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Organization: Northern Plains Resource Council

State: Montana

Agency: Surface Transportation Board

Initiative: Tongue River Railroad

Submission Text

Attached, please find comments on the TRR DEIS submitted on behalf of Northern Plains Resource Council. Please ensure that they get entered into the record. -Steve Charter



Ken Blodgett
Surface Transportation Board
395 E Street SW
Washington, D.C. 20423-0001

Attention: Environmental Filing, Docket No. FD 30186

September 23, 2015

Dear Mr. Blodgett:

On behalf of Northern Plains Resource Council (Northern Plains) members, I am submitting the following comments to the Surface Transportation Board (STB) in response to its Office of Environmental Analysis (OEA) April 24, 2015, release of the draft environmental impact statement (DEIS) for the 2012 application to build the Tongue River Railroad (TRR) in Montana. As set out in Northern Plains' comments on the transportation merits, the TRR is inconsistent with the public convenience and necessity. Nevertheless, if the STB concludes, contrary to the overwhelming evidence, that the TRR project is needed, financially viable, and in the public interest, then the STB must take a hard look at the environmental and socioeconomic impacts of the proposal. Northern Plains' comments here demonstrate that the DEIS fails to adequately consider and analyze these impacts.

Northern Plains is a grassroots conservation and family agriculture non-profit organization based in Billings, Montana. Northern Plains organizes Montana citizens to protect our water quality, family farms and ranches, and unique quality of life. Northern Plains is dedicated to providing the information and tools necessary to give citizens an effective voice in decisions that affect their lives. These comments are also submitted on behalf of the Western Organization of Resource Councils (WORC), a regional network of eight grassroots community organizations that includes 12,200 members and 40 local chapters in seven states; Northern Plains is a member of WORC. WORC is committed to building sustainable environmental and economic communities that balance economic growth with the health of people and stewardship of their land, water, and air resources.

Northern Plains formed in 1972 over the issue of coal strip mining and its impacts on private surface owners who own the land over federal and state mineral reserves as well as the environmental and social impacts of mining and transporting coal. Many of our members own farms and ranches along the various alternative routes discussed in the DEIS as well as in the area along Otter Creek that is slated for coal development to supply that railroad. Our members' livelihoods depend entirely on clean air and water, native soils and vegetation, and lands that remain intact. The proposed TRR would bisect and disrupt not only individual ranches but an entire rural, agricultural valley that has existed sustainably for more than 100 years. Many more

of our members live along and near railroad lines that would be the subsequent conduits for the millions of tons of coal proposed for shipment by the TRR to the coal's final destination.

Northern Plains has opposed the building of this railroad since it was first proposed in the 1980s. For more than 30 years, various promoters have unsuccessfully tried to build a railroad through the Tongue River Valley in southeastern Montana. This area is a highly productive and economically sustainable agricultural area that currently has no coal mine. The TRR "master plan" has always been to get a coal strip mine – any mine, but this time the proposed Otter Creek mine – permitted and then to make money hauling that coal. But, without a coal mine (and we are a long way from any coal mine being permitted in this area), there is no need for a railroad. The project devised by those behind the TRR has always been – and remains – pure speculation and contrary to the public need. These comments, like Northern Plains' comments in the TRR permit proceeding, will lay out the many reasons why, in addition to its devastating impact on southeastern Montana and beyond, domestic and international political and market conditions mean the TRR could not be successfully operated.

However, while the evidence strongly indicates that the TRR will never be profitably constructed and operated in current and projected market conditions, the STB must still nevertheless take a hard look at the impacts of the construction and operation of the TRR in its DEIS before the agency considers issuing a permit to TRRC. And those impacts are many. The TRR would tear up the land; condemn private property; sever ranches; damage water quality; displace or destroy costly private property capital improvements such as fences, corrals, wells, and/or irrigation systems; harm wildlife and wildlife habitat; destroy cultural resources; increase vehicular traffic on public roads during construction and, thus, increase inconvenience and the likelihood of accidents; impair and degrade air quality as a result of railroad engine combustion and coal dust as well as from fugitive dust during construction and operation of the railroad; increase the spread of noxious weeds; increase the incidence of wildland fire; decrease firefighting crews' access across the tracks in order to fight fire; increase public concerns and impact public safety due to potential derailments, fuel spills, and other toxic material spills; devastate the agriculturally productive economy of the region; eliminate jobs at existing coal mines; and negatively impact many communities down the rail lines all so that out-of-state corporations could haul (hoped-for) coal somewhere – yet to be determined – for their private profit. That coal would then be burned in a power plant – somewhere – further polluting the air and increasing the problems posed by climate change.

The long and speculative history of the TRR is detailed in the administrative record and briefly summarized in the DEIS. The fact that this project has been hanging over the heads of our member landowners and others for more than 30 years has resulted in lessened property values and in landowners being unduly concerned about whether or not to make certain improvements to their properties. Through all these years, the project's promoters have never been able to raise the money needed to build the railroad nor have they been able to find any coal to transport. This railroad has always been a speculator's dream, yet it has harmed many.

The TRR is not now and has never been a "common carrier." It is a private, single-purpose railroad – this time to haul hoped-for Otter Creek coal – that will have significant and devastating consequences for the Otter Creek and Tongue River valleys and their residents. If

permitted, this railroad would be given the right to use federal eminent domain law to acquire land from non-willing property owners. Landowners all along the chosen alternative right-of-way would face condemnation so that a private railroad could haul coal for private profit to a market that (as we show below) does not exist.

This is the fourth application submitted to the STB in an attempt to build the TRR, and in January 2013, Northern Plains along with Rocker Six Cattle Company filed a petition to revoke the December 2012 supplemental permit application. From that date through March 26, 2015, numerous documents have been submitted by Northern Plains to the STB and entered into the record. Northern Plains incorporates all of those documents by reference into these comments on the DEIS.

Under the National Environmental Policy Act (NEPA) and the Council on Environmental Quality (CEQ) regulations implementing NEPA, “the NEPA process is intended to help public officials make decisions that are based on understanding of [the] environmental consequences [of a project] . . .” Thus the purpose of an EIS is to disclose all the information and analyze and evaluate that information so that the environmental consequences of a project are fully disclosed to the public and for consideration by decision makers. Unfortunately, this DEIS does not fully disclose or analyze the issues, costs, consequences, or connected and cumulative impacts of permitting and building the TRR. Nor does the DEIS fully and accurately analyze the public need or necessity for the TRR.

Moreover, the nearly 4,000 pages of the DEIS are largely based on the Integrated Planning Model (IPM) and two corollary models that are proprietary to the OEA’s contractor. Neither the public nor the decision makers are provided with the information and/or data that were input into these models. Nor does the DEIS divulge the output data that has resulted in the rosy-picture conclusions for coal markets that are used to support the need for the TRR. Consequently, there is no way to verify the results. But it is apparent to us that OEA’s assumptions used in the modeling exercises are in conflict with current industry information and trends, and other assumptions are unsupported by any evidence (see discussion below).

Additionally, OEA’s modeling results are often presented as a series of averages across years and/or across scenarios, neither of which provides a meaningful indicator of the conclusions reached. This method of presenting results combines mutually exclusive scenarios. This method of presenting results also precludes understanding the impacts and consequences of any given scenario and it does not provide a reader (or decision maker) with the information necessary to understand the likelihood that one scenario might be more advantageous than any of the others, including the no-action alternative.

Further, as described in the attached Power Consulting Report¹, OEA’s use of the IPM for this effort is flawed. The IPM does not incorporate the basic economic principle of price elasticity of demand. As a result, the IPM analysis fails to address whether opening a massive, purportedly low cost coal reserve would increase overall demand and, consequently, lead to

¹ “Misuse of Integrated Planning Model as an Assessment Tool in the Tongue River Railroad DEIS,” by Thomas Michael Power and Donovan S. Power of Power Consulting, Inc. and Joel M. Brown of Aesir Consulting, LLC. September 22, 2015.

greater environmental and socioeconomic impacts. Because the OEA's assessment of the environmental impacts of the TRR as laid out in the DEIS, relies on misuse of IPM, the DEIS does not accurately or fully analyze the environmental and social consequences of construction and operation of the proposed project.

The DEIS also violates what we consider to be a central tenet of NEPA – to clearly and concisely convey to the public and decision makers the environmental impacts of the proposed project and why the project is needed. Further, this DEIS does not meet NEPA's requirement for informed public participation because the model data, assumptions, and analysis that are used in the DEIS to support the conclusions reached are not transparent and do not reflect changed conditions and information available within the past two years. Consequently, this document fails to take a hard look at the proposed project as required by NEPA. This DEIS fails to provide the public and the agency decision makers with sufficient information to make an informed decision.

BACKGROUND INFORMATION

As mentioned above, this is the fourth application to build the TRR. The project was first proposed in the early 1980s, and the initial application for the TRR was submitted to the Interstate Commerce Commission (ICC; precursor agency to today's STB) in 1983. The promoters at the time, principally Wesco Resources and Mr. Mike Gustafson, wanted to build a rail line, the TRR, from a proposed coal mine in the Ashland, Montana, area (the Montco Mine) to Miles City where the TRR would join the existing rail line and transport coal to the Upper Midwest. Subsequent applications by the TRR Company to the STB sought to extend that original permit south into Wyoming to access coal mines in that state after the proposed Montco Mine was not constructed (and its mining permit was later withdrawn by the State of Montana).

This time around, the principal promoter of the TRR is Arch Coal. Arch Coal owns 34.68% of the TRR and 100% of the lease for the Otter Creek coal tracts through its wholly owned subsidiary, Ark Land Company. The history of how Arch Coal, the nation's second largest coal company, became so deeply involved in the TRR and the Otter Creek coal tracts began more than 10 years ago – at a time when prices for coal (particularly export coal) were at all-time highs.

In October 2007, the TRR Company received a permit-to-build TRR III from the STB.² (This permit extended the original Ashland-to-Miles City rail permit, TRR I, south into Wyoming, generally along this document's proposed Decker alternative route.) The TRR Company and others began seriously promoting the idea that the State of Montana should offer for bid a lease for the Otter Creek coal tracts, which in 2002 Montana had acquired from the federal government.³ These coal tracts are checker-boarded with private coal reserves owned by

² Northern Plains and others filed petitions challenging this decision at the 9th Circuit Court of Appeals, which, after lengthy review, finally reversed and remanded the majority of that permit decision in December 2011.

³ These federal lands were acquired by the State (after years of negotiation) for a perceived loss of mining jobs as part of the agreement to retire the hard-rock mining claims of the New World Mining District, northeast of Yellowstone National Park.

Great Northern Properties.⁴ Alone, neither the (now) state coal tracts nor the private coal tracts are minable, but together, they form contiguous blocks that could be strip mined if permits for the Otter Creek state coal tracts could be obtained. In November 2009, Arch Coal signed a lease agreement with Great Northern Properties to mine all of its Otter Creek coal reserves.

In December 2009, the Montana Land Board voted to lease the state's Otter Creek coal tracts to Arch Coal (the sole bidder), through its subsidiary, Ark Land Company; the deal was finalized in March 2010 when Arch Coal paid \$85.8 million to the State of Montana for the 10-year lease. In July 2012, Otter Creek Coal LLC (OCC), a new subsidiary of Arch Coal established to operate the proposed Otter Creek Mine, submitted a permit application to the Montana Department of Environmental Quality (DEQ) to develop the first phase of the proposed mine in Tract 2 of the lease (the lease encompasses three tracts).

In July 2011, Mr. Gustafson sold his TRR III permit to Arch Coal and Burlington Northern Santa Fe Railroad (BNSF). Forrest Mars, who had opposed the TRR III extension into Wyoming, then purchased the southern portion of the railroad permit from Arch Coal and BNSF "to keep the tracks from running through his Diamond Cross Ranch" according to the *Billings Gazette* (August 27, 2011).

Arch Coal and the other promoters of the TRR now thought that the stage was set to finally open a new mine, build a railroad, and begin hauling coal (from the proposed Otter Creek Mine) to the West Coast to sell on the export market for huge profits. However, many things were already beginning to change, not only for coal markets but also for Arch Coal. The company is in serious financial trouble, and it is questionable whether or not it has the ability to fulfill all of its commitments to the intertwined and connected projects that are the sole reason and justification for constructing the TRR.

ARCH COAL'S FINANCIAL FITNESS

Arch Coal owns 34.68% of the TRR and 100% of the lease for the Otter Creek coal tracts through its wholly owned subsidiary, Ark Land Company. Additionally, Arch Coal owns 38% of the proposed Longview, Wash., export terminal facility (Millennium Bulk Terminals), which Arch Coal stated in a January 2011 press release would "give us a direct stake in participating in the growth of U.S. coal exports off the West Coast." But neither the Otter Creek coal tracts nor the Longview export terminal have been permitted, and both have significant regulatory hurdles to pass before any permits are issued.

The decline in coal sales nationwide (see below) has resulted in Arch Coal's share price dropping from more than \$67 in 2008 to less than \$1 in 2015. In May 2015, Arch Coal was notified by the New York Stock Exchange (NYSE) that it was out of compliance with the market's continued-listing rule requiring an average closing price of at least \$1/share of common stock for 30 consecutive trading days (in July 2015 Arch Coal's share price on the NYSE was fluctuating around 22¢/share); the company was given six months to regain compliance. In early

⁴ Great Northern Properties was formed in 1992 to acquire the coal-related assets of Burlington Northern Railroad (BN). In 1995, the BN Railroad merged and became the Burlington Northern Santa Fe Railroad.

August 2015, Arch Coal carried out a 10:1 reverse stock split in order to boost its share price above the \$1/share minimum required for listing on the NYSE.

Arch Coal reported \$736 million in losses in 2013; in 2014 the company reported losses of \$558 million and suspended dividends to its shareholders. First and second quarter 2015 losses total more than \$281 million. Just this year, Arch Coal either declined to bid on or abandoned coal leases that are next to existing, operating coal mines – mines served by existing rail lines – in Wyoming. Additionally, Arch Coal paid \$50 million in liquidated damages in 2014 for unused export terminal capacity due to weak overseas prices that are a result of over-supplied coal markets; it is likely that similar liquidated damage payments will be made in 2015. Arch Coal has nearly \$2 billion in debt due for payment in 2018, and an additional \$3 billion in debt due on various dates between 2019 and 2021. It was recently reported⁵ that Arch Coal’s senior creditors favor pushing Arch Coal into bankruptcy sooner rather than have them make interest payments on their debt and delay bankruptcy – an event which the senior creditors appear to believe is inevitable. This would ensure that there is more cash in Arch Coal’s cash accounts to cover its debts and, allow larger payouts at bankruptcy to the senior creditors.

In May 2015, Moody’s Investor Service downgraded Arch Coal’s credit rating because the analyst believes that Arch Coal has an untenable financial structure. Moody’s says that Arch Coal’s extremely weak debt protection metrics and high leverage ratio are problematic for the company. Significantly, Moody’s does not believe this will change in the next 18 months and possibly longer.⁶ Nor is it surprising that in April 2015 BB&T Capital Markets told investors that while Arch Coal may not file for bankruptcy in 2015, restructuring is “possible in 2016.”⁷

It is, thus, questionable whether or not Arch Coal will have the capital necessary for its share of the costs to build the TRR, let alone the capital needed to open the proposed Otter Creek coal mine. We note that Table 6-6 of Appendix C (page C-6-26) lists the NPV [net present value] for the Otter Creek Mine (these are the costs for the Otter Creek Mine that are not associated with constructing/operating the railroad) at -274. There is no discussion of this number and what it means anywhere in the DEIS, but it suggests to us that the profitability of the mine is in question. If this is the case, the final EIS must include a robust discussion of the Otter Creek Mine’s NPV and the expected profitability of the mine and railroad.

It also appears that Arch Coal’s financial fitness (or lack thereof) make it unlikely that the company would have the capital necessary for its share of the development costs for the proposed Longview export terminal facility, if it is permitted. This is the export terminal that Arch Coal previously determined (and publicly stated) that it needed in order to make the proposed Otter Creek coal mine profitable.

The financial fitness of Arch Coal raises many questions of grave concern to Northern Plains and its member landowners who would be directly affected by this proposed project, should it be approved. What happens if the proposed project is approved but abandoned before

⁵ <http://www.bloomberg.com/news/articles/2015-09-15/as-arch-coal-lenders-balk-at-bond-deal-miner-faces-debt-payment>

⁶ https://www.moody.com/research/Moodys-downgrades-Archs-CFR-to-Caa3-outlook-negative--PR_324474

⁷ <https://www.snl.com/InteractiveX/article.aspx?CDID=A-32308593-10294&ID=32308593&Printable=1>

completion due to the financial collapse of Arch Coal? What provisions would be in place for remediation, reclamation, and rehabilitation of the area affected by any construction? What would happen to any easements acquired by the TRR Company? Or, if a permit is given but construction of the railroad never takes place, what remedy would property owners have in the face of the specter of this unresolved project that will diminish their property values and prohibit them from initiating necessary ranch improvements? Arch's financial fitness and the facts surrounding the marketability of the coal the railroad hopes to haul (see discussion below) make these questions of vital importance to this discussion.

PURPOSE AND NEED FOR THE TONGUE RIVER RAILROAD

The TRR is inextricably intertwined with the proposed Otter Creek coal mine – without the coal mine, there is no public need for the TRR.

There is no market for the coal from the proposed Otter Creek Mine, either domestic or international, thus, there is no public need for the TRR, and a permit would be inconsistent with any public convenience and necessity.

There is no reasonable expectation that any other coal mine might someday be permitted in the area that the TRR would service, thus, there is no public need for the TRR, and a permit would be inconsistent with any public convenience and necessity.

The Status of the Market for Coal

Throughout the DEIS, the premise put forth for the TRR project is that there is a robust market for coal from new mine(s) in the Tongue River area, not only domestically but also internationally. Additionally, it is claimed that the coal that the TRR hopes to haul would cost less to produce than other Powder River Basin (PRB) coal (these claims can be found throughout the DEIS but particularly in Questions and Answers and Appendix C: Coal Production and Markets). Nothing could be further from the truth.

The computer model relied on by OEA for the conclusions reached in this DEIS used erroneous assumptions and significantly old and inaccurate data for its inputs. Because there is no explanation of the model or the assumptions used or how parameter inputs were determined, defined, and put into the model, there is absolutely no transparency for the conclusions reached. Some of these transparency failures are laid out in the Power Consulting Report⁸. Neither the public nor the decision makers can verify these conclusions, and, thus, the DEIS is deficient and inadequate.

Because of the IPM's shortcomings as well as all the relevant and current information we present below, it is imperative that the OEA re-examine the use of this model as well as the underlying assumptions and the data that were used in modeling. We believe that, based on the

⁸ "Misuse of Integrated Planning Model as an Assessment Tool in the Tongue River Railroad DEIS," by Thomas Michael Power and Donovan S. Power of Power Consulting, Inc. and Joel M. Brown of Aesir Consulting, LLC. September 22, 2015

information presented below, the model conclusions are factually incorrect. We believe that if a more appropriate model were used and if the assumptions and the data inputs were corrected and updated, the rosy conclusions for current and future coal production volumes and markets would not be considered valid. Until a more appropriate model is applied, and until more appropriate assessment metrics for the model's results are used, nothing in the DEIS can be assumed to be accurate.

The U.S. Energy Information Administration (EIA) produces an Annual Energy Outlook (AEO) each year; this is a report on the status of energy use, including coal use, in the United States. Around 1984, the tonnage of coal produced in western U.S. coal mines finally equaled the tonnage of coal produced in eastern U.S. coal mines, which had been operating for more than a century. This was, in part, due to the fact that Western coal has lower production costs because coal strip mining is primarily used instead of the underground mining techniques necessary to access eastern coal,⁹ and because the topography of Western surface mines allows more efficient recovery of coal than Eastern surface mines.

At that time, the AEO predicted incredible increases in Western coal production, the majority of which would come from Wyoming's PRB. (Southeastern Montana, including the Otter Creek area, is considered part of the northern PRB; Montana contributes slightly less than 10% of the total PRB coal production.) Not only was the AEO's prediction based on the fact that production costs are lower in the West, but also because the coal in the PRB is low in sulfur when compared to the coals of Appalachia and the Illinois Basin. Low-sulfur PRB coal gained an upward market pressure because, in the 1980s, the Environmental Protection Agency (EPA) was beginning to implement air pollution regulations that had been promulgated following passage of the Clean Air Act, including regulations to reduce sulfur emissions from coal-fired power plant stacks.

In 2005, the AEO was still predicting staggering growth for PRB coal. But, by 2010, the PRB was only producing about half of what had been projected, around 500 million tons.¹⁰ Today, the EIA forecasts declining coal production numbers for the coming years. Both the domestic and global markets for coal are oversupplied, and low coal prices and other market factors, such as low natural gas prices and increasing use of renewable energy sources, are driving down coal production. The outlook for the coal industry is no longer robust. At best, coal production will remain flat; more likely, coal production will continue to decline.¹¹ These facts conflict with what appears to be one of OEA's basic assumptions: that coal production and coal prices in the PRB will remain high. The DEIS is inadequate because it is based on these flawed assumptions.

According to EIA, between 2011 and 2013, 264 coal mines in the nation closed down, and many of those remaining are in serious trouble – even the coal mines in Wyoming, the state

⁹ "Changes in the Market for Montana Powder River Basin Coal between 1986 and 2012," Power Consulting, November 2012. <https://www.northernplains.org/wp-content/uploads/2013/06/PowersReportChangeMarketMTPRBCoalFNL2012-12.pdf>

¹⁰ *Ibid.*

¹¹ Verified Statement of Thomas Sanzillo, 25 March 2015, submitted by Northern Plains to the STB as part of their petition to revoke the December 2012 TRR application.

that produces the most coal in our nation. Since 2009 (again, according to the EIA), total coal production in Wyoming has declined about 10%. And, in the past couple of years, coal companies in the state of Wyoming are withdrawing their bids from coal leases and coal lease expansions in the PRB. Of importance to the discussion of this DEIS that is examining the environmental consequences for the construction of new transportation infrastructure – the TRR – for a yet-to-be-permitted coal mine, each one of these Wyoming coal leases is adjacent to an operating coal mine that is each served by existing rail infrastructure¹²:

- In 2013, Kiewit Mining asked the Bureau of Land Management (BLM) office in Wyoming to again delay the Hay Creek II coal lease-by-application (LBA) because of the “difficulty that the market conditions pose.” The LBA contained an estimated 167 million tons of coal and is adjacent to the existing, operating Buckskin Mine.
- The BLM in Wyoming received no bids in 2013 for the Maysdorf II North LBA, consisting of 148 million tons of coal and located west of and adjacent to the existing, operating Cordero Rojo Mine.
- In 2014, Cloud Peak Energy Resources through its subsidiary Cordero Mining Company, asked the BLM office in Wyoming to delay re-offering the Maysdorf II South coal LBA, which is adjacent to the existing, operating Cordero Rojo Mine, because “economic and industry conditions remain depressed.”
- In 2014, Arch Coal, through its subsidiary Ark Land Company, asked the BLM office in Wyoming (for the third time) to delay the North Hilight Field coal LBA adjacent to the existing, operating Black Thunder Mine (the second-largest coal mine in the nation), because “conditions . . . continue to place downward pressure on projected coal demand.”
- Finally, in 2014, Arch Coal, through its subsidiary Ark Land Company, formally withdrew from its 2006 West Jacobs Ranch LBA, which consists of nearly 1 billion tons of coal adjacent to the existing, operating Black Thunder Mine (the largest coal strip mine in the nation), because of the “continued economic downturn and subsequent reduced output over the past five years.” The BLM, in January 2015, formally closed the West Jacobs Ranch LBA.

Additionally, PRB coal mining company profits (or lack thereof) are continually in the news. The major coal companies in Wyoming (as well as other smaller mining companies) are struggling despite the low production costs for mining coal in the PRB. For example:

- Peabody Energy, the largest coal producer in Wyoming, reported losses of \$787 million last year and a \$1 billion loss for the second quarter of 2015 due to low natural gas prices and weak Chinese demand. Peabody’s share price has dropped 90% since 2011. In July 2015, Peabody suspended quarterly dividends to shareholders and cut 550 jobs across its operations.

¹² www.blm.gov/wy/st/en/programs/energy/Coal_Resources/PRB_Coal.html,
http://www.blm.gov/style/medialib/blm/wy/programs/energy/coal/prb_maps.Par.66178.File.dat/prbcoallsestatmap.pdf and <http://www.snl.com/InteractiveX/article.aspx?CDID=A-27059948-12323&ID=27059948&Printable=1>,
<https://www.snl.com/InteractiveX/Article.aspx?cdid=A-25644801-13102>,
<https://www.snl.com/InteractiveX/article.aspx?CDID=A-24611960-12338&ID=24611960&Printable=1>,
http://www.gilletteNewsRecord.com/news/local/article_47ef793b-dee5-592d-af2d-0e37b10a72e6.html

- Arch Coal, Wyoming's second largest coal producer, has seen its share price drop from more than \$70 in 2008 to less than \$1 today; it reported \$558 million in losses for 2014 and suspended dividends to shareholders (see above for more information on Arch Coal's financial problems). Second quarter 2015 losses were reported at \$168 million.
- Cloud Peak Energy, based solely in the PRB, is in a better financial situation than other, nationally operating coal companies, but it has been losing money on export sales to Asia since the middle of 2013. In July 2015, it reported second quarter losses largely due to low natural gas prices.

Additionally, Australian miner Ambre Energy, Arch Coal's partner in the Millennium Bulk Terminals coal export facility in Longview, Wash., sold all of its U.S. coal investments to Resource Capital Funds, a Colorado-based hedge fund in 2014. In the notice and explanatory statements for the directors and general shareholders meeting concerning this sale, Ambre Energy cited "what industry analyst firm Wood Mackenzie has described as a substantial oversupply of thermal coal in the seaborne market. . . ." The document went on to state that Ambre Energy had "struggled in the face of a sharply deteriorating thermal coal market to raise the capital required to fund the operations of AENA [Ambre Energy North America], that is, the development of its U.S. port projects, the optimization of its U.S. coal mining assets, and the implementation of its US coal export strategy."¹³

If the coal companies operating in the nation's most productive coal-mining state are having significant financial and market problems, it is unbelievable that OEA could predict in the DEIS that there is a market for yet-to-be-permitted Otter Creek coal. Even more unbelievable is that the DEIS states that Otter Creek coal could compete with these existing mines, many producing coal that has a lower sodium content than Otter Creek coal (see below for discussion of this significant issue). We believe that OEA has failed to consider these relevant factors in its analysis as presented in the DEIS, and thus the DEIS is neither accurate nor adequate.

While coal companies want to believe that coal markets will improve, that appears highly unlikely for both domestic and export markets.¹⁴ This negative outlook for the coal industry is shared by the world's leading investment banks and coal consultants. Since 2013 major U.S. financial institutions from Goldman Sachs¹⁵ to Bank of America¹⁶ as well as the World Bank have been pulling back from and entirely divesting from coal. Additionally, non-profits such as the Rockefeller Brothers Fund and public institutions like Stanford University have also removed coal from their portfolios, as has the Norwegian government's pension fund.¹⁷ Other financial institutions and analysts, including Deutsche Bank¹⁸, Sanford Bernstein & Co.,¹⁹ Morningstar,²⁰

¹³ Ambre Energy, Form 5057A Filing with the Australian Securities & Investment Commission, November 2014, http://media.oregonlive.com/environment_impact/other/Ambre%20filing.pdf

¹⁴ <http://www.bloomberg.com/news/articles/2015-07-13/the-latest-sign-that-coal-is-getting-killed>

¹⁵ http://thinkprogress.org/wp-content/uploads/2013/08/GS_Rocks_Ores_-_Thermal_Coal_July_2013.pdf

¹⁶ http://about.bankofamerica.com/assets/pdf/COAL_POLICY.pdf

¹⁷ <http://www.nytimes.com/2015/06/06/science/norway-in-push-against-climate-change-will-divest-from-coal.html>

¹⁸ "Thermal Coal: Coal at a Crossroads," Deutsche Bank Markets Research, May 2013

¹⁹ "Asian Coal & Power: Less, Less, Less . . . The Beginning and the End of Coal," Bernstein Research, June 2013

²⁰ "Burned Out: China's Rebalancing Heralds the End of Coal's Growth Story," Morningstar, April 2014

Goldman Sachs,²¹ and others, are predicting that the coal market bubble has burst and production numbers and prices will remain low and even decline for many years to come.

It is particularly notable that Goldman Sachs went from being a significant investor in the proposed Gateway Pacific Terminal coal export facility near Bellingham, Wash., to divesting all of its shares in that project in January 2014.²² The investment company later stated that “we believe that new investment in large-scale projects requiring new infrastructure is unlikely to earn a return; the window for profitable investment in new mining and infrastructure capacity has closed.”²³

While it is recognized that coal will not disappear from the energy stream immediately, market forces do indicate that coal is increasingly going to have a smaller and smaller share of the energy market, domestically as well as internationally. Opening new coal mines that require major additional investments in transportation infrastructure – like the TRR – does not make fiscal sense, especially when the proponent of that coal mine (Arch Coal) is in precarious financial straits. As noted above, Table 6-6 of Appendix C (page C-6-26) lists the NPV for the Otter Creek Mine (these are the costs for the mine that are not associated with constructing/operating the railroad) at -274. There is no discussion of this number and what it means anywhere in the DEIS, but we suspect it does not bode well for profitability of the mine.

Domestic Coal Markets

The analysis presented in the DEIS of coal production and markets (Appendix C) states that “Tongue River [Otter Creek] coal production would be economically viable in most market conditions from 2018 to 2037.”

According to the EIA, electricity generated from coal in the U.S. amounted to 39% of the total electricity used in 2014. And, from 2005 to 2013, the amount of U.S. electricity generated from coal had dropped 10.5%. Analysts’ predictions are for this trend to continue. For example, a recent Bloomberg New Energy Finance forecast predicts that as much as 17% of the nation’s coal energy generation is expected to shut down in the next few years.²⁴ Consequently, it is clear (to all but the OEA) that the domestic coal market is in decline, and, for the many reasons detailed below, there is no domestic market for Otter Creek coal. The economics of coal’s viability as an energy source, let alone adding the costs of opening new mines that have no transportation infrastructure in place, are, we believe, the opposite of what the DEIS predicts. OEA has failed to use an appropriate modeling tool or consider these relevant factors, as well as those listed below, in its analysis and therefore the DEIS is inadequate.

²¹ “The Window for Thermal Coal Investment is Closing,” Goldman Sachs, July 2013, http://thinkprogress.org/wp-content/uploads/2013/08/GS_Rocks__Ores_-_Thermal_Coal_July_2013.pdf and “The Thermal Coal Paradox,” Goldman Sachs, May 2014, http://www.eenews.net/assets/2014/05/28/document_gw_02.pdf

²² “Wall Street Giant Backs Away From Washington Coal Export Project,” Oregon Public Broadcasting, January 2014, <http://opb.org/news/article/wall-street-giant-backs-away-from-washington-coal/>

²³ “The Window for Thermal Coal Investment is Closing,” Goldman Sachs, July 2013, http://thinkprogress.org/wp-content/uploads/2013/08/GS_Rocks__Ores_-_Thermal_Coal_July_2013.pdf

²⁴ <http://www.bloomberg.com/news/articles/2015-07-13/the-latest-sign-that-coal-is-getting-killed>

Many domestic coal-generation power plants are switching to natural gas because it is cheaper. Many other domestic coal-generation power plants are closing. Either those power plants are at the end of their predicted life expectancy or it is too costly for them to comply with new EPA regulations that would reduce carbon emissions (the Clean Power Plan) and control mercury and other toxic by-products released when coal is burned. Additionally, renewable energy sources (especially wind) have become more competitive and are displacing fossil fuels.²⁵ The DEIS is inadequate because it does not sufficiently consider and analyze how reasonably foreseeable initiatives or regulations concerning limiting carbon dioxide and/or increasing renewable energy sources could affect the domestic market for coal.

The DEIS in Appendix C claims that “Tongue River [Otter Creek] coal would be sold to existing coal power plants, and would displace other sources of coal, including PRB coal already accessed by rail.” Nothing could be further from reality. The DEIS is perpetuating a myth of perfect substitution, which the IPM is designed to prove regardless of economic realities in energy markets, but that presumption does not hold up under scrutiny. As explained in detail above, domestic coal markets are declining. Even though Appendix C goes on to state that the “displacement would occur because Tongue River coal has competitive production costs and a rail distance advantage to key markets compared to other Powder River Basin coal,” nowhere does the DEIS account for the huge costs of not only constructing the TRR but also the proposed Otter Creek Mine, if it is permitted. Perfect substitution might work if it involved an already permitted and operating mine that had transportation infrastructure in place, but that is not the case here.

Additionally, the assumption that Otter Creek coal would be competitive with other PRB coal presupposes that domestic power plants are free to purchase coal on the spot market. In reality, according to EIA, more than 80% of coal plant owners enter into long-term contracts for coal supplies in order to avoid the fluctuations of short-term markets. The model used by OEA does not appear to consider long-term contract prices or contract terms; instead, the model appears to rely on spot-market prices for its rosy-picture conclusions.

Add to those issues the fact that Otter Creek coal, like other northern PRB coal, has a higher sodium content than coal mined in Wyoming’s southern PRB. When burned, high-sodium coal causes “slagging” in power plant boilers. While Attachment A of Appendix C acknowledges the sodium problem, OEA totally downplays the issue, not only for Otter Creek coal but also for the “potentially induced mines” at Poker Jim Creek-O’Dell Creek and Canyon Creek. The DEIS is inadequate because it does not sufficiently consider and analyze the issue of high-sodium coal and its impact on the marketability (especially domestically) of Otter Creek (and other area) coal.

The concentration of sodium in Otter Creek coal ranges from 5.8% to 8.8% (Attachment A of Appendix C states that the average is 7.4%); coal from southern Wyoming PRB mines averages 1.2% sodium concentration. This is a huge difference, especially in a declining coal market. Even though Otter Creek coal is sub-bituminous and has a low-sulfur content, its high-sodium content severely limits its marketability (as opposed to what the DEIS says in Appendix

²⁵ “Declining Markets for Montana Coal,” Synapse Energy Economics, Inc., February 2013. <https://www.northernplains.org/wp-content/uploads/2013/06/NPRC-Domestic-Coal-Report-Synapse-1March13-Final.pdf>

C at 3.2.2.6). Only a small number of domestic power plants in the upper Midwest are equipped with the specially designed boilers that can burn high-sodium coal and many of them are being retired or retrofitted.

In the 2009 Norwest Corporation appraisal of the Otter Creek coal tracts, prepared prior to the Montana's leasing of the tracts to Arch Coal, a number of power plants were identified as potential market customers for Otter Creek coal. The appraisal cautioned numerous times, however that "[c]oals with high sodium content share a limited market due slagging problems . . . This limits the market for high sodium coals to a small number of mid-western electric generating plants and some industrial plants."²⁶ Norwest's appraisal also admits that Otter Creek coal would have to compete with other mines in the area that are already serving this limited market and states that this competition would likely drive down the price of the coal sold to these markets.

The high-sodium content of the coal that the TRR hopes to transport is problematic for that coal's marketability, especially in a declining coal economy. The analysis of the Norwest appraisal by Dr. Thomas Power²⁷ of Power Consulting, Inc. is particularly helpful in understanding the lack of domestic markets for Otter Creek coal. We believe that OEA has failed to consider the relevant negative factors surrounding the high-sodium content of the coal to be shipped by the TRR in its analysis as presented in the DEIS, and, thus, we believe the model's conclusions on the marketability of this coal are in error.

According to the EIA, in 2010, about 330 million tons of PRB coal were delivered to the Upper Midwest, of which about 22 million tons came from Montana's portion of the PRB.²⁸ The relative percentages of Wyoming and Montana coal sold to the Upper Midwest in 2010 are approximately the same relative percentage seen for the previous decade. Again, the DEIS claims that Otter Creek coal (which the TRR hopes to haul) "would be sold to existing coal power plants, and would displace other sources of coal, including PRB coal already accessed by rail" (Appendix C). We do not believe that this optimistic statement is correct or even believable. Any new Montana PRB coal (Otter Creek coal) would be competing with the same markets Wyoming and other Montana coal mines already have access to – and those markets are shrinking. The existing coal markets already have contracts with the existing Wyoming and Montana coal mines. Not only that, but Otter Creek coal (the "new PRB coal") generally has a higher sodium content than those "other sources of coal."

According to Dr. Thomas Power,²⁹ the difference between transportation cost advantages to markets served by Montana and Wyoming are dictated by the markets to which high-sodium Montana coal has access. Inroads by the proposed Otter Creek coal into markets that cannot use high-sodium coal will not happen, despite the assertion by the DEIS that this high-sodium coal would be mixed with other coal and then used in Upper Midwest power plants. Wyoming mines,

²⁶ "Montana Otter Creek State Coal Valuation," Norwest Corporation, January 2009.

²⁷ "The Value of the Otter Creek Coal Tracts to the State of Montana: The Dangers of Relying on the Norwest Corporation Appraisal," Power Consulting, July 2009.

²⁸ "Changes in the Market for Montana Powder River Basin Coal between 1986 and 2012," Power Consulting, November 2012. <https://www.northernplains.org/wp-content/uploads/2013/06/PowersReportChangeMarketMTPRBCoalFNL2012-12.pdf>

²⁹ *Ibid.*

with their lower-sodium content coal, are already making inroads into the Upper Midwest markets that Montana mines had previously and exclusively served. Consequently, we believe that OEA has failed to consider these relevant factors in its analysis as presented in the DEIS, and we believe the model's conclusions on transportation-cost advantage are erroneous.

The assumption used by OEA that there are markets for coal (both domestically and internationally) is problematic at best and erroneous at worst. For this issue, it does not appear that the models used by OEA were constructed in a manner that considered the differences in the sodium content of coal when making determinations about coal sales and consumption at power plants, either domestically or internationally. It also does not appear that the models were constructed in a manner that considered the trade-offs between coal quality and costs, even though those topics are mentioned by OEA in the DEIS.

Since Montana leased the Otter Creek coal tracts, stricter environmental regulations are adding to the costs of operating coal-fired power plants. The EPA has established National Ambient Air Quality Standards (NAAQS) for sulfur dioxide, nitrogen dioxide, carbon monoxide, ozone, particulate matter (both PM₁₀ and PM_{2.5}), and lead; it is in the process of making some of these NAAQS more stringent through new standards being promulgated for greenhouse gas (GHG) emissions from coal-fired power plants (per the Clean Power Plan released in August 2015). Strict emission limitations (Maximum Achievable Control Technology) have set stack-emission limits for mercury, other metal toxins, and other organic and inorganic hazardous air pollutants as well as acid gasses. And, in 2010, EPA proposed new regulations for coal combustion residuals (coal ash). These are just a few of the many regulations that substantially impact the operation of coal-fired generation facilities and are leading to the retirement or conversion of many U.S. coal-fired power plants.

Analysis by Synapse Energy Economics in 2013 showed that after complying with environmental regulations, the majority of the potential customers for Otter Creek coal would have to incur substantial costs to upgrade their facility to burn Otter Creek coal, and those costs would be higher than the cost of building and operating a new combined-cycle natural gas plant. In fact, by 2013, four of the ten coal plants identified in the Norwest appraisal report as the initial target market for Otter Creek coal had already announced their partial retirement or conversion to natural gas or biomass.³⁰

The Norwest appraisal report identified a second set of 14 power-generation plants that might also serve as a market for Otter Creek coal, including the four Colstrip, Montana, power plants. All 14 potential markets are already served by a Montana coal mine. For Otter Creek coal to succeed in the marketplace, it must compete with other Montana coal mines. Many of these mines are already struggling to reach production targets and maintain their "market share" of the declining coal sector. Otter Creek coal, if the mine is approved and begins operation, would only create competition within an already tight marketplace and would decrease the price of coal and

³⁰ "Declining Markets for Montana Coal," Synapse Energy Economics, Inc., February 2013.
<https://www.northernplains.org/wp-content/uploads/2013/06/NPRC-Domestic-Coal-Report-Synapse-1March13-Final.pdf>

further depress the market.³¹ Additionally, if Otter Creek coal did succeed in replacing coal from other Montana coal mines, the negative economic and social impacts to the livelihoods of the miners who would be laid off at those existing mines is not even discussed in the DEIS.

The DEIS is inadequate because the OEA has failed to consider the various relevant factors explained above concerning domestic coal markets in its analysis. And, consequently, we find no basis for OEA's claim in the DEIS that the coal that the proposed TRR hopes to haul would go to domestic markets. The shrinking number of power plants that can use high-sodium Otter Creek coal coupled with the decline in use of coal throughout the energy market makes many of the model's conclusions outdated and erroneous.

There is no domestic market for Otter Creek coal, and, thus, there is no public need for the TRR, and a permit would be inconsistent with any public convenience and necessity.

International Coal Markets

When Arch Coal secured a lease for the Otter Creek coal tracts and then submitted an application to begin the process for obtaining a mining permit, not only had the STB issued a permit for the TRR (although that was later remanded by the 9th Circuit Court), but the international coal export market in Asian nations such as India, Japan, South Korea, and, especially, China was beginning to boom. In 2011, as domestic coal sales were beginning to flatten (and decline), the three coal companies that dominate the PRB (and are among the largest coal companies in the world) each touted the potential of the Asian coal export market:

- Peabody Coal: "We are opening the door to a new era of U.S. exports . . ." (Chairman & CEO Gregory Boyce, E&E Report March 2, 2011)
- Cloud Peak Energy: "A booming market in Asia will continue to demand coal exports from the Powder River Basin." (Wyoming *Star-Tribune* June 24, 2011)
- Arch Coal: "With our superior operating position in the Powder River Basin . . . we have the capability to service growing coal demand in Asia, the world's largest and fastest-growing coal market." (Press Release on Arch's website "Arch Coal Acquires Equity Interest in West Coast Terminal," January 20, 2011)

In fact, Arch Coal was so confident in the potential for a booming international market for coal that it purchased a 38% share of the proposed Longview, Wash., export terminal facility that remains in complicated and contentious permitting and environmental analysis processes. Arch Coal stated in a January 2011 press release that Longview would "give us a direct stake in participating in the growth of U.S. coal exports off the West Coast."

It was no wonder then that questions were raised when the current TRR Company (Arch Coal, BNSF Railroad, and Forrest Mars) submitted its October 2012 permit application to the STB. That application said that the TRR Company was "seeking authority to modify the rail line

³¹ "Changes in the Market for Montana Powder River Basin Coal between 1986 and 2012," Power Consulting, November 2012. <https://www.northernplains.org/wp-content/uploads/2013/06/PowersReportChangeMarketMTPRBCoalFNL2012-12.pdf>

between Miles City, Montana and Ashland/Otter Creek, MT that was previously approved by the ICC in 1986 [TRR I].” Later, in December 2012, the TRR Company submitted a “supplemental” application that superseded its earlier request. This permit application (the subject of this DEIS) clearly aimed the proposed TRR toward the west (and proposed coal export terminals) by now naming the Colstrip route as the TRR Company’s preferred alternative.

International coal sales from the PRB had grown from 3.8 million tons in 2009 to 20 million tons in 2011, and Arch Coal envisioned a growing export market for its coal. This rosy picture led Arch Coal to not only secure the lease for the Otter Creek coal tracts but also to buy into a coal export terminal – and the TRR. However, by 2012, the international coal export markets in Asia, especially China, were showing signs of decline. While 31 million tons of coal were exported in 2014, this tonnage was below the EIA forecast, and EIA has now downgraded its 2015 and 2016 export outlook by 30% from its 2014 export outlook.³²

While the DEIS acknowledges (in Chapter 2 and Appendix C) that there are many uncertainties ahead, because of its model outputs, OEA states that it is reasonably foreseeable that coal export terminals in the Pacific Northwest will be expanded. Appendix C goes on to state that “. . . Arch Coal is the developer or co-developer of the TRR, the Otter Creek Mine, and one of the export terminals (Millennium Bulk Terminal). Hence, Arch Coal might choose to export rather than sell domestically. . . .” But the case for coal export appears to be built on hope, not data, some of which we present below.

Benchmark prices for thermal coal (which are based on the price of Australia’s Newcastle coal) are the lowest they have been since 2007. At its peak in January 2011, the price was \$141.94/ton; by mid-March 2015, the price was \$59.50/ton. Prices are predicted to stay at or below \$60/ton through 2021. This is below the profitability level that existing coal mines in the PRB have stated they need to participate in the export market (*e.g.*, in 2010/2011, both Peabody Energy and Arch Coal said they needed the price of coal to be in the \$90/ton range to make it worthwhile to export coal, and, in 2014, Cloud Peak Energy said it needed the Newcastle price to be between \$80 and \$90/ton for it to export coal at a profit).³³

Chinese thermal coal imports are declining dramatically (Chinese imports peaked in 2013), and its coal consumption fell 3% in 2014 despite an increase in energy demand; that trend has continued in 2015 with thermal coal imports down 39.1% in January to July over the same period in 2014.³⁴ At least five major coal-fired power plants have or are being shut down as that country deals with dramatic air pollution issues and industrial overproduction, issues that are significantly affecting China’s gross domestic product. More than 6,000 coal mines have already been closed in China. The Chinese government has announced plans to limit its annual coal consumption to 4.2 billion tons by the end of this decade – and its current production capacity is beyond 4 billion tons so it is unlikely that coal imports will increase.³⁵

³² Verified Statement of Thomas Sanzillo, 25 March 2015, submitted by Northern Plains to the STB as part of their petition to revoke the December 2012 TRR application.

³³ *Ibid.* and <http://www.greenpeace.org/usa/wp-content/uploads/legacy/Global/usa/planet3/PDFs/Coal%20Market%20Report%20Q1%202015.pdf>

³⁴ <http://www.businessinsider.com.au/chinese-coal-imports-are-collapsing-2015-9>

³⁵ “Asian Coal & Power: Less, Less, Less . . . The Beginning and the End of Coal,” Bernstein Research, June 2013; “Burned Out: China’s Rebalancing Heralds the End of Coal’s Growth Story,” Morningstar, April 2014;

While Asian countries are still importing some coal, it is closer and cheaper to import coal from Australia and Indonesia as well as either Russia or South Africa rather than from the PRB of the United States. The DEIS in Appendix C focuses its analysis of the potential for an export market on Japan; however, Japan is discussing potential new coal deals with Indonesia, not the U.S., and the price negotiations are in the \$60/ton range.³⁶ Any substantial increase in the export of PRB coal is dependent on the Chinese market, which is declining as explained above.

Indonesia is the world's largest exporter of coal with Australia being second. Australia has plans to increase its port capacity. Should that happen, there would be a significant impact on market prices for coal in Pacific Rim countries. Even if that doesn't happen, there are still problems for the viability and growth in tonnage of PRB coal into the international coal market. Development of West Coast port capacity is not assured, distance to Pacific Rim markets compared to the distances that Australia and Indonesia coal travel adds significant cost, and the monetary exchange rate all present problems for PRB coal exports increasing.

For U.S. coal to be competitive with Australian and Indonesian coal, the value of the dollar is key; declining exchange rates make those foreign coals more expensive. The assumption used by OEA that recent advantageous exchange rates would remain the norm for the future has changed. For example, the value of the Japanese yen, Indonesian rupiah, Australian dollar, and Russian ruble have declined in relation to the U.S. dollar.³⁷ The OEA needs to provide data and justification for its assumption that the international demand for coal will continue to grow and that prices will continue to rise and that the exchange rate will remain advantageous to the U.S.

Additionally, as mentioned above, the coal that the TRR proposes to haul (from the Otter Creek Mine and the "potentially induced" mines) has a high sodium content, which we have shown above makes this coal much less marketable domestically. The same is true for the international market. It appears to us that OEA has based its assumption that higher-sodium coal is marketable internationally solely on the fact that 4.4 million tons of Spring Creek coal (a nearby operating mine) were exported through the main existing West Coast coal export terminal (in Vancouver, BC) in 2012, which was nearly all the coal that was exported from that port. While Spring Creek coal has a higher sodium content, it also has a higher heat content than Otter Creek (et al.) coal, thus it is likely a more desirable coal than the proposed Otter Creek coal.

The global coal market is oversupplied. In Europe, coal use (both production and imports) has been declining significantly in recent years. South Korea recently imposed a significant import tax on coal, which is structured to specifically prejudice against the sub-bituminous coal in Otter Creek coal's BTU range. In fact, the tax itself (on a per metric ton basis)

<http://www.newsweek.com/beijing-shuts-down-coal-power-plants-air-pollution-costs-economy-316829>;
<http://www.mcclatchydc.com/2015/03/11/259356/chinas-push-to-cut-coal-use-may.html>

³⁶ Verified Statement of Thomas Sanzillo, 25 March 2015, submitted by Northern Plains to the STB as part of their petition to revoke the December 2012 TRR application **and** <http://www.greenpeace.org/usa/wp-content/uploads/legacy/Global/usa/planet3/PDFs/Coal%20Market%20Report%20Q1%202015.pdf>

³⁷ <http://www.greenpeace.org/usa/wp-content/uploads/legacy/Global/usa/planet3/PDFs/Coal%20Market%20Report%20Q1%202015.pdf>

is larger than the cost of a metric ton of coal at the mine mouth of some PRB coal mines.³⁸ As explained above, China's imports of thermal coal fell dramatically from 2014 to 2015, and coal consumption at its electricity-generating power plants fell 10% in the same time period. China has a 6% coal tariff on U.S. coal, but it has no tariff on coal imported from Indonesia, which is closer to China and with which China has a free-trade agreement. Cloud Peak Energy, a PRB coal company that is currently exporting coal, is suffering losses in its export operations because of declines in export sales and the futures contracts it signed.³⁹

Equally important to the decline in the coal market is the explosion of renewable energy options for countries such as China and India. Citizens in these and other countries are demanding that pollution problems associated with burning of fossil fuels be cleaned up. Severe air pollution problems caused by the burning of fossil fuels in major Chinese and Indian cities have resulted in governmental policies changing. China is the world's biggest investor in renewable energy sources, spending a total of \$400 billion on clean energy in the past 10 years. China is already the world's top wind power market (it added an additional 19.8 gigawatts of wind turbines to its grid last year), and it installed more solar panels than any other nation in 2014.⁴⁰

As noted above, many financial institutions and investment analysts are advising that the export market for U.S. coal is oversupplied, under severe stress, and likely to remain in this condition for the foreseeable future. Chinese coal imports drive the U.S. export market. The decline in the international market for coal affects PRB coal company plans for a vibrant export market to make up for the lack of a domestic market for coal. The OEA has failed to consider these relevant factors in its analysis as presented in the DEIS, and thus, the DEIS is inadequate.

There is no international market for Otter Creek coal, and, thus, there is no public need for the TRR, and a permit would be inconsistent with any public convenience and necessity.

Proposed Otter Creek Coal Mine

Arch Coal, through its subsidiary Ark Land Company, received a 10-year lease for the Otter Creek coal tracts from the state of Montana in March 2010. In July 2012, Otter Creek Coal submitted a permit application to the Montana DEQ to develop the first phase of the mine in Tract 2 of the lease (the lease encompasses three tracts). Following a series of internal reviews, the DEQ declared the permit application "administratively complete" in December 2012 and began the "technical adequacy" phase of the permit process, which is ongoing. Northern Plains is fully participating in the public processes for this permit application as well as the air quality permit and water quality permit processes and the state's EIS process under the Montana

³⁸ "South Korea's All New Tax on Imported Coal," Clark Williams-Derry, Sightline Institute, July 2014, <http://daily.sightline.org/2014/07/01/south-koreas-all-new-tax-on-coal-exports/> **and** <http://carbunion.com/panel/infoprecios/uploads/MCR%20327.pdf>

³⁹ <http://www.greenpeace.org/usa/wp-content/uploads/legacy/Global/usa/planet3/PDFs/Coal%20Market%20Report%20Q1%202015.pdf>

⁴⁰ <http://www.bloomberg.com/news/articles/2015-08-18/longyuan-first-half-profit-climbs-on-stronger-wind-output> **and** <http://www.bloomberg.com/news/articles/2015-07-01/china-s-climate-goal-calls-for-aggressive-push-on-solar-wind>

Environmental Policy Act (MEPA). We will have more to say about the proposed Otter Creek coal mine in our comments on the [connected and] cumulative effects of the TRR, but we include the following comments on the proposed mine in this section concerning the purpose and need for the TRR.

The Otter Creek Mine is a true connected action to the TRR, but the TRR DEIS does not fully examine or analyze it as such. The proposed TRR is solely designed to haul coal from the proposed Otter Creek coal mine – without the coal mine, there is no need for the TRR. Without the TRR, there would be no way to move the proposed Otter Creek coal to market (if there was a market in which to sell that coal). However, neither project includes the other project's costs when presenting their case for economic viability.

In the case of the TRR, OEA claims that Otter Creek coal will cost less to produce than other PRB coal and, thus, would be able to undercut those other mine's prices. However, OEA does not include any of the many specific relevant factors that would impact those costs when analyzing and comparing the economic viability of Otter Creek coal in relation to other PRB coal. Most notably, the transportation infrastructure costs that must be spent up-front in order to bring Otter Creek coal to market are not considered. The DEIS also neglects to consider the potential high costs of crafting an Otter Creek mine plan that can comply with the federal Surface Mining Control and Reclamation Act (SMCRA). This compliance is potentially impacted by the fact that several previous studies have found significant alluvial valley floor (AVF) areas within and around the proposed mine plan (see discussion below). Additionally, the presence of intermittent streams in the area means that certain federal regulations regarding stream buffers around mine plan areas must be considered and could impact Arch Coal's ability to create a significant and contiguous logical mining unit. All of these (and other) issues should be included and considered when calculating production costs of Otter Creek coal. The DEIS is inadequate in this regard as it does not provide all the information necessary for the public and decision makers to take a hard look at the primary connected project that the TRR would depend on for economic viability in order to truly evaluate the rail proposal.

The main assumption made by OEA in the DEIS that is used for justifying the permitting and building of the TRR is that the Otter Creek coal mine will be permitted. However, there are numerous issues that must be resolved before a permit to build the proposed Otter Creek mine would be granted. As noted above, one technical issue of significant importance yet to be resolved is whether or not, and to what extent, AVFs are located within the proposed mine area. Under Montana law, if portions of the proposed Otter Creek mine and/or life-of-mine area are determined to be an AVF, the Montana DEQ's review of the mine permit application must evaluate the feasibility of full and complete reclamation of the productivity and function of the AVF(s). If complete reclamation cannot be demonstrated, Montana DEQ must evaluate the impact of partial or selective denial of the permit. We believe there is a strong likelihood that the AVF issue will affect the permitting of the proposed mine.

It has also yet to be determined what the potential hydrologic consequences (PHC) of permitting the proposed Otter Creek Mine might mean for the area (OEA has based its discussion of this issue on the OCC application [see Appendix U-138]; however, Montana DEQ's evaluation of that application is what matters, and that is not yet complete). Coal seams are filled with water and function as vital aquifers in this region. Coal strip mines sever and

destroy these aquifers. Montana DEQ must evaluate the likelihood that the permit applicant (Arch Coal through its subsidiary OCC) can meet the requirements of Montana's Surface and Underground Mining Reclamation Act (SUMRA) to restore the hydrologic balance of the area as well as determine how it will replace any water resources damaged by strip mining that are not restored. Until that is done, no permit for the proposed Otter Creek Mine can be issued.

The water quality discharge permit that is necessary for the proposed mine is also a long way from being resolved (OEA has based its discussion of this issue on the OCC application [see Appendix U-138]; however, Montana DEQ's evaluation of that application is what matters, and that is not yet complete). Numeric standards for the Tongue River as well as standards for its tributaries (Otter Creek is a tributary of the Tongue) mean that the proposed Otter Creek Mine is obligated to ensure that its operations do not harm the water quality of the Tongue River and its tributaries, which we doubt the mine can prove.

Finally, before a permit for the proposed Otter Creek Mine can be issued, it must be determined how the proposed mine might impact the status of the TMDL [total maximum daily load] process for the Tongue River, as Otter Creek is a tributary of the Tongue. Because TMDLs have yet to be established for the Tongue River, we believe that process must be completed before a mine permit can be issued (OEA has based its discussion of this issue on the OCC application [see Appendix U-138]; however, Montana DEQ's evaluation of that application is what matters, and that is not yet complete).

The TRR is inextricably intertwined with the proposed Otter Creek mine – without the coal mine, there is no need for the TRR. The administrative permit process, environmental analysis process, and the financial challenges faced by the proponent (Arch Coal) of the proposed Otter Creek Mine result in reasonable doubt that the Otter Creek Mine will ever become a reality. The primary reason for the proposed TRR, hauling coal from the proposed Otter Creek Mine, is in serious doubt. The OEA has failed to consider these relevant factors in its analysis of the need for the TRR as presented in the DEIS.

“Potentially Induced Mines”

The DEIS in multiple locations and particularly in Appendix C suggests that there could be additional “potentially induced mines” in the area. These mines appear to be used, in the document, to justify approval of the TRR, since the specter of such mines suggest that the TRR could serve more than just one reasonably foreseeable shipper. However, while OEA must fully and adequately analyze the impacts of these mines, market conditions strongly suggest that these mines will never be constructed, and therefore these mines cannot be used as an argument for the public convenience and necessity of the Tongue River Railroad. There is no mining company seriously talking about coal leases at Poker Jim Creek–O'Dell Creek or at Canyon Creek. If mining companies operating in the Southern PRB are not even bidding on coal leases adjacent to existing, operating mines that are already served by rail networks (as described above), it is particularly unlikely that these non-mine areas in Montana would be developed. These coal deposits also have a high sodium content, so these “potentially induced mines” face many of the same challenges as for the proposed Otter Creek Mine.

The coal deposits in the Poker Jim Creek – O’Dell Creek area are the same deposits proposed for mining by the now-defunct Montco Mine, the initial shipper that justified the TRRC’s first application. In 1984, the Montana Department of State Lands (DSL) issued the Montco Mine a surface mine permit, but the mine was never built. In 1994, because no work had begun, DSL denied Montco a renewal to its mining permit. This denial resulted in court challenges in which Northern Plains, Native Action, and the Northern Cheyenne Tribe participated as intervenors on the side of the State to deny the permit renewal. The case was eventually decided in the State’s and interveners’ favor by the Montana Supreme Court in October 1997. The result is that there is no permit to mine coal at the Montco Mine site (the area of the “potentially induced” Poker Jim Creek–O’Dell Creek mine). Of additional note, many of the AVF and PHC concerns that a mine at Otter Creek would face are similar to what the developers of the Montco Mine faced. Because the promoters of the Montco Mine could not figure out how to deal with those issues in the 1980s, no work could commence on the proposed mine and, eventually, this resulted in the mine’s permit being revoked.

The “potentially induced” Canyon Creek mine is discussed in 3.2.3.3 of Appendix C. It is stated that 77% of the surface rights owners are either private or tribal landowners. The DEIS states that 90% of the mineral rights are owned by the federal and state governments (the DEIS does not reveal how much of that percentage is federal versus state ownership). Based on other areas of the state, we assume most of the mineral rights are held by the federal government. Under the federal Surface Mining Control and Reclamation Act (SMCRA), surface owners above federal minerals have the right of surface owner consent (and can thereby prevent mining) if a coal strip mine is proposed.

The Diamond Cross Ranch is one of the private surface owners in the “potentially induced” Canyon Creek mine area. The Diamond Cross is owned by Forrest Mars, Jr., the person who in 2011 purchased the southern portion of the TRR permit from Arch Coal and BNSF “to keep the tracks from running through his Diamond Cross Ranch” (according to the *Billings Gazette*, August 27, 2011). Given that he spent a reported \$60 million in this move to prevent the TRR from traveling through his property, we would be surprised if Mr. Mars would give his consent for a coal company to strip mine his property. The other surface owners may or may not welcome a coal strip mine on their property. And, just like mining the area of the proposed Otter Creek mine was not possible until Arch Coal and Great Northern Properties were able to consolidate checkerboard holdings, mining in the Canyon Creek area would face the same issue before a proposed mining area made any sense.

Coal markets are declining nationally and internationally for all the reasons enumerated above. It is highly unlikely that any other coal mine might someday be permitted in the area that the TRR would service. The DEIS analysis of mines being “stimulated” as a result of the TRR’s construction is a long shot for all of the market reasons enumerated above. Because of the particular unlikelihood of these additional mines, we again conclude that the TRR is not a “common carrier.” The proposed TRR remains a private, single-purpose railroad that would serve one proposed coal mine that has yet to be permitted (and that would doubtfully be developed). Like the proposed mine at Otter Creek, these other induced mines are highly unlikely. The proposed TRR would in all likelihood service no mines and therefore, its permit application should be denied. However, if the STB ignores this evidence and finds that the

project is viable, which it would have to do before issuing a permit, it must first adequately analyze the impacts of what it has approved. The DEIS's analysis of the proposed induced mines is deficient. It fails to appropriately analyze markets, surface owner rights, the challenges of mining at these other sites, their impact on Native American cultural sites, and more. All of these are yet additional reasons why the DEIS is inadequate.

Demand Elasticity and the 'Myth of Perfect Substitution'

As established above, there is no market for Tongue River coal, and as such, the TRR is at-face not in the public interest (in addition to all of the railroad's negative impacts detailed below, which would be sufficient cause in their own right to reject the TRR). Simply put, the bar is too high for Tongue River coal to overcome. "Misuse of Integrated Planning Model as an assessment tool in the Tongue River Railroad DEIS," a report prepared for Northern Plains by Power Consulting, Inc. and Joel Brown, principal of Aesir Consulting, LLC, does not seek to refute that claim. Rather, it operates within parameters established by OEA and shows that the DEIS fails to adequately analyze the impacts of the proposed railroad. If the STB chooses to ignore the reality that there is no market for Tongue River coal and, in erroneously assuming the existence of a robust domestic and/or international coal market, ponders permitting the TRR, the STB must consider the impacts of the TRR in that scenario. Elsewhere in these comments Northern Plains details the negative impacts of greenhouse gas emissions and increased coal train traffic from the TRR, and so will not do so here. Rather, we draw attention to the failure of OEA's Integrated Planning Model to take these impacts into account.

As mentioned elsewhere in these comments, by holding demand constant and failing to account for the price elasticity of demand, the IPM is designed to arrive at certain pre-ordained conclusions, which are then incorporated into the DEIS. Namely, the pre-ordained conclusion built into the IPM is that Tongue River coal will simply displace other coal, and therefore that downrail coal train traffic increases and greenhouse gas impacts will be minimal or nonexistent. The aforementioned Power Consulting report provides great detail as to why this assumption is false, which we do not seek to duplicate in these comments. Instead, we would here note that, even if there were a scenario in which Tongue River coal has a viable market to sell into at a profit, the DEIS fails to consider the effect of increasing the quantity of coal introduced into the domestic or international market. In short, STB must consider a scenario in which the TRR is constructed and transports Otter Creek coal to ports or power plants, and which exerts downward pressure on the delivered price of coal and therefore upward pressure on coal consumption. By utilizing a model that fails to consider changes in electricity or coal demand, the DEIS willfully ignores potential increases in both downrail coal train traffic and greenhouse gas emissions.

The 'myth of perfect substitution' (simple one-for-one substitution of coal resources) is false, as has been found by multiple courts⁴¹. The STB's reliance on this myth in the DEIS is a deficiency that does a disservice to the more than one dozen towns who've written to the STB

⁴¹ including High Country Conservation Advocates v. United States Forest Service ([http://earthjustice.org/sites/default/files/files/91%20-%20Order%20on%20Merits%20\(2\).pdf](http://earthjustice.org/sites/default/files/files/91%20-%20Order%20on%20Merits%20(2).pdf)), a ruling which cites a similar ruling from the Court of Appeals for the Eighth Circuit in Mid States Coalition for Progress v. Surface Transportation Board.

expressing concerns that construction and operation of the TRR will significantly increase coal train traffic and its associated impacts in their communities. If the STB persists in its erroneous conclusion that there is a market for Tongue River coal, it must abandon the myth of perfect substitution. The IPM is not appropriate for the analysis used in the DEIS. Any model that is used to evaluate the proposed TRR must capture the long-run and short-run elasticity responses of a change in the delivered price of coal.

COMMENTS ON SPECIFIC ISSUES PRESENTED IN THE DEIS

Northern Plains firmly believes that there is no market for the coal that the proposed TRR wants to haul, and, thus, there is no reason to permit the TRR. If, contrary to the evidence we have presented above, the STB arbitrarily decides to permit the proposed TRR, we believe that the DEIS has failed to consider the environmental and social consequences of the issues we raise here, among others. We believe that OEA's analysis as presented in the DEIS is inadequate and deficient because it fails to adequately address any of these issues.

Proposed Alternative Routes and Impacts to Landowners

Under the National Environmental Policy Act (NEPA) and the Council on Environmental Quality (CEQ) regulations implementing NEPA, agencies must fully consider the "no-action" alternative. Project approval is not – and should not be – automatic. Throughout these comments on this DEIS, we show that there are many reasons that the proposed TRR should not be approved and permitted. We urge the STB to choose the "no-action" alternative.

According to CEQ's NEPA regulations, an agency should "*identify the agency's preferred alternative* [emphasis added] or alternatives, if one or more exists, in the draft statement . . ." (§ 1502.14 (e)). This should be done to "present the environmental impacts of the proposal and the alternatives in comparative form, thus sharply defining the issues and providing a clear basis for choice among options by the decision maker and the public" (§ 1502.14). Even though the TRR Company in its December 17, 2012, supplemental application stated that the Colstrip alternative was its preferred alternative, OEA has not named a preferred alternative and, instead, has chosen to "equally" examine five separate routes – each with two variations – as well as the no-action alternative.

The decision by OEA to not choose a preferred alternative has made the DEIS extremely complicated to review and adds significant burden to landowners along each and every route. Some of these landowners are Northern Plains' members and are submitting their individual comment letters on the DEIS to STB. However, due to the significant negative consequences that the proposed TRR would have on rancher landowners and other agricultural interests, we are also including as attachments certain of those comment letters with our comments to further emphasize the points we raise herein that are deficiencies of the DEIS.⁴²

Not only has OEA chosen not to indicate which of these ten build alternatives is the agency's preferred route, it has also included in the routes being considered the Decker alternative (and its variant). Forrest Mars, Jr., one of the three owners of the TRR Company, has

⁴² Comment letters to the STB on the TRR DEIS submitted by Mark Fix and Clint McRae, September 2015

stated that he opposes this route because it would cross his ranch and that he purchased his $\frac{1}{3}$ interest in the TRR Company to prevent this alternative from being built. Is the public to believe that the Decker alternative is at all probable when one of the TRR Company partners refuses to let it happen?

Equally unsettling is the OEA's discussion of other route alternatives. Is the public to believe that the preferred alternative named by the TRR Company, the Colstrip alternative, really not the direction that Arch Coal wants the railroad to head in order to reach its hoped-for markets? From the DEIS, it appears that OEA has relied on its model to determine that Arch Coal really doesn't understand coal markets. It appears that the assumptions and data that went into the model lead OEA to conclude that Arch Coal's plans to send its hoped-for coal to the West Coast for export is "not economical" (see Q&A). The model's outputs go on to predict that the market for this hoped-for coal is domestic and, thus, the TRR should head east. While we don't disagree with the OEA's hypothesis that there is little reason to believe there would be an international market for this hoped-for coal, we can't agree with the alternative for all the reasons enumerated above.

OEA has used its model – with no public explanation of the assumptions or the data used to reach its conclusions – to determine that the market for Otter Creek coal would go to the already oversupplied and shrinking domestic market. This domestic market, by the way, is already being supplied by other coal mines and companies from the PRB. Even though Appendix C states that the coal from the proposed Otter Creek Mine would displace other PRB coal because it has "competitive production costs and a rail distance advantage to key markets," nowhere does the DEIS account for the huge up-front costs of not only constructing the TRR but also opening and starting production at the Otter Creek Mine – if it is ever permitted. On one level, one could posit that such substitution might work if it involved an already permitted and operating mine that has infrastructure in place, but that is not the case in this situation.

If, as the OEA claims in the DEIS, the coal from the proposed Otter Creek Mine would merely "displace" other PRB coal, why would the STB even consider ripping up productive agricultural lands, native short-grass prairie lands, and nearly pristine prairie-riverine ecosystem streams and bottomlands? For the STB to permit the building of the TRR in order to solely service a mine that would simply "displace" other operating mines in the region would result in significant, and often irretrievable, environmental consequences as well as harm to the ranchers and other landowners along the railroad's route. It would also result in tremendous negative social and economic costs for the employees of existing mines and their communities that the proposed Otter Creek mine would only "displace;" those employees would not necessarily be able to move to the proposed Otter Creek Mine for new employment. If it merely displaces other coal production without any corresponding benefit, the TRR project is not in the public interest. Nowhere does the DEIS adequately address or critically analyze these issues, and the DEIS is, thus, deficient and inadequate.

As mentioned earlier, OEA's modeling results are often presented as a series of averages across scenarios to discuss various issues. This methodology provides no meaningful indicator of comparing alternatives or understanding the conclusions reached. Sometimes mutually exclusive scenarios are combined in the conclusions presented and discussed. This method of presenting

results precludes the reader (and decision maker) from understanding the impacts and consequences of any given alternative or scenario, and it does not provide the information necessary to understand the likelihood that one alternative or scenario might be more advantageous than others. Nor does this method give an accurate presentation of any of the alternatives when compared to the no-action alternative.

In the abstract, the entire presentation of route alternatives seems like the game-of-chance known as the shell game – but, in this case, there is nothing under any of the shells because there is no market for the coal that the TRR hopes to haul. In reality, however, this is a high-stakes game-of-chance for landowners along any and all of the ten proposed routes. These ranchers must cope with the threat of federal condemnation if the STB decides to permit this railroad along a route through their land (more on this issue later).

To add insult to this injury, in its original application, the TRR Company asked for a 200-foot right-of-way, which Northern Plains (in our scoping comments) questioned the need for if this was truly a “single-track” proposal. Now, it is disheartening to read in Section 2.2.1 of the DEIS that this right-of-way width has been clarified – and widened even more. The width of the right-of-way now varies depending on the alternative route and would be from 367 feet to 455 feet *on average* [emphasis added], with maximum right-of-way widths varying up to 1,450 feet. We again dispute the need for any single-track railroad requiring such right-of-way widths. Not only that, but in 2.2.12.3, the DEIS states that “[d]epending on the build alternative selected, TRR Company would construct one or two 8,500-foot passing sidings *at locations to be determined*” [emphasis added]. The TRR Company would also construct set-out tracks to provide temporary storage for repair and maintenance . . . rang[ing] in length from 500 to 4,000 feet . . . *depending on the build alternative*” [emphasis added].

There is a significant amount of detail missing about where these tracks and associated disturbances would be placed, which makes this DEIS less than useless for understanding these major proposed aspects of the project. While there are lines on a map showing a general placement of the proposed alternative routes, it is more than difficult for any landowner or concerned citizen to know what might be in store for areas along any of the potential routes that could be of critical importance to ranching operations, wildlife or other natural and/or cultural resources.

The location of the sidings and set-out tracks, in particular, could negatively and critically impact ranching operations and other issues. These associated railroad service facilities are for parking trains, sometimes for long periods of time. There would not be crossings along these sidings and set-out tracks. Not only would parked trains obstruct wildlife movement and cut off access for wildland fire fighting operations and for hunters, but they could impede critical access necessary for ranching operations. Parked trains would obstruct access to cattle, which is critical at certain times of year, for example, in winter when cattle must be fed or in spring during calving. Parked trains would also block moving cattle. This lack of clarity and detail is a deficiency in the DEIS and prevents landowners and others from truly assessing the impact of the proposed railroad. However, it is absolutely clear that rights-of-way of the magnitude discussed above would severely amplify the negative impacts of the proposed railroad for landowners and land users in the area.

Throughout the document, the OEA reduces the alternatives to their length in miles, width in feet, and total acres. However, this approach does not truly take into account the impacts to the agricultural economy and vitality of the area, the cultural values this area holds for many Native American tribes and others, or to the ecological value of the habitat. This project cannot be reduced to proposed miles of track or feet or acres of disturbance because a reduction in miles or feet or acres does not necessarily equate to a reduction in the severity of the impacts. The consequences of this project, in many cases, are significant and severe – and in some cases irreparable.

In 2.2.1, the DEIS states, “OEA assumed that the entire right-of-way would be acquired by TRR Company.” **What is not said here is that if the TRR Company is given a permit, they also will be granted the right of federal eminent domain.** Montana’s farmers and ranchers would face condemnation if the TRR is permitted.

Private property rights are at the core of our constitutional democracy and civil society. For a wholly speculative railroad to hold private property owners “hostage” to its schemes offends our fundamental ideas of due process and fair play. Eminent domain is a formidable governmental power that should be used rarely and only as a last resort. Eminent domain gives the government the right to take an individual’s private property – but it is only supposed to be used for public projects that advance the public good. The TRR Company is a private corporation that would be given the right to take Montana farmers’ and ranchers’ private property for the corporation’s own profit. We believe that this is wrong. The private property of multi-generational Montana ranchers and others should not be condemned to build a private, for-profit railroad. The land in question is often productive agricultural land, which provides the basis for the economic livelihoods for our members and others. This is not a minor issue. Agriculture is Montana’s number one economy, and will remain thus for any foreseeable future.

The use of eminent domain for such a speculative project is seen by many as a threat and creates significant hardships for landowners along any of the proposed alternative routes. Many along these routes see eminent domain as a club that will be used against them to force the signing of agreements that would, in reality, be detrimental to their ranching operations. From past experience with the TRR Company (after TRR I and TRR III were permitted), landowners were told that if they did not sign an agreement, they would be taken to court where, following condemnation, they would receive less than what the TRR Company was offering. This was heavy-handed coercion. And, unfortunately, this coercion is likely to happen again if the TRR is granted a permit. In our view, the speculative TRR project is no different from the Dakota, Minnesota, and Eastern (DM&E) Railroad. In the legal case of DM&E Railroad Corporation v. Tracy, the federal court noted that it is “an abuse of the condemnation process [to initiate] a condemnation action for a project that was always speculative at best . . .” and that such actions “squander not only a great deal of the Defendants’ hard-earned money, but also a great deal of [the] Court’s time.”⁴³

The implication in 2.2.1 is that the STB assumes that the TRR Company would acquire these rights-of-way by fee title. But under Montana law, when eminent domain must be used, an

⁴³ Dakota, Minn. & E. R.R. Corp. v. Tracy, No. 07-CV-00144-WFD, ¶13 (D. Wyo. July 20, 2011)

easement is the preferred method for taking property. This is an issue that is not addressed in the DEIS, and, consequently, the DEIS is deficient and inadequate.

Should an easement be given – or obtained via condemnation – then that easement should be for one purpose only (the railroad), unless additional payments are negotiated for other uses. The DEIS states there could be other facilities located in that easement without regard to additional easement agreements and payments. While some of those additional facilities are related to the railroad (siding tracks and set-out tracks), others (communication towers and power distribution lines) are often for other purposes than just the railroad. The landowner is burdened with more industrial infrastructure than simply the railroad, likely without compensation. This is unacceptable, and the DEIS is inadequate because the easement issue was not fully understood by OEA or sufficiently analyzed with the consequences to the landowner(s) presented. Nor does OEA discuss anywhere in the DEIS what happens if the TRR is permitted, eminent domain authority is given, private land is acquired by easement or condemnation, and then the railroad is not built. What happens to that right-of-way easement? This scenario is as valid a “reasonably foreseeable” alternative as some of the other scenarios that OEA posits and addresses in the DEIS.

Further, often when land is taken through eminent domain only a strip or chunk of a larger piece of land is taken (as will be the case with any of the proposed TRR route alignments). The DEIS generally only considers impacts and consequences within the proposed right-of-way. But, for ranchers, many long-established operations that were set up to ensure that the ranch operation functioned efficiently and most effectively would forever be changed by a rail line, and these consequences are not considered in the DEIS. If the proposed TRR crosses a ranch then portions of the property, including agricultural fields, irrigated pastures, winter pastures, summer pastures, calving pastures, irrigation lines and circle pivots, water pipelines, water tanks, water wells, natural water sources, water impoundments, and other important ranch areas, among many other aspects of the ranch could be severed. Severed portions of ranches could now be unusable, for example, a sizeable piece of land that had been part of the ranching operation could be “lost” because it now lies, for example, between the railroad and a highway or a waterway or a cliff or a bluff. Nowhere is this significant loss-of-use economic issue addressed. Severance is real, and its impacts can be enormous.

In the case of water pipelines, if the railroad crosses a ranch pipeline, how is a rancher going to maintain that line? Would the rancher have the ability to fix a broken line under the rail line or is s/he responsible for the cost and time to move that line – if that is even possible? What happens if the rail line severs (cuts off) the rancher’s ability to get water to the “other side of the tracks?” This could have significant negative consequences to the operation of a ranch. If the water source that is severed is a natural spring, then there were – pre-railroad – minimal costs involved for the rancher to water his/her cattle. But to replace that water source with a well and to now have to use electricity to operate that well would result in significant costs to the rancher. Nowhere does the DEIS adequately address this issue.

While Mitigation Measure-68 (Chapter 19, page 19-23) states that “where capital improvements are displaced by construction or operation of the rail line, TRR Company shall relocate or replace these improvements or provide appropriate compensation based on fair-

market value . . .”, it remains unclear if this applies to improvements that are severed and not directly in the right-of-way or to the consequences to changed ranching operations. Some examples of those situations include (but are not limited to) the need to: relocate distant corrals and/or fences due to changed operations at the ranch, buy additional feed if cattle cannot be pastured as they were before the railroad was built, and/or incur additional labor costs if cattle must be herded to new areas as a result of the railroad severing pastures. Some ranch areas cannot be severed as the ranch would not continue to be profitable because some areas are not replaceable elsewhere due to specific requirements or reasons for their current location (e.g., calving areas located near ranch homes for easier access during this multi-day, 24-hour critical time; e.g. irrigated pastures near water sources).

The DEIS states that if the STB grants the permit, the TRR Company will “negotiate” with landowners for access, rights-of-way, and compensation for all the harm and impacts the railroad would cause to the landowner and their ranching operation. However, past experiences with the TRR Company demonstrate that this company is a “bad actor.” Previously, the TRR Company threatened condemnation rather than negotiating in good faith with landowners. Previously, reasonable requests for slight adjustments to alignments in order to avoid impacting critical aspects of ranching operations were met with refusal. For the STB to consider giving a permit to this company without strict and clearly defined rules, including oversight, for how these “negotiations” are carried out is unconscionable.

The DEIS states that the TRR Company will “negotiate” with landowners for any crossings they want and need for continuing critical ranch operations. However, conversations with ranchers severed by the recently constructed Broadview rail line (from the Signal Peak Mine) reveal that that railroad (the BN) required ranchers to show that they had \$1 million in liability insurance before negotiations began. Additionally, the rancher was required to assume responsibility, including maintenance, of that crossing. Should the crossing not be maintained to the railroad’s satisfaction, the rancher would be charged up to \$800/hour for the railroad to maintain the crossing. This way of doing “business” puts a rancher between a “rock and a hard place.” That rancher did not ask for a railroad to cross his/her land and potentially affect the ranch’s viability and profitability. That rancher has little choice especially when faced with condemnation, and this is not right or fair.

Aside from the crossing issue, what is the liability of the rancher for anyone who is injured or killed on the railroad right-of-way that severs his/her ranch? That rancher did not ask for the railroad to sever his/her ranch. Many of the ranchers in this area allow hunters on their ranch either with individual permission or as part of Montana Fish, Wildlife and Parks’ block management program. If one of these hunters is hit by a train or injures him or herself in any way in the railroad easement, who is truly liable? Not the rancher, in our view. By the way, the Amish community that would be crossed by the Colstrip alternative does not carry liability insurance. What would happen in their situation if an accident happened in the railroad easement through their land?

Additionally, who is responsible for maintaining fences along the easement, and, when broken and needing repairs, who is responsible? If the TRR Company is responsible, as we believe that entity should be, what mechanism compels them to quickly repair the break in a

fence? Would the rancher be compensated if cattle get onto the railroad because of the break and are injured or killed? Would a rancher be compensated if cattle are trapped by the railroad grade and unable to escape rising spring flood waters or if new-borne calves are frightened by train engines and their horns and then run into streams or rivers to get away and drown? The rancher did not ask for this railroad to sever his land and disrupt his operations.

The value of the entire ranch would be diminished (there would be a loss in fair-market value) should a railroad bisect any portion of the ranch. A railroad crossing a ranch could result in the ranch no longer being marketable at all. Increasingly, potential buyers of a ranch include those who are looking for solitude and/or recreational opportunities (e.g., hunting). A railroad crossing a ranch would decrease that ranch's value to such buyers and reduce its salability, yet this issue is not discussed in the DEIS.

The DEIS discusses livestock passageways (see 2.2.8) that would be constructed if the rail line is located in particular areas of a ranch and cattle movement is affected. But, despite many comments submitted to the record in past EIS processes and during scoping for this DEIS, OEA still proposes culvert passageways for livestock. Long-time cattle owners' experiences have shown that these types of passageways do not work. Because cattle will only reluctantly use such passageways – if at all – strong herding is required, which normally still does not work. Ranchers do not have time to add this herding to their daily workload, but their cattle would still need water or access to severed pastureland on the other side of the rail line. The long-established operation of a ranch, and, most likely, its profitability would be affected by these types of passageways.

Water rights are the right a user has to take water from a river, stream, or other water source. The DEIS states in section 2.2.5 that "TRRC plans to use water for dust suppression and soil compaction during construction. The construction contractor would coordinate the purchase of water rights from the Tongue River, the Yellowstone River, water wells, or a combination thereof." We are quite interested to understand from whom or where these water rights would be obtained. The DEIS states that millions of gallons of water would be necessary during construction. But, water in the proposed alternative route areas is extremely limited and is a precious commodity for the agricultural interests currently holding water rights (some of which are senior water rights, which are "first in time, first in right"). This is true for both surface water and ground water. Pumping water from groundwater wells would draw down the water table, which would, in turn, affect other private wells. This issue is not adequately addressed in the DEIS and, therefore, the document is deficient.

A corollary concern about the water that would be used during construction (if the railroad is permitted) involves the control of dust that would result from both construction and increased vehicle use of non-paved roads. Excess dust generated during construction of the railroad would coat vegetation, inhibiting plant growth and proper plant respiration. In the dry climate of southeastern Montana, few rainstorms would "wash" the plant leaves free of that dust. Cattle exposed to too much dust develop what ranchers refer to as dust pneumonia. Hot, dry conditions coupled with excess dust can lead to respiratory disease in cattle, especially calves. This disease often results in weight loss and, potentially, death. For these reasons, proper and

adequate watering of the construction area and non-paved roads is truly necessary. But, again, where is that water coming from?

Additionally, the DEIS notes that should the rail line cross through a well, that well would be plugged. What happens then? Would the well be replaced? If a well is replaced, the appropriation date of the water right for that original well is lost. How do you compensate the rancher for that significant loss? If the replacement well is deeper than the well that is lost, would the TRR Company pay the additional electricity costs the landowner incurs? This issue is not adequately addressed in the DEIS and, therefore, the document is deficient.

The DEIS completely fails to accurately examine the costs to agriculture of the proposed TRR; these costs are either significantly disregarded, miscalculated, or both. Northern Plains and many landowners affected by the proposed TRR have made these points repeatedly in past TRR EIS processes and during the scoping period for this current DEIS. But, once again, these issues that are critical to operating a ranch (and making a profit) have not been understood by OEA. Nowhere does the DEIS address these and other issues critical to ranching operations. Nor does the DEIS explain how a landowner would be fairly compensated by the proposed railroad for these impacts.

In 2.2.2, the DEIS states that the TRR Company “would use existing roads crossing the build alternative for entry and exit to the rail line access roads and does not anticipate the need to construct new lateral access roads. . . . and would not construct a continuous access roads [sic] along any build alternative; rather, the roads would connect to the nearest existing road crossing to minimize their lengths.” These statements seem highly problematic not only with regard to the operation of the rail line but also for officials needing to respond to accidents and/or to fight fires that could be started by the TRR (see discussion on fire below). There is no existing access road along the Tongue River alternative route. There is no access from Miles City to the SH Ranch on the west side of the river or between the Harwood Ranch and Brandenburg along the Tongue River Road alternative route. There is no access road along the Moon Creek alternative route. How will these areas be serviced if that alternative is chosen? How would emergency personnel and fire fighters access these areas?

The table on page 2-44 of Chapter 2 lists the cut requirements (in million cubic yards) for each alternative and the table on page 16 of Appendix N also lists both the cut and fill requirements for each alternative. The tables in Chapter 13 on page 13.2-25 again show the cut-and-fill requirements as well as the slope analysis for each alternative. However, nowhere is there an adequate discussion of exactly what these numbers mean nor are there any simulated images of what cuts would do to hillsides, rock cliffs, or bluffs or what fills would do to valleys. We know of many locations where either a cut or a fill would dramatically change the landscape and would lead to many environmental consequences. There is no way to understand the differences between alternatives with regard to cuts and fills because of the lack of discussion of this topic. The DEIS needs to provide the engineering specifications and visualizations for the cut and fill impacts of the TRR. While Appendix N clearly states that the Colstrip alternative would be the least damaging to waterways, that does not mean this alternative would not present negative cut-and-fill consequences, and the lack of cut and fill information in the DEIS makes

this conclusion challenging to comment on. We find this lack of information and analysis to be a serious deficiency.

A significant aspect of the cut-and-fill issue involves drainage, which is critical in this area of Montana. Frequent and sometimes severe thunderstorms (including those storms in upper portions of a watershed a long distance from the proposed rail line) often result in significant down-gradient flooding that increases the cubic-feet-per-second (cfs) flow of a creek or ephemeral drainage dramatically, sometimes with devastating consequences. Berming, and even in some cases bridging (due to buttressing), any of the creeks, streams, or (dry) gullies on any of the alternative routes could have serious negative consequences not only to the rail line but also to the property and improvements in the path of this high water. In some winters, this part of Montana also is prone to severe ice-jamming on all types of waterways (from creeks with a flow of less than 5 cfs to major rivers). On the Moon Creek alternative, it appears that the cuts and fills necessary for this alignment could alter natural drainage patterns, and water flowing into the Moon Creek drainage could be diverted into the Tongue River drainage. Such a shift in water flow pattern would have a significant and negative impact on water availability for ranching operations. Nowhere do we see these issues discussed or fully addressed in the DEIS, which adds to its inadequacy and deficiency. Additionally, there appears to be a huge proposed cut and fill across the Tongue River on the Colstrip alternative. Such an undertaking would have major impacts on riparian corridors, soils, weeds, the area viewshed, and more. These impacts need to be spelled out in the EIS. Further, the scope and magnitude of these impacts only underscores the argument made above – namely, that there must be more information about cut and fill plans, including specifications, maps showing precise routes with all necessary cut and fill operations (as well as sidings, new/moved roads, and other things mentioned elsewhere in these comments as missing). Without such detailed information, these parts of the DEIS are rendered inaccessible to the public, landowners are denied the ability to plan and adequately comment, and the STB is left with an insufficient analysis of the impacts of the TRR.

The Tongue River flows through Miles City. Recent revisions of the Federal Emergency Management Agency (FEMA) floodplain maps have resulted in significant local concern about flooding. A large part of Miles City is in the river's floodplain (79% of the structures in town) with approximately 5% of these structures in the designated floodway. Any of the TRR alternative routes that enter into this floodplain in order to join the existing BN east-west rail line could significantly increase/exacerbate flooding in Miles City. Despite the analysis presented in Chapter 9.4, we continue to believe that a specific and complete flood analysis study of the impacts that construction of any alternative route through the area would create for Miles City is warranted. Included in this study should be a thorough analysis of ice buildup in winter during low flows on the lower Tongue River and at its juncture with the Yellowstone River and the resultant flooding back along the Tongue River and into Miles City, which is a common occurrence.

As mentioned above and as explained in our comments to the STB on the TRR Company's Supplemental Application,⁴⁴ even if the TRR is licensed but never built, it will have

⁴⁴ Northern Plains Resource Council and Rocker Six Cattle Company Comments to Tongue River Railroad Company's Supplemental Application, 2 April 2013, Finance Docket No. 30186. (see the URL on the following page)

significant impacts on Northern Plains members and other area landowners. The threat of the TRR passing through private lands prevents ranchers and farmers from improving their operations because the railroad could literally destroy those investments. The threat also creates a significant cloud on the property, making it difficult or impossible to sell at a reasonable price.

This is not idle speculation. One landowner (and member of Northern Plains) who would potentially be crossed by the TRR has for years wanted to improve the efficiency of his ranch by constructing cross-fencing and livestock watering pipelines. Although these improvements are critical to the ranch's productivity and viability and would both significantly reduce labor costs/demands while increasing grazing efficiency (and, thus, increase how many cattle he could manage), he has not made these improvements because he cannot afford to make them twice – and, to date, the railroad would not be responsible for reimbursing him for the costs of moving the fence and water pipelines.⁴⁵

Another landowner and Northern Plains member has been hampered in making the most effective use of his ranchland by the TRR Company's changing route proposals. For instance, he was forced to delay the construction of a circle-pivot irrigation system for nearly a decade due to the ICC's approval of TRR I and, later, by the TRR Company's contradictory route proposals. Additionally, he has had to consider how to manage his cattle if the TRR bisects his lands, cutting off his pastures from the ranch's primary water source. In a verified statement, he states that "ranching is not an easy business and we need to be efficient to compete in the global market. We have put our business and lives on hold because any improvements we make to the ranch could be severely impacted by TRR Company's eminent domain rights. We would not be compensated for these losses. The restrictions TRR proposals have placed on our ranch has caused uncertainty in our future." He reports that delaying improvements on account of the threat of having the TRR cross his ranch has cost him approximately \$405,000 in lost sales.⁴⁶

Outside of lost improvements, the threat of the TRR greatly impacts property values and the salability of a ranch as mentioned above. As one example, licensed real estate professional Roger Jacobs was unable to sell the Ball Ranch, which lies along the TRR I route because potential buyers felt it was "too risky" to purchase ranchland that was threatened by industrialization. This unwelcome and unpreventable development would ruin wells, circle pivots, water tanks, and fences. Mr. Ball was finally able to sell the ranch after the TRR Company abandoned that route.⁴⁷

<http://www.stb.dot.gov/filings/all.nsf/8b0338bbd8126ced852572b000767459/c8390267fc282cb685257b4100730023?OpenDocument>. (Northern Plains also incorporates by reference its 2015 Tongue River Railroad comments available at

<http://www.stb.dot.gov/filings/all.nsf/8b0338bbd8126ced852572b000767459/15214f1e2176f37785257e15003e8aa4?OpenDocument>, and the rest of its filings on the Tongue River Railroad permit, available at

<http://www.stb.dot.gov/filings/all.nsf/WebDocketNum?OpenForm&Start=393&Count=300&Expand=453>).

⁴⁵ Verified Statement of Clint McRae in Support of Northern Plains Resource Council and Rocker Six Cattle Company Comments to Tongue River Railroad Company's Supplemental Application, March 2015

⁴⁶ Verified Statement of Mark Fix in Support of Northern Plains Resource Council and Rocker Six Cattle Company Comments to Tongue River Railroad Company's Supplemental Application, March 2015

⁴⁷ Verified Statement of Roger Jacobs in Support of Northern Plains Resource Council and Rocker Six Cattle Company Comments to Tongue River Railroad Company's Supplemental Application, March 2015

The DEIS is deficient because it fails to take into account the material harm that the proposed TRR presents through the threat of condemnation. The DEIS is also deficient because it fails to consider the impact of the consequences of permitting the TRR but its lack of construction (especially for many years) due to lack of markets and/or financing.

These are just a few of the many aspects of the proposed alternative routes that are not considered nor are they adequately addressed. Each of these issues involves significant consequences to the landowners affected by any of these proposed routes. The discussion of proposed alternatives is complicated as the reader must wade through many chapters and appendices to understand one alternative and then must start at the beginning and do that all over again for the next proposed alternative. And, to make this process even more complicated, there are ten alternatives to consider. The assumptions made by OEA and the outdated information used in the computer models about coal markets has also complicated the review and understanding of proposed alternatives. The DEIS is inadequate in its analysis of alternatives and the impacts to landowners from the proposed railroad, and, thus, the DEIS is deficient.

Rail Operations

Rural southeastern Montana does have low population numbers, but OEA downplays grade-crossing delays, safety issues, and potential accidents that could result if the TRR is built. Nowhere in the document is there a discussion of whether or not there would be a need for “helper units” on any of the proposed alternative railroad grades. Nor is there any discussion of speed restrictions due to grades or curvatures or community agreements/regulations along any of the particular route alternatives.

The DEIS states (in 3.3.2.2) that it is estimated that a grade-crossing delay would be 2.5 minutes per train. This is an optimistic assessment. Each passing coal train has the potential to cause six- to seven-minute delays at rail crossings⁴⁸ or longer should a downrail community have a negotiated limit on rail speeds. But even this does not account for trains that are slowed or stopped for whatever reason, blocking a grade crossing for a longer time. For the roads and streets identified in the DEIS that have more than 100 vehicles traversing each day, this could be significant. For the other roads identified, there are likely no alternative routes available because the area is rural. Should the vehicles that are stopped at a grade crossing include emergency vehicles (fire, ambulance, or law enforcement), this could be especially significant. OEA states that it considers these delay impacts to be negligible (3.3.4.4). If the delay impacts an emergency situation, we disagree with that assessment. There are several medical emergency conditions that are time-sensitive. In certain stroke patients, five minutes may make the difference between being able to treat the patient with thrombolytics or not (in certain stroke patients, thrombolytics can reverse devastating neurological affects of a stroke). In heart attack victims, a delay of

⁴⁸ “Cherry Point Coal Export Facility Rail Operations-City of Seattle-Preliminary Report, GTC #11-036,” Gibson Traffic Consultants, Inc., February 2012. <http://www.powerpastcoal.org/wp-content/uploads/2012/10/GTC-Seattle-Traffic-Report-SO-small.pdf> (this study based the delay times on a 1.5 mile-long-coal train travelling at 35 miles per hour; delays are approximately three to four minutes for trains travelling at 50 miles per hour)

minutes can result in heart muscle death. And, in major traumas, time delays can result in increased blood loss and organ failure.⁴⁹

Table 3.4-1 predicts accident intervals at specific grade crossings to be from 110 to 402 years apart. This is an example of how use of numbers and/or statistics can be totally misleading. Should the sole reason for the proposed TRR (the proposed Otter Creek Mine) be permitted and strip mining activities begin, there would be more auto and truck traffic on the roads being discussed. However, that does not appear to be factored into this analysis. Thus, the DEIS is inadequate and deficient.

Trains are noisy and federal law requires that the train blow its whistle at all grade crossings. The area being considered for the proposed TRR is rural, non-industrialized, and agricultural. The ambient quiet and the low humidity of the area mean that noise will travel far, and the baseline background decibel level is low. Not only will the solitude of the area be impacted, but the medical literature links noise to significant human health issues. Noise is linked to cardiovascular disease, including increased blood pressure, arrhythmia, stroke, and ischemic heart disease. Noise is linked to cognitive impairment in children. Noise is linked to sleep disturbance and resultant fatigue, hypertension, arrhythmia, and increased rate of accidents and injuries. Noise can exacerbate mental health disorders such as depression, stress and anxiety, and psychosis. Not only will noise impact humans, but it will impact wildlife and livestock. Noise impacts to livestock can include loss of weight, which would affect the rancher's profitability when the livestock is sold at market.

While the DEIS acknowledges that noise will increase and could be adverse on the Colstrip alternative (through the Colstrip subdivision), it assumes that the increase in noise that is the result of operating the TRR is acceptable. We disagree. The changes in noise levels all along any of the alternative routes is a significant environmental consequence that has more impact than the DEIS recognizes.

Finally, the discussion of wildfire in the DEIS is totally inadequate. In 8.2.3.2 OEA acknowledges that fires are a part of the natural ecosystem of this area, and "dry conditions of eastern Montana favor fire risk." The document goes on to say "the windy conditions that are typical of eastern Montana can cause wildfires to spread rapidly." The DEIS also states that railroad operations "only" contribute 4% of the total fires in Montana, but these figures, once again, do not explain the entire issue or the consequences of fire in southeastern Montana. This statement is also somewhat deceptive, both in probability of trains starting fires and in the potential impact of those fires.

Worn brakes, sparks from brake shoes or wheels, arcing from traction motors, failed wheel bearings, dripping oil, sparks smoldering on old creosoted cross-ties, and thrown rods from locomotives all have the potential to start fires. Because of reduced employee numbers on trains, a train-caused fire might not be detected until it is burning more intensely.

⁴⁹ Dr. Eric Schultz in "Health concerns about coal export in the Northwest," Power Past Coal, 2013. <http://powerpastcoal.org/wp-content/uploads/2013/12/health-impacts-03.pdf>

Most railroads in Montana are differently situated than the proposed TRR would be because those other rail lines lie next to a river, irrigated fields, and/or a paved highway, which all serve as impediments to fire-starts as well as barriers to the spread of fire. The Tongue River area is climatically dryer than many regions of Montana. The Tongue River Valley and Rosebud Creek drainage are marked by steep bluffs, open rangeland, and dry grass-shrubland. In many of the remote locations that any of the TRR alternative routes would traverse, there would likely be delays in detecting and reporting a fire. Add to that the time required for local fire fighters to respond to a fire, especially if located in a remote area, and one can understand how any fire started by the TRR could result in a fire that is larger than “typical” railroad-related fires.

Within the last century, Montana has seen a 1.3°F increase in its average temperature.⁵⁰ The Intergovernmental Panel on Climate Change has projected that, within the 21st century, temperatures will increase 4°F in the spring and summer months and 5°F in fall and winter. Among other things, this increase in temperature will lead to an increase in wildfires. Wildfires are already becoming more prevalent and destructive in Montana, especially during summer months.

Table 8.2-3 of the DEIS compares rail-caused fires and acres burned to all Montana fires. This table focuses on the years 2007 through 2011 in its analysis of fires. This comparison conveniently leaves out the fires of 2012 (even though most issues addressed in the DEIS use data through 2012). That was the most destructive wildfire season in Montana since 1910, and fires in southeastern Montana were prominent in that destruction.

Near the end of June 2012, the Ash Creek fire exploded in Rosebud and Powder River counties, leaving a “moonscape” of 249,562 acres. It was the largest wildfire of the year in Montana and burned 39 structures, including many homes on or near the Northern Cheyenne Reservation. Before it was controlled, it cost \$7.5 million to suppress. In August 2012, another group of fires in southeastern Montana called the Rosebud complex erupted, burning 171,444 acres and 10 structures and costing \$9 million to suppress.

While it may be that a railroad did not start either of these fire complexes, what happened in 2012 shows the dramatic scope, size, and destruction that fire presents for this part of Montana. Fire is a constant threat and worry for residents here; initial responders to these fires are often ranchers who live in the area. Lack of access along some of the proposed alternative routes has been pointed out above. Even if only 4% of the fires in Montana are caused by trains, what happens if one of those train-caused fires occurs in an area with little or no road access? Again, we find it interesting that while most issues discussed in the DEIS cite information and data through at least 2012 and often 2013, for this significant issue, the fire information ends at 2011. The DEIS is inadequate in its consideration and analysis of fire, and, thus, is deficient.

Air Quality

Medical studies have shown a clear link between both diesel air pollutants and coal dust and disease. While those with chronic disease, the elderly, young children, and pregnant women

⁵⁰ *Climate Change and Montana*, EPA, 1997, http://www.spatialsci.com/files/images/EPA_MT_climchange.pdf

are most at risk, the health effects from particulate matter exposure may occur years later, so even healthy individuals need to be concerned.⁵¹

The DEIS is inadequate because OEA fails to fully consider or adequately analyze the human health effects of added coal train emissions increasing (and exceeding) the NAAQS standards. While OEA acknowledges that coal dust is emitted from coal trains, the DEIS is inadequate because the OEA fails to fully consider or adequately analyze the human health effects that result from coal dust.

In a paper titled, “PRB Coal Degradation, Causes and Cures,” Roderick J. Hossfeld and Rod Hatt explain that “PRB coal is extremely friable [crumbly] and will break down into smaller particles virtually independent of how the coal is transported or handled.” They go on to say that “once PRB coal is exposed by mining, the degradation process begins – the majority of the damage can occur in a very short time, even as short as a few days. The extent of the degradation that occurs depends in large part on . . . how long the coal is exposed to the atmosphere during transportation.”⁵²

Previously, on the BNSF website,⁵³ it was stated that as much as 500 pounds of coal dust could be lost from each coal car in a train (there are typically 115-140 cars in a coal train; TRR’s application lists 125 cars/ train). In 2011, Northern Plains began using this information in its presentations opposing the proposed increase in the number of coal trains through Montana communities that would result as a result of proposals for increased coal exports. Soon after Northern Plains began using this number, that piece of information was removed from the BNSF website.

The OEA explains in the DEIS that the STB has issued rulings to limit fugitive coal dust emissions from trains in order to avoid fouling the ballast of rail lines (Chapter 6, page 6-21). These rulings are in line with the National Transportation Safety Board’s conclusions that coal dust on railroad tracks has been a contributor to derailments. Through trials, BNSF determined that shaping the profile of the loaded coal in rail cars combined with approved topper agents could reduce emissions of fugitive coal dust by at least 85% (Chapter 6, page 6-21), and BNSF requires this of shippers (this is termed a tariff). The TRR Company has promised to follow the tariff requirements, and OEA accepts this as sufficient to mitigate fugitive coal dust in its analysis of the environmental consequences resulting from coal dust. But, it must be noted that there is no independent verification or enforcement mechanism for this tariff.

Despite acknowledging that fugitive coal dust is emitted from moving trains, the OEA determined that “coal dust from rail cars on the proposed rail line would not affect human health” (Q&A-6). In Chapter 6 (page 6-5) of the DEIS “OEA did not identify any scientific studies that specifically examined the human health risks associated with coal dust from moving

⁵¹ see “Whatcom Docs Position Statement” for extensive documentation of scientific and medical research on the health effects of these air pollutants; <http://www.coaltrainfacts.org/whatcom-docs-position-statement-and-appendices>

⁵² <http://krtcommodities.com/files/PRB%20COAL%20DEGRADATION.pdf>

⁵³ <http://www.coaltrainfacts.org/docs/BNSF-Coal-Dust-FAQs1.pdf>

rail cars.” However, there are many scientific studies available that do establish this link.⁵⁴ The DEIS is inadequate and deficient because it does not thoroughly analyze and consider the health consequences of fugitive coal dust.

On page E-154 of Appendix E of the DEIS “OEA conservatively selected the maximum value at 40 meters for the coal dust exposure analysis even though this distance would typically be within the right-of-way where humans would not typically be exposed.” However, on page 12 of a study prepared by the Multnomah County [Oregon] Health Department,⁵⁵ which used available literature in its analysis, it is reported that “coal dust may travel approximately 500 meters to 2 kilometers ($\frac{1}{3}$ to $1\frac{1}{4}$ miles or 1,640.42 feet to 6,561.68 feet) from the tracks, depending on weather conditions and train speed.” The study found that coal dust from rail transport has the potential to result in growth and development problems, heart and lung problems, cancers, and safety-related injury and death.

The same Multnomah County study identified that “coal dust may contain traces of heavy metals, such as lead, mercury, chromium, and uranium that are toxic to the human nervous system. Children are particularly vulnerable to heavy metals . . .” (page 7) and that the populations living within 500 meters of the rail lines in the county are “communities of color, children, older adults, and people earning low incomes” (page 17). By the way, this issue is not adequately addressed in Chapter 16, Environmental Justice, of the DEIS, and, thus, the DEIS is inadequate and deficient with regard to environmental justice.

Another study by Daniel A. Jaffe et al.⁵⁶ measured particulate matter (PM) emissions at two rail sites in Washington State. The “measurements demonstrate that rail traffic emits substantial quantities of diesel exhaust and that PM_{2.5} concentrations are significantly enhanced for residents living close to the rail lines. . . . after passage of coal trains there was a statistically significant enhancement in large particles . . . [that] most likely consist of aerosolized coal dust.” the Jaffe study goes on to state that “the enhancement in PM_{2.5} is not only due to the [emission] spikes that occur as a train passes, but also the residual that accumulates in the local airshed.”

Additionally, a report by Dr. Alan Lockwood,⁵⁷ found that coal trains are responsible for releasing coal dust particles and diesel fumes “into the air, degrading air quality and exposing nearby communities to dust inhalation,” and the report specifically noted that “railroad engines and trucks release over 600,000 tons of nitrogen and 50,000 tons of particulate matter into the air every year in the process of hauling coal, largely through diesel exhaust. Diesel engines currently produce approximately 1.8 million tons of NO_x [nitrogen oxides] and 63,000 tons of small particles (less than 2.5 microns in diameter) each year. These emissions adversely affect many organ systems.” It is worth noting that children often face the most severe health risks from coal

⁵⁴ see reference list in Appendix B of “Whatcom Docs Position Statement”; <http://www.coaltrainfacts.org/whatcom-docs-position-statement-and-appendices>

⁵⁵ “The Human Health Effects of Rail Transport of Coal Through Multnomah County, Oregon: Health Analysis and Recommendations for Further Action” February 2013.

http://media.oregonlive.com/environment_impact/other/Coal%20Report%20.pdf

⁵⁶ “Diesel Particulate Matter Emission Factors and Air Quality Implications from In-Service Rail in Washington State, USA” January 2014. http://www.atmos.washington.edu/jaffegroup/uploads/Jaffe_2014_trains_final.pdf

⁵⁷ “Coal’s Assault on Human Health,” Dr. Alan Lockwood, et al., November 2009.

<http://www.psr.org/assets/pdfs/psr-coal-fullreport.pdf>

dust pollution, with Dr. Lockwood noting that children and infants are the most vulnerable population in five of eleven enumerated diseases caused by coal dust pollution.

More than 600 health professionals have spoken out about safety threats associated with increased coal train traffic. Dr. Melissa Weakland of the Washington Academy of Physicians stated, “We know from the data that the coal trains would negatively impact the health of our communities because of increased air pollution from diesel particulates and coal dust, delays in emergency response time because of long waits and railroad crossings, and increases in noise pollution in our communities.”⁵⁸ These safety threats are the same whichever direction the TRR coal trains travel.

The DEIS is inadequate. It fails to address the human health effects from increased air pollution that will result from an increase in the number of trains that would result if the TRR is approved. While the DEIS indicates that there would be 7.4 additional trains each day, under some scenarios the increase is 18.6 to 26.7 additional trains each day. It is unacceptable that the DEIS does not evaluate the human health effects that could result from such an increase in coal train traffic. The DEIS is wholly deficient in this regard.

Greenhouse Gases/Climate Change

The sole purpose of the TRR is to haul coal. Coal is the world’s most carbon-intensive fossil fuel. When coal is burned, carbon dioxide (CO₂) and other greenhouse gases (GHG) are released into the atmosphere (conversely, this CO₂ is trapped as carbon inside the coal in the ground and does not impact the earth’s atmosphere). It is now well-established in the scientific community that the burning of coal and other fossil fuels is putting us on a dangerous path toward irreversible climate change.⁵⁹ According to the 2009 *U.S. Global Change Research Report*,⁶⁰ “The global warming observed over the past 50 years is due primarily to human-induced emissions of heat-trapping gases. These emissions come from the burning of fossil fuels (coal, oil, and gas), with additional contributions from the clearing of forests and agricultural activities.” The potential climate impacts that would result from the proposed TRR cannot be ignored. The TRR DEIS must give full consideration to the long-term, connected, direct, and indirect impacts that the proposed TRR project would have on global climate change.

Construction and operation of the proposed TRR would have direct climate impacts due to diesel combustion emissions both from transporting materials and operating equipment for the construction of the railroad and, notably, from operation of the railroad itself. The principal climate impacts, however, would be indirect and come from the combustion of the coal carried by the proposed TRR, an undeniable cumulative and connected impact of the railroad’s construction and operation.

⁵⁸ “Health concerns about coal export in the Northwest,” Power Past Coal, 2013. <http://powerpastcoal.org/wp-content/uploads/2013/12/health-impacts-03.pdf>

⁵⁹ Fact Sheet: Social Cost of Carbon, EPA (Nov 2013), <http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf>.
and <http://climate.nasa.gov/scientific-consensus/>

⁶⁰ <http://downloads.globalchange.gov/usimpacts/pdfs/climate-impacts-report.pdf>

Virtually every ecological community and natural system in Montana, and, indeed, the world, is already being impacted by global climate change. These impacts will continue to become more and more severe unless the use of coal is dramatically curtailed and all nations make a concerted effort to develop other forms of energy. Wherever the Otter Creek coal (and any other “potentially induced” Tongue River coal) that is transported by the proposed TRR is burned, the GHG emissions will eventually impact Montanans.

Within the last century, Montana has seen a 1.3°F increase in its average temperature.⁶¹ The Intergovernmental Panel on Climate Change has projected that, within the 21st century, temperatures will increase 4°F in the spring and summer months and 5°F in fall and winter. In Montana, increasing temperatures are:

- leading to a loss of snowpack through earlier snowmelt with resulting effects on the water supply available for humans, livestock, crops, fish, and wildlife. Snowpack in Montana holds about 75 percent of the State’s water supply. Less snowfall and earlier snowmelt affects aquifer recharge, stream flow, and stream temperature. Early snowmelt also produces an increase in stream flow in winter and spring but a reduction in summer and fall flows. This is detrimental because the summer and fall flows are critical for irrigation, power generation, fishery protection, recreation, and other uses.
- leading to extreme heat waves. In general, heat waves are already occurring at a more frequent rate, thereby increasing mortality and morbidity. EPA studies indicate that Montana is particularly susceptible to more heat waves since it already has irregular, intense heat waves as part of its weather pattern. Heat waves produce a variety of problems, including increased fatalities among the elderly and other vulnerable populations. They also increase the spread of pests and invasive species. In reference to pests, EPA has reported that mosquito populations having the potential to carry encephalitis already exist in Montana. As conditions become warmer, the habitat for disease-spreading insects and pathogens will likely expand and create a greater risk of infection for Montanans.
- increasing the danger of wildfires. Wildfires are already becoming more prevalent and destructive in Montana, especially during summer months. During the period from 2000 through 2007, three National Forests in Montana experienced a loss of over 1,420,000 acres of land due to wildfires. Moreover, in fiscal year 2008 alone, Montana spent \$84.3 million on fire and damage control. The 2012 fires in southeastern Montana alone burned 421,006 acres and cost \$16.5 million to fight. These costs to the State will only increase as global warming escalates. Wildfires also release huge quantities of CO₂ thereby creating a feedback loop that drives global warming ever higher.

Climate change is expected to have significant impacts on water supplies and the productive capacity of agricultural lands. In Montana, agriculture is the state’s largest industry and comprises 64% of the state’s land area. Along with the problems for water supplies that result from climate change in Montana, increasing summer temperatures can negatively affect cattle and crops, reducing weights and yields, respectively. Climate change also results in more violent storms and other weather pattern changes during other seasons. Agricultural producers

⁶¹ *Climate Change and Montana*, EPA, 1997, http://www.spatialsci.com/files/images/EPA_MT_climchange.pdf

are greatly affected by these changes not only for how it affects their operations but also because these changes often result in economic losses. As Northern Plains member Mark Fix testified in the 2014 EPA hearings on the draft Clean Power Plan, climate change is resulting in more violent winds and hail storms during spring and summer, which harm and destroy cattle and crops. There are more cold temperatures for longer periods of time during some winters and, increasingly into spring. These changes particularly can negatively impact calf survival.⁶²

According to Dr. Steven Running, a University of Montana climate scientist, 30 years ago snow melts in Montana occurred around the beginning of April. In recent years, they have occurred in mid-March, and this trend is only continuing. The growing season currently begins a month earlier than it did 30 years ago, and summers are longer, hotter, and drier with lower river flows and more wildfires.

The reliance OEA puts on “a myth of perfect substitution” in all the analyses used in the TRR DEIS has led the agency to largely dismiss the climate impacts of the proposed TRR; this is both insufficient and dangerous. The IPM and other models used by OEA’s contractor to prepare this DEIS have significant shortcomings as we have detailed elsewhere in these comments. As mentioned, the basic assumption of the IPM is that electricity price elasticity is zero⁶³, which is to say that energy demand does not change with price. That is clearly not the case in supply/demand economics. When gasoline prices are down, people drive more. Similarly, increasing power costs incentivize efficiency, while cheap power incentivizes power use. Supply/demand dynamics are basic economics. As explained in the 2009 Norwest appraisal of the Otter Creek coal tracts, “flooding” the market with Otter Creek coal would necessarily have an impact on price by lowering the market cost of coal.⁶⁴ The failure of the IPM to take this into account is a failure in OEA’s climate model, analysis, and discussion of the environmental consequences of transporting new coal to wherever it would be burned. The DEIS is inadequate on this subject.

Additionally, the DEIS assumes largely domestic consumption of Otter Creek coal. While Northern Plains contends that there are no markets for this coal anywhere and, thus, there is no need for the TRR, the particular lack of domestic markets (due to the high-sodium content of Otter Creek and other “potentially induced” coal, a significant structural decline in domestic coal consumption, and other reasons documented elsewhere in these comments) make export the more likely of the two improbable scenarios. This seems particularly relevant given that TRR Company’s preferred alternative (the Colstrip route) points west, away from domestic markets and toward proposed export terminals. The IPM is designed to simulate domestic power markets. The international component of the model is much less detailed, utilizing generalized assumptions and outputs instead of specific input assumptions and variables. According to OEA’s own projections, export scenarios have GHG emissions that are much higher than those in which coal is burned domestically. In even a modest review of these export scenarios, it appears that OEA likely underestimated the climate impacts of the proposed TRR (and the

⁶² Testimony of Mark Fix on behalf of Northern Plains Resource Council at the Denver, Colorado, EPA hearings on the draft Clean Power Plan, July 29, 2014

⁶³ “Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model,” U.S. EPA, November 2013, <http://www.epa.gov/airmarkets/documents/ipm/Documentation.pdf>

⁶⁴ “Montana Otter Creek State Coal Valuation,” Norwest Corporation, January 2009

connected proposed coal mine(s)) even under its own limited and problematic assumptions. The IPM's domestic focus (and international deficiency) is another reason that the DEIS is inadequate and totally deficient for a decision maker to understand the full impacts of this proposed project.

Finally, the DEIS fails to take into account the social cost of carbon. Under the leadership of the Office of Management and Budget (OMB), the social cost of carbon was developed by a dozen federal agencies and offices in 2010 (and updated in 2013), and is the best existing tool to help agencies and the public make decisions regarding projects that impact the climate. The social cost of carbon estimates the global financial cost of each ton of extra carbon pollution in the atmosphere and seeks to incorporate impacts as diverse as drought, fire, diminished agricultural productivity, and more.⁶⁵ The social cost of carbon is backed by years of peer-reviewed scientific and economic research and has already been used by agencies in both rulemaking and project-level NEPA review. In June 2014, a U.S. District Court ruled against the federal government in *High Country Conservation Advocates, et al. v. U.S. Forest Service, et al.* citing, among other things, its failure to analyze the social cost of carbon.⁶⁶ After this decision and in response to a letter from more than two dozen conservation organizations, the U.S. Department of Agriculture affirmed that the social cost of carbon is an "appropriate tool for measuring and disclosing the social and economic implications" of federal coal leasing decisions.⁶⁷ The OEA's failure to examine the social cost of carbon associated with the proposed TRR is a significant deficiency and makes the DEIS totally inadequate.

Cultural and Historical Resources

Southeastern Montana is not only considered a homeland and culturally important to the Northern Cheyenne, but also to the Crow, Arapahoe, and numerous bands of the Sioux Nation among others. All of these Nations have expressed deep and abiding attachment to this area as well as significant concern about the proposed TRR (and the proposed Otter Creek coal mine).

Despite a better effort by OEA than what had occurred in the past to involve tribes in developing a Programmatic Agreement (PA) for this project, the resulting PA remains deficient. Unfortunately, there is little understanding by the agency and contractor (and, indeed, by most Euro-Americans) of what the proposed TRR truly means to these Nations. Industrialization of this region directly and indirectly affects sacred and important areas of these homelands. To the Native American tribes, this development is not just about "sites" that should be identified and "mitigated," it is also (and maybe more so) about the cultural importance of the area to their traditions and history. The PA may or may not be signed by Tribal consulting parties, but, unfortunately, that non-signature would not stop the proposed project, if approved.

⁶⁵ <https://www.whitehouse.gov/blog/2013/11/01/refining-estimates-social-cost-carbon> and <http://www.epa.gov/climatechange/EPAactivities/economics/scc.html>

⁶⁶ "Court Blocks Coal Mine Expansion For Not Counting The Costs of Carbon Pollution", Nidhi Thakar, June 2014, <http://thinkprogress.org/climate/2014/06/30/3454764/court-blocks-arch-mine-coal-expansion/>

⁶⁷ Letter from Robert Bonnie, Under Secretary for Natural Resources and Environment, U.S. Department of Agriculture, to J. Nichols, WildEarth Guardians (Mar. 6, 2015)

While OEA accommodated tribal participation in the cultural resource survey field work by including a Native American participant, those surveys were cursory. Many important sites, especially those without actual artifacts but having traditional and/or religious importance, were not recognized by the non-Native surveyors. And, for many reasons that are valid, the Native American tribal members accompanying the teams may not have disclosed those sites. Time and financial constraints meant that field surveys were done quickly and often only sections of proposed alternative routes were visited. No ethnographic study of the area has been done for this project despite requests from Tribes and others.

The “promise” of the PA is that once an alternative route is chosen – if the STB approves the proposed project – more in-depth and complete surveys of the route will be done. However, “mitigation” of any sites identified means “recovery,” which means artifacts are documented and removed. That removal destroys much of what is important to Native Americans and their culture. Again, this method of mitigation does not address non-artifact-containing sites. The railroad alignment would not be moved at this point no matter how culturally important a site is to a Tribe.

Comments from Tribal Nations will more completely address these issues, but we believe that the DEIS, while compiling a nice overview of paleo-historic and historic Native American and Euro-American historic information, lacks substance when addressing cultural issues.

Biological Resources

Southeastern Montana is relatively undeveloped and still has large expanses of the last remaining short-grass prairie and sagebrush-steppe ecosystems and habitats that once dominated the Upper Great Plains. The Tongue River is one of the last remaining warm-water prairie-river ecosystem streams that once were widespread in Great Plains.

Construction activity, railroad operation, mine operation, increased human presence, increased traffic, increased noise, disruption of water resources, fencing, and many other factors that the proposed TRR project would bring to this quiet, low population, rural agricultural and still largely intact natural area would potentially be devastating. Wildlife does not just move to adjacent areas or even distant areas when development occurs. The DEIS catalogues and enumerates what would soon be diminished or absent from this area if the proposed TRR project is approved. Interestingly, the DEIS does not include wildlife surveys after the fires of 2012 (the DEIS does not acknowledge this major natural event in its analysis); wildlife are forced to move after catastrophic natural events, and new patterns are established. While wildlife will move through areas that were decimated by the 2012 fires, habitat and home range shifts have occurred because of that significant event. Any understanding of these changes requires multiple years (a minimum of at least three) to truly understand. The DEIS is inadequate and deficient by not surveying wildlife after this major, area-wide ecological event and acknowledging, at a minimum, what has happened for wildlife in the area. We cannot assume that the analysis presented in the DEIS is totally accurate because of this glaring omission.

Southeast Montana, particularly the Tongue River region, is an important and popular big game and bird hunting area. Hunting is an important management tool used by wildlife agencies

to help ensure healthy wildlife populations. Hunting is also critically important for the regional economy. It is well-known that industrialization of an area leads to wildlife population declines, some of which undoubtedly relate to an increase in roading as well as poaching. Compromised, fragmented, and/or lost native habitats are well documented as major limiting factors for wildlife species. Antelope, in particular, are known to be innately committed to their summer and winter ranges and the long-established migration corridor between the two. Disruption of any part of this territory will likely have serious, negative, and possibly irreparable consequences. Antelope do not jump fences, but must crawl under or through fencing. It is documented that both antelope and deer (including large numbers of each) have been killed by trains after becoming trapped or disoriented on tracks.

A specific concern for wildlife (as well as cattle) is noise, which carries a far distance in this region. The noise that the construction and operation of the TRR as well as the Otter Creek coal strip mine would generate would significantly impact a host of wildlife species that now enjoy a quiet, rural, non-industrialized, agricultural and natural area.

The sagebrush steppe is one of the most severely threatened bird habitats in the Intermountain West. Many prairie bird species and other neo-tropical migratory species are struggling due to declines in this once wide-spread habitat. Songbird species richness and breeding bird densities are often highest in riparian and wetland habitats of this ecosystem. As with antelope (as described above), construction activity, railroad and mine operation, increased human presence, increased traffic, noise, disruption of water resources, and many other factors that would result from this proposed project would negatively affect these species.

Small creeks and intermittent streams and ephemeral channels are extremely important in this area, one of the last remnants of a once widespread Great Plains riverine-prairie ecosystem. A significant body of research in the Great Plains indicates that not only do intermittent streams support fish (they can be an important nursery area for juvenile fish), but they also play an important role in the biodiversity of the region.

The Miles City Hatchery, which could be crossed by certain of the route alternatives is an important state hatchery/rearing facility for warm-water fishes, especially the pallid sturgeon. A few years ago, the TRR Company (before the permit for TRR III was remanded by the 9th Circuit Court back to the STB), attempted to acquire an easement to cross the hatchery grounds. The Montana Fish, Wildlife and Parks Commission was disinclined to grant such an easement due to many issues, particularly noise and vibration concerns. Despite an attempt by the TRR Company to “prove” that those concerns were not valid, the Commission refused to sign any easement agreement.

Construction of any kind, but especially large-scale transportation route construction, is notorious for spreading weeds. The Tongue River Valley is currently relatively free of noxious, exotic weeds. As noted by Jennifer Esp, Powder River County’s Weed Supervisor, in her scoping comments on this proposed project, “railroad rights-of-way are high-risk sites for introduction, establishment, and spread of noxious weeds. Weeds can be carried on vehicles, in the loads they carry, and on the construction and maintenance equipment. They can be inadvertently introduced into rights-of-way during restoration projects by use of contaminated

mulch, soil or gravel, plants seed and sod. Noxious weeds established on railroad sidings can spread into adjacent non-infested areas and can also be transported to surrounding counties.” Ms. Esp went on to say that she had personally witnessed the spread of weeds from both the Montana Rail link and the Central Montana Rail Line in this manner.

Weed control poses significant additional expenses and time for landowners along the proposed route (if approved), and, potentially could interfere with crop quality if the infestations of noxious and other weeds are intensive or extensive enough. Weeds not only affect ranch operations, but also have negative, deleterious effects on wildlife, from insects to birds to small mammals to ungulates. In the past few decades, the “battle” against weeds has assumed an unfortunate top priority with all types of land managers.

All of this is to say that the proposed TRR would have an immense and significant effect on the area of Southeastern Montana, despite the project being viewed by the OEA as only really affecting a “narrow” strip of land, albeit miles long. We believe that the DEIS is deficient in its analysis of biological resources, particularly by not considering the wildfires of 2012 and by not considering fully the cumulative effects of all the industrialization of this area that would result if the proposed TRR were approved.

Worker Housing and Road Issues

In Section 2.2.7 (Worker Housing) the DEIS states that the “TRR Company does not anticipate needing construction camps to provide temporary housing for construction workers. TRR Company anticipates that construction workers from outside the area would locate appropriate temporary housing in communities near the proposed rail line.” While the DEIS has a table in Section 15.4.2 that lists all the rental properties (among other housing) in the surrounding area, the DEIS does not adequately analyze all the additional traffic (and potential accidents and injuries) that would potentially result because workers are traveling long distances after long work days. The DEIS is inadequate regarding to this issue.

Section 2.2.11 (Road Relocations) the DEIS states that TRR Company has identified from 10 to 49 roads that would be relocated to accommodate the TRR with the length of any given relocation ranging from 0.05 mile to 2.7 miles, depending on build alternative. The DEIS, however, fails to identify any of these roads or explain if they are all public roads. Road relocation would have impacts on traffic flows (and, relatedly, dust, noise, and safety), people’s access to their homes or other structures, as well as farm and ranch operations by severing fields and pastures and impeding people’s use of their land. Additionally, the construction of new roads could entail the additional use of eminent domain. These impacts need to be considered and analyzed in the DEIS. Additionally, the failure to disclose the locations of any road relocations is a deficiency of the DEIS. Landowners and other interested parties are unable to accurately comment on the impacts from the movement, demolition, and construction of any proposed road relocations.

Paving of the Tongue River Road (S-332) and any environmental consequences of this action is not addressed and analyzed in the DEIS. There have been discussions for years about paving the Tongue River Road, and development of the Otter Creek coal tracts is usually

mentioned as a pre-condition. Specifically, the 2013 Montana Legislature discussed House Bill 606 to appropriate funds for highway paving, and the principal justification cited in committee was development of the Otter Creek coal tracts. Additionally, public meetings were held in October 2012 to gather input on paving the road. Various options were presented at that time, including expanding the road width to 40 feet, presuming traffic levels were high enough. Such an expansion would have significant impacts in the immediate area of the road itself, as the route would need to change somewhat to accommodate increased traffic flow and land would have to be acquired and industrialized to accommodate expansion.

Paving the Tongue River Road would increase traffic, and, as a result, increase noise and safety issues as well as increase diesel emissions within the transportation corridor. If this road were paved, general traffic flows in southeastern Montana would change and increase in areas now receiving little traffic. Residents of Broadus, Montana, expressed opposition to the proposed bill introduced into the legislature (HB 606) out of concern that paving the Tongue River Road would divert traffic from the Broadus Highway (MT-59), with a resultant detrimental economic impact to the town of Broadus and to Powder River County. The DEIS is deficient because it fails to address the issue and the environmental and social consequences of paving the Tongue River Road.

Connected and Cumulative Effects

The CEQ regulations implementing NEPA require that a federal agency consider both the *connected* [emphasis added] actions and the cumulative impacts that might result if the proposed project was approved.

Connected actions are defined in 40 C.F.R. §1508.25(a)(1)(ii-iii) to include actions that *cannot or will not proceed unless other actions are taken previously or simultaneously* [emphasis added] or are interdependent parts of a larger action and depend on the larger action for their justification. The proposed Otter Creek Mine is a significant connected action – actually it is the primary and only reason for the proposed TRR. While we do not believe there are any additional “potentially induced” coal mines in the region that would ever be built, for the purposes of this discussion they are also a connected action. Again, without the TRR, these coal mine projects would never be built. And, without these coal mine projects there is NO reason for the TRR to be built. We believe that OEA has failed to consider these relevant facts in its analysis of the TRR as presented in the DEIS.

Cumulative impacts are defined in 40 C.F.R. §1508.7 as the impact on the environment which results from the *incremental impact* of the action *when added to* other past, present, and reasonably foreseeable future actions [emphasis added].

We find the entire Chapter 18 (titled “Cumulative Impacts”) and Appendix U (titled “Cumulative Impacts Analysis”) to be confusing and designed to gloss over and minimize regional on-going or reasonably foreseeable projects. Because the DEIS discusses a specific issue (*e.g.*, grade-crossing safety or air quality or vegetation) for all the various projects and potential projects together rather than discussing each project individually (describing its impacts on various resources, etc.), the reader can be confused or misled. This approach also lessens the

reader's complete understanding of the cumulative environmental and social impacts that the proposed TRR would have on the region in conjunction with a specific project.

We strongly disagree with the approach used by OEA to examine cumulative impacts. We believe that OEA is required to look at the TRR's cumulative impacts to the environment when it is added to other past, present, or reasonably foreseeable future actions as directed by 40 C.F.R. §1508.7.

The Proposed Otter Creek Coal Mine

The proposed Otter Creek coal mine not only has cumulative impacts that are significant to the proposed TRR project, but it is truly a connected action. **Without the Otter Creek Mine, there is no reason to build the TRR.** Consequently, fully addressing the proposed Otter Creek Mine and its significant environmental and social consequences is a requirement under NEPA when considering the proposed TRR. We do not believe that the DEIS examines this primary "reasonably foreseeable" project in a thorough or complete manner, thus, OEA has failed to consider all the relevant factors of this project in its analysis of the TRR. In the TRR DEIS, OEA has based its discussion of the proposed Otter Creek Coal Mine on the *permit application*; however, Montana DEQ's evaluation of that application is what matters, and that process is not yet finished. In fact, Arch Coal's responses to the second deficiency letter about its application have yet to be received. Consequently, OEA failed to take a hard look at the potential cumulative effects of this connected project.

In July 2012, Arch Coal, through its subsidiary Otter Creek Coal, submitted a permit application to the Montana DEQ to develop the first phase of the mine in Tract 2 of the Otter Creek lease. Following a series of internal reviews, the DEQ declared the permit application "administratively complete" in December 2012 and began the "technical completeness" phase of the permit process, which is ongoing. Northern Plains is fully participating in the public processes for this permit application as well as the air quality and water quality discharge permit processes and the state's EIS process under MEPA.

There are many significant issues that must be resolved before a permit is issued by the State of Montana for the proposed Otter Creek Mine, if such a permit is ever granted. For example, it has yet to be determined if and to what extent AVFs are located within the proposed mine area. In 1985, the U.S. Geological Survey published a report on Otter Creek's alluvial aquifer and the effects surface coal mining would have on dissolved solids in Otter Creek.⁶⁸ Also in 1985, the Commissioner of Montana's DSL issued a declaratory ruling that concluded certain properties within the Otter Creek drainage were, in fact, part of an alluvial valley floor. This is important because if, during the current coal mine permit application process, portions of the proposed Otter Creek mine and/or life-of-mine area are determined to be an AVF, the Montana DEQ's review of the mine permit application must evaluate the feasibility of full and complete reclamation of the productivity and function of the AVF(s). If complete reclamation cannot be

⁶⁸ "Effects of Potential Surface Coal Mining on Dissolved Solids in Otter Creek and in the Otter Creek Alluvial Aquifer, Southeastern Montana," by M.R. Cannon, USGS Water-Resources Investigations Report 85-4206, October 1985. <http://pubs.usgs.gov/wri/1985/4206/report.pdf>

demonstrated, Montana DEQ must evaluate the impact of partial or selective denial of the permit on the rest of the initial proposed mine area and on the life-of-mine operation.

It should be noted here that under SMCRA, contemporaneous reclamation is supposed to occur at coal strip mines. However, there is a woeful lack of reclamation effort and success throughout the West, and this is a significant issue in Montana. Coal strip mines have been operating in Montana for more than 40 years. But as of 2014, of the 39,953 acres that have been disturbed by coal strip mining operations, only 19,497 acres have achieved Phase I reclamation and bond release, which means that a permittee has completed the backfilling, re-grading, topsoil replacement, re-contouring, and drainage control required for a bonded area. Of particular concern, during this time only 67 acres have achieved Phase IV bond release where all surface coal mining and reclamation activities and all disturbed lands within any drainage basin have been reclaimed, including successful hydrologic restoration that supports post-mining land use.⁶⁹

It has also yet to be determined what the potential hydrologic consequences (PHC) of permitting the proposed Otter Creek Mine might mean for the area (OEA has based its discussion of this issue on the OCC application [see U-138]; however, Montana DEQ's evaluation of that application is what matters, and that is not yet complete). Coal seams are filled with water and function as vital aquifers in this region. Coal strip mines sever and destroy these aquifers. The impacts of this severance can be seen many miles from the mine. Not only do down-gradient wells and springs dry up when the aquifer is severed, but springs and seeps above the mine that are hydrologically tied to the coal-seam aquifers will be drained and will dry up. Many of these springs are important sources of water for livestock as well as wildlife and require no electricity for pumping and, thus, are a valued resource. These springs also provide runoff for intermittent and ephemeral streams and pools that support riparian vegetation, which is important if not critical habitat for numerous wildlife species, including amphibians, migratory birds, and a diversity of aquatic life especially adapted to these environments.

Water is a precious resource in this semi-arid region of the state. Ranchers and other residents who live in this area rely on surface waters for irrigation and agricultural production. Shallow aquifers provide water for domestic and livestock use as well as sub-irrigate the agricultural land. There are 231 domestic and stock wells and 114 springs in the area surrounding the Otter Creek coal mine tracts on both private, state, and U.S. Forest Service land.⁷⁰ Reduction in water availability could have a negative economic impact on agricultural production in the region as well as the area's ecological health.

Montana DEQ must also evaluate the likelihood that the permit applicant (Arch Coal through its subsidiary OCC) can meet the requirements of Montana's Surface Use and Mining Reclamation Act (SUMRA) to restore the hydrologic balance of the area as well as determine how it will replace any water resources damaged by strip mining that are not restored. Until that is done, no permit for the proposed Otter Creek Mine can be issued (OEA has based its discussion of this issue on the OCC application [see U-138]; however, Montana DEQ's evaluation of that application is what matters, and that is not yet complete).

⁶⁹ "Undermined Promise II," Western Organization of Resource Councils, National Resources Defense Council, and National Wildlife Federation. 2015. (<http://underminedpromise.org/UnderminedPromiseII.pdf>)

⁷⁰ Montana Bureau of Mines and Geology

Numeric water quality standards for the Tongue River (Otter Creek is a tributary of the Tongue) as well as standards for its tributaries mean that Arch Coal is obligated to ensure that the operation of the proposed Otter Creek Mine does not harm the water quality of the Tongue River and its tributaries (OEA has based its discussion of this issue on the OCC application [see U-138]; however, Montana DEQ's evaluation of that application is what matters, and that is not yet complete). Water quality standards for sodium adsorption ratio (SAR) and electrical conductivity (EC) were implemented by the State of Montana after a long, detailed, and scientifically based process before the Montana Board of Environmental Review (BER) in 2003. In 2006, the BER implemented a non-degradation clause to those water quality standards.

The water quality standards for the Tongue River in winter (November 1 to March 1) are 1500 EC and 5 SAR; for the summer (March 2 to October 31), the standards are 1000 EC and 3 SAR. Water quality standards for tributaries to the Tongue River (including Otter Creek) were set at 500 EC with SAR of 3 (summer) and 5 (winter).⁷¹ Water in the Knobloch coal seam that comprises the Otter Creek coal has EC levels of 3100 and SAR levels of 12 to 56. When coal seams are mined, the aquifer water contained within that coal is released. The water quality discharge permit (MPDES or Montana Pollution Discharge Elimination System permit) that is necessary for the proposed mine is a long way from being resolved (OEA has based its discussion of this issue on the OCC application [see U-138]; however, Montana DEQ's evaluation of that application is what matters, and that is not yet complete).

While Arch Coal succeeded during the 2015 Montana legislature in passing legislation designed to change the water quality standards for Otter Creek (in order to more easily receive a MPDES permit), that process is a long way from finalization. A rule-change petition must be submitted to the BER for consideration, and a public comment process must be held before the BER makes any changes to the current water quality standards for Otter Creek. At their hearing in July 2015, the BER determined that more information was required before they considered a rulemaking change. Northern Plains and other southeastern Montana irrigator associations and groups are fully engaged in that process as we believe those new standards will not be protective of current beneficial uses and users.

The water quality of the region is critical to the agricultural health and survival of ranches. Soils surrounding coal seams and the underground aquifers in coal seams are highly laden with sodium salts. Improper discharge of these sediments and highly saline waters will impact surface water quality. Despite Arch Coal's plans to "contain" these highly saline coal-seam waters, long-time residents have raised concerns because they have witnessed past localized storm events in the Otter Creek drainage. These intense storms have resulted in Otter Creek's flow rising from 2 cubic feet per second to as much as 1,000 cfs in a few hours time. These floodwaters spread out across the valley floor. Natural occurrences such as these will have significant and troublesome impacts on the mining plans as well as raise serious concerns for water quality standards downstream should Arch Coal's containment ponds be breached.

Additionally, before a permit for the proposed Otter Creek Mine can be issued, it must be determined how the proposed mine might impact the status of the TMDL [total maximum daily load] process for the Tongue River, as Otter Creek is a tributary of the Tongue. Unfortunately,

⁷¹ Administrative Rules of Montana (ARM) 17.30.670

TMDLs have yet to be established for the Tongue River, and we believe that that process must be completed before a mine permit can be issued (OEA has based its discussion of this issue on the OCC application [see U-138]; however, Montana DEQ's evaluation of that application is what matters, and that is not yet complete).

There are many other issues of importance that also must be addressed before a permit is issued for the proposed Otter Creek Mine, including completion of the MEPA process. There is a long list of important issues that will need to be addressed during that process, and OEA has failed to consider all of these connected and cumulative impacts in the TRR DEIS. For example, construction activities and operation of any coal strip mine are known to impact wildlife species. Wildlife does not just move to adjacent areas or even distant areas when development occurs, so the consequences of a mine in this area need to be fully discussed. Construction of any kind is notorious for spreading weeds. The Otter Creek Valley is currently relatively free of noxious, exotic weeds. How control of noxious weeds and revegetation of reclaimed areas would be handled are not yet finalized and approved. In this dry and windy environment, construction activities that denude the soil will lead to blowing dust, dirt, and debris degrading air quality. Additionally, as a result of both blasting and mine operations, coal dust would be in the air. Coal dust not only affects the health of the mine workers but has a negative effect on the surrounding environment. These issues are yet to be resolved. Noise carries a far distance in this low-humidity, rural region. Blasting and heavy equipment operations at the proposed mine site would affect nearby communities and area ranches, including their livestock, which are negatively affected (as are wildlife) by this noise. These cumulative issues have not been fully addressed.

We do not yet understand how the Otter Creek Mine would get electrical power that it would need for its operations. We know that this electrical usage would be substantial. We do not yet know how that usage would affect the existing and anticipated electrical needs of the region. The local rural electric co-operative that supplies electricity to this region, the Tongue River Electric Co-op, has approximately 3,000 members, and there are no large industrial users in its service area. The co-op has faced numerous financial challenges in recent years including the need to replace a majority of their power poles, which were knocked down during a bad storm, and being part of the Southern Montana Electric Generation and Transmission cooperative that went bankrupt. The mine's electrical needs must not impact the current users of Tongue River Electric Co-op power or those users rates, and these cumulative issues must be addressed.

While we do not disagree with the idea that the Otter Creek coal strip mine would provide temporary construction jobs and some new mining jobs, the impacts to the communities and the region from the influx of those new workers would be significant. Eastern Montana and North Dakota communities are reeling under the oil-and-gas boom economy. The lives of local residents have been up-ended by this dramatic change to their communities, and local governments are unable to provide all the services that are needed because of this boom. The crime rate in these communities has skyrocketed, including increases in drug dealing and prostitution and with indications that organized crime is possibly involved. Tax revenues from mining operations in coal mining areas typically lag behind demand for government services, and, therefore, tax revenues are insufficient for the counties and communities to cover the increased costs of law enforcement, emergency services, schools, infrastructure maintenance,

social services, and other government services (to name just a few). Communities often are faced with aging infrastructure, including water treatment and sewage treatment facilities, which could be overwhelmed by the increased use presented by these workers. These cumulative issues have yet to be addressed.

There is a strong possibility that the existing coal strip mines at Colstrip and elsewhere in the region could be displaced if the Otter Creek coal strip mine is approved and becomes operational. In fact, in a letter dated February 6, 2013, Mr. David H. Coburn, attorney for the TRR Company, responded to a query from the STB asking for specific information about the potential market locations for the coal that would be transported from the mines identified by TRR Company in its December 17, 2012, application. Mr. Coburn stated, “. . . This means that the coal can be mined efficiently and at a lower cost than at the other Montana mines with which Otter Creek coal would compete, which will make that coal more competitive.” While we do not necessarily agree with this statement, the economic consequences of developing the Otter Creek mine on other Montana mining communities should be addressed as a cumulative impact of the TRR DEIS.

There would be increased traffic on Montana Highway 484 as well as U.S. Highway 212 because of the construction and operation of the mine. Commercial truck traffic is already high on U.S. Highway 212, and the increase in traffic associated with the mine would significantly affect local traffic. There would also be increased traffic on Montana Highway 332 (the Tongue River Road) and Montana Highway 59 as well as all the rural roads in the area depending on the route alternative chosen. Increased traffic will result in increased wildlife death. Increased traffic will likely result in an increase in human injury and death from vehicle crashes. These cumulative issues have yet to be fully addressed.

The socio-economic effects on ranching and farming operations in the Otter Creek area could be significant if the mine is permitted. If area ranchers lose local hay meadows or access to local hay, they must pay the costs of winter feed for cattle, which may not be nearby, thus increasing shipping charges that will impact the economics of their ranch operation. It is also possible that a rancher would be forced to change from a cow/calf operation, which also would impact the economics of the ranch operation. These impacts extend beyond the proposed Otter Creek mine area. Southeastern Montana farms and ranches are often mutually dependent, and the abundant hay production from the AVFs in the Otter Creek Valley provide a cheap, local, and reliable feed source for other regional ranchers. If that supply is impacted, ranchers may have to ship in hay from a greater distance at greater cost, which could very well impact the profitability of their operations. The increase in human presence could also lead to trespass issues, increased crime, increased wildlife poaching incidents, increased vandalism, among other things. All of these consequences need to be addressed as cumulative impacts.

The Otter Creek coal strip mine (and its requisite TRR) would affect the nearby Northern Cheyenne Reservation. While the Tribal government is not eligible for any of the local, county, or state tax revenues that OCC would pay, it would still face (and have to deal with) many of the same impacts that other area communities would face. Otter Creek was the site of historic Northern Cheyenne tribal member homesteads. Those members were forced to surrender those homesteads when the reservation boundary was modified and shifted to the west bank of the

Tongue River. The Northern Cheyenne people continued using the Otter Creek area even after their removal, and their ties to this particular area are great. These cumulative impacts must be addressed.

The proposed Otter Creek coal strip mine would industrialize a quiet, low population, rural agricultural area that currently enjoys clear air, clean water, native grasslands, valuable fish and wildlife habitat, quiet communities, and abundant recreational opportunities. The area would be permanently and negatively affected by the proposed mine. If the mine is permitted, there would be increased traffic, increased noise, increased human presence, increased dust and other degradations to air quality, significant negative impacts to surface and underground water resources, disruption of wildlife resources, an increase in weeds, negative impacts to cultural resources and landscapes, as well as a long-lasting legacy of scarred landscape, among other things.

We believe that OEA has failed to consider these relevant factors in its analysis of the connected and cumulative impacts that the proposed Otter Creek Mine would add to the environmental and social impacts that would result from the proposed TRR. Thus, again, the DEIS for the TRR is inadequate.

Downrail Impacts

Through use of its model, OEA concludes that the proposed TRR project would haul coal that would “primarily” supply domestic markets (e.g., see Chapter 17.3, “OEA used coal market modeling to determine that the majority of project-related coal traffic would travel to destinations in the Upper Midwest” and Appendix C, page 1-14: “an average of 96% of Tongue River coal would be shipped domestically”). This conclusion is not adequately explained anywhere in the DEIS, and the assumptions and data used in the model are not revealed. As we described above, this conclusion is highly unlikely as domestic markets for coal are declining significantly and, indeed, the coal-fired generation plants that can use the high-sodium coal that the proposed TRR would transport are extremely limited and also declining.

Additionally, this domestic market conclusion conflicts with other statements and conclusions in the DEIS (particularly in Appendix C). Those statements indicate that the international coal export market is growing (which we have shown above to be a mis-informed assumption in the OEA analysis). For example, in Appendix C (page 2-1) the OEA states “Anticipated growth in international coal demand and rising coal prices will increase demand for Powder River Basin coal.” Also, in Appendix C (page 1-14) OEA states that “all scenarios [from the model used] show that the export terminals would be fully used to export other Powder River Basin coal” and “it is reasonably foreseeable that coal export terminals in the Pacific Northwest will be expanded.” Under some of the scenarios examined by the model (although none of the assumptions and data input into the model are disclosed or explained), up to 53% of the Tongue River coal could be exported (Appendix C, page 1-14). While the DEIS acknowledges (in Chapter 2 and Appendix C) that there are many uncertainties ahead, OEA states that “. . . Arch Coal is the developer or co-developer of the TRR, the Otter Creek Mine, and one of the export terminals (Millennium Bulk Terminal). Hence, Arch Coal might choose to export rather than sell domestically. . . .” This statement explains the TRR Company’s preferred alternative (the

Colstrip alternative), however, because the DEIS concludes that the market for the coal that the TRR would haul are domestic, the Colstrip route alternative would be counterintuitive and counterproductive for efficient transportation and lowest possible costs for coal going east to domestic markets. Once again the DEIS, instead of clarifying issues has obfuscated things for the public and decision makers.

While we do not agree that the international market for coal would grow or that the proposed export terminals would be built, we want to know why OEA has not thoroughly examined the downrail impacts of coal going west for export if, by their own admission, this is a reasonably foreseeable option. Not only that, but if the export market is growing and that would require more terminal capacity on the West Coast, why would OEA predict that (in Appendix C, page 1-23) “changes in nonlocal rail traffic to the west would occur at the same levels whether or not the Tongue River Railroad is built.” It seems to us that if there truly is a demand for more export coal (while we disagree with this statement, OEA seems to believe it), proposed Otter Creek coal would more likely be shipped west along the proposed TRR and into that market particularly because (according to the DEIS in Attachment A of Appendix C) higher sodium coal is less of an issue for export markets than domestic ones (although, again, we do not agree with this conclusion).

