August 27, 2008

The Coal Sector

Turning Up the Heat

Paradise Coal-fired Plant, Western Kentucky

The Coal market has never been more attractive. The price of coal, a major input in the production of electricity and steel, has more than doubled since early 2008, pushing earnings and stock prices of coal producers to record highs.

Global electricity and steel demand are key drivers of coal prices. Coal has relative energy value and tends to track global energy markets. Rising oil and natural gas prices are favorable to coal prices as consumers switch to cheaper coal as an alternative energy source.

Global coal supply shortages are likely here to stay due to infrastructure bottlenecks - the inability to expand rail networks and port facilities to keep pace with unprecedented global demand for thermal and metallurgical coal. The coal market will likely remain tight for years suggesting coal prices could remain strong. However, a global slowdown or pull back in global energy markets could negatively impact coal prices.

Continued growth of fossil fuel consumption puts upward pressure on global CO_2 emissions. Environmental concerns cannot preclude the world's need for coal - although its continued use will likely progress towards cleaner and more efficient processes.

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EXECUTIVE SUMMARY

Coal has and will continue to be the key fuel in electrifying the world. The fundamentals remain strong with increasing global demand for electricity and steel, supporting both thermal and metallurgical coal prices. Supply shortages started to move global coal prices; floods in Australia, snow storms in China and power outages in South Africa, led to disruptions. As a result, we have witnessed a remarkable upswing in coal prices since the beginning of the year.

Dundee Securities is initiating coverage of the coal sector. In this report, we discuss coal supply and demand, and influencing factors such as transportation costs, efficiency factors and emission allowances as the key drivers for the industry. We introduce you to Dundee's economic model to provide insight on an energy unit (BTU) spread differential between coal and natural gas and how it impacts their respective prices.

Coal continues to be a dominant player in the world's energy mix

Coal accounts for 25% of global primary energy consumption, while oil and natural gas account for 35% and 21%, respectively. Coal is the most abundant fossil fuel with over 847 billion tonnes of proven coal reserves worldwide, enough to last for more than 130 years. It has emerged as the world's fastest growing fuel in part because reserves are located in key consuming countries and it has been cost competitive compared to other fuel sources.

Coal production is growing, but demand is growing faster

World coal production grew by 3.3% last year to 6.4 billion tonnes; however, world consumption grew by 4.5% last year to 6.3 billion tonnes. Coal has been the fastest growing fuel for five consecutive years, driven by Chinese consumption that has accounted for more than two thirds of total growth. China reportedly added over 90 Giga-watts of new coal-fired power plant capacity in 2006 alone – the equivalent of nearly two large coal power plants a week, and more than the existing portfolio of coal generating plants in the United Kingdom.

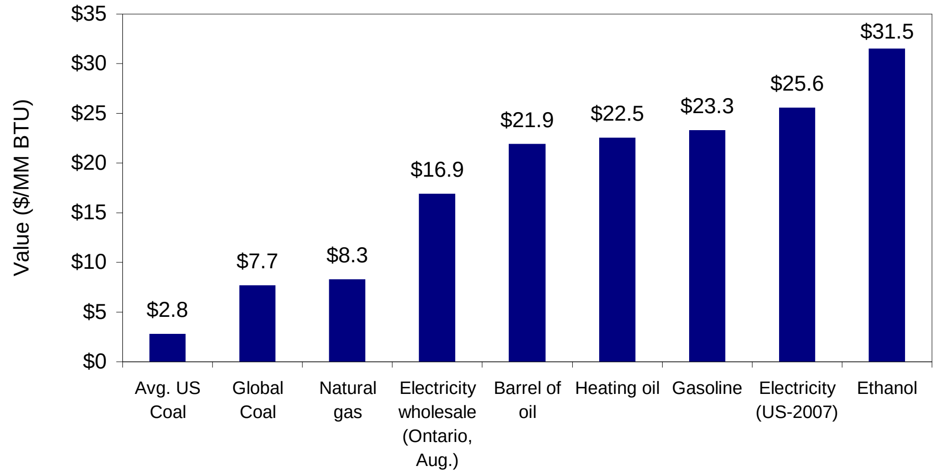
Per capita electricity consumption is relatively low in developing countries

Electricity consumption on a per capita basis differs significantly from developed to developing countries. Electricity consumption typically tracks GDP growth. As lifestyles and incomes in developing nations rise, per capita electricity demand tends to expand rapidly. The Indian economy; however, has been growing at twice the rate of the growth of electrical supply. We expect India to require significant additional capacity in the near term.

Thermal coal remains the cheaper option

Thermal coal accounts for about three quarters of all coal production and is the most widely used source of fuel for the generation of electrical power. Natural gas competes with coal for its share of electricity production. However, given the choice, utilities often build plants that use the cheapest source of fuel. As natural gas prices rise, utilities have more incentive to build coal plants. In energy terms, coal remains the cheapest form of fuel (Figure 1). Although the global coal and natural gas price gap has narrowed, American coal remains much cheaper. Transportation costs, emission allowances and energy efficiency factors account for the constant gap between coal and natural gas prices. Any further gap beyond this would create an opportunity for utilities to switch fuels.

Figure 1: Relative Value of Energy Commodities



Sources: Bloomberg, Energy Information Administration, Independent Electricity System Operator, Dundee Securities

Effect of seasonality on coal stocks

Coal consumption seasonality results in a clear signal for investment in coal stocks. Weather affects seasonal demand for electricity, and hence, coal consumption. This seasonal demand for coal will directly impact revenue of coal producers. The change in share price of the Dow Jones US coal index in highly correlated to the seasonal change in the stockpiles of the coal-fired plants. Historically, share prices of US coal producers have generally peaked in May and November, with July being the weakest month for returns on share. This suggests that short term investors should consider buying coal company shares in February, selling them in June, buying them back in September, and selling in December.

Dwindling stockpiles cause concern

Utilities are carrying lower than average coal inventories, largely as a result of supply shortages. In some areas the situation looks bleak and has become a cause for concern for some utilities. It appears that the coal market could remain in tight balance for some time and further shortages will be positive for coal prices as utilities begin to source coal for short-term delivery from non-traditional suppliers.

Metallurgical coal demand is growing due to a rapidly expanding steel industry

Metallurgical coal is used in the manufacture of iron and steel and accounts for approximately 11% of all coal production. Consumption reached 706 million tonnes in 2006. Demand has risen 58% over the past seven years alone, driven largely by steel consumption in China and India. BRIC (Brazil, Russia, India and China) nations now account for 41% of global steel demand and most pundits expects to see over 10% annual growth in the next few years.

Metallurgical coal demand is spilling over into the thermal market

Australia controls 55% of the global metallurgical coal export market. Recent floods in Queensland caused the temporary shutdown of those regions open-pit coal mines, causing a worldwide shortage of metallurgical coal. This lack of supply prompted hungry steel mills to start using higher quality thermal coal. This, in turn, triggered thermal coal producers to begin directing shipments to higher paying metallurgical coal consumers. The result was a deterioration of better quality and overall thermal coal inventory stockpiles at the utilities. As stockpiles dwindled to alarming levels, producers were able to ask for higher prices in the face of fierce demand.

