

Carbon supply cost curves: Evaluating financial risk to coal capital expenditures



About Carbon Tracker

The Carbon Tracker Initiative (CTI) is a team of financial specialists making climate risk real in today's financial markets.

Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system with the energy transition to a low carbon future.

This latest research series aims to explore in more detail the capital expenditure plans of the coal, oil and gas sectors.

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This paper is a summary which draws on research conducted in partnership with Energy Transition Advisors, ETA, and the Institute of Energy Economics and Financial Analysis, IEEFA. The full background research papers produced by ETA are available on our website. ETA is led by Mark Fulton, who worked with Tim Buckley of IEEFA and Clyde Henderson of Energy Economics. James Leaton, Luke Sussams, Andrew Grant, Reid Capalino and Margherita Gagliardi contributed from CTI. The demand analysis applied in these research papers was developed by IEEFA.

The underlying analysis in this report, prepared by CTI-ETA, is based on on supply cost data licensed from the Global Economic Model of Wood Mackenzie Limited. Wood Mackenzie is a Global leader in commercial intelligence for the energy, metals and mining industries. They provide objective analysis on assets, companies and markets, giving clients the insights they need to make better strategic decisions. The analysis presented and the opinions expressed in this report are solely those of CTI-ETA.

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Executive summary

Carbon supply cost curves

CTI's research is designed to prompt new thinking about the future of energy and climate for the investment community. In this report, the second in a series, CTI worked with Energy Transition Advisors (ETA) to bring together for the first time future coal demand and supply projections from the leading industry and economic sources in the form of a cost curve. This analysis provides a valuable tool for considering the real world and market impacts of different energy demand and carbon emissions scenarios over time. Among other things, the research summarized here provides a powerful risk analysis methodology to help the majority of investors who cannot simply divest from an entire sector but need to understand and adjust their risk exposure to coal in today's world. Investors can then determine, with some degree of confidence and specificity, how to redirect capital away from high cost, high carbon projects and towards more economically and environmentally sustainable alternatives.

Key findings

Our research consists of a package of detailed analyses of coal supply, demand and financial trends, which are summarised in this document. The core themes that emerged are:

- Profits in thermal coal are already hard to find in today's market. Coal companies are facing greater headwinds all the time with greater energy efficiency, cheaper alternatives and new pollution regulations eroding demand.
- Future demand and price levels may not meet current industry expectations. High cost coal producers are gambling on survival in the hope that prices will somehow recover.
- Peak thermal coal demand in China could be imminent. OECD demand is already falling. The resulting oversupply could flood the market, further weakening prices and asset values.
- Deploying additional capital expenditure into high cost production is risky, especially for new mines, which typically require expensive new rail infrastructure and port facilities to get coal to market.

(Mtpa) potential thermal production (averaged over 2013–2014)

Standardised BECP (Newcastle equivalent price required)

- Cash cost (C1+ royalty) adjusted to 6,000 NAR

US/t free-on-board

Demand assumptions unravelling

Global demand for coal is falling due to a number of factors and trends – energy efficiency, grid efficiency improvements, decentralisation, and diversification. The costs of renewable technologies continue to drop at a pace faster than most have predicted, making renewable alternatives to coal already competitive in some markets. In addition, governments are introducing a growing patchwork of air quality and carbon emissions measures, further destabilising coal demand.

Huge carbon overhang

Our analysis breaks down Wood MacKenzie supply cost data into key regional domestic markets and the seaborne export market. We then overlay the low-demand scenario created by the Institute for Energy Economics and Financial Analysis (IEEFA) to understand what this means for specific coal mines that need to cover their costs. It is clear that the potential coal supply exceeds a 2°C carbon budget, creating a huge carbon overhang. However current coal prices only support a reduced-demand scenario that does not need to use all of the potential coal production to 2035.

All chasing the same markets

What were previously segregated national and regional markets are becoming increasingly connected. OECD markets remain oversupplied, and with shrinking demand, excess supply overflows onto the seaborne market, meaning coal producers are increasingly betting on new growth in Asian markets.

The tide is turning in coal demand

China drives the global coal market, and peak thermal coal demand in China could come as soon as 2014. If Chinese coal imports decline, the seaborne coal market will further weaken. IEEFA's low-demand scenario has China peaking in 2016 which indicates China could thus become an opportunistic exporter in the next few years. Meanwhile, the global demand picture will further deteriorate if India fails to deliver on the infrastructure and finance needed to increase its imports. Moreover, the US EPA's latest regulatory measures may signal an accelerating pace for coal plant retirements, driving demand down further in OECD countries.

Planning for disruption

The scale of the reduction in coal use required to prevent dangerous levels of climate change should not be underestimated. Achieving these cuts will likely require some disruptive technologies to drive down the cost of renewables further and build out robust energy storage capabilities. Government interventions will also be important, and there are signs of movement from the big players – China and the US. Unpredictable factors such as extreme weather events in major cities could also accelerate regulatory change. Overall, regulatory uncertainty may increase the chance of stranded assets, especially if rapid corrections are made.

Is coal a sinking ship?

Over the last three years, the Bloomberg Global Coal Equity Index has lost half of its value while broad market indices are up over 30 percent. In the pure coal sector there is only one trend – downward; coal prices are down, returns are down, share prices are down. Some analysts are already calling a structural decline in the seaborne thermal coal market.

Prices may not bounce back

Our cost analysis indicates that, for around half of potential 2014 thermal coal export production, current prices fail to cover even 'cash costs' (i.e. variable costs). Coal producers are waiting for a rebound in coal prices; however this would require significant increases in demand (and therefore emissions) to get prices back over \$100/tonne.