Arch Coal has stated that there would be 7.4 trains each day using the proposed TRR to haul coal from the proposed Otter Creek Mine. Conveniently, this is just below the STB’s threshold of 8 trains per day, which would require analysis of the environmental impacts that would occur due to increased train traffic. OEA did examine some rail segments where their 3 trains per day threshold for air quality nonattainment areas was met. Earlier, OEA used the argument that the “potentially induced” Poker Jim Creek–O’Dell Creek mine and Canyon Creek mine would mean that the proposed TRR was not being built to simply haul coal from one mine (the proposed Otter Creek mine).

However, in Chapter 17, OEA downplays the development of these mines by not fully discussing the projected 18.6 trains per day (northern routes) or 26.7 trains per day (southern routes) that could result if they were built. OEA had stated in the DEIS that if those mines were developed, this would mean that more coal would be exported. Such a scenario (or even simply the scenario where Arch Coal decides to send the Otter Creek coal, if a mine is permitted, west to the Longview port it partially owns in order to export that coal) means that thousands of Montana citizens and many others along the rail lines to the West Coast would be affected. OEA has failed to consider the relevant data and information when it analyzed the potential increase in the number of trains and the downrail impacts. This is a particularly egregious deficiency given the vast public input and concern that OEA received from western downrail communities including Livingston, Missoula, and Whitefish, Montana; Sandpoint and Bonner County, Idaho; Seattle, Washington; Mosier, Oregon; and many other communities in between.

OEA again uses its “substitution” argument by stating in Chapter 17: “Rail traffic carrying Tongue River coal would add only incrementally to rail traffic carrying coal from other regions because it would displace some of the existing rail traffic.” Again, there is no explanation of why this myth of perfect substitution should be believed. What data was used and what assumptions went into the model to come up with the idea that the amount of coal produced

in the PRB would simply stay the same if the proposed Otter Creek Mine is permitted and the proposed TRR is built?

The impacts to Montanans and Montana communities from increased rail traffic are real and significant – and these impacts will go far beyond "inconveniences."⁷² There would be health, safety, quality of life, as well as actual financial costs to Montana citizens and communities from an increase in coal train traffic. Billings, Montana, would be most affected by this increase in the number of coal trains as it is a bottleneck for rail traffic. All outgoing coal trains from the PRB headed for Pacific Northwest ports pass through Billings, and this includes the trains operating on the proposed TRR. Many other Montana (and Pacific Northwest) communities would also be affected by any increase in train traffic.

The increased number of trains would mean more noise, a greater potential that emergency responders would be delayed in reaching residents when there is a medical emergency (or a fire or the need for police), and a greater potential for vehicle collisions with trains and for pedestrian accidents. More trains would mean an increase in the amount of airborne pollutants (particulate matter) from diesel engines as well as from coal dust (see discussion of these issues earlier in our comments). The DEIS does not fully examine any of these issues for trains headed west (as it assumes nearly all the trains would move east).

The financial costs of increased train traffic to downrail communities is also not discussed. It is true that if a rail company needs to upgrade their track or a bridge or a crossing in order to facilitate current or increased train traffic, they will do so and they will pay for it. However, if a city or county wants to have a particular crossing in their community upgraded to deal with local impacts and the rail company doesn't need to do this in order to facilitate increased train traffic, under existing law the railroads do not have to respond to these local government concerns. The only choice citizens have at that point is to pay for any upgrade with public money – taxes from somewhere be it federal, state, county, or municipality taxes.

We believe that OEA has failed to consider these relevant factors in its analysis of the cumulative impacts that the transportation of coal through downrail communities would add to the environmental and social impacts that would result from the proposed TRR. Thus, again, the DEIS for the TRR is inadequate.

Coalbed Methane [coalbed natural gas] Development

While coal bed methane (CBM) [called coalbed natural gas (CBNG) in the DEIS] development in Montana has been at a temporary standstill due to the cheaper production costs and quicker production time that are the advantage for deep oil and gas development, ongoing CBM production in Wyoming continues to impact southeastern Montana, particularly with regard to water quality issues.

OEA states in Chapter 18 (page 18-8) that “BLM estimated that a maximum of 7,600 wells, including CBNG [CBM] wells, would be drilled in the planning area between 2011 and

⁷² see the 2014 report by the Western Organization of Resource Councils, “Heavy Traffic Still Ahead”; <http://www.heavytrafficahead.org>

2030, of which 1,200 would be CBNG wells” In Section U.3.3.4 of Appendix U, OEA determined that none of the currently approved wells would be in the project area or near the build alternatives. However, we disagree that CBM [CBNG] wells pose no cumulative impact. We believe that it is quite conceivable that within the foreseeable future CBM [CBNG] development could resume in Montana in the area in question.

The same ranchers and residents who would face the impacts and environmental consequences that would result from the TRR (and its integrally connected and requisite Otter Creek coal strip mine) could also face the prospect of the construction of miles of access roads and pipelines, hundreds of well pads, compressor stations, and the construction of impoundments to dispose of methane wastewater.

When and if CBM [CBNG] development and production occur in the immediate area proposed for development of the TRR (and its integrally connected and requisite Otter Creek coal strip mine), numerous cumulative impacts would occur to farming and ranching operations including but not limited to:

- cumulative noise impacts on the silence and solitude of the area;
- cumulative impacts on everyday ranching operations;
- the loss of productive acres from surface disturbance;
- impacts on irrigation diversion and transportation structures from increased suspended sediment caused by increased erosion and sediment loading;
- impacts to water quality;
- loss of property value;
- air quality impacts including visibility impairment and degradation;
- increased dust affecting air quality, vegetation, and livestock;
- increased traffic on county, state, and private access roads and the resulting increased accident rates;
- increased risk of fires; and
- increased infestation and spread of noxious weeds.

These direct cumulative impacts on ranches and other agricultural areas would have indirect cumulative impacts on the region’s economy – an economy heavily dependent on agriculture sector jobs. The OEA has must consider the added and potentially devastating cumulative impacts on the farming and ranching community from continued and potentially increased CBM [CBNG] development projects. The TRR DEIS is inadequate in its analysis of this issue.

Salinity and Sedimentation

Construction and maintenance of the TRR would directly and indirectly lead to an increase in salinity and sediment load in the Tongue River. The cumulative effects to the region’s waterways and Montana agriculture from the proposed TRR and its connected and “reasonably foreseeable” projects, would result in great harm. The DEIS is deficient because it fails to take a hard look at the cumulative impacts that these pollutants would have on the water quality of the Tongue River system.

In the December 2011 ruling in *Northern Plains Resource Council v. STB*, the 9th Circuit Court of Appeals states, “Petitioners’ last cumulative effect argument is that the FSEIS does not analyze the combined effects of the railroad, CBM, and coal mines as to water quality . . . Construction of the railroad is estimated to increase sediment loading in the Tongue River. Thus, were, simultaneous construction to occur, the Board must address this water quality issue.”⁷³

Existing and potential CBM [CBNG] development in the region, existing Decker Coal Mine discharge, and the possible development of the Otter Creek coal tracts and any other “potentially induced” coal mines as posited in the DEIS have and would continue to increase the loads of both salinity and sediments in the Tongue River. Despite water quality standards that were set by the State of Montana in 2003, the Tongue River is already impaired for both of these parameters. At times, the State of Montana’s standard of 1000 for EC and 3 for SAR is exceeded at Miles City, Montana.

These pollutants have a significant impact on agricultural productivity. For instance, while alfalfa is the dominant crop grown along the Tongue River and its threshold for harm is 2000, there are several hundred acres of beans grown in the area, most of which are irrigated with water from the Tongue River. Beans have an EC threshold of 1000. Once a pollutant threshold is reached, crop yields begin to decrease at a dramatic rate. This decline can be precipitous. For instance, the Montana DEQ found that even an increase in EC levels of 100 above its safe threshold can have a 4.8 to 9.3% deleterious impact on alfalfa production.⁷⁴

Produced water from the Otter Creek mine would have an EC averaging 3100 according to the Montana DEQ, several times higher than the safety threshold for crops like beans, but also higher than the threshold for more resilient crops like alfalfa. These effects can be additive over years, as salts accumulate in soil. During the last decade’s CBM boom, some Tongue River irrigators saw their crop yields decrease by as much as 60% over eight years. The DEIS should examine the potential loss to agriculture when soils are permanently damaged by degradation in irrigation water.

CONCLUSION

The purpose of an EIS is to disclose all the information and analyze and evaluate that information so that the environmental consequences of a project are fully disclosed to the public and for consideration by decision makers. Those consequences (costs) are to be weighed against the benefits of the proposed project in the final analysis. For all the reasons enumerated above, the TRR DEIS prepared by the OEA for the STB is deficient, inadequate, and fails to take a hard look at this proposed project as required by NEPA.

⁷³ *Northern Plains Res. Council v. Surface Trans. Bd.*, 668 F. 3d 1067, (9th Cir. 2011)

⁷⁴ “A Review of the Rational for EC and SAR Standards,” Montana Department of Environmental Quality, August 2011

We have shown that the assumptions used in preparing this DEIS are not transparent and are likely inaccurate. Without a way to independently verify the projections of the model that was used by OEA (the IPM), the public and decision makers have no way to ensure that the proposed TRR would not have unacceptable impacts on the environment. We have shown that the data input in the IPM model and used to reach the OEA's conclusions on coal markets do not reflect information available within the past two years. Further, we have shown that the IPM model used was inappropriate for the project being analyzed because it did not incorporate the basic economic principle of the price elasticity of demand. We have shown that there is no such thing as "perfect substitution" for this proposed project, which is what OEA has based its conclusions upon.

Beyond the clear evidence we have presented on the lack of domestic and international coal markets showing that there is no purpose and need for the proposed TRR, the STB is required by NEPA to consider whether or not the benefits of the proposed TRR outweigh its costs. We have shown that the DEIS has failed to fully and accurately consider the environmental and social consequences (the costs) of many issues⁷⁵, most significantly the consequences to agricultural landowners in the path of the proposed TRR and its totally connected and necessary-for-its-success proposed coal mine at Otter Creek (which is, as yet, not permitted).

We have also shown that for Otter Creek coal to succeed in the marketplace, it must compete with other Montana (and Wyoming) coal mines. Many of these mines are already struggling to reach production targets and maintain their "market share" of the declining market. Otter Creek coal, if the mine is approved and begins operation, would only create competition within an already tight marketplace and would decrease the price of coal and further depress the market.⁷⁶ Additionally, if Otter Creek coal did succeed in replacing coal from other Montana (and Wyoming) coal mines, the negative economic and social impacts to the livelihoods of the miners who would be laid off at those existing mines is not even discussed in the DEIS.

In considering what benefit this project would have for the nation, we cannot understand why the STB would even consider disrupting and, in many cases, destroying undeveloped and often pristine country as well as negatively affecting the economic livelihoods of so many in order to permit a railroad to a yet-to-be-permitted coal mine when, by admission in the DEIS, this proposed coal mine would simply displace existing coal mines that have existing transportation infrastructure. For all the reasons detailed above, this makes no economic,

⁷⁵ We would once again affirm that there is no market, the railroad would therefore not operate, and the STB should therefore deny the TRRC's permit application. However, for the STB to deny this reality and erroneously consider permitting the railroad, NEPA requires the agency to fully consider the impacts of the TRR, which it fails to do. Relatedly, we would affirm that the 2015 Power Consulting report referenced various places in our comments does not seek to establish that there is a market for Tongue River coal, but rather, that if the STB chooses to operate as if there is one, that its model is woefully deficient and its failure to incorporate demand elasticity leads to faulty conclusions and underpresents coal train and greenhouse gas impacts.

⁷⁶ "Changes in the Market for Montana Powder River Basin Coal between 1986 and 2012," Power Consulting, November 2012. . <https://www.northernplains.org/wp-content/uploads/2013/06/PowersReportChangeMarketMTPRBCoalFNL2012-12.pdf>

⁷⁶ *Ibid.*

environmental, or societal sense. The costs of the proposed TRR far outweigh the benefits to the nation. Frankly, this project only benefits a private corporation that may or may not have the financial wherewithal to follow through with the interconnected and totally interdependent corollary project(s) that is required.

It is time to finally and forever put a stop to this waste of time and tax dollars not to mention the costs to the people in the path of this proposed scheme. For more than 30 years, the TRR has been promoted by speculators “betting on the come.” Coal as an energy source is on a steep decline in this nation and in the world. While coal may remain in the energy stream for the foreseeable future, it is questionable, at best, whether or not Otter Creek coal could competitively enter any market. This is especially true as the capital necessary to open any new coal mine in this area that has no existing transportation infrastructure makes little fiscal sense in today’s coal market economy.

Northern Plains firmly believes that there is no market for the coal that the proposed TRR wants to haul, and, thus, there is no reason to permit the TRR. If, contrary to all the evidence we have presented, the STB arbitrarily decides to permit the proposed TRR, we believe that the DEIS has failed to consider the environmental and social consequences of the issues we raise here, among others. We believe that OEA’s analysis as presented in the DEIS is deficient and that it fails to adequately address any of these issues.

We request and urge the STB to choose the “no-action” alternative for the proposed TRR.

Sincerely,

A handwritten signature in cursive script that reads "Steve Charter". The signature is written in dark ink and is positioned above the typed name and title.

Steve Charter, Chairman
Northern Plains Resource Council

Attached, please find the footnoted documents for which working URLs were not provided. In instances where there was a working URL, please see those web addresses for the documents.

Footnote 1

Misuse of Integrated Planning Model as an assessment tool in the Tongue River Railroad DEIS

A Report Prepared for the
Northern Plains Resource Council

By

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September 22, 2015

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Foreword

In this report, the authors do not address the likelihood of the construction of the proposed Tongue River Railroad nor are we attempting to address whether the mines that the proposed railroad will serve will be built. Rather, we address the validity of the basis for the Surface Transportation Board's Office of Environmental Assessment's analysis of the environmental impacts of the proposed railroad and induced mines. All assumptions of the existence of the potential railroad as well as the potential mines induced by the railroad are constructs of the Office of Environmental Assessment as is the assumption of an expansion of coal shipping ports in the Pacific Northwest.

I. Introduction

In the Draft Environmental Impact Statement (DEIS) for the Tongue River Railroad (TRR), the Surface Transportation Board's Office of Environmental Analysis (OEA) uses the Integrated Planning Model (IPM) to "*assess likely coal production, rail traffic, and distribution patterns resulting from development of the Tongue River Railroad*"¹ as well as "*to forecast CO₂ emissions from the combustion of Tongue River, U.S., and global coal.*" In this report, we examine the IPM and how it was implemented by the OEA.

It is important to understand the IPM is a *tool* designed for a specific purpose. As with most tools designed for a specific purpose, there is some flexibility in how the tool can be used to achieve a desired result. This flexibility in implementation can result in a model output that does not account for key factors in the system being modeled.

II. Background on IPM

The IPM is a proprietary model developed by ICF International (originally Inner City Fund) to support government and industry analysis of the U.S. and global power sector. The IPM is a linear programming (LP) model that employs commercial grade LP solvers to minimize an objective function while adhering to a series of constraints and decision variables; this is more succinctly referred to as optimization. Specifically, the IPM calculates the mix of energy generation and transmission that meets a constant electrical demand at the lowest total cost while adhering to physical and regulatory limits. The IPM constructs a sophisticated representation of the supply side of the energy economy² for the United States with international fuel trading also considered. It incorporates representations of fuel extraction, transportation, and different sources of electrical generation into the model. According to the OEA, IPM is used by 18 private

¹ Tongue River DEIS Appendix C: p.C.5-1.

² The term energy economy encompasses all of the portions of the economy that relate to the generation or consumption of energy. The energy economy can be divided into two separate categories: the supply side of the energy economy and the demand side of the energy economy. The supply side encompasses all parts of the energy economy that are involved with the production and distribution of energy including extraction (i.e. coal mining, oil extraction, natural gas extraction, etc.), generation, and distribution of both physical commodities such as coal and oil as well as transmission of electricity. The demand side of the energy economy encompasses all parts of the energy economy that are involved with the consumption of energy including direct fuel consumption (i.e. fuel used in electric generation and transportation or gas used in heating, etc.) as well as the consumption of electricity by the residential, commercial, and industrial sectors.

sector entities,³ which are all energy generation/transmission corporations, and at least 5 public sector entities.⁴

The IPM is used in analyses of many types of problems related to the supply side of the energy economy; however, analyzing the environmental impact of the proposed TRR is a misuse of the model because the purpose of the TRR is to serve the new coal mines which would be accessed by the TRR (called Tongue River Coal in the DEIS). The introduction of new coal mines assumes that the coal from the new mines is competitive. By modeling the addition of Tongue River coal to the market, the OEA has affected the demand side of the energy economy. However, the IPM cannot account for changes in the demand side of the economy; this constitutes a misuse of the IPM.

Publicly available documentation of the IPM is limited; the most thorough publicly available description of the model is published by the U.S. Environmental Protection Agency (EPA). The EPA uses the IPM in analysis of regulations and legislative proposals.⁵ The IPM works well for these analyses because the IPM represents the supply side of the energy economy with a relatively high degree of geographic detail. This high degree of geographic detail results in a precise analysis of the effects that federal as well as local regulations may have on factors within the energy economy such as the price of energy or the mix of energy sources needed to meet a specified amount of demand. In its most recent description of how it uses the IPM, the EPA states that

“Electricity demand projections are input at the model region level in IPM. The 22 NEMS [National Energy Modeling System] regions level electricity demand from AEO [Annual Energy Outlook] 2015 is downscaled to 64 EPA Base Case v5.15 IPM regions.”⁶

In other words, total electric demand is derived from the NEMS analysis of the energy economy, and is a constant. This methodology assumes zero price elasticity of demand.

³ Private sector users include PEPCO, Entergy, Exelon, Tucson Electric Power, Florida Power and Light (FPL), Dominion, NRG, Delmarva Power, Southwestern Electric Power Company, Calpine, APS, Duke Energy, American Electric Power, Otter Tail Power Company, Xcel Energy, Dogwood Energy, Peabody Energy, and Dynegy.

⁴ Public sector users include U.S. Environmental Protection Agency, State public service commissions, Environment Canada, the European Union, and the Natural Resources Defense Council.

⁵ EPA Power Sector Modeling web page accessed on 9/9/15 at: <http://www.epa.gov/powersectormodeling/>. Starting 10/1/15 the page will be hosted at: <http://www.epa.gov/airmarkets/powersectormodeling.html>.

⁶ EPA Base Case v.5.15 Using IPM Incremental Documentation, August 2015.

III. Electricity prices and the response of consumers: elasticity of demand

When determining the impacts of regulatory decisions that influence the access to coal for mining such as the proposed TRR DEIS, one of the main economic considerations that should be modeled is the price elasticity of demand.⁷ Here, price elasticity of demand specifically refers to the relationship between electricity prices and consumer's electric consumption decisions. This relationship is a negative feedback loop.⁸ For example, if the TRR is approved, then delivered coal prices could go down, which decreases the price of electricity. When the price of electricity decreases, end use consumers increase the amount of electricity that they use which increases demand for electricity which, in turn, causes more generators to come on-line or increase their output. The increased demand for electricity means that more fuel (coal, natural gas, etc.) is consumed and more fuel is extracted; both increased consumption *and* increased extraction⁹ are likely to affect the environmental impact (specifically the GHG emissions impact) of the TRR. Reduced coal transit distances that would be a result of the TRR would lead to reduced delivered coal costs; this leads to a downward adjustment of the cost of fuels which leads to a lower electricity price. This is true for foreign markets as well as US markets. The amplitude of the price signal is proportional to the amplitude of the feedback (in this case an increase in consumption) multiplied by the elasticity factor,¹⁰ and the feedback is not instantaneous. This price elasticity should be modeled and the sensitivity of the feedback (the elasticity) should be realistic.

Elasticity of demand needs to be considered on at least two different time scales. Soon after a price change, the short run elasticity deals with the consumers' response to a higher or lower price. This decision can be viewed, for example, as a consumer's near term response to higher electricity prices. When prices increase, in the short term, the consumer can reduce electrical use by diligently keeping lights off in unoccupied rooms. In the long term, assuming that the price of electricity stays high, that same consumer may choose to replace all of the bulbs in their house with high efficiency light bulbs. In the short term, the consumer may not be able to alter their decision making because of constraints placed on them (the need to light their house in the evening, for example), so the short run elasticity response would be small. In the long run, assuming the consumer buys the more efficient bulbs, the elasticity response could be substantial as they consume far less electricity to light their home or business.

⁷ The price elasticity of supply is also important. It is embodied in each mine's supply curve that slopes or steps upward to the right.

⁸ When prices go up, consumption falls; when prices go down, consumption increases.

⁹ The extraction of coal both consumes energy in the form of oil (Diesel fuel) as well as releases methane that is trapped in the coal.

¹⁰ There can be an elastic response where the consumption increases or decreases by more than the price change or there can be an inelastic response where consumption increases or decreases by less than the price reduction. The point is that there is a market response to a change in the price.

Any model that is used to evaluate the proposed TRR needs to be able to capture the long run and short run elasticity responses of a change in the delivered price of coal.

The basic economic principle of elasticity of demand has been applied to energy modeling in many different ways. Recently in a *Nature Climate Change* article,¹¹ the impact of an increased supply of Canadian Oil Sands oil onto the global market by the proposed Keystone XL Pipeline was shown to increase oil consumption by 0.6 barrels of oil for every barrel of oil produced because of the incremental decrease in the price of global oil. They found a corresponding increase in the GHGs associated with the increased extraction and consumption of the oil. A 2013 White paper by Power Consulting¹² came to the same conclusion about an increase in the GHG associated with Powder River Basin coal going to China via coal export ports in the Pacific Northwest. These examples highlight the potential for increased energy consumption associated with different energy policy decisions and the important role that elasticity of demand can play. Any model that is used to look at the GHG emissions impacts associated with energy policy decisions should have price elasticities of demand that allow for a different energy future than the “base case” or whichever scenario the modeled run is compared against.

IV. The IPM and elasticity of demand

Within the EPA documentation of the IPM it is unclear if the model has the *ability* to account for elasticity of demand. In the most extensive version of their documentation of IPM, the EPA states

“EPA Base Case v.5.13 has the capability to consider endogenously the relationship of the price of power to electricity demand. However, this capability is typically only exercised for sensitivity analyses where different price elasticities of demand are specified for purposes of comparative analysis. The default base case assumption is that the electricity demand shown in Table 3-2, which was originally derived from EIA modeling that did consider price elasticity of demand, must be met as IPM solves for least-cost electricity supply. This approach maintains a consistent expectation of future load between the EPA Base Case and the corresponding EIA Annual Energy Outlook

¹¹ Erickson, P., and M. Lazarus (2014), Impact of the Keystone XL pipeline on global oil markets and greenhouse gas emissions, *Nat. Clim. Chang.*, 4(9), 778–781.

¹² Power, T., Power, D. (2013) The Impact of Powder River Basin Coal Exports on Global Greenhouse Gas Emissions. Prepared for the Energy Foundation.
http://www.powereconconsulting.com/WP/assets/GHG-Impact-PRB-Coal-Export-Power-Consulting-May-2013_Final.pdf

reference case (e.g., between EPA Base Case v5.13 and the AEO2013 reference case).”¹³

This statement indicates that in the IPM base case the price elasticity of demand is assumed to be zero. The predetermined total demand for electricity that NEMS has calculated, taking price elasticity into account, now has to be met exactly within IPM.¹⁴ Changes in the cost of supplying electric generators with fuel cannot impact the demand for electricity within the IPM. It can only change the mix of supply sources and the transportation routes used to supply that fleet of electric generators. That is, the way EPA uses IPM does not confirm their assertion that IPM is capable of allowing endogenous adjustments of electric demand to the changes in the price of electricity. Multiple studies corroborate the conclusion that IPM does not allow for electricity demand adjusting to changes in the price of electricity. For example, when describing the IPM, Jaglom et al. (2014) state that “*An implication of using exogenously specified demand is that demand does not respond to power prices (i.e., the price elasticity of demand is zero)*”¹⁵ and McFarland et al. categorize “*the electricity demand response to price*” of the IPM as “*inelastic*.”¹⁶

The ultimate purpose of the IPM, then, is to find the least cost way of generating electricity under a constant demand scenario. The IPM finds this least cost solution through fuel substitution (i.e. a balance of coal, natural gas, renewables, and other energy sources as well as the least cost source of each of these fuels for each of the generating facilities).¹⁷ When used properly, the IPM is a very powerful model that outputs precise projections of the supply side of the energy economy under a constant demand scenario. Many private corporations in the power sector find these precise projections helpful in analyzing the least cost mixture of energy generation. For example, they may use the IMP to determine where and when they should expect more production from a natural gas fired generator and less from a nearby coal fired

¹³ Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model, Section 3.2.1 Demand Elasticities. EPA # 450R13002. November 2013.

¹⁴ The NEMS models the entire energy economy on a larger grid size than the IPM. The NEMS accounts for short term price elasticity of demand by iteratively optimizing supply and demand side modules until the price does not affect the demand (to a predefined tolerance). The elasticity coefficient is low and the NEMS does not consider international elasticity of demand, however, the model is open source, meaning the code is freely available, making augmentation of the code possible. From: U.S. Energy Information Administration. Integrating Module of the National Energy Modeling System: Model Documentation 2014, July 2014. <http://www.eia.gov/forecasts/aeo/nems/documentation/>

¹⁵ Jaglom, W. S. et al (2014). Assessment of projected temperature impacts from climate change on the US electric power sector using the Integrated Planning Model®. *Energy Policy*, 73, 524-539.

¹⁶ McFarland, J. et al (2015). Impacts of rising air temperatures and emissions mitigation on electricity demand and supply in the United States: a multi-model comparison. *Climatic Change*, 131(1), 111-125.

¹⁷ This is also referred to as cross-price elasticity of demand, which is not the same principle as price elasticity of demand. Cross-price elasticity of demand is the response of demand for one good to a change in price of another good. For example, if natural gas prices rise dramatically the demand for coal increases.

generator. Federal agencies, such as the EPA, use the IPM in conjunction with other energy economy models to estimate the total emissions produced under a least cost, constant demand scenario. However, when the IPM is used improperly, it outputs precise projections of the supply side of the energy economy that are inaccurate¹⁸ and possibly misleading.¹⁹ Since the model does exactly what the modeler tells it to do, the model output is in part determined by the input data and the constraints applied to the model. With unnecessary constraints and inaccurate inputs, the IPM output can be limited in its range of possible output solutions.²⁰

V. OEA's implementation of the IPM

In the DEIS for the TRR, the OEA present a brief overview of the IPM which includes this description of the public documentation in Section 5.2.2.2:

“USEPA uses IPM to analyze the impact of air emissions policies on the U.S. electric power sector. As part of this analysis, USEPA publishes its assumptions and other information regarding its use of IPM on its website (U.S. Environmental Protection Agency 2012). Although this documentation provides insight into USEPA’s assumptions, the data and assumptions used by OEA in this analysis are not necessarily the same as used by USEPA.”²¹

This section is followed by sections that describe the key assumptions²² and methods²³ used in the modeling for the DEIS. The section of the DEIS quoted above leads to two

¹⁸ The IPM is a deterministic model. This means that if the objective function is minimized to within a certain limit, the IPM will provide an output.

¹⁹ This is true of almost any complex model. Typically there are also coefficients in the model that can be changed to ‘tune’ the model to the unique situation for which it is employed.

²⁰ In section VI of this document we show that the OEA use questionable constraints on the distribution of TRR coal and an inaccurate representation of the total energy demand (they represent the demand as static; it should be elastic) in their implementation of the IPM.

²¹ Tongue River DEIS Appendix C: Model Framework – Public Documentation, C.5-8.

²² The key assumptions section (Section 5.3 of the DEIS) includes descriptions of assumptions about surface and underground coal mine productivity; natural gas production and demand; air, waste, and water regulations; renewable energy regulations; reserve margin targets; power plant mothballing and retirement; and transmission. There is no mention of power demand or demand elasticity.

²³ The methods section (Section 5.4 of the DEIS) includes a description of how the model years 2013-2037 are aggregated into 7 model run years to reduce model complexity; a brief overview of how CoalDOM is used to model US and international coal production; a description of the aggregate Powder River Basin supply curve; a description of how coal demand is calculated and allocated in CoalDOM; a brief description of how CoalDOM and IPM estimate coal transportation costs; a brief description of how IPM implements and incorporates environmental compliance factors including constraints on pollutants, CO₂ emissions, renewable portfolio standards, and “other state and regional requirements”; a brief description of the Gas Market Module (GMM) and how it is used to construct supply curves for natural gas; a list of assumptions on natural gas demand; a description of how the GMM characterizes natural gas demand; and how the IPM and the GMM are used to develop “a set of robust natural gas supply

possible implications: 1) all of the data, methods, and assumptions that are NOT mentioned in the DEIS are consistent with the USEPA documentation on the IPM and 2) the OEA does not believe that it is necessary to inform the public of their modeling work using the IPM that underlies the energy modeling in the DEIS. The second implication would be a clear violation of transparency and would constitute an unacceptable practice for any assessment of the impacts of a project conducted by a federal entity such as the OEA. We assume, then, that the OEA's implementation of the IPM is consistent with the USEPA documentation in all aspects except those specifically stated in the DEIS.

From the DEIS and the USEPA documentation on the IPM, it is clear that the OEA does not consider elasticity of demand when assessing the potential impacts of the proposed TRR. Demand elasticity response is extremely important to be able to capture when predicting the impacts of energy production decisions. If the response to approving the TRR is a change in the price of energy, then there will be some short and long run demand elasticity response. The IPM *does* model fuel substitution. However, it is quite probable that the demand response²⁴ will be as large, or larger, than the potential demand response associated with a fuel substitution response (or cross price elasticity). While the implementation of the IPM described by the OEA will be able to capture the fuel substitution response, it does not capture any change in the overall consumption of electricity associated with an electricity price change. Thus, one of the main problems with the OEA's implementation of the IPM is that it is assuming that there is zero elasticity of demand to model a solution which should recognize the price elasticity of demand.

The IPM *does* have a place in modeling the energy economy; it solves for the supply side of the energy economy at a higher geographic resolution than other energy economy models (such as the NEMS). This higher geographic resolution is achieved by making the entire demand side of the energy economy an input instead of a part of the model calculations.²⁵ Where a constant energy demand assumption is valid, the IPM

curves that incorporates these dynamics between electricity demand, new power plants, retirements of power plants, coal prices, and environmental policies."

²⁴ Demand response is an increase or decrease in the consumption of electricity that results from fluctuations in the price of electricity.

²⁵ There must be a trade-off between resolution and breadth of a model, to elucidate this we compare the IPM to the NEMS. The documentation of both the IPM and NEMS state that the model runs are typically conducted on basic workstation-grade computers, meaning they are not run on 'super computers' or via 'cloud computing'. The computational limits of the computing system results either in a limited node resolution or in a limited number of variables being modeled. Further, even if the models were run on the most advanced platforms in the world, there is a limit to the size of a matrix that LP solvers can currently solve in a reasonable amount of time (less than months). Both the IPM and the NEMS incorporate a number of variables on the order of 10^6 which quickly escalates as node resolution escalates. For example in the NEMS, there are 49 representative subsectors within the 6 major economic subsectors, 16 representative coal demand regions each with 41 representative coal supply curves; therefore there

may be an appropriate model to conduct detailed analysis of the impacts associated with regulatory decisions. However, even if the constant energy demand assumption were valid for modeling the environmental impacts of the TRR,²⁶ we could not validate the OEA's model results because the only publicly available documentation for the IPM is limited to a description of the source of the input variables and vague descriptions of the methods employed in the model.

This leads us to another important problem with the OEA's use of the IPM: the IPM is not independently verifiable.²⁷ As the EPA states:

*"ICF Resources, Inc. maintains an IPM user manual for the purpose of training internal staff and licensees of the model. Since it contains proprietary business information pertaining to the source code, it is not available for public dissemination."*²⁸

Since the actual source code that runs the model cannot be independently accessed and verified, the IPM is essentially a "black box" to anyone outside of ICF. This leaves the reliability of the results of the IPM model open to speculation without any means to eliminate the doubt or uncertainty about the model's output in any particular application. This is unacceptable for any model that is used in any scientific endeavor. For the IPM to be a trusted source of projections that influence public regulatory decisions, such as the greenhouse gas impact of the proposed TRR, full documentation of the code and inputs must be available to the public.²⁹ Without this documentation, the results of the modeling are not defensible since there is no way to verify that the methodology or implementation of the model is correct or in line with accepted economic principles.

are $16 \times 41 \times 49 = 32,144$ potential representative coal transportation routes in the NEMS. In the IPM there are roughly 560 coal demand regions (since each coal power plant is considered a separate demand region), 67 representative coal supply curves, and if the transportation routes were calculated for the 49 representative subsectors of the economy defined in the NEMS there would be a potential 1,838,480 routes; more than 57 times the potential routes for the NEMS. With the current state of computing, modeling the breadth of the NEMS on the resolution of the IPM would require an unacceptable amount of time and computational expense (on the order of months per run).

²⁶ We show in the next section that the addition of the TRR violates the constant demand requirement of proper usage of the IPM.

²⁷ ICF routinely performs "Quality assurance and verification" of the code. However, the license cost of the IPM is hundreds of thousands of dollars (personal communication with an ICF Senior Technical Specialist) making external verification of the IPM out of reach for most private organizations. EPA Science Inventory Integrated Planning Model – EPA Applications. Accessed on 9/9/15 from: http://cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=74919&CFID=37279577&CFTOKEN=14581785

²⁸ EPA Science Inventory Integrated Planning Model – EPA Applications. Accessed on 9/9/15 from: http://cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=74919&CFID=37279577&CFTOKEN=14581785

²⁹ The source code does not need to be divulged but the equations used in the code must be available to validate model results.

Thus, the OEA's use of the IPM as part of the proposed TRR DEIS is completely inappropriate for a number of reasons including:

1. The IPM is a black box model without open external verification. Since there is no way to validate the projections of the IPM model, the public has no way to verify if the proposed TRR will have an unacceptable impact on the environment.
2. The results of the OEA modeling are also indefensible because they do not explicitly describe their methods, including any deviation from the USEPA documented methodology. As Jaglom et al. (2014) state, "[the] *IPM is flexible with respect to data and input assumptions. In general, all inputs to the model are user-defined and case-specific and reflect the specific policy, physical conditions, or market conditions being analyzed.*"³⁰ The data and input assumptions that the OEA use in their modeling effort are not well defined in the DEIS. Instead OEA states that the data and assumptions are "*not necessarily*"³¹ the same as the data and assumptions in the EPA documentation that they allude to.
3. The IPM does not incorporate the basic economic principle of the price elasticity of demand.³² As a result the impacts of changes in transportation infrastructure and new coal supply routes that will affect the delivered price of coal are not allowed to influence the demand for coal or the environmental consequences of changes in the quantity of coal produced and consumed. The OEA cannot account for the effects of reduced coal prices on total demand with the IPM. Without accounting for price elasticity of demand the OEA has not modeled the true outcomes associated with the proposed TRR and its associated coal mines.

VI. Evidence of the specific misuse of the IPM model in the TRR DEIS

The Powder River Basin (PRB) is the largest single source of coal in the U.S. and is one of the largest coal deposits in the world. The Montana (or northern) portion of the PRB has historically lagged in coal production behind the Wyoming (or southern) portion of the PRB for more than 30 years. In 1975 Montana produced about 22 million tons of coal and Wyoming produced about 24 million tons of coal. By 1990 Montana was producing almost 38 million tons of coal and Wyoming produced 184 million tons of coal. With the passage of the Clean Air Act there was a large demand placed on the PRB to supply cheap, low sulfur coal to meet the emissions limits of coal fired generators all across the United States. Montana's coal production has been essentially stagnant since the mid-1970s while Wyoming's coal production has skyrocketed to

³⁰ Jaglom, W. et al. (2014). Assessment of projected temperature impacts from climate change on the US electric power sector using the Integrated Planning Model®. *Energy Policy*, 73, 524-539.

³¹ Tongue River DEIS Appendix C: Model Framework – Public Documentation, C.5-8.

³² McFarland, J. et al. (2015). Impacts of rising air temperatures and emissions mitigation on electricity demand and supply in the United States: a multi-model comparison. *Climatic Change*, 131(1), 111-125.

around 400 million tons of coal.³³ Although the Montana PRB coal is traditionally slightly lower in Btu content (98 percent the same) and higher in sodium, it is the transportation advantage that the southern PRB has to the coal consumption areas of the U.S. domestic market over the northern PRB that accounts for the large disparity in tons of coal that are mined in each region each year.³⁴

The OEA states that “[e]xport through the Pacific Northwest terminals would provide Tongue River coal with a rail cost advantage over Wyoming Powder River Basin coal. Montana Powder River Basin rail costs to the Pacific Northwest are about \$2 per ton lower than Wyoming Powder River costs.”³⁵ This rail cost advantage is translated into a delivered cost advantage to the Pacific Rim (the OEA use Japan as an example) of 4 cents per million Btu (MMBtu) over the southern PRB coal.³⁶ Rather than building its discussion of the market for TRR coal, the OEA asserts that the TRR coal will not be cost competitive with the southern PRB coal in the Pacific Rim market because the TRR coal has a low Btu content compared to the southern PRB coal. However, despite the lower Btu content of the TRR coal it still has a lower delivered price (per MMBtu) to the Pacific Rim than the southern PRB coal. Since the coal has a lower price delivered to the Pacific Rim, the principle of price elasticity of demand requires that it will encourage more energy consumption in the Pacific Rim. Despite this, the OEA concludes that:

*“If some or all of the proposed terminals were constructed, there would be sufficient terminal capacity to export all of the Otter Creek coal, as well as other Tongue River coal. Regardless of the extent of new Pacific Northwest terminal capacity, the proposed rail line would not lead to a net increase in tons of coal exported.”*³⁷

The reason the OEA concludes that there is not an increase in the tons of coal exported is that they assume the southern PRB coal can be perfectly substituted for the TRR coal even though TRR coal has a delivered price advantage over other PRB coal to the Pacific Northwest and the Pacific Rim (per MMBtu). In fact, the OEA assumes that most of the TRR coal (the 8600 Btu/lb coal) will not be exported in favor of the southern PRB higher delivered cost coal.³⁸ The cost analysis mentioned above shows that both the southern PRB coal and the TRR coal competitively price into the Pacific Rim markets

³³ http://www.eia.gov/state/seds/sep_prod/pdf/PT1_MT.pdf and http://www.eia.gov/state/seds/sep_prod/pdf/PT1_WY.pdf

³⁴ Duffield, J., Silverman, A., and Tubbs, J. (1985), Montana Coal Market to the Year 2000: Impact of Severance Tax, Air Pollution Control and Reclamation Costs. Prepared for the Montana Department of Commerce, Helena, Montana.

³⁵ Tongue River DEIS Appendix C: Coal production and Markets. p.4-7.

³⁶ Ibid. p.4-9.

³⁷ Ibid. p.4-10.

³⁸ It appears that there is a non-economic constraint placed on the export of coal to the Pacific Rim where only 8800 Btu/lb or higher coal is exported. This is shown in their analysis by scenario #20 where only the introduction of a higher Btu coal from the induced Canyon Creek mine allows the export of TRR coal.

with the TRR coal having a 4 cent per million Btu advantage over the southern PRB coal. In the OEA scenarios, the ports are the limiting factor on volume of coal shipped to the Pacific Rim, not the delivered price of the coal.³⁹ This technically allows the OEA's statement that "*the proposed rail line would not lead to a net increase in tons of coal exported*" to be true. What is missing from this statement is the competitive advantage that the TRR coal has in the Pacific Rim and the effects of that competitive advantage.

If 72 million tons of TRR coal (the assumed total coal production under the Southern Alternative High Production Scenario⁴⁰) is allowed to price into the Pacific Rim, then the Pacific Rim will receive a cost savings of at least \$155 million dollars per year.⁴¹ This, in turn, will encourage the Pacific Rim to burn more coal than they otherwise would have and thus produce more GHG than they otherwise would have without the TRR. The economic principle of the price elasticity of demand requires that this is the outcome.

The existing Montana PRB mines (not the TRR mines) have a transportation advantage to the Upper Midwest and the southern PRB mines have a transportation advantage to the southeast and southwest. Replacing these coal sources with TRR coal that has a similar production cost but a rail shipping disadvantage does not make economic sense. The TRR coal would have to travel past the existing coal fields to get to a domestic market that is already served. Thus the advantages of the TRR coal heavily points towards the PNW ports. This is confirmed by the \$2.00 per ton rail shipping advantage over the southern PRB as well as the delivered 4 cent per million Btu cost advantage to the Pacific Rim.

By allowing the perfect substitution of southern PRB coal for TRR coal in the IPM modeling, the OEA is ignoring the increase in the amount of coal that would be burned by the Pacific Rim because of the competitive price advantage that the TRR coal has. Price elasticity of demand requires that access to a cheaper source of coal will encourage more consumption of coal. Since the port capacity is assumed to be limited, (it should adjust to the market-supported level of Pacific Rim demand) the additional coal consumption that will be induced by the lower delivered price of TRR coal will have to come from a different international source. Simply because it does not come from the

³⁹ Again there appears to be a non-economic constraint placed on the development of the TRR coal. If it is more competitive into the Pacific Rim then why couldn't it all be developed at the same time to serve the port demand of 107 million tons? Instead the maximum capacity of the TRR is leveled off at 72 million tons. See table 3-11 in Appendix C of the TRR DEIS.

⁴⁰ Tongue River DEIS Appendix C: Coal production and Markets. p.3-31 table 3-11.

⁴¹ Accounting for the total Btu content per ton of the TRR coal, multiplying by the 4 cent per million Btu difference, and applying the savings per ton to 72 million tons of production from the TRR under scenario #20 yields, this result. Note that this is a conservative estimate since 22 million tons of that coal would be coming from the Canyon Creek mine which has a higher heat content (9200 Btu/lb) but is assumed to be mined at the same cost as the Otter Creek 8600 Btu/lb coal. If the Canyon Creek coal can be mined at the same cost then it would be more competitive than the Otter Creek coal when compared to the southern PRB coal.

U.S. does not mean that it does not exist. This induced additional energy consumption should have been modeled and the perfect substitution of a more expensive coal source (the southern PRB) should not have been allowed in the model. Allowing a higher delivered cost source of coal (in \$/MMBtu), simply because it has a higher energy content does not make economic sense. It imposes a non-economic constraint on the model and is based on faulty rationale.

As we discuss above, there is perfect substitution of one coal for another. The OEA states that there is a different delivered price per million Btu for coal delivered to the Pacific Rim; and yet one is perfectly substituted for the other without any market response. This is an economic impossibility and an argument that the courts have consistently thrown out. Judge R. Brook Jackson rejected the perfect substitution argument in a recent District Court of Colorado ruling by stating:⁴²

“In other words, coal is a global commodity, and if the coal does not come out of the ground in the North Fork consumers will simply pay to have the same amount of coal pulled out of the ground somewhere else—overall GHG emissions from combustion will be identical under either scenario. The agencies reached this conclusion in part by relying on a U.S. Department of Energy report forecasting a small annual increase in the demand for coal. Based on that assumption, the agency concluded that perfect substitution would occur.

I cannot make sense of this argument, and I am persuaded by an opinion from the Court of Appeals for the Eighth Circuit that rejected a nearly identical agency justification for not analyzing the future effects of coal combustion. In Mid States Coalition for Progress v. Surface Transportation Board, the court held that an agency violated NEPA when it failed to disclose and analyze the future coal combustion impacts associated with the agency’s approval of a railroad line. In that case—like this one—the agency argued that emissions would occur regardless of whether the railroad line were approved because “the demand for coal will be unaffected by an increase in availability and a decrease in price.” Id. The court rejected this argument as “illogical at best” and noted that “increased availability of inexpensive coal will at the very least make coal a more attractive option to future entrants into the utilities market when compared with other potential fuel sources, such as nuclear power, solar power, or natural gas.”

⁴² High Country Conservation Advocates v. United States Forest Service, 52 F. Supp. 3d 1174 (D. Colo. 2014).

Allowing the perfect substitution of one coal for another, even when there are delivered cost differences, wipes out any difference in consumption (and thus environmental impacts such as greenhouse gas emissions) associated with differences in delivered costs and demand elasticity, just as Judge Jackson recognized. There are also non-economic constraints that were placed on the model that did not allow the ports to expand in response to the markets as well as constraints that were placed on the timing of coal coming from the TRR, both of which limit the amount of TRR coal that goes to the Pacific Rim. These are major flaws in the OEA's use of the IPM.

We have identified four flaws in the OEA's implementation of the IPM which artificially predetermined the model result of a low GHG and market impacts from the proposed TRR and its induced coal mines. The first flaw is that the OEA determined that the majority of the TRR coal would be undesirable to export to the Pacific Rim, even though the delivered cost of the TRR coal per MMBtu would be cheaper than the southern PRB coal that is largely exported in its place. The second flaw is that the OEA assumed that the PNW port volume would be restricted; the port capacity should be dependent on the demand placed on it by the Pacific Rim. The third flaw is the limits that are placed on the development of the TRR induced mines. The mines should be allowed to come on line in response to the demand that they are serving. Since TRR coal is cheaper to ship to the Pacific Rim compared to southern PRB coal, all of the TRR induced mines should be allowed to come on line at the same time and send their coal to the Pacific Rim displacing more of the southern PRB coal. This would in turn show a larger total impact of TRR coal that is not perfectly substitutable for other PRB coal sources. The fourth flaw is that energy demand is held constant which neglects the basic economic principle of elasticity of demand. Because the total energy demand does not change within any given scenario, the model is not able to pick up the induced energy consumption that would occur if the TRR coal was allowed to be shipped to the Pacific Rim in place of the southern PRB coal. If the model allowed for elasticity of demand and was not constrained by the flaws mentioned above, then there should be an increase in energy consumption that is proportional to the short and long run elasticities of demand. This increase in energy consumption, above and beyond what would have happened if the TRR was not constructed (the no action alternative), has GHG consequences that were not modeled by the OEA. Because the model was constrained by the four flaws mentioned above, the results of the model are flawed and should not be used in this DEIS process.

VII. Conclusion

It is clear that the IPM is not designed for the modeling problem for which the OEA has employed it. The IPM does not account for demand elasticity, which can have a large

impact on total energy use. The IPM is not documented in a manner which would allow external validation of the results; in that sense it is a black box. The OEA's misuse of the IPM model to assess the GHG emissions impacts of the proposed TRR either reveals a complete lack of understanding of the appropriate model usage or it is an attempt to ignore a vital portion of the impact that the proposed railroad may have. It is certain that the proposed railroad would have an effect on the delivered price of coal (the OEA state this in their DEIS), thus it would have an effect on the price of energy. Any appropriate energy economy model must account for demand response that is associated with energy price changes and must be documented with a detailed description of the model methodology and the implementation of the model must be freely available for external verification. Further, the modeling must be conducted with realistic constraints and assumptions that do not predetermine the model result. We have shown in this report that the OEA's implementation of the IPM fails in all these aspects.

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Footnote 11

**BEFORE THE
SURFACE TRANSPORTATION BOARD**

STB FINANCE DOCKET NO. 30186

**TONGUE RIVER RAILROAD COMPANY, INC.—RAIL CONSTRUCTION
AND OPERATION—IN CUSTER, POWDER RIVER AND
ROSEBUD COUNTIES, MT**

VERIFIED STATEMENT OF THOMAS SANZILLO

My name is Thomas Sanzillo and I am Finance Director for the Institute for Energy Economics and Financial Analysis (“IEEFA”). I have served in this job since May 2012 but have been involved in fossil fuel finance matters since September 2007. In this capacity I research and prepare studies, memos, and testimony (and supervise the same) and speak publicly on a range of fossil fuel issues. I have authored, co-authored, or provided related research on United States domestic coal markets and plant finances, U.S. coal producer and mine finance and financial regulation, federal coal leasing in the Powder River Basin (“PRB”), federal coal subsidies, federal/state mine reclamation, utility finance, public power financials (including municipal power systems, rural cooperatives, and state power agencies). I have testified before three Public Service Commissions (Minnesota, Wisconsin, and Colorado) and submitted affidavits in two coal related federal proceedings as well as before an administrative proceeding at the Exim Bank. My work has involved energy and coal issues in at least 25 states.

My work has also included analysis of global economic trends and coal markets. I have co-authored a number of international coal market studies related to India and

Australia (with our office in Sydney, Australia) and provided oversight, research, and direction on a global analysis of coal markets with Carbon Tracker Institute. In addition, I have published a number of reports related to U.S. coal exports.

Prior to my work with IEEFA, I served for seventeen years (1990-2007) in various senior management positions in New York City and State government finance. My last position was the First Deputy Comptroller for New York State (I served for a short period as the State Comptroller due to an early resignation). The New York State Comptroller is the sole trustee of a \$156 billion globally invested public pension fund, chief accountant and procurement officer, chief auditor for state finances, agencies, and local governments, and reviews and approves most public debt.¹

I present this Verified Statement on behalf of the Northern Plains Resource Council (“Northern Plains”). The purpose of this Verified Statement is to offer my professional opinion on the viability of the Otter Creek mine project, the only coal mine that would be served by the proposed Tongue River Railroad. My Verified Statement: 1) provides historical and up to date information on the status of coal markets in the United States and globally; 2) offers information and analysis on the current and future financial outlook of Arch Coal, Inc. (“ACI”), a 38.29% owner of the Tongue River Railroad Company (“TRRC”), and 3) provides an overall opinion on the viability of the Otter Creek project that would be served by the Tongue River Railroad.

To prepare this testimony I have reviewed TRRC’s December 17, 2012 Supplemental Application for Construction and Operation Authority, Northern Plains’

¹ Thomas Sanzillo, *The New York State Comptroller’s Office*, *The Oxford Handbook of New York State Government and Politics* 287, 292 (2012).

April 2, 2013 Comments on TRRC's application, TRRC's June 7, 2013 Reply, Northern Plains' July 2, 2013 Sur-reply, and TRRC's August 9, 2013 Reply as well the affidavits and material provided as part of those submissions. I have also reviewed all of the highly confidential documents² produced in discovery by the TRRC and its owners including various internal documents of both ACI and BNSF Railway Company ("BNSF"). I have also reviewed discovery deposition transcripts from this proceeding.

My testimony also draws upon many of the same external sources used by the parties in this proceeding, most notably the reports and statistical projections of domestic and international coal markets provided by the United States Energy Information Administration ("EIA"). I supplement this largely quantitative data from the EIA with additional quantitative and qualitative analysis provided by several large banks with long histories with the coal industry. I further rely on detailed analysis of global coal markets conducted by Carbon Tracker Institute ("CTI") in September 2014.³ CTI and my organization, IEEFA, collaborated on significant portions of the report, and many of the modeling assumptions regarding national and global coal markets were derived from IEEFA's modeling. Where necessary and appropriate I rely upon market price information provided by coal companies and independent market pricing data, analytical, and industry reporting sources.

² Confidential documents are identified in the body of this affidavit along with appropriate Bates numbers and other identifiers. Further clarifying information is provided in accompanying footnotes where appropriate.

³ See generally Carbon Tracker Initiative, <http://www.carbontracker.org/report/carbon-supply-cost-curves-evaluating-financial-risk-to-coal-capital-expenditures/> (last updated Mar. 24, 2015).

SUMMARY OF CONCLUSIONS

- **There is no need or market demand for Otter Creek coal for the foreseeable future.** Based upon what we can see today and for the foreseeable future there is insufficient demand from the domestic and international thermal coal markets to warrant any finding of a viable market for this new coal mine and the underlying rail infrastructure to support it.
- **Coal production in the PRB is shrinking due to structural, long-term changes in the domestic and international markets.** From 2005 through 2011 the region produced on average 462 million tons per year (“mtpa”). From 2012 through 2014 the region produced on average 415 mtpa, a 47 mtpa decline or just over 10%.
- **Looking forward through 2016 coal production is expected to continue declining nationally and in the PRB.** From 2011 through 2016 the Western Region, the region dominated by the PRB, is expected to shrink by 73 mtpa.
- **The EIA has downgraded its long-term forecasts.** In 2011 the EIA estimated that by 2030 the PRB would produce 699 mtpa. By 2014 the EIA downgraded its 2030 forecast to 493 mtpa, a 206 mtpa decline in expected PRB production.
- **There is no room in the current or projected market for Otter Creek coal.** In recent years Montana coal production has been consistent with the historical average of the last ten years, approximately 42 mtpa. The EIA is projecting some long-term growth but there are two other companies in Montana positioned to meet this demand. In addition, there are four other coal producers in the PRB looking to export coal off the west coast. With six competitors vying for a minimal amount of new coal production there is just no room for another, poorly positioned entrant into the market. In addition, EIA’s projections for coal exports to Asia identify a maximum long-term market in the 21 mtpa range. Current Montana coal producers have exported 12 mtpa in a good year.
- **Plans to export the coal from Otter Creek will not materialize.** The EIA has recently substantially downgraded its estimate of short-term export potential. ACI has done the same. According to four major investment advisors (J.P Morgan, Goldman Sachs, Citibank, and Bernstein Research), the current unfavorable market for exported coal from the United States is either never going to rise or will not do so for the foreseeable future. Investors and coal companies have scaled back or completely pulled out of the export market and related infrastructure projects. For example, ACI anticipates paying \$50 million in liquidated damages in 2015 for unused export terminal capacity due to weak seaborne coal markets.
- [REDACTED]

- **ACI is not financially fit to make the investments needed to open the Otter Creek mine and/or the Tongue River Railroad.** The financial condition of ACI, like the coal industry in general has deteriorated over the last four years. The company has posted three consecutive years of losses totaling more than \$1 billion and is expected to lose money in 2015 as well. Its stock price has fallen from a high of \$67.00 per share to its current level just under \$1.00 per share. The company faces \$5.1 billion in debt maturities in 2018-2021. It is considered one of the most financially challenged companies in the industry. ACI will not be able to raise the capital necessary to finance Otter Creek or the Tongue River Railroad.

I. THERE IS NO NEED OR MARKET DEMAND FOR OTTER CREEK COAL.

[REDACTED]⁴ This is the conclusion of Wood Mackenzie (“WM”); a coal consultant relied upon by TRRC and its owners. Based upon what we can see today and for the foreseeable future there is insufficient demand from the domestic and international thermal coal markets to warrant any finding of a viable market for this new coal mine and the underlying rail infrastructure to support it.

Currently the domestic and global thermal coal markets are oversupplied. Low coal prices and other market factors are driving down annual coal production, including in the PRB. The annual amount of coal burned for electricity nationwide has decreased and is expected to fall further.⁵ The EIA has for the last several years consistently downgraded the size of future domestic markets and the rate of growth of regional coal production, including in the PRB. ACI’s own signature mine in the PRB, Black Thunder

⁴ [REDACTED]
 [REDACTED]
 U.S. Energy Info. Admin., *Short-Term Energy Outlook (STEO)*, EIA.gov 1, 39 (Feb. 10, 2015), <http://www.eia.gov/forecasts/steo/archives/feb15.pdf> [hereinafter *2015 STEO*].

has produced approximately 100 mtpa.⁶ The mine has a permitted capacity⁷ [REDACTED].⁸ The EIA's declining production forecasts, which now extend to estimates for U.S. coal exports, are part of a negative outlook for the industry shared by the world's leading investment banks and coal consultants. In addition, the largest coal producers in the PRB, including ACI, have posted multiple years of dismal financial performance, including sizeable yearend losses in the hundreds of millions.

In the five-year period prior to TRRC's application, TRRC and its principal coal consultants, the EIA, and most analysts estimated significant growth in PRB production based on then-recent history in the domestic and international thermal coal market. The markets, however, changed during those years and subsequent to the submission of TRRC's application. None of these past robust assumptions about U.S. coal producers capturing significant amounts of future growth have materialized.

A. The PRB is producing less coal than it has in the recent past.

According to the EIA, in 2009 the PRB produced 455 mtpa of coal. By 2013, the amount declined to 407 mtpa. According to SNL Energy⁹ data released on 2014 coal

⁶ U.S. Sec. & Exch. Comm'n, *ACI 2015 Form 10K*, SEC.gov 1, 14 (Feb. 27, 2015), <http://sec.gov/Archives/edgar/data/1037676/000104746915001419/a2223254z10-k.htm> [hereinafter *ACI 2015 10K*].

⁷ *Id.* at 15.

⁸

⁹ SNL Energy is an online trade news service and database on energy issues, including coal. At the time I prepared this Verified Statement, the EIA has not published formal 2014 production numbers. SNL, a trade publication, reports an unofficial count much sooner as part of its broader

production, the PRB showed some increase.¹⁰ From 2005 through 2011, the region produced on average 462 million tons per year (see Table I). During the current period, 2012 through 2014, the region produced on average 415 mtpa, a 47 mtpa decline or just over 10%. The historical trajectory is clear; the region is producing less coal.

Some in the coal industry see this decline as a short-term blip against an otherwise long-term tide of rising coal production. As described below, a consensus of large investment banks, financial analysts, and other coal industry leaders see this decline as either a long-term trend or a permanent secular decline.

Table I: EIA Accounting of Powder River Basin Coal Production (000/tons of coal)

Year	Powder River Basin		Wyoming ¹¹	Montana	Wyoming + Montana ¹²
2014	418,156		N/A	N/A	N/A
2013 ¹³	407,567		387,924	42,231	430,155
2012	419,066		401,442	36,694	438,136
2011 ¹⁴	462,600		438,673	42,008	480,681

reporting functions. SNL works closely with the EIA on coal reporting. For example, SNL operates the EIA's spot coal website, http://www.eia.gov/coal/news_markets/.

¹⁰ Darren Epps and Hira Fawad, *Top Producing Powder River Basin Coal Mines in Q4'14*, SNL Financial (Jan. 30, 2015).

¹¹ U.S. Energy Info. Admin., *Coal Data Browser*, EIA.gov, <http://www.eia.gov/beta/coal/data/browser/#/topic/33?agg=1,0&geo=vvvvvvvvvvvvo&freq=A&start=2008&end=2013&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0> (last visited Mar. 25, 2015).

¹² The reason for the difference between PRB numbers and aggregate Wyoming and Montana numbers is that some of the mines in each state are not technically within the designated borders of the PRB.

¹³ U.S. Energy Info. Admin., *Table 1. Coal Production and Number of Mines by State and Mine Type, 2013 and 2012*, EIA.gov, <http://www.eia.gov/coal/annual/pdf/table1.pdf> (last visited Mar. 25, 2015) (there is no 2013 Annual Coal Report available).

¹⁴ U.S. Energy Info. Admin., *Annual Coal Report 2011*, EIA.gov 1, 3 (Nov. 2012), <http://www.eia.gov/coal/annual/archive/05842011.pdf>.

2010	468,428		442,522	44,732	487,254
2009¹⁵	455,503		431,107	39,486	470,593
2008	479,000		467,644	44,786	512,430
2007¹⁶	496,000		453,568	43,390	496,958
2006	449,000		446,742	41,822	488,564
2005¹⁷	430,000		404,318	40,353	444,671

The most recent 2015 EIA, Annual Short Term Energy Outlook (“STEO”) projects a 104 mtpa loss of coal consumption for electricity in the U.S. from 2011 through 2016.¹⁸

During this same period, the U.S. is expected to lose 144 mtpa on the production side.

The Western Region, the region dominated by PRB production, is expected to see a 73 mtpa decline during this same period.¹⁹ Similarly, the outlook shows a slight decline in the delivered price of coal nationwide through 2016.²⁰

TRRC’s consultant, Seth Schwartz, President of Energy Ventures Associates (“EVA”), offers the view of a rising coal market in his Verified Statement²¹ and Rebuttal

¹⁵ U.S. Energy Info. Admin., *Annual Coal Report 2010*, EIA.gov 1, 12-13 (2010), <http://www.eia.gov/coal/annual/archive/05842010.pdf>.

¹⁶ U.S. Energy Info. Admin., *Coal Production by Region and Type, Reference Case*, EIA.gov, <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2010&subject=7-AEO2010&table=95-AEO2010&region=0-0&cases=aeo2010r-d111809a> (last visited Mar. 25, 2015).

¹⁷ U.S. Energy Info. Admin., *Table 92. Domestic Refinery Distillation Base Capacity, Expansion, and Utilization*, EIA.gov, http://www.eia.doe.gov/oiaf/archive/aeo07/supplement/pdf/sup_ogc.pdf (last visited Mar. 25, 2015).

¹⁸ *2015 STEO*, *supra* note 5.

¹⁹ *Id.*

²⁰ *Id.*

²¹ Verified Statement of Seth Schwartz in Support of Tongue River Railroad Company’s Reply to NPRC Comments to Supplemental Application at 2, *Tongue River R.R. Co.—Rail Construction and Operation—In Custer, Powder River and Rosebud Counties, Mont.*, No. 30186 (S.T.B. June 7, 2013) [hereinafter Schwartz Comments].

Verified Statement.²² The data shows otherwise. In Mr. Schwartz's August 2013 statement he points to the long-term rise of coal production out of the PRB starting in 1986. Mr. Schwartz shows a historical annual increase from 1986 until 2011 of 4.8%.²³

Mr. Schwartz states the EIA is now showing forward annual growth rates at 0.8%.²⁴ He acknowledges that this growth rate is smaller than historic numbers²⁵ but he counters that the actual amount of coal production should increase according to the 2013 EIA Annual Coal Outlook. So, with growth from 460 mtpa in 2011²⁶ to 540 mtpa by 2030, he concludes the PRB is clearly growing.²⁷ Mr. Schwartz's points are partial accounts of the EIA data and a mischaracterization of the facts as they existed at the time of his statements to this Board.

There was ample evidence on the public record at the time that required a more qualified statement than the one offered. Mr. Schwartz offered his initial testimony in June 2013 and a rebuttal in August 2013. The production baseline Mr. Schwartz establishes for the PRB are taken from the 2009 through 2011 period; approximately 460 mtpa (see Table I above).²⁸ Mr. Schwartz essentially disregarded the precipitous drop in PRB coal production in 2012 by arguing it was the result of the twin anomalies of mild weather and a temporary decline in natural gas prices. In June he claimed the "short-term

²² Rebuttal Verified Statement of Seth Schwartz in support of Tongue River Railroad Company's Reply to NPRC Comments to Supplemental Application at 2, *Tongue River R.R. Co.—Rail Construction and Operation—In Custer, Powder River and Rosebud Counties, Mont.*, No. 30186, (S.T.B. Aug. 9, 2013) [hereinafter Schwartz Rebuttal Comments].

²³ *Id.* at 7.

²⁴ *Id.* at 6.

²⁵ *Id.*

²⁶ *Id.*

²⁷ *Id.*

²⁸ Schwartz Comments, *supra* note 21, at 4.

drop in domestic level coal demand is expected to turnaround in 2013.”²⁹ If he believed this in June by August it was clear 2013 would be a lot like 2012. By August 2013, SNL was projecting flat or decreased coal demand for 2013.³⁰ By December 2013 PRB coal production fell from an already low level of 419 mtpa in 2012 to 407 mtpa for 2013. (See Table I)

Mr. Schwartz’s analysis is also at odds in important ways with his own firm, Energy Ventures Analysis, Inc. (“EVA”), from earlier in the year.³¹ At the January 2013 Coaltrans³² conference in Miami, EVA’s representative made the following points: 1) displacement of coal by natural gas was taking place since 2010; 2) all of the coal production decline in 2012 was due to natural gas displacement—all 170 million tons;³³ 3) the extended period of low natural gas prices had caused utilities to reconsider their investments of coal plants, citing the Big Sandy coal project canceled by AEP,³⁴ and 4) low natural gas prices in the United States were resulting in higher levels of exports of coal and driving down global coal prices.³⁵ The robust coal rebound referred to by Mr. Schwartz would occur according to EVA when natural gas prices rose above

²⁹ *Id.* at 5-6.

³⁰ Jesse Gilbert & Steve Piper, *Eroding Prospects for Summer Demand Highlight SNL Energy’s August Coal Forecast*, SNL Financial (Aug. 1, 2013).

³¹ Emily S. Medine, *Coal-Gas Switching*, Energy Ventures Analysis, Inc. 4 (Jan. 31, 2013) [hereinafter EVA–Coaltrans].

³² Coaltrans supports conferences on emerging coal trends for market participants. Its conferences are organized on a worldwide basis. The Miami conference quoted here was the United States coal conference. In attendance are CEOs from the coal industry and many business and trade leaders.

³³ EVA–Coaltrans, *supra* note 31, at 2.

³⁴ *Id.* at 20.

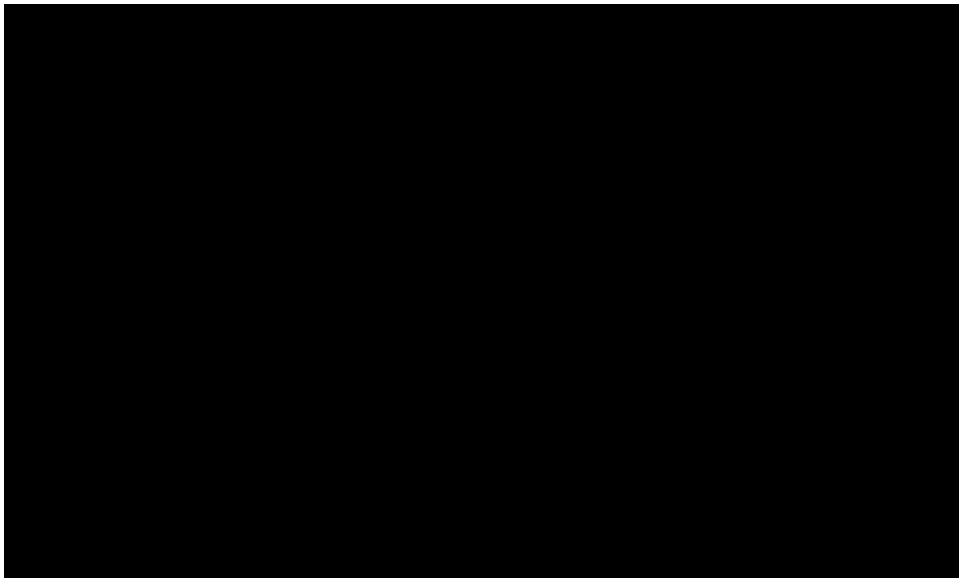
³⁵ *Id.* at 18.

\$5mm/btu.³⁶ According to the EIA, since January 2013 the average monthly price of natural gas rose above \$5.00 mmbtu in only one month.

Had Mr. Schwartz provided a more circumspect analysis of the long-term impacts of low natural gas prices and reflected actual 2013 coal production in both his statements, his claims would have been confounded by the facts of declining production, slowing markets, plummeting prices, and the persistence of low natural gas prices.³⁷

In sum, while Mr. Schwartz is technically correct to portray the EIA's scenario as a growth scenario, the growth scenario is essentially flat. As demonstrated throughout this Verified Statement, in order for Otter Creek to succeed, it would require coal market growth that is far more robust than the flat growth EIA and other coal analysts project.

B. The recent past shows deterioration in PRB demand and the future looks worse.



³⁶ *Id.* at 22.

³⁷ U.S. Energy Info. Admin., *Natural Gas*, EIA.gov, <http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm> (last visited Mar. 26, 2015).

The forward outlook for coal gets worse. Mr. Schwartz used the EIA 2013 Annual Energy Outlook (“2013 AEO”) to support his claim of a robust market.³⁸ However, the EIA’s outlook for the PRB has declined precipitously year after year. Year to year comparisons of EIA’s estimates highlight general market direction and production levels. In 2011, the EIA’s AEO Coal Outlook estimated PRB coal production in 2030 at 699 mtpa (See Table II: EIA 2011 AEO). In the 2013 AEO scenario, the EIA’s estimate for 2030 dropped by more than 150 mtpa to 540 mtpa (see Table II).³⁹ In 2014, after Mr. Schwartz’s August 2013 Verified Statement, the EIA reduced its PRB coal outlook in 2030 by 47 mtpa to 493 mtpa (See Table II: EIA 2014). The EIA reduced its 2030 long-term outlook by 206 mtpa in three years.

**Table II: Actual/Projected PRB Production Arch/EIA: 2010-2030 (Table Format)
(Million tons)**

Year	Arch PRB December 2011	EIA 2011 AEO April 2013	EIA 2013 AEO June 2013	EIA 2014 AEO	Actual
2010	473	477	473	473	468
2011	465	465	468	468	463
2012	491	483	431	425	419
2013	514	488	460	447	408
2014	522	486	453	458	418

³⁸ Schwartz Comments, *supra* note 21, at 7.

³⁹ One cannot find this number in the actual EIA file on the website. Mr. Schwartz has combined the projections for Western Montana and Powder River Basin. This combining of categories is a reasonable way to interpret PRB data consistent with EIA’s other definitions of the region. See U.S. Energy Info. Admin., *Total Energy Supply, Disposition, and Price Summary, Reference Case*, EIA.gov, <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=7-AEO2011&table=95-AEO2014&region=0-0&cases=ref2014-d102413a> (last visited Mar. 25, 2015).

2015	544	491	425	481	
2016	567	493	406	450	
2030		699	540	493	

Mr. Schwartz had access to the earlier EIA Outlooks. The trend was (and is) down, not the robust growth he states. He also had access to mid-year EIA 2013 data showing continued weakened demand. Had Mr. Schwartz included these key data points—EIA reductions in the long-term PRB outlook plus the flat/declining trend evident by actual production through 2Q 2013—there would have been insufficient support for his overly optimistic market perspective for the Otter Creek project.

Figure I, shown above, also strongly suggests that the EIA projections overestimated PRB production for the last several years. For EIA data to be of value it requires broader context. In contrast to Mr. Schwartz's approach, the standard practice among analysts is to supplement EIA data with knowledgeable market analysis and data of actual performance.⁴⁰

[REDACTED]⁴¹ [REDACTED]
[REDACTED] For example, [REDACTED]
[REDACTED] The EIA's 2011 estimate for PRB in 2016 was 493 mtpa.

⁴⁰ The EIA publishes a comparison of its projections against actual performance. It also frequently updates its information with data and analysis on changing trends. See U.S. Energy Info. Admin., *Analysis & Projections: Annual Energy Outlook Retrospective Review – Evaluation of 2013 and Prior Reference Case Projections*, EIA.gov (Apr. 7, 2014), <http://www.eia.gov/forecasts/aeo/retrospective/>.

⁴¹ [REDACTED]

All of EIA’s projections estimate very slow growth for the PRB region, if any. The estimates are consistent with the last three years of coal production in the United States and the PRB. This weak outlook reflects the actual condition of the coal market in the PRB.

C. EIA projections for Montana coal follow the same downward adjustments as the rest of the PRB.

Mr. Schwartz makes an aggressive case for Montana coal—the market for the coal is growing he says:

EIA forecasts growth in domestic demand of 20 million tons over 2011 by 2030 . . . and an increase of 10 million tons in domestic demand by 2019. Importantly, this is just the projected increase in domestic demand for Montana PRB coal. A significant share of the new development of Otter Creek mine coal is likely to be shipped to the growing export market as well.⁴²

However, the data do not support his claims.

Table III. EIA Projections of Montana Coal 2012, 2013 and 2014 and actuals (2011-2014)

Year	AEO EIA 2012	AEO EIA 2013	AEO EIA 2014⁴³	Actual
2011	48.99	41.65	41.65	42.0
2012	43.21	30.95	36.4	36.7
2013	48.83	36.22	43.27	42.2

⁴² Schwartz Rebuttal Comments, *supra* note 22, at 6.

⁴³ U.S. Energy Info. Admin., *Coal Production by Region and Type, Reference Case*, EIA.gov, <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=7-AEO2014&table=95-AEO2014&region=0-0&cases=ref2014-d102413a> (last visited Mar. 25, 2015).

2014	52.4	39.95	46.3	42.2(est)
2015	58.77	44.2	50.99	
2016	63.06	41.63	48.7	
2020	66.55	53.74	55.3	
2025	76.74	57.42	57.46	
2030	73.5	62.55	56.97	
2035	80.68	68.61	59.25	

Although Mr. Schwartz portrays Montana as a region with rapid demand, the last ten years of growth have been flat. Since 2005, (see Table I) Montana has averaged 41.7 mtpa. The most recently reported period from 2012 to 2014 is in the 42 mtpa range. (Table III: Montana Actual). There have been some up years and some down years, but over the last three years the production has been about average. There are no precipitating events or long term growth trends that Mr. Schwartz can point to sustain an argument of robust growth.

Mr. Schwartz's claims are incorrect for several reasons. First, looking forward, the 2013 AEO forecast relied upon by Mr. Schwartz shows a 2030 production level of 62.55 mtpa (see Table III) from Montana, 20 mtpa more than actual 2011 production (and average annual production from 2012 to 2014 in the 42 mtpa range).⁴⁴ The 2013 EIA

⁴⁴ Mr. Schwartz makes a point that the 2013 EIA Annual Energy Outlook data he identifies is domestic demand data. He asserts that the mine will also serve an unspecified export demand. Mr. Schwartz refers the reader to: U.S. Energy Info. Admin., *Coal Supply, Disposition, and Prices, Reference Case*, EIA.gov, <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=7-AEO2013&table=95-AEO2013&region=0-0&cases=ref2013-d102312a> (last visited Mar. 25, 2015). This chart is entitled "Coal Production by Region Type and Reference." It represents total production by sub-region, including Western Montana. This chart is inclusive of all production with no distinction

AEO demonstrates continued growth after 2030. This level of demand might support a new mine, but according to the EIA this demand level [REDACTED]

[REDACTED].⁴⁵ The 2012-2025 average annual production anticipated by EIA, 2013 EIA Montana estimates is 43.4 million tons, slightly above the historical average.

Second, such an assumption ignores the fact that Cloud Peak Energy and Signal Peak/Gunvor also mine and ship coal out of their Montana operations at Spring Creek⁴⁶ and Bull Mountain for both export and domestic consumption. Production in 2014 for

made for import and exports for Western Montana coal. Other charts in this database do make distinctions. See U.S. Energy Info. Admin., *Total Energy Supply, Disposition, and Price Summary, Reference Case*, EIA.gov, <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=7-AEO2013&table=15-AEO2013&region=0-0&cases=ref2013-d102312a> (last visited Mar. 25, 2015). This chart, "Supply, Disposition and Prices," nets out U.S. imports and exports to show total U.S. supply. The total production numbers are the same for both charts. Mr. Schwartz's observation regarding the EIA data is wrong.

⁴⁵ The Application before the STB states that the first year of commercial operation for the mine is 2017. Verified Statement of William M. Rowlands at 3, *Tongue River R.R. Co.—Rail Constr. & Operation—In Custer, Powder River & Rosebud Cntys., Mont.*, No. 30186 (S.T.B. Sept. 21, 2012) and reaffirmed in William M. Rowlands' later Verified Statement (S.T.B. Dec. 13, 2012).

[REDACTED]
[REDACTED]
[REDACTED] The date for commencement of mining is January 2019. See ARM 17.24.303_R1_20141021_Otter Creek Mine, Exhibit 202C, Ownership and Control Otter Creek Mine, <http://deq.mt.gov/ea/ottercreek1stoundresponse.mcp>x (last visited Mar. 26, 2015). On March 19, 2015, the DEQ submitted a 65 page list of deficiencies that needed to be corrected. This should take the process through the end of at least 2015 putting the in service date optimistically in 2019 or 2020. [REDACTED]

[REDACTED]
Cloud Peak Energy, Inc., *Annual Report (Form 10-K)* 5 (Feb. 14, 2014), available at <http://api40.10kwizard.com/cgi/convert/pdf/CLD-20140214-10K-20131231.pdf?ipage=9391982&xml=1&qquest=1&rid=23&section=1&sequence=-1&pdf=1&dn=1>. The Spring Creek mine serves both domestic and international markets.

export out of these mining operations was approximately 12 million tons.⁴⁷ Each company is producing below capacity levels.⁴⁸ Each company is heavily involved with mining Montana coal for international export. Having made significant capital investments, it is unlikely that these companies will abandon their export expansion plans. In addition, Peabody Energy,⁴⁹ Ambre Energy/Resource Capital Funds,⁵⁰ and Alpha Natural Resources⁵¹ also have plans to move PRB coal off the west coast and into the Asian market.

Third, ACI claims it may open the Otter Creek mine in the 2020 period. According to the EIA's 2013 outlook, in 2020 Montana is expected to produce 54 million tons, 12 million above the current levels. Given the existing competition, there is no prospect for a 20 mtpa Montana mine entering the market in the early 2020 period.

Fourth, Mr. Schwartz's incomplete analysis relied on EIA's 2013 AEO forecast. After TRRC submitted Mr. Schwartz's Verified Statement, the EIA revised its 2014 long-

⁴⁷ Coal and Energy Report, *Powder River/Bull Mountain Production 2008-2013, 2014 Projected*, (Hanou Energy), (Oct. 29, 2014) reports 8.2 million tons projected from Bull Mountain/Signal Peak in 2014. SNL Energy/Companies and Assets/Signal Peak/Power Plants Served reported domestic deliveries of 263,000 tons in 2014. Cloud Peak reports between 4.0 and 4.5 million tons exported. Cloud Peak Energy, *Press Release: Cloud Peak Energy Amends Throughput Agreement with Westshore Terminals to Increase Committed Export Capacity and Extend Term* (Aug. 8, 2014), <http://investor.cloudpeakenergy.com/press-release/business-development/cloud-peak-energy-amends-throughput-agreement-westshore-terminals>.

⁴⁸ Spring Creek production was down slightly in 2014 from 2013 levels. Epps & Fawad, *supra* note 10. Gunvor reported 8.7 million tons in 2013 and has a stated goal for the mine of 15 million tons per year. Christopher Coats, *OSM Increases Signal Peak's Footprint with Environmental Review*, SNL Financial (Oct. 28, 2014).

⁴⁹ Clifford Krauss, *U.S. Coal Companies Scale Back Export Goals*, N.Y. Times (Sept. 13, 2013) http://www.nytimes.com/2013/09/14/business/energy-environment/us-coal-companies-scale-back-export-goals.html?pagewanted=all&_r=0.

⁵⁰ Darren Epps, *Vote Set for Private Equity to Take Over Ambre Energy's U.S. Operations*, SNL Financial (Nov. 28, 2014).

⁵¹ Mayur Sontakke, *Why ANR's Operations in the Powder River Basin Face Challenges*, Market Realist (Nov. 6, 2014), <http://marketrealist.com/2014/11/why-anrs-operations-powder-river-basin-face-challenges/>.

term outlook downward to 57 mtpa by 2030. From the EIA 2011 to the EIA 2014 estimate of 2030 there is an anticipated 16 mtpa reduction of the Montana production estimates. According to the EIA, the out years through 2035 get worse, not better, as the gap between its 2012 and 2014 estimate for Montana is now a 21 mtpa decline. Again, technically there is some projected growth, but the trajectory of production estimates is declining and is insufficient to warrant new mine investment.

D. Price signals undermine what little support there may be for opening Otter Creek.

The trend toward declining PRB production and the erosion in the EIA's long-term production estimate for the PRB and Montana is further illustrated by low coal prices in the region. The spot price for PRB 8800 coal currently stands at \$10.95 per ton.⁵² Few spot market sales occur at this level as coal producers would lose money. For example, ACI's 2014 cost of production in the PRB is \$11.04 per ton.⁵³

Companies, like ACI, achieve a better price through longer-term, more reliable demand secured through multi-year contracts with domestic utilities. ACI, for example, disclosed PRB coal sales for 2014 at \$12.86 per ton and offered guidance for 2015 and 2016 based on some contracted capacity at \$13.39 per ton and \$14.58 per ton, respectively.⁵⁴ Cloud Peak posted estimated 2014 results at \$13.01 per ton and anticipates

⁵² Platts McGraw Hill Financial, *Coal Trader: Incorporating Coal Outlook, Platts Daily OTC Assessment 1* (Mar. 23, 2015).

⁵³ Arch Coal, Inc., *Press Release: Arch Coal, Inc. Reports Fourth Quarter and Full Year 2014 Results* (Feb. 3, 2015, 7:45 AM), available at <http://news.archcoal.com/phoenix.zhtml?c=107109&p=irol-newsArticle&ID=2012926> [hereinafter *Press Release: Arch Coal, Inc.*].

⁵⁴ *Id.*

2015 prices at \$12.92 per ton.⁵⁵ Alpha Natural Resources posted PRB coal revenues at \$11.89 per ton in 2014 and anticipates a slight decline to \$11.83 per ton with 82% capacity committed.⁵⁶

Even as ACI secures contract prices significantly higher than spot prices and higher than some of its peers, the company posted razor thin PRB margins of \$0.28 per ton in 2014.⁵⁷ These slim margins were achieved after the company significantly reduced operating costs in the PRB.⁵⁸ The 2015 EIA STEO anticipates additional price slippage in 2015 and 2016.⁵⁹ The current market price of coal received by ACI and other PRB producers does not cover expenses and sufficient profit to warrant additional investment in new mine capacity. For example, citing weak market conditions, ACI has pulled back an application for a new long-term lease for the West Jacobs mine.⁶⁰

E. The United States domestic price of coal is down and the global thermal export market offers no opportunity for ACI to improve its cash position from the Otter Creek mine.

With shrinking opportunities in the United States, ACI, like many other coal producers, announced plans to move forward with coal export strategies. In 2011 and 2012, rising

⁵⁵ Cloud Peak Energy, Inc., *Press Release: Cloud Peak Energy, Inc. Announces Results for Fourth Quarter and Full Year 2014* (Feb. 17, 2015), available at <http://investor.cloudpeakenergy.com/press-release/earnings/cloud-peak-energy-inc-announces-results-fourth-quarter-and-full-year-2014>.

⁵⁶ Alpha Natural Resources, *Press Release: Alpha Natural Resources Announces Results for Fourth Quarter and Full Year 2014* (Feb. 2, 2015), available at <http://ir.alphanr.com/file.aspx?IID=4100842&FID=27648419>.

⁵⁷ *Press Release: Arch Coal, Inc.*, *supra* note 53.

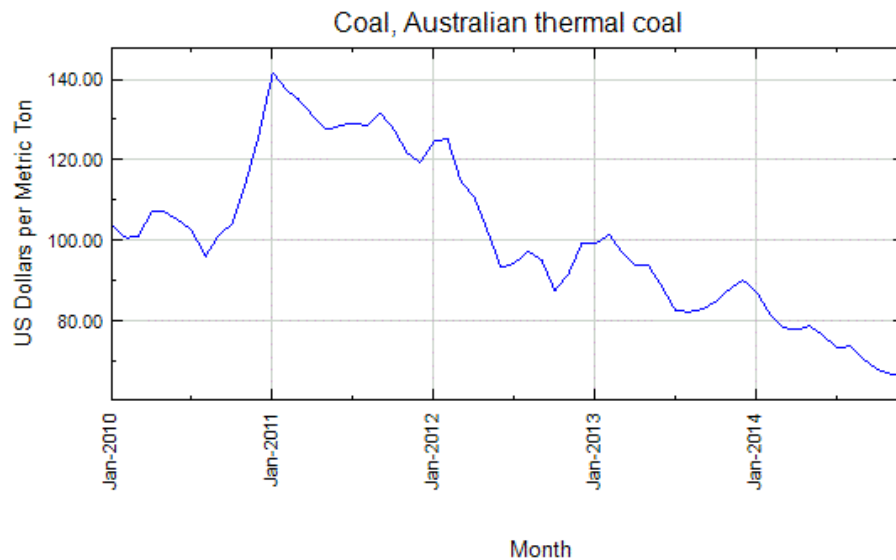
⁵⁸ *Id.*

⁵⁹ *2015 STEO*, *supra* note 5.

⁶⁰ Associated Press, *Arch Coal Cites Weak Market in Request to Withdraw Coal Lease Application in NE Wyoming*, *Daily J.*, <http://www.dailyjournal.net/view/story/950e3db1c7e44f24bd6c38a0efe79a09/WY--Coal-Lease/> (last updated Mar. 9, 2015, 7:44 AM).

global demand and prices on the thermal market gave this scenario plausibility. However, the global thermal coal market is now oversupplied. In the current market and for the foreseeable future, U.S. coal producers and PRB coal producers have limited export opportunities. Current international thermal market sales from the United States are probably based on pre-existing contracts and are not profitable.⁶¹ Going forward, the overall market for U.S. coal producers in the Pacific Rim is likely to get worse.⁶²

Figure II: U.S. Exports: Global Price Collapse



Index Mundi.com⁶³

⁶¹ John Bridges, J.P. Morgan, North America Equity Research, *Global Coal Update: Oversized Mine, Rail and Port Capacity Leads to Skinny Prices; U.S. Miners Watch their Thermometers* (June 29, 2014), available at http://pg.jrj.com.cn/acc/Res/CN_RES/INDUS/2014/6/29/37603388-1ecd-419e-8cbd-bd7d51fc5902.pdf.

⁶² For a detailed analysis of the nature of changes in the global seaborne thermal market as China's 25% market share declines see the Bernstein Research. Bernstein Research, *Asian Coal & Power: Less, Less, Less . . . The Beginning of the End of Coal* 117–24 (June 2013), available at http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CB4QFjAA&url=http%3A%2F%2Fwww.fossil.energy.gov%2Fprograms%2Fgasregulation%2Fauthorizations%2F2013_applications%2Fsierra_club_13-69_venture%2FEx._110_-_Bernstein_peak_coal_report.pdf&ei=JQcTVbPiJqblsASR6oHYCA&usg=AFQjCNE87qzDcOc_8deqxSAYQTgSZbTE9Q&bvm=bv.89217033,d.cWc.

⁶³ IndexMundi, *Coal, Australian Thermal Coal*, IndexMundi.com, <http://www.indexmundi.com/commodities/image.aspx?commodity=coal-australian&months=60> (last visited Mar. 25, 2015).

International thermal coal prices have collapsed (see Figure II) and are likely to stay low for the foreseeable future. The price of Newcastle Coal, an Australian coal product used as a global benchmark for thermal coal, fell dramatically from 2011 to the present. At its peak in January 2011, the price was \$141.94 per ton. On March 19, 2015, the Newcastle price was \$59.50 per ton.⁶⁴ Looking forward, one Newcastle Coal Futures database identifies coal price contracts from 2016 to 2021 trading in the \$61.00 to \$66.00 range.⁶⁵ (See Figure III) Persistent low prices are a sign that demand is falling. More to the point, the robust assumptions made by ACI and many other coal consultants at the high point of the market in 2011 no longer have a sound basis.

In late 2010,⁶⁶ Peabody Energy and early 2011 ACI⁶⁷ each provided an analysis of the Chinese coal markets using price points in the \$90 per ton range. Each company was predicting net back profits (the amount of profit received by the U.S. coal producer from the international market price of coal minus transport and logistics costs) in the \$20 per ton margins for this market. In 2012, China imported 318 million tons of coal (up from 200 million tons in 2011)⁶⁸ and coal producers worldwide were predicting longer-

⁶⁴ For the current price of coal, see Platts McGraw Hill Financial, *Coal Trader International, Incorporating International Coal Report 1* (Mar. 19, 2015). Some analysts see the price dropping below \$60.00 per ton through 2016. Jonathan Rowland, *Coal Prices to Drop Further – BofA Merrill Lynch*, World Coal (Dec. 3, 2014) <http://www.worldcoal.com/coal/12032015/Coal-prices-to-drop-further-BofA-Merrill-Lynch-coal2059/>.

⁶⁵ *ICE NewCastle Coal Futures Prices*, Barchart.com (Mar. 24, 2015) http://www.barchart.com/commodityfutures/ICE_NewCastle_Coal_Futures/LQ.

⁶⁶ Peter Gartrell & John Miller, *Peabody Projections Show Lucrative Chinese Market for PRB Coal*, Platts Coal Trader (Dec. 6, 2010).

⁶⁷ Peter Gartrell, *Arch CEO Sees \$20 Range for PRB Coal to Asia*, Platts Coal Trader (Jan. 31, 2011).

⁶⁸ U.S. Energy Info. Admin., *International Energy Statistics 2008-2012*, EIA.gov, <http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=1&pid=1&aid=3> (last visited Mar. 25, 2015).

term growth from this source.⁶⁹ More recently, Cloud Peak Energy stated it would require a Newcastle price between \$80 and \$90 per ton before selling coal to China.⁷⁰

During 2014, the market for Chinese imported coal and the global coal market more generally cooled (see discussion below) and global prices have collapsed.⁷¹ Most financial analyst projections have evolved to a clear consensus: as China reduces its import needs, sufficient capacity from the Pacific Rim producers (Australia, South Africa, Indonesia, and Russia) exists to meet the needs of the remaining import countries, including India. United States coal producers will fill a niche market but one not much larger than what exists today (see discussion below by Goldman Sachs, J.P. Morgan, Bernstein Research, and Citigroup). This is also the conclusion of the extensively researched product released by Carbon Tracker Institute and the Institute for Energy Economics and Financial Analysis.⁷² A recent compilation of futures market contracts for Newcastle Coal places the price range from 2015 to 2021 in the mid \$60 per ton range.⁷³

⁶⁹ Dan Lowrey, *Woodmac Sees Half of US Coal Production Exported by 2030*, SNL Financial (Mar. 7, 2012).

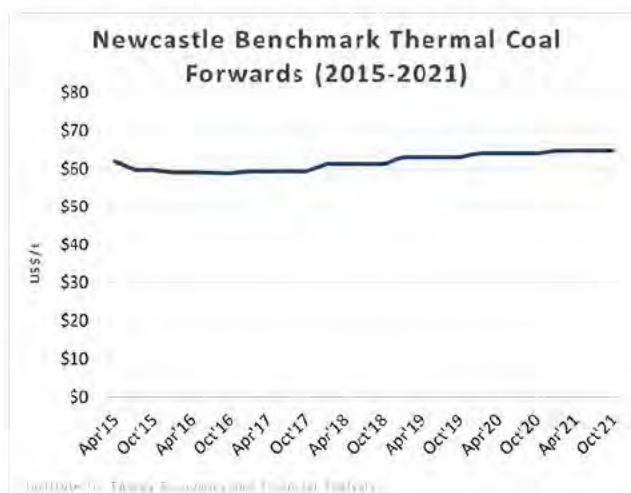
⁷⁰ *Cloud Peak Energy's CEO Discusses Q1 2014 Results – Earnings Call Transcript*, SeekingAlpha.com (Apr. 29, 2014, 5:00 PM), <http://seekingalpha.com/article/2175763-cloud-peak-energys-ceo-discusses-q1-2014-results-earnings-call-transcript?part=single>.

⁷¹ Damian Carrington, *China's Coal Use Falls for First Time this Century, Analysis Suggests*, Guardian (Oct. 22, 2014, 9:37 AM), <http://www.theguardian.com/environment/2014/oct/22/chinas-coal-use-falls-for-first-time-this-century-analysis-suggests>.

⁷² Inst. for Energy Econ. & Fin. Analysis, *Carbon Tracker Initiative* (Sept. 22, 2014), available at <http://www.carbontracker.org/wp-content/uploads/2014/09/Coal-Demand-IEEFA-complete.pdf>.

⁷³ *Stock Market Quotes & Charts: Quote Board*, eSignal.com (Mar. 24, 2015) <http://quotes.esignal.com/esignalprod/quote.action?symbol=NCFQ-ICE>.

Figure III: Newcastle Benchmark Thermal Coal Forwards (2015-2021)



F. The supposed cost of production advantage at Otter Creek is eviscerated by the severe and persistent drop in the price of coal on the global thermal market.

[REDACTED]

[REDACTED]⁷⁴ The Norwest appraisal, prepared as part of the Montana State Land Board coal lease deliberation, assumed in 2006 that 2015 prices for the first year of production would be between \$6.20 and \$6.82⁷⁵ per ton. Using a 2% annual adjustment (and assuming a 2020 date of commercial operation) this would make the first year estimated costs between \$6.90 per ton and \$7.50 per ton.⁷⁶ ACI has not independently updated the 2006 Norwest appraisal, nor offered its own analysis of the cost of production from the mine. ACI's 2014 cost of production for its PRB mines was \$11.04 per ton and when

⁷⁴ [REDACTED]
[REDACTED]
[REDACTED]

Norwest Corporation, *Otter Creek Property Summary Report: Volume I of II* (July 12, 2006).

⁷⁶ Another document prepared by JT Boyd Consultants in 2011 relying on subsequent mining studies of OC place the advantage for ACI at \$4.00 per ton in 2020 and pegs the 2020 cost of production at \$8.96 per ton. John T. Boyd Co., *Powder River Basin Coal Resource & Cost Study* (Sept. 2011), available at <http://www.xcelenergy.com/staticfiles/xcel/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/8-Roberts-Exhibit-No-MWR-1.pdf>.

adjusted through 2020 ACI's cost of production would be \$12.45 per ton. The relative advantage using these assumptions for Otter Creek is \$5.0 to \$5.6 per ton over Arch's average PRB costs.

TRRC claims about the cost advantage of the Otter Creek mine are offered based on an almost ten-year-old estimate. The conclusory statements Messrs. Blumenfeld and Schwartz make regarding the Otter Creek mine are not based on any actions taken by ACI to verify the estimates independently. The estimate lacks a solid foundation. Assuming this range of relative cost advantage is accurate, a closer look at other potential revenue and expense factors show the purported advantage rapidly disappears.

Table: IV Comparison of ACI/Peabody 2010/11 Estimates of Coal Export Profits versus current markets

	ACI/BTU - December 2010 ⁷⁷	Current
Asian Coal Price	\$96.28	\$65.00
Expense Transport	(\$58.71)	(\$58.71)
Market Price US	(\$13.65)	(\$13.39)
	\$23.92	(\$7.10)

When ACI and Peabody (see Table IV) identified the price they needed to make a comfortable profit on exported coal in 2010 and 2011, they said a comfortable coal price would be \$96.28 per ton. Looking forward, the Newcastle price is in the mid \$60 per ton range.⁷⁸ At this price, using basically the same assumptions and ACI's most recent contracted coal prices for 2015, coal exports lose money. The \$31.00 per ton drop in

⁷⁷ Gartrell & Miller, *supra* note 66. See also Gartrell, *supra* note 67.

⁷⁸ On March 19, 2015, Platts Coal International listed prices for the Quinhuangdao 4200 and 5000 coal products as \$52.50 and \$58.40 per ton respectively. Platts McGraw Hill Financial, *supra* note 64, at *China Coal Index Physical Coal Benchmark Prices*. These coals are comparable to PRB coal. As noted above the Newcastle benchmark price was at \$59.50 per ton.

market price for thermal coal from 2010/2011 to today and through 2020/2021 eviscerates the profit margin identified by ACI and Peabody at the \$96.28 per ton level for exported coal. PRB coal in China and exports to Asia more generally are ‘out of the money’, uncompetitive.

Mr. Schwartz also asserts that Otter Creek would replace higher cost mines and therefore be a good source of coal for domestic use. This is a statement without sufficient foundation. To be accurate, TRRC should support this conclusion with a business plan. Such a plan would reflect a realistic market price for coal in a much smaller domestic market, updated operating costs for Otter Creek certified by ACI (preferably with independent corroboration), and the full debt service costs inclusive of the mine, rail, and port. ACI has taken on full ownership of the mine and partial ownership of the rail and port. Unlike a typical domestic mine where capital investment is restricted to mine acquisition and mine development costs, ACI has determined that, in order to move this coal to market, it must also invest in a rail line and port. [REDACTED]

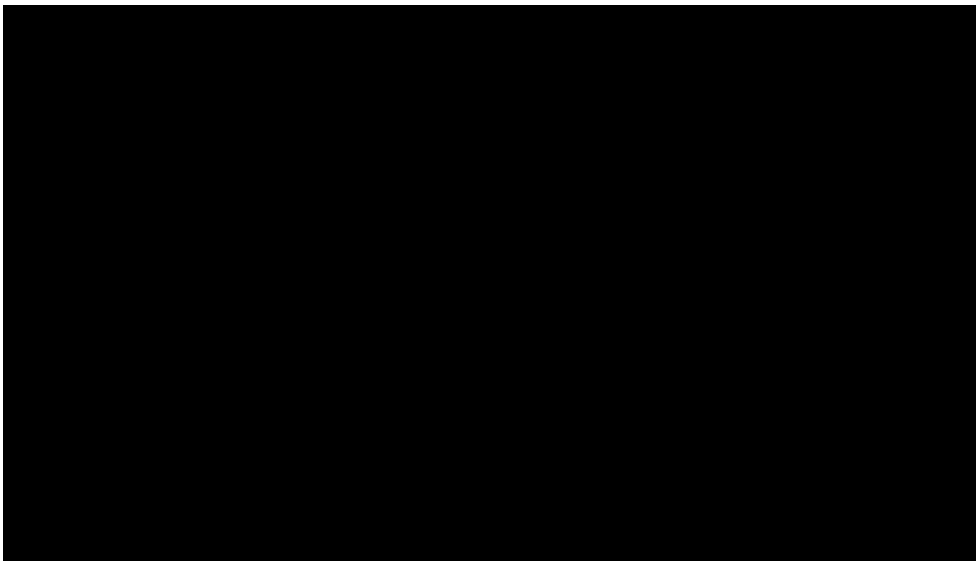
[REDACTED]

[REDACTED]

[REDACTED] The debt burden on Otter Creek does not disappear simply because coal is sold domestically. In fact, the financial viability is made worse the more domestic coal is sold at a lower price than exported coal in a future, presumably more robust market. ACI is already severely overburdened by debt (see discussion below: *Looming Debt Burden*). Otter Creek is only likely to increase ACI’s substantial debt burden.

G. EIA data on exports show a weakening market for United States coal exports both on a short and long-term basis.

Between 2011 and 2013, the EIA increased its estimate of United States thermal coal exports. Recently the EIA has downgraded its short-term exports outlook. Actual thermal coal exports out of the United States have declined since peak 2012 levels (Figure IV: Actual). Export levels are expected to stay flat or drop through 2030 according to a host of investment bankers and analysts (see discussion below of J.P. Morgan, Morgan Stanley, Bernstein Research, and Citigroup).



There are three observations regarding actual thermal coal export performance and the projections of ACI and the EIA. First, actual thermal coal exports peaked in 2012 and have dropped in each year thereafter. (Figure IV: Actual). Second, [REDACTED]

[REDACTED]

⁷⁹ SNL's Coal Forecast of Steam coal demand ranges from 40 mtpa in 2015 rising to 47 mtpa in 2017 and dropping off to 40 mtpa in 2020.

██████████⁸⁰ In 2014, only 31 million tons were exported.⁸¹ Third, the most recent 2015 EIA STEO published February 10, 2015 downgrades the 2015 and 2016 export outlook by 30% from the EIA's 2014 outlook (See Figure IV: EIA STEO 2015).

The EIA's underlying long-term outlook for Asian coal exports has been low and remained relatively stable. The Annual Energy Outlooks for 2012,⁸² 2013,⁸³ and 2014⁸⁴ start with 2011 baseline figures between 8 and 12 mtpa (actual was 8.1 million tons) and rise to a range of 21.3 to 22.4 mtpa by 2030. This estimate supports, perhaps 10 mtpa of new demand in an environment where there are six known competitors. Even when the EIA projected increases in overall United States coal exports its view of Asian demand remained relatively static, lagging other markets as a destination region for United States coal exports.

H. Industry analysts forecast weak United States coal exports.

Like many other analysts, WM, a coal consultant relied upon by ACI and BNSF, have altered their once-optimistic position with regard to the export potential of PRB

⁸⁰ ██████████

⁸¹ Rohan Somwanshi, *Global Coal Exports in 2014 Exceed Demand, a Gap Expected to Widen in 2015*, SNL Financial (Feb. 27, 2015).

⁸² U.S. Energy Info. Admin., 2012 Annual Energy Outlook, *World Steam Coal Flows By Importing Regions and Exporting Countries, Reference Case*, available at <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=7-AEO2012&table=96-AEO2012&region=0-0&cases=ref2012-d020112c>.

⁸³ U.S. Energy Info. Admin., 2013 Annual Energy Outlook, *World Steam Coal Flows By Importing Regions and Exporting Countries, Reference Case*, available at <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=7-AEO2013&table=96-AEO2013&region=0-0&cases=ref2013-d102312a>.

⁸⁴ U.S. Energy Info. Admin., 2014 Annual Energy Outlook, *World Steam Coal Flows By Importing Regions and Exporting Countries, Reference Case*, available at <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=7-AEO2014&table=96-AEO2014&region=0-0&cases=ref2014-d102413a>.

coal. The company published a broad analysis of domestic and global coal markets and export potential out of the United States in March 2012. Nationwide WM projected United States exports would increase to 500 mtpa by 2030.⁸⁵ This analysis was widely distributed within the coal and investor community.⁸⁶ [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED];⁸⁹ 3) GDP growth and specific additions to coal fired generation capacity were critical to the increases; 4) United States exports of thermal coal would expand from 53 mtpa in 2012 to 363 mtpa in 2030; and 5) United States market share would rise from 6% to 17% of the world market for thermal coal. [REDACTED]

[REDACTED].⁹⁰

⁸⁵ Wood Mackenzie, *Changing Supply/Demand Fundamentals Allow the U.S. to Reduce Dependence on Foreign Energy and Emerge as Important Energy Player* (Mar. 7, 2012), <http://www.woodmacresearch.com/cgi-bin/wmprod/portal/corp/corpPressDetail.jsp?oid=10429709>.

⁸⁶ Lowrey, *supra* note 69.

⁸⁷ [REDACTED]

[REDACTED]

⁸⁹ [REDACTED]

[REDACTED] See also Wood Mackenzie, *Global Thermal Trade Flow Changes will Ensure Security of Thermal Coal Supply, Albeit at a High Price* (Mar. 14, 2012), <http://www.woodmacresearch.com/cgi-bin/wmprod/portal/corp/corpPressDetailOpen.jsp?pass=10441615>.

⁹⁰ [REDACTED]

WM's aggressive export numbers were tempered by an otherwise bearish analysis of the domestic PRB market. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

In February 2015, WM⁹⁶ reversed its outlook on Asian demand for United States coal exports. WM identified a slowing Chinese economy, a growing divergence between commodity price and market growth versus GDP growth, and particularly identified short and medium term problems for United States coal producers⁹⁷ looking to export. The company identified a slowing economy, a change in economic priorities, and new policy directions in China policy with regard to air pollution. The company is projecting that the global thermal market will stay in a condition of oversupply through 2021 plus or minus how many new mine projects are actually delayed.⁹⁸

91 [REDACTED]

⁹⁶ CHINA: Energy Demand has Decoupled Significantly from GDP, says Wood Mackenzie Economist, EnergyAsia (Feb. 17, 2015), <http://energyasia.com/blog/china-energy-demand-decoupled-significantly-gdp-says-wood-mackenzie-economist/>. See also Wood Mackenzie: China's Energy Demand Needs Review Amid Economic Changes, Rigzone (Jan. 29, 2015), http://www.rigzone.com/news/oil_gas/a/136981/Wood_Mackenzie_Chinas_Energy_Demand_Needs_Review_Amid_Economic_Changes/?all=HG2.

⁹⁷ Wood Mackenzie, *Australian Coal Mines Best Positioned; US Most at Risk* (Feb. 8, 2015), <http://www.woodmac.com/public/media-centre/12526159>.

⁹⁸ Rohan Somwanshi, *Analyst: Sporadic Coal Mine Closures to Not Enough to Rebalance Oversupplied Market*, SNL Financial (Feb. 17, 2015).

SNL Energy maintains a database of coal industry information. It also offers a Coal Forecast consisting of supply, demand, and price estimations through 2025 (see Appendix I). [REDACTED].⁹⁹ SNL estimates for the PRB show largely flat production levels but declining overall projections for United States production. Production levels fall through 2025 from 1.008 billion tons per year in 2015 to 999 million tons by 2025. Southern PRB production is flat through 2025 and Montana coal (Northern PRB) drops slightly from 40 mtpa to 38 mtpa. Steam coal export estimates remain largely flat in the 44-47 million ton range through 2020 and then drop to 40 million ton per year by 2035 (See Appendix I).

I. Independent investment analysts overwhelmingly project severe retrenchment in the global thermal coal market.

The four investment perspectives quoted below were originally released in June, July, September, and October 2013. These perspectives support and enrich the trends and direction of the EIA data discussed above. The perspectives provide qualitative support that the export market for United States coal is presently under severe stress and it is likely to remain so for the foreseeable future. The studies and several actions by these banks and analysts form a general consensus that the international coal market is oversupplied. Global coal producers will face low prices and tight margins. Bernstein Research points to the structural nature of the changes stating the trend is not likely to reverse itself. Citibank concludes that the end of the coal super cycle is here. Goldman Sachs says capital shifts from larger mining concerns suggest a significant move away from coal. J.P. Morgan concludes it is not economic to export coal at present.

⁹⁹ [REDACTED]

These trends will likely continue as China's need for coal imports diminish. Each of these analyses uses as a backdrop the dramatic rise of Chinese thermal imports over the last decade. The Chinese import market peaked in 2013 at 330 mtpa.¹⁰⁰ The worldwide market for seaborne was approximately 858 million tons in 2013.¹⁰¹ In 2014, China's coal imports declined to 289 mtpa.¹⁰² When China buys less coal on the global market it drives down demand and price.

Bernstein Research concluded its work in the spring of 2013:

Decelerating power growth and structural weakness in other end markets, combined with more hydro, nuclear and renewables and more coal production and rail capacity in China, add up to the once unthinkable: zero net imports in 2015 and falling Chinese demand by 2016.

Globally, Chinese demand for coal has been the primary driver or the backstop behind every new investment in coal mining over the last decade; the "global coal market" ended with the collapse in price in 2012; regional miners will see almost zero demand in China from 2015.

Once Chinese coal demand starts to fall there is no robust growth for seaborne thermal coal anywhere; developed market demand is weak due to gas, environmental concerns or industrial activity; that leaves just one large structural growth market for seaborne coal: India.¹⁰³

¹⁰⁰ Kalayano Teodoro, *Global Shipping Index Falls to Record Low as China Cuts Coal Imports* (Feb. 11, 2015).

¹⁰¹ Euracoal, Euracoal Market Report: World Coal Market Developments (1/2014), *World Coal Production and Seaborne Trade* (May 2014), available at http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CB4QFjAA&url=http%3A%2F%2Fwww.euracoal.com%2Fcomponenten%2Fdownload.php%3Ffiledata%3D1401266763.pdf%26filename%3DEuracoal%2520Market%2520Report%25201-14.pdf%26mimetype%3Dapplication%2Fpdf&ei=SgUTVar4LPSRsQT_qIDACg&usg=AFQjCNE7vyzD9bxBMmA-rPtZpFGHJFATQ.

¹⁰² Teodoro, *supra* note 100.

¹⁰³ Bernstein Research, *supra* note 62, at Cover Page.

The Bernstein analysis concludes that the global thermal coal market will never recover.¹⁰⁴ Thermal coal imports to China declined by 36 million tons in 2014 approximately 11%.¹⁰⁵ Goldman Sachs 2013 view of thermal coal markets cast a profile of a weak and declining market.

Earning a return on incremental investment in thermal coal mining and infrastructure capacity is becoming increasingly difficult. In the short term, a sharp deceleration in seaborne demand (we expect average annual growth to decline to 1% in 2013-17 from 7% in 2007-12) has moved the market into oversupply and caused a downward shift in the cost curve; **we downgrade our price forecasts** to US\$83/t in 2014 and US\$85/t in 2015 (down 13% and 11% respectively) and maintain a relatively flat outlook for the rest of our forecast period to 2017.

Mines are long-lived assets with a long payback period, and investment decisions today are sensitive not just to prices and margins today, but also to projections going well into the next decade. We believe that thermal coal's current position atop the fuel mix for global power generation will be gradually eroded by the following structural trends: 1) environmental regulations that discourage coal-fired generation, 2) strong competition from gas and renewable energy and 3) improvements in energy efficiency. The prospect of weaker demand growth (we believe seaborne demand could peak in 2020) and seaborne prices near marginal production costs suggest that most thermal coal growth projects will struggle to earn a positive return for their owners; in our view, this is reflected in the way diversified mining companies are reallocating their capital towards more attractive sectors¹⁰⁶

¹⁰⁴ *Id.* at 1.

¹⁰⁵ Naomi Christie and Kiyotaka Matsuda, *Shipping Costs Test New Low as China Coal Imports Slide: Freight*, Bloomberg Business (Feb. 5, 2015, 7:01 PM), <http://www.bloomberg.com/news/articles/2015-02-06/shipping-costs-test-new-low-as-china-coal-imports-slide-freight>.

¹⁰⁶ Goldman Sachs, *The Window for Thermal Coal Investment is Closing*, Rocks and Ores1 (July 24, 2013), available at <http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CB4QFjAA&ur>

Goldman Sachs' price downgrade in 2013 was followed by actual price declines far greater than estimated. Goldman anticipated a price of \$83 per ton in 2014. The average price for 2014 was \$70 per ton.¹⁰⁷ In January 2014, Goldman Sachs sold its stake in a coal port greenfield project in Bellingham, Washington a joint venture with SSA Marine Terminals (40+ million ton per year capacity).¹⁰⁸

In October 2013, J.P. Morgan analysts expressed their concerns regarding the ability of United States coal producers to access the global thermal coal market: “[w]hile the outlook for ILB coal appears stronger than other basins, the region is not immune from the challenged coal market,” Further, “[e]xport markets have been crucial in balancing supply-demand in the US; however, depressed international prices appear to have closed the door on new export contracts and could create domestic oversupply.”¹⁰⁹ In 2014, the company continued to weigh in with its analysis of the global thermal coal trade estimating a decline of United States thermal coal exports through 2016 from 49 mtpa to 36 mtpa.

It's not economic to export US coal at present, and while some sales are continuing; probably driven by take or pay commitments, we doubt new sales will be signed outside long standing relationships.

l=<http%3A%2F%2Fdivestinvest.org%2Fwp-content%2Fuploads%2F2014%2F01%2FGoldman-Sachs-Rocks-and-Ores-2013.pdf&ei=hQkTVd-3GazisATC7II4&usg=AFQjCNHCv0D3bT2qtx2wf1hlItQxpg7W6A&bvm=bv.89217033,d.cWc>.
¹⁰⁷ *World Bank Commodities Price Data (The Pink Sheet)*, World Bank (Jan. 6, 2015), http://siteresources.worldbank.org/INTPROSPECTS/Resources/334934-1111002388669/829392-1420582283771/Pnk_0115.pdf.

¹⁰⁸ *UPDATE 2-Goldman Fund Sells Stake in Port Eperator SSA Marine*, Reuters (Jan. 7, 2014, 8:48 PM), <http://www.reuters.com/article/2014/01/08/goldman-port-sale-idUSL2N0KI00U20140108>.

¹⁰⁹ Darren Epps, *Analyst: Illinois Basin Stable but Not Immune to Coal Market Weakness*, SNL Financial (Oct. 8, 2013).

US coal exports are falling more quickly now, but with other countries apparently concluding it's easier to drop costs rather than production, seaborne prices are reaching new lows.¹¹⁰

In September 2013, Citibank¹¹¹ offered its view identifying broad changes in Chinese GDP, pollution and energy policy, internal country improvements, rising influence of renewables, and other energy sources to conclude that coal producer's looking to enter the export market were going to find it very difficult to succeed.

As the range of forecasts for Chinese coal demand is wide, we believe investors should price in higher probabilities of lower coal demand. Optimistic long-dated coal prices may be unsupported. Although lower prices may spur demand growth elsewhere, the demand slowdown in China should more than offset such gains, in our view. Coal exporting countries that have been counting on strong future coal demand could be most at risk. The end of the supercycle should weigh on both the mining and equipment sectors. But sectors that excel at renewable integration, distributed generation, transmission could benefit the most.

In October 2014, several major investment banks announced they would not provide financing to support a large coal mining and export infrastructure in Australia.¹¹² This is one of the largest proposed mining initiatives in the world that would serve the same Asian markets as PRB producers.¹¹³

¹¹⁰ Bridges, *supra* note 61.

¹¹¹ Anthony Yuen et. al., *The Unimaginable: Peak Coal in China*, Citi Research (Sept. 4, 2013), available at <https://ir.citi.com/z5yk080HEXZtoIax1EnHssv%2Bzm4Pc8GALpLbF2Ysb%2Fl21vGjprPCVQ%3D%3D>.

¹¹² *Briefing: The Outlook for Financing for Australia's Galilee Basin Coal Proposals*, IEEFA (Oct. 22, 2014), available at <http://www.ieefa.org/wp-content/uploads/2014/10/IEEFA-briefing-Galilee-Financiers.pdf>.

¹¹³ Rohan Somwanshi, *Report: U.S. Banks Will Not Fund Australia Coal Terminal Expansion*, SNL Financial (Oct. 28, 2014).

J. Even ACI sees no market for Otter Creek coal.

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

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114 [REDACTED]

115 [REDACTED]

116 [REDACTED]

117 [REDACTED]

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119 [REDACTED]

4. [REDACTED]
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[REDACTED]
[REDACTED]

II. ACI WILL NOT BE ABLE TO FULFILL ITS FINANCIAL OBLIGATIONS FOR ITS PARTICIPATION IN THE TONGUE RIVER RAILROAD AND OTTER CREEK PROJECT.

ACI is not in a position to fulfill its financial obligations to this project. Even if ACI receives the necessary permits to move forward with developing Otter Creek,¹²⁴ it is questionable whether it could deliver on its significant capital commitment in the next 5-10 years. ACI's financial performance for the last decade has seriously lagged the nation's publicly traded companies. Its stock price has collapsed, revenues are down, costs are rising, debt levels are dangerously high, and liquidity has depleted. ACI is reducing production, capital investment, and generally in the market, is considered perilously close to insolvency. The prospect for coal price increases that could improve margins and cash position is unlikely to be of sufficient size or duration to foster a

¹²⁰ [REDACTED]

¹²⁴ Matthew Brown, *Montana Regulators Say Coal Mine Proposal Can't Proceed Without More Information from Company*, Daily Journal (Mar. 20, 2015, 5:58 PM), <http://www.dailyjournal.net/view/story/c484bf7b155c4ebc8182ff41154dd88f/MT--Otter-Creek-Mine/>.

turnaround in company finances. At the time, the Otter Creek project will require a significant capex infusion the company is likely to have neither the cash reserves nor debt available to complete the project. Much of ACI's Central Appalachian holdings are in the red¹²⁵ and its PRB margins show only the slimmest upside. The company has posted three consecutive years of losses totaling more than \$1 billion. The outlook for 2015 and 2016 suggest reduced production and price increases insufficient to drive a companywide rebound. In addition, further depletion of liquidity is anticipated.

Over the last several years, the significant changes in coal markets domestically and worldwide have frustrated several of ACI's strategic turnaround plans. The company first announced prospective sales specifically to China (discussed above). In responses to questions from the STB and others, ACI clarified its view that it is only going to export some of the coal to China. ACI has no contracts in China.¹²⁶ The company has also targeted Japan,¹²⁷ South Korea, and Taiwan. Over this period, ACI's revenue from Asian sales has dropped. It was presented as a solution a vision for large scale exporting of metallurgical coal out of its Central Appalachian mines. During ACI's 2014/3rd quarter conference call, management put exports on a back burner vying instead for greater

¹²⁵ Appalachian operating margins are posted as negative \$8.82 per ton. Arch Coal, *News Release: Arch Coal, Inc. Reports Fourth Quarter and Full Year 2014 Results* (Feb. 3, 2015), <http://news.archcoal.com/phoenix.zhtml?c=107109&p=irol-newsArticle&ID=2012926> [hereinafter *ACI Fourth Quarter and Full Year 2014 Results*].

¹²⁶ David Coburn, Attorney for Tongue River Railroad Corporation to Kenneth Blodgett, Surface Transportation Board, Docket FD 30186, Information Request # 1, p. 3.

¹²⁷ Recent talks between Japanese utilities and coal producers for new deals going forward have identified Indonesia as a new significant supplier as well as other subbituminous coal suppliers. None of the published reports mention that any U.S. coal producer is in the running for a significant share of the market. Pricing levels discussed in the press place negotiations for coal in the \$60 per ton range and below. Joseph Green, *Japan Seeks Coal, but Not Australian Coal*, World Coal (June 3, 2015), <http://www.worldcoal.com/coal/06032015/Japan-coal-Australian-seeks-2025/>.

domestic share.¹²⁸ At a recent Coaltrans conference in Miami, ACI's CEO, John Eaves, raised the potential for United States coal suppliers to fill voids from future Indonesian coal bottlenecks.¹²⁹

Some coal producers are now pointing to India as a potential long-term importer of coal,¹³⁰ placing potential import figures as high as 200 million tons per year. In 2013, United States coal producers exported less than 1 million tons of thermal coal to India.¹³¹ While India is likely to increase coal imports in the short term, the current providers of coal, principally Indonesia and South Africa, are already in the market and Australian and Indian coal interests are trying to develop new mine capacity in Australia.¹³² Furthermore, the Indian government has set an import goal significantly lower than current levels.¹³³

In its 2014 year-end filing, ACI acknowledged that coal exports from the United States would likely see further decline in 2015.¹³⁴ This represents a significant downward

¹²⁸ Arch Coal's (ACI) CEO John Eaves on Q3 2014 Results - Earnings Call Transcript, Seeking Alpha (Oct. 28, 2014 3:54 PM ET), <http://seekingalpha.com/article/2606325-arch-coals-aci-ceo-john-eaves-on-q3-2014-results-earnings-call-transcript?page=6&p=qanda&l=last> [hereinafter *ACI Q3 2014 Results*].

¹²⁹ Darren Epps, *US Coal Exports Finish 2014 Below 100 Million Tons, But CEOs Remain Resolute*, SNL Financial (Feb. 9, 2015).

¹³⁰ *Indian Coal Demand Growth Overtakes China*, Wood Mackenzie (Mar. 04, 2015), <http://www.woodmac.com/public/views/india-coal-growth>.

¹³¹ U.S. Energy Info. Admin., *Quarterly Coal Report October – December 2013* 16 (2013), available at <http://www.eia.gov/coal/production/quarterly/pdf/0121134q.pdf>.

¹³² Tim Buckley & Tom Sanzillo, *Stranded: A Financial Analysis of GVK's Proposed Alpha Coal Project in Australia's Galilee Basin*, The Institute for Energy Economics & Financial Analysis (June 2013), available at <http://ieefa.org/report-stranded-alpha-coal-project-in-australias-galilee-basin/>.

¹³³ Krishna N. Das, *Goyal: May Stop Thermal Coal Imports in 2-3 Years* (Nov. 13, 2014), <http://in.reuters.com/article/2014/11/12/india-coal-imports-idINKCN0IW0FJ20141112>.

¹³⁴ *ACI Fourth Quarter and Full Year 2014 Results*, *supra* note 125.

estimate from the more aggressive estimates offered to the Surface Transportation Board by its consultants in this proceeding.

A. ACI's financial performance is weak with very little upside potential.

1. Market and Coal Industry: Lagging Stock Performance

For most of the last twenty years, ACI has been a marginal stock performer and significantly lagging the Dow Jones Industrial Average (see Table VII). From 2001 to the present, the SNL Coal Index, a measure of industry performance, rose 26% while ACI declined by 87%. ACI's stock has been in a precipitous decline since 2008, falling from a peak of \$ 67.00¹³⁵ per share to its current levels, which hover around \$1 per share. Arch has also underperformed its peers.

Figure V: Arch Coal Versus Dow Jones: Percent Growth/Loss (20 years)

Benchmarks	Arch Coal	Dow Jones Industrial
One Year	(-62%)	(+12%)
Two Year	(-77%)	(+41%)
Five Year	(-94%)	(+80%)
Ten Year	(-92%)	(+71%)
Twenty Year	(-91%)	(+354)

SNL Energy, February 11, 2015

¹³⁵ *ACI Historical Prices*, Yahoo! Finance, <http://finance.yahoo.com/q/hp?s=ACI&a=07&b=12&c=2007&d=02&e=20&f=2015&g=d&z=66&y=1584>.

2. *ACI's Declining Revenues*

ACI revenues grew from 2008-2011, at a time when the company also led its industry peers in stock performance. Since 2011, ACI revenues have declined by \$950 million, or 25%. Export revenues from 2012 to 2013 dropped by \$331 million.¹³⁶ The short-term industry consensus is for flat or declining revenues in 2015¹³⁷ and ACI expects further declines in export sales.

Table III: ACI Revenues 2008-2014

	2008	2009	2010	2011	2012	2013	2014
Revenues	2.983	2.576	3.186	3.883	3.768	3.014	2.937

Arch Coal, Form 10K CY 2008, 2010, 2012, 2013

3. *ACI and PRB Producer Financial Performance 2010-2014*

In 2014, ACI posted its third consecutive year of losses. The company improved its performance in 2014, posting losses of \$558 million against losses in excess of \$700 million in 2011 and 2012. Other large PRB producers also posted losses or marginal gains. Peabody, the PRB's largest producer also posted the largest losses but not quite as large as ACI.

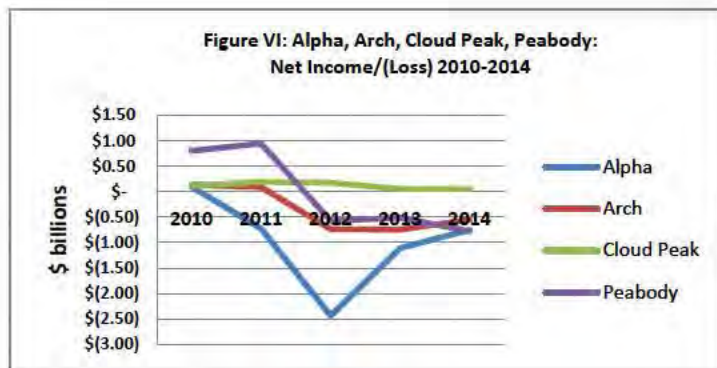
¹³⁶ All Export revenue was \$1.153 billion in 2012 and \$822 million in 2013, and Asian coal export revenue dropped from \$203 million in 2012 to \$160 million in 2013. Arch Coal, Securities & Exchange Comm'n (Form 10-K) 19 (Mar. 01, 2013),

<https://www.sec.gov/Archives/edgar/data/1037676/000104746913002059/a2213264z10-k.htm>;

Arch Coal, Securities & Exchange Comm'n (Form 10-K) 19 (Feb. 28, 2014),

<https://www.sec.gov/Archives/edgar/data/1037676/000104746914001604/a2218540z10-k.htm>.

¹³⁷ Darren Epps, *Coal Industry Looks to 2016 for Relief from Low Natural Gas Prices*, SNL Financial (Feb. 11, 2015).



Institute for Energy Economics and Financial Analysis

4. Declining ACI Liquidity

In a severely declining market, ACI has concentrated on cost reduction and management of its liquidity. ACI designs its liquidity management efforts to show investors that the company has the resources to weather a prolonged down cycle. In ACI's 2013 10K, ACI described its liquidity position:

As described below, we took actions during the fourth quarter of 2013 to further bolster our liquidity and extend debt maturities. These proactive steps will help us navigate the current market cycle by providing us greater flexibility. We now have more than \$1.4 billion of liquidity, with \$1.2 billion of that in cash or highly liquid investments. We have no meaningful maturities of debt until 2018, after successfully refinancing our 2016 notes without increasing our interest costs; and significantly relaxed financial maintenance covenants. We have suspended or eliminated most financial maintenance covenants that pertain to our \$250 million revolver until June of 2015, when a relaxed, senior secured leverage ratio covenant steps back in. Until then, only a minimum liquidity covenant remains in place. With these transactions, we have implemented a flexible capital structure, with high levels of

prepayable debt, which should allow us to de-lever our balance sheet, should markets and our cash flows improve.¹³⁸

From 2011 to 2013, ACI increased its cash and cash equivalents from \$138 million to \$911 million.¹³⁹ During 2014, ACI's cash and cash equivalent declined to \$734 million.¹⁴⁰ ACI's highly liquid short-term investments remained flat year-to-year 2013 to 2014. In total, by the end of 2014, ACI's position from cash and short-term investment declined to \$983 million, down from \$1.2 billion identified at the end of 2013.

Liquidity is the top financial priority for ACI officials.¹⁴¹ Cash and cash equivalents are down. ACI's CFO, John T. Drexler, reassured the investment community that most of ACI's liquidity was in cash and short-term investments with only a limited amount in its credit lines.¹⁴²

¹³⁸ Arch Coal, Sec. & Exch. Comm'n (Form 10-K) 68 (Feb. 28, 2013), <http://www.sec.gov/Archives/edgar/data/1037676/000104746914001604/a2218540z10-k.htm>.

¹³⁹ *Id.* at F-8.

¹⁴⁰ *Press Release: Arch Coal, Inc., supra* note 53.

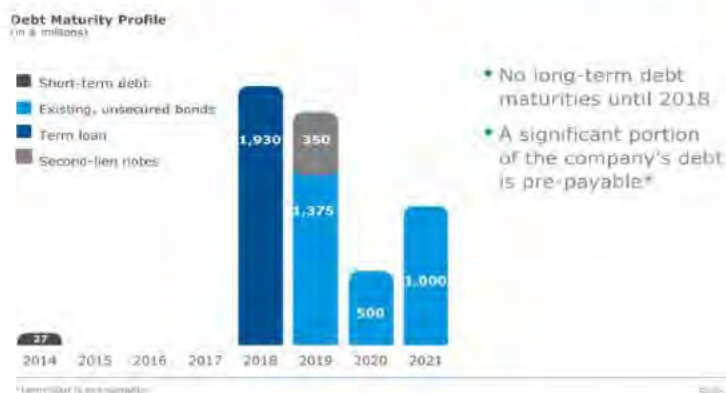
¹⁴¹ *Arch Coal's (ACI) CEO John Eaves on Q4 2014 Results – Earnings Call Transcript*, SeekingAlpha.com (Feb. 3, 2014, 7:48 PM), <http://seekingalpha.com/article/2880806-arch-coals-aci-ceo-john-eaves-on-q4-2014-results-earnings-call-transcript>.

¹⁴² *ACI Q3 2014 Results, supra* note 128.

5. Looming Debt Burden

Figure VII: Arch Coal Debt Burden Looking Forward

Arch's funded debt maturity profile extends to 2018



Arch Coal

[REDACTED]

[REDACTED] These observations made in June 2013 remain industry consensus today.

According to ACI, from 2018 to 2021, it will be required to address \$5.1 billion in debt (See Figure VII). Depending upon the final capital contribution ratios set between the TRRC partners, ACI could pay some or all of the capital to develop the rail and mine.

[REDACTED]

[REDACTED] ACI also owns a 38% interest in the Millennium

143 [REDACTED]

144 [REDACTED]

145 [REDACTED]

Bulk Terminal, which is expected to move forward during the same time-period. The cost of this project is currently listed at \$650 million.¹⁴⁶

ACI currently is on negative credit watch by Standard and Poor's and Moody's and has a CCC rating from Fitch.¹⁴⁷ Analysts¹⁴⁸ place some of the company's corporate bond yield to maturity at 37%, reflecting the sharp downturn in equity value and weak outlook. ACI's distressed credit profile suggests that such a heavily leveraged project and series of related investments during the 2018-2021 period would meet strong headwinds from the investment community.

WM analysts summarize the current state of the investment environment in the PRB:

[REDACTED]

[REDACTED]¹⁴⁹

III. THE TRRC PROJECT IS NOT IN THE PUBLIC INTEREST.

The Surface Transportation Board should reject TRRC's permit request. This permit and supporting materials ask permission for a project that is neither reasonable nor prudent. The only benefit that will accrue to the public will be incidental to other considerations.

¹⁴⁶ Ambre Energy, Millennium Bulk Terminal (2012), *available at* <http://www.ambreenergy.com/millennium-bulk-terminal>.

¹⁴⁷ Mayur Soutakke, *What Credit Rating Agencies Think about Arch Coal*, Market Realist (October 20, 2014, 1:00 PM), *available at* <http://finance.yahoo.com/news/credit-rating-agencies-think-arch-170019501.html>.

¹⁴⁸ Mayur Soutakke, *Why Arch Coal's Debt Profile Hinges on Liquidity* (Oct. 20, 2014), <http://finance.yahoo.com/news/why-arch-coal-debt-profile-130018583.html>.

¹⁴⁹ [REDACTED]

A leading PRB coal company executive in a recent interview observed that Japanese coal consumers were looking at U.S. ports to supply coal from the United States 30 and 40 years¹⁵⁰ into the future. TRRC (ACI and BNSF) have asked the STB for permission to move forward now.

ACI officials as part of this proceeding have acknowledged the weak market that existed in 2012 when they submitted their application. [REDACTED]

[REDACTED] 151 [REDACTED]

[REDACTED] The EIA, another key resource for market information has consistently downgraded the expectations of PRB market growth and is now also dampening its outlook on PRB export potential. Most major investment banks conclude likewise and my organization along with Carbon Tracker Institute has produced arguably one of the most extensive and publicly available studies on global coal markets in the world. ACI still has confidence in the future of Asian exports but at no specified time, in a variety of prospective places, not necessarily with Otter Creek as the resource or with ACI as the supplier. TRRC and ACI produce no business plan to outline future profitability in part because to do so would be premature.

As a former public finance official responsible for investing a \$156 billion public pension fund in companies like ACI and as a senior manager with extensive government to business procurement experience, I am quite attuned to how private companies use

¹⁵⁰ Darren Epps, *In Interview: Cloud Peak CEO Makes the Case for Coal Export Strategy*, SNL Financial (Feb. 15, 2015).

¹⁵¹ [REDACTED]

public resources to build value. In this case, TRRC seeks a public decision in the form of a permit from the Surface Transportation Board. TRRC does so having provided evidence that barely meets the definition of a speculative market. The Tongue River Railroad and Otter Creek mine have a high risk of loss. The expectation of reward is limited and without meaningful foundation from TRRC.

TRRC is not seeking this permit decision, an allocation of public rights and resources, to provide public benefit that one would expect from a private company. If approved with the information, background, and support TRRC offered, it would award an unpromising private venture with very little expectation of serving the public interest. ACI's inability to produce a business plan and its reliance on broad demand assumptions is of concern. ACI, a company in a severe state of financial crisis, needs to adopt higher standards of diligence when spending annually on speculative projects.

There is no evidence that more coal mining has any public benefit to the nation at this point. Coal markets are oversupplied here and abroad. Whatever markets will exist in the future, the proposed Otter Creek mine will play an insignificant role. The idea that the mine is cost competitive does not stand up under even modest scrutiny.

The ancillary public benefits also cannot be found in this presentation. The lack of a real time frame means there is no discussion of when job growth will occur from construction or new mine employment. There is no discussion of when enhanced tax collection can start. The government cannot plan royalty income at the state and federal level from this mine project. Neither BNSF nor ACI has Otter Creek in any known capital construction plan. These normal components of a timely, reasonable, and prudent

application to the Surface Transportation Board are non-existent. This project and application are premature.

More traditional investment analysis yields additional insights worthy of the Surface Transportation Board's consideration. ACI is in severe financial distress. Any responsible financial scenario suggests that there will be a major reorganization of ACI over the next few years, including a high potential for sale or trading non-core assets like Otter Creek mine. United States coal mining assets are trading at historically low values.¹⁵² In this respect, a decision to approve the permit serves ACI's short-term objective to enhance its asset base, which will help ACI in negotiations about its financial future. In this case, the public interest, the domain of the Surface Transportation Board, is placed second to a host of other considerations.

¹⁵² See Darren Epps, *From \$2 to \$296M, Coal Acquisitions Hit Furious Pace as New Players Arrive*, SNL Financial (Nov. 12, 2014).

APPENDIX I: SNL Coal Supply Forecast (1000 tons)									
As Of: 12/31/2014									
Term	Central Appalachia	Northern Appalachia	Southern Appalachia	Illinois Basin	Southern Powder River Basin	Northern Powder River Basin	Uinta Basin	Gulf and Interior	
15-Jan	114,000	128,000	16,000	146,000	405,000	40,000	35,000	50,000	
16-Jan	109,000	125,000	16,000	150,000	411,000	39,000	33,000	50,000	
17-Jan	101,000	122,000	15,000	157,000	416,000	39,000	31,000	50,000	
18-Jan	92,000	120,000	14,000	170,000	416,000	39,000	29,000	50,000	
19-Jan	90,000	118,000	13,000	178,000	416,000	38,000	28,000	50,000	
20-Jan	86,000	116,000	13,000	184,000	412,000	38,000	28,000	50,000	
21-Jan	83,000	114,000	13,000	188,000	411,000	38,000	28,000	50,000	
22-Jan	83,000	114,000	13,000	190,000	405,000	38,000	28,000	50,000	
23-Jan	83,000	114,000	13,000	195,000	404,000	38,000	28,000	50,000	
24-Jan	83,000	114,000	13,000	199,000	404,000	38,000	28,000	50,000	
25-Jan	82,000	113,000	13,000	199,000	404,000	38,000	28,000	50,000	

Other Western Basins	Total Basin Production	Steam Coal Imports	Total Steam Coal Supply
74,000	1,008,000	9,000	1,017,000
72,000	1,005,000	9,000	1,014,000
70,000	1,001,000	9,000	1,010,000
68,000	998,000	9,000	1,007,000
66,000	997,000	9,000	1,006,000
64,000	991,000	9,000	1,000,000
63,000	988,000	9,000	997,000
63,000	984,000	9,000	993,000
63,000	988,000	9,000	997,000
63,000	992,000	9,000	1,001,000
63,000	990,000	9,000	999,000

VERIFICATION

I, Thomas Sanzillo, hereby verify under penalty of perjury under the laws of the United States of America that the foregoing is true and correct to the best of my knowledge and belief.



Thomas Sanzillo

Dated this 25 day of March, 2015.

Footnote 18



Commodities Special Report

Thermal Coal: Coal At A Crossroads

In the medium to long term, thermal seaborne coal markets face a combined threat of steadily growing supply in the largest producing regions and a levelling-off or decline in demand in consuming regions. Three of the most important demand centers, China, Europe and the US, contain the seeds of a softening in demand growth, while US export capability may grow. We believe this trend will develop out of emissions control standards, higher renewables output, a structural shift in the Chinese economy, improved transport infrastructure, and stagnating US demand.

As demand disappoints versus producer expectations, rational decision-making will require that major expansion projects be delayed, as existing capacity will largely be capable of meeting demand. As a result, in our base-case scenario forecasting coal prices out to 2020, we assume only a very small increase in net new capacity and take marginal costs as the best guide for prices. This leads to our forecast of nominal prices of \$95/t in 2015 and \$101/t in 2020 on a FOB Newcastle basis. In 2013 real terms, these prices are \$91/t and \$85/t, respectively.

Having modelled our base case assuming rational behaviour on the part of producers, there is still a risk that current plans for capacity expansion may be followed through to completion despite slow demand growth. Therefore, we also model a bear case as an alternative to our base case in which global export potential exceeds import demand by 356mt in 2020, as opposed to 213mt in our base case. Measuring demand against a representative cost curve indicates that prices in this scenario will reach \$86/t in 2020 nominal terms, or \$73/t in 2013 real terms.

Although aggregated producer plans to increase export production by 3% per annum through 2020 may appear conservative relative to a market which has grown at 7% per annum since 2003, we believe that new demand preferences in the largest consuming nations will result in much lower demand growth going forward, pushing prices lower in real terms through 2020.

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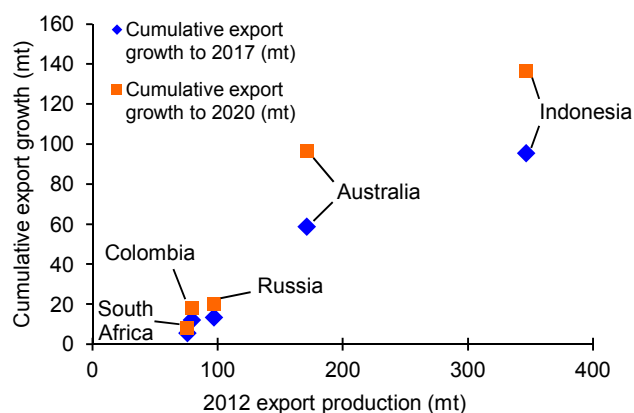




#1 Executive Summary

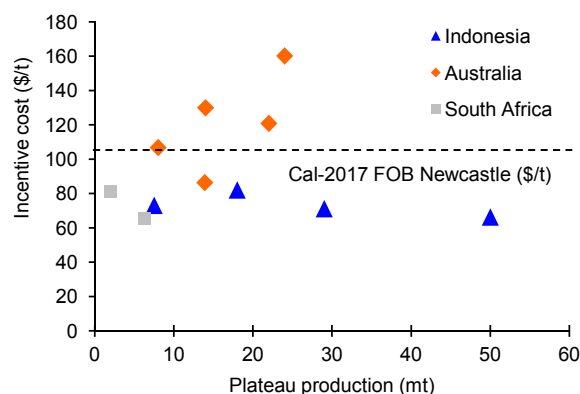
- In the medium to long term, thermal coal markets face a combined threat of steadily growing supply in the largest producing regions and a leveling off or decline in demand in consuming regions. As a result, this is an opportune moment to assess the dimensions of the shifting market balance through 2020.
- By way of introduction, we provide a technical foundation for understanding thermal coal fundamentals. We examine coal geology and mining techniques, and methods of assessing quality and price. We outline our expectations for the evolution of marginal cost, seaborne trade flows, the global distribution of reserves, production and consumption, concluding with a discussion of the feedback process between cost measures and production over the long term.
- Three of the most important demand centres, Europe, the US, and China contain the seeds of a softening in import demand growth, while US export capability may also grow.
- In Europe, emissions policies already in place will result in net closures of coal-fired generation over the next five years, while expanding renewable output will push coal utilisation lower through 2020.
- In the US, increasing pressure from air pollution regulation particularly in 2016 will suppress coal demand in the electricity market which constitutes 95% of US thermal coal demand, although consistently higher gas prices will reduce this pressure somewhat. With 2020 levels of consumption remaining below the 2010 level and rising coal production out of the low-cost Powder River Basin, this suggests a persistent US surplus in the long term.
- In China, the lower growth target combined with a goal to reduce the energy intensity of GDP growth implies softer Chinese coal demand growth going forward. From 2004 to 2011, realised GDP growth exceeded the 8.0% target by 2.8%, in comparison to 2012 GDP growth of 7.8% relative to the lower 7.5% target. In addition, power demand growth exceeded GDP growth in eight of 11 years from 2001 to 2011, while 2012 power demand grew by only 4.2%, in keeping with a new focus on the sustainability and stability of growth.

Figure 1: Cumulative planned thermal-coal export growth to 2020 relative to 2012 exports



Source: McCloskey, Deutsche Bank

Figure 2: Energy-adjusted incentive cost and plateau production at selected projects



Source: Wood Mackenzie, Deutsche Bank



- We believe growing concern over the level of air pollution in China versus international standards may result in a stronger policy response, crimping long-term demand growth. A greater emphasis than currently planned to develop alternative energies including nuclear, gas, hydro, wind, solar could ultimately push coal's market share as well as the absolute level of Chinese thermal coal demand lower in the long term.
- As demand disappoints versus producer expectations, rational decision-making will require that major expansion projects be delayed. Existing capacity will largely be capable of meeting demand, with limited net new capacity additions required. Therefore, marginal costs are likely to be the best guide for prices this decade, leading to our forecast of \$95/t nominal in 2015 and \$101/t nominal in 2020 on a FOB Newcastle basis. In 2013 real terms, these prices are \$91/t and \$85/t, respectively.
- While we estimate that 90% of global productive potential was in operation in 2012, the actual FOB Newcastle average spot price of \$94.3/t (at the 82nd percentile of the global FOB cash cost curve) suggests that 8% of global production operated at a loss relative to spot prices. This is explained by the fact that some production is sold at a higher contracted price or forward-hedged, and some production may be left in operation to avoid incurring shut-down and start-up costs or to make use of committed infrastructure.
- During periods of weakness such as 2012, producers have responded by rationalising operations, cutting costs, and modernizing equipment. The logical extension of these decisions would be to scale back expansion plans. However, the risk exists that current plans may be followed through to completion despite slow demand growth.
- Therefore, we also model a bear-case alternative to our base case, wherein producers persist with existing expansion plans, resulting in excess capacity of 356mt in 2020 in comparison to 213mt in our base case. We estimate that this could result in prices trading as low as \$90/t in 2015 and \$86/t in 2020 in nominal terms, or \$85/t and \$73/t in 2013 real terms.

Figure 3: Base-case scenario

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Global seaborne supply potential (mt)	1,142	1,177	1,188	1,200	1,212	1,224	1,237	1,249	1,274
Total seaborne thermal demand (mt)	1,027	1,027	1,036	1,020	1,020	1,032	1,033	1,035	1,061
Proportion of supply required	0.900	0.873	0.871	0.850	0.842	0.843	0.835	0.829	0.833
Implied market price (2013 real)	103.7	92.8	92.1	88.2	86.3	85.9	85.0	85.1	85.3
Implied market price (nominal)	103.7	92.8	94.4	92.7	92.9	94.8	96.1	98.7	101.4

Source: AME, Deutsche Bank

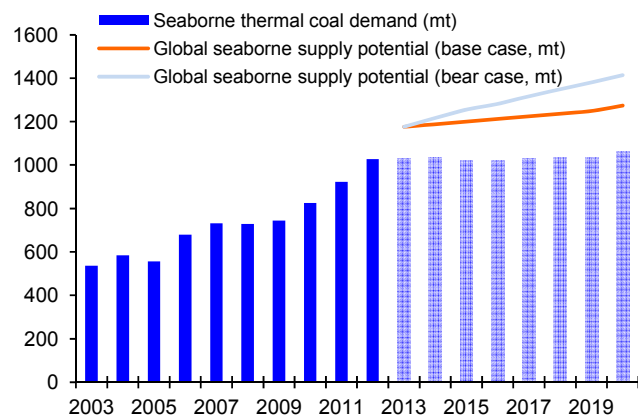
Figure 4: Bear-case scenario

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Global seaborne supply potential (mt)	1,142	1,177	1,217	1,256	1,282	1,317	1,349	1,384	1,417
Total seaborne thermal demand (mt)	1,027	1,027	1,036	1,020	1,020	1,032	1,033	1,035	1,061
Proportion of supply required	0.900	0.873	0.851	0.813	0.796	0.783	0.766	0.748	0.749
Implied market price (2013 real)	103.7	92.8	88.8	85.2	81.8	80.4	77.8	72.3	72.7
Implied market price (nominal)	103.7	92.8	91.0	89.5	88.1	88.7	88.0	83.8	86.4

Source: AME, Deutsche Bank

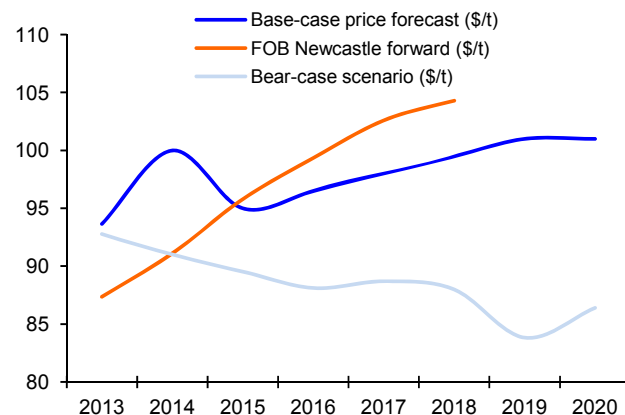


Figure 5: Demand and total supply potential under base case and bear case scenarios (million tonnes per year)



Source: McCloskey, Deutsche Bank

Figure 6: Nominal price forecasts and FOB Newcastle forward curve (\$/t)



Source: AME, Deutsche Bank

- To summarise our base-case scenario, although aggregated producer plans to increase export production by 3% per annum through 2020 may appear conservative relative to a market which has grown at 7% per annum since 2003, we believe that new demand preferences in the largest consuming nations will result in much lower demand growth going forward, pushing prices lower in real terms through 2020.

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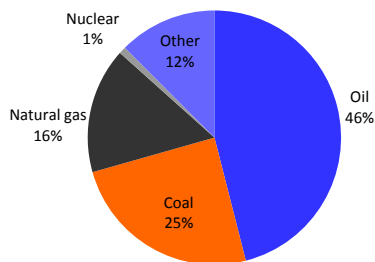


#2 Coal in context

Coal in the global energy mix

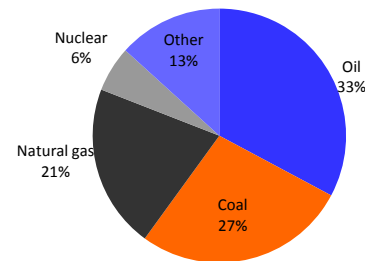
Coal appears in numerous forms, the two main categories being hard coal, and brown coal (or lignite). Coal in this broad sense is the second most important source of primary energy in the world after oil, and has had a relatively stable relative share in the global energy mix over the last forty years. According to the International Energy Agency (IEA), coal's share of total fuel supplied rose from 25% in 1973 to 27% in 2009, Figure 7 and Figure 8.

Figure 7: Breakdown of global primary-energy supply (6,111mtoe), 1973



Source: IEA

Figure 8: Breakdown of global primary-energy supply (12,150mtoe), 2009



Source: IEA

In absolute terms, coal more than doubled its contribution to global primary-energy supplies over the last four decades, rising from 1,527 million tonnes of oil equivalent (mtoe) out of the total 6,111mtoe of primary energy supplied in 1973, to 3,280mtoe out of the total 12,150mtoe supplied in 2009.