The US coal industry is evolving

The US is the second largest coal producer after China, accounting for 19% of global production. It also has the world's largest coal reserves estimated at 243 billion tonnes. The Powder River Basin in Wyoming accounts for 43% of US production, followed by Central Appalachia at 23%. While production of high BTU coal in the east remains flat, lower BTU coal in the west must pick up the slack. With increased scrubber installation at power plants, there will likely be more demand for high sulphur Illinois Basin coal. Coal shortages from China and Australia, combined with the US' competitive advantage in shipping costs have increased demand for Appalachian coal from Europe.

Coal plants are working overtime in the US

The US has in excess of 1,075 GWe of installed generation capacity. In light of rising gas prices, natural gas-fired plants tend to operate at full capacity only at peak times. Meanwhile, utilities prefer to keep the cheap coal plants burning, such that, they account for 49% of the electricity produced, despite only a 31% share of total installed capacity. While there is a strong focus on expanding renewable energy, most emerging capacity in the US will still be fueled by traditional sources (coal, natural gas and nuclear) for the foreseeable future.

Infrastructure is becoming the bottleneck

Mine production constraints are not the only issue impacting coal supply. Major coal producing and exporting countries are being hampered by the fact that expansion of rail networks and port facilities have not kept pace with the expansion of their mining operations. However, preparing transportation facilities for additional capacity will likely take time. This suggests that coal prices are unlikely fall back to previous levels any time soon.

Shipping costs are also driving prices higher

Seaborne thermal coal trade has increased an average of 7.5% annually since 1986, leading to an increase in the shipping cost component as a percentage of delivered coal prices. As a result, coupled with higher rail and trucking costs, we are seeing a shift in trading patterns as producers tend to prefer to sell to closer to home consumers. This has the net effect of increasing coal prices further from sources.

Emissions control is paramount to coal users

Power companies are reacting to stricter environmental limits by building plants with more efficient boilers, adding scrubbers and demanding washed coal to help reduce greenhouse gas (GHG) emissions. Research for clean coal technology such as carbon capture and storage is ongoing with a long term goal of zero emissions. However, the industry is susceptible to rising capital and operating costs from initiatives such as carbon taxes, and cap and trade schemes. Removing coal's stigma as the dirty fuel will provide significant benefit in improving its appeal as the fuel of choice.

There are several risk factors that may negatively impact the coal industry

- Legislative, regulatory and judicial developments, environmental restrictions, changes in energy policy and energy conservation measures that may adversely affect the coal industry, such as legislation limiting carbon emissions (carbon taxes).
- Competition for the production of electricity from non-coal sources, including the price and availability of alternative fuels, such as natural gas and oil, and alternative energy sources, such as nuclear, hydroelectric, wind and solar power.
- Project risk and cost overruns may delay or cancel new projects.
- Transportation costs and other input costs.

Dundee's Coal Price Forecasts

Historically, prices of thermal coal track natural gas. We anticipate global coal prices will stabilize near current levels; although a pull back in the global energy markets may negatively impact prices in the short term. We would expect US coal prices to move upwards as demand for American coal increases.

Thermal Coal Price Forecasts

		2006	2007	2008 YTD	2008E	2009E	2010E	2011E	2012E	Long-term Estimate
Northern Appalachian	**US$/short ton**	42	46	91	100	120	100	90	90	65
Central Appalachian	**US$/short ton**	na	52	94	105	125	100	90	90	65
Illinois Basin	**US$/short ton**	36	32	51	65	80	75	70	65	50
Powder River Basin (8800)	**US$/short ton**	13	10	14	15	20	20	18	18	18
Global Thermal Coal*	**US$/metric tonne**	64	89	159	175	180	170	150	125	75

* Europe Thermal Coal (CIF); Rest FOB

Source: Dundee Securities Estimates, Bloomberg

Metallurgical coal supply remains constrained. With limited potential for new supply, and ongoing demand by the steel industry, this market will likely remain tight for years. Metallurgical coal prices should hold up well in the current market, and should continue to be supported by Indian and Chinese growth.

Metallurgical Coal Price Forecasts

		2006	2007	2008E	2009E	2010E	2011E	2012E	Long-term Estimate
US Met Coal (FOB)	**US$/short ton**	91	89	250	275	225	200	170	100
Global Met Coal*	**US$/metric tonne**	–	–	290	300	275	250	200	120

* Japanese Met Coal (CIF)

Source: Dundee Securities Estimates, Bloomberg

INTRODUCTION

Coal – Turing Up The Heat

Coal market has never been more attractive. The price of coal, a major input in the production of electricity and steel, has essentially doubled since early 2008, pushing the earnings and stock prices of coal producers to record highs. In the past eight months several factors – from bad weather to infrastructure bottlenecks – have seemingly conspired to cause supply disruptions in coal-producing regions. These supply problems, set against a backdrop of rising energy demand, have led to a jump in coal prices. The main European benchmark for thermal coal hit a record $210 per tonne at the end of June 2008, a rise of 85% since the start of the year. The metallurgical coal price recently topped $350 per tonne.

Supply and demand fundamentals prevail. Monsoonal rains in late 2007 flooded mines in eastern and northern Australia; heavy snowstorms in China affected coal output and caused rail transportation issues; and power shortages in South Africa caused rationing of electricity to mining companies who were forced to cut production levels. Collectively these disruptions in global coal production put pressure on the market. Meanwhile consumption for commodities such as thermal and metallurgical coal in developing countries like China, India and Brazil quickly accelerated pushing the prices for those commodities higher.

Global electricity and steel markets are the key drivers for coal prices. Coal has relative energy value and tends to track global energy markets. Rising oil and gas markets, reflecting a tight balance between supply, and demand are favorable to the coal price because of the ability of users to substitute between forms of energy.

China became a net importer for coal for the first time in 2007. China is the largest producer of coal accounting 41% of the total global production in 2007, and coal fuels 79% of China's electricity generation. However, China is grappling with its sixth year of power shortages caused by economic growth, averaging more than 10% annually in the past five years. China's electricity production has not been able to keep the pace with this unprecedented growth in industrialization. Insufficient coal supplies forced closure of 58 power-generating units in central and northern China, or 2.5% of the country's coal-fired power plants according to data from the State Grid Corp. of China.

Coal reserves are large offering energy security to those who have it. British Petroleum (BP) estimates that there are 847 billion tonnes of proven coal reserves worldwide, equivalent to 130 years at current consumption rates. This compares to 42 years and 60 years for oil and natural gas respectively, which are predominately sourced from unstable parts of the world.

Continued growth in fossil fuel consumption continues to increase global CO_2 emissions. This adds to the pressure on policy makers around the world to address energy security and climate change issues. The environmental concerns cannot preclude the world's need for coal – although it's continued use will likely progress towards cleaner and more efficient processes.