Understand exposure on the cost curves

In the countries for which we analyse supply cost data, a total of \$488bn could be spent on coal production by 2025. \$220bn of this relates to existing mines, and can deliver around 5700mtpa of production out to 2035. This is more than enough to meet our lowdemand scenario. The larger share of \$268bn relates to new mines, and would deliver a further 2300mtpa out to 2035.

Questionable capex

There is a total of \$112bn of potential capex, excluding China, to 2025 that exceeds the breakeven prices of our low demand scenario. This corresponds with over 1000mtpa of coal production projected to 2035 or an estimated 42GtCO₂. 61% of 'greenfield' (i.e. new) mines are over the thresholds of our low demand/ price scenario, compared to 30% of existing mine expansion.

New mines excess to requirements

Our analysis shows how much more capital-intensive and expensive new mines are, in many cases even before the cost of new infrastructure such as ports and rail capacity has been factored in. Our lowdemand breakeven prices are similar to current prices which do not support many proposed new mines. When the capital cost of infrastructure is factored in, greenfield investments are an even less attractive proposition. The economics of coal are not looking good, and investors should scrutinise the economics of new mines in particular.

Diversified miners have options

The big western diversified mining companies have the option to divert capital into other commodities. Some have already chosen to sell coal assets and press the pause button on capex for new mines. With positive cashflows harder to find, other minerals simply offer better prospects.

Do the business models of pure coal companies add up?

Some producers have tried to switch production to the seaborne market or have diversified geographically. In a low-demand scenario this may not add up, as a chronically oversupplied seaborne market chases low demand that is likely to remain stagnant well below current industry hopes. Continuing to spend capex on new production with such uncertainty over demand and prices is risky business indeed.

Recommendations for investors

Asset owners and managers should consider the following:

- 1. Understand the exposure of your portfolio/ fund to the upper end of the carbon cost curve, and articulate how this risk is being managed.
- 2. Identify the companies with the majority of capex earmarked for high cost projects.
- Focus engagement on export projects requiring \$75/ tonne or above, (Newcastle 6000kcal FOB equivalent), as a starting point. And review equivalent low demand price thresholds for domestic production.
- 4. Set thresholds for exposure to projects at the high end of the cost curve for portfolio companies to adhere to.
- 5. Make it known to company management that you are seeking value not volume.
- 6. Ensure remuneration policy at companies is consistent with shareholder return objectives not just rewarding production levels or spending capital.
- 7. Require improved disclosure of demand and price assumptions underpinning capex strategy and business models.
- Support transparency of company exposure to the cost curve and impairment trigger points, e.g. through annual publication of sensitivity analysis/stress tests to coal prices.

Foreword

CTI's research has created a new debate around climate change and investment literally reframing the debate – 'the climate swerve'. CTI's work to date has started this process by translating key aspects of the climate science, the carbon budget, into the language of the financial markets. CTI started this journey by considering the stocks of carbon in coal, oil and gas and comparing them to the carbon budget necessary to keep average global temperature increase below 2°C. Our earlier work in 2011 demonstrated the concept of 'unburnable carbon' and then in 2013 we highlighted the potential for wasted capital and stranded assets. Building on this previous work, we now take this to the granular level. We look specifically at individual projects to see if we can identify where such wasted capital is most likely to sit.

This series of Carbon Supply Cost Curve reports, mark the start of a new generation of CTI research, CTI 2.0, delivering a fresh look at energy economics, starting with the oil markets and now with this report coal. These reports take a closer look into how carbon constraints intersect with the economics of fossil fuels. This report is, so far as we are aware, the first time anyone has sought to look at the global coal industry in such a holistic way. So in that sense alone it is a unique and important milestone.

For the purposes of this report we have assumed that coal would have a 36% share of a global carbon budget. This does of course raise interesting questions around other scenarios, where oil or gas might have a larger share of the budget at the expense of coal. Even more so than oil, our analysis also shows that if demand for coal is not substantially reduced we are clearly heading for a level of warming far in excess of 2°C.

This report reveals a global industry very different from that of oil. Where the oil industry is relatively homogenous coal is not. It is far more fragmented, significantly less financially strong, and heavily dependent on Government subsidies for critical infrastructure. The global coal industry is both a giant and a pygmy. Viewed through the lens of carbon intensity it dwarfs oil & gas yet it is considerably smaller financially than oil.

There are a host of signals that Chinese demand for coal is close to peaking which will cause a seismic shift in the market. This is potentially a risky business for investors. The question from a climate perspective is how steep the decline will be. It is clear that if we are to avoid levels of warming described as catastrophic by many there will need to be effective policy, regulatory and monetary intervention. Our report is further evidence, if any were needed, that Governments and policy makers need to address coal if there is any hope of avoiding catastrophic climate change. Alongside that we are seeing the potential for disruptive advances in energy technology which can outcompete centralised coal power generation and provide cheap access to renewable energy for all.

There is a realisation that ignoring climate risk and hoping it will go away is no longer an acceptable risk management strategy for investment institutions. Pension funds are under increasing pressure to articulate how they are addressing the need to both mitigate emissions and adapt to changing climates and markets. Investors need to ask whether the writing is on the wall for coal as constraints continue to be added.

Carbon Tracker is not an advocate of a pure divestment approach to fossil fuels. Rather we advocate engagement as a starting point, correctly pricing the risk premium associated with fossil fuels, transparency and the closure of high cost, high carbon projects – project level divestment. We look to shrink the fossil fuel industry to fit within the carbon budget. However given much of the US coal mining industry is already below investment grade, many investors will have limited exposure already.

This does not need to be a negative issue for investors or diversified resource companies. As active stewards of capital they can, using tools such as the carbon supply cost curve, ensure that value is maximised, either through redeployment of capital within companies, or by returning the capital to shareholders. There is clear alignment between high cost and excess carbon through the cost curve. This analysis serves as a reminder to investors to ensure company strategy is aligned with their best long-term interests.

