coal-fired power plant in the world. Mild growth of 1.4% per year is projected for non-OECD Europe/Eurasia countries for the outlook period; demand will reach 274 Mtce in 2019.

Box 3.4 Malaysia: A gas exporting country building coal plants

Currently, Malaysia's* power generation industry is heavily dominated by fossil fuels. Oil dominated the country's fuel mix before natural gas took over in the early 1990s as the main fuel and has since led the fuel mix in the power generation, particularly throughout the 2000s, a period that saw its highest share of close to 80% in 2001. The country's exceptionally low regulated domestic price for natural gas contributes to this situation. The domestic natural gas price for power was capped at MYR 13.7/MBtu (approximately USD 4.5/MBtu), which is less than one-third of the amount industry players pay in the region (Asian spot prices).

Table 3.3 New generation projects in Malaysia by 2019 (as of August 2014)

Project	Fuel	Installed capacity (MW)	Major stakeholders	Target online
Manjung IV	Coal	1 010	Tenaga Nasional Berhad (TNB)	2015*
CBPS Repowering	Natural gas	343	TNB	2015
Hulu Terengganu	Hydro	250	TNB	2015
Hulu Terengganu (Tembat)	Hydro	15	TNB	2016
Ulu Jelai	Hydro	372	TNB	2015-16
Tanjung Bin Energy	Coal	1 000	Malakoff	2016
Track 1 (TNB Prai CCGT)	Natural gas	1 071	TNB	2016
Pengerang Co-Generation	Natural gas	400	Petronas	2017
Track 3A (Manjung)	Coal	1 000	TNB	2017
Additional Chenderoh	Hydro	12	TNB	2018
Track 3B (Jimah)	Coal	2 000	1MDB, Mitsui	2018-19
Total		**7 473**		

* Actually, Manjung IV was synchronised to the Malaysian grid in October 2014.

Source: Based upon data from Malaysia's Energy Commission.

However, the low levels of natural gas prices are no longer sustainable, as the country, a major natural gas exporter, began importing LNG in 2013 to address declining domestic production and increasing demand for natural gas. The domestic price for natural gas was increased in early 2014 by 11% to MYR 15.2/MBtu (about USD 5/MBtu) and further upward revisions are anticipated that will bring the natural gas price to market level. Besides, any additional demand that is fulfilled through LNG import will not be entitled for subsidy and will be based upon market prices instead.

Box 3.4 Malaysia: A gas exporting country building coal plants (continued)

With natural gas becoming more expensive as a result of the subsidy removal, the move to increase coal's share in the country's fuel mix makes sense economically, which is also in line with the current trend in Asia of turning to coal as the preferred fuel. Coal's positive impact on TNB's financial performance is already felt – Malaysia's largest electric utility company, TNB, attributed the company's higher profit in 2013 to reduction in coal prices as the average coal price purchased by the company in 2013 was USD 83.60 per tonne, 20% lower compared to USD 103.60 per tonne in the year before. The move towards coal is also part of the government's fuel diversification initiative to reduce the country's over-reliance on oil and natural gas under its 2010's New Energy Policy.

From 11 new power plants to be built in Malaysia by 2019, four of them will be coal-fired plants with a total capacity of 5 010 MW. These represent two-thirds of the total new capacity, which sees coal surpassing natural gas as the preferred fuel from 47% of the fuel mix in 2013 to 64% by the end of the forecast period. Nevertheless, the move towards coal may be seen as backward progress towards a greener environment and counterproductive to Malaysia's effort to reduce its carbon footprint. In 2009, Malaysia pledged to reduce its greenhouse gas (GHG) emissions intensity of GDP by up to 40% by the year 2020 compared to 2005 levels, although this is conditional upon receiving the transfer of technology and finance of adequate and effective levels (MYCarbon, 2012). However, it is worth noting that all new coal power plants to be built in the country will employ supercritical and ultra-supercritical technology, which is up to 20% more efficient and produces up to 40% less carbon dioxide than conventional subcritical ones.

* Malaysia is made up of Peninsular Malaysia, and Sarawak and Sabah in Borneo. However, as the electricity consumption in Peninsula is 90% of the country's total consumption and most of the electricity planning by Malaysia's Energy Commission is focused on Peninsula, this section presents the electricity outlook for Peninsular Malaysia rather than the country as a whole.

Met coal

Non-OECD economies account for the vast majority of global met coal demand (79.5% in 2013). Their share will grow to 81.1% by 2019, as 95.0% of global incremental met coal demand will come from non-OECD countries. Non-OECD met coal demand will total 802 Mtce in 2019, up from 708 Mtce in 2013 (+2.1% average growth per year).

Accounting for 61.8% of global met coal use in 2013, China is by far the largest met-coal-consuming country in the world. Met coal consumption grew strongly over the last five years (+9.1% average per year) driven by strong demand for steel, cement and other building material. Even though this general trend is projected to continue, its pace will slow substantially to an average growth of 2.0% per year by 2019. However, despite this projected slowdown, China will still account for 69.9% of global incremental met coal demand in 2019. Met coal use is projected to grow by 69 Mtce, mostly driven by continued increases in steel production, totalling 619 Mtce in 2019.

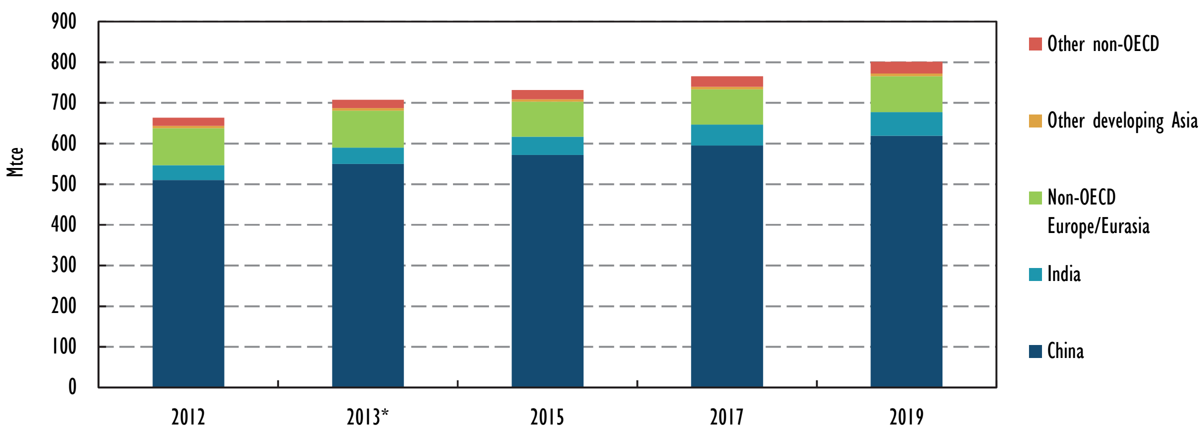
The iron and steel industry is the largest non-power coal consumer in China. Even though not directly influencing our demand forecast, driven by actual iron production rather than by capacity, it is worth looking at the current overcapacities in these industries. Related to this situation, China's Ministry of Industry and Information Technology released a regional plan in June 2014 that envisaged total capacity reductions in China's steel sector in 2014 of 30 million tonnes per year (Mtpa). These reductions will most likely not be enough to curb overcapacities, as approximately 24 blast furnaces, with a combined capacity of 35 Mtpa, are expected to start operations in 2014. Hebei province, whose reduction targets are even higher than the ones proposed by the ministry, aims to achieve its goals by imposing environmental restrictions, limiting overall production and encouraging merger and acquisitions in the industry.

India is the fourth-largest steel producer and second-largest cement producer in the world. Even though rated comparably inefficient in these industries, India's efficiency gains will be moderate in the medium term. Driven by strong economic growth, met coal demand in India will increase by 18 Mtce (+6.4% per year), to 58 Mtce in 2019.

In relative terms, growth in Latin America is strong. Met coal demand in the region grows by almost 9% per year, from 14 Mtce in 2013 to a projected 24 Mtce in 2019, mostly driven by Brazil. Strong economic growth and huge deposits of high-quality iron ore will spur crude steel production and hence met coal demand in the country.

Met coal demand in non-OECD Europe/Eurasia, the second-largest consuming region among non-OECD countries, will decrease slightly over the outlook period. Total met coal demand in the region is projected to amount to 88 Mtce in 2019, down from 91 Mtce in 2013. Demand in Africa and the Middle East as well as other Asia and ASEAN countries is not projected to increase substantially during the outlook period.

Figure 3.9 Forecast of met coal demand for OECD non-member economies



* Estimate.

Global coal supply forecast

Global coal supply is forecast to grow by 752 Mtce (+2.1% per year on average), from 5 709 Mtce in 2013 to 6 462 Mtce in 2019. Over 90% of incremental coal supplies come from non-OECD countries (+686 Mtce), most notably China (+443 Mtce) and India (+74 Mtce). Coal supplies in OECD countries increase by 67 Mtce, with the bulk of incremental volumes coming from OECD Asia Oceania. Coal production in OECD Europe and OECD Americas will decrease over the outlook period, continuing their recent downward trends.

Thermal coal and lignite supply forecast, 2014-19

Thermal coal and lignite production is forecast to amount to 5 472 Mtce in 2019, up from 4 810 Mtce in 2013. Total incremental mining activity is 663 Mtce, equivalent to an average 2.2% growth per year. Incremental thermal coal and lignite volumes account for 88.1% of overall incremental coal production until 2019, thereby raising the share of thermal coal and lignite in the global coal supply to 84.7%. Non-OECD countries contribute the bulk (+617 Mtce) of incremental supplies. Increasing supply in OECD countries (+46 Mtce) mainly comes from OECD Asia Oceania. Supplies from OECD Americas will decline, driven by developments in the United States. Coal production in OECD Europe slightly increases, from 197 Mtce in 2013 to 204 Mtce in 2019.

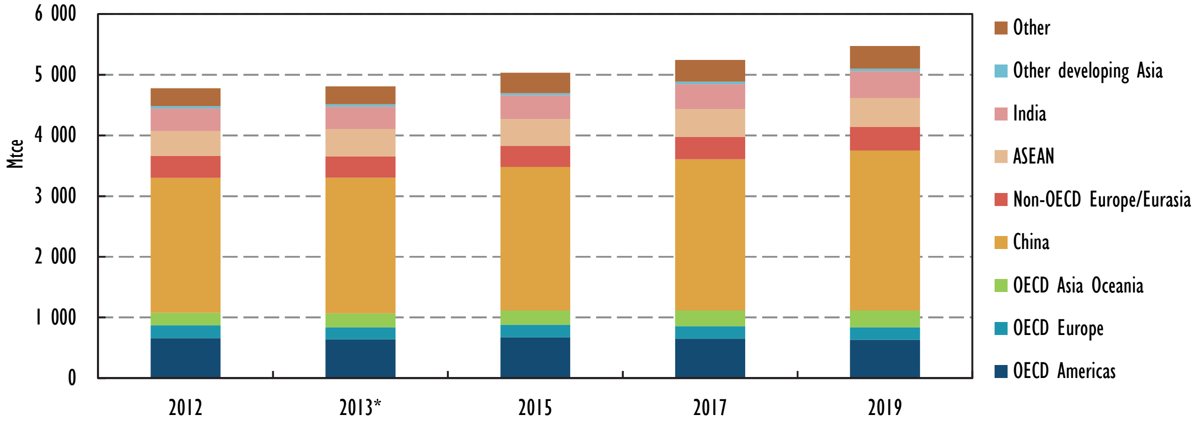
Thermal coal and lignite production in the United States, the largest producer in the OECD, will continue its decline. Its production is forecast to amount to 587 Mtce in 2019, down 23 Mtce from 610 Mtce in 2013. Production in Australia, the second-largest producer in the OECD will grow by 66 Mtce, thus contributing to most incremental volumes in the OECD.

China will remain the world's biggest thermal coal and lignite producer in 2019. Recent and ongoing closures of small mines in China (such as in the Sichuan province) are more than offset by higher efficiency in big mining projects. In 2013, 2 237 Mtce of thermal coal and lignite were mined in China, approximately 47% of global production. This share will increase to 48% by 2019: incremental supplies in China are forecast to amount to 404 Mtce, equivalent to 61% of incremental global supply, thereby raising Chinese production to 2 641 Mtce.

Supplies from India are projected to grow on average by 3.0% per year, totalling 444 Mtce in 2019. Strong hopes lie on the newly elected government to improve on the situation in India's coal mining sector. The measures taken by the government and their impact on coal production are however not yet fully clear. Among others, the government has announced plans to increase efficiency in the coal-mining sector and even a potential split of Coal India Limited (CIL), India's biggest coal producer, has been discussed.

Coal production in ASEAN countries amounts to 478 Mtce in 2019, an increase of 30 Mtce (+1.1% per year) from 2013. Growth in the ASEAN country group is mainly driven by developments in Indonesia, which will become the world's third-largest coal producer by 2019, surpassing India. Production in Africa and the Middle East is projected to increase by 3.3% per year on average, mainly driven by increasing production in South Africa. Growth in export capacity in Colombia will spur thermal coal and lignite supplies in Latin America (+5.4% per year on average). Although Mongolia is not a big thermal coal player, production could be triggered if the memorandum of understanding signed to produce 16 bcm of coal-based SNG for export to China is developed. However, our projections do not consider this likely to occur during the outlook period.

Figure 3.10 Forecast of thermal coal and lignite supply



* Estimate.

Met coal supply forecast, 2014-19

Global met coal production is projected to increase from 900 Mtce in 2013 to 989 Mtce in 2019, corresponding to an average annual growth rate of 1.6%. Non-OECD countries will remain the main driver of met coal production in the world (+1.8% average growth per year), accounting for more than 75% of incremental supply and almost 70% of global supply in 2019.

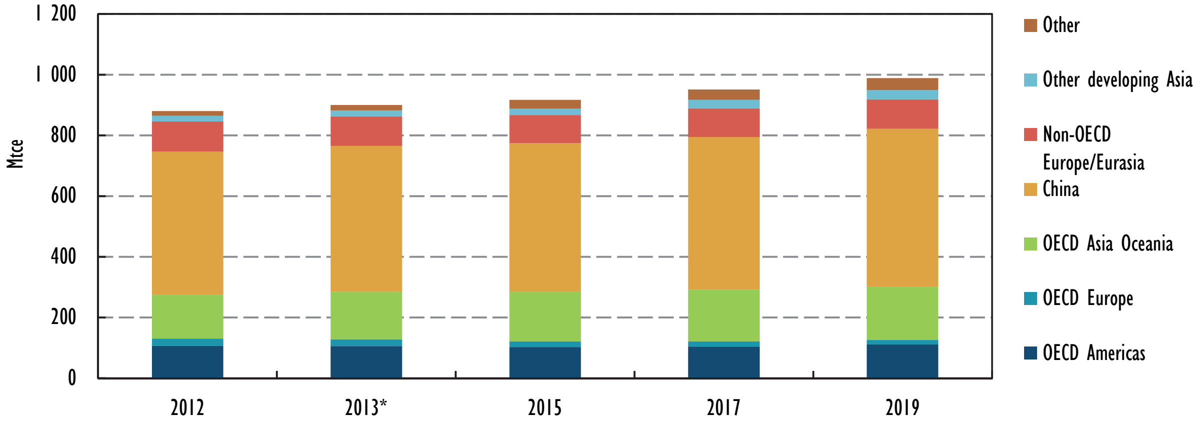
China is by far the largest met coal producer in the world (481 Mtce), accounting for more than half of global met coal supplied in 2013. Incremental volumes over the outlook horizon amount to 39 Mtce, corresponding to an average annual growth rate of 1.3%. Chinese met coal production, which will rise to 520 Mtce in 2019, will mostly serve domestic demand.

In India, met coal statistics are generally difficult to interpret. Not all coals classified as coking coal are suitable to produce coke to be used in metallurgical processes because of quality issues, and are therefore used in steam and heat making. Met coal supplies in India used for met coal processes are projected to increase on average by 4.8% per year, totalling 8 Mtce in 2019.

Relative growth will be strong in most other non-OECD regions. Supply growth in Africa and the Middle East (+14.0% per year on average) and Latin America (+23.2% per year on average) even exceeding the 10% mark. Incremental volumes in ASEAN countries and other developing Asian countries amount to 12 Mtce. Concerning the highly debated market of Mozambique, although the potential is there, we do not project significant incremental volumes entering the market given recent issues, particularly related to infrastructure development. Current low price levels contribute to the problem. However, future forecasts might revise this and further scrutiny of this market is needed.

Production in OECD countries will grow by 21 Mtce (+1.2% per year on average) to 305 Mtce in 2019. Virtually all growth in OECD member countries comes from Australia, the biggest met coal exporter in the world. Other main exporting countries, Canada and the United States, are forecast to slightly raise met coal output over the outlook horizon. Supply in OECD Europe declines mainly due to the phase-out of domestic production in Germany by 2018.

Figure 3.11 Forecast of met coal supply



* Estimate.

Box 3.5 Coal-related CO_2 emissions can only rise in the medium term

Overall CO_2 emissions from fuel combustion have risen by approximately 2.4% since the beginning of the 2000s, to 31.7 $GtCO_2$ in 2012. Coal-related CO_2 emissions over the same time horizon have grown more rapidly by an average of 3.6% per year to 13.9 $GtCO_2$ in 2012. Consequently, coal's share in overall CO_2 emissions from fuel combustion has risen steadily from approximately 38.1% in 2000 to approximately 43.8% in 2012. Non-OECD countries, specifically China, accounted for almost the entire growth: coal-related CO_2 emissions decreased in OECD countries (-0.8% per year) compared to a steady increase in non-OECD countries by approximately 6.4% per year.