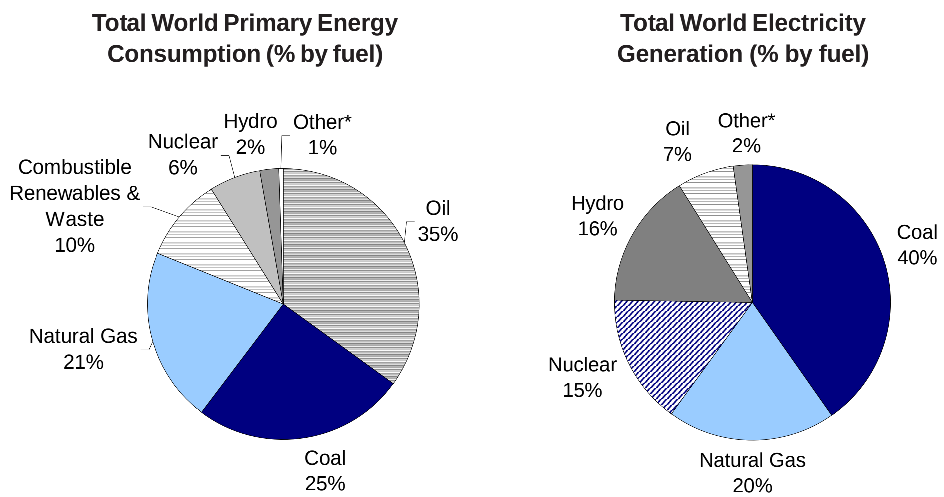
Coal is making a come-back.

COAL AND THE WORLD'S ENERGY MIX

Coal remains a dominant player in the world's energy mix.

Coal accounts for 25% of global primary energy consumption while oil and natural gas account for 35% and 21%, respectively (Figure 2). Coal is the world's most abundant fossil fuel with over 847 billion tonnes of proven coal reserves worldwide, sufficient for 132 years at current consumption. Based on current reserve estimates, and current rates of extraction, the world's oil is expected to last for 42 years and natural gas for 60 years (Figure 3). Coal has emerged as the world's fastest-growing fuel in part because reserves are located in key consuming countries, and it has been cost competitive.

Figure 2: World Energy Mix: Primary Energy Consumption and Electricity Generation



* Other includes geothermal, solar and wind

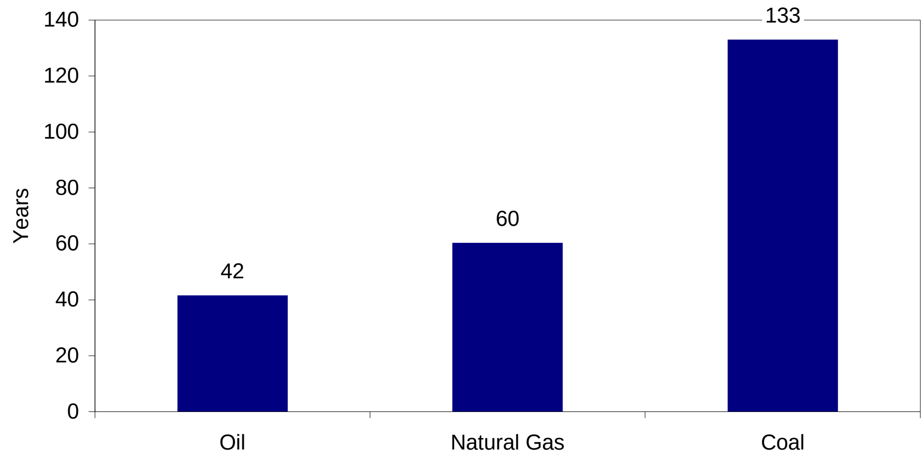
Source: International Energy Agency

Coal-fired power plants are the main source of electricity.

Coal fuels 40% of global electricity generation . . . this share is likely to grow.

About 40% of global electricity comes from coal-fired thermal plants (Figure 2). According to the Energy Information Administration (EIA), coal may continue to take the lead role in providing electric power generation, increasing from 40% to 45% by 2030. Rising oil and natural gas prices, coupled with the fact that these resources are often found in unstable parts of the world, lead to critical cost and energy security issues. While nuclear energy is expected to be part of the energy mix, permitting issues and capital costs have lead to a relatively slow expansion. Hydroelectric power has site specific constraints and other renewable energy sources such as geothermal, solar and wind power face their own challenges. Relative cost is often cited as the primary barrier to growth in renewable energy, but the fact that these resources are not yet suitable for producing reliable base-load power is also an impediment.

Figure 3: Current Reserve to Production Ratio in Years



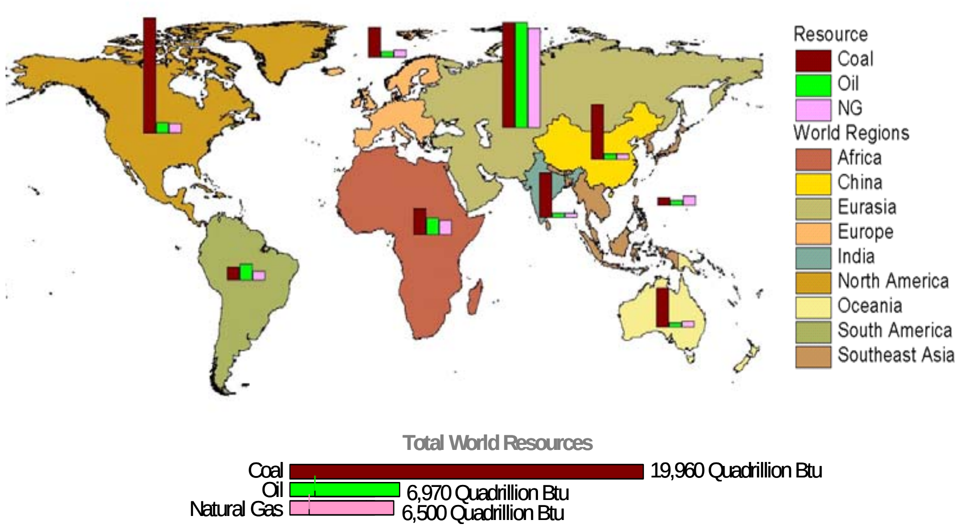
Source: BP Statistical Review of World Energy, Dundee Securities

Global coal reserves are widely distributed near its consumers.

Large coal reserves are located within major, stable economies.

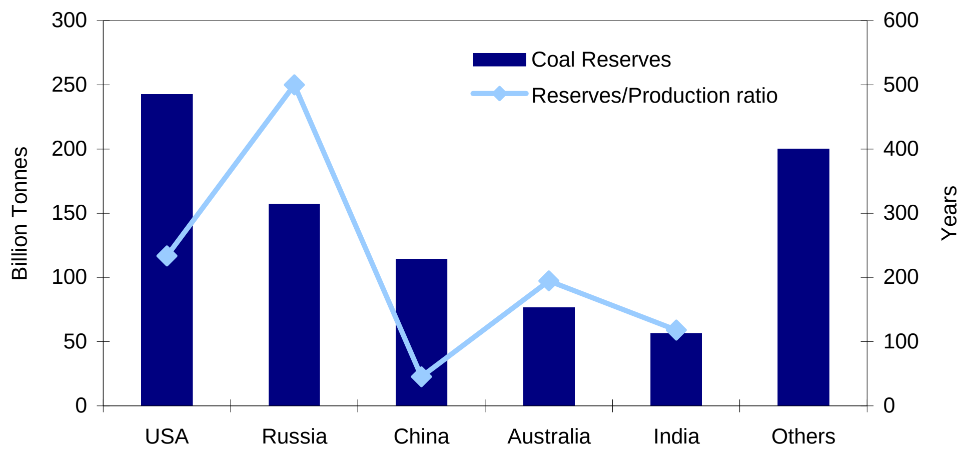
Most of the world's coal reserves are located away from conflict zones, in countries with already higher growing energy demand (Figure 4). About 76% of total global coal reserves are located in five countries: the US, Russia, China, Australia and India (Figure 5).