Anthony Hobley

CEO, The Carbon Tracker Initiative September 2014

1. Introduction

Regional markets

The thermal coal market can be divided up into many segregated markets, with c.17% of coal traded at the margins. China dominates the global coal picture accounting for around half of production and consumption. CTI is focusing purely on thermal coal, excluding metallurgical coal for this analysis.

The majority of coal production is considered captive for domestic use – it supplies a power station close to the mine mouth and does not have access to or compete on an open market. Beyond this is the seaborne trade, which usually requires significant infrastructure (rail and port) to get the coal to market. Costs are higher here, but so are prices, and it is these margins which attract the most interest from international coal mining companies. Traditionally this export system has been split into the Atlantic and Pacific markets.

Is coal a sinking ship?

The current slump in the coal market puts the coal sector in a weak position. Over the last three years the Bloomberg Global Coal Equity Index has lost more than half of its value during a period when the MSCI World Index has increased by over thirty percent. In the US, recent years have seen 26 companies go bankrupt – including once-major producers such as Patriot Coal Corp. and James River Coal. Remaining listed US coal miners have debt ratings below investment grade. These companies are having to pay more to borrow, on the assumption that the market for their coal will pick up in the near future. This may just be delaying the inevitable, rather than creating value for shareholders.

Structural decline or cyclical downturn

Coal analysts are already questioning whether the current slump in the seaborne coal market is just the bottom of a commodity cycle, or a trough that the sector cannot escape. The decline of demand in key markets has created oversupply, further weakening prices and devaluing assets.

Strong signals

The landscape for coal as a power generation fuel is rapidly changing. There have been strong signals in both the US and China that ongoing pollution from coal will not be tolerated. With every day that passes the costs of alternatives are coming down. Any investor should already be questioning whether high cost thermal coal production can turn a profit.

Fire sale?

Diversified mining companies are a more common holding for international investors. A number of these companies have already pressed pause on thermal coal capital expenditure. Some are going further – for example, Rio Tinto disposing of assets in Australia and Mozambique before value drops further, or BHP Billiton putting unwanted South African coal mines into a spin-off company. These mining companies have the option to concentrate on other commodities, where they see better returns. This is an opportunity for active shareholders to ensure diversified miners are limiting their exposure to losses in the thermal coal business.

Any investor should already be questioning whether high cost thermal coal production can turn a profit

2. Bridging cost and carbon

Allocating the carbon budget

Continuing from our oil cost curve earlier in 2014, we have now turned our attention to coal. Using the same reference point of a global carbon budget for 2013–2050 of 900GtCO₂, this gives a carbon budget of around 324GtCO₂ (36%) for coal. The 900GtCO₂ is the budget estimated by the Grantham Research Institute on Climate Change at LSE to give an 80% probability of limiting anthropogenic warming to 2°C.

For this study we have had to delineate the scope of coal covered, and have adjusted the carbon budget accordingly:

- Timeframe: WoodMac only project Chinese production in detail for 20 years, so we have limited the timeframe to 2035, rather than a 2050 endpoint; reducing the carbon budget to 229GtCO₂.
- Metallurgical Coal: Our focus in on the power sector and therefore we have not included metallurgical coal in our study, for which we have allocated 40GtCO₂. We see less potential for substitution of coking coal.

This leaves an adjusted carbon budget for thermal coal for to 2035 of 189GtCO₂.

Carbon supply cost curves

In contrast to oil which is a globally traded commodity, it is not appropriate to produce a global cost curve for coal. Coal has much more segregated markets, with significant amounts of captive domestic production which will never compete on an international market. Indeed the seaborne coal trade only accounts for around one sixth of current coal supply. However this is also where most listed companies operate as it offers the most potential for a profit margin.

Cash cost or breakeven price?

The breakeven price approach which CTI-ETA used in our oil analysis is our preferred methodology to reflect the need for investors to gain a return, and consider the cost of capital. We have maintained this approach where possible for contestable coal production. This has applied the breakeven tool in WoodMac's Global Economic Model (GEM) database using its default Internal Rate of Return (IRR) of 10%. One innovation is to use a price-ratio adjustment for export coal using actual prices achieved to normalise the breakevens to our reference Newcastle 6000kcal coal.

For domestically consumed coal we have used a traditional thermal value ratio to convert different quality coals to our reference coal.

For domestic markets we have also produced a cash cost curve which reflects the basic price needed for projects to cover costs. We believe this is more appropriate for state-owned operations where the same investment returns are not required. This is the approach used for Chinese domestic production.

Geographic split

We have produced a series of cost curves covering the seaborne export market, as well as a number of major domestic markets, with special focus on the US and China. We have also split the reference carbon budget in proportion to IEEFA's low demand scenario, to provide an indication of a lower demand intersection point on the regional cost curves. The July 2014 version of WoodMac's GEM database used for the analysis did not have global coverage, most notably excluding India.

Degrees of warming

The adjusted coal price that intersects with a particular average level of coal consumption (and the related CO_2 emissions) indicates the price that would be required to support the production (either on a cash cost or breakeven basis). Users of the curves can adjust where the level of demand/carbon intersects with the curve to understand different scenarios.

Impact of CCS

The reference carbon budget indicated on the curves is equivalent to the International Energy Agency (IEA) 450 scenario. This could be adjusted depending on expectations of carbon capture and storage, (CCS). However most scenarios consider it unlikely that CCS can start to scale before 2030, meaning it does not make a significant difference in the timeframe to 2035 considered by this analysis.