Indeed, and as shown in Figure 9, in absolute terms the production of coal increased by more than that of any other fuel source, rising by 1,753mtoe and thereby accounting for 30% of the total increase in primary energy supply over 1973-2009 (i.e. 1,753mtoe/6,039mtoe).

Figure 9: Change in the composition of global primary-energy supply, 1973 versus 2009

	2009 (mtoe)	1973 (mtoe)	Increase (mtoe)	Increase (%)
Oil	4,010	2,811	1,199	42.7%
Coal	3,280	1,527	1,753	114.8%
Gas	2,551	978	1,573	160.8%
Other	2,309	795	1,514	190.4%
TOTAL	12,150	6,111	6,039	98.8%

Source: BP Statistical Review of World Energy 2012, Deutsche Bank

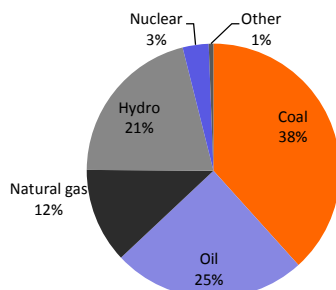
As explained in greater detail below, the main driver of this increase in coal supply was the very sharp rise in demand from power generators, as the growth of electricity consumption over the last four decades has greatly outpaced that of energy-consumption overall.

Figure 10 and Figure 11 show the share of primary-fuel sources as a feedstock for power generation in 1973 and 2009 respectively, and Figure 12 shows the



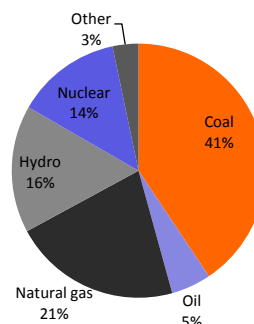
absolute increases in power production from the different primary-energy sources over the period.

Figure 10: Breakdown of electricity generation by fuel (6,115TWh), 1973



Source: IEA

Figure 11: Breakdown of electricity generation by fuel (20,055TWh), 2009



Source: IEA

Figure 12: Change in the composition of fossil-fuel feedstocks for power generation, 1973 versus 2010

	2010 (TWh)	1973 (TWh)	Increase (TWh)	Increase (%)
Oil	1,023	1,510	-487	-32.2%
Coal	8,142	2,342	5,800	247.7%
Gas	4,292	740	3,552	480.0%
Other	6,598	1,523	5,075	333.2%
TOTAL	20,055	6,115	13,940	228.0%

Source: BP Statistical Review of World Energy 2012, Deutsche Bank

Whereas the total supply of primary energy essentially doubled between 1973 and 2009, the production of electricity more than trebled, with the amount of power generated from coal increasing by 5,800TWh over the period, or by three-and-a-half times.

And as explained below, the IEA expects growth in electricity demand to continue outpacing that of primary-energy demand over the next 25 years. Given that most of this growth will be in developing countries, this points to continuing strong demand for coal as a feedstock for power generation over the next two to three decades (although as explained below, the evolution of both international climate negotiations and national climate policies in countries like China will be crucial in determining the extent to which other primary-energy sources displace coal against the BAU trajectory).

Remaining reserves: coal versus oil and gas

Figure 13 shows the remaining proved reserves of the three main hydrocarbons as at year-end 2011 as given by BP in its 2012 Statistical Review of World Energy. Although there are numerous caveats to acknowledge with regard to any estimates of remaining reserves (most notably relating to the transparency and quality of reported data, which vary greatly between countries), the BP figures are generally regarded as a key reference point, and in providing a synthesis of all hydro-carbon reserves they facilitate comparison between oil, coal, and gas.



Figure 13: Remaining proved reserves* of global hydro-carbons as at year-end 2011

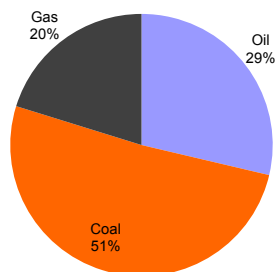
	2011	Reserves/Prod (years)	EJ	% of world total energy reserves
Oil (bn tonnes)	234	54	10,776	29%
Coal (bn tonnes)	861	112	19,190	51%
o/w anthracite/bituminous	405		11,435	30%
o/w lignite/sub-bituminous	456		7,755	21%
Gas (tcm)	208	64	7,587	20%
TOTAL			37,552	

Source: BP, Deutsche Bank; *BP defines 'proved reserves' as follows: "generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known deposits under existing economic and operating conditions".

Taking the absolute numbers given by BP (in billions of tonnes for oil and coal, and trillions of cubic metres for gas), we can then derive an estimate for the total amount of energy left in the world's remaining hydro-carbon reserves using standardized factors for the energy-content per-unit mass of oil and coal, and the energy-content per-unit volume of natural gas.

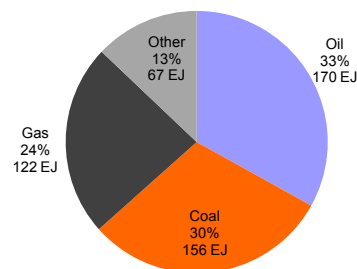
Accordingly, we calculate the exa-joules (EJ) remaining in each energy source by applying the following standard factors to each source: for oil, 46 gigajoules (GJ) per tonne; for coal, 28GJ per tonne for anthracite/bituminous coal, and 17GJ per tonne for lignite/sub-bituminous coal; for natural gas, 36GJ per thousand cubic metres.

Figure 14: DB estimate of breakdown of energy value in remaining global hydro-carbon reserves in 2011



Source: BP, Deutsche Bank

Figure 15: 2011 primary-energy consumption by fuel source (516EJ)



Source: BP, Deutsche Bank

As shown in Figure 13, on this basis the total amount of energy remaining in the world's fossil-fuel reserves at year-end 2011 would come to 37,552EJ, and of this coal would account for fully half at 19,190EJ. As a result, coal has the highest reserves-to-production (R/P) ratio (see the third column in Figure 13), with 112 years of production at current rates remaining, compared with 54 for oil and 64 for gas. Figure 14 shows a diagrammatic breakdown of the proportion of remaining global hydro-carbon energy in the different fossil fuels as at year-end 2011.

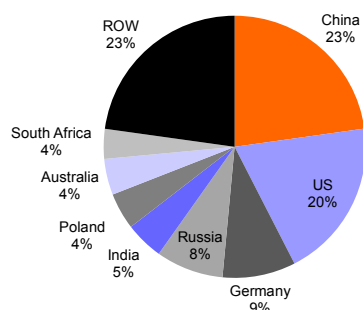
To put these numbers into perspective, Figure 15 shows the breakdown of 2011 primary-energy consumption in exa-joules. Total primary-energy consumption came to 516EJ, of which 449EJ was in the form of fossil fuels, with coal accounting for 156EJ, or 30% of the total.



A snapshot of global coal production

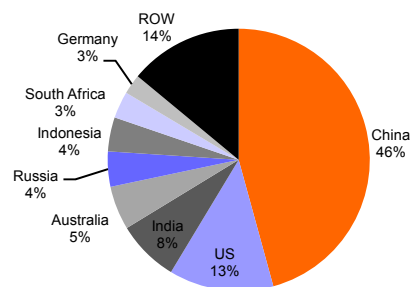
Breaking down the production of coal (hard coal and lignite combined) by the main producers, Figure 16 and Figure 17 show the rise in importance of Asia in general, and China in particular, over the last 20 years.

Figure 16: Global coal production, 1990 (4,740Mt)



Source: BP

Figure 17: Global coal production, 2011 (7,695Mt)



Source: BP

As can be seen, the total tonnage of coal produced increased by 62% from 4,740Mt in 1990 to 7,695Mt, with the other very striking trend being the tremendous shift in the geographical breakdown of supply.

Whereas in 1990 China and India accounted for only 28% of global production (and the Asia-Pacific region overall for 34%), by 2011 China alone produced 46% of the world's total, and the Asia Pacific region overall 65%.

The composition of coal production

Figure 18 breaks down global production in 2011 by the top eight producers, and shows their respective absolute and relative increases versus 1990. The four largest absolute and relative increases in production over the last two decades were all in the Asia-Pacific region: China, India, Indonesia, and Australia.

Figure 18: Top coal producers in 2011 and increase versus 1990

	2011 (mt)	1990 (mt)	Increase (mt)	Increase (%)
China	3,520	1,080	2,440	226%
United States	993	934	59	6%
India	588	223	365	164%
Indonesia	325	10.7	314	2928%
Russia	334	395	-62	-16%
Australia	415	210	205	97%
South Africa	255	175	80	46%
Germany	189	427	-238	-56%
Rest of World	1,265	1,286	-20	-2%
TOTAL	7,695	4,740	2,955	62%

Source: BP Statistical Review of World Energy 2012, Deutsche Bank

Figure 19 then shows the breakdown of production between hard coal (comprising steam coal and coking coal) on the one hand, and lignite on the other, in 1990 and 2011 respectively, with Figure 20 and Figure 21 showing the relative increase in the production of steam coal at the expense of lignite over the last two decades.

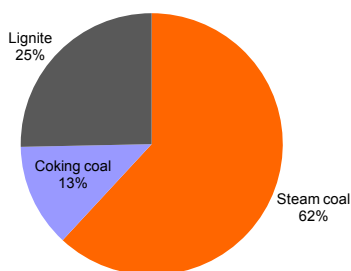


Figure 19: Breakdown of global coal production by type, 2011 versus 1990

	2011 (mt)	1990 (mt)	Increase (mt)	Increase (%)
Hard coal	6,637	3,493	3,144	90.00%
o/w steam coal	5,670	2,894	2,776	95.90%
o/w coking coal	967	598	369	61.70%
Lignite	1,041	1,184	-143	-12.10%
TOTAL	7,678	4,677	3,001	64.10%

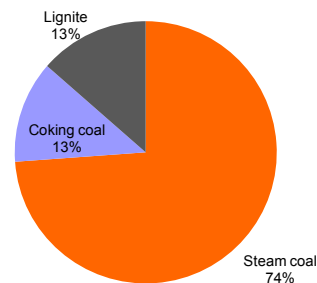
Source: World Coal Association

Figure 20: Breakdown of global coal production by type, 1990 (4,677Mt)



Source: World Coal Association

Figure 21: Breakdown of global coal production by type, 2011 (7,678Mt)

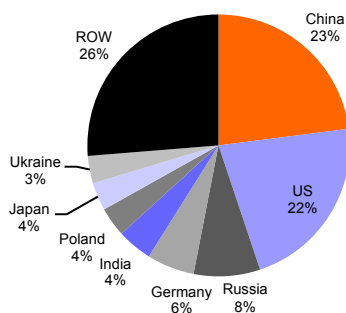


Source: World Coal Association

A snapshot of global coal consumption

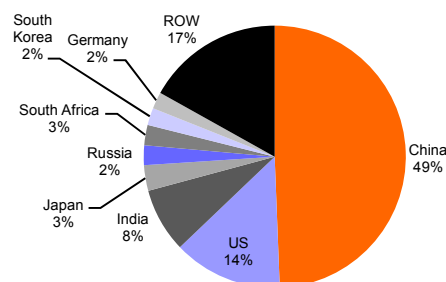
An examination of global coal consumption by country over the last 20 years shows that in 1990, China and the United States were roughly equal. While the absolute volume of consumption has grown in both the United States and China, Chinese consumption growth has so far eclipsed that in the rest of the world that it now constitutes nearly half of global consumption. We can also observe a doubling of India's share of global consumption from 4% to 8%, and a contraction in Russia's share of global consumption from 8% to 2%.

Figure 22: Global coal consumption, 1990 (2,207mtoe)



Source: BP Statistical Review of World Energy 2012

Figure 23: Global coal consumption, 2011 (3,724mtoe)



Source: BP Statistical Review of World Energy 2012



The uses of coal

In discussing the uses of coal, we first describe coking coal separately, as it is used exclusively for the production of steel. The specification for the type of raw coal used to produce coking coal is that it should be high in carbon and energy content, while also being low in moisture, ash, and sulphur, and phosphorus content. The raw coal must also have caking properties which allow it to melt, swell, and resolidify into a solid, coherent mass during the coking process. Coke-making consists of baking the coal in an anoxic environment at a temperature of 1,000 to 1,100°C for 12-36 hours to eliminate volatile compounds. The coke produced is then suitable for use in the steelmaking process in combination with iron ore and fluxes in the basic oxygen furnace. According to the World Coal Association, 70% of the world's steel is produced using basic oxygen furnaces, while 29% is produced using electric arc furnaces which use steel scrap instead of iron ore as the basic feedstock.

The focus of this report is thermal coal, which is the dominant form of coal produced in the world by volume. Thermal coal generally cannot be a replacement for coking coal, but coking coal can be used in thermal coal applications. Since coking coal commands a premium price in steelmaking applications, however, it is not typically sold as thermal coal unless it is in oversupply and inventories are excessively high. In these cases, coking coal supply may "cross over" and bleed into the thermal coal market.

Figure 24: Breakdown of global coal production by type including Anthracite, 2011 versus 1990

	2011 (mt)	1990 (mt)	Increase (mt)	Increase (%)
Hard coal	6,631	3,693	2,939	79.6%
o/w Anthracite	606	316	290	91.6%
o/w Bituminous	6,025	3,376	2,649	78.4%
Coking coal	606	368	239	64.9%
Lignite	1,044	1,108	-63	-5.7%
TOTAL	8,282	5,168	3,114	60.3%

Source: EIA, Deutsche Bank

Thermal coal can be divided into four main types in descending order of energy content and market value: anthracite, bituminous coal, sub-bituminous coal, and lignite. A breakdown of global production into these types using data available from the U.S. EIA is shown in Figure 24 and conforms to a large degree with the figures shown earlier from the World Coal Association.

Anthracite is a unique type of exceptionally hard, glossy, high carbon, low moisture coal which has undergone longer exposure to high pressure and temperature underground. Since it burns with very little smoke, it is often processed into briquettes which sell at a premium for use in home heating applications.

Lignite, on the other end of the spectrum, has undergone relatively little compression and exposure to high temperatures, and therefore is less dense, more friable, and contains a high proportion of moisture and volatile and semi-volatile organic compounds. Because of its low energy content, transportation of lignite is usually considered uneconomic in Europe and therefore it is more viable to burn lignite in purpose-built powerplants near the mined source, for example, in Germany, which produced an estimated 186mt of lignite in 2012. However, in China, lignite was imported at a rate of 53.7mt in 2012, mainly from Indonesia which exported 50.1mt to China.



The remainder of coal produced can be considered bituminous and sub-bituminous and accounted for the majority, 78.5%, of total thermal coal production in 2011.

The use of bituminous and sub-bituminous coal is dominated by power generation. In China, 2009 figures released by the National Bureau of Statistics indicate that 1,440mt of coal was used in power generation, representing 59% of non-coking coal consumption. An additional 28% of coal was consumed in industrial applications, the bulk of which is likely to be used in captive power generation on site. In 2011, power generation represented 95% of thermal coal consumed in the United States, and 93% of that consumed in the United Kingdom, Figure 25.

Figure 25: Thermal coal consumption by category in China, US and UK

	Million tonnes	% of Total
China (2010)		
Power generation	1,545	60.5%
Industry	681	26.7%
Other end-uses	162	6.3%
Heating	152	6.0%
Gas production and coal-to-liquids	13	0.5%
Total	2,556	
US (2011)		
Power generation	842	95.0%
Industrial CHP	22	2.5%
Other industrial	20	2.2%
Commercial CHP	1.5	0.2%
Other commercial	0.8	0.1%
Residential	0.3	0.03%
Total	887	
UK (2011)		
Power generation	42	93.1%
Industry	1.7	3.8%
Other	1.4	3.1%
Total	45	

Source: NDRC, DECC, EIA, Deutsche Bank

A second major industrial use for coal is in the cement making process. Although other fuels such as biomass and scrap tires may be used, coal is most common fuel used to fire kilns for the production of clinker, the basic ingredient of cement which is created by heating ground limestone and clay to 1,500°C. Coal used to fire cement kilns should be of low moisture and low in contaminants such as sulphur and chlorine.

Other common industrial uses for coal include on-site captive combined heat and power (CHP) generation for aluminium refining, paper manufacturing, and chemical and pharmaceutical industries. Coal may also be used to produce activated charcoal for filtering, and coal by-products are used in the manufacture of chemicals, solvents, dyes, plastics and fibres, according to the World Coal Association.



The outlook for consumption preferences

Coal is instrumental in many of the industrial applications mentioned above, including cement production, and as such we expect these uses will continue to be important. In coal's largest consumption mode, power generation, the need for a cheap and abundant fuel for growing economies such as India and China has meant that coal has been responsible for a preponderance of new power generation capacity in the past decade. There is little doubt that the immensity of the world's reserves of coal, which exceed those of oil and gas combined on an energy basis, Figure 13, has been and will continue to be a major driving force behind the accessibility and appeal of coal as a basic energy source, especially considering the very large installed base of existing coal-fired power generation capacity..

However, the clear counterpoint to this tendency is the growing concern over the effect of coal-burning on the environment, not only in the form of carbon dioxide emissions but also soot, particulate matter, sulfur dioxide, oxides of nitrogen, harmful trace elements including mercury, arsenic, chromium, and nickel, and acid gases including hydrochloric acid and hydrofluoric acid, according to the US EPA's ruling on Mercury and Air Toxics Standards (MATS) for power plants. Already clear policy actions have been taken in the US and Europe and will unfold over the coming decade in terms of their impact on coal consumption in these regions. Owing primarily to the MATS in the US, 36GW of coal-fired power stations are scheduled to be closed on a net basis over the 2012-2017 period, according to the EIA. In the UK, the implementation of the Carbon Price Support beginning in April 2013 and rising on a schedule of real carbon prices through to 2030 will promote gas-fired and renewable generation at the expense of coal.

In China, popular protests against coal-fired power plants and associated pollution have signalled growing opposition in Haimen, Jiangsu in December 2011 and Hainan Island in April 2012. In Q1-2013, widespread reporting on the elevated level of air pollution in Beijing based on Air Quality Index (AQI) measurements and the level of particulate matter smaller than 2.5 microns (PM2.5) have raised the stakes for policy makers, in our view. Rectifying the pollution issue will require a powerful combination of long-term measures to disincentivize coal consumption through taxes or a firm commitment to a consumption limit (as opposed to the current nonbinding limit of 4bn tonnes of coal equivalent by 2015), greatly increased domestic gas production and Central Asian natural gas imports, and strong investment in renewables and nuclear power.

Details of the potential implications of a more aggressive national investment program into clean energies (which includes gas, nuclear, solar, wind and hydro) can be found in our China economist Jun Ma's report *Big bang measures to fight air pollution*, 3 March 2013, and our assessment of the resulting impact to coal and other commodities, *Addressing China's Pollution Crisis*, 1 March 2013. The end result may well be that China's overall coal consumption growth levels out and perhaps even declines in the long term.



#3 Coal formation and quality

Coal is created from woody tissues of plants, buried as peat deposits, then transformed through a series of processes collectively known loosely as coalification. In a progressive fashion, the carbon content of the deposit increases, while the hydrogen and oxygen content decreases. Coal resulting from a more (or less) complete process of transformation is referred to as being of higher (or lower) rank. The materials undergoing the process can be divided into minerals, composed of inorganic substances, and macerals, composed of organic material.

The initial stages consist of diagenetic processes (*diagenesis* refers to any chemical and physical processes resulting in the conversion of sediment to rock) of aerobic and anaerobic decay, which are essentially biochemical and involve the elimination of carbon dioxide and water. These stages result in the creation of low-rank forms of coal including peat and lignite. Later stages in the coalification process involve metamorphic processes triggered by deeper burial and higher temperatures which result in higher-rank forms of coal: sub-bituminous coal, bituminous coal and anthracite, in order of maturity.

The primary characteristics used to evaluate the maturity and quality of coal are moisture content, volatile matter, ash content, fixed carbon content, and calorific value. **Moisture content** declines with increasing coal rank and maturity, and can range from close to 1% to as much as 50%. Moisture has no calorific value, increases the cost of transportation through its mass, and also consumes energy through evaporation during burning. **Volatile matter** consists of lighter, hydrogen-rich compounds which are released in the form of gases and vapour when coal is heated in the absence of air, and is measured by the resulting loss in weight.

Ash is a residue left over after combustion, and results from a variety of minerals contained in the coal. The amount of ash produced incurs costs of disposal, especially because the ash can form a molten slag and then solidify into a crystalline material after cooling. Ash content can vary from as low as 3% to as high as 49%; at 50% and higher, the substance can no longer be referred to as coal, according to the USGS. **Fixed carbon**, according to the US Geological Society, is solid, combustible matter which remains after volatile matter, moisture and ash is eliminated.

Coals of higher rank result from deeper burial at higher temperatures, and tend to be harder, with higher fixed carbon content, lower moisture content, less volatile matter and higher calorific value.

The lower volatile matter content in higher-rank coals means that they will only ignite after having been heated to relatively high temperatures (496°C in the case of anthracite), whereas lignite may spontaneously ignite under certain conditions. Spontaneous combustion of coal is a particular problem in large stockpiles which can undergo self-heating and must sometimes be cooled through the application of a water spray.

Figure 26: Typical proximate analysis by coal type

	Fixed Carbon	Total Moisture	Volatile Matter	Calorific Value (kcal/kg)
Lignite	26-32%	25-50%	38-50%	<4600
Sub-bituminous	37-45%	10-25%	36-38%	4600-6400
Bituminous	45-81%	5-10%	13-40%	5800-8500
Anthracite	81-92%	<5%	2-15%	7500-8500

Source: American Society for Testing and Materials



#4 Coal mining techniques

Coal mining takes two primary forms: surface mines and underground mines. Surface mining typically results in lower costs and higher rates of extraction. Underground mining tends to be more capital-intensive and involves the use of more specialised machinery.

Surface mining techniques

Surface mining is employed when the coal seam is relatively near the surface, usually less than 200 feet deep. Mining is performed through open-cut strip mines which first remove vegetation and level the surface, then remove rock and soil above the coal seam in long, narrow bands. This rock and soil, termed **overburden**, is then set aside for land rehabilitation after the mining process is complete.

One of the major variables in mining cost is the degree of overburden per unit of coal mined, usually referred to as a **strip ratio** and measured in bank cubic metres per raw metric tonne. Bank cubic meters is a measure of volume in situ. When the material is blasted or excavated out of the ground, its volume increases as it is broken up, yielding a greater volume, referred to as loose cubic meters. The difference between the two is given by the swell factor.

Once the overburden is removed, the coal seam below can be loosened by drilling and blasting and then collected. Up to 95% of the coal seam can be recovered through this technique.

The measurement of the overburden removed is given in volume per raw metric tonne of coal recovered, rather than volume per clean metric tonne of coal. Raw coal is differentiated from clean coal by the **washing** process which reduces ash content to an acceptable level for sales. This can result in a considerably smaller tonnage of clean coal produced. The yield of clean coal from raw coal over the subset of mines surveyed here ranges from 73% to 100%.

Contour stripping is a surface mining technique used when the coal seam is located on steep terrain, and involves the removal of overburden along a hillside. Open-pit mining is a technique used when several coal seams are located close to one another on flat terrain, and differs from open-cut strip mining in that a deeper pit is excavated, and in that the overburden is typically not replaced after mining is completed.

Underground mining techniques

Underground mining techniques become necessary when the coal seam is located deeper below the earth's surface. Underground mining generally falls under one of two main types – room-and-pillar mining, and longwall mining. In room-and-pillar mining, coal is first partially removed as miners advance into a coal seam, leaving pillars to support the roof of the cavity. As miners retreat, the remaining coal is removed from the pillar structures, and the roof is allowed to collapse.

In longwall mining, a machine with a rotating shearer moves along the coal seam laterally, removing sections up to a mile long, 600-800 ft wide, and 7 feet high while the roof is supported by self-advancing hydraulic jacks. As the cutting machine moves past the roof support, the support is moved closer to the rock face and the roof behind allowed to collapse. Longwall mining offers higher productivity compared to room-and-pillar mining, but involves higher capital costs for equipment. Roughly 80% of the coal seam can be recovered by this method.



#5 Coal quality analysis

A word must be said about the energy content of coal, as buyers are interested not in the coal itself but rather the energy released from burning the coal, either for power generation, the creation of clinker for cement production, or industrial heating and drying processes. The energy content of coal is contained in volatile matter (hydrogen and oxygen) and fixed carbon, while the remaining components, which do not contribute any energy at all, are termed ballast and consist of moisture and ash.

Moisture and ash have no energy content, and therefore add to the cost of transporting coal owing to the additional mass. Thus, higher moisture and ash contents translate into lower prices paid. Furthermore, moisture reduces the amount of energy released by combustion as it consumes energy through evaporation. This energy is generally lost through exhaust as the water vapour is not condensed to recover the energy lost. The net energy content in coal differs from the gross energy content by the energy required to convert water from a liquid to its gaseous form.

Ash is an inorganic residue left over after combustion, and creates the additional problem of fouling boilers and furnaces, requiring additional expense for cleaning and disposal. Similarly, sulphur is a pollutant in exhaust gases, and may require removal in its various forms of oxides of sulphur through flue-gas desulphurisation (FGD) depending on the jurisdiction, which incurs additional cost.

Therefore, premiums for higher energy content and discounts for higher moisture, ash, and sulphur content will be used to adjust the price of a specific quality of coal relative to a benchmark quality specification.

A comparison of regional average coal characteristics shows that the major exporting nations of Russia, Australia, Colombia and South Africa are quite close to the API-2 benchmark of 6,000kcal/kg NAR. Indonesia falls significantly below this standard and has high moisture content, but has the advantage of having much lower ash content than Australian or Colombian coal. Similarly, Powder River Basin coal has even lower energy content, but also has low ash content, and low sulphur content.

Figure 27: Regional average coal qualities

	Total Moisture (%)	Ash Content (%)	Volatile Matter (%)	Total Sulphur (%)	Specific energy (kcal/kg NAR)
Australia	9.7	14.6	28.6	0.57	6,008
Colombia	12.1	7.2	34.4	0.68	6,129
South Africa	7.7	13.8	22.6	0.80	6,141
Indonesia	22.2	6.9	39.8	0.72	5,029
China	11.6	20.0	23.7	0.81	5,495
Central Appalachia (US)	8.0	9.9	34.3	0.95	6,736
Powder River Basin (US)	29.8	5.2	30.3	0.34	4,354
Russia	8.3	11.7	29.8	0.34	6,177

Source: Wood Mackenzie, AME, Deutsche Bank

The composition of coal as described in percentages of moisture, ash, volatile matter and fixed carbon are given by the **proximate analysis**, which is carried out according to specified procedures using an air-dried sample. The moisture, volatile matter, and ash contents can be determined by heating the sample in a prescribed fashion and then comparing the difference in mass before and after heating.

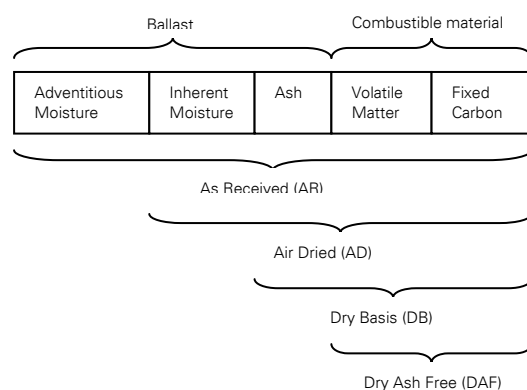


A more precise assessment of the constituents in coal is achieved through the **ultimate analysis**, which gives an exact measure of the amount of carbon, hydrogen, sulphur, nitrogen, oxygen and ash in the sample using laboratory techniques.

Energy content can be expressed in the following ways, in order of decreasing ballast content: As-Received (AR), Air-Dried (AD), and Dry Basis (DB), according to the World Coal Institute. These measurements differ by the amount of moisture contained in the sample. Moisture content can be described in several ways, including adventitious moisture and inherent moisture. Adventitious moisture is surface moisture which is easily removed by air drying at a low temperature of 40°C. Inherent moisture is contained within the spaces in the interior of the coal body. Coal on an As-Received basis includes both adventitious moisture and inherent moisture (collectively termed total moisture, or "TM"), while air-dried coal includes only inherent moisture ("IM"), and dry basis coal contains no moisture at all. Finally, the energy content of a coal from which all moisture and ash ("A") have been removed is described as Dry Ash-Free basis (DAF), Figure 28.

The latter two measurements of energy content can give the appearance of a higher heating value, but are not representative of what is achievable in practice and are relevant only under laboratory conditions.

Figure 28: Coal components and energy basis



Source: World Coal Institute, Deutsche Bank

While the basis of the stated energy content may not necessarily have anything to do with the actual condition of the coal delivered, the less moisture or ash assumed to be in the sample, the higher the energy content per unit mass.

For instance, if we take a coal from Australia's Mount Arthur with TM of 10%, IM of 3.5% and calorific value of 6700kcal/kg on a Gross Air Dried (GAD) basis, we would calculate a calorific value of $6700 \times ((1-0.1)/(1-0.035)) = 6248\text{kcal/kg}$ Gross As Received (GAR) using the formula in Figure 29.



Figure 29: Conversions among bases of measurement

$$AR = AD \left(\frac{100 - TM\%}{100 - IM\%} \right)$$

$$AD = DB \left(\frac{100 - IM\%}{100} \right)$$

$$DB = DAF \left(\frac{100 - A\%}{100} \right)$$

Source: World Coal Institute

The exclusion of ash further increases the numeric value of the energy content, as we can see in an example below which assumes TM of 10%, IM of 3.5%, and ash content of 14%, Figure 30.

Figure 30: Example of energy measurement bases

	As Received (AR)	Air Dried (AD)	Dry Basis (DB)	Dry Ash Free (DAF)
Gross Calorific Value (GCV), kcal/kg	6,248	6,700	6,943	8,073

Source: Deutsche Bank

In addition, calorific value can be stated on a gross or net basis, which differs by the latent heat of the water vapour produced. The determination of gross calorific value (GCV) requires the products of combustion to be cooled to 15°C whereby the water vapour is condensed, releasing the latent heat. However, the net calorific value (NCV) is a more accurate representation of the usable heat recoverable in practice, and is therefore the heating value which would typically be used to calculate the thermal efficiency of a combustion plant.

A conversion between GCV and NCV depends on the total moisture content ("TM"), hydrogen content ("H") and oxygen content ("O") of the coal which are derived from the ultimate analysis, Figure 31.

Figure 31: Conversion between GCV and NCV, as received basis including total moisture

$$NCV = GCV - 50.64H - 5.84TM - 0.191O$$

Source: American Society for Testing and Materials

Revisiting our example from Figure 30, and using hydrogen content of 4.6% and oxygen content of 8.2%, we calculate net calorific value on an as-received basis (NAR) of 5,920kcal/kg, which compares with 6,248kcal/kg gross calorific value on an as-received basis (GAR), for a difference of 328kcal/kg. Often, a difference of 260kcal/kg is assumed as a shortcut, but the above calculation shows that the actual conversion can be somewhat different in practice.



#6 Coal-price benchmarks

Coal price benchmarks can be specified in a number of different ways based on point of delivery, energy content, and whether the price refers to a contract or a spot price.

Contract price benchmarks

While Japanese coal contracts are negotiated several times a year, the largest volume is agreed on a Japanese Fiscal Year (JFY) basis once a year in March, and delivery takes place over the following 1 April to 31 March period. Other negotiations take place for smaller annual volumes delivered beginning in July and October. Japanese contract prices are specified on a Free On Board (FOB) basis, which means that the coal is delivered at a port in the country of origin.

Figure 32: JFY thermal coal settlements (FOB Newcastle)

Period	Price (\$/mt)
2002-03	31.84
2003-04	26.75
2004-05	45
2005-06	53
2006-07	52.5
2007-08	55.5
2008-09	125
2009-10	70.35
2010-11	98
2011-12	129.85
2012-13	115.25
2013-14	95.8 (est.)

Source: Australian Government Department of Resources, Energy and Tourism, Australian Bureau of Agricultural and Resource Economics, Platts, Deutsche Bank

Under FOB terms, the buyer takes title once the goods pass over the ship's rail. The subsequent cost of transporting the coal from the port of origin to the destination country is borne by the buyer, as well as any insurance costs and the risk of loss or damage in transit.

By contrast, under Cost Insurance Freight (CIF) terms, the buyer does not take title of the goods until they are delivered to an agreed destination port, and the seller assumes responsibility for the cost of transporting the coal, as well as the insurance costs and the risk of loss or damage in transit. Cost and Freight (CFR) terms are the same except that they exclude the insurance component which is borne by the buyer.

According to the Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES), the JFY contract price specifies a calorific value of 6,700 kcal/kg GAD.

Spot-price benchmarks

The remainder of the price benchmarks described here are spot-price markers which can be traded on an over-the-counter basis rather than bilaterally agreed contract prices.

The Argus/McCloskey Coal Price Index service is the source of API prices, which are the most commonly-followed indications of market prices. According to Argus, the API 2 index is an average of the Argus CIF Rotterdam assessment and McCloskey's Northwest European steam coal marker. The



coal is delivered to the Port of Rotterdam in the Netherlands and has an energy content of 6,000 kcal/kg NAR.

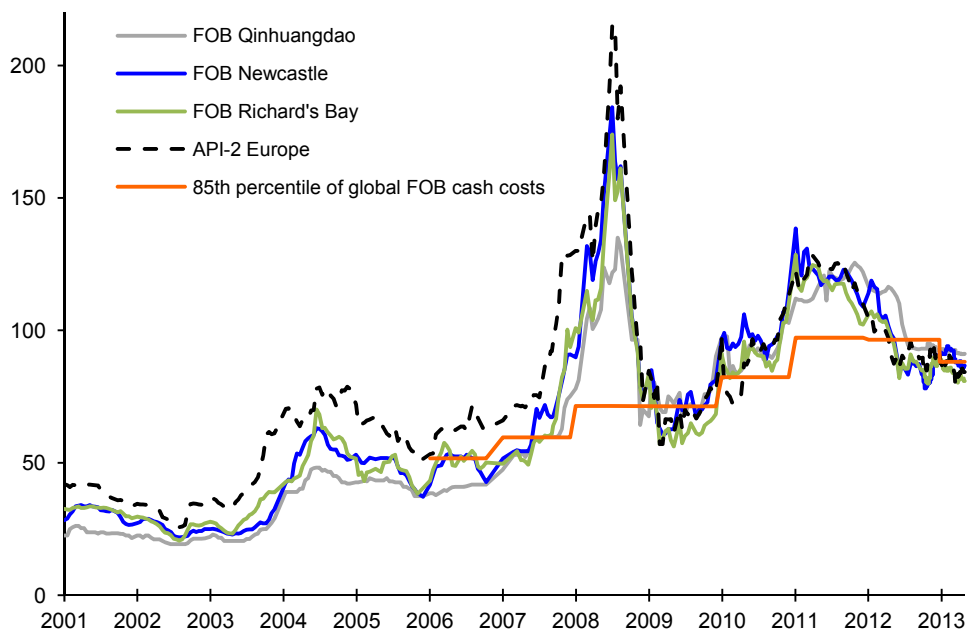
The API 4 index is calculated as an average of the Argus FOB Richards Bay assessment and the McCloskey's FOB Richard's Bay marker. The coal is delivered at Richards Bay Coal Terminal in Africa and also has an energy content of 6,000 kcal/kg NAR.

Other less commonly cited reference prices are the API 5 index of 5,500 kcal/kg NAR coal delivered FOB Newcastle, API 6 index of 6,000 kcal/kg NAR coal delivered FOB Newcastle, and the API 8 index of 5,500 kcal/kg NAR coal delivered CIF South China.

Our price forecasts include Japanese Fiscal Year (JFY) contract prices, the API 2 and API 4 indices, and coal delivered FOB Newcastle in Australia with an energy content of 6,700 kcal/kg GAD.

The Qinhuangdao (QHD) benchmark price bears some special mention as it is a closely watched measure of Chinese domestic prices, delivered to the port of Qinhuangdao on the Bohai Sea. From this point, domestically produced coal is shipped via intercoastal freight to other Chinese ports in central and southern China. The QHD price tracked in the following graph is net of a 10% export tax and 17% VAT.

Figure 33: Thermal coal price history (\$/mt, adjusted to 6,000kcal/kg NAR)



Source: Bloomberg Finance LP, AME, Deutsche Bank



#7 Producer cost analysis

Short-term costs

The short-run marginal cost represents the incremental cash outlay required to produce an additional metric tonne of coal, including royalties which are calculated as a percentage of revenue, but excluding any capital investment in fixed assets and infrastructure. In this document, we will refer to this cost as simply the '**marginal cost**' or 'marginal price.'

In order to evaluate the short-term costs for thermal coal, we evaluate marginal prices for as wide as possible a cross-section of mines currently in operation in major producing regions. We utilise cash costs per metric tonne in order to assess short-run marginal cost. These costs are the sum of mining cost, processing (including washing), transport, port costs, administrative overhead, and royalties. In our current outlook, marginal costs provide a fundamental basis for price support in an oversupplied market.

Long-term costs

The long-run marginal cost is the sum total of all fixed and variable costs to be incurred over the life of the project, after taxes and in nominal terms, divided by the total volume of coal produced. This represents the coal price above which a rational investor would choose to invest in the project in question. For this reason, we will refer to this as the '**incentive cost**' or 'incentive price' in this document.

For long-term costs we first identify major exporting regions with the greatest likelihood of production growth, and then examine incentive costs at selected individual mines in each region which are responsible for largest shares of production growth potential in the decade from 2013-2022. We examine annual revenues and expenses over the life of the project with nominal post-tax cashflows discounted at a 15% internal rate of return (IRR). The coal price at which the project breaks even then becomes our estimate of a long-run incentive cost.

Conceptual framework

Conceptually, the short-run marginal cost is the price below which we would expect individual mines to shut-in production, limiting the downward movement of prices in an oversupplied market. The long-run incentive cost is the coal price at which we would expect producers to be incentivised to sanction new development of productive capacity. In an oversupplied market, prices should be limited by the ability of consumers to switch into substitute fuels, such as natural gas for power generation.

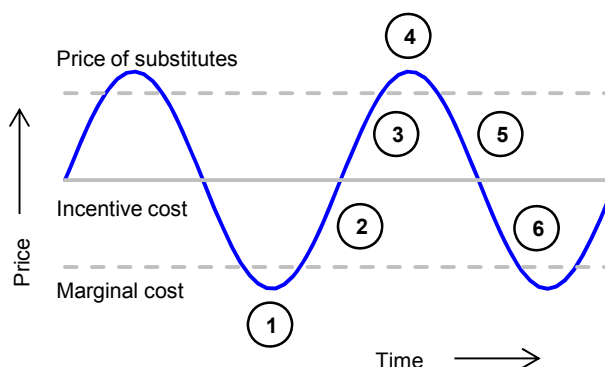
With these three price concepts in mind, we can formulate a hypothetical market in which price oscillations are governed by these idealised interactions. In this idealised market (Figure 12), prices at point (1) are too low for some producers to justify continued production from existing assets, so total production volume falls. If this contraction in production brings the market into balance, then prices may remain at point (1) for some time. If at any point in the future, demand rises for whatever reason, then undersupply begins to manifest in rising prices, bringing us to point (2), with prices above marginal cost. By definition, this causes producers to restart idled production. This rise in production may very well balance the market, keeping prices in a range between the marginal cost and the incentive cost for some time.

However, if demand continues to grow after idle mines have been pressed into service, this could lead to a more extreme condition of undersupply wherein even production at maximum capacity of existing assets cannot satisfy demand. This brings prices above the incentive cost at point (3), and triggers



producers to invest capital in new productive capacity. This investment will continue as long as forward prices are above the incentive cost. However, there is some delay between the decision to invest in new capacity and the date at which that capacity actually comes to market. If demand continues to rise, this can result in further price increases until point (4) at which some buyers find it economically justified begin to switch into alternatives.

Figure 34: Idealised progression of prices



Source: Deutsche Bank

The switching response of buyers to alternative fuels reduces demand and may keep prices stable at point (4) for some time. But as long as the coal price is above the price of substitutes, a further switching response is incentivised, and at some point, the reduction in demand is likely to push prices to back below the cost of substitutes to point (5), at which point the switching response is halted and some buyers may even switch demand back into the primary good. This activity can keep prices in a range between the cost of substitutes and the incentive cost for some period of time. However, keep in mind that all the while, producers are incentivised to invest in new capacity, which may have the effect of raising the average marginal cost of producing assets. At any rate, the longer this pricing state continues, the more new capacity enters the market. At some point, the continued commissioning of new capacity tips the market into oversupply, bringing about a decline in prices to point (6), below the incentive cost, and thus eliminating the investment rationale.

Therefore, producers stop investing in new capacity. However, we note that there is a delay between investment and commissioning, so that it is entirely possible that at this point, the delayed effect of investment at points (3), (4), and (5) continues to pressure the market lower with new productive capacity as it is brought online. This can push prices down further, bringing us back to point (1). Alternatively, the market may settle into a new price equilibrium between the incentive cost and the marginal cost. During this period, no new investment is occurring. However, existing assets degrade over time and are retired as they end their productive lives, thus resulting in a gradual contraction in productive capacity. The longer this period continues, the more net productive capacity is retired, eventually tipping the market into undersupply and bringing us back to point (3).

This provides the conceptual framework which we believe lies behind the importance of marginal and incentive costs, and describes the ways in which market prices influence production and consumption decisions. With this framework in mind, we now move to a consideration of how marginal cost may evolve over the forecast period.



#8 Evolution of marginal cost

The advance in thermal coal prices in real terms over the past ten years has reflected increases in thermal coal production and export costs to a large degree, and some portion of this increase is a result of the sensitivity of mining costs to crude oil.

Globally speaking, mining costs account for 53% of total FOB thermal coal export costs. Mining costs, in turn, have been estimated to be 40% dependent on the price of crude oil as a result of input materials such as diesel for mining equipment, tires and explosives (which are manufactured from petrochemicals), and other chemicals. The second-largest component is freight and transport which account for 28% of global volume-weighted FOB costs. The freight and transport component is also likely to have some sensitivity to the price of crude oil.

We can look to historical real price movements for confirmation of the correlation between crude oil and coal prices. Although this does not prove the relationship, it is consistent with what we would expect. From 2001 to 2012, nominal prices of Australian and South African seaborne thermal coal exports have risen by 4.0% per annum in real terms, using world inflation figures implied from global GDP figures available from the World Bank and assuming that 2012 inflation is in line with the preceding ten years.

Over the same period, 2001 to 2012, Brent crude oil prices have risen by 8.9% per annum in real terms using the same measure of world inflation, which would be consistent with a 45% sensitivity of the overall FOB cost of thermal coal to crude oil.

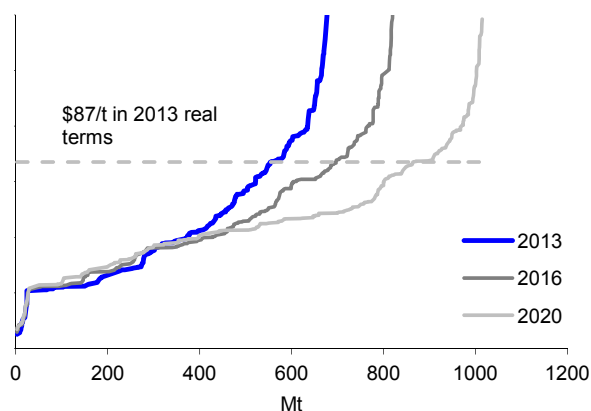
Our view on oil prices over the 2013-2015 period is that Brent crude will average \$112/bbl in nominal terms. This is consistent with oil consumption as a percentage of global GDP settling near the “sweet spot” of roughly 4% as global growth remains above the level at which significant downside risks to the oil price become evident, while not stretching productive capacity and thus not building in the likelihood of any significant oil-related increase in the mining cost base.

This is consistent with our expectation for the evolution of the global thermal coal cost curve, Figure 35 and Figure 36. On a long-term view through 2020, thermal coal export costs may actually decline for a fixed quantity of supply, as the cost curve shifts to the right, if all current investment plans are allowed to come to market. In other words, drawing a vertical line at any particular fixed volume in Figure 35 would intersect the cost curve at progressively lower price points, in 2013 real terms, the greater the amount of net new capacity. However, postponement or cancellation of some plans is likely, which would attenuate the rightward shift. On the whole, we believe that there will not be any sustained real-terms increase in thermal coal production costs.

We would note that the mine data in the following chart covers only approximately two-thirds of the global thermal coal export mines actually in production and should only be used as an indicative measure.



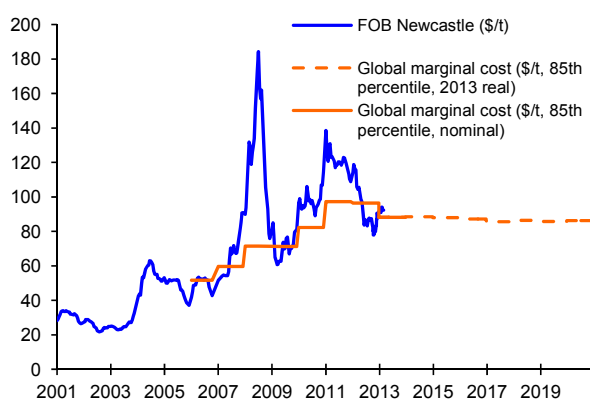
Figure 35: Global thermal coal FOB export costs in 2013 real terms (\$/t)



Source: AME, Deutsche Bank

In order to use individual mine cost data to assess the market-clearing price, the global export supply potential of all mines must also be known. A further uncertainty arises from the possibility of an over- or under-representation of high- or low-cost mines in the mine database, which could lend a high or low bias to the market-balancing price. At the moment, given the level of oversupply in the market today, most industry observers would agree that prices are trading at or near the 85th percentile. Our base-case assessment of the growth in global export supply potential indicates that market prices will find support in 2013 real terms at \$87/t through 2020, as shown in Figure 36, assuming limited net new capacity additions in line with our base-case scenario (our base-case and bear-case scenarios are explained in more detail in Section 20, Supply-demand balance). However, over- or under-investment in productive assets would result in market prices under- or over-shooting this mark.

Figure 36: Global thermal coal FOB export costs, 2013 real terms (\$/t)



Source: AME, Deutsche Bank

On the whole, we do not expect a large degree of price inflation in mining and transport costs over the next several years, which together account for 81% of global 2013 FOB production costs. The next surge in upside risks will likely come in 2014 as forecast global GDP growth of 4.0% approaches the long-term trend rate up from 2.9% in 2012 and 3.2% in 2013. While the resulting level of coal demand will not overly strain productive assets, we suggest that a moderate degree of cost inflation over marginal cost is likely.



#9 Production and trade flows

The world's overall production and consumption of thermal coal, in all its forms including anthracite, bituminous coal, sub-bituminous coal and lignite is concentrated in two countries: China and the United States (Figures 5 and 7). Next, we would draw two observations from the map, which shows volume of production (blue) and consumption (orange) represented by area: (i) Of the three largest producers (China, the United States and India), two are net importers; and altogether, the three largest producers summed together are a net importer, and (ii) small percentage fluctuations in the demand of the top two consumers can have an outsized impact on the balance of seaborne trade. However, the practicalities of port infrastructure and land transport mean that variations in short-term demand are limited to some extent.

Among EU-27 countries, Germany (189mt) and Poland (139mt) are the two largest producers by far, and a significant proportion of this production is lignite, particularly in Germany. This results in a low implied energy content in Germany of only 2,370 kcal/kg, dragging down the EU-27 average to 2,885 kcal/kg, Figure 37.

Figure 37: Production and consumption of thermal coal* in the largest producing countries in 2011

	2011 Production (mt)	2011 Consumption (mt)	Implied calorific value of production (kcal/kg)
China	3,520	3,678	5,561
United States	993	910	5,613
India	588	715	3,783
EU-27	550	763	2,885
Australia	415	129	5,557
Russia	334	237	4,720
Indonesia	325	52	6,154
South Africa	255	190	5,640
Kazakhstan	116	75	5,072
Ukraine	87	71	5,205
Colombia	86	5	6,504
Turkey	77	104	2,153
Canada	68	48	5,230
Vietnam	44	25	5,604

Source: BP Statistical Review of World Energy, Energy Information Administration

*Includes hard coal (anthracite and bituminous), sub-bituminous coal, and lignite, and excludes coking coal

The world's major trade flows (above 10mt on a country basis) are concentrated mostly in the Pacific Basin (Figure 38 and Figure 39), involving the exporting countries of Indonesia and Australia and the importing countries of China, India, Japan, Korea, and Taiwan.



Figure 38: Trade flows of thermal coal greater than 10mt in 2011 (EU-27 split on a country basis)

Exporter	2011 exports (mt)	Importer
Indonesia	62.9	China
Vietnam	22	China
Australia	20.5	China
North Korea	11	China
Indonesia	73.6	India
South Africa	17	India
Australia	71.1	Japan
Indonesia	35.1	Japan
Indonesia	40.2	South Korea
Australia	32.6	South Korea
Russia	12	South Korea
Indonesia	27.3	Taiwan
Australia	26.3	Taiwan
Colombia	18	Netherlands
Russia	11.9	UK
Colombia	10.4	Germany

Source: McCloskey, Deutsche Bank

Figure 39: Trade flows of thermal coal greater than 10mt in 2011 (EU-27 considered as a whole)

Exporter	2011 exports (mt)	Importer
Indonesia	62.9	China
Vietnam	22	China
Australia	20.5	China
North Korea	11	China
Indonesia	73.6	India
South Africa	17	India
Australia	71.1	Japan
Indonesia	35.1	Japan
Indonesia	40.2	South Korea
Australia	32.6	South Korea
Indonesia	27.3	Taiwan
Australia	26.3	Taiwan
Russia	42.4	EU-27
Colombia	40.1	EU-27
South Africa	13.3	EU-27
Indonesia	12.4	EU-27

Source: McCloskey, Deutsche Bank



#10 Reserves

In general, the largest producers are also in possession of the largest shares of thermal coal reserves, although the scale of those reserves varies widely. In particular, two of the most important exporting nations, Colombia and Indonesia, are also near last in the list of major reserves.

We would caution that the statement of reserves is subject to numerous uncertainties and variables including methods of estimation and investment in exploration. This makes the volume of reserves a less accurate indicator of geological endowment than we would like it to be.

With this caveat, we would note that the relationship of the volume of reserves to current year production also varies considerably among major producing countries. In particular, China and Indonesia stand out as having the lowest reserves in terms of years of production, 33 years and 17 years, respectively. Thus it would appear that both the world's largest producer and the world's largest exporter may be depleting their respective coal resources at a rapid rate relative to the two countries with the largest coal reserves, the United States and Russia, Figure 41.

While additional investment in exploration could boost China's estimated reserves, the low reserves-to-production (R/P) ratio may go a considerable way towards explaining why China imports some coal each year rather than meeting its entire requirement through domestic production.

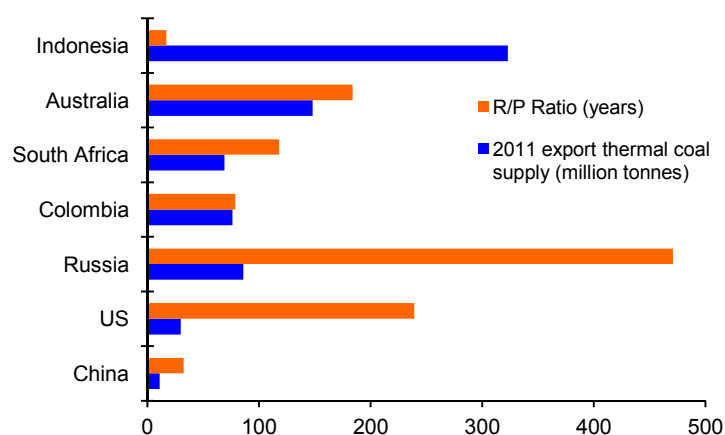
In Indonesia, the low R/P ratio is a large part of the government's motivation in seeking to better manage the country's natural resources. In recent years, this has taken the form of a discussion over a possible export ban on low-calorific coal. Although the ban was abandoned because of inadequate development of coal washing technology, the rationale underlying the ban continues to influence policy regarding other commodities and resulted in a qualified ban on exports of 14 raw minerals by contract-of-work producers in May 2012.

Figure 40: Thermal coal reserves in 2011 (EU-27 considered as a whole)

Country	2011 reserves (mt)	R/P Ratio
United States	237,295	239
Russia	157,010	471
China	114,500	33
Australia	76,400	184
India	60,600	103
EU-27	55,603	101
Ukraine	33,873	390
Kazakhstan	33,600	290
South Africa	30,156	118
Colombia	6,476	79
Canada	6,582	97
Indonesia	5,529	17
Other	43,314	
World Total	860,938	112

Source: BP Statistical Review of World Energy 2012, Deutsche Bank

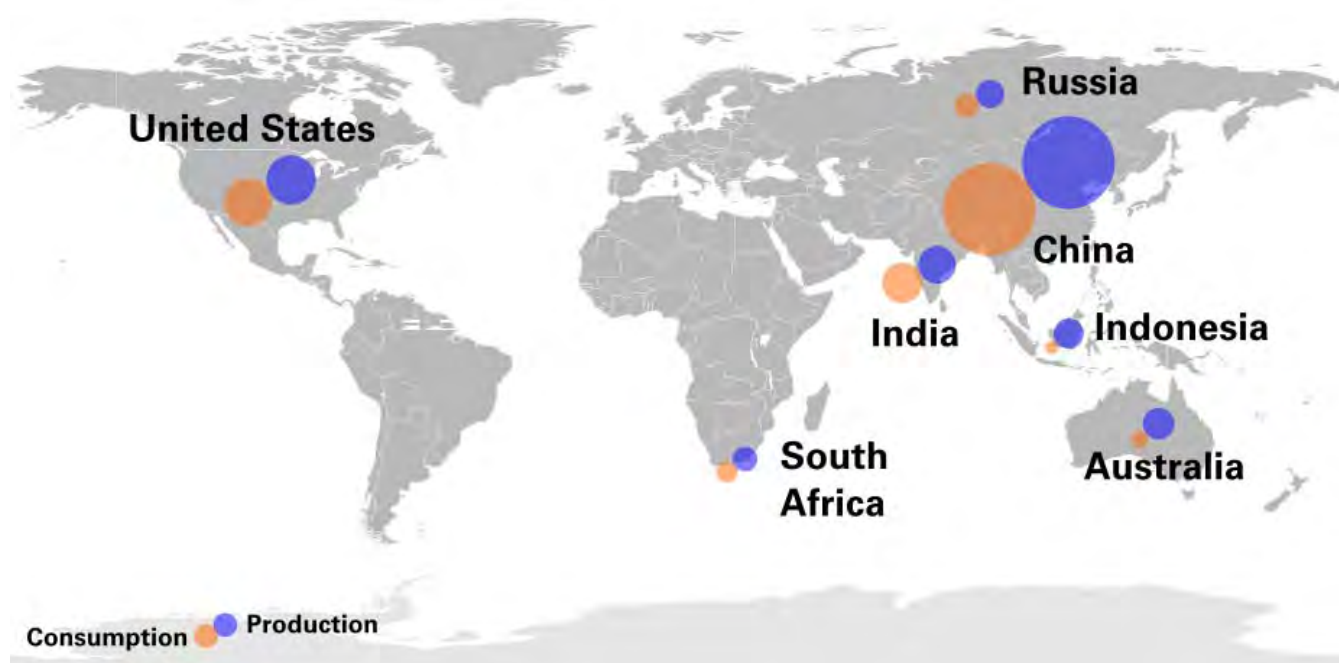
Figure 41: Reserves-to-production ratios and export production



Source: BP Statistical Review of World Energy 2012, Deutsche Bank

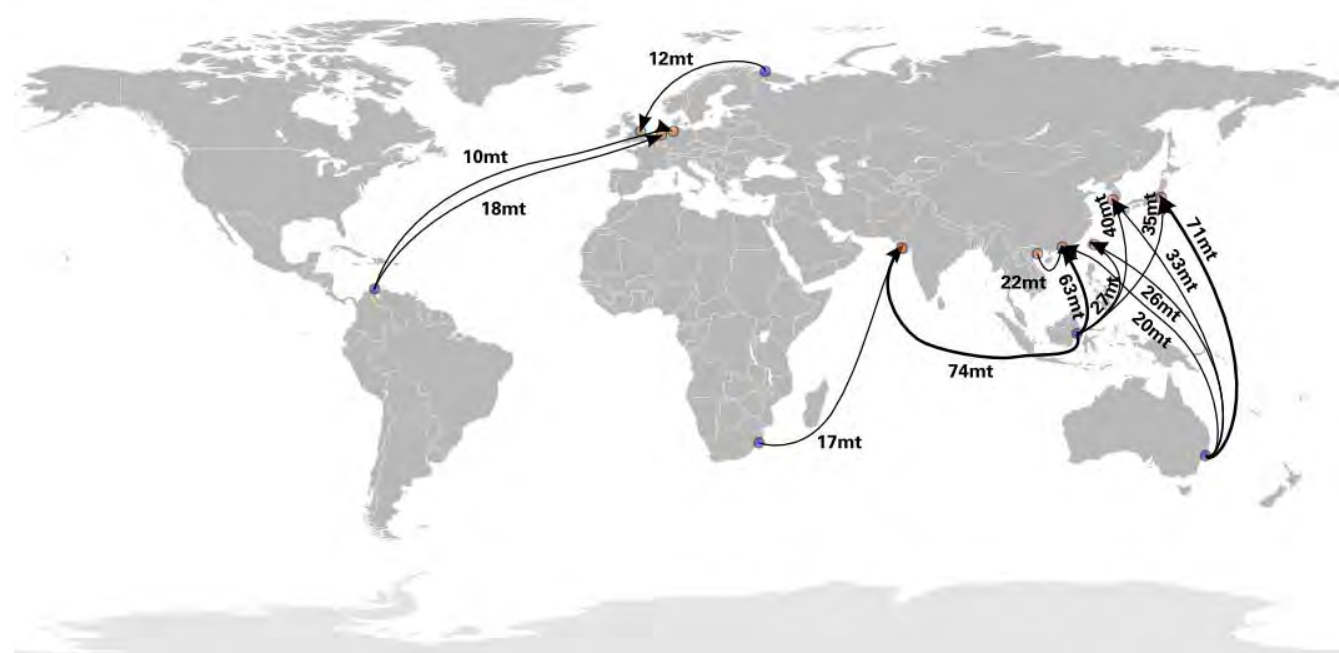


Figure 42: Production and consumption in the seven largest producing countries in 2011



Source: EIA, Deutsche Bank

Figure 43: Trade flows of thermal coal greater than 10mt in 2011



Source: McCloskey, Deutsche Bank



#11 Indonesia

Figure 44: Indonesia at a glance

2012 thermal coal exports	347mt
2012 thermal coal production	387mt
Calorific value	5,030kcal/kg NAR (est.)
2013 export cash cost, wt avg	\$51.6/t
2013 export cash cost, 85th percentile	\$63.5/t
5-year forecast export growth rate	4.5%

Source: Deutsche Bank

The world's largest low-cost exporter

Indonesia is the largest low-cost thermal-coal exporting region consisting exclusively of opencast surface mines, from which 85% of production is exported, and 95% of exports are destined for Asian countries. Indonesian coal production is concentrated in Kalimantan (93%) with the remainder located in Sumatra.

Figure 45: Indonesian coal-bearing regions



Source: Wood Mackenzie, Deutsche Bank

Domestic transportation infrastructure consists of coastal and barging in Kalimantan and Sumatra, and river barging along the Mahakam and Barito Rivers in Kalimantan. Small barges take coal to transshipment facilities where material is then loaded onto larger seagoing vessels.

The Indonesian government determines a single reference price at which producers can sell spot coal in any given month, both for domestic buyers and export markets. This reference price is called the Harga Batubara Acuan (HBA) index which is on a 6,322kcal/kg GAR basis and is calculated from the average of the Indonesia Coal Index, Newcastle Coal Index, Global Coal Index, and Platts. In our price analysis below, we scale marginal and incentive costs to match the HBA index for comparison purposes. From this reference HBA coal price, eight primary coal benchmark prices for coal of varying quality from 4,200kcal/kg to 7,000kcal/kg GAR can then be derived. These are referred to as the Harga Patokan Batubara (HPB) prices.

The formula used for seven of the eight primary coal benchmark prices is given in Figure 46, whereby the adjustment to arrive at an HPB price from the HBA index is calculated from specific energy (SE), total moisture (TM), sulphur (S), and ash content (A). There is a discount for calorific value below 6,322kcal/kg GAR, moisture above 8%, sulphur above 0.8%, and ash content above 15%.



The eighth primary coal benchmark includes a further adjustment for moisture content.

Figure 46: Indonesian coal quality adjustment for primary coal benchmarks 1-7

$$HPB = HBA \cdot \left(\frac{SE}{6322} \right) \cdot \left(\frac{100 - TM}{100 - 8} \right) - (S - 0.8) \cdot 4 - (A - 15) \cdot 0.4$$

Source: Directorate General of Minerals, Coal & Geothermal Regulation

Falling energy content of export coal

For the past decade, the energy content of Indonesian export coal has been falling steadily as miners deplete the most economic seams and are forced to move production to less attractive acreage. This trend has been in place since at least 2004, and we expect weighted average energy content to continue its decline through 2020. However, it is also important to note that despite the decline in energy content, energy-adjusted thermal production is forecast to rise at an annual average rate of 4.8% from 2012 to 2020. In other words, the rise in total volume of production significantly outweighs the drop in energy content.

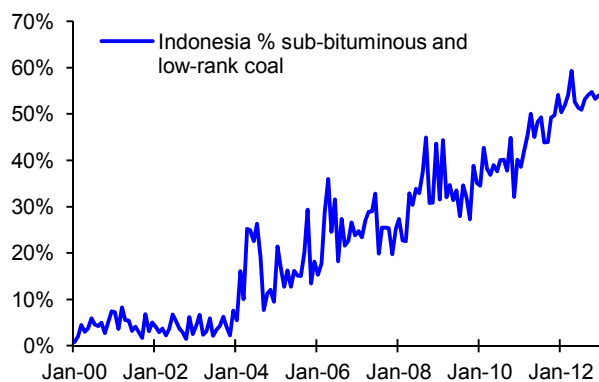
Figure 47: Energy-adjusted Indonesian thermal coal production

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total thermal production (mt)	224	255	290	327	368	425	472	506	517	533	556	579	582
Weighted average energy content (kcal/kg)	5,421	5,385	5,303	5,241	5,224	5,169	5,124	5,077	5,036	4,991	4,936	4,871	4,803
Energy-adjusted thermal production (mt, HBA equivalent)	192	217	243	271	304	347	382	406	412	421	434	446	442

Source: Wood Mackenzie, Deutsche Bank

Another way of viewing the decline in coal quality is to simply plot the percentage of total coal exports represented by sub-bituminous coal, which has now risen to 54% as of December 2012, up from only 1% in January 2000, Figure 48.

Figure 48: Percentage of sub-bituminous coal in Indonesian exports



Source: McCloskey, Deutsche Bank



Cost assessment of the fastest-growing mines

In Indonesia, we assess four of the fastest-growing mines which are collectively responsible for 28% of total projected export production increase by 2017, and 69% of the total projected export production increase expected by 2022 (Figure 49 and Figure 50).

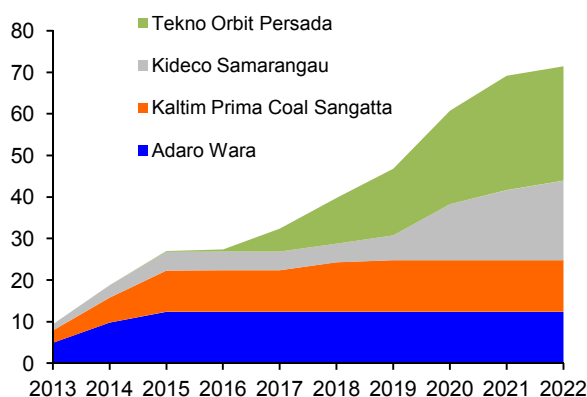
The figures used here only refer to production volumes available for export, and exclude those volumes which are expected to supply the domestic market. Although the overall growth in export production begins to turn negative in 2020, this is primarily a result of the fact that production increases towards the end of the period will be largely realised from projects which are not yet known or planned in detail. Finally, the fact that only one of the four mines is expected to produce bituminous coal indicates that the proportion of sub-bituminous coal in Indonesian production may continue to rise further over the next decade, continuing the trend already firmly in place since 2004, Figure 48. As of April 2012, this ratio has risen to 59%.

Figure 49: Indonesia export growth through 2022 from selected mines only

	Est. 2012 production (mt)	Est. 2022 production (mt)	10-yr prod. growth (mt)	Coal Type
Adaro Wara	5.6	18	12.4	Lignite
Kaltim Prima Coal Sangatta	37.6	50	12.4	Bituminous
Kideco Samarangau	8.3	29.3	21	Lignite
Tekno Orbit Persada	0	27.5	27.5	Lignite

Source: Wood Mackenzie, Deutsche Bank

Figure 50: Cumulative annual export growth from selected mines (mt)



Source: Wood Mackenzie, Deutsche Bank

Adaro Wara

The Adaro Wara mine, operated by Adaro Energy, has been in production since 2009 and is characterised by a relatively low strip ratio (4.0bm/raw tonne) and flat terrain, which results in lower mining costs. However, we include in the mining cost the expense of the 74km road haul to the processing and barge loading facility on the Barito River. This, combined with the fact that the mine produces coal of a relatively low calorific value (4,100kcal/kg GAR), means that after adjusting the mining cost into HBA terms based on the formula in Figure 46, Adaro Wara is the highest in terms of mining cost out of the four mines considered.



The barge transit of 240km along the Barito River ends at Taboneo where the coal can be loaded by crane onto dry bulk vessels. This is a relatively lengthy route so total transport and port costs are also the highest among the four mines considered.

The overall project cost at the Adaro Wara mine is lower than it might otherwise have been since a considerable infrastructure investment, including the coal haul road, crushing systems and barge-loading facilities, were constructed for the benefit of the associated Tutupan mine which began production in 1997 and is part of the same complex.

Altogether this results in a cash cost of \$39.2/t and an incentive price only \$3/t higher at \$42.6/t which reflects the low capital costs. After converting to HBA basis, this equates to a cash cost of \$74.1/t and an incentive price of \$82.0/t. According to Wood Mackenzie, cash costs are likely to increase in the future as overburden becomes greater in newer areas of production.

Kaltim Prima Coal Sangatta

The Kaltim Prima Coal Sangatta mine is operated by Bumi Resources, and began production in 1991. It is characterised by a higher strip ratio of 12.5bm/raw tonne in comparison to Adaro Wara and consequently a higher cash mining cost on an unadjusted basis (\$28/t versus \$22/t). However, its strip ratio is considered low for a project producing bituminous coal (KPC Sangatta is the only mine in our group of four Indonesian mines which produces bituminous coal). So after adjusting for its higher calorific value and lower moisture, KPC Sangatta's cash mining cost on an HBA basis is actually lower than Adaro Wara (\$33/t versus \$42/t).

Wood Mackenzie expects that the strip ratio will decline over the long term to 6bm/raw tonne as production shifts to the Pinang North pit. Coal is trucked an average of 16km to a coal preparation plant, after which an overland belt conveyor transports coal 13km to Tanjung Bara Coal Terminal for ship loading. This is a relatively short transport route, comparing favourably against Adaro Wara; KPC Sangatta's total transport and port costs are less than a quarter of those at Wara (\$4/t versus \$18/t on an HBA-adjusted basis).

Although there are still investments to be made, production has been underway for quite some time and cash flows in future years of operation are not expected to be negative at any point. Thus, calculating an incentive price may not make sense in the same way that it does for a new project. Nevertheless we show an HBA-adjusted incentive price of \$66.3/t in Figure 51 for comparison purposes. The unadjusted marginal cost at Sangatta is \$43.7/t, which when converted to an HBA-equivalent price, is \$52.1/t.

Kideco Samarangau

Kideco Samarangau began operation in 2009 and is operated by Kideco Jaya Agung. At this lignite-producing mine, overburden is blasted and the coal extracted to a crushing facility, after which it is trucked 38km to the Tanah Merah barge-loading facility. While transport costs are similar to Adaro Wara, Samarangau benefits from a low mining cost as a result of its low strip ratio (4.3bm/raw tonne), giving it a cost advantage on an unadjusted basis.

On an adjusted basis, its advantage versus Adaro Wara is increased further by its lower moisture, lower ash and lower sulfur content. We find that with cash costs of \$29.8/t and incentive price of \$40.4/t on an unadjusted basis, and \$48.0/t and \$71.1/t converted to HBA basis, Kideco Samarangau has the lowest marginal cost of the three mines covered thus far in Indonesia.



Tekno Orbit Persada

Tekno Orbit Persada, to be operated by MEC Holdings, is the only one of the four mines in our Indonesia analysis that has not yet begun production. Its very low calorific value of 3,430kcal/kg GAR will be one of the lowest in Indonesia, according to Wood Mackenzie, and therefore is a risk to the project if buyers choose to seek higher-quality volumes elsewhere. The mine also has the highest moisture content of the four mines surveyed here, at 46%. However, the proposed acquisition of a 25% stake in MEC by Nalco, an aluminium producer, indicates that the demand exists for at least 8mt of product of this quality. The project will also supply 6.5mt p.a. to a nearby power plant attached to an aluminium smelter yet to be built.

Challenges to the project may emerge from the Indian power industry, which is likely to be its main customer. The project was originally scheduled to come online in 2009 but has been delayed owing to delayed power plant construction in India. Also, India's participation in foreign coal projects may be postponed after departures from International Coal Ventures Ltd. (ICVL), a consortium of Indian state-owned companies created to acquire overseas coal resources. NTPC, India's largest power producer, exited ICVL in 2011, while Coal India, India's largest coal producer, left in May 2012. Nevertheless, Tekno Orbit Persada remains an important project in terms of volume of potential production and therefore, in regards to benchmarking costs.

Tekno Orbit Persada is distinguished by its extremely low strip ratio of 1.1bm/raw tonne and the thickness of the coal seam, which contribute to low mining costs. The project will also be able to keep cash transport costs under control owing to the construction of a purpose-built 130km rail line and associated coal terminal and port. However, the \$880m construction cost of the dedicated rail line and the \$320m construction cost of the port facilities adds considerably to the fully-amortised project cost, making the long-run incentive cost of coal from Tekno Orbit Persada nearly as expensive as that of its peers.

On an unadjusted basis, we find that the marginal cash cost is \$18.4/t and the incentive price is \$30.6/t. Adjusted to HBA-equivalence, we find a cash cost of \$35.0/t and incentive price of \$73.1/t. This makes Tekno Orbit Persada by far the cheapest in terms of marginal cost, but slightly more expensive than Kideco Samarangau on a fully-amortised project basis for incentive cost.



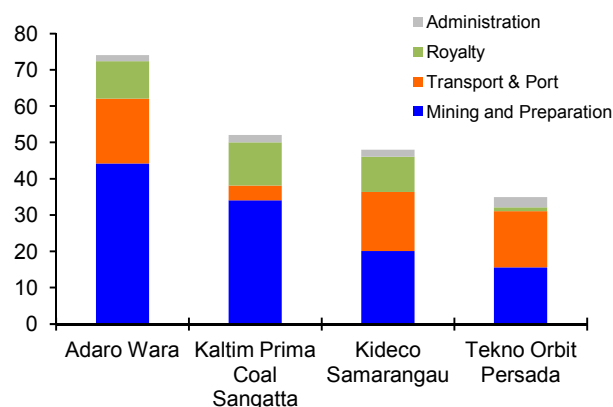
Figure 51: Indonesia thermal coal mine fact table (costs adjusted to HBA-equivalent)

	Adaro Wara	KPC Sangatta	Kidco Samarangau	Tekno Orbit Persada
Permit Type	Gen 1 CCoW	Gen 1 CCoW	Gen 1 CCoW	IUP
Operators	Adaro Energy	Bumi Resources	Kidco Jaya Agung	MEC Holdings
Production Start	2009	1991	2009	2014
Region	South Kalimantan	East Kalimantan	East Kalimantan	East Kalimantan
Marketable reserves (ROM)	382mt	1,152mt	411mt	768mt
Plateau export production	18mt in 2015	50mt in 2019	29mt in 2023	27.5mt in 2021
Mine type	Open-cut surface	Open-cut surface	Open-cut surface	Open-cut surface
Mining method	Truck & shovel	Truck & shovel	Truck & shovel	Truck & shovel
Total cash cost (\$/t, HBA basis)*	\$74.1	\$52.1	\$48.0	\$35.0
Mining	\$42.4	\$32.9	\$18.4	\$13.8
Preparation	\$1.8	\$1.2	\$1.7	\$1.9
Transport	\$14.5	\$1.1	\$11.7	\$8.7
Port	\$3.4	\$3.0	\$4.6	\$6.7
Royalty	\$10.4	\$11.9	\$9.7	\$1.1
Admin	\$1.6	\$2.1	\$1.9	\$2.8
Fully-amortised incentive cost (\$/t, HBA basis)	\$82.0	\$66.3	\$71.1	\$73.1
Coal quality				
Type	Lignite	Bituminous	Lignite	Lignite
Specific energy (GAR) kcal/kg	4,100	5,500	4,100	3,430
Total moisture (%)	38%	21%	35%	46%
Total sulphur (%)	0.3%	0.5%	0.1%	0.1%
Ash (%)	3%	6%	2.5%	3.8%
Strip ratio (bm ³ /raw tonne)	4.0	12.5	4.3	1.1
Yield	100%	98%	100%	100%

Source: Wood Mackenzie, Deutsche Bank
 *Costs given in 2012 inflation-adjusted dollars

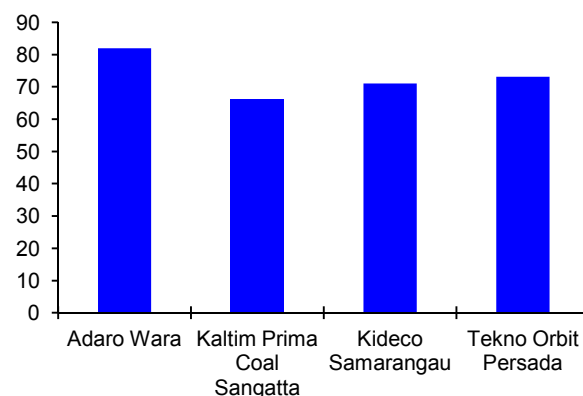


Figure 52: HBA-equivalent cash costs (\$/t)



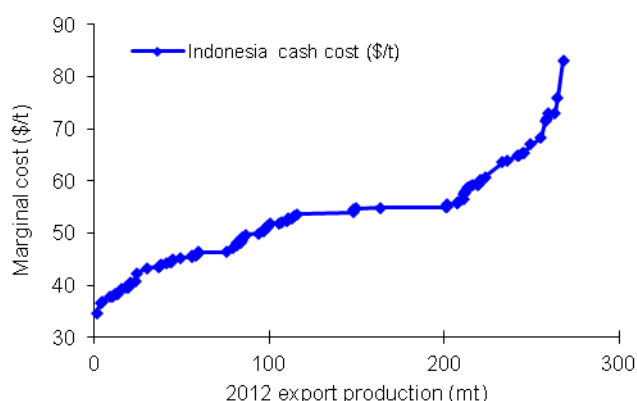
Source: Wood Mackenzie, Deutsche Bank

Figure 53: HBA-equivalent incentive costs (\$/t)



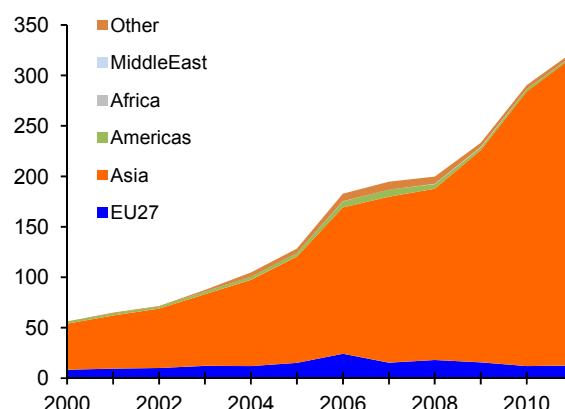
Source: Wood Mackenzie, Deutsche Bank

Figure 54: Marginal cost of Indonesian exports, energy adjusted (\$/t)



Source: Wood Mackenzie, Deutsche Bank

Figure 55: Destination of Indonesian thermal coal exports (million tonnes per year)



Source: McCloskey, Deutsche Bank

Indonesian projects not likely to be at risk from lower prices

On an energy-adjusted basis, 90% of Indonesian export production is economical at a marginal cost of \$64.8/t, while 85% is economical at a cost of \$63.6/t. Incentive costs of the most significant thermal coal projects tops out at \$82/t, so neither future growth in Indonesian export production nor the current level of Indonesian exports appears to be at risk based on the current price environment. Despite the high volume of export growth that we expect to occur through 2017, we do not believe that Indonesia will be among the exporting nations to make a significant volume adjustment to lower prices. The caveat to this statement is that some of Indonesian production originates from small miners which typically do not sell on long-term contracts and therefore are more exposed to short-term dips in buying interest, as we observed in 2012.



#12 Australia

Figure 56: Australia at a glance

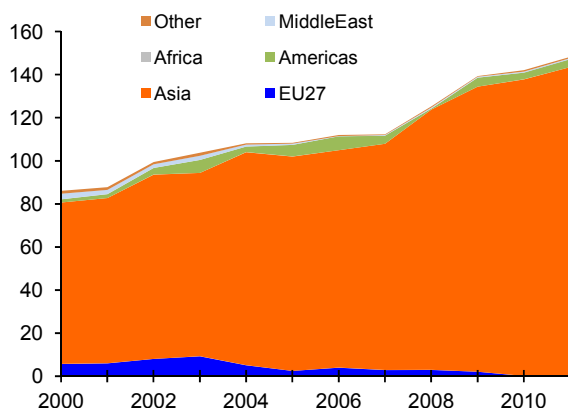
2012 thermal coal exports	171mt
2012 thermal coal production	235mt
Calorific value, domestic	5,042kcal/kg NAR
Calorific value, export	6,008kcal/kg NAR
2013 export cash cost, wt avg	\$71.6/t
2013 export cash cost, 85th percentile	\$87.3/t
5-year forecast export growth rate	6.6%

Source: Deutsche Bank

High-cost producer with large planned capacity additions

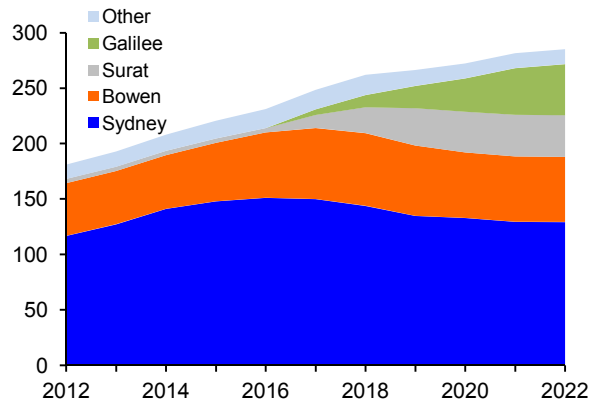
Like Indonesia, Australia supplies Asian markets almost exclusively but is a higher cost producer of relatively high-quality coal. In Australia, the majority of production is located in the Sydney and Bowen Basins, and it is here that marginal costs are important for determining a price level below which production from currently producing projects may be negatively affected. Near-term production increases over the 2013-2016 period will occur primarily in the Sydney and Bowen Basins, while projected production increases over the 2017-2022 period will take place primarily in the Surat and Galilee Basins, Figure 58. In these areas, Surat Basin increases will be front-loaded over the 2017-2019 timeframe while Galilee Basin increases will be more evenly spread over the 2017-2022 period.

Figure 57: Australian thermal exports by destination
(million tonnes per year)



Source: McCloskey, Deutsche Bank

Figure 58: Australian thermal production by basin
(million tonnes per year)



Source: Wood Mackenzie, Deutsche Bank

New projects are infrastructure-intensive

A key consideration in the capital intensity of Surat and Galilee Basin projects is the requirement for entirely new infrastructure construction in the way of railway transportation and port facilities. This will inevitably lead to take-or-pay infrastructure payment arrangements to secure financing for the large investments necessary. Such take-or-pay contracts already characterise most of current Australian production and complicate the consideration of marginal costs.

In other words, marginal cost may not be the most relevant trigger point for producers' decision-making on annual volume in Australia, but rather the



marginal cost less infrastructure payments (rail transport and port costs). While this is somewhat speculative, it does make sense that a producer would only choose to reduce volume once losses on each additional tonne of coal become greater than the take-or-pay cost per tonne of coal.

That having been said, volume decisions are probably not extremely sensitive to spot-price or front-month coal prices, given that Australian production is dominated by large miners with long-term contracts and sophisticated hedging strategies which insulate margins to some degree from price movements.

Our selection of key projects which will add most significantly to production volume in Australia includes Rio Tinto's Mt Pleasant project in the Sydney Basin, which will add 8.0mt cumulatively, and Xstrata's Rolleston project in the Bowen Basin, which will add 7.5mt.

In the Galilee Basin, GVK's Alpha project and Mineralogy's China First project will collectively add 38mt of annual production by 2021. In the Surat Basin, we examine Xstrata's Wandoan project which is planned for 22mt of capacity in 2019.

Figure 59: Australian in situ coal resources



Source: Geoscience Australia, Australian Government, Deutsche Bank

Mt Pleasant

Located in the Hunter Valley region of New South Wales, Mt Pleasant is a Sydney Basin surface mine project to be operated by Rio Tinto. The mine had not yet begun construction as of May 2012, with the investment decision said to hinge on the outcome of a potential cut to the diesel fuel tax credit benefiting miners. Although the federal government has since decided to leave the tax credit unchanged, an investment decision from majority owner Rio Tinto (80%) is yet to be made. Comments this year from Rio Tinto CEO Tom Albanese raised doubts over the viability of the project owing to high costs, while residents in nearby Muswellbrook township (3km away) have objected on the basis of potentially increased levels of coal dust from the operation.



Whether or not the project goes ahead, an analysis of its costs can inform us about the investment environment for thermal coal projects in the Sydney Basin.

Mt Pleasant, like the other four projects in Australia described here, is a proposed opencast operation which would utilise a dragline combined with the truck and shovel method for overburden removal. Coal mined by an excavator will then be transported by truck to the coal processing facility, and then moved via a 6.7km conveyor facility.

Cash mining costs are moderate but will increase gradually over the life of the mine as the strip ratio rises from 5.0 to 7.0 bm/raw tonne over the life of the mine through 2058. Transport and port costs are also relatively modest, giving a total cash cost on an adjusted basis of \$72.0/t in 2012 dollars.

Given that Mt Pleasant is located in the largest coal-producing region, it would not require any additional transport infrastructure investment and can utilise the existing Bengalla rail loop for the 115km rail journey to the Port of Newcastle where existing third-party shipper arrangements can be used. Capital costs at the outset would therefore be limited to mining equipment, coal preparation plant, and the conveyor. As a result, the incentive cost on an adjusted basis is \$106.7/t.

Rolleston

The Rolleston mine, operated by Xstrata, is located in the second-largest currently producing region, the Bowen Basin. Like all of the mines in this group, it is an open-cut surface mine which uses a dragline, truck and shovel operation to remove overburden and excavate coal. It is the only one of the five mines in our analysis which is already in production (since 2003). However, we expect a doubling of current production as a result of an expansion project from 2015 to 2018, lifting overall production from 8.5mtpa to 16mtpa, of which a constant 2.1mtpa is supplied domestically to the Gladstone Power Station.

Although the mine's strip ratio of 7.0 bm/raw tonne is higher than Mt Pleasant, the raw coal's low ash content means that it does not need to be washed and is only crushed and sized before export, hence the 100% yield figure. Rolleston's cash mining cost of \$32.7/t is among the lowest of all currently exporting Australian thermal coal mines. Coal is loaded and railed on a 424km route to the Port of Gladstone, compared with Mt Pleasant's 115km rail journey. 110km of the 424km rail route was financed specifically for this project by Xstrata. This explains the relatively high transport cost of \$16.2/t compared to Mt Pleasant's \$8.7/t.

At the present time, coal is exported via the RG Tanna terminal at Gladstone Port, but the additional volume produced via the expansion over 2015-2018 will require some new export capacity. The expansion project is contracted to use 11mt of capacity at the WICET terminal, which is currently under construction, and this will raise port costs from the current level.

Our estimate of adjusted marginal cash cost derives from 2018 cashflows in 2012 dollars, once maximum production volume of 18mt is reached, so this takes into account the increase in port costs, averaged over all production. The mine's energy-adjusted incentive cost of \$86.3/t is relatively low compared to Mt Pleasant.



Alpha

The Alpha coal project is one of the largest projects located in the important Galilee Basin, which will provide 16% of total Australian thermal export production by 2022. The project is led by India's GVK Power & Infrastructure Ltd which owns 79%, and Hancock Coal which owns the remainder. Of the three major projects in the Galilee Basin which include Kevin's Corner and China First, Alpha will be the first to come online and will shoulder the burden of the largest infrastructure costs, although we also build in revenues from third-party access. Facilities will include a 495km dedicated rail line to the Port of Abbot Point and the new Terminal 3 port facility there, with a capacity of 60mtpa. The rail line, approved by the Queensland State Government on 6 June 2012, would have initial capacity of 60mtpa but would be scalable to 120mtpa on a single line, according to GVK. These two projects imply high capital costs, adding A\$6.5bn to the initial investment required.

However, it also gives low operating costs as the Alpha project is able to take advantage of the owner-operated infrastructure and does not incur the same rates that outside customers would be charged, resulting in a low rail cost of \$3.1/t and a low port cost of \$2.9/t. Revenues from third-party charges for access to spare capacity on rail and port facilities constitute part of the project cashflows.

Additional infrastructure challenges include the provision of water and power for mining and coal processing operations. A 200km power transmission line called the Galilee Basin Transmission Line Project will be built by Powerlink, westwards from the Lilyvale Substation to Surbiton Hill Substation. The Connors River Dam project and was proposed to be built by SunWater, with an storage capacity of 373,540ML and supply rate of 49,500ML per year, including a 133km pipeline to Moranbah. Both Powerlink and SunWater are government-owned companies, and charges are incorporated in mining and processing costs. Recently, the A\$1.3bn Connors River Dam was cancelled by the Queensland State Government on 27 July 2012 in order to cut costs, leaving water supply in question.

Even with the Connors River Dam and associated pipeline, the water infrastructure would limit the total volume of coal export possible from the Galilee Basin in the medium term to 94mt, as Wood Mackenzie estimates 333 megalitres (ML) required per million tonnes of export capacity, the pipeline to Alpha will provide 25,000 ML per year, and 6,000 ML could be available from local groundwater sources. At this time, there are no further water supply projects proposed.

The mining operation will consist of six open-cut pits along a 24km-long strike. Marginal cash costs of mining will be \$37.9/t, slightly higher than Mt Pleasant as both share a 75% yield but Alpha will have a strip ratio of 6.0 bm³/raw tonne instead of 5.0. Export coal will be processed by a dense medium cyclone which separates export coal from refuse based on differing density.

The large upfront investment results in a high incentive price of \$140.1/t, which when adjusted for energy density and quality equates to 160.1/t. Our analysis of prices raises the risk that the project will be delayed indefinitely as forward Newcastle 2017 currently prices at \$105/t, but that if and when it does proceed, that marginal costs will be so low that its production will be one of the last to close if prices were to decline. Although the project was given approval for its Environmental Impact Statement (EIS) by the State of Queensland on 29 May 2012, a separate environmental assessment process is now being conducted by the federal Department of Sustainability, Environment, Water, Population and Communities. This appears to be the only remaining technical obstacle to government approval and GVK's investment decision.



China First

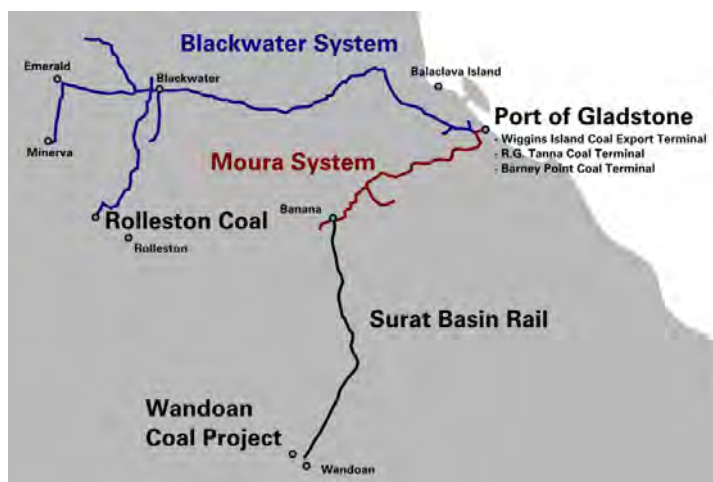
The China First coal project is also located in the Galilee Basin, directly south of the Alpha project, and will be owned and operated by Waratah Coal, which is in turn owned by Mineralogy. Although Waratah Coal envisions as much as 40mt of annual production from two open-cut and four underground mines, Wood Mackenzie estimates that it is more realistic to expect 14mt of production from open-cut mines only by 2021, given the volume of other projects planned in the Galilee and Surat Basins.

The project's name indicates the significant involvement by Chinese firms. Waratah Coal has a 20mtpa sales and purchase agreement with China Power International for 21 years, a financing agreement for 70% of the capital cost with China's Export-Import (Exim) Bank, a construction contract with Chinese firm Metallurgical Corp. of China (MCC) Overseas, and a railway contract with China Railway Group. An earlier sales agreement with Vitol for 20mtpa for a term of 20 years was terminated on 11 May 2012 for commercial reasons, according to Platts.

Waratah Coal proposes a new 470km dedicated rail line to the Port of Abbott Point, along with a new T4-9 coal terminal. However, the Queensland State Government has approved the GVK Rail Corridor instead of Waratah Coal's plans, with the stipulation that third party rail haulage services be made available to other coal producers. A second rail line connecting the Galilee Basin to the Bowen Basin would allow coal evacuation to the east but the most likely scenario is that Waratah Coal exports via the GVK Rail Corridor and pays third-party access charges to GVK. Our incentive cost estimate of \$114.5/t unadjusted (and \$128.9/t adjusted) assumes that this is the case. It now appears unlikely that any further rail plans will be approved by the government, according to Queensland Deputy Premier Jeff Seeney.

A strip ratio of 6.0 bm/raw tonne and yield of 75% from the open-cut pits results in a similar mining cash cost to Alpha, \$39.0/t. Coal processing plants will perform sizing and separation from reject material using dense medium cyclones and spirals. Relatively high rail transport and port costs of \$18.3/t and \$12.9/t result from the third-party access charges for GVK's infrastructure. The resulting energy-adjusted marginal cash cost of \$93.4/t would be towards the upper end of the range in Australia.

Figure 60: Wandoan infrastructure map



Source: Wood Mackenzie, Deutsche Bank



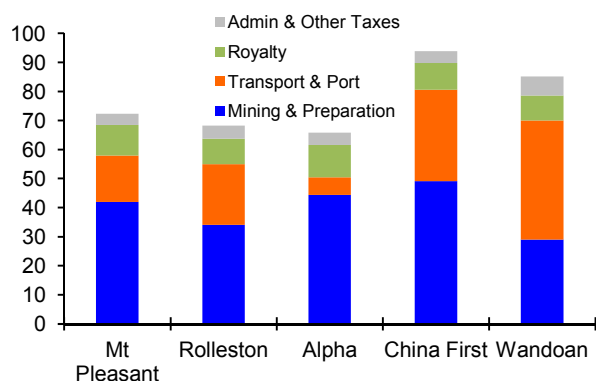
Wandoan

The Wandoan project is located in the Surat Basin, an area of development straddling Queensland and New South Wales states which could be responsible for 13% of total Australian export production by 2022. According to operator and majority owner Xstrata, the project is undergoing a final approval process by the Queensland government as of July 2012. Wandoan is the largest of planned projects in the Surat Basin, and similar to projects in the Galilee Basin, it will require significant new rail and port infrastructure to be built. In terms of rail infrastructure, Wandoan will require the 214km Surat Basin Rail (SBR) project (also known as the "Southern Missing Link") to be built, which would link the mine with the existing Moura rail line, which then runs to the Port of Gladstone. Port facilities will also require expansion in the form of the Wiggins Island Coal Export Terminal (WICET), which will provide 27mtpa of capacity in Stage One from 2015 and an additional 30-32mtpa of capacity in the first expansion (WEXP1) from 2017. Wandoan

While Wandoan will be reliant on the new-build infrastructure, Xstrata is one of three joint-venture partners in the SBR project, and one of eight owners in the WICET consortium. Therefore the capital investment is less than it might otherwise be, although Wandoan will be subject to elevated operational expenses as capacity charges will be on a cost-recovery basis. Thus rail and port costs are relatively high at \$25.7/t and \$15.1/t.

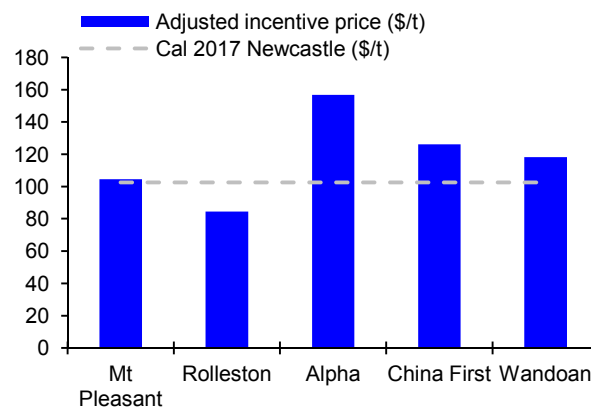
Cash mining costs are the lowest of the group at \$23.0/t with a very low initial strip ratio of 2.7 bm/raw tonne although this will rise over the life of the mine to 4.5 bm/raw tonne.

Figure 61: Quality-adjusted cash costs (\$/t)



Source: Wood Mackenzie, Deutsche Bank

Figure 62: Quality-adjusted incentive costs (\$/t)



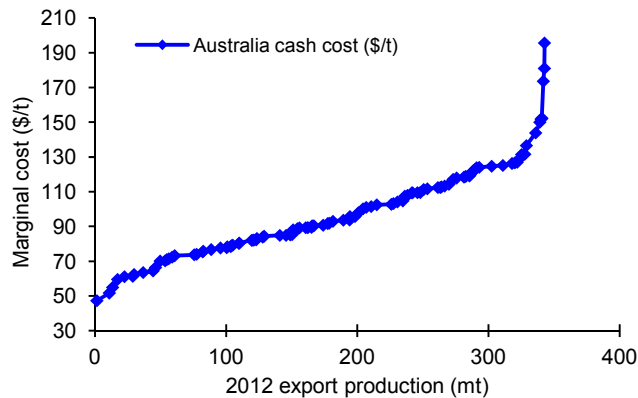
Source: Wood Mackenzie, Bloomberg Finance LP, Deutsche Bank

Australian projects are pivotal for coal supply towards the end of the decade

Regarding marginal cost, 90% of Australian exports are economical at \$89/t, while 85% are economical at \$87/t. However, these figures include rail transport and port charges, which in most cases must be paid by the exporter regardless of whether the capacity is used. Therefore we also calculate cash costs excluding transport charges which would theoretically give us adjusted marginal costs of \$72.5/t. Clearly the short-term dip in spot prices to \$78/t on a Newcastle FOB basis in October 2012 was not sufficient to trigger any production decisions. Recent reports that producers such as Xstrata and Yancoal are looking to offload excess port capacity confirm the existence of such take-or-pay infrastructure deals.



Figure 63: Marginal cost of Australian exports (\$/t)



Source: Wood Mackenzie, Deutsche Bank

Taking this into account combined with the likelihood that the sales price for a significant proportion of total volume over any given fiscal year is protected by fixed-price contracts for large producers, we hypothesize that we would need to see prices in the mid-70's or lower for a year or more before major cuts to existing export projects are made.

On the subject of incentive cost, we find that at least three major projects may be vulnerable to postponement or cancellation based on the current Cal-2017 Newcastle price of \$103/t. Collectively, Alpha, China First and Wandoan could be responsible for plateau export production of 60mtpa, which would make a significant difference in balancing our expectations of supply and demand towards the end of the decade. We expect that these projects are cancelled in our base-case scenario, or that Pacific Basin coal prices will be under further downward pressure as indicated in the bear-case scenario when these volumes enter the market.



Figure 64: Australia thermal coal mine fact table (energy-adjusted terms)

	Mt Pleasant	Rolleston	Alpha	China First	Wandoan
Operator	Rio Tinto	Xstrata	GVK	Waratah Coal	Xstrata
Production Start	2014	2003	2017	2018	2017
Coal Basin	Sydney	Bowen	Galilee	Galilee	Surat
Marketable reserves (ROM)	394mt	286mt	828mt	300mt	635mt
Plateau export production	8mtpa	13.9mtpa	24mtpa	14mtpa	22mtpa
Mine type	Open-cut surface	Open-cut surface	Open-cut surface	Open-cut surface	Open-cut surface
Mining method	Dragline, truck & shovel	Dragline, truck & shovel	Dragline, truck & shovel	Dragline, truck & shovel	Dragline, truck & shovel
Total cash cost (\$/t)	\$72.0	\$67.9	\$65.5	\$93.4	\$84.7
Mining	\$35.6	\$32.7	\$37.9	\$39.0	\$23.0
Preparation	\$6.2	\$1.3	\$6.2	\$9.9	\$5.9
Transport	\$8.7	\$16.2	\$3.1	\$18.3	\$25.7
Port	\$6.4	\$4.5	\$3.5	\$12.9	\$15.1
Royalty	\$9.2	\$8.7	\$11.1	\$9.1	\$8.6
Admin & Other Taxes	\$3.9	\$4.5	\$4.1	\$4.2	\$6.4
Fully-amortised incentive cost (\$/t)	\$106.7	\$86.3	\$160.1	\$129.9	\$120.8
Export coal quality					
Type	Bituminous	Bituminous	Bituminous	Bituminous	Bituminous
Energy (GAR) kcal/kg	6,170	5,970	5,860	5,865	5,977
Total moisture (%)	11%	16%	15%	15%	15%
Total sulphur (%)	0.7%	0.55%	0.6%	0.5%	0.4%
Ash (%)	14%	7.5%	9.5%	8%	9.5%
Strip ratio (bm/raw tonne)	5.0	7.0	6.0	6.0	2.7
Yield	75%	100%	75%	75%	73%

Source: Wood Mackenzie, Deutsche Bank

*Costs given in 2012 inflation-adjusted dollars with an assumed future rate of inflation of 2.5% p.a.



#13 South Africa

Figure 65: South Africa at a glance

2012 thermal coal exports	75mt
2012 thermal coal production	269mt
Calorific value, export	6,141kcal/kg NAR
Calorific value, domestic	5,093kcal/kg
2013 export cash cost, wt avg	\$45.9/t
2013 export cash cost, 85th percentile	\$61.9/t
5-year forecast export growth rate	1.8%

Source: McCloskey, Wood Mackenzie, Deutsche Bank

Pivoting exports to the Pacific Basin

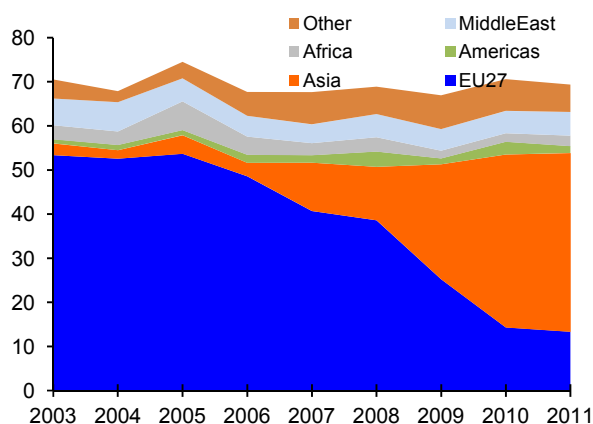
South African thermal coal production is characterised by relatively high energy content, a significant proportion of underground mines (25% underground and an additional 22% from mixed underground and surface mine complexes), and yet relatively low FOB costs, helped by modest domestic freight and port charges of \$13.7/t total on average.

Exports have shown perhaps the most marked change in global flows of thermal coal in recent years as the customer base has shifted dramatically from European countries to Asian countries since 2006, Figure 66, as Asian demand has increased by 11.3% annually from 2006 to 2012, while European demand increased by only 1.0% over the same period.

Despite 91mt in nameplate export capacity from Richards Bay, overall South African exports have remained near 70mt per year over the last nine years, while our export forecast envisions only 80mt possible by 2017. Therefore, South African export growth will not be as great either in absolute or relative terms as we expect to see in Indonesia and Australia.

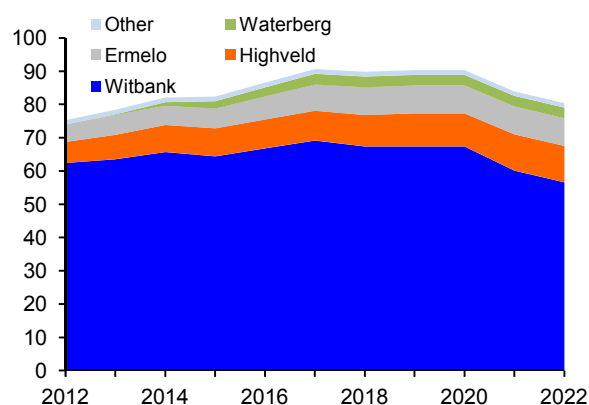
In fact, we can organise export countries into two groups: (i) high-growth, high-volume exporters: Indonesia and Australia, and (ii) low-growth, lower volume exporters: South Africa, Russia and Colombia. Over the five-year period from 2013 to 2017, we expect growth from 2012 exports in Indonesia of 95mt, Australia 59mt, Russia 13mt, Colombia 12mt and South Africa 5mt.

Figure 66: South Africa thermal exports by destination (million tonnes per year)



Source: McCloskey, Deutsche Bank

Figure 67: South Africa export production by coalfield (million tonnes per year)



Source: Wood Mackenzie, Deutsche Bank



Sustaining capital expenditure is certainly necessary to maintain current production and some new investment is required to expand production in line with our expectations through 2017. However, since South Africa is not responsible for a very large proportion of future export growth, we focus relatively less attention on the incentive cost of mines expanding or coming online in the next five years, and more on South Africa's position in the global marginal cost curve for existing production.

South African export production can be analysed by the coalfield of origin as in the figure below. We can see that the majority of current production occurs in the Witbank coalfield, located just east of Johannesburg, in the Mpumalanga province, while the majority of remaining reserves is located in the Waterberg coalfield in the Limpopo province, near the border with Botswana. The Mpumalanga province also includes the Highveld and Ermelo coalfields, and is thus by far the largest coal-producing province.

Although potential growth in export production of 12.1mt over the next five years is the greatest in the Mpumalanga province, there is potential growth of 3.1mt from the Waterberg coalfield from virtually zero production currently. In reality, we expect that export growth will be limited by rail system throughput on the Transnet Freight Rail (TFR) network, and that total export production growth will only be 6.8mt over the five years from 2013 through 2017.

Figure 68: South Africa remaining recoverable coal reserves as at the end of 2000

Coalfield	Province	Remaining reserves (million tonnes)
Waterberg	Limpopo	15,103
Witbank	Mpumalanga	10,140
Highveld	Mpumalanga	10,007
Free State	Free State	4,919
Ermelo	Mpumalanga	4,597
Other		6,179
Total		50,944

Source: The Journal of The South African Institute of Mining and Metallurgy

Port capacity, on the other hand, has grown in recent years with the Phase V expansion project at the Richards Bay Coal Terminal (RBCT), lifting capacity from 72mt in 2006 to 91mt in 2010. The expansion project was partly funded by South Dunes Coal Terminal (SDCT) Company, which originally planned to construct a smaller, independent terminal. The SDCT project was absorbed into the Phase V expansion, with SDCT project participants agreeing to accept capacity at RBCT of 6mt per year.

Including capacity at the Dry Bulk Terminal (2mt) at Richards Bay, the Bulk Connections Terminal (2.5mt) at Durban and the Port of Maputo in Mozambique (4.5mt), theoretical port capacity for South African coal exports is in the range of 100mt. However, these other terminals are used for a wide variety of commodities so only a portion of their capacity may be allocated to coal.



Figure 69: South African coalfields



Source: The Journal of The South African Institute of Mining and Metallurgy

We examine two mines here which represent the largest expansions or additions to productive capacity through 2017 in order to ascertain incentive costs in South Africa. One is located in the dominant Witbank coalfield and the other is located in the developing Waterberg coalfield.

Klipspruit

The Klipspruit mine is located in the Witbank coalfield in Mpumalanga province, and is operated by BHP Billiton. The opencast mine began production in 2004 and benefits from a low strip ratio of 2.6 bm/raw tonne. It shares a joint-venture coal preparation plant with Anglo American, which processes coal from both Klipspruit and the Zibulo mine. The operator chose to produce a lower-quality coal (5,400 kcal/kg instead of 5,900 kcal/kg) in order to target the Indian market. Export product is railed to Richards Bay Coal Terminal at a distance of 540km.

Boikarabelo

The Boikarabelo mine (the name means “being responsible” in the local dialect) is located in the Waterberg coalfield in Limpopo province, and is operated by Resource Generation. The project is supported by two long-term offtake agreements with Bhushan Steel (20 years) and CESC (India) (38 years). The mine will also deliver 3mt per year to Eskom’s domestic power stations in Mpumalanga.

Capital expenditures at the outset include power supply, water supply, a coal preparation plant, and a 50km rail line connecting the mine with the existing Transnet Freight Rail network (TFR), from which export product can be railed to Richards Bay Coal Terminal, Durban’s Bulk Connections Terminal and Maputo. This would be the least expensive choice, but there are concerns regarding the ability of TFR to make better utilisation of the new 91mt capacity at Richards Bay. A more expensive alternative would be to consider the possibility of the Trans-Kalahari Rail Project which would build a rail link westwards through Botswana to the port of Walvis Bay in Namibia. The calculated incentive price of \$81/t is based on the former scenario.

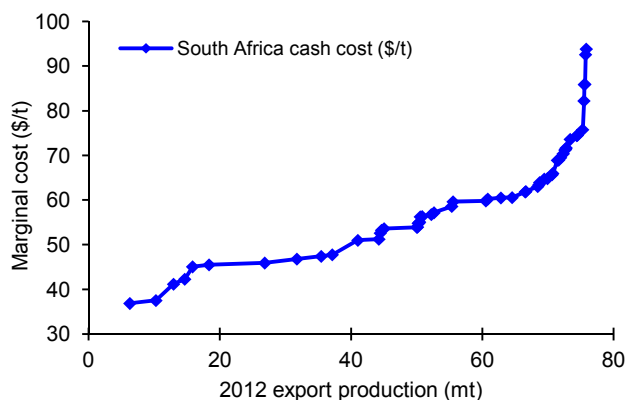
Although product yield after processing will be only 46%, overburden may be as little as 0.6 bm/raw tonne at the start, rising to 0.7 bm/raw tonne over the life of the project, thus keeping mining costs relatively low.



Low marginal costs shield production

With relatively low cash costs of production, we believe that 90% of export production volume is economical at a short-run marginal cost of \$63/t, and 85% of export production volume is economical at a short-run marginal cost of \$61/t. As we assume relatively few major additions in new productive capacity over the term of our market model, the main risk for South African production is likely to be strike action, which has resulted in significant interruptions to mining operations in the recent past.

Figure 70: Marginal cost of South African exports (\$/t)



Source: Wood Mackenzie

Figure 71: South Africa thermal coal mine fact table (energy-adjusted terms)

	Klipspruit	Boikarabelo
Operator	BHP Billiton	Resource Generation
Production Start	2004	2014
Coal Basin	Witbank, Mpumalanga	Waterberg, Limpopo
Marketable reserves (ROM)	208mt	294mt
Plateau export production	6.3mtpa	2mtpa
Mine type	Open-cut surface	Open-cut surface
Mining method	Dragline, truck & shovel	Dragline, truck & shovel
Total cash cost (\$/t)	\$47.2	\$65.0
Mining	\$16.9	\$21.8
Preparation	\$4.5	\$8.5
Transport	\$18.3	\$26.3
Port	\$1.7	\$4.0
Royalty	\$1.6	\$1.4
Admin & Other Taxes	\$4.2	\$3.2
Fully-amortised incentive cost (\$/t)	\$65.5	\$81.0
Export coal quality		
Type	Bituminous	Bituminous
Energy (GAR) kcal/kg	5,680	5,880
Total moisture (%)	8.5%	8%
Total sulphur (%)	0.9%	0.9%
Ash (%)	19%	15%
Strip ratio (bm ³ /raw tonne)	2.6	0.7
Yield	78%	46%

Source: Wood Mackenzie, Deutsche Bank



#14 Russia

Figure 72: Russia at a glance

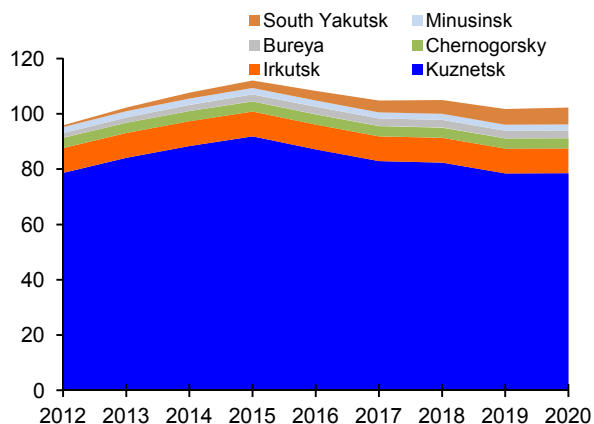
2012 thermal coal exports	100mt (est.)
2012 thermal coal production	352mt
Calorific value	6,177 kcal/kg NAR
2013 export cash cost, wt avg	\$92.5/t
2013 export cash cost, 85th percentile	\$99.5/t
5-year forecast export growth rate	2.60%

Source: McCloskey, Wood Mackenzie, Deutsche Bank

A high-cost producer by virtue of infrastructure charges

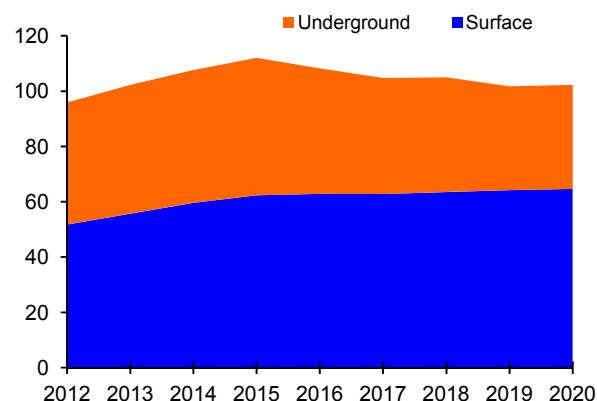
The majority of Russian thermal coal production originates from five coal basins: Kuznetsk, Donetsk, Pechora, Kansk-Achinsk, and South Yakutia. Out of these, the Kuznetsk Basin is by far the most productive, responsible for 82% of export production in 2012. We expect that the Kuznetsk Basin's share of production will continue to dominate Russian production but fall slightly to 79% around 2017.

Figure 73: Russian coal export production by region (mt/year)



Source: AME, Deutsche Bank

Figure 74: Russian coal export production by mine type (mt/year)



Source: AME, Deutsche Bank

Underground longwall mines constitute 44% of current production in 2012, but this proportion can be expected to fall over the coming decade, which implies that there may be a moderation in costs over the long term as the proportion of production owing to lower-cost surface mines increases.

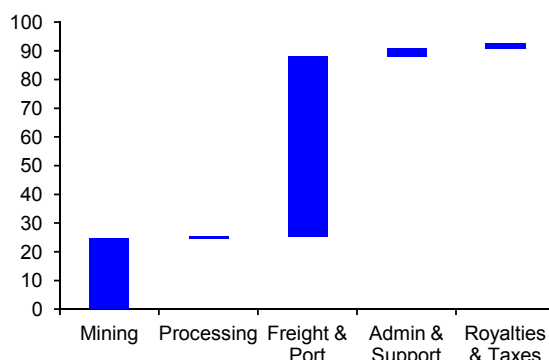
Russian production is of high quality with a weighted average energy content of 6,177kcal/kg NAR, and benefits from being low in sulphur and moisture content. However, a very large proportion of total FOB export costs consist of rail freight costs, given the long distances from Russian mines to ports. Domestic freight and port charges make up \$51.6/t, or 58% of the total estimated 2012 FOB cost of \$88.4/t. This is rivaled only by the Powder River Basin in the US where freight and port charges constitute 68% of total FOB cost.

Rail transport carried out on the Trans-Siberian Railway which runs east-to-west across the southern part of the country, intersecting the Kuznetsk Basin. The rail network has often been the most significant bottleneck affecting coal exports in the past, as congestion and logistical inefficiencies limit utilisation.



Ports are probably operating near capacity, and a new coal port across the bay from the existing coal port at Murmansk is now planned by SDS-Ugol, a coal producer in the Kuzbass region. Construction is slated to begin this summer and the port should begin operation in 2015, with capacity of 18mtpa.

Figure 75: Russian FOB export coal costs (\$/mt)



Source: AME, Deutsche Bank

A significant proportion of the cost base in mining is sensitive to oil prices, both from the direct cost of diesel as well as consumables (such as explosives) derived from petroleum, while the cost of rail freight is also highly dependent on diesel prices. With the very high proportion of mining and freight components, and relatively low processing, overhead and royalty components, it may be reasoned that Russian marginal cash costs would have a relatively high sensitivity to oil prices.

Capacity expansions are limited

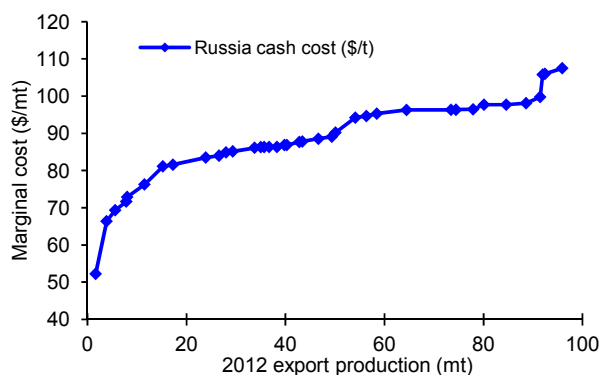
Planned expansions to capacity are relatively limited, and only one project, Pervomaysky, is expected to add significant volume in the next five years by raising export production from only 2mt in 2012 to a plateau level of 10mt by 2017. The mine is held by the joint-stock holding company Siberian Business Union (SBU), and operated by the SBU-Coal subsidiary. Although SBU-Coal indicates that capital expenditures will total RUB16bn, and the Chernihiv coal processing facility will cost RUB5bn, no estimates of operating costs are available. If we make a ballpark estimate of operating costs at the median of existing Russian mines, a Mineral Resources Extraction Tax (which can range from 3.8% to 8%) of 5%, and corporate tax of 20% then we can estimate an incentive cost of \$104/t.

Marginal cost is at the top end of the global range

With 85% of export production volume requiring a FOB price of \$98/t to meet short-run marginal costs, Russian production is the highest-cost major exporting region in the world. However, production has also been relatively stable, and appears to be somewhat less subject to interruptions than other major producing regions from strike action, environmental injunctions, or flooding. In terms of sensitivity to pricing, Russian miners are likely to be selling mainly on fixed price contracts as the weak pricing in 2012 did not result in major production cuts. In fact, 2012 export production rose by 13% to a new record level as new operations began production in the Kuznetsk Basin. We expect much more modest increases in production going forward as producers focus more strongly on cost control.



Figure 76: Marginal cost of Russian exports (\$/t)



Source: AME, Deutsche Bank

Figure 77: Russia thermal coal producing regions and railway distances from Kuznetsk Basin



Source: Rosugol, Raspadskaya, Wikimedia Commons, Deutsche Bank



#15 Colombia

Figure 78: Colombia at a glance

2012 thermal coal exports	79mt
2012 total coal production	89mt
Calorific value	5,945kcal/kg NAR
2013 FOB cash cost, wt avg	\$53.4/t
2013 FOB cash cost, 85th percentile	\$59.5/t
5-year forecast growth rate	7.10%

Source: McCloskey, Wood Mackenzie, Deutsche Bank

Low-cost exporter with vulnerabilities

The bulk of Colombia's thermal coal-producing mines are located in the far north of the country, in the two departments of Cesar and La Guajira, and export via ports on the Caribbean coast. A single mine, Cerrejón, accounts for 41% of export production. The mine is operated by a consortium consisting of Anglo American, BHP Billiton, and Xstrata, and is located in the La Guajira department. A dedicated rail line owned by Carbones de Cerrejón transports coal to Puerto Bolivar, and hence, transport costs are exceptionally low for the Cerrejón mine, at \$1.35/t.

On the other end of the spectrum, smaller mines operated by Pacific Coal do not have railway spurs allowing access to the Fenoco railway, and therefore incur much higher transport costs by trucking coal to port, as is the case for the Caypa mine in La Guajira, which incurs a \$24/t cost for trucking coal production from the Caypa mine in La Guajira (265km) and the Cerrolargo Norte mine in Cesar (298km) to Santa Marta.

Figure 79: Colombia thermal coal mines

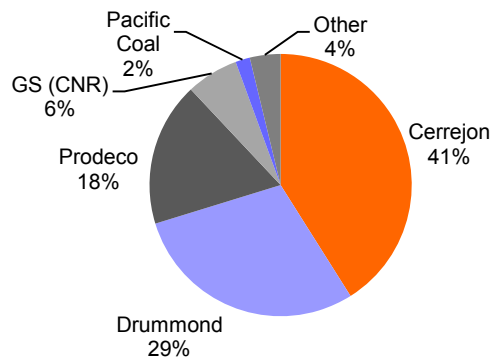


Source: Wikimedia Commons, Deutsche Bank

Treading a middle ground are the mines located in Cesar owned by Drummond & Itochu, Glencore (operated by Prodeco), and Goldman Sachs (operated by Colombian Natural Resources). These mines transport coal via the Fenoco railway to ports in the north including Puerto Prodeco, Puerto Drummond, Port of Santa Marta, Barranquilla Port, or Rio Cordoba Port. Transport costs on the Fenoco railway for these mines average \$6.4/t.

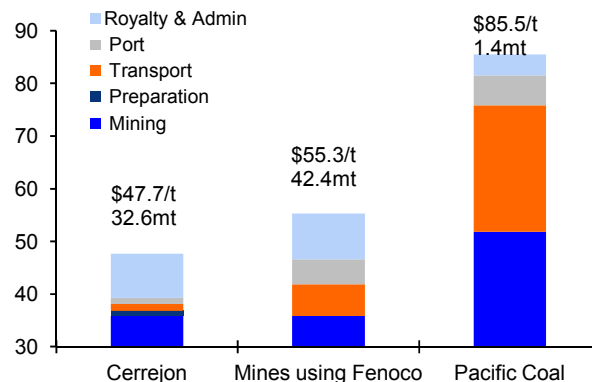


Figure 80: Colombia thermal coal exports by operator
(2012 total = 79.4mt)



Source: Wood Mackenzie, Deutsche Bank

Figure 81: Marginal cost breakdown by group, total cost and total 2012 export volume (\$/t)



Source: Wood Mackenzie, Deutsche Bank

Strikes and environmental regulation

In February 2013, Colombia production was interrupted by a combination of strikes and environmental injunctions which brought 96% of production to a halt for a short period. In fact labour issues have been an ongoing struggle for the continuity of production, especially at times of contract negotiations which take place periodically. The strike at Cerrejon in February 2013 lasting 32 days removed 2.9mt from production alone.

Environmental protection issues have also been an obstacle for production this year, with noise from railway operations and a coal spillage incident topping the headlines in February and March 2013, contributing to 2.0mt to a 5.1mt total disruption in Q1-2013, eclipsing the 1.7mt disruption in August 2012 resulting from a railway strike at Fenoco.

Environmental authorities note that coal spillages have taken place periodically in the past, and more general environmental concerns since the 1990s include the spread of coal dust as well as traffic along north-bound roads in the departments of Cesar and Magdalena.

The coal-loading area of Puerto Bolivar is close to the Bahía Portete Fauna and Flora Sanctuary, which has been described as environmentally sensitive owing to its mangrove and reef ecosystems. In the case of Puerto Drummond and Santa Marta, the tourist town of Ciénaga lies close by. In both cases, coal dust and spillage of coal from capsized barges have been blamed for environmental degradation and an impact on tourist activity.

Finally, the noise of trains operating overnight has disturbed the communities of Bosconia, Lleras, Fundación and Aracataca. This issue has been ongoing since at least October 2009, when a detour was ordered to be constructed by the environmental authority. Trains ran in violation of the overnight ban dated 10 December until overnight operations were suspended on 8 February 2013. The ban instituted by Corpocesar, a regional authority, was then lifted by the ANLA, the national environmental authority, on 1 March 2013. As of April 2013, the Colombian government has recognised a 3mt impact, reducing the 2013 coal output target from 97mt to 94mt.

While we believe that Colombia will continue to be one of the lowest-cost exporters in the long term, it has also been subject to large disruptions which introduce an element of upside risk for markets.



#16 China

Figure 82: China at a glance

2012 thermal coal net imports	174mt
2012 total coal production	3,900mt (est.)
Calorific value	5,450 kcal/kg NAR
2013 coastal FOB cash cost, wt avg	\$71.9/t
2013 coastal FOB cash cost, 85th percentile	\$88.9/t
5-year forecast supply growth rate	4.70%

Source: McCloskey, Wood Mackenzie, Deutsche Bank

The world's largest producer

China is by far the world's largest producer of coal, with 2011 production of 3,520mt making up 46% of global production. The next largest producer, the United States, produces less than a third of China's volume. Although China's thermal coal reserves are distributed throughout the country, current production is concentrated in three provinces: Inner Mongolia, Shaanxi and Shanxi, Figure 83. Inner Mongolia has only become the largest producing province in the recent past, with Shanxi being the largest producer as recently as 2009. Although Xinjiang is currently only the ninth largest producing province, it is expected to be the most rapidly growing province in the next five years, and may produce as much as 422mt in 2017.

We highlight Xinjiang province in particular as it holds considerable reserves, while current production is relatively small in comparison, Figure 84. Coal reserves in Xinjiang province have been under-utilised in the past because of their location far from industrial and consuming regions. However, the province is likely to be a major growth region for Chinese domestic supply as its reserves are close to the surface and can therefore be mined relatively cheaply. Clearly it will be a major challenge to grow transport infrastructure to keep pace with production growth, but we believe the commitment exists to make these large investments. In addition to physical transportation of coal, coal gasification and ultra-high voltage direct current transmission lines will be significant methods of monetising remote coal reserves.

Figure 83: China total coal production by province

Province	2007 marketable production (mt)	2012 marketable production (mt)	Reserves (mt)
Inner Mongolia	480	937	28,377
Shanxi	838	922	24,890
Shaanxi	171	385	11,398
Henan	203	197	4,601
Guizhou	133	182	4,469
Shandong	152	170	3,895
Anhui	106	138	3,428
Yunnan	66	115	2,864
Xinjiang	63	114	11,567
Hebei	64	93	2,090
Heilongjiang	90	91	2,100
Sichuan	81	88	2,170
Ningxia	40	80	2,875
Other	284	322	8,313

Source: Wood Mackenzie, Deutsche Bank

We have already seen early development of these alternative evacuation methods. A coal-to-gas pilot project could supply up to 5bcm from Xinjiang as

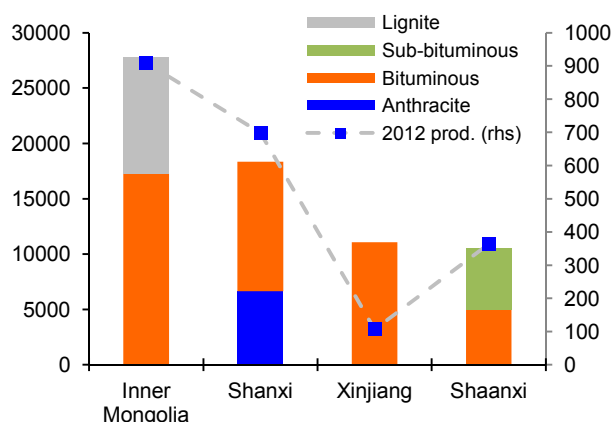


part of the third West-East Gas Pipeline project which began construction on 16 October 2012, while an ultra-high-voltage direct current (UHV DC) 800kV transmission line is currently under construction from Hami, Xinjiang to Zhengzhou, Henan.

Types of producing companies

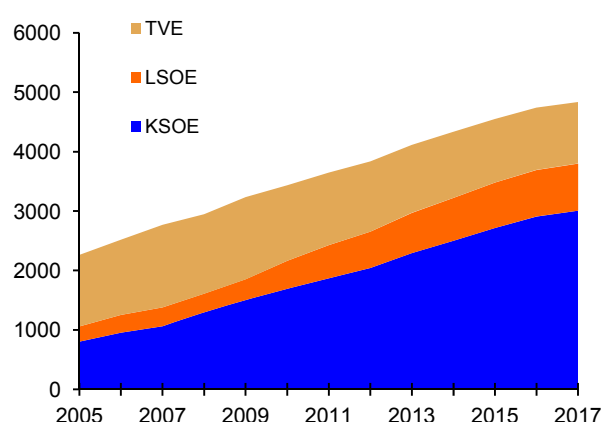
Chinese coal production can be broken down into three types of producing companies. In order from largest to smallest, these are the Key State-Owned Enterprises (KSOEs), Local State-Owned Enterprises (LSOEs), and Town and Village Enterprises (TVEs). KSOEs operate under the direct supervision of the Chinese central government while LSOEs report to the provincial authorities. TVEs are privately or collectively owned enterprises organised at the local level. As recently as 2008, TVEs were responsible for the largest share of production, but a program of consolidation conducted by the NDRC in major coal-producing provinces in 2010 resulted in the closure of 1,355 mines with capacity of 125.2mt in the first nine months of 2010, according to Xinhua. This initiative was driven by the need to improve safety and reduce carbon emissions and pollution resulting from the use of outdated equipment and technology. Local governments were urged to increase the rate of mergers and acquisitions, as the government aims for companies with annual production of at least 50mt to account for 65% of total production by 2015. Presumably the producing assets from former TVEs would be reorganised under KSOEs and LSOEs. One concern arising from this program is that overall production costs could rise, as TVEs are responsible for much of the lowest-cost production volume in China. As a consequence of the policy we expect that TVE production will stay level or decline modestly, while the bulk of new production growth will be organised under KSOEs and LSOEs, Figure 85.

Figure 84: China marketable reserves and production (million tonnes), selected regions only



Source: Wood Mackenzie, Deutsche Bank

Figure 85: China coal production by company type (mt/year)



Source: Wood Mackenzie, Deutsche Bank

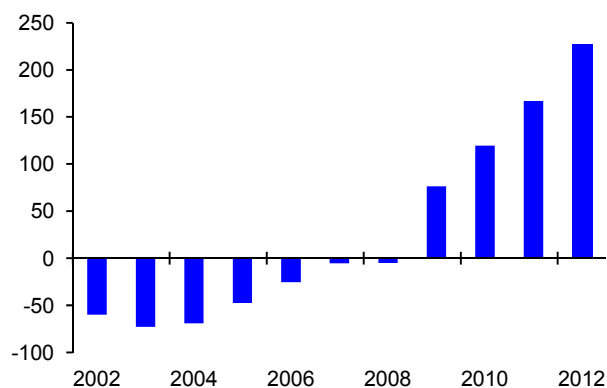
A relatively new importer

Despite being the world's largest producer, China is also responsible for 227mt in net imports of all types of coal in 2012, including 34mt of anthracite and 54mt of lignite. This constitutes 21% of global seaborne thermal coal supply, which we estimate will total 1,037mt in 2012. Yet China is relatively new as an importer, and was a net exporter as recently as 2008, Figure 86. This shift from exporter to importer occurred over a period in which raw coal production increased by an estimated 1,336mt from 2008 to 2012, which clearly speaks to China's rapid increase in overall consumption and power generation requirements.



Put within a larger context, the volume of both Chinese exports before 2008 and Chinese imports after 2008 is clearly miniscule in comparison to total domestic production. Although the impact of Chinese demand for imported coal can have a significant influence on seaborne markets, Chinese imports of thermal coal only represent 7% of national consumption.

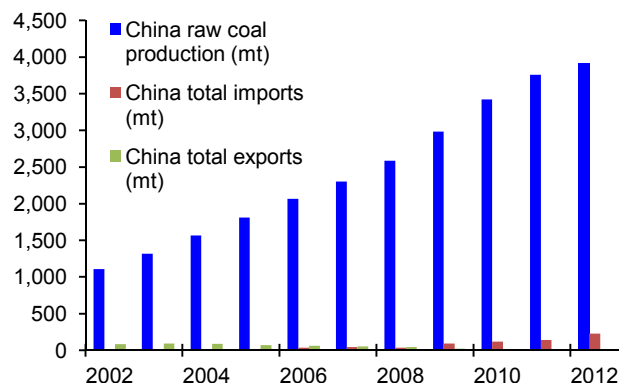
Figure 86: China thermal coal net imports including lignite (mt/year)



Source: McCloskey, Deutsche Bank

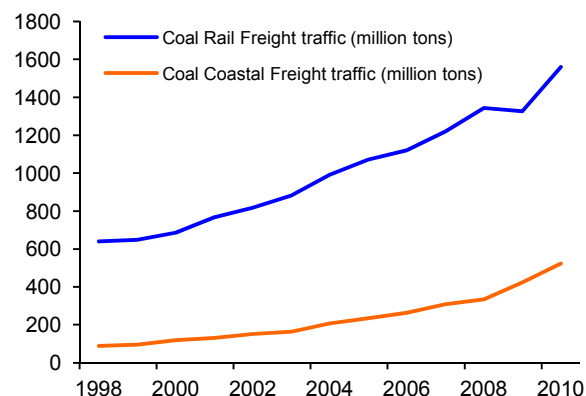
China's shift to a major net importer is made possible by the fact that industrial centers are primarily near the coast, and is also a consequence of underinvestment in freight railway capacity. Additionally, there is a predominance of east-to-west railway lines compared with a relative scarcity of north-to-south railway lines. This makes it expedient to rail coal from Inner Mongolia, Shanxi and Shaanxi provinces to coastal ports, and then ship it onwards to southern China. Since 1998, the volume of coal transported domestically by rail freight has increased by 143%, or 7.7% CAGR, while the volume of coal transported by seaborne coastal freight has increased by 493%, or 16.0% CAGR, Figure 88.

Figure 87: China raw coal production, imports, and exports including coking coal (mt/year)



Source: WIND, SX Coal, McCloskey, Deutsche Bank

Figure 88: China shipments of all coal by transport method



Source: National Bureau of Statistics, Deutsche Bank

Once seaborne imports have become a customary method of supplying southern Chinese buyers, then it becomes a smaller step to adjust the balance to include a share of international imports. Port infrastructure requires only the additional investment for blending facilities to accommodate imported coal.



However, this is a workable solution only for coastal demand centers, as the cost to move imported coal inland is likely to be uneconomic, logistically difficult, or both. Additionally, the need to shut down smaller mines to improve safety and for consolidation may have increased the need for a bridging volume of supply from imported coal in 2010-2011.

Greater rail capacity could dampen net import growth

These factors suggest that a flattening of China's net import growth is possible if north-to-south freight railway capacity increases, as domestically-produced coal will be better able to meet demand. We describe a number of these new rail investments in our survey of coal transport infrastructure, *Thermal Coal: Assessing China's coal infrastructure*, 22 February 2013.

Figure 89: China coal freight railway projects

Project	Length (km)	Investment (CNY bn)	Capacity(mt)	Construction period
West Inner Mongolia-Central China (Mengxi-Huazhong)	1,837	158	200	2015-17
Central and S. Shanxi (Shanxi-Shandong)	1,167	103.8	200	Begins 2014
Chidabai Jinchi	282	8	50	2013
Xinqiu-Bayan Ul	487	5.9	12/25/35	2013
Hongliuhe-Santanghu/Naomaohu	625	10.2	150	2012-14
Taiyuan-Xing county	164	8.6		2012
Wuhan-Sanduao	750	60	300	2013+
Zhungeer-Caofeidian	1,000	170	200	2013+

Source: Deutsche Bank

Altogether, including the projects listed in Figure 89, China's coal railway capacity will rise by 335mtpa by 2015 from 2012, and a further 300mtpa by 2020. In conjunction, port loading capacity will also increase at the Caofeidian, Rizhao, and Jinzhou ports on the Bohai Sea, which will be balanced by expansions in unloading capacity at central and southern ports. By comparison, Chinese coal consumption has increased at an average annual rate of 342mt over the past three years, which indicates that these capacity expansions are indeed substantial.

An increased proportion of rail infrastructure investments in the future may come from private sources. In 2012, the Ministry of Railways (MoR) sought private financing for the 1,860km Mengxi-Huazhong Railway project, a major undertaking which will have a government ownership share of only 20%. This represents a departure from previous policy wherein the government would retain a controlling stake of at least 50%. Such a policy shift may lead to a more rapid buildout of capacity as a more diverse group of investors is able to take participation. Previous rail projects were led either by China Railway Investment Corp. or Shenhua Energy.

Railway capacity quotas are allocated by the NDRC and the MoR and have historically been assigned on a yearly basis at an annual coal conference where annual fixed-price contracts were settled. However, we understand that this method of allocating rail capacity in the future will be reformed in the near future as a result of the new domestic coal pricing scheme described below.

The capacity allocation system formerly served as a major motivating factor for coal producers to sign annual contracts, which then allowed them to qualify for limited rail transportation quotas at a lower price than was otherwise available. While the MoR set the 2012 coal railway allocation quota at 835mt, down 10% from 2011, it announced in early 2013 that it would allocate greater rail capacity to the coal industry this year, without specifying an exact figure.

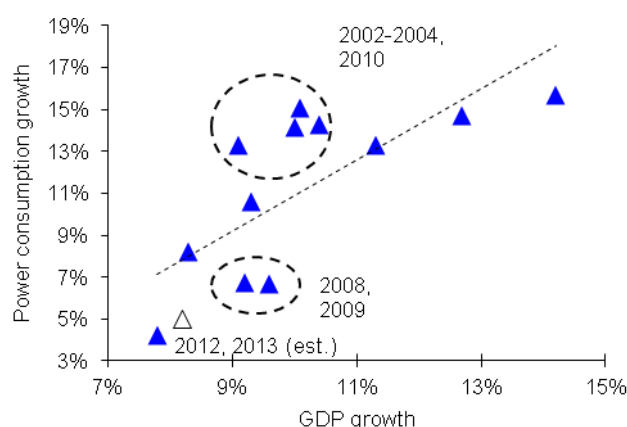


Structural factors which may limit import demand in the medium term

Perhaps more importantly, there are three wider structural factors which one could reasonably expect may lead to a moderation in net import growth in the medium term. China is in the midst of a rebalancing effort from coast to the interior, from investment to consumption and from manufacturing to services. Several important consequences follow from this shift in development focus.

First, the lower growth target of 7.5% combined with a stated goal to reduce the energy intensity of GDP growth by 16% and the carbon intensity of GDP growth by 17% by 2015 implies softer Chinese coal demand growth going forward. These goals are enshrined in the Twelfth Five Year Plan and suggest that power consumption may increase more slowly in the future, as it did in 2008, 2009 and 2012, Figure 90.

Figure 90: China power consumption growth and GDP growth



Source: World Bank, Deutsche Bank

Second, the urbanization of the interior means that a significant proportion of future demand growth will occur closer to the regions of domestic coal production, and further from coastal ports, disadvantaging imported coal. Third, the very real possibility exists for a more emphatic response to the level of air pollution in urban areas, following well-publicised record-high readings of PM2.5 pollution in Beijing this year. Already, more stringent soot and particulate matter emission limits have been legislated for 47 major cities and will take effect over the next two years.

A scenario put forth by our Asia Economics team suggests that a workable plan to reduce particulate matter could entail an annual decline of 0.7% in coal consumption through 2030. Although this remains a hypothetical exercise at the moment, it describes the potential impact of an important shift in China's trajectory of coal demand growth, Figure 91.

We also note that China's efforts in growing natural gas supply are well underway and have shown recent signs of progress, supplementing alternative means of power generation including nuclear, hydropower, wind and solar. In support of the goal of growing the domestic gas market, CNPC has begun construction of the third West-East Gas Pipeline (30bcm p.a.) which will be completed by 2014, bringing the total capacity of the three West-East gas pipelines to 77bcm p.a. Turkmenistan has agreed to supply 65bcm annually, while negotiations which began with Russia in 2009 regarding a possible 68bcm, 30-year deal have advanced with a memorandum of understanding



signed in March 2013 regarding a possible 38bcm supply deal beginning in 2018, although a price agreement remains a major obstacle.

Figure 91: Possible impact to China's net thermal coal import demand as a result of environmental policy revisions

	2012	2013	2014	2015
Scenario I: Government takes no further action to address the country's pollution crisis				
Thermal coal demand	3,403	3,597	3,784	3,954
Coal demand growth rate	2.2%	5.7%	5.2%	4.5%
Thermal coal production	3,176	3,377	3,574	3,764
Net imports (incl. lignite)	227	220	210	190
Scenario II: Reduced demand following stricter government measures to curb pollution				
Thermal coal demand	3,403	3,546	3,659	3,751
Coal demand growth rate	2.2%	4.2%	3.2%	2.5%
Thermal coal production	3,176	3,377	3,574	3,764
Net imports (incl. lignite)	227	169	85	-13

Source: Deutsche Bank

Domestic pricing policy

As recently as 2012, China's domestic pricing scheme was a two-tiered system under which producers signed annual contracts at government-controlled prices with limits to annual price increases, while the remainder of coal was sold at spot prices, sometimes capped by the government to limit inflation and costs for power generators. Indeed, the inflationary effects of potential rises in power tariffs were the primary reason for the government's tight control over coal prices.

A typical example of the workings of the old system were seen at the end of 2010, when the National Development and Reform Commission (NDRC) mandated that contract coal prices would remain unchanged in 2011. Then at the end of 2011, the NDRC allowed for a maximum price rise of 5% in the 2012 annual contract price, lifting average contracts to CNY603/t, according to SX Coal. Despite the contract price increase, producers chose to sell less coal on annual contracts at the start of 2012 in order to take advantage of even higher spot coal prices. In February 2012, Yanzhou Coal chose to lower contract volumes 14% yoy in order to sell additional coal in the spot market, where prices are capped at CNY800/t on a 5,500 kcal/kg NAR basis including 17% VAT.

In 2011, the volume of coal sold on annual contract was increased to 769mt by the NDRC. In 2012, negotiations between the Chinese government and independent power producers took place regarding the elimination of the existing system of annual government-regulated contract pricing. Last year, the government allowed a 5% increase in the price of annual contracts, and settled near CNY603/t, according to SX Coal. The current spot price of Qinhuangdao excluding VAT has neared this level, potentially making the policy revision more manageable. The revised scheme will allow buyers to sign 2-5 year contracts with annual price reviews and a structure of a base price plus variable component. According to our China metals and mining equity research team, any policy move will need to be bundled with fuel price pass-throughs on power tariffs and changes to railway allocations.

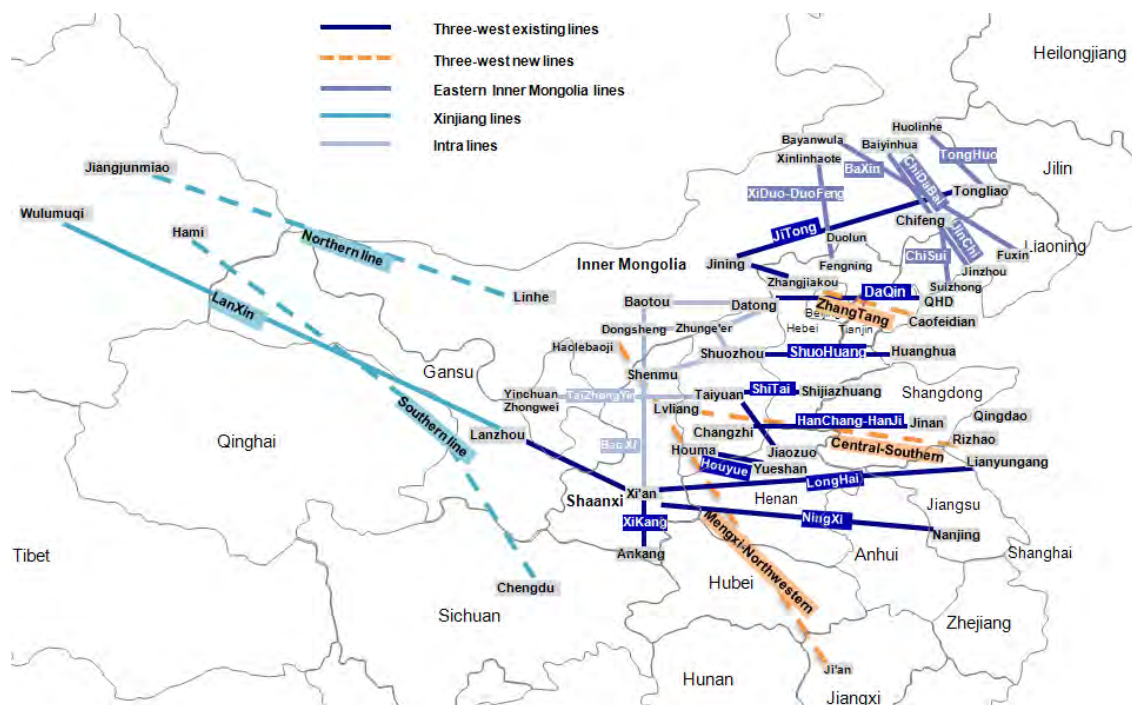


Figure 92: China thermal coal producing provinces and seaborne routes



Source: Wikimedia Commons, Deutsche Bank

Figure 93: China thermal coal producing provinces and seaborne routes



Source: Deutsche Bank China Metals & Mining Equity Research



#17 United States

Figure 94: United States at a glance

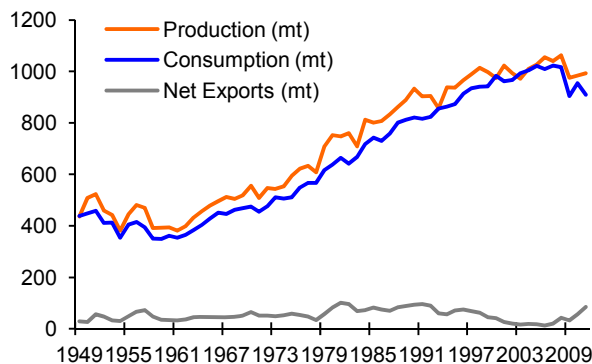
2012 thermal coal net exports	41mt
2012 total coal production	909mt
Calorific value, Powder River Basin	4,567 kcal/kg NAR
Calorific value, Appalachian	6,676 kcal/kg NAR
2013 coastal FOB cash cost, wt avg Appalachian	\$111.1/t
2013 coastal FOB cash cost, 85th percentile Appalachian	\$132.3/t
2013 coastal FOB cash cost, wt avg Powder River Basin (energy adjusted)	\$77.9/t
2013 coastal FOB cash cost, 85th percentile PRB (energy adjusted)	\$81.5/t
5-year forecast growth rate, Central Appalachian	-4.70%
5-year forecast growth rate, Powder River Basin	3.50%

Source: Wood Mackenzie, McCloskey, Deutsche Bank

The new exporter on the block

The US holds the largest coal reserves in the world at 237.3 billion tonnes (exceeding Russia's reserves of 157bt and China's reserves of 114.5bt), and is the second-largest producer at 993mt in 2011. Like China, the US is a very large market which has historically been largely self-contained. As imbalances emerge, however, the potential exists for a significant impact on global seaborne balances. The US coal supply-demand balance has softened because of a multi-year acceleration in gas production while increasingly stringent air pollution restrictions will restrict coal-fired power generation over the next decade. The resulting export push has already become a significant influence on thermal coal pricing worldwide, while an expansion of export capacity, if achieved, could provide a wider outlet for US coal production.