Figure 4: Worldwide Distribution of Fossil Fuel



Source: International Energy Annual (EIA), BP Statistical Review of World Energy

Figure 5: Largest Coal Reserve Countries



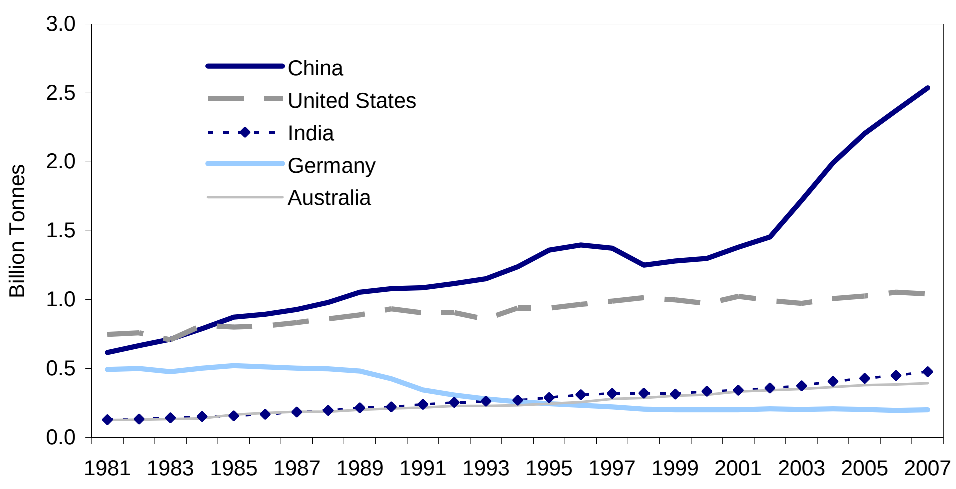
Source: BP Statistical Review of World Energy, Dundee Securities

Coal production is growing . . .

Coal production reached 6.4 billion tonnes.

World coal production reached 6.4 billion tonnes in 2007, up 3.3% YOY and 36% over the past ten years. China accounted for 41% of the total by producing 2.5 billion tonnes in 2007. The US is second at 1.0 billion tonnes, accounting for 19% of total production (Figure 6).

Figure 6: Coal Production from Selected Countries



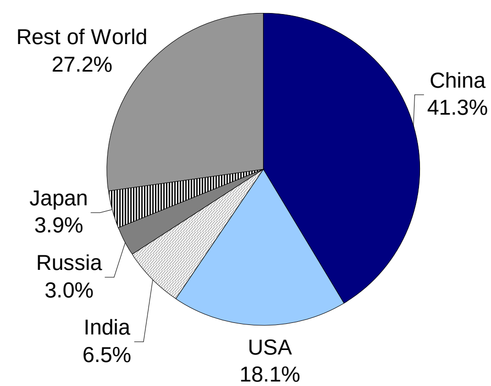
Source: BP Statistical Review of World Energy

. . . but coal consumption is growing faster . . .

Coal has been the fastest growing fuel for five years straight.

World coal consumption grew by 4.5% to 6.3 billion tonnes in 2007, well above the 10-year average of 3.2%. China accounted for 41% of total consumption, followed by the US (18%) and India (6.5%) (Figure 7). In developing economies with rapidly increasing demand for electricity, coal is often the go-to fuel of choice. Coal has been the world's fastest-growing fuel for the fifth consecutive year, driven by Chinese consumption growth that accounted for more than two-thirds of total growth.

Figure 7: World Coal Consumption, 2007



Source: BP Statistical Review of World Energy

. . . and future demand is unlikely to cool.

Global coal consumption may reach 10 billion tonnes by 2030.

According to the EIA, world coal consumption is projected to increase at an average annual rate of 2%. Using this assumption, 10 billion tonnes of annual coal consumption is expected by 2030. With its large coal resource and strong economic growth, China alone is believed to account for 71% of the estimated increase in world coal consumption by 2030 whereas the US and India should each account for 9% of the expected increased consumption. China and India together are expected to consume 5.7 billion tonnes of coal or 57% of the world's coal consumption by 2030.

Thermal and Metallurgical coal.

As we have discussed, there are two parallel and interdependent coal markets: thermal coal used for power generation, and metallurgical coal used in the manufacture of iron & steel. About three quarters of the coal currently produced is used for electricity generation, and 11% for the production of steel. The remainder of the world's coal production is used in other industrial areas including the cement industry.

DYNAMICS OF THE THERMAL COAL MARKET

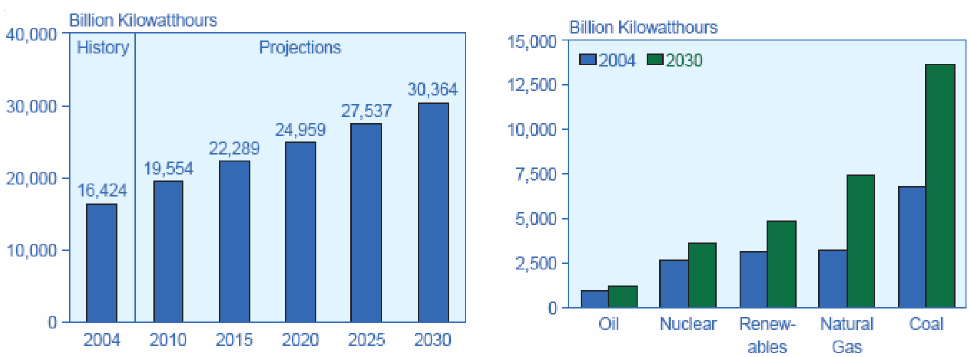
Coal-based Electricity Generation

Estimating the energy needed for power generation requires an assessment of electricity demand. Electricity demand is strongly linked to GDP growth. As economies grow and incomes rise, per-capita electricity use increases to serve an expanding variety of needs – from appliances and air conditioning in homes to commercial office equipment and the manufacture of goods.

Electricity demand is strongly linked to GDP growth.

Globally, coal is the most widely used fuel for power generation and will likely continue to be the largest fuel source going forward (Figure 8). The EIA estimates that global electricity demand could grow by 2.4% per year, from 16,424 billion kWh in 2004 to 30,364 billion kWh in 2030 (Figure 8). Meeting electrical demand will require strong growth in fuel supplies.

Figure 8: World Electric Power Generation and Generation by Fuel, 2004 and 2030



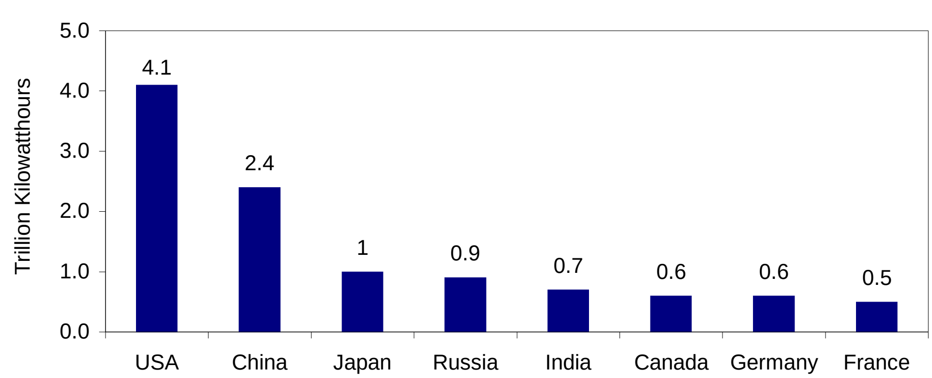
Source: EIA

The US and China dominate coal-fired electricity production.