3. Demand and price

Demand scenarios

There are a number of scenarios produced by the IEA and industry, as well as regulators seeking to deliver emissions reductions. A more detailed demand paper looking at the largest markets accompanies this summary. Analysis by IEEFA indicates that applying the latest regulatory announcements and technical advances can deliver a scenario with demand below the previous IEA New Policies Scenario (NPS) – the Low Demand scenario on the chart. However it is clear more interventions from regulators and more disruptive technological shifts will be required to get near the IEA 450 Scenario. The demand scenarios displayed in Figure 1 are for global total coal consumption, so include both metallurgical and thermal coal.



Figure 1: Coal demand scenarios

Source: IEA WEO 2013 and IEEFA-ETA analysis

Demand and price 9

Key factors

A number of themes arose in IEEFA's review of demand determinants:

- Energy efficiency continues to improve, meaning economic growth can decouple from energy requirements.
- 2. Grid efficiency will reduce in significance as there is an increasing contribution from decentralised and off-grid sources. Transmission losses in some countries (eg 25% in India) still provide opportunities for improvement.
- 3. Countries will continue to seek energy diversity as a means of securing sustainable economic growth by delivering greater energy security and protection from commodity price volatility.
- 4. There is ever increasing potential for substitution of coal by a range of alternatives, including renewables which continue to outpace predictions for cost reductions.

Planning for disruption?

The ETA/IEEFA low demand scenario that has been developed demonstrates that current policy and technology are not sufficient to limit global warming to 2°C. It is becoming clear that some major policy interventions and disruptive technology will be required to deliver the objective the world's governments have signed up to.

Peak coal demand in China?

China currently represents around half of the global thermal coal market and will be critical to the future levels of consumption and seaborne market structure. Alongside the IEEFA low demand model, a number of mainstream coal analysts from investment research houses, (Deutsche Bank, Bernstein, Morningstar) expect Chinese coal demand peaking by 2016 or sooner.

Peak coal demand in China in the next couple of years would be like changing the direction of an escalator for the seaborne coal market. The IEEFA low demand model indicates China could become an opportunistic exporter within a few years of demand peaking. Investors and companies need to start thinking about what it means if 2014 is the year of peak coal demand in China.

Platt's recently reported that the levels of coal production and sales in the first half of 2014 were down 2% on the same period in the previous year. Reuters reported that Chinese coal imports in August 2014 were down 18.9% year-on-year, to 18.86 million tonnes. This market trend saw Chinese spot prices for coal hit a six year low.

In early September 2014 the National Council set out draft measures to introduce a cap on coal use in the five year plan starting in 2016, as well as restrict imports of low quality coal with high ash and sulphur content. The quality standard would likely affect low quality Australian and South African exports the most.

Can India deliver?

India is the next major hope of the coal exporters. The future balance between domestic supply and expensive imports is uncertain. On a practical level, India needs to finance and construct domestic infrastructure and improve efficiencies. However the current price of electricity cannot support continued expensive imports of coal; and India's weak financial system cannot continue issuing non-performing loans to help grow a loss-making power and distribution sector. There is clear potential for coal demand to grow in India, but the combination of these factors means the level may ultimately disappoint those expecting rapid growth in the next few years.

Peak coal demand in China in the next couple of years would be like changing the direction of an escalator for the seaborne coal market

Atlantic decline

Russia and Colombia are the major suppliers to the Atlantic basin, followed by the US and South Africa. The EU is the major importer, currently accounting for nearly 70% of Atlantic import demand. However the EU market is also contracting with significant plant closures expected under the Large Combustion Plant Directive, which will be followed by the Industrial Emissions Directive. Potential new markets like Turkey are not enough to compensate for the continuing closure of coal plants in Western Europe. The EU's Roadmap to decarbonisation indicates a dwindling role for coal, down to 5–10% of power generation by 2030.

With the Atlantic market expected to move into oversupply, export routes to the Pacific are being sought. The tide has already turned in the US, with domestic thermal coal demand declining over the last five years. This has led to producers attempting to divert contestable production towards exports where possible. Swing producers like South Africa and the US will also seek to divert supply to the Pacific if the price differentials are sufficient.

Pacific flatlining?

Without ongoing Chinese imports and rapid Indian growth the Pacific market demand levels are not sufficient to support stronger prices. This suggests that there will be no recovery of prices to the levels above \$100/tonne enjoyed in 2011–12. Other economies in South East Asia (eg Taiwan, Korea) may increase demand but not at sufficient volumes to drive up price significantly.

Renewables getting cheaper every day

The pace of growth in installed renewables capacity has outperformed most predictions since 2000. Average Photo-Voltaic module prices have fallen by nearly 75% in the past three years. Bloomberg New Energy Finance projects costs continuing to fall out to 2030. Wind and solar are already pricecompetitive with fossil fuels in some markets – the US and Australia. Energy industry projections need to be constantly updated to reflect the lower levelised costs of electricity renewables can offer.

Infrastructure dependent

There are a number of key infrastructure projects currently being proposed which would open up production. The significant investment required should be factored in to the economics of mine production.

The data used in this analysis focuses on capex requirements for coal mining assets. The costs of new infrastructure requirements for getting production to export markets is not usually included unless it is integral to the asset. This can apply both to existing mines looking to switch contestable production to export markets, and also to new mines.

US coal stranded?

In 2013 only 15% of US exports went to the Pacific. Significantly expanding US coal exports to Asia will require adding multiple new ports on the US west coast. Overall, the period since 2010 has demonstrated not just the regulatory but also the substantial financial risks attached to development of coal export terminals. 2013 saw cancellation of five proposed coal export terminals not just in the Pacific Northwest but also on the Gulf Coast as well as the withdrawal/ deferral of IPOs by two US coal producers with ambitious plans for exports. The analysis above suggests that companies that move ahead with remaining proposals will be exposing their investors to considerable long-term financial risks.

Current export coal pricing

2014 supply curves for export thermal coal are notably flat; even medium-cost producers generally see only modest profits, which can disappear due to variation in input costs or exchange rates.