Figure 95: US coal balances (mt)



Source: US EIA, Deutsche Bank

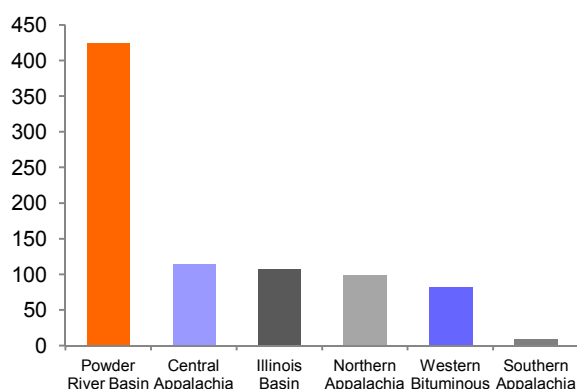
The largest share of US coal production comes from the Western region, which accounts for 52.7% of total production in 2012, according to the EIA. Within the Western region, the state of Wyoming alone, home of the Powder River Basin (PRB), accounts for 38.7% of total production. PRB coal is classed as sub-bituminous, and the standard reference price of PRB coal specifies an energy content of 8,800 btu/lb GAR, or 4,892 kcal/kg. Using the conversion specified in Figure 31 and total moisture of 19.5%, hydrogen content of 4.88%, and oxygen content of 1.02%, we can arrive at an estimated net energy content of 4,531 kcal/kg NAR according to the benchmark specification. The actual weighted average net energy content is close to this at 4,567kcal/kg NAR.



The second most important coal region is the Appalachian Basin, which accounts for 31.5% of 2012 production, and is dominated by the states of West Virginia (12.8%), Kentucky (10.2%), and Pennsylvania (5.7%). Appalachian coal is classed as bituminous coal, and the standard NYMEX reference price of Central Appalachian (CAPP) coal specifies an energy content of 12,000 btu/lb GAR, or 6,671 kcal/kg. Using total moisture of 7.2%, hydrogen content of 4.4%, and oxygen content of 7.6%, we arrive at an estimated net energy content of 6,405 kcal/kg NAR. This is somewhat below the actual weighted average of production which we believe is roughly 6,676kcal/kg NAR.

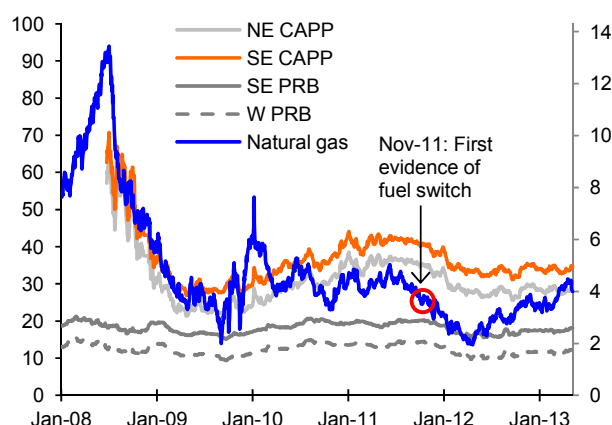
Illinois Basin coal is also bituminous, but typically has a lower energy content (circa 10,300 btu/lb GAR, or 5,726 kcal/kg GAR and 5,447 kcal/kg NAR) than Appalachian Basin coal. The Illinois Basin falls into the Interior region in the EIA's grouping, which accounts for 15.8% of 2012 production. The Interior region also includes the Gulf province lignite-producing regions across the southeastern United States.

Figure 96: US coal production by region (mt)



Source: Wood Mackenzie, Deutsche Bank

Figure 97: Price comparison between coal and gas for power generation (lhs \$/MWh, rhs \$/mmBtu)



Source: Bloomberg Finance LP, Deutsche Bank

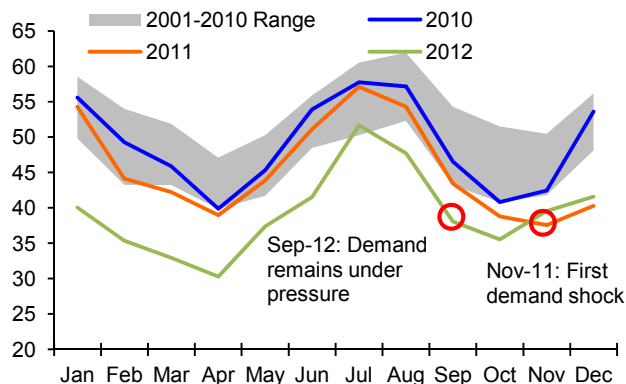
Weakness in natural gas triggered fuel switching

Beginning in Q4-2011, the fall in natural gas prices below the comparable cost of thermal coal for the purpose of power generation caused a shift in fossil fuel consumption patterns in the US.

In November 2011, monthly consumption of coal in the Eastern US states was down 4.9mt per month (-11.5% yoy), but coal consumption in the Western US states was only down 0.5mt per month (-2.3% yoy), as one would expect given that gas prices at that time had only managed to fall below the cost of Central Appalachian (CAPP) coal, which is mined in the Eastern states, and not Powder River Basin (PRB) coal, which is mined in the Western states. However, by January, even coal consumption in Western states had begun to be affected, down 3.5mt per month (-12.6% yoy). The negative impact to coal demand reached its greatest point in April 2012, when Western consumption was down 5.2mt per month (-24% yoy), and Eastern consumption was down 8.7mt per month (-22% yoy).

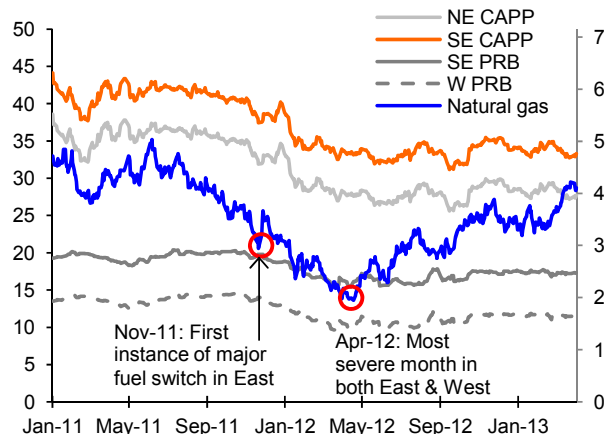


Figure 98: US Eastern coal consumption for power (mt/month)



Source: US EIA, Deutsche Bank

Figure 99: Price comparison between coal and gas for power generation (lhs \$/MWh, rhs \$/mmBtu)

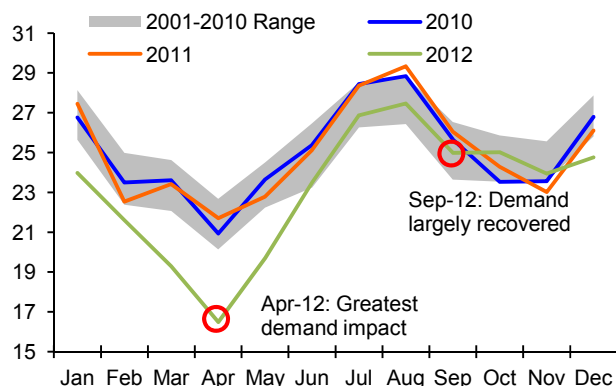


Source: Bloomberg Finance LP, Deutsche Bank

The fuel choice of power generators matches closely with the movement in relative prices, indicating that decisions are largely made on a rational basis. In November 2011, the first demand shock occurred with respect to Eastern coal demand, and corresponded with the first time that gas prices fell below \$3.00/mmBtu (to \$2.94/mmBtu) on 23 November 2011. We observe that the impact to Western coal demand was greatest in April 2012, when gas prices dipped below the comparative price of PRB coal delivered to Southeastern power generators, "SE PRB" in Figure 99. Since April, Western coal demand has recovered as gas prices rose steadily above the SE PRB price, until the months of October and November 2012, when Western coal demand was actually higher year-on-year.

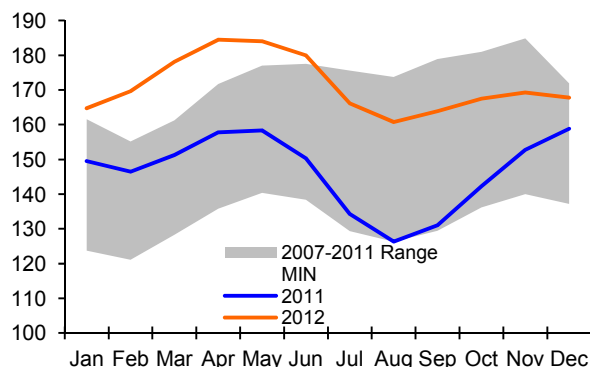
For Eastern power utilities, the Henry Hub gas price is starting to enter the range in which CAPP coal can compete again. We estimate that at a gas price of \$4.2/mmBtu, Appalachian coal becomes competitive again in the Northeast, so we could see healthier domestic coal demand this year.

Figure 100: US Western coal consumption for power (mt/month)



Source: US EIA, Deutsche Bank

Figure 101: Coal inventory in electric power sector (mt)



Source: US EIA, Deutsche Bank



Effect on US coal exports

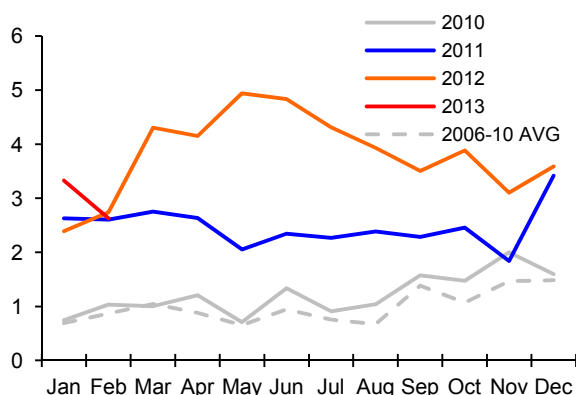
This shift in fossil fuel consumption for power generation had the most marked impact on thermal coal exports in 2012 as buyers on take-or-pay contracts sought an outlet for obligatory purchases. The abnormally high level of inventories was also a likely driver for exports, as some electric utilities may have found that they no longer had space to store unneeded volumes especially from February to May 2012, Figure 101.

Consequently, seaborne thermal coal exports to countries other than Canada and Mexico rose markedly in December 2011, with total 2011 exports of 29.7mt more than doubling the previous year's figure of 14.6mt. As a result of further increases beginning in March, 2012 gross seaborne exports totalled 46mt, by far the highest rate since at least 2000. Total thermal coal exports including Canada and Mexico equaled 50mt in 2012.

On a yearly basis, seaborne thermal coal exports in 2012 exceeded the average rate of exports over the 2000-2010 period of 9mt/year by a wide margin, Figure 102. As we expect Henry Hub prices to remain strong in 2013 at an average of \$3.75/mmBtu, it follows that thermal coal exports will subside from the high level observed in 2012, but may remain high in the longer term as coal-fired generation comes under pressure from emissions reduction legislation.

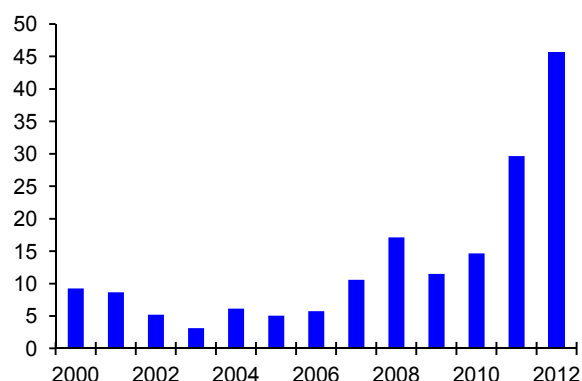
The lagged nature of the coal demand data from the EIA means that there has probably been a further increase in domestic coal consumption since the start of 2013, given the rise in the gas price to \$4.25/mmBtu. Generator decisions to deploy coal or gas-fired generation are typically taken on a month-ahead basis. If sustained this means that US thermal coal exports in 2013 may be closer to the 2011 level (30mt) than the 2012 level (46mt) and that pressure on thermal coal prices from US supply will be held in check. February US thermal coal exports were 2.6mt, down from the average of 3.8mt/month last year, Figure 102.

Figure 102: US seaborne thermal coal exports (mt/month)



Source: McCloskey, Deutsche Bank

Figure 103: US seaborne thermal coal exports (mt/year)



Source: McCloskey, Deutsche Bank



Headwinds for coal consumption may raise exports

In the medium term, we believe that US coal consumption will be pressured and that seaborne thermal coal exports will likely rise again, owing to two structural themes going forward: (i) the increasing disfavour with which coal-fired generation is regarded, which finds concrete expression in the Mercury and Air Toxics Standards (MATS) from the Environmental Protection Agency (EPA), and (ii) continued expansion of Powder River Basin coal production at an annualised rate of 3.5% to 2017 and 2.6% to 2020, and the proposed construction of additional port capacity at a number of locations on the US West Coast and Canadian West Coast.

Emissions standards to limit coal consumption

A rising degree of popular and political support for measures aimed at reducing reliance upon coal-fired generation is notable. In Los Angeles, the Department of Water and Power announced in March 2013 that it would abandon power purchases from coal-fired power generation. In New York, the mayor's charitable organisation donated \$50m to the Sierra Club in 2011 to support a Beyond Coal campaign to reduce power generation from coal. Continuing pressure from air pollution regulation and environmental groups will put pressure on the electricity market which constitutes 95% of US thermal coal demand.

The MATS will mandate reduced emissions from both new and existing coal- and oil-fired power plants larger than 25MW, with respect to heavy metals (including mercury, arsenic, chromium, and nickel) and acid gases (hydrochloric acid and hydrofluoric acid). The rule had been under reconsideration after petitions were submitted following the initial rulemaking in December 2011. The EPA issued a final rule on 4 April 2013 which sets the mercury emissions limit at 0.003 pound/GWh, up from 0.002 pound/GWh in its previous formulation. Existing power plants will have four years with which to comply with the regulation. The EPA estimates that there are 1,100 coal-fired units and 300 oil-fired units at 600 power plants covered by the rule.

As a result of new emissions standards, 192 coal-fired units are known to be scheduled for closure through 2026. In total, netting out planned capacity expansions, coal-fired generation capacity could fall from 310GW in 2012 to 273GW in 2020. Although coal-fired powerplant utilisation should rise as gas prices remain stable to higher in our view over the long term, closures of capacity particularly in 2016 mean that coal consumption for power generation will remain below the 2010 level through 2022, Figure 104.

Figure 104: US coal-fired power generation and implied coal consumption

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Electricity generation from coal (TWh)	1,847	1,730	1,547	1,610	1,616	1,614	1,520	1,567	1,600	1,636	1,656	1,663	1,692
Coal-fired generation capacity (GW)	313	314	310	310	308	297	275	274	273	273	273	272	272
Implied utilisation rate (%)	67.4%	62.8%	57.0%	59.3%	59.9%	62.0%	63.1%	65.4%	66.8%	68.3%	69.2%	69.7%	71.0%
Implied coal consumption* (million tonnes)	865	810	724	754	757	756	712	734	749	766	775	779	792

Source: US EIA, Deutsche Bank

*Assumed heat rate of 10,400btu/kWh and a national average coal energy content of 5,600kcal/kg NAR

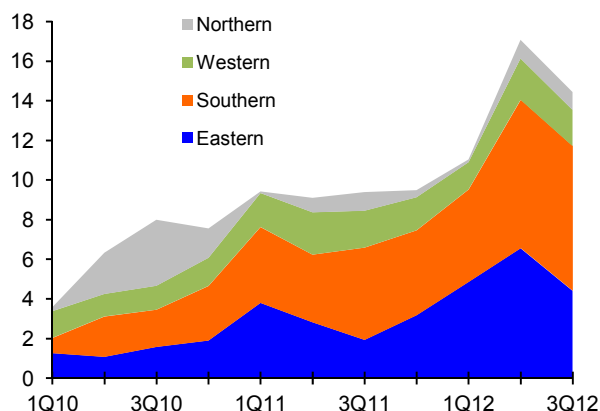
Expansions of port capacity could open a release valve

The combination of a large domestic coal resource and stagnant demand in the long term as a result of environmental regulations means that there is a strong basis for higher coal exports in the future. This is particularly true as we expect that domestic production in the Powder River Basin will grow as miners are able to keep costs low, while Appalachian coal will find it more difficult to compete as a result of significantly higher mining costs from primarily underground operations.



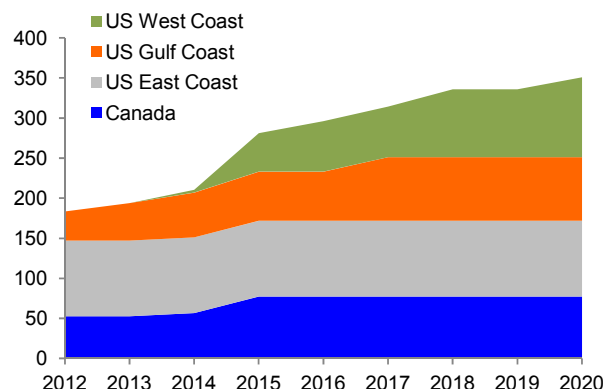
However, this will depend crucially upon the expansion of port capacity, much of which is currently utilised for metallurgical coal exports, particularly at the Canadian West Coast terminals of Westshore and Neptune. This bottleneck prevents Powder River Basin (PRB) coal from reaching the Pacific Basin in large volumes. According to our analysis, energy-adjusted PRB coal has the most realistic export growth potential, as it prices favourably against international benchmarks whereas Appalachian coal is too expensive.

Figure 105: US coal exports by region (mt per quarter)



Source: US EIA, Deutsche Bank

Figure 106: North American planned coal port capacity expansions (mt per annum)



Source: Reuters, Terminal operators, Deutsche Bank

We expect that Powder River Basin coal, as a low-cost, low ash and low sulphur variety of coal, can compete well particularly in Pacific Basin markets where energy content in the range of 4,200-5,500kcal/kg NAR is considered quite acceptable and matches well with the specification of coal typically exported by Indonesian producers and accepted by Indian and Chinese power stations.

Existing coal export capacity is concentrated in the Northeast, including the three terminals clustered in Virginia at Hampton Roads, Norfolk and Newport News where combined capacity of 73mt is located.

The Gulf Coast is the next largest region within the US, while Canada's ports on the West Coast are primarily responsible for metallurgical coal exports. In 2012, the marked increase in thermal exports from the US originated primarily from the Gulf Coast and Eastern regions.

Plans to expand bulk materials port capacity in the US and Canada are significant, equating to an increase of 167mt in 2020 versus 2012, Figure 107. However, in many cases these projects are subject to environmental approval and face opposition based on potential negative impacts on local ecology, air quality from coal dust, noise from train movements, concerns over global warming from the resulting carbon emissions in Asia, and mercury emissions. Additionally, we would note that an increase of 167mt by 2020 does not necessarily equate with an increase of the same volume in coal exports, as bulk material terminals can also be used for the export of a variety of other goods.



Figure 107: North American coal export terminals

Terminal	Location	2012 capacity (mt)	2016 planned capacity (mt)	2020 planned capacity (mt)
Neptune Bulk Terminals	North Vancouver, British Columbia	7.7	16.3	16.3
Ridley Island Terminal	Prince Rupert, British Columbia	12.0	24.0	24.0
Fraser Surrey Docks	Surrey, British Columbia	0.0	4.0	4.0
Westshore Terminal	Roberts Bank Delta, British Columbia	33.0	33.0	33.0
Canada Subtotal		52.7	77.4	77.4
Chesapeake Bay Terminal	Baltimore, Maryland	6.4	6.4	6.4
CNX Marine	Baltimore, Maryland	13.6	13.6	13.6
Dominion Terminal Associates (DTA)	Hampton Roads, Virginia	18.1	18.1	18.1
Fairless Hills	Delaware River	2.0	2.0	2.0
Lamberts Point	Norfolk, Virginia	43.5	43.5	43.5
Pier IX	Newport News, Virginia	10.9	10.9	10.9
US East Coast Subtotal		94.5	94.5	94.5
Armstrong Coal Terminal	Myrtle Grove, Louisiana	0.0	5.4	5.4
Burnside Bulk Marine	Ascension Parish, Louisiana	0.0	10.4	10.4
IC Rail Marine	Convent, Louisiana	3.6	3.6	3.6
McDuffie Coal Terminal	Mobile, Alabama	10.0	10.0	15.4
Mobile River Terminal	Mobile, Alabama	0.0	3.6	3.6
International Marine Terminal	Myrtle Grove, Louisiana	7.3	7.3	7.3
Port of Corpus Christi	Corpus Christi, Texas	5.4	5.4	18.1
United Bulk Terminal	Davant, Louisiana	10.0	15.4	15.4
US Gulf Coast Subtotal		36.3	61.2	79.4
Gateway Pacific Terminal	Cherry Point, Whatcom County, Washington	0.0	21.8	21.8
Millenium Bulk Terminal	Longview, Cowlitz County, Washington	0.0	22.7	39.9
Port Westward	Port of St Helens, Oregon	0.0	15.0	30.0
Morrow Pacific	Port of St Helens, Oregon	0.0	3.5	8.0
US West Coast Subtotal		0.0	63.0	99.7
North American Total		183.5	296.1	351.0

Source: Terminal Operators, Deutsche Bank

Risks to the view

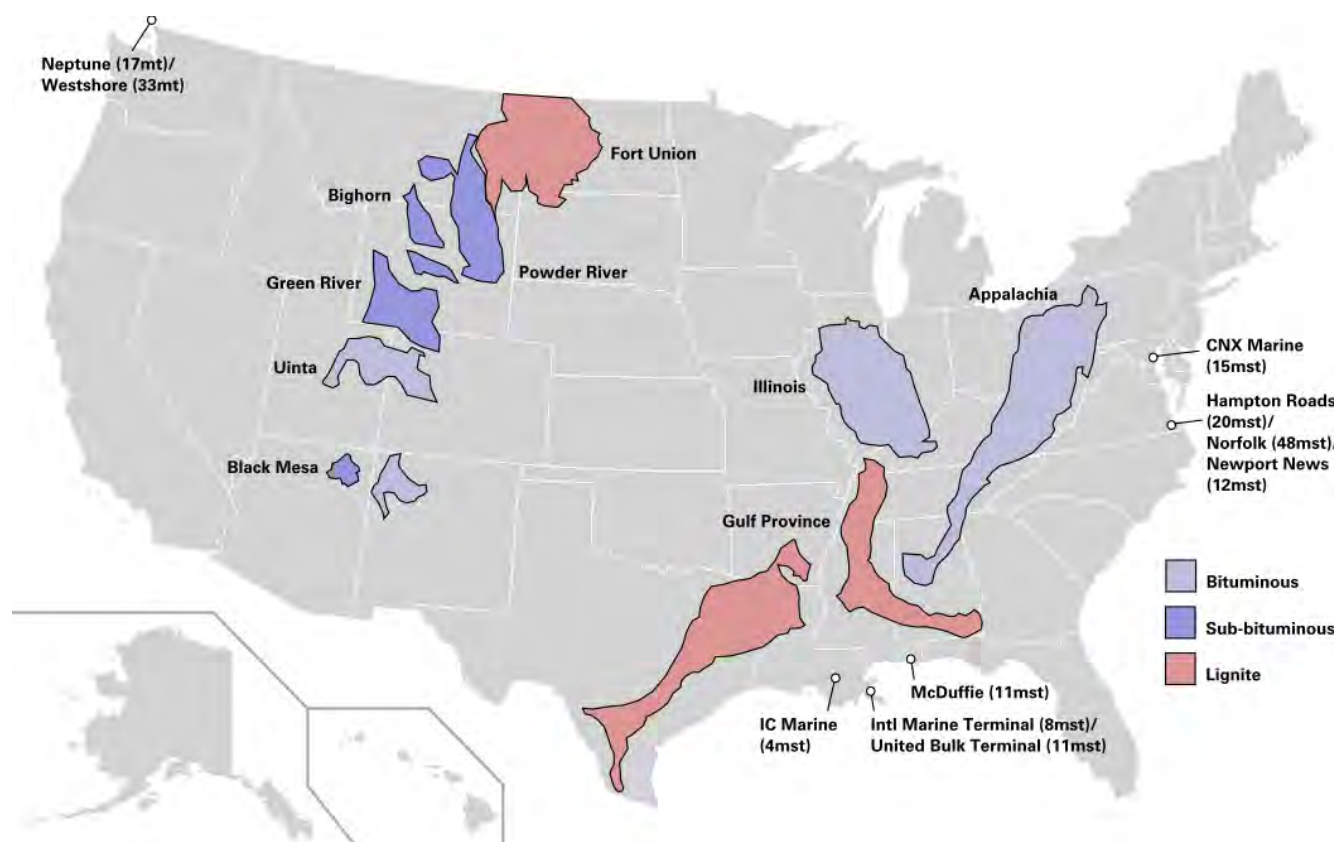
There are notable risks to our view that more stringent emissions standards will lead to a long-term decline in coal-fired power generation in the US. First, affordable energy advocates may become more successful in fighting regulations limiting emissions. These groups argue that reducing coal-fired generation will lead to higher and more volatile power prices, and that the EPA is overstepping its bounds by enacting such rules.

In fact, in August 2012, the US Court of Appeals in Washington found that the EPA's Cross State Air Pollution Rule (CSAPR) exceeded the agency's statutory authority and invalidated the rule. The Clean Air Interstate Rule (CAIR) of 2005 will remain in place until a replacement to this regulation can be formulated.

The CSAPR would have required 25 states in the Central and Eastern US to improve air quality by limiting SO₂ and NO_x emissions from power plants, which contribute to ozone and fine particle pollution. Emissions reductions would have begun to take effect on 1 January 2012 for SO₂ and on 1 May 2012 for NO_x, with the aim of helping states to attain compliance with the National Ambient Air Quality Standards (NAAQS).



Figure 108: US thermal coal producing regions and ports



Source: BNSF Rail, Wikimedia Commons, Deutsche Bank

Second, the possibility exists that technological improvements to lower the cost of clean coal technology (CCS) could make clean coal power plants economic against other forms of power generation. However, as of 2010, the US EPA estimated that the incremental cost of CCS in a new coal-fired plant ranges from \$60 to \$95 per tonne of CO₂ avoided. Assuming a typical carbon intensity of 0.9 tonnes CO₂/MWh, this means that CCS technology would triple the current cost of generating power (\$34/MWh) from the highest-cost coal-fired plants (burning Appalachian Basin coal including transport cost to the Southeast US).

Finally we note the possibility that very little of the currently planned port capacity is eventually permitted and allowed to proceed with construction, given the environmental objections described above.

In short, we believe that the evolving supply-demand dynamics of thermal coal in the US have the potential to have a larger negative effect on global seaborne prices in the next decade than we observed in 2012, especially in light of the large size of the domestic market, the appeal of PRB coal in international markets, and the large incremental growth potential in West Coast ports capable of handling coal in the US and Canada.



#18 Europe

Figure 109: Europe at a glance

2012 thermal coal imports:	221mt
2012 total coal production, hard coal	124mt
2012 total coal production, lignite	460mt
5-year forecast annual growth rate of imports	-2.2%

Source: Eurostat, McCloskey, Deutsche Bank

A major market poised to shrink

Until 2012, Europe taken as a whole was the largest import destination for seaborne thermal coal, and constituted 39% of the global market as recently 2005. As of last year, Europe consumed only 22% of global exports.

Europe is a major producer of lignite, which is consumed entirely within its borders, primarily via mine-mouth power generation. In terms of hard coal, its consumption is primarily supplied through imports from Russia, Colombia, and increasingly, the US, Figure 110.

Figure 110: Selected European country* imports by source (mt)

	2011	2012
Russia	52.5	60.3
Colombia	50.3	58.7
US	18.5	35.8
South Africa	18.2	13.8
Indonesia	9.6	9.4
Australia	2.7	2.0
Ukraine	1.0	0.7
Czech Republic	2.0	1.0
Venezuela	0.7	0.7
Canada	0.4	0.2
Other	1.4	1.3
Total	157.4	184.1

Source: McCloskey, Deutsche Bank

*UK, Netherlands, Germany, Turkey, Spain, Italy, France, Poland, Belgium, Portugal, Finland

Since the majority of coal consumption is for the purpose of power generation, coal demand can be sensitive to the comparative pricing of coal and gas in those countries with an ability to switch between these fuels. This ability is most notable in the United Kingdom, where imports of hard coal increased by 41% in 2012 from 26mt to 37mt as coal prices fell relative to gas, Figure 112. As we expect a structural reform of the EU Emissions Trading System to take some time, European gas prices to remain just below oil-indexed levels, and coal pricing to be subdued, the incentive to continue burning coal instead of gas should remain in place over the next several years.

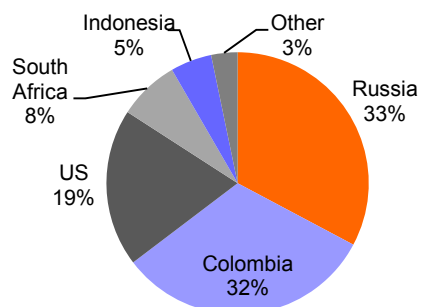
However, in the longer term, we expect that progress towards Europe's green energy targets will be accomplished partly at the expense of coal-fired power generation.

Closures of coal-fired generation capacity will be required for plants opting out of compliance with the Large Combustion Plants Directive as they consume the limited running hours allowed under the scheme (20,000 hours to be used between 2008 and 2015). Utilisation of remaining plants (which have benefited from investment in scrubbing technology) over the 2013-2015 period should remain high, however, as long as emissions prices remain too low to



incentivise greater utilization of gas-fired generation. This factor therefore limits the decline of electricity generated from coal over this period below what it otherwise might have been. In the longer term from 2017 to 2020, we expect that utilisation rates of existing plant will fall as an increasing share of supply will be met by renewables and gas-fired generation.

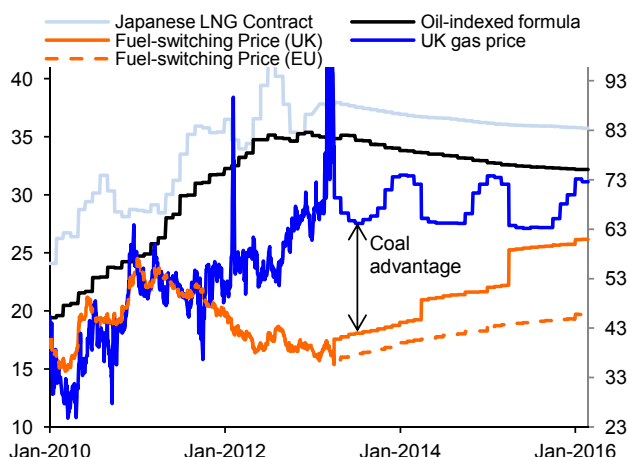
Figure 111: Selected European country* imports by source in 2012



Source: McCloskey, Deutsche Bank

*UK, Netherlands, Germany, Turkey, Spain, Italy, France, Poland, Belgium, Portugal, Finland

Figure 112: Coal and gas in comparative terms for power generation (lhs €/MWh, rhs GB pence/therm)



Source: Bloomberg Finance LP, Deutsche Bank

As a result of cumulative net closures of coal-fired generation capacity of 28GW from 2012 to 2020, and declining utilisation of generation capacity beginning in 2017, total power generated from coal declines from 968TWh in 2012 to only 719TWh in 2020. Although we assume that EU domestic hard-coal production declines at an average annual rate of 4.7%, the fall in coal consumption outpaces this decline and results in an expectation of lower imports levels going forward. Thus, the outlook for European coal-fired generation levels together with our domestic coal production assumption suggests that European hard coal imports are likely to begin a downward trend after 2014.

Figure 113: European Union hard coal-fired power generation and implied import requirements (excluding lignite)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal-fired capacity (GW)	190	187	187	181	171	172	170	167	162
Power generated from coal (TWh)	968	958	945	905	866	842	781	720	719
Implied coal consumption* (mt)	365	362	357	342	327	318	295	272	271
Production (mt)	124	118	112	107	102	97	93	88	84
Imports (mt)	221	224	224	215	205	201	182	163	167
Other supply (mt)	20	20	20	20	20	20	20	20	20
Plant utilisation	58%	58%	58%	57%	58%	56%	53%	49%	51%

Source: Wood Mackenzie, Deutsche Bank

*Assumed 6,000kcal/kg NAR coal and 38% thermal efficiency



#19 India

Figure 114: India at a glance

2012 thermal coal imports	119mt
2012 total coal production	557mt (est.)
Calorific value	3,783kcal/kg NAR
2013 domestic cash cost	\$18.8/t (est.)
3-year forecast growth rate of domestic supply	6.2%

Source: Deutsche Bank

Low domestic costs limit import viability

India is a major centre of consumption representing 7.9% of total global consumption in energy terms in 2011 and 11.5% of seaborne trade in 2012. Indian domestic mining is dominated by Coal India (est. 80% of national total in FY2012) and benefits from an extremely low cost of domestic production, although much of produced coal is of a very low calorific value and can be quite high in ash content (as much as 40%). Domestic coal meets the majority of demand (est. 82% in FY2012), but imported coal is still necessary to meet a shortfall relative to total demand, and imports may provide a benefit in blending with domestic coal to reduce ash content and raise energy content. Roughly 80% of national coal demand is from the power generation industry. However, low power tariffs and the issue of affordability for both industrial and residential consumers means that the high cost differential between imported coal and domestically produced coal is the greatest limiting factor for consumption. Consequently, insufficient power supply and low capacity utilisation of the installed power generation base have arguably been a drag on overall economic growth.

A review of Indian power sector reforms

The widespread national power outages on 30-31 July 2012 highlighted the dimensions of the ongoing difficulty India faces in making sufficient power supply available to the country. In order to understand the context, we review the history of Indian power sector development to shed light on the current situation.

In our view, the inadequacy of power supply in India today can be directly attributed to low levels of capacity investment in the 1990s. In addition, low power tariffs relative to the cost of generation, highly subsidised power tariffs made available to agricultural consumers, financial distress of State Electricity Boards (SEBs) causing non-payment to power generators, high transmission and distribution losses, and insufficient supply of cheap domestically produced fuel (both coal and gas) which has led to low plant load factors (PLF).

An examination of the history of power capacity and economic growth will show that in terms of megawatts (MW) of power capacity per US\$ bn of GDP in year 2000 dollars, the availability of power capacity grew rapidly from 1950 to 1992 with the development of heavy industry and as power capacity grew to accommodate new demand, Figure 115 and Figure 116.

However, availability of power capacity then fell from 1992 to 2007, as investment by privately owned power generators fell far short of government targets. Private investment was both legalised and incentivised by the Electricity Laws Act of 1991, which guaranteed a return on equity of 16% for those power projects operating for at least 6,000 hours per year. Independent power producers (IPPs) were allowed to sign power purchase agreements (PPAs) with state electricity boards (SEBs), and for "fast-track" projects, guaranteed by the central government against payment defaults.



Figure 115: India power sector and economic growth*

	Power Capacity (GW)	GDP (US\$ bn in real 2000 dollars)	MW per US\$ bn real GDP	Power capacity growth	Real GDP growth	Elasticity of power demand
1950	1.7	65.3	26.2			
1985	42.6	207	206	9.60%	3.40%	2.87
1990	63.6	276	230	8.40%	6.00%	1.41
1992	69.1	295	234	4.20%	3.20%	1.29
1997	85.8	396	216	4.40%	6.10%	0.73
2002	105	518	203	4.10%	5.50%	0.75
2003	108	559	193	2.70%	7.90%	0.34
2004	113	603	187	4.50%	7.80%	0.57
2005	118	659	180	5.10%	9.30%	0.55
2006	124	720	173	4.90%	9.30%	0.53
2007	132	790	167	6.50%	9.80%	0.66
2008	143	821	174	8.10%	3.90%	2.08
2012E	200	1,102	181	8.70%	7.70%	1.14

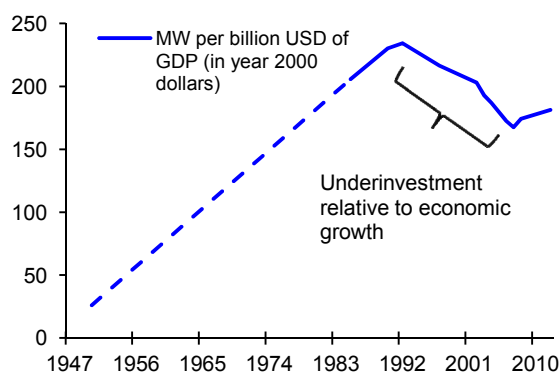
Source: Council of Power Utilities, Central Electricity Authority, World Bank, National Accounts Statistics of India, Deutsche Bank

*Growth rates in each year are calculated over the period starting in the preceding line of the table. For instance, 1985 growth rates are given over the 1950 to 1985 period, while 1990 growth rates are given over the 1985 to 1990 period.

Despite this, only 17GW of capacity was added from 1992 to 1997, compared to a target of 40GW, owing to difficulties in obtaining environmental clearances and securing fuel supply from both domestic and imported sources, and ambivalence within the government regarding the balance of concessions given to IPPs versus risks for SEBs. We suggest that the existence of the target at 40GW indicated an official recognition of the magnitude of power capacity additions required.

Fuel supply has been a challenge because IPPs generally supply power under a fixed power tariff and cannot pass on the cost of imported fuel. Therefore, utilities are constrained by the volume of fuel available from domestic producers to provide coal or natural gas, which is generally available at lower prices. By contrast, government-owned power generation companies which fall under the category of public sector undertakings (PSUs) sell power on a regulated basis with fuel-cost pass-throughs as part of the power tariff structure. However, regulatory clearance and (power) buyer approval must be obtained for each coal shipment and therefore can be problematic.

Figure 116: India power capacity in relation to GDP



Source: Council of Power Utilities, Central Electricity Authority, World Bank, National Accounts Statistics of India, Deutsche Bank



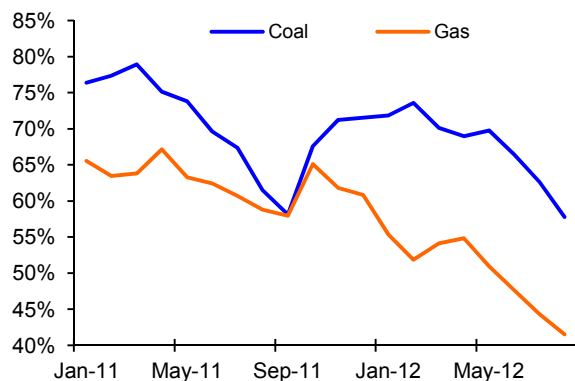
Thus, the decline in power capacity per real dollar of GDP over the 1992 to 2007 period is more likely evidence of demand being constrained by the slow growth in power supply relative to the economy's needs, rather than a natural reduction in energy intensity of economic production. As a guide, we reference the Planning Commission's assumption of 0.9 elasticity of power demand to GDP over the duration of the Twelfth Plan (2012-2017) and 0.8 elasticity of power demand for the Thirteenth Plan (2017-2022). It is unlikely, in our view, that an elasticity of 0.34 to 0.75 over the 1992 to 2007 period reflected the optimal rate of power demand growth, and by extension, economic growth.

Contemporary issues

Currently, one of the most serious issues is the lack of payment flowing from State Electricity Boards (SEBs) to power generators, and thus lower plant load factors (PLF), Figure 117, as generators hesitate to supply power that ultimately may not be paid for. Part of the underpayment results from the very low or zero power prices charged to agricultural customers as a part of local government policies. While the SEBs sell at the subsidised price, the subsidy payment from the government has not always been timely or regular, thus causing losses to the SEBs.

The method of reform now aimed at tackling this problem is the restructuring of 50% of SEB debt to extend the term of repayment, and the assumption of 50% of SEB debt by state governments, according to McCloskey. We believe that this could improve the financial condition of SEBs such that they become better able to make payments to power generators, and more importantly, motivate state governments to raise power tariffs to reflect the real cost of power generation (including the cost of a 10% blend of imported coal).

Figure 117: India plant load factor by fuel type (% of monitored capacity)



Source: Central Electricity Authority, Deutsche Bank



Tariff hikes have been instituted for a number of states, including Andhra Pradesh (from 1 April 2012), Madhya Pradesh, and Tamil Nadu in the past year. A summary of the tariff increases in Andhra Pradesh is given below.

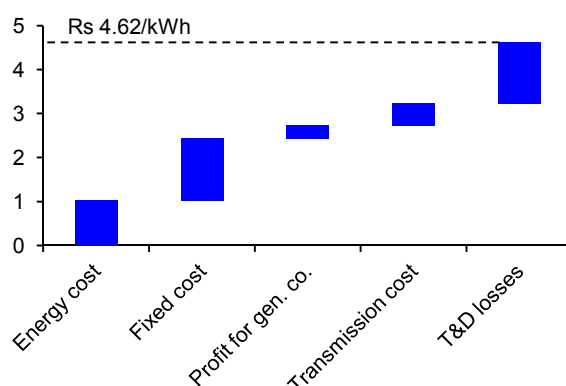
Figure 118: Andhra Pradesh state power domestic (residential) tariff increases

Consumption band	Previous	From 1 April 2012
0-50 units	Rs 1.45	Rs 1.45
51-100 units	Rs 2.80	Rs 2.60
101-200 units	Rs 3.05	Rs 3.60
201-300 units	Rs 4.75	Rs 5.75
301-500 units	Rs 6.00	Rs 6.75
500+ units	Rs 6.25	Rs 7.25

Source: Andhra Pradesh Electricity Regulatory Commission

A calculation of the actual costs of power generation, however, show that some of these tariff rates are still too low to compensate for the sum of all-in costs including fuel (assuming a 10% blend of imported coal), operating and maintenance, depreciation, transmission cost, and distribution losses.

Figure 119: Estimated cost structure of power generation and distribution (Rs/kWh)



Source: Deutsche Bank

Moreover, the debate around tariff revisions in Tamil Nadu this year points to the difficulty which state governments face in raising power tariffs to levels which reflect real costs. After encountering political resistance to a higher tariff structure, the Chief Minister announced that the government would subsidise the rate increase for customers consuming up to 250 units/month, resulting in actual rates paid which would be lower than those in effect since August 2010, Figure 120 and Figure 121.

Figure 120: Tamil Nadu state power domestic (residential) tariff from 1 Aug 2010

Consumption slabs	Previous tariff from 1 Aug 2010
0-25 units	Rs 1.10
26-50 units	Rs 1.30
51-100 units	Rs 2.60
101-300 units	Rs 3.50
Above 300 units	Rs 5.75

Source: Tamil Nadu Electricity Regulatory Commission



For example, a customer using 100 units/month (kWh/month) would have paid an average rate of Rs 1.90/unit under the previous tariff, using the weighted average of the first three rates in the table for each tier of usage. Under the new plan, the same customer pays a rate of Rs 1.80, which is then reduced to a subsidised rate of Rs 1.50/unit with the revision. For a customer using 200 units/month, the old tariff averages to Rs 2.70/unit whereas the new tariff averages to Rs 3.25/unit, and Rs 2.50/unit after the subsidy.

Figure 121: Tamil Nadu state domestic (residential) tariff increase as of 1 April 2012

Consumption slabs	Initial FY 12-tariff	Effective from 1 April 2012
Up to 50 units/month	Rs 1.10	Rs 1.00
Up to 100 units/month	Rs 1.80	Rs 1.50
Up to 250 units/month		
First 100 units	Rs 3.00	Rs 2.00
101-250 units	Rs 3.50	Rs 3.00
Up to 500 units/month		
First 100 units		Rs 3.00
101-250 units		Rs 4.00
Above 250 units		Rs 5.75

Source: Tamil Nadu Electricity Regulatory Commission

Clearly these tariff increases are a step in the right direction, but based on our calculation of the costs of imported coal, further moves may be necessary before a more meaningful appetite for imported coal is realised. Additionally, the difficulty encountered in Tamil Nadu indicates that the future pace of such reforms may be slow.

Figure 122: Andhra Pradesh state industrial tariff increases

Industrial consumption category	Previous	From 1 April 2013
11 kv	Rs 3.52	Rs 4.80
33 kv	Rs 3.25	Rs 4.37
132 kv	Rs 2.97	Rs 3.97

Source: Central Electricity Authority, Deutsche Bank

Today, enhancing the fuel supply for power generation remains a point of major concern, both in terms of growing the country's supply of inexpensive domestic coal, and sharing the added cost of importing coal.

The development of domestic coal supply has been slower than it might have been, as many coal blocks allocated to companies for mining development over the 2004-2009 period have not met agreed production milestones. This has led to an investigation into the propriety of the allocation process this year. The investigation includes some 54 coal blocks of which 30 coal blocks are specifically for power generation. These 30 coal blocks total 3,992mt in reserves, according to our equity research team, and the reassessment process may result in blocks being reallocated to more productive counterparties such as Coal India. This holds out hope that these coal blocks will be developed more effectively over the coming decade. The government expects that at least 16 coal blocks will be reallocated by December 2012.

The availability of fuel for power generation has long been a reason for low plant load factor (PLF) among public power projects. Two measures are now under consideration to improve the situation. The first is the guarantee of fuel supply by Coal India Limited (CIL) to power generation projects commissioned



between March 2009 and March 2015. Under newly signed fuel supply agreements (FSAs), the plants would be guaranteed fuel corresponding to 80% of PLF, and CIL would be liable for underdelivery penalties.

The second measure under consideration addresses the importation of foreign coal for power generation, which has long been held back by the price disparity between domestic supplies and imports. The high price of imported coal is at odds with the power tariffs enshrined in PPAs agreed by public power projects. The proposed introduction of a price pooling mechanism by Coal India is now being discussed. Under this arrangement, all power producers which buy coal from Coal India would share the burden of the increased cost of importing coal. Presumably, power tariffs would need to be raised in concert with the implementation of price pooling. However, doubt has been cast upon Coal India's support as its independent directors cited possible losses of INR30bn p.a. under the plan.

[A hunger for power but at a low price](#)

The historical underinvestment in power-generating infrastructure, a very low cost of domestic coal production, and relatively low power tariffs mean that latent industrial and residential appetite for greater power output is frustrated, and an energy deficit continues to hold back economic growth. The most effective means for the country to improve power supply would be to increase production of domestic coal, as this has historically come at the cheapest cost. In some cases, the expansion of domestic production has been delayed because of difficulty in obtaining environmental clearances. In other cases, overall mine supply has been hampered by the closure of mines which still have coal to produce, but which have become uneconomic for various reasons, such as an increase in the strip ratio, or which suffer from a lack of continuing investment. So this again comes back in a circular fashion to the problem of costs, which appears to limit the expansion of domestic supply just as it restricts imports.

In the event of a much more drastic fall in prices than our base case scenario indicates, the Indian power generation market could potentially be a source of greater import demand at much lower international prices, although we believe it is unrealistic to expect that CIF India prices could ever be comparable to domestic Indian coal prices.



#20 Supply-demand balance

Excess capacity in the long term

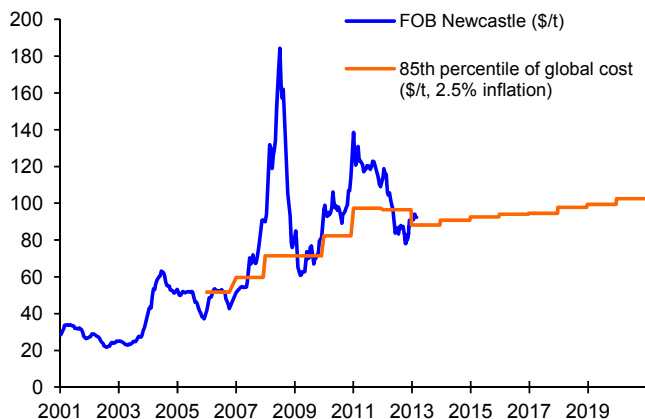
In stark contrast to the overwhelming trend in the global coal market since 1990 during which global production rose 62% from 4,740mt to 7,695mt in 2011 and power generated from electricity has more than tripled since 1973, our market model suggests that we may be on the cusp of an important shift in coal markets. One may be forgiven for thinking that such a change is implausible, but we should keep in mind that the consumption preferences which we see changing are located in the top two coal producing and consuming countries in the world, China and the United States, which together accounted for 59% of global coal production and 63% of global coal consumption in 2011.

We should note that our estimate of global productive potential in 2020 will not actually result in 213mt (1,274 - 1,061) of excess production being added to stockpiles at ports, mines, or power stations. Inevitably, prices, demand and supply will all contribute some degree of adjustment which when summed together will bring about an equilibrium.

It is important to note that the reasons behind the shift in consumption preferences have nothing to do with a substitution response to high prices. Quite to the contrary, concerns over emissions of all sorts (greenhouse gases, mercury, particulate matter, sulfur dioxide, soot), gradual changes in energy intensity, and development of alternative methods of power generation are all aimed at goals unrelated to direct generation costs. Therefore, lower coal prices will not result in a reversal of these policies, despite the fact that unmitigated coal-fired generation provides the cheapest form of power.

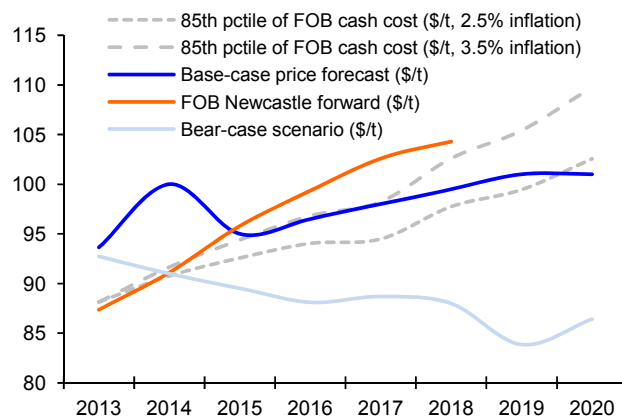
A second important note is that producers have been able to reduce costs by streamlining operations, reducing consumables, modernising equipment, and investing in new technology, all the while maintaining existing production volumes. While it remains to be seen whether producers can achieve a sustainable, material reduction in costs around the world, we believe it will be difficult if oil prices remain stable as we expect.

Figure 123: Historical prices and 85th percentile of global cost (\$/t)



Source: AME, Bloomberg Finance LP, Deutsche Bank

Figure 124: Price forecast and global cash costs (\$/t)



Source: AME, Deutsche Bank



Base-case scenario and price forecast

In developing our price forecast, we therefore believe that the global cost curve in its current incarnation will be fairly stable as a guideline for prices. In 2014, we expect that global real GDP growth rising to 4.0% from 3.2% in 2013 will be a catalyst for prices to trade at a higher premium to marginal cost, although price pressures should remain moderate. Clearly in the longer term we are less optimistic and expect that the impact of production increases will exceed the slowing pace of global demand growth, particularly from major demand centres of Europe and China. We are also concerned that slackening demand in the US will result in a higher level of exports to the Pacific Basin, although we do not assume this in our base-case scenario.

In order to assess the market-clearing price in each forecast year, we first estimate that in 2012, 90% of global productive potential is in operation, while actual Newcastle average prices of \$94.3/t (at the 82nd percentile of the cost curve) suggests that 8% of global production operated at a loss relative to spot prices. This is explained by the fact that some production is sold at a higher contracted price or forward-hedged, and some production may be left in operation to avoid shut-down and start-up costs or to make use of committed infrastructure.

Figure 125: Base-case scenario

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Global seaborne supply potential (Mt)	1,142	1,177	1,188	1,200	1,212	1,224	1,237	1,249	1,274
Total seaborne thermal demand (Mt)	1,027	1,027	1,036	1,020	1,020	1,032	1,033	1,035	1,061
Proportion of supply required	0.900	0.873	0.871	0.850	0.842	0.843	0.835	0.829	0.833
Implied market price (2013 real)	103.7	92.8	92.1	88.2	86.3	85.9	85.0	85.1	85.3
Implied market price (nominal)	103.7	92.8	94.4	92.7	92.9	94.8	96.1	98.7	101.4

Source: AME, Deutsche Bank

We go on to postulate a growth in the total productive potential of global supply of 1% per annum through 2020, which is well below the 3% figure which we would estimate from a bottom-up aggregation of regional production forecasts. Essentially, it is this adjustment from 3% growth to 1% growth which is required to balance the market in the long term. As a result, using the demand forecast in our model, we assess the market-clearing price implied by restrained supply growth at the 85th percentile of the cost curve in 2015 and the 84th percentile of the cost curve in 2020. Our nominal FOB Newcastle benchmark price forecasts of \$95/t in 2015 and \$101/t in 2020, equivalent to \$90/t and \$85/t in 2013 real terms, respectively, are guided by these points in the cost curve.

Bear-case scenario

While our base-case scenario implies that producers will restrain growth in productive assets as prices remain below the incentive costs for some projects, an alternative scenario can be derived from the assumption that all production plans currently in place are allowed to proceed.

Figure 126: Bear-case scenario

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Global seaborne supply potential (mt)	1,142	1,177	1,217	1,256	1,282	1,317	1,349	1,384	1,417
Total seaborne thermal demand (mt)	1,027	1,027	1,036	1,020	1,020	1,032	1,033	1,035	1,061
Proportion of supply required	0.900	0.873	0.851	0.813	0.796	0.783	0.766	0.748	0.749
Implied market price (2013 real)	103.7	92.8	88.8	85.2	81.8	80.4	77.8	72.3	72.7
Implied market price (nominal)	103.7	92.8	91.0	89.5	88.1	88.7	88.0	83.8	86.4

Source: AME, Deutsche Bank



The assumption of unrestrained supply growth would result in a larger volume of new production being added at a marginal cost below the existing market-clearing price, and thus a larger volume of uneconomic mines.

Consequently the total theoretical productive potential of all mines grows from 1,142mt in 2012 to 1,417mt in 2020, as compared with 1,274mt in 2020 in the base-case scenario. Next, we operate on the assumption that the set of mines in our cost database is representative of the global population of mines. Using the existing demand forecast in our model, we assess the market-clearing price implied by unrestrained growth in supply at the 81st percentile of the cost curve in 2015, and the 75th percentile of the cost curve in 2020, resulting in nominal FOB Newcastle benchmark prices of \$90/t and \$86/t, respectively, which is equivalent to \$85/t and \$73/t in 2013 real terms.

Risks

In bringing together the various building blocks of regional analysis which form the foundation of the supply-demand market balance, we recognise that developing forecasts involves numerous uncertainties. With this in mind, we highlight the risks to our view in this section.

The most significant short-term risk is that Chinese net imports do not level off as soon as we forecast, given delays in formulating and implementing environmental policy to reduce air pollution. In the longer term, there exists the possibility that Chinese policy revisions include measures which raise the cost of domestic coal relative to imported coal through taxes, and that these measures outweigh the effect of broader measures such as a carbon tax or overall consumption cap which would tend to reduce import demand. Under this scenario, Chinese net imports could continue to rise substantially despite domestic infrastructure improvements in transporting coal and coal products from Xinjiang and Inner Mongolia.

In Europe, the risk of a failure to meaningfully reform the EU Emissions Trading System to more effectively modulate supply in response to shifting economic conditions could mean that coal consumption is not reduced to the degree that we expect beyond 2016, and therefore presents a risk to the upside. In India, the possibility exists that a more rapid resolution to the debate around pricing of imported coal, an improvement in the financial condition of SEBs and higher power tariffs or more widespread fuel pass-through arrangements could raise the appetite for imported coal substantially.

In all cases, unplanned outages from all causes are not accounted for in the modeling. Specifically, disruptions of production from strikes, environmental injunctions and flooding are not taken into account in the model. The model represents a best-case scenario for supply given the underlying assumptions on depletion of existing production and the delivery of new projects and expansions. Therefore we note major unscheduled maintenance as an upside risk, although the magnitude of such a disruption would have to be quite large to make a difference to modeled annual surpluses.

Technologically, the risk exists that clean coal technology in the form of carbon capture and storage (CCS) could be economically deployed in a widespread fashion, thereby eliminating the need to reduce coal consumption to reach carbon intensity and carbon emissions targets. However, as of 2010, the US EPA estimated that the incremental cost of CCS in a new coal-fired plant ranges from \$60 to \$95 per tonne of CO₂ avoided. Assuming a typical carbon intensity of 0.9 tonnes CO₂/MWh, this means that CCS technology would raise the cost of generating power from the highest-cost coal-fired generation by 60% to 153% (power generated from Appalachian Basin coal including transport cost to the Southeast US has averaged \$37.6/MWh since 2008).



Figure 127: Global marginal costs by year in real and nominal terms (\$/t)

	Global FOB cash cost (\$/t, 85th percentile, 2013 real terms)	Global FOB cash cost (nominal \$/t, 85th percentile, 2.5% inflation)	Global FOB cash cost (nominal \$/t, 85th percentile, 3.5% inflation)	FOB Newcastle benchmark forecast (\$/t)	Total production represented in cost curve (mt)	85th percentile of global FOB cash cost curve (mt)
2006	51.73	51.73	51.73	48.9	477.6	405.8
2007	59.64	59.64	59.64	66.9	485.2	412.4
2008	71.46	71.46	71.46	129.0	507.4	430.1
2009	71.37	71.37	71.37	71.7	506.6	430.3
2010	82.38	82.38	82.38	99.0	533.1	451.6
2011	97.27	97.27	97.27	120.5	570.3	483.2
2012	96.45	96.45	96.45	94.3	624.9	530.4
2013	88.13	88.13	88.13	93.7	676	571
2014	88.55	90.8	91.6	100.0	712.8	604.2
2015	88.11	92.6	94.4	95.0	757.1	636.8
2016	87.32	94.0	96.8	96.5	819.8	696.8
2017	85.6	94.5	98.2	98.0	876.5	728.7
2018	86.39	97.7	102.6	99.5	920.3	779
2019	85.76	99.5	105.4	101.0	970.4	818.7
2020	86.28	102.6	109.8	101.0	1014.3	862

Source: AME, Wood Mackenzie, Deutsche Bank

From a foreign exchange point of view, our currency strategists believe that the US dollar is on the verge of a multi-year upswing through 2015 which will pressure AUD/USD, and thereby reduce production costs for Australian coal from the perspective of the USD-denominated thermal coal market. To the extent that Australian coal is a marginal, price-setting ton of coal in the international market, weakness in the Australian dollar may be a downside risk for coal prices in the medium term.

Finally, despite the accumulation of scientific evidence that global temperatures are indeed rising, that human activity is at least in part a cause of this warming, and even recent findings that the warming effect of soot is higher than previously estimated, the urgency of the global policy response to the risks posed by rising greenhouse-gas emissions has stalled over the last three years owing to the impact of ongoing macro-economic problems across the industrialized world (especially high levels of indebtedness and low or negative growth), and hence to the policy imperative of dealing with these ahead of other policy challenges.

As a result, if the macro-economic problems of the industrialized world continue to impinge upon policy momentum on climate change beyond 2015, then it is possible that the move away from coal towards other forms of power generation might be slower than we are assuming in our base-case scenario, and hence that demand for coal out to 2020 might be higher than indicated in our base case.

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Figure 128: Global seaborne supply potential versus import demand by region (million tonnes)*

	2010	2011	2012	2013e	2014e	2015e	2016e	2017e	2018e	2019e	2020e
Indonesian exports	291	323	347	371	393	417	429	442	455	469	483
growth	24%	11%	7%	7%	6%	6%	3%	3%	3%	3%	3%
Australian exports	142	148	171	182	197	208	214	230	241	253	265
growth	2%	4%	15%	6%	8%	6%	3%	7%	5%	5%	5%
Russia exports	75	86	97	100	103	106	108	110	113	115	117
growth	-3%	15%	13%	3%	3%	3%	2%	2%	2%	2%	2%
South African exports	71	69	76	76	77	79	81	81	82	83	84
growth	5%	0%	6%	0%	2%	2%	2%	1%	1%	1%	1%
Colombian exports	69	76	79	83	85	87	89	91	93	95	97
growth	9%	10%	4%	5%	2%	2%	2%	2%	2%	2%	2%
US exports excl. Canada & Mexico	15	30	46	35	30	25	25	25	25	25	25
China exports	18	11	8	10	10	10	10	10	10	10	10
Other exports	119	142	178	180	182	183	185	187	189	191	193
Total seaborne supply potential (Mt)	799	886	1,002	1,037	1,077	1,116	1,142	1,177	1,209	1,241	1,274
growth	9%	11%	13%	3%	4%	4%	2%	3%	3%	3%	3%
Japanese imports	131	126	139	143	146	148	150	152	154	157	159
growth	12%	-4%	10%	3%	2%	1%	1%	1%	1%	1%	1%
Korea & Taiwan imports	163	174	170	173	176	179	183	186	189	192	196
growth	11%	6%	-2%	2%	2%	2%	2%	2%	2%	2%	2%
European imports	187	209	221	220	220	211	201	197	179	160	164
growth	-5%	12%	6%	-1%	0%	-4%	-5%	-2%	-9%	-10%	3%
China imports	137	178	235	230	220	200	195	195	195	195	195
growth	40%	29%	32%	-2%	-4%	-9%	-3%	0%	0%	0%	0%
India imports	75	92	119	122	127	134	142	150	162	175	189
growth	25%	23%	29%	3%	4%	6%	6%	6%	8%	8%	8%
Other imports	131	144	143	144	146	148	150	152	154	156	158
Total seaborne thermal demand (Mt)	825	922	1,027	1,032	1,036	1,020	1,020	1,032	1,033	1,035	1,061
Growth	11%	12%	11%	0%	0%	-1%	0%	1%	0%	0%	3%
Notional market balance	-26	-36	-26	5	41	95	121	145	176	206	213
Price forecasts (\$/t)											
Japan contract	91	122	119	101	100	97	98	99	100	101	101
API 4 (FOB Richard's Bay)	91	116	93	89	97	93	95	97	99	101	101
Newcastle FOB	99	121	94	94	100	95	97	98	100	101	101

All other units in million tonnes

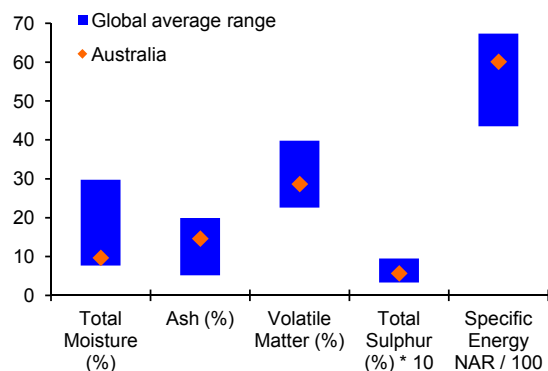
Source: Deutsche Bank

*including Anthracite, Bituminous, Sub-bituminous, and Lignite

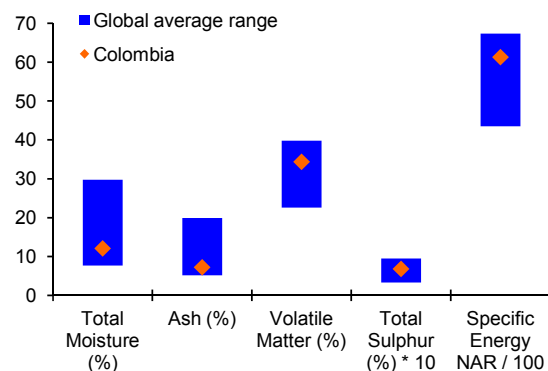


Figure 129: Coal quality by regional weighted average

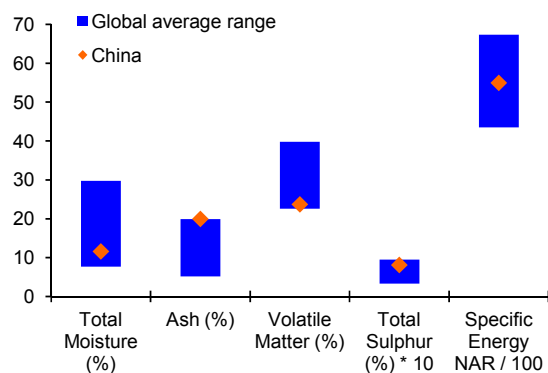
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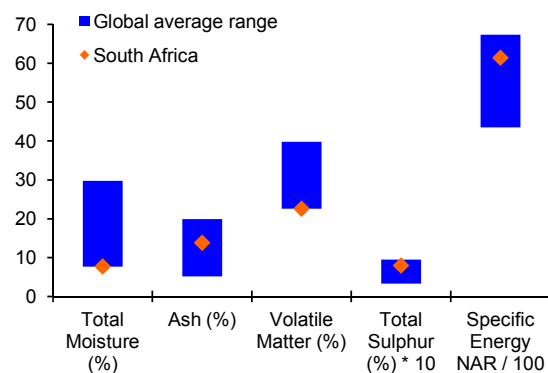
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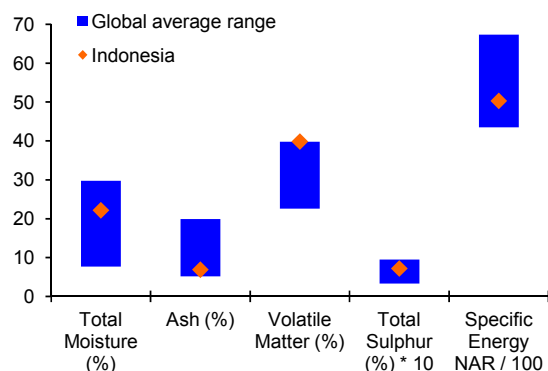
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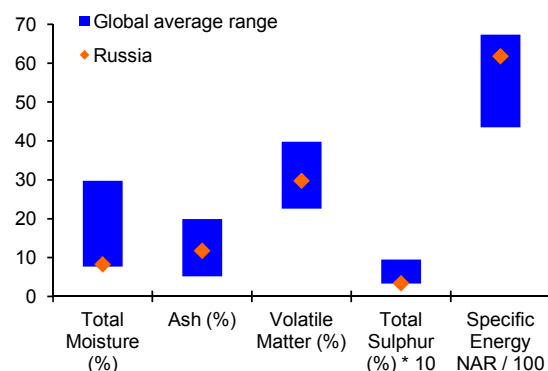
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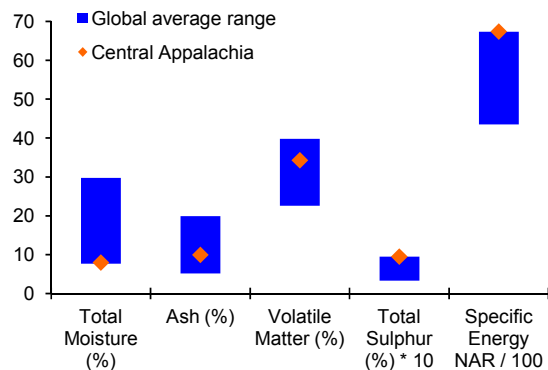
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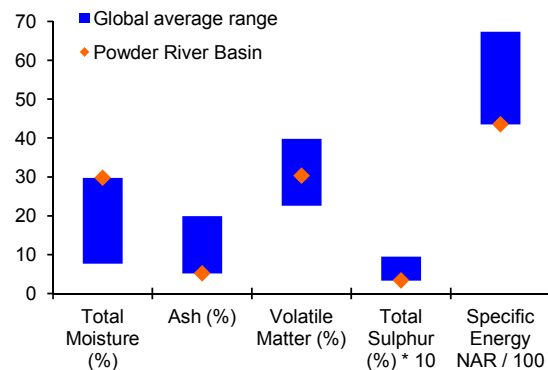
Russia



Central Appalachia



Powder River Basin

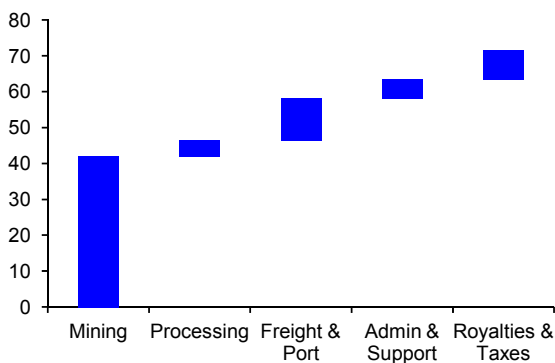


Source: AME, Deutsche Bank

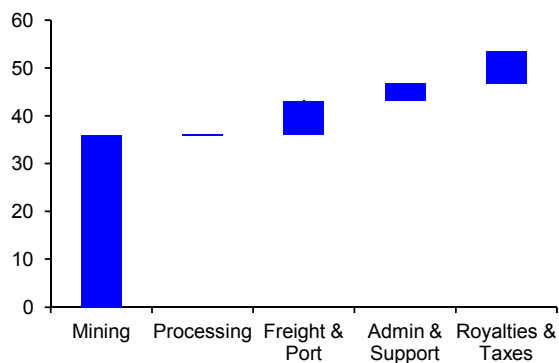


Figure 130: Export FOB weighted average cost structure by region

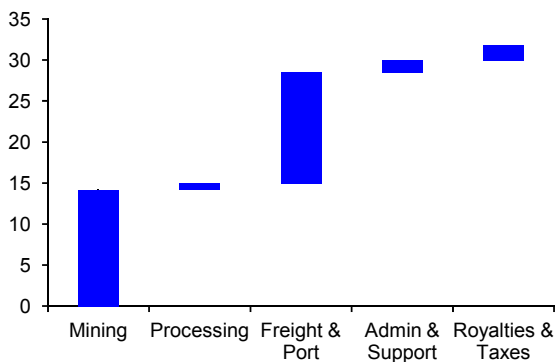
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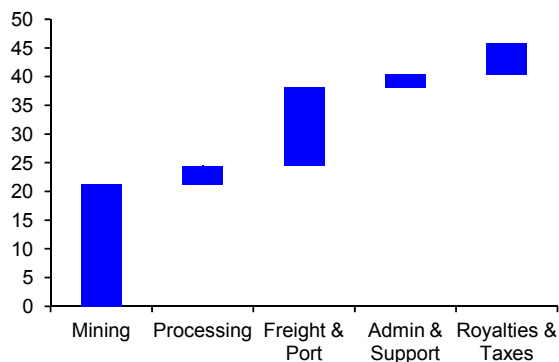
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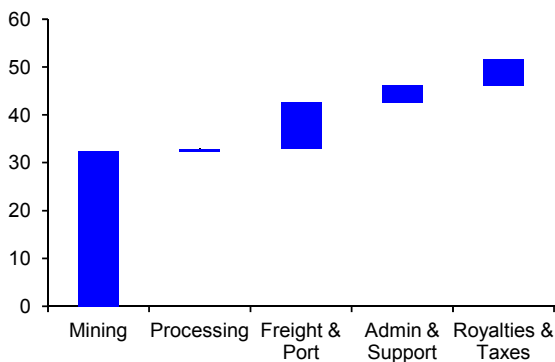
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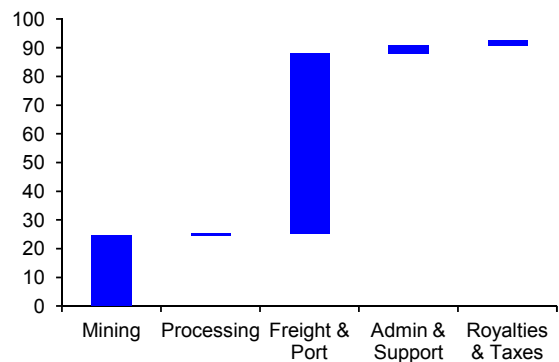
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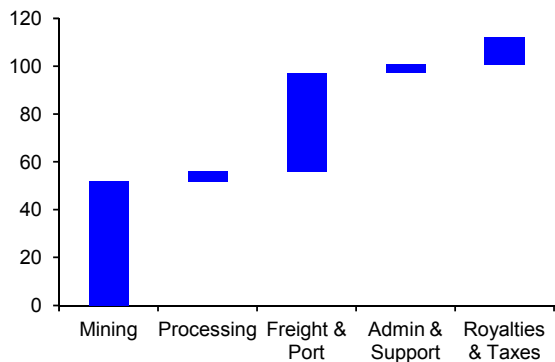
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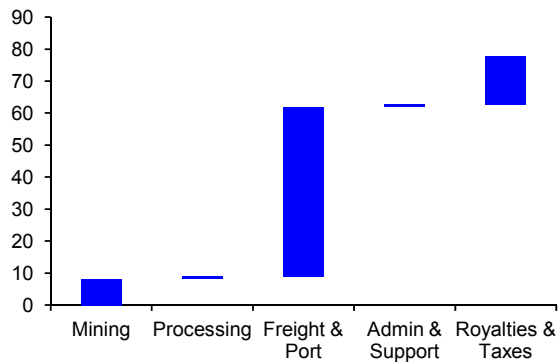
Russia



Central Appalachia



Powder River Basin

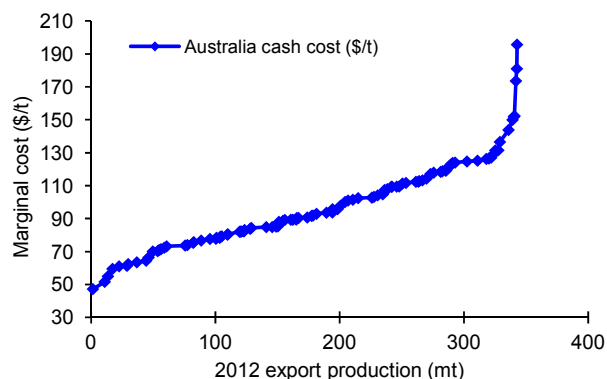


Source: AME, Wood Mackenzie, Deutsche Bank

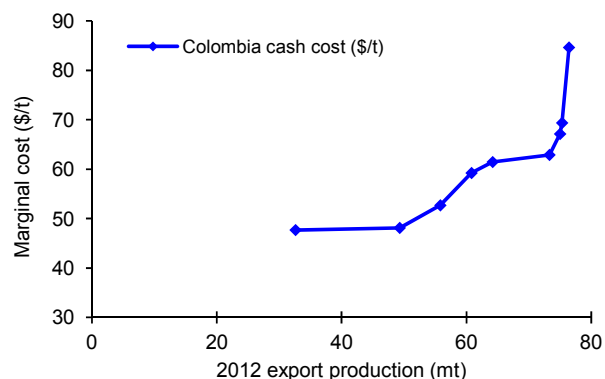


Figure 131: Marginal FOB energy-adjusted cost curves by region

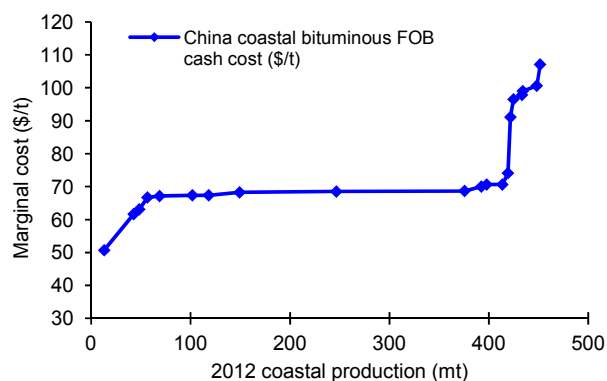
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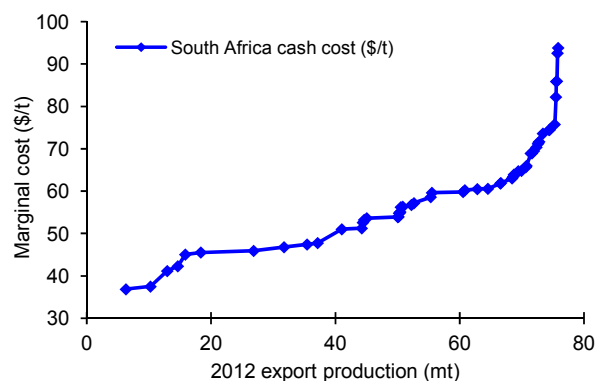
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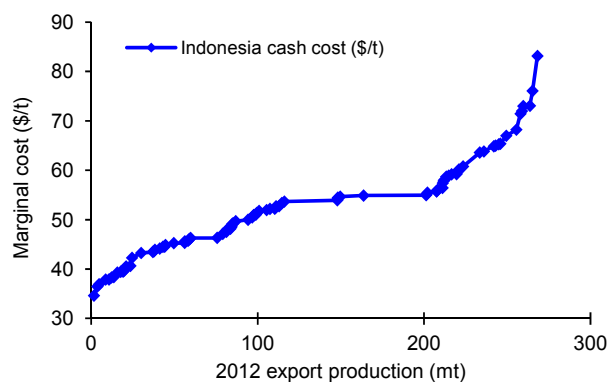
China coastal bituminous



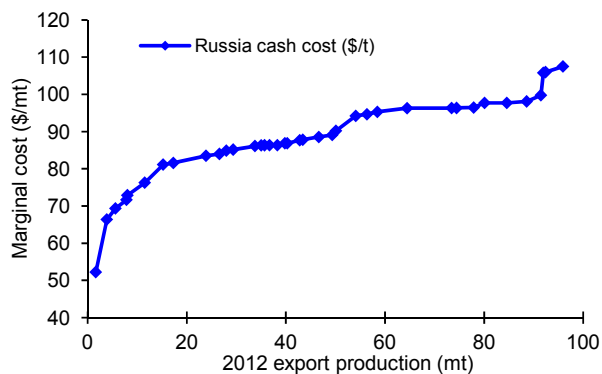
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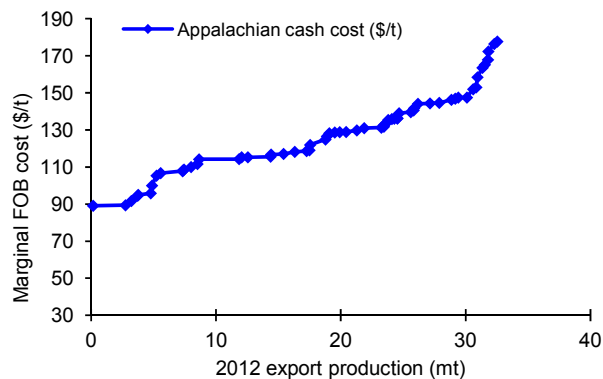
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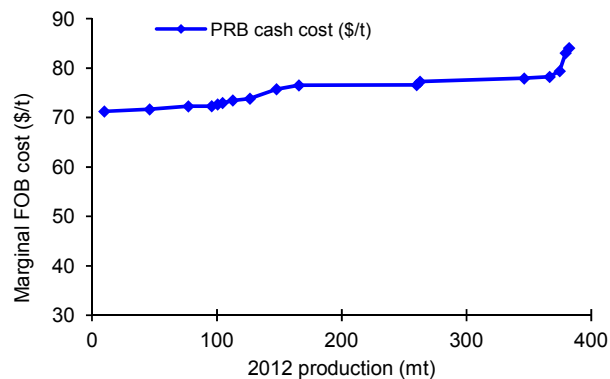
Russia



Central Appalachia



Powder River Basin

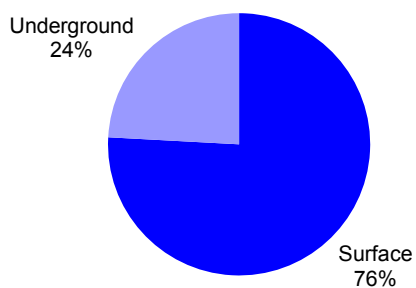


Source: AME, Wood Mackenzie, Deutsche Bank

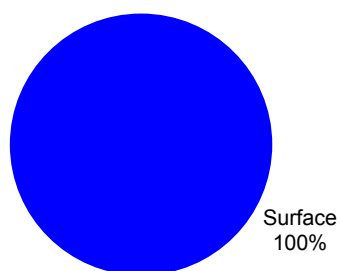


Figure 132: Mining type by region

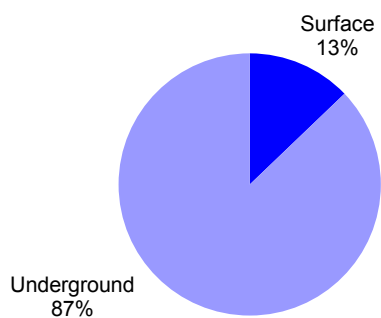
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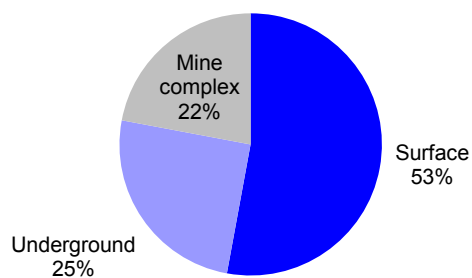
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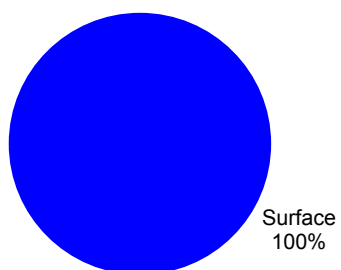
China



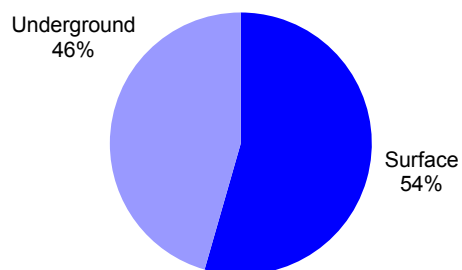
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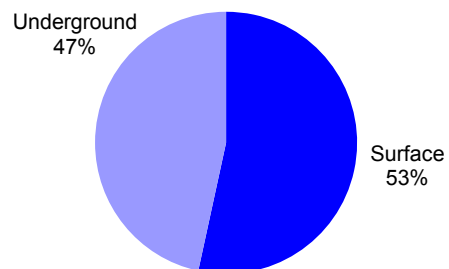
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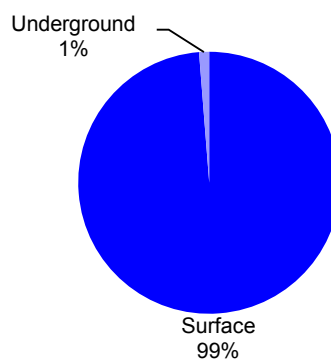
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Central Appalachia



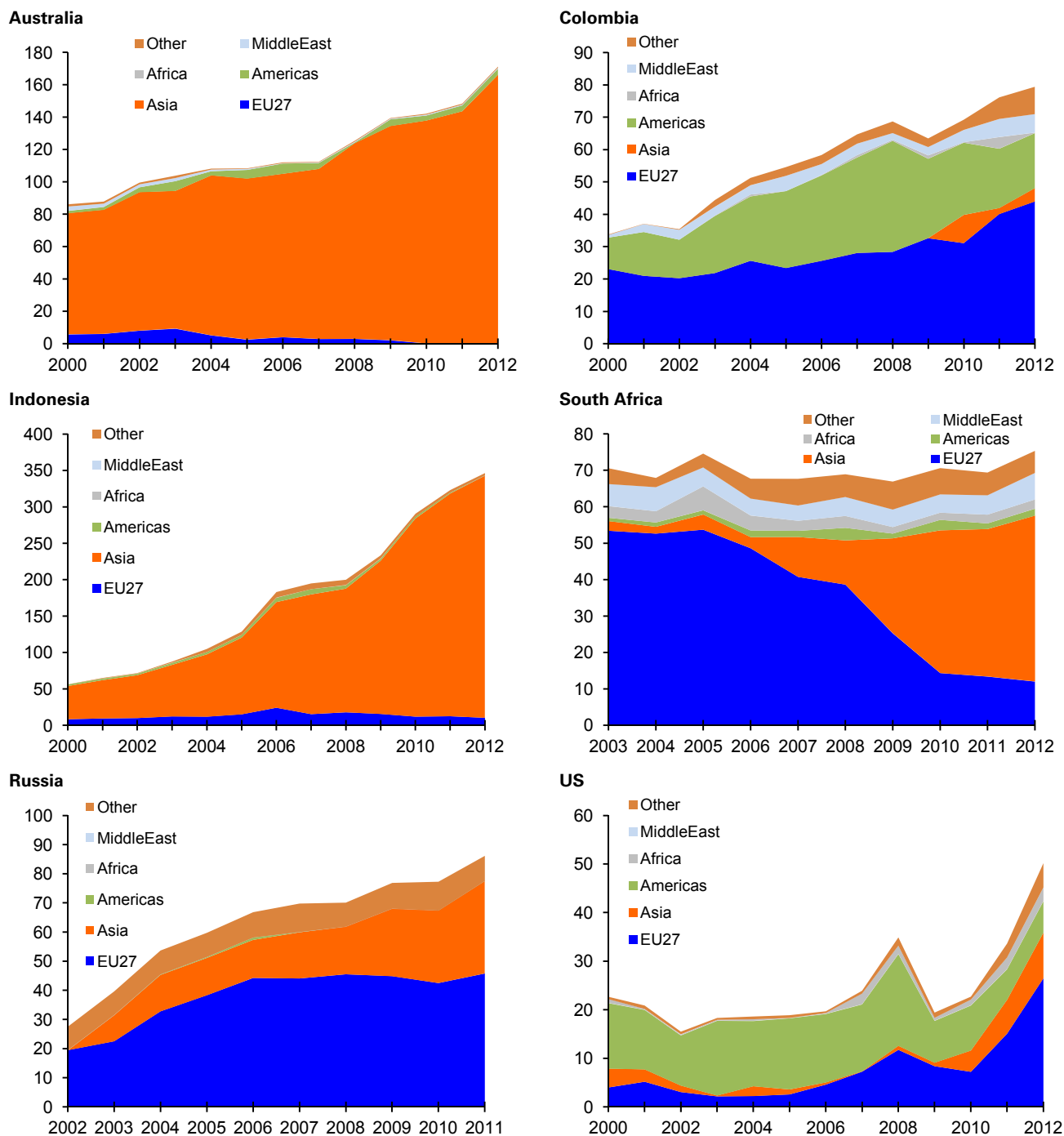
Powder River Basin



Source: AME, Wood Mackenzie, Deutsche Bank



Figure 133: Regional exports by destination country



Source: AME, Wood Mackenzie, Deutsche Bank



Appendix 1

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Footnote 19

Asian Coal & Power: Less, Less, Less... The Beginning of the End of Coal

JUNE 2013

Political, social and economic pressures add up to one simple outcome for China's favorite fuel

All industrialized societies eventually decide that, while cheap sneakers are nice, the environmental damage caused by uncontrolled industrial activity is no longer tolerable; China — at least coastal China — is today at that point; coal is the biggest loser from this development

Decelerating power demand growth and structural weakness in other end markets, combined with more hydro, nuclear and renewables and more coal production and rail capacity in China, add up to the once unthinkable: zero net imports in 2015 and falling Chinese demand by 2016

Globally, Chinese demand growth for coal has been the primary driver or the backstop behind every new investment in coal mining over the last decade; the "global coal market" ended with the collapse in price in 2012; regional miners will see almost zero demand in China from 2015

Once Chinese coal demand starts to fall, there is no robust growth market for seaborne thermal coal anywhere; developed market demand is weak due to gas, environmental concerns or industrial activity; that leaves just one large, structural growth market for seaborne coal: India

Portfolio Manager's Summary

For a decade or more, it has been an article of faith among resource and energy investors that China's addiction to ever more coal was an unending source of...well, pollution and carbon emissions obviously...but also extraordinary returns from investing in coal mines just about anywhere in the world.

But betting that the fast-moving laggard (in this case, Chinese industrialization and power demand) will eventually catch up has a natural limit: eventually, it does. China now consumes as much power as Poland on a per capita basis but is half as wealthy (again, on a per capita basis). Coastal provinces consume power at the same levels — on a per capita basis — as western European countries. The model of the energy-intensive North Asian tiger cannot apply for all of China. Jiangsu may become South Korea in terms of energy intensity, but the entire country will not. Global demand is simply not big enough for China to export its energy consumption in the form of finished goods, the way Korea does. Power consumption growth will now continue to moderate. And with it coal demand.

By our estimates, China will cease to import coal in 2015 and will see a decline in coal consumption in absolute terms in 2016 as hydro, nuclear, renewables and gas-fired generation take market share in the power sector; steel, cement and fertilizer demand growth will continue to moderate; and other uses for coal in China (municipal boilers used for winter heating and factory furnaces, for example) will decline. We expect that China will start aggressively decommissioning coal-fired power stations and replacing them with nuclear or renewables by the second half of this decade.

The economics of this energy evolution are not compelling. Coal prices have now fallen permanently. Nuclear and hydro are cheaper than coal-fired power generation in China, but gas, wind and solar are far more expensive. What we are witnessing is not simply driven by economics: China is transitioning through the same environmental and public health crisis that has seen every industrialized nation take steps to constrain its use of coal in the interest of something other than short-term economic growth.

None of this means that China turns into Iceland by the end of the decade, using non-fossil fuel sources for almost 100% of power generation. Nor will China turn into Northern California, with services — not industry — dominating the economy. China will remain the largest consumer of coal globally, by many multiples, for decades. But the change we are observing does mean that the growth story for coal consumption in China is over. And valuations for the Chinese coal stocks — and coal stocks everywhere — will reflect a sector in terminal decline.

The Chinese coal miners are now entering the end of a period that began in 2008 when small-scale, high-cost coal mines were forced out of business first by government edict and then by large-scale, low-cost miners expanding production. This development has resulted in a flat coal price for the last year that is likely to continue through 2015, at least. All the while, the miners will see a squeeze on gross margins as the cost curve both rises and flattens. From 2015, the large-scale miners will take over the entire industry, pushing out imports, and raising, for the first time since 2008, the possibility of Chinese coal net exports.

To state the obvious, terminal decline is bad news for coal miners. It is a mixed blessing for the power sector, which benefits from flat coal prices...but has to build and pay for what comes next — a lot of gas-fired generation and renewables.

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June 17, 2013

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Exhibit 1 Financial Overview						
Company	China Shenhua	Yanzhou Coal	China Coal Energy	China Longyuan	Datang Renewable	Huaneng Renewables
Ticker	1088.HK	1171.HK (NYSE: YZC)	1898.HK	916.HK	1798.HK	958.HK
Share Price as of 14-June-2013 (HKD)	23.35	6.78	4.61	7.89	1.86	2.75
52-Week High (HKD)	35.45	14.48	9.04	8.32	2.07	3.02
52-Week Low (HKD)	23.25	6.63	4.57	4.60	0.71	0.87
Rating	Underperform	Underperform	Underperform	Outperform	Market-Perform	Outperform
Target Price (HKD)	20.00	5.00 (ADR: 6.50)	3.00	11.00	1.60	4.00
Market Cap (USD M)	61,674	7,779	11,559	8,227	1,746	2,993
Enterprise Value (USD M)	70,270	14,657	18,617	17,883	8,052	7,532
6M Avg Daily Trad. Volume (USD M)	68.2	37.9	26.4	18.5	3.2	7.0
EPS (RMB)						
2011	2.30	1.76	0.71	0.35	0.10	0.14
2012	2.46	0.73	0.68	0.35	0.02	0.07
2013E	1.99	0.51	0.39	0.48	0.04	0.14
2014E	1.95	0.38	0.19	0.68	0.08	0.20
2015E	1.91	0.14	0.01	0.86	0.12	0.29
EPS Growth						
2011-2012	6.6%	-58.6%	-4.5%	0.3%	-84.7%	-53.0%
2012-2013E	-19.0%	-30.4%	-42.4%	39.7%	145.7%	108.0%
2013E-2014E	-1.8%	-24.4%	-52.2%	39.6%	106.1%	46.3%
2014E-2015E	-2.4%	-63.5%	-94.1%	26.8%	58.0%	43.4%
P/E						
2012	7.5	7.3	5.4	18.0	95.3	32.9
2013E	9.3	10.5	9.3	12.9	38.8	15.8
2014E	9.4	13.9	19.5	9.2	18.8	10.8
2015E	9.7	38.2	331.7	7.3	11.9	7.5
Metrics						
Total Debt/Total Assets (2012)	14.8%	30.9%	26.2%	54.4%	67.7%	61.3%
EBITDA/Net Interest Expense (2012)	41.7x	20.8x	66.5x	3.9x	2.1x	2.5x
Capital Intensity (2012)	20.2%	15.2%	40.5%	69.0%	123.4%	121.0%
FCFE Yield	5.0%	-3.9%	-47.4%	-26.8%	-52.1%	-17.4%
Dividend Yield	5.2%	6.7%	5.8%	1.0%	1.6%	0.7%
Return on Invested Capital (2012)	23.6%	9.1%	12.7%	5.4%	3.5%	4.4%
Return on Equity (2012)	19.1%	8.1%	9.9%	10.0%	1.6%	4.8%
Main Business Segments	Thermal coal, power, railway, port and shipping	Thermal and coking coal (China and Australia), railway, coal chemicals, power and heat	Thermal and coking coal, coke and coal-chemical, coal mining equipment	Power, steam, equipment and coal	Power	Power
Other Income as % of Total Income	0.2%	4.3%	0.9%	7.7%	5.9%	4.5%
2012 Commercial Coal Prod. (M tons)	304.0	61.9	114.4			
– Foreign %	0.7%	27.7%	0.0%			
– Coking Coal %	0.0%	11.3%	0.7%			
Domestic Unit Prod. Cost (2012, RMB/ton)	130.2	309.9	223.0			
Domestic Coal ASP (2012, RMB/ton)	426.2	600.4	477.4			
Coal Mine Locations	Shaanxi, Inner Mongolia and Indonesia; Australia (under development)	Shandong, Inner Mongolia and Shaanxi, Shanxi; Australia	Shanxi, Jiangsu, Shaanxi			
Average Utilization Hours				1,985	1,752	1,774
Average Wind Tariff (RMB/MWh)				497.8	515.6	516.9

Note: The stocks are benchmarked against the MSCI Asia Pacific Ex Japan and S&P 500 indexes, which had closing prices of 440.07 and 1626.73, respectively, on June 14, 2013.

Source: Bloomberg L.P., corporate reports and Bernstein estimates and analysis.

Significant Research Conclusions

In the summer of 2007, everyone knew that Roger Federer was the greatest tennis player of all time, that Tiger Woods was a shoe-in to win the most Majors ever, and that Lance Armstrong was the greatest cyclist of all time. More parochially, everyone knew that Tom Brady was the greatest quarterback ever, that Alex Rodriguez was destined to break the career home run record and expunge the shame of baseball's steroids era, and that Dan Carter was perhaps the greatest All Black ever.

Six years later, Federer is likely to retire with a losing record against two of his contemporaries. Tiger Woods has been within striking distance during the last round of a Major just once in five years. Tom Brady has a losing record when it counts against the third-best quarterback in the Manning family. Rodriguez has admitted to doping. Lance Armstrong. And finally (this one truly pains me), Dan Carter has a "knock-out" record in Rugby World Cups of one win out of a possible nine.

In short, in every walk of life, six years is a long time. And, at any given time, we know a lot less than we think.

In the summer of 2007, everyone also knew that Chinese demand for commodities in general and energy in particular was limitless. Twenty million people were urbanizing each year and would continue to do so for another two decades. The world — or at least the mining sector as configured at the time — was not large enough to support Chinese demand. Globally, Chinese demand growth for coal was and has remained the primary driver or the backstop behind every new investment in coal mining anywhere. Even as recently as 2011, the dip in demand caused by the global financial crisis had apparently been shrugged off and demand growth was back to the "normal" level: double digits.

Over the course of 2012 and this year, demand growth for coal has decelerated. Views on the short- and medium-term rates of Chinese growth have come down on a variety of fronts...coal, power, steel, aluminum, cement, and the economy in general. The Chinese government is now taking active steps to reduce coal consumption on the east coast.

But — in the same way that there are still plenty of people around who will defend the 2007 consensus assessments of Federer, Woods, Armstrong, Brady, Rodriguez and Carter — the idea that China's deceleration in commodity consumption growth might be permanent and that it might eventually lead to a reduction in coal demand in absolute terms is still a long way from consensus, in our view. Opinions, once formed, change slowly.

The "short coal" trade has still not turned into a recognition that the last, best structural demand story for coal globally is now over. And with it, "short coal" isn't a trade; it's a permanent state of affairs, in our view. Coal demand in China is about to start falling, and — with India and Indonesia the only remaining structural growth markets for coal — the global thermal coal market will never recover.

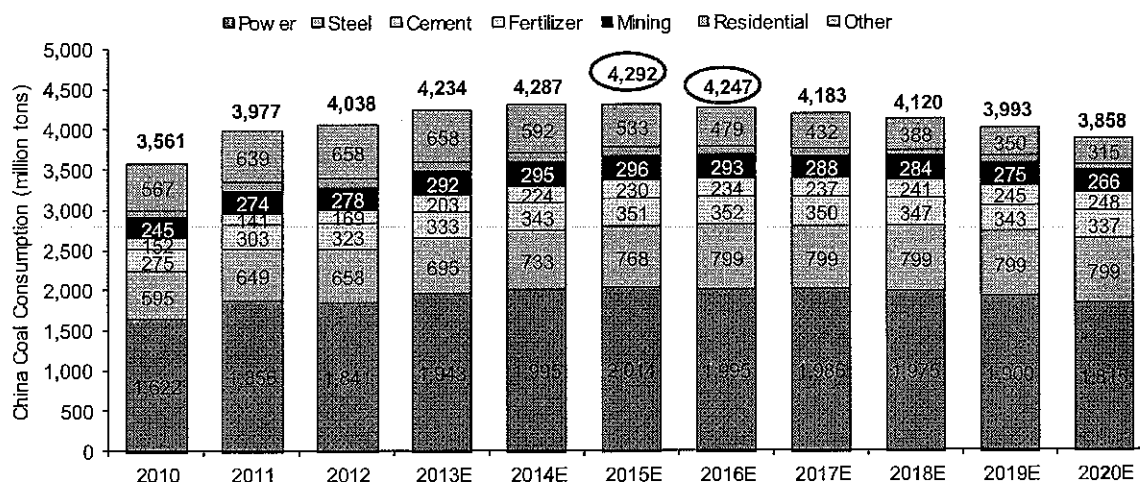
To complete the parallel, Roger keeps on losing to a lefty *and* a righty...but we can't quite bring ourselves to acknowledge that the 2007 assessment (admittedly reached with a mountain of evidence) might not be right.

Decreasing Chinese Power Intensity and the Rise of the Services Sector

In China, decelerating power demand growth, combined with more gas-fired, nuclear, hydro, renewables and nuclear generation, and decelerating or falling demand in other coal end markets (steel, cement, fertilizer, industrial usage), give rise to an outcome that is mathematically obvious but still difficult to say or write: 2015 is going to be the peak year for Chinese coal consumption *ever*.

Exhibit 2

China Coal Consumption by Sector (2010-20E)



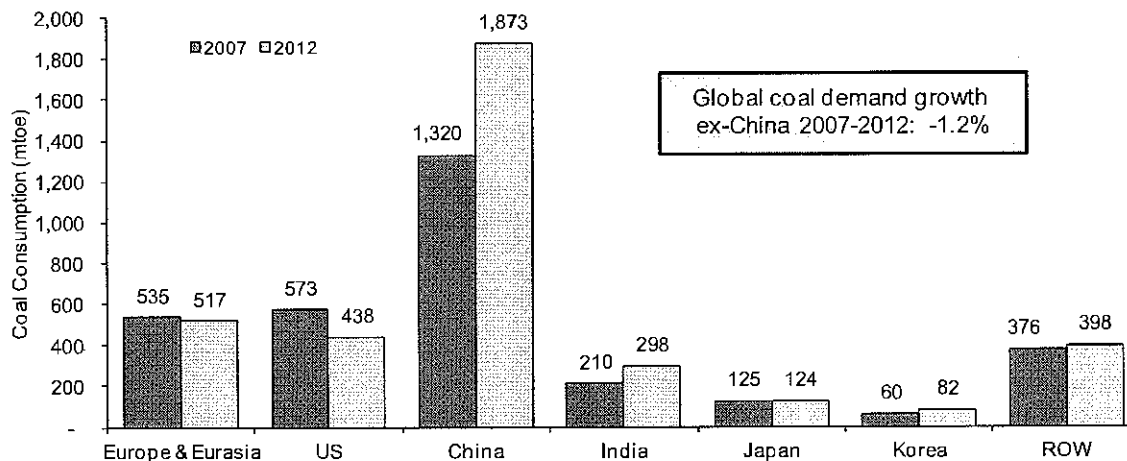
Source: CEIC and Bernstein estimates and analysis.

From 2016, Chinese coal demand will fall in absolute terms, and that trend will never (business cycle fluctuations aside) reverse (see Exhibit 2). There are five primary drivers of falling imports in 2015 and falling coal consumption in absolute terms that we forecast by 2016: (i) continuing investment in coal mining and transportation infrastructure; (ii) decreasing Chinese power intensity; (iii) increasing power generation capacity from nuclear, gas, hydro and renewables; (iv) falling demand growth for steel, cement and fertilizer, and the demise of the "inferior" end markets for coal; and (v) the emergence of the environment as a politically sensitive issue in China and the need to improve air quality...quickly. We discuss each briefly below and in detail later in this *Blackbook*.

More broadly, the implications settle on two key themes. First, publicly traded Chinese coal miners have enjoyed the economic rents associated with being some of the few entities with access to both low-cost coal and transport capacity on China's previously stretched rail network. Without those structural advantages and facing a negative terminal growth and poor capital discipline, the warranted multiples will continue to contract.

Exhibit 3

Global Coal Consumption (2007 vs. 2012)



Source: BP Energy Survey 2013 and Bernstein analysis.

Second, China has been almost 100% of global coal consumption growth over the last decade. Global coal demand growth ex-China was -1.2% from 2007 through 2012. As Chinese consumption begins to fall (mirroring the trend in the U.S. and Europe), the global market will enter a period of terminal decline (see Exhibit 3).

(i) Continuing Investment in Coal Mining and Transportation Infrastructure and a Resulting Flattening of Costs

We expect that by 2015, the investment in large-scale, highly mechanized coal mines and coal-dedicated rail transport throughout China's coal producing regions will be complete. The frictions to move coal to market will have been removed.

The top 55 Chinese coal miners produced ~2.9 billion tons of coal in 2012, ~8% higher than the top 55 miners produced in 2011 (~2.7 billion tons). This group accounted for ~73% of total coal production in 2012. With further consolidation in the industry, we believe the sector will continue to shift towards larger-scale and lower-cost miners. This will squeeze the high-cost coal miners on the right-hand side of the cost curve out of the market. We believe this group of 55-60 miners will continue to take share in coming years and we expect these miners to be over 90% of the industry by the end of 2015.

(ii) Decreasing Chinese Power Intensity and the Rise of the Service Sector

The various edicts that the Chinese government has issued in recent years about reducing energy intensity and not sacrificing the environment for economic growth are aided by one important fact. The change that the Chinese government is attempting to orchestrate is happening organically regardless of policy.

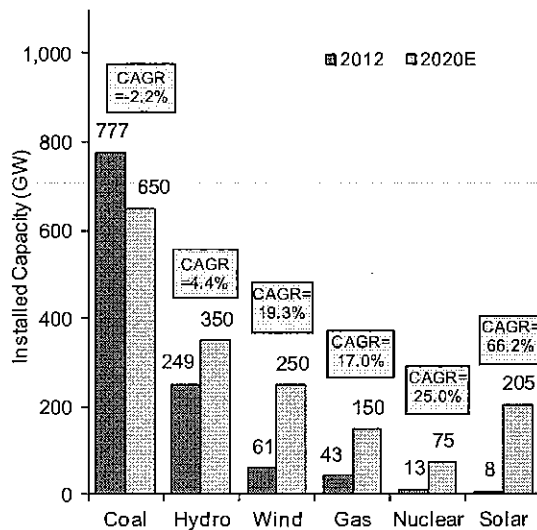
Over the past decade, China's economic growth has been shifting towards the less energy-intensive services sector. The services sector's share of GDP increased to 44.6% in 2012 from 39% in 2000, while the industrial sector's share of GDP has trended down slightly since the middle of the last decade. The industrial sector in China is roughly 6x more power intensive than the services sector. Therefore, a slight share shift away from the industrial sector serves to reduce power production growth significantly.

The falling power multiplier is a reflection that China is shifting away from heavy industries to less energy-intensive sectors to drive future economic growth. Power represents roughly half of Chinese coal consumption. However, the trend throughout the key end markets is largely the same. As with every other economy, as the Chinese economy becomes more developed, it is becoming more energy efficient: the same amount of power production growth is creating more GDP growth. This is consistent with the natural evolution of any economy going through the middle innings of economic development.

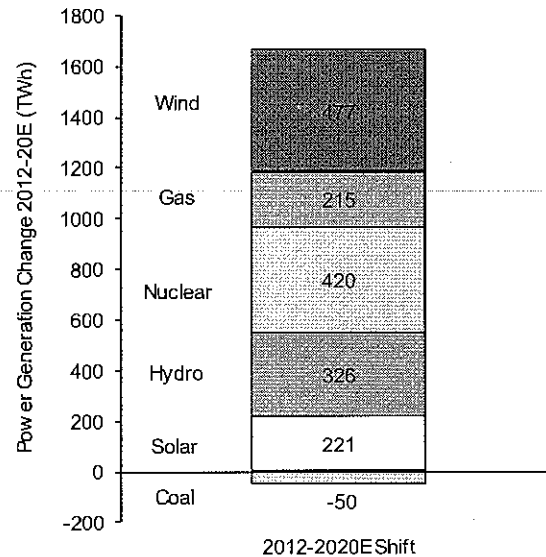
(iii) Increasing Power Generation Capacity from Nuclear, Gas-Fired Power Generation, Hydro and Renewables

We believe that coal-fired power generation capacity will fall from ~800GW of installed capacity today to 650GW by the end of the decade as inefficient, small, old power stations are decommissioned. Hydro will increase from ~250GW to 350GW. Gas will go from ~40GW to 150GW. Nuclear will increase from ~13GW to 75GW. Solar and wind will be 200GW and 250GW by the end of the decade, respectively (see Exhibit 4 and Exhibit 5).

Over this period, power demand will increase by 1,323TWh (up by one-third compared to 2012) and coal-fired generation will decline. With lower power consumption growth and less coal consumption overall — and in an environment of continuing constrained gas supply — renewables will be the source of incremental power supply. Given the long lead times of hydro and nuclear, renewables are the primary means of accelerating the transition away from coal. We think both solar and wind installed capacity could be at least 200GW by decade's end (up from 8.3GW of solar and 61GW of wind today).

Exhibit 4 Installed Capacity by Fuel Source (2012 and 2020E)

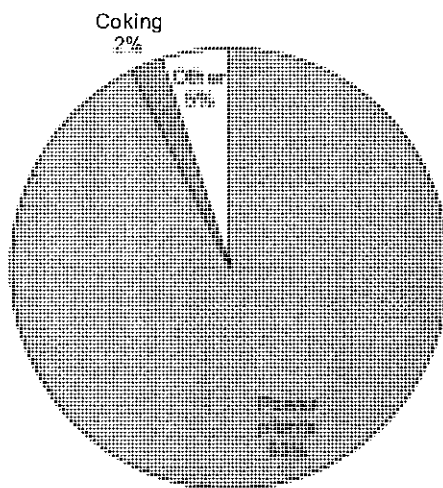
Source: CEIC and Bernstein estimates and analysis.

Exhibit 5 Power Generation Shift by Fuel Source (2012-20E)

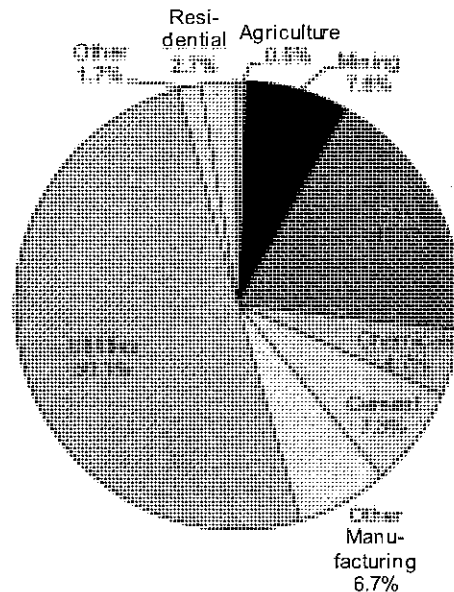
Source: CEIC and Bernstein estimates and analysis.

(iv) Falling Demand Growth for Steel, Cement and Fertilizer, and the Demise of the "Inferior" End Markets for Coal

Within the power sector, generation growth from gas, nuclear, hydro, wind and solar will start crowding out coal-fired power generation growth. The steel, cement and fertilizer sectors account for another ~30% of consumption.

Exhibit 6 U.S. Coal Consumption by End Market (2012)

Source: EIA and Bernstein estimates and analysis.

Exhibit 7 Chinese Coal Consumption by End Market (2011)

Source: CEIC and Bernstein estimates and analysis.

The remainder is mining itself, manufacturing, residential use, agriculture and other. Efforts to curb coal consumption outside of the four key end markets have already begun. The ultimate composition of coal usage is clear too: in developed economies, coal is used in power generation and coke production. And that is it.

Chinese coal consumption in factories, municipal entities burning coal for heat and steam, residential usage, the mining sector itself will see coal usage fall from ~800 million tons today to, eventually, zero — the level of coal consumption by these sectors in the U.S. or Europe (see Exhibit 6 and Exhibit 7). Coal demand growth in the steel, cement and fertilizer sectors will moderate.

(v) The Emergence of the Environment as a Politically Sensitive Issue in China and the Need to Improve Air Quality...Quickly

Rich economies reach an inflection point where the population will no longer stand for the environmental damage that its industrial sector is creating. Political pressure follows together with new requirements for environmental remediation and lowered emissions. That means higher costs for industry, and those costs tend to push the polluting activities elsewhere. The focus of economic activity changes: enter the design studios, advertising agencies and artisan cheese makers.

Perhaps the biggest surprise in China in 2012 was that the country appears to have reached that point. The heightened concern over Beijing air quality over the winter capped off a 12-month period of various street-level protests over air, soil and water quality issues. In July, protests forced the suspension of construction on a copper plant in Chifang in Sichuan. In August, in Qidong in Jiangsu, following street protests, officials announced the cancellation of a paper mill waste-water pipeline that would have fed into local fishing grounds, injecting — according to protesters — various carcinogens into the local food supply. In November, Sinopec scrapped a petrochemical plant project in Ningbo in Zhejiang. These announcements came after local protests, some of which were violent.

And then came Beijing's air quality crisis over the winter, and — perhaps more surprisingly — the government announcement that something would be done about it and various statements subsequently that the environment will not be sacrificed for economic growth.

The protest and the government response seem entirely predictable given China's changing demographics and economy plus its atrocious domestic air and water quality. The surprise is that these events are perhaps a decade ahead of schedule. Six months ago, most observers would have guessed that this rising environmentalism was still a decade away. Suddenly, instead it is shaping Chinese energy policy today.

Any economic planner responsible for setting targets for Chinese power supply over the rest of the decade faces a dilemma in roughly eight parts. The key imperative has been simplified in the first half of 2013: keep the lights on, but make sure the skies in Beijing are clear next winter...and every winter going forward.

First, China needs power...and more of it. The economy is slowing but it hasn't stopped. Power demand growth will continue to increase in coming years as a fraction of GDP growth, rather than as a multiple. But power demand is going to continue to go up nonetheless. Further, expectations about reliability of supply are rising as China gets wealthier and a greater share of the economy is dedicated to services. A more sophisticated economy requires higher reserve margins (the percentage of the fleet that is idle but available for dispatch at the moment of peak demand) in order to increase reliability of supply and reduce power cuts throughout the country.

Second, the cheapest and easiest source of power supply in China is coal-fired power stations. China has spent a decade building a modern fleet of coal-fired power stations, and today there is plenty of low-priced coal available throughout China.

Third, despite the attractive economics of coal-fired power generation, the use of coal in east coast cities is being restricted and will be restricted further in coming years. China — like every industrialized economy — is weighing up the impact of

ever-increasing pollution on its population and is reducing usage. The fact that the simple, short-term economics militate in favor of more coal does not mean that China will use more coal. As economies get richer, the decision making in this regard gets more complex.

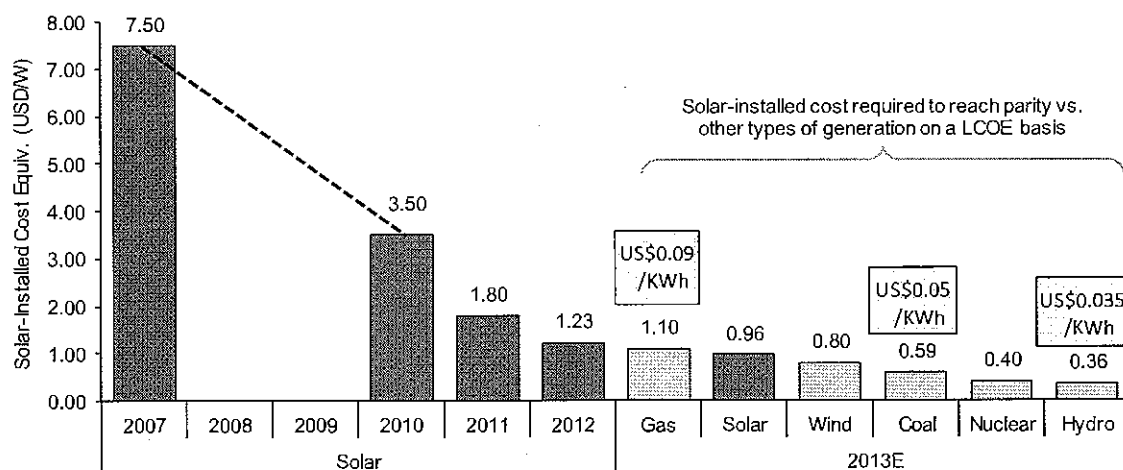
Fourth, China is increasing both domestic gas production and imports. Gas supply to the power sector and gas-fired generation as a share of total generation will increase in coming years. However, gas supply is still constrained and the power sector ranks below residential, commercial, industrial and, potentially, transportation users in terms of priority of supply. If supply to the power sector reaches 70BCM by 2020, it will represent ~5% of total power generation.

Fifth, China continues to expand hydro generation capacity. Total installed capacity at the end of 2012 was ~250GW. However, there are no non-navigable, large, fast-flowing rivers in deep, uninhabited valleys left in China. The easy opportunities were dammed years ago. And large-scale projects like the Three Gorges Dam (given its massive environmental impact and population displacement) are not going to be repeated. That leaves smaller dams. We believe that China will add 100GW of hydro over the rest of the decade. Hydro will remain ~17% of total generation by 2020.

Sixth, nuclear power generation is continuing to ramp up. Installed capacity is currently ~14GW and plans are for China to reach 75GW by the end of the decade. This will mean nuclear capacity will go from less than 3% of total generation to ~10% of total generation. The limiting factor is not technology, ambition, safety concerns or uranium. The constraint to China expanding its nuclear fleet any faster is experienced engineers who can manage these facilities. That is a multi-decade, not a multi-year, development task.

Seventh, wind is currently an under-utilized source of power generation in China. The 61GW of installed capacity operated at a utilization rate of ~19% in 2012. This low utilization rate was a function of an inability or unwillingness from State Grid to dispatch all of the electricity being generated. We believe that the normal level of utilization will (by 2015) be 27%. We believe that State Grid will remain under pressure to connect wind farms and absorb all of the electricity generated.

Exhibit 8 Solar Installed Cost Required to Reach Parity vs. Other Types of Clean Energy Generation on a LCOE Basis



Source: Government announcements, media reports, World Nuclear Association, corporate reports and Bernstein estimates and analysis.

Eighth, solar is a rounding error within the Chinese power portfolio today. However, with installed cost now approaching \$1/W, solar is economic with gas-

fired power generation in China and — on a distributed basis — is economic against on-grid power prices (see Exhibit 8).

Given those constraints and an objective of increasing reliability of supply, improving environmental impacts and controlling cost (probably in that order), we believe that the focus within the power sector will be on (i) completing hydro, gas-fired and nuclear projects on time; (ii) decommissioning old and inefficient coal-fired power stations; and (iii) encouraging renewables to the greatest extent possible. In short, there is simply no room for incremental coal consumption — and the consequential levels of pollution — in any of that.

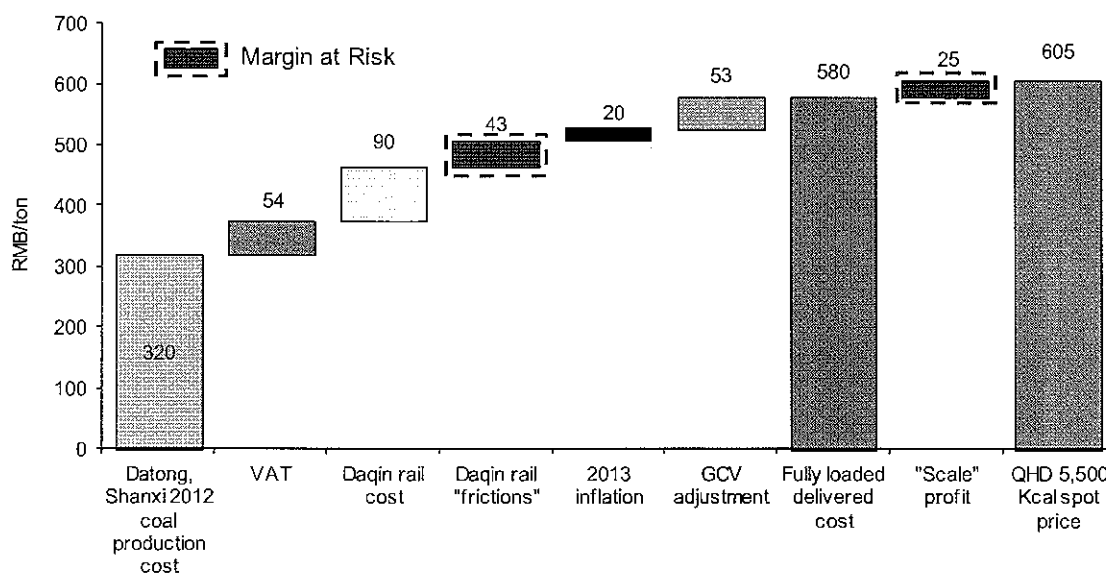
Implications for Coal and Power Stocks

The implications of all this for the Chinese coal miners are terrible. The three Chinese coal miners that we cover — Shenhua, Yanzhou and China Coal Energy — have to a greater or lesser extent enjoyed, since mid-2007, the benefits or an idiosyncratic commodity story: yes, China needed coal like it needed other commodities. But China *has* coal; it just could not get that coal to market.

The Chinese coal miners enjoyed the economic rents that arose from being some of the few entities with access to low-cost mines *and* rail access to get coal to market. That advantage is now fading. We are outlining a future with a negative terminal industry growth rate, flat prices, intensifying competition and ever greater capital and operating expense to mine coal.

We believe that for an increasing share of the large Chinese coal miners, the economics of incremental production to sell into a RMB605/ton coastal coal market are only marginally attractive (see Exhibit 9).

Exhibit 9 Qinhuangdao Coal Price Composition (June 2013)

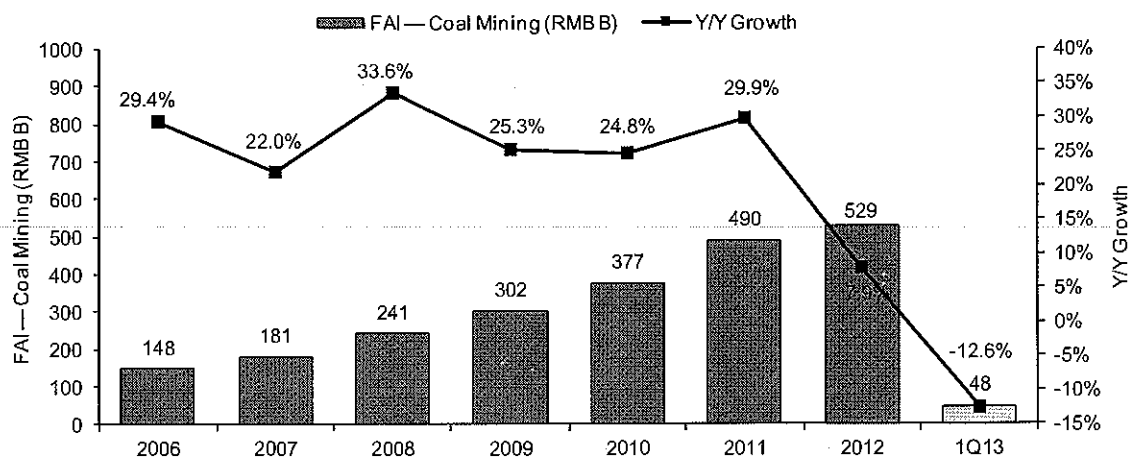


Source: Bloomberg L.P., SX Coal and Bernstein estimates and analysis.

In short, we have reached a flat part of the cost curve where coal price volatility is likely to be low over the long term and coal mining profitability is likely to remain stressed. This stressed group is no longer simply high-cost, small-scale miners with poor access to transport but includes the publicly traded Chinese coal miners too. Coal prices will remain flat, volume growth will be weak and costs will continue to go up. Investment in new coal mining production capacity is now falling (see Exhibit 10). However, the lag between investment and commissioning means that we will see hundreds of millions of tons of new Chinese coal production capacity come on-stream in the next two years.

Exhibit 10

FAI in China Coal Mining Sector (2006-1Q:13)

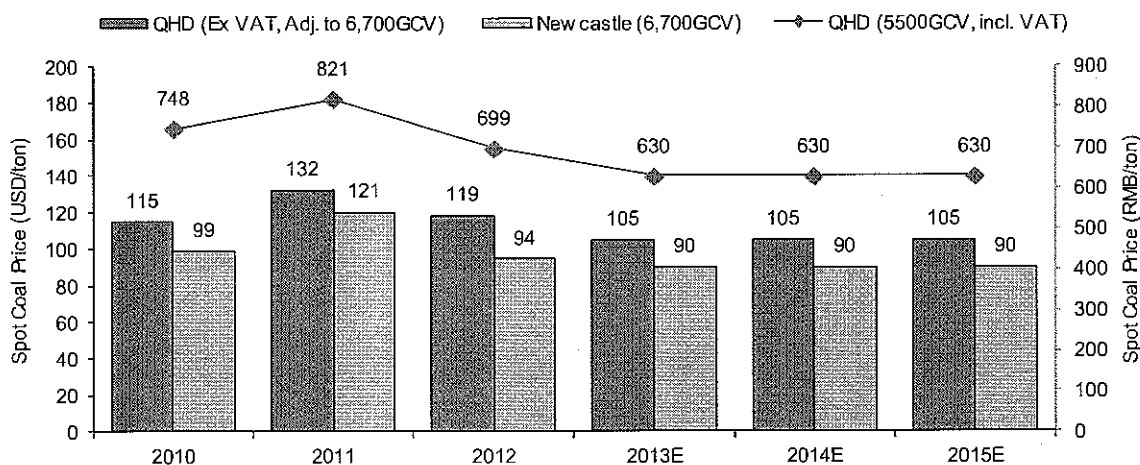


Source: NBS, CEIC and Bernstein analysis.

As costs rise across the industry, so will the cost curve. But the cost curve will also flatten as new capacity from scaled miners comes on-stream. We believe that coal prices will remain roughly flat through 2015 at least (see Exhibit 11).

Exhibit 11

Bernstein Coal Price Forecasts: Qinhuangdao and Newcastle



Note: Figures for 2010-15E are yearly average prices.

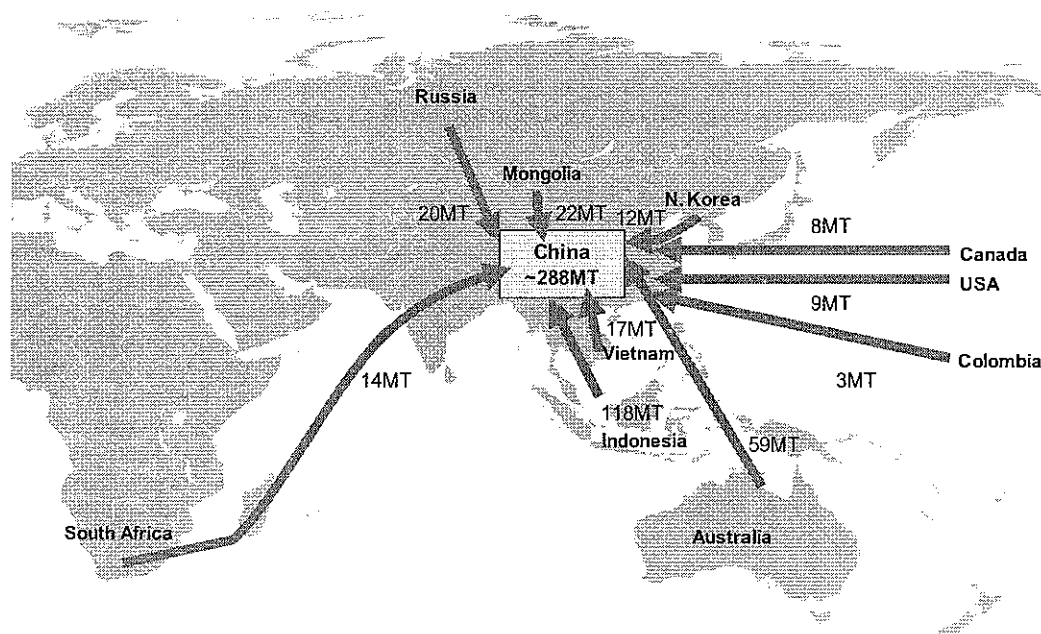
Source: Bloomberg L.P., SX Coal and Bernstein estimates and analysis.

The seaborne market's expansion in the last five years has been largely driven by Australian and Indonesian miners competing against small-scale Chinese coal miners (with high costs and poor access to transport) in serving power stations in coastal China. In short, it hasn't been a fair fight.

And it won't be going forward. China has been the prize of the coal mining sector globally for the last five years. However, now that domestic demand has fallen, large-scale miners with access to much improved transportation will push out the seaborne market...or the government will do it for them by banning ever-higher grades of imported coal. China is going to start giving back almost 300 million tons of coal to the seaborne market annually (almost 30%). The next best option for this market is not good: India (see Exhibit 12).

Exhibit 12

Major Seaborne Coal Exporters Supplying China (2012)



Source: Wikimedia commons, SX Coal, Public Press, EIA, BREE, RBCT and Bernstein estimates and analysis.

For the power sector, counter-intuitively, prospects do not seem that much better. The primary benefit of the falling coal price — cheap coal — is now priced in. From an earnings perspective, the second quarter of 2013 will be the last time that the power companies have easy comparisons against year-ago coal prices. From July, the power companies face a world of flat coal price, flat power pricing...and flat demand growth. At the same time, the power companies now have the primary responsibility to build the gas-fired power stations and renewable power generation capacity that will crowd out coal-fired generation going forward. The capital cycle for the power sector is, as we outline in this *Blackbook*, beginning again.

Valuation Methodology

Chinese Coal Miners: We value China Shenhua at HK\$20.00 per share on a P/E basis by applying a forward multiple of ~8x to our 2014 EPS estimate of RMB1.95. Further, assuming that the company maintains a ~40% dividend payout ratio, a \$20 share price implies a 5% dividend yield, which we believe investors will require given the continuing deteriorating profile of the industry. We value China Coal Energy at HK\$3.00 per share by taking the average of (i) a forward P/E multiple of ~8x to our 2014 EPS estimate of RMB0.19 and (ii) a P/B multiple at the average of the lower quintile of global coal mining peers. We value Yanzhou at HK\$5.00 per share on a P/E basis by taking the average of (i) a forward P/E multiple of ~8x to our 2014 EPS estimate of RMB0.38 and (ii) a P/B multiple at the average of the lower quintile of global coal mining peers. Our valuation for Yanzhou (ticker YZC; the NYSE-listed ADR) multiplies Hong Kong valuation by 10.0 (the number of H-shares each ADR represents) and divides by the HK\$ exchange rate. We believe China Coal Energy and Yanzhou can find some support at these levels. On a DCF basis, we believe that China Coal Energy and Yanzhou stocks are worth zero. However, we do not believe that will be reflected in valuation over the next 12 months.

Chinese Renewable Operators: We value China Longyuan at HKD11.00 by applying an average P/E ratio of ~13x to our 2014 EPS estimate of RMB

0.67/share. The valuation reflects an equity raise in 2013 that the company announced on May 2012. We value Datang Renewable at HKD1.60 by applying an average P/E ratio of ~16x to our 2014 EPS estimate of RMB 0.08/share. Valuation is stretched due to concerns around the company's debt levels and the potential for an equity raise in 2013. We value Huaneng Renewables at HKD4.00 by applying an average P/E ratio of ~16x to our 2014 EPS estimate of RMB 0.20/share.

Risks

There are numerous risks to our investment thesis on Shenhua, China Coal Energy and Yanzhou. Some of these risks are below.

First, contrary to our expectations, electricity demand growth may continue to grow at its historically high rate, increasing demand for thermal coal. Second, contrary to our expectations, steel growth may accelerate, increasing demand for coking coal. Third, coal production and rail transportation capacity may not increase at the rate that we are forecasting over the long term. As a result, coal pricing may not decline in the manner we are anticipating. Further, in the event that rail transportation capacity expansion fails to materialize, movement of coal resources across internally owned logistics and shipping assets may benefit diversified coal and generation companies like Shenhua. Fourth, the companies may decide to alter their investment strategies or enter into new business segments, changing capital expenditures or dividend payout rates and dividend growth rates. Fifth, China may relax its coal export quotas and India may become a more significant importer of coal than we are forecasting, providing a source of additional growth for the coal companies that are not currently included within our estimates. Sixth, the global economy may accelerate, leading to higher-than-anticipated demand for Chinese manufactured goods, increasing demand for Chinese coal and pushing up the price of seaborne coal. Seventh, the Chinese government may choose to stimulate the economy, resulting in an increase in demand for steel, power, cement and — ultimately — thermal and coking coal.

The key risks to the wind power companies' business model are: a reduction in the wind installed capacity target in China or a change to the mandatory tariff, grid connection and dispatch policy. In addition, a reduction in the amount of debt financing available for renewable energy projects in China would negatively impact growth rates both in terms of installed capacity and earnings. An increase in wind turbine prices is a risk given that more than 50% of construction costs relate to turbines. Finally, a reduction in transmission infrastructure construction in China would negatively affect the sector.

An increase in interest rates would negatively affect the companies as they are all highly levered. As with most utilities, given the stable nature of the revenues, high levels of debt are warranted. As a natural consequence of falling manufacturing costs, a stable regulatory environment and improved infrastructure, we anticipate an increasing sophistication among the renewable energy generators over sources of debt funding (more corporate bonds, less bank borrowing) and lower cost of debt over time. Accelerating inflation over the medium term and continuing monetary tightening are risks to our positive stance on the sector.

Investment Conclusion

Our expectation of flat coal prices and easing supply constraints in China in coming years is premised on a structural slowdown in Chinese power consumption growth at the same time as improvements in coal production capacity and transport capacity ease the path to market. We expect this to be an ongoing process that started at the end of 2011 and is likely to continue broadly through 2015.

We rate Shenhua (1088.HK), China Coal Energy (1898.HK), and Yanzhou Coal (1171.HK) **underperform** with target prices of HK\$20.00, HK\$3.00 and HK\$5.00, respectively. We rate China Lougyuan (916.HK) and Huaneng Renewables (958.HK) **outperform** with target prices of HK\$11.00 and HK\$4.00, respectively. We rate Datang Renewable (1798.HK) **market-perform** with a target price of HK\$1.60.

Less, Less, Less: The Beginning of the End of Coal — Why, How and When Chinese Coal Consumption Falls

Chinese Consumption Falls in Absolute Terms from 2016

For a decade or more, it has been an article of faith among resource and energy investors that China's addiction to ever more coal was an unending source of...well, pollution and carbon emissions, obviously...but also extraordinary returns from investing in coal mines just about anywhere in the world. But betting that the fast-moving laggard (in this case, Chinese industrialization and power demand) will eventually catch up has a natural limit: eventually, it does.

In this chapter, we set out our view that (i) China faces lower power consumption growth and less coal consumption overall by 2016, and that (ii) in an environment of continuing constrained gas supply, renewables and nuclear are the source of incremental power supply. We think both wind and solar installed capacity could be over 200GW by the end of this decade (up from 61GW of wind and 8.3GW of solar in 2013). In this chapter, we also outline what we think the Chinese power portfolio looks like by 2020.

Our expectation of flat coal prices and easing supply constraints in China in coming years is premised on a structural slowdown in Chinese power consumption growth at the same time as improvements in coal production capacity and transport capacity ease the path to market. We expect this to be an ongoing process that started at the end of 2011 and is likely to continue broadly through 2015. Over that entire time, we expect coal prices to trend downward, while still being susceptible to seasonal bumps. Coal prices are today ~30% lower than the 2011 peak in November 2011.

In this chapter, we also set out our view that South Korea and the U.S. are poor proxies for "mature" per capita Chinese power consumption. The two main counter-arguments we hear to our view that the current weak power consumption growth in China is structural and therefore long term are: China consumes 3,700KWh per capita while South Korea and the U.S. consume ~9,500KWh and ~12,500KWh, respectively. Therefore — goes the argument — there is plenty of headroom left for China. We do not agree.

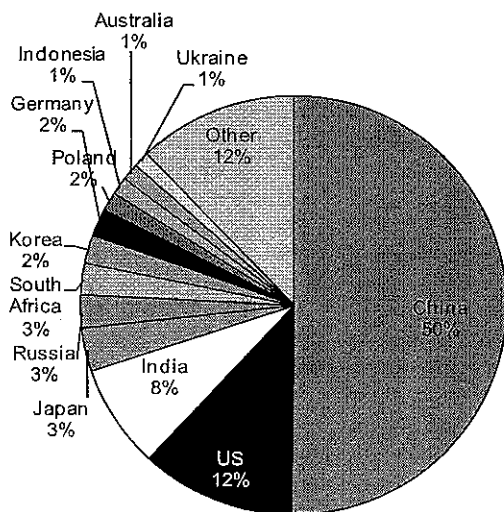
South Korea is 48 million people making one-third of the world's ships and roughly half of the flat screens. Half of South Korea's GDP is from exports. Roughly 40% of the country's imports are minerals, coal, gas and oil; 60% of exports are machinery and electronics. China is simply too large to replicate that kind of export-dominated, energy-intensive model over the long term...or, more accurately, the rest of the world is too small.

The U.S. is also a poor proxy for "mature" per capita Chinese power consumption because of the sheer scale of residential power consumption. The U.S. consumes 12,500KWh per capita; 40% of that power consumption is residential and is a function of wealth (TVs, computers, set top boxes), home size (air conditioning, lighting, heating), or both. China will not mirror that kind of power consumption by 2020.

The Stakes for Global Coal Once Chinese Demand Starts to Decline

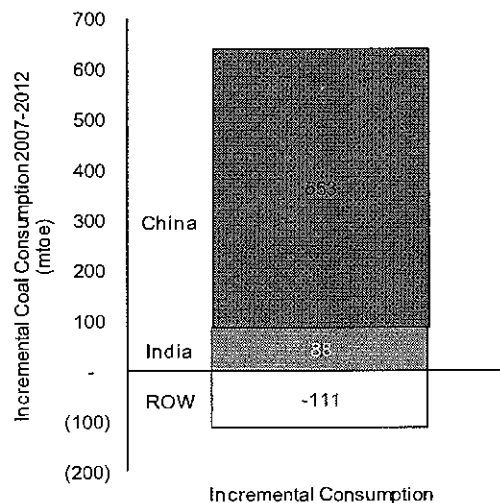
It is not possible to overstate the importance of China to the seaborne coal market or the global coal market altogether (see Exhibit 13). Coal consumption in the rest of the world (outside of China and India) has been in decline over the last decade (see Exhibit 14 and Exhibit 15). Cheap gas in the U.S., combined with tightening emissions standards everywhere and falling (or more efficient) industrial activity, has resulted in falling power demand and/or falling coal demand in most developed economies.

Exhibit 13 World Coal Consumption (2012)



Source: BP Energy Survey 2013 and Bernstein analysis.

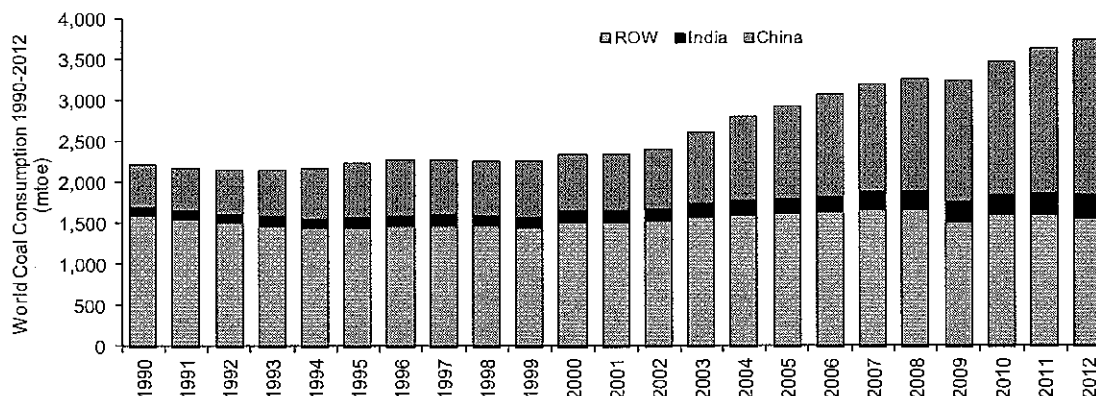
Exhibit 14 Incremental Coal Consumption (2007-12)



Source: BP Energy Survey 2013 and Bernstein analysis.

Globally, Chinese demand growth for coal has been the primary driver or the backstop behind every new investment in coal mining over the last decade. The "global coal market" ended with the collapse in price in 2012.

Exhibit 15 World Coal Consumption (1990-2012)



Source: BP Energy Survey 2013 and Bernstein analysis.

Regional miners will see almost zero demand from China in 2015, a drop of almost 300 million tons. There is simply nowhere else for that coal to go. India is a miserable next best option for the seaborne market. And the trend of declining consumption in the rest of the world is unlikely to reverse.

How and Why Chinese Coal Consumption Starts Falling

The Chinese government is, in our view, today motivated to improve air quality and the country's environment in general.

All industrialized economies reach the point where the collective decision is made that — while cheap sneakers are nice — it is better to have someone else pollute their air, their water and their soil in order to produce the high tops. China — at least coastal China — has reached that point. The coal sector is, in coming years, the biggest loser from this development. And the hits have already started landing.

In May, Beijing's municipal environmental agency announced that the city will reduce coal consumption from 23 million tons annually currently to 15 million tons in 2015 and 10 million tons in 2020. Four new gas-fired heating and power stations will be commissioned in 2014 to supply the energy lost with declining coal use.

In April, Chart Industries CEO Samuel Thomas noted on the company's first-quarter conference call that they were told by Petrochina that "they don't expect to see new coal-fired power plants built in any of the coastal cities, they don't expect to see significant new coal gasification projects allowed anywhere that will affect the air quality of the coastal cities."

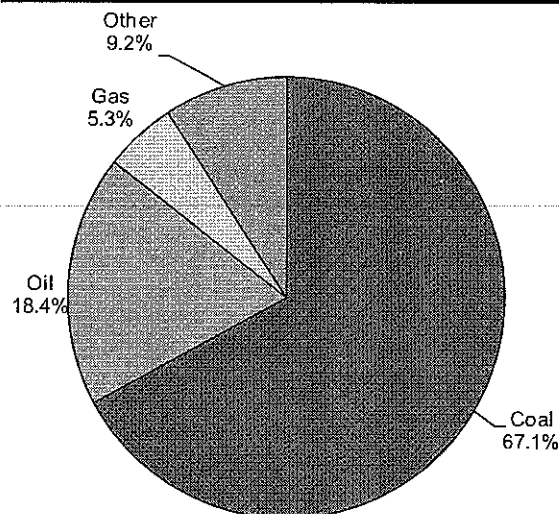
In short, the long term doesn't look very good for the coal industry. And neither does the short term. The recent much-publicized National Development and Reform Commission (NDRC) proposal to ban imports of coal with low gross calorific value also included a less-publicized proposal to ban the use of low-quality coal in China from all sources, domestic or imported. This policy proposal wasn't an action to protect domestic coal miners, but to reduce coal consumption permanently. In short, the Chinese government is now legislating against the coal mining sector.

For any industry, when the government in your largest end market starts banning the sale of your product, the long-term implication is poor. Bans on imports may be good news for domestic coal miners on the day the news hits in terms of supply and demand (less coal) but the Chinese government's clear intention is ultimately terrible news for the sector — less coal.

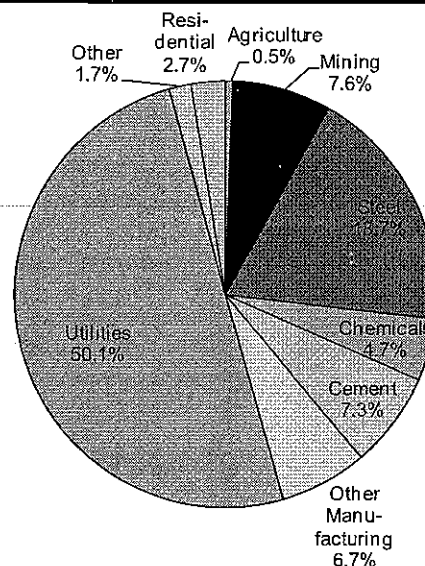
Industrial societies reach a point where they determine that the long-term economic cost (in terms of health outcomes and the environment) of burning coal in inefficient facilities in large cities outweighs the short-term economic benefits. China has reached that moment. Following Beijing's lead, coal consumption in large east coast cities is going to decline in coming years due to falling energy demand growth, substitution from gas and renewables, and the transition of economic activity to the interior of the country.

In short, the air quality crisis in Beijing over the winter is not being wasted. It came at an opportune moment. First, public opinion was focused on this issue throughout 2012. Second, the new government could adopt aggressive policies to alleviate the problem without facing criticism for directly causing pollution in the first place (*"not on my watch"*). Third, the economy has reached a point where power consumption growth and energy consumption growth overall are structurally slowing while the working age population is now falling. The trend is on the Chinese government's side. The problem can be acknowledged because there are viable solutions to fix it. In all that, coal is the biggest loser. Coal is still the largest source of energy in the Chinese economy (see Exhibit 16). The uses of coal in China include end markets that no developed, modern economy would tolerate (see Exhibit 17).

Coal use in factories and for water heating and steam in large east coast cities is going to be phased out over the rest of the decade (at least in instances where there is no remediation of pollutants).

Exhibit 16 Chinese Energy Consumption by Source (2012)

Source: CEIC and Bernstein estimates and analysis.

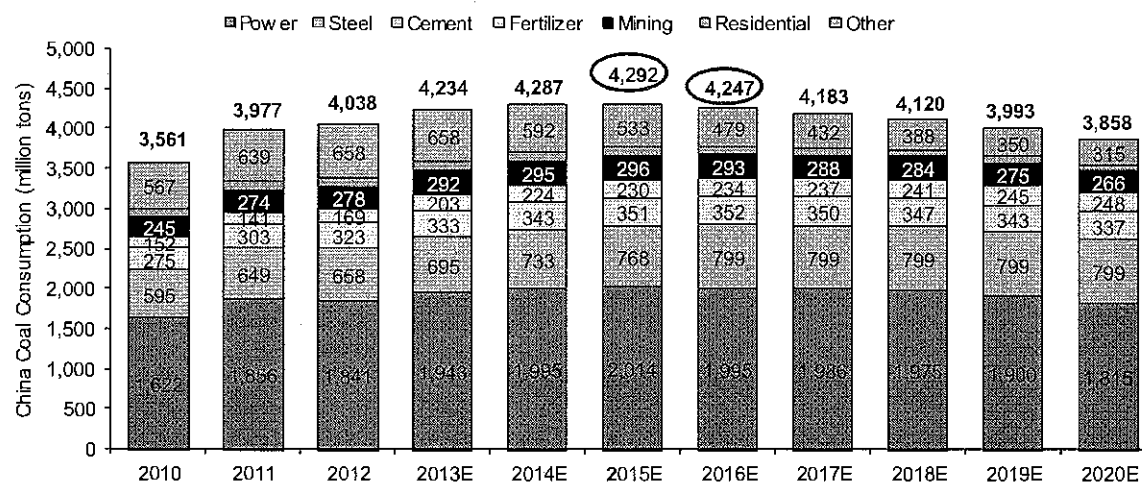
Exhibit 17 Chinese Coal Consumption by End Market (2011)

Source: CEIC and Bernstein estimates and analysis.

Coal demand growth in steel, cement and fertilizer sectors will moderate. Coal demand in the manufacturing, mining, residential sectors and in other industries will fall between now and 2020. And, as a consequence, coal consumption in the power sector will fall too.

In short, we expect that Chinese coal net imports will be close to zero by 2015 and that coal consumption in China will start to fall in absolute terms in 2016 (see Exhibit 18).

The open questions are: (i) whether China will begin exporting coal again (potentially above the previous quota of 50 million tons) and (ii) whether it will be gas-fired generation, nuclear or renewables that will take the most share from coal in terms of peak power supply in coming years.

Exhibit 18 China Coal Consumption by Sector (2010-20E)

Source: CEIC and Bernstein estimates and analysis.

The Chinese government is clearly motivated to improve air quality and China's environment in general. Renewables are a significant part of the initiative to reduce coal demand. We believe that gas availability to the Chinese power sector will be limited to 60-70BCM (sufficient for only 4-5% of demand by 2020). Hydro opportunities are limited. The ramp-up on nuclear is constrained not by safety, technology or uranium but by access to qualified and experienced engineers to run the stations at the end of the quintupling of nuclear capacity by the end of this decade. Solar and wind therefore become the primary near-term sources of power generation and coal substitution that the government can boost.