Non-OECD countries accounted for the vast majority, approximately 72%, of coal-related CO_2 emissions in 2012. China alone accounted for almost half of global coal-related CO_2 emissions in 2012. Despite gains in efficiency through the increased use of ultra-supercritical technology, with global coal consumption projected to increase by on average 2.1% per year over the outlook period, coal-related CO_2 emissions are projected to rise as well. CCS is not projected to play a significant role for CO_2 emissions reduction over the outlook period. Non-OECD countries, which drive global coal demand growth, will also be the driver of future CO_2 emissions as OECD countries continue on their downward trajectory (Figure 3.12).

Figure 3.12 Coal-related CO_2 emissions of OECD member countries versus OECD non-member countries, 2000-19

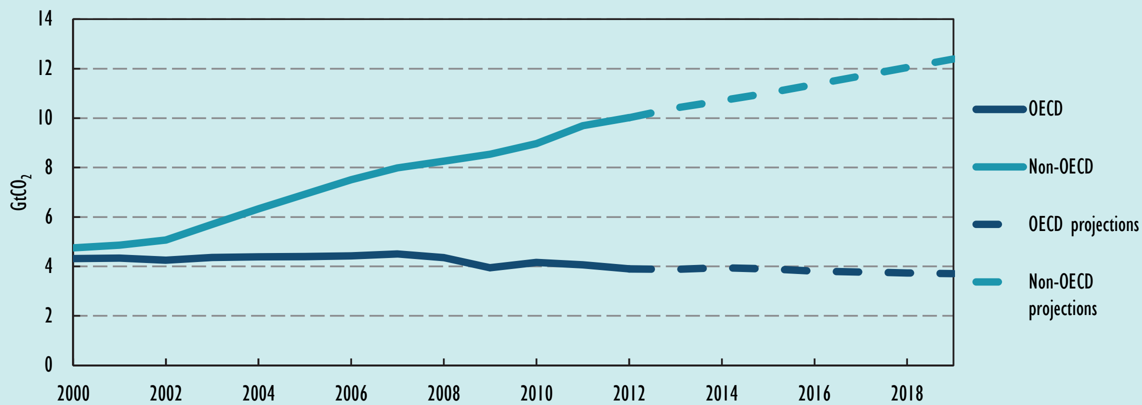
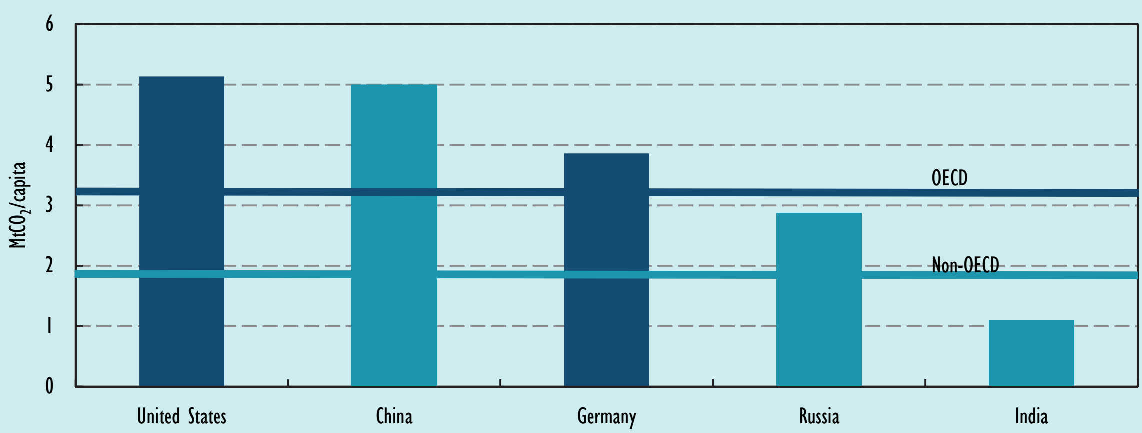


Figure 3.13 Coal-related CO_2 emissions per capita of selected countries and regions, 2012



Source: IEA analysis based on IMF (2014), *World Economic Outlook* database, April 2014, Washington, D.C., www.imf.org.

Box 3.5 Coal-related CO_2 emissions can only rise in the medium term (continued)

When examining per capita CO_2 emissions from coal, the picture is more evenly distributed (Figure 3.13). Global per capita emissions are approximately 2.1 $MtCO_2$ in 2012. This compares to 5.0 $MtCO_2$ in China and 5.1 $MtCO_2$ per capita in the United States, the two largest emitting countries in the world. Per capita emissions in the two countries have converged towards each other in the last years, reaching almost the same levels in 2012. Similarly, coal-related emissions per capita from OECD and non-OECD countries approached since 2000 as well and are projected to continue this trend over the outlook period.

References

IEA (International Energy Agency) (2014a), *Medium-Term Oil Market Report 2014*, OECD/IEA, Paris.

IEA (2014b), *Medium-Term Gas Market Report 2014*, OECD/IEA, Paris.

IEA (2014c), *Medium-Term Renewable Energy Report 2014*, OECD/IEA, Paris.

IEA (2013a), *Medium-Term Coal Market Report 2013*, OECD/IEA, Paris.

IEA (2013b), *World Energy Outlook 2013*, OECD/IEA, Paris.

IMF (International Monetary Fund) (2014), *World Economic Outlook* (database), April 2014, Washington, D.C., www.imf.org.

MNRE (Ministry of Natural Resources and Environment) (2014), *MYCarbon GHG reporting Guidelines,* NRE, Malaysia, www.mycarbon.gov.my.

Salva Report India (2014), *Salva Report India*, accessed February 2014, https://salvareport.com/.

Suruhanjaya Tenaga (2013), *Peninsular Malaysia Electricity Supply Industry Outlook 2013,* Suruhanjaya Tenaga, Malaysia, www.st.gov.my.

TNB (Tenaga Nasional Berhad) (2013), *Annual Report for 2013,* TNB, Malaysia, www.tnb.com.my.

4. MEDIUM-TERM FORECAST OF SEABORNE COAL TRADE

Summary

- **International seaborne hard coal trade is forecast to grow on average by 3.1% per year (+212 million tonnes of coal-equivalent, Mtce), from 1 039 Mtce in 2013 to 1 251 Mtce by 2019.** Based upon this forecast, seaborne thermal coal trade will provide the biggest spark and grow by 164 Mtce (+3.2% on average per year) to 950 Mtce. Seaborne met coal trade is projected to grow by 48 Mtce (+3.0% per year), totalling 301 Mtce by 2019.

- **The OECD country group, a net importer of oil and gas, is forecast to become a net exporter of coal by 2019.** This is mainly caused by decreasing demand in OECD Europe and OECD Americas as well as increasing production (and exports) from OECD Asia Oceania. Australia will become the world's largest coal exporter (measured by energy content) by 2019.

- **The shift in international coal trade to the Pacific Basin will continue.** Imports by India are projected to grow by 103 Mtce (+9.7% per year) until 2019, accounting for almost half of the growth in international seaborne trade. Chinese imports are projected to slow and peak in 2017. Compared to 2013, Chinese seaborne imports will have increased by 10 Mtce (+0.7% per year) by 2019.

- **Australia and Indonesia will supply the bulk of incremental thermal coal exports (approximately 60%).** Australia is projected to significantly increase thermal coal exports by 5.0% per year (+55 Mtce) to 2019. Indonesian thermal coal export growth will slow over the outlook period, averaging 2.0% per year (+42 Mtce until 2019).

- **More than 40% of incremental seaborne met coal exports come from Australia.** Australian met coal exports are projected to increase by 21 Mtce (+2.2% per year), totalling 171 Mtce by 2019.

Methodology and assumptions

The *Medium-Term Coal Market Report 2014* (*MTCMR 2014*) uses spatial equilibrium models to derive medium-term projections of international thermal[1] and met coal[2] trade. These models estimate trade flows between exporting and importing countries until 2019, based upon assumptions regarding the future development of coal demand, transport and production costs as well as mining and infrastructure capacities.

The simulation models include the major coal mining regions and demand hubs, and feature detailed datasets on mining and transport costs, as well as port, railway and mine capacities. Expansions of mine and infrastructure capacities are derived from detailed project lists. Different coal qualities are distinguished by type (thermal or met coal) and energy content. The evolution of mining costs is projected using assumptions based upon the price developments of input factors such as diesel fuel, steel products or labour force. Productivity gains are assumed to be lower than increases in infrastructure and mining costs due to input price escalations and deteriorating geological conditions. It is further assumed that the main policies regarding coal, such as climate policies, export quotas, taxes and royalties, stay constant during the outlook period unless changes have been firmly committed.

[1] For more details see previous editions of this report. A detailed model description is provided in Paulus and Trüby (2011).
[2] For further details, please refer to Trüby (2013).

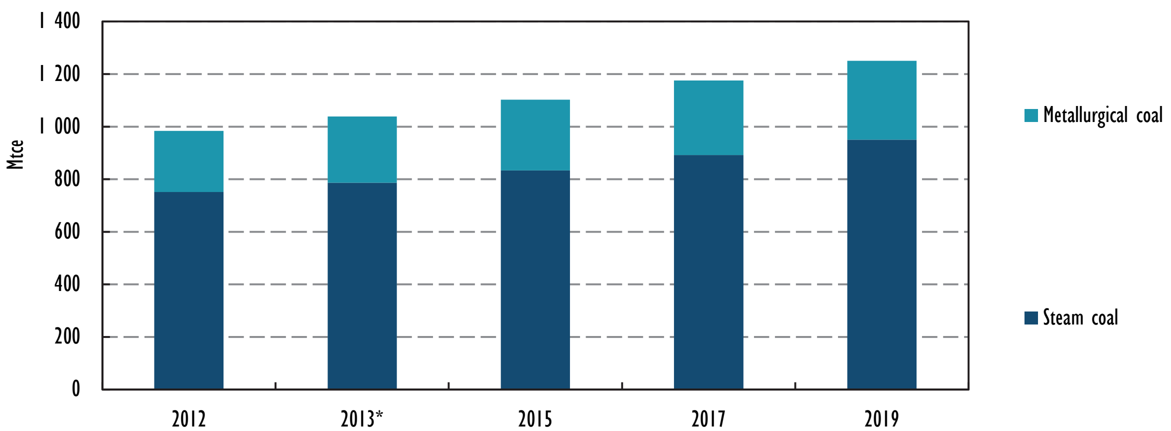
Seaborne trade

Seaborne hard coal trade is forecast to grow by 212 Mtce (+3.1% per year), from 1 039 Mtce in 2013 to 1 251 Mtce by 2019. Most incremental volumes come from thermal coal (+164 Mtce), which accounts for approximately three-quarters of the global seaborne coal trade. The seaborne market for met coal will grow by 48 Mtce, totalling 301 Mtce by 2019.

The OECD country group will become a net exporter of hard coal by 2019. This is mainly caused by decreasing demand in OECD Europe and OECD Americas as well as increasing production (and exports) from OECD Asia Oceania. Australia will become the world's largest coal exporter by 2019 when measured in energy content.

Regarding OECD non-member countries, net hard coal imports in India will rise from 139 Mtce in 2013 to 242 Mtce by 2019, causing India to become the second-largest coal importer, surpassing Japan and approaching Chinese import levels. Net hard coal imports in China will peak in 2017 and decline slightly thereafter until 2019. Demand growth in Association of Southeast Asian Nations (ASEAN) countries will lead to rising net imports, despite an increase in Indonesian production and exports. Net exports from Latin America (in particular Colombia) are projected to rise significantly over the outlook period.

Figure 4.1 Development of the international seaborne steam and metallurgical coal trade



* Estimate.

Seaborne thermal coal trade forecast, 2014-19

Seaborne thermal coal trade is forecast to grow by 3.2% per year over the outlook period, from 787 Mtce in 2013 to 950 Mtce by 2019. The share of seaborne thermal coal trade in global thermal coal consumption will remain relatively low at 18.4%. Hence, most global consumption will still be domestically produced. Increasing imports to the Pacific Basin and, in particular, to Asian countries account for almost the entire growth in seaborne thermal coal trade.

India will become the largest thermal coal importer by 2019, surpassing China. Its imports will rise on average by 10.7% per year from 104 Mtce in 2013 to 191 Mtce by 2019. This development is primarily caused by a strong increase in thermal coal demand (+4.9% per year) and a domestic coal production that cannot keep pace (+2.9% per year). However, the balance of domestic production and demand growth has to be monitored carefully in coming years. The newly elected government has announced plans to raise production at Indian coal mines and accelerate commissioning processes for new power plants. Which of these developments outweighs the other will significantly affect future import demand in India.

Box 4.1 China's low quality coal ban: Killing or triggering imports?

After many rumours and announcements during the past years, on 1 January 2015 a new regulation restricting some coal qualities will come into force. This regulation, called "Interim Measures on the Management of Commercial Coal Quality", and still subject to definitive interpretation, is summarised in Table 4.1.

Table 4.1 Restrictions of low quality coal in China

	Coal type	Min CV (kcal/kg NAR)	Max ash (%)	Max sulphur (%)
General restriction for coal sales	Lignite		30	1.5
	Other coal		40	3
Coal to be transported > 600 km	Lignite	3 941	20	1
	Other coal	4 300	30	2
***San mei* in selected areas**	All		16	1

Note: kcal/kg = kilocalories per kilogramme.

This table requires some clarification. First of all, as mentioned in Footnote 1 of Chapter 1, this report follows International Energy Agency (IEA) statistics, in which all the coal consumed in China is classified as hard coal. However, a significant share of Chinese consumption is actually lignite. Likewise, all Indonesian thermal exports are classified as hard coal, but a portion is lignite, as mentioned in Footnote 1 of Chapter 2. Moreover, the term *san mei* mentioned in the regulation is still subject to debate. In principle, we presume that it refers to coal for residential heating. Even if this ban applies also to some small industries, it seems that it will not be applied to power generators. The selected area in which coal for heating is restricted to less than 16% ash content and 1% sulphur are Beijing-Taijin-Hebei Delta, Yanztze River Delta and Pearl River Delta.

This regulation will impact both domestic and international markets. In principle, the price gap between low and high calorific value coal should widen, favouring other low calorific coal importers such as India and incentivising washing. Traders with blending facilities could receive benefits from this deal.

Australian exporters should not be significantly affected. Despite a portion of their exports containing higher ash than 16%, this should not impact Australian exporters if restrictions in the three Delta regions are not to be applied to power generation. In 2013, the three Delta regions imported 140 million tonnes (Mt).

Initially, Indonesia seems to be most negatively affected by the restrictions. However, most Indonesian coal has low or very low sulphur content. Additionally, ash limits seem to be compatible with most Indonesian coal exports. The calorific value limit seems to be a barrier for both lignite and sub-bituminous coal exports as well as sulphur for some mines in East Kalimantan. However, if bans in the three Delta regions are not applied to power generation, the main impact will be to hamper transport of this coal beyond more than 600 km, with limited effect.

Further clarification of this rule by the Chinese government is expected. In the interim, this rule should be assessed together with other policy measures adopted by the Chinese government, for example, for a new import tax for coal (of which Indonesian coal is exempted due to the free trade agreement) and the directives sent to the big companies to cut both production and imports in 2014.

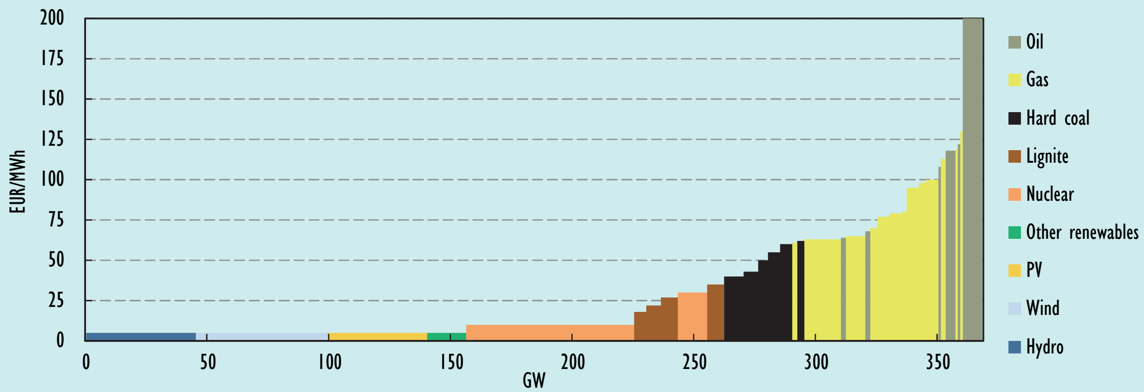
Box 4.2 Is coal the medicine to cure the Russian gas disease?

Although the fears of a potential disruption of Russian gas exports to Europe have eased for the moment, it is worth analysing the role that coal could play in this scenario as well as the potential impact of such a disruption on the coal markets.

Whereas in Europe thermal coal is mainly used to produce electricity, natural gas is used roughly equally for residential, commercial, industry and power. In principle, coal can only replace gas in producing power, so this first limitation is obvious. However, in 2013 gas demand for power generation in OECD Europe was 139 bcm, amounting to 28% of total gas demand in the region. This represents more than 80% of Russian gas exports to OECD Europe.

Figure 4.2 shows the electricity supply curve for the central system for Germany, France, the Netherlands, Belgium, Luxembourg and Switzerland, where markets are well-interconnected and integrated. Even if other regions have a different power mix, these observations on the coal-to-gas competition are largely valid in other regions. The supply curve shows renewables and nuclear being dispatched first, then lignite, followed by hard coal and gas, with very little overlapping between hard coal and gas plants.