The recent decline in thermal coal prices is eroding profits and risking losses for producers across a wide range of supply cost levels. For nearly half of potential production, Bloomberg's August 2014 Newcastle Free-On-Board (FOB) price of \$68/tonne is insufficient to cover the cash costs of production, (i.e. C1 + royalty displayed in the chart). If instead a breakeven approach, (including capital costs and IRR), is applied to these projects, this leaves only a third passing this test.

On a breakeven basis with current spot prices, half or more of potential export production capacity appears unprofitable in Indonesia, Australia, Russia, Colombia, and the USA (and nearly 40% in South Africa). Though mines have closed in response to these conditions, in several countries incentives for miners to keep producing (e.g. take-or-pay rail contracts in Australia, government policies in Russia) are delaying the exit of high-cost capacity and prolonging a situation of unsustainably low prices.

The futures price does improve the picture with an increase projected to \$82/tonne for 2018. This indicates, however, that the market does not expect a recovery in prices to above \$100/tonne. This futures price would be consistent with the breakeven for annual production of 1040mtpa – around the current size of the export market.





Million tonnes per annum (mtpa) potential thermal production 2014

----- Standardised BECP (Newcastle equivalent price required)

—— Cash cost (C1 + royalty) adjusted to 6,000 NAR

4. Potential production and capex

An analysis of the potential production out to 2035 from the next twelve years of capex can be split into:

- sustaining and expanding existing mines ('brownfield')
- sustaining and expanding new mines ('greenfield')

The level of capex on existing mines is lower than new mines, yet the related amount of production from existing mines, (and ultimately CO_2 emissions), is more than double. The potential production just from existing mines in the WoodMac universe is almost enough to meet the global IEEFA low demand scenario. If other potential production from India and other producers were added there is a clear excess of coal that could be produced. The table below indicates the breakdown of the next twelve years of capex, related production to 2035, and the lifecycle emissions that would result from combustion.

Figure 3: Breakdown between existing and new mines

	Existing mines	New mines
Capex 2014–25	\$220bn	\$268bn
Production 2014–35	5,689mtpa	2,313mtpa
CO ₂ Emissions	225GtCO ₂	92GtCO ₂

Source: Energy Economics, utilising Wood Mackenzie's GEM package and CTI-ETA analysis



Figure 4: 'Brownfield' thermal capex (export and domestic)

Do we need new mines?

These numbers suggest that, subject to being able to transport production economically to the demand, expensive new mines would be surplus to requirements in a low demand scenario. The geographic distribution of this production and its ability to be transferred would determine whether it could actually fulfil a low demand scenario.

There is a total of \$112billion of potential capex excluding China that exceeds the breakeven price of our low demand scenario. 61% of greenfield mines are over the thresholds of our low demand/price scenario compared to 30% of brownfield. Greenfield regions are also likely to require investment in infrastructure making them even less economically viable. This suggests that high cost new mines are the most likely to be affected from a low demand/price scenario.

Greenfield regions are also likely to require investment in infrastructure making them even less economically viable



Figure 5: 'Greenfield' thermal capex (export and domestic)

5. Carbon cost curve for potential seaborne export production

For the global export market we have indicated both a cash cost curve and a breakeven curve. Applying the breakeven to build in an investor return indicates that only production up to \$75/tonne will be supported in our low demand scenario.

The cash curve intersection for the current level of seaborne exports is around \$67/tonne – a similar level to the August 2014 Newcastle FOB price (\$68). This reflects the fact that the seaborne price is very close to the operating margin for producers. As a result any extra production is only likely to cover costs, rather than turn a decent profit. If demand softens in line with our projections there will be no recovery in the coal price. This questions whether operations with costs higher than this price will see positive cashflow from these projects in the future.

If demand softens in line with our projections there will be no recovery in the coal price



Figure 6: World export thermal cash cost & break even price (BECP) level (2014–2035)

Figure 7: Geographical breakdown of potential export capex above/below \$75/t breakeven threshold

The map below shows the level of potential capex for export from the largest ten countries. This is split above and below the \$75/tonne breakeven price where the low demand scenario intersects with the export cost curve, with the high cost capex indicated by the green circles on the map below.



Breakdown of potential export production by mine phase

China and Russia have a significant proportion of potential production requiring over \$75/t to breakeven from existing mines. Australia, Mozambique, Botswana and Indonesia are all highly exposed to new high cost mines for export.

These countries will also have to develop rail and port connections if they are to increase exports as sufficient capacity is not in place. Perhaps the most high profile example is the Galilee Basin in Australia. Development of mines in this remote part of Queensland require new rail connections to new ports inside the Great Barrier Reef.

Quality concerns

There continue to be reports that China will restrict imports of low quality, high sulphur and ash coal. This will help deliver urban air quality objectives. There may therefore be an overlay required to adjust for this going forward. This kind of measure would restrict markets for that 5500kcal coal with high sulphur and ash content from exporters in South Africa and Australia for example.



Figure 8: Export thermal coal capex by mine phase (over \$75/t only)

Figure 9: Potential Australian coal capex for export

Apart from China, Australia has the largest amount of potential capex in new mines above the \$75 threshold. The gap between the cash cost and the breakeven price increases in the higher part of Australia's cost curve. This reflects the high capital costs of new mines. The companies with the largest amount of capex above the \$75 threshold broken down by mine stage are displayed in the table below.