US currently leads electricity generation at 23% of global production – China will likely lead by 2030.

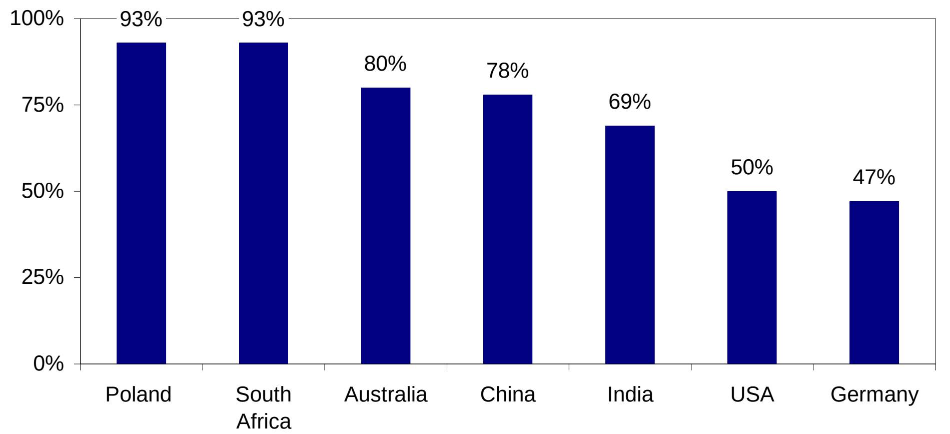
The US continues to be the largest electricity producer, accounting for 23% of total world electricity production in 2005, followed by China at 14% (Figure 9). The EIA estimates that by 2030, China may take the lead with 20% of total share of global electricity generation, followed by US with 19%. This is an annual electricity generation growth of 4.4% for China and 1.5% for the US. Several other major economies also depend heavily on coal for their electricity needs (Figure 10).

Figure 9: Top Electricity Generating Countries in 2005



Source: EIA

Figure 10: Percentage of Electricity Generated from Coal for Select Countries



Source: World Coal Institute, 2006

Per capita electricity consumption is relatively very low in developing countries. Electricity consumption on a per-capita basis is generally very different in Organization for Economic Co-operation and Development (OECD) countries versus non-OECD countries. The OECD regions, led by North America, had the highest demand per capita in 2005. In total, they accounted for about 60% of global electricity use despite having less than 20% of the world's population.

Per capita electricity consumption is growing significantly in the developing world.

As lifestyles change and incomes in developing nations rise, per capital electricity demand is expected to expand rapidly. From 2001 to 2005, per capital consumption in China and India grew by 65% and 19%, respectively (Table 1). This compares to a rate of growth of 3% in Canada and the US during the same period.

Table 1: Per Capita Electricity Consumption (kWh)

Country	2001 (kWh)	2005 (kWh)	% Change
Canada	16,253	16,775	3.2%
USA	**12,467**	**12,869**	**3.2%**
Japan	7,318	7,629	4.2%
Germany	6,412	6,612	3.1%
Russia	4,987	5,451	9.3%
China	**1,020**	**1,685**	**65.2%**
India	**371**	**443**	**19.3%**

Source: EIA, World Bank, Dundee Securities

Coal Remains the Cheaper Option

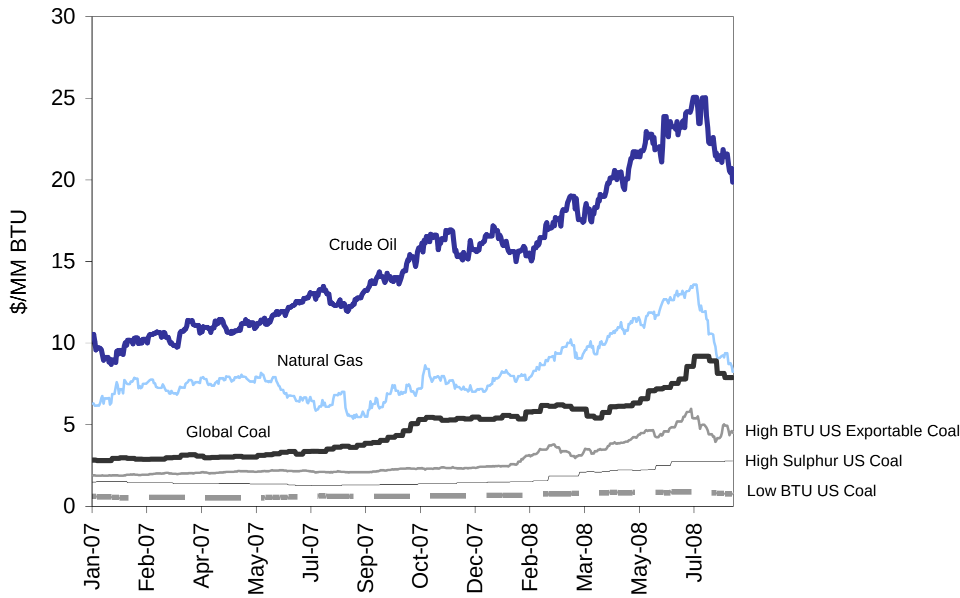
Coal is often lumped together with other fuels including oil and natural gas in global energy circles. Fundamentally, worldwide coal prices tend to track oil and natural gas prices. On a micro level coal tends to compete with natural gas in electricity production. Over the past several years, a gap has developed between coal prices and (until recently) the more rapidly appreciating natural gas and oil prices (Figure 11).

Utilities gravitate to cheaper sources of energy.

Supply and demand fundamentals suggest that coal prices should increase as consumers move towards its cheaper pricing, while the cost of other sources of less utilized fuels could fall. However, we expect coal to always trade at a lesser value, as transportation costs, emission allowances and energy efficiency factors will likely maintain the gap in prices.

With the recent pull back of natural gas prices, this spread between global coal and natural gas price has narrowed. However, we believe the spread appears to still be quite large in the US coal markets. This bodes well for further upward movement in US coal prices.

Figure 11: Tracking Oil, Natural Gas and Coal Price



Source: Bloomberg, Dundee Securities

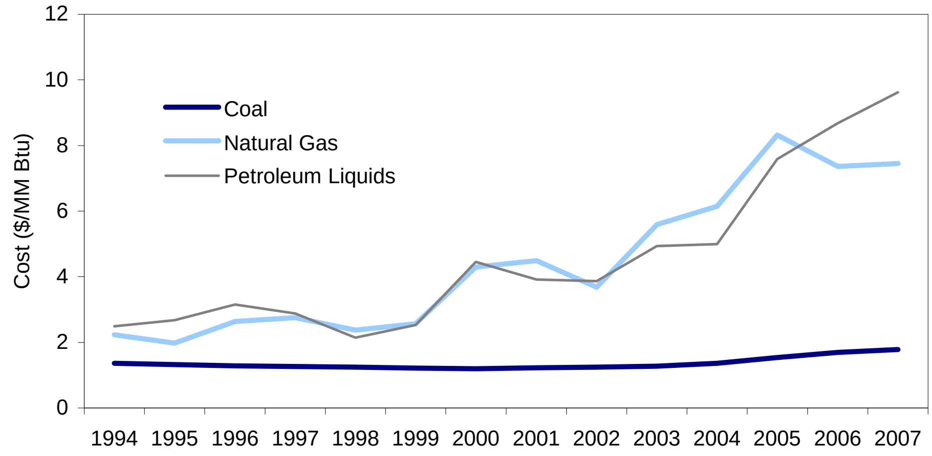
Fuel cost is the key cost component of electricity generation.