Figure 4.2 Approximate North West European merit order that decides the power plant dispatch



Source: IEA (2014a), *The Impact of Global Coal Supply on Worldwide Electricity Prices*, OECD/IEA, Paris.

Gas used in co-generation is dispatched first, but in view of the chart, CCGTs are mainly dispatched when most of the coal is running, in cases of either peak demand or low renewable generation (actually, it is a combination of both, together with the unavailability of nuclear and lignite which largely defines the thermal gap). Therefore, even though hard coal plants in Europe are running far from full load factors, their potential to replace gas is limited. Moreover, the significant available coal generation capacity in places like Spain is of little use due to the lack of sufficient interconnection with France.

Consequently, while some additional coal could come to market in Europe in case of a gas supply disruption, coal could not substantially replace Russian gas. Nevertheless, coal is indeed important for the security of electricity supply in Europe, especially on a windless, cold and dark winter day when gas imports to Europe have become scarce.

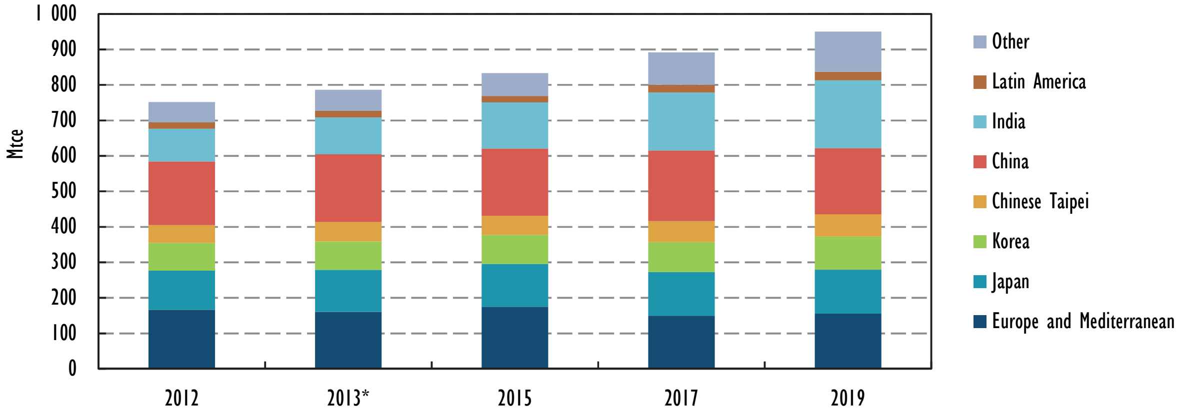
Chinese imports will decrease from 191 Mtce in 2013 to 186 Mtce by 2019, after peaking in 2017 at 199 Mtce. This development can be explained by Chinese coal buying behaviour: China traditionally arbitrages between buying coal from the international markets and consuming domestic coal. Low prices for seaborne thermal coal in previous years spurred Chinese coal imports. Current forward prices do not suggest significantly rising prices, indicating that China will continue importing coal at large levels in the medium term. However, a new railway infrastructure that might increase railway capacity to 3 billion tonnes (Bt) by 2020 according to Chinese plans, such as the two railway line projects, Caofeidian port/Hebei in Inner Mongolia and Rizhao port/Shangdon in Shanxi, and efficiency gains in Chinese mining will drive domestic prices further downward at the end of the outlook period. This will lead to rising domestic coal consumption in China and reduce import requirements. However, Chinese policies will be pivotal for defining import levels, as they can modify the competition between domestic and international coal in the East Coast of China, which is essential to defining prices and import volumes.

Declining demand for thermal coal in most parts of Europe will reduce import need. Thermal coal imports to Europe and the Mediterranean will slightly drop from 160 Mtce in 2013 to 155 Mtce by 2019. Lower domestic coal supplies in several European countries, most prominently the United Kingdom and Germany, as well as increasing domestic demand in Turkey soften the drop in imports.

Korea and Japan rely on imports to meet their thermal coal demand. Thermal coal imports to Japan will rise moderately by 0.7% per year reaching 124 Mtce by 2019. Imports to Korea will grow by 2.4% per year until 2019 spurred by increasing electricity demand and the commissioning of approximately 10 gigawatts (GW) of new coal-fired power plant capacity. Seaborne imports to Korea will amount to 93 Mtce by 2019. Imports to Chinese Taipei will grow by 2.5% per year on average, reaching 63 Mtce by 2019.

Increasing coal-fired electricity generation will push import demand in countries such as Malaysia, Thailand, Viet Nam and the Philippines. Imports to ASEAN countries are therefore projected to grow significantly over the outlook period. Viet Nam will become a net importer by 2017. ASEAN countries are subsumed under the country group "Other" in Figure 4.3, together with several smaller importers and the United States.

Figure 4.3 Seaborne thermal coal imports



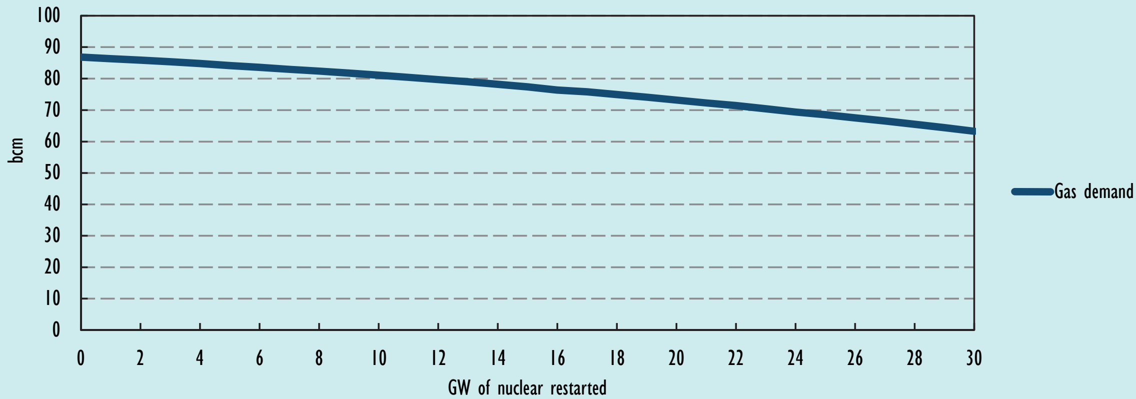
* Estimate.

Indonesia will remain the world's largest thermal coal exporter, with a market share of approximately 40% in 2019. A decline in the calorific value of their exports is expected. Although Indonesian exports will increasingly come from mines farther away from their seaports, Indonesian exports will remain in the lower cost range of the global supply curve. Compared to the average annual growth rate over the past ten years (+18.1%), exports will increase by only 2.0% per year, reaching 379 Mtce by 2019. Regarding the absolute increase, Indonesia will contribute approximately one-forth of all incremental thermal coal exports. Indonesian exports will benefit in particular from the surge in import demand in India.

Box 4.3 Impact of Japanese nukes on coal? Maybe in Europe!

In April 2014, the government of Japan launched the first energy strategy following the Fukushima nuclear accident resulting from the earthquake of 2011. In this new strategic energy plan, which sets basic policies for the next 20 years, the cabinet positioned nuclear power as one of the key "base-load power sources," abandoning the zero-nuclear goal of the previous administration. The aim of the government is to promote restarting nuclear reactors, if they pass the new regulatory requirements based upon the standards established by the Nuclear Regulation Authority following the Fukushima nuclear accidents. By doing so, the Japanese government hopes to recover a lower-cost, stable power supply system. Based upon the new standards, ten electricity companies have applied for a safety review of 20 reactors in 13 nuclear complexes as of October 2014.

Figure 4.4 Gas demand for power vs. nuclear plants



The shutdown of all reactors over the past three years has led to an increase in Japanese import of liquefied natural gas (LNG), raising the price of LNG in Asian spot markets. In 2012, LNG imports marked a record high of 87.3 Mt compared to 70 Mt in 2010. A new record was again set in 2013 with LNG imports marking 87.5 million. Nevertheless, LNG import growth has notably slowed over the past year (see IEA, 2014b).

While LNG is more expensive than coal and price differentials will remain despite the foreseen progressive decrease of Asian gas prices, the IEA projects that LNG will be partially displaced by the return of nuclear power, along with Japan's limited oil-fired power generation. A simple dispatching model for Japan confirms the basic logic that on average every terawatt hour (TWh) of nuclear will replace two-thirds of gas and one-third of oil power generation.

The restart of nuclear power plants in Japan would lead to a relaxation of the global LNG market, freeing up gas volumes that could be diverted to other parts of the world such as Europe and displace some coal. In the past, European LNG imports approximately halved on an aggregate basis compared to 2011, reaching 46 billion cubic metres (bcm) in 2013 due to low gas demand surrounding the Eurozone crisis, European countries favouring cheaper sources of gas such as Russia and low coal prices.

In summary, when Japanese nuclear plants restart, the impact upon coal demand will be stronger in Europe than in Japan. Coal plants in Japan will run at full load in any case, whereas lower demand for gas in Japan can push LNG prices down causing natural gas to displace some coal in Europe.

A number of coal policies have been discussed and/or introduced in Indonesia in past years. The main purpose of these policies is to secure supplies for domestic demand, expand the range of coal resources and ensure coal revenues for the state. One policy, for example, is an announced production cap which will prove difficult to implement: after a new mining law in Indonesia was passed in 2009, the authority to issue mining licences has been decentralised to local governments, and many licences have been issued to small producers. These producers have been producing rapidly over the past few years, and are not always accountable to the central government. Last year, the central government claimed that over 70 Mt of coal were produced illegally. Some portion of that coal appears to have been produced by those small mines.

Another policy that has been discussed is a ban on low calorific coal exports. As revenues for the government from low calorific coal are low, Indonesian authorities seek to increase revenues from coal by pushing producers to upgrade coal before export. However, as a commercial coal upgrading technology does not exist, the implementation of this regulation has been delayed.

A change in foreign ownership divestment has also been proposed, potentially requiring foreigners that own coal concessions to divest the ownership of their investment. This would most likely reduce interest from foreign investors on large projects. A raise of royalties for IUP[3] mines from the existing 3 to 7% of revenue to 13.5% of revenue has been discussed as well. Coal Contracts of Work (CCoWs) and Coal Cooperation Agreements (CCAs) are already required to pay royalties at the rate of 13.5% of revenue, while IUP royalties are lower and based upon the type of coal sold.

The Indonesian government is now also putting effort into controlling exports. As of October 2014, new export licenses had been introduced which were required for all coal exports. Issuing these licenses requires the payment of outstanding royalties, among other requirements, and as some miners did not obtain the licences in time, this change led to some delays in coal deliveries. These coal policy developments must be closely monitored, as they might have significant impact on Indonesian coal supply and lead to revisions in trade projections in the future. Box 4.4 provides an analysis on the effect of the realisation of a production cap in Indonesia.

In absolute terms, Australian exports will grow the strongest over the outlook period (+55 Mtce), up from 160 Mtce in 2013 reaching 215 Mtce by 2019. Australia will thus strengthen its position as the second-largest thermal coal exporter. Exports will benefit from new infrastructure and mining projects that either have already started or are about to start operations. However, several mining operations are facing challenges due to escalating costs and low coal prices. Consequently, we do not expect a full rollout of the Galilee and Surat Basins by 2019. However, a full development of these basins has the potential to meet any demand, no matter how big it can be (see Chapter 5).

Russia is traditionally a high-cost supplier due to high inland transport distances and associated transport costs. Its coal will therefore be partially eased out of the European market by increasing competition from exporters from Colombia and the United States. Fostered by a rise in Asian import demand and infrastructure extensions in Russia's Far East, the trend of increasing Russian exports to the Pacific market will continue. Overall, Russian exports will rise from 96 Mtce in 2013 to 114 Mtce by 2019.

[3] There are three main types of coal mining licenses in Indonesia; Coal Co-operation Agreements (CCA), Coal Contracts of Work (CCoW) and Izin Usaha Pertambagan licenses (IUP).

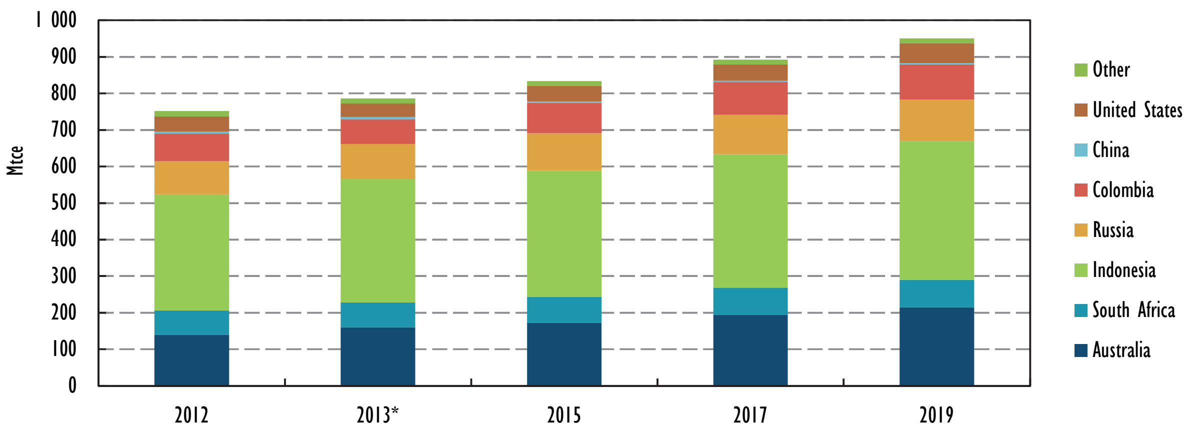
New mining capacity and export infrastructure will boost Colombian thermal coal exports. Colombia benefits from low production costs and high-quality coal that will increasingly come from mines further inland. Colombian exports are projected to grow at the second highest rate among the major exporters. Colombian exports will grow at 6.2% per year, from 68 Mtce in 2013 to 97 Mtce by 2019. The main export destinations will be Europe, the Mediterranean and Latin America.

South African coal exports have been limited by a lack of sufficient infrastructure in the past. New infrastructure projects surrounding the Richards Bay Coal Terminal (railway connections and port extensions) will lead to an increase in South African exports to 75 Mtce by 2019, up from 69 Mtce in 2013. This increase in exports will be limited by rising domestic demand. Exports will shift more and more towards the Pacific Basin, following price signals.

The United States, like Russia, is a swing supplier to the seaborne thermal market, and exports from the United States are generally at the upper end of the supply curve, except competitive coal from the Illinois and the Powder River Basin (PRB). In our analysis, we do not project significant export volumes from the PRB over the outlook period, partially due to opposition regarding the necessary infrastructure expansions. However, declining domestic coal consumption in the United States will free coal volumes that can serve the export market. Thermal coal exports from the United States are therefore projected to increase, reaching 55 Mtce by 2019.

A new mining project is expected to start operations in the Lublin Basin in Poland and will strengthen exports from Poland towards the end of the outlook period. The new mine will be very close to the Bogdanka mine, which is one of the lowest-cost mines in the seaborne market (USD 43/t). The characteristics of the coal and the seam of the new mine should prove similar to the Bogdanka mine, so with more modern equipment, coal might be exploited at mining cash costs of USD 37/t. The mine will benefit from existing rail and port infrastructure. Until now, the last mine to be commissioned in Poland was in 1984. However, investment conditions in Poland are positive, with a 19% corporate tax, government support, royalties of USD 1.2/t and a skilled labour force available.

Figure 4.5 Seaborne thermal coal exports



* Estimate.

Box 4.4 Capping production in Indonesia, shaking world coal trade

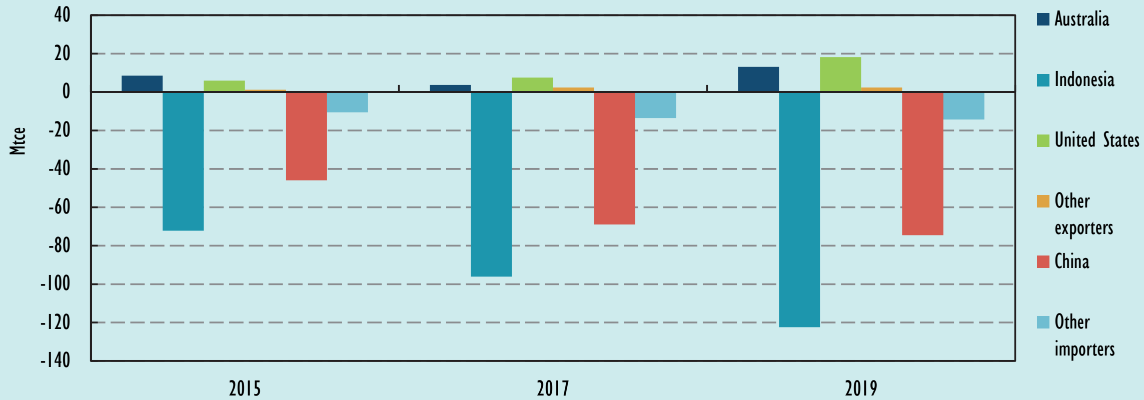
Indonesia has been the world's biggest thermal coal exporter since 2005, and during the past ten years the country increased exports by a factor of 5. In 2013, Indonesia exported 423 Mt and produced 486 Mt of thermal coal. Indonesian reserves are limited, and the government wants to preserve some for the future. This concern, combined with current oversupply in global coal trade and plummeting prices, encouraged the Indonesian Ministry of Mineral and Energy Resources to aim at limiting coal production. For the year 2014, the government announced a production cap of 400 Mt, although 420 Mt and other tonnages were also discussed. The forecast of the report is based on increasing production and exports in Indonesia. This Box analyses the impact of a cap on global trade.