Company	Existing mines – sustain BECP >\$75/t	Existing mines – expand BECP >\$75/t	New mines – sustain BECP >\$75/t	New mines – expand BECP >\$75/t
GVK	0	0	327	5,378
Adani	0	0	350	3,646
Meijin	0	0	68	3,848
BHP Billiton	138	27	98	3,314
Mitsubishi	123	3	9	2,664
Glencore Xstrata	120	7	94	2,223
Bandanna Energy	0	0	249	1,391
Shenhua	0	0	177	1,071
Anglo American	36	30	124	922
Hancock	0	0	87	950

Source: Energy Economics, utilising Wood Mackenzie's GEM package and CTI-ETA analysis

Figure 10: Potential Indonesian coal capex for export

Indonesia may struggle to maintain current export levels as new mine options are further inland and of poorer quality. This combination of increased costs and lower prices means these options are not economic at current prices.

Company	Existing mines – sustain BECP >\$75/t	Existing mines – expand BECP >\$75/t	New mines – sustain BECP >\$75/t	New mines – expand BECP >\$75/t
BEP Coal	0	0	578	2,168
MEC Holdings	0	0	170	1,500
Churchill Mining	0	0	150	1,500
Adaro Energy	209	21	184	239
Reliance ADA	0	0	120	151
Delma Mining	0	0	167	55
Bayan Resources	115	85	0	0
Pan Asia	0	0	14	180
Bumi Resources	5	4	40	130
Kangaroo Resources	0	0	76	79

6. Carbon cost curve for potential China domestic production

China has significant low cost production. Assuming only cash costs are required to be covered, China can average 3000mtpa to 2035 at \$60/tonne. China has adopted an 'everything-but-coal' energy strategy to improve energy diversity. This has already seen demand reduce, and there are signs that a peak in demand could even come in 2014. Either way if Chinese domestic thermal coal demand effectively stabilises at current levels then this has an overflow effect on the rest of the world.

Domestic producers are currently feeling the strain with prices down 20% in the first 8 months 2014, reflecting softening demand and oversupply. Reuters reported that over half of China's coal companies are operating at a loss over the first half of 2014. If China switches from being a net importer to a net exporter of coal it will reverse the flows in the Pacific market. This also challenges whether the export plans of many companies adds up. What will all those companies relying on China as an export market do if the demand dries up?

Chinese data is amalgamated at a regional level and therefore exposure by company is not available. Around a quarter of potential capex is in Xinjiang – this is all below \$60/tonne costs. Shanxi has a similar amount of capex, with projects in the East, North and West of the province coming in above \$60/ tonne costs.



Figure 11: China's domestic thermal cash cost & BECP (energy-only adjustment)

US regulation kicking in

The breakeven point, (adjusted for thermal value), for a low demand US scenario is around \$53/metric tonne for domestic production. This is aggregated at a national level In order to apply it to US regional markets we have had to develop equivalent regional price points.

US thermal coal demand in 2013 was around 778 metric tonnes, (858 short tons). The IEEFA low demand scenario sees US coal demand reducing by -2.2% CAGR to 2025.

Recent Bernstein analysis indicates that after adding in the recent Clean Power Plan, the aggregate decline in utility coal demand between now and the end of the decade could be as much as 228 million short tons, (207 million metric tonnes).The US has already experienced significant closures of coal plants with more expected over the coming years – a further 90GW of coal-fired plants by 2025 (i.e. nearly one-third of the US coal fleet). The fact that Wood Mackenzie does not have sufficient production to meet current consumption levels over the next 20 years in its database is consistent with a significant decline in US demand.

The aggregate decline in utility coal demand between now and the end of the decade could be as much as 228 million short tons, (207 million metric tonnes)

US Regional Breakdown

US coal production is grouped into several regional markets which are grouped around geological formations of coal of similar quality. In order to attribute the low demand scenario across the different regions we apportioned the demand using 2018 futures prices. This was done to reflect market sentiment about relative future demand shifts. The percentage supply for each region that resulted is as follows:

Figure 12: US Regional breakdown

Region	Percentage of 2013– 2035 demand	Regional BECP (energy- adjusted)
Central Appalachia (CAPP)	2.3%	\$74
Illinois Basin (ILB)	31.1%	\$53
Northern Appalachia (NAPP)	8.3%	\$58
Powder River Basin (PRB)	46.4%	\$17
West Bitumous (WBIT)	9.0%	\$39
Other	2.9%	-

Source: SNL Coal futures prices, CTI-ETA Analysis 2014

The average breakeven coal price that relates to the 600mtpa low demand scenario is \$53. The regional equivalents, (adjusted for thermal value, US short tons converted into metric tonnes, and into 2014 US\$) are displayed for each region. Around half of the production affected is in the PRB, with the other half split between CAPP, NAPP, and ILB. The capex in the CAPP region relates only to existing mines; the other regions have a majority of new mine capex affected.

The companies with the largest exposure to potential capex for future production requiring breakevens over these levels are listed in Figure 14.



Figure 13: USA's domestic thermal cash cost & BECP (energy-only adjustment)

Figure 14: US potential domestic capex by company (BECP over regional only)

The data indicates significant potential investment in new mines that would not breakeven in a low demand scenario. Continuing with these investments risks mines not generating a positive cashflow if prices do not improve. The regional breakevens indicated on the US cost curve, (Figure 12) are applied here.

Company	Existing mines – sustain >regional breakeven	Existing mines – expand >regional breakeven	New mines – sustain >regional breakeven	New mines expand >regional breakeven
CONSOL	5	12	490	3,371
Alpha	609	138	118	1,131
Peabody	63	54	110	1,278
Murray	344	126	102	803
Cloud Peak	308	801	0	0
Alliance	439	51	170	306
Arch	355	162	0	0
Patriot	361	103	0	0
Terra Nova	0	0	34	410
James River	235	9	20	66

Source: Energy Economics, utilising Wood Mackenzie's GEM package and CTI-ETA analysis

Figure 15: US potential export capex by company (BECP over \$75/t only)

Going back to the export curve (Figure 6), this table identifies potential company capex for export. Comparing the list with the adjacent table indicates that some companies have secured high cost options for export as well as domestic production.