Fuel is the major cost component of electricity generation for both coal-fired and natural-gas-fired plants. The choice of input fuel for electric generation is largely based on the cost of that input fuel when available.

In BTU terms, the price gap between global coal and natural gas prices has narrowed.

As gas prices rise, the economic incentive for utilities to use coal increases (assuming accepted transportation and environmental considerations). Coal continues to be the cheapest form of fuel in BTU terms. Historically coal provided usable energy at a cost of between $1 to $3 per MM BTU compared to $6 to $12 per MM BTU for oil and natural gas (Figure 12). The current global thermal coal price of $195/tonne (10,800 MM BTU/lb) equates to $8.20 per MM BTU, close to the current natural gas price of $8.50 per MM BTU. Average US prices remained below $3 per MM BTU in 2007. The lower US prices is in part due to a large proportion (43%) of consumption that is sourced from the lower (BTU) quality Powder River Basin which trades at less than $1.00 per BTU.

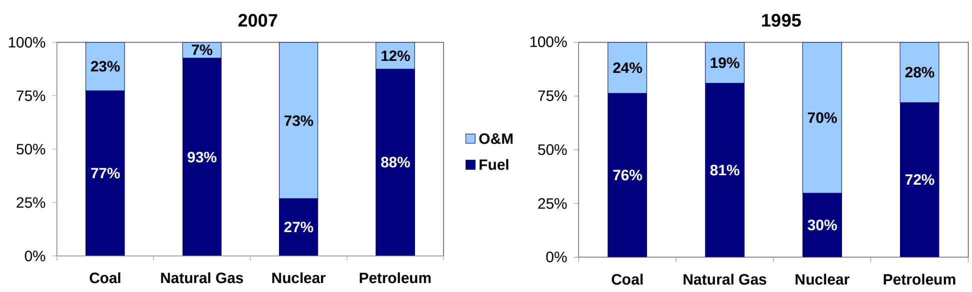
Figure 12: Average Fuel Cost in $/MM BTU in the US, 1994-2007



Source: EIA, Dundee Securities

Figure 13: Proportion of Fuel Costs of Total Operating Costs for Electricity Generation

Fuel accounts for 77% of total operating costs in coal-fired plants . . . lower than for natural gas.

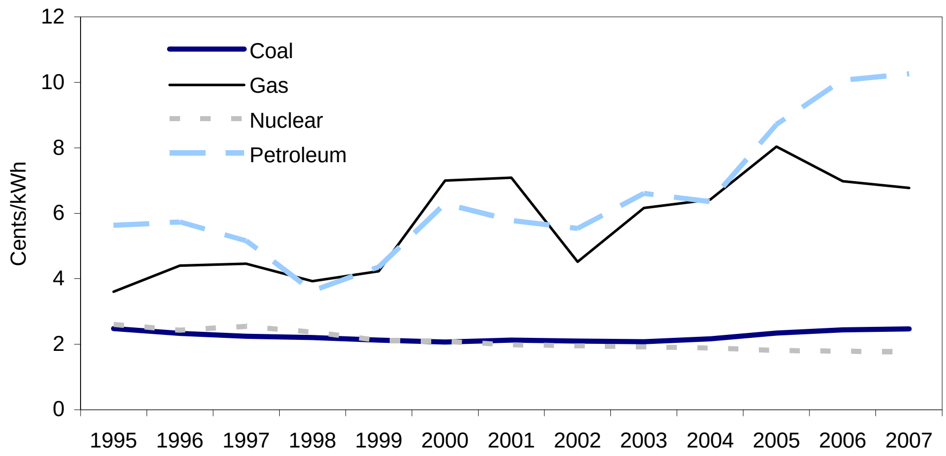


Source: Global Energy Decisions, Dundee Securities

Electricity prices on the rise as fuel prices increase.

Electricity production costs are directly proportional to the fuel costs. Natural gas is more influential in setting electric power prices because it is so frequently on the margin. In 2007, the cost to produce one kWh at a gas-fired plant was about 7 cents. A coal-fired plant that produced the same amount of electricity cost less than 3 cents a kWh (Figure 14). Last year, average electricity prices in cents per kWh for the US were 10.6 for residential, 9.7 for commercial, and 6.4 for industrial uses (Figure 15).

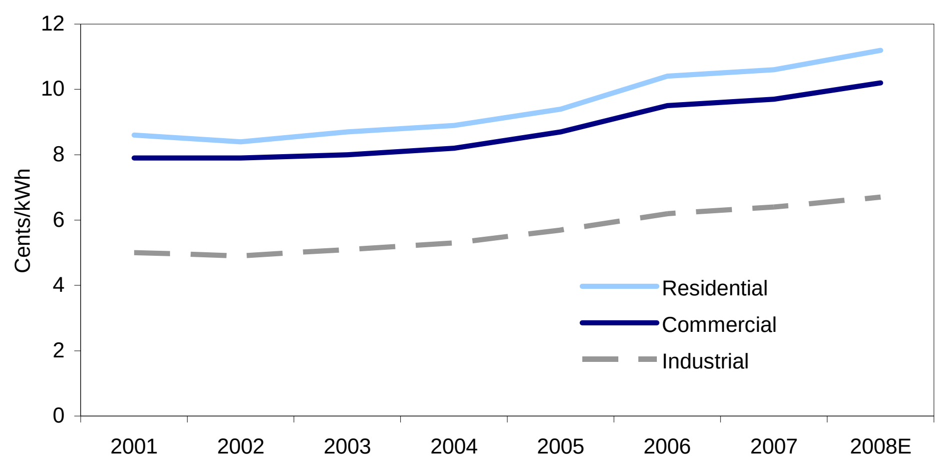
Figure 14: Total Production Cost of Electricity in the US
(2007 cents per kWh)



Source: Global Energy Decisions, Dundee Securities

Figure 15: US Electricity Prices for Different Sectors in Cents/kWh

US electricity prices are heading north.



Source: EIA

Capital Costs

All projects require upfront capital investments. Higher capital costs deter investments or demand a higher return on investment to justify the initial outlay. However, there is often a trade off between capital and operating costs. Lower cost projects may not always be attractive when operating costs are high due to high commodity prices.

Table 2 below identifies various technologies and their corresponding capital costs.