Distributed solar is the ideal technology for a modern economy facing low reserve margins, high-peak power demand, environmental concerns around the use of coal and economic concerns about the price of LNG. As Pollyannaish as it sounds, we expect coal consumption in China to fall by mid-decade and adoption of renewables to continue to accelerate. Economics aside, the impact on both the environment and greenhouse gas emissions globally is unambiguous if we are right.

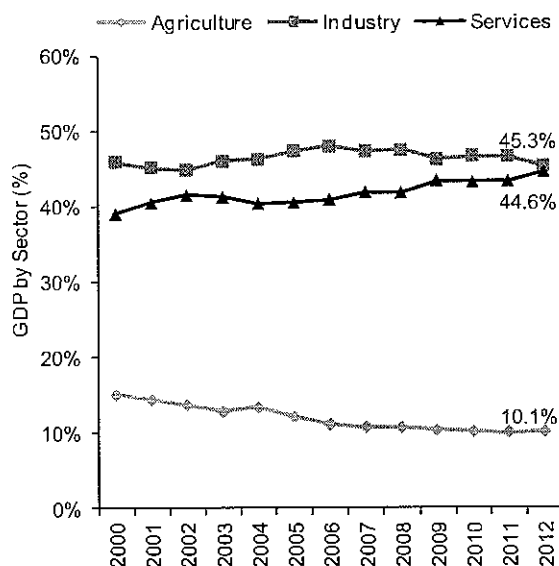
Slowing Power Consumption Growth in China Is Structural and Permanent and Leads to a Decline in Coal Consumption by 2016

The once unthinkable — a decline in China coal consumption — will be the reality by 2016, in our view. There are various drivers of this outcome. However, the key one is slowing power consumption growth. Power consumption growth (4.5% in 2012; 3.8% year-to-date) is now lower than power generation growth from hydro, nuclear, gas and renewables. In short, coal is losing growth share.

By 2016, coal will be losing total share too. Deceleration in power consumption growth will not meaningfully reverse in the coming year for the simple reason that China doesn't need that much more power to drive its economy.

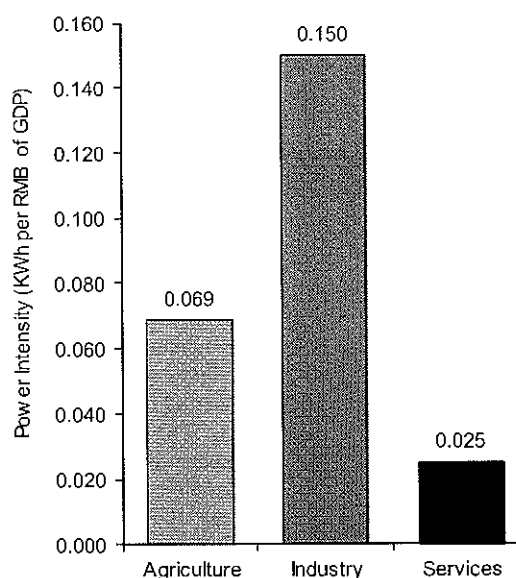
The various edicts that the Chinese government has issued in recent years about reducing energy intensity and not sacrificing the environment for economic growth are aided by one important fact: the change that the Chinese government is attempting to orchestrate is happening organically regardless of the policy.

Exhibit 19 China: GDP Share by Sector (2000-12)



Source: NBS, CEIC and Bernstein analysis.

Exhibit 20 China: Power Intensity by Sector (2011)



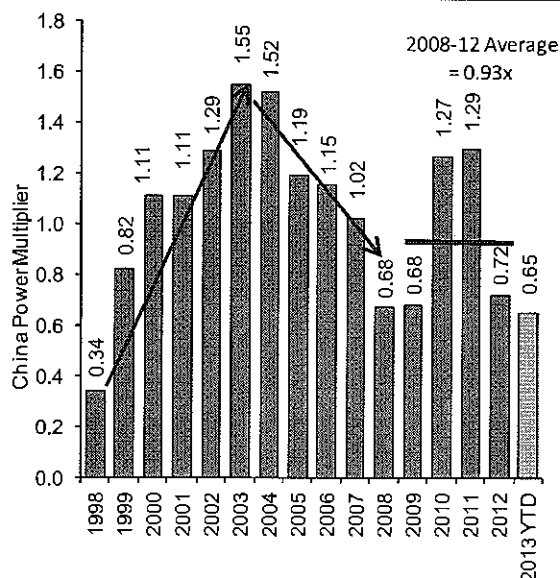
Source: NBS, CEIC and Bernstein analysis.

Over the past decade, China's economic growth has been shifting towards the less energy-intensive services sector. The services sector's share of GDP has increased to 44.6% in 2012 from 39% in 2000 (see Exhibit 19), while the industrial

sector's share of GDP has trended down slightly since the middle of the last decade. The industrial sector in China is roughly 6x more power intensive than the services sector (see Exhibit 20). Therefore, a slight share shift away from the industrial sector serves to reduce power production growth significantly.

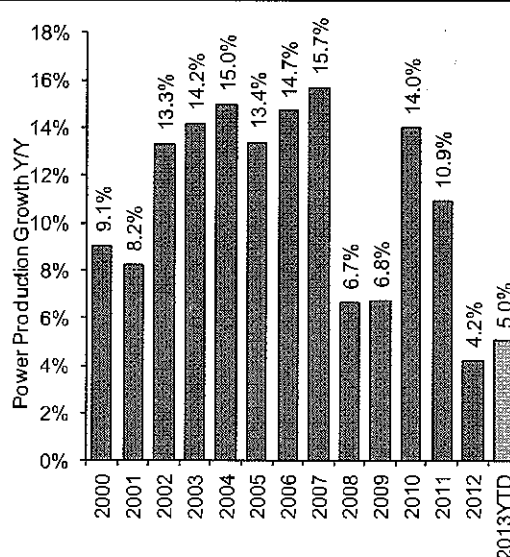
This evolution is entirely predictable given Chinese economic development but was thrown off-course in 2008 by the global financial crisis, the Chinese stimulus that followed, and the heightened levels of spending on infrastructure and construction that inflated power and coal demand in 2010 and 2011. Chinese power consumption growth is slowing structurally and is now below 1x GDP growth and falling. In our view, this is a continuation of a long-term structural shift that started in 2004 (see Exhibit 21), when China's power multiplier (power production growth divided by GDP growth) first started to fall. In 2013, this implies a power consumption growth rate slightly below GDP growth (see Exhibit 22).

Exhibit 21 China Power Intensity (1998-2013 YTD)



Source: CEIC, NBS and Bernstein analysis.

Exhibit 22 China Power Production Growth Y/Y

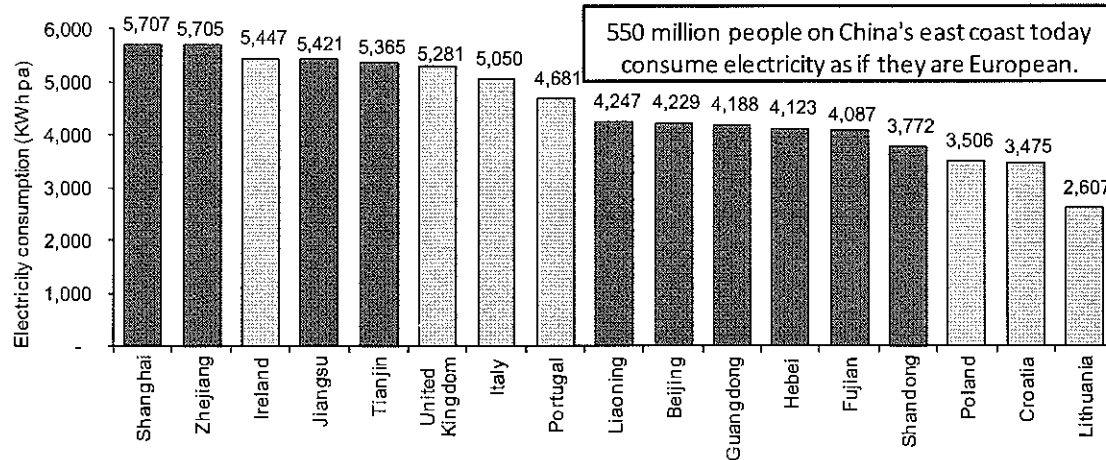


Source: CEIC, NBS and Bernstein estimates and analysis.

The falling power multiplier is a reflection that China is shifting away from heavy industries to less energy-intensive sectors to drive future economic growth. Power represents roughly half of Chinese coal consumption. However, the trend throughout the key end markets is largely the same. As with every other economy, as the Chinese economy becomes more developed, it is becoming more energy efficient: the same amount of power production growth is creating more GDP growth. This is consistent with the natural evolution of any economy going through the middle innings of economic development.

The rapid acceleration in power production in China over the last decade means that the country is today tremendously power intensive. Some 550 million people on the east coast of China now consume electricity as if they are European (see Exhibit 23). Power consumption in Shanghai (a city of 23 million) and Zhejiang (a province of 55 million) are now higher than power consumption on a per capita basis in Ireland. Tianjin and Jiangsu have eclipsed Italy and the United Kingdom.

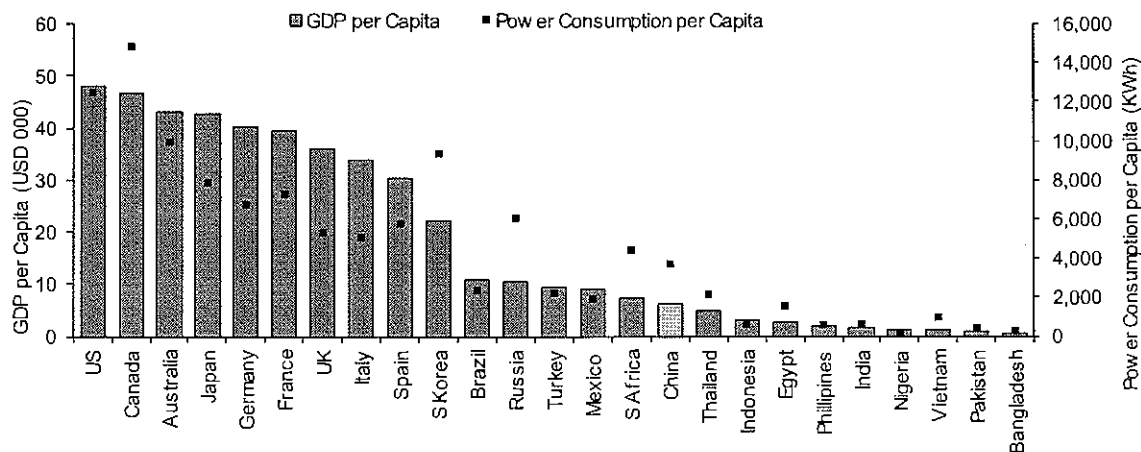
Exhibit 23 Chinese Electricity Consumption per Capita Relative to Selected EU Member States



Source: World Bank, NBS, CEIC, EIA and Bernstein analysis.

And it is not simply the industrialized east where power consumption is high on a per capita basis (see Exhibit 24).

Exhibit 24 Power Consumption per Capita and GDP per Capita — Selection of 25 Developed and Developing Nations (2010)



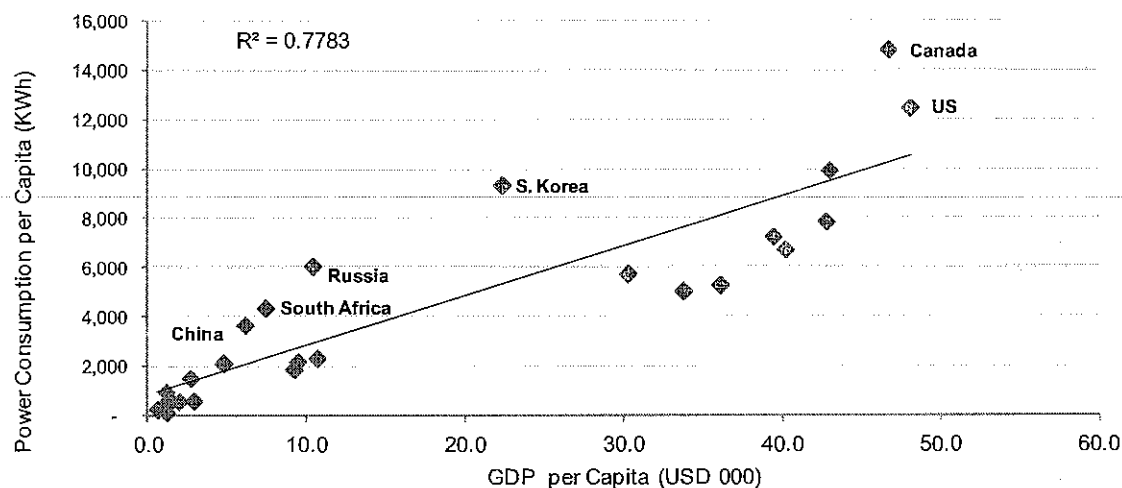
Note: China and Korea data is for 2012, and the U.S. is for 2011.

Source: EIA, World Bank and Bernstein estimates and analysis.

Overall, Chinese power consumption per capita is roughly 3,700KWh or approximately the same level as Poland. Poland's GDP per capita (on a PPP basis) was roughly \$20,000 in 2011; China's was \$8,400, according to the World Bank (see Exhibit 25).

Exhibit 25

Correlations Between Power Consumption per Capita and GDP per Capita — Selection of 25 Developed and Developing Nations (2010)



Note: China and Korea data is for 2012, and the U.S. is for 2011.

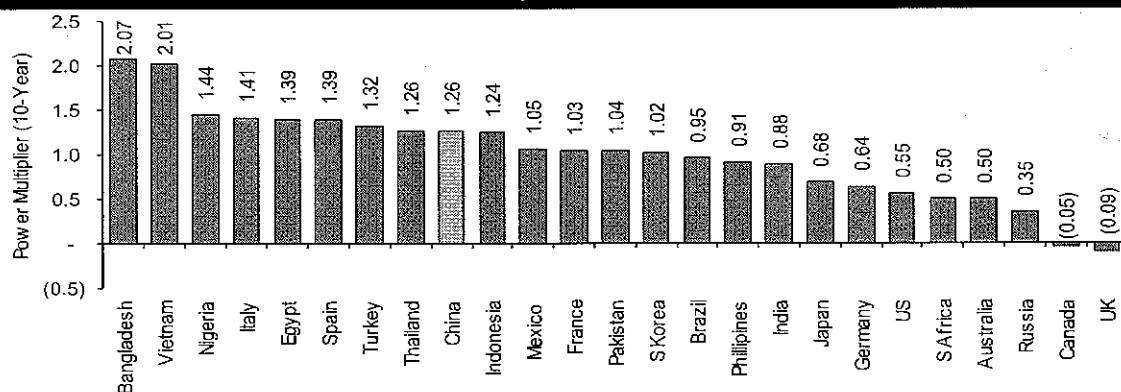
Source: EIA, World Bank and Bernstein estimates and analysis.

In short, it isn't just the east coast that is consuming electricity at levels far above its income; it is the whole country. A deceleration in power consumption growth is overdue. In short, we believe that Chinese GDP growth and its power multiplier are structurally slowing and falling, respectively (see Exhibit 26). This means that a mid-single-digit growth rate in power is likely to remain the norm over the next several years. Given hydro, renewables, nuclear and gas-fired power generation growth are all higher than that, coal-fired demand will continue to decelerate. By 2016, we believe it will be negative.

The remaining end markets for coal (steel, cement, fertilizer and the mining sector itself being the most prominent) will see a similar deterioration.

Exhibit 26

10-Year Power Multipliers — Selection of 25 Developed and Developing Nations



Source: EIA, World Bank and Bernstein estimates and analysis.

We believe that by 2015, Chinese net imports of coal will be close to zero, and by 2016, Chinese coal consumption will be falling too (see Exhibit 27 and Exhibit 28).

Exhibit 27

China Power Demand Model (2011-20E)

China Power Demand Model	2011	2012	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
GDP Growth	9.3%	7.8%	7.5%	7.0%	6.5%	6.0%	5.0%	5.0%	4.0%	4.0%
Power Multiplier	1.17x	0.54x	0.80x	0.80x	0.80x	0.70x	0.60x	0.50x	0.40x	0.40x
Power Consumption per Capita (KWh)	3,521	3,670	3,890	4,108	4,322	4,503	4,639	4,755	4,831	4,908
Installed Capacity (MW)										
Coal	735,643	776,520	807,479	831,884	839,774	814,581	781,998	742,898	698,324	650,000
Gas	32,650	42,650	47,650	57,650	67,650	82,650	97,650	112,650	132,650	150,000
Hydro	229,917	248,900	253,900	268,900	290,000	302,000	314,000	326,000	338,000	350,000
Nuclear	11,915	12,570	20,048	30,416	40,770	40,770	40,770	49,770	61,770	75,000
Wind	47,001	60,830	78,830	98,830	120,000	150,000	180,000	205,000	230,000	250,000
Solar	4,943	8,300	18,300	30,300	45,300	70,300	100,300	135,300	170,300	204,860
Total Installed Capacity	1,062,069	1,149,770	1,226,207	1,317,980	1,403,494	1,460,301	1,514,718	1,571,618	1,631,044	1,679,860
Installed Capacity Growth (%)										
Coal	9.2%	5.6%	4.0%	3.0%	0.9%	-3.0%	-4.0%	-5.0%	-6.0%	-6.9%
Gas	-8.7%	30.6%	11.7%	21.0%	17.3%	22.2%	18.1%	15.4%	17.8%	13.1%
Hydro	6.4%	8.3%	2.0%	5.9%	7.8%	4.1%	4.0%	3.8%	3.7%	3.6%
Nuclear	10.0%	5.5%	59.5%	51.7%	34.0%	0.0%	0.0%	22.1%	24.1%	21.4%
Wind	58.9%	29.4%	29.6%	25.4%	21.4%	25.0%	20.0%	13.9%	12.2%	8.7%
Solar	1639.1%	67.9%	120.5%	65.6%	49.5%	55.2%	42.7%	34.9%	25.9%	20.3%
Total	9.9%	8.3%	6.6%	7.5%	6.5%	4.0%	3.7%	3.8%	3.8%	3.0%
Utilization Rates (%)										
Coal	59.9%	55.4%	55.8%	55.4%	54.8%	54.8%	56.6%	58.9%	60.0%	61.2%
Gas	25.0%	25.0%	24.0%	24.0%	24.0%	24.0%	24.0%	24.0%	24.0%	24.0%
Hydro	31.2%	35.6%	35.6%	35.6%	35.6%	35.6%	35.6%	35.6%	35.6%	35.6%
Nuclear	91.1%	89.8%	60.0%	80.0%	80.0%	90.0%	95.0%	95.0%	95.0%	95.0%
Wind	21.4%	19.3%	20.0%	24.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%
Solar	n/a	n/a	10.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%
Power Generation (TWh)										
Coal	3,698	3,667	3,872	3,975	4,014	3,974	3,958	3,935	3,786	3,617
Gas	75	82	95	111	132	158	190	221	258	297
Hydro	609	747	785	816	872	924	961	999	1,036	1,074
Nuclear	86	94	86	140	213	321	339	339	414	514
Wind	72	91	122	187	259	319	390	455	514	568
Solar/Other	37	90	98	112	129	158	192	232	272	311
Total Power Generation	4,577	4,771	5,058	5,341	5,619	5,855	6,030	6,181	6,280	6,380
Memo: Y/Y Growth	10.9%	4.2%	6.0%	5.6%	5.2%	4.2%	3.0%	2.5%	1.6%	1.6%
Power Generation Growth										
Coal	14.7%	-0.8%	5.6%	2.7%	1.0%	-1.0%	-0.4%	-0.6%	-3.8%	-4.5%
Gas	5.8%	10.1%	15.1%	16.6%	19.0%	20.0%	20.0%	16.6%	16.6%	15.2%
Hydro	-7.6%	22.7%	5.0%	4.0%	6.9%	5.9%	4.1%	3.9%	3.8%	3.6%
Nuclear	17.1%	8.5%	-8.5%	63.9%	51.7%	50.8%	5.6%	0.0%	22.1%	24.1%
Wind	69.7%	26.5%	34.5%	52.7%	38.6%	23.4%	22.2%	16.7%	13.0%	10.3%
Solar/Other	-33.7%	141.9%	9.8%	13.9%	15.2%	22.0%	21.7%	20.8%	17.2%	14.5%
Total Power Generation Growth	10.9%	4.2%	6.0%	5.6%	5.2%	4.2%	3.0%	2.5%	1.6%	1.6%

Source: SX Coal, CEIC, NBS, China General Administration of Customs and Bernstein estimates and analysis.

The single most common counter-argument we hear to our view that the current weak power consumption growth in China is structural and therefore long term are: China consumes 3,700/KWh per capita while South Korea and the U.S. consume 9,500KWh and 12,500KWh, respectively. Therefore — goes the argument — there is plenty of headroom left. In the following sections, we outline the policy decisions available to the Chinese government, given the imperative to improve air quality and the organic deceleration in coal demand, together with an analysis of why we think the U.S. and South Korea are poor comparables for "mature" Chinese consumption.

Exhibit 28**China Coal Demand Model (2011-20E)**

China Coal Demand Model	2011	2012	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Domestic Coal Production (M tons)	3,808	3,940	4,084	4,237	4,292	4,247	4,183	4,120	3,993	3,858
Memo: Incremental Production	395	132	144	152	55	(45)	(64)	(63)	(127)	(135)
Net Imports	169	280	150	50	-	-	-	-	-	-
Total Reported Coal Supply	3,977	4,220	4,234	4,287	4,292	4,247	4,183	4,120	3,993	3,858
Memo: Y/Y Growth	11.7%	6.1%	0.3%	1.2%	0.1%	-1.0%	-1.5%	-1.5%	-3.1%	-3.4%
Coal Consumption by Sector (M tons)										
Power	1,856	1,841	1,943	1,995	2,014	1,995	1,986	1,975	1,900	1,815
Memo: Y/Y Growth		-0.8%	5.6%	2.7%	1.0%	-1.0%	-0.4%	-0.6%	-3.8%	-4.5%
Steel	649	658	695	733	768	799	799	799	799	799
Memo: Y/Y Growth		1.5%	5.6%	5.4%	4.7%	4.1%	0.0%	0.0%	0.0%	0.0%
Cement	303	323	333	343	351	352	350	347	343	337
Memo: Y/Y Growth		6.6%	3.1%	3.0%	2.4%	0.2%	-0.5%	-0.9%	-1.2%	-1.6%
Fertilizer	141	169	203	224	230	234	237	241	245	248
Memo: Y/Y Growth		20.2%	20.0%	10.0%	3.0%	1.5%	1.5%	1.5%	1.5%	1.5%
Mining	274	278	292	295	296	293	288	284	275	266
Memo: Y/Y Growth		1.5%	4.9%	1.2%	0.1%	-1.0%	-1.5%	-1.5%	-3.1%	-3.4%
Residential	115	110	110	105	100	95	90	85	81	77
Memo: Y/Y Growth		-4.0%	0.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%
Other	639	658	658	592	533	479	432	388	350	315
Memo: Y/Y Growth		3.0%	0.0%	-10.0%	-10.0%	-10.0%	-10.0%	-10.0%	-10.0%	-10.0%
Change in Coal Inventory	0	182	0	0	0	0	0	0	0	0
Total Coal Consumption	3,977	4,038	4,234	4,287	4,292	4,247	4,183	4,120	3,993	3,858
Memo: Y/Y Growth	11.7%	1.5%	4.9%	1.2%	0.1%	-1.0%	-1.5%	-1.5%	-3.1%	-3.4%
Memo: Incremental Consumption	416	61	14	52	5	(45)	(64)	(63)	(127)	(135)
EOY Coal Production Capacity	3,808	3,940	4,584	4,584	4,584	4,247	4,183	4,120	3,993	3,858

Source: SX Coal, CEIC, NBS, China General Administration of Customs and Bernstein estimates and analysis.

Renewables Are the Only Incremental, Scalable Source of Substitution Between Now and 2020; Wind Could Triple Installed Capacity Over the Next Seven Years; Solar Could Increase 20-Fold

Decelerating power consumption growth is organic; the compounding negative effect of reduced coal consumption is policy driven. Renewables are a significant part of the initiative to reduce coal demand. We believe that gas availability to the Chinese power sector will be limited to 60-70BCM by 2020 (sufficient for only 4-5% of demand). Hydro opportunities are limited. The ramp-up on nuclear is constrained not by safety, technology or uranium but by access to qualified and experienced engineers to run the stations at the end of the quintupling of nuclear capacity by the end of this decade. Solar and wind therefore become the primary sources of power generation and coal substitution that the government can boost.

Distributed solar is the ideal technology for a modern economy facing low reserve margins, high-peak power demand, environmental concerns around the use of coal and economic concerns about the price of LNG. As Pollyannaish as it sounds, we expect coal consumption in China to fall by mid-decade and adoption of renewables to continue to accelerate. Economics aside, the impact on both the environment and greenhouse gas emissions globally is unambiguous if we are right.

Any economic planner responsible for setting targets for Chinese power supply over the rest of the decade faces a dilemma in roughly eight parts.

First, China needs power...and more of it. The economy is slowing but it hasn't stopped. Power demand growth will continue to increase in coming years as a fraction of GDP growth, rather than as a multiple. But power demand is going to continue to go up nonetheless. Further, expectations about reliability of supply are rising as China gets wealthier and a greater share of the economy is dedicated to services. A more sophisticated economy requires higher reserve margins (the percentage of the fleet that is idle but available for dispatch at the moment of peak demand) in order to increase reliability of supply and reduce power cuts throughout the country.

Second, the cheapest and easiest source of power supply in China is coal-fired power stations. China has spent a decade building a modern fleet of coal-fired

power stations, and today there is plenty of low-priced coal available throughout China.

Third, despite the attractive economics of coal-fired power generation, the use of coal in east coast cities is being restricted and will be restricted further in coming years. China — like every industrialized economy — is weighing the impact of ever-increasing pollution on its population and is reducing usage. The fact that the simple, short-term economics militate in favor of more coal does not mean that China will use more coal. As economies get richer, the decision making in this regard gets more complex.

Fourth, China is increasing both domestic gas production and imports. Gas supply to the power sector and gas-fired generation as a share of total generation will increase in coming years. However, gas is still constrained and the power sector ranks below residential, commercial, industrial and, potentially, transportation users in terms of priority of supply. If supply to the power sector reaches 70BCM by 2020, it will represent ~5% of total power generation.

Fifth, China continues to expand hydro generation capacity. Total installed capacity at the end of 2012 was ~250GW. However, there are no non-navigable, large, fast-flowing rivers in deep, uninhabited valleys left in China. The easy opportunities were dammed years ago. And large-scale projects like the Three Gorges Dam (given its massive environmental impact and population displacement) are not going to be repeated. That leaves smaller dams. We believe that China will add 100GW of hydro over the rest of the decade. Hydro will represent ~17% of total generation by 2020.

Sixth, nuclear power generation is continuing to ramp. Installed capacity is currently ~14GW and plans are for China to reach 75GW by the end of the decade. This will mean nuclear capacity will go from less than 3% of total generation to ~10%. The limiting factor is not technology, ambition, safety concerns or uranium. The constraint to China expanding its nuclear fleet any faster is the shortage of experienced engineers who can manage these facilities. That is a multi-decade, not a multi-year, development task.

Seventh, wind is currently an under-utilized source of power generation in China. The 61GW of installed capacity operated at a utilization rate of ~19% in 2012. This utilization rate was a function of an inability or unwillingness from State Grid to dispatch all of the electricity being generated. We believe that the normal level of utilization will (by 2015) be 27%. We also believe that State Grid will remain under pressure to connect wind farms and absorb all of the electricity generated.

Eighth, solar is a rounding error within the Chinese power portfolio today. However, with installed cost now approaching \$1/W, solar is economic with gas-fired power generation in China and — on a distributed basis — is economic against on-grid power prices.

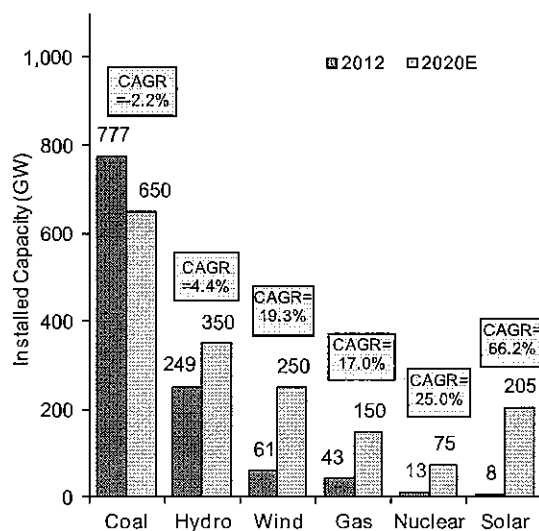
Given those constraints and an objective of increasing reliability of supply, improving environmental impacts and cost control (probably in that order), we believe that the focus within the power sector will be on (i) completing hydro, gas-fired and nuclear projects on time; (ii) decommissioning old and inefficient coal-fired power stations; and (iii) encouraging renewables to the greatest extent possible.

With lower power consumption growth and less coal consumption overall — and in an environment of continuing constrained gas supply — renewables are the source of incremental power supply. We think both wind and solar installed capacity could be over 200GW by the end of the decade (up from 61GW of wind and 8.3GW of solar today).

In short, given the long lead times associated with hydro and nuclear and the supply constraint around gas, the primary levers available to economic planners and to the grid operator is to encourage solar and wind...and hope that the current deceleration in power consumption growth and falling power intensity persist.

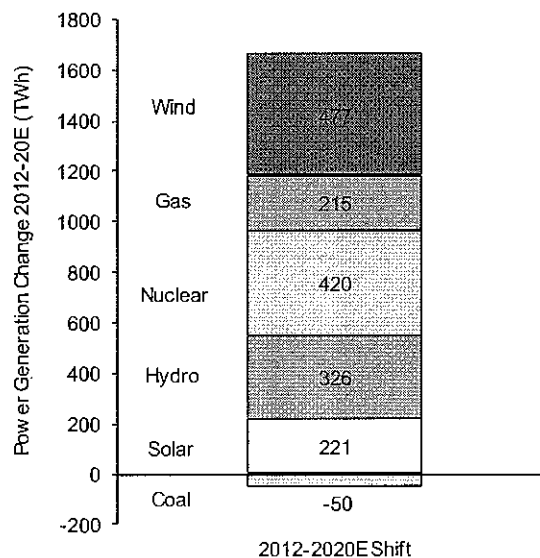
We believe that coal-fired power generation capacity will fall from ~800GW of installed capacity today to 650GW by the end of the decade as inefficient, small, old power stations are decommissioned. Hydro will increase from ~250GW to 350GW. Gas will go from ~40GW to 150GW. Nuclear will increase from 13GW to 75GW. Solar and wind will be 200GW and 250GW by the end of the decade, respectively (see Exhibit 29). Over this period, power demand will increase by 1,323TWh (up one-third compared to 2012) and coal-fired generation will decline (see Exhibit 30).

Exhibit 29 Installed Capacity by Fuel Source (2012 and 2020E)



Source: CEIC and Bernstein estimates and analysis.

Exhibit 30 Share Shift by Fuel Source (2012-20E)



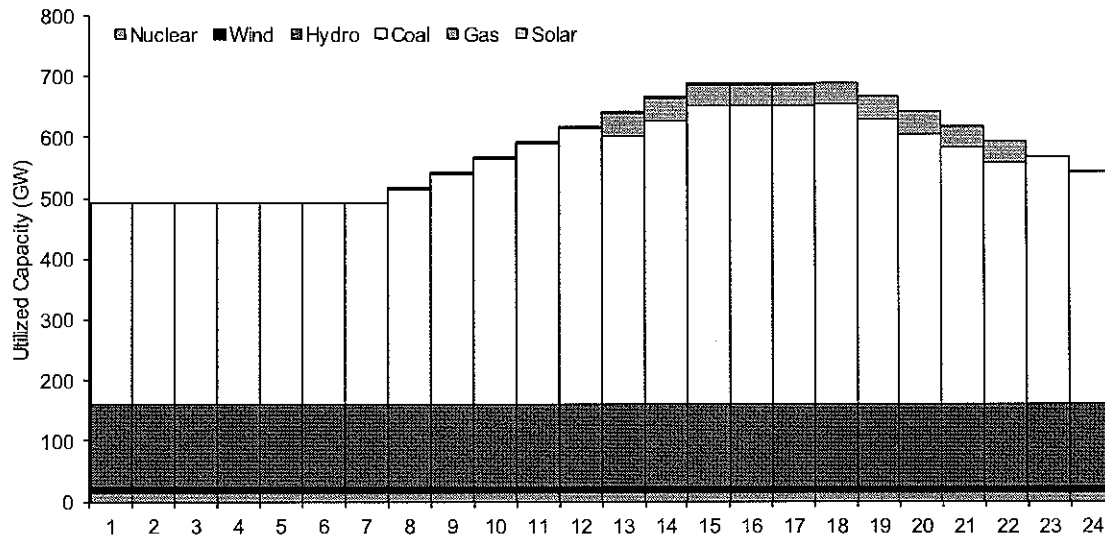
Source: CEIC and Bernstein estimates and analysis.

The nature of power demand in any fleet is that consumption is highest during the day. In the summer, thanks to air conditioning, peak demand lasts from early afternoon into the evening. In the winter, peak demand is more focused around the dinner hour (especially in more developed economies where residential consumption represents a more significant share of total consumption).

Currently, coal-fired power stations in China serve both base-load and peak-load demand. The difference is literally putting more coal in the fire. This means that utilization across the fleet is low as some portion of capacity serves peak demand, which — by definition — means the capacity is only necessary for a few hours a day. With more peak capacity available, coal-fired generation becomes more and more base-load only. This should mean higher utilization for the larger, cleaner-burning, more efficient power plants in the fleet and the opportunity to decommission everything else.

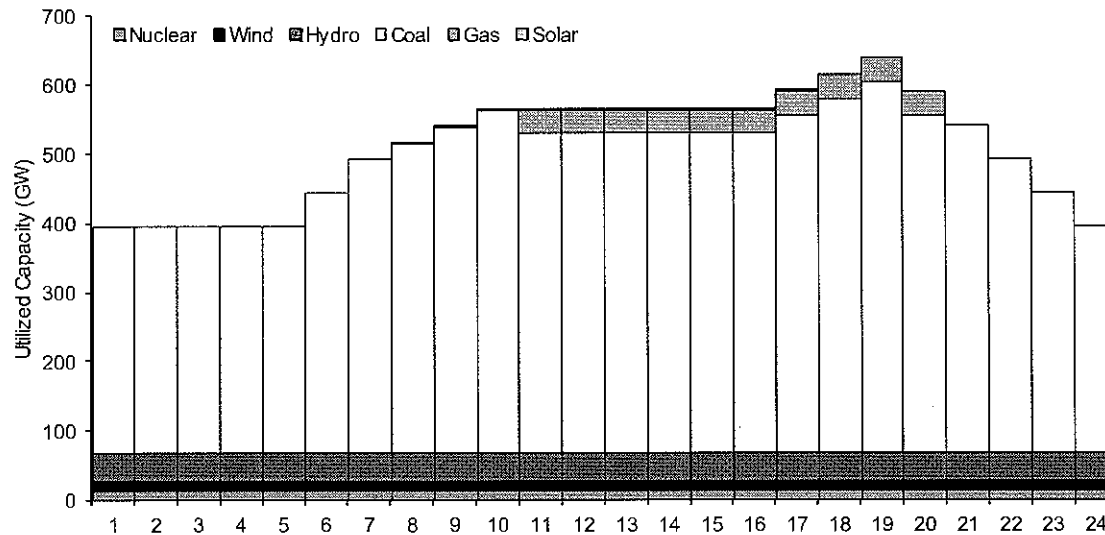
In that transition, three things are clear: First, the lack of gas supply for the power sector limits the options for any economic planner. Nuclear and hydro construction projects run on their own (long) timelines. If coal consumption is going to fall on the east coast, it has to be replaced with either gas or renewables.

Second, utilization for the coal-fired fleet that remains will trend higher. With gas and renewables expanding faster than overall power generation growth and generating in the middle of the day, coal-fired generation capacity will increasingly be retired or will become base-load. The Chinese summer and winter power generation is currently dominated by coal (see Exhibit 31).

Exhibit 31**SCB Estimates for 2012 Chinese Summer Power Portfolio Dispatch**

Source: CEIC, NBS and Bernstein estimates and analysis.

In the summer, hydro generation acts as base-load power supply. In the winter, power generation is almost entirely coal-fired (see Exhibit 32).

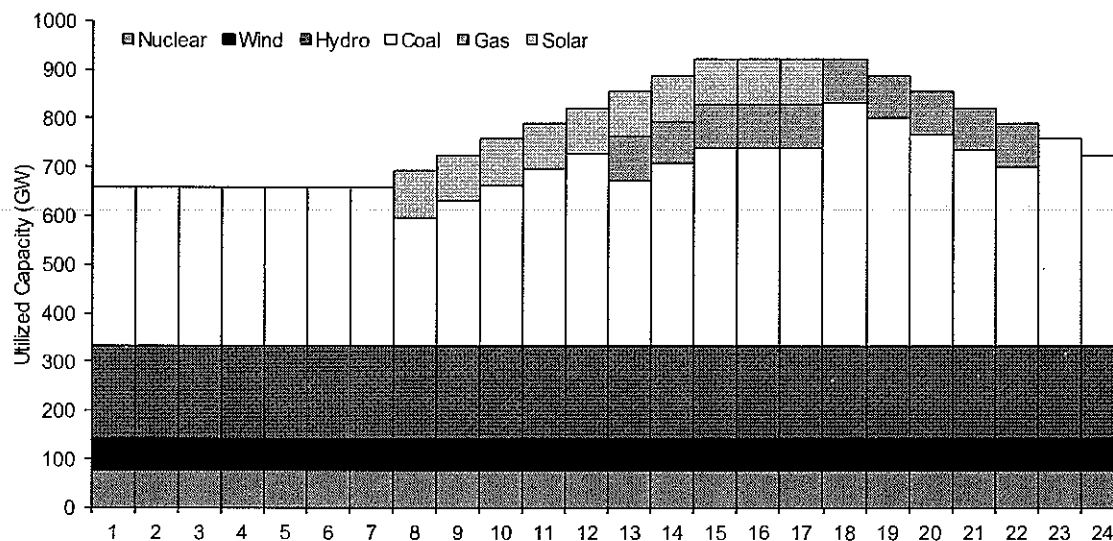
Exhibit 32**SCB Estimates for 2012 Chinese Winter Power Portfolio Dispatch**

Source: CEIC, NBS and Bernstein estimates and analysis.

By 2020, diversification within the portfolio becomes more evident (see Exhibit 33). Nuclear, wind and hydro are contributing to base-load power demand. Gas and solar are taking out a great deal of peak power demand. Coal becomes the intermediate source of power generation.

Exhibit 33

SCB Estimates for 2020 Chinese Summer Power Portfolio Dispatch

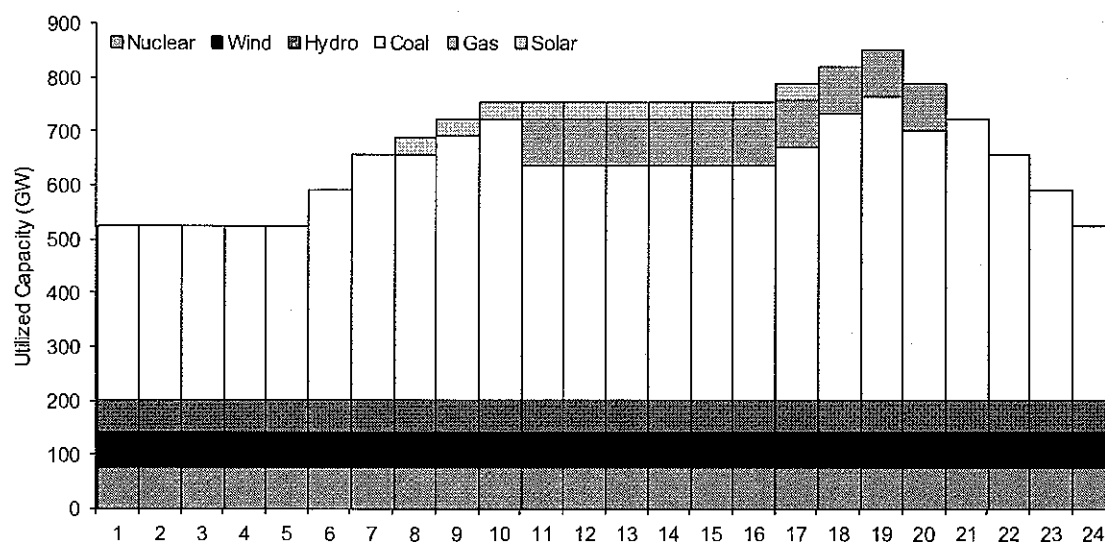


Source: CEIC, NBS and Bernstein estimates and analysis.

In the winter, without hydro and solar contribution, coal remains dominant (see Exhibit 34).

Exhibit 34

SCB Estimates for 2012 Chinese Winter Power Portfolio Dispatch



Source: CEIC, NBS and Bernstein estimates and analysis.

Third, solar is the only option to shore up reserve margins, address peak power demand, accelerate the reduction in coal consumption, improve air quality in east coast cities and reduce demand for expensive LNG or domestic gas supply within various other competing end markets.

By 2014, we believe that solar will be cost competitive on an unsubsidized basis, with gas-fired power generation. As costs for solar continue to fall, the economics become more attractive. Japan is currently demonstrating how an Asian economy that is, at present, struggling to serve summer peak power demand and is

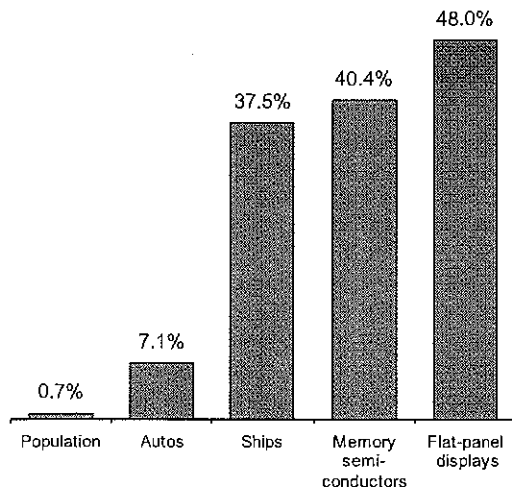
looking to avoid incurring the cost of high-priced LNG can use distributed solar to kill peak demand. We do not believe that this lesson will be lost on China. Given that Italy went from less than 400MW of solar installed capacity additions in 2008 to over 9GW in 2011, we do not believe that there are any real logistical barriers to the rapid deployment of solar in coming years. Once the economics work, installed capacity expansion — as Italy, Spain, Germany, Czech, Romania and Japan have now proved — happens much faster than anyone expects.

The South Korean Model of Export-Focused, Energy-Intensive Growth Is Not Sustainable in China for the Simple Reason That End-Market Demand in the Rest of the Model Is Not Big Enough to Sustain a Chinese-Sized South Korea

South Korea is, in our view, a poor proxy for "mature" per capita Chinese power consumption. South Korean power consumption is largely exported in the form of finished goods. Half of South Korea's GDP is from exports.

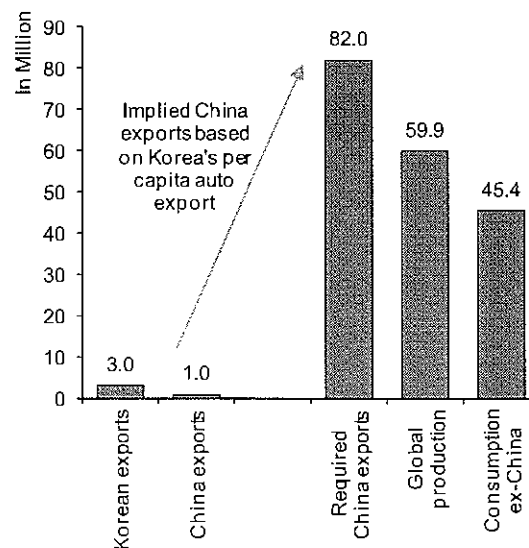
The simplest reason that South Korea makes no sense as a parallel to Chinese economic development is that Korea is a ridiculously energy-intensive economy, and it can maintain that intensity because of the size of its export sector. South Korea is 48 million people building one-third of the world's ships, 40% the world's memory semiconductors, roughly half the world's flat screens and 5 million cars each year (see Exhibit 35 and Exhibit 36).

Exhibit 35 South Korea Share of Global Population; Global Auto, Ship, Memory Semiconductor and Flat-Panel Display Production



Source: DisplaySearch, Gartner, KAMA and Bernstein estimates and analysis.

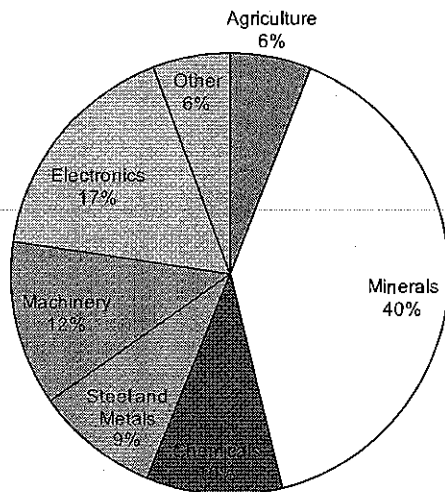
Exhibit 36 South Korea vs. China Auto Exports



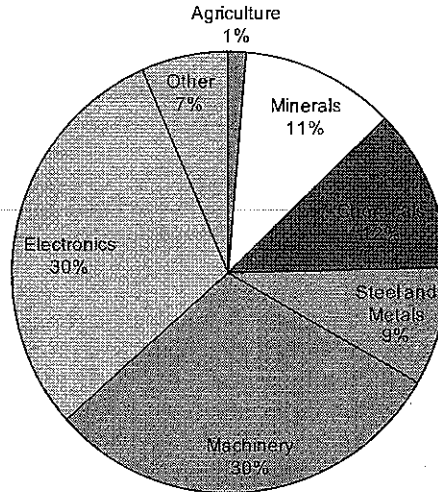
Source: KAMA, CAAM and Bernstein estimates and analysis.

This level of production (and energy consumption) is sustainable — for a country of 48 million people — because of the size of the export market relative to the size of Korea's domestic population. In short, there is an export market ~139x the size of Korea to which Korea can sell cars, ships, semiconductors and TVs. China has an export market that is ~5x its own size...and does not include the single-greatest untapped market opportunity for selling consumer goods of this or any other age: China.

Roughly 40% of South Korea's imports are minerals, coal, gas and oil (see Exhibit 37); 60% of exports are machinery and electronics (see Exhibit 38).

Exhibit 37 South Korean Imports by Category (2012)

Source: Korea Customs Service and Bernstein analysis

Exhibit 38 South Korean Exports by Category (2012)

Source: Korea Customs Service and Bernstein analysis

China is simply too large to replicate that kind of export-dominated, energy-intensive model over the long term...or, more accurately, the rest of the world is too small. Korean power consumption per capita is ~9,500KWh and GDP per capita is \$30,000 — roughly Spanish-level income, with 50% more power consumption.

China simply cannot replicate the impact of exports on resource and power consumption measured on a per capita basis. One example: South Korea currently exports ~3 million cars annually, but China exports only ~1 million cars annually. However, for China's auto exports to rise to the level of South Korea's in terms of per capita power consumption contribution, China would need to export 78 million vehicles annually (3×26) — 77 million more than it does currently. Total global auto consumption is 80 million cars annually. Adjusting for domestic consumption, China would need to supply 125% of non-Chinese auto consumption if China's auto industry is to replicate South Korea's in terms of contribution to power and resource consumption on a per capita basis. In short, it just cannot happen.

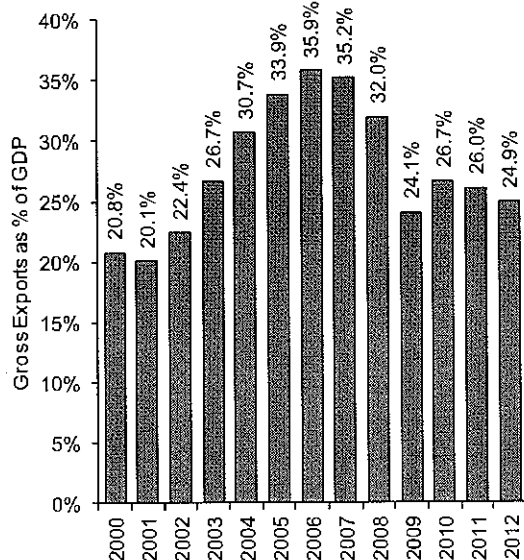
China is not going to end up producing all of the world's cars...or all the world's ships, semiconductors, flat screens or anything else. And, if not, the rest of North Asia is of little relevance in predicting long-term per capita Chinese power consumption. Residential power consumption parity between China (460KWhpa per capita) and South Korea (1,300KWhpa per capita) would mean a 2.5% growth rate in Chinese power consumption annually for the next decade. After that, it is largely domestic consumption of manufactured goods that drives power consumption growth higher.

This seems, to us, the greatest flaw in comparing power consumption and resource use (or even wealth) among the various North Asian economies and then extrapolating that as the long-term outcome for China. Yes, there are very good reasons why Guangdong, Zhejiang or Jiangsu may replicate Taiwan, Korea and Japan in terms of wealth, and energy and resource consumption on a per capita basis one day. But there are also very good reasons why the entire country will *not* see Taiwanese, Japanese or Korean levels of economic development and resource use. The difference is exports. China may not lack for ambition to match Korea economically, and the rest of the world may not lack for resources to supply that

ambition...but the problem is there isn't enough demand in the rest of the world to make it happen.

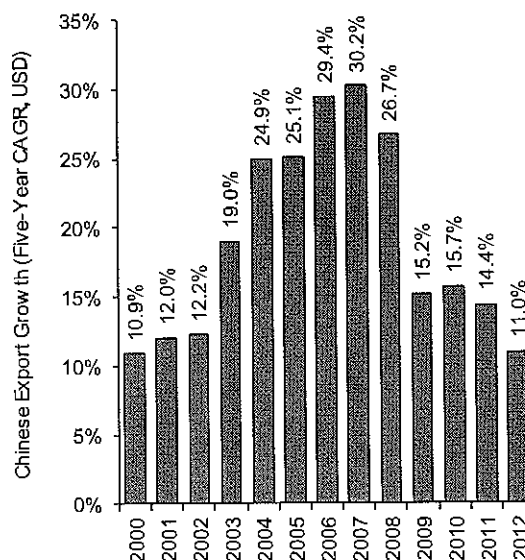
Today, Korean exports (gross) have a ~50% share of GDP. In China, that number was 24% last year and has been trending down since 2006 (see Exhibit 39). In short, China cannot double the size of its economy by 2020 *and* increase exports as a share of GDP (at least if those exports are going to continue to be resource and power intensive). The global economy is simply not big enough or growing fast enough to absorb the output (see Exhibit 40).

Exhibit 39 Chinese Gross Exports as a Percentage of GDP



Source: NBS, CEIC, General Administration of Customs and Bernstein analysis.

Exhibit 40 Chinese Gross Exports Growth — Five-Year CAGR (2000-12)



Source: NBS, CEIC, General Administration of Customs and Bernstein analysis.

We are not arguing that China cannot double the size of its economy over the course of the current decade. We do think it is unlikely that gross exports would be 50% of GDP by 2020 in this circumstance (i.e., where South Korea is today). However, we believe it is simply impossible for China to do these two things and establish an export mix that is as power and resource intensive as South Korea's — the global market for cars, ships, phones, TVs and microchips just isn't big enough.

The U.S. Model of Tremendous Energy Intensity Is a Function of High-Residential Power Consumption and Energy-Intensive Infrastructure

The U.S. is also a poor proxy for "mature" per capita Chinese power consumption, in our view. There are two primary reasons for this.

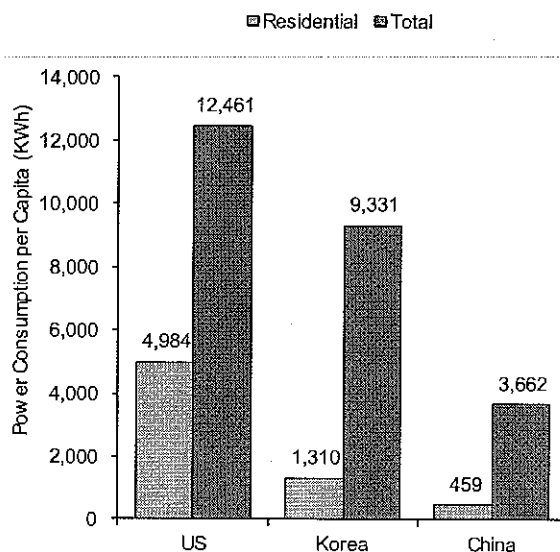
First, the sheer scale of residential power consumption in the U.S. means that U.S. power consumption is disproportionately high. The U.S. consumes 12,500KWh per capita; 40% of that power consumption is residential and is a function of wealth (TVs, computers, set top boxes), home size (air conditioning, lighting, heating), or both. China will not mirror that kind of consumption by 2020.

The 5,000KWh per capita in residential electricity consumption in the U.S. dwarfs Chinese residential usage (see Exhibit 41). This is a function of two things: housing stock and wealth. Wealth levels in China will change over time. However, it is unlikely that the housing stock (in terms of square meters per unit) is going to increase in size dramatically in China as the country continues to urbanize.

Space cooling, lighting and space heating account for 42% of U.S. residential power consumption (see Exhibit 42). This is largely a function of dwelling unit size. The average home size in the U.S. is 2,700 square feet, or 300 square meters.

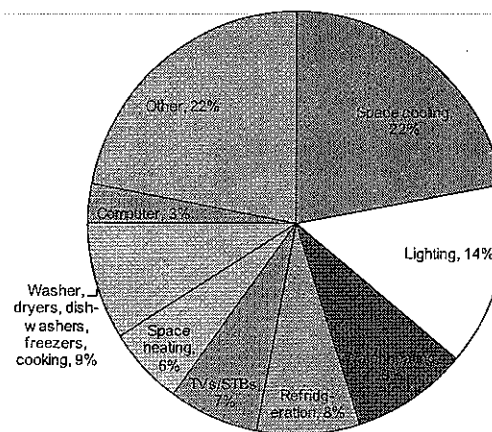
The average Chinese apartment is 80 square meters (based on the combination of commodity and government-built housing stock — see Exhibit 43). At the margin, this may change over the next few decades, but there will not be a fundamental shift in Chinese housing stock area by 2020.

Exhibit 41 Residential and Total Power Consumption per Capita



Source: CEIC, EIA and Bernstein estimates and analysis.

Exhibit 42 U.S. Residential Power Consumption by Use

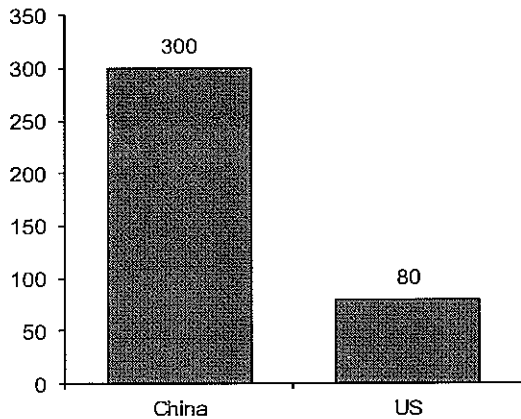


Source: EIA and Bernstein estimates and analysis.

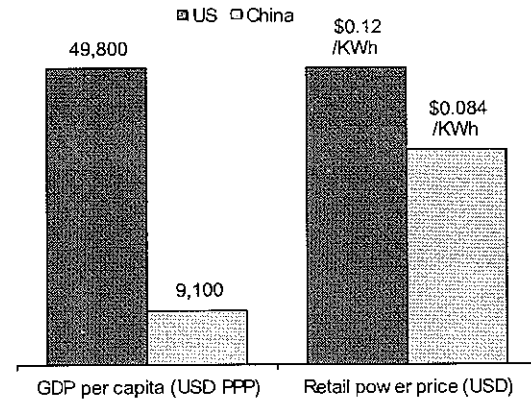
Second, the wealth effect drives the delta in power consumption at the residential level. Flat screens, set-top boxes, washer/dryers, dishwashers and computers all add up. This delta between the U.S. and China should fall in the coming years. However, given the focus on energy efficiency in household appliances, the two trend lines are likely to converge from both ends rather than Chinese consumption simply mirroring U.S. patterns.

Third, power prices at a residential level in China are expensive. Even adjusting for purchasing power parity, GDP per capita in China is still less than one-fifth of GDP per capita in the U.S. (see Exhibit 44). Yet retail residential power prices in China are only 40% cheaper than in the U.S. Not surprisingly, power consumption on a per capita basis is far lower.

Fourth, the U.S. national infrastructure was largely built at a time when energy in general and power in particular was cheap. As a consequence, there is a legacy of high power consumption that is difficult to turn around.

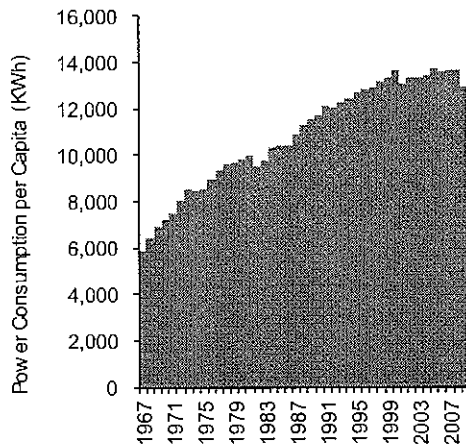
Exhibit 43 U.S. and Chinese Average Dwelling Unit Size

Source: National Association of Home Builders and Bernstein estimates and analysis.

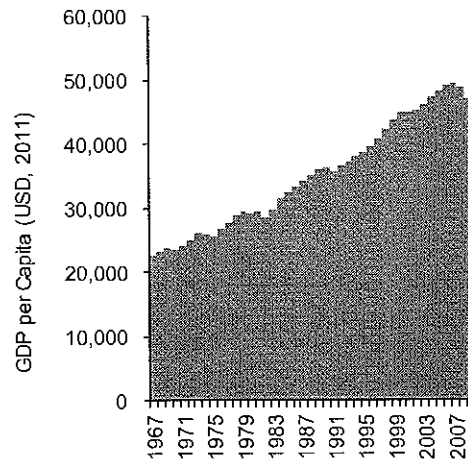
Exhibit 44 U.S. and Chinese GDP per Capita and Power Prices

Source: CIA Factbook, EIA, NBS, CEIC and Bernstein estimates and analysis.

Fly on a clear night across the Midwest from Cleveland to Kansas City and all you see underneath you the entire time are lights. On a direct flight, you are passing over Indianapolis, Indiana and Springfield, Illinois. To the north and south are Columbus, Ohio; Fort Wayne, Indiana; Cincinnati, Ohio; St Louis, Missouri; and Peoria, Illinois. In short, Interstate-70 is not the Great White Way. And yet, this level of light usage and the associated power consumption is not replicated anywhere in the developing world, including China. This century-old legacy of tremendous wealth — and therefore tremendous energy intensity — is hard to shake.

Exhibit 45 U.S. Power Consumption per Capita (1967-2009)

Source: BLS, EIA and Bernstein analysis.

Exhibit 46 U.S. GDP per Capita (1967-2009)

Source: BLS, EIA and Bernstein analysis.

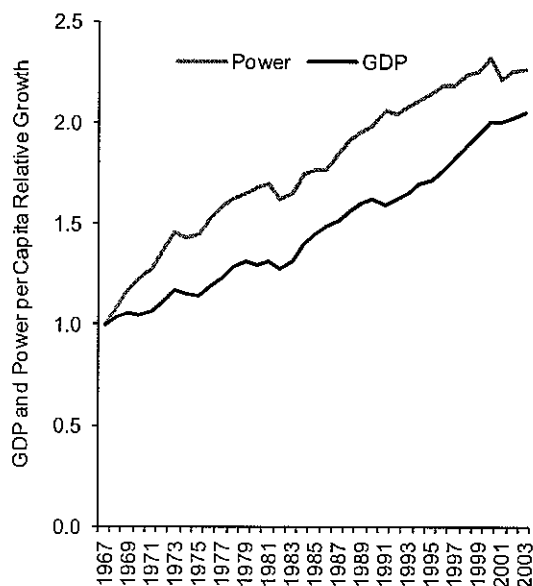
The final point is that power consumption per capita growth and GDP per capita growth have happened largely simultaneously. It is not the case that the U.S. reached 12,500KWh per capita per annum 30 years ago and GDP has since "caught up." Accordingly, the basis to argue that Chinese power consumption growth

continues to over-index Chinese GDP growth on a per capita basis is therefore weak.

From 1967 to 1997, U.S. power consumption per capita increased at a CAGR of 2.6% while GDP per capita increased at a rate of 2%. Between 1997 and 2007, power consumption growth increased at a 0.6% CAGR while GDP per capita was up 1.9% (see Exhibit 45 and Exhibit 46).

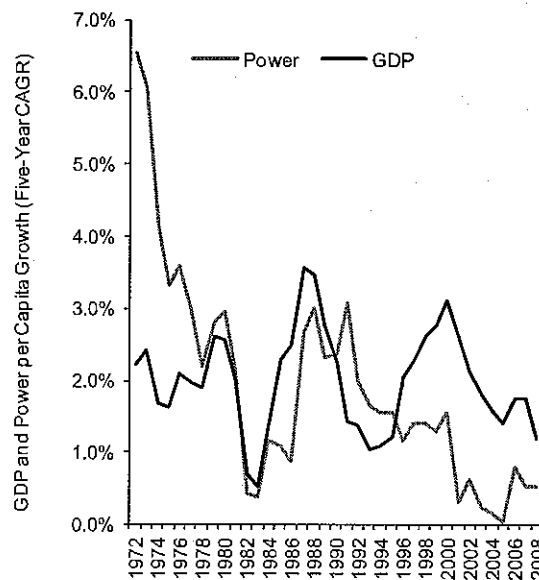
In short, the U.S. started at a high level of power consumption, and it simply got higher as the country became richer (see Exhibit 47 and Exhibit 48).

Exhibit 47 U.S. GDP per Capita and Power Consumption: Indexed Growth (1967-2009)



Source: BLS, EIA and Bernstein analysis.

Exhibit 48 U.S. GDP per Capita and Power Consumption Growth (Five-Year CAGR) — 1967-2009



Source: BLS, EIA and Bernstein analysis.

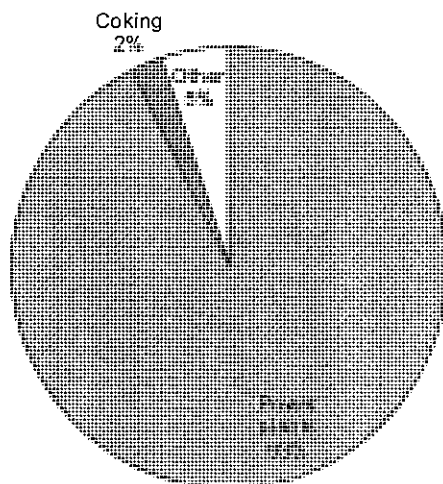
The "power hungry first, rich later" effect only started in the last 15 years. It was only at the end of the 1990s when power consumption growth on a per capita basis fell beyond GDP growth on a similar basis. Since 2007, power consumption growth has trailed GDP growth.

In short, for a variety of historical and economic reasons, we do not believe that China is going to replicate the U.S. in terms of power consumption per capita — at least not by 2020.

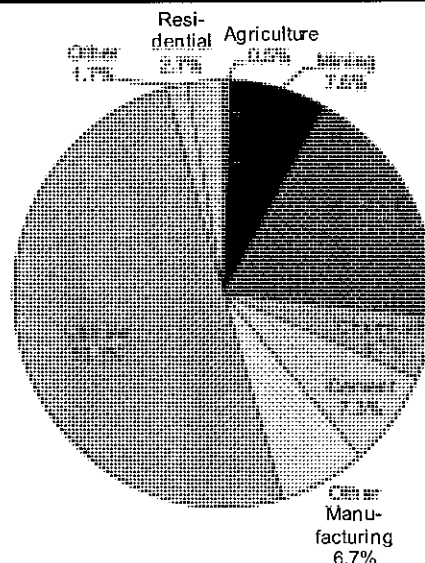
Growth (or Lack Thereof) in Other End Markets for Coal

When it comes to coal, the power sector is only half the story...but not for long.

The steel, cement and fertilizer sectors account for another ~30% of consumption. The remainder is mining itself, manufacturing, residential use, agriculture and other (see Exhibit 50). Efforts to curb coal consumption outside of the four key end markets have already begun. The ultimate composition of coal usage is clear too: in developed economies, coal is used in power generation and coke production. And that is it (see Exhibit 49).

Exhibit 49 U.S. Coal Consumption by End Market (2012)

Source: EIA and Bernstein estimates and analysis.

Exhibit 50 Chinese Coal Consumption by End Market (2011)

Source: CEIC and Bernstein estimates and analysis.

Coal use in factories and for water heating and steam in large east coast cities is going to be phased out over the rest of the decade (at least in instances where there is no remediation of pollutants). Coal demand growth in the steel, cement and fertilizer sectors will moderate. Coal demand in the manufacturing, mining, residential sectors and in other industries will fall between now and 2020.

Six months ago, the general consensus was that China would move to a developed-market model of coal consumption over perhaps 30 years. Instead, that transition is likely to occur over the course of the next decade, in our view. Demand growth for coal from the steel, cement and fertilizer sectors is likely to be in the low-single-digit range over the next few years. For factory usage, mining, agriculture, residential and other end markets, growth will be negative, in our view, as first Beijing and then the rest of the east coast eliminate non-power and steel coal usage.

The Once Unthinkable Eventually Becomes Thinkable

The once unthinkable — a decline in China coal consumption — will be the reality by 2016, in our view. The key driver is slowing power consumption growth.

Power consumption growth (4.5% in 2012; 3.8% year-to-date) is now lower than power generation growth from non-coal sources. Coal is therefore losing growth share currently. As these trends continue to diverge, by 2016, coal will be losing total share too. The deceleration in power consumption growth will not meaningfully reverse in coming years for the simple reason that China doesn't need that much more power to drive its economy.

China now consumes as much power as Poland on a per capita basis but is half as wealthy (again, on a per capita basis). Coastal provinces consume power at the same levels — on a per capita basis — as western European countries. The model of the energy-intensive North Asia tiger cannot apply for all of China. Jiangsu may become South Korea in terms of energy intensity, but the entire country will not. Global demand is simply not big enough for China to export its energy consumption in the form of finished goods — the way Korea does. Power consumption growth will now continue to moderate, and with it coal demand.

By our estimates, China will cease to import coal in 2015 and will see a decline in coal consumption in absolute terms in 2016 as hydro, nuclear,

renewables and gas-fired generation take market share in the power sector; steel, cement and fertilizer demand growth will continue to moderate; and other uses for coal in China (municipal boilers used for winter heating and factory furnaces, for example) will decline. We expect that China will start aggressively decommissioning coal-fired power stations and replacing them with nuclear or renewables by the latter half of this decade.

The economics of this energy evolution are not compelling. Coal prices have now fallen permanently. Nuclear and hydro are cheaper than coal-fired power generation in China, but gas, wind and solar are far more expensive. But what we are witnessing is not simply driven by economics: China is transitioning through the same environmental and public-health crisis that has seen every industrialized nation take steps to constrain its use of coal in the interest of something other than short-term economic growth.

Renewables: A Slow, Relentless Attack on Coal

All of a Sudden, an Overnight Success

Wind and solar represent a tiny share of Chinese power generation and installed capacity today. This is a legacy of three factors: historically high installed costs; poor transmission capacity in remote — but windy and sunny — parts of the country; and an absence of regulatory support for renewables in China.

Yet, because of heightened concerns about air quality in northeast China and pollution concerns generally since the start of 2013, things are changing, in our view.

The ~61GW of installed wind power generation capacity in China has gone from an albatross around the neck of State Grid to the only source of under-utilized existing power generation capacity in the whole country that consumes no coal, emits no carbon and creates no pollution. Wind is now part of the solution to the inter-related problems of China's reliance on coal and east coast air quality.

Solar — and distributed solar in particular — represents the ideal technology for any economy with a high-peak power demand spike due to air conditioning usage, low reserve margins, an environmental sensitivity towards the use of coal, a high gas price and good levels of summer sunshine. In other words, distributed solar, given current cost, is attractive in almost any Asian market. Japan's new solar feed-in tariff is driving adoption with the explicit purpose of lowering peak demand, lowering the gas bill, improving reserve margins and buying the government time to decide what to do on nuclear.

China — and India and Korea — is no doubt watching. We expect China to be the largest end market for wind and solar installed capacity globally over the next few years.

Chinese Wind and Solar Capacity Expansion Is Just Getting Started

We believe wind and solar will expand from roughly 61GW and 8.3GW of installed capacity currently to 250GW and 200GW, respectively, by the end of the decade (see Exhibit 51). In combination, wind and solar will account for roughly half of incremental power generation over the rest of the decade, by our estimates (see Exhibit 52).

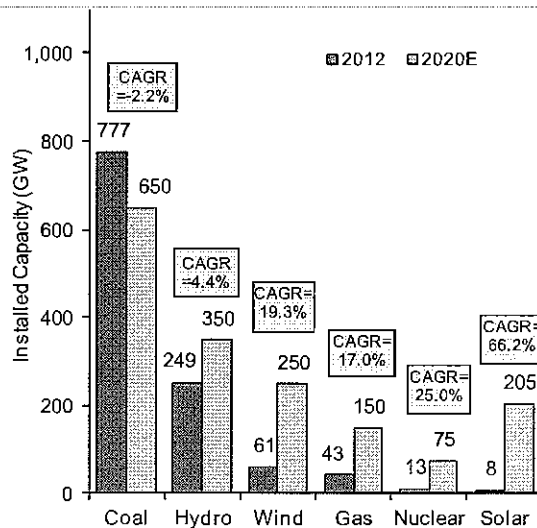
Wind is currently an under-utilized source of power generation in China. The 61GW of installed capacity operated at a utilization rate of ~19% in 2012. This utilization rate was due to an inability or unwillingness of State Grid to dispatch all of the electricity being generated. We believe that the normal level of utilization will (by 2015) be 27%. We believe that State Grid will remain under pressure to connect wind farms and absorb all of the electricity generated as part of the push towards improving air quality in northeastern China.

Solar is a rounding error within the Chinese power portfolio today. However, with installed cost now approaching \$1/W, solar is economic with gas-fired power generation in China, and — on a distributed basis — is economic against on-grid power prices.

Today, solar is at or near "grid parity" in China: the unsubsidized cost to generate electricity from solar is the same as the cost of electricity from the marginal unit of power generation. No subsidies are required. In short, solar is entering the global — or at least the Chinese — energy market (see Exhibit 53). And since costs in the technology sector tend to fall over time and costs for extractive industries tend to rise over time, the competitive position of solar versus fossil fuels as a source of power generation is likely to improve in coming years.

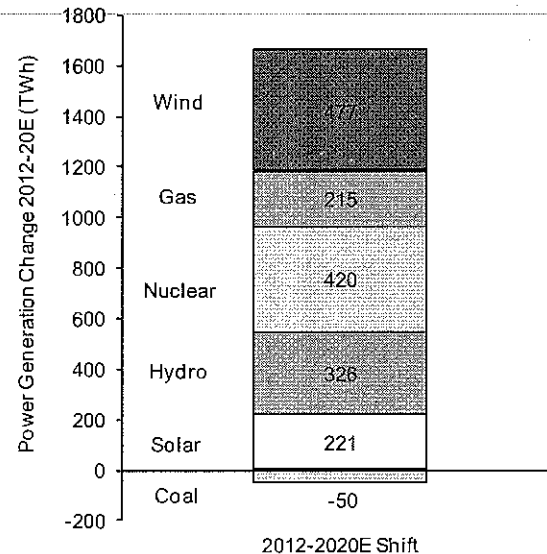
In this chapter, we set out the basis for our bullish view on wind and solar expansion in China over the remainder of the decade. The three limiting factors for renewables in China to date — installed cost, a refusal from the regulator to force State Grid's hand and an indifference to the environmental impacts of ever more coal — have, after years of false starts, suddenly disappeared.

Exhibit 51 Installed Capacity by Fuel Source (2012 and 2020E)



Source: CEIC and Bernstein estimates and analysis.

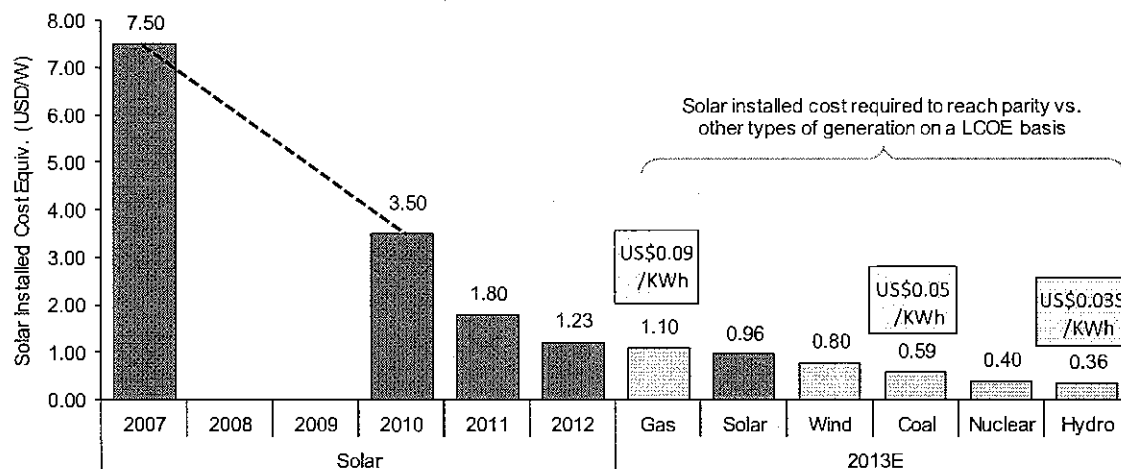
Exhibit 52 Power Generation Shift by Fuel Source (2012-2020E)



Source: CEIC and Bernstein estimates and analysis.

Solar and wind are now a permanent and important part of both Chinese industrial and energy policy. As such, we expect China to embrace both technologies as a means of displacing coal from both peak- and base-load power supply.

Exhibit 53 Solar Installed Cost Required to Reach Parity vs. Other Types of Clean Energy Generation on a LCOE Basis



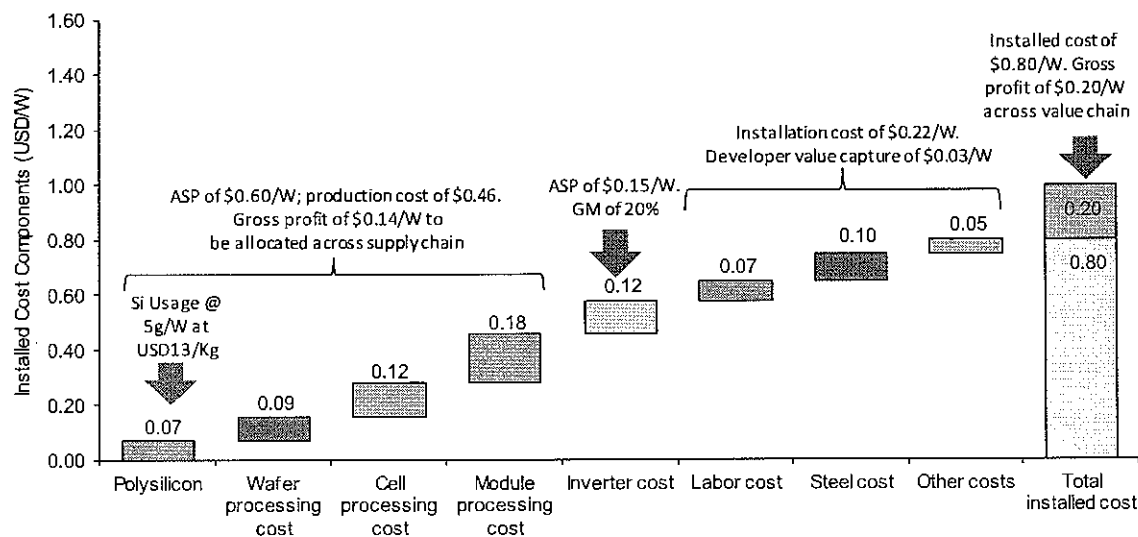
Source: Government announcements, media reports, World Nuclear Association, corporate reports and Bernstein estimates and analysis.

Solar Is the Ideal Power Source for Urbanizing China

Demand for solar — at the 2013 levelized cost of energy in developing markets implied in Exhibit 53 (US\$0.08/KWh) — should continue to ramp up globally. The path to the industry dropping costs further is clear to us (see Exhibit 54), meaning the economic viability of the supply chain is improving.

Exhibit 54

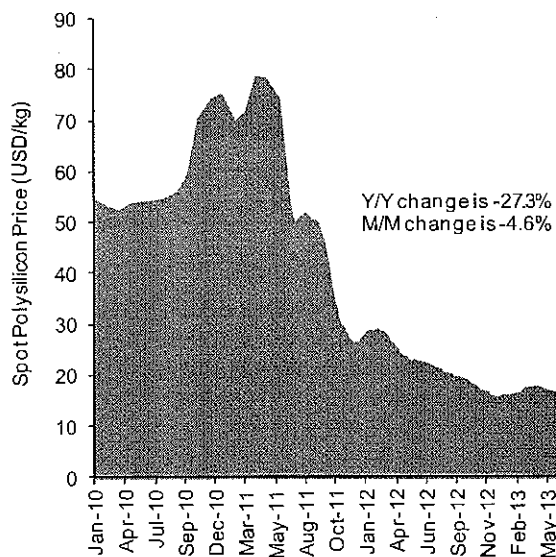
EOY 2013 SCB Estimate of Solar Value Chain Economics for Utility-Scale, Developing Market Solar PV Projects



Source: Corporate reports and Bernstein estimates and analysis.

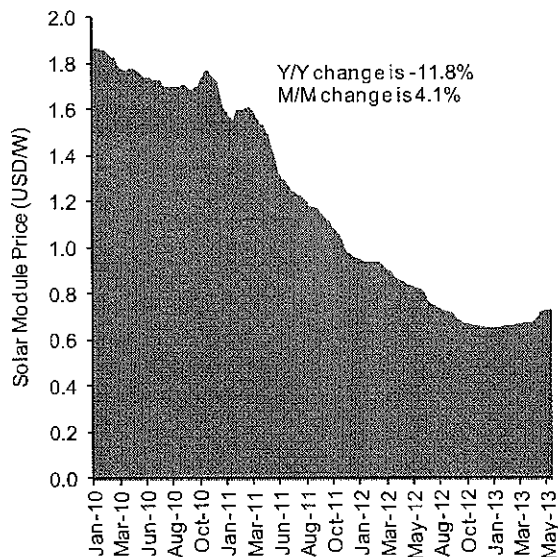
Prices for modules can stabilize and polysilicon price can rise modestly without disturbing demand (see Exhibit 55 and Exhibit 56).

Exhibit 55 Polysilicon Spot Price



Source: Bloomberg L.P. and Bernstein analysis.

Exhibit 56 Silicon Solar Module Spot Price



Source: Bloomberg L.P. and Bernstein analysis.

The quadrupling of the industry over the last five years happened at a time when subsidies were driving growth, and without any significant participation from China. Growth in demand, now that solar is competitive in the unsubsidized global energy market, should be brisk.

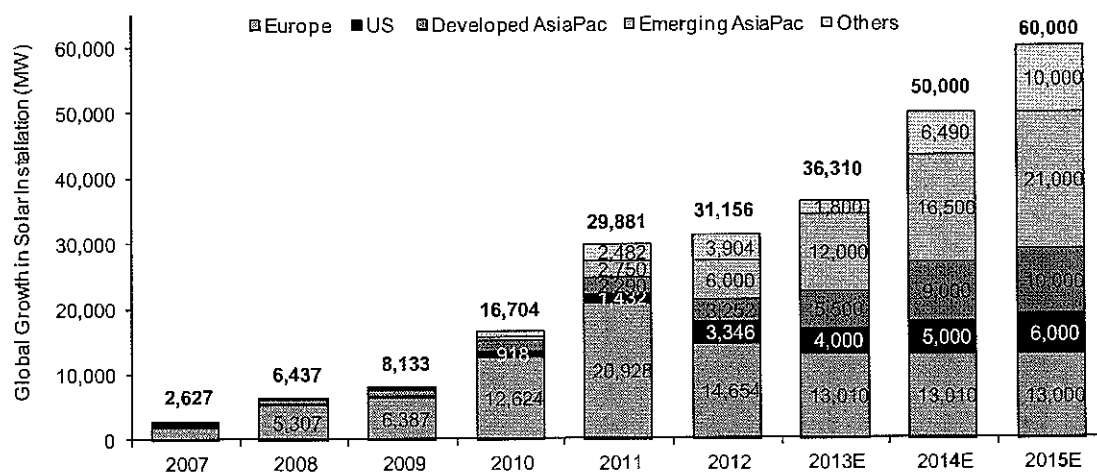
Solar is no longer creating its own market based on incentives offered at a state, provincial or national level. It is instead now part of a US\$5 trillion energy market...and it is a tiny part of that market. Demand for solar is — at \$1/W — nearly unlimited (see Exhibit 57).

Exhibit 57		Global Annual Solar Installed Capacity Additions, 2007-15E (in MW)								
Country	2007	2008	2009	2010	2011	2012	2013E	2014E	2015E	
China	20	40	160	500	2,500	5,000	10,000	12,500	15,000	
Y/Y growth	67%	100%	300%	213%	400%	100%	100%	25%	20%	
Germany	1,271	1,950	4,446	6,988	7,485	7,604	7,500	7,500	7,500	
Y/Y growth	51%	53%	128%	57%	7%	2%	-1%	0%	0%	
US	207	338	448	918	1,432	3,346	4,000	5,000	6,000	
Y/Y growth	42%	64%	32%	105%	56%	134%	20%	25%	20%	
Japan	210	225	483	991	1,296	2,000	3,000	5,000	5,000	
Y/Y growth	-27%	7%	114%	105%	31%	54%	50%	67%	0%	
India	16	40	75	125	250	1,000	2,000	4,000	6,000	
Y/Y growth	100%	150%	88%	67%	100%	300%	100%	100%	50%	
Italy	70	338	723	2,321	9,301	3,438	2,000	2,000	2,000	
Y/Y growth	462%	382%	114%	221%	301%	-63%	-42%	0%	0%	
Australia	12	22	83	383	837	1,000	1,500	2,000	3,000	
Y/Y growth	26%	80%	278%	361%	118%	19%	50%	33%	50%	
France	31	105	201	817	1,463	1,032	1,200	1,200	1,200	
Y/Y growth	187%	234%	92%	308%	79%	-29%	16%	0%	0%	
South Korea	45	276	167	131	157	252	1,000	2,000	2,000	
Y/Y growth	104%	509%	-40%	-21%	19%	61%	297%	100%	0%	
Greece	1	10	37	143	426	912	900	900	900	
Y/Y growth	-50%	900%	270%	286%	198%	114%	-1%	0%	0%	
Belgium	23	81	519	428	996	599	500	500	500	
Y/Y growth	1050%	252%	541%	-18%	133%	-40%	-17%	0%	0%	
United Kingdom	4	4	4	44	906	679	500	500	500	
Y/Y growth	12%	16%	-20%	1151%	1968%	-25%	-26%	0%	0%	
Spain	557	2,758	60	392	345	277	400	400	400	
Y/Y growth	463%	395%	-98%	553%	-12%	-20%	44%	0%	0%	
Czech Republic	2	61	398	1,491	6	113	10	10	-	
Y/Y growth	100%	2950%	552%	275%	-100%	1783%	-91%	0%	-100%	
Other	157	188	331	1,032	2,482	3,904	1,800	6,490	10,000	
Y/Y growth	-2%	20%	76%	212%	141%	57%	-54%	261%	54%	
Global	2,610	6,387	8,021	16,436	29,455	31,156	36,310	50,000	60,000	
Y/Y growth	62.3%	144.7%	25.6%	104.9%	79.2%	5.8%	16.5%	37.7%	20.0%	

Source: BP Energy Survey 2013, EPIA, corporate reports and Bernstein estimates and analysis.

The implication is a massive increase in solar installed capacity in developing markets in general and China in particular in coming years. We estimate emerging Asia-Pacific and other developing markets will be the key drivers of growth in coming years (see Exhibit 58 through Exhibit 60).

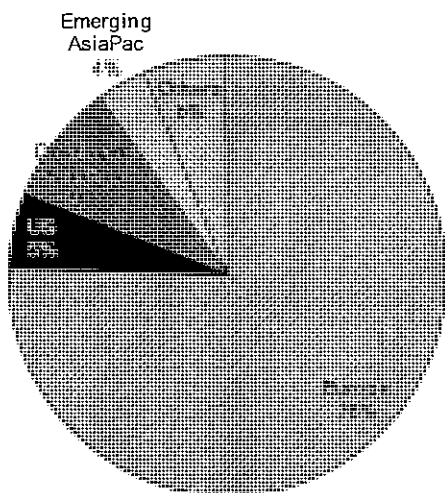
Exhibit 58 Global Annual Solar Installed Capacity Additions, 2007-15E (in MW)



Source: BP Energy Survey 2013, EPIA, corporate reports and Bernstein estimates and analysis.

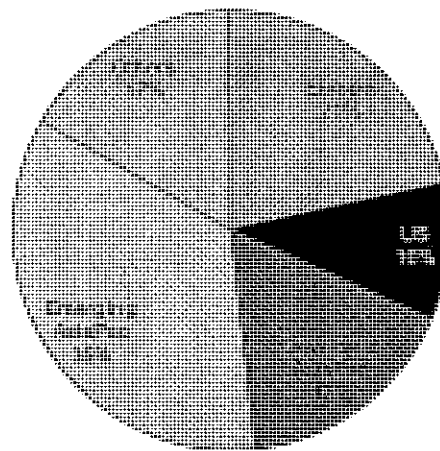
The German, Chinese and Indian markets (totaling 19.5GW or 54% of 2013 newly installed capacities) are all price sensitive. Accordingly, this demand trajectory is premised on the view that solar can achieve and maintain an installed price of \$1/W.

Exhibit 59 2010 Solar-Panel Installed Capacity



Source: Corporate reports and Bernstein estimates and analysis.

Exhibit 60 2015E Solar-Panel Installed Capacity

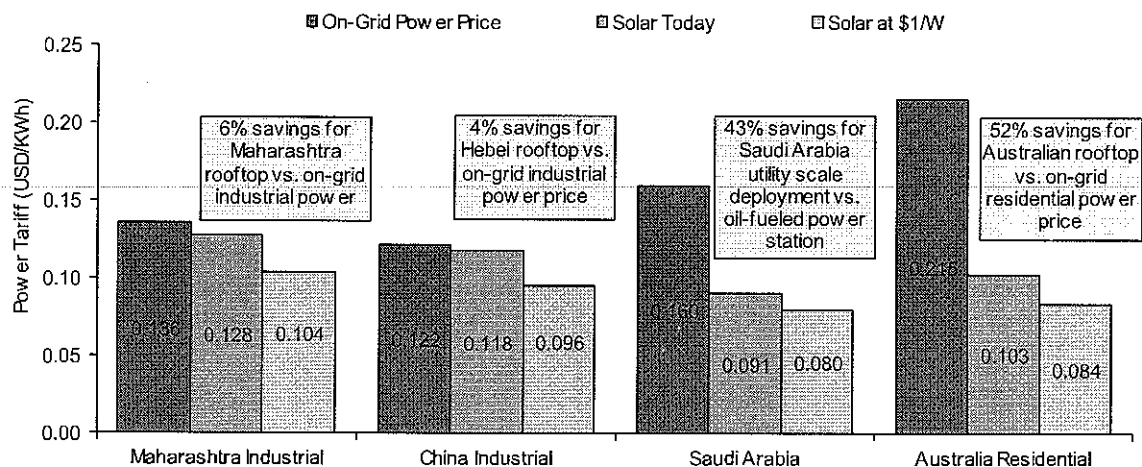


Source: Corporate reports and Bernstein estimates and analysis.

At this price point, utility-scale projects in Saudi Arabia, industrial usage in Maharashtra (India), industrial usage in Baoding (China), and residential usage in Australia are all economic on an unsubsidized basis. We compare on-grid electricity prices or opportunity cost with the current solar price and our 2013 target solar installed prices. Unsubsidized solar is economic today in these markets.

Exhibit 61

Already There...Current on-Grid Tariff vs. Solar Levelized Cost of Energy in China, India, Saudi Arabia and Australia



Note: Solar installed cost today is US\$1.25/W (distributed), while Saudi Arabia's installed cost today is \$1.15/W (utility scale). Assumed solar installed cost is \$1/W for all in the year 2013 case.

Source: Corporate reports and Bernstein estimates and analysis.

We estimate that at an IRR of 8% and at the current solar installed cost (assuming US\$1.15/W for Saudi Arabia's utility-scale installation and US\$1.25/W distributed installation), unsubsidized solar in both India and China is slightly below retail power prices. In Saudi Arabia and Australia, at current prices, solar achieves ~40-50% cost savings. Further savings are available at a solar installed cost of US\$1/W (our EOY 2013 target level) — see Exhibit 61.

Exhibit 62 China Installed Capacity (2009-20E)

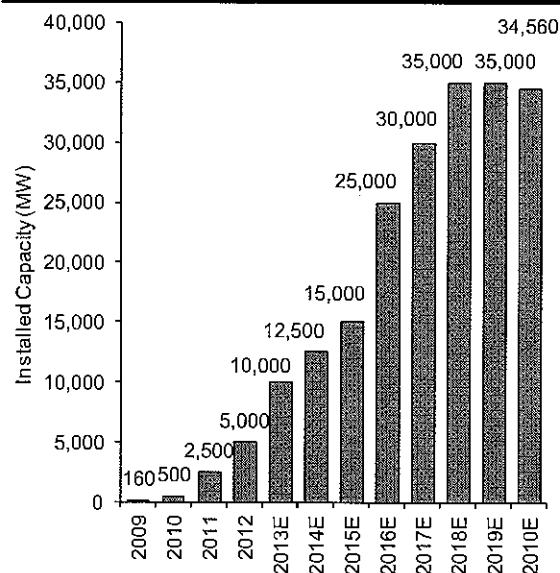
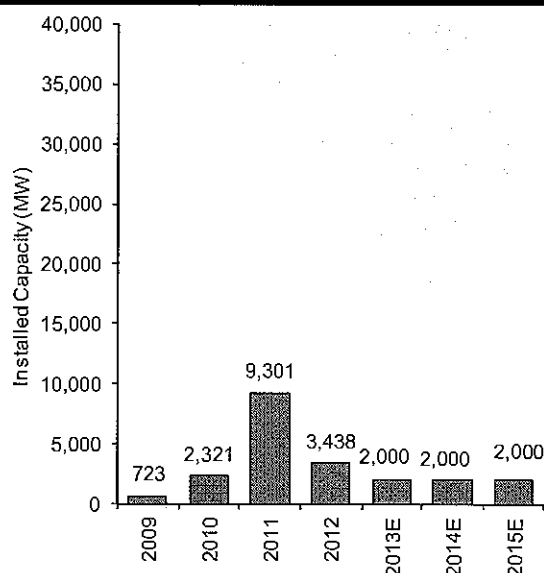


Exhibit 63 Italy Installed Capacity (2009-15E)



Source: NBS, BP Energy Survey and Bernstein estimates and analysis. Source: EPIA, BP Energy Survey and Bernstein analysis.

This is exactly the combination of events that led to an explosion in installed capacity in Germany and Spain in 2008 and 2009 and Italy in 2011: falling solar installed costs in a market with a subsidized solar power tariff that suddenly made poor projects economic and viable projects tremendously profitable...and resulted in a spike in demand for solar panels globally. We expect the same in China (see Exhibit 62 and Exhibit 63).

The Driver for Growth Is Now the Attractive Unsubsidized Economics

The economics of solar in China are tremendously attractive today given the current subsidies of RMB1/KWh (US\$0.15/KWh).

Exhibit 64

China Solar Economics at \$1.20/W (Installed, Distributed) Based on Subsidy

Revenue (RMB)	1,009	On-grid tariff (ex-VAT; RMB/KWh)	0.850	Installed Cost USD/W	1.20
Capital expense	7,560	Solar Insolation (KWh/m ² /day)	5.00	X to KW	1,000
Depreciation (20 year SL)	378	Net Utilization (AC)	13.6%	Exchange rate	6.3
O&M charge (RMB4500/KW)	45	Net generation per annum (KWh; AC)	1,188	Total construction cost per KW (RMB)	7,560
Debt as percentage of total cost	80.0%	Panel capital cost per KW	3,326		
Interest expense	5.50%	Panel cost as percentage of construction cost	44%		
Tax rate	25.0%	Total construction cost per KW	7,560		

LCOE - Solar 850.0 RMB/MWh 134.4 USD/MWh													
--	--	--	--	--	--	--	--	--	--	--	--	--	--

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13
Revenue		1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009
Operating and Maintenance Expense		45	45	45	45	45	45	45	45	45	45	45	45	45
Depreciation		378	378	378	378	378	378	378	378	378	378	378	378	378
Operating income		586	586	586	586	586	586	586	586	586	586	586	586	586
Interest expense		333	316	299	283	266	249	233	216	200	183	166	150	133
Net Profit before tax		254	270	287	304	320	337	354	370	387	403	420	437	453
Tax		-	-	-	38	40	42	44	93	97	101	105	109	113
Net Profit after tax		254	270	287	266	280	295	309	278	290	303	315	328	340
Free cash flow to firm														
Operating income		586	586	586	586	586	586	586	586	586	586	586	586	586
Add: Depreciation		378	378	378	378	378	378	378	378	378	378	378	378	378
Less: taxes		-	-	-	(73)	(73)	(73)	(73)	(147)	(147)	(147)	(147)	(147)	(147)
Free cash flow to firm	(7,560)	964	964	964	891	891	891	891	818	818	818	818	818	818
Project IRR		9.88%												
Free cash flow to equity														
Operating income		586	586	586	586	586	586	586	586	586	586	586	586	586
Add: Depreciation		378	378	378	378	378	378	378	378	378	378	378	378	378
Less: interest		(333)	(316)	(299)	(283)	(266)	(249)	(233)	(216)	(200)	(183)	(166)	(150)	(133)
Less: taxes		-	-	-	(38)	(40)	(42)	(44)	(93)	(97)	(101)	(105)	(109)	(113)
Less: Repayment of loan principal		(302)	(302)	(302)	(302)	(302)	(302)	(302)	(302)	(302)	(302)	(302)	(302)	(302)
Free cash flow to equity		329	346	363	341	356	370	385	353	366	378	391	403	416
Equity IRR		23.44%												

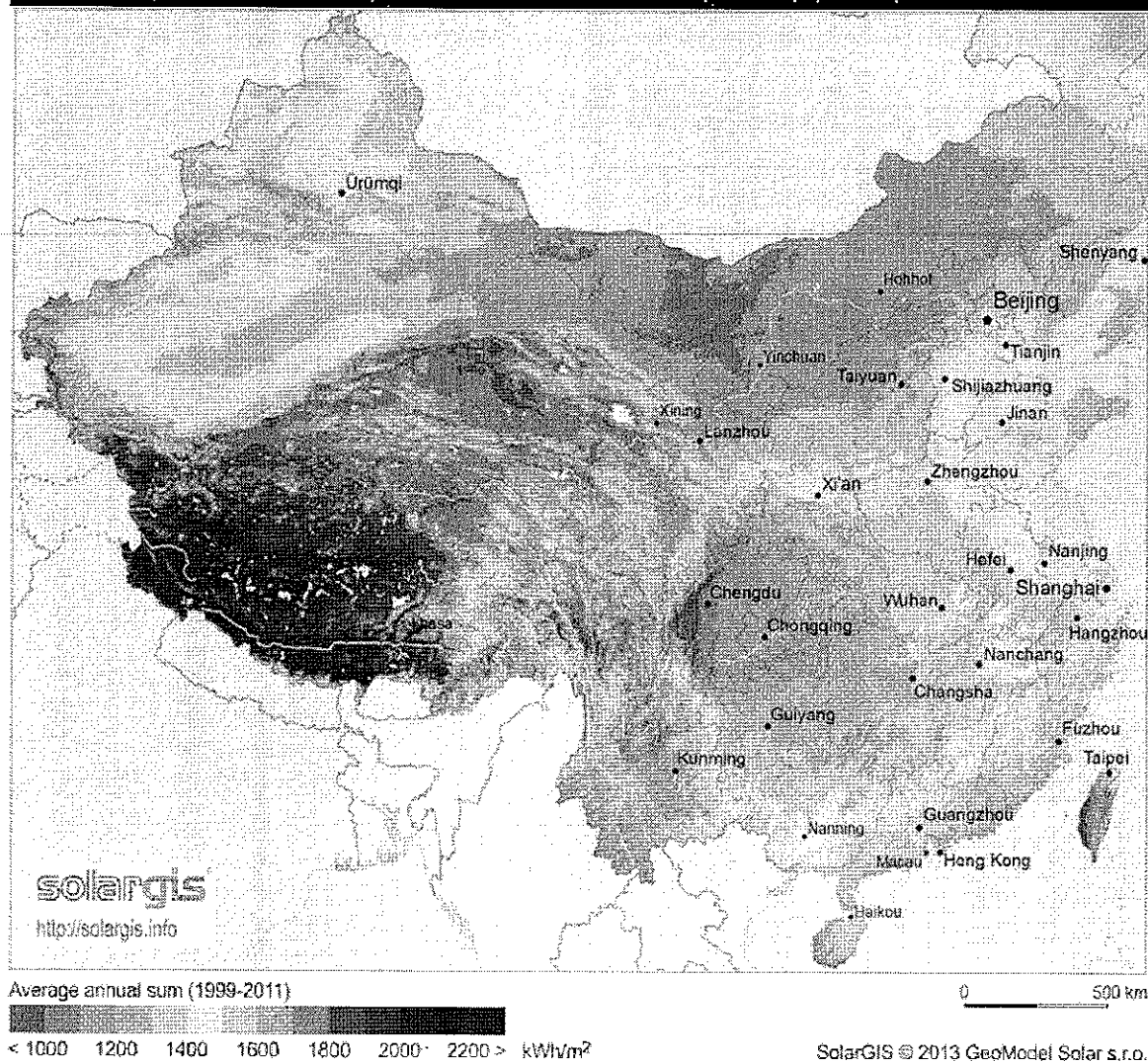
Source: Corporate reports and Bernstein estimates and analysis.

We think it is significant that two months after China announced (on January 9, 2012) that it will be the largest solar end market in the world this year with 10GW of installed capacity, there were press reports that Chinese solar tariffs are to be cut. We interpret this as a sign that installed cost has already fallen to such an extent that the NDRC clearly believes it can cut tariffs *and* still achieve its 10GW expansion target.

We estimate that installed cost is close to \$1.20/W in China currently. Various companies we have talked to have put the cost closer to \$1.40/W but we believe this to be a retrospective estimate...or just plain conservative. At RMB1/KWh and \$1.20/W to install, utility-scale projects in western China look, by our estimate, to be tremendously attractive with equity IRRs of ~23% (see Exhibit 64). In short, the fact that the NDRC is reportedly reducing tariffs in parts of Qinghai by 25% is, in our view, not at all surprising (see Exhibit 65).

Exhibit 65

China— Global Horizontal Irradiation (KWh/M2/yr)



Source: SolarGIS © 2013 GeoModel Solar s.r.o and Bernstein analysis.

State Grid has not covered itself in glory in building transmission capacity to evacuate power generated by wind farm operators in Inner Mongolia and throughout northeastern China. However, we believe that transmission capacity is improving in China as State Grid is adding 30,000 km of high-voltage transmission capacity currently. Further, the imposition of a Renewable Portfolio Standard in China (long rumored and now potentially imminent) and additional requirements on State Grid in terms of supporting solar power are likely to lower site preparation costs as outlined earlier.

And distributed solar, which addresses all of the weaknesses within China's east coast power market (low reserve margins, high peak demand, sensitivity to environment impacts and therefore coal; high gas prices; and falling tolerance for disruptions to power supply), is a tailor-made solution for Chinese power needs over the next decade. And its adoption supports Chinese industrial policy — the focus on clean technologies with the current five-year plan — at the same time.

Inner Mongolia — An Enigma Wrapped in a Wind Cheater

The provincial tariff structure established for wind power in China in 2009 was configured so that provinces with high wind speeds and therefore high levels of utilization also had lower tariffs. On that basis, any project — no matter where it was located — would achieve a broadly similar return.

Accordingly, Inner Mongolia — which has good wind speeds — has a tariff that is RMB0.10/KWh lower than most of the country. However, the tariff differential was clearly not great enough to drive the desired behavior. Inner Mongolia installed capacity — and that in Jilin, Liaoning and Heilongjiang (the northeast) — has outstripped transmission capacity in recent years leading to curtailment and low utilization in these low-tariff areas.

The companies have taken note. Longyuan added wind generation capacity of 1,946MW in 2012. But the expansion was predominantly in parts of the country without curtailment problems. Longyuan is organically reducing its curtailment exposure, while State Grid solves the problems directly in Inner Mongolia and the northeast.

The attraction to Inner Mongolia (at least for operators of wind farms) is clear. The windiest part of the U.S. is from west Texas to North Dakota. Utilization on west Texas wind farms is routinely in the low-30% range. Inner Mongolia has similar wind speeds, and therefore should — once utilization issues are resolved — offer similar levels of utilization (see Exhibit 66).

Exhibit 66

Global Wind Map — Texas Through North Dakota in the U.S. Has the Same Wind Speed as Inner Mongolia in China



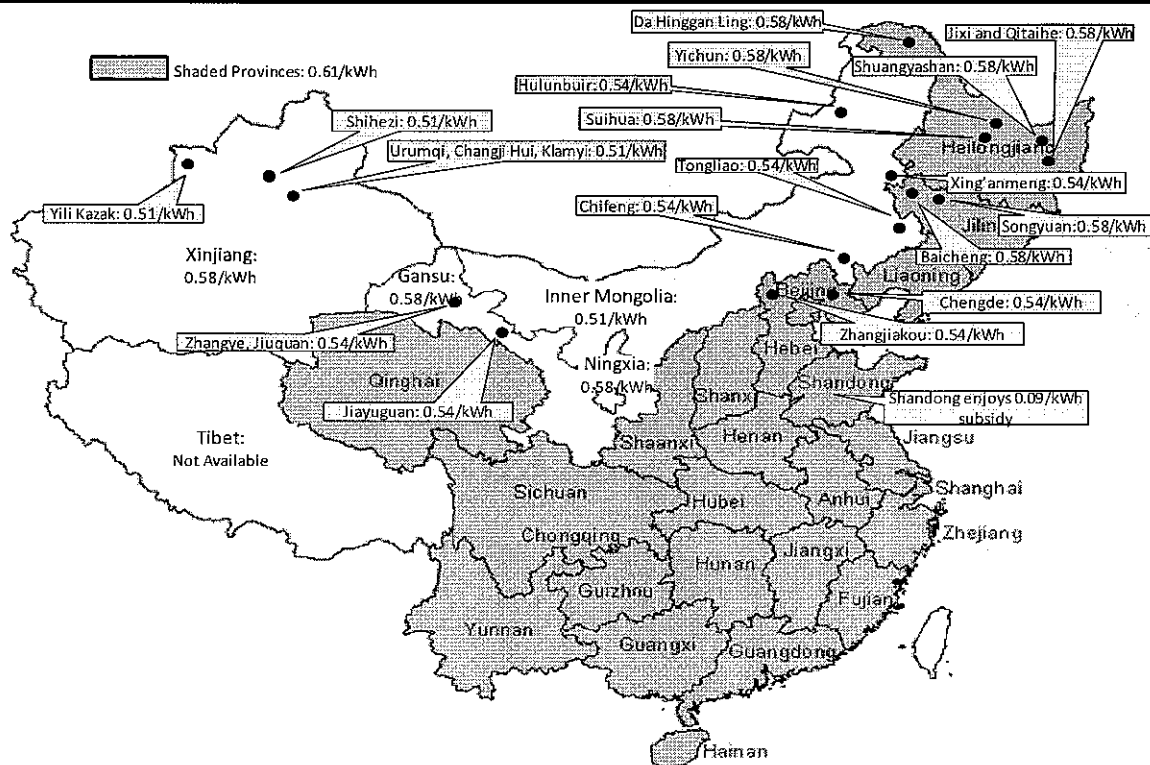
Source: Copyright © 2013 3TIER, Inc and Bernstein analysis.

Wind power generation of Longyuan in the first quarter of 2013 increased 32.7% year-over-year. Wind power generation in Heilongjiang, Jilin, Liaoning and Inner Mongolia was up 52%, 33%, 7% and 21% year-over-year, respectively. These growth rates exceed installed capacity growth by a wide margin everywhere but Liaoning. According to the company, the wind power curtailment rate in the first quarter was 17%, compared to 22% in the same period last year. Curtailment rate further improved to 14% in March 2013, and was the best month in the first quarter.

The policy splits China into four main wind resource regions and sets benchmark prices for each region according to wind resource and project development conditions.

A simple analysis of the China wind tariff map alongside a wind speed map (see Exhibit 66) leads to a clear conclusion: build as much as wind capacity you can in Inner Mongolia, Heilongjiang, Liaoning and Jilin. Yes, tariffs are lower in Inner Mongolia than in the rest of the country, but the differences in wind speed make up for it.

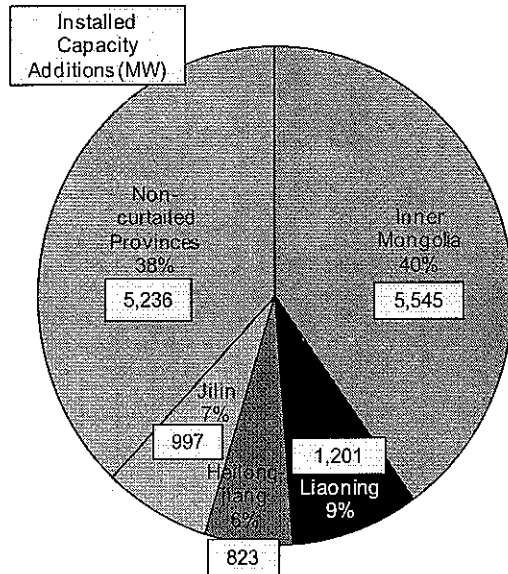
China Wind Tariff Map by Zone (Including VAT)



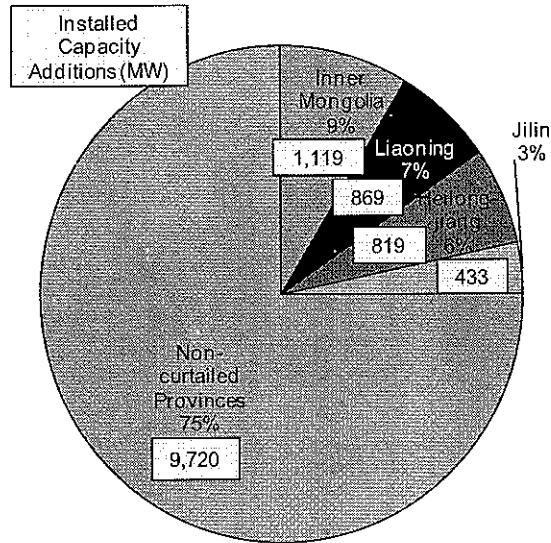
Source: "Circular on Improving Wind Power On-grid Tariff Policy" (NDRC Price [2009] No.1906), corporate reports and Bernstein analysis.

And so from 2009 until 2011, that is what all of the companies that we cover did: they built most of the new capacity in the windiest parts of the country, and most acutely in western Inner Mongolia. Roughly 60% of all new wind capacity in 2009 was built in one of those four provinces (see Exhibit 68). The problem with this approach is that there is nothing else in western Inner Mongolia. And so, once the wind farms were completed, there were no cities or industrial centers to draw the electricity and insufficient inter-provincial transmission capacity to take the electricity anywhere else.

The industry is learning. In 2012, additions in the four curtailed provinces were only 25% of industry growth (see Exhibit 69). On the other hand, the high utilization and high-tariff regions have recorded high installed capacity growth in 2012. Yunnan's installed capacity increased by 111% year-over-year, Guizhou was up by 160%, Henan was up by 64% and Shanxi was up by 55%.

Exhibit 68 Chinese Wind Power Installed Capacity Additions 2009

Source: CWEA and Bernstein analysis.

Exhibit 69 Chinese Wind Power Installed Capacity Additions 2012

Source: CWEA and Bernstein analysis.

Today, curtailment is still a problem. China still has most of its capacity installed in provinces with high wind speeds but low levels of utilization, including Inner Mongolia, Heilongjiang, Jilin and Liaoning. Curtailment is now falling and utilization is going up. In short, this dysfunctional, upside-down outcome will eventually reverse.

Exhibit 70 and Exhibit 71 set out the utilization for the best-performing portfolios among the three operators (Longyuan, Huaneng Renewables and Datang Renewable) on a per-province basis.

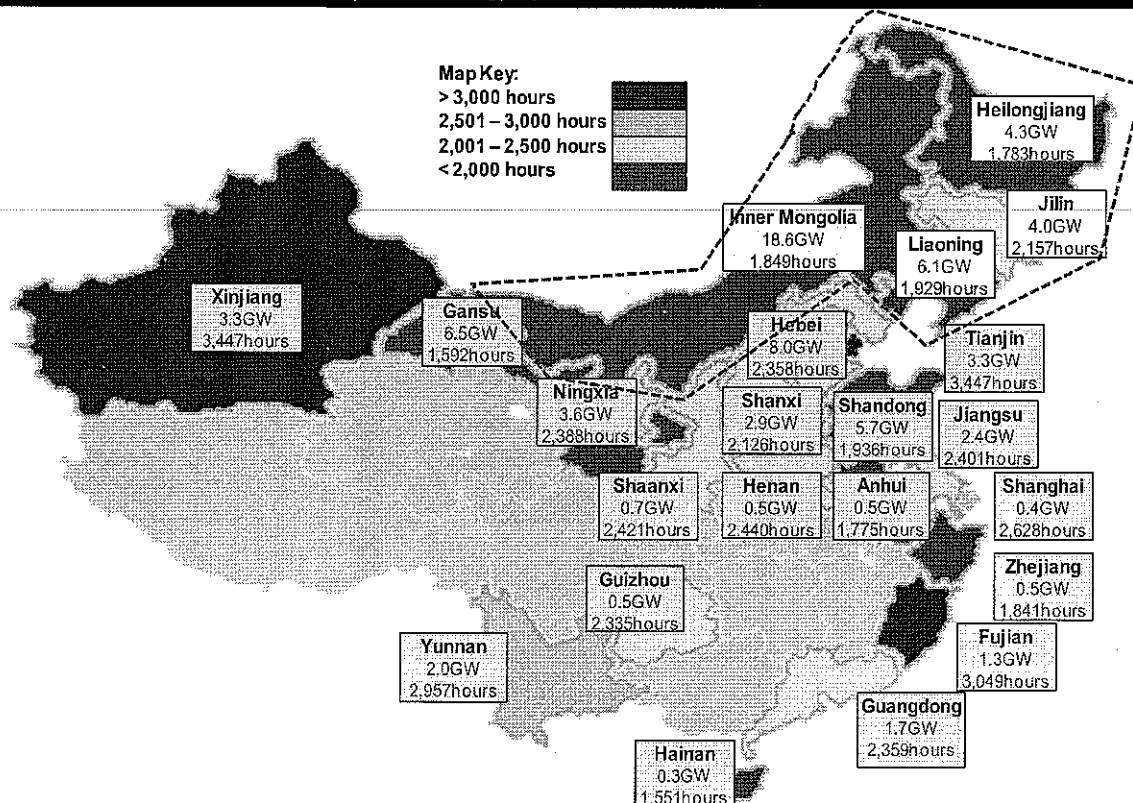
We estimate that the maximum weighted average utilization for China nationwide could reach ~2,382 hours, or 27% in 2015.

Our methodology is simple: the best-performing portfolios in each of the non-curtailed provinces is likely to become the industry standard over time: there is trial and error associated with site selection everywhere, which will improve over time; some level of curtailment is likely to have been experienced in most parts of the country, operational problems in the early stages of some projects is likely. Accordingly, we believe that the "best" portfolio performance is likely to be matched and become the industry average in each province in coming years.

Second, for the four curtailed provinces (Inner Mongolia, Heilongjiang, Jilin and Liaoning), utilization hours of Longyuan, Huaneng Renewables and Datang Renewable averaged 1,715 (19.5%); 1,457 (16.6%) and 1,719 (19.6%), respectively, in 2012. We assume that the curtailed provinces can — if transmission problems are resolved — exceed utilization in non-curtailed provinces by 10% (this is little more than a naïve guess but the fact that the Inner Mongolia tariff is 16% lower than the rest of the country implies that the policy makers, who set the tariff, expected Inner Mongolia utilization to be roughly 20% higher).

Exhibit 70

Wind Installed Capacity and Maximum Utilization Hours by Province for the Three Renewable Energy Operators



Source: Wikimedia commons, CWEA, corporate reports and Bernstein estimates and analysis.

We reach our target using "best-in-class" utilization by the three operators in non-curtailed provinces currently (see Exhibit 71 and Exhibit 72), our expectation that roughly half of the national fleet will be in currently curtailed provinces over time, and our expectation that performance in those currently curtailed areas will be 10% higher than in non-curtailed areas. This means that over the next two and a half years, we expect to see improving utilization based on the efforts of both State Grid and the companies themselves in organically growing away from problem areas.

Exhibit 71 China Wind Power Utilization Hours of the Non-Curtailed Provinces by Company					
Province	2012 Installed Capacity (MW)	Longyuan Utilization Hours	Huaneng Renewables Utilization Hours	Datang Renewable Utilization Hours	Maximum Utilization Hours
Anhui	494	1,775			1,775
Fujian	1,291	3,049			3,049
Gansu	6,479	1,578		1,592	1,592
Guangdong	1,691		2,359	2,060	2,359
Guizhou	507	2,144	2,335		2,335
Hainan	305	1,551			1,551
Hebei	7,979	2,358	1,952	1,693	2,358
Henan	493			2,440	2,440
Jiangsu	2,372	2,401			2,401
Ningxia	3,566	2,388		1,625	2,388
Shaanxi	710		2,421	1,850	2,421
Shandong	5,691	1,661	1,936	1,656	1,936
Shanghai	352		2,044	2,628	2,628
Shanxi	2,907	1,976	2,126	2,084	2,126
Tianjin	278	2,067			2,067
Xinjiang	3,306	2,540	3,447		3,447
Yunnan	1,964	2,957	2,758	2,824	2,957
Zhejiang	482	1,841			1,841
Other	1,455				2,111
Non-Curtailed Provinces	42,320				2,282

Source: CWEA, corporate reports and Bernstein estimates and analysis.

The companies are now also focusing on areas outside of the curtailed provinces. Longyuan's installed capacity additions dropped sharply overall and especially in curtailed regions between the second half of 2010 and the second half of 2012.

Exhibit 72 Expected Utilization Levels of the Curtailed and Non-Curtailed Provinces in 2015			
Province	2012 Installed Capacity (% / MW)	2012 Maximum Utilization Hours	2015 Expected Utilization Hours
Heilongjiang	5.7%	1,783	2,510
Inner Mongolia	24.7%	1,849	2,510
Jilin	5.3%	2,157	2,510
Liaoning	8.1%	1,929	2,510
Non-Curtailed Provinces	56.2%	2,282	2,282
China Nationwide	75,324	2,111	2,382

Curtailed provinces at 10% higher utilization than non-curtailed provinces

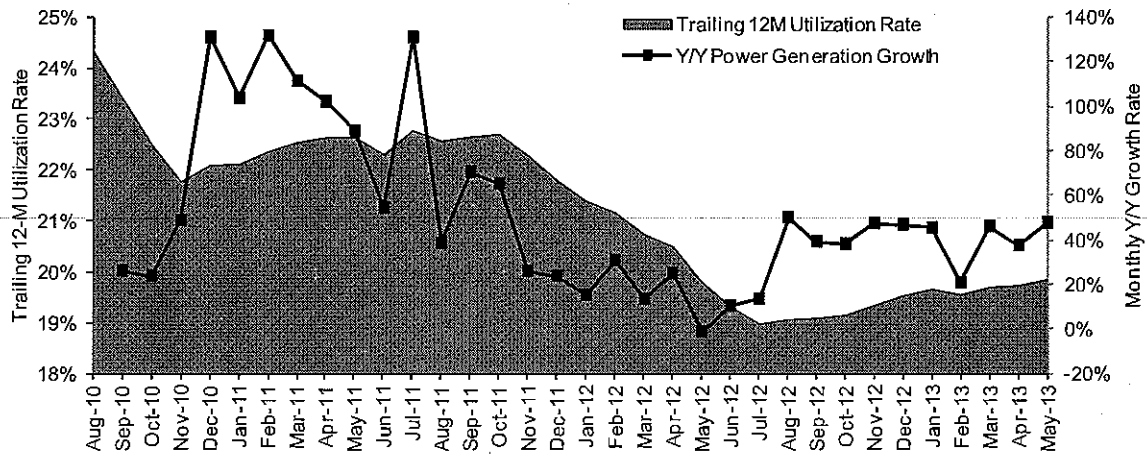
Non-curtailed provinces at 2012 maximum utilization

Source: CWEA, corporate reports and Bernstein estimates and analysis.

Utilization for China wind fleet is now trending up, off a low, low base (see Exhibit 73). Based on our adjusted capacity estimate for May 2013 (assuming 4.7GW added year-to-date), we calculate the average rolling 12-month utilization for wind power generation as 19.9% in May.

Exhibit 73

Rolling 12-Month Average Utilization and Y/Y Generation Growth

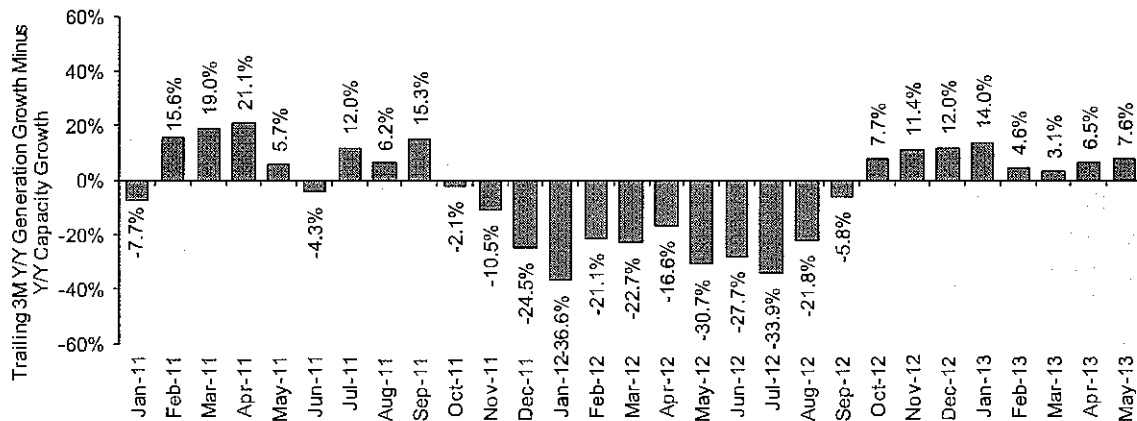


Source: CEIC, NBS and Bernstein estimates and analysis.

In the last nine months, generation growth has outstripped installed capacity growth, implying higher utilization as a result of improving transmission in Inner Mongolia and the northeast and more judicious placement of new wind farms in parts of the country, with fewer curtailment problems.

Exhibit 74

Trailing Three-Month Y/Y Generation Growth vs. Trailing Three-Month Y/Y Capacity Growth



Note: Trailing April 2013 data is reduced to two months to adjust for the effect of February 2013/January 2012 Chinese New Year.

Source: CEIC, NBS and Bernstein estimates and analysis.

Looking at the trailing three-month year-over-year generation growth minus year-over-year capacity growth, the result turned positive in October and improved further since (see Exhibit 74).

The curtailment issues being faced in four north and northeastern provinces — Inner Mongolia, Liaoning, Jilin and Heilongjiang — are the major reason for lower utilization hours. The year 2013 is a big improvement but the project to build more transmission is still a work in progress. That said, we believe that utilization is going to steadily improve over the next two and a half years and that by 2015 State Grid will have completed large, high-voltage transmission projects to address specific bottlenecks in transmitting wind power around the country, curtailment

will be reduced, and the true or normal long-term utilization rates across the country will be realized. At that point, utilization should settle in the high-20% range. And wind and solar will continue to see an increase in installed capacity additions.

With each 1GW of wind installed, coal consumption falls by 1 million tons. The insidious aspect of renewable energy investment for other sources of power supply is that the 1 million tons of demand never returns. With zero variable cost and a 20-year life, renewables — once installed — are, for practical purposes, forever.

The Nuclear Option: China's Energy Future...With French Characteristics

Godzilla Risk Minimal in China's Nuclear Ramp

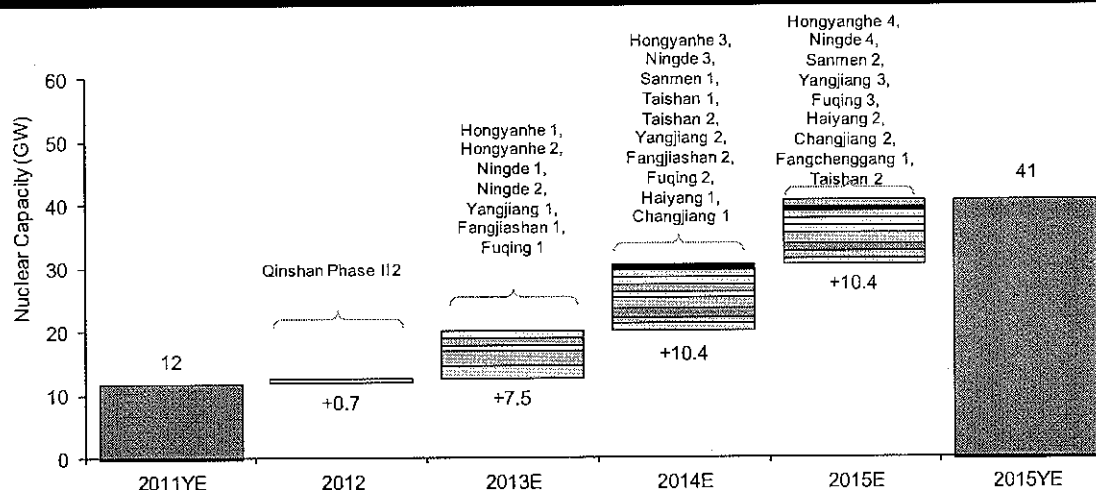
Nuclear power generation within China is a tiny part (currently less than 2%) of overall power production. Even under an aggressive expansion scenario, nuclear power generation will struggle to exceed 5% of total power generation by 2020. However, given the slowdown in power production growth that China is currently experiencing, share of incremental production absorbed by the growing nuclear fleet is significant, roughly one-quarter, in our view. For the coal sector, this is further incrementally negative.

The Post-Fukushima, existential risk to nuclear is minimal in our view. The risk that air quality in Beijing deteriorates further next winter from last winter level is far more important than concerns about events at yet-to-be-built power stations that rely on a technology that China has several decades of experience managing: *what might kill you is less important than what will kill you.*

China on Track to Reach at Least 40GW of Nuclear Capacity by 2015

The Chinese government is currently targeting 40GW of nuclear power capacity by the end of 2015, representing a CAGR of ~30% from 2010. Based on a plant-by-plant analysis of China's nuclear power projects (see Exhibit 75), the country could even exceed this target and reach 41GW of capacity if all of its projects are commissioned on time. In any event, China is almost certain to have the fourth-largest nuclear installed capacity base in the world by 2015.

Exhibit 75 China Nuclear Power — 2011-15E Expansion Plan



Source: CEIC, NBS, NEA, Ministry of Environmental Protection and Bernstein estimates and analysis.

In 2012, China commissioned one unit at the Qinshan nuclear power station in Zhejiang. Two units (Hongyanhe 1 in Liaoning and Ningde 1 in Fujian) have already been commenced in February and April this year, respectively. The announced nuclear capacity target of 40GW by 2015 would be a 35% CAGR from 2011 and requires ~7GW of incremental generation capacity per year from 2012. Until this year, China had never added more than ~2GW of nuclear capacity in a single year. We believe that with the commissioning of units at Ningde and

Hongyanhe earlier this year, the acceleration in China's nuclear expansion has officially begun.

Roughly 1GW of nuclear generation capacity (operating at standard utilization) displaces ~4 million tons of coal. With ~8GW of nuclear capacity coming on line in 2013, 30 million tons of coal will be displaced. In the context of an overall market of almost 4 billion tons of coal consumption, 30 million tons is nothing. But in the context of a market that is expanding coal consumption at 100 million tons per year, displacing 30 million tons is significant...in an already oversupplied market.

And the effect is compounding. According to the World Nuclear Association, roughly 200GW of nuclear installed capacity is planned for construction in China within the next two decades: that is, 800 million tons of annual consumption of coal will potentially be displaced by nuclear alone by 2030, ~30 million tons at a time.

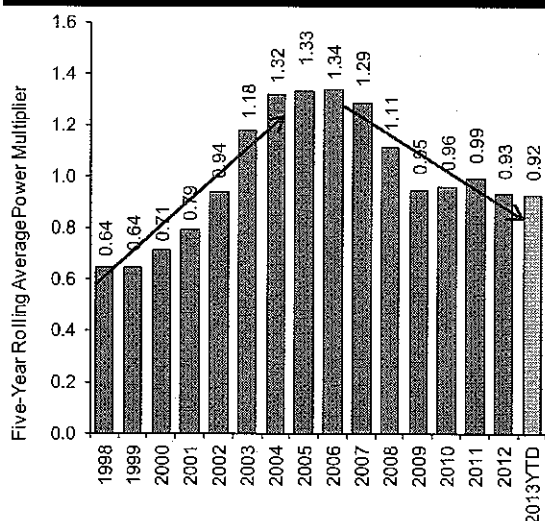
The progress being made in the Chinese nuclear fleet is another headwind for coal prices and the coal mining sector. China is going to become less coal intensive over this decade. And we believe the transition is happening incrementally right now. The power sector is the beneficiary of falling coal prices. However, the extent to which the publicly traded power companies will invest in nuclear power stations (the economics of which are murky) could become an overhang.

Nuclear Is Currently a Tiny Part of Overall Energy Consumption in China

The causes of potential idiosyncratic supply shocks within the global coal market are well known: floods in Queensland, mining strikes in South Africa or Colombia, increasing U.S. gas supply, Daqin rail maintenance, etc. Less focus is placed on the impact of permanent displacement of Chinese coal demand by gas, renewables, hydro...and nuclear.

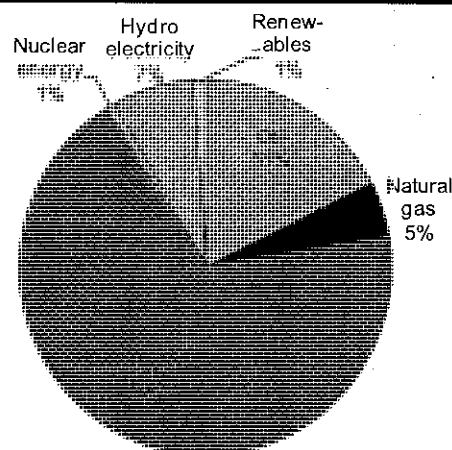
Chinese power consumption growth is likely to come in at ~5% this year and next. With the trend at less than 1x GDP growth currently, small changes in alternate sources of energy can rapidly add up. On a rolling five-year average basis, the power multiplier is ~0.9x through the recent cycle (see Exhibit 76). Energy consumption in China remains heavily dominated by coal, with non-fossil fuels accounting for only ~9% share (see Exhibit 77). The Chinese government is looking to increase this share to 11.4% by 2015 and ~15% by 2020. This share shift reflects an aggressive expansion in China's renewables and nuclear installed capacity, which will hurt incremental coal consumption over the next several years.

Exhibit 76 China Power Multiplier (Five-Year Rolling Average)



Source: CEIC, NBS and Bernstein analysis.

Exhibit 77 China Energy Consumption by Source (2012)



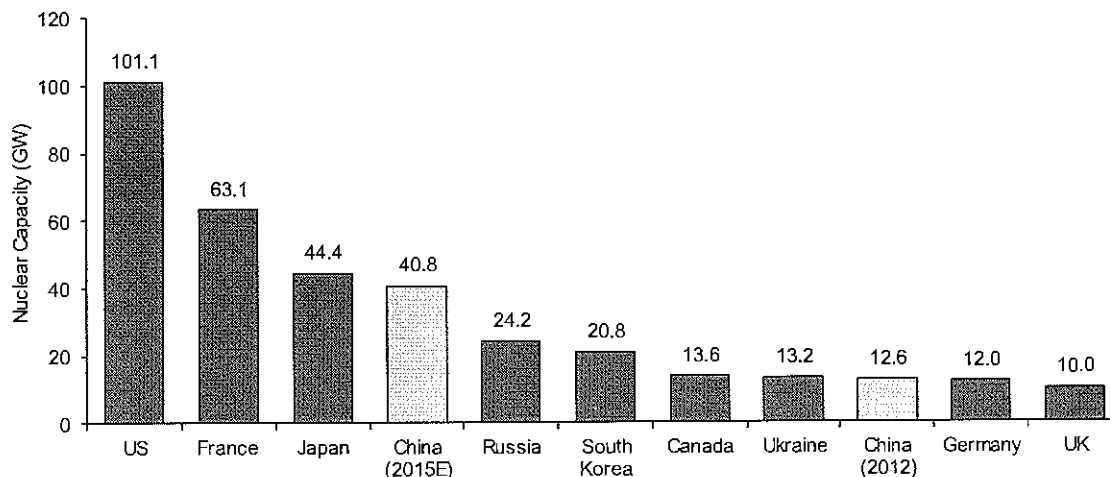
Source: BP Energy Survey 2013 and Bernstein analysis.

Plant-by-Plant Analysis of China's Nuclear Fleet Expansion

The Chinese government is currently targeting 40GW of nuclear power capacity by the end of 2015, representing a CAGR of ~30% from 2010. Based on a plant-by-plant analysis of China's nuclear power projects, the country could even exceed this target and reach 41GW of capacity if all of its projects are commissioned on time (see Exhibit 78). In any event, China is almost certain to have the fourth-largest nuclear installed capacity base in the world by 2015.

Exhibit 78

Global Nuclear Power Fleet (2012)

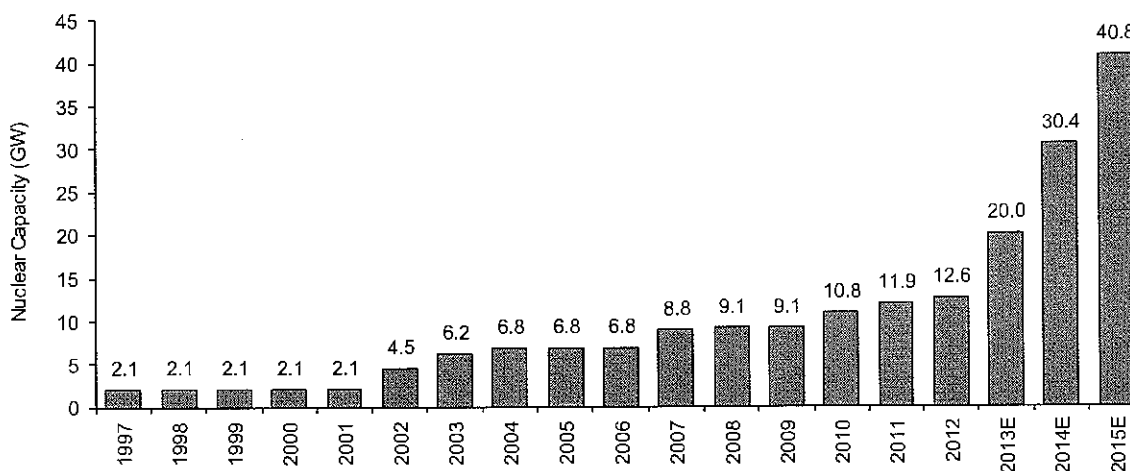


Source: CEIC, NBS, World Nuclear Association and Bernstein estimates and analysis.

China has never added more than 2.4GW of nuclear capacity in a single year — until this year (we are writing in early June) — see Exhibit 79.

Exhibit 79

China Nuclear Fleet (1997-2015E)



Source: CEIC, NBS, government reports and Bernstein estimates and analysis.

The Fleet Today and Near-Term Expansion

After the Fukushima disaster in March 2011, China suspended approvals for new nuclear power projects. Most of the projects that are currently in the pipeline have been under construction since 2008, and were therefore not caught by the suspension. However, they have been subject to engineering reviews.

On May 31, 2012, the State Council approved in principle the NEA and Ministry of Environmental Protection's *National Civilian-Use Nuclear Power*

Safety Inspection Report as well as the *Nuclear Safety Twelfth Five-Year Plan and 2020 Long-Term Target*, which reaffirmed the expected operational dates of 10 nuclear power station projects. Later, on October 24, 2012, the State Council approved the *Nuclear Safety Plan 2011-2020*, the *Nuclear Power Medium-Long Term Development Plan 2011-2020* and the *China Energy Policy White Book*, which also reaffirmed the 40GW target by 2015.

Currently, we estimate that China has about 14GW of nuclear capacity, including the 650MW expansion in Qinshan Phase II that was commissioned in April 2012, and Ningde 1 and Hongyanhe 1 commissioned earlier in 2013 (see Exhibit 80). Note that currently, all the operational nuclear power stations are owned and operated by either China Guangdong Nuclear Power Corporation (CGN) or China National Nuclear Corporation (CNNC), although the five IPPs and local governments may have minority stakes in these projects.

Exhibit 80 Chinese Nuclear Power Projects — Operational					
Units	Province	Operator	Net Capacity (MW)	Commissioning	Reactor Design
Daya Bay 1&2	Guangdong	CGN	1,888	1994	M310 (Areva)
Qinshan Phase I	Zhejiang	CNNC	298	1994	CNP-300 (Domestic)
Qinshan Phase II, 1-4	Zhejiang	CNNC	2,440	2002-2012	CNP-600 (Domestic)
Qinshan Phase III, 1&2	Zhejiang	CNNC	1,300	2002-2003	Candu 6 (Canada)
Ling Ao Phase I, 1&2	Guangdong	CGN	1,876	2002-2003	M310 (Areva)
Tianwan 1&2	Jiangsu	CNNC	1,980	2007	VVER-1000 (Russia)
Ling Ao Phase II, 1&2	Guangdong	CGN	2,040	2010-2011	CPR-1000 (Domestic)
Ningde 1	Fujian	CGN	1,020	Apr-13	CPR-1000 (Domestic)
Hongyanhe 1	Liaoning	CGN-CPI	1,000	2013	CPR-1000 (Domestic)
Total			13,842		

Source: NEA, Ministry of Environmental Protection, World Nuclear Association and Bernstein estimates and analysis.

We expect the second units of the Hongyanhe and Ningde projects to become operational by the end of 2013 (see Exhibit 81). Currently, based on the 12 projects that we track, we estimate that China has a pipeline of ~56GW of new nuclear capacity that is under construction through the end of this decade.

There are key design differences between currently operational nuclear power stations and the ones that are currently under construction.

First, the new power stations will use significantly larger reactors, with most projects using units with at least 1GW in capacity (the largest being Areva's 1.75GW EPR units at the Taishan project in Guangdong).

Second, most new projects will use CPR1000 reactors that are mainly domestically produced. The CPR1000 is designed by the China Nuclear Engineering Corporation (a part of CGNPG) based on Areva's 900MWe M310 units used in Daya Bay. Areva still maintains the intellectual property rights to the CPR1000, according to the World Nuclear Association. However, manufacturing is mainly done domestically.

Exhibit 81 Chinese Nuclear Power Projects — Under Construction

Project	Province	Operator	Capacity	Commissioning	Reactor Design	Details
Hongyanhe	Liaoning	CGN-CPI	5,517	2013-2016	CPRI1000 (Domestic)	Project began construction in August 2007. First unit started up in January 2013 and was connected to the grid in Feb 2013. Commercial operation planned in 2013. CPI and Dalian city also have shares in the project. Nuclear island component and generation equipment manufactured by Shanghai Electric with the help of CGNPC and the Nuclear Power Institute of China. The first two units will be at least 70% domestically produced, and the third and fourth units will be at least 80% domestically produced. Turbine units for units 5 and 6 will be manufactured by Dongfang Electric. Safety equipment supplied by Harbin Electric.
Ningde	Fujian	CGN-Datang	5,427	2013-2015	CPRI1000 (Domestic)	Project began construction in February 2008. First unit was grid connected in late 2012 and commercially operated in April 2013. As of October 2012, Unit 3 has completed construction. Main nuclear island and boiler equipment manufactured by Dongfang Electric. Reactor pressure vessel produced by Shanghai Electric. Safety equipment produced by Harbin Electric. This is CGNPC's first power station outside Guangdong.
Sanmen	Zhejiang	CNNC	6,760	2014-2020	AP1000 (Westinghouse) / BN800 (Domestic)	Project began construction in April 2009, and will be the world's first power station to use Westinghouse's third generation AP1000 reactor. First unit is expected to be commissioned in March 2014 and the second unit is expected to be in operation in 2015. Shanghai Electric responsible for building the nuclear island. Some auxiliary equipment is manufactured by Harbin Electric. Zhejiang Power Development Company, CPI and China Huadian have minority interest in the project.
Taishan	Guangdong	CGN	3,500	2014-2015	EPR (Areva)	Project began construction in December 2009. First unit expected to be commissioned by the early 2014 and second unit in 2015. The power station will use Areva's third generation EPR reactor, as well as turbines and other equipment from Dongfang Electric and Alstom. The EPR reactor is currently the largest in the world at 1,750MW. Power station will be jointly operated by CGNPC and Areva. Shanghai Electric responsible for building the nuclear island. Some auxiliary equipment is manufactured by Harbin Electric. Total investment for the project is expected to be RMB50.2B.
Yangjiang	Guangdong	CGN	6,504	2013-2017	CPRI1000 (Domestic)	Main construction for the project began in December 2008. Construction for unit 1 has completed as of July 2012, and the unit is currently in testing phase. Unit 2 is undergoing equipment installation, while unit 3 completed construction of its outer structure as of June 2012. Units 1 and 2 are expected to become operational in 2013-2014. Main nuclear island equipment built by Shanghai Electric, steam generators provided by Dongfang Electric and some auxiliary equipment provided by Harbin Electric.
Fangjiashan/ Wanjiashan	Zhejiang	CNNC	2,174	2013-2014	CPRI1000 (Domestic)	An expansion of the Qinsan power station in Zhejiang, the project is located 600m away from Qinsan Phase I and began construction in March 2008. As of October 2012, fuel loader for unit 1 has been installed. This is China's first self-produced fuel loader (produced by China Nuclear Engineering Corp., Xi'an Nuclear Equipment Co. and CNNC). Other main equipment supplied by Dongfang Electric.
Fuqing	Fujian	CNNC	6,534	2013-2016	CPRI1000 (Domestic) / ACP1000 (Domestic)	Units 1 and 2 are currently in the installation phase. Main equipment supplied by Dongfang Electric. Media reports suggest that units 5 and 6 may use the ACP1000 design, China's domestic third-generation reactor. First unit is expected to be commissioned in November 2013, while units 2 and 3 are expected to operate in 2014-2016.
Haifang	Shandong	CPI	5,000	2014-	AP1000 (Westinghouse)	Power station to use Westinghouse's third-generation AP1000 reactor. Shanghai Electric responsible for manufacturing other key equipment in the nuclear island. Some auxiliary equipment is manufactured by Harbin Electric. First unit expected to be commissioned in May 2014, while the second unit will be in March 2015.
Changjiang	Hainan	CNNC-Huaneng	1,300	2014-2015	CNP600 (Domestic)	Construction started in April 2010 in Hainan Island. First unit expected to become operational in end of 2014 and the second unit in 2015. The project is modeled after the Qinsan Phase II project in Zhejiang, and will use a domestically produced Gen 2+ CNP600 reactor. China Huaneng has also invested in this project.
Shidaowan	Shandong	Huaneng	3,010	2016-2018	HTR-PM (Domestic) / CAP1400 (Westinghouse / Domestic)	The project is jointly owned by CHNG (40%), Huaneng International Power Development (30%), and Huaneng Power International (30%).
Tianwan	Jiangsu	CNNC	4,280	2017-2018	WER-1000 (Atomstroyexport) / CPR-1000 (Domestic)	The construction of Tianwan II was included in the 12th Five-Year Plan. The project is a joint venture with Russia's Atomstroyexport. Commercial operation is expected to be in 2018-2019.
Fangchenggang	Guangxi	CGN	6,480	2015-2016	CPRI1000 (Domestic)	Construction began in July 2010. Main equipment for units 1 and 2 are currently being installed. First unit is expected to become operational in 2015.
Total			56,486			

Source: NEA, Ministry of Environmental Protection and Bernstein estimates and analysis.

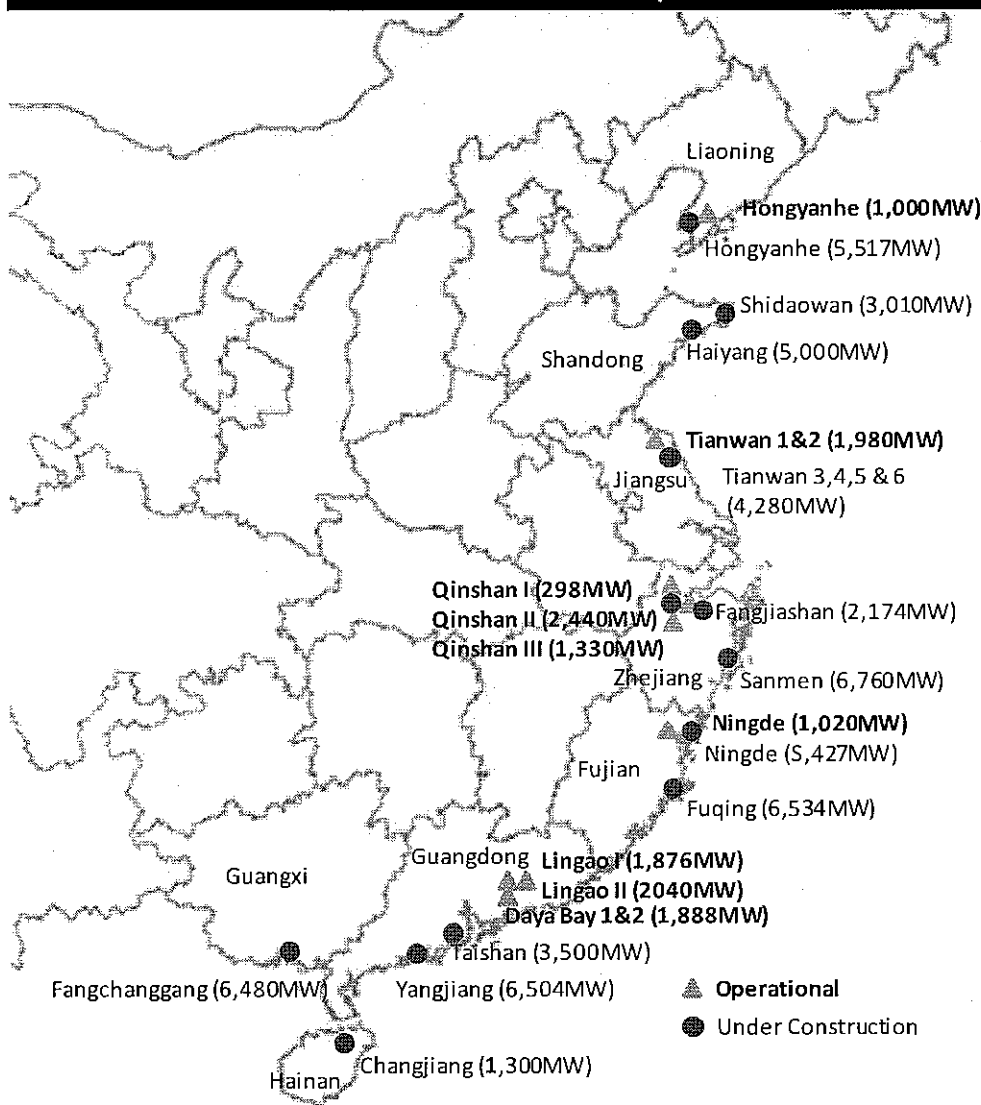
For example, units 1 and 2 of Hongyanhe project in Liaoning are expected to be at least 70% domestically produced. This share is expected to increase to 80% for units 3 and 4, and we assume the same for other projects that are using CPR1000.