The overall production limit is, however, difficult to realise for the government for at least two reasons: First, a substantial amount of Indonesian coal production comes from illegal mining. The Indonesian Coal Mining Association has estimated these volumes to be approximately 74 Mt in 2013. Second, it is not clear if the government is able or willing to sanction mining companies if their production exceeds the target. Current Indonesian production numbers underline the difficulties: For the first five months of 2014, official data shows that production has already increased by 4.5% year-on-year. However, it is still unknown how the Indonesian government will react if companies exceed their production limit. Sanctions or the withdrawing of licenses are currently in the discussion as well as simply doing nothing.

No matter how the government reacts, international coal markets should scrutinise developments concerning a production cap in Indonesia. Therefore we have calculated the effect that the enforcement of the output limit of 400 Mt (including successful measures against illegal mining) by 2015 would have on global coal trade.

Figure 4.6 illustrates the effects of a production cap on thermal coal imports and exports. The figure shows the differences compared to the trade forecast from this report. Notably, Indonesian exports are highly and immediately affected, as they are more than 60 Mtce lower due to the production cap. The effect of a cap increases over time until 2019, as this report's market outlook expects both increasing production and demand in Indonesia. Lower Indonesian exports are primarily compensated by higher domestic production in China (+43 Mtce by 2019), higher exports in particular by the United States (+18 Mtce) and Australia (+13 Mtce) and slightly less coal consumption due to higher international coal prices. In China, for example, prices increase by 6% by 2019, which causes a demand reduction of 30 Mtce. Although Indonesian coal is almost entirely sold to Asian countries, price reactions are expected globally due to arbitrage connections between the different world regions.

Figure 4.6 Effects of Indonesian production cap on global thermal coal exporters and importers



Seaborne met coal trade forecast, 2014-19

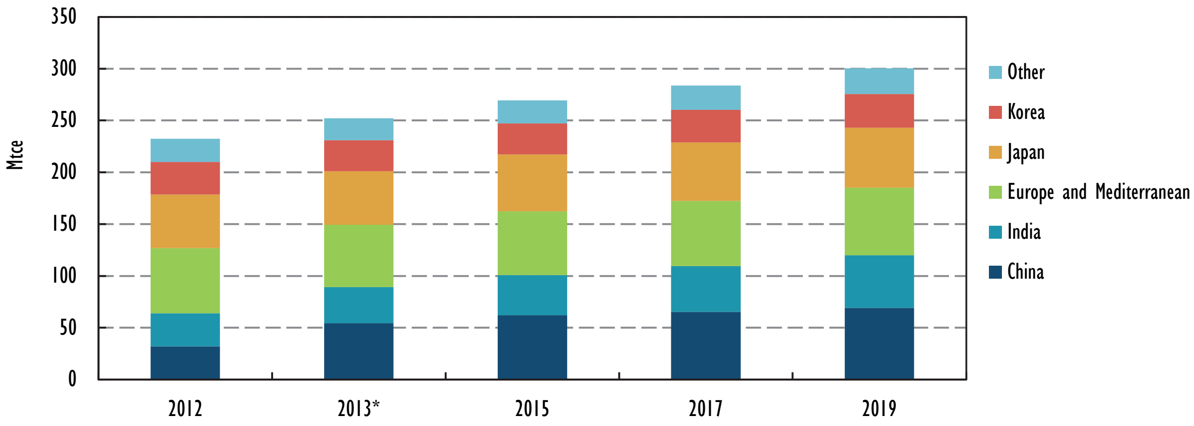
Seaborne met coal trade will increase from 252 Mtce in 2013 to 301 Mtce by 2019, growing on average 3.0% per year. Import demand will rise in both the Atlantic and the Pacific Basin, however most significantly in Asian countries. As growth in seaborne trade will be stronger than demand growth, the share of seaborne trade in met coal demand will increase, from 28% in 2013 to 30% in 2019.

China is the largest met coal consumer and importer in the world. Its seaborne imports will grow by 4.1% per year, from 55 Mtce in 2013 to 69 Mtce by 2019. In addition to its seaborne imports, China will continue to import significant volumes from Mongolia via overland transport. Mongolia is the world's largest overland met coal exporter, and its exports to Chinese markets are highly cost-competitive. Free-on-board (FOB) costs in Mongolia typically range between USD 40/t and USD 65/t. Exports from Mongolia to China are projected to increase by 13 Mtce, totalling 30 Mtce by 2019. A boost for exports will be the new 267 km rail line from Ukhaa Khudag mine to the Gashuum Sukhail border by 2015, significantly reducing transportation costs. Shenhua Group, the largest Chinese producer, will buy 1 Bt over the next 20 years in accordance with recent announcements.

Japan, Korea and Chinese Taipei are dependent upon imports, as none of these countries has a domestic met coal production. Import demand growth in these countries is primarily caused by economic growth and demand in the steel sector. Economic growth outlook by the International Monetary Fund (IMF) is mostly positive for the outlook period. Consequently, all three countries will see moderate import growth until 2019. Japan, the world's largest seaborne met coal importer in 2012, will increase imports by 1.8% per year, from 52 Mtce in 2013 to 58 Mtce by 2019. Imports to Korea and Chinese Taipei are projected to increase by 1.5% and 1.3% per year respectively.

Projected import growth for India, which has limited high-quality met coal reserves, is the highest among all major importing countries. Spurred by strong economic growth, imports to India will increase by 6.5% per year, from 35 Mtce in 2013 to 51 Mtce by 2019. Incremental volumes amount to 16 Mtce and are the highest among all countries.

Figure 4.7 Seaborne met coal imports



* Estimate.

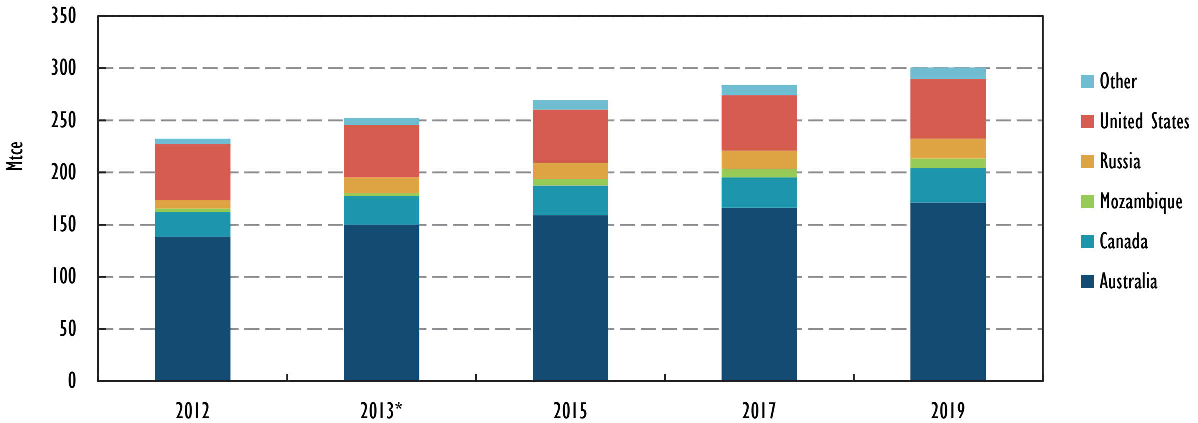
Imports to the Atlantic Basin are also projected to increase over the outlook period. Imports to Latin America are projected to grow by 1.9% per year to 14 Mtce by 2019, led primarily by Brazil. Its local steel industry benefits from Brazil's cost-competitive, high-quality iron ore reserves. Diminishing domestic production in Europe and rising demand in growing countries such as Turkey will lead to modest import growth (+1.4% per year) in Europe and the Mediterranean, with imports in 2019 amounting to 65 Mtce.

Seaborne met coal supply sources remain highly concentrated, both on a country and company level. Australia, Canada and the United States account for approximately 90% of the 2013 global seaborne met coal market. This share will drop slightly to 87% by 2019. On the company level, five companies together (BHP Billiton, Rio Tinto, Glencore, Anglo American and Peabody Energy's Australian operations) controlled more than 50% of seaborne met coal export capacity (Lorenczik, 2014). In the past, seaborne metallurgical trade has been primarily marketed through long-term contracts. Recently, a shift towards a more spot-based trade can be identified, and this trend is likely to persist during the outlook period.

Australia is the largest met coal exporter in the world, accounting for almost 60% of the global seaborne trade in 2013. High prices in previous years have spurred investment activity. These mines are now becoming operational to serve the seaborne market. Australian producers are on the upper end of the supply curve and face the risk of escalating operation costs. Given recent low prices for met coal, some Australian met coal producers have been reported to be producing at a loss (see also analysis in Chapter 2). With some mines facing closure and investment projects being delayed, Australian export growth projection is less bullish than in previous editions of this report. Australian met coal exports are projected to grow by 2.2% per year on average, from 150 Mtce in 2013 to 171 Mtce by 2019.

The United States will maintain its status as the second-largest met coal exporter. Despite Appalachian met coal (the only source for met coal exports from the United States) being typically high-cost, exports are projected to increase by 2.2% per year, totalling 57 Mtce by 2019. Exports will mostly serve markets in Europe, the Mediterranean and Latin America (Brazil).

Figure 4.8 Seaborne met coal exports



* Estimate.

Canadian exports are primarily directed towards the Pacific Basin. Recent infrastructure projects on Canada's west coast (see Chapter 5) will allow Canadian exports to grow by 3.4% per year, reaching 33 Mtce by 2019. Incremental Russian met coal exports will mostly serve the demand centres in the Pacific Basin (for example China and other Asian countries) and the new export infrastructure in Russia's Far East and new mining capacity (such as Mechel's Elga mine) will spur exports. Russian exports are projected to grow by 4.1% per year, totalling 19 Mtce by 2019.

Even though Mozambique achieves the highest growth rate of all major exporting countries (+18.2% per year), we do not project any significant volumes from the country until 2019. Exports are projected to reach 9 Mtce by 2019, up from 3 Mtce in 2013. Infrastructure problems have been the bottleneck for exports from Mozambique in the past, and currently all exports are shipped through the Sena railway line or overland via truck. These infrastructure problems are projected to ease in the time period through the outlook horizon (see Chapter 5).

References

IEA (International Energy Agency) (2014a), *The Impact of Global Coal Supply on Worldwide Electricity Prices*, OECD/IEA, Paris.

IEA (2014b), *Medium-Term Gas Market Report 2014*, OECD/IEA, Paris.

Lorenczik S. Malischek R. and Trüby J. (2014), *Modelling Strategic Investment Decisions in Spatial Markets*, EWI Working Paper, No. 14/09.

Paulus M. and Trüby J. (2011), *Coal Lumps vs. Electrons: How do Chinese Bulk Energy Transport Decision Affect the Global Steam Coal Market?* Energy Economics, Elsevier, Amsterdam.

Trüby J. (2012), *Strategic behaviour in international metallurgical coal markets*, Energy Economics, Elsevier, Amsterdam.

5. EXPORT CAPACITY INVESTMENT OUTLOOK

Summary

- **The coal industry is currently undergoing significant changes moving from a period of pronounced investment activity to a period in which these capacities enter production.** Decreasing prices for both thermal and metallurgical coal (met coal) in 2013 as well as the perception of an oversupplied market have led investors to delay, postpone or cancel several mining and infrastructure projects.

- **Probable new export mining capacities amount to approximately 100 million tonnes per year (Mtpa) by 2019.** The largest capacity additions are projected for Australia, which accounts for approximately two-fifths of global probable mine additions over the outlook period.

- **Potential export mining capacity amounts to more than 400 Mtpa by 2019.** The likelihood of realisation varies significantly between projects. While projects in Indonesia are more likely to be realised, projects in the Galilee and Surat basins of Australia face high levels of uncertainty.

- **Worldwide port handling capacity is projected to increase by approximately 270 Mtpa by 2019.** However, coal transport infrastructure to ports, specifically railway infrastructure, remains a key requirement for increasing exports, future utilisation of ports and the realisation of mining projects.

Investment in export mining capacity

Investments in export mining capacity typically have a lead time of several years. Therefore, analysing export mining projects currently in the planning or construction phase allows us to estimate the development of export mining capacity in the coming years.

Within our methodology, we distinguish between probable and potential expansion projects. Those whose current status is either “approved”, “committed”, or “under construction” have been classified as probable additions. Less advanced projects whose current status is either “feasibility study”, “environmental impact study” or “awaiting approval” have been classified as potential additions, which have been based upon estimates for countries where detailed project lists were not available. Projects classified as “potential” face uncertainty as to whether they will be able to come online over the outlook period, or be realised at all for reasons such as insufficient financial funding or environmental constraints.

Additionally, potential projects can be delayed for years. In the current situation of oversupplied markets and low prices, many potential projects are simply not profitable enough to be realised. Currently, all Indonesian capacity additions are classified as potential due to limited information on specific projects. Further, for many probable and potential projects, the targeted mine capacity is rarely reached in the start-up year, as achieving full capacity might take a few years. We assume ramp up time to range between two to six years.

In general, the timing and volume of mining capacity entering the market depend on various factors: First, the size of the resource base is a crucial factor in determining project capacity. Second, current and expected demand and price levels, as well as the country’s expected position in the supply cost curve, are decisive to project profitability. Third, export mine projects stand or fail with the availability of export infrastructure, for example seaports and inland transports. Delays in the construction or expansion of infrastructure may substantially hamper the realisation of a mining project. Additionally, future regulatory frameworks, public opposition or political risks are key investor uncertainties affecting the likelihood of a project's realisation and economic success. Finally, access to capital, in particular for greenfield projects requiring new infrastructure, can be a critical issue: strategic foreign direct investment remains significant to investment activity over the outlook horizon with, for example, Chinese and Indian firms continuing to invest in coal projects worldwide.

New export mining capacity classified as "probable" amounts to slightly more than 100 Mtpa over the outlook period (see Figure 5.1). Around two-fifths of capacity additions are projected to be in Australia, which will increase both thermal and met coal capacity. Colombia and Russia are also projected to add export mining capacity by 2019. Additional volumes in Mozambique and South Africa, even though classified "probable", are subject to higher levels of uncertainty, as they require substantial export infrastructure additions.

Figure 5.1 Cumulative probable expansion of hard coal export mining capacity, 2015-19

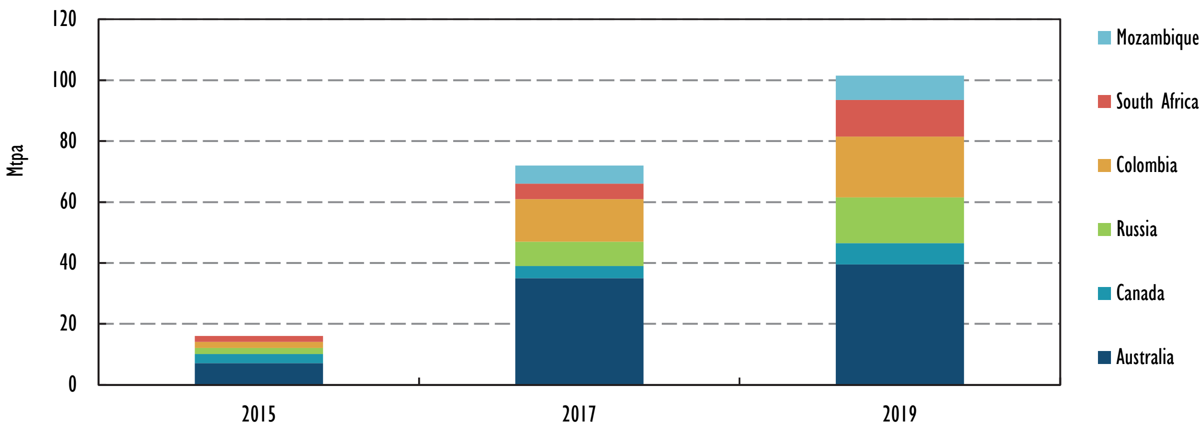
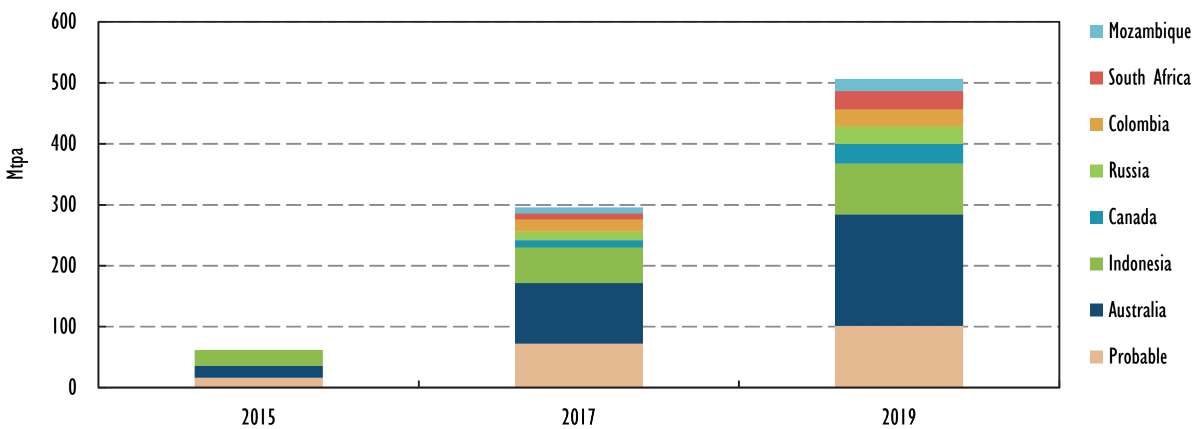


Figure 5.2 Cumulative probable and potential expansion of hard coal export mining capacity, 2015-19



Potential export mining additions to 2019 are assumed to be slightly above 400 Mtpa. However, this does not imply that these projects will be brought online over the outlook horizon. Some of them will be delayed, postponed or cancelled. Nevertheless, some potential mines are assumed to come online over the outlook period, in particular in Indonesia, which is projected to increase export capacity.