Table 2: Capital Cost of Various Electricity Generating Methods

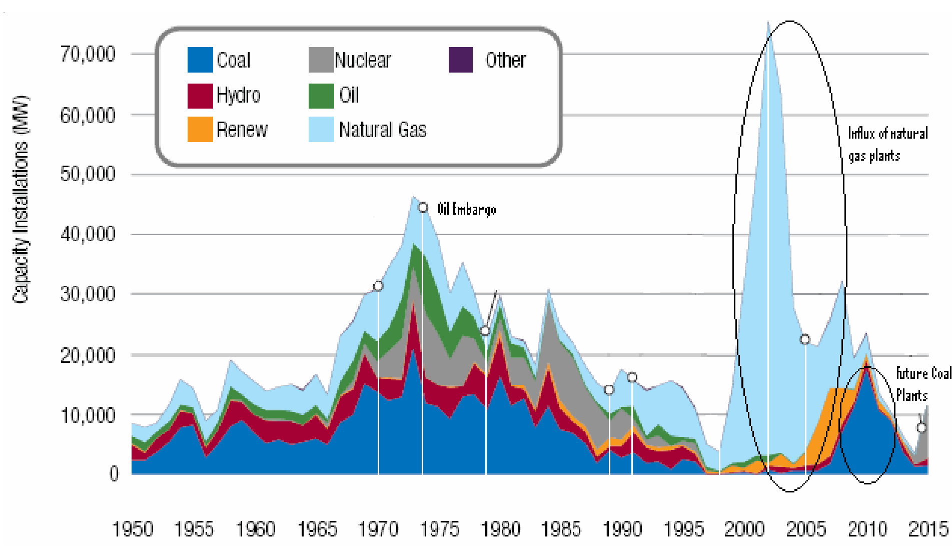
Technology	**Size** (MW)	**Leadtime** (years)	**Capital Cost in 2007** (2006 $/kw)	**Heatrate** (Btu/Whr)	**Capital Cost in 2007** ($ million)
Scrubbed Pulverized Coal Plant	600	4	1,534	9,200	920
Integrated Coal-Gasification Combined Cycle (IGCC)	550	4	1,773	8,765	975
Natural Gas Combined Cycle	250	3	717	7,196	179
Nuclear	1,350	6	2,475	10,400	3,341
Hydropower	500	4	1,551	–	776
Wind	50	3	1,434	–	72
Geothermal	50	4	1,110	–	56
Solar	100	3	3,744	–	374
Advanced Technology to Capture CO_2					
IGCC with Carbon Sequestration	380	4	2,537	10,781	964
Natural Gas Combined Cycle with Carbon Sequestration	400	3	1,409	8,613	564

Source: EIA, Dundee Securities

Natural gas-fired plants have lower capital costs but higher natural gas prices are hurting its economics.

Capital costs for coal plants range from $1,500/kW to $1775/kW, which is in line with capital costs of building hydropower and wind power on an energy output basis. Greenhouse gas emission controls have recently added significantly to coal and gas-fired power plant capital costs. The lower capital cost to build natural gas-fired plants led to an influx of gas plants in the late 1990's (Figure 16). Higher natural gas prices in recent years has helped reduce gas plant construction.

Figure 16: Power Plant Construction in US



Source: Ventyx, Dundee Securities

Dundee's Economic Model: The Coal vs. Natural Gas Decision

We have reviewed the efficiencies and economics of building and operating several types of electricity producing power stations. Power companies have the ability to substitute between natural gas or coal, depending on commodity price movements. **On an energy unit (BTU) terms, high oil and gas prices and low coal prices cannot be sustained over longer term.** All else being equal and given a choice, a company with a coal plant and a natural gas plant would operate only the lower cost plant, thereby creating demand for one fuel in preference to the other.

The thermal efficiencies of older coal-fired plants are still around 30%, while modern sub-critical cycles have attained efficiencies close to 40%. With improved technology, current super-critical coal fired plants have achieved efficiencies of up to 45%. Thermal efficiency of natural gas-fired plant ranges from 55 to up to 60%. In our model we assume 38% efficiency for coal fired plants and 58% efficiency for natural gas-fired plants.

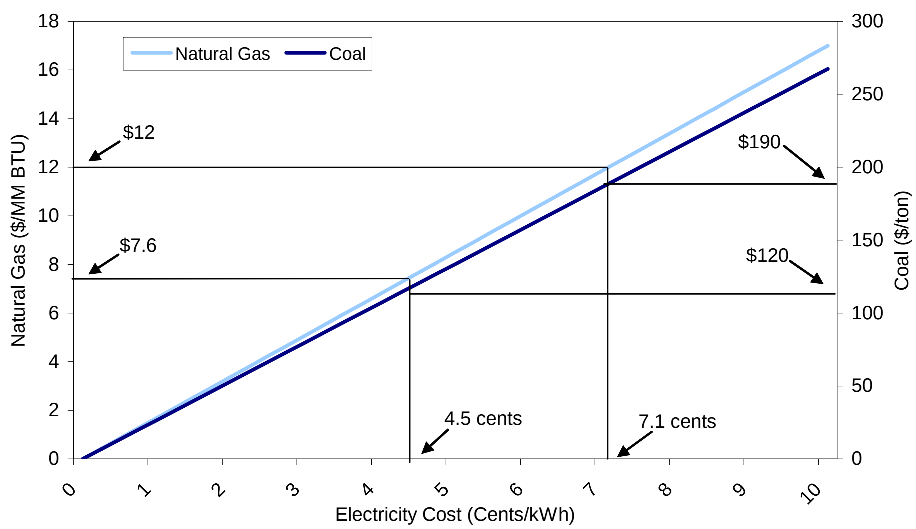
From an operational cost stand point based on the fuel cost and the plant efficiency, we have calculated the price of fuel costs and corresponding cost to produce kWh electricity for both coal and natural gas.

At a $12/MM BTU natural gas price, natural gas-fired plants can produce electricity at 7.1 cents/kWh. In order to produce electricity at same 7.1 cents/kWh, a coal-fired plant can pay up to $190/ton for its coal. **Our economic model indicates that every $1/MM BTU increase in natural gas prices equate to a $16/ton increase in coal prices in an efficiency market (Figure 17).** Any price differential between the costs of fuel to produce electricity should be arbitraged out or at most the price gap between coal and natural gas prices would likely narrow.

Dundee's model suggests that a $120/ton Central Appalachia coal price (12,000 BTU/lb quality) would prompt utilities to switch to natural gas-fired plants when prices of natural gas drops below $7.6/MM BTU. See Appendix VI for detailed calculations.

At $120/t coal, any drop of natural gas below $7.60/ MM BTU would make the natural gas plant the favourable option.

Figure 17: Dundee's Economic Model: Spread between Coal and Natural Gas Price as an Input to Power Generation



Assumptions: Coal 12,000 BTU/lb, efficiencies of 58% and 38% for natural gas and coal, respectively.

Source: Dundee Securities

European power plants can offer to pay more than twice as much for coal compared to their US counterparts.

Electricity prices in Europe are among the highest in the world (Table 3). Based on Dundee's economic model we estimate that a coal plant with a 10 cent/kWh in fuel cost would equate to just over a $250/ton coal price. This compares closely to the all time high European coal price of $210/tonne in early July.

Table 3: Average Electricity Prices in the US and Europe

Per 100 KWh	Residential	Industrial
EU27 (Euro)	16.0	9.6
EU27 (US$)	25.5	15.2
USA (US$)	10.0	6.0

Source: Eurostat, EIA

High European coal prices should lead to increased domestic prices in US.