According to government announcements and media reports, manufacturing and production of equipment used at these nuclear power stations are dominated by Shanghai Electric (2727.HK; not covered), Dongfang Electric (1072.HK; not covered) and Harbin Electric (1133.HK; not covered). According to Shanghai Electric, it currently holds a 100% market share for the control rod mechanism, 46% for nuclear islands, 30% for conventional islands and a 37% market share for the main nuclear reactors.

Similar to the past, all these new projects are built along the eastern coast, close to the load centers (see Exhibit 82). Several projects of note are the Sanmen (7,500MW), Haiyang (5,000MW) and Taishan (3,500MW), which will use third-generation reactors produced by either Westinghouse or Areva.

Exhibit 82

China Nuclear Power Stations: Operational and Under Construction

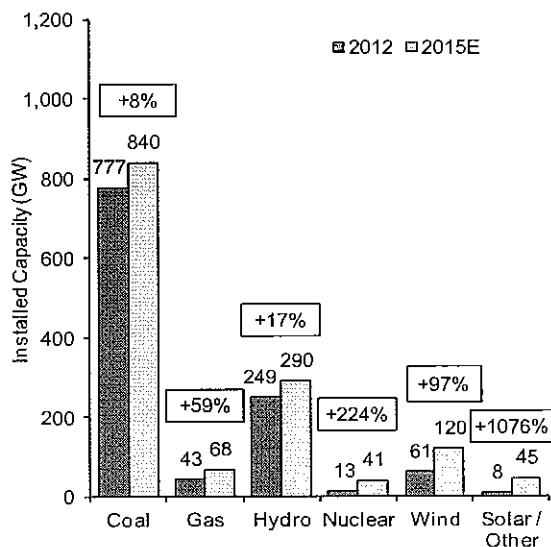


Source: Wikimedia Commons, NEA, Ministry of Environmental Protection and Bernstein estimates and analysis.

We Estimate That 1GW of Nuclear Generation Capacity Displaces ~4 Million Tons of Coal per Annum

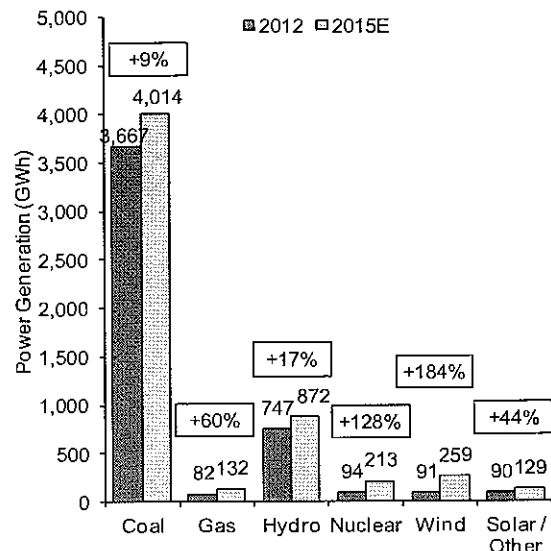
By 2015, we expect nuclear power capacity (see Exhibit 83) and generation (see Exhibit 84) to at least double from current levels. In addition, we expect hydro, wind and solar generation to take share away from thermal power over the next several years. We expect wind and solar installed capacity to reach 120GW and 45GW, respectively, by 2015 — more bullish than the recent government targets of 100GW and 21GW, respectively.

Exhibit 83 China Power Capacity: 2012 vs. 2015E



Source: CEIC, NBS and Bernstein estimates and analysis.

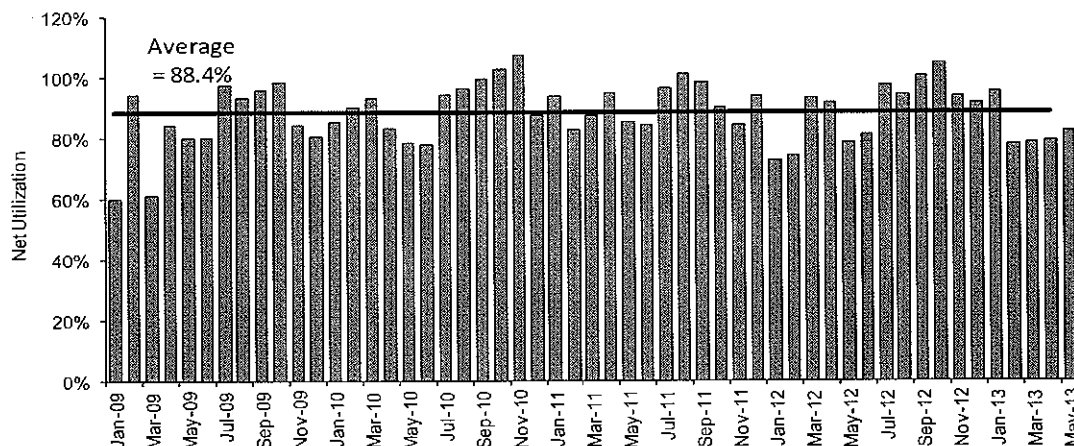
Exhibit 84 China Power Generation: 2012 vs. 2015E



Source: CEIC, NBS and Bernstein estimates and analysis.

Nuclear power utilization has been high and stable over the last several years, averaging ~88% (see Exhibit 85). February to May in 2013 saw a decrease in utilization, reflecting new capacity being added (according to media reports, Ningde 1 and Hongyanhe 1 have come on line in the first half of 2013).

Exhibit 85 China: Nuclear Power Utilization (2009-May 2013)



Source: CEIC, NBS and Bernstein estimates and analysis.

We believe nuclear and other non-fossil fuel generation will take share from thermal generation. We expect thermal power production to remain at low single digits over the next several years (see Exhibit 86).

Exhibit 86

China Power Demand Model (2011-20E)

China Power Demand Model	2011	2012	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
GDP Growth	9.3%	7.8%	7.5%	7.0%	6.5%	6.0%	5.0%	5.0%	4.0%	4.0%
Power Multiplier	1.17x	0.54x	0.80x	0.80x	0.80x	0.70x	0.60x	0.50x	0.40x	0.40x
Power Consumption per Capita (KWh)	3,521	3,670	3,890	4,108	4,322	4,503	4,639	4,755	4,831	4,908
Installed Capacity (MW)										
Coal	735,643	775,520	807,479	831,884	839,774	814,581	781,998	742,898	698,324	650,000
Gas	32,650	42,650	47,650	57,650	67,650	82,650	97,650	112,650	132,650	150,000
Hydro	229,917	248,900	253,900	268,900	290,000	302,000	314,000	326,000	338,000	350,000
Nuclear	11,915	12,570	20,048	30,416	40,770	40,770	40,770	49,770	61,770	75,000
Wind	47,001	60,830	78,630	98,830	120,000	150,000	180,000	205,000	230,000	250,000
Solar	4,943	8,300	18,300	30,300	45,300	70,300	100,300	135,300	170,300	204,860
Total Installed Capacity	1,062,069	1,149,770	1,226,207	1,317,980	1,403,494	1,460,301	1,514,718	1,571,618	1,631,044	1,679,860
Installed Capacity Growth (%)										
Coal	9.2%	5.6%	4.0%	3.0%	0.9%	-3.0%	-4.0%	-5.0%	-6.0%	-6.9%
Gas	-8.7%	30.6%	11.7%	21.0%	17.3%	22.2%	18.1%	15.4%	17.8%	13.1%
Hydro	6.4%	8.3%	2.0%	5.9%	7.8%	4.1%	4.0%	3.8%	3.7%	3.6%
Nuclear	10.0%	5.5%	59.5%	51.7%	34.0%	0.0%	0.0%	22.1%	24.1%	21.4%
Wind	58.9%	29.4%	29.6%	25.4%	21.4%	25.0%	20.0%	13.9%	12.2%	8.7%
Solar	1639.1%	67.9%	120.5%	65.6%	49.5%	55.2%	42.7%	34.9%	25.9%	20.3%
Total	9.9%	8.3%	6.6%	7.5%	6.5%	4.0%	3.7%	3.8%	3.8%	3.0%
Utilization Rates (%)										
Coal	59.9%	55.4%	55.8%	55.4%	54.8%	54.8%	56.6%	58.9%	60.0%	61.2%
Gas	25.0%	25.0%	24.0%	24.0%	24.0%	24.0%	24.0%	24.0%	24.0%	24.0%
Hydro	31.2%	35.6%	35.6%	35.6%	35.6%	35.6%	35.6%	35.6%	35.6%	35.6%
Nuclear	91.1%	89.8%	60.0%	60.0%	60.0%	90.0%	95.0%	95.0%	95.0%	95.0%
Wind	21.4%	19.3%	20.0%	24.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%
Solar	n/a	n/a	10.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%
Power Generation (TWh)										
Coal	3,698	3,667	3,872	3,975	4,014	3,974	3,958	3,935	3,786	3,617
Gas	75	82	95	111	132	158	190	221	258	297
Hydro	609	747	785	816	872	924	961	999	1,036	1,074
Nuclear	86	94	86	140	213	321	339	339	414	514
Wind	72	91	122	187	259	319	390	455	514	568
Solar/Other	37	90	98	112	129	158	192	232	272	311
Total Power Generation	4,577	4,771	5,058	5,341	5,619	5,855	6,030	6,181	6,280	6,300
Memo: Y/Y Growth	10.9%	4.2%	6.0%	5.6%	5.2%	4.2%	3.0%	2.5%	1.6%	1.6%
Power Generation Growth										
Coal	14.7%	-0.8%	5.6%	2.7%	1.0%	-1.0%	-0.4%	-0.6%	-3.8%	-4.5%
Gas	5.8%	10.1%	15.1%	16.6%	19.0%	20.0%	20.0%	16.6%	16.6%	15.2%
Hydro	-7.6%	22.7%	5.0%	4.0%	6.9%	5.9%	4.1%	3.9%	3.8%	3.6%
Nuclear	17.1%	8.5%	-8.5%	63.9%	51.7%	50.8%	5.6%	0.0%	22.1%	24.1%
Wind	69.7%	26.5%	34.5%	52.7%	38.6%	23.4%	22.2%	16.7%	13.0%	10.3%
Solar/Other	-33.7%	141.9%	9.8%	13.9%	15.2%	22.0%	21.7%	20.8%	17.2%	14.5%
Total Power Generation Growth	10.9%	4.2%	6.0%	5.6%	5.2%	4.2%	3.0%	2.5%	1.6%	1.6%

Source: CEIC, NBS and Bernstein estimates and analysis.

Roughly 1GW of nuclear generation capacity (operating at standard utilization) displaces ~4 million tons of coal. With 7.5GW of nuclear capacity coming on line in 2013, ~30 million tons of coal will be displaced. In the context of an overall market of almost 4 billion tons of coal consumption, 30 million tons is nothing. But in the context of a market that is expanding coal consumption at ~100 million tons per year, displacing 30 million tons is significant...in an already oversupplied market (see Exhibit 87).

Exhibit 87

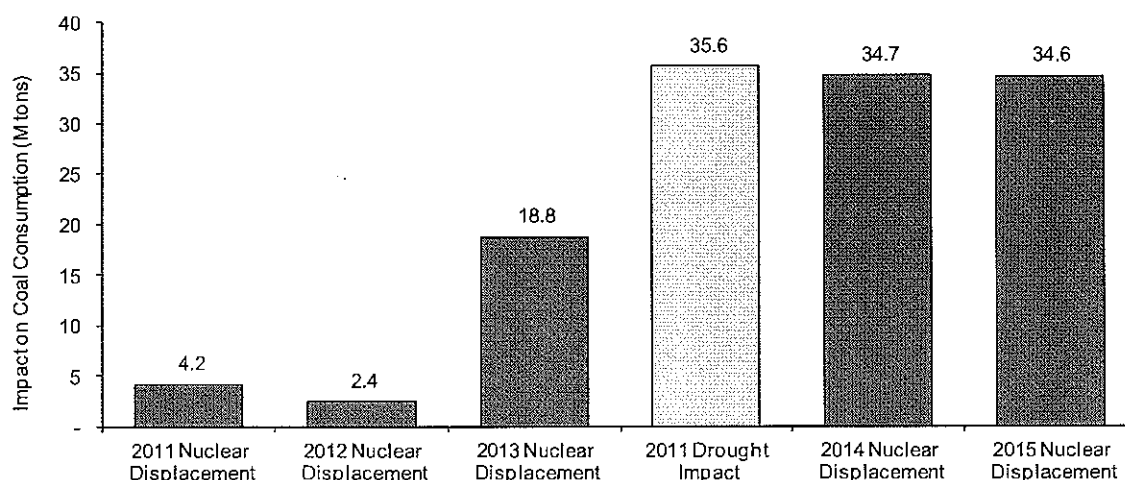
Tons of Coal Consumption Displaced by Nuclear Power (2011-15E)

	2011	2012	2013E	2014E	2015E
Nuclear Expansion					
Incremental Nuclear Capacity (GW)	1.1	0.7	7.5	10.4	10.4
Utilization	91%	90%	60%	80%	80%
Incremental Power Generation (TWh)	8.8	5.1	39.4	72.7	72.6
Coal Displacement					
Grams per KWh — Standard Coal	375	375	375	375	375
Tons per TWh — Standard Coal	375,000	375,000	375,000	375,000	375,000
Adjusted to Benchmark (5,500KCal vs. 7,000KCal)	477,273	477,273	477,273	477,273	477,273
Tons of Coal Displaced (M)	4.2	2.4	18.8	34.7	34.6
Cumulative Annual Coal Displacement (M tons)	4.2	6.6	25.4	60.1	94.7
Displaced Coal as % of Incremental Consumption	1.0%	1.0%	129.6%	66.6%	693.0%

Source: CEIC, NBS and Bernstein estimates and analysis.

To place 30 million tons in some kind of context, the 2011 drought in southwestern China lowered hydro utilization for the year by roughly 500 bp. This loss equated to ~36 million tons of incremental coal that was consumed to operate coal-fired power stations that would, in a normal year, have instead come from hydro generation (see Exhibit 88). In short, in coming years, we expect that the Chinese power sector will effectively experience the opposite of the 2011 drought each year cumulatively — additional power generation from nuclear that serves to displace coal demand and put further pressure on coal prices.

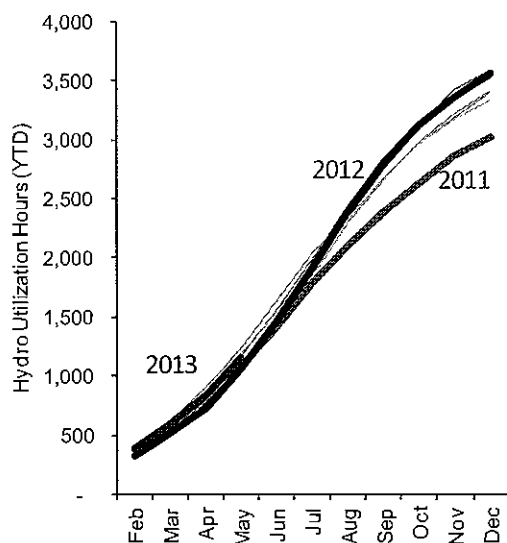
Exhibit 88 China Coal Incremental Displacement by Nuclear vs. 2011 Drought



Source: CEIC, NBS and Bernstein estimates and analysis.

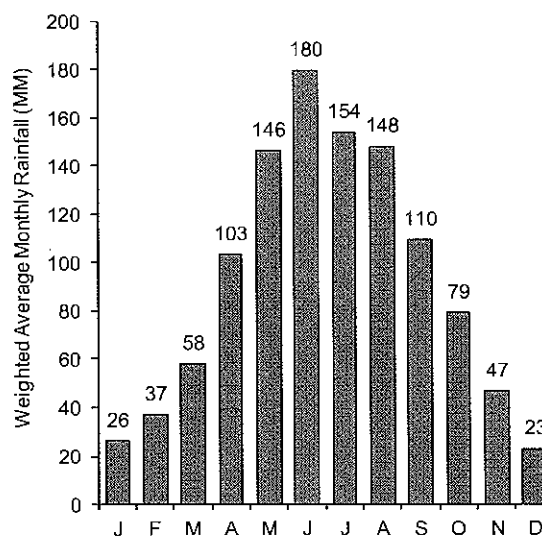
Of course, during 2011, the decline in hydro power generation during the peak summer monsoon season exacerbated pricing pressures given that the shortfall in supply came during a short period of time. Hydro utilization hours in 2011 were ~12% lower than historical averages (see Exhibit 89 and Exhibit 90).

Exhibit 89 China Hydro Utilization Hours



Source: CEIC, CEC and Bernstein analysis.

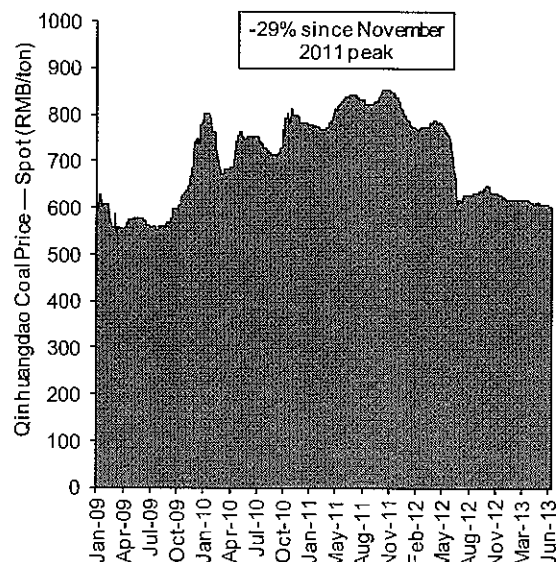
Exhibit 90 Monthly Rainfall, Weighted Average for Hydro Generating Provinces



Source: UN World Meteorological Organization, Bernstein analysis

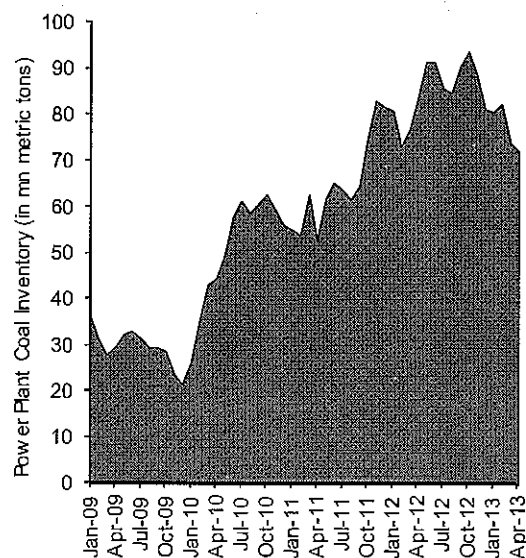
In 2011, coal prices rose significantly over the summer in part due to weak hydro generation and, in part, from lower inventories (see Exhibit 91 and Exhibit 92). The shift to nuclear power is unlikely to have the same kind of effect on coal price volatility given the nuclear power is base load and operates throughout the year. However, diversifying sources of power serves to reduce the risk of spikes in coal prices.

Exhibit 91 Qinhuangdao 5,500 Kcal Coal Spot Price (2009-June 2013)



Source: SX Coal and Bernstein analysis.

Exhibit 92 China Power Station Coal Inventories (2009-April 2013)



Source: SX Coal and Bernstein analysis.

Is There Enough Uranium?

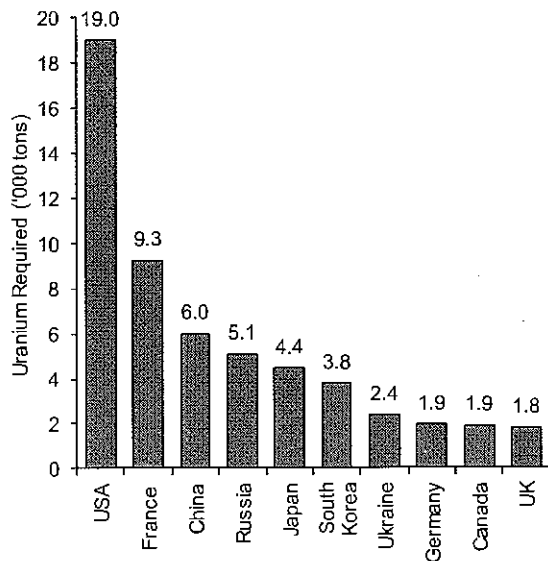
All of this begs the obvious question: what is going to happen to uranium prices as China becomes the source of the majority of nuclear power capacity expansion in coming years? We are in no way claiming expertise in the area of uranium mining. However, there are at least three reasons to believe that the pattern of spiking commodity prices as Chinese demand increases is probably misleading in this instance.

First, the growth in China's nuclear installed capacity is going to happen over a long period of time. It will become noticeable at the margin in 2013 based on the displacement of coal, as described earlier. However, China will — in the best-case scenario — have ~20GW of nuclear capacity at the end of 2013, equivalent to ~5% of total nuclear capacity globally. The ramp is, in our view, over too long a period to result in a spike in commodity prices.

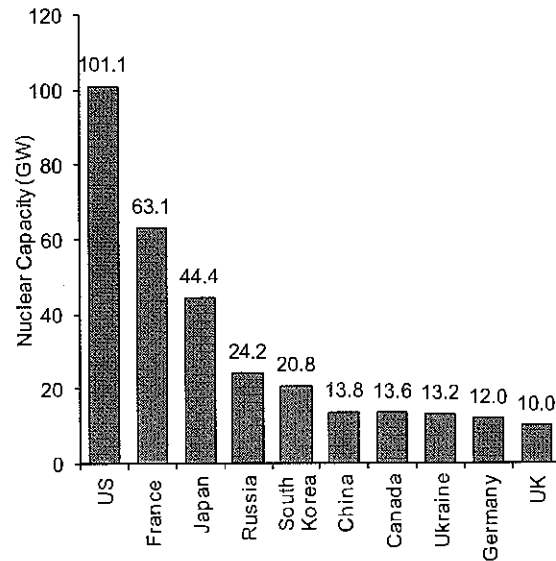
Second, uranium is a common metal with proven reserves in a variety of locations. Because there is not likely to be a sudden spike in demand, the usual dynamics rewarding those who have invested in capacity well ahead of the demand boom are unlikely to play out. The locations with significant uranium reserves include Kazakhstan, Canada, Niger, Mongolia, China and Australia (see Exhibit 95). Without one location or supplier being able to tie up share over the rest of the decade, we believe a spike in prices — or a lack of supply — is unlikely as producers from all of these regions increase supply roughly simultaneously.

The World Nuclear Association now estimates that China will demand ~6,000 tons of uranium in 2013 (see Exhibit 93), making it the third-largest consumer of uranium in the world. Since China's nuclear capacity was only eighth in the world at the end of 2011 (see Exhibit 94), the strong demand suggests that China is

already ramping up its procurement of uranium ahead of commissioning ~30GW of nuclear capacity over the next several years.

Exhibit 93 2013E Uranium Required

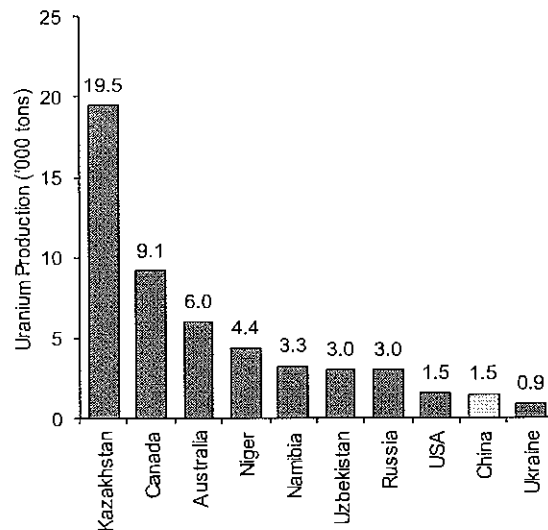
Source: World Nuclear Association and Bernstein analysis.

Exhibit 94 Nuclear Installed Capacity by Country, as of June 2013

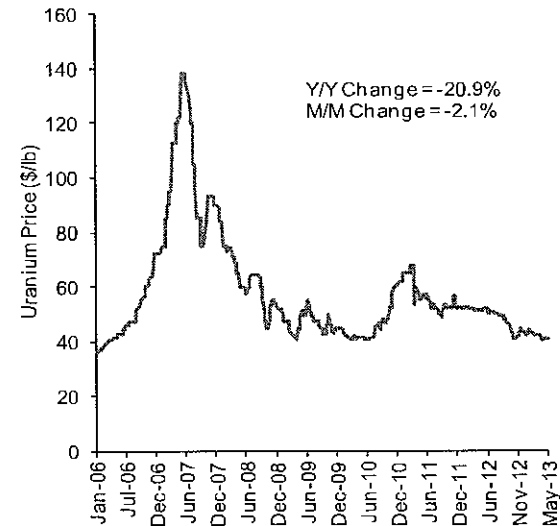
Source: World Nuclear Association and Bernstein analysis.

If China is, in fact, already buying ahead of demand, it has yet to register in terms of uranium pricing (see Exhibit 96).

Third, China is developing its own uranium supply. In 2012, Xinhua announced that geologists have found significant uranium deposits in Inner Mongolia, and that the area could become one of the top uranium mines in the world. China produced ~1,500 tons of uranium in 2011 (see Exhibit 95), significantly less than its expected uranium requirement.

Exhibit 95 2011 Uranium Production

Source: World Nuclear Association and Bernstein analysis.

Exhibit 96 Uranium Spot Price (USD/lb)

Source: Bloomberg L.P. and Bernstein analysis.

Game Done Changed: Cost Structures and Strategies Within the Chinese Mining Sector

Why Aren't the Large Chinese Coal Miners Taking Market Share

The most surprising thing about the Chinese coal mining sector in the first half of 2013 has been the fact that the large, publicly traded miners are not taking share. Prices have fallen 30% since November 2011, and these coal miners are reporting falling earnings year-over-year. The textbook response is to ramp up production. Yet that isn't happening. In this chapter, we explore the best explanations.

We also update our estimate of marginal production cost for the large miners and the delivered cost at the coast based on recently reported 2012 production and financial data from the 21 publicly traded Chinese coal mining companies.

We believe that the two dynamics — a flattening cost curve and a falling array of options for the coal miners in the face of weak pricing and high inventories — are related.

It's Good to Be Cheap

The 60 largest coal miners in China produced, by our estimate, ~2,871 million tons of coal in 2012, representing ~73% of the industry. Yet growth, this year, from the publicly traded miners is surprisingly weak. At this point in the cycle, you might expect that large, low-cost producers would take share to bolster earnings. To the extent that a miner has positive gross margins on incremental supply, this is the economically rational next step.

Yet Shenhua's production growth was up just 1.5% year-to-date through April 2013. The 21 publicly traded Chinese coal miners expanded production at ~11% in 2012 but the covered companies are slowing production growth year-to-date.

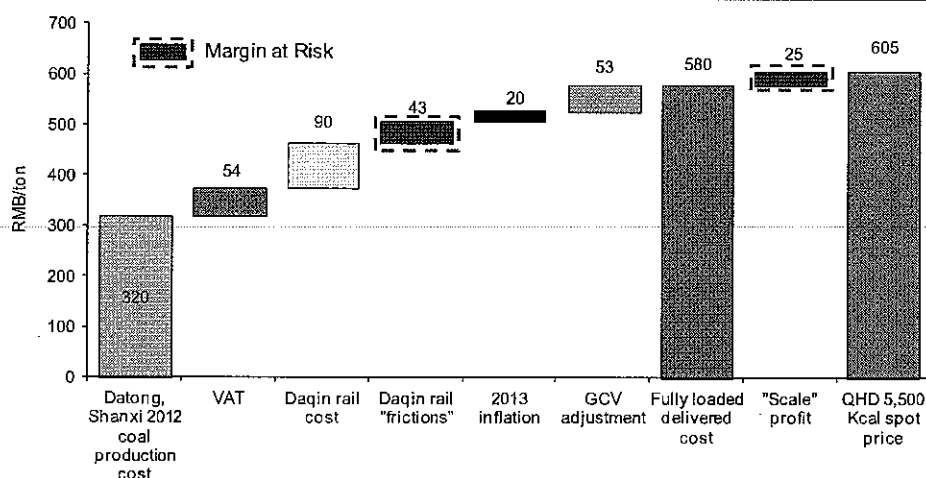
We believe that the best explanation for the weak production growth year-to-date is simply a combination of three factors. First, inventories remain high at all points across the supply chain (including with the miners). Second, the publicly traded coal miners' marginal production costs may be, in many cases, significantly higher than their average cost, meaning incentives to ramp up production at marginal mines are weak and the cost curve is even flatter than we have previously believed. Third, rail bottlenecks are improving but still mean that there are frictions in connecting low-cost interior coal production with coastal demand.

The spread between the incremental ton of coal being supplied by large-scale miners and the spot price is ~RMB25/ton in June 2013 (see Exhibit 97). In short, this is an oversupplied market with deteriorating long-term demand growth and a flat cost curve. Options, whether strategic or otherwise, for any miner are limited.

In any industry, it is good to be a low-cost producer. And in a fragmented industry, when everything else goes wrong — prices fall, demand is weak, customers take production in-house, and imports go up — low-cost producers can always increase volumes, take market share and thereby boost earnings. Sure, the action is corrosive to the long-term economics of the industry as it pushes out higher-cost producers and places more pressure on price. But it is still the best strategy for low-cost suppliers at a certain point in the cycle. And in a fragmented industry, if you don't do it, someone else will.

Exhibit 97

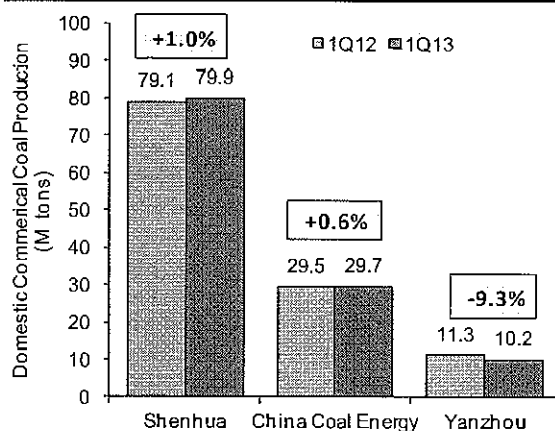
Qinhuangdao Coal Price Composition (June 2013)



Source: Bloomberg L.P., SX Coal and Bernstein estimates and analysis.

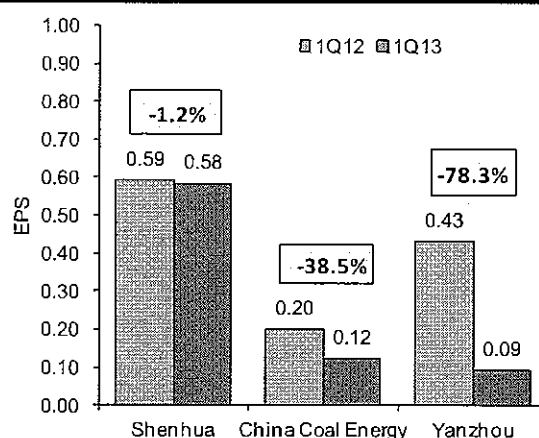
The most surprising thing about the Chinese coal mining sector so far in 2013 has been the fact that the large, publicly traded miners are not executing this strategy. Coal prices have fallen 30% over the last 18 months, and all coal miners are reporting a decline in earnings year-over-year (see Exhibit 99). Yet production growth is also weak year-over-year for large miners. Shenhua and China Coal Energy are reporting flat production year-over-year, while Yanzhou's domestic production is down sharply (see Exhibit 98). The textbook response for what happens next isn't playing out: the big miners aren't taking market share to boost earnings.

Exhibit 98 Domestic Commercial Coal Production 1Q:12 and 1Q:13



Source: Corporate reports and Bernstein analysis

Exhibit 99 EPS 1Q:12 and 1Q:13



Source: Corporate reports and Bernstein analysis

And the explanation for "why not?" is not immediately obvious. Shenhua's production cost averaged RMB130/ton in the first quarter of 2013 and its average selling price was over RMB400/ton. On a cash basis, it would seem to make sense to produce more coal. In our view, the industry remains too fragmented for large-scale miners to attempt to exert any price discipline. The industry is consolidated to the point where 60 miners accounted for 73% of the industry in 2012 and closer to 75% of the industry now. But the second-largest coal miner in China has a market

share of less than 5%. This stresses the fact that the industry remains massively fragmented.

As we set out in this chapter, production, consumption and inventory data do not tie. We believe that the most likely reason is understated inventory data (likely in the form of inventories at the miner's coal yards and in transit). Given the fragmented nature of the industry, this is a more likely explanation than the miners imposing some form of pricing discipline on themselves.

High inventories mean that we do not believe upward pressure on coal price is likely in coming months. But at the same time, even putting together the best case in terms of incremental supply, we do not believe that there is near-term downside risk to coal price given the timing of new rail line commissioning and the "go slow" the large miners are now working to in terms of taking market share.

In short, the status quo looks like the most likely scenario. We expect coal prices to remain stable into 2015 (RMB630/ton this year, 2014 and 2015). Inflationary pressures will inevitably raise coal costs over time. To the extent that the top 55-60 miners push out high-cost miners, the cost curve flattens as it rises.

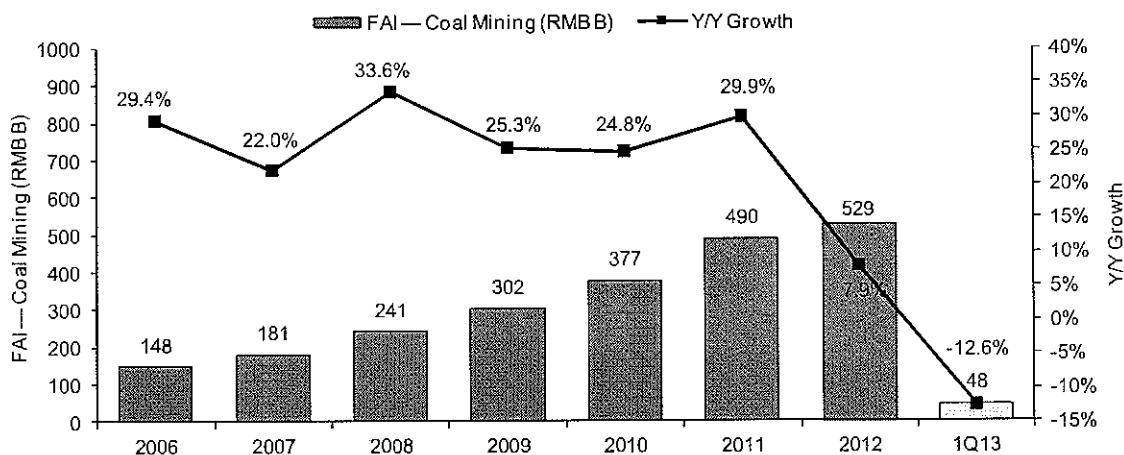
Coal Production Cost Analysis of the Top 21 and Top 55 Chinese Miners

The simplest way to explain the fact that coal prices fell 22% over the course of 2012 despite the fact that the overall demand for coal was essentially flat is the share shift within the Chinese coal mining sector. In short, the bigger players got bigger and, in the absence of continuing rapid demand growth, the smaller, high-cost miners got squeezed out. Production share was taken by lower-cost coal miners, who set a low spot price.

We anticipate that domestic production capacity growth in 2013 will expand at a similar rate as in 2012 and the high-cost domestic producers will continue to lose share, although this is happening slower than we would have guessed. Fixed asset investment (FAI) in coal mining in recent years reflects a slowdown in investment since mid-2012, but new capital is still entering rapidly (see Exhibit 100).

Exhibit 100

FAI in China Coal Mining Sector (2006-1Q13)



Source: NBS, CEIC and Bernstein analysis.

Exhibit 101 sets out the coal production volumes of the 21 publicly traded Chinese coal miners.

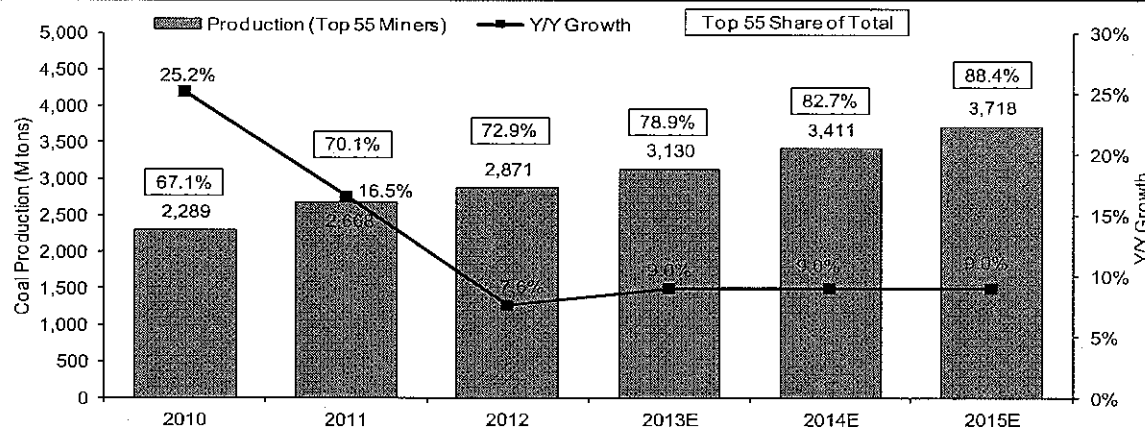
Exhibit 101 Coal Production Volumes of the 21 Publicly Traded Chinese Coal Miners (2008-12)

Company Name	Coal Production (000 tons)					2012 CAGR%
	2008	2009	2010	2011	2012	
China Shenhua	186,500	209,500	241,100	282,300	306,800	13.3%
China Coal Energy	74,100	78,970	89,750	101,720	111,120	10.7%
Huolinhe Opencut Coal Industry Corp. (China Power)	36,820	42,340	42,450	43,960	45,000	5.1%
Shanxi Guoyang New Energy Co	36,333	39,528	45,380	51,110	56,530	11.7%
Pingdingshan Tianan Coal Mining	34,506	37,405	39,810	38,613	38,394	2.7%
Yanzhou Coal Mining Company Limited	33,501	34,332	36,234	40,882	44,416	7.3%
Inner Mongolia Yitai Coal Company Limited	18,196	26,042	36,129	35,085	49,760	28.6%
Shanxi Lu'an Environmental Energy Development	23,230	26,710	33,220	34,230	28,720	5.4%
Jizhong Energy Resources Co., Ltd	11,669	25,895	31,021	34,146	36,425	32.9%
Datong Coal Industry	17,471	25,786	29,290	30,940	38,190	21.6%
Shanxi Xishan Coal and Electricity Power Co	16,172	17,796	21,111	21,321	25,437	12.0%
Anhui Hengyuan Coal Industry	4,611	9,672	10,418	11,509	12,198	27.5%
SDIC Xinji Energy	10,825	10,964	13,379	13,843	16,361	10.9%
Inner Mongolia PingZhuang Energy Limited (China Guodian)	9,212	10,053	9,622	10,698	9,866	1.7%
Guizhou Panjiang Refined Coal	2,371	9,312	11,400	12,300	13,549	54.6%
Shanxi Lanhua Sci-Tech Venture	5,427	5,816	5,697	5,307	5,776	1.6%
Zhengzhou Coal Industry and Electric Power	4,620	4,810	4,890	4,860	11,110	24.5%
Shanghai Ace Company	3,920	3,936	3,326	3,358	3,141	-5.4%
Gansu Jingyuan Coal Industry and Electricity Power Co.	1,775	1,930	2,450	2,600	10,552	56.2%
Sundiro Holding (Wujiu Coal Group)	1,864	1,864	2,410	2,679	2,471	7.3%
Inner Mongolia Tehong Coal Group Co.	264	453	820	1,081	906	36.1%
Total	533,386	623,114	709,906	782,543	866,721	12.9%
Y/Y Growth		16.8%	13.9%	10.2%	10.8%	

Source: Corporate reports and Bernstein analysis.

Generally, at this point in the cycle, you might expect that large, low-cost producers would take share to bolster their earnings. To the extent that a miner has positive gross margins on incremental supply, the economically rational next step is to increase production. We believe that the industry's reticence in expanding production is more a function of current inventory levels rather than challenging economics of marginal supply. In short, large-scale miners still have a cost advantage over the bottom quintile of the industry, although that advantage is fading.

The top 55 Chinese coal miners produced ~2.9 billion tons of coal in 2012, ~8% higher than the 2011 level at ~2.7 billion tons (see Exhibit 103). These top 55 coal producers accounted for ~73% of total coal production in 2012, compared to ~70% in 2011 (see Exhibit 102).

Exhibit 102 Top 55 Coal Miners' Production and Their Share of Total Production (2010-15E)

Source: China National Coal Association, SX Coal, corporate reports and Bernstein estimates and analysis.

Exhibit 103

Top 55 Coal Miners' Production (2008-12)

Company	Coal Production (mmt)					Y/Y Growth
	2008	2009	2010	2011	2012	
Shenhua Group	281.3	327.8	357.0	407.1	440.0	8.1%
China National Coal Group	114.1	125.1	146.8	163.6	176.0	7.6%
Shanxi Datong Coal Mining Group	88.9	74.5	101.2	115.4	132.1	14.5%
Shanxi Coking Coal Group	80.3	80.8	102.1	110.1	105.4	-4.2%
Shaanxi Coal & Chemical Industry Group	60.4	71.0	100.4	101.9	114.0	11.9%
Shandong Energy Group	n/a	n/a	79.1	108.2	123.0	13.7%
Hebei Jizhong Energy Group	35.8	42.4	73.3	102.2	115.0	12.6%
Henan Coal & Chemical Industry Group	44.7	57.0	74.0	84.8	75.2	-11.4%
Shanxi Lu'an Mining Industry Group	42.1	55.1	71.0	77.2	80.1	3.8%
Yankuang Mining Group	39.7	49.7	60.1	70.8	75.3	6.4%
Hebei Kailuan Group	32.9	40.5	60.9	70.6	83.5	18.3%
Anhui Huainan Mining Group	56.7	67.2	66.2	67.5	70.1	3.8%
Shanxi Yangquan Coal Industry Group	37.3	44.1	51.6	58.5	68.8	17.6%
China Guodian	n/a	n/a	47.0	65.1	68.5	5.3%
China Huaneng	n/a	n/a	46.3	64.1	68.6	7.1%
China Power Investment Corporation	n/a	n/a	54.1	60.7	60.5	-0.4%
Inner Mongolia Yitai Group	25.7	36.7	51.1	63.3	68.2	7.7%
Heilongjiang Longmei Mining Group	55.0	54.9	50.1	51.7	54.0	4.4%
Shanxi Jincheng Anthracite Mining Group	37.4	42.6	46.0	52.5	54.7	4.1%
Inner Mongolia Yidong Group	16.2	21.2	39.5	49.3	50.0	1.4%
China Pingmei Shenma Group	41.2	45.8	49.7	47.6	50.0	5.1%
Shanxi Coal Transportation & Marketing Group	15.6	21.8	28.0	28.0	50.4	80.0%
Henan Yima Coal Industry Group	21.9	22.6	31.2	33.6	30.0	-10.8%
Anhui Huabei Mining Group	26.5	27.3	30.6	33.7	36.3	7.7%
Jilin Coal Industry Group	20.6	26.1	28.1	32.2	34.7	7.7%
Inner Mongolia Huineng Coal & Power Group	18.8	23.0	27.5	30.6	33.0	7.7%
Inner Mongolia Mengtai Coal Group	10.9	28.8	30.6	36.3	39.1	7.7%
Liaoning Tietia Coal Group	21.8	24.1	23.1	26.7	27.7	7.7%
Inner Mongolia Yongli Coal Company	n/a	n/a	n/a	24.6	26.5	7.7%
China Huadian	n/a	n/a	9.3	22.6	25.1	11.2%
Henan Zhengzhou Coal Industry Group	16.7	18.4	22.0	22.5	24.3	7.7%
Jiangsu Xuzhou Mining Group	19.4	19.4	18.8	21.2	20.9	-1.1%
Inner Mongolia Manshi Coal Group	4.1	8.9	15.0	21.0	22.6	7.7%
Inner Mongolia Erdos Wulan Coal Group	n/a	n/a	12.0	17.6	18.9	7.7%
Anhui Wanbei Coal Group	12.8	14.0	16.2	17.4	18.8	7.7%
Guizhou Panjiang Coal & Power Group	11.9	13.4	12.9	17.2	18.6	7.7%
China Resources Power	n/a	n/a	11.4	16.4	16.8	2.8%
Liaoning Shenyang Coal Industry Group	17.0	15.4	11.1	15.8	17.0	7.7%
SDIC Xinji Energy	11.8	12.5	15.1	15.3	16.5	7.9%
Inner Mongolia TeHong Coal Group	n/a	n/a	10.1	14.0	15.1	7.7%
Inner Mongolia Ruide Coal Chemical Co.	n/a	n/a	n/a	13.8	14.9	7.7%
Inner Mongolia Zhalaibao Coal Co.	n/a	n/a	n/a	13.7	14.7	7.7%
Chongqing Energy Investment Corporation	12.4	12.9	13.1	13.7	13.9	1.9%
China Datang	n/a	n/a	11.3	13.8	13.0	-5.8%
Sichuan Coal Industry Group	13.0	14.1	13.1	13.1	14.1	7.7%
Shanxi Lanhua Coal Industry Group	10.2	12.6	13.5	13.0	14.0	7.7%
Liaoning Fuxin Mining Group	12.1	13.5	12.0	12.1	13.0	7.7%
Guizhou Shuichang Mining Group	8.1	10.2	10.7	11.6	16.0	37.8%
Shandong Tianlong Group	14.4	13.5	13.5	11.1	11.9	7.7%
Yunnan Xiaolongtan Mining Bureau	10.1	9.8	9.8	11.7	12.6	7.7%
Shanxi Liansheng Energy Company	n/a	n/a	n/a	10.9	11.8	7.7%
Inner Mongolia Kaiyuan Shiyue Group Co.	n/a	n/a	n/a	10.7	11.5	7.7%
Shanxi Hunyuan Baichuan Coal Industry Company Ltd.	n/a	n/a	n/a	10.6	11.4	7.7%
Gansu Jingyuan Coal Industry Group	9.8	9.4	10.0	10.5	11.3	7.7%
Shanxi Kexing Energy Development Group Co.	n/a	n/a	n/a	10.5	11.3	7.7%
Inner Mongolia Ximeng Group	12.3	13.4	15.8	n/a	n/a	n/a
Jilin Liaoyuan Mining Group	8.6	11.0	12.5	n/a	n/a	n/a
Jiangxi Coal Group	8.0	8.6	9.6	n/a	n/a	n/a
Yunnan Dongyuan Coal Industry Group	9.6	8.4	8.4	n/a	n/a	n/a
Hunan Coal Industry Group	7.3	7.7	7.7	n/a	n/a	n/a
Shanghai Ace Company	4.0	3.9	3.3	3.4	3.1	-6.5%
Sundiro Holding Company	1.6	1.9	2.4	2.6	2.5	-4.3%
Huolinhe Opencut Coal Industry Corporation	37.1	42.2	42.5	44.0	45.0	2.4%
Inner Mongolia Pingzhuang Coal Industry Group	22.8	25.3	n/a	n/a	n/a	n/a
Huaneng Hulanbeier Energy Development	20.7	23.0	n/a	n/a	n/a	n/a
Shandong Xinwen Mining Group	13.6	18.3	n/a	n/a	n/a	n/a
Shandong Zaozhuang Mining Group	16.9	17.5	n/a	n/a	n/a	n/a
Gansu Huating Coal Industry Group (Huaneng)	17.5	17.0	n/a	n/a	n/a	n/a
Shandong Zibo Mining Group	13.8	13.2	n/a	n/a	n/a	n/a
Shandong Longkou Mining Group	8.0	8.3	n/a	n/a	n/a	n/a
China Energy Corporation	1.6	1.9	n/a	n/a	n/a	n/a
Total	1,592	1,829	2,289	2,668	2,871	7.6%

Source: China National Coal Association, SX Coal, corporate reports and Bernstein estimates and analysis.

With further consolidation and technical improvements in the industry, we believe the sector will continue to shift towards larger-scale, lower-cost miners. This will squeeze the high-cost coal miners on the right hand side of the cost curve

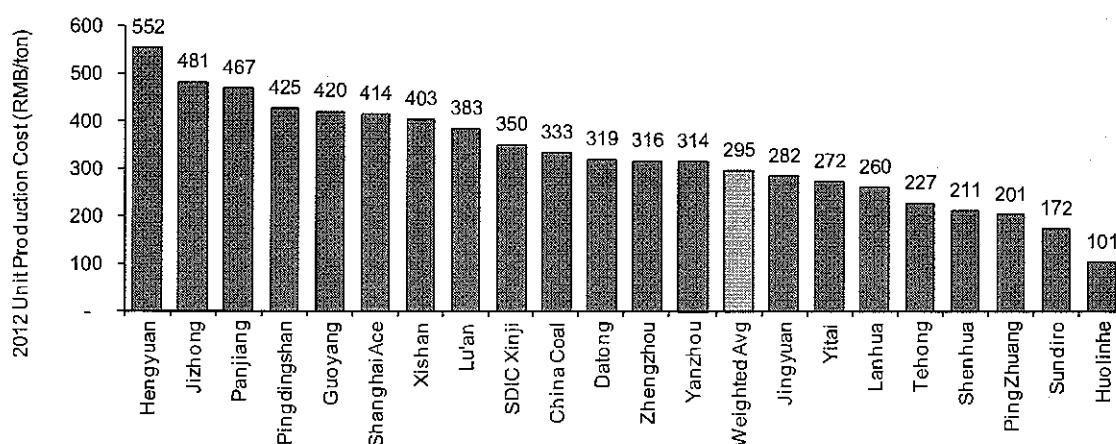
out of the market. Based on our demand forecast, we believe demand for domestically produced coal will remain at ~4.1 billion tons in 2013, up ~60 million tons from 2012.

We project a 9% growth rate for the top 55 miners between now and 2015. By 2015, we believe these companies will account for ~88% of the total domestic market (see Exhibit 102). Today, there is another roughly 1 billion tons of Chinese production capacity in the market. Given that the 50th largest coal miner in China today produces ~10 million tons of coal, this implies at least another 100 coal miners still in operation, and in all likelihood, the real number is several thousand. In short, even after all this, the industry is highly fragmented.

Weighted average unit production cost (delivered) has pretty much stayed flat at RMB295/ton in 2012, compared to RMB296/ton in 2011. Hengyuan was the highest-cost coal producer among the 21 publicly traded Chinese coal miners (see Exhibit 104).

Exhibit 104

Unit Production Cost for 21 Publicly Traded Chinese Coal Miners (2012)

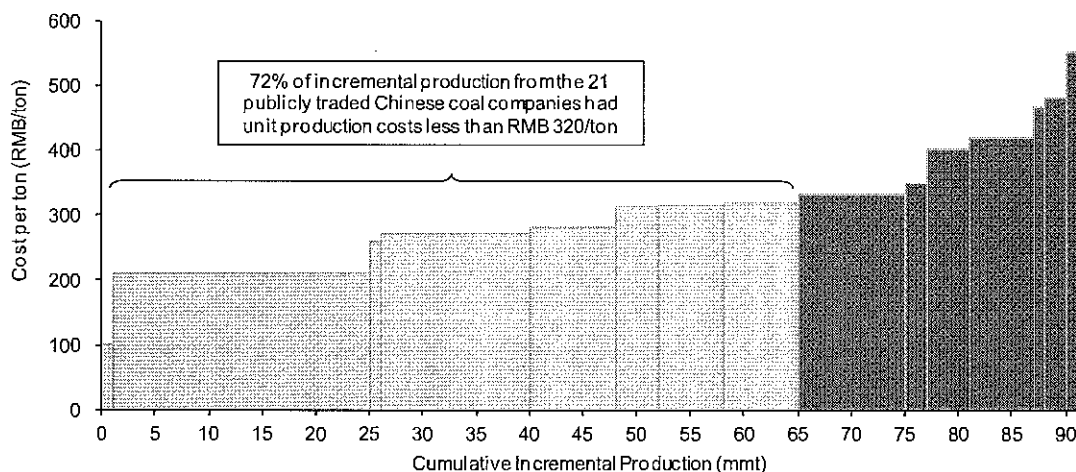


Source: Corporate reports and Bernstein estimates and analysis.

Based on 2012 data, we estimate that the 75th percentile of new supply costs at ~RMB320/ton (see Exhibit 105).

Exhibit 105

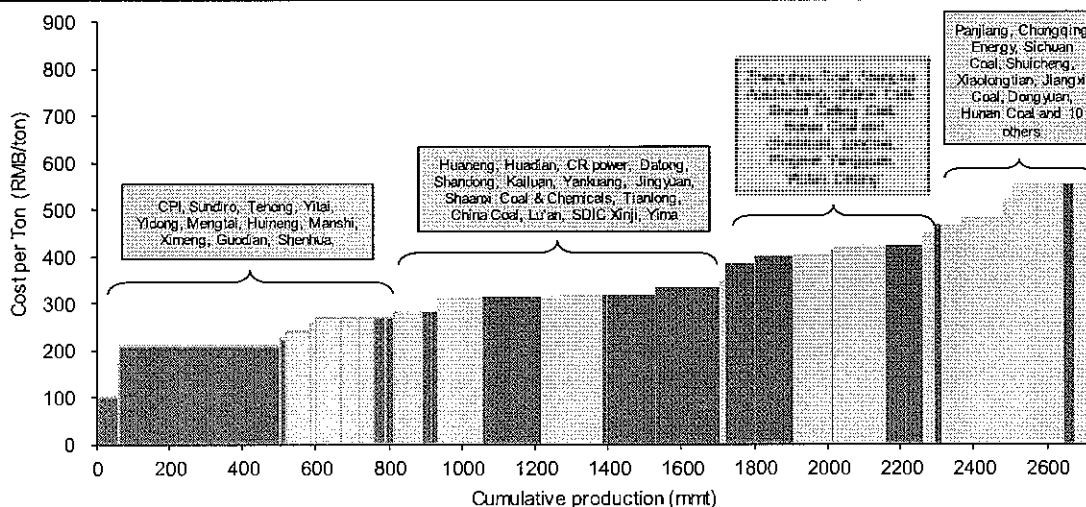
Cost Curve of Incremental Coal Production from 21 Publicly Traded Miners (2012)



Source: Corporate reports and Bernstein estimates and analysis.

Adding VAT at 17% implies a price (at short-run variable cost) of RMB374/ton. Add on RMB90/ton to rail that coal to the coast and this implies a delivered cost for the top 55 producers of RMB580/ton, after adjusting for transport frictions, a GCV adjustment and inflation in 2013. Combining the known cost structures of the publicly traded coal miners with the production level of the rest of the top 55, we have pieced together our view of the coal cost curve in 2012 (see Exhibit 106).

Exhibit 106 Cost Curve for Top 55 Chinese Coal Miners (2012)



Note: Bars in dark blue represent costs based on corporate reports; bars in light blue represent estimates based on production volume and region; see online version for colors.

Source: Corporate reports and Bernstein analysis.

Looking at the 21 publicly traded Chinese coal miners, production cost for the ~75th percentile in 2012 was RMB320/ton at or near the mine mouth. These costs represent the average, rather than the incremental, cost from these 21 coal miners. Given that incremental cost is likely to be higher, the incentives to push additional production into the marketplace may simply not be there for even large miners.

Why Are the Big Getting Bigger?

There is no satisfying answer to this question of why Shenhua is not increasing production volume right now. Presumably, the fact that its customers don't want any more coal, are happy with current supply relationships and will only switch to greater volumes at further discounts is playing a part. The textbook answer says Shenhua should be producing more coal. But if the customers won't read the textbook and won't buy the coal, and Shenhua won't cut pricing because of the concern over ripple effects, then more production just means higher inventories.

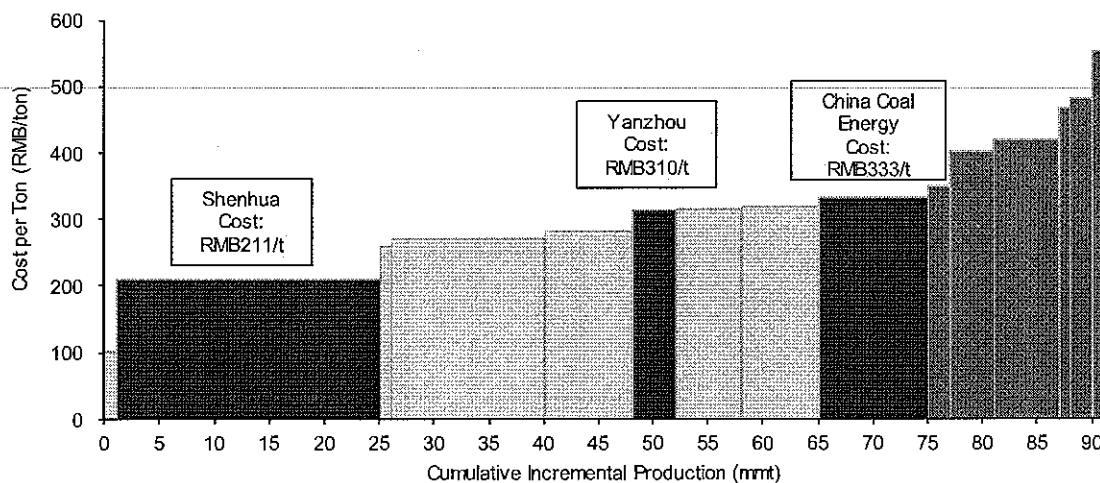
The answer to the same question for China Coal Energy is much simpler, as we outline later in the chapter. We believe that a combination of the flat cost curve, high inventories and rail bottlenecks are slowing production volume growth from the large-scale miners currently. In short, the cost curve may be even flatter than we think.

Flat Cost Curves Have Consequences

China Coal Energy's 2012 unit production cost sits in the higher end of the cost curve of the 21 publicly traded Chinese coal miners (see Exhibit 107). We estimate that at a unit production of RMB333/ton near the mine (with some local transportation), China Coal Energy's fully loaded delivery cost to Qinhuangdao is RMB610/ton currently.

In other words, China Coal Energy is out-of-the-money on a fully loaded basis if it sells incremental production into the spot market (see Exhibit 108). Yes, we should take out depreciation (may be RMB30/ton) but we should also adjust cost up for marginal rather than average cost.

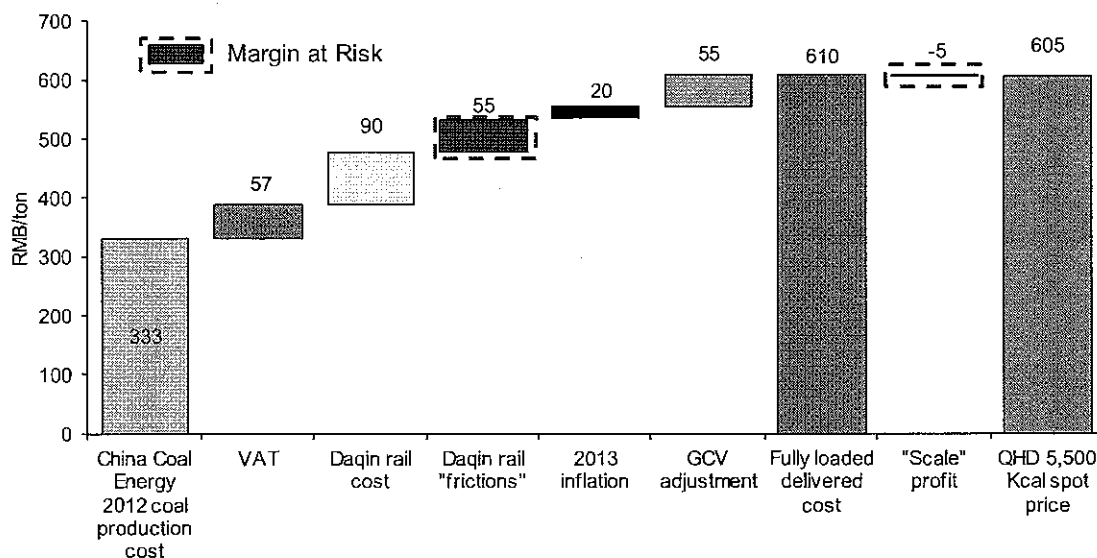
Exhibit 107 Cost Curve of Incremental Coal Production from 21 Publicly Traded Miners (2012)



Source: Corporate reports and Bernstein estimates and analysis.

In short, China Coal Energy cannot expand production for the simple reason that doing so would just come at a small cash loss. We believe that a large number of scaled Chinese coal miners are likely to be in a similar position.

Exhibit 108 China Coal Energy's Cost and Margin at the Coastal Region

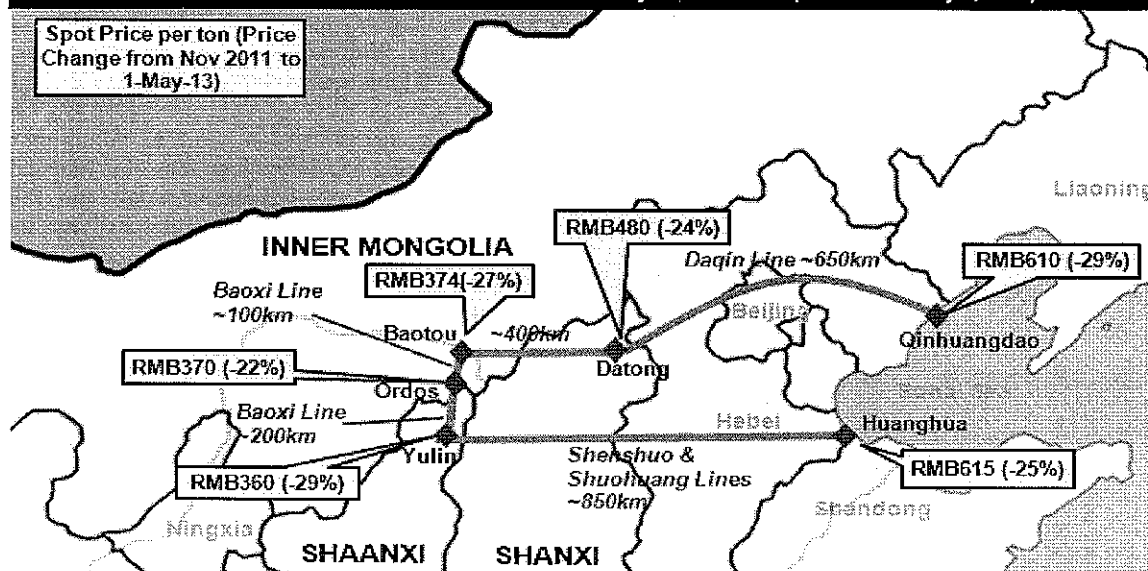


Source: Bloomberg L.P., SX Coal and Bernstein estimates and analysis.

Further, given the recent changes in coal prices in Baotou, Huanghua, Qinhuangdao and Ordos, it is not clear that the Qinhuangdao coal price will hold up if further supply starts coming on right now.

Over the last month and a half, coal prices were down 12% in Baotou but almost flat in Qinhuangdao (see Exhibit 109 and Exhibit 110) after prices moving across these regions in sympathy for 17 of the last 18 months. Efforts by the coal miners to push more coal to the coast risks a further drop in benchmark coal prices.

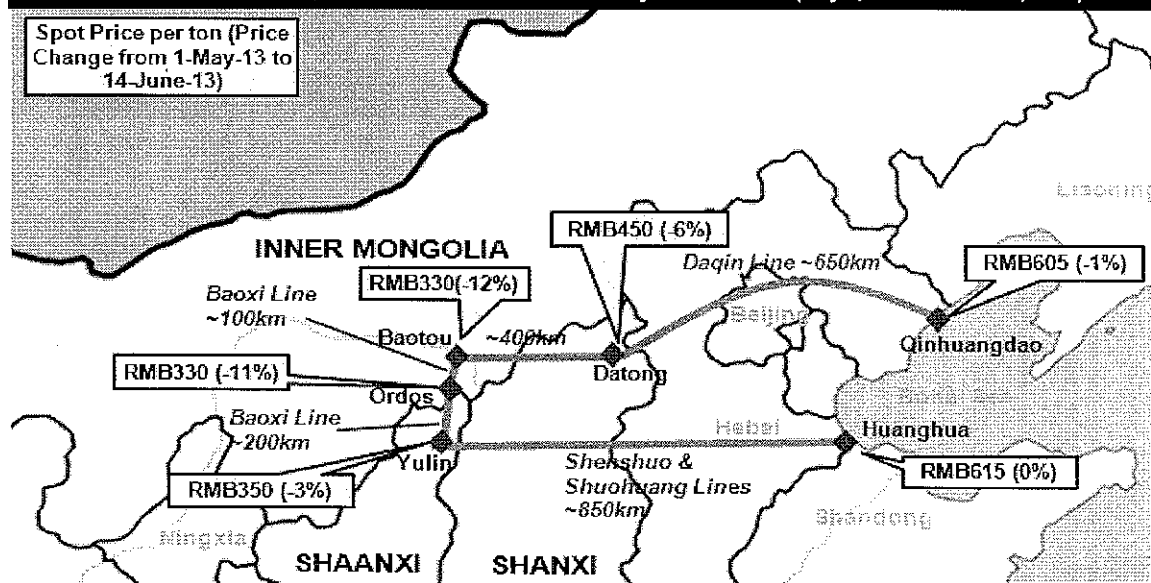
Exhibit 109 Thermal Coal Prices in China by Province/Port (Nov 2011 to May 1, 2013)



Source: Wikimedia commons, SX Coal and Bernstein analysis.

The textbook suggests that coal prices cannot fall from here given that such a move would cut into the muscle of the coal mining industry (companies such as China Coal Energy). However, if inventories are as high as we suspect (discussed in later sections), there is clearly some downside risk, especially given the sudden disparity in coal prices over the last one month and a half.

Exhibit 110 Thermal Coal Prices in China by Province/Port (May 1, 2013 to June 14, 2013)



Source: Wikimedia commons, SX Coal and Bernstein analysis.

Inventories in the Chinese Coal Supply Chain

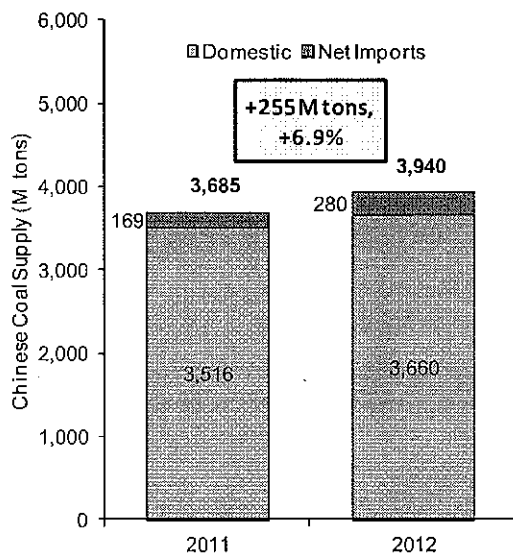
Hindsight is 20:20...except when it comes to the Chinese coal mining sector. The data produced by the mining sector for 2012 remains opaque. Even the simplest data — 2012 production — is inconsistent between the two most credible providers, and doesn't reconcile with consumption and the movement in inventory over the year either.

Based on both SX Coal data and the NBS data, domestic coal supply in 2012 increased 6-7% last year. According to NBS, Chinese domestic coal production increased 4.1% to 3.66 billion tons in 2012. With net imports of 280 million tons, Chinese coal supply was therefore 3.94 billion tons in 2012, up 7% (see Exhibit 111).

According to SX Coal, Chinese raw coal production was 3.63 billion tons through November 2012. Assuming something like 300 million tons of production in December 2012 would mean 3.94 billion tons of domestic supply and 280 million tons in net imports, meaning total supply was 4.2 billion tons last year, up 6% (see Exhibit 112).

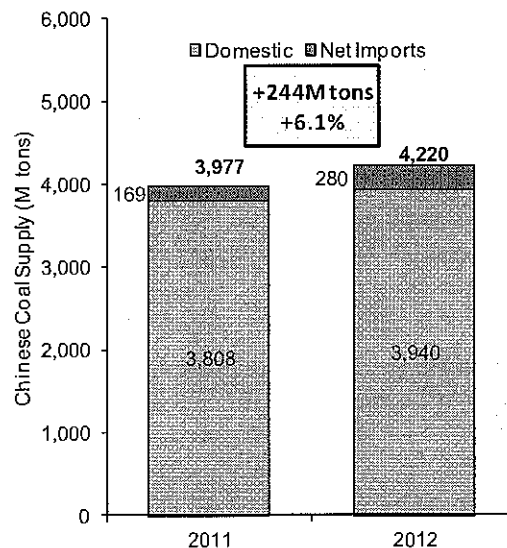
Yet none of these numbers make great sense to us. Coal demand growth in 2012 (and in every year in China) was dominated by power demand growth. Thermal power generation growth in 2012 in China fell 0.6%.

Exhibit 111 Chinese Coal Supply Based on NBS Data (2011-12)



Source: NBS, CEIC and Bernstein analysis.

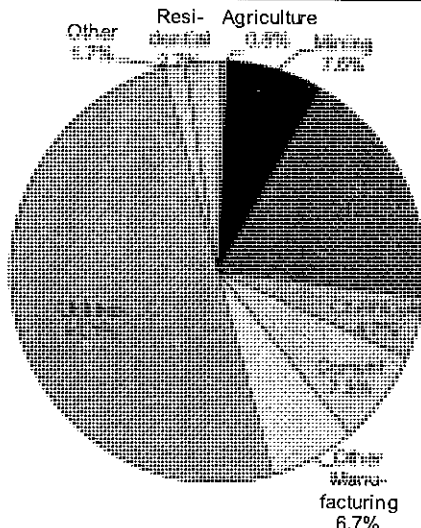
Exhibit 112 Chinese Coal Supply Based on SX Coal Data (2011-12)



Source: SX Coal and Bernstein analysis.

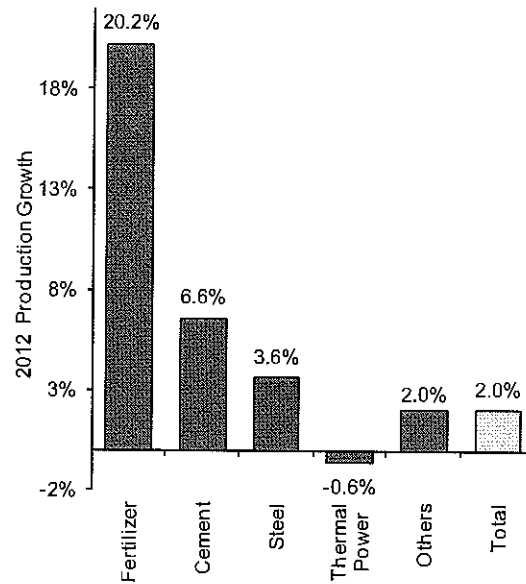
Steel and cement (which account for another 25% of Chinese coal consumption) saw production increases of 3.6% and 6.6%, respectively (see Exhibit 114). Fertilizer was the only "growth" story among Chinese coal end markets in 2012 (up 20.2% year-over-year); chemicals were only 5% of Chinese coal consumption (see Exhibit 113).

Exhibit 113 Chinese Coal Consumption by Segment (2011)



Source: NBS, CEIC and Bernstein analysis.

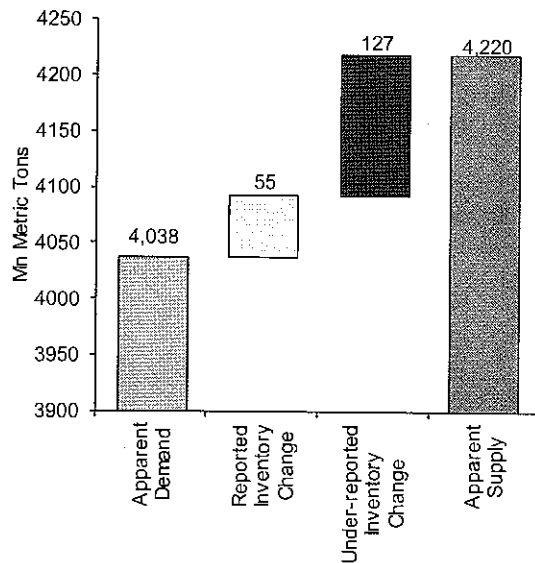
Exhibit 114 Coal Consuming Sectors Production Growth (2012)



Source: NBS, CEIC, media reports and Bernstein analysis.

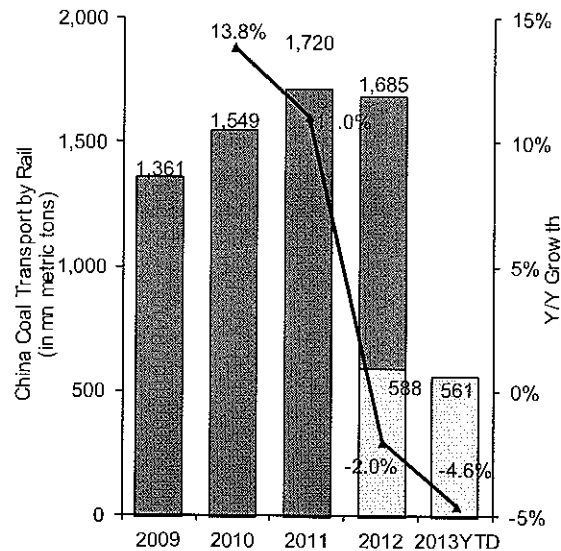
Transport and inventory data reflect rising inventories and falling transport volume (see Exhibit 116 through Exhibit 118).

Exhibit 115 Reported vs. Under-Reported Coal Inventories (2012)

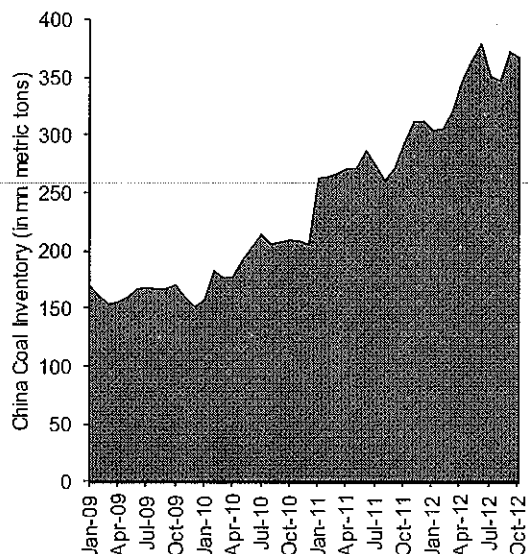
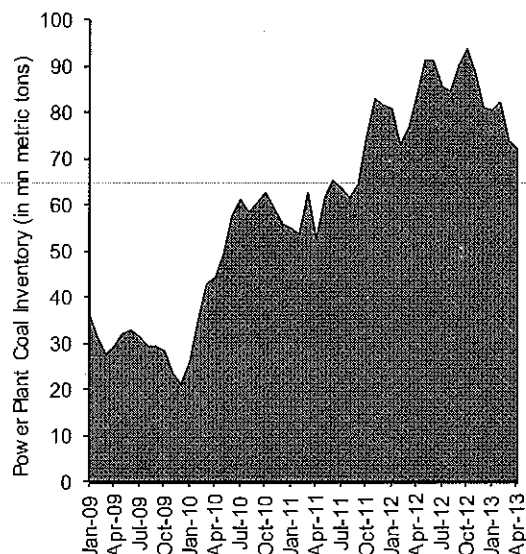


Source: SX Coal and Bernstein estimates and analysis.

Exhibit 116 China Coal Transport Volumes by Rail (2009-April 2013)



Source: SX Coal, State Administration of Coal Mine Safety and Bernstein analysis.

Exhibit 117 China National Coal Inventories (2009-October 2012)**Exhibit 118 China Power Plant Coal Inventories (2009-April 2013)**

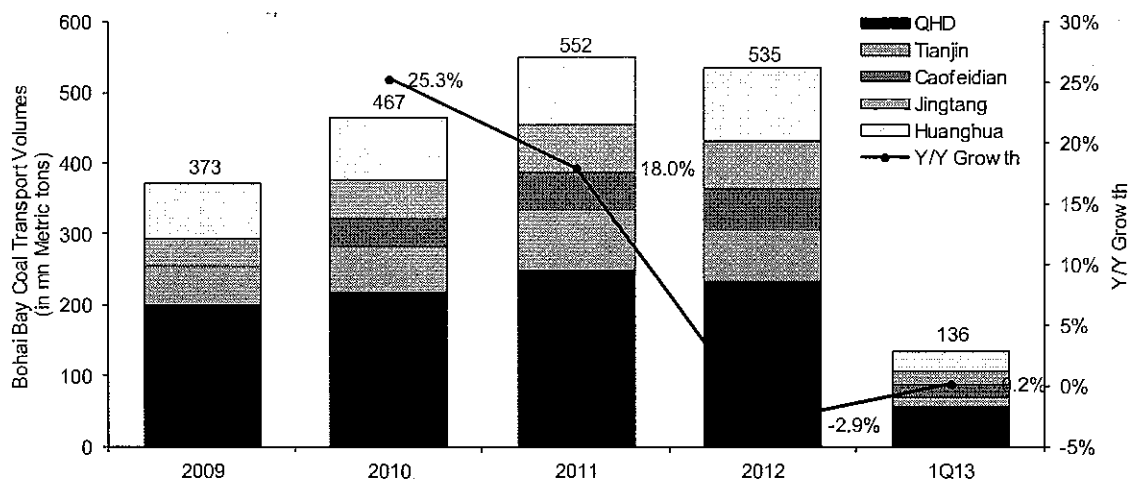
Note: No recent data is available.

Source: SX Coal and Bernstein analysis.

Source: SX Coal and Bernstein analysis.

The shortfall between incremental demand and incremental supply is ~160-180 million tons (see Exhibit 115). Yet reported national inventories increased only 55 million tons between December 2011 and October 2012 (see Exhibit 117).

Bohai Bay coal transport volumes and Chinese coal rail transport volumes were also down in 2012 year-over-year and continued to fall this year (see Exhibit 119). In short, either the inventory data was understated by ~125 million tons (the most likely explanation) or the production data in 2012 was overstated. Either way, we believe that low utilization among marginal mining facilities and/or high coal inventories throughout Chinese coal end markets are the best explanation for the stable pricing year-to-date.

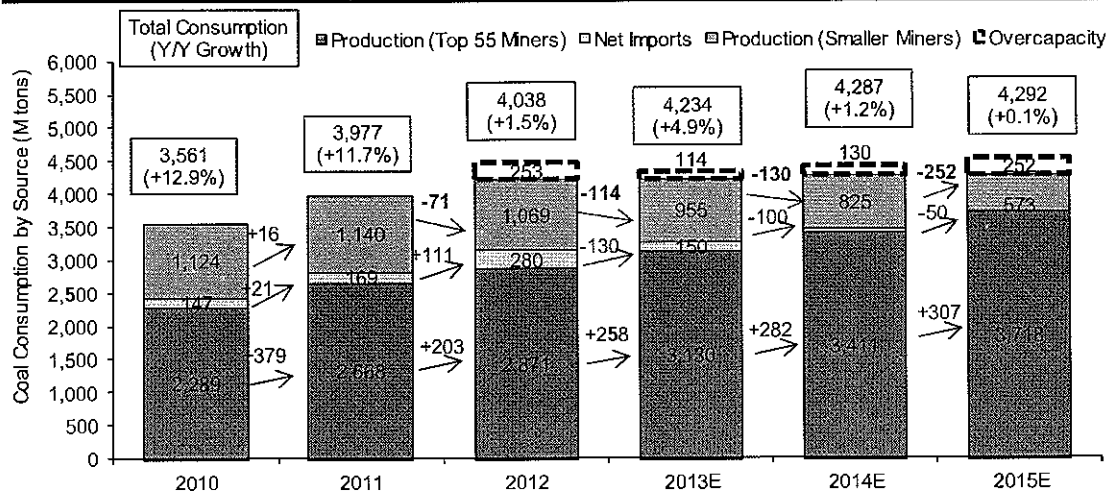
Exhibit 119 Bohai Bay Coal Transport Volumes (2009-Mar 2013)

Source: SX Coal, State Administration of Coal Mine Safety and Bernstein analysis.

And given weak production growth, we expect this stable pricing to continue (see Exhibit 120). In short, the miners (even the large ones) are reluctant to expand production, in our view, because the entire system is full of coal.

Exhibit 120

Chinese Coal Supply by Source (2010-15E)

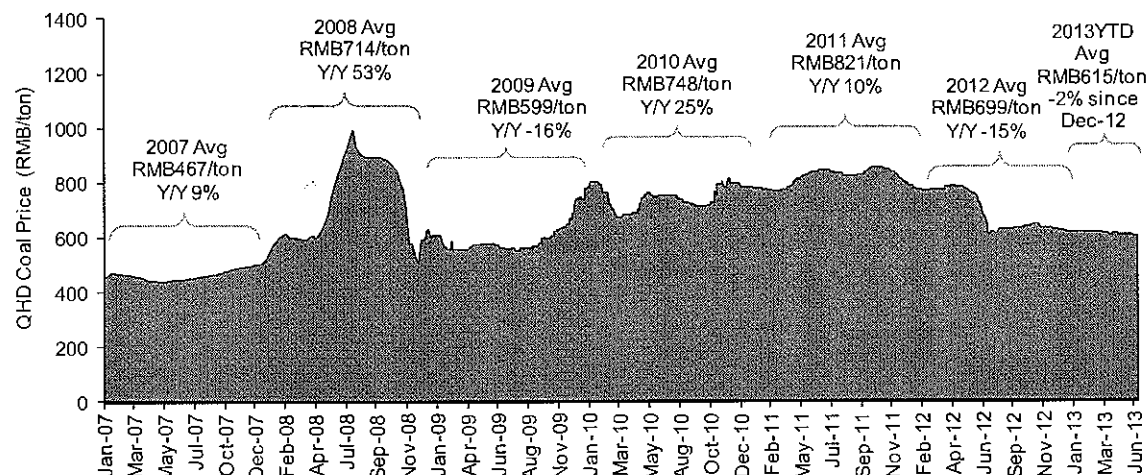


Source: SX Coal, CEIC, NBS, China General Administration of Customs and Bernstein estimates and analysis.

Coal prices have fallen 2% since the beginning of the year from RMB620/ton to RMB605/ton in June 2013 (see Exhibit 121). Coal prices have fallen ~29% since November 2011 when the price touched RMB855/ton. We are in the longest sustained period of stable pricing since at least 2006, at Qinhuangdao.

Exhibit 121

Qinhuangdao 5,500 Kcal Spot Coal Price (2007-June 2013)

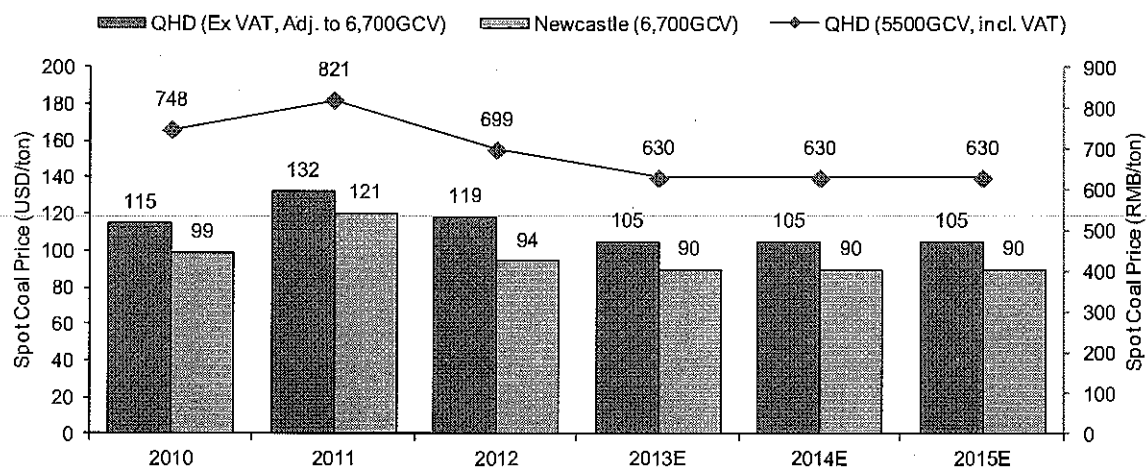


Source: SX Coal and Bernstein estimates and analysis.

Exhibit 122 shows our coal price forecasts from 2013E to 2015E.

Exhibit 122

Bernstein Coal Price Forecasts: Qinhuangdao and Newcastle



Note: Figures for 2010-15E are yearly average prices.

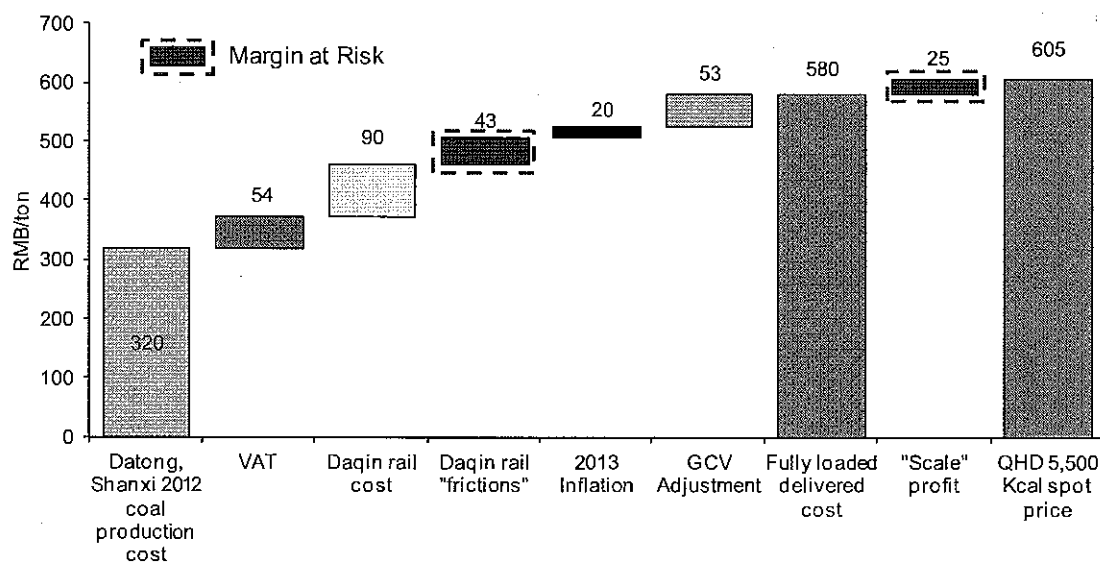
Source: Bloomberg L.P., SX Coal and Bernstein estimates and analysis.

Impact of Rail Bottlenecks and the Effect of New Rail Line Commissioning

Coal prices have fallen 30% since November 2011. Over that time, there hasn't been a single "golden spike" moment where the commissioning of a new rail line resulted in a sudden decrease in coal prices as supply of coal from a low-cost region flooded into either a demand center or high-cost coal producing region, displacing higher-cost coal. We don't think this is likely to change. The "network effect" within the already complex Chinese rail system means that additions to existing rail capacity and the commissioning of new links simply eases the path of coal to market, creates optionality for moving coal around the country, and results in long-term deflationary pressure on coal price.

Exhibit 123

Qinhuangdao Coal Price Composition (June 2013)



Source: Bloomberg L.P., SX Coal and Bernstein estimates and analysis.

But the frequency of those deflationary shocks should pick up over the next 18 months as new lines are commissioned. Currently, lack of new rail capacity may be contributing to weak production growth among the publicly traded miners.

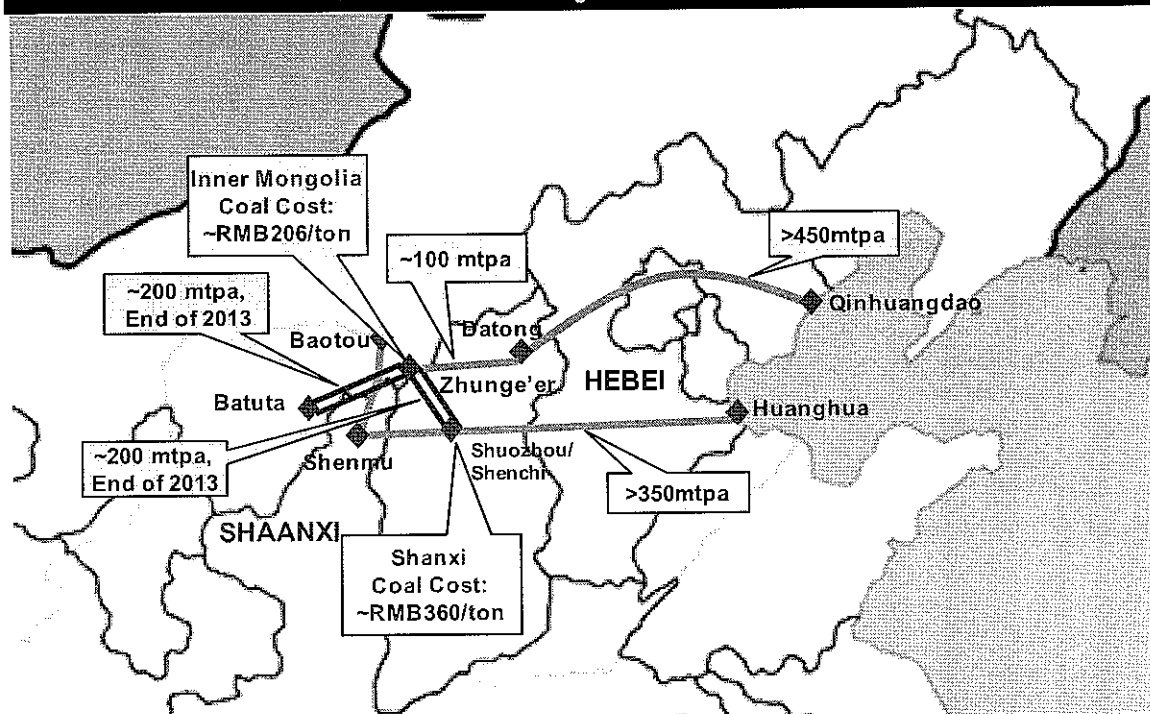
The earlier-mentioned analysis (where we estimate that the incremental ton of coal has a cost of ~RMB580/ton currently) assumes that the marginal ton of coal today is coming from Datong in Shanxi (see Exhibit 123).

With improving rail capacity into Inner Mongolia, the math changes at the margin if the source of the incremental ton of coal is Inner Mongolia. That sourcing could change as new rail lines are commissioned (see Exhibit 124).

Transporting coal from Zhunge'er in Inner Mongolia to Qinhuangdao currently requires railing that coal to Datong and then on to Qinhuangdao. The capacity of the line from Zhunge'er to Datong is ~100 million tons. The Daqin line has a capacity of 450 million tons per annum (although not all of that coal makes it to Qinhuangdao).

Exhibit 124

Batuta to Zhunge'er Line, Zhunge'er to Shenchì Line, Daqin Railway and Shenmu/Shuozhou/Huanghua Line

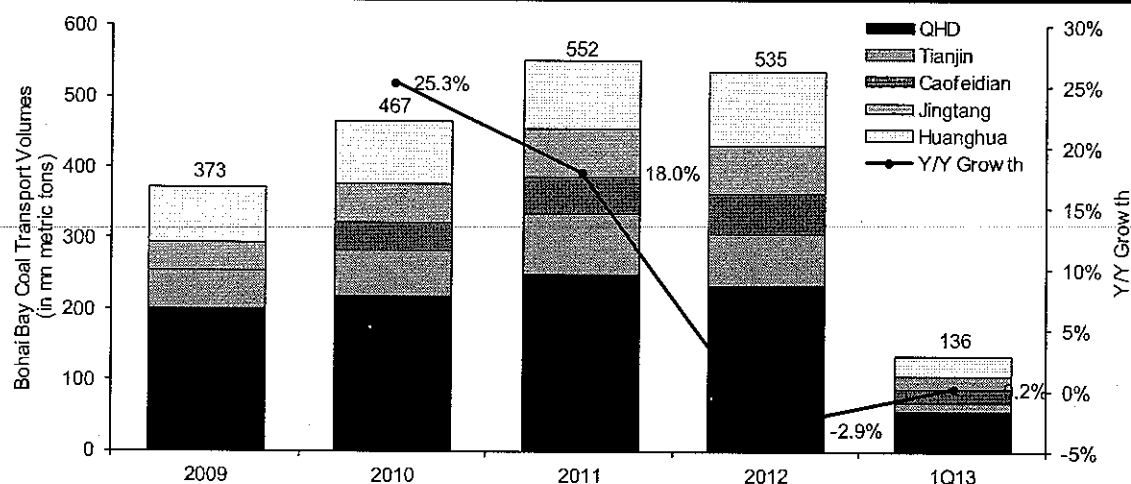


Source: Shenhua Group, Chinese Ministry of Railways and Bernstein analysis.

With the commissioning of the new (Shenhua) line between Zhunge'er and Shenchì at the end of 2013, a new pathway to market opens up. The new route takes Inner Mongolian coal south into Shanxi and then east on the Shenmu-to-Huanghua line. The new line has a capacity of 200 million tons per annum and so will represent a significant increase in the amount of coal heading for Bohai Bay (see Exhibit 125).

Exhibit 125

Bohai Bay Coal Transport Volumes (2009-Mar 2013)



Source: SX Coal, State Administration of Coal Mine Safety and Bernstein analysis.

China transports ~1.7 billion tons of coal via its railway system each year and about 530 million tons of coal was shipped from the northern Chinese ports to various domestic locations in 2012 (see Exhibit 126). Exports were negligible.

Exhibit 126

Coal Transport Volumes (Domestic) via Bohai Ports (2011-12)

Port (in M metric tons)	2011 Domestic	2012 Domestic	Y/Y Growth
QHD	251	234	-6.6%
Tianjin	80	71	-10.7%
Caofeidian	52	55	5.0%
Jingtang	66	68	2.1%
Huanghua	93	100	7.6%
Total	542	527	-2.6%

Source: SX Coal, State Administration of Coal Mine Safety and Bernstein analysis.

Another line that Shenhua is working on is the Batuta to Zhunge'er line (Bazhun line) — see Exhibit 124. The capacity of that line should also reach 200mtpa. Shenhua is expecting to complete this line around the same time as the Zhunchi line. The Bazhun line is designed to connect either to the Shuozhou/Huanghua line (with over 350mtpa of capacity) via the Zhunchi line or to the Daqin line (with over 450mtpa of capacity) via the Datong/Zhunge'er line. Both the Zhunchi and Bazhun lines will be serving Shenhua's mines in Inner Mongolia. Shenhua expects the capacity at Huanghua Port could ramp up to ~200mtpa of capacity by the end of 2013, which should match up with the rail capacity. New rail capacity (and this is by far not the full extent of all new rail capacity coming on this year; see the chapter, "Coal Train's Slow Blues: Why Weak Rail Capacity Additions in 2012 Won't Re-Bottleneck Chinese Coal") may be another gating factor behind weak production growth from the large Chinese coal miners.

But perhaps the most important aspect of the new rail lines is that it will bring low-cost Inner Mongolian coal south into Shanxi, potentially displacing high-cost Shanxi coal. Inner Mongolian coal production cost — based on the 21 publicly traded miners with Inner Mongolia — has a weighted average unit cost of ~RMB206/ton (see Exhibit 127).

Exhibit 127 **Production Cost of the Publicly Traded Chinese Miners With Assets in Inner Mongolia (2012)**

Company	Production (M metric tons)	Unit Production Cost (RMB/ton)
China Shenhua	306.8	210.8
Huolinhe Opencut Coal Industry Corp. (China Power)	45.0	101.3
Inner Mongolia Yitai Coal Company Limited	49.8	271.7
Inner Mongolia PingZhuang Energy Limited (China Guodian)	9.9	201.4
Sundiro Holding (Wujiu Coal Group)	2.5	172.5
Inner Mongolia Tehong Coal Group Co.	0.9	226.7
Total	414.8	205.8

Source: Corporate reports and Bernstein estimates and analysis.

This compares to a Shanxi coal cost that averaged RMB360/ton in 2012 (see Exhibit 128). Thus, we believe the higher cost Shanxi coal could potentially be displaced.

Exhibit 128 **Production Cost of the Publicly Traded Chinese Miners With Assets in Shanxi (2012)**

Company	Production (M metric tons)	Unit Production Cost (RMB/ton)
China Coal Energy	111.1	332.8
Shanxi Guoyang New Energy Co	56.5	420.0
Shanxi Lu'an Environmental Energy Development	28.7	383.3
Datong Coal Industry	38.2	319.0
Shanxi Xishan Coal and Electricity Power Co	25.4	402.7
Shanxi Lanhua Sci-Tech Venture	5.8	259.8
Total	265.8	359.9

Source: Corporate reports and Bernstein estimates and analysis.

Of course, there are other differences in the coal (primarily heat content) that make the Shanxi coal more valuable than the Inner Mongolian coal. Further, these new lines are likely to ramp up over time rather than all at once. In addition, there is a cost associated with transporting coal on the Zhunge'er to Shuozhou line. All of this means that the commissioning of these lines is unlikely to result in a steep, sudden drop in coal prices at the start of 2013. However, it does reflect the fact that coal price deflation from improving transportation is likely to counter coal production cost inflation in coming years.

The winners from this are the consumers of coal, just about anywhere. The losers are the Chinese coal miners, which are unable to pass on cost increases in an oversupplied market.

In short, prospects for the coal miners look miserable both in the short term and the long term.

Appendix

This section briefly describes the listed Chinese coal producers outside of our coverage that we have used in the previous analysis.

- Huolinhe Opencut Coal Industry Corp (SZSE: 002128): The company is located in Inner Mongolia and operates one of the largest open-pit mines in China. However, the coal the company produces is lignite that has low calorific value, which is very costly if transported over long distances. Most of the company's revenue therefore comes from Inner Mongolia, Jilin and Liaoning. The company is 70% owned by China Power Investment Corporation. It produced 45 million tons of coal in 2012.
- Shanxi Guoyang New Energy Co (SHSE: 600348): Founded in 2003, the company has mine resources around Shanxi's Yangquan city, which is close to the Shitai Railroad that transports coal to Shijiazhuang in Hebei. The company is 58.34% owned by Yangquan Coal Industry Group. It produced 56.5 million tons of coal in 2012.
- Pingdingshan Tianan Coal Mining (SHSE: 601666): The company was founded in 1997 after a merger between several coal companies in Henan. It is 57% owned

by Zhong Ping Energy, which in turn is 65% owned by the provincial SASAC. The company produced 38.4 million tons of coal in 2012.

- Inner Mongolia Yitai Coal Company Limited (SHSE: 900948): The company was established in 1997, and is now one of the largest coal enterprises in Inner Mongolia. It is 54.64% owned by Inner Mongolia Yitai Group. The company also owns railroads and highways in Inner Mongolia. The company received approval from the CSRC in June 2010 to list its shares in the Hong Kong Stock Exchange. The company produced 49.8 million tons of coal in 2012.
- Shanxi Lu'an Environmental Energy Development (SHSE: 601699): Established in 2001, the company's coal resources are located in southeastern Shanxi. The company was co-founded by five companies, including Lu'an Group, Zhengzhou Ministry of Railways and the Rizhao Port Company Ltd. Lu'an Group still owns 64% of the company. The company's largest customers are located in Shanxi, Shandong, Henan and Hubei. Shanxi Lu'an produced 28.7 million tons of coal in 2012.
- Jizhong Energy Resources Co., Ltd (SHSE: 000937): The company was founded in 1999 in Hebei and has coal resources in Hebei and Shanxi. As a part of a restructuring, the company was merged with Fengfeng Group, Handan Coal Group and Zhangkang Group in 2008. The company is 39% owned by Jizhong Energy Group, and produced 36.4 million tons of coal in 2012.
- Datong Coal Industry (SHSE: 601001): The company was incorporated in 2001 in Datong, Shanxi, which is close to some of the main coal-dedicated railroads in China, including the Daqin Line. The company's largest customer is Beijing Datang Fuel Company, which accounts for 57% of its revenue. The company is 60% owned by Datong Coal Mining Group, and produced 38.2 million tons of coal in 2012.
- Shanxi Xishan Coal and Electricity Power Co (SHSE: 000983). The company is based in Taiyuan, Shanxi, and was formerly part of the Shanxi Coal Administration, which was established in 1956. Shanxi Xishan's coal mines are located in Shanxi and Inner Mongolia, and the company's products are sold across 20 provinces. The company is 54% owned by Shanxi Coking Coal Group, and produced 25.4 million tons of coal in 2012.
- Anhui Hengyuan Coal Industry (SHSE: 600971): The company was founded in 2000 and was listed on the A-share market in 2004. The company's coal resources are located in the eastern provinces of China, and are accessible by the major railroads. The company's main customers are located in Anhui, Shandong and Zhejiang. The company is 60% owned by Anhui Wanbei Coal and Power Group. The company produced 12.2 million tons of coal in 2012.
- SDIC Xinji Energy (SHSE: 601918): The company first began its coal mine development in 1989 in Anhui, and was listed on the A-share market in 2007. It is also engaged in other businesses, such as property development and food and beverage; however, coal mining still accounts for 99% of its revenue. The company is 42% owned by the State Development and Investment Corporation (SDIC), and produced 16.4 million tons of coal in 2012.
- Inner Mongolia PingZhuang Energy Limited (SHSE: 000780): The company was established in 1993 in Chifeng, Inner Mongolia, and is 61% owned by Inner Mongolia PingZhuang Coal Industry, which is in turn 51% owned by a China Guodian subsidiary. The company was listed in mainland China in 1997, and in 2008, China Guodian acquired a controlling stake in the company. Although the company's coal production is based in Inner Mongolia, only 24% of the company's revenue is generated in the province, with the rest generated elsewhere in China. The company produced 9.9 million tons of coal in 2012.
- Guizhou Panjiang Refined Coal (SHSE: 600395): The company was founded in 1999 in Liupanshui in Guizhou and is 41% owned by Panjiang Coal and Power Group. It produced 13.5 million tons of coal in 2012.
- Shanxi Lanhua Sci-Tech Venture (SHSE: 600123): The company was established in 1998 and is currently 45% owned by Shanxi Lanhua Coal Industry Group. It is

located close to Jincheng, Shanxi, and is also engaged in fertilizer production. The company produced 5.8 million tons of coal in 2012.

- Zhengzhou Coal Industry and Electric Power (SHSE: 600121): The company was established in 1997 and engages in both coal production and electricity generation businesses. The company is 53% owned by Zhengzhou Coal Industry Group. It produced 11.1 million tons of coal in 2012.
- Shanghai Ace Company (SHSE: 600652): The company was incorporated in 1996 and has coal mines in Shandong, Inner Mongolia and Shanxi. The company produced 3.1 million tons of coal in 2012.
- Gansu Jingyuan Coal Industry and Electricity Power Co. (SZSE: 000552): The company was founded in 1993 in Gansu and is currently 47% owned by Gansu Jingyuan Coal Industry Group. The company produced 10.6 million tons of coal in 2012.
- Sundiro Holding (Wujiu Coal Group) (SZSE: 000571): The company was founded in 2001 and engages in two very different businesses: coal mining and motorcycle manufacturing, although 70% of the company's revenue is still from the coal mining segment, which operates under its subsidiary, Wujiu Coal Group. The company's coal mines are located in Inner Mongolia, and they produced 2.5 million tons of coal in 2012.
- Inner Mongolia Tehong Coal Group Co. (OTCBB: CHGY): The company's coal mine is located in the Dongsheng district of Ordos. The company produced 0.9 million tons of coal in 2012.

Dark and Full of Terrors: Valuing Miners in Terminal Decline

No Cash, No Replacement Value, No Reserve Value, But Aside from That...

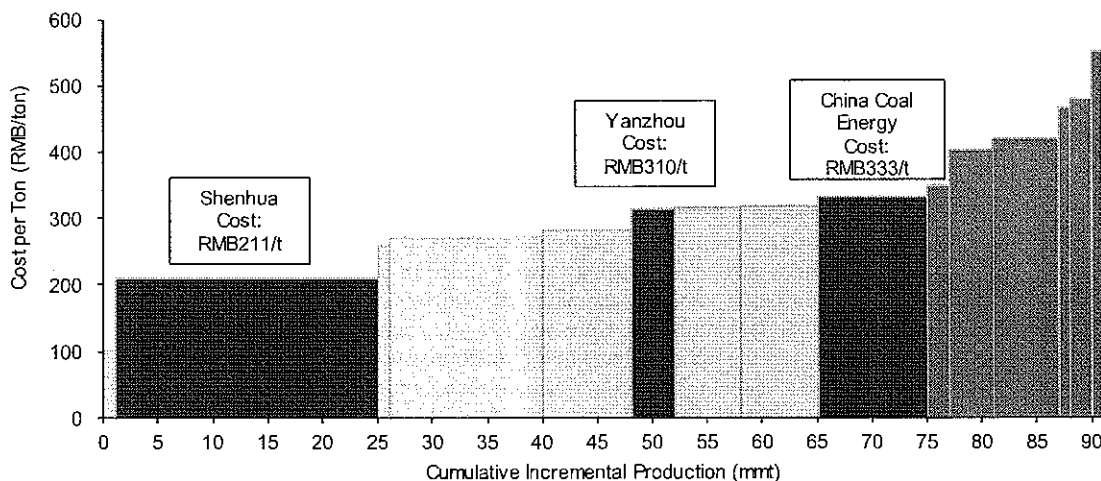
The Chinese coal miners have fallen in value by at least 25% since the start of 2013 and have all underperformed the MSCI Asia-ex Japan by ~32%. We have argued for the last 18 months that — given the structural shift in the industry — historical P/B and P/E multiples are meaningless for valuing these stocks. Now that Shenhua, even on our numbers, is pushing the lower end of these historical trading ranges, we are expanding our approach to valuation and look at EV/EBITDA, DCF, free cash flow, dividend yield and comparisons to global peers. All three stocks under our coverage still look expensive to us. We reiterate our underperform rating.

The structure of the industry has changed. Today, there is more coal production capacity than demand; transport bottlenecks are being resolved; the government is putting policies in place not just to reduce coal imports but to reduce coal consumption overall. And coal prices have come down 30% since November 2011. We view this change as permanent. Putting a *zero-growth-Chinese-energy-SOE* earnings multiple (~8x) on our forward earnings estimates continues to provide plenty of downside.

For Yanzhou and China Coal Energy, it is possible to argue that the stocks are worth zero. The companies are not producing any free cash flow currently. If the companies do not reduce capital spending in coming years, production costs continue to rise and coal prices remain flat, they will slowly spend themselves into insolvency. We assume that eventually capital spending will moderate to maintenance capital levels. However, we expect that as the industry continues to consolidate, the cost curve will become flatter and flatter. Coal will eventually be priced at short-run variable cost plus maintenance capital spending for scaled miners like Yanzhou and China Coal Energy (see Exhibit 129). The value of these businesses, once they reach this juncture, is close to zero.

Exhibit 129

Cost Curve of Incremental Coal Production from 21 Publicly Traded Miners (2012)

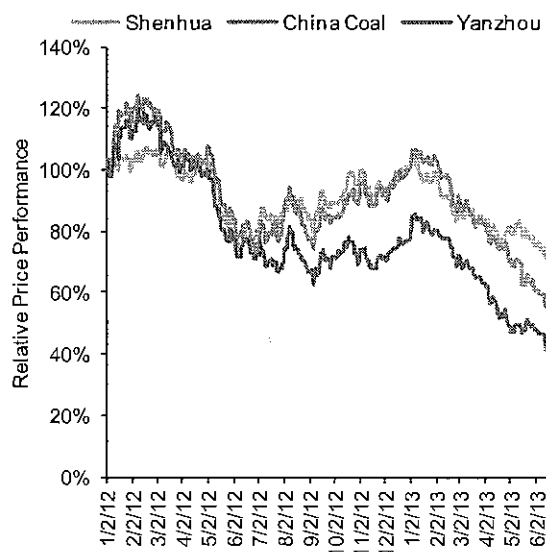


Source: Corporate reports and Bernstein estimates and analysis.

The outlook for Shenhua is more positive than for China Coal Energy and Yanzhou...which isn't saying much. We still believe that — based on cash-based valuation metrics — Shenhua looks expensive too but we estimate that it will remain cash flow positive through 2018 at least. Assuming that the company maintains its current dividend payout ratio of ~40% and that investors will demand a 5% dividend yield given the absence of growth, we believe that the stock is worth ~\$20.

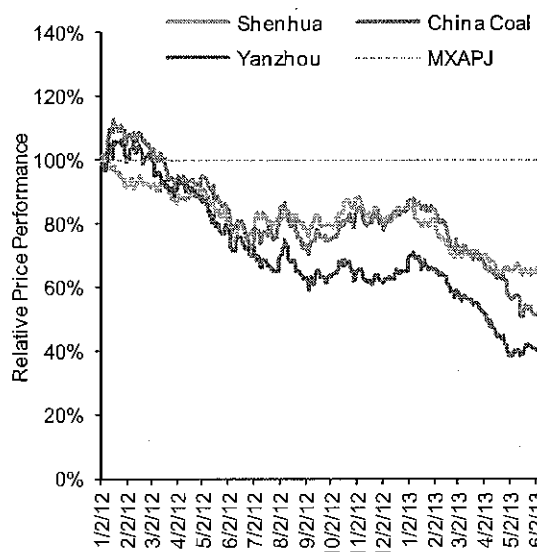
For a group exposed to the kind of pricing pressure that China Coal Energy and Yanzhou face, earnings and return profiles in coming years are miserable (see Exhibit 130 and Exhibit 131). With a return on equity significantly below the cost of equity, there is no reason to believe that 1x book is a floor, especially if you take the view that the industry is in overcapacity currently and will eventually start to contract. In that case, there is no replacement value for high-cost miners for the simple reason that no one would invest to build excess out-of-the-money capacity...except perhaps Chinese SOEs.

Exhibit 130 Chinese Coal Miners — Stock Performance Since January 2012 (Absolute)



Source: Bloomberg L.P. and Bernstein analysis.

Exhibit 131 Chinese Coal Miners — Stock Performance Since January 2012 (Relative to MSCI Asia-ex Japan)



Source: Bloomberg L.P. and Bernstein analysis.

That gives rise to the question of whether the selloff is now done. The main pushback that we hear currently to our sell recommendations is that the forward earnings multiple is well below historical trading ranges, and China Coal Energy and Yanzhou are trading at well under 1x on a price/book basis. But in our view, consensus earnings estimates still reflect inflated coal prices and sales volumes. Historical multiples were set at a time when demand and price were going up. Given the industry has gone through a structural change in the last 18 months, we believe that historical multiples no longer make sense.

But if the old trading ranges are no longer relevant, P/E and P/B are tremendously imprecise valuation tools. The historical ranges were set during a period that does not resemble the current coal market at all. It is easy to argue that the stocks should trade below their historical ranges while they are above those ranges. Now that Shenhua is pushing the bottom of those ranges, more precision in valuation is required.

In this chapter, we cast the net a little wider in terms of valuation. And that is where the trouble really starts...because on cash valuation metrics, the stocks look even worse than on P/E.

The End Game for the Chinese Coal Miners

In the end of May 2013, Beijing's municipal environmental agency announced that the city will reduce coal consumption from 23 million tons annually currently to 15 million tons in 2015 and 10 million tons in 2020. Four new gas-fired heating and power stations will be commissioned in 2014 to supply the energy lost with declining coal use.

All industrial societies reach a point where they determine that the long-term economic cost (in terms of health outcomes and the environment) of burning coal in inefficient facilities in large cities outweighs the short-term economic benefits. China has reached that moment. Following Beijing's lead, coal consumption in large east coast cities is going to decline in coming years due to falling energy demand growth, substitution from gas and renewables, and the transition of economic activity to the interior of the country. In short, the long term doesn't look very good for the coal industry.

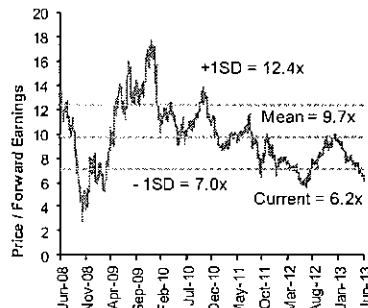
We agree that P/E and P/B are imprecise tools to try to value these businesses when the industry is in this kind of flux. In this chapter, we look for other valuation tools.

Valuing the Stocks Hong Kong-Style: P/E and P/B

On a P/FE or P/B basis, the Chinese coal miners are now trading below historical average multiples, based on consensus.

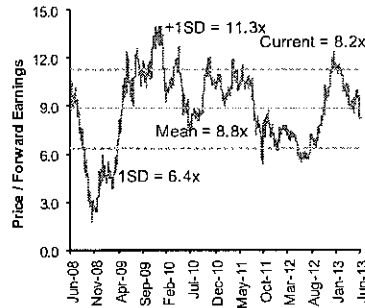
Shenhua, over the last five years, has traded on average at 11.6x forward consensus EPS and 2.75x on a P/B basis. Currently, it is trading at 7.4x and 1.43x, respectively. Yanzhou and China Coal Energy are currently trading at 8.2x and 6.2x, respectively, below their historical P/FE averages and 0.57x and 0.56x, respectively, below their historical P/B averages (see Exhibit 132 through Exhibit 134).

Exhibit 132 China Coal Energy — P/FE Multiple



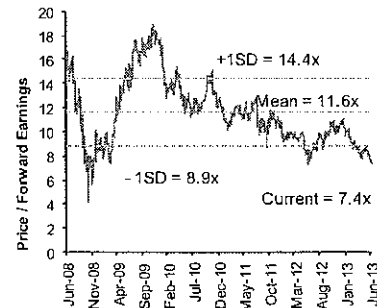
Source: Bloomberg L.P. and Bernstein analysis.

Exhibit 133 Yanzhou — P/FE Multiple



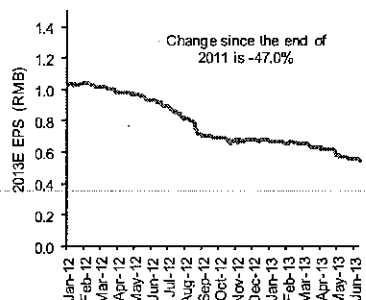
Source: Bloomberg L.P. and Bernstein analysis.

Exhibit 134 Shenhua — P/FE Multiple

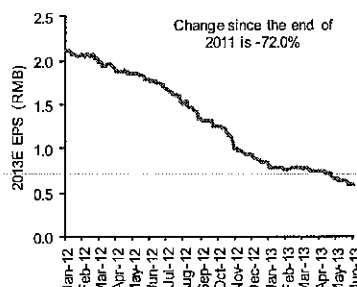


Source: Bloomberg L.P. and Bernstein analysis.

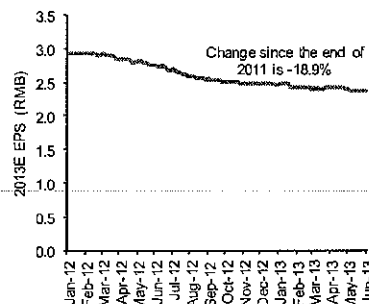
Consensus earnings estimates have all trended down since the end of 2011. Shenhua's 2013 consensus EPS estimate at the end of 2011 was RMB2.90. Today, consensus 2013 EPS estimate is RMB2.35 (representing an 18.9% decline). For Yanzhou and China Coal Energy, the decline in consensus earnings estimates for 2013 since the end of 2011 has been 72.3% and 47.0%, respectively (see Exhibit 135 through Exhibit 137).

Exhibit 135 China Coal Energy — Consensus 2013E EPS

Source: Bloomberg L.P. and Bernstein analysis.

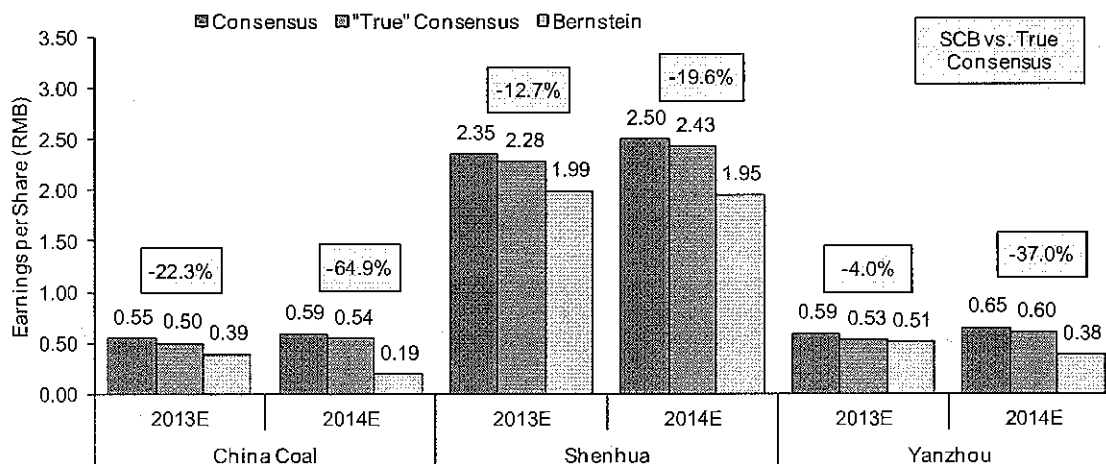
Exhibit 136 Yanzhou — Consensus 2013E EPS

Source: Bloomberg L.P. and Bernstein analysis.

Exhibit 137. Shenhua — Consensus 2013E EPS

Source: Bloomberg L.P. and Bernstein analysis.

All that said, we believe that consensus estimates remain too high (see Exhibit 138).

Exhibit 138 Chinese Coal Miners Consensus and SCB EPS (2013 and 2014)

Note: "True" consensus contains the 12 most recent estimates posted on Bloomberg L.P.

Source: Bloomberg L.P., corporate reports and Bernstein estimates and analysis.

We extract "stale" consensus estimates in Exhibit 138 to get to a truer sense of consensus thinking from the 12 most recently published analyst estimates. The earnings revision trend and the "true" consensus trend tell the same story — earnings expectations are declining.

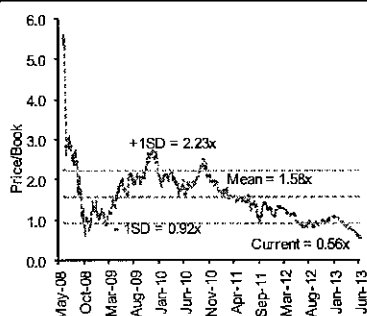
We believe that the stocks are now trading at multiples (on our earnings estimates) near or above historical averages. Shenhua is trading at 9.4x 2014 our earnings estimates (historical average is 11.6x). Yanzhou and China Coal Energy are trading at 13.9x and 19.5x, respectively (historically, they have traded at ~9x and ~10x, respectively).

We believe that slow growing Chinese SOEs in the energy sector, with no pricing power, should trade at roughly 8x. Accordingly, there is plenty of downside on our numbers for all three stocks. In our view, Yanzhou and China Coal Energy have not even started to de-rate.

The defense about these stocks that we hear from investors is that our price targets cannot be right as they imply P/B multiples less than 1x...a level these

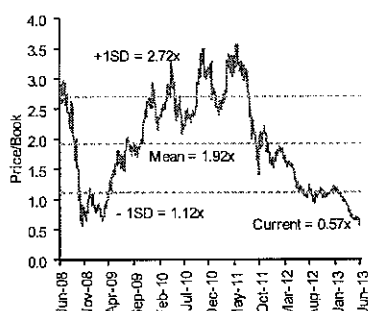
stocks have rarely seen (see Exhibit 139 through Exhibit 141). All three stocks are trading below their historical average P/B multiples.

Exhibit 139 China Coal Energy — P/B multiple



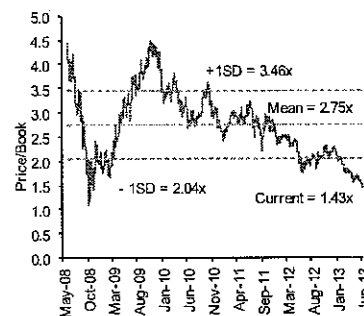
Source: Bloomberg L.P. and Bernstein analysis.

Exhibit 140 Yanzhou — P/B multiple



Source: Bloomberg L.P. and Bernstein analysis.

Exhibit 141 Shenhua — P/B multiple



Source: Bloomberg L.P. and Bernstein analysis.

However, for a group facing the kind of pricing pressure that China Coal Energy faces, earnings and return profiles in coming years are miserable. With a return on equity significantly below the cost of equity, there is no reason to believe that 1x book is a floor, especially if you take the view that the industry is in overcapacity currently and will eventually start to contract. In that case, there is no replacement value for high-cost miners for the simple reason that no one would invest to build excess out-of-the-money capacity...except perhaps Chinese SOEs.

Looking for Cash...DCF, Free Cash Flow Yield, Dividend Yield, EV/EBITDA

All of the Chinese SOEs that we cover follow the simple maxim that there is no such thing as free cash flow in China.

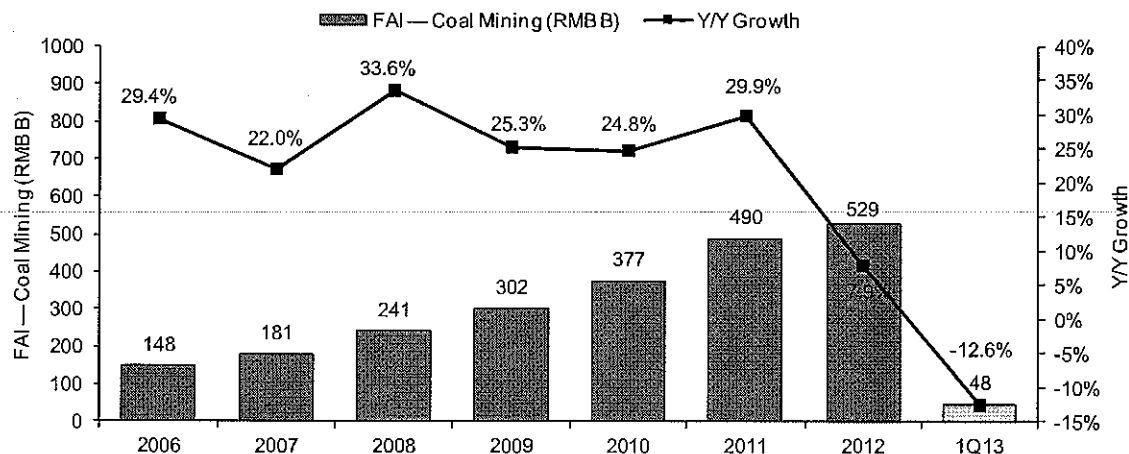
For the utilities, there is always the hope that — given slowing power consumption growth — capital spending will moderate eventually and the companies will turn into "real" utilities. Power consumption growth will continue to go up and the utilities may eventually be run for cash. In theory, you can build a DCF with positive free cash flow in the terminal year and a positive terminal growth rate beyond.

That is unlikely to be true for most of China's coal miners. Demand ultimately will fall. The terminal growth rate in any DCF is therefore a debate between 2%, zero and something worse. Terminal-year free cash flow is (for most coal miners) negative. And so is current-year free cash flow. China will still consume lots of coal in 2020, 2030 and 2040...but consumption in absolute terms will fall. The industry will slowly move down the cost curve, with the least-efficient mines slowly shutting down. Pricing pressure will be contained by this deflationary effect.

We expect capital spending for both the industry and the three companies that we cover to moderate. This has already started at the national level, although fixed asset investment in coal mining in China is likely to match 2010 levels this year, in the RMB300-400 billion range (see Exhibit 142). Investment in the coal mining fixed assets in 2011 was up 29.9% year-over-year, compared to a 7.9% increase in 2012. In the first quarter of 2013, it declined 12.6% year-over-year.

Exhibit 142

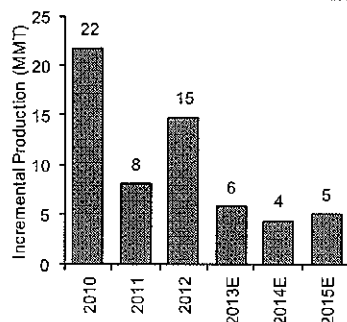
Chinese Coal Mining Fixed Asset Investment (2006-1Q:13)



Source: CEIC, NBS and Bernstein analysis.

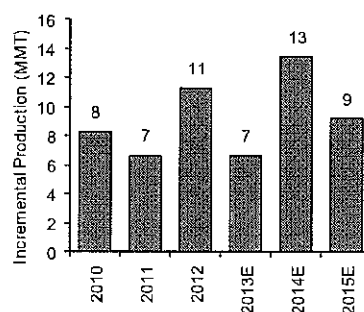
Incremental production from the miners should slow as a function of the slowing of the market (see Exhibit 143 through Exhibit 145).

Exhibit 143 China Coal Energy — Incremental Production



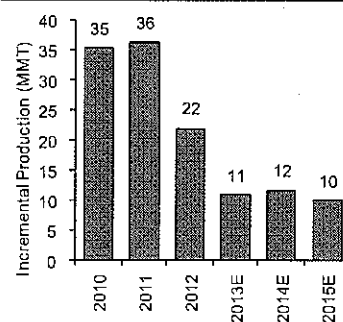
Source: Corporate reports and Bernstein estimates and analysis.

Exhibit 144 Yanzhou — Incremental Production



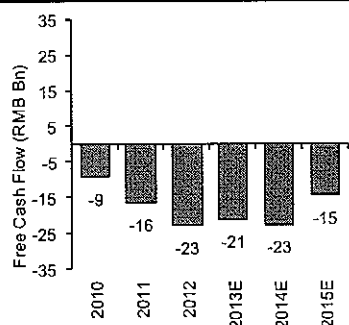
Source: Corporate reports and Bernstein estimates and analysis.

Exhibit 145 Shenhua — Incremental Production

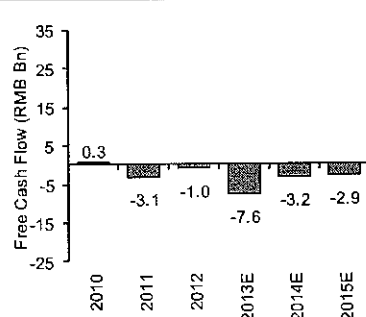


Source: Corporate reports and Bernstein estimates and analysis.

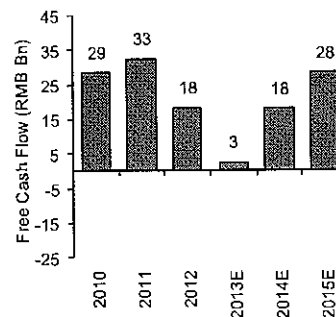
For Yanzhou and China Coal Energy, it is possible to argue that the stocks are worth zero. The companies are not producing any free cash flow currently (see the DCFs in Exhibit 164 through Exhibit 166). If the companies do not reduce capital spending in coming years, production costs continue to rise and coal prices remain flat (our view on all three counts), they will spend themselves into insolvency. We assume that eventually capital spending will moderate to maintenance capital levels (see Exhibit 146 through Exhibit 148).

Exhibit 146 China Coal Energy — Free Cash Flow (RMB Bn)

Source: Corporate reports and Bernstein estimates and analysis.

Exhibit 147 Yanzhou — Free Cash Flow (RMB Bn)

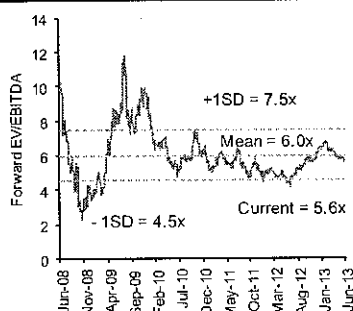
Source: Corporate reports and Bernstein estimates and analysis.

Exhibit 148 Shenhua — Free Cash Flow (RMB Bn)

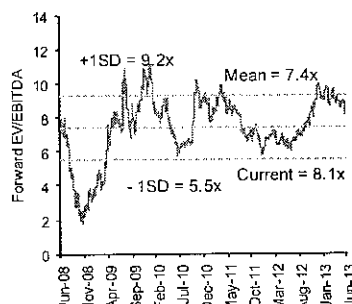
Source: Corporate reports and Bernstein estimates and analysis.

However, as we expect that the industry continues to consolidate, the cost curve will become flatter and flatter. Coal will eventually be priced at short-run variable cost plus maintenance capital spending. The value in these businesses is accordingly close to zero. On a DCF basis, the outlook for Shenhua is more positive than for China Coal Energy and Yanzhou. In our modeling, we believe that Shenhua will remain a cash flow positive company through 2018 at least. Assuming that the company maintains its current dividend payout ratio, we believe the stock is worth ~\$20, assuming a 5% dividend yield.

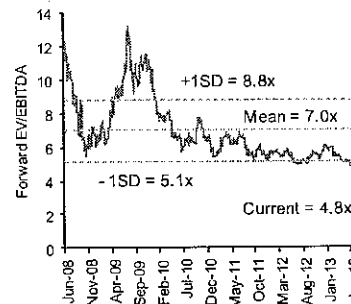
Yanzhou has the highest EV/EBITDA of 8.1x. Shenhua has the lowest EV/EBITDA of 4.8x (see Exhibit 149 through Exhibit 151). We tend not to focus on these companies on an EV/EBITDA basis given that they have positive earnings and limited debt levels currently, although both characteristics are subject to pressure going forward.

Exhibit 149 China Coal Energy — EV/EBITDA Multiple

Source: Bloomberg L.P. and Bernstein analysis.

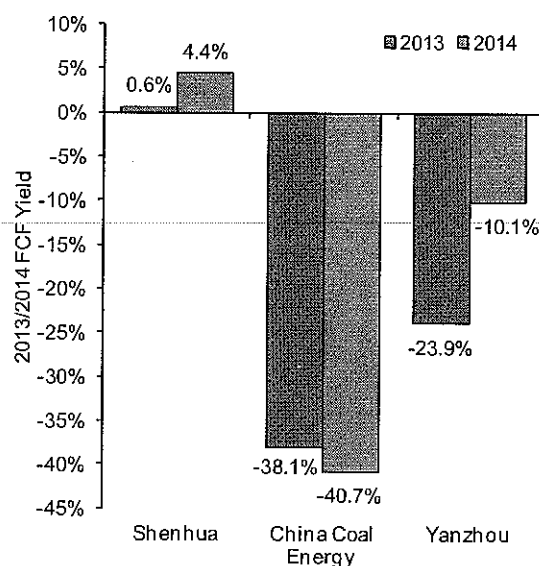
Exhibit 150 Yanzhou — EV/EBITDA Multiple

Source: Bloomberg L.P. and Bernstein analysis.

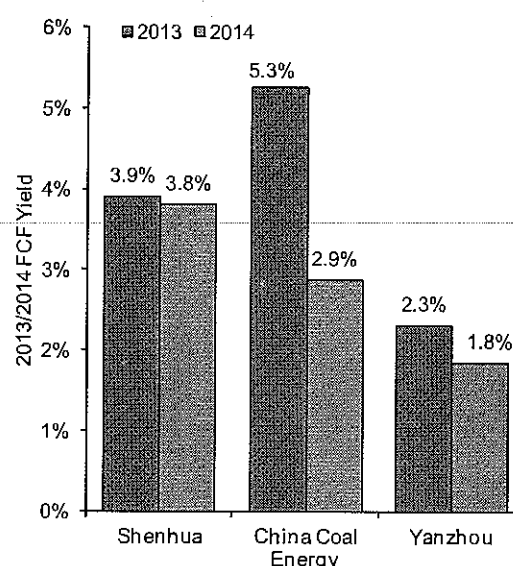
Exhibit 151 Shenhua — EV/EBITDA Multiple

Source: Bloomberg L.P. and Bernstein analysis.

On a free cash flow basis (see Exhibit 152), all three companies are paying dividends but China Coal Energy and Yanzhou will — if they maintain dividends at current payout ratios — be funding those dividends out of debt. Shenhua has a ~40% dividend payout ratio (see Exhibit 153).

Exhibit 152 2013-14E Free Cash Flow Yield

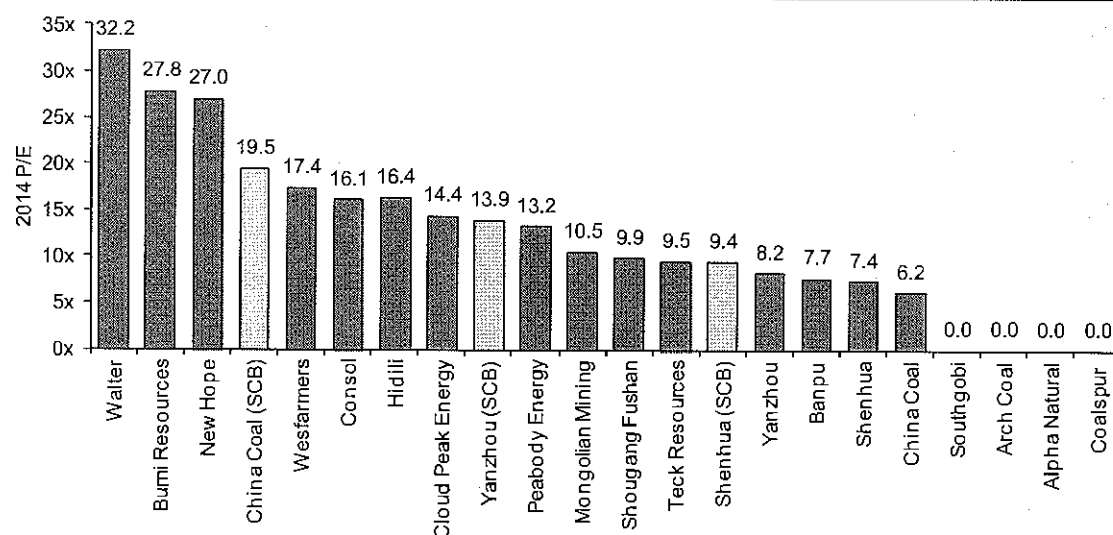
Source: Bloomberg L.P., corporate reports and Bernstein estimates and analysis.

Exhibit 153 2013-14E Dividend Yield

Source: Bloomberg L.P., corporate reports and Bernstein estimates and analysis.

Global Comparisons

On a P/E basis, the three stocks are in the middle of the pack compared to global peers, using our earnings estimates (see Exhibit 154). We are below true consensus on 2013 and 2014 earnings per share estimates for all three coal miners — ~22% below for China Coal, ~13% below for Shenhua and ~4% below for Yanzhou on 2013 earnings (see Exhibit 138). Our P/E multiples are therefore higher than consensus.

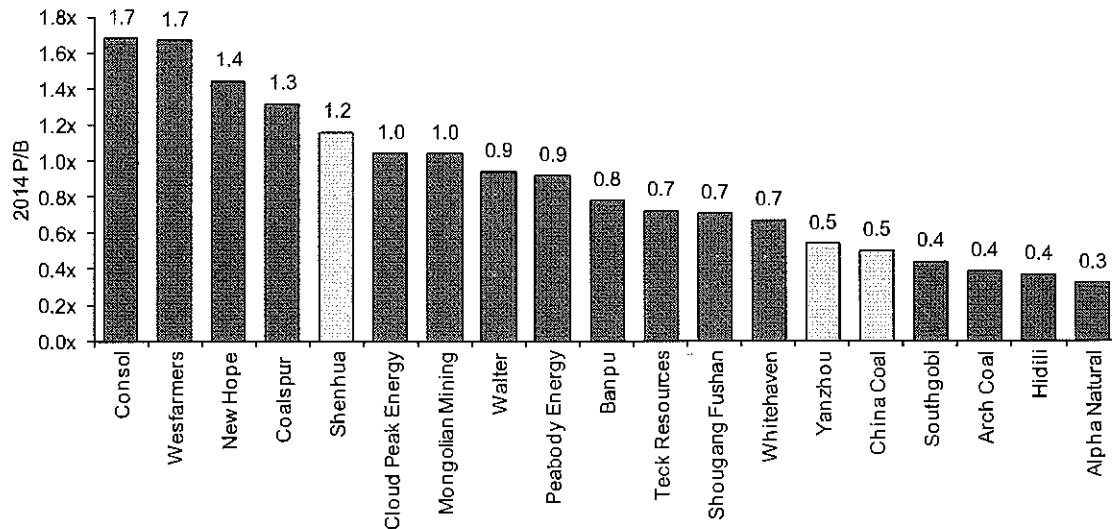
Exhibit 154**Global Coal Miners' 2014 P/E Multiples on Consensus and SCB Estimates**

Note: Whitehaven is removed as its 2014 P/E is not meaningful.

Source: Bloomberg L.P., corporate reports and Bernstein estimates and analysis.

Similarly, on a price-to-book basis, at current valuations, the Chinese coal miners do not stand out as being over or undervalued versus peers (see Exhibit 155).

Exhibit 155 Global Coal Miners' 2014 P/B Multiples on Consensus and SCB Estimates

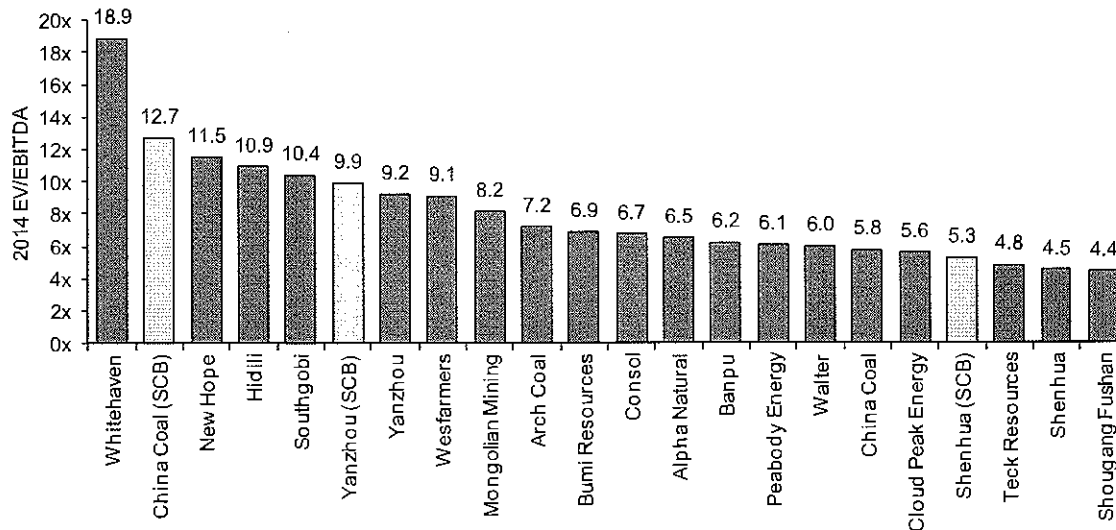


Note: Bumi is removed as its 2014 P/B is not meaningful.

Source: Bloomberg L.P., corporate reports and Bernstein estimates and analysis.

Finally, on an EV/EBITDA basis, Shenhua — even on our numbers — looks cheaper than the global coal companies (see Exhibit 156).

Exhibit 156 Global Coal Miners' 2014 EV/EBITDA Multiples on Consensus and SCB Estimates



Note: Whitehaven is removed as its 2014 EV/EBITDA is not meaningful.

Source: Bloomberg L.P., corporate reports and Bernstein estimates and analysis.

Exhibit 157 gives details of the companies within this global coal miners' screen.

Exhibit 157 Comps Table of the Global Coal Miners

Company	Local Currency	Share price (local)	Shares (M)	52-W High	52-W Low	EV (\$B)	EV (Local M)	P/E		P/B		EV/EBITDA		Avg. Daily Trading Volume (6 mo)		Market cap (US\$M)	Dividend Yield 2013E	
								2013E	2014E	Current	Forward	2013E	2014E	M Shares	USD M			
HK-Listed Thermal Coal Miners																		
China Shenhua (H)	HKD	23.35	3,399	35.5	23.3	70,270	545,452	7.8x	7.4x	1.28x	1.16x	4.9x	4.5x	18.1	66.2	61,674	5.2%	
China Coal Energy (H)	HKD	4.61	4,107	9.0	4.6	18,617	144,515	6.7x	6.2x	0.53x	0.50x	6.6x	5.8x	29.9	26.4	11,558	5.8%	
Yanzhou Coal (H)	HKD	6.78	1,956	14.5	6.6	14,657	113,777	9.0x	8.2x	0.56x	0.54x	10.3x	9.2x	27.2	37.9	7,779	6.7%	
HK-Listed Coking Coal Miners																		
Mongolian Mining	HKD	1.90	3,705	5.6	1.7	1,689	13,101	25.8x	10.5x	1.12x	1.04x	12.5x	8.2x	3.7	1.5	859	0.0%	
Southgobi	HKD	11.52	182	41.4	11.0	351	2,728	nm	nm	0.45x	0.44x	nm	10.4x	0.1	0.3	270	-	
Hedali	HKD	1.70	2,064	2.6	1.5	1,631	12,644	74.6x	16.4x	0.37x	0.36x	14.8x	10.9x	8.3	2.4	452	0.0%	
Shougang Fushan	HKD	2.77	5,302	3.7	1.9	1,639	12,724	10.5x	9.9x	0.74x	0.70x	4.6x	4.4x	23.6	9.7	1,892	5.4%	
U.S.-Listed Coal Miners																		
Arch Coal	USD	4.38	212	8.9	4.3	5,062	5,062	nm	nm	0.37x	0.38x	11.7x	7.2x	10.9	63.2	930	4.6%	
Alpha Natural Resources	USD	6.23	221	10.7	5.3	4,147	4,147	nm	nm	0.30x	0.32x	9.9x	6.5x	12.9	106.8	1,376	0.0%	
Consol	USD	32.44	229	37.4	26.4	10,577	10,577	38.1x	16.1x	1.83x	1.68x	9.3x	6.7x	2.5	81.9	7,417	1.9%	
Walter	USD	14.69	63	48.0	13.9	3,284	3,284	nm	32.2x	0.99x	0.84x	10.8x	6.0x	4.4	108.8	918	3.4%	
Teck Resources	USD	24.34	571	38.6	23.4	18,635	18,635	11.3x	9.5x	0.77x	0.72x	5.5x	4.8x	2.5	74.4	14,128	3.4%	
Peabody Energy	USD	17.37	270	29.8	16.8	10,236	10,236	nm	13.2x	0.96x	0.92x	8.4x	6.1x	7.4	163.5	4,683	2.0%	
Cloud Peak Energy	USD	18.16	61	22.3	14.1	1,588	1,588	19.2x	14.4x	1.13x	1.04x	6.5x	5.6x	0.9	16.0	1,105	0.0%	
Australian/UK Coal Miners																		
New Hope	AUD	3.73	831	4.6	3.3	1,628	1,810	26.6x	27.0x	1.43x	1.44x	11.5x	11.5x	0.2	0.7	2,972	2.9%	
Westfarmers	AUD	38.35	1,007	44.3	28.8	45,627	47,332	19.5x	17.4x	1.69x	1.67x	10.0x	9.1x	2.6	106.7	42,689	4.3%	
Whitehaven	AUD	2.15	1,026	4.6	1.8	2,535	2,609	nm	143.3x	0.67x	0.67x	nm	18.9x	5.8	15.3	2,116	1.4%	
Coalpur	AUD	0.27	640	1.1	0.2	152	159	nm	nm	1.15x	1.32x	nm	nm	1.2	0.7	166	0.0%	
SEA Coal Miners																		
Bumi Resources	IDR	550.00	20,773	1,260.0	490.0	5,972	58,267,258	nm	27.8x	2.93x	2.42x	8.6x	6.9x	95.9	7.5	1,157	-	
Barito	THB	252.00	263	478.0	245.0	5,020	149,680	9.4x	7.7x	0.81x	0.76x	7.2x	6.2x	1.2	13.8	2,171	7.1%	

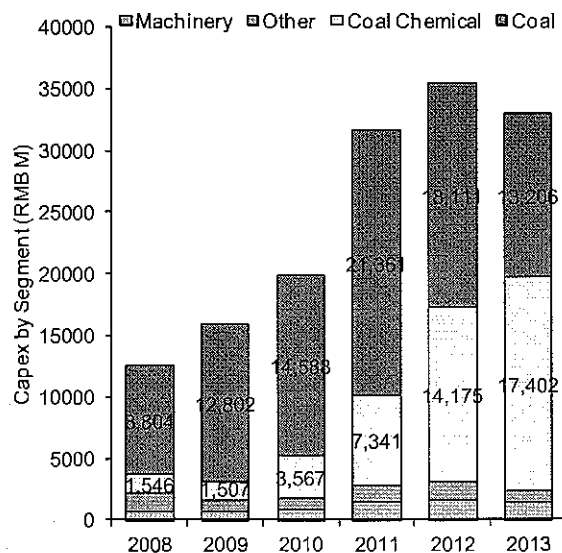
Source: Bloomberg L.P., corporate reports and Bernstein analysis.

The Step Back — Are There Other Businesses to Consider Within These Companies?

There are no other businesses operated by China Coal Energy or Yanzhou that we believe represent an upside risk to valuation.