Box 5.1 Carbon capture and storage: Taking off?

As noted elsewhere, coal use in its current form is unsustainable. Coal-fired heat and power generation is the largest single source of carbon dioxide (CO_2) emissions resulting from fuel combustion today. In this year's report, we are including for the first time an update on the progress of the only technology available currently to significantly reduce emissions from coal combustion: carbon capture and storage (CCS).

2014 is an appropriate year to include CCS. A CO_2 capture plant at the Boundary Dam coal-fired power plant in Canada entered operation this year, reducing the emissions rate to 130 kilogrammes per megawatt hours (kg/MWh), easily meeting the regulatory performance standard of 420 kg/MWh. In July 2014, the Petra Nova Carbon Capture Project took a final investment decision to retrofit 250 megawatts (MW) of a coal-fired power plant in Texas with CO_2 capture. In 2015, the 590 MW Kemper County integrated gasification combined-cycle coal plant in Mississippi will commence operation with an emissions rate matching a natural gas combined-cycle plant.

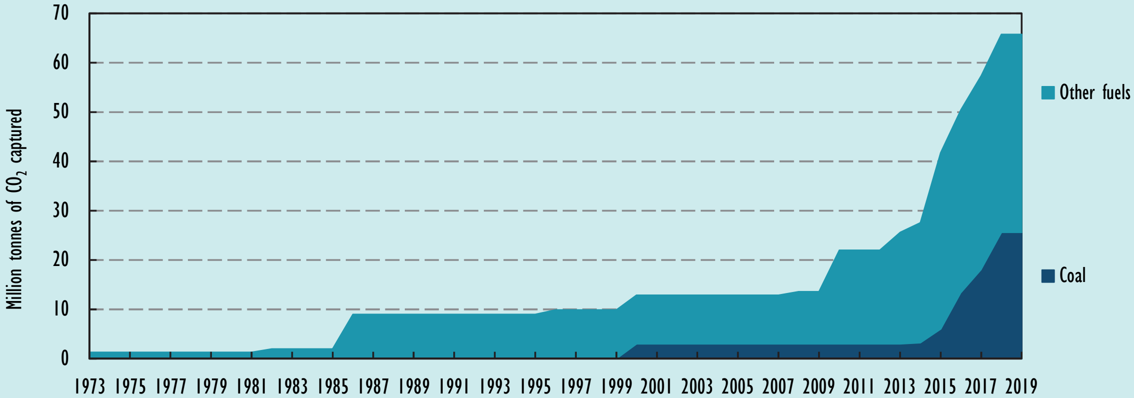
CCS: A pollution control technology for CO_2

The first step in CCS is the capture of CO_2 from a large pollution source (a power plant or an industrial facility). The captured CO_2 must then be transported to a suitable storage site, where it is injected and monitored to ensure that it will not escape into the atmosphere.

Around 20 million tonnes (Mt) of CO_2 are currently captured per year from fossil fuel use, mostly from natural gas (Figure 5.3). However, projects that use coal are projected to increase sharply in number through 2020. Projects based upon coal-fired power are under development in Canada, China, the United States and the UK. But CCS is not only a technology for the power sector: CCS projects to mitigate the significant levels of emissions from coal-to-gas, coal-to-liquids, coal-to-chemicals and blast furnaces are also under development.

While pipeline transport of CO_2 (and similar fluids) is widely practiced, particularly in the United States, identification and development of storage sites can be costly and time consuming. Not all locations are universally suitable for CO_2 storage. There are currently approximately 6 000 kilometres (km) of CO_2 pipelines in the United States. 5 Mt of CO_2 per year is currently safely stored in on-shore and off-shore aquifers as well as depleted gas fields and oil reservoirs. In oil-producing regions, CO_2 can be a commodity for enhanced oil recovery (EOR), and most of today's CO_2 capture projects sell the CO_2 for use in EOR.

Figure 5.3 Cumulative CO_2 captured from production and use of different fuels



Note: This chart represents large-scale projects integrated with geological CO_2 injection defined in accordance with Global CCS Institute Status of CCS Project Database. Projects not operational by 2014 have been included if they have reached an advanced stage of planning (at least the Define stage in Global CCS Institute Asset Lifecycle Model).

Box 5.1 Carbon capture and storage: Taking off? (continued)

CCS increases a plant's demand for coal

One reason that CCS is not more widely deployed is that current climate policies in most countries do not support the additional capital and operational costs. Full CO_2 capture (90% of CO_2) is expected to increase the capital cost of a coal-fired power plant by 45% to 75% and reduce the efficiency by between 20% and 25%, although there are current efforts being made to reduce this energy penalty. Therefore, the annual coal input for a state-of-the-art 1 gigawatt (GW) power plant could increase from 1 750 Mtce to 2 190 Mtce. The expected net result is an increase in the levelised cost of electricity to approximately 40% to 75%.

What the future holds

IEA scenario modelling for keeping climate change within safe limits (the 2°C scenario, or 2DS) indicates that the most cost-effective route to emissions reduction will include a significant role for CCS alongside other technologies. The public and private sectors have made cumulative investments in major CCS projects of approximately USD 10.5 billion. Today, these investments are made in locations where they are supported by climate policies and an expectation of continued fossil fuel use.

However, the market for CCS lags a long way behind developments in the coal market. Tackling climate change requires that these two markets begin to develop together. It has been suggested that CCS investments are akin to an insurance policy for the coal industry. Nevertheless, as other factors impact the market outlook for coal, government action is required to raise the likelihood that such a policy will pay off. Putting a price on CO_2 emissions, incentivising low-carbon power generation and supporting exploration for suitable CO_2 storage are among the necessary actions.

For more information: IEA (2013), *Technology Roadmap: Carbon Capture and Storage*, OECD/IEA, Paris.

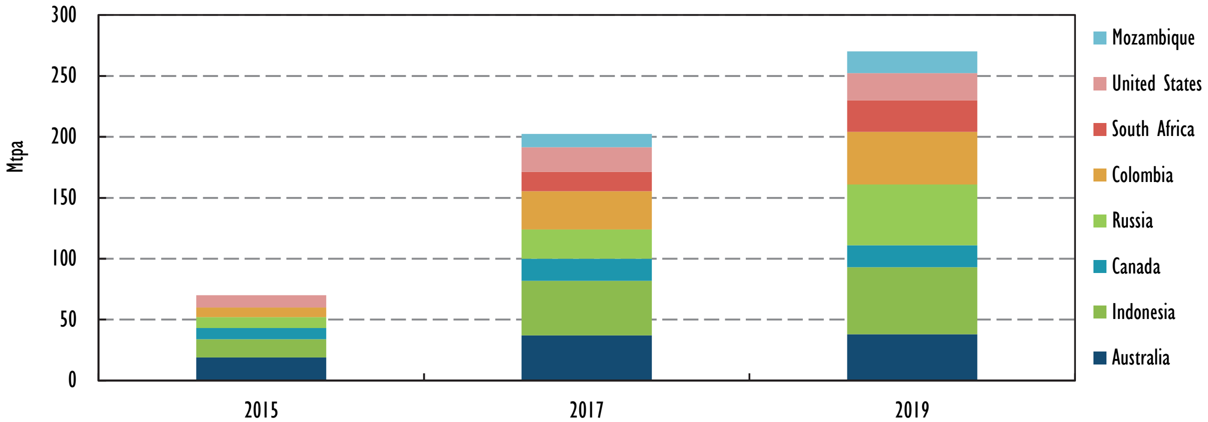
Investment in export infrastructure capacity

As with investments in export mines, export infrastructure investments (for example seaports and inland transports) are associated with lead times of several years. Therefore, analysing projects currently under construction or in the planning stages allows us to estimate the development of export infrastructure capacity in the coming years.

Export infrastructure investments play a key role in future exports and the development of export mining projects whose success or failure is dependent upon the availability of sufficient export infrastructure. Mozambique and South Africa are just two prominent examples of countries whose exports suffered in the past because of insufficient transport infrastructure.

Several port capacity projects are currently under construction, for example in Australia, and numerous other projects are projected to come online over the outlook period resulting in an incremental coal terminal capacity of 270 Mtpa by 2019 (see Figure 5.4). The largest capacity additions will take place in Russia and Indonesia which together account for more than one-third of all additions over the outlook horizon. Further coal terminal capacity is projected to come online in Australia, Colombia and South Africa, as shown in the representative projects discussed in the next section.

Figure 5.4 Projected cumulative additions to coal terminal capacity, 2015-19



Regional analysis

The following section is a regional analysis of current investment projects in both coal mining and export infrastructure over the outlook period.

Australia

Investment in export mining capacity

Several mining projects have been completed in Australia since the last publication of this report. Their combined production capacity exceeds 32 Mtpa at an estimated investment cost of over USD 5 billion. Major projects that entered production stage are the new 5.5 Mtpa Caval Ridge coking coal mine in Queensland operated by the BHP Billiton Mitsubishi Alliance (BMA), the 6.7 Mtpa expansion of the Ulan West thermal coal mine in New South Wales jointly operated by Glencore and Mitsubishi and the 8 Mtpa expansion of the thermal and semi-soft coking coal Ravensworth North mine in New South Wales jointly operated by Glencore and the Japanese trading company Itochu.

Australia accounts for approximately two-fifths of global probable mining additions projected for the outlook period. Probable mining additions in Australia amount to 40 Mtpa. Approximately one-half of the projects will come online in Queensland, mostly in mature mining regions, and the remainder in New South Wales.

Major greenfield projects such as the Eagle Downs project and the Grosvenor underground mine are projected to start operations in Queensland. The Eagle Downs coking coal project (4.5 Mtpa) is operated by Aquila Resources and Vale and slated for first output in the first half of 2017. The project is approximately six months behind schedule because of weak coal prices and legal disputes between the companies. Anglo America intends to start operations at its Grosvenor underground coking coal mine (5 Mtpa) in 2016. The Maules Creek project (10.8 Mtpa), operated by Australian mining firm Whitehaven Coal and the Japanese companies Itochu and J-POWER, is a major greenfield project in New South Wales projected to start operations in 2015. The mine, which is located 16 km from the main rail line and some further 360 km to the Port of Newcastle in the Gunnedah basin, will produce semi-soft coking coal and thermal coal. However, the Maules Creek project faces severe community opposition, which may lead to delays.

Potential capacity additions in Australia are significant and exceed 180 Mtpa until 2019. A majority of these projects are located in new basins, such as the Galilee basin in Queensland and the Surat basin which stretches from New South Wales to Queensland. Successful realisation of these projects critically hinges not only on financing and environmental issues but also on adequate connection of the mines to the coal export terminals. Four big greenfield projects located in the Galilee basin comprise a combined targeted capacity of over 160 Mtpa: the 32 Mtpa Alpha Coal Project operated by GVK Hancock Coal, the 60 Mtpa Carmichael coal project operated by Adani, the 40 Mtpa China First coal project operated by Waratah Coal and the 30 Mtpa Kevin's Corner project by GVK. A further major project in Queensland is the Project China Stone (45 Mtpa) operated by MacMines Austasia. The project is currently at the publicly announced stage. However, although production starts prior to 2019 have been announced, the above listed projects are not likely to be operational until 2019 due to low coal prices as well as environmental and infrastructure concerns.

Investment in export infrastructure capacity

Export infrastructure has undergone some significant changes since the last publication of this report. In May 2014, the world's largest coal export terminal, the Port of Newcastle was leased for USD 1.5 billion by the New South Wales government for 98 years to a consortium of infrastructure investor Hastings Funds Management and China Merchants Group (CMG), a Chinese state-owned enterprise. The Port of Newcastle comprises the terminals of Port Waratah Coal Services (PWCS) and of the Newcastle Coal Infrastructure Group (NCIG). With the newly expanded coal terminal Kooragang and Carrington, PWCS now has a nameplate capacity of 145 Mtpa. NCIG reached a capacity of 66 Mtpa after completion of its expansion in 2013.

The Port of Gladstone in Queensland currently has an export capacity of 77 Mtpa. The expansion of Wiggins Island Coal Export Terminal (WICET) will add another 27 Mtpa by the end of 2014. Further plans exist for expansions at the North Queensland Bulk Ports (NQBP) facility. NQBP includes the coal terminals Abbott Point Coal Terminal, the Dalrymple Bay Coal Terminal and the Hay Point Coal Terminal as well as Mackay Port and Weipa port. Hay Point capacity is extended to 55 Mtpa resulting in a combined throughput from this facility of 190 Mtpa in 2015. Plans for the USD 10 billion Dudgeon Point Coal Terminal (180 Mtpa) and phase two of WICET were withdrawn in June 2014. Extensions of Abbott Point coal terminals 1 to 4 are at less advanced stages. BHP Billiton has pulled down development of its terminal due to the current market situation and the huge capital involved. Even though the government in Queensland has already given environmental approval to the port, the terminals are subject to environmental concerns, among others by the UNESCO because of its proximity to the Great Barrier Reef. Several big banking institutions such as RBS, Deutsche Bank and HSBC have announced that they will not finance the project. Abbot Point terminal and its associated infrastructure will be crucial for the development of the Galilee basin.

In the past, railway transport has caused problems for Australian coal exporters. However, due to recent additions, rail capacity is sufficient to handle current export volumes. New railway connections from new and existing mine basins to export terminals will be crucial for future export growth from Australia. Concerning rail connection of major ports to the Galilee basin, the Queensland government announced that it will allow for two rail networks to haul coal. Most likely are the rail corridor from the Alpha coal mine operated by Indian GVK which will join the rail network by Australian Aurizon and the 189 km rail line from the Carmichael mine project which will join existing rail infrastructure. Further, the Australian Rail Track (ARTC) plans to build an USD 700 million rail track at the Port of Newcastle to ease congestion.

Colombia

Investment in export mining capacity

Colombian export mining capacity is projected to increase until 2019. Probable export mining capacity additions amount to approximately 20 Mtpa over the outlook horizon, almost all of which will come from thermal coal.

Several projects are under way in Colombia. Turkish Yildirim Holding is currently involved in three mining projects, which it acquired from Brazilian-based Carvão da Colômbia S.A. (CCX) in early 2014 for USD 125 million along with several logistic projects. Yildirim Holding took over CCX's plans to open the Canaverales thermal coal mine by 2019 aiming at an ultimate capacity of 5.5 Mtpa, the Papayal met coal mine with an ultimate capacity of 2 Mtpa by 2017 and the 16 Mtpa thermal coal mine San Juan by 2019. Goldman Sachs also invests in new mining capacity in Colombia and aims to start-up the Cerrolargo Sur mine during the outlook period. Drummond is involved in El Descanso mine, targeted to produce 12 Mtpa. Additions of new mining equipment at Cerrejon will allow output to reach 40 Mtpa. Further investment could increase production up to 60 Mtpa by 2019.

Investment in export infrastructure capacity

Inland transport infrastructure and export port capacity in Colombia are projected to increase significantly over the outlook period. In line with Colombian plans to further increase exports in the coming years, several projects have recently been finished or announced. The expansion of Prodeco's Puerto Nuevo in Ciénaga has been completed. Cerrejon is moving forward with its USD 1.3 billion infrastructure expansion programme, which is projected to be finished by the end of 2014. The project includes work at the Cerrejon mine, at the 150 km railway serving the Cerrejon mine and expansions at Puerto Bolivar. Altogether, the project will allow output to grow from 32 Mtpa to 40 Mtpa. Capacity could be further lifted to 60 Mtpa if market conditions are favourable. Puerto Drummond, which had to halt operations in early 2014 as it has failed to install a compulsory direct loading system by 1 January 2014, currently has 30 Mtpa of installed port capacity. Capacity is projected to reach 60 Mtpa by the end of 2014 through the addition of a second ship loader and an extension of the pier. The new multi-purpose port of Puerto Brisa is scheduled to ramp up operations from 3.5 Mtpa to reach 20 Mtpa by 2019.

Inland transport infrastructure in Colombia is decisive to deliver coal from the inland mines to the export terminals. It has been a bottleneck for exports in the past as it suffered from rebel attacks and strikes. The Colombian government is involved in negotiations with several rebel groups aiming to increase security for inland coal transports. Several transport infrastructure projects have been announced. International investors have shown interest in a USD 700 million railway line that is projected to connect Colombia's new port of Puerto Brisa with the Central Railway. The 324 km railway will connect Puerto Brisa to the town of Chiriguaná, in the Caribbean province of Cesar. The Colombian government is investing USD 1.3 billion in an infrastructure project at Rio Magdalena, which could reduce transport costs by up to 30%. It will improve navigability for barges on the river and allow coal to be shipped from Central Colombia to the port of Barranquilla. Shipping coal through the Panama Canal might prove a further export option for Colombian coal producers.