Company	Existing mines – sustain BECP >\$75/t	Existing mines – expand BECP >\$75/t	New mines – sustain BECP >\$75/t	New mines – expand BECP >\$75/t
Arch	92	368	5	223
Peabody	89	331	42	167
Terra Nova	0	0	0	390
Alpha	136	24	0	46
Patriot	96	45	0	21
Hartshorne Mining Group	0	0	0	145
Cloud Peak	129	16	0	0
White Oak	0	0	35	79
Cline Group	0	0	0	108
Usibelli	27	0	12	55

8. Diversified mining companies

The big four

The four largest coal-producing diversified mining companies (Anglo American, BHP Billiton, Rio Tinto, and GlencoreXstrata) are major suppliers to global coal markets. With operations concentrated in Australia and South Africa (with additional mines in Colombia), these four companies control roughly 25% of production capacity for thermal coal export markets (and maintain a similarly large presence in met coal markets). On average across these four companies, coal accounted for 13% of total 2013 revenues (with coal's share of total revenues ranging from 5–20%).

Pressure on margins

Operations of the four large diversified miners are in the middle portions of the export thermal cost curve, with energy-adjusted cash costs concentrated between \$50–70/tonne and Newcastle-equivalent BECPs between \$60–80/tonne. With over half of 2014 production having BECPs over \$70/tonne – i.e. equal to the current Newcastle spot price – some mines have ceased to be profitable amid the recent decline in thermal coal prices. While most mines continue to be profitable on a cash-cost basis, cash margins of 15–20% are below company targets.

Declining profitability of coal production

Coupled with cost inflation as a result of supply chain pressures and Australian currency appreciation, the post-2011 decline in prices for both thermal and met coal has significantly eroded the average EBIT margin on coal for these four companies from 30% in 2011 to 10% in 2013.

M&A for thermal coal assets

In October 2013 Rio Tinto divested an Australian mine (Clermont) that accounted for 25% of its 2013 thermal coal production, and thermal/met prospects in Mozambique (having some years earlier sold off a major thermal coal development in the US Powder River Basin). In the same vein, as of writing (August 2014) BHP is in the process of spinning-off several 'non-core' thermal coal mines in South Africa (along with a met coal mine in Australia). BHP's spin-off builds on previous sales of thermal coal mines in South Africa, as well as in Australia and the USA. On the other end of the spectrum is GlencoreXstrata, which has acquired Rio Tinto's Clermont mine and several of BHP's former mines in South Africa as part of a strategy to increase exposure to thermal coal.

Alternative options

As diversified mining companies, these companies have interests across a range of minerals, and can divert capital into commodities where they see better earnings prospects. In terms of their thermal coal business, as large players they also have options on projects spread along the cost curve. Reducing company exposure to the higher end of the cost curve makes sense given the warnings from analysts that the sector is in structural decline.

Some of these companies have already pressed pause on capex for new thermal coal mines. The economics of any proposed new thermal coal mines should certainly be given close scrutiny by shareholders. The actions of the big diversifieds on thermal coal should raise questions for investors about the plans of pure coal mining companies.

9. Pure coal producers

Value destruction signs

Pure-play coal producers have been hit hard by the post-2011 decline in prices (down 47% for thermal coal and 40% for met coal) and, in some cases, rising costs due to lower-quality coal seams, stressed supply chains, and unfavorable exchange rate dynamics. Surveying data for 83 global coal producers with a market cap above \$200 million, we find recent demand/price/cost trends to have generated flat revenue growth and, for many producers, EBIT margins that are lower than at any point since 2003 Averaging across our sample, average returns on equity have fallen to at or near the cost of equity – a sign of value destruction for investors.

Uncertain future

Since the 2008 peak, valuations of leading coal companies have lost more than 70% of their value. On a YTD/1-year/3-year/5-year/10-year basis, leading coal indices have underperformed the MSCI World Index while also displaying significantly more volatility. Recent declines in P/E and EV/EBITDA ratios of leading coal companies suggest continuing market skepticism about the long-term prospects of these companies. For more discussion of these issues, see our companion research note on financial trends for listed mining companies.

Capital discipline required

Diminished returns have as of late led coal companies to restrain annual growth in capex budgets. That said, annual capex of the global coal sector remains 3X cash returns to shareholders – which suggests that capital management decisions ought to be a major priority for shareholders of coal companies. Given the headwinds facing higher cost projects in many parts of the world, now is a time for greater capital discipline.



Figure 16: Ratio of capex to shareholder returns in the coal sector

Source: Bloomberg, CTI/ETA analysis 2014

10. Conclusion and recommendations

Demand

China dominates global demand for coal. Signs that a peak in thermal coal demand could be imminent cannot be ignored. This could switch China to being an opportunistic exporter of coal within a few years. This would change the whole dynamic of the seaborne trade market. Investors need to be prepared for Chinese coal demand peaking.

India is the next big hope of the coal sector for increased demand. The rate of consumption is challenged by a number of factors. In particular, whether the country can afford to subsidise the necessary infrastructure; and whether the current power market can afford the price of expensive imported coal.

Perhaps of more significance for listed companies is the knock-on effects of demand falling short of industry expectations in key markets. This will only serve to weaken the prices for seaborne coal, rather than see prices rebound to the levels required to make some mines profitable again. Existing mines are at risk of becoming stranded assets – ones that do not yield the expected returns.

Bridging cost and carbon

It is clear that there is ample coal in existence to blow through the carbon budget in the next couple of decades. However at current price levels much of this coal is not going to generate positive cashflows, providing economic reasons why coal production may decrease.

With some analysts observing a structural decline in the coal market, the pure economics of many new mines do not make sense without a major upswing in the market.