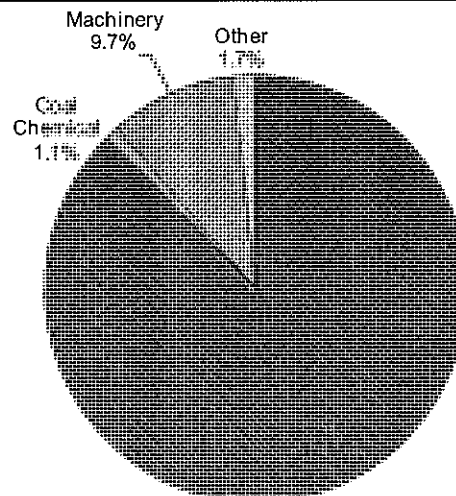
For China Coal Energy, the machinery business is clearly tied to the demand for coal in China overall, and so we see it as a weak performer going forward. The coal-to-chemicals business is an entirely new operation for China Coal Energy. We do not believe that prospects for significant earnings contribution from newly commissioned facilities in 2014 are high. In fact, this unit is likely to be a drain on China Coal Energy's capital budget for some time (see Exhibit 158 and Exhibit 159).

Exhibit 158 China Coal Energy: Capital Expenditure (2008-2013E)



Source: Corporate reports and Bernstein estimates and analysis.

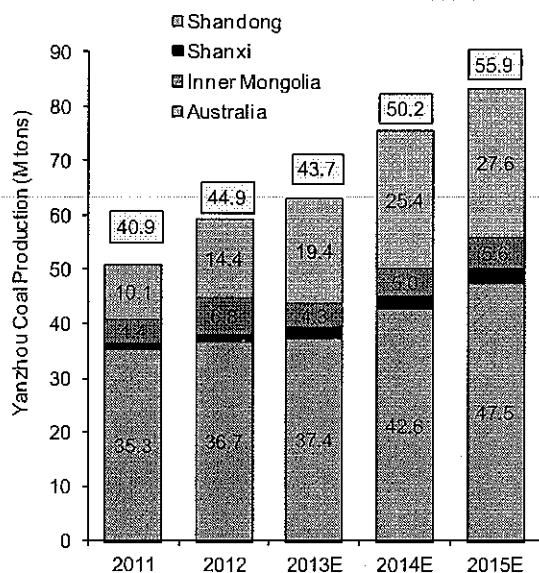
Exhibit 159 China Coal Energy: 2012 Gross Profit by Segment



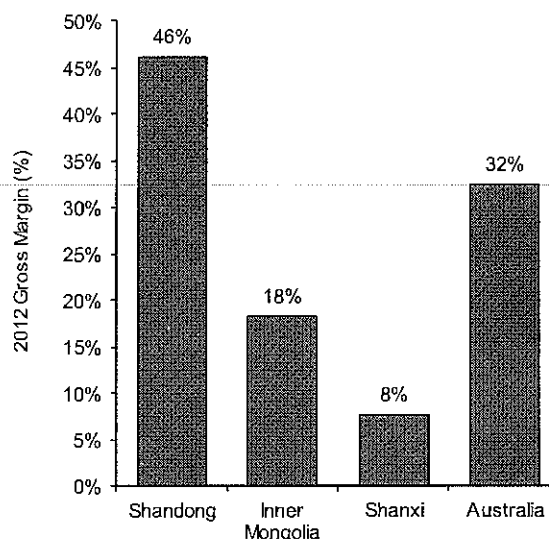
Source: Corporate reports and Bernstein estimates and analysis.

Yanzhou's Australian business is levered to exactly the same demand trends that Yanzhou faces. In fact, given that the business is located in a high-cost jurisdiction with an inflexible labor market and is a great distance from any end market, the business is in worse shape than Yanzhou's domestic operations.

The hope that a devaluation of the dollar will aid Yanzhou's Australian business is half right: the profitability of the unit (with costs in Australian dollars and revenues in U.S. dollar) will go up. The value of the Australian asset would presumably fall if potential buyers value the assets on a replacement-cost basis in Australian dollars (see Exhibit 160 and Exhibit 161).

Exhibit 160 Yanzhou: Coal Production by Geography (2011-2016E)

Source: Corporate reports and Bernstein estimates and analysis.

Exhibit 161 Yanzhou: 2012 Gross Profit by Segment

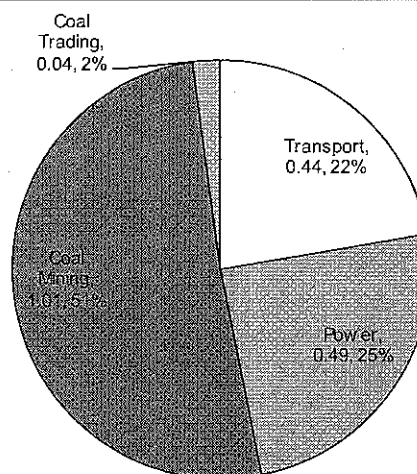
Source: Corporate reports and Bernstein estimates and analysis.

Shenhua is often referred to as a diversified business because of its rail, mining, power and port assets. All are, to state the obvious, levered to coal demand. All of these markets in China are entering an extended period of overcapacity (see Exhibit 162 and Exhibit 163).

Exhibit 162 Shenhua: Sum-of-the-Parts Analysis

Segment	2012 EPS	2013E EPS	Warranted Multiple	Implied Valuation	FX RMB/HKD	Implied Valuation
	RMB	RMB		RMB		HKD
Coal	1.58	1.06				
Mining	1.51	1.01	8.0	8.11	1.25	10.10
Trading	0.06	0.04	2.0	0.09	1.25	0.11
Power	0.38	0.49	8.0	3.91	1.25	4.86
Transport	0.37	0.44	8.0	3.55	1.25	4.42
Total						
Segment Value	2.33	1.99	7.9	15.65	1.25	19.48
Excess cash per share						1.81
SOTP valuation per share						21.29

Source: Corporate reports and Bernstein estimates and analysis.

Exhibit 163 Shenhua: 2013E EPS Contribution by Segment

Source: Corporate reports and Bernstein estimates and analysis.

Exhibit 164	China Coal Energy — Discounted-Cash Flow Valuation						
Discounted Cash Flow Analysis (RMB M)	2013E	2014E	2015E	2016E	2017E	2018E	Terminal
Revenue	83,579	86,558	88,724	91,262	94,153	95,209	
Gross Profit	14,091	10,466	7,334	4,461	2,343	404	
EBIT	8,189	4,353	1,069	(1,562)	(3,871)	(5,880)	
Tax Rate	25%	25%	25%	25%	25%	25%	
EBIT*(1-t)	6,142	3,265	801	(1,172)	(2,903)	(4,410)	
Add:							
Depreciation	3,772	4,624	5,285	5,722	6,145	6,556	
Less:							
Capital Expenditure	(32,889)	(30,000)	(20,000)	(20,000)	(20,000)	(20,000)	
Chg in NWC	63	39	47	60	69	51	
Free Cash Flow to Firm	(22,913)	(22,073)	(13,867)	(15,390)	(16,689)	(17,803)	(243,141)
Discount Factor	1.00	0.91	0.83	0.76	0.70	0.64	0.58
Discounted FCF	(22,913)	(20,163)	(11,572)	(11,732)	(11,622)	(11,325)	(141,292)
Weighted Average Cost of Capital	9.5%						
Cost of Equity	12.4%		Cost of Debt			6.6%	
Risk Free Rate	3.4%		Book Value of Debt			39.4%	
Beta	1.50		Market Value of Equity			60.6%	
Market Risk Premium	6.0%		Corporate Tax Rate			25.0%	
Terminal Growth Rate	2.0%						
Valuation							
Aggregate, Discounted FCF	(230,619)		Implied DCF Valuation (HKD)		(25.00)		
Less: Book Value of Debt	(50,466)		Target Share Price	\$	3.00		
Less: Minority Interest	(14,911)		Current Share Price		4.61		
Add: Cash	23,035		Delta from Current Share Price		-34.9%		
Add: Associates and JVs	10,704						
Total	(262,256)						
Shares Outstanding	13,259						

Source: Bloomberg L.P., corporate reports and Bernstein estimates and analysis.

Exhibit 165								Shenhua — Discounted Cash Flow Valuation							
Discounted Cash Flow Analysis (RMB M)				2013E	2014E	2015E	2016E	2017E	2018E	Terminal					
Revenue				248,276	253,275	258,936	269,782	278,633	284,588						
Gross Profit				72,427	71,280	70,979	71,398	68,723	64,086						
EBIT				60,710	59,952	58,326	58,203	55,085	50,150						
Tax Rate				20%	20%	20%	20%	20%	20%						
EBIT*(1-t)				48,568	47,962	46,661	46,562	44,068	40,120						
Add:															
Depreciation				19,150	21,729	23,171	24,160	25,090	25,966						
Less:															
Capital Expenditure				(63,442)	(50,021)	(40,017)	(40,017)	(40,017)	(40,017)						
Chg in NWC				63	57	60	56	66	74						
Free Cash Flow to Firm				4,340	19,726	29,875	30,761	29,206	26,143	358,998					
Discount Factor				1.00	0.91	0.84	0.76	0.70	0.64	0.58					
Discounted FCF				4,340	18,026	24,949	23,476	20,369	16,661	209,088					
Weighted Average Cost of Capital				9.4%											
Cost of Equity				10.3%	Cost of Debt				5.3%						
Risk Free Rate				3.4%	Book Value of Debt				14.0%						
Beta				1.15	Market Value of Equity				86.0%						
Market Risk Premium				6.0%	Corporate Tax Rate				25.0%						
Terminal Growth Rate				2.0%											
Valuation															
Aggregate, Discounted FCF				316,908	Implied DCF Valuation (HKD)				16.65						
Less: Book Value of Debt				(66,914)	Target Share Price				\$ 20.00						
Less: Minority Interest				(52,798)	Current Share Price				23.35						
Add: Cash				57,746	Delta from Current Share Price				-14.3%						
Add: Term deposits				2,373											
Add: Associates and JVs				4,691											
Total				262,006											
Shares Outstanding				19,890											

Source: Bloomberg L.P., corporate reports and Bernstein estimates and analysis.

Exhibit 166**Yanzhou — Discounted Cash Flow Valuation**

Discounted Cash Flow Analysis (RMB M)	2013E	2014E	2015E	2016E	2017E	2018E	Terminal
Revenue	53,310	56,228	62,038	63,849	67,435	70,710	
Gross Profit	11,541	11,394	10,965	11,116	9,844	8,978	
EBIT	3,935	3,406	2,152	2,631	1,022	(319)	
Tax Rate	25%	25%	25%	25%	25%	25%	
EBIT*(1-t)	2,951	2,554	1,614	1,973	766	(239)	
Add:							
Depreciation	3,773	5,647	6,417	6,646	6,851	7,040	
Less:							
Capital Expenditure	(12,005)	(10,800)	(10,100)	(9,900)	(9,850)	(9,800)	
Chg in NWC	49	34	61	9	12	33	
Free Cash Flow to Firm	(5,230)	(2,565)	(2,009)	(1,272)	(2,221)	(2,965)	(47,432)
Discount Factor	1.00	0.92	0.85	0.79	0.72	0.67	0.62
Discounted FCF	(5,230)	(2,367)	(1,710)	(999)	(1,610)	(1,983)	(29,272)
Weighted Average Cost of Capital	8.4%						
Cost of Equity	11.4%		Cost of Debt				3.6%
Risk Free Rate	3.4%		Book Value of Debt				34.6%
Beta	1.33		Market Value of Equity				65.4%
Market Risk Premium	6.0%		Corporate Tax Rate				25.0%
Terminal Growth Rate	2.0%						
Valuation							
Aggregate, Discounted FCF	(43,172)		Implied DCF Valuation (HKD)		(19,20)		
Less: Book Value of Debt	(41,100)		Target Share Price		\$ 5.00		
Less: Minority Interest	(5,822)		Current Share Price		6.78		
Add: Cash	11,899		Delta from Current Share Price		-26.3%		
Add: Associates and JVs	3,487						
Total	(74,707)						
Shares Outstanding	4,918						

Source: Bloomberg L.P., corporate reports and Bernstein estimates and analysis.

Coal Train's Slow Blues: Why Weak Rail Capacity Additions in 2012 Won't Re-Bottleneck Chinese Coal

Mining It and Moving It Proved Less Difficult Than Was Initially Assumed...Now China Is Building for the Next 30 Years

The old bull case for Chinese coal held that China could mine all of the additional coal it wanted; if it couldn't also move the coal, there would be no impact on coal price from all the new coal production capacity.

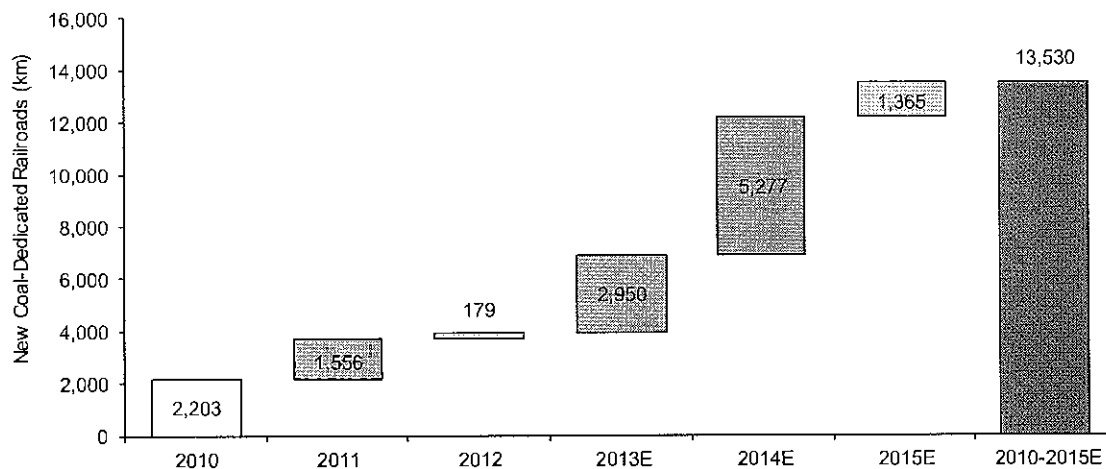
Things haven't worked out that way. We track or have tracked 46 different coal-dedicated rail projects in China that were commissioned in 2010-12 or will be commissioned between 2013 and 2015. In total, this is roughly 12,000 km of new rail lines. To date, 4,000 km have been commissioned and yet rail bottlenecks have dropped dramatically since 2011. We expect that the downward pressure on coal prices from improving rail logistics will continue through 2015 as new capacity comes on line.

Why Weak Rail Capacity Additions in 2012 Won't Re-Bottleneck Chinese Coal

Rail capacity growth is a core aspect of our bearishness on the Chinese coal sector (see Exhibit 167). The year 2012 was a disappointment on this score. Yet the drop in the coal price — despite the near-total lack of new coal-dedicated rail capacity additions — highlights, in part, the progress made in 2010 and 2011 in adding new transport lines. Given the restoration of funding to the projects we track (see Exhibit 169), by the end of 2014, we expect ~8,000 km of new capacity to be added, with new lines coming on every two to three months. In short, the old bull case on Chinese coal (most of the new rail capacity isn't coming on until 2013-14) is now a core part of the bear case (most of the new rail capacity is coming on in 2013-14).

Exhibit 167

2010-15E Chinese Coal-Dedicated Railroads — Completed and Under Construction

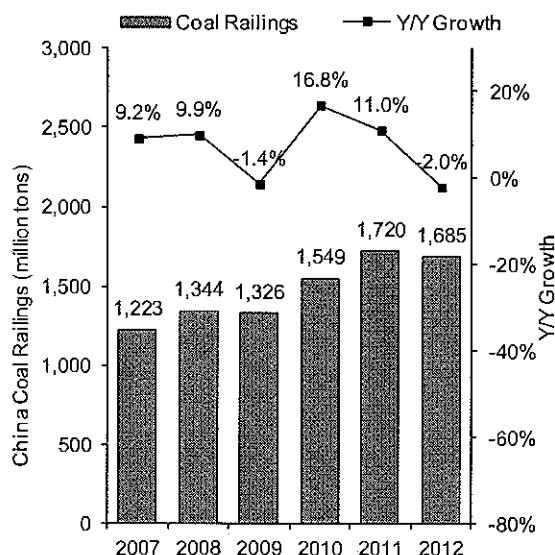


Source: Government announcements, CRCC, media reports and Bernstein estimates and analysis.

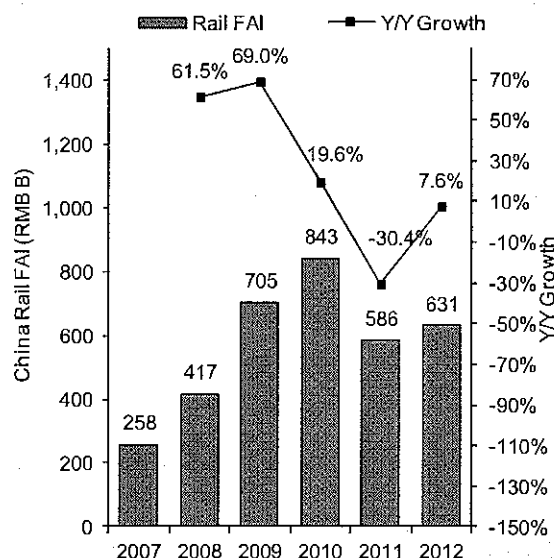
Total coal-dedicated rail line additions in 2012 were dismal: just 179 km, down 88% from 2011 and a fraction of what we expected in early 2012 (~3,000 km). Yet coal prices fell over the course of 2012 anyway. Delays were caused mainly by the

temporary loss of funding after the Zhejiang rail accident in 2011 and the subsequent fallout at the Ministry of Rail. As delayed projects are commissioned in 2013, paths to market will expand and pressure on coal price will persist, in our view.

Total coal-dedicated rail lines commissioned in China in 2012 totaled 179 km. Only one of the 11 new lines we were monitoring for commissioning was actually completed. The rest have been delayed and most are now due for commissioning in 2013. Yet 2012 proved the right year to miss a deadline: coal transported by rail in China in 2012 decreased 2.0% year-over-year to 1.69 billion tons, while total coal transported on the Datong to Qinhuangdao line (the Daqin line) fell 3.2% for the full year. Coal prices fell by roughly one quarter over the course of 2012. There is an excess of transport capacity in China today and, based on our analysis, things only get worse (or better) from here (see Exhibit 168).

Exhibit 168 China Coal Transported by Railway

Source: SX Coal and Bernstein analysis.

Exhibit 169 China Rail Fixed Asset Investment

Source: CEIC and Bernstein analysis.

Transport Constraints in China's Coal Sector Are Falling...and It Isn't Just More Railway Lines

Since we first attempted to calculate coal-dedicated rail lines under construction in China in September 2010, roughly 4,000 km of new coal-dedicated lines have been commissioned. The pace has been slower over the last two years than we had anticipated. However, it is noteworthy that none of the projects that we have identified in the four times that we have now carried out this exercise have been abandoned.

In 2013, the pressure on Chinese coal prices from improving logistics continues to mount.

First, we anticipate ~3,000 km and ~5,000 km of new lines in 2013 and 2014, respectively. Total coal transportation capacity from the eight high-profile projects into Bohai Bay totals 690 million tons. Given that more than half of all the coal in China is consumed in the provinces in which it is produced, 690 million tons of inter-provincial rail capacity heading to Bohai Bay equates to ~1.4 billion tons of new coal consumption over the next three years. There is no scenario in which that is likely. Instead, this new transport capacity is going to speed the path to market for existing supply, putting pressure on pricing all the while.

Second, industrial activity is heading west...towards the sources of coal supply and simplifying transportation logistics. The air pollution problems in Beijing earlier this year were just the latest in a series of particularly visceral messages over

the last year that industrial activity is likely to migrate in coming years away from the east coast. In many ways, that makes the logistics for domestic coal supply easier and the logistics for seaborne coal supply more difficult. The implication is that the demand growth for coal dedicated rail lines we are reviewing will slow in coming years, even as these projects are being commissioned.

Finally, coal by wire — or power transmission — removes the need for coal transportation altogether. Go back just five years and coastal provinces had a preference for the fixed asset investment and economic activity associated with coal-fired power stations. Accordingly, power generation was built at the load center rather than at the source of coal supply. As emissions and coal consumption considerations become an increasingly important part of provincial government performance metrics, those preferences may well invert. Again, inter-provincial transmission removes the need for coal transportation entirely.

Our expectation of flat coal prices and easing supply constraints in China in coming years is premised on a structural slowdown in Chinese power consumption growth at the same time as improvements in coal production capacity and transport capacity ease the path to market. We expect this to be an ongoing process that started at the end of 2011 and is likely to continue broadly through 2015. However, that does require that the weak performance by the Chinese rail sector in adding new capacity in 2012 is not repeated in 2013.

In short, our bearish view on the Chinese coal sector once again is reliant on the premise that China is good at building infrastructure.

4,000 km Down, 8,000 km to Go

Of the seven major projects into Bohai Bay, the Handan-Huanghua line should be completed in September this year. The remaining six projects are on track for completion through 2014 and 2015, bringing an incremental 690 million tons of transport capacity. These projects, and their long-dated completion targets, used to be part of the bull case on Chinese coal prices because of the high trucking and handling costs rail bottlenecks created. Today, for the coal stocks, these projects are the heart of the bear case, in particular for Shenhua. Completion of more and more rail transport capacity puts further pressure on coastal coal prices and destroys the value of any synergies in Shenhua's "integrated" model.

We often hear that coal prices fell so sharply in 2012 (down 23% over the course of the year) because everything that could go wrong for the Chinese coal mining sector did go wrong. We disagree. Yes, U.S. natural gas prices fell, meaning more U.S. coal was exported to Europe, displacing South African coal into Asia-Pacific. The Australian summer was dry, meaning that the disruptions in coal supply in the first quarter of 2011 were not repeated in the first quarter of 2012. Indonesian coal supply to China increased, and the weakening rupee meant that the Indian power sector was unable to benefit to any great extent from falling seaborne coal prices. It all meant that a lot more coal was available from the seaborne market for China. We have set out previously our view of why the impact of the seaborne thermal coal market on Chinese coal prices is often overstated (see "The Appalachian Butterfly Effect: A Eulogy for the Global Thermal Coal Market" chapter). In short, the volume of additions in the seaborne market fails to explain the extent of the coal price move in China last year).

In our view, if you are looking for a part of the Chinese economy where little went right in 2012, it's not the Chinese coal mining sector but the Chinese rail sector. As a consequence, most of the projects that we expected to be completed in 2012 are now scheduled for completion during 2013.

Exhibit 170**Chinese Coal-Dedicated Railroads — Completed in 2010**

Start Date	Project Location	Distance (km)	Completion Year	Completion Year Source
Aug-06	Yimin to Arxan, Inner Mongolia	185	2010	People's Rail
Jul-07	Sanbeiyang to Xinshanghaimiao, Inner Mongolia	136	2010	China Railway
Feb-08	Baotou to Xi'an, Inner Mongolia to Shaanxi	801	2010	People's Rail
May-08	Taiyuan, Shanxi to Zhongwei, Ningxia	944	2010	Xinhua
Oct-08	Baotou to Mandoula, Inner Mongolia	91	2010	People's Rail
Nov-08	Guoyang to Linhuan, Anhui	45	2010	Anhui Coal
2010 - Subtotal		2,203		

Source: Government announcements, media reports and Bernstein analysis.

To put 179 km in context, China has over 90,000 km of rail infrastructure in operation today and added ~2,200 km of coal-dedicated rail lines in 2010 (see Exhibit 170) and over 1,500 km in 2011 (see Exhibit 171).

Exhibit 171**Chinese Coal-Dedicated Railroads — Completed in 2011**

Start Date	Project Location	Distance (km)	Completion Year	Completion Year Source
Mar-06	Huangtong to Zhijin, Guizhou	63	2011	Media Reports
Jul-05	Xinghe, Ulanqab, Inner Mongolia	9	2011	Media Reports
May-06	Zhangjiakou, Hebei to Jining, Inner Mongolia	178	2011	Government
May-08	Huoxinhe Coal Industry Line, Shanxi	8	2011	Media Reports
Nov-08	Western Kuqa to Ehuobulake, Xinjiang	86	2011	Government
Jan-09	Gangqimao to Jinquan, Inner Mongolia	175	2011	Government
Jun-09	Gulian to Yueyahu, Heilongjiang	34	2011	Government
Aug-09	Zhunge'er to Hushi, Inner Mongolia (Expansion)	59	2011	Media Reports
Sep-09	Renjiazhuang, Ningxia	10	2011	Media Reports
Dec-09	Tongliao to Huolinhe, Inner Mongolia (Expansion)	402	2011	Government
Dec-09	Wellong to Yinchuan, Ningxia (Expansion)	97	2011	CRCC
Dec-09	Qingting to Baishan District, Anhui (Expansion)	152	2011	CRCC
Mar-10	Gangika to Kulun, Inner Mongolia	70	2011	CRCC
May-10	Xintai to Linyi, Shandong	60	2011	Media Reports
Aug-10	Xilinhaote to Sanggedalai, Inner Mongolia (Expansion)	153	2011	Media Reports
2011 - Subtotal		1,556		

Source: Government announcements, CRCC, media reports and Bernstein analysis.

In 2012, only one rail line — between Jinquan and Wanquan in Inner Mongolia — was commissioned (see Exhibit 172).

Exhibit 172**Chinese Coal Dedicated Railroads — Completed in 2012**

Start Date	Project Location	Distance (km)	Completion Year	Completion Year Source
Jan-09	Jinquan to Wanquan, Inner Mongolia	179	2012	Media Reports
2012 - Subtotal		179		

Source: Government announcements, media reports and Bernstein analysis.

Delays were caused mainly by the temporary loss of funding after the Zhejiang rail accident in 2011 and the subsequent fallout at the Ministry of Rail. Press reports explain the delays as being a function of weather, problems in some instances with land clearance and resettlement and temporary lack of funding. In short, the resetting of rail fixed asset investment in 2011 has had an effect on commissioning in 2012 (see Exhibit 169).

Yet this slowdown has not resulted in re-bottlenecking for the simple reason that Chinese coal consumption from domestic sources fell in 2012 (and so did coal transported by rail) — see Exhibit 168. We expect the various "stimulus" announcements last autumn that focused on rail investment — together with the eventual completion of the projects we track — will spike new capacity commissioning in 2013 and 2014.

We expect 13 rail lines that we are tracking to be commissioned with a total distance of 2,950 km in 2013 (see Exhibit 173). We anticipate another ~8,000 km of rail lines to be commissioned over the following 18 months, with new lines opening roughly every two to three months.

Exhibit 173 Chinese Coal Dedicated Railroads — To Be Completed in 2013E

Start Date	Project Location	Distance (km)	Completion Year	Completion Year Source
Nov-07	Bayanwula, Inner Mongolia to Fuxin, Liaoning (Baxin Line)	496	2013E	Railway-China
Nov-08	Xilinhaote to Wulanhaote, Inner Mongolia	651	2013E	Media Reports
Apr-09	Batuta to zhungeer, Inner Mongolia (Bazhu Line Expansion)	135	2013E	Media Reports
Jun-09	Zalantun to Arun, Inner Mongolia (Aza Line)	60	2013E	Government
Jul-09	Suzhou, Anhui to Hua'an, Jiangsu	211	Nov 13E	Media Reports
Sep-09	Yuhuai Railway (North Chongqing to Fuling Section)	98	Sept 13E	Government
Nov-09	Handan, Hebei to Jinan, Shandong (Expansion)	232	2013E	Media Reports
Mar-10	Handan, Hebei to Changzhi, Shanxi (Expansion)	223	2013E	Media Reports
Mar-10	Zhunge'er, Inner Mongolia, to Shenchui, Shanxi	180	2013E	Media Reports
Apr-10	Handan to Huanghuagang, Hebei	433	Sept 13E	Government
Aug-10	Sanggedalai to Duolun, Inner Mongolia (Expansion)	103	Aug 13E	Government
Sep-11	Daigou to Erdaohu, Inner Mongolia (Expansion)	59	2013E	Government
Sep-11	Songgenshan to Dongwuqi, Inner Mongolia	71	2013E	Government
2013E - Subtotal		2,950		

Source: Government announcements, media reports and Bernstein estimates and analysis.

We expect a further 5,277 km of coal-dedicated rail lines to be commissioned in 2014, with large projects from Urumqi in Xinjiang to Gansu (connecting Xinjiang to China's coal-dedicated rail network for the first time) and Lvliang to Rizhao (see Exhibit 174).

Exhibit 174 Chinese Coal Dedicated Railroads — To Be Completed in 2014E

Start Date	Project Location	Distance (km)	Completion Year	Completion Year Source
Nov-09	Lanzhou, Gansu to Urumqi, Xinjiang (Expansion)	1,776	2014E	CRCC
Dec-09	Lvliang, Shanxi to Rizhao, Shandong	1,260	2014E	Government
Mar-10	Zhangjiakou to Tangshan (Caofeldian), Hebei	528	2014E	Media Reports
Jun-10	Xulun Hoh Qi, Inner Mongolia to Zhangjiakou, Hebei	247	2014E	Government
Jul-10	Dezhou to Dajawa, Shandong	256	2014E	Railway-China
Aug-10	Jining to Tongliao, Inner Mongolia (Expansion)	923	2014E	Media Reports
Nov-09	Longkou to Yantai, Shandong	113	2014E	Railway-China
Feb-11	Hohhot to Shengli (via Zhunge'er)	174	2014E	Media Reports
2014E - Subtotal		5,277		

Source: Government announcements, CRCC, media reports and Bernstein estimates and analysis.

We now expect 1,365 km to be commissioned over three projects in 2015 (see Exhibit 175).

Exhibit 175 Chinese Coal Dedicated Railroads — To Be Completed in 2015E

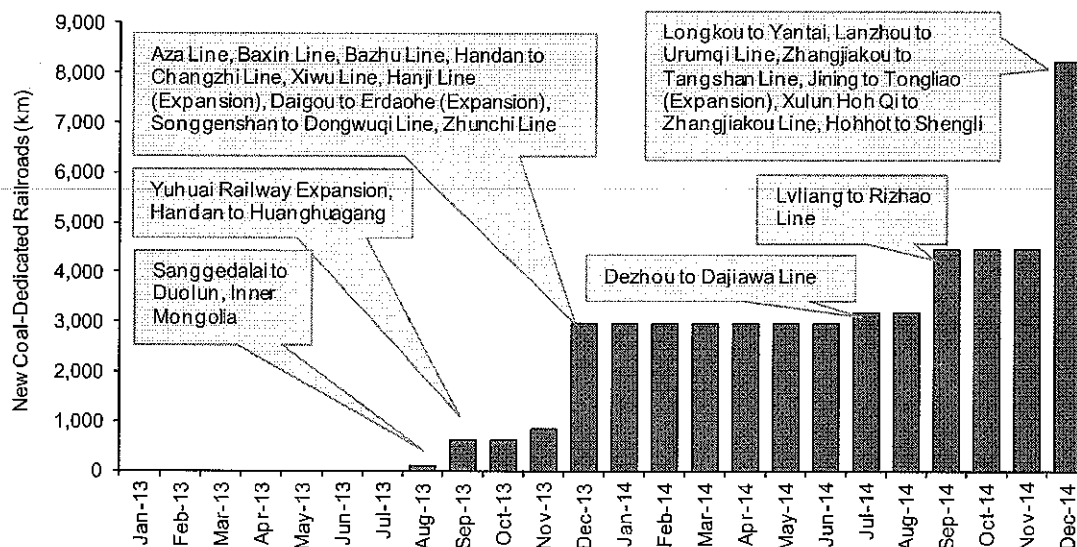
Start Date	Project Location	Distance (km)	Completion Year	Completion Year Source
Jun-08	Chifeng, Inner Mongolia to Jinzhou, Liaoning	282	2015E	Media Reports
Sep-08	Lanzhou, Gansu to Chongqing	820	2015E	Media Reports
Jul-09	Shimen to Changsha, Hunan (Expansion)	263	2015E	Media Reports
2015E - Subtotal		1,365		

Source: Government announcements, media reports and Bernstein estimates and analysis.

Of the eight major projects into Bohai Bay, the Handan-Huanghua line and Handan-Changzhi expansion should be completed by the end of 2013 (see Exhibit 176 through Exhibit 178). The remaining six projects are on track for completion through 2014 and 2015. These eight projects will bring an incremental 690 million tons of transport capacity.

Exhibit 176

New Coal-Dedicated Rail Lines (2013E-2014E)



Source: Government announcements, media reports and Bernstein estimates and analysis.

These projects, and their long-dated completion targets, used to be the basis for the bull case on Chinese coal prices because of the high trucking and various grey costs rail bottlenecks created. Today, for the coal stocks, these projects are the heart of the bear case, in particular for Shenhua. Completion of more and more rail transport capacity puts further pressure on coastal coal prices and destroys the value of any synergies in Shenhua's "integrated" model.

Exhibit 177

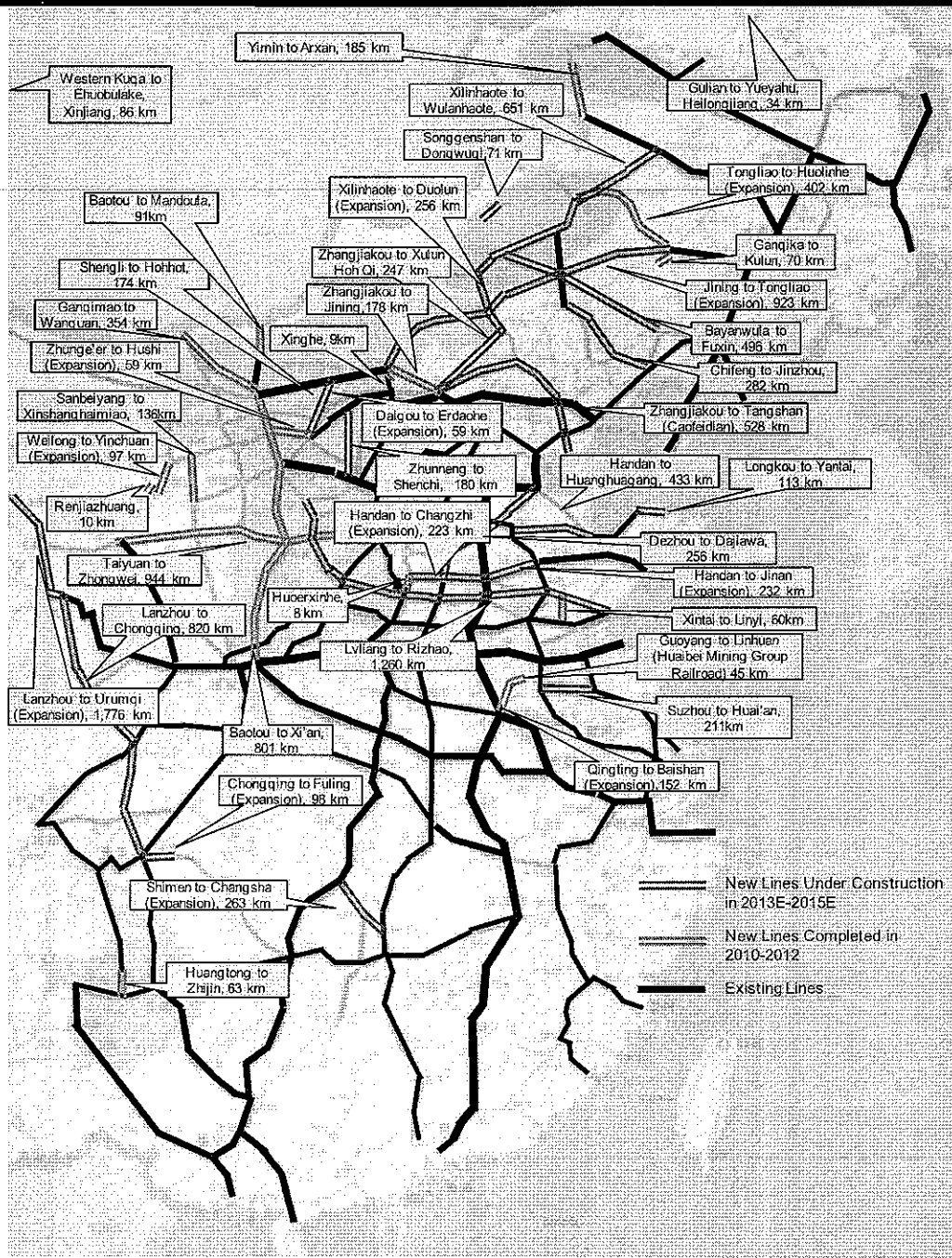
New Xi-to-Sea Projects — Commissioning Between 2013 and 2015

Start Date	Project Location	Distance (km)	Completion Year	Additional Coal Rail Capacity (M tons)	Details
Mar-10	Handan, Hebei to Changzhi, Shanxi (Expansion)	223	2013E	150	Once the expansion is completed, rail capacity will increase from ~30M tons per annum to 180M tons per annum.
Apr-10	Handan to Huanghuagang, Hebei	433	2013E	-	The rail line will open a new path in Hebei to the Huanghua harbor. Once completed, the rail line will have transportation capacity of 40M tons per annum.
Nov-09	Longkou to Yantai, Shandong	113	2014E	-	A part of the Delongyan Line, which will transport coal through northern Shandong.
Apr-10	Dezhou to Daijawa, Shandong	256	2014E	-	A part of the Delongyan Line, which will transport coal through northern Shandong.
Jun-08	Chifeng, Inner Mongolia to Jinzhou, Liaoning	282	2015E	140	Connecting eastern Inner Mongolia to Liaoning, this line will have capacity of 22M tons per annum on a single line, and 140M tons once its second line is completed.
Mar-10	Zhangjiakou to Tangshan (Caofeidian), Hebei	528	2014E	200	Connecting Shanjiakou in central Hebei to the ports in Tangshan, this line will have a long-term capacity of 200M tons per annum.
Dec-09	Lvliang, Shanxi to Rizhao, Shandong	1,260	2014E	200	Also known as the "Shanxi South-Central Rail Channel," this line will have a long-term capacity of 200M tons per annum.
Aug-10	Jining to Tongliao, Inner Mongolia (Expansion)	923	2014E	-	Operated by the Inner Mongolia Jitong Railway Company, the expansion project will, including the construction of a second line, which would increase total coal transportation capacity by 35-50+ M tons.
Subtotal		4,018		690	

Source: Chinese Ministry of Railways, media reports and Bernstein estimates and analysis.

Exhibit 179

Chinese Coal-Dedicated Rail Network — Lines Completed in 2010-12 and New Lines to Be Completed in 2013-15E



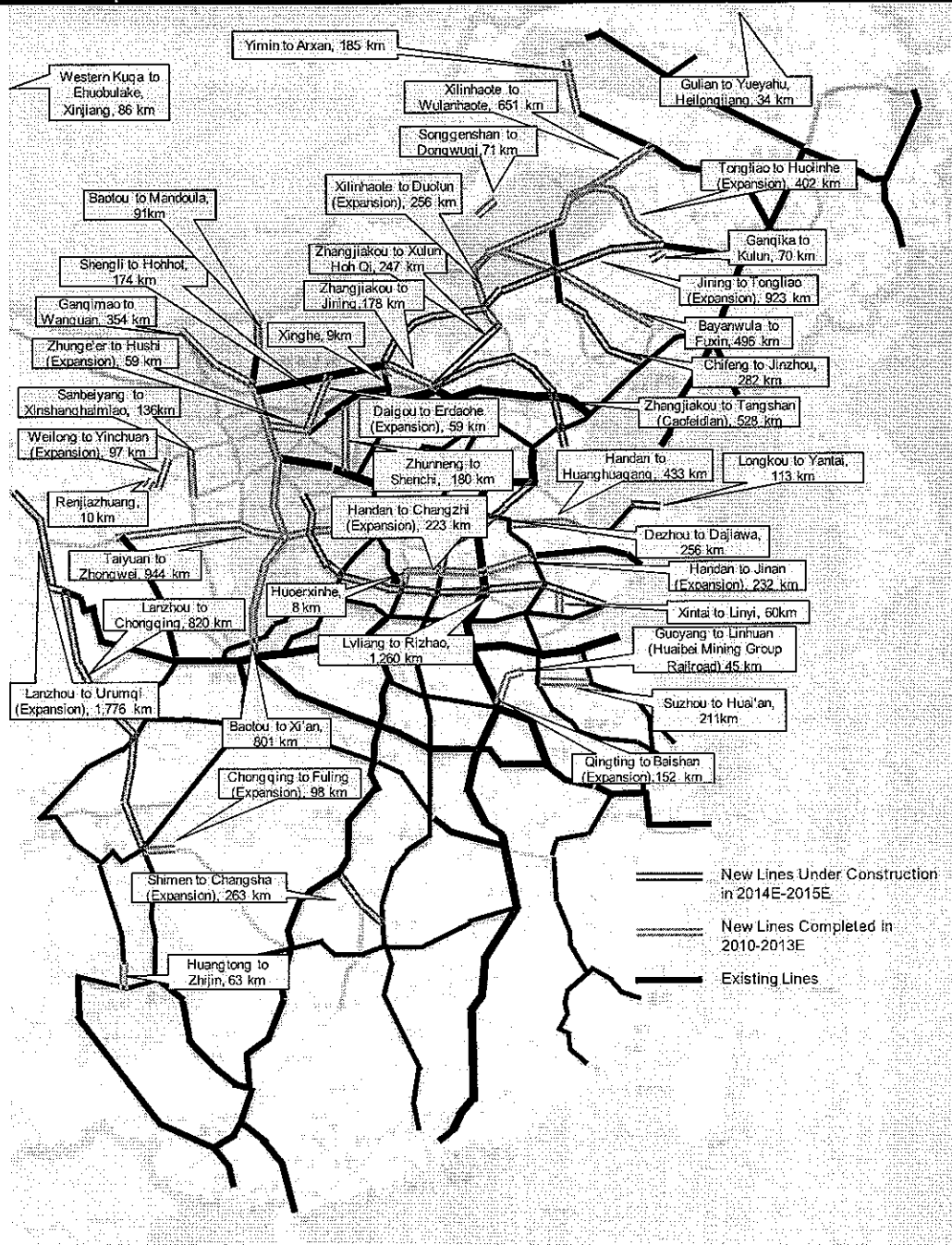
Note: Please see online version for colors.

Source: Chinese Ministry of Railways, media reports, corporate reports and Bernstein estimates and analysis.

Projects that, based on our estimates, will be completed by the end of 2013 are reflected in green in Exhibit 180 (see online version for colors).

Exhibit 180.

Chinese Coal-Dedicated Rail Network – 2010-15E Completions at EOY 2013



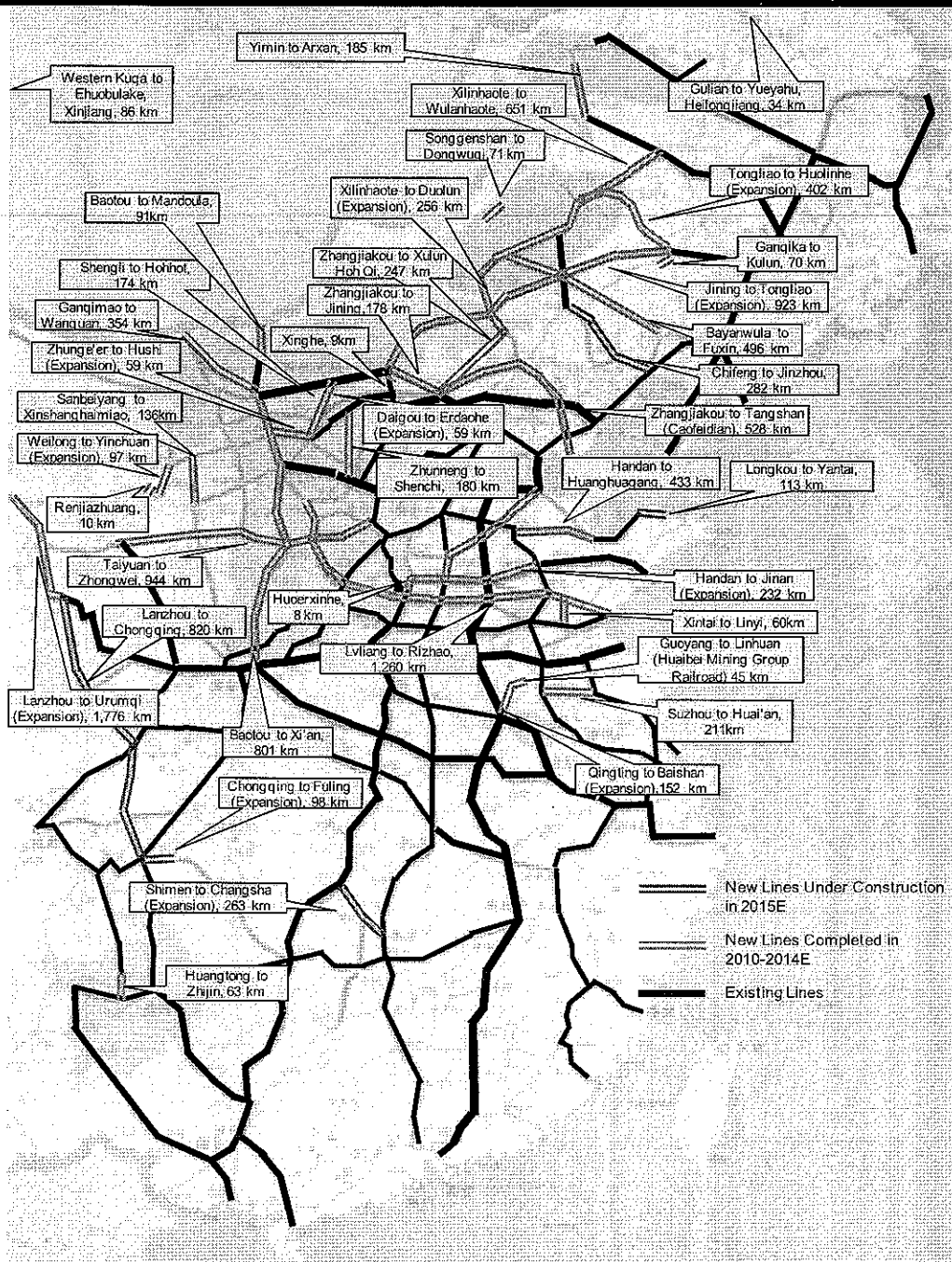
Note: Please see online version for colors.

Source: Chinese Ministry of Railways, media reports, corporate reports and Bernstein analysis.

Projects that, based on our estimates, will be completed by the end of 2013 are reflected in green in Exhibit 181 (see online version for colors).

Exhibit 181

Chinese Coal-Dedicated Rail Network — 2010-2015E Completions at EOY 2014



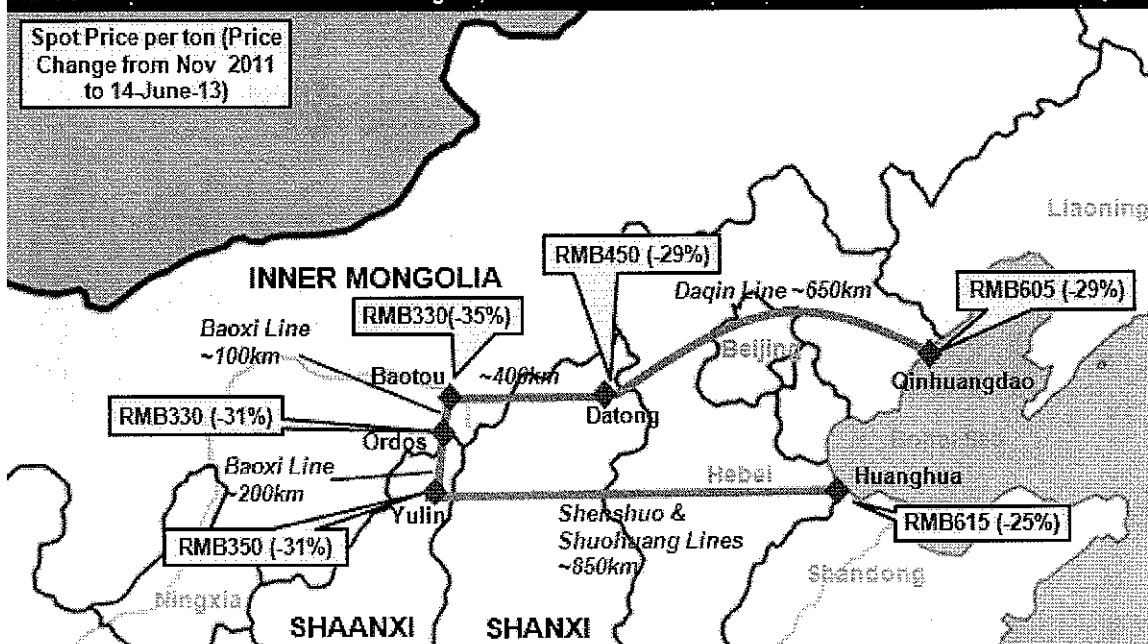
Note: See online version for colors.

Source: Chinese Ministry of Railways, media reports, corporate reports and Bernstein analysis.

Coal prices are down ~30% since November 2011 both on the coast and in the coal-producing interior regions (see Exhibit 182).

Exhibit 182

Inner Mongolia, Shaanxi and Shanxi vs. Port Coal Prices

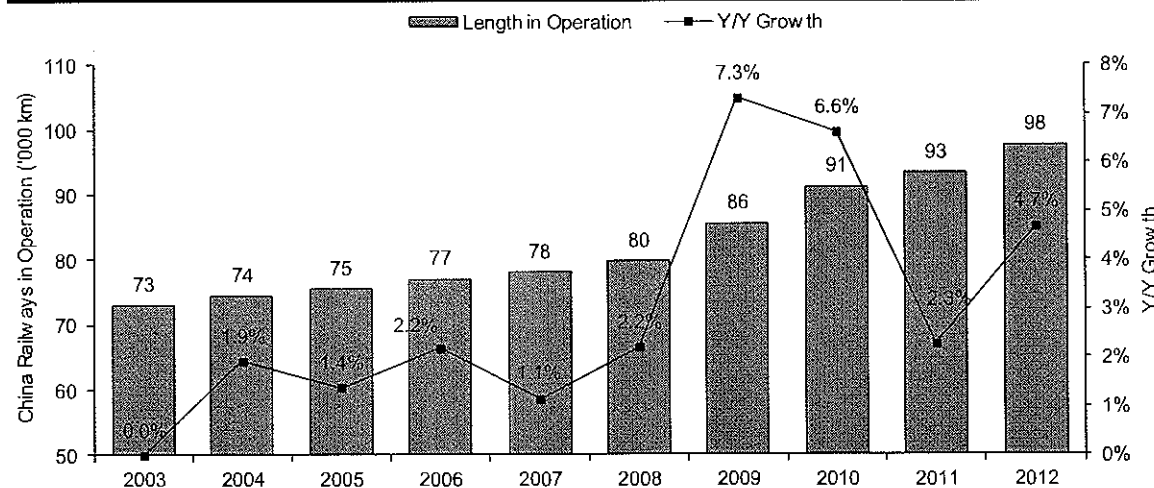


Source: Wikimedia commons, SX Coal and Bernstein estimates and analysis.

Out of the ~5,000 km of new railway lines added in 2012, only ~180 km were added as coal-dedicated usage. However, the incremental freight lines and passenger lines (including the high-speed rails) should help offloading the non-coal usage in the entire system (see Exhibit 183).

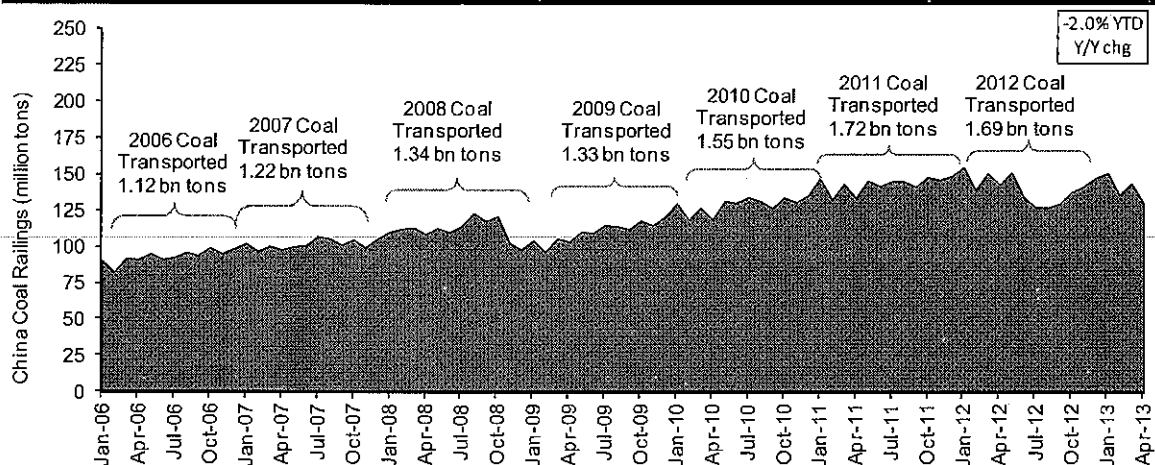
Exhibit 183

China Railway in Operation — Length



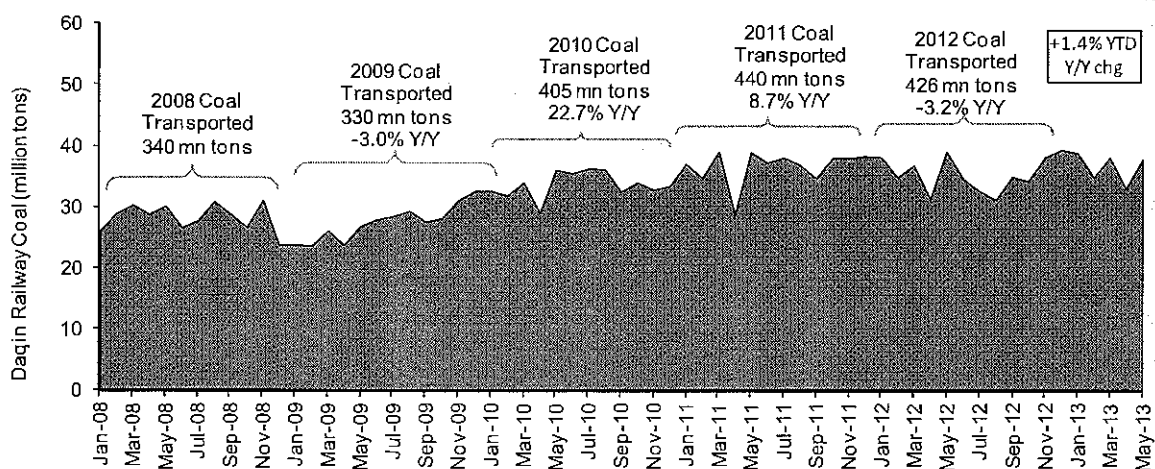
Source: CEIC and Bernstein analysis.

2012 proved the right year to miss a deadline. The coal transported by rail in China decreased 2.0% year-over-year to 1.69 billion tons in 2012 (see Exhibit 184).

Exhibit 184**China Coal Transported by Railway — Monthly**

Source: SX Coal and Bernstein analysis.

Total coal transported by the Datong-to-Qinhuangdao line (the Daqin line) fell 3.2% in 2012 (see Exhibit 185).

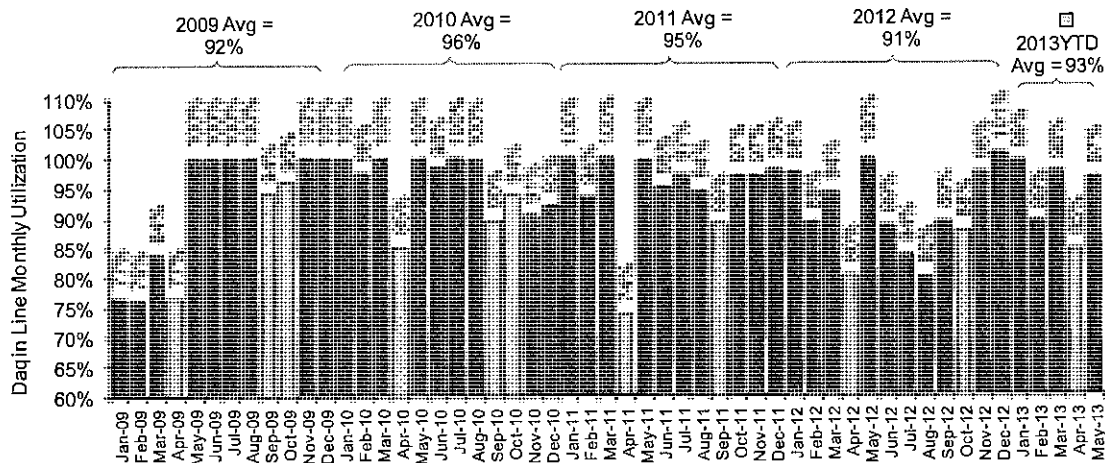
Exhibit 185**Chinese Coal Transported by Daqin Railway — Monthly Through May 2013**

Source: SX Coal and Bernstein analysis.

The Daqin line operated with excess capacity most of 2012 (see Exhibit 186).

Exhibit 186

Daqin Line Monthly Utilization (2009 to May 2013)



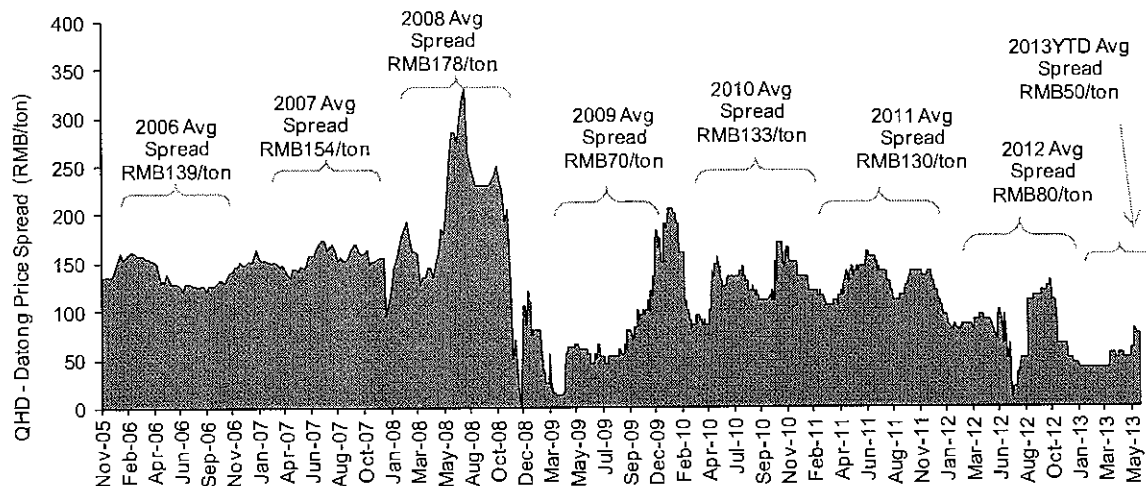
Note: Light blue months are the maintenance months; see online version for colors.

Source: SX Coal and Bernstein estimates and analysis.

The Qinhuangdao-Datong coal price spread fell over the year to RMB50/ton, after the adjustment for transportation costs is made (see Exhibit 187). Said differently, the value of this arbitrage has fallen by ~62% since 2011. More than any other measure, this is ultimately the best indicator of rail transport capacity. To the extent that there are bottlenecks within the coal transportation network, these bottlenecks will maintain themselves in economic rents for intermediaries. That, in turn, will result in the widening of the Datong-Qinhuangdao spread. That spread continues to trend down.

Exhibit 187

QHD 5,500 and Datong Nanjiao 5,500 Coal Price Spread (Adjusted for Transport Cost)

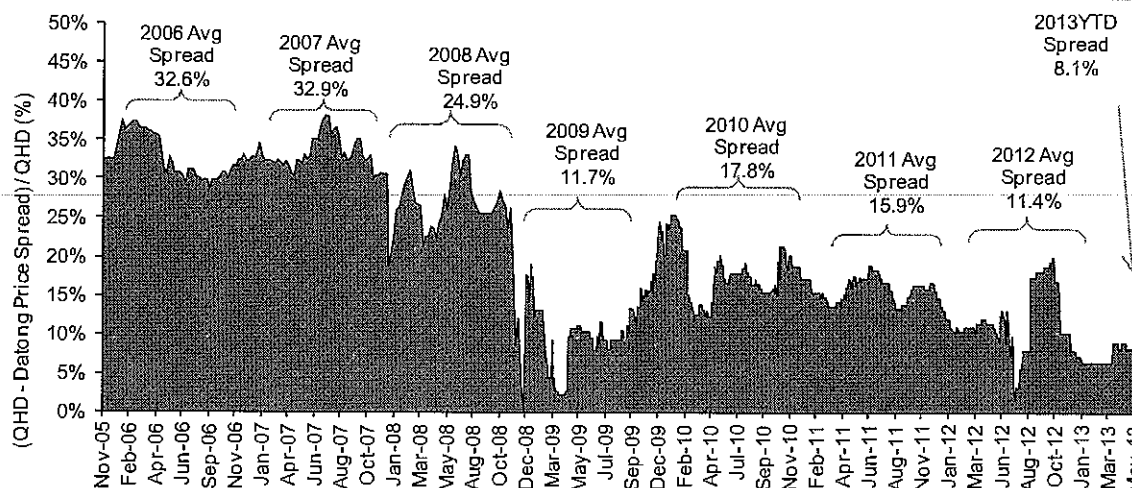


Source: SX Coal and Bernstein analysis.

In fact, as a percentage of the final Qinhuangdao price, the Datong-Qinhuangdao spread (adjusted for transportation) has rarely been lower going back to at least 2006 (see Exhibit 188).

Exhibit 188

QHD 5,500 and Datong Nanjiao 5,500 Coal Price Spread Relative to QHD (Adjusted for Transport Cost)



Source: SX Coal and Bernstein analysis.

Appendix: Line-by-Line Analysis

We set out below details for each of the rail lines we expect to be completed in 2013 and in 2014:

Yuhuai Railway (North Chongqing to Fuling Section) (98 km) — This project is located within the Chongqing municipality and construction started in September 2009. Press reports blame bad weather for the delay in railway construction. Officials representing the Chongqing government are quoted in the press stating they expect this project to be completed in the first half of 2013 but recent press articles are pointing to the end of 2013. Total investment for the project is RMB3.59 billion and the average train speed on the rail line will be 120 km/hour.

Bayanvula, Inner Mongolia to Fuxin, Liaoning (496 km) — Construction for the Baxin Line was approved in 2007 and construction started in March 2009. The Baxin line has a short-term transportation capacity of 21 million tons with a longer-term capacity expansion plan of 35 million tons. Total investment in the project is RMB5.86 billion. Project construction was suspended in 2010-11 as a result of a lack of funding and was resumed in April 2012. Media reports suggest that colder than expected weather affected the project progress in late 2012 and that this project will be completed by the end of 2013.

Batuta to Zhunge'er, Inner Mongolia (Expansion) (135 km) — Construction for the Bazhu Line was approved in October 2009 and construction started in December 2010. Total investment for the project is RMB7.2 billion. Once the expansion is completed, rail capacity will increase from ~100 million tons per annum to 200 million tons per annum. Shenhua expects that this project will be completed in the second half of 2013.

Zhunge'er, Inner Mongolia, to Shenchì, Shanxi (180 km) — The Zhunchi Line is situated between the Dazhun line and the Shuohuang line and will link the two existing lines upon completion. Total investment for the entire line is RMB13.5 billion, and the line is expected to have near-term transportation capacity of 90.7 million tons per annum and long-term transportation capacity of 200 million tons per annum. The Zhunchi line, together with the existing Dazhun and Shuohuang lines, will create a coal transport network throughout western Inner Mongolia. Media reported that this project would be completed in the second half of 2013.

Handan, Hebei to Changzhi, Shanxi (Expansion) (223 km) — Once this expansion project (second line and electrification) is completed, the rail transportation capacity will increase from ~19 million tons to ~200 million tons in

the long term, and average train speed will increase from 60 km/hour to 100 km/hour. Total project cost is RMB5.55 billion. Press reports suggest that railway construction was delayed due to construction difficulties. According to these reports, this project would be completed in the second half of 2013.

Handan to Huanghuagang, Hebei (433 km) — This rail line will open a new path in Hebei to the Huanghua harbor. Once completed, the rail line will have transport capacity of 40 million tons per annum. Total project investment is RMB16.8 billion. Due to difficulty in land acquisition and funding, project construction was suspended in 2011 but resumed in March 2012. According to press reports, the Hebei government expects this project will be completed in September 2013.

Zalantun to Arun, Inner Mongolia (60 km) — Construction for the Aza Line was approved in 2008 and started in June 2009. Total investment for the project is RMB0.8 billion. Initial transportation capacity is 3.8 million tons per annum, expanding to 8.5 million tons per annum in the medium term and 12 million tons in the long term. According to press reports, due to difficulty in obtaining funding for the project, this project was suspended in 2011 but resumed in April 2012. Recent news articles suggest that the project will be completed by the end of 2013.

Suzhou, Anhui to Huai'an, Jiangsu (211 km) — The project will transport coal from the mining regions in Anhui to Jiangsu. Total investment is RMB4.93 billion and the line is expected to have transportation capacity of 25 million tons per annum. The average train speed on the rail line is designed at 120 km/hour. Construction, which was started in July 2009, was suspended in 2011 due to difficulty in obtaining funding but was resumed in early 2012. Media reported that this project will be completed in November 2013.

Xilinhaote to Wulanhaote, Inner Mongolia (651 km) — The Xiwu Line runs across eastern Inner Mongolia and will become the main artery in the region's coal mining region. Total investment for the project is RMB11.3 billion. Construction for the Xiwu Line started in November 2008. Once completed, the line is expected to have a transportation capacity of 30 million tons/year in the short term and 50 million tons/year in the long term. The project was suspended in August 2011 as part of a national railway construction review and lack of funding but construction resumed in September 2012. Media reported that this project would be completed in 2013.

Handan, Hebei to Jinan, Shandong (Expansion) (232 km) — The original Hanji Line was completed in 2000 and runs from Handan, Hebei to Jinan, Shandong. Total investment for the project is RMB6.98 billion. Once the expansion is completed, rail capacity will increase from ~30 million tons per annum to 180 million tons per annum. This project is one of the railways of main focus in China's 11th Five-Year Plan. The progress of the project construction was slightly delayed due to slower-than-expected land acquisition. Media reported that this project would be completed in 2013.

Sanggedalai to Duolun, Inner Mongolia (Expansion) (103 km) — This project is one of the railways of main focus in China's 12th Five-Year Plan. Total investment for the entire line is RMB 2.8 billion. The Xilinhaote to Sanggedalai segment of the Xiduo line was completed in 2011. The Sanggedalai to Duolun segment of the line began its expansion in August 2010. Recent new articles suggested this project would be completed in August 2013.

In 2014, the following projects will be added:

Dezhou to Dajiawa, Shandong (256 km) — Total investment for the project is RMB2.16 billion. The average train speed on the rail line is designed at 160 km/hour. The line is expected to have transportation capacity of 44.6 million tons per annum. The construction started in July 2010. Media reports state that this project will be completed in July 2014. The Longkou to Yantai line (113 km) should be completed by the end of 2014.

Lvliang, Shanxi to Rizhao, Shandong (1,260 km) — The project will transport coal from the mining regions in Shanxi, through Henan, to Shandong. Total

investment for the project is RMB99.8 billion. The average train speed on the rail line is designed at 120 km/hour. This project is one of the railways of main focus in China's 11th Five-Year Plan. The Shandong Government expects this project to be completed in September 2014.

Lanzhou, Gansu to Urumqi, Xinjiang (Expansion) (1,776 km) — This rail line will add a second line to the existing Lanxin Line. The project connects the distant western regions around Xinjiang to the rest of the country, running across Gansu, Qinghai, and Xinjiang province. It is the first high speed railway that China will build in high-altitude regions. Construction for the Lanxin Line was approved in August 2009 and the construction started in November 2009. This project is one of the railways of main focus in China's 12th Five-Year Plan. Total investment for the project is RMB143.5 billion. The progress of the project construction was slightly delayed due to slower-than-expected land acquisition and high construction difficulties. According to press reports, CRCC expects this project to be completed in December 2014.

Zhangjiakou to Tangshan, Hebei (528 km) — Once completed, this Zhantang Line will connect Zhangjiakou to the sea. Total investment for the project is RMB40 billion. Media reported that this project would be completed in 2014.

Jining to Tongliao, Inner Mongolia (Expansion) (923 km) — Media reported this project would be completed in 2014.

Xulun Hoh Qi, Inner Mongolia to Zhangjiakou, Hebei (247 km) — This project is one of the railways of main focus in China's 11th Five-Year Plan. Total investment for the project is RMB8 billion. The construction started in June 2010. The government states that this project would be completed in 2014.

Hohhot to Shengli (174 km) — Total investment for the project is RMB18.8 billion. The line is expected to have transportation capacity of 110 million tons per annum in the near term and 200 million tons per annum in the long term. Media reported that this project would be completed in 2014.

Of the eight high-profile rail projects that are commonly cited as bringing new coal transport capacity into Bohai Bay, the Changzhi-Handan-Huanghua links will be completed this year. Another five projects will be completed in 2014 (see Exhibit 177 and Exhibit 178). Together with the remaining project that is on track for completion through 2015, they will be bringing an incremental 690 million tons of transport capacity.

The Appalachian Butterfly Effect: A Eulogy for the Global Thermal Coal Market

China Has Been 100% of the Growth in the Seaborne Demand Over the Last Five Years; We Think It Will Be a Zero by 2015

Decelerating power demand growth and structural weakness in other end markets, combined with more hydro, nuclear and renewables and more coal production and rail capacity in China adds up to the once unthinkable — zero net imports in 2015 and falling Chinese demand by 2016.

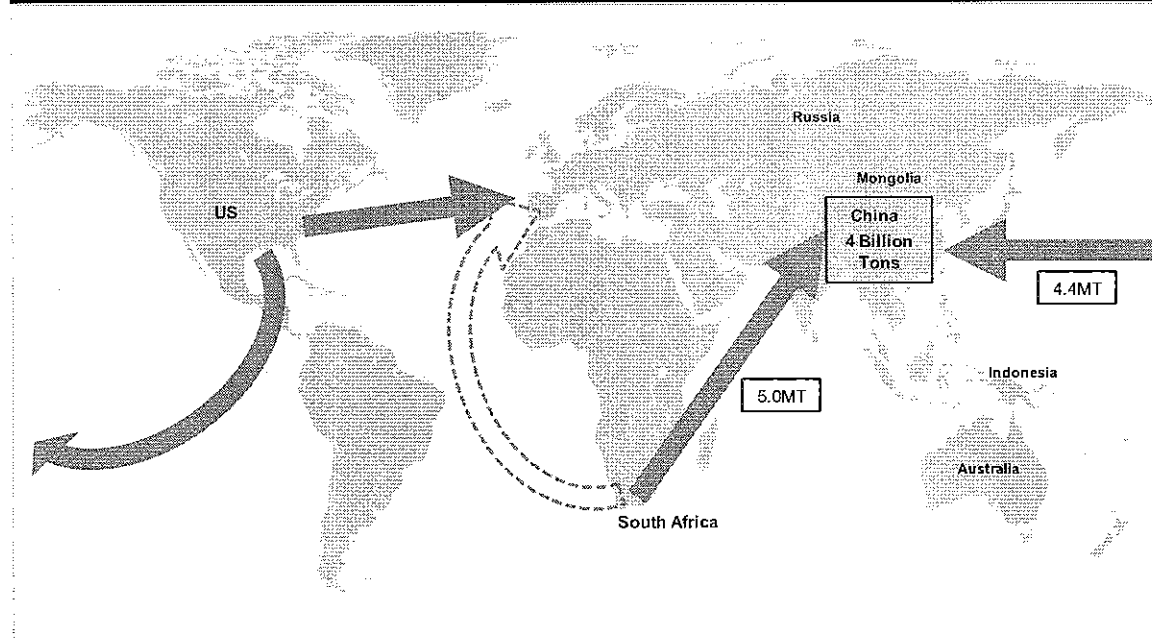
In our view, from 2015, the large-scale Chinese miners will take over the entire domestic market, pushing out imports and raising, for the first time since 2008, the possibility of Chinese coal net exports. Once Chinese coal demand starts to fall, there is no robust growth market for seaborne thermal coal anywhere. Developed market consumption is weak everywhere due to some combination of low gas prices, rising environmental concerns and low levels of industrial activity. That leaves just one large, structural growth market for coal — India.

A Eulogy for the Global Thermal Coal Market

There is nothing that delights the sell-side more than the thought of being able to describe the world in the context of one grand, unifying idea: *you may understand the movement of the individual pieces, but let us show you the whole board.* For much of 2012, correlated coal price movements in the U.S. and Asia gave rise to the inference that we were seeing the emergence of a global thermal coal market. As coal prices fell in the U.S., exports increased; U.S. coal shipments to Europe displaced South African coal into Asia...and coal prices in China fell. It certainly looked like one market (see Exhibit 189).

Exhibit 189

Seaborne Coal Displacement and Incremental Supply Into China (2012)



Source: Wiki commons, SX Coal, Public Press, EIA, BREE, RBCT and Bernstein estimates and analysis.

The elegance of the narrative overwhelmed questions like whether an extra 10 million tons of U.S. coal exports could really tank a 4 billion ton Chinese market; or whether the economics of shipping thermal coal halfway around the world would still work once prices had fallen ~30%.

We believe the impact of imports on the decline in Chinese coal prices in 2012 is often overstated. The risk of this over-attribution is that it creates a tendency to overestimate volatility in the Chinese coal price in 2013 and beyond. In short, the risk of upward pressures on coal prices outside of China resulting in a sharp snap-back in the domestic price is, in our view, lower than what the market generally believes.

The three primary reasons for the 30% decline in Chinese coal prices since November 2011 have been China (demand), China (supply) and China (transportation). The Appalachian Butterfly Effect — U.S. coal and coal prices into Asia — runs a distant fourth. The ~10 million ton increase in Chinese imports from the U.S. and South Africa in 2012 was simply not large enough, in isolation, to explain the drop in the spot price in the 4 billion ton Chinese coal market (see Exhibit 189).

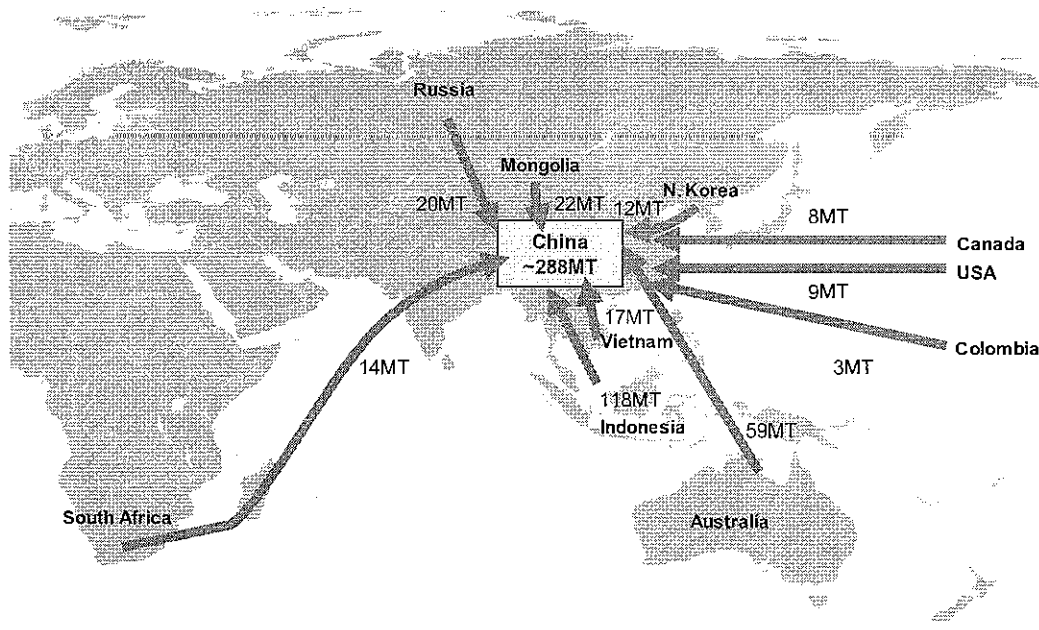
In 2012, U.S. coal imports into China were 9.3 million metric tons, almost double the 2011 level (4.9 million tons). South African coal exports to China in 2012 more than doubled year-over-year to 14.3 million tons from 9.3 million tons.

On the other hand, Chinese coal imports from Australia and Indonesia increased by 20-30 million tons each in 2012 and were more significant contributors to downward pressure on domestic prices than U.S. coal supply.

But the greater force (by far) in pushing Chinese coal prices down has been domestic production capacity growth (~800 million tons by our estimate since 2011) in a structurally decelerating demand environment. These pressures will persist throughout 2013, 2014 and 2015 regardless of happens to U.S., South African, Colombia, Australian and Indonesia coal exports (see Exhibit 190).

Exhibit 190

Major Seaborne Coal Exporters Supplying China (2012)



Source: Wiki commons, SX Coal, Public Press, EIA, BREE, RBCT and Bernstein estimates and analysis.

We believe that Chinese coal imports are likely to fall in absolute terms in 2013 as lower-priced domestic supply pushes out imports. The great hope for the global thermal coal market is now India. However, coal imports (135 million tons

in the previous fiscal year) are unlikely to increase over 175 million tons in the next few years due to a combination of port capacity constraints and low power prices, which net back to a low supportable coal price. India will fail to pick up the slack in the seaborne market from the loss of China's volume and, as a marginal buyer, will support a far lower price than China has in recent years.

China and the Seaborne Thermal Coal Market

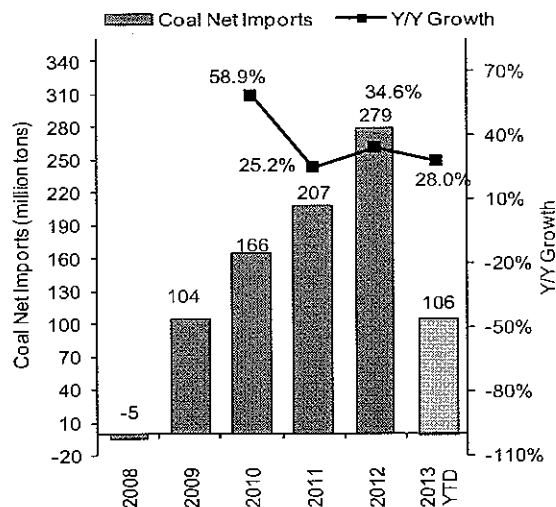
For those watching the thermal coal price in 2012, the grand idea was that of a global thermal coal market taking shape. In 2012, low gas prices in the U.S. pulled down thermal coal prices as North American utilities switched generation from coal-fired to gas-fired units, weakening demand for coal. U.S. coal miners on the east coast — rather than shuttering mines in the wake of falling U.S. demand — started exporting coal to Europe. U.S. coal shipments to Europe displaced South African coal from Europe into Asia. And, as a result, coal prices in China, Australia and Indonesia started to fall.

We like a big idea as much as anyone but there is a problem with this particular explanation of 2012 coal price movements. Yes, the changes in flows as depicted in Exhibit 190 occurred. But these changes in seaborne coal volumes globally in 2012 relative to the size of Chinese market mean that attributing the 25% drop in Chinese coal prices solely to the uptick in U.S. coal exports (~20 million tons) is, in our view, incorrect. Our outlook for 2013-15 for Chinese thermal coal is therefore driven by China, China and China...demand, supply and transportation. The role of Australia, South Africa, Indonesia and the U.S. is a secondary — and diminishing — consideration, in our view.

In this chapter, we set out our view for falling Chinese coal imports in coming years and close to zero net imports in 2015. In addition, we discuss the reasons we believe India will be unable — even at today's lower coal prices — to take up all of the available supply.

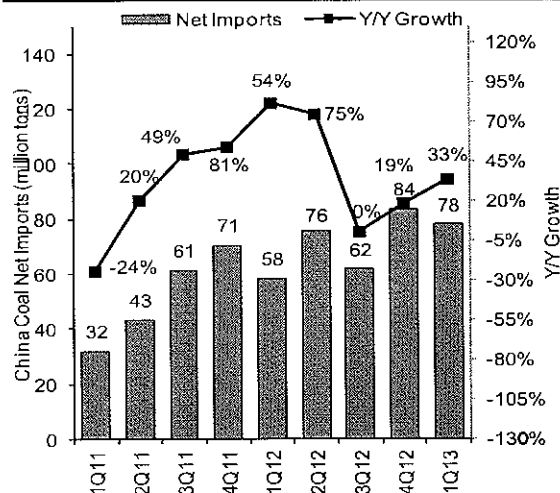
China imported ~280 million tons (net) of coal in 2012, up 35% from 2011 (see Exhibit 191). Imports reached record high at 106 million tons in the first four months (see Exhibit 192). The total seaborne market is roughly 1.1 billion tons.

Exhibit 191 China Coal Net Imports — Annual



Source: CEIC and Bernstein estimates and analysis.

Exhibit 192 China Coal Net Imports — Quarterly

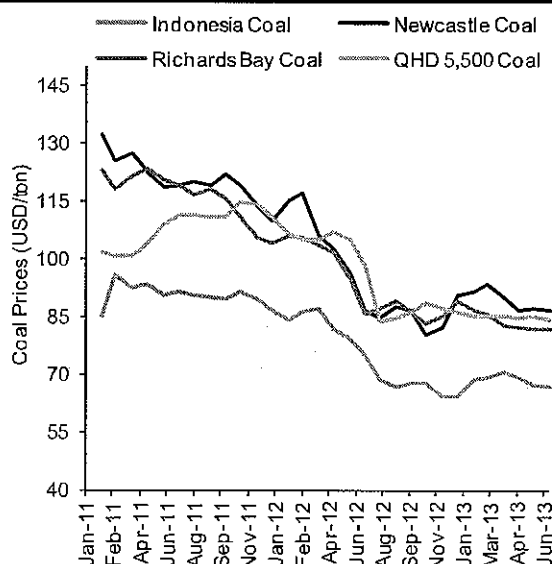


Source: CEIC and Bernstein estimates and analysis.

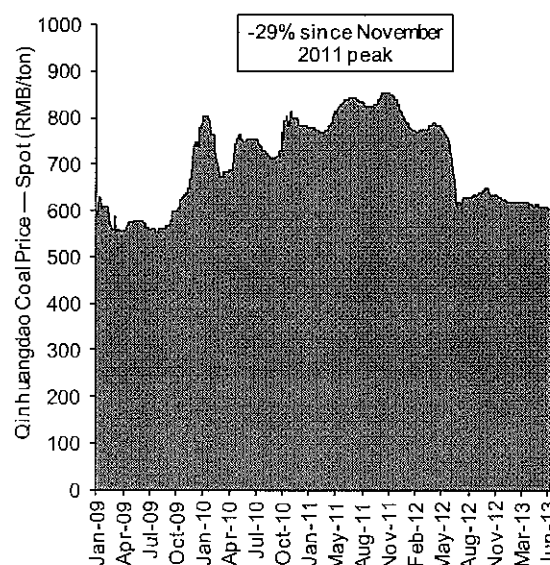
With Chinese coal imports (net) up almost 80 million tons in a seaborne market of just over one billion tons, it is worth noting the significant trends within Chinese supply, specifically:

- U.S. coal exports were up 17% year-over-year at 114 million tons (126 million short tons) in 2012. U.S. coal imports into China were ~9 million metric tons, almost double the 2011 level (5 million metric tons).
- South African coal exports to China increased over 50% year-over-year to 14.3 million tons in 2012 from 9.3 million tons in 2011.
- Australian coal exports to China increased 82% to 59.5 million tons in 2012 from 32.6 million tons in 2011.
- Indonesia coal exports to China increased 17% to 118.5 million tons in 2012 from 101.0 million tons in 2011.
- Mongolia, Russia, North Korea and Vietnam each supplied roughly 10-20 million tons of coal to China in 2012.

In total, the increase in Atlantic Basin coal exports to China (i.e., from the U.S. and South Africa) was only ~10 million tons. But perhaps the most remarkable aspect of the increase in Chinese coal imports in 2012 is that the ramp-up occurred while coal prices globally continued to fall (see Exhibit 193 and Exhibit 194). The coal price globally fell as demand in the U.S. declined in absolute terms and demand growth in China slowed down.

Exhibit 193 Coal Price Benchmarks

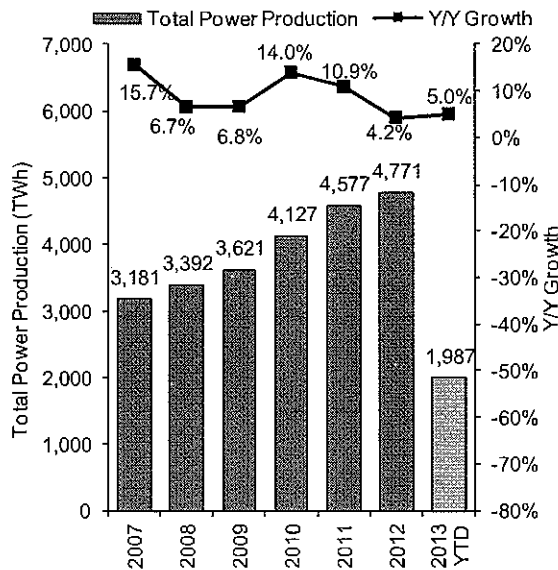
Source: Bloomberg, SX Coal and Bernstein estimates and analysis.

Exhibit 194 QHD 5,500 Coal Price

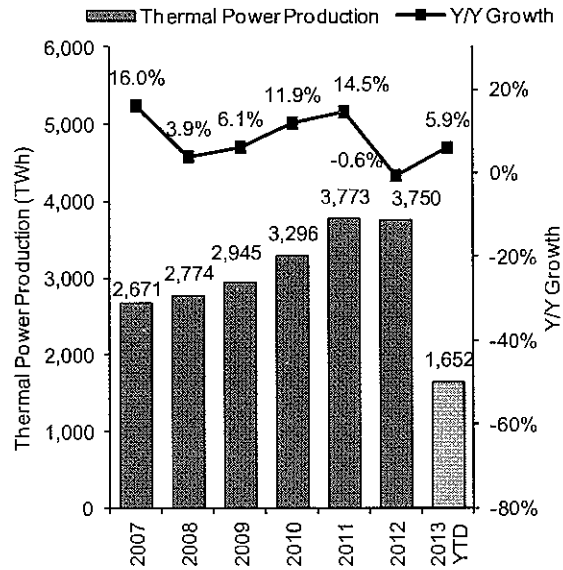
Source: SX Coal and Bernstein estimates and analysis.

In our view, the fall in coal price in China was not triggered primarily by increased, low-priced imports. The primary cause of weakening coal prices in China was weakening demand growth from the power, steel and cement sectors paired with production and transport capacity growth that exceeded demand growth.

Power production in China was up 4.2% year-over-year in 2012, while thermal power production (which accounts for roughly half of Chinese coal consumption) was down ~1% year-over-year (see Exhibit 195 and Exhibit 196).

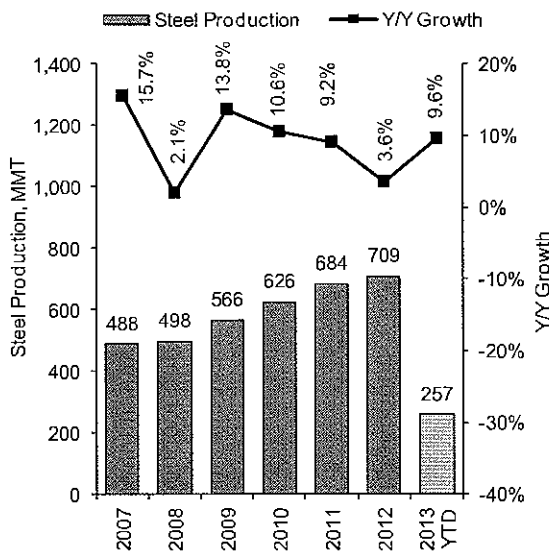
Exhibit 195 China Total Power Production — Annual

Source: CEIC and Bernstein estimates and analysis.

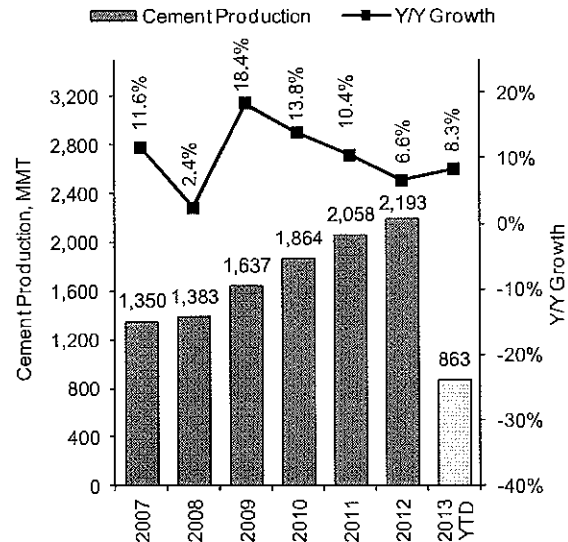
Exhibit 196 China Thermal Power Production — Annual

Source: CEIC and Bernstein estimates and analysis.

Chinese steel production (which accounts for roughly 18% of coal consumption) increased 3.6% in 2012 while cement production (which accounts for roughly 7% of coal consumption) increased 6.6% last year (see Exhibit 197 and Exhibit 198).

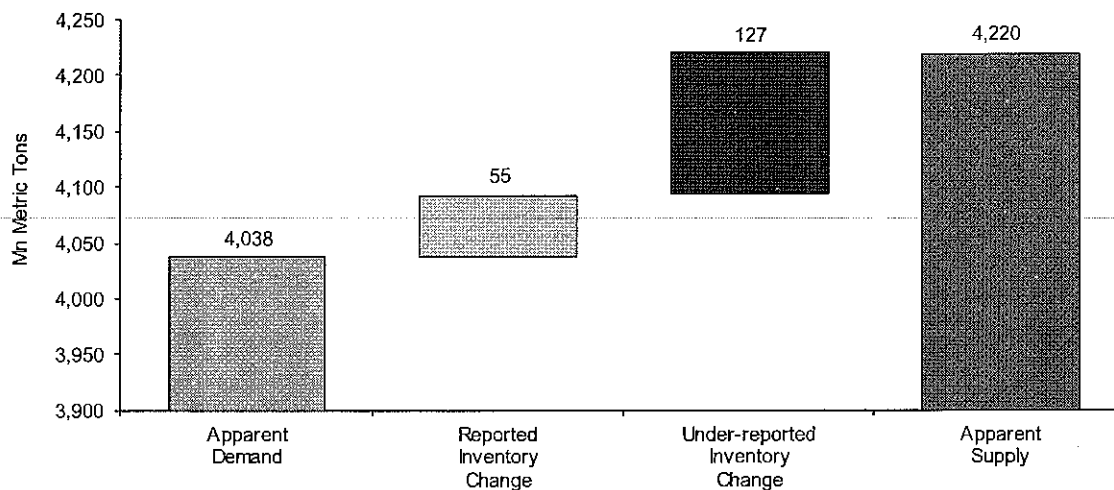
Exhibit 197 China Steel Production — Annual

Source: CEIC and Bernstein estimates and analysis.

Exhibit 198 China Cement Production — Annual

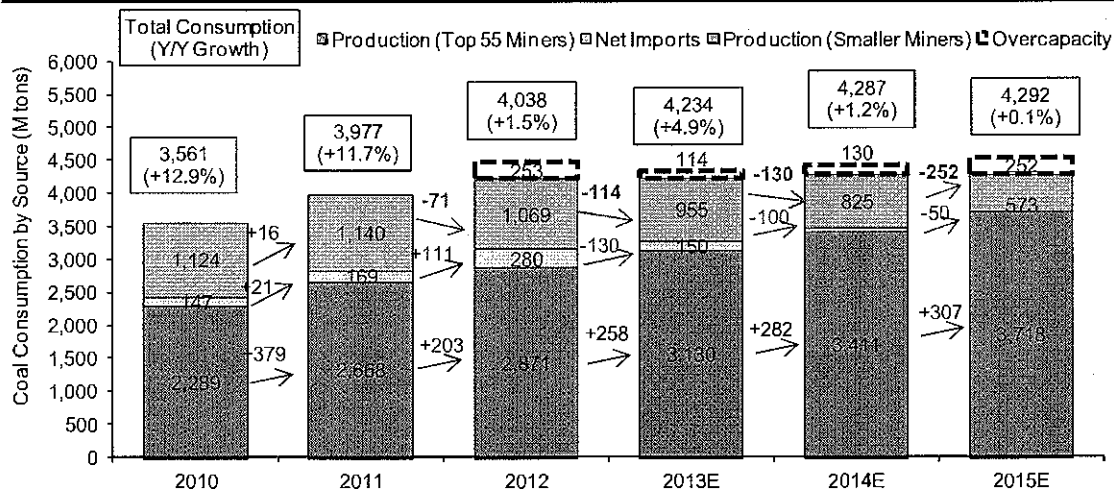
Source: CEIC and Bernstein estimates and analysis.

Based on a combination of official statistics and our own estimates, Chinese apparent demand held steady at ~4,000 million tons annually in 2012 (see Exhibit 199). And yet coal prices fell.

Exhibit 199 China Coal Apparent Demand Analysis (2012)

Source: SX Coal and Bernstein estimates and analysis.

The simplest way to explain the fact that coal prices fell 25% over the course of 2012 despite the fact that, overall, demand for coal was essentially flat, is the share shift within the Chinese coal market sector. In short, the bigger players got bigger and, in the absence of continuing rapid demand growth, the smaller, high-cost miners got squeezed out (see Exhibit 200).

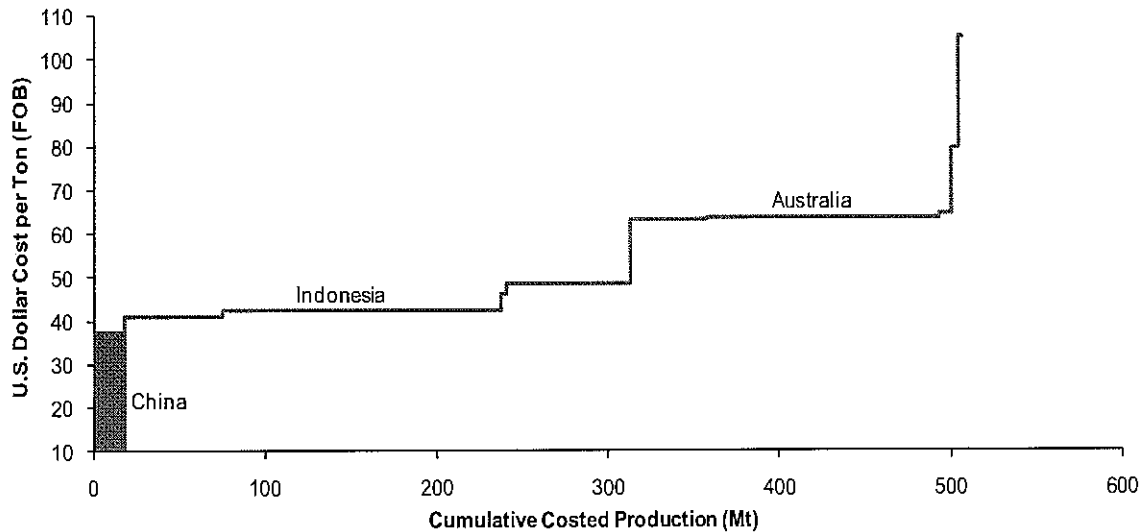
Exhibit 200 Chinese Coal Supply by Source (2010-15E)

Source: SX Coal, CEIC, NBS, China General Administration of Customs and Bernstein estimates and analysis.

To us, this is a far more plausible explanation for the collapse in coal prices and their stubborn refusal to rise again than the idea that ~10 million tons of incremental coal from South Africa and the U.S. resulted in a collapse in pricing in a 4.0 billion ton Chinese coal market. Indeed, the view that the decline in coal prices over the last year is the result of the Appalachian Butterfly Effect assumes a Chinese coal cost curve that is so dramatically S-shaped that it — rather than coal imports — would be, by far, the more important and interesting dynamic (see Exhibit 201). The simplest explanation is that production share was taken by lower-cost Chinese coal miners and that these miners set a low spot price.

Exhibit 201

Exported Thermal Coal Cost Curve (2010)

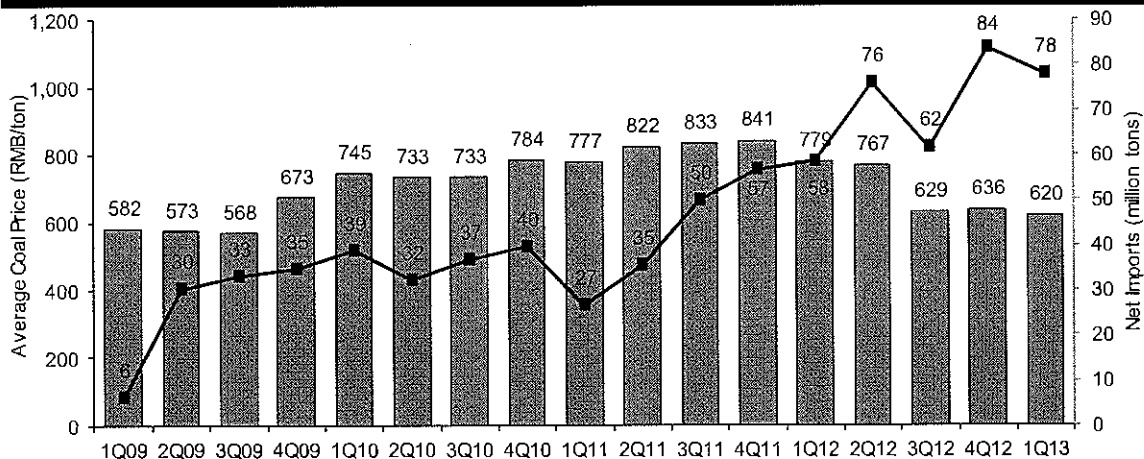


Source: AME and Bernstein estimates and analysis.

The Chinese coal traders and power companies have continued to opportunistically increase imports where the seaborne market will supply at less than the falling Chinese domestic coal price (see Exhibit 202). This will continue to happen through 2013, but it will become tougher for the seaborne market to meet the China price. We anticipate that production capacity growth in 2013 domestically is expanding at a similar rate to 2012 and the high-cost domestic producers will continue to lose share. The difference between 2012 and 2013 is that we expect the large-scale Chinese producers to start taking share from the seaborne market too. Cost structures among large-scale miners in each of these markets (even China) will ultimately dictate supply (see Exhibit 201).

Exhibit 202

Average QHD Coal Price vs. Net Imports — Quarterly



Source: CEIC, SX Coal and Bernstein estimates and analysis.

We expect coal prices to trade within a narrow range going forward owing to the fact that there is plenty of supply available both domestically and from the seaborne market if coal prices creep back up. The Qinhuangdao spot price as of mid-June 2013 is RMB605/ton. The summer peak in coal price will be, in part, a

function of hydro generation, which is inherently unpredictable. We forecast an average price of RMB630/ton for 2013, 2014 and 2015, down ~10% from 2012 (see Exhibit 203).

Exhibit 203		SCB QHD Coal Price Forecast					
		Average Annual Price					
RMB/Metric ton, including VAT	Current	2010	2011	2012	2013E	2014E	2015E
Datong Premium (5,800 kcal/kg)	655	790	871	758	664	664	664
Shanxi Premium (5,500 kcal/kg)	620	748	821	699	630	630	630

Source: SX Coal and Bernstein estimates and analysis.

We continue to expect that the large-scale Chinese coal miners will force out both small, high-cost miners and, from 2013, the seaborne market. The seaborne market was ~1.1 billion tons in 2012, and China represented almost 25% of demand. If our forecast of Chinese net imports falling to zero by 2015 is accurate, the question is: *where does all that coal go?*

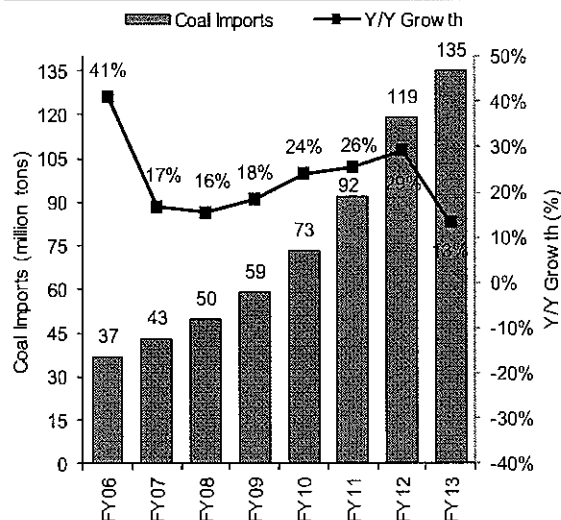
Can India Take Up the Slack?

If, as we expect, Chinese demand for seaborne coal begins a period of terminal decline this year, the next and last source of long-term structural demand growth for seaborne thermal coal is India. The problem in India is not lack of coal; according to the BP Energy Survey, India has the fifth-largest coal reserves of any country behind only the U.S., Russia and China and Australia (see Exhibit 205). Yes, Indian coal has a lower calorific value and higher ash, sulfur and moisture content than might be ideal for generating power but this is not news to anyone...least of all the Indian power sector. The coal-fired power fleet has been designed with the limitations of Indian coal in mind. The question is whether the Indian coal mining sector (i.e., Coal India) can mine the coal and the Indian Ministry of Rail can move the coal in the quantities required.

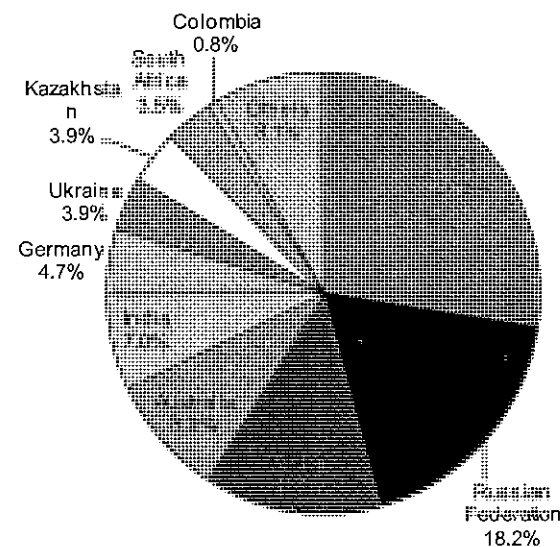
If not, (and the answer to date has been "not"), imported coal is the only remaining option. With China exiting the seaborne market, coal supply will free up at lower prices than have been offered in many years. The second question is therefore: are prices low enough? The final question is: does India have the port and rail infrastructure to import significantly more coal?

India's coal imports have been increasing in recent years (see Exhibit 204). In FY 2013 (ending March 31, 2013), coal imports increased 13% year-over-year. The Planning Commission of India projects India's coal imports to increase to 185 million tons by FY 2017 (ending March 31, 2017).

Coal India accounts for about 80% of total coal production in India. The company reported only 3.8% production growth in FY 2013 (see Exhibit 206), primarily owing to monsoon and labor issues. This weak domestic supply growth suggests that there is plenty of opportunity to increase coal imports.

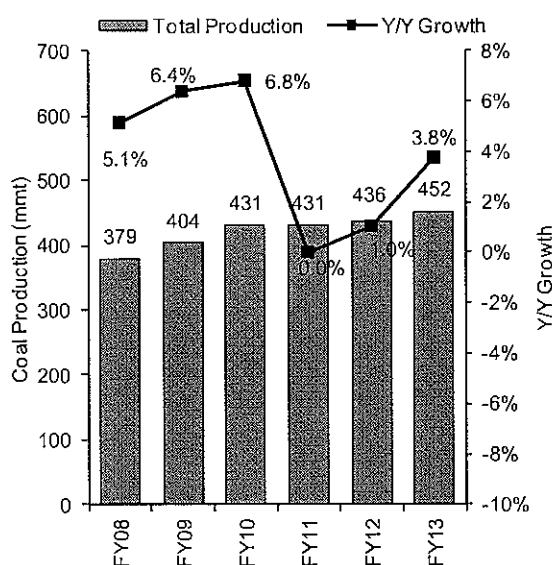
Exhibit 204 India Coal Imports by Fiscal Year (March 31 Year End)

Source: Ministry of Coal, RBI, CEIC, Public Reports and Bernstein analysis.

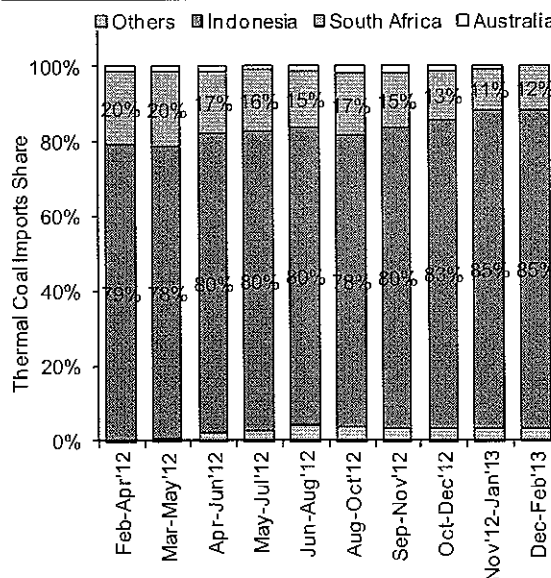
Exhibit 205 Global Coal Reserves by Country (2012)

Source: BP Energy 2013 and Bernstein analysis.

Indonesia dominates coal imports to India, followed by South Africa, while Australia is not a significant source of coal imports to India (see Exhibit 207). Constraints on importing more coal are therefore infrastructure (port and rail capacity) and the fact that the seaborne coal price remains above the regulated price that Coal India charges for domestic coal (even once the adjustment has been made for calorific value).

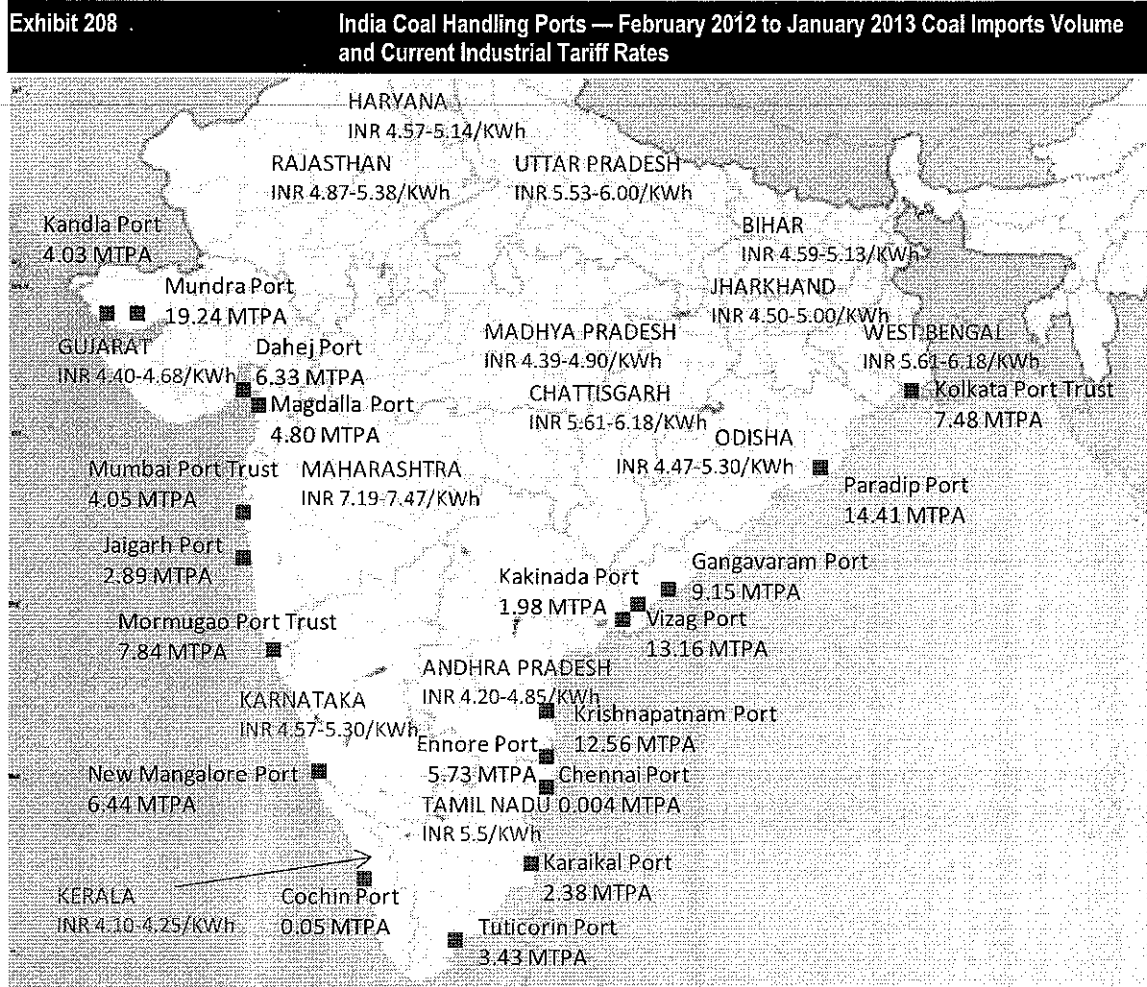
Exhibit 206 Coal India Production and Y/Y Growth (Annual)

Source: Corporate reports and Bernstein estimates and analysis.

Exhibit 207 India Thermal Coal Rolling 3 Million Imports by Supply at Top Ports (February YE)

Source: Coal Insight and Bernstein analysis.

All of the 10 coastal states in India have at least one port to handle coal (see Exhibit 208) — some ports (like Karaikal in Puducherry) cater to the neighboring states (Tamil Nadu). By our estimate, total port capacity is ~265 million tons annually. The ports on the eastern side of India handle more coal cargo — approximately 15 million tons more than the one on the western side.



Source: India Coal Market Watch, SEBs reports, Wikimedia commons and Bernstein estimates and analysis.

In short, the limitation on increasing Indian coal imports is not — on its face — lack of port capacity.

There are, of course, other considerations. Due to the cost of railings coal around India, the ability of a port to increase coal imports is largely a function of port capacity, seaborne coal price, availability of coal-fired power stations in the importing coastal state and the local power price. Maharashtra has the highest average industrial power tariff of INR7.63/KWh while Kerala has the lowest at INR4.20/KWh. Ports, handling capacity, average power prices, current imports and co-located coal-fired generation capacity are set out in Exhibit 209.

Exhibit 209 Indian Coal Receiving Ports Represent Around 91% of Total Coal Imports (February 2012 to January 2013)

State	Port	Coal Capacity / Imports (mtpa)	Coal Import LTM (mt)	Coal Capacity (mtpa)	Avg Domestic Tariff (INR/unit)	Avg Industrial Tariff (INR/unit)	Coal Based Plant (MW)
Gujarat	Mundra	60.00	19.24	60	3.6	4.5	15,190
	Kandla	4.03	4.03				
	Magdalla	4.80	4.80				
	Dahej	20.00	6.33	20			
Maharashtra	Mumbai Port Trust	4.05	4.05		5.2	7.3	15,866
	Jaigarh	2.89	2.89				
Goa	Mormugao	11.00	7.84	11	Between Maharashtra and Kamataka		0
Karnataka	NMPT	6.44	6.44	5	4.0	4.9	4,780
Kerala	Cochin	0.05	0.05		4.5	4.2	0
	Tuticorin	12.55	3.43	13			
Tamil Nadu	Erinore	21.00	5.73	21	3.2	5.5	8,160
	Chennai	3.270	0.004	3			
Puducherry	Karaikal	16.00	2.38	16	On Tamil Nadu Border		0
	Vizag	25.00	13.16	25			
Andhra Pradesh	Krishnapatnam	12.56	12.56		4.9	4.5	10,143
	Gangavaram	20.00	9.15	20			
	Kakinada	4.00	1.98	4			
Orissa	Paradip	21.50	14.41	22	4.1	4.9	6,790
West Bengal	Kolkata Port Trust	14.50	7.48	15	5.6	5.9	12,065
Total		263.64	125.94				72,994

Source: Indian Ports Association, India Coal Market Watch, Coal Insight, Coal Portal report, CEA, SEBs reports and Bernstein analysis.

All of the state electricity boards raised power tariffs in 2012 and still raising in 2013.

Exhibit 210 Average Power Tariff Rates of Domestic Consumers
AVERAGE DOMESTIC TARIFF RATES

State	Date	New Avg. (Rs./unit)	Date	Old Avg. (Rs./unit)	% Chg
Uttar Pradesh	May 31 2013	3.80	Oct 1 2012	3.08	23.38%
Maharashtra	Aug 1 2012	5.17	Nov 1 2011	4.82	7.16%
Bihar	Apr 1 2012	3.10	May 1 2011	2.99	3.55%
West Bengal	Mar 6 2012	5.63	Dec 30 2011	4.96	13.54%
Andhra Pradesh	Apr 1 2012	4.85	Apr 1 2011	4.05	19.75%
Madhya Pradesh	Apr 2012	4.28	FY2012	3.87	10.47%
Rajasthan	May 17 2013	4.25	Aug 10 2012	4.05	4.94%
Tamil Nadu	Apr 1 2012	3.16	FY2012	2.85	11.03%
Karnataka	Apr 30 2012	4.00	Oct 28 2011	3.90	2.56%
Gujarat	Jun 1 2012	3.61	Sep 1 2011	3.54	2.12%
Orissa	Apr 1 2012	4.08	Apr 1 2011	3.50	16.43%

Source: State Electricity Boards' Reports and Bernstein analysis.

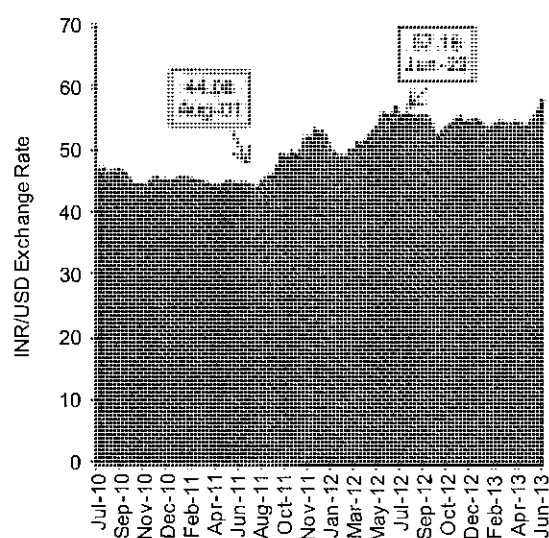
The average hike in 2012 for the 11 largest states by population (accounting for ~80% of India's total population) was ~9% for domestic consumers and 12-14% for industrial customers (see Exhibit 210 and Exhibit 211).

Exhibit 211**Average Tariff Rates for Low Tension (LT) and High Tension (HT) Industrial Consumers****AVERAGE INDUSTRIAL TARIFF RATES**

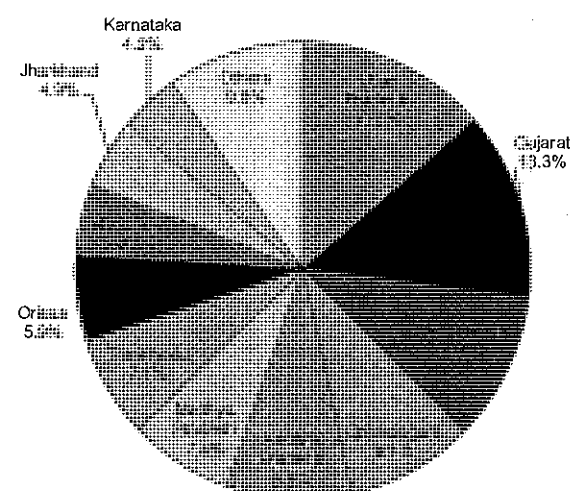
State	Section	Date	New Avg. Rs/Unit	Date	Old Avg. Rs/Unit	% chg
Uttar Pradesh	Industrial LT	May 31 2013	6.00	Oct 1 2012	5.85	2.56%
	Industrial HT		5.53		5.53	0.00%
Maharashtra	Industrial LT	Aug 1 2012	7.19	Nov 1 2011	6.80	5.74%
	Industrial HT		7.47		6.97	7.17%
Bihar	Industrial LT	Apr 1 2012	5.13	May 1 2011	4.65	10.22%
	Industrial HT		4.59		4.20	9.23%
West Bengal	Industrial LT	Mar 6 2012	6.18	Dec 30 2011	5.50	12.20%
	Industrial HT		5.61		5.23	7.30%
Andhra Pradesh	Industrial LT	Apr 1 2012	4.20	Apr 1 2011	3.33	26.11%
	Industrial HT		4.85		4.09	18.53%
Madhya Pradesh	Industrial LT	Apr 2012	4.90	FY2012	4.54	7.99%
	Industrial HT		4.39		4.00	9.65%
Rajasthan	Industrial LT	May 17 2013	4.87	Aug 10 2012	4.87	0.00%
	Industrial HT		5.38		5.38	0.00%
Tamil Nadu	Industrial LT	Apr 1 2012	5.50	FY2012	4.50	22.22%
	Industrial HT		5.50		4.00	37.50%
Karnataka	Industrial LT	Apr 30 2012	4.57	Oct 28 2011	4.37	4.58%
	Industrial HT		5.30		5.10	3.92%
Gujarat	Industrial LT	Jun 1 2012	4.40	Sep 1 2011	4.21	4.51%
	Industrial HT		4.68		4.56	2.47%
Orissa	Industrial LT	Apr 1 2012	5.30	Apr 1 2011	4.80	10.42%
	Industrial HT		4.47		4.25	5.10%

Source: State Electricity Boards' Reports and Bernstein analysis.

As coal prices have fallen since November 2011, the rupee has weakened meaning that the benefit of the lower seaborne coal price in India has been muted (see Exhibit 212).

Exhibit 212 INR-USD Exchange Rate

Source: Bloomberg L.P. and Bernstein analysis.

Exhibit 213 Coal Plant Capacity by State (April 2013)

Source: CEA and Bernstein analysis.

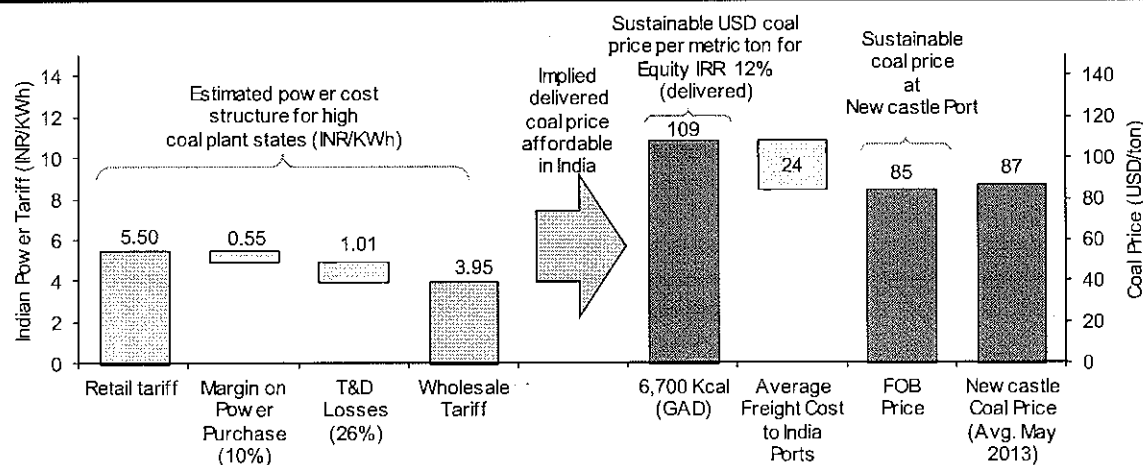
The average retail price of electricity for industrial consumers in the largest 12 states in India (as measured by coal-plant-installed capacity) is INR5.50/KWh (or ~US\$0.10/KWh) — see Exhibit 211. These states have around 91% of total coal-fired power station capacity in India.

Given that a reasonably effective pass-through mechanism exists in the Indian power sector for coal costs, the amount of coal that the country may purchase is a function of port capacity, coal-fired power generation capacity, the seaborne coal price, the retail power price and the level of demand for electricity given that power price. Assuming the country-wide Transmission & Distribution losses (T&D) as 26% and margin on power purchase of State Electricity Boards (SEBs) as 10%, the average retail tariff of INR5.50/KWh converts to the required levelized cost of electricity at the power station of ~INR3.95/KWh or ~US\$0.07/KWh (see Exhibit 214).

A generic coal-fired power station in India operating at 62% utilization, charging INR3.95/KWh wholesale tariff and using blended coal of 4,250Kcal/Kg GAR, can achieve a return on equity of 12% using coal with a delivered price at port of US\$109/ton (Newcastle 6,700 GAD), US\$110/ton (Richards Bay 6,000 NAR) and US\$91/ton (Indonesia 5,900 GAR).

Incorporating the average shipping cost of ~US\$24/ton to India ports from Newcastle, the supportable FOB price comes to be US\$85/metric ton at Newcastle — below the May average FOB price of US\$87/ton.

Exhibit 214 India: Implied Affordable Newcastle Coal Price for Top 12 States by Coal-Based Plant Capacity

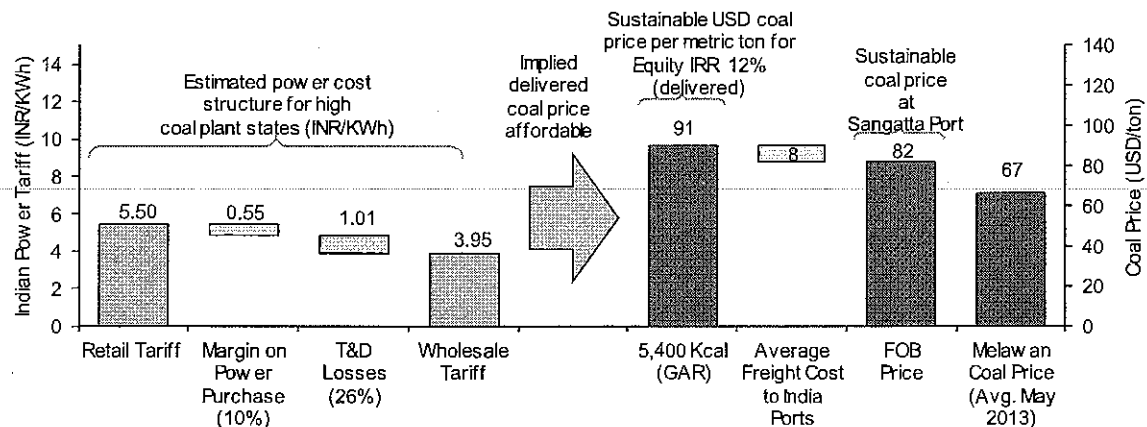


Source: Government announcements, SEB Annual Reports, Coal Insight, Bloomberg L.P. and Bernstein estimates and analysis.

The supportable FOB price in Indonesia is US\$82/ton, taking average shipping cost to ports of India at around US\$8/ton (see Exhibit 215). The sustainable price is around \$15/ton higher than May average Indonesian coal price.

Exhibit 215

India: Implied Affordable Indonesia Coal Price for Top 12 States by Coal-Based Plant Capacity



Source: Government announcements, SEB Annual reports, Coal Insight, Bloomberg L.P. and Bernstein estimates and analysis.

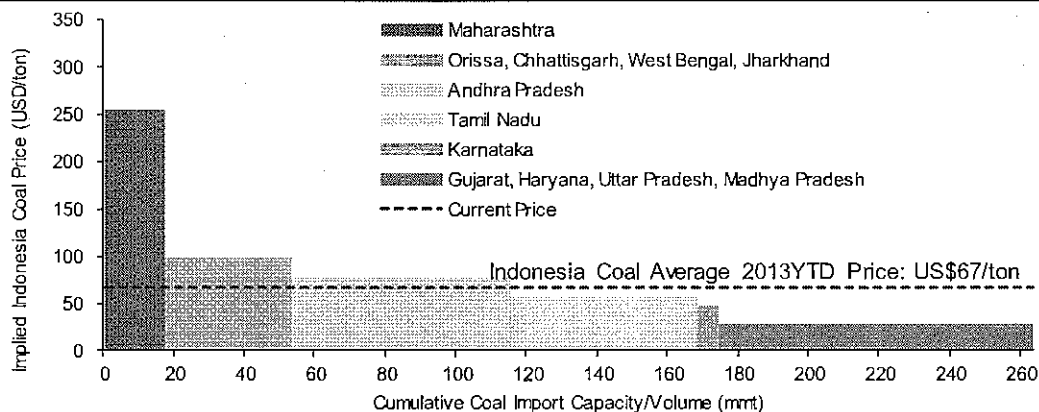
In short, at a national level, Indonesia is likely to continue to dominate coal sales to India as Australian and South African coal prices, even at current levels, remain challenging.

But the Economics of the "Average" Power Station Doesn't Matter

Of course, this approach looks at *average* power prices in coastal states. That consideration is not the correct one in the short term. A more sophisticated approach is to layer the ability to pay at a state level with port capacity at a state level. On that view, only four coastal states — Maharashtra, Orissa, West Bengal and Andhra Pradesh, totaling to 116 million metric tons of imported coal handling capacity — can afford to import coal priced at levels greater than or equal to the current Indonesian coal FOB price (see Exhibit 216).

Exhibit 216

India Imported Coal Cost Curve — Indonesia



Source: Indian Ports Association, India Coal Market Watch, Bloomberg L.P., SEB Annual reports, Coal Insight and Bernstein estimates and analysis.

Because of lower shipping costs, Indonesian and South African coal is viable in Tamil Nadu and Karnataka too. However, there is, in total, only 175 million tons of port capacity for seaborne coal at current prices. India is importing 135 million tons today. And China is about to give back 280 million tons to the seaborne market. Prospects for seaborne coal are going to continue to deteriorate, almost regardless of power demand in India.

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Disclosure Appendix

VALUATION METHODOLOGY

Chinese Coal Miners: We value China Shenhua at HK\$20.00 per share on a P/E basis by applying a forward multiple of ~8x to our 2014 EPS estimate of RMB1.95. Further, assuming that the company maintains a ~40% dividend payout ratio, a \$20 share price implies a 5% dividend yield, which we believe investors will require given the continuing deteriorating profile of the industry. We value China Coal Energy at HK\$3.00 per share by taking the average of (i) a forward P/E multiple of ~8x to our 2014 EPS estimate of RMB0.19 and (ii) a P/B multiple at the average of the lower quintile of global coal mining peers. We value Yanzhou at HK\$5.00 per share on a P/E basis by taking the average of (i) a forward P/E multiple of ~8x to our 2014 EPS estimate of RMB0.38 and (ii) a P/B multiple at the average of the lower quintile of global coal mining peers. Our valuation for Yanzhou (ticker YZC; the NYSE-listed ADR) multiplies Hong Kong valuation by 10.0 (the number of H-shares each ADR represents) and divides by the HK\$ exchange rate. We believe China Coal Energy and Yanzhou can find some support at these levels. On a DCF basis, we believe that China Coal Energy and Yanzhou stocks are worth zero. However, we do not believe that will be reflected in valuation over the next 12 months.

Chinese Renewable Operators: We value China Longyuan at HKD11.00 by applying an average P/E ratio of ~13x to our 2014 EPS estimate of RMB 0.67/share. The valuation reflects an equity raise in 2013 that the company announced on May 2012. We value Datang Renewable at HKD1.60 by applying an average P/E ratio of ~16x to our 2014 EPS estimate of RMB 0.08/share. Valuation is stretched due to concerns around the company's debt levels and the potential for an equity raise in 2013. We value Huaneng Renewables at HKD4.00 by applying an average P/E ratio of ~16x to our 2014 EPS estimate of RMB 0.20/share.

RISKS

There are numerous risks to our investment thesis on Shenhua, China Coal Energy and Yanzhou. Some of these risks are below.

First, contrary to our expectations, electricity demand growth may continue to grow at its historically high rate, increasing demand for thermal coal. Second, contrary to our expectations, steel growth may accelerate, increasing demand for coking coal. Third, coal production and rail transportation capacity may not increase at the rate that we are forecasting over the long term. As a result, coal pricing may not decline in the manner we are anticipating. Further, in the event that rail transportation capacity expansion fails to materialize, movement of coal resources across internally owned logistics and shipping assets may benefit diversified coal and generation companies like Shenhua. Fourth, the companies may decide to alter their investment strategies or enter into new business segments, changing capital expenditures or dividend payout rates and dividend growth rates. Fifth, China may relax its coal export quotas and India may become a more significant importer of coal than we are forecasting, providing a source of additional growth for the coal companies that are not currently included within our estimates. Sixth, the global economy may accelerate, leading to higher-than-anticipated demand for Chinese manufactured goods, increasing demand for Chinese coal and pushing up the price of seaborne coal. Seventh, the Chinese government may choose to stimulate the economy, resulting in an increase in demand for steel, power, cement and — ultimately — thermal and coking coal.

The key risks to the wind power companies' business model are: a reduction in the wind installed capacity target in China or a change to the mandatory tariff, grid connection and dispatch policy. In addition, a reduction in the amount of debt financing available for renewable energy projects in China would negatively impact growth rates both in terms of installed capacity and earnings. An increase in wind turbine prices is a risk given that more than 50% of construction costs relate to turbines. Finally, a reduction in transmission infrastructure construction in China would negatively affect the sector.

An increase in interest rates would negatively affect the companies as they are all highly levered. As with most utilities, given the stable nature of the revenues, high levels of debt are warranted. As a natural consequence of falling manufacturing costs, a stable regulatory environment and improved infrastructure, we anticipate an increasing sophistication among the renewable energy generators over sources of debt funding (more corporate bonds, less bank borrowing) and lower cost of debt over time. Accelerating inflation over the medium term and continuing monetary tightening are risks to our positive stance on the sector.

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Outperform: Stock will outpace the market index by more than 15 pp in the year ahead.

Market-Perform: Stock will perform in line with the market index to within +/-15 pp in the year ahead.

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1171.HK	U (RC)	12/14/11
1798.HK	M (RC)	05/22/12
1898.HK	U (RC)	06/13/12
916.HK	O (RC)	01/31/13 M (RC) 05/22/12
958.HK	O (RC)	01/31/13 M (RC) 05/22/12
YZC	U (RC)	12/14/11

Rating Guide: O - Outperform, M - Market-Perform, U - Underperform, N - Not Rated
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ASIAN COAL & POWER: LESS, LESS, LESS... THE BEGINNING OF THE END OF COAL

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Basic Materials Observer

April 2014

Burned Out

China's Rebalancing Heralds the End of Coal's Growth Story

The first in a four-part series on coal.

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Cheap and plentiful, coal has been the fuel behind China's stellar economic growth, with demand rising nearly threefold since 2000. It's also the main cause of the smog that chokes China's major cities and is the world's single largest source of carbon dioxide emissions.

Most forecasts see China's appetite for coal continuing to grow, if slower than it did in the last decade. We believe China has reached two inflection points—one economic and one political—that lead to a decidedly different outcome: no growth at all.

First, China's economic rebalancing will trigger a sharp deceleration in electricity demand growth. As GDP growth slows and China transitions away from the energy-intensive, investment-led economic model, we expect electricity use to grow at less than half the rate of the past decade.

Second, a shift in political priorities will undermine coal's traditional advantage over rival power sources. Nuclear, hydro, wind, and solar will all gain at the expense of coal as the government promotes an "all of the above" strategy to reduce China's costly reliance on "cheap" coal.

In our analysis, coal-fired generation peaks by 2014, then declines through 2020. Neither an economic rebalancing nor a political shift alone is sufficient to halt China's runaway coal demand growth. But together, they herald its end.

Basic Materials Observer

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About This Report

“Burned Out: China’s Rebalancing Heralds the End of Coal’s Growth Story” inaugurates Morningstar’s four-part series on coal, the world’s second leading source of energy, top source of energy demand growth for the past decade, and leading source of air pollution and CO2 emissions. The next two reports in the series will analyze coal in the United States and India—the world’s second- and third-largest coal markets, respectively. We will conclude the series with the seaborne market.

Domestic coal markets in China, the U.S., and India are each far larger than the entire seaborne market. As a consequence, small shifts in supply and demand in these countries can have major ramifications abroad: redefining competitive landscapes and reshaping trade flows. An additional rail line connecting Inner Mongolia to China’s coast can close coal mines throughout Central Appalachia in the U.S. Red tape in India can swing South African export volumes from Amsterdam to Mumbai.

China is a natural place to kick off our series. Chinese coal demand has nearly tripled since 2000, underpinning strong global demand growth for coal. The country now ranks as the world’s largest coal consumer and uses roughly as much of it as the rest of the world put together.

Most forecasts, including base-case outlooks from the EIA and IEA, see China’s appetite for coal continuing to grow, if slightly slower than the last decade. The consequences of such a trajectory would be profound. It would be good to be a coal miner in such a world. It would be less pleasant to be a Chinese urbanite, since the midday sky over Beijing would probably retain its sickly yellowish-brown hue. Similarly, life on the coast, in China or elsewhere, would be increasingly dicey as CO2 emissions would continue to rise.

This report provides our forecast for China’s thermal coal consumption to 2020. We begin with an outlook for Chinese power demand, coal’s top end use, and examine the likely evolution of China’s electricity usage as GDP expands slower than it has in the past decade and as the economy rebalances away from investment and toward consumption. Our conclusions for China’s power needs are very different from most forecasts.

We then consider how that demand will be met. To do so, we bring together Morningstar analysts covering Chinese coal miners, infrastructure companies, and power producers, which affords an integrated view of China’s rapidly evolving coal market. It also allows us to identify prospective shifts in the competitive landscape and the consequences up and down the value chain.

The final two sections of the report look at the consequences of our forecast: for Chinese coal-mining companies (we cover three), for China’s air pollution problem, and for global CO2 emissions.

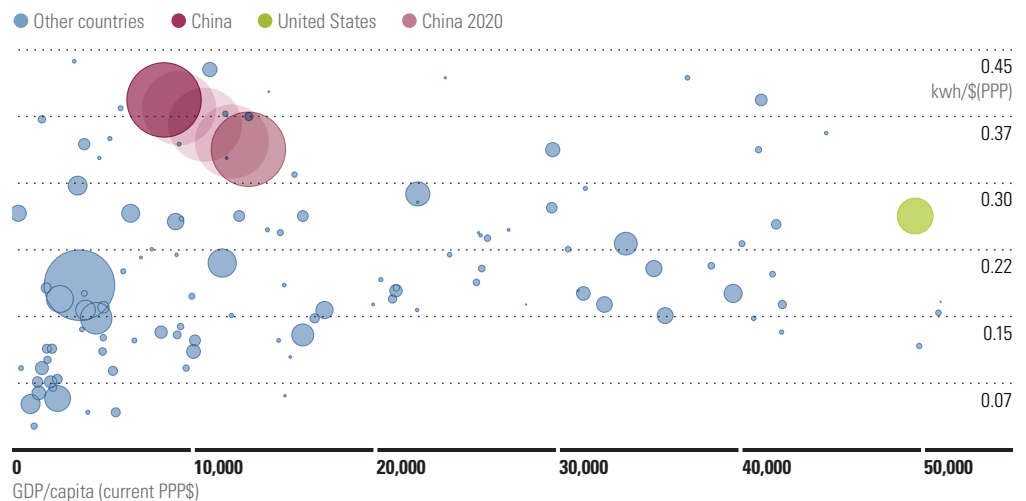
—Daniel Rohr

Key Takeaways

Electricity Demand: Less Than Most Expect

- ▶ China uses more electricity than any other country: about 5,000 terawatt-hours in 2013. The Chinese economy has grown increasingly “electricity intensive” over the past decade or so. Electricity use grew a cumulative 302% from 2000 to 2013 (11.3% annually), outpacing 244% GDP growth (10.0%).
- ▶ China uses about 0.40 kilowatt-hours to generate a dollar of GDP, adjusted for purchasing power parity. That’s twice the typical amount for a country of its income level.
- ▶ China’s high electricity intensity is a direct consequence of the boom in real estate and infrastructure, which reoriented the manufacturing base to especially electricity intensive activities, including cement and metals production.
- ▶ China’s electricity intensity will decline as the economy rebalances to a more sustainable growth model, weighing on electricity demand growth. Industry’s share of GDP will decline and industry itself will become less electricity intensive as the sector is less oriented toward energy-hungry cement and metals production.

Exhibit 1 China’s Electricity Intensity: Current Versus 2020



Source: IEA, World Bank, Morningstar
 Note: Bubble size denotes population.

- ▶ While household electricity use should grow strongly, underpinned by rising incomes and urbanization, it would be coming off too small a base (13% of overall usage) to materially affect the overall trajectory of China's electricity use.
- ▶ We expect electricity demand to rise to roughly 6,200 TWh by the end of the decade, or 3% annually. This is a contrarian view. For example, the IEA's Current Policies Scenario envisions electricity demand of 7,200 TWh by 2020. The difference between our forecast and theirs is equivalent to the size of Japan's total power consumption.
- ▶ Sharply lower electricity demand growth bodes ill for coal, which will be fighting over a smaller electricity demand pie than most imagine.

Coal Demand: Growth Grinds to a Halt

- ▶ As its power needs quadrupled from 2000 to 2013, cheap and plentiful domestic coal was the obvious choice for China. Coal maintained a mid- to high-70s percentage share of total power generation over this period.
- ▶ The all-in costs of cheap coal have begun to take a steep environmental and public health toll. Beijing has responded with an "all of the above" approach, which includes nuclear, wind, solar, hydro, and natural gas, in a bid to diminish the country's reliance on coal-fired power. The build-out of a network of long-distance ultra-high-voltage lines will allow far-flung wind, hydro, and solar generation to compete where they previously could not.

Exhibit 2 Coal's Killers

	2013		2020		Change	
	TWh	Share %	TWh	Share %	TWh	Coal equivalent (Mt)
Total power generation	5,357	100	6,583	100	1,226	567
Less:						
Nuclear	112	2	483	7	370	-171
Wind	144	3	488	7	344	-159
Hydro	888	17	1,142	17	254	-117
Solar	14	0	178	3	164	-76
Gas	117	2	224	3	107	-49
Other	92	2	126	2	34	-16
Oil	6	0	6	0	0	0
Coal plant efficiency	—	—	—	—	—	-91
Equals: Coal	3,985	74	3,937	60	-48	-113

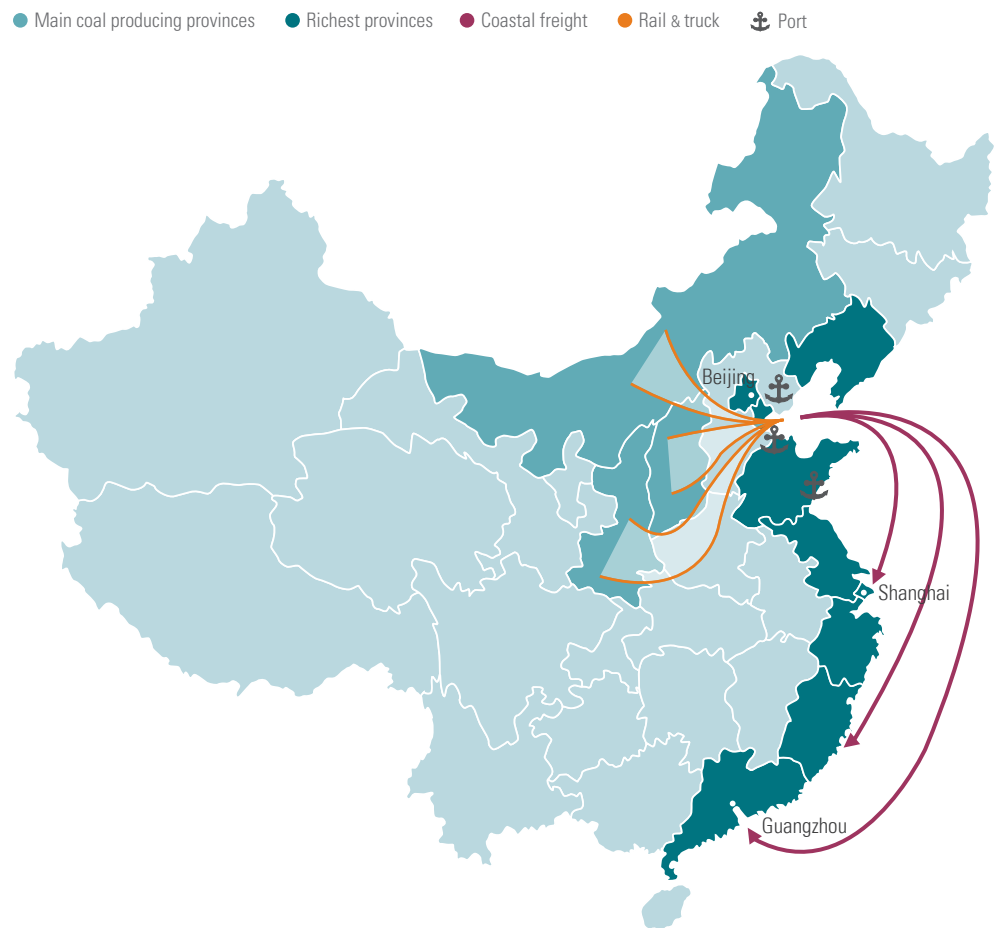
Source: China Electricity Council, Morningstar

- ▶ Diminished power demand growth will mean a smaller-than-expected pie to fight over. Because installed capacity of hydro, wind, nuclear, and solar boast lower marginal costs than that of coal, it is coal that loses share in the struggle.
- ▶ We expect coal's share of power generation to fall from 74% in 2013 to 60% by 2020. Nuclear, hydro, and wind are the biggest thieves. Coal-fired generation tops out at 4,000 TWh before falling to 3,900 TWh in 2020.
- ▶ We expect that the average efficiency of China's coal-fired fleet will continue to improve through 2020, though slower than it has in the past decade. The average amount of coal used to generate each kwh of electricity slips 5%.
- ▶ Falling coal-fired generation and improved plant efficiency combine to reduce power-sector coal consumption from a peak of 1.9 billion metric tons in 2014 to 1.7 billion metric tons in 2020.
- ▶ Demand weakness will be especially acute in China's coastal provinces: the front lines of Premier Li Keqiang's recently announced "war" on pollution. Already, leadership has looked to bar new coal-fired plants in and around Beijing, Shanghai, and Guangzhou.
- ▶ Competition will stiffen for existing coal-fired plants on the coast. A network of ultra-high-voltage lines will transmit electricity from inland regions richer in hydro, wind, solar, and coal. We also expect 44 new nuclear power plants to come on line by 2020, all on the coast. Together, these new sources of electricity can displace nearly 400 million metric tons of coastal coal consumption, more than all of China's 2013 import demand (about 240 million metric tons).
- ▶ Demand for coal outside the power sector fares only slightly better, essentially flat-lining at 2014 levels: 1.2 billion metric tons through 2020. Coal-to-gas conversion projects represent the strongest source of demand growth outside the power sector. Meanwhile, coal used for home heating and cooking declines sharply. Demand growth from the cement and metals industries stalls as China's investment boom concludes.
- ▶ In total, we forecast China's total thermal coal demand (power plus nonpower) at 3.3 billion metric tons by 2020, down approximately 2% from 2013 and far less than most expect.

Coal Production: Railway Build-Out Unleashes Low-Cost Supply

- China is blessed with massive coal reserves, the world's second largest. But the great distance separating China's main coal reserves in the northwest from the population centers on the coast makes it challenging to marry supply and demand. Infrastructure is critical to the domestic supply and demand balance.
- In recent years, China's surging demand for coal outstripped its ability to cost-effectively transport coal from mine to consumer. Mine production was up to the demand challenge, but insufficient rail capacity forced volumes on to highways, driving up domestic marginal costs and obligating the coal-rich country to turn to imported volumes to meet demand.