South Africa

Investment in export mining capacity

Several small export focused mines, each with an export capacity smaller than 3 Mtpa, were commissioned in 2013. Many new mining projects are currently under construction. However, how much of this capacity will be available for the export market is not clear. The expansion of the Grootegeluk mine (+14.6 Mtpa), commissioned in 2013, is the rather exceptional example of a recent major mining project. Much of its supplies will serve Eskom's new Medupi Power Station and the mine's ramp up has been delayed in line with continued delays at the Medupi power plant. Phase 1 of the Boikarabelo mine, located in the Waterberg region and operated by Australian/South African mining company Resource Generation is projected to be finished in 2015 with an initial capacity of 6 Mtpa. Glencore's 10 Mtpa (ROM) Zonnebloem mine is a major project scheduled to start operations in 2016. However, most major export projects appear to be on hold, either as a consequence of insufficient export capacity or investor uncertainty. Indeed, labour unrest does not help either.

Future exports from South Africa are not only determined by expansions of mining capacity but are also caused by domestic demand and inland transport infrastructure. Domestic South African coal demand is projected to increase over the outlook period and additional mining capacity will also be used to serve growing domestic demand. The decline in in-situ grades and growing demand for low-grade exports means that the domestic and export market will increasingly compete in the future. Inland transport infrastructure, in particular the railway infrastructure from mines in the interior of the country to the Richards Bay Coal Terminal (RBCT) has in the past been a major bottleneck for South African exports. Consequently, RBCT's nameplate capacity (currently at 91 Mtpa) has not been reached in any year since 2000.

Investment in export infrastructure capacity

Approximately 94% of all South African coal exports in 2013 passed through the Richards Bay corridor with some small volumes exported out of Maputo and Durban. Currently announced export terminal projects include a new port terminal at Maputo with operating capacity of 14 Mtpa slated to be operational in the beginning of 2015 and the extension of Grinrod's Navitrade at Richards Bay by 2017-18. Further projects, which are not likely to materialise over the outlook horizon, are an expansion at RBCT bringing additional capacity of approximately 20 Mtpa and a new USD 1.5 billion terminal at Richards Bay by Transnet, the local rail operator.

Railway infrastructure has been the bottleneck for South African coal exports in the past. Although Transnet has announced several projects, this is likely to continue in the upcoming years. The Coal Link project (capital expenditure [CAPEX] approximately USD 1 billion) will link the Mpumalanga region to Richards Bay. It is scheduled to go online in 2017 with a capacity of up to 15 Mtpa. The Mpumalanga network will link coal mines to both power stations and the Coal Link main line. Construction is ongoing and new capacity will be approximately 20 Mtpa. The new Waterberg rail link linking Lephalale and the Central basin is not expected to start operation before 2018, with a capacity of 23 Mtpa. At the moment, a 4 Mtpa rail link exists that can be further expanded to 7 Mtpa. The Waterberg Link becomes increasingly important as South Africa's older Witbank mines are depleted and producers look to new coalfields in the Waterberg region. Waterberg is located in Limpopo province approximately 900 km from RBCT. Currently, the region lacks sufficient rail connection to RBCT and the basic local infrastructure needed for full development.

Mozambique

Investment in export mining capacity

Mozambique's Tete province holds large undeveloped coal reserves estimated at approximately 23 gigatonnes. However, exploration and transportation of these coals to the export ports have proven more difficult than initially expected. As a consequence several big mining companies had to write-off on their Mozambican assets and are currently rethinking their positioning in the area.

Even though several projects are in the pipeline, none of them are viable without access to sufficient port and rail infrastructure. Mining projects in Tete's Moatize basin that have received initial government approval include the 7 Mtpa Revuboe mine majority-owned by Japanese steel manufacturer Nippon Steel and Sumitomo Metal, ICVL's Zambeze project,[1] Beacon Hill's 7 Mtpa Midwest mine and the 7 Mtpa Ncondezi project.

Investment in export infrastructure capacity

At present the only export route for producers in the Tete province is via the 500 km Sena rail line and through the port of Beira. This export route has, however, failed to operate at its 6.5 Mtpa nameplate capacity due to flooding, railway disruptions and security issues. The government rejected shipping coal via the Zambezi River to the port of Beira for environmental reasons.

The Nacala Corridor, which passes through Malawi, is an export option currently being built by Brazilian mining company Vale. Vale has shown interest in selling a portion of its 70% stake in the project. The Nacala line will rail Moatize coal 900 km (200 km of which through Malawi) to the Nacala deepwater export port, which is supposed to be in operation by the second half of 2015, and projected to have an ultimate capacity of 18 Mtpa. The Nacala project is scheduled to gradually ramp up capacity from approximately 11 Mtpa by the end of 2015 to 13 Mtpa in 2016 and 18 Mtpa in 2017.

A third option for Mozambican coal exports is via railway from Moatize to the port of Macuse in the Zambézia province. The Mozambican government, Italian-Thai Development Public Company, and China Railway Construction Corporation (CRCC) are moving ahead with feasibility studies for the project. They plan to build a railway of approximately 530 km and a 25 Mtpa deep seaport at a cost of approximately USD 4 billion with construction scheduled to begin in 2016. Due to current market conditions, delays to the project are likely.

Russia

Investment in export mining capacity

Incremental export mining capacity in Russia is difficult to project as a significant share of production is targeted for domestic demand. Therefore, probable thermal and met coal capacity expansions are estimated rather conservatively at 13 Mtpa until 2019 with approximately another 30 Mtpa classified as potential.

Two new mining projects started operations in 2013. Uzhkuzbassugol's new Erunakovskaya-8 mine produced 1.2 Mt of coking coal in 2013 and has a projected mine capacity of approximately 2.5 Mtpa. KOKS-Mining's Butovskaya mine started production in 2013 with an initial output of 0.5 Mt coking coal and expects to ramp up capacity to 2.5 Mtpa. In addition, expansions at SUEK's WP Kirova mine added another 6 Mtpa washing capacity.

[1] ICVL bought Rio Tinto's assets in Mozambique.

Due to low prices for thermal and met coal, several producers in Russia are losing money and some mining projects were delayed or cancelled. However, projects currently under construction or committed to are likely to materialise. Major expansion projects are projected to be realised over the outlook period. SUEK plans to ramp up 8.1 Mtpa additional capacity by 2016 at its Urgal mine located in Khabarovsk Krai. Sakjalinugol's Solncevskoe deposit will increase capacity gradually by 5 Mtpa by 2015 and a further 5 Mtpa by 2020. Several greenfield projects are also projected by 2019. Russian coal miner Mechel will start production at its Elga coal mine (8 Mtpa) by 2017 and further ramp up capacity to 23 Mtpa by 2021. Elga is Russia's largest deposit of high-quality coking coal. Project funding amounts to USD 2.5 billion, a portion of which will be used to increase railway capacity on the Ulak-Elga line. Kolmar's new Ingalinskaya mine will have an ultimate capacity of 10.5 Mtpa, with 6 Mtpa projected to be operational by 2015. The Tuva Energy Industry Corporation (TEPK) aims for 15 Mtpa by 2020 at its Elegest mine. Production started at the mine in June 2014, using open-pit mining and aiming to build a mining and processing complex by 2018. Karakan Invest intends to start production at its 6 Mtpa Karakanskoe thermal coal field by 2017.

Investment in export infrastructure capacity

In recent years, Russian producers have increasingly focused upon exporting coal to the Pacific Basin. As a consequence, coal terminals in Russia's Far East were working at full capacity in 2013 and investment activity in export infrastructure in the region is strong. In addition, Russian ports in the Barents Sea and the Black sea are also aiming for expansions. Projected port capacity additions over the outlook horizon amount to 50 Mtpa.

Several major export terminals plan to increase their throughput capacity. SUEK's Vanino port terminal Daltransugol will increase capacity by another 8 Mtpa by 2015. Expansion projects in Russia's Far East include Posyet seaport and Shakhtersk seaport. The combined additional capacity of the two projects amounts to 9.5 Mtpa at an investment volume of USD 140 million. The new 20 Mtpa coal port terminal at Sukhodol seaport is not projected to materialise before 2020. Additional potential port handling capacity during the outlook period might also come from a new coal terminal at Port Taman (+12 Mtpa) in the Black Sea, the new Lavna coal terminal (+18 Mtpa) at Murmansk in the Barents Sea and several projects at Vostochny (+25 Mtpa to 28 Mtpa) in the Far East Federal District.

In addition to port capacity, railway capacity will determine future Russian export growth. All railways belong to the Russian Railway (RZD) and development of railway infrastructure will be carried out according to RZD's investment program. Major investments will focus on the Far East infrastructure in order to provide among others coal volumes to the Pacific Basin. In 2013, the Russian government approved the development of the Trans-Siberian and Baikal-Amur mainlines by 2018 at an estimated total cost of USD 18 billion. Government funding in the project, which will provide a link to the Far Eastern ports, amounts to USD 8 billion. Further, Russian company TEPK signed an agreement with the Russian government to build the 400 km railway infrastructure linking the Elegest coking coal deposits to Vanino port by 2017. Railroad capacity expansion in sections near the ports together with the price environment in the nearest term will determine the implementation of most port projects with deadline 2020 onwards.

Indonesia

Investment in export mining capacity

Incremental export mining capacity in Indonesia is estimated at approximately 85 Mtpa by 2019. However, one has to bear in mind that capacity additions for Indonesia are hard to predict as there are no comprehensive mining project lists available. Therefore, all Indonesian mining additions are classified as potential.

Most large Indonesian producers are expecting to ramp up production and exports in the upcoming years aiming to achieve further economies of scale. Potential for export capacity increases from smaller producers is limited as several of them are currently struggling with low international coal prices and a depreciation of the rupiah. Future export mining additions will also crucially depend on decisions by the Indonesian government on potential export limits and on energy policy decisions in major importing countries such as China, India and Korea. Mining additions over the outlook period are expected in all major Indonesian mining regions. Projects that have been proposed include Adaro Energy's Mustika Indah Permai project in South Sumatra, Cokal's 2 Mtpa Bumi Barito Mineral project in Central Kalimantan or Indika's Mitra Energi Agung project in East Kalimantan. Start of the Reswara Minergi Hatama's project in Aceh has been delayed in mid-2014 due to weather conditions. The project is expected to gradually ramp up capacity to around 8.5 Mtpa by the end of the outlook period. It has a significant shipping advantage to other Indonesian projects, as shipping from Aceh to India is roughly five days faster than from Samarinda.

Investment in export infrastructure capacity

Export port capacity is projected to increase by 55 Mtpa until 2019 and is therefore not expected to be a bottleneck for Indonesian exports. Data availability on individual port projects continues to be rather limited. However reports on some projects exist: the first stage of PT Bara Ria Sukses's Jambi Coal Terminal, located in Sumatra's Jambi province, started operations in June 2014. The cost of the project amounted to USD 5 million. PT Nusa Tambang Pratama is currently constructing a continuous barge unloader with installed capacity of 12 Mtpa at the North Pulau Laut coal terminal in South Kalimantan. The project should complete in December 2014. Further, state-owned port operator PT Pelindo III, through its subsidiary PT Berlian Jasa Terminal Indonesia, is planning to increase capacity at Satui coal port in South Kalimantan.

Several railway infrastructure projects are currently underway in Indonesia and are expected to be completed by the end of the outlook horizon. These projects are significant for future Indonesian exports as production is increasingly moving away from inland rivers which are now typically used to barge coal to the main export terminals. A prominent example of a railway infrastructure currently under construction is the 191 km rail line from Kutai Barat to Balikpapan in East Kalimantan. The second phase of the project will bring an additional 60 km rail line connecting Murung Raya in Central Kalimantan to the Kutai Barat-Balikpapan line. Costs of the project are estimated at USD 2.4 billion with the project slated to be finished by 2018.

Canada

Investment in export mining capacity

Canada is the world's third-largest exporter of met coal. Comparably, thermal coal exports are relatively small. Several mining projects whose planning processes were initiated during the high price period of 2011 are projected to come online by the end of the outlook period. However, some projects are delayed due to current low market prices and growing environmental concerns on the part of the public.

Most coal mining projects in Canada, such as Glencore's Sukunka project, Cardero Resource's Carbon Creek project and the Murray River project by HD Mining, are located in the Peace River basin in British Columbia. Together, the above-mentioned four projects would add up to 12 Mtpa of met coal capacity over the outlook horizon. Canada's biggest coal producer Teck Resources deferred the restart of its Quintette met coalmine in British Columbia. The mine, which was closed in 2002, is now on maintenance and care until met coal prices improve. Australia-listed mining company Jameson Resources is currently working on four projects in the Peace River basin. Among others, it is drilling at the Dunlevy metallurgical coal project and pursuing a pre-feasibility study on the Crown Mountain project.

Projects in Alberta include the 12 Mtpa Vista (low sulphur) thermal coal project and the 2 Mtpa Grassy Mountain met coal project in the Crownsnest Pass basin. The Vista project (6.5 Mtpa in Phase 1, 12 Mtpa by end of Phase 2) by Australia and Canada listed Coalspur is yet to receive all environmental and regulatory approvals. Coalspur has delayed the start of construction of the project, which was initially scheduled for June 2014. First production targets for mid-2016 are therefore also delayed.

The 2.75 Mtpa Donkin underground project in Nova Scotia aims for first production of thermal and coking coal by 2016. Coking coal will be exported from the Port of Sidney. The project, which is 30 km off the Atlantic coast, is owned by Glencore (75%) and Canadian-based Morien Resources (25%).

Investment in export infrastructure capacity

Canada's export terminals on the west coast are expanding capacity to handle additional met coal volumes from Canada as well as potentially larger coal volumes from the Powder River Basin (PRB) in the United States. The Westshore Coal Terminal, the biggest coking coal port in North America, expanded capacity in 2013 from 29 Mtpa to 33 Mtpa. Further equipment upgrades will allow it to increase its loading capacity by a further 2 Mtpa to 3 Mtpa. The Ridley Coal Terminal, located at Prince Ruppert, is expected to double capacity to 24 Mtpa from its current 12 Mtpa by the end of 2014. Work at Ridley includes the retrofit of two existing stacker-reclaimers as well as the addition of a second tandem rotary dumper. The Neptune Bulk Terminal located in the Vancouver area aims to increase capacity from 10 Mtpa to 18.5 Mtpa by 2015. The approval to construct a direct transfer coal facility at Fraser Surrey Docks by Port Metro Vancouver has been challenged by environmental groups in Canada's Federal Court. This new project would allow handling of up to 4 Mt of PRB coal from the United States.

United States

Investment in export mining capacity

The outlook for incremental export mining capacity in the United States remains unchanged from last year's report. No significant incremental export mining capacity is projected to come online over the outlook period because of sluggish domestic demand expectations and low international coal prices.

Investment in export infrastructure capacity

The current nameplate capacity of export terminals in the United States stands at over 150 Mtpa. There have been large increases recently in port capacity in the Gulf Coast through expansions at existing terminals and growth in mid-stream river capacity. Kinder Morgan in April 2013 for instance completed the third phase of its expansion project at International Marine Terminal (IMT) in Myrtle Grove, Louisiana adding 4.5 Mtpa of export throughput capacity. It also raised throughput capacity by 1.4 Mtpa at Pier IX in Newport News, Virginia by completing a storage yard expansion. The expansion of the Deepwater facility in Deer Park, Texas, added a further 9 Mtpa of export coal capacity.

Total and proposed export capacity in the United States is significant. Multiple projects have been announced but only a few have been completed or have started construction. A few developers have cancelled or delayed plans. Coking coal producer Walter Energy is moving forward with the development of its 6.5 Mtpa coal export terminal in Mobile, Alabama. Further growth is possible in the Gulf Coast. Proposed expansions in the Pacific Northwest, which would handle coal from the PRB, are facing difficult permitting processes as well as public opposition. A key permit for building a dock at Port Morrow, which would allow barging coal down the Colombia River to Port Westward, was denied in August 2014 due to environmental concerns regarding tribal fisheries. If and how this will impact the permitting processes at two proposed megaprojects, the Millennium Bulk Terminals Longview and the Pacific Gateway Terminal, is not clear. Together, these two projects would increase capacity by up to 90 Mt and open up the way for significant exports from the PRB to serve the Asian markets. Alternative routes for coal from the United States (in particular from the PRB) are via ports in Canada or even proposed ports in Mexico. Whereas the former is already a viable option for exports from the United States, it remains to be seen whether the latter option will materialise given current low coal prices, long inland transport distances and probable public opposition. Altogether, we do not project any significant exports from the PRB through any of the above-mentioned export channels over the outlook horizon.

References

BREE (Bureau of Resources and Energy Economics) (2014), *Resources and Energy Major Projects*, BREE, Canberra, http://bree.gov.au/sites/default/files/files//publications/remp/remp-2014-04.pdf.

IEA (International Energy Agency) (2013), *Technology Roadmap: Carbon Capture and Storage*, OECD/IEA, Paris.

ANNEX

Table A.1 Coal demand, 2012-19 (million tonnes of coal-equivalent [Mtce])

	2012	2013*	2015	2017	2019	CAGR
OECD	1 449	1 451	1 462	1 419	1 402	-0.6%
OECD Americas	655	672	671	648	618	-1.4%
United States	607	623	616	593	561	-1.7%
OECD Europe	442	422	431	408	408	-0.6%
OECD Asia Oceania	352	356	359	362	375	0.9%
Non-OECD	4 077	4 239	4 488	4 775	5 060	3.0%
China	2 821	2 972	3 121	3 287	3 443	2.5%
India	504	517	568	627	694	5.0%
Africa and Middle East	154	157	174	185	195	3.7%
Europe/Eurasia	356	343	335	349	362	0.9%
ASEAN	127	130	157	183	209	8.3%
Other developing Asia	86	87	95	103	108	3.7%
Latin America	30	34	37	42	49	6.2%
Total	**5 526**	**5 690**	**5 949**	**6 194**	**6 462**	**2.1%**

Note: CAGR = compound average growth rate; OECD = Organisation for Economic co-operation and Development.