Plotting a linear decline in coal demand based on what is known to be feasible or part of policy today does not achieve a 2°C world. It is clear that more policy intervention and technological disruption is required. But renewables continue to outpace predictions of their cost reductions and penetration in many markets, whilst efficiency continues to improve. And concern over air quality and carbon pollution continues to rise. This means the substitution for coal is increasingly both possible and required.

Seaborne coal market

The decline of EU coal consumption that fits with the energy roadmap to 2030 sees many existing plants closing and very limited new capacity. The impact of US EPA measures also sees US producers seeking alternative overseas markets where possible. This oversupply to the Atlantic region will overflow into the Pacific market. This makes it even more critical to the future of export-oriented coal production that demand grows in China and India.

Our analysis shows that a low demand scenario does not support new export production from existing or new mines requiring over \$75/tonne to breakeven. This is around the current spot price for seaborne coal. This suggests that prices are very unlikely to recover to triple digit levels again without a major upswing in demand.

There is already a significant amount of production which is barely covering cash costs. On a breakeven basis applying current spot prices, half or more of 2014 potential export production capacity appears unprofitable in Indonesia, Australia, Russia, Colombia, and the USA Some operators are clearly gambling on an upturn in the coal price.

Global capex

There is a total of \$112billion of potential capex excluding China to 2025 that exceeds the breakeven prices of our low demand scenario. This corresponds with over 1000mtpa of coal production projected to 2035 or an estimated 42GtCO₂. 61% of 'greenfield' (i.e. new) mines are over the thresholds of our low demand/price scenario compared to 30% of existing mine expansion.

US exposure

The direction of travel for coal consumption in the US is clear. Producers are exposed to both domestic power switching away from coal, and being on the margins for coal exports. The high levels of uncertainty for those at the wrong end of the cost curve certainly make it difficult to justify capex in new production.

Pacific exposure

The potential for continuing weak prices, challenges the logic behind developing vast coalmines in remote Australia, and building new railways and ports to get them to the seaborne market. The capital cost of transport infrastructure is one of the major financial hurdles facing new coal projects. Indonesian options face similar challenges as potential new mines are further inland and of low quality.

Diversified companies

The big four Western diversified miners (i.e. GlencoreXstrata, BHP Billiton, Rio Tinto, and Anglo American) account for a quarter of the global thermal coal trade. However there are already signs that some of these companies are concentrating on other commodities. Some have put new thermal coal capex on hold, whilst others have sold assets. For large companies with these options, it makes sense to limit exposure to the low end of the cost curve, and focus on minerals where there exist better margins; alternatively, another option is to return more capital to investors via dividends and share repurchases, as some large diversified miners have begun doing.

Pure coal companies

The coal sector has been facing heavy weather in recent times and some companies have already gone under. Some operators appear to be trying to see the storm out and hope they are still afloat for the residual market. Some companies have already tried to diversify into the export market to compensate for a domestic downturn. However this geographic hedge carries its own risks. Further adaptation plans may be needed in order to demonstrate a viable business model in a low demand scenario.

Recommendations for investors

Asset owners and managers should consider the following:

- 1. Understand the exposure of your portfolio/ fund to the upper end of the carbon cost curve, and articulate how this risk is being managed.
- 2. Identify the companies with the majority of capex earmarked for high cost projects.
- Focus engagement on export projects requiring \$75/ tonne or above, (Newcastle 6000kcal FOB equivalent), as a starting point. And review equivalent low demand price thresholds for domestic production.
- 4. Set thresholds for exposure to projects at the high end of the cost curve for portfolio companies to adhere to.
- 5. Make it known to company management that you are seeking value not volume.
- 6. Ensure remuneration policy at companies is consistent with shareholder return objectives not just rewarding production levels or spending capital.
- 7. Require improved disclosure of demand and price assumptions underpinning capex strategy and business models.
- Support transparency of company exposure to the cost curve and impairment trigger points, e.g. through annual publication of sensitivity analysis/stress tests to coal prices.

Technical analysis

ETA employed Energy Economics to operate the GEM software and use it to generate the supply cost curves used in this report. They used Wood Mackenzie (WM) Global Economic Model (GEM) as at June 2014. All data for supply cost curves and capital expenditure for thermal coal is mine based and comes from the WM GEM as at May 2014 – supplemented by minor additions from other WM data sources. GEM is a coal data and discounted cash flow modeling package designed to facilitate coal asset 'market valuations, M&A transactions, benchmarking, strategic planning and fiscal analysis.'

GEM contains 15 countries with cost data, so does not cover total world supply/demand. This leaves a gap that also has to be estimated separately in terms of future supply in order to derive the carbon budget. GEM incorporates a comprehensive set of cost, production and price data for each asset (historical and forecast through to the expected end of the life of the mine), as well as fiscal regime and currency exchange rate information to enable calculation of royalties and taxes. The asset and fiscal regime data is part of the 'Wood Mackenzie Read-Only Data' which users can adopt or copy and modify using different price assumptions etc.

Energy Economics used essentially unaltered the 'Wood Mackenzie Read-Only Data' (except for the creation of separate domestic thermal and export thermal projects) during the course of this assignment – adopting the Wood Mackenzie currency exchange rate and price assumptions unchanged. This was a conscious decision in order to retain clarity that the underlying core mine data was firmly based on the widely used Wood Mackenzie data set. In addition to the standard set of assets provided as part of the GEM package, Wood Mackenzie also provided data for an additional set of 155 potential mine projects ranked as 'possibles'. This increased the total assets in the project to 1,431. Ownership data was not supplied for the 'possibles' assets, however Wood Mackenzie subsequently provided a list of the operators of these assets. In general, Energy Economics assumed that the operator of the project owned 100% the asset, however more detailed ownership data was entered by Energy Economics for some of the 'possibles' assets where available. All of our results are based on the full 1,431 asset data set.

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