Exhibit 3 China's Coal Supplies Are Far From Its Main Electricity-Consuming Regions



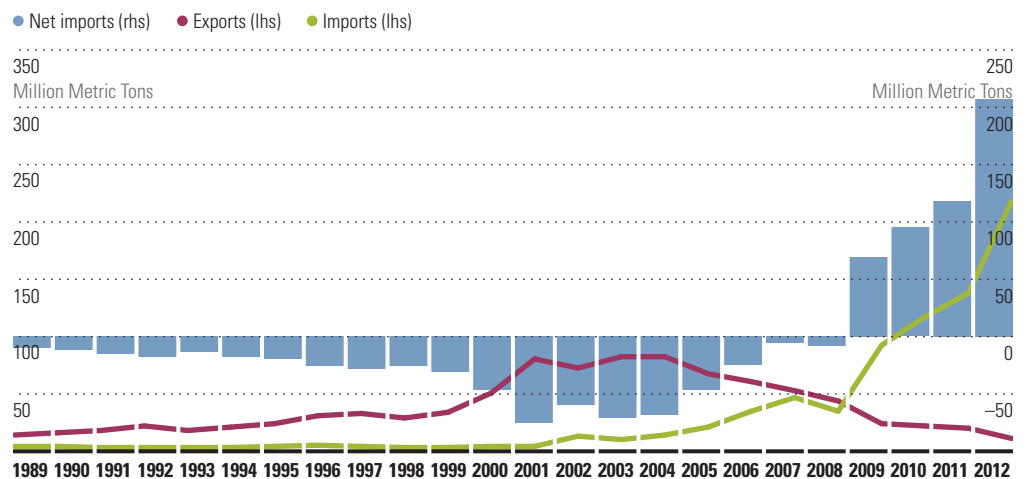
Source: Morningstar

- After long-lagging mine capacity additions, railway construction is kicking into high gear. We expect China to swing from infrastructure deficit to surplus by 2015 and believe the surplus is likely to swell in subsequent years.
- Improved infrastructure will reduce the distance disadvantage. Inner Mongolia, Shanxi, and Shaanxi, while far from demand sources, will grow production strongly at the expense of high-cost coal production in other provinces. Inner Mongolia's share will rise the most because of low mine costs and sharply diminished reliance on highway transport. Older mining districts, such as Shandong's, will enter terminal decline as ever-deeper mines make costs prohibitive.
- In the context of weaker demand growth, the railway build-out will drive down domestic marginal costs and diminish import requirements. We expect prices to remain far below the heady levels of the past several years.
- Given the record amount of investment in new coal-mine construction between 2011 and 2013, we anticipate overcapacity in the industry to cap any pricing increases.

Coal Imports: Diminishing Needs

- The biggest event in global coal markets in recent memory has been China's transition from major coal exporter to the world's largest coal importer in the span of just a few years. Low-cost Indonesian coal has captured the lion's share of Chinese import demand.

Exhibit 4 Tectonic Shift: China Swung From Net Exporter to Net Importer in 2009



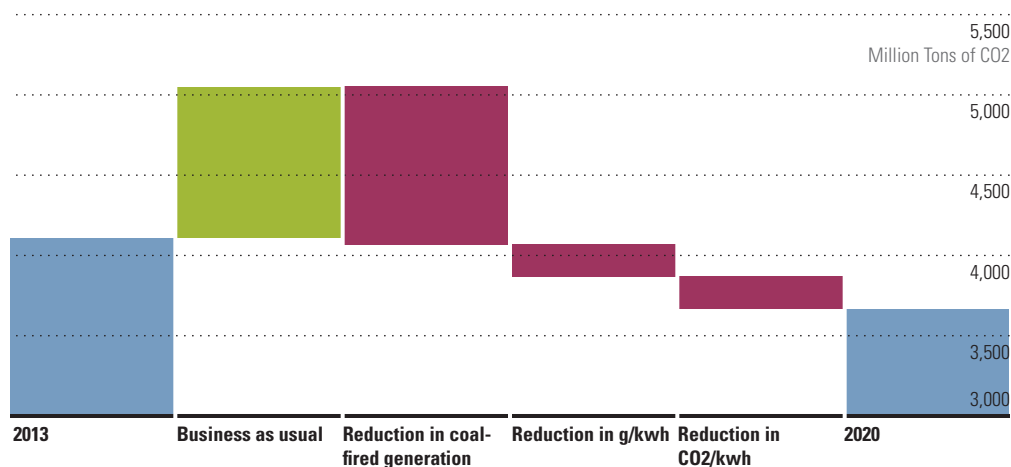
Source: IEA, Morningstar.

- ▶ China's domestic coal production and consumption dwarf not only its import needs, but the size of the entire seaborne coal market. Minor changes in China's domestic supply and demand balance can have major consequences for coal importers and exporters around the world.
- ▶ We expect China's import requirement to fall during the next several years, as coal demand peaks and domestic supply de-bottlenecks. Ultra-high-voltage power lines linking the interior with the coast and 44 new coastal nuclear plants heighten the risk to imported coal volumes. Comparably high-cost Australian coal would be first on the chopping block.
- ▶ The past few years of heavy coal imports by a coal-rich China is likely a historical anomaly. Growing domestic production and falling demand suggest that China could revert to its prior status as a major coal exporter by 2017.

Coal and the Environment: Clearer Skies Ahead

- ▶ China's reliance on cheap and plentiful coal to fuel its economic growth has had clear public health and environmental consequences. Coal is China's largest source of energy and largest source of air pollution.
- ▶ Growing public discontent has forced a shift in the leadership's priorities. Economic growth remains the party's main concern, but it will no longer be pursued at all costs.
- ▶ Beijing has chosen an "all of the above" strategy that includes nuclear, hydro, wind, solar, and natural gas to wean the economy off its coal addiction.

Exhibit 5 Non-stop Ascent of Coal Plant CO₂ Emissions to Reverse



Source: World Bank, IEA, Morningstar

- ▶ Government promotion of alternatives is unlikely to significantly reduce China's reliance on coal if the economy and electricity demand remain on the current trajectory.
- ▶ A significant deceleration in electricity demand growth will make the government's environmental goals far more attainable than most expect.
- ▶ We think a combination of falling coal-fired generation and a more efficient coal-fired fleet will drive material nationwide reduction in PM2.5 emissions.
- ▶ The improvement in Beijing and China's other major coastal cities will be even greater, aided by the growth of a wholly coastal nuclear fleet and ultra-high-voltage power lines delivering electricity from distant regions rich in hydro, wind, and solar resources.
- ▶ The environmental benefits of a rebalancing China extend well beyond its borders. The combination of factors that cuts PM2.5 concentrations will do the same for CO2 emissions.
- ▶ Chinese coal plants have been the leading source of global CO2 emissions growth in the past decade. That seemingly unstoppable trend reverses in our forecast. We expect CO2 emissions of 3.7 billion metric tons in 2020 from coal-fired generation, down from an estimated 4.1 billion metric tons in 2013.
- ▶ Our base-case outlook for coal-plant CO2 emissions is far less than the 4.6 billion and 5.2 billion metric tons forecast in the IEA's New Policies and Current Policies scenarios. It matches the results of the IEA's aggressive 450 Scenario, which imposes the policy changes necessary to limit the increase in global temperatures to 2 degrees Celsius.

Chinese Coal Miners: No Place to Hide

- ▶ While Chinese coal-mining shares have underperformed for the past few years, downside risk remains.
- ▶ Rail capacity is likely to meaningfully exceed demand as early as 2015, exacerbating 2013's excess supply situation and flattening the cost curve.
- ▶ Combined with falling demand growth, this will mean persistent weakness in coal prices. We expect long-term prices to be 18% below 2013's already soft levels.
- ▶ Moats will be more important than ever in such circumstances. Low-cost, narrow-moat China Shenhua should perform the best, while high-cost, heavily indebted Yanzhou Coal is most at risk.

Exhibit 6 Better Infrastructure + Tepid Demand = Weak Coal Prices



Source: SX Coal, Morningstar

Note: Forecast in constant CNY.

Electricity Demand: Less Than Most Expect

Daniel Rohr, CFA

Electricity Demand Frames Coal's Future in China

China's future thermal coal demand depends greatly on the country's future electricity demand. Power generation accounts for roughly two thirds of China's thermal coal use. In this section, we gauge the growth potential for Chinese electricity demand through 2020, aiming to define the "pie" over which coal, natural gas, nuclear, hydro, and renewables will compete.

Exhibit 1 China Thermal Coal Consumption by End-Use, 2011

End-Use	Million tons	% of total
Electricity plants	1,755	63
Nonmetallic minerals (mainly cement)	240	9
Metals and mining	179	6
Heat plants	168	6
Residential	86	3
Chemicals	76	3
Other industrial	139	5
Miscellaneous	159	6
Total	2,801	100

Source: IEA, Morningstar

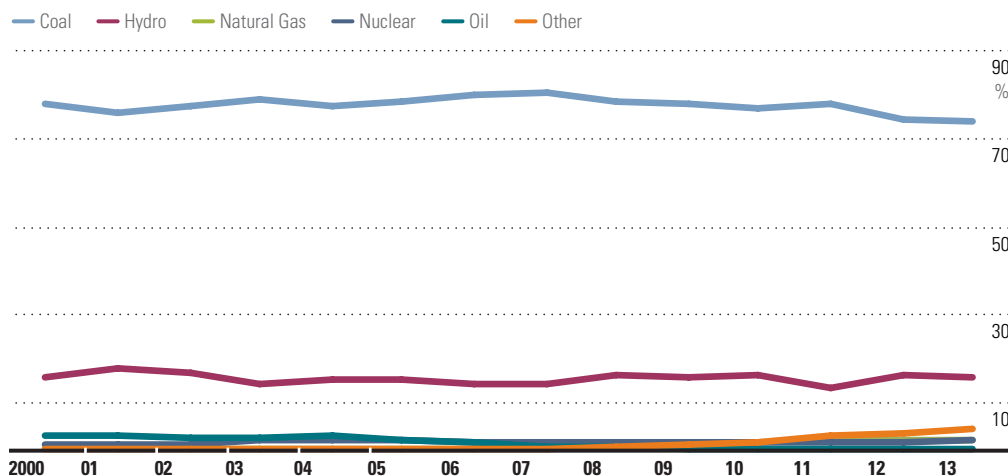
Though not yet the world's largest economy, China already uses more electricity than any other country, overtaking the U.S. in 2011 after posting 12% annual growth in electricity use since 2000. And since thermal coal is China's dominant source of power generation, accounting for roughly three quarters of electricity output over the past decade, this makes China the world's largest coal consumer.

Exhibit 2 China Is Now the World's Largest Electricity User (TWh)

Country	China	US	Japan	Russia	India	Germany	Canada	S Korea	Brazil	France
2011	4,433	4,127	1,003	927	835	579	566	506	480	476
2000	1,254	3,857	1,012	762	407	546	523	278	332	441
Change	3,179	270	-9	165	428	34	43	228	148	36

Source: World Bank, Morningstar

Exhibit 3 Coal Has Maintained a Dominant Share of China's Power Mix
Share of Power Generation

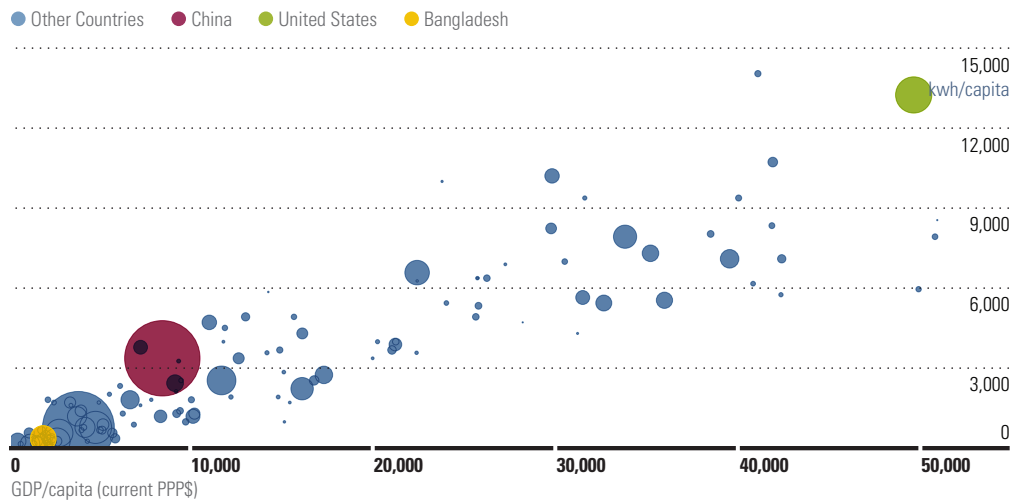


Source: World Bank, China Electricity Council, Morningstar

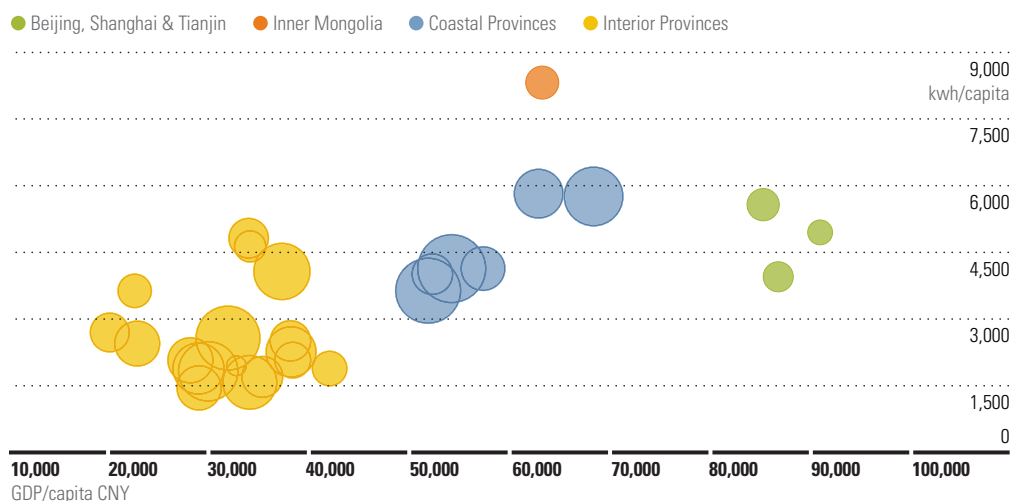
The Connection Between GDP Growth and Electricity Use: Important but not Defining

The economy is the most important driver of electricity demand in any country, including China. As countries scale the income ladder, they consume more electricity. Taking an example from each major World Bank income category, Exhibit 4 shows that low-income Bangladesh consumed 259 kwh per capita, middle-income China at 3,298 kwh per capita, and the high-income U.S. at 13,246 kwh per capita in 2011. Exhibit 5 illustrates a similar relationship between electricity use and incomes within China: Richer provinces such as Jiangsu and Zhejiang along the coast use far more electricity per capita than poorer provinces in the interior.

Exhibit 4 Strong Connection Between GDP and Electricity Use



Source: Source: World Bank, Morningstar
Note: Bubble size denotes population.

Exhibit 5 Strong Connection Within China, Too

Source: China Electricity Council, National Bureau of Statistics

While the connection between electricity demand and GDP is clearly strong, it's far from perfect. For example, in terms of purchasing power, U.S. incomes are six times higher than Chinese incomes. But the gap is smaller when it comes to electricity use. Per capita, the U.S. uses four times as much electricity as China. Within China, Inner Mongolia and Zhejiang have similar GDP per capita—roughly CNY 63,500—but Inner Mongolia uses 38% more electricity per capita. In other words, differences in economic output don't wholly explain differences in electricity demand.

Electricity Intensity: Measuring Buzz for the Buck

This is where the concept of "electricity intensity" comes into play. We'll use the term throughout the report, so it's worth specifying precisely what we mean by it and how we measure it.

When it comes to electricity usage, not all economic activities are created equal. Activity A and Activity B may produce the same quantity of GDP, but that doesn't mean they use the same amount of electricity. Electricity intensity gives us a simple way to compare those differences at the economy level: How much electricity does a country use relative to its GDP?

We measure electricity consumption in kilowatt-hours. We measure economic output in dollars of GDP. Electricity intensity is measured in kilowatt-hours per dollar, or kwh/\$. If Country X has a higher electricity intensity than Country Y, it uses more power to generate a dollar of GDP.

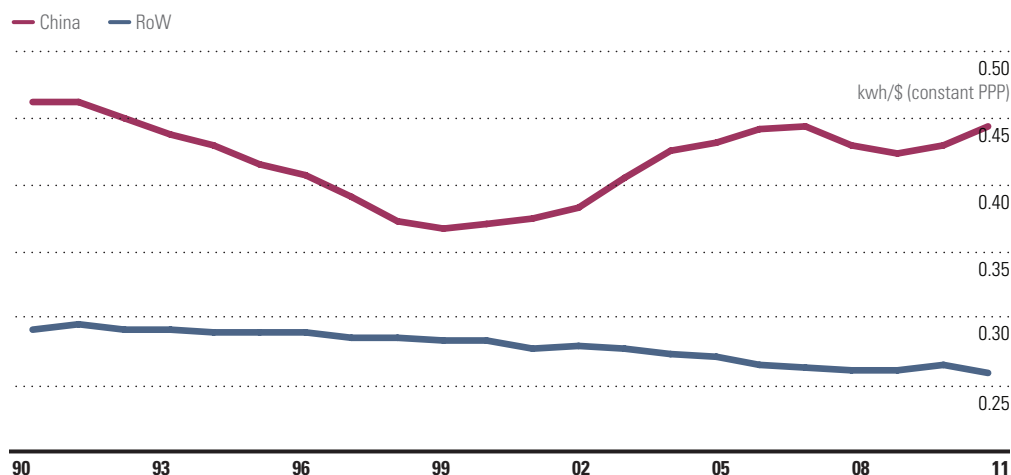
To facilitate cross-country comparisons, we measure GDP in dollars adjusted for purchasing power parity. For comparisons across countries and across time, we use PPP-adjusted constant dollars to control for exchange rates and inflation, with 2005 as the base year.

More Buzz for the Buck: China's Electricity Intensity Rose in the Past Decade

Chinese GDP and electricity consumption have tended to move together, but the link is far from perfect. From 2000 to 2010, China's economy expanded 171% cumulatively. But electricity use grew even faster, at 214%. China's electricity intensity rose 16% over this interval, from 0.37 kwh/\$ to 0.43 kwh/\$. It has continued to rise since 2010 and stands at 0.44 kwh/\$ today (in constant 2005 PPP dollars). Interestingly, the rise in electricity intensity marked a reversal of the trend from 1990 to 2000, when the electricity intensity of the Chinese economy actually declined.

China's rising electricity intensity in the past decade stands out from the rest of the world. Excluding China, the electricity intensity of the global economy was 0.28 kwh/\$ in 2000. By 2010, it was essentially unchanged at 0.27 kwh/\$.

Exhibit 6 Electricity Intensity of GDP Since 1990: China Versus the Rest of the World

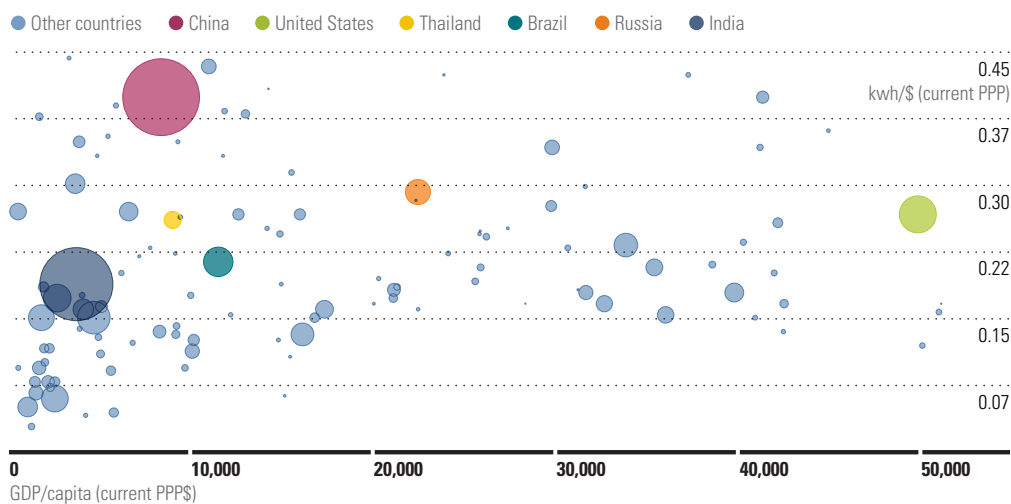


Source: World Bank, Morningstar

China's Electricity Intensity Is High by Nearly Any Standard

Surging electricity intensity over the past decade has made China not only the world's largest consumer of electricity, but also the most electricity-intensive major economy in the world. In current PPP dollars, China has an electricity intensity of 0.40 kwh/\$ compared with 0.27 kwh/\$ for the U.S. This is why, despite a far lower GDP than the U.S., China uses more electricity. Exhibit 7 shows how China's electricity intensity stacks up against the rest of the world.

Here, we see that China is not only an outlier relative to rich countries but to countries of similar income. Thailand's income roughly matches China's (Thailand at \$8,944 per capita versus China at \$8,322), but has a far lower electricity intensity of 0.26 kwh/\$. BRIC peers Brazil, Russia, and India sport electricity intensities of 0.21, 0.29, and 0.19, respectively.

Exhibit 7 China's Electricity Intensity Exceeds That of Other Major Economies, Developed or Emerging

Source: World Bank, Morningstar
 Note: Bubble size denotes population.

Unusual GDP Composition Explains China's Elevated Electricity Intensity

Is China simply a woefully inefficient electricity user? Probably not. Rather, China just tends to do things that use a lot of electricity. We can get a clear picture of this by comparing China's GDP composition to other countries, in particular those with similar income.

A country's GDP can be deconstructed in two basic ways: the output side and the expenditure side. The output side consists of the value added by the agricultural, industrial, and services sectors. The expenditure side looks at how that output is put to use: household consumption, government consumption, gross capital formation (commonly referred to as "investment"), and net exports.

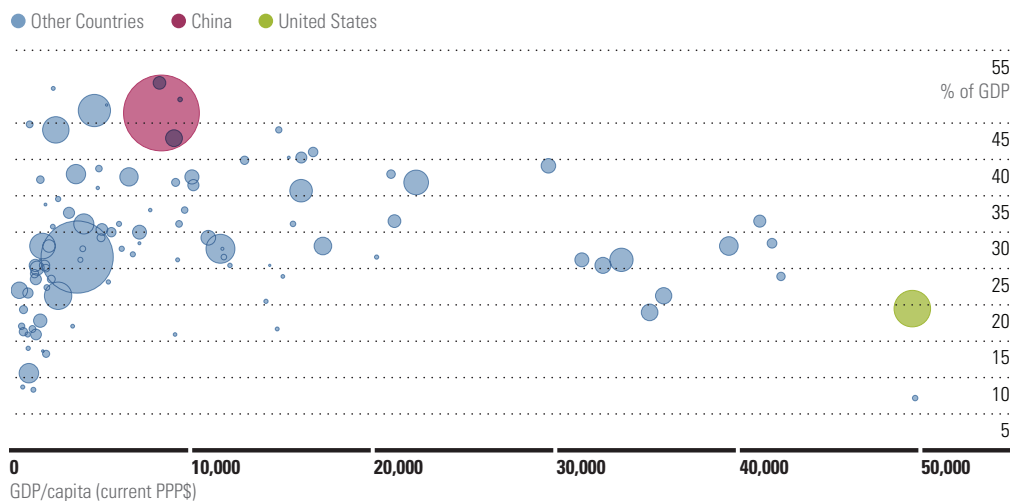
As we've highlighted in previous reports (see, for example, China's Unsustainable Investment Boom from September 2011 or China's Rebalancing Act from August 2013), China's present economic composition is unusual on both the output and expenditure sides. And in both cases, it's also unusual relative to the "typical" country of its income level. China's outlier economic composition is what accounts for its high electricity intensity.

Big Industrial Sector, Small Services Sector Drive Heavy Electricity Use

Exhibits 8 and 9 show how China stacks up on the output side of the economy.¹ At 47% of GDP, China's industrial sector claims a greater share of economic output than in most countries. In countries with incomes similar to China, an industry share around 30% to 40% is the norm. Fellow BRIC countries Brazil, Russia, and India clock in at 28%, 37%, and 27%, respectively. For context, industry is 19% of U.S. output and in the high-20s for manufacturing-oriented rich countries like Germany and Japan.

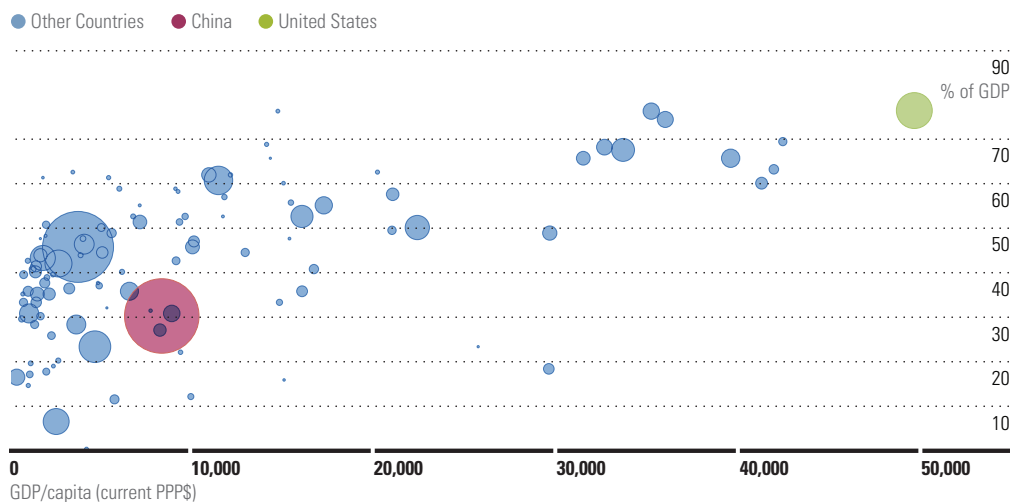
Meanwhile, China's services sector accounts for 43% of output. That's low versus the 50% to 60% typical of countries with comparable income levels, much less the 70%-plus norm among high-income countries. Brazil, Russia, and India are at 67%, 59%, and 56%, respectively.

Exhibit 8 Industry Share of GDP Versus GDP per Capita



Source: World Bank, Morningstar
Note: Bubble size denotes population.

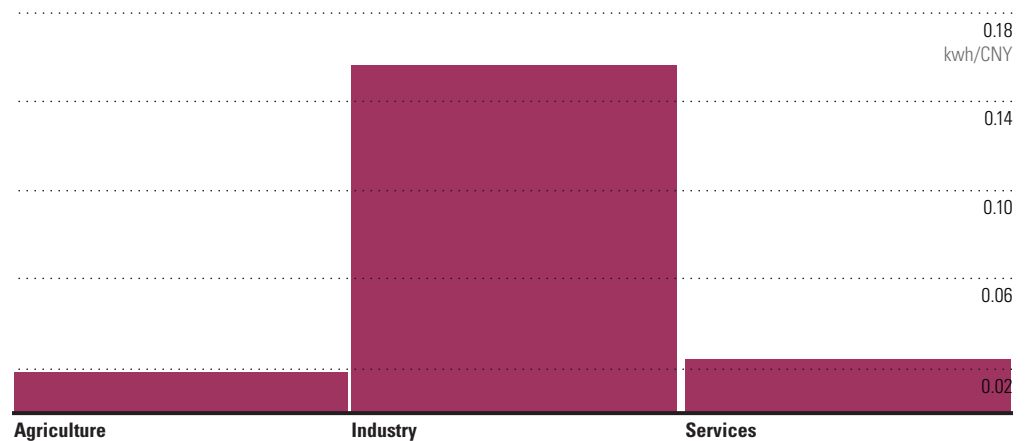
Exhibit 9 Services Share of GDP Versus GDP per Capita



Source: World Bank, Morningstar
Note: Bubble size denotes population.

China's industry-heavy, services-light economy largely accounts for the country's elevated electricity intensity. According to data from the China Electricity Council, the country's industrial sector uses more than 6 times as much electricity for each unit of output than the services sector.

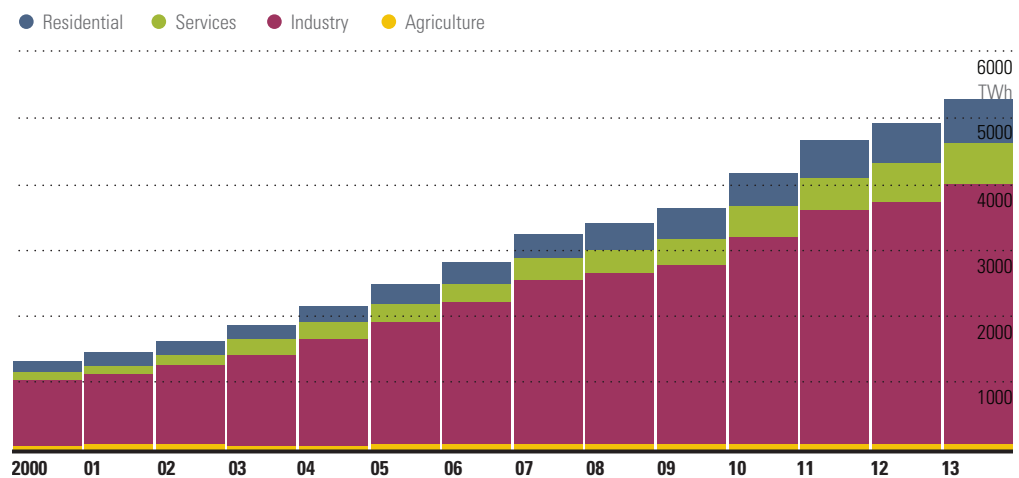
Exhibit 10 Electricity Intensity of China's National Accounts: Output Side



Source: NBS, China Electricity Council, Morningstar

Not surprisingly, China's big, electricity-intensive industrial sector uses far more electricity (3,914 TWh in 2013) than its small, electricity-light services sector (627 TWh). It's also been the dominant driver of electricity demand growth since 2000, an incremental 2,936 TWh compared with 497 for the services sector.

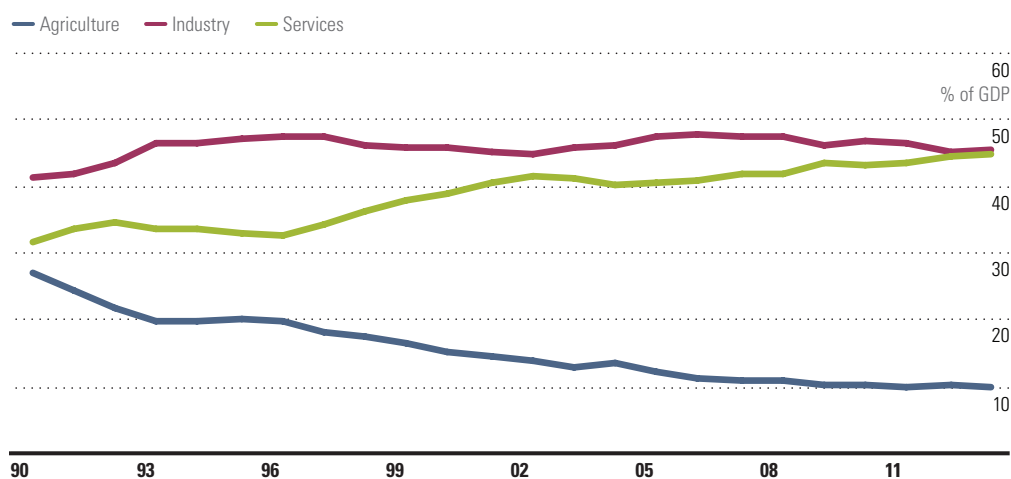
Exhibit 11 Industry Dominates China's Electricity Use



Source: China Electricity Council

All else equal, were China's mix of industry and services more typical of its income level (a 35/55 split instead of 47/43), we estimate the economy's electricity intensity would be 16% lower: 0.33 kwh/\$ instead of 0.40 kwh/\$. But even 0.33 kwh/\$ would be high relative to China's income level (0.20 to 0.30 kwh/\$ is typical), so the output side mix differences can't fully explain why China looks so different. Similarly, because the industrial share of GDP has been fairly constant for the past decade, we need to dig a little deeper to explain the 16% increase in China's electricity intensity.

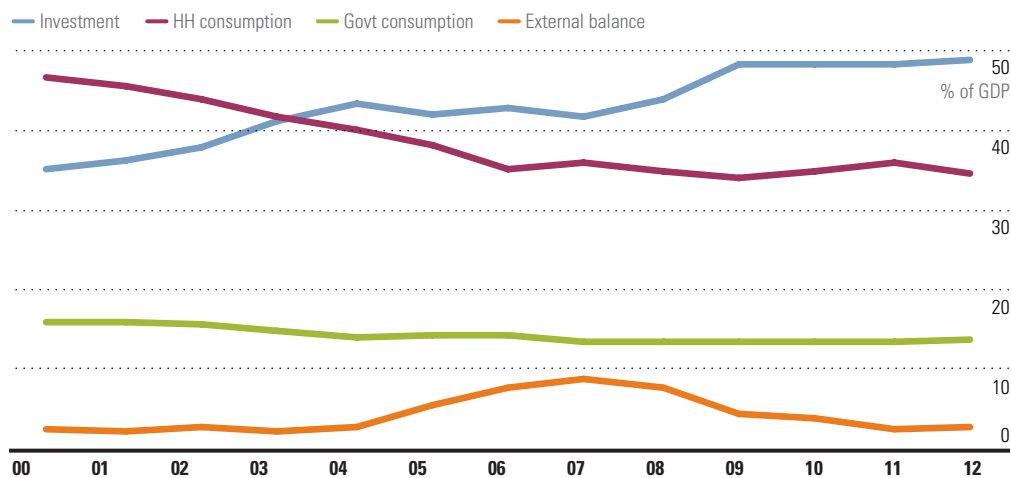
Exhibit 12 China's National Accounts: Output Side



Source: World Bank, NBS

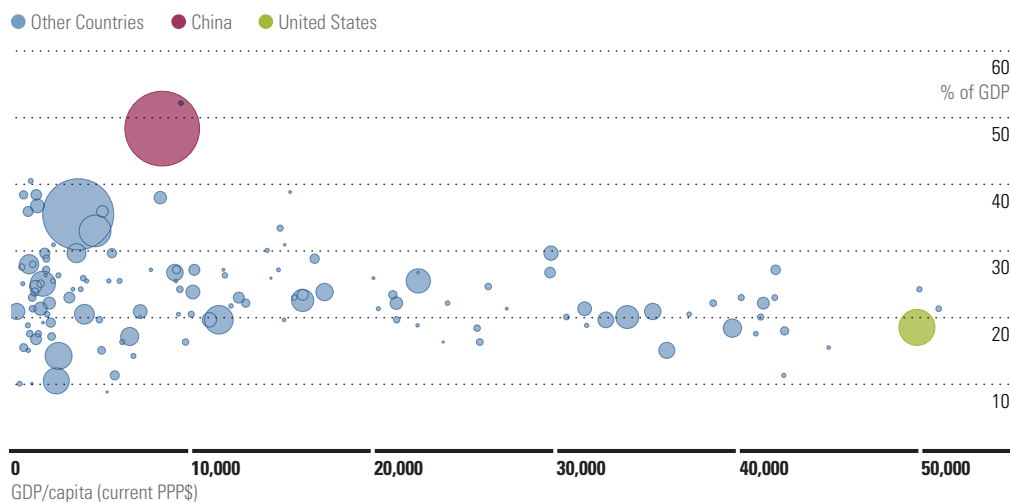
China's Investment Boom Made Industrial Sector More Electricity Intensive

On the expenditure side, instead of looking at how much China's industrial sector has been producing, we focus on what it's been producing. Over the past decade, there's been a big shift. China has been spending an increasing share of its economic output on physical capital: infrastructure, real estate, and manufacturing capacity. From 2000 to 2012, the investment share of GDP rose to 49% from 35%. The household consumption share of GDP fell to 35% from 47% over the same interval.

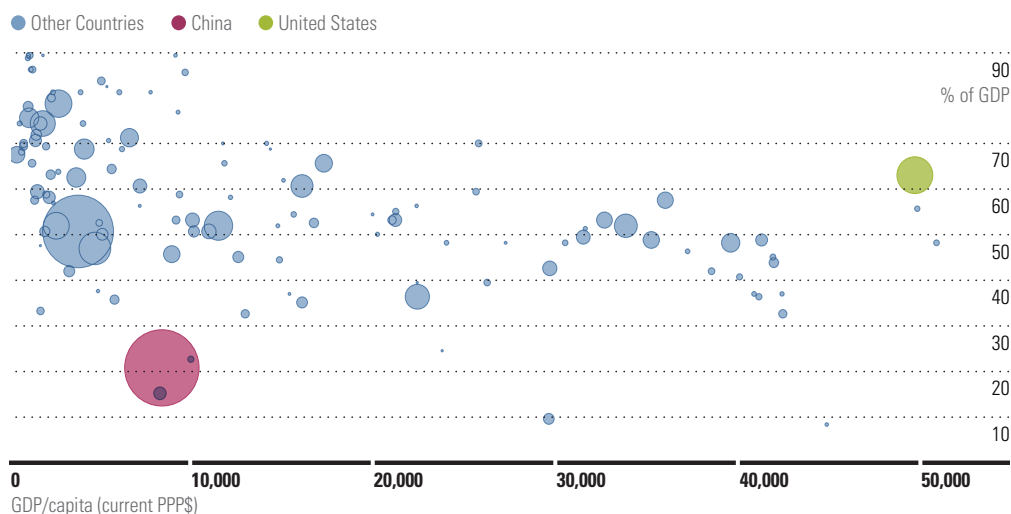
Exhibit 13 China's National Accounts: Expenditure Side

Source: World Bank

These are utterly outlandish figures relative to any contemporary economy, emerging or developed, low income or high, lightly or heavily populated. Relative to the size of its economy, China now invests at a rate more than 3 times the global average. Its households consume at a rate of roughly half the global average.

Exhibit 14 Investment Share of GDP Versus GDP per Capita

Source: World Bank, Morningstar
 Note: Bubble size denotes population.

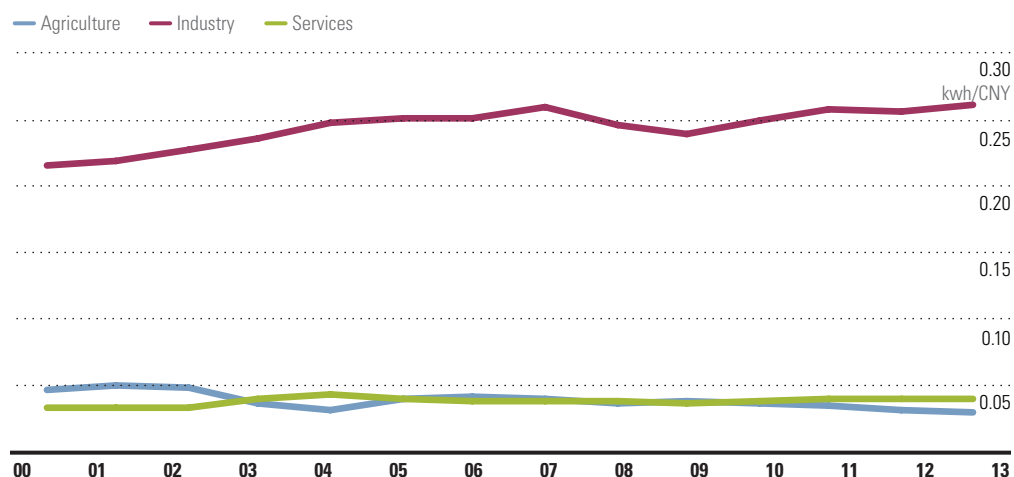
Exhibit 15 Household Consumption Share of GDP Versus GDP per Capita

Source: World Bank, Morningstar

Note: Bubble size denotes population.

We argue that a growing investment share on the expenditure side explains why, despite a stable industrial share on the output side, China's electricity intensity has risen so dramatically. China's industrial sector has become increasingly focused on furnishing the inputs for the country's infrastructure and real estate boom, including cement and metals. Since 2000, cement and metals output production growth has risen roughly 400%, far outpacing growth in total industrial output (+240%). These activities consume enormous amounts of electricity. For example, producing one metric ton of cement requires an average 111 kwh of power. Put in perspective, that's enough to power a typical Chinese home for about three months.

With Chinese industry increasingly focused on furnishing the power-hungry building blocks of the country's investment boom, the industrial sector grew more electricity intensive. From 2000 to 2013, the electricity intensity of China's industrial sector rose 22% in constant local currency terms. For context, it's now roughly 70% higher than the electricity intensity of the U.S. industrial sector and 50%-100% higher than levels typical of middle-income countries like Brazil, Malaysia, and Thailand.

Exhibit 16 Electricity Intensity of Industrial, Agricultural, And Services Sector (Constant 2000 CNY)

Source: China Electricity Council, NBS

By 2011, China's cement and metals industries accounted for a staggering 1,167 TWh of electricity consumption, or 26% of the country's total. For perspective, that's roughly twice Chinese household electricity use (562 TWh), equivalent to Japan's total electricity consumption (1,003 TWh), and within striking distance of total U.S. household electricity consumption (1,423 TWh).

Exhibit 17 Electricity Consumption by End Use

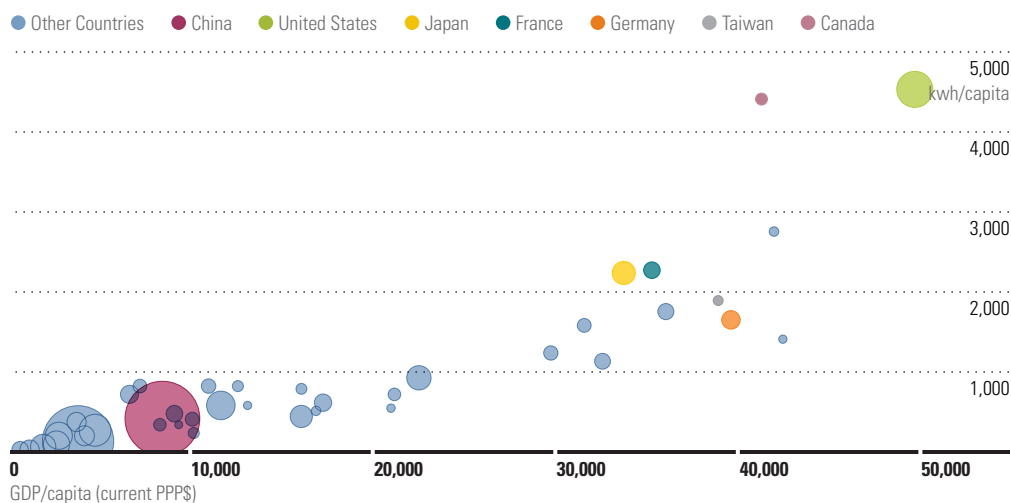
	US		China	
	(TWh)	Share (%)	(TWh)	Share (%)
Cement and metals	200	5	1,167	26
Other industry	699	17	1,488	34
Residential	1,423	34	562	13
Utilities and energy	337	8	570	13
Commercial and public	1,328	32	221	5
Other	140	3	426	10
Total	4,127	100	4,433	100

Source: IEA, Morningstar

Households Are a Minor Player in China's Total Electricity Use and Will Remain So for Many Years

While China's industrial electricity consumption is highly unusual, its residential electricity consumption is not. In 2011, the last year for which we have a full global dataset, Chinese households consumed 418 kwh per capita (it's since risen to 500 kwh per capita in 2013). As shown in Exhibit 18, Chinese household electricity consumption is typical for countries of similar income, a category that includes Thailand (494 kwh) and Colombia (426 kwh).

Exhibit 18 Residential Electricity Consumption per Capita



Source: IEA, World Bank, Morningstar
 Note: Bubble size denotes population.

Exhibit 18 suggests ample room for growth in Chinese residential electricity usage as income levels rise in the long term. For high-income countries, household electricity consumption tends to be in the neighborhood of 2,000 kwh per capita, four times that of China. France (2,273 kwh), Germany (1,670 kwh), Japan (2,270 kwh), and Taiwan (1,903 kwh) are all in this range. The U.S. and Canada are big outliers among rich countries, at 4,566 kwh and 4,438 kwh, respectively—mainly because of North Americans' unusually large homes.

Rich countries aren't the best proxies for China's potential in the medium term. If China were to sustain 7% GDP growth through 2020 (unlikely in our view, but possible), GDP per capita would approximate that of high-middle-income countries like Chile, Malaysia, Poland, and Turkey. Household electricity consumption of 750 kwh is typical for countries in this income category. Through 2020, this would imply a 50% increase (about 6% annually) versus the 500 kwh per capita that Chinese households registered in 2013.

Though strong growth, it wouldn't meaningfully buoy overall Chinese electricity demand. As previously shown in Exhibit 17, households account for 13% of total electricity use in China. All else equal, 50% growth in residential electricity consumption would raise China's total electricity consumption by 6.5%, equivalent to 0.9% compounded annually.

Our Electricity Demand Outlook

At the most basic level, forecasting China's electricity demand requires we answer two fundamental macroeconomic questions. First, how fast will GDP grow? Second, how will the composition of GDP change?

The consensus response to both questions points to weaker electricity demand growth than the 11% annual growth since 2000. To summarize conventional wisdom, most would answer that China will see:

- 1) Lower GDP growth than in the 2000s.
- 2) Rising services and consumption shares of GDP (and falling industry and investment shares).

While there's general agreement on the direction of these fundamental macroeconomic drivers, opinions vary considerably regarding magnitude. For GDP growth, most agree that the 10% pace of the 2000s is unlikely to be sustained in the 2010s. But whether the new normal is 7% or lower remains an open question.

Similarly, most expect a transition from the industry- and investment-led model of the past decade to an increasingly services- and consumption-led model. This necessarily implies reduced electricity intensity of GDP. But views on the pace and timing of China's economic transition differ widely.

So while there's implicit agreement that China's electricity demand growth is likely to weaken, there's little agreement on the magnitude of that weakening.

To accommodate divergent investor views on the Chinese economy, we've modeled two scenarios for Chinese electricity use through 2020: Our base-case outlook, which we refer to as the "Major Rebalancing" scenario, and an outlook that we think approximates consensus, which we refer to as the "Minor Rebalancing" scenario. Exhibit 19 summarizes the key assumptions and results.

Exhibit 19 China Electricity Demand Outlook: Major Versus Minor Rebalancing

		Major Rebalancing				Minor Rebalancing		
		% Change				% Change		
	Unit	2013	2020	Cumulative	per year	2020	Cumulative	per year
GDP (constant 2005 PPP)	\$ billions	11,573	16,284	41	5	18,694	62	7
Per capita	\$	8,505	11,560	36	4	13,270	56	7
Electricity intensity	kwh/\$	0.44	0.38	-13	-2	0.40	-8	-1
Electric power consumption	TWh	5,037	6,188	23	3	7,477	48	6
Per capita	kwh	3,702	4,393	19	2	5,308	43	5

Source: Morningstar

Major Rebalancing

This scenario reflects our base-case outlook for China's rebalancing away from the debt-fueled investment-led growth model of the past decade. Relative to consensus, it incorporates much lower GDP growth than the recent pace, a major rebalancing away from investment and heavy industry, and a corresponding material decline in electricity intensity of GDP. Household incomes rise faster than GDP, reversing the trend of the past decade and underpinning strong growth in residential electricity demand. But coming off such a small base, the impact is limited. Overall electricity demand grows roughly 3% annually to about 6,200 TWh by 2020. Electric power use per capita rises from 3,702 kwh to 4,393 kwh. This would put China's electricity consumption per capita on par with high-middle-income countries like Hungary, Malaysia, and Poland.

Minor Rebalancing

This scenario reflects what we believe to be market consensus and is largely based on the International Monetary Fund's China forecast in its most recent World Economic Outlook.² This scenario incorporates moderately lower GDP growth than China has enjoyed in the past couple of years, a minor rebalancing away from investment, and a commensurately modest decline in the electricity intensity of the Chinese economy. Electricity demand in this scenario grows about 6% annually to 7,500 TWh by 2020. Per capita, electric power consumption rises to 5,308 kwh, equivalent to levels in Italy, Spain, and the United Kingdom.

How Reasonable Is Our Major Rebalancing Outlook?

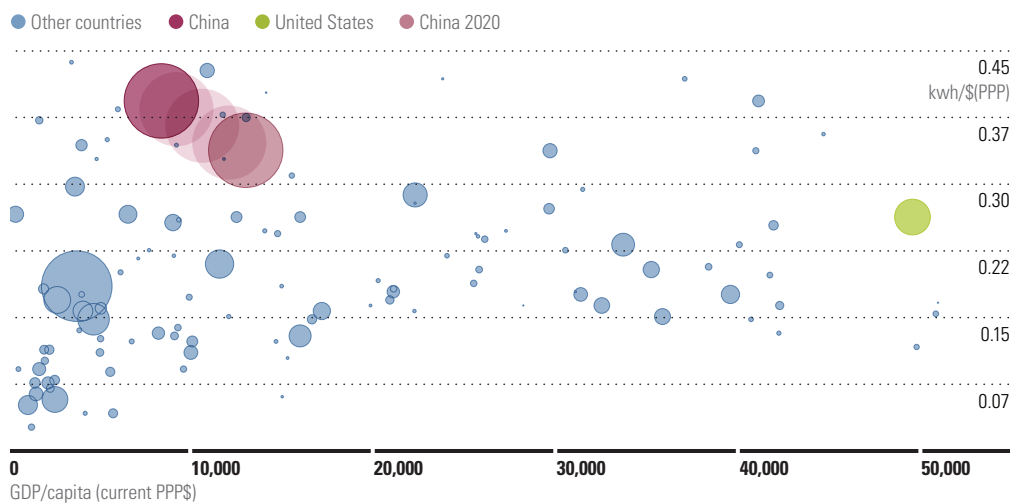
To a large extent, our assumptions regarding GDP growth, composition of GDP, and electricity intensity of GDP reflect our answer to a single question: How sustainable is China's investment-led growth model?

If the model still has room to run, investment can expand at mid- to high-single-digit rates (if not the double-digit pace of the past decade). At roughly half the economy, solid, if not spectacular, investment growth would underpin the 7% GDP growth contemplated by consensus. As a result, the investment share of GDP would dip only modestly. That's precisely the outcome contemplated in the IMF's outlook, wherein the investment share of GDP falls from 49% to 47% by 2018. In turn, this gradual decline in investment share would translate to a modest dip in electricity intensity.

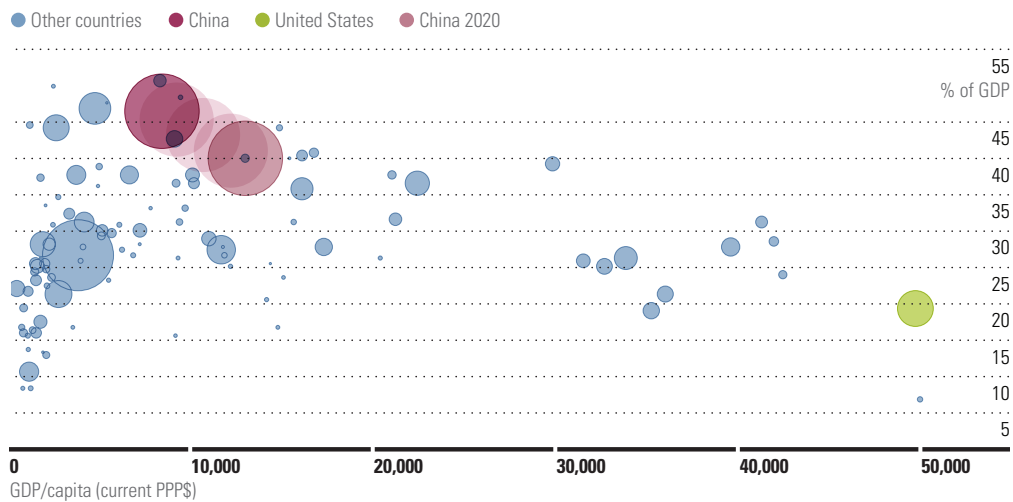
If, however, the model is exhausted, investment is likely to muster low-single-digit growth, which history suggests is the typical post-boom outcome.³ This would constitute a major drag on total GDP growth. Assuming consumption fails to accelerate but maintains the pace of the prior decade, GDP growth falls well below 7% as a matter of simple arithmetic. With comparatively electricity-light consumption growing at double the pace of electricity-heavy investment, the overall electricity intensity of GDP declines meaningfully. And even if consumption growth were to accelerate, it wouldn't matter much to overall electricity demand given the low base for household electricity use in China.

What will determine the sustainability of the investment-led growth model? Debt. In a world of diminishing returns, it is debt that ultimately defines the limits of the model. Returns tend to fall as low-hanging fruit are picked, which makes it harder to cover borrowing costs. And the investment-led growth model shakes loose a lot of fruit. In our view, China can't continue down the path of investing more and more, year in and year out, without suffering seriously diminishing returns and ultimately running into a debt crisis. In other words, China is likely to endure a major rebalancing one way or another.

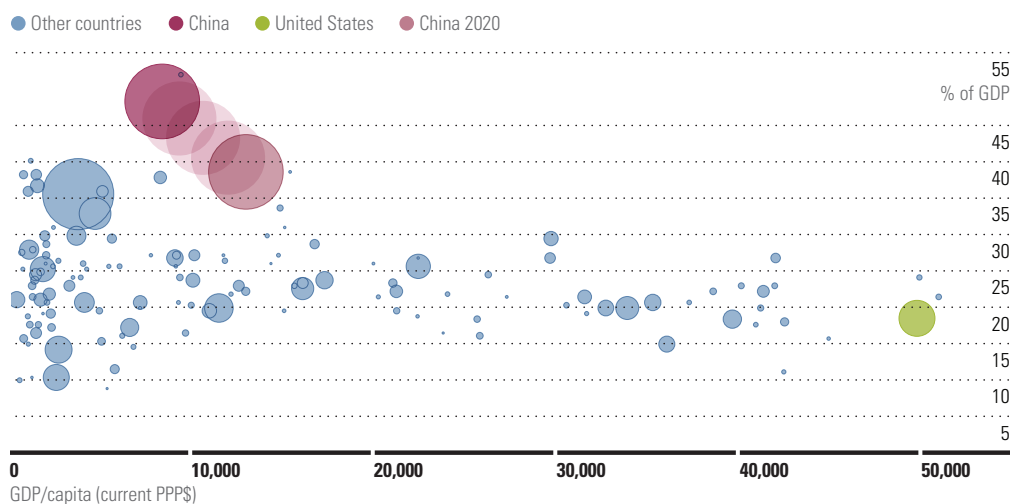
To contextualize some key assumptions behind our Major Rebalancing outlook, the following exhibits show the evolution of China's electricity intensity of GDP and GDP composition relative to other countries. In each case, while China remains somewhat of an outlier relative to its income level, it becomes less so in our forecast.

Exhibit 20 China's Electricity Intensity: Current Versus 2020

Source: IEA, World Bank, Morningstar
 Note: Bubble size denotes population.

Exhibit 21 China's Industry Share of GDP: Current Versus 2020

Source: World Bank, Morningstar
 Note: Bubble size denotes population.

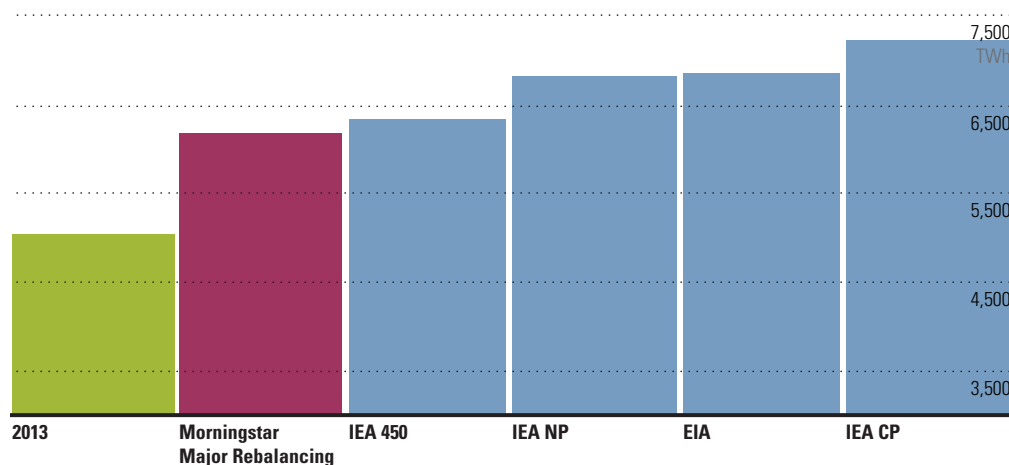
Exhibit 22 China's Investment Share of GDP: Current Versus 2020

Source: IEA, World Bank, Morningstar
 Note: Bubble size denotes population.

Our Major Rebalancing Electricity Demand Forecast Differs Sharply From Commonly Cited Long-Term Forecasts From EIA and IEA

Below, we compare our electricity use outlook for China versus forecasts from the U.S. Energy Information Administration and the International Energy Association. The IEA provides multiple scenarios to illustrate the impact of different energy and climate policies as well as technology deployment.

- 1) The IEA's Current Policies Scenario takes into account "only those policies and measures ... formally enacted as of mid-2013." The IEA notes that this scenario is "designed to provide a baseline picture ... if established trends in energy demand and supply continue unabated."
- 2) The IEA describes the New Policies Scenario as its "central scenario." Here, the agency models energy markets based on policies and measures formally enacted as well as less formal "commitments," which would include a variety programs to "support renewable energy and improve energy efficiency."
- 3) The IEA's 450 Scenario reflects aggressive policies necessary to "set the global energy sector on a course compatible with a near 50% chance of limiting the long-term increase in the average global temperature to two degrees Celsius." This would include carbon prices in all key markets, including China. Greenhouse gas concentration in this scenario would eventually stabilize around 450 parts per million, hence the name.

Exhibit 23 A Contrarian Outlook for China's Electricity Consumption

Source: IEA, EIA, Morningstar, China Electricity Council

Note: IEA and EIA provide forecasts for generation, but not consumption. These figures have been adjusted to consumption by assuming 6% transmission and distribution losses, in line with recent averages in China.

Our Major Rebalancing outlook for Chinese electricity demand is clearly contrarian. It results in 1,000 TWh less consumption than in the IEA's Current Policies Scenario, a gap equivalent to the size of Japan's entire electricity consumption. And it's 670 TWh less than the EIA's reference case and 660 TWh less than the New Policies Scenario.

Interestingly, our forecast is roughly in line with the IEA's 450 Scenario. But whereas the 450 scenario would require a major overhaul of China's regulatory regime, including imposition of a \$10 per metric ton CO₂ price for all sectors of the economy, economic rebalancing is sufficient to do the job in our forecast.

We suspect that the big gap between our base-case Major Rebalancing outlook and the principal EIA and IEA forecasts reflect our continued bearish macroeconomic views relative to consensus. While consensus expectations for China's economic growth have moderated over the past several years, most continue to expect what we regard as only a modest deceleration in Chinese GDP growth.

Similarly, while the notion of rebalancing continues to gain traction, few forecasts actually reflect what we consider real rebalancing to a more sustainable, less credit-dependent growth model. For example, the IMF's base-case forecast includes hardly any rebalancing at all: a mere 2 percentage point reduction in the investment share of GDP by 2018.

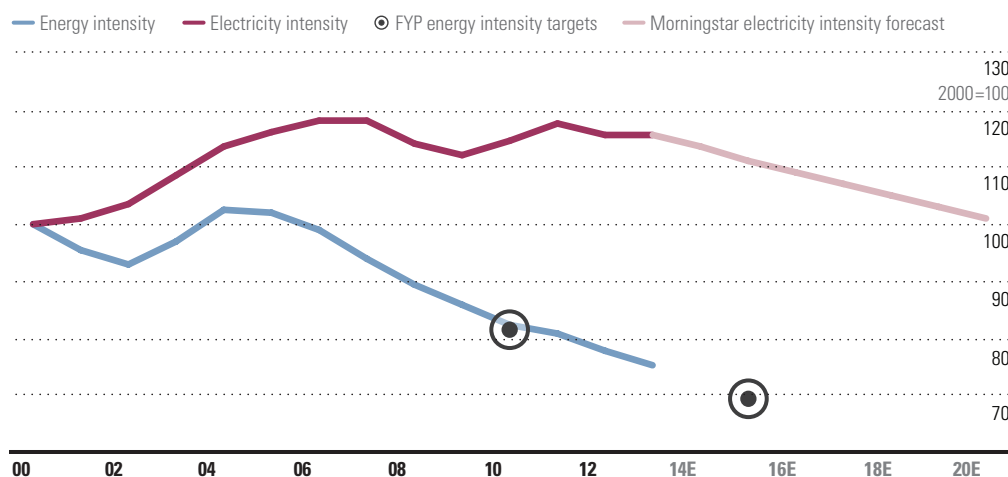
Our Outlook Aligns With Beijing's Broad Policy Objectives

While our electricity demand forecast is more bearish than consensus, our outlook for a 13% decline China's electricity intensity by 2020 aligns with Beijing's major policy objectives. Part and parcel of the government's broader aim to put the country on a more sustainable growth path is to reduce the energy intensity of the country's economic output. For example, the 12th Five-Year Plan, which covers 2011 to 2015, targets a 16% reduction in energy intensity.

Here, it's important to distinguish electricity intensity from energy intensity. Electricity intensity refers only to power consumption. Energy intensity, by contrast, includes all forms of energy, including coal (consumed in power generation or otherwise), oil (in vehicles or otherwise), natural gas (for heat or power), hydro, solar, and so on.

While one might assume that electricity intensity and energy intensity move in concert, that isn't always the case. Consider China's last decade: The energy intensity of GDP declined 18% from 2000 to 2010, but as discussed previously, electricity intensity rose 15%.

Exhibit 24 China Energy Intensity and Electricity Intensity



Source: National Bureau of Statistics, World Bank, Morningstar

What explains the apparent discrepancy? Oddly, it has been China's massive build-out of its coal-fired fleet that has done the trick. New plants were far more efficient than the old ones, consuming fewer tons of coal to generate the same amount of power. From 2000 to 2010, China's coal-fired generation increased 214%. Coal consumed by those plants increased significantly, too, but less so: about 140%.

This enabled China to essentially meet the energy intensity targets set forth in the 11th Five-Year Plan, which called for a 20% reduction in energy intensity from 2005 to 2010 (China achieved 19%). Meanwhile, electricity intensity declined a mere 1% over the same interval.

Looking ahead, there's diminished scope to reduce energy intensity further via coal plant technology improvements. That's because China's coal-fired fleet is among the world's most efficient, more so than the United States, for example.

Rather, if China is to meaningfully decrease the energy intensity of its economy, it will need to decrease the electricity intensity of its economy by a comparable amount. So while our forecast of a 13% reduction in China's electricity intensity through 2020 may appear aggressive, it is solidly in line with Beijing's objectives. ■■

1 China's agricultural sector accounts for about 10% of China's economic output. For rich countries like the U.S. and Japan, agriculture is about 1% of economic output. But China's agriculture share is fairly comparable for a country of its income level.

2 Issued October 2013 and updated January 2014. The IMF outlook includes year-by-year forecasts through 2018 for both GDP and the investment share of GDP, which we extend through 2020. See <http://www.imf.org/external/pubs/ft/weo/2013/02/weodata/index.aspx>.

3 See China's Rebalancing Act from August 2013.

Coal Demand: Growth Grinds to a Halt

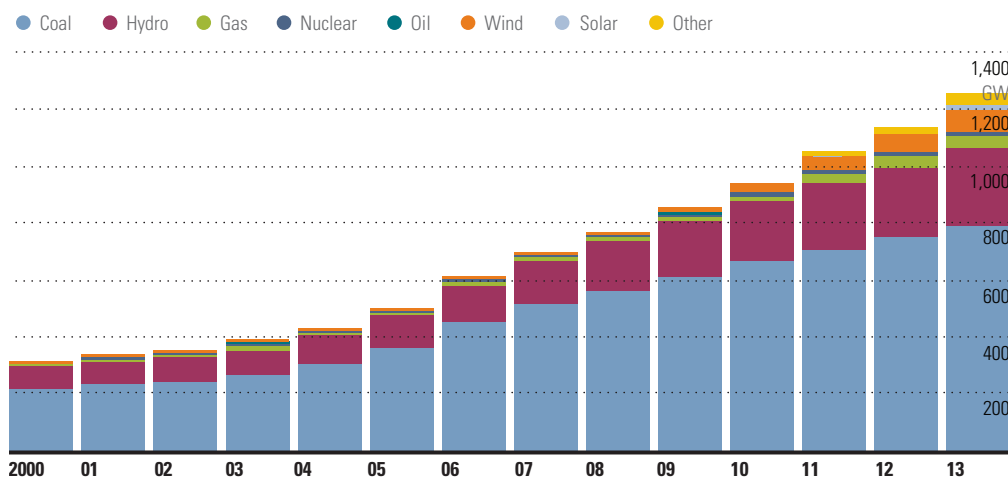
Daniel Rohr, CFA
Jennifer Song
David Wang
Zhao Hu
Stephen Simko, CFA

Coal Has Long Dominated China's Power Generation

China's power needs have soared during the past decade. Total electricity usage rose a cumulative 301% from 2000 to 2013, 11% annually. With domestic coal cheap and plentiful and coal-fired plants quick and easy to build, China turned largely to coal to meet this challenge. From 2000 to 2006, China's coal-fired fleet doubled in size from 226 gigawatts to 460. This added the equivalent of the European Union's entire coal fleet (about 200 GW) to installed capacity. China's coal-fired capacity doubled again by 2013 and now stands at 799 GW, nearly as large as the installed capacity of all other countries combined.

Other power sources also enjoyed strong growth since 2000. China's hydro capacity, for instance, expanded to 280 GW from 79 GW. Easily the world's top hydro producer, China's installed capacity equals that of the next three largest producers (Brazil, the United States, and Canada) combined. Wind capacity grew from a paltry 0.33 GW in 2000 to 75 GW in 2013. China now has the world's largest wind fleet, roughly equivalent to the installed capacities of wind-friendly Germany, Spain, the United Kingdom, Italy, and France combined.

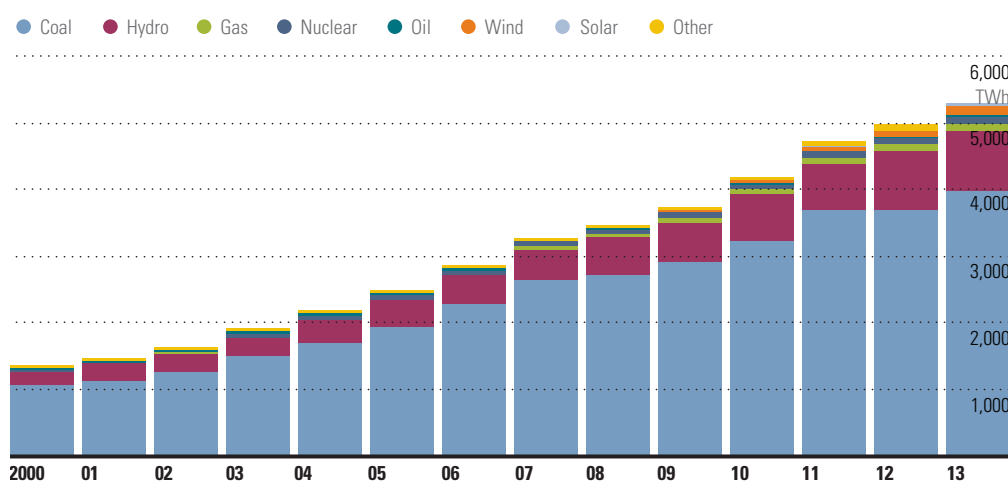
Exhibit 1 Power Generation Capacity by Source



Source: China Electricity Council, Morningstar

Capacity figures understate China's reliance on coal. In 2013, coal's contribution to China's overall power generation was a larger percentage than its share of the installed capacity. The electricity output of coal-fired power plants was 3,985 TWh in 2013, accounting for 74% of total electricity output, as shown in Exhibit 2. That was down from a 79% share in 2000. Most of the decline came in the past few years, with significant installation of new hydro and wind capacity.

Exhibit 2 Power Generation by Source



Source: China Electricity Council, Morningstar

Coal's share of generation exceeds its share of capacity because a significant portion of China's coal fleet meets the country's base-load power needs, running essentially all day, every day. Coal's low cost and good reliability make it well-suited to this role.

Spare coal-fired capacity can also be ramped up when needed, so in addition to its base-load role, China also deploys coal to meet seasonal and daily demand fluctuations. As in the U.S., China's electricity use spikes in the summer and winter months and so does the country's coal-fired generation. Used to meet base load and peak power needs, China's coal fleet has lower capacity utilization (56%) than in countries where it is used only for baseload power (typically 70% more more).

Low-cost and reliable nuclear also contributes base-load power, running all out except during refueling every 12 or 18 months. Utilization averages around 90%. However, nuclear presently accounts for a far smaller share of China's total capacity (1%) and generation (2%).

Other power sources are less amenable to base-load power use unless paired with some means of power storage. Hydro power accounts for 22% of China's power capacity and 17% of generation. Hydro power can be "stored" in reservoirs and behind dams. Hydro's shortcomings are its strong seasonality and variability attributable to rainfall and snowmelt. Utilization rates average 36% for hydro.

By contrast, wind and solar, while essentially zero-cost once installed, are intermittent power sources that depend on weather and the time of day. They have commensurately lower utilization rates (20% and 12%, respectively).

Coal's Dominance Will Wane as Pollution Concerns Have Shifted Political Priorities

Heavy reliance on coal has come with heavy environmental and health costs, which we address in greater detail in "Coal and the Environment." Government officials, who have long seen economic growth as a means of keeping the population satisfied and the Communist Party in power, are beginning to take a more nuanced view. This shift is encapsulated by a recent editorial in the *People's Daily*, an organ of the Party's Central Committee (President Xi Jinping is the committee's general secretary):

After 30 years of rapid development, the environmental issue is not only an economic problem or a social problem; it is also a political problem. The local economic development should not be only measured by GDP, financial growth, and residential income growth. If people can't breathe, what's the point of faster economic growth?
People's Daily, Nov. 13, 2013

To be sure, economic growth remains the Party's top policy priority. But it will no longer be pursued at all costs. In his work report to the National People's Congress in March, Premier Li Keqiang said the country would "declare war" on pollution, calling smog "nature's red-light warning against inefficient and blind development." Putting a point on Li's declaration, Xi said officials "who make blind decisions that cause serious consequences due to negligence towards the environment must be held responsible—lifetime responsibility."

Granted, we've heard similar promises from Chinese leaders before, but skies over China's major cities have only gotten worse. Importantly, though, repeated promises are beginning to coalesce into formal targets. And formal targets are being put into action, all of which point to a diminished role for coal in the next several years.

At the national level, the State Council (chaired by Li) in September 2013 issued a policy document that prioritized increasing "the supply of clean energy so that by 2017 coal consumption accounts for less than 65% of the total energy consumption." The document also ordered China's most densely populated regions along the coast (the areas around Beijing, Shanghai, and Guangzhou) to "strive to realize negative growth of the total coal consumption."

What would Beijing have to fill the gap left by coal, especially as China's power needs continue to rise? Everything else. Beijing isn't backing any particular horse. It's betting on the field: nuclear, solar, wind, and hydro. At present, the non-fossil-fuel share of China's total energy consumption stands at 9.8%, but the government is looking to raise it to 11.4% in 2015 and 15.0% in 2020. With vehicle ownership likely to rise and oil therefore likely to play a greater role in China's total energy picture, it's coal that's on the chopping block.

We've reproduced the government's specific capacity targets in Exhibit 3. Those for 2015 are from the 12th Five-Year Plan. Those for 2020 are from the State Council and the National Energy Administration, the top regulatory body for China's energy sector.

Exhibit 3 Reducing Reliance on Coal: China's Key Energy Targets

	Unit	2010	2013	2015	2020
Non-fossil-fuel energy as percentage of total primary energy	%	8.6	9.8	11.4	15.0
Installed power capacity:					
Coal	GW	660	797	960	n/a
Hydro	GW	220	280	290	420
Nuclear	GW	11	15	39	58
Natural gas	GW	26	39	56	75
Wind power	GW	31	75	100	200
Solar	GW	1	18	21	50

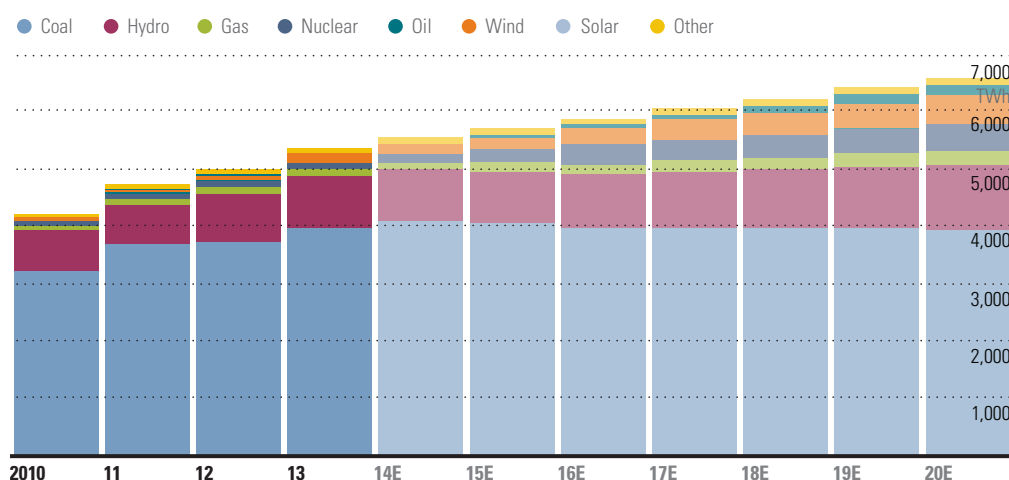
Source: 12th Five-Year Plan, National Energy Administration, State Council, Morningstar

Our Forecast for Coal-Fired Power Generation

As detailed in "Electricity Demand," we believe China's electricity consumption will rise to roughly 6,200 TWh by 2020 from about 5,000 TWh in 2013. Holding transmission and distribution losses steady at 6% of output, this implies an increase of power generation to about 6,600 TWh by 2020 from 5,400 TWh in 2013.

In our base-case outlook, coal's share of total generation slips materially, to about 60% in 2020 from 74% in 2013. The mechanism is straightforward: Once built, nuclear, hydro, wind, and solar are cheaper sources of power than coal. And China is building an enormous capacity of each.

Accordingly, we model demand for fossil-fuel-fired generation (coal, plus a modest amount of natural gas and an even smaller amount of oil) as residual after defining capacity and utilization assumptions for nuclear, hydro, wind, and solar. We see coal-fired generation topping out at roughly 4,000 TWh before entering a period of terminal decline.

Exhibit 4 Morningstar Power Generation Forecast to 2020

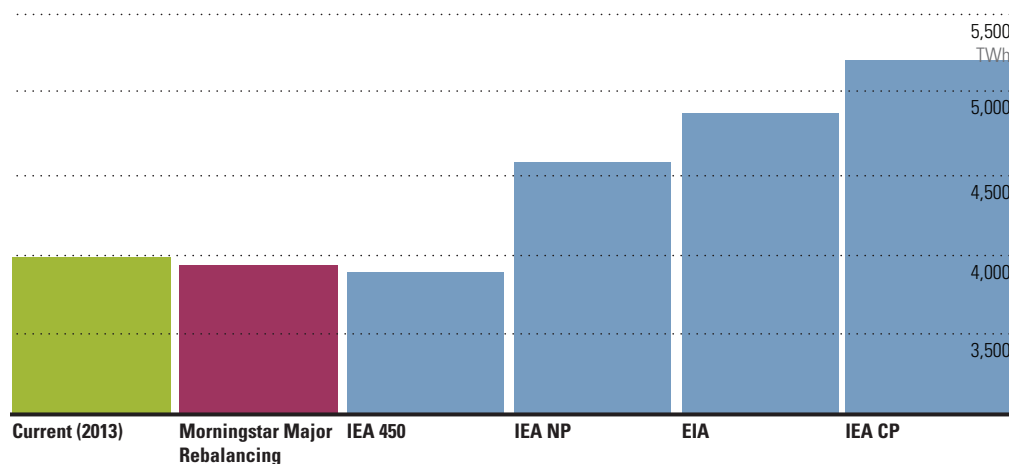
Source: China Electricity Council, Morningstar

How This Forecast Compares With Others

Prominent forecasts are more bullish on coal-fired generation growth in China. For example, the U.S. Energy Information Administration forecasts 4,887 TWh by 2020. The International Energy Agency's Current Policies Scenario, which forecasts business as usual with respect to emissions policy, sees China's coal-fired generation rising to 5,212 TWh by that time. The IEA's New Policies Scenario, which involves more stringent policies regarding CO2 emissions, pegs generation at 4,570 TWh in 2020, still well above our forecast. As discussed in "Electricity Demand," a comparably bullish macroeconomic outlook underpins these projections.

The IEA's 450 Scenario, which implements policies the agency believes are necessary to prevent a 2 degree Celsius rise in global temperatures, is much closer to our outlook. In this scenario, coal-fired output falls to 3,881 TWh by 2020, essentially in line with our forecast.

Exhibit 5 Prominent Forecasts Expect Coal-Fired Generation to Rise Strongly to 2020 Unless Strict Emissions Standards Are Put in Place



Source: China Electricity Council, IEA, EIA, Morningstar

Coal's Killers

China's power demand grows by 1,226 TWh to 2020 in our base case. That'd be equivalent to 567 million metric tons of coal at current power plant efficiency. Power sector coal use nonetheless falls 113 million metric tons by 2020 as China's "all of the above" strategy bears fruit and coal plant efficiency improves. Exhibit 6 shows how coal loses all its potential growth (and then some).

Exhibit 6 Coal's Killers

	2013		2020		Change	
	TWh	Share %	TWh	Share %	TWh	Coal equivalent (Mt)
Total power generation	5,357	100	6,583	100	1,226	567
Less:						
Nuclear	112	2	483	7	370	-171
Wind	144	3	488	7	344	-159
Hydro	888	17	1,142	17	254	-117
Solar	14	0	178	3	164	-76
Gas	117	2	224	3	107	-49
Other	92	2	126	2	34	-16
Oil	6	0	6	0	0	0
Coal plant efficiency	—	—	—	—	—	-91
Equals: Coal	3,985	74	3,937	60	-48	-113

Source: China Electricity Council, Morningstar

Nuclear power generation grows the most in our base case forecast, 370 TWh, lopping off 171 million metric tons of potential coal demand. Wind and hydro play significant roles too (159 million and 117 million metric tons), followed by solar (76 million metric tons). Natural gas generation growth is more limited. We detail our forecasts for nuclear, wind, hydro, solar, and natural gas on pages 39–54.

Finally, higher coal-plant efficiency eliminates 91 million metric tons of potential demand, wiping out the remainder of potential coal demand growth and leaving us with our 2020 power-sector coal-demand forecast of about 1.7 billion metric tons, down from 1.8 billion metric tons in 2013.

Coal Plant Efficiency Gains Likely to Continue, Though Slower

The average efficiency of China's coal-fired fleet (the amount of power generated per unit of coal consumed) has been rising for at least two decades, with the replacement of smaller, less efficient plants with larger, more efficient plants. From 2000 to 2013, average efficiency rose 18%. As discussed in "Electricity Demand", better average plant efficiency has been the main reason China was able to cut the energy intensity of GDP amid rising electricity intensity of GDP.

China continues to add massive and highly efficient coal plants to its fleet. The new Shanghai Waigaoqiao power plant has two 1 GW ultra-supercritical units with a coal consumption rate of 276 grams/kwh, equivalent to thermal efficiency of 44.5%. In theory, the plant is capable of achieving an efficiency of 46.5%, which would surpass Japan's new 600 megawatt Hirono plant, the current world record holder at a 45.2% thermal efficiency. Additions like Shanghai Waigaoqiao, along with further closures, should underpin additional reductions to the quantity of coal China requires to generate a given amount of electricity.

However, the scope for improvement today is far less than it was in 2000. Already, China's average coal-plant efficiency exceeds the OECD average and the U.S. average. And compared with 2000, small (less than 300 MW) and inefficient plants comprise a far smaller slice of total coal-fired capacity. Much of the remaining small plants are owned by nonutilities and used to generate power for onsite industrial needs. Closing these plants tends to be a far more protracted process. In our base-case outlook, we see the average coal-plant efficiency improving 5% by 2020.

A flattish nationwide demand outlook masks what we expect to be divergent regional demand trajectories. Specifically, the outlook for power-sector coal demand looks stronger in China's interior, where the bulk of new coal-fired capacity is slated to come on line. Much of this new capacity will generate power for coastal provinces, with transmission facilitated by a new network of ultra-high-voltage power lines set to come on line through 2020 (see Page 52).

Exhibit 7 Inland Provinces Dominate List of Planned Coal-Fired Capacity Additions

● 0–10 GW ● 11–20 GW ● 21–30 GW ● 31–50 GW ● 51+ GW



Source: World Resources Institute, Morningstar

Hydro: Runaway Growth Will Slow as the Government Reacts to Three Gorges Discontent

Chinese leaders have a long history of championing hydroelectric dams to harness the nation's powerful rivers. Hu Jintao, president from 2002-12, graduated with a degree in hydroelectric engineering from China's esteemed Tsinghua University. Former Premier Li Peng, another hydroelectric engineer, pushed through the passage of the Three Gorges Dam in the early 1990s against political opposition within the Party. The leadership's affinity for hydropower has led some to refer to this as China's "hydro-industrial complex."

Hydro is second only to coal in supplying electricity to China as of 2013. These dams are built to not only supply the country with electricity but to control flooding along China's powerful rivers. Among the various forms of renewable energy, hydroelectricity is the most mature and reliable. It does not rely on the wind to blow or the sun to shine. The biggest fluctuation recently occurred in 2011, when China experienced particularly low rainfall. Utilization fell 4 percentage points to 33%, which was a 10-year low. We believe that a normalized level is closer to 36%, equivalent to 2013 levels and the average for the past 30 years.

Exhibit 8 The Majority of China's Hydroelectric Dams Are in the Southwest



Source: Hydrochina

China enjoys the natural advantage of being immediately downstream from the Great Himalayan Watershed. As the glaciers of the Tibetan Plateau melt, water rushes down the Yangtze, Yellow, and Mekong rivers, where China has built a cascade of hydroelectric dams.

Many of the dams are located in Sichuan and Yunnan in the southwest. In order to connect them to the power demand centers in the southeast, such as Shanghai, Guangdong, and Zhejiang, China is constructing interprovincial ultra-high-voltage (UHV) transmission lines. We estimate that 31.1 GW of southwest-to-southeast UHV lines have already been constructed, and at least 17.5 GW of additional capacity should come on line by 2017. Altogether, we believe that the 48.6 GW of new UHV lines should be more than adequate to cover the 42.0 GW of additional hydro capacity that we expect to come on line by 2017.

The Chinese government aims to boost hydro capacity to 420 GW by 2020, 140 GW more than its already world-leading hydro capacity. At first glance, adding 140 GW of hydroelectric capacity might seem unattainable. After all, China has already dammed its rivers with record-setting infrastructure projects. The Three Gorges Dam is by far the world's largest power plant, at 22.5 GW, nearly double the capacity of the world's second-largest power plant and 10 times that of the U.S. Hoover Dam.

Despite the massive build out we've already seen, China still has half of its economically exploitable hydro resource left according to the World Energy Council. Even if China hits its 420 GW capacity target in 2020, the country would still have nearly a quarter of its hydropower resources remaining. That said, potential does not necessarily mean success.

Financing is a potential hurdle. Even though hydroelectric dams generate cheap electricity once they are constructed, they require high upfront costs. China's 12th Five-Year Plan (2011-15) targets funding of 127.7 billion CNY (about \$21.0 billion) in hydroelectric power, which is nearly as much as the 139.3 billion CNY (about \$22.8 billion) combined investment in nuclear and wind power. Since Five-Year Plans don't actually allocate funding from the central government budget, it might be difficult to obtain this massive amount of capital.

We think social and environmental concerns are the main obstacles to meeting the 420 GW target. Before the completion of the Three Gorges Dam, local officials built dams with impunity. The mandate to build dams is divided among China's state-owned power companies, with each controlling various regions. This fragmented system allowed builders to construct dams as they saw fit, and local governments viewed dams as a way to boost economic performance. Environmental impact studies were merely a formality, as many projects began construction before they even received final approval.

However, the construction of the Three Gorges Dam from 2003–12 brought the darker side of China's pride and joy to the public's attention. The project displaced more than 1.4 million people in 4,000 villages. Landslides and other geological incidents have increased 70% since 2010, as rising water levels in the reservoir accompanying the dam make surrounding land unstable. A study by the Chinese Academy of Social Sciences estimates that more than 100,000 acres of fertile farmland were flooded by the reservoir, such that it would take more than 370,000 additional acres of average farmland to replace the high-yield land that was lost. Critics also point out that silt collecting in the reservoir could threaten the stability of the dam.

These issues make China far more sensitive to the construction of new hydroelectric plants than before. The government has promised to crack down on developers who start construction before the completion of environmental impact studies. We are starting to see this increased stringency in capacity builds. Only 26.8 GW of new capacity was approved for construction from 2011–13, which is less than a quarter of the capacity that was originally scheduled. Controversial projects in the Nu River in Yunnan are unlikely to receive approval in the near term.

In the long run, we think that China will temper its high expectations for hydro. This is not to say that it will stop building dams, but rather that we expect China to take a far more deliberate and measured approach. As such, we expect that China will hit an installed capacity of 370 GW by 2020, missing the National Energy Administration's 2020 target of 420 GW.

Exhibit 9 China's Hydro Build-Out Will Continue, but at a Slower Pace Than NEA Had Targeted

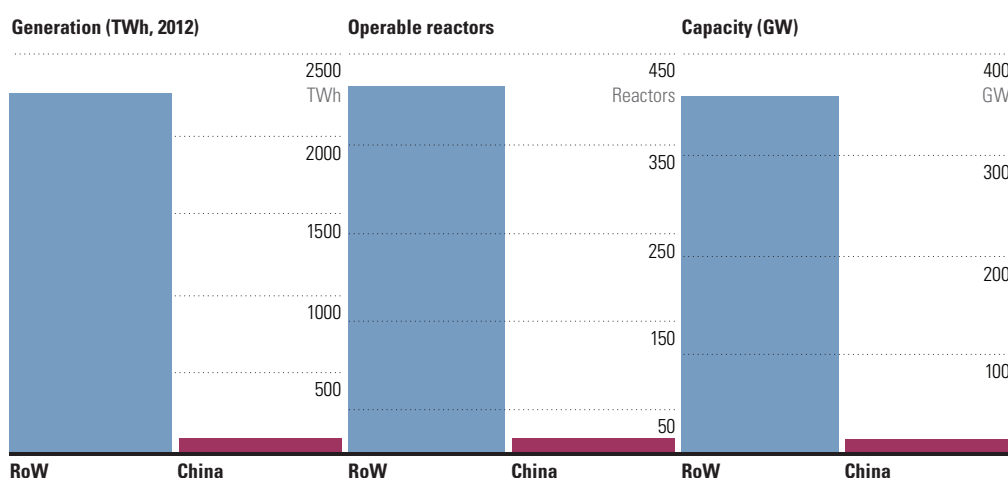
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014e	2015e	2016e	2017e	2018e	2019e	2020e
Generation (TWh)	379	417	464	559	588	690	668	856	888	891	907	940	990	1,041	1,091	1,142
Government capacity target (GW)	—	—	—	—	—	—	—	—	—	—	290	—	—	—	—	420
Capacity (GW)	115	130	145	172	197	213	233	249	280	285	290	306	322	338	354	370
Capacity adds (GW)	7	15	15	26	25	17	20	16	31	5	5	16	16	16	16	16
Utilization (%)	38	37	36	37	34	37	33	39	36	36	36	36	36	36	36	36

Source: China Electricity Council, State Council, 12th Five-Year Plan, Morningstar

Nuclear: The Leading Candidate to Fill Coal's Base-Load Role, Particularly Along the Coast

Relative to China's enormous power needs, its nuclear fleet is tiny, at 1% of the country's installed power capacity and 2% of output. China's nuclear capacity is less than 5% of the global total, with a fleet roughly the size of Canada's.

Exhibit 10 China's Nuclear Power in Context



Source: IEA, World Nuclear Association

China's prominence in the world of nuclear power is set to increase markedly in the coming decade. The project pipeline is fat. Having completed five new reactors in the past two years, China has 20 in operation as of March, representing 17 GW of capacity. At present, 28 are under construction, representing an additional 32 GW. Another 58 are in the planning phase (63 GW). Excluding any projects at an earlier phase, that's 106 reactors in total representing 112 GW. Put into context, the U.S. has the world's largest reactor fleet, with 100 units and 99 GW of capacity.

Only a portion of China's pipeline is likely to be realized through 2020. The most recent target laid out by the State Council is for "at least" 58 GW to be in operation by 2020 with an additional 30 GW in the construction phase by that time.

Based on our analysis of the project pipeline, we expect roughly 61 units, representing 64 GW, to be in operation by year-end 2020 (17 GW current plus 46 GW new), with 2014, 2015, and 2016 shaping up to be particularly big years for start-ups.

Exhibit 11 Nuclear Power Forecast

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014e	2015e	2016e	2017e	2018e	2019e	2020e
Generation (TWh)	54	55	63	69	71	75	87	98	112	147	242	326	362	391	436	483
Government capacity target (GW)	—	—	—	—	—	—	—	—	—	—	39	—	—	—	—	58
Capacity (GW)	7	7	9	9	9	11	13	13	14	23	38	45	47	52	59	64
Capacity adds (GW)	0	0	2	0	0	2	2	0	1	9	15	7	3	5	7	5
Utilization (%)	89	92	81	89	89	79	79	89	92	90	90	90	90	90	90	90

Source: World Nuclear Association, State Council, 12th Five-Year Plan, Morningstar

China's aggressive expansion plan is a direct consequence of nuclear power's unique role in Beijing's "all-of-the-above" strategy. Like hydro, wind, and solar, nuclear power addresses local concerns about air quality and global concerns about climate change. But in contrast to hydro, nuclear isn't site-dependent. And unlike solar or wind, it is an all-weather, 24-hour power source.

Nuclear power's key advantages over other alternatives to coal are its reliability and scale, making it particularly well-suited to filling the base-load role coal plays in China's power portfolio. Unaided by large-scale power-storage technology, wind and solar simply cannot fill this role.

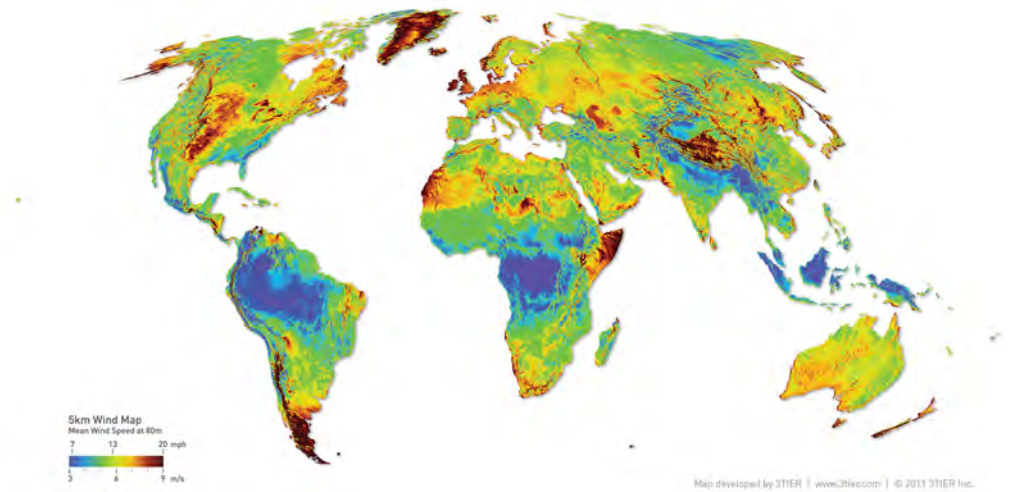
Nuclear power, of course, is not worry-free, as Japan's Fukushima disaster plainly demonstrated. The plant's failure in 2011 engendered circumspection among Chinese officials: The government halted approvals for new plants and undertook a full review of safety practices at existing and planned reactors. After a pause, Beijing affirmed its commitment to nuclear power, which indicates that officials remain more worried about the surety of coal's hazards than the possibility of a Fukushima-like event. Out of the review came a greater focus on safety and upgraded operating standards.

Concern over possible river pollution associated with a Fukushima-type accident have delayed the construction of any plants in China's interior until at least 2015. Our forecast includes no contribution from inland plants.

Wind: Capacity Will Blow Past Government Targets

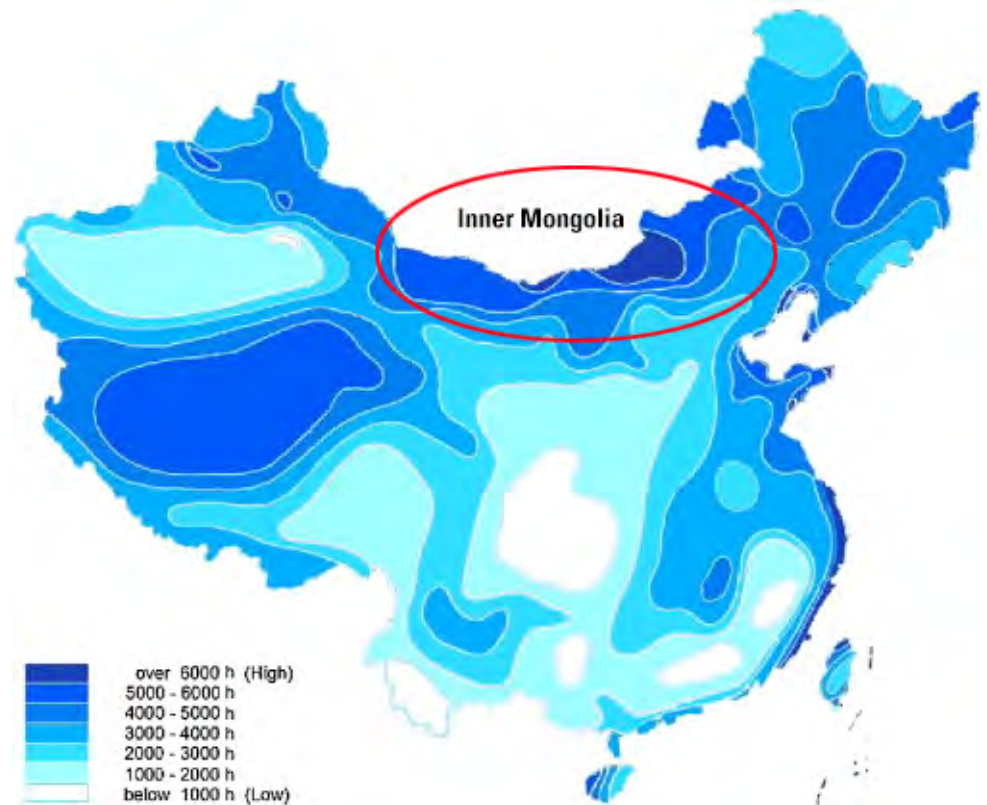
With a sweeping land mass and expansive coastline, China has exceptional wind resources by global standards. As the imperative to develop clean and renewable energy in China has grown, so has the country's installed capacity of wind power. The country has gone from being a negligible player in 2005 to surpassing the U.S. in 2010 and becoming the world's largest wind operator by capacity. Wind capacity at year-end 2013 was 75 GW, up from only 1 GW in 2005.

Exhibit 13 China's Wind Resources Rank Among the World's Best



Source: 3TIER

But because of geography and climate, wind farms tend to be concentrated in northern and western China, far from electricity consumption centers. Inner Mongolia has the greatest build-out at nearly 19 GW in 2012, or 25% of China's total wind capacity. Other top wind-generation provinces include Liaoning, Jilin, and Heilongjiang.

Exhibit 14 The Wind Blows Hardest in Inner Mongolia

Source: China Meteorological Administration Wind and Solar Energy Resources Assessment Centre

However, China's build-out of wind-power generation has far outstripped its inadequate investments in interprovincial transmission lines to carry this electricity to where it is actually used. This has led to curtailment in wind-generation provinces like Inner Mongolia, such that not all of the electricity being generated by the wind turbines is delivered to the end user. Curtailment ranges from 18% in Inner Mongolia to 33% in Liaoning. In aggregate, the IEA estimates that about 20 TWh, or 20% of generation, was not used by the grid in 2012, an improvement from the 25% in 2011.

Exhibit 15 Waiting for a Hookup

Province	Capacity (MW)	Grid-connected capacity (MW)	Grid-connected as % of total
Inner Mongolia	17,594	14,384	82
Hebei	6,970	5,552	80
Gansu	5,409	4,991	92
Liaoning	5,249	4,040	77

Source: Global Wind Energy Council

China is actively working on various ways to improve this low utilization rate.

First, China is building out a better system of transmission lines, including ultra-high-voltage lines. Much of this infrastructure development centers on connecting wind-rich, but sparsely populated, Inner Mongolia with major population centers to the south. The Ximeng (Inner Mongolia)-Nanjing (Jiangsu) alternating current line (9.4 GW) is planned to be complete by 2015-16. It has already received preliminary approval from the National Energy Administration and final approval from the National Development and Reform Commission, so construction should begin shortly. Concurrently, a western Inner Mongolia-Changsha (Hunan) alternating current line (10 GW) has received preliminary approval and is expected to be complete by 2015-16, as well. There are 37.7 GW of additional transmission capacity from Inner Mongolia that should come on line by 2017, bringing the total to 57.1 GW. We estimate that 44.4 GW will be allocated to wind, and the remainder to coal. Assuming that 40% of the additional wind capacity from 2014-17 will be constructed in Inner Mongolia, we think that the 33.5 GW of wind capacity constructed in the province will be more than covered by the transmission line expansions, even taking into account the province's current 3-4 GW of curtailed capacity.

Secondly, the latest batch of 27.6 GW of wind projects that were approved are slated to be constructed closer to population centers. Because of their proximity, these new projects require little in the way of transmission lines to bring the electricity to where it is ultimately used. Utilization may fall to 20 % in 2014 as the transmission lines are still being constructed. However, we believe that curtailment will be eliminated, with Chinese wind utilization rates inching up to discounted U.S. levels of 26% by 2017, as additional transmission capacity and generation build-out near the coast come on line.

We believe that wind-generation capacity will exceed government targets.

Historically, China has far underestimated its ability to build wind farms. In 2007, the government's plans for renewable energy development indicated that wind capacity would reach 30 GW by 2020. Instead, it reached that target in 2010.

Unlike hydropower, wind is not subject to major societal or environmental constraints, so the government feels no political pressure to restrain the push for this renewable energy.

The ramp-up time for wind farms is faster than that of nuclear or hydro. Wind will probably act as a bridge for electricity as large-scale nuclear and hydro plants are under construction. While it takes five to seven years to complete a nuclear plant and seven to nine years for a hydro plant, a wind farm can be completed in as little as two to six months.

The government plans to build 18 GW of wind generation in 2014 and 22 GW in 2015. These targets are ambitious, as the country has been adding capacity at the pace of about 15 GW per year since 2009 and only completed about 16 GW of its 18 GW 2013 target. However, we believe mounting pollution concerns are likely to motivate a major push to meet these capacity targets.

Compounded by the freedom to build wind farms without environmental constraints and the technology's ability to plug in generation gaps quickly, we believe that China can sustain an annual 22 GW pace after 2016. We believe China can reach 225 GW by 2020, exceeding its 200 GW target.

Exhibit 16 Wind Capacity Builds Should Exceed Government Targets

	2007	2008	2009	2010	2011	2012	2013	2014e	2015e	2016e	2017e	2018e	2019e	2020e
Generation (TWh)	6	13	27	50	74	103	144	148	201	288	338	388	438	488
Government capacity target (GW)	—	—	—	—	—	—	—	—	100	—	—	—	—	200
Capacity (GW)	5	9	16	31	46	61	75	93	115	137	159	181	203	225
Capacity adds (GW)	2	4	7	15	15	15	14	18	22	22	22	22	22	22
Utilization (%)	14	17	19	18	18	19	22	20	22	26	26	26	26	26

Source: China Electricity Council, State Council, 12th Five-Year Plan, Morningstar

Solar: Government Support in Place to Drive Material Growth

Solar power has more or less the same growth profile that wind power enjoyed a few years before it. In both cases, subsidies and increased government support led to huge growth that vaulted China to the top of global rankings in terms of annual installations. In 2010, 520 MW of solar was installed in the country, or less than 10% of the 7.7 GW installed that year by Germany, then the largest solar market. China at that point was not even among the five largest solar markets in the world.

But over just a couple of years, installation of solar has exploded in China, easily surpassing every other country in 2013 alone (more than 10 GW, according to initial estimates). This growth is completely attributable to the introduction of a variety of government subsidies, the most important of which from today onwards is a national feed-in-tariff that subsidizes solar electricity generation. Other subsidies have also been put in place, including billions of dollars to finance projects from the China Development Bank, 1.8 GW of distributed demonstration projects by the National Energy Bureau, and regional subsidies that can be used in addition to the national ones. It goes without saying that China is very serious about investing in solar power generation.

Market expectations for 2014 typically fall between 12–15 GW. We're projecting 12.5 GW. Given the material support solar is now being provided, we expect annual installations to reach 15 GW by 2015 and 20 GW for the rest of the decade.

Exhibit 17 Solar Power Forecast

	2011	2012	2013	2014e	2015e	2016e	2017e	2018e	2019e	2020e
Generation (TWh)	1	4	14	25	42	63	89	117	147	178
Government capacity target (GW)	—	—	—	—	21	—	—	—	—	50
Capacity (GW)	2	3	18	31	46	66	86	106	126	146
Capacity adds (GW)	n/a	1	15	13	15	20	20	20	20	20
Utilization (%)	3	12	9	12	13	13	14	14	15	15

Source: China Electricity Council, State Council, 12th Five-Year Plan, Morningstar

Natural Gas: Plenty of Potential, but Shale Revolution Unlikely in the Medium Term

With limited conventional natural gas reserves and very high natural gas prices—roughly three to four times higher than in the United States, coal-to-gas switching has struggled to gain traction in China. At 117 TWh in 2013, gas-fired electricity generation in China represented a mere 2% of total power output.

China relies on imports to meet 27% of its gas needs. Turkmenistan and Russia are the main overland suppliers. A mammoth project that would transport Turkmen gas 6,206 kilometers to Shanghai via Uzbekistan and Kazakhstan is scheduled to reach design capacity in 2015. Concurrently, China is building 20 liquefied natural gas terminals along the east coast to handle additional imports.

The shale gas bonanza enjoyed in the U.S. offers China the tantalizing prospect of reducing its reliance on natural gas imports in the medium term and possibly even its reliance on coal in the long term. According to a study by the EIA and Advanced Resources International, China's technically recoverable shale gas resource (1,115 tcf) ranks second only to the U.S. (1,161 tcf).

The government aims to tap that resource in a major way. The 12th Five-Year Plan calls for ramping shale gas production from 7 billion cubic feet in 2010 to 228 bcf by 2015 and 3.5 tcf by 2020. Putting the time frame in context, it took the U.S. almost two decades to accomplish that feat: from 200 bcf in 1990 to 3.5 tcf by 2009.

Should China achieve the 228 bcf target by 2015, roughly 16 million tons of coal could be displaced by shale gas, a tiny sum relative to the 2 billion metric tons used in coal-fired power generation. If the 2020 objective were achieved, the numbers become more meaningful. Assuming 100% of the shale gas is used to generate electricity, 3.5 tcf would generate 445 TWh of electricity, sufficient to displace 241 million metric tons of coal.

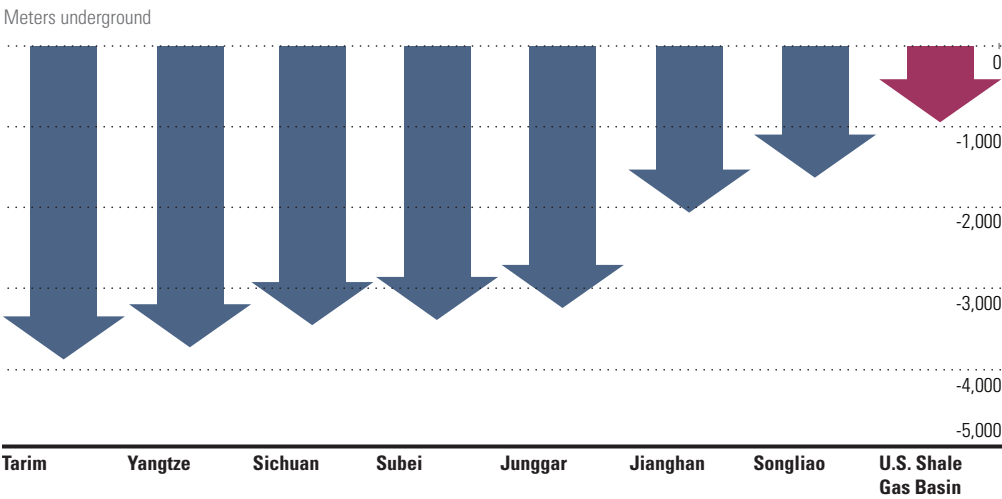
Despite impressive potential and government ambitions, we expect that geological difficulties and above-ground challenges stand in the way of China realizing a shale revolution. Our forecast calls for gas-fired power generation to roughly double, from 117 TWh to 224 TWh in 2020, fueled by a combination of imports and impressive, but below-target, shale gas production.

Of the nine shale gas basins in China, two large sedimentary basins, the Sichuan Basin in southwest China and Tarim Basin in the northwest, are believed to have the most potential. Unlike the U.S., where most of the shale formation is situated in plains, which made it easy for building infrastructure and drilling, the Sichuan and Tarim basins are in unfavorable terrain.

The Sichuan Basin is adjacent to the mountainous Tibetan Plateau, making it very difficult to build pipelines and scale up drilling activities. The Tarim Basin is in the middle of the Gobi Desert, where water scarcity would pose a problem for large-scale hydraulic fracturing.

Additionally, it is much harder to drill for the shale gas resources in China compared with the U.S. While one can find shale gas between 1,000 to 3,000 meters in most of the U.S., China’s shale gas pay zones are in much deeper underground formations, reaching on average 3,500 meters, according to EIA and Advanced Resources International’s research. Consequently, this adds to the difficulty and cost for large-scale shale gas production.

Exhibit 18 On Average, China’s Shale Gas Is Buried Much Deeper Than the U.S.



Source: EIA, Advanced Resources International, Morningstar

Judging from the experience of shale gas development in the U.S. and Canada, four above-ground factors play a key role: the right incentives, infrastructural readiness, technical know-how, and water availability. On each count, China faces considerable hurdles.

Exhibit 19 Shale Revolution Checklist

	China	U.S.
Development incentive	Government-backed monopolies are slow to take on comprehensive survey and drilling missions.	Private ownership encourages development and geological survey.
Technical know-how	Lack of experience working with less permeable clay formation.	Mature technology working with permeable rock.
Infrastructure readiness	40,000 km (gas pipeline).	488,000 km (gas pipeline).
Water scarcity	Key basins face severe water scarcity.	Less concern over water.

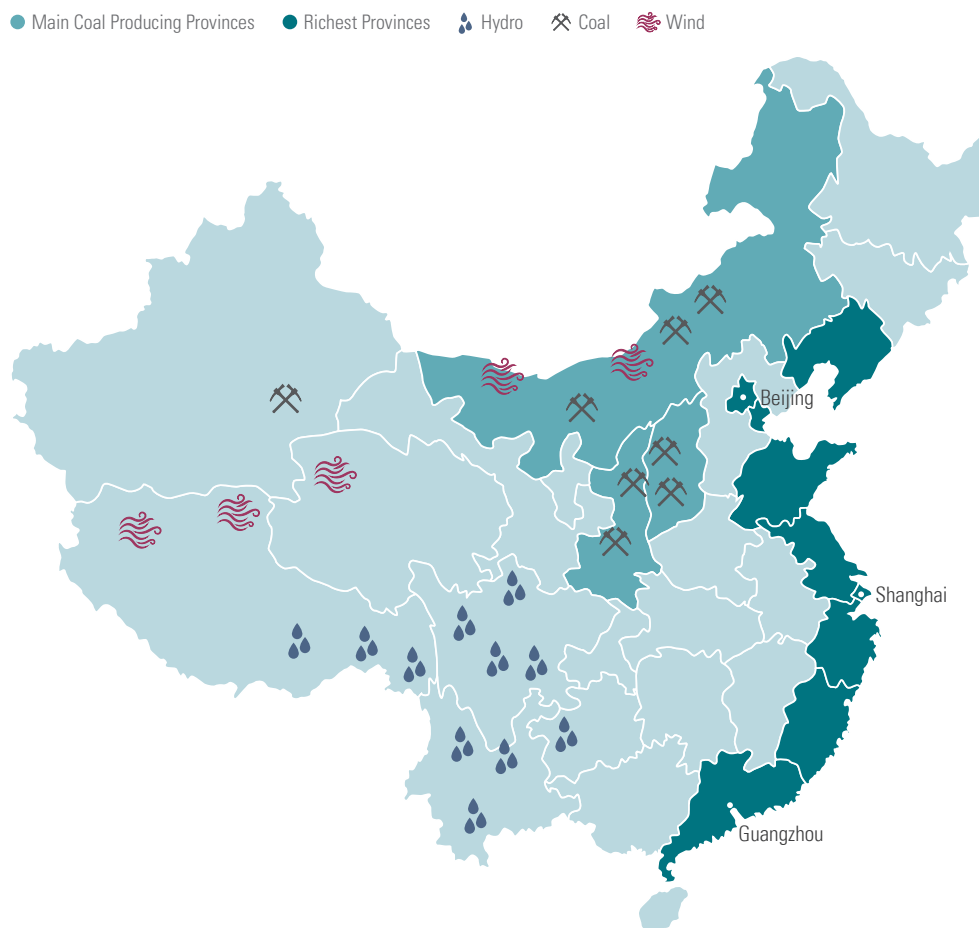
Source: EIA, Advanced Resources International, Morningstar

Ultra-High-Voltage Network Will Facilitate Ramp-Up of Hydro and Wind Generation

China's energy resources are characterized by highly uneven distribution. Coal production is mostly concentrated in the north and west, including Inner Mongolia, Shanxi, Shaanxi, and Xinjiang. Inner Mongolia is also home to enormous wind-power potential. China generates hydropower resources mainly in the southwest, from the many massive rivers that pour out of the Himalayas.

Meanwhile, China's economic center of gravity, as well as its power demand, is in the east along the coast. During 2013, China's most economically vibrant regions, the east, north, and south, accounted for about 18% of China's total land area, but accounted for 64% of GDP and consumed 63% of its electricity.

Exhibit 20 China's Energy Resources are Distant from its Demand Centers



Source: National Bureau of Statistics of China, Morningstar

Reducing China's overall reliance on coal requires linking inland hydro and wind resources to coastal centers of power demand. China is constructing a network of ultra-high-voltage electricity transmission lines that would do just that.

Two entities are handling this monumental undertaking: State Grid Corporation of China and China Southern Power Grid. State Grid operates China's power transmission system in most of the country and covers the majority of China's population. China Southern, as the name suggests, operates the power transmission system in the south, covering the provinces of Guangdong, Guangxi, Yunnan, Guizhou, and Hainan.

Exhibit 21 State Grid's Ultra-High-Voltage Plan



Source: State Grid Corporation of China

State Grid plans a network of three vertical and three horizontal ultra-high-voltage power lines (shown in Exhibit 21), which we expect will be completed by 2017. The three vertical lines would facilitate transmission of wind and coal-fired power generated near China's northern border with Mongolia south to its main population centers. The top two horizontal lines would transmit coal-fired power from coal-rich Shaanxi to the coast. The bottom east-west line would transmit hydro power from Sichuan all the way to Shanghai.

China Southern has its own ultra-high-voltage line ambitions. The plan articulated in September 2013 foresees construction of 8 AC and 8 DC lines, mainly aimed at connecting China's hydro resources in Yunnan and Guizhou provinces with the coastal province of Guangdong (home to Guangzhou and Shenzhen). These are to be completed by 2020.

By our estimates, UHV lines will connect approximately 240 GW of hydro and wind capacity to the coast. These UHV lines would displace 538 TWh of coal generation, reducing coal consumption by 236 million metric tons, which is about the size of China's 2013 imports.

Our Forecast for Nonpower Thermal Coal Use

Roughly 37% of China's thermal coal use occurs outside the power sector, a high share by most standards. In the U.S., for example, only 7% of thermal coal consumption is nonpower. The difference largely reflects China's unusually industry-oriented economy.

Exhibit 22 China Thermal Coal Consumption by End-Use, 2011

End-Use	Million tons	% of total
Electricity plants	1,755	63
Nonmetallic minerals (mainly cement)	240	9
Metals and mining	179	6
Heat plants	168	6
Residential	86	3
Chemicals	76	3
Other industrial	139	5
Miscellaneous	159	6
Total	2,801	100

Source: IEA, Morningstar

Minerals (mainly cement) and metals are the main industrial uses and account for roughly half of total demand outside power: 8% and 6% of total thermal coal use, respectively. As cement and metals production surged to meet the needs of China's stimulus-aided building boom over the past several years, associated growth in coal demand rose strongly as well.

We expect nonpower thermal coal demand to grow far slower in the years to come as China's real estate and infrastructure boom comes to an end and as the cement and metals industries continue to improve energy efficiency. Through 2020, we forecast average annual coal demand growth of 1% for cement and 2% for metals.

The outlook is somewhat stronger for chemicals and coal conversion, which presently account for a combined 3% of total thermal coal demand within China and depend less on the fortunes of real estate and infrastructure.

Coal has a long history as a raw material for the chemicals industry. Recently, ample coal reserves have prompted efforts to develop coal-to-gas (CTG), coal-to-liquids (CTL), and coal-to-chemicals (CTC) conversion technologies. The first commercial CTG production kicked off in coal-rich Inner Mongolia and Xinjiang provinces in 2013. China Coal Energy, China's second-largest coal miner, has made a foray into CTC. The company produced roughly 200,000 tons of methanol and 200,000 tons of urea from coal in 2013, although at a material loss.

With a better energy conversion ratio and economics than CTL, we expect CTG production will be the bigger driver for coal consumption in the medium term. Coal-to-gas projects also enjoy governmental backing. China's economic planning body, the National Development and Reform Commission, recently approved nearly 20 CTG projects, which should provide 1,235 to 1,412 billion cubic feet of gas. State-owned enterprises such as China Shenhua, Datang, and CNOOC all have construction underway. In December 2013, China's first CTG plant, designed to pipe roughly 140 bcf of natural gas per year to Beijing by the end of 2016, commenced production in Inner Mongolia.

At present, about 39 CTG projects are being planned, with a total 6.2 trillion cubic feet of natural gas capacity. Assuming that it takes roughly 0.087 tons of coal to generate 1,000 cubic feet of natural gas, it would take 530 million metric tons, or 7 times the chemical industry's current coal consumption, to produce the 6.2 tcf of planned capacity by 2020.

While NDRC approvals suggests the Chinese government is starting to look favorably on the technology, there are a number of headwinds to widespread adoption. For starters, building a massive fleet of water-intensive plants in northwestern China, an area that already faces severe water shortages, makes little sense.

In addition, despite having superior economics to CTL, CTG is and will probably remain more expensive than natural gas production in China. Therefore, without substantial subsidies to cover the extremely high capital cost (between \$3 billion and \$5 billion per CTG plant, with 140 bcf per year of designed capacity), the economics of the technology are difficult to sustain. Currently, only Sasol, a South African chemicals company, and the Great Plains Synfuels Plant in the U.S. manage to earn a profit from CTG or CTL.

In our opinion, coal-to-gas capacity and production growth are likely to be far more muted than suggested by the NDRC approvals or project pipeline. We project that coal use for chemicals and coal conversion is more likely to grow an average of 7.6% through 2020.

Lastly, we expect that the continued urbanization process and infrastructure buildout in rural areas will mean the continued decline of direct coal usage at home. In our forecast, we expect residential coal consumption to fall from 83 million metric tons in 2013 to 57 million metric tons by 2020.

All told, we forecast nonpower demand for thermal coal of 1.19 billion metric tons in 2020, up from 1.14 billion in 2013. ■■■

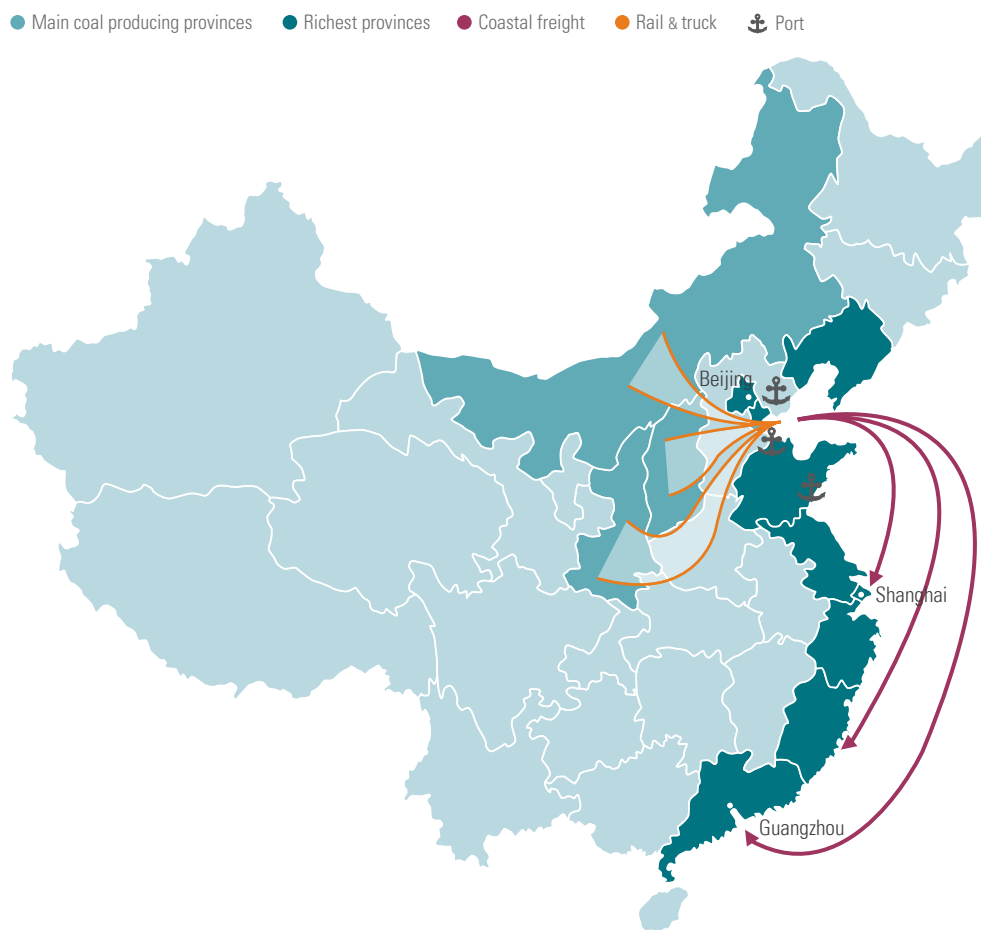
Coal Production: Railway Build-Out Unleashes Low-Cost Supply

Zhao Hu
Ralph Du, CFA
Daniel Rohr, CFA

China Possesses Abundant Coal Resources

China consumes more coal than any other country, but won't run out anytime soon. China has 180 billion tons of proven reserves (22% of the world's total and second behind the United States) and 5 trillion tons of resources. At annual production of roughly 4 billion tons, China has a 53-year reserve life and a millenium of resource life.

Exhibit 1 China's Coal Supplies Are Far From Its Main Electricity-Consuming Regions



Source: Morningstar

Geographic Separation of Supply and Demand Is a Defining Feature of China's Coal Market

The remoteness of China's abundant coal lies at the heart of China's coal supply challenges. China's comparatively isolated northwestern region accounts for a majority of reserves. About 70% of 2013 output originated from the inland provinces of Shaanxi, Shanxi, and Inner Mongolia: China's "Big Three" coal producers. China's economic center of gravity, as well as the bulk of its power demand, is on the east coast.

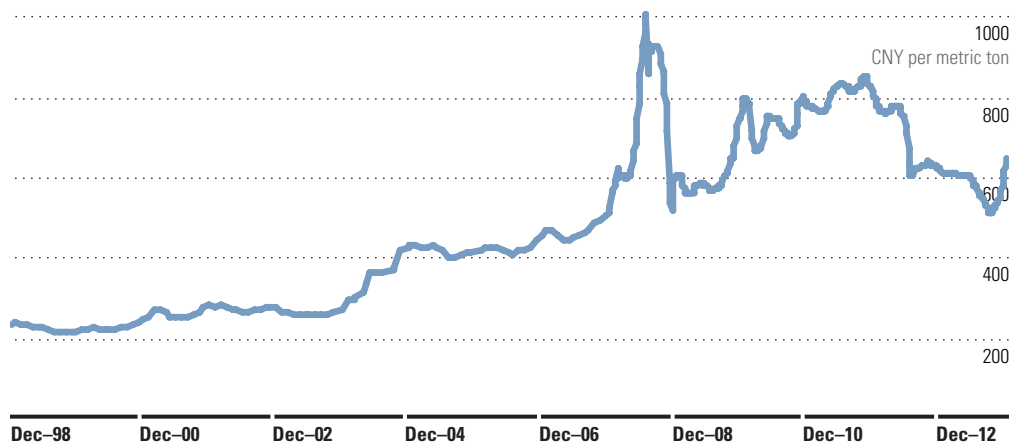
This mismatch—and the often vast distances between China's centers of production and its centers of consumption—define China's coal trade flows. China's major railway freight lines reflect these trade flows.

Insufficient Railway Capacity Has Been the Key Bottleneck

Rail capacity has struggled to keep pace with demand since the middle of the last decade. As a result, during peak demand seasons (summer and winter), coal has been forced onto highways, which costs 3-4 times more than rail and can add up to CNY 300 per metric ton (\$50) to the total delivered cost. Heady coal prices were a natural consequence.

Exhibit 2 Infrastructure Bottlenecks Have Underpinned Buoyant Prices

Benchmark China coal price: Qinhuangdao 5,500 kcal/kg



Source: SX Coal, Morningstar

The rail capacity problem has been particularly acute in Inner Mongolia, in part because there was so little infrastructure in the lightly populated region to begin with. From 2000 to 2012, Inner Mongolia coal production rose tenfold to over 1 billion metric tons. The region saw its share of China's total production rise from just 5% to 27% over this interval. The growth far exceeded the expectation of government planners. Inadequate railways meant 200 million metric tons left the province by highway in 2011, roughly equivalent to China's total import volume that year.

Infrastructure availability has been somewhat better in Shanxi and Shaanxi, where more modest sums have had to be transported by highway. Still, bottlenecks exist. For example, because Shenhua's Shenshuo and Shuohuang railways always give priority to the company's own mines, non-Shenhua mines have found capacity harder to come by.

Debottlenecking Is in the Works

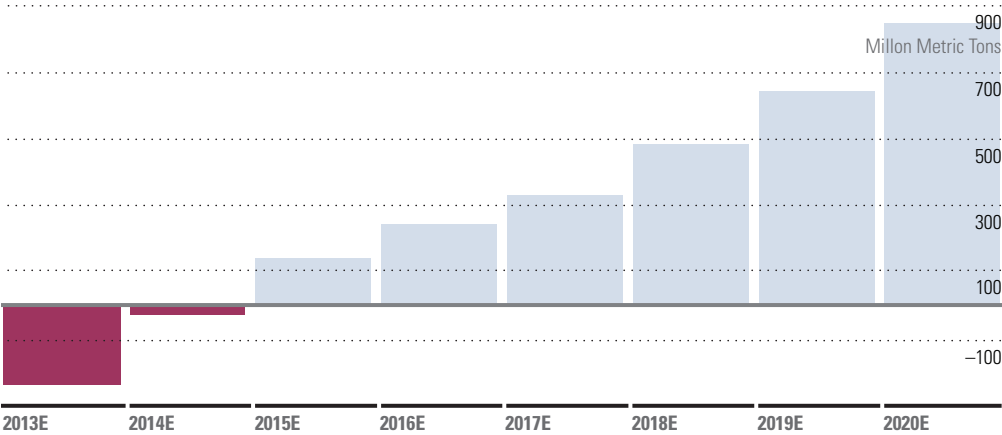
A major, multiyear railway investment program is underway to address the coal infrastructure shortfall. The undertaking promises to transform the domestic supply situation, as distance will be a less decisive factor in the competitive landscape.

Considerable rail capacity has been added over the past year, resulting in lower freight costs and helping to take some steam out of coal prices. Further capacity will enter service in the next several years. In our demand forecast, China would swing from infrastructure deficit to infrastructure surplus by 2015.

Much of the new rail capacity will serve Inner Mongolian mines. The Mengji line will add capacity connecting Inner Mongolia to Caofeidian port near Beijing, from which point coal can be shipped south to China's major cities along the coast. The Menghua line out of Inner Mongolia will head south to central provinces such as Hubei and Hunan. Together, these projects would add 300 million metric tons of annual capacity by 2017 and reach 400 million metric tons by 2020. That's equivalent to nearly half of Inner Mongolia's total production in 2013.

New rail capacity will also be added in Shanxi and Shaanxi. For example, the Central South Shanxi Coal Freight Channel, expected to be operational by late 2014, will add 200 million tons per year of transport capacity. This channel shortens the transport distance from mine to port by more than 1,000 kilometers, as coal produced in central and south Shanxi can be shipped via Rizhao instead of Bohai rim ports like Caofeidian.

Exhibit 3 Railway Capacity: From Deficit to Surplus
Railway capacity less production available for interprovincial trade



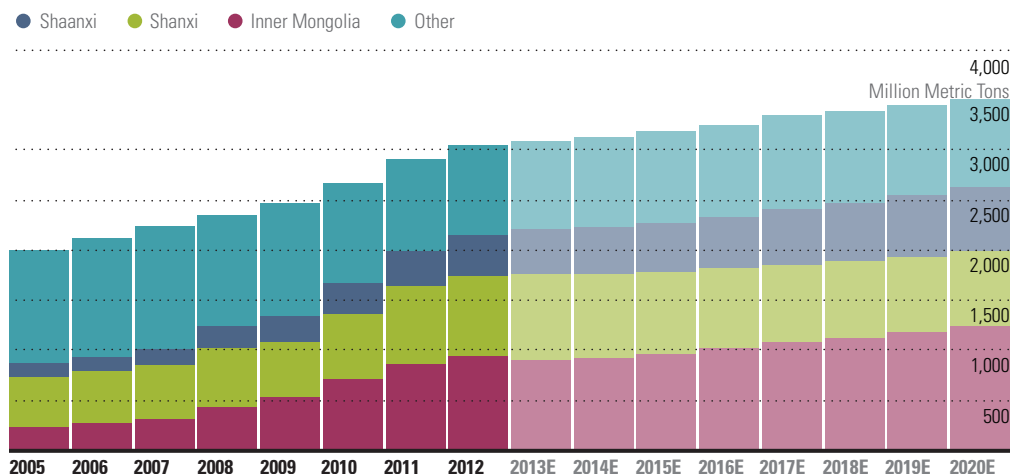
Source: Ministry of Transport, Morningstar

Port capacity should remain ample. We estimate that 520-570 million tons per year of port capacity will come on line between 2012 and 2016, adding to the more than 600 million tons per year of existing capacity for northern ports. Once the new railways linking mine and port are added, significant new volumes could to be shipped to China’s coal-poor southern coast. Nearby export destinations, such as Korea and Japan are also a possibility.

Domestic Supply Forecast: The Continued Rise of Inner Mongolia

China’s thermal coal production rises to 3.5 billion metric tons by 2020 from 3.1 billion in 2013 (2% annually) in our base case, constrained by tepid demand rather than any production or infrastructure shortcomings. All of the production growth comes from the generally larger and lower-cost mines in China’s northwest (mainly Inner Mongolia and Shaanxi). Production from older, higher-cost mines falls significantly.

Exhibit 4 Big Three Will Continue to Dominate Production, Inner Mongolia Will Tighten Its Grip on the Top Spot
Thermal coal production by province



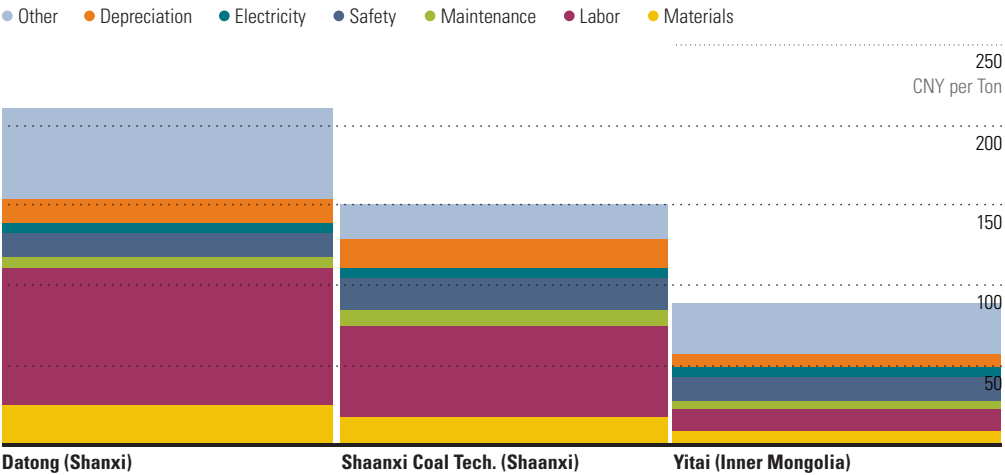
Source: SX Coal, NBS, IEA, Morningstar

Inner Mongolia gains the most. In our base case demand forecast, Inner Mongolia's production rises to 1.3 billion metric tons in 2020 (36% share of China's coal production) from 0.9 billion in 2013 (30% share), cementing its position as China's largest coal producing region.

As new rail capacity absorbs the remaining trucked volumes, marginal costs for Inner Mongolian production fall by about CNY 150 per ton (\$25) from 2013 levels. Improved infrastructure lays bare Inner Mongolia's basic advantage: it's simply easier and cheaper to mine coal there. Shallow deposits allow for open-pit mining and Inner Mongolia boasts the highest mine mechanization rate (80%).

Exhibit 5 illustrates Inner Mongolia's fundamental edge. We compare Yitai, a fairly typical Inner Mongolian coal miner, with representative producers in Shanxi (Datong Coal Co.) and Shaanxi (Shaanxi Coal Tech). Yitai's mining costs are CNY 120 (\$20) lower than Datong Coal's and CNY 60 (\$10) lower than Shaanxi Coal Tech's.

Exhibit 5 Coal Mines in Inner Mongolia Are Generally Lower Cost Than Shanxi or Shaanxi



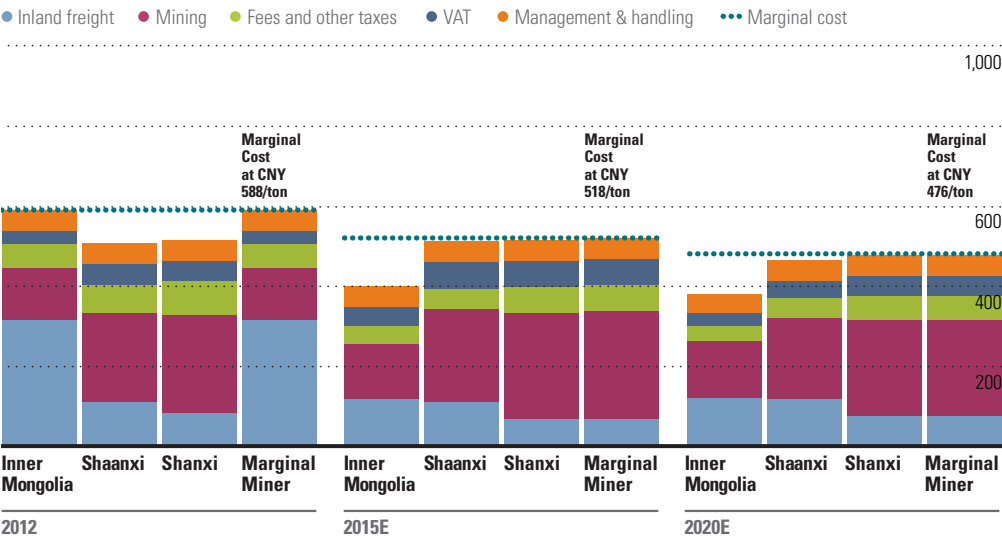
Source: Company filings

Coal Price Forecast

Growing low-cost Inner Mongolian supply displaces a significant quantity of existing higher-cost production in our base-case forecast. Much of this comes out of Shandong and other coastal provinces, where mine depths are rapidly approaching uneconomic levels. When Inner Mongolia was poorly connected to coastal demand centers, these mines were viable. Better rail capacity and a build-out of ultra-high-voltage lines change the competitive landscape, rendering older, higher-cost mines obsolete.

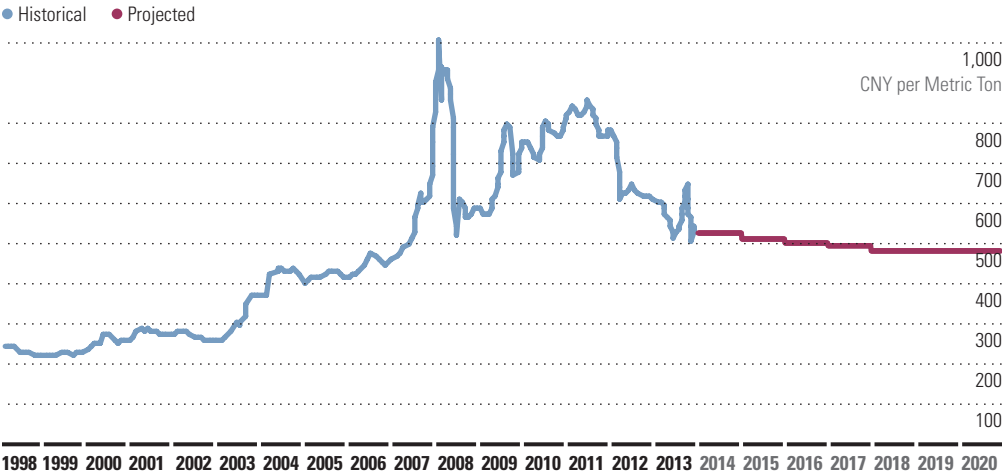
The marginal cost of coal delivered to the major ports near Beijing (starting point for China’s coastal trade) falls to roughly CNY 475 by 2018 (real terms) as this process unfolds. Exhibit 6 illustrates, focusing on production from the Big Three, which dominate the coastal trade. Back in 2012, the highest-cost mines in Inner Mongolia defined the upper bound of the cost curve at around CNY 600, largely because of the expense of trucking coal long distances. Once fully integrated into China’s freight network, delivered costs for Inner Mongolia’s highest-cost mines fall materially. The highest-cost producers in Shaanxi and Shanxi are the new marginal producers for the coastal trade. As large mines within the Big Three continue to ramp up, production displacement continues in Shaanxi and Shanxi, exerting further pressure on prices, which fall to CNY 480 (real terms) for benchmark 5,500 kg/kcal coal delivered Qinhuangdao by 2018.

Exhibit 6 Falling Freight Costs Will Push Marginal Costs Lower



Source: Company filings, Morningstar

Exhibit 7 Better Infrastructure + Tepid Demand = Weak Coal Prices



Source: SX Coal, Morningstar
Note: Forecast in constant CNY.

Flatter Cost Curve and Spare Production Capacity Will Limit Price Rallies

Stronger-than-expected economic growth and commensurately higher coal demand represent the main risks to our coal price forecast. But the flattening of the cost curve enabled by better infrastructure means the price implications of a more bullish demand trajectory would be fairly muted.

Assuming, for example, 4.3 billion metric tons of thermal coal demand by 2020 (versus our 3.3 billion base case), we estimate a long-term price of CNY 540 per metric ton (real terms) would be sufficient to clear the market, only 12.5% higher than the long-term price of CNY 480 we forecast in our base-case demand outlook. ■■■

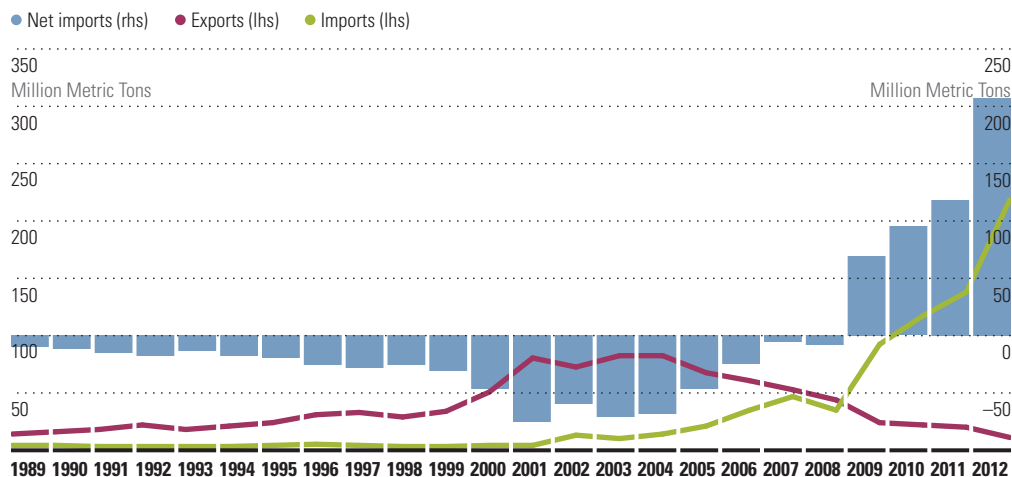
Coal Imports: Diminishing Needs

David Wang

Since Becoming a Net Importer, China Has Been Instrumental in Driving Global Seaborne Coal Demand

Long the world's largest coal producer, China has historically had little need for imported supplies. But demand growth and infrastructure constraints in the past several years made seaborne imports competitive in China for the first time in 2009. Not long after, the world's largest coal producer became, counterintuitively, the world's largest coal importer as well.

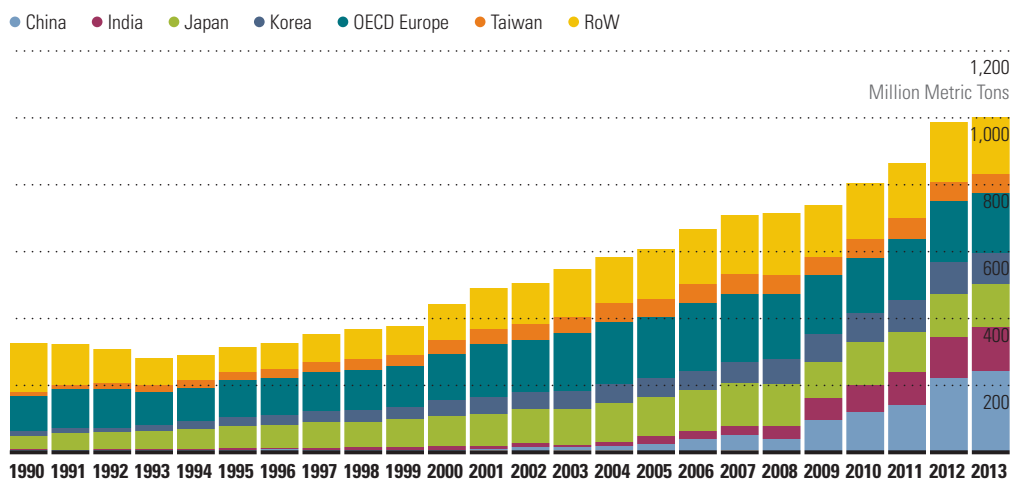
Exhibit 1 Tectonic Shift: China Swung From Net Exporter to Net Importer in 2009



Source: IEA, Morningstar.

Since 2009, China has accounted for about 70% of the world's incremental growth of imported coal. In 2012, China imported 218 million tons of coal, which was the most that any country has ever imported and about the amount of the next two largest coal-importing countries, Japan and South Korea, combined. That China was able to swing so quickly from net exports to net imports underscores the versatility of its coal-fired power plants to use a blend of foreign and domestic coal.

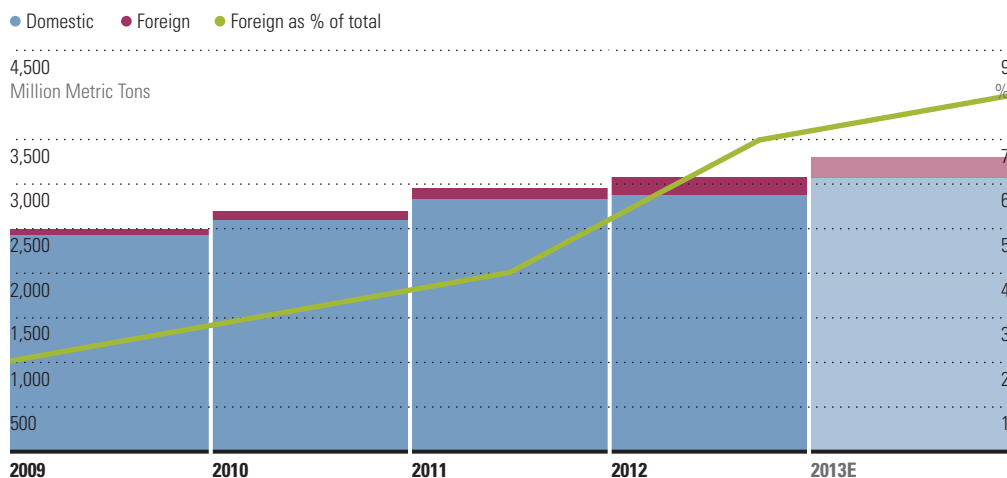
Exhibit 2 China Has Accounted for the Majority of Growth in the Seaborne Market
Seaborne Thermal Coal Imports by Country



Source: IEA, Morningstar.

While China's emergence as a net importer has had huge global ramifications, China continues to rely mainly on domestic coal. The import share of China's consumption has ticked up since 2009, though it still made up only 7% of its total consumption by 2012. In 2013, we estimate that imports ran at 243 million metric tons, up 11% from the previous year. Although the import growth rate decelerated from an incredible 60% in 2012, it still grew faster than the 7.3% demand growth rate, implying that imports continued to take share from domestic producers in 2013.

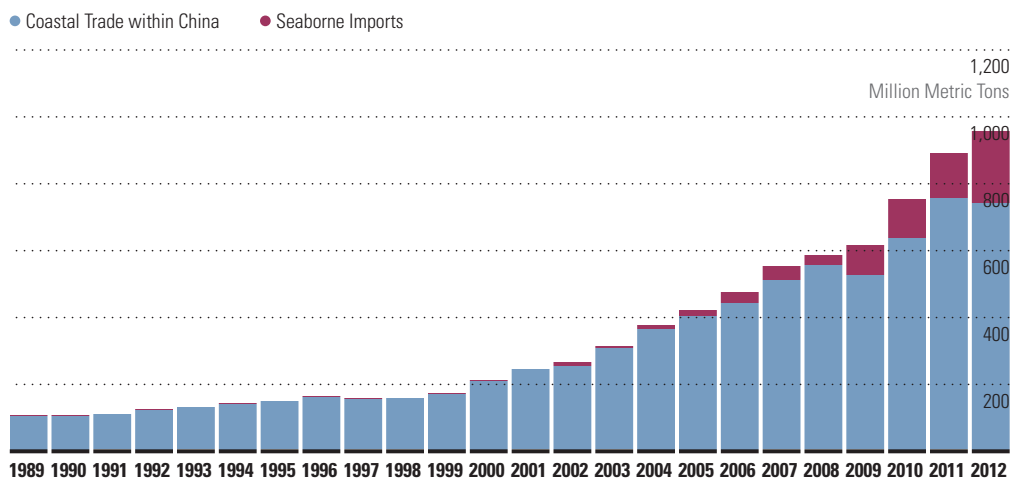
Exhibit 3 China's Domestic Coal Market Dominates Consumption, Though It Has Gradually Lost Share to Imports



Source: IEA, Morningstar.

Chinese coal consumption dwarfs the global seaborne market several times over. Even China's domestic seaborne trade along its coast is larger than its imports. In 2012, seaborne trade from the coal-rich north to the south totaled 743 million metric tons compared with just 218 million metric tons of foreign imports.

Exhibit 4 Even China's Coastal Trade Is Larger Than Its Seaborne Imports



Source: IEA, NBS

Even the World's Biggest Producer Will Import if Seaborne Coal Is Cost-Competitive

Blessed with ample domestic coal reserves, as discussed in "Coal Production," it's a bit counter-intuitive that China needs to import meaningful volumes of coal at all. China's import requirement is largely a function of enormous coal demand growth in recent years, which made China's coastal province demand up for grabs, pitting high-cost domestic coal miners against foreign miners.

Because China's domestic demand for coal had outgrown its rail infrastructure, miners had to truck growing amounts of coal from inland Inner Mongolia to Qinhuangdao port. Moving coal by truck is far more expensive than by rail, \$0.40 per ton-mile compared with \$0.09. After that, coal was shipped south by sea to Zhejiang, Guangdong, and other populous coastal provinces.

Foreign coal found it fairly easy to win share against the bottlenecked competition. Depressed dry-bulk shipping rates provided an additional catalyst. In the wake of the global financial crisis, shipping rates in 2009 collapsed nearly 60% from highs of \$95,000 per day for capesize vessels to \$39,000 per day after a massive oversupply of vessels flooded the market and global shipping demand fell. That same year, Chinese imports surged over 150% and have continued growing ever since as dry-bulk shipping rates have remained below \$20,000 per day.