* Estimate.

Table A.2 Thermal coal and lignite demand, 2012-19 (Mtce)

	2012	2013*	2015	2017	2019	CAGR
OECD	1 265	1 269	1 276	1 233	1 214	-0.7%
OECD Americas	629	646	646	623	594	-1.4%
United States	588	603	597	574	543	-1.7%
OECD Europe	368	353	360	338	339	-0.7%
OECD Asia Oceania	268	269	270	271	281	0.7%
Non-OECD	3 413	3 531	3 756	4 009	4 258	3.2%
China	2 310	2 422	2 549	2 692	2 824	2.6%
India	468	477	523	576	635	4.9%
Africa and Middle East	148	152	168	179	190	3.8%
Europe/Eurasia	265	252	249	262	274	1.4%
ASEAN	127	129	157	183	209	8.3%
Other developing Asia	80	80	89	97	101	3.9%
Latin America	15	20	20	22	25	4.0%
Total	**4 677**	**4 800**	**5 032**	**5 242**	**5 472**	**2.2%**

* Estimate.

Table A.3 Metallurgical (met) coal demand, 2012-19 (Mtce)

	2012	2013*	2015	2017	2019	CAGR
OECD	184	182	185	186	187	0.4%
OECD Americas	26	27	26	25	25	-1.5%
United States	19	20	19	19	18	-1.0%
OECD Europe	74	69	71	70	69	0.1%
OECD Asia Oceania	85	87	88	91	94	1.3%
Non-OECD	664	708	732	766	802	2.1%
China	510	550	572	595	619	2.0%
India	37	40	45	51	58	6.4%
Africa and Middle East	5	6	6	6	6	0.3%
Europe/Eurasia	91	91	86	87	88	-0.5%
ASEAN	0	0	0	0	0	0.0%
Other developing Asia	6	7	6	6	7	0.3%
Latin America	15	14	17	20	24	8.8%
Total	**848**	**890**	**917**	**952**	**989**	**1.8%**

* Estimate.

Table A.4 Coal production, 2012-19 (Mtce)

	2012	2013*	2015	2017	2019	CAGR
OECD	1 353	1 351	1 404	1 408	1 418	0.8%
OECD Americas	767	747	775	756	744	-0.1%
United States	708	685	705	684	666	-0.5%
OECD Europe	238	220	226	223	219	-0.1%
OECD Asia Oceania	348	383	400	426	452	2.8%
Non-OECD	4 304	4 358	4 546	4 786	5 044	2.5%
China	2 695	2 718	2 852	2 998	3 161	2.5%
India	372	378	399	419	452	3.0%
Africa and Middle East	219	219	244	261	271	3.7%
Europe/Eurasia	460	450	441	463	483	1.2%
ASEAN	416	450	445	462	483	1.2%
Other developing Asia	55	57	56	65	68	3.1%
Latin America	88	87	108	117	127	6.5%
Total	**5 657**	**5 709**	**5 949**	**6 194**	**6 462**	**2.1%**

* Estimate.

Table A.5 Thermal coal and lignite production, 2012-19 (Mtce)

	2012	2013*	2015	2017	2019	CAGR
OECD	1 077	1 066	1 115	1 113	1 113	0.7%
OECD Americas	661	642	673	653	633	-0.2%
United States	630	610	632	610	587	-0.6%
OECD Europe	213	197	207	206	204	0.6%
OECD Asia Oceania	203	227	235	255	275	3.3%
Non-OECD	3 699	3 743	3 917	4 129	4 360	2.6%
China	2 224	2 237	2 363	2 496	2 641	2.8%
India	370	373	393	412	444	3.0%
Africa and Middle East	213	213	235	249	259	3.3%
Europe/Eurasia	359	352	349	368	386	1.5%
ASEAN	413	448	442	459	478	1.1%
Other developing Asia	35	37	35	37	38	0.5%
Latin America	83	83	101	107	114	5.4%
Total	**4 776**	**4 810**	**5 032**	**5 242**	**5 472**	**2.2%**

* Estimate.

Table A.6 Met coal production, 2012-19 (Mtce)

	2012	2013*	2015	2017	2019	CAGR
OECD	276	284	289	295	305	1.2%
OECD Americas	106	106	102	104	111	0.9%
United States	78	75	73	75	79	0.9%
OECD Europe	24	23	19	17	15	-7.0%
OECD Asia Oceania	145	156	164	171	176	2.0%
Non-OECD	604	616	629	657	684	1.8%
China	471	481	489	503	520	1.3%
India	2	6	6	7	8	4.8%
Africa and Middle East	6	6	9	11	13	14.0%
Europe/Eurasia	99	98	93	95	97	-0.2%
ASEAN	3	3	3	3	4	8.9%
Other developing Asia	19	20	21	28	30	7.4%
Latin America	4	4	8	10	13	23.2%
Total	**880**	**900**	**917**	**952**	**989**	**1.6%**

* Estimate.

Table A.7 Hard coal net imports, 2012-19 (Mtce)

	2012	2013*	2015	2017	2019	CAGR
OECD	105	81	58	11	-16	5.6%
OECD Americas	-98	-90	-104	-108	-126	3.6%
United States	-92	-85	-89	-92	-105	-0.7%
OECD Europe	203	197	205	185	189	24.7%
OECD Asia Oceania	3	-20	-41	-64	-77	-
Non-OECD	-105	-81	-58	-11	16	-
China	224	257	269	289	283	1.6%
India	125	139	169	208	242	9.7%
Africa and Middle East	-62	-66	-70	-76	-76	2.4%
Europe/Eurasia	-92	-105	-106	-115	-121	2.3%
ASEAN	-277	-297	-287	-280	-274	-1.3%
Other developing Asia	38	43	39	38	40	-1.4%
Latin America	-60	-52	-71	-75	-78	7.0%

* Estimate.

Table A.8 Seaborne steam coal imports, 2012-19 (Mtce)

	2012	2013*	2015	2017	2019	CAGR
Europe and Mediterranean	166	160	175	149	155	-0.5%
Japan	110	119	121	124	124	0.7%
Korea	78	80	81	84	93	2.4%
Chinese Taipei	51	54	54	59	63	2.5%
China	179	191	190	199	186	-0.4%
India	93	104	130	164	191	10.7%
Latin America	18	19	18	21	24	4.4%
Other	57	60	64	92	113	11.3%
Total	**752**	**787**	**833**	**892**	**950**	**3.2%**

* Estimate.

Table A.9 Seaborne steam coal exports, 2012-19 (Mtce)

	2012	2013*	2015	2017	2019	CAGR
Australia	140	160	173	194	215	5.0%
South Africa	67	69	71	75	75	1.5%
Indonesia	317	337	345	365	379	2.0%
Russia	91	96	103	107	114	2.8%
Colombia	76	68	84	90	97	6.2%
China	6	6	4	3	3	-10.3%
United States	41	37	43	44	55	6.7%
Other	15	14	12	13	13	-1.8%
Total	**752**	**787**	**833**	**892**	**950**	**3.2%**

* Estimate.

Table A.10 Seaborne met coal imports, 2012-19 (Mtce)

	2012	2013*	2015	2017	2019	CAGR
Europe and Mediterranean	63	60	61	63	65	1.4%
Japan	52	52	55	56	58	1.8%
Korea	31	30	30	31	33	1.5%
China	32	55	62	65	69	4.1%
India	32	35	39	44	51	6.5%
Other	22	21	22	24	25	2.7%
Total	**232**	**252**	**269**	**284**	**301**	**3.0%**

* Estimate.

Table A.11 Seaborne met coal exports, 2012-19 (Mtce)

	2012	2013*	2015	2017	2019	CAGR
Australia	138	150	159	166	171	2.2%
Canada	24	27	29	29	33	3.4%
Mozambique	3	3	6	8	9	18.2%
Russia	8	15	16	18	19	4.1%
United States	54	50	51	53	57	2.2%
Other	5	7	9	10	11	8.6%
Total	**232**	**252**	**269**	**284**	**301**	**3.0%**

* Estimate.

Table A.12 Coal demand, 2012-19 (million tonnes [Mt])

	2012	2013*	2015	2017	2019	CAGR
OECD	2 148	2 136	2 161	2 124	2 109	-0.2%
OECD Americas	889	915	911	887	850	-1.2%
United States	820	843	836	806	764	-1.6%
OECD Europe	798	763	783	763	767	0.1%
OECD Asia Oceania	460	458	467	474	493	1.2%
Non-OECD	5 539	5 740	6 086	6 491	6 909	3.1%
China	3 698	3 894	4 095	4 326	4 555	2.6%
India	775	791	856	944	1 047	4.8%
Africa and Middle East	202	205	231	257	279	5.3%
Europe/Eurasia	561	537	541	550	557	0.6%
ASEAN	165	170	207	241	279	8.6%
Other developing Asia	104	104	114	124	134	4.4%
Latin America	34	39	43	49	58	6.7%
Total	**7 687**	**7 876**	**8 247**	**8 614**	**9 019**	**2.3%**

* Estimate.

Note: projections have been produced in million tonnes of coal-equivalent. For reference, this Annex also includes coal volumes in million tonnes. We have not analysed the calorific value of coal to be produced; therefore, projections in million tonnes should be consulted with caution.

Table A.13 Thermal coal and lignite demand, 2012-19 (Mt)

	2012	2013*	2015	2017	2019	CAGR
OECD	1 961	1 951	1 971	1 932	1 917	-0.3%
OECD Americas	863	888	884	860	824	-1.2%
United States	801	823	817	787	746	-1.6%
OECD Europe	726	695	712	693	697	0.0%
OECD Asia Oceania	372	368	375	380	396	1.2%
Non-OECD	4 814	4 967	5 292	5 661	6 040	3.3%
China	3 139	3 292	3 471	3 677	3 881	2.8%
India	733	745	808	889	984	4.7%
Africa and Middle East	196	200	224	251	274	5.4%
Europe/Eurasia	464	439	449	457	464	0.9%
ASEAN	165	169	207	241	279	8.7%
Other developing Asia	98	97	107	117	127	4.6%
Latin America	20	25	26	29	32	4.2%
Total	**6 775**	**6 918**	**7 263**	**7 593**	**7 956**	**2.4%**

* Estimate.

Table A.14 Met coal demand, 2012-19 (Mt)

	2012	2013*	2015	2017	2019	CAGR
OECD	187	185	191	191	193	0.7%
OECD Americas	26	27	27	26	26	-0.5%
United States	19	19	19	19	18	-1.1%
OECD Europe	73	68	71	70	70	0.4%
OECD Asia Oceania	88	90	93	95	97	1.2%
Non-OECD	725	773	793	830	870	2.0%
China	559	603	624	649	675	1.9%
India	42	46	48	55	63	5.3%
Africa and Middle East	5	5	6	6	6	1.7%
Europe/Eurasia	98	97	92	92	93	-0.8%
ASEAN	0	0	0	0	0	0.0%
Other developing Asia	6	7	6	7	7	0.8%
Latin America	15	14	17	21	26	10.7%
Total	**912**	**958**	**984**	**1 021**	**1 062**	**1.7%**

* Estimate.

Table A.15 Coal production, 2012-19 (Mt)

	2012	2013*	2015	2017	2019	CAGR
OECD	2 024	1 994	2 085	2 096	2 119	1.0%
OECD Americas	1 015	991	1 033	1 012	997	0.1%
United States	932	904	944	917	892	-0.2%
OECD Europe	572	538	560	559	555	0.5%
OECD Asia Oceania	438	466	492	525	568	3.3%
Non-OECD	5 770	5 828	6 160	6 517	6 899	2.8%
China	3 532	3 561	3 754	3 962	4 194	2.8%
India	604	613	641	678	736	3.1%
Africa and Middle East	270	270	316	347	371	5.4%
Europe/Eurasia	685	663	670	686	702	1.0%
ASEAN	516	557	589	625	659	2.8%
Other developing Asia	66	68	69	80	84	3.5%
Latin America	97	97	122	138	153	7.9%
Total	**7 794**	**7 823**	**8 247**	**8 614**	**9 019**	**2.4%**

* Estimate.

Table A.16 Thermal coal and lignite production, 2012-19 (Mt)

	2012	2013*	2015	2017	2019	CAGR
OECD	1 736	1 697	1 787	1 791	1 803	1.0%
OECD Americas	900	877	922	900	876	0.0%
United States	851	826	867	839	810	-0.3%
OECD Europe	547	515	541	542	540	0.8%
OECD Asia Oceania	289	305	323	349	387	4.0%
Non-OECD	5 112	5 157	5 476	5 802	6 154	3.0%
China	3 017	3 034	3 218	3 412	3 624	3.0%
India	602	606	634	670	728	3.1%
Africa and Middle East	264	264	306	335	358	5.2%
Europe/Eurasia	578	558	571	585	598	1.2%
ASEAN	512	554	587	622	654	2.8%
Other developing Asia	46	48	47	51	53	1.6%
Latin America	93	93	114	128	139	7.0%
Total	**6 848**	**6 855**	**7 263**	**7 593**	**7 956**	**2.5%**

* Estimate.

Table A.17 Met coal production, 2012-19 (Mt)

	2012	2013*	2015	2017	2019	CAGR
OECD	288	297	298	305	316	1.0%
OECD Americas	115	114	111	112	121	0.9%
United States	81	78	77	78	82	0.9%
OECD Europe	25	23	19	17	15	-7.0%
OECD Asia Oceania	149	160	168	176	181	2.0%
Non-OECD	658	671	684	714	744	1.7%
China	516	527	536	551	570	1.3%
India	2	6	7	8	8	4.8%
Africa and Middle East	6	6	10	12	13	14.3%
Europe/Eurasia	107	105	99	102	104	-0.2%
ASEAN	3	3	3	3	4	8.2%
Other developing Asia	20	20	22	29	31	7.4%
Latin America	4	4	8	10	13	23.0%
Total	**946**	**968**	**984**	**1 021**	**1 062**	**1.5%**

* Estimate.

Table A.18 Seaborne steam coal imports, 2012-19 (Mt)

	2012	2013*	2015	2017	2019	CAGR
Europe and Mediterranean	172	165	183	162	169	0.4%
Japan	132	142	144	149	152	1.2%
Korea	93	95	98	101	112	2.7%
Chinese Taipei	59	61	61	67	74	3.1%
China	230	236	258	269	260	1.7%
India	126	139	174	219	256	10.8%
Latin America	19	20	19	24	27	5.0%
Other	64	65	72	105	150	14.9%
Total	**895**	**923**	**1 009**	**1 096**	**1 201**	**4.5%**

* Estimate.

Table A.19 Seaborne steam coal exports, 2012-19 (Mt)

	2012	2013*	2015	2017	2019	CAGR
Australia	160	182	200	228	263	6.4%
South Africa	74	72	80	88	89	3.7%
Indonesia	386	423	443	473	511	3.2%
Russia	107	108	122	128	135	3.8%
Colombia	82	72	94	107	119	8.9%
China	9	7	5	4	4	-10.9%
United States	51	44	50	52	64	6.5%
Other	24	17	16	17	17	-0.3%
Total	**895**	**923**	**1 009**	**1 096**	**1 201**	**4.5%**

* Estimate.

Table A.20 Seaborne met coal imports, 2012-19 (Mt)

	2012	2013*	2015	2017	2019	CAGR
Europe and Mediterranean	67	62	63	64	67	1.3%
Japan	53	54	58	59	60	1.7%
Korea	32	31	30	32	33	1.2%
China	38	59	66	70	74	3.9%
India	36	38	41	47	55	6.3%
Other	26	22	25	27	29	5.0%
Total	**253**	**265**	**284**	**299**	**317**	**3.1%**

* Estimate.

Table A.21 Seaborne met coal exports, 2012-19 (Mt)

	2012	2013*	2015	2017	2019	CAGR
Australia	142	154	163	170	175	2.2%
Canada	30	32	33	34	39	3.4%
Mozambique	3	3	6	9	10	21.4%
Russia	11	16	17	19	21	4.1%
United States	59	53	54	56	60	2.2%
Other	8	8	10	11	12	8.6%
Total	**253**	**265**	**284**	**299**	**317**	**3.0%**

* Estimate.

Table A.22 Current coal mining projects

Country	Project	Company	Type	Estimated start-up	Estimated new capacity (Mtpa)	Resource	Status
Australia	Alpha Coal Project	GVK – Hancock Coal	N	2016	32	TC	F
Australia	Appin Area 9	BHP Billiton	E	2016	3.5	CC	C
Australia	Ashton South East Opencut	Yancoal Australia	E	2015	3.6	TC, PCI	C
Australia	Baralaba North Expansion	Cockatoo Coal	E	2016	2.5	PCI, TC	F
Australia	Baralaba South Project	Cockatoo Coal	N	2015	3	PCI, TC	F
Australia	Bengalla Continuation	Rio Tinto/ Wesfarmers	E	2017	4.3	TC	F
Australia	Boggabri Opencut	Idemitsu Kosan	E	2015	3.5	TC	C
Australia	Byerwen Coal Project	QCoal/JFE Steel Corporation	N	2015	10	CC	F
Australia	Carmichael Coal Project (mine and rail)	Adani	N	2017	60	TC	F
Australia	China First Coal Project (Galilee Coal Project)	Waratah Coal	N	2018+	40	TC	F
Australia	Codrilla	Peabody Energy	N	2019+	3.2	PCI	F
Australia	Colton	New Hope	N	2015	0.5	CC	F

Australia	Comet Ridge	Acacia Coal/ Bandanna Energy	N	2015	0.4	TC, CC	F
Australia	Curragh Mine	Wesfarmers	E	..	1.5-2	CC	F
Australia	Dingo West	Bandanna Energy	E	2016	1	PCI, TC	F
Australia	Drake Coal Project	QCoal	N	2015	6	TC, CC	F
Australia	Drayton South	Anglo Coal Australia	E	..	..	TC	F
Australia	Duchess Paradise	Rey Resources	N	2016	2.5	TC	F
Australia	Eagle Downs (Peak Downs East Underground)	Aquila Resources/ Vale	N	2017	4.5	CC	C
Australia	Eaglefield	Peabody Energy	E	..	5	CC	F
Australia	Elimatta	New Hope	N	2017	5	TC	F
Australia	Ellensfield Coal Mine Project	Vale	N	..	5.5	TC, CC	F
Australia	Grosvenor Underground	Anglo American	N	2016	5	CC	C
Australia	Jax	QCoal	N	2015	1.8	CC	F
Australia	Kevin's Corner	GVK	N	2016	30	TC	F
Australia	Maules Creek	Whitehaven	N	2015	10.8	TC, CC	F
Australia	Metropolitan	Peabody Energy	E	2015	1.5	CC	C
Australia	Middlemount (stage 2)	Peabody Energy/ YanCoal	E	2014	3.6	PCI, CC	C
Australia	Minyango	Caledon Resources	N	2016	7	TC, CC	F
Australia	Moolarben (stage 2)	Yancoal Australia	E	..	5	TC	F
Australia	Mt Thorley – Warkworth Extension	Rio Tinto	E	..	0	TC	F
Australia	New Acland (stage 3)	New Hope Coal	E	2016	2.7	TC	F
Australia	North Surat – Collingwood Project	Cockatoo Coal	N	2018	4	TC	F
Australia	NRE No. 1 Colliery	Wollongong Coal	E	2015	3	CC	F
Australia	NRE No. 1 Colliery (preliminary works project)	Wollongong Coal	U	2015	0	CC	C
Australia	Oaky Creek (phase 2)	Glencore, Sumisho, Itochu, ICRA OC	E	..	5	CC	F
Australia	Orion Downs	V&D Mining	N	2014	2.5	TC	F
Australia	Rolleston (phase 2)	Glencore, Sumisho, IRCA	E	..	3	TC	F
Australia	South Galilee Coal Project (three phases)	Bandanna Energy	N	2015	17	TC	F
Australia	Springsure Creek (stage 1)	Bandanna Energy	N	2015	5.5	TC	F
Australia	Springsure Creek (stage 2)	Bandanna Energy	E	2019+	5.5	TC	F
Australia	Stratford	Yancoal Australia	E	2015	2.6	TC, CC	F

Australia	Taroborah	Shenhuo International	N	2016	2.3	CC	F
Australia	Teresa	Linc Energy	N	2016	6	PCI. TC	F
Australia	The Range Project	Stanmore Coal	N	2016	5	TC	F
Australia	Vermont East/Wilunga	Peabody Energy	N	2015	3	PCI, TC	F
Australia	Vickery	Whitehaven	N	..	4.5	TC, CC	F
Australia	Wallarah Underground Longwall	Korea Resources Corp/Sojitz Corp	N	..	5	TC	F
Australia	Wards Well	BHP Billiton Mitsubishi Alliance (BMA)	N	2017	5	CC	F
Australia	Washpool Coal Project	Aquila Resources	N	..	2.9	CC	F
Australia	Watermark	Shenhua Energy	N	2015	6.15	TC	F
Australia	Wongawilli Colliery	Wollongong Coal	E	2016	3	CC	F
Canada	Carbon Creek	Cardero Resource	N	x	2.9	CC	F
Canada	Donkin	Glencore, Morien Resources	N	2016	2.75	TC, CC	C
Canada	Echo Hill	Hillsborough Resources	N	..	1.5	TC	F
Canada	Grassy Mountain	Riversdale Resources	N	..	2	CC	F
Canada	Horizon	Peace River Coal	N	..	1.6	CC	F
Canada	Murray River	HD Mining	N	..	6	CC	F
Canada	Quintette	Teck Resources	N	..	3.5	CC	F
Canada	Sukunka	Glencore	N	2018	3	CC	F
Canada	Trend	Anglo American	E	2016	1	CC	C
Canada	Vista Coal Project	Coalspur Mines	N	2016-17	6.5	TC	F
Colombia	Canaverales	Yildirim Holding	N	..	2.5	TC	F
Colombia	Cerrejon Expansion	Cerrejon	E	2015	8	TC	C
Colombia	Cerrolargo Sur	Goldman Sachs	N	..	..	TC	F
Colombia	El Descanso	Drummond	E	..	12	TC	F
Colombia	Papayal	Yildirim Holding	N	..	2.5	CC	F
Colombia	San Juan	Yildirim Holding	N	..	25	TC	F
Indonesia	Bumi Barito Mineral	Cokal	N	2016	2	CC	C
Indonesia	IndoMet Coal Project	BHP Billiton/Adaro	N	..	..	CC/TC	F
Indonesia	Mitra Energi Agung	Indika	N	..	..	TC	F
Indonesia	Mustika Indah Permai	Adaro	N	..	..	TC	F
Indonesia	PT Bukit Enim Energi	Adaro	N	..	..	CC	F
Indonesia	PT Juloi Coal	BHP Billiton	N	..	..	CC/TC	F
Indonesia	PT Kalteng Coal	BHP Billiton	N	..	..	CC/TC	F
Indonesia	PT Lahai Coal	BHP Billiton	N	..	..	CC/TC	C
Indonesia	PT Maruwai Coal	BHP Billiton	N	..	..	CC/TC	F
Indonesia	PT Pari Coal	BHP Billiton	N	..	..	CC/TC	F
Indonesia	PT Ratah Coal	BHP Billiton	N	..	..	CC/TC	F
Indonesia	PT Sumber Barito Coal	BHP Billiton	N	..	..	CC/TC	F

Indonesia	PT Tekno Orbit Persada	MEC Coal	N	..	17	TC	F
Mozambique	Midwest	Beacon Hill	N	..	7	TC	F
Mozambique	Ncondezi	Ncondezi Energy	N	2018	7	TC	F
Mozambique	Revuboe	Nippon Steel and Sumitomo Metal	N	2016	7	CC	F
Mozambique	Zambeze	ICVL	N	..	..	CC	F
Russia	Amaam	North Pacific coal company	N	2017	10	CC	F
Russia	Apsatskoe	SUEK	N	2013-19	0.65-2.4	CC	C
Russia	Bistryanskaya mine 1-2	Rostov	N	2015	0.75	CC	C
Russia	Chulmakanskoe	Kolmar	N	2018	1.25	CC	F
Russia	Denisovskoe	Kolmar	N	2014	2.5	CC	C
Russia	Elegest	TEPK	N	2015	3	CC	F
Russia	Elga	Mechel	N	2017	8	TC, CC	C
Russia	Ingaliskaya	Kolmar	N	2015	6	CC	C
Russia	Karagaylinskoe	Zarechnaya	N	2014	2	CC	C
Russia	Karakanskoe field	Karakan Invest	N	2017-18	6	TC	C
Russia	Kiyzasskiy open pit	Kiyzasskiy open pit	N	2014	4.5	CC, TC	C
Russia	Kostromovskaya	MMK, (Belon)	E	2017	1-2	CC	F
Russia	Mezhegey	Evraz	N	2015	1.3	CC	F
Russia	Solncevskoe depozit	Sakhalinugol	E	2016	5	TC	C
Russia	Taybinski	Invest – Uglesbyt	N	2014	1-1.8	TC, CC	C
Russia	Urgal	SUEK	E	2016	4.6-8.1	TC	C
Russia	Uvalnaya	Sibuglemet	N	2018	4.5	CC	F
South Africa	Argent	Glencore/Shanduka	N	2015	1.5	TC	F
South Africa	Belfast	Exxaro	..	..	1.8	TC	..
South Africa	Boikarabelo	Resgen	N	2014	6	TC	C
South Africa	Brakfontein	Goldridge	N	2015	..	TC	C
South Africa	Consbrey	Glencore	N	2016	..	TC	..
South Africa	DeWittekranz	Continental	N	2015	2.6	TC	..
South Africa	Elandspruit	Wescoal	N	2014	2.3	TC	C
South Africa	Elanspruit	Eyethu	N	2014	<1	TC	C
South Africa	Elders Complex	Anglo American	N	..	..	TC	..
South Africa	Eloff	Mbuyelo	N	2016	3.3	TC	C
South Africa	Grootegeluk expansion	Exxaro	E	2013/14	14.6	TC	C
South Africa	Imbani	HCI	N	2014	<1	TC	C
South Africa	Impumelelo	Sasol	N	2014	8.5	TC	C
South Africa	Kangala	Universal Coal	N	2014	2	TC	C
South Africa	Klipfontein	Eyethu	N	2015	<1	TC	C
South Africa	Koornfontein OC	Glencore/Optimum	E	2019	3.3	TC	..
South Africa	Kriel	Anglo American	E/N	..	5-7	TC	F
South Africa	Leeupoort	Eyethu	N	2015	<1	TC	C
South Africa	Mafube life extension	Anglo American	E	..	3.5	TC	..
South Africa	Matla	Exxaro	E	..	..	TC	..
South Africa	New Largo	Anglo American	N	..	12	TC	F
South Africa	Nooitgedacht	Glencore	N	2016	3	TC	F
South Africa	Roodekop	Universal Coal	N	2014	1	TC	F

South Africa	Schoongezicht	Mzobani	N	2013	<1	TC	C
South Africa	Smitspan	Sekoko/Firestone Energy	N	..	>1	TC	..
South Africa	Sterkfontein	Keaton Energy	N	..	1	TC	..
South Africa	Thabametsi	Exxaro	N	2016/17	3.8	TC	..
South Africa	Tweefontein Optimisation	Glencore	E	2013/14	2	TC	C
South Africa	Vlakvarkfontein	Mbuyelo	N	2013	1.2	TC	C
South Africa	Wildfontein	Hlagisa	N	2013/14	..	TC	C
South Africa	Wonderfontein	Glencore/Umcebo	E	2014	2.5	TC	C
South Africa	Zonnebloem	Glencore	N	2016	10 ROM	TC	F

Notes: The table lists currently discussed mining projects according to publicly available information but has no claim to completeness. Data on the start-up data is according to public information but does not necessarily represent our view concerning expected export capacity additions. Data on the estimated capacity represents the targeted capacity, which is often not available in the year of start-up.

Type: N = new project, E = expansion.

Resource: TC = thermal coal; CC = coking coal; AN = anthracite; PCI = pulverised coal injection.

Status: F = feasibility; C = committed.

.. = missing value or not available; 0 = nil or negligible.

Sources: McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com; BREE (Bureau of Resources and Energy Economics) (2014), *Resources and Energy Major Projects*, Canberra, http://bree.gov.au/sites/default/files/files//publications/remp/remp-2014-04.pdf; CIAB information; various sources.

GLOSSARY

Regional and country groupings

Africa

Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries (Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda).

ASEAN

Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, the Philippines, Singapore, Thailand and Viet Nam.

China

Refers to the People's Republic of China, including Hong Kong.

Europe and Mediterranean

Includes non-OECD Europe/Eurasia, OECD Europe and North Africa regional groupings.

Latin America

Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries (Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermudas, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands).

Non-OECD Europe/Eurasia

Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyz Republic, Latvia, Lithuania, the Former Yugoslav Republic of Macedonia, Moldova, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

North Africa

Algeria, Egypt, Libya, Morocco and Tunisia.

OECD

Includes OECD Europe, OECD Americas and OECD Asia Oceania regional groupings.

OECD Americas

Canada, Chile, Mexico and United States.

OECD Asia Oceania

Australia, Japan, Korea and New Zealand. For statistical reasons, this region also includes Israel.[1]

OECD Europe

Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

Other developing Asia

Bangladesh, Chinese Taipei, the Democratic People's Republic of Korea, Mongolia, Nepal, Pakistan, Sri Lanka and other Asian countries and territories.

List of acronyms, abbreviations and units of measure

Acronyms and abbreviations

API	Argus McCloskey's Coal Price Index
ARA	Amsterdam Rotterdam Antwerpen
ARTC	Australian Rail Track
ASEAN	Association of Southeast Asian Nations
BFI	blast furnace iron
BHP	Broken Hill Proprietary Company
BMA	BHP Billiton Mitsubishi Alliance
BREE	Bureau of Resources and Energy Economics
BSER	Best System of Emission Reduction
CAGR	compound average growth rate
CAPEX	capital expenditures
CCA	Coal Cooperation Agreement
CCoW	Coal Contracts of Work
CCS	carbon capture and storage
CEA	Central Electricity Authority (India)
CFR	cost freight
CIF	cost insurance freight
CIL	Coal India Limited
CMG	China Merchants Group
CNR	Colombian Natural Resources
CO	carbon monoxide
CO_2	carbon dioxide
CRCC	China Railway Construction Corporation
EIA	Energy Information Administration
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
ESP	electrostatic precipitator
EU	European Union
FOB	free-on-board

[1] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

FSA	Fuel Supply Agreements
FYP	Five-Year Plan
GDP	gross domestic product
GHG	greenhouse gases
HSBC	Hong Kong & Shanghai Banking Corporation Holdings PLC
ICI	Indonesian Coal Index
IEA	International Energy Agency
IMF	International Monetary Fund
IMT	International Marine Terminal
IPP	independent power producers
IUP	Izin Usaha Pertambangan
LHV	lower heating value
LNG	liquefied natural gas
Ltd.	Limited
LCPD	Large Combustion Plant Directive
MATS	Mercury and Air Toxics Standards
MTCMR	*Medium-Term Coal Market Report*
MoU	memorandum of understanding
NAR	net as received
NCIG	Newcastle Coal Infrastructure Group
NQBP	North Queensland Bulk Ports
OECD	Organisation for Economic Co-operation and Development
PCI	pulverised coal injection
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PGE	Polska Grupa Energetyczna
PM	particulate matter
PR	People's Republic
PRB	Powder River basin
PV	photovoltaics
PWCS	Port Waratah Coal Services
RBCT	Richards Bay Coal Terminal
RBS	Royal Bank of Scotland
reACT	regenerative activated coke technology
ROM	run-of-mine
ROW	rest of world
RZD	Russian Railways
SCR	selective catalytic reduction
SNG	synthetic natural gas
SO_2	sulphur dioxide
SUEK	Sibirskaja ugolnaja energetitscheskaja kompanija
TNB	Tenaga Nasional Berhad
UHV	ultra-high voltage
UK	United Kingdom
UMPP	Ultra Mega Power Projects
UNESCO	United Nations Educational, Scientific and Cultural Organization
US	United States

VAT	value added tax
WICET	Wiggins Island Coal Export Terminal

Currency codes

AUD	Australian dollar
CAD	Canadian dollar
CNY	Chinese yuan renminbi
COP	Colombian peso
IDR	Indonesian rupiah
INR	Indian rupee
MYR	Malaysian ringgit
RUB	Russian ruble
USD	United States dollar
ZAR	South African rand

Units of measure

bbl	barrel
bcm	billion cubic metres
°C	celsius
dwt	deadweight tonnage
GJ	gigajoule
Gt	gigatonne
GW	gigawatt
$GtCO_2$	gigatonne carbon dioxide
h	hour
kg	kilogramme
km	kilometre
kcal	kilocalories
kV	kilovolt
m	metre
µg	microgramme
Mbtu	million British thermal units
Mdwt	million deadweight tonnages
mg	milligramme
MPa	megapascal
Mt	million tonnes
Mtce	million tonnes of coal-equivalent
$MtCO_2$	million tonnes carbon dioxide
Mtpa	million tonnes per year
MW	megawatt
MWh	megawatt hour
Nm^3	normal cubic metre
ppm	parts per million
t	tonne
TWh	terawatt hours

IEA Publications, 9, rue de la Fédération, 75739 Paris cedex 15

Printed in France by ISI Print, December 2014
(612014341P1) ISBN 9789264221871; ISSN 23070307
Cover design: IEA. Photo credits: © GraphicObsession

COAL

Medium-Term Market Report 2014

The *Medium-Term Coal Market Report 2014* provides IEA forecasts on coal markets for the coming five years as well as an in-depth analysis of recent developments in global coal demand, supply and trade. The fourth annual report shows that, while China will continue to dominate global coal markets between now and the end of the decade, India and Southeast Asia will also drive coal demand growth, although on a smaller scale.

Despite coal's reputation as an old-fashioned, 19th-century fuel, coal markets today are very dynamic: a variety of qualities are traded, new price indexes have been created for different qualities in different regions and an increasing amount of paper trading is taking place. Meanwhile, physical flows of coal are quite sensitive to demand and price developments – not to mention policy changes throughout the world.

This report examines whether and when China's efforts to diversify its energy mix – the so-called ABC (*anything but coal*) policy – will lead to peak demand for coal in the world's biggest coal market. It also analyses how the current environment of low prices for coal will affect not just demand and investments but also the ability of coal producers to stay in business, and how new regulations in the main importing and exporting countries may affect international trade.

Market Analysis and Forecasts to 2019

€100 (61 2014 34 1E1)
ISSN 2307-0315
ISBN: 978-92-64-22188-8

9 789264 221888