European utilities are paying a higher price than the US domestic market. This has begun to motivate American producers to export their product to buyers in Europe. American utilities must now raise their purchase price to account for both lower domestic supply, and as incentive for domestic coal producers to continue to deliver coal domestically.

Impact of Carbon Taxes on Power Plants

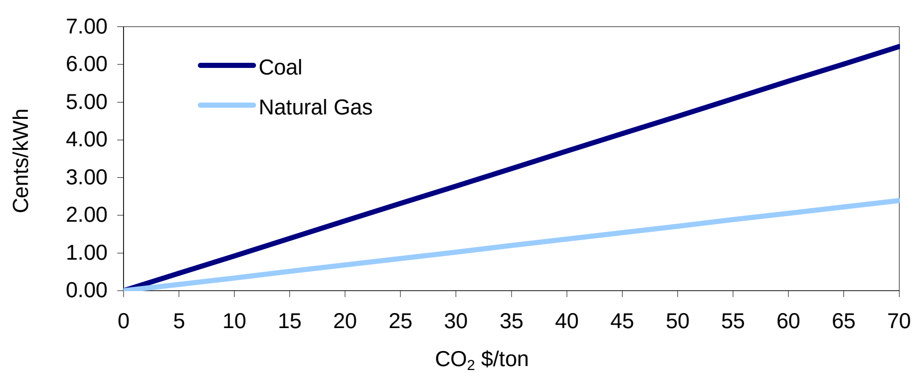
Coal is inherently a higher-polluting and more carbon-intensive fuel than other energy alternatives. One of the most significant efforts in addressing global climate change has been to reduce greenhouse gas (GHG) emissions. Europe has already introduced the carbon trading mechanism in an effort to penalize heavy CO_2 emitters and hence curb GHG emissions, but North America has yet to see a widely implemented policy.

At a $30 per ton CO_2 charge, electricity costs would rise 2.75 cents/kWh for coals plants, but only 1.00 cent/kWh for natural gas plants.

Carbon taxes (or cap and trade) are expected to negatively impact coal-fired plants and to a lesser extent natural gas-fired plants. In the event of the introduction of carbon taxes, we estimate a $30 per ton CO_2 charge may translate into an additional 2.75 cents/kWh to the cost of production of electricity for a coal fired plant. This same tax would only add another 1.0 cent/kWh cost to a natural gas plant (Figure 18).

Rising electricity demand is expected to lead to increased coal consumption despite the higher environmental costs: Coal's inherently lower starting price more than offsets the added costs relating to reducing GHG.

Figure 18: Cost of CO_2 Emission Charges on Coal and Natural Gas Plants



Source: Dundee Securities

Based on fuel price assumptions of $120/ton for coal price and $12/MM BTU for natural gas, the incremental cost of producing electricity would be same for both coal and natural gas at $44/ton CO_2 emission costs (Table 4). Coal would be a preferred fuel when carbon costs are less than $44/ton. We note that this break-even on fuel choice inclusive of CO_2 charges largely depend on the respective fuel cost and the efficiency of the plant.

Table 4: Comparing Coal to Natural Gas as Fuel for Generating Electricity, with and without CO_2 Emission Costs

Type	Fuel Costs		Electricity Costs	Electricity Costs including CO_2 Costs		
	$/ton	$/MM BTU	Cents/kWh	Cents/kWh @ $30/ton CO_2	Cents/kWh @ $50/ton CO_2	Cents/kWh @ $44/ton CO_2
Coal	120	5	4.49	7.27	9.12	8.56
Natural Gas	–	12	7.06	8.09	8.77	8.57

Source: Dundee Securities Estimates

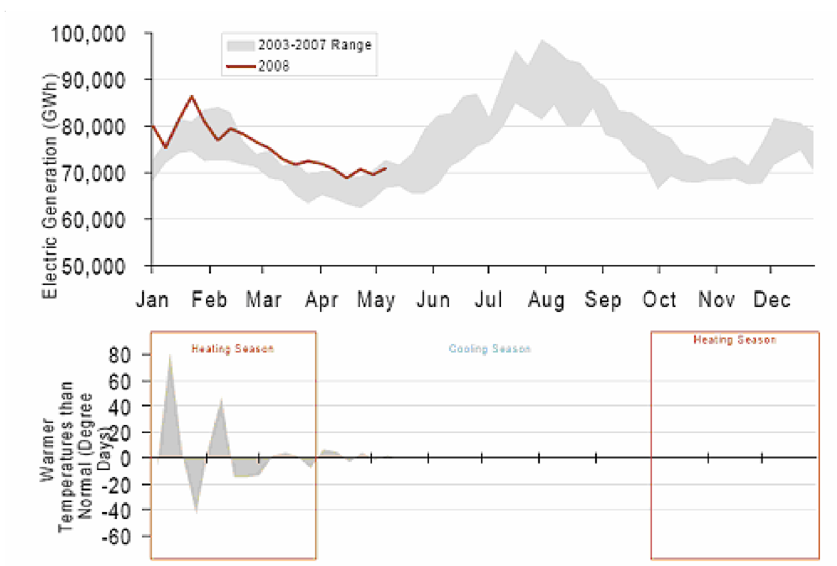
Seasonality Effect on Coal Consumption

Weather affects seasonal demand for electricity, and hence, coal consumption. A hot summer suggests increased coal consumption due to increased electricity generation to power air conditioners. Similarly, heating in winter also leads to increased demand.

Hot summers and cold winters drive coal demand.

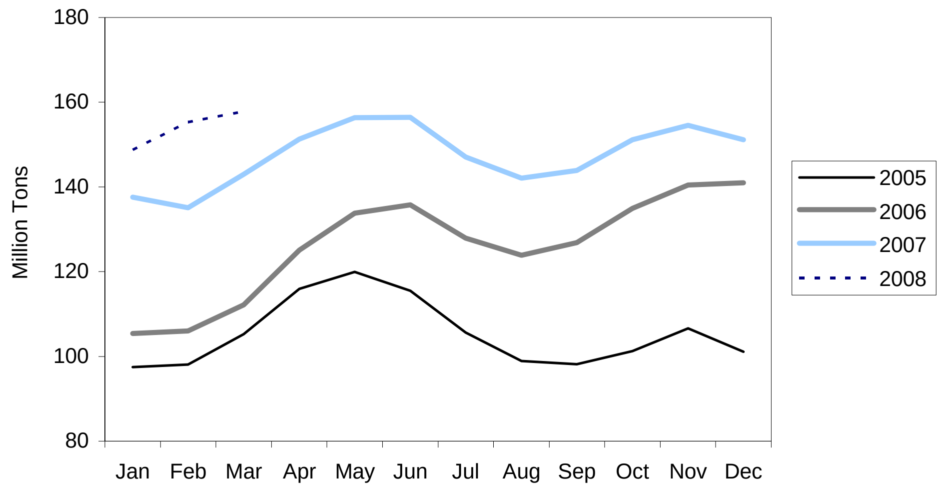
The electric consumption/generation peaks in August and February in the US (Figure 19). In order to produce the needed peak consumptions during summer and winter periods, electricity producers normally build up coal stockpiles a few months ahead of time. The stockpiles typically peak just prior to the power plant's electricity production ramp-up (Figure 20).

Figure 19: Tracking Weekly US Electric Generation Output Relative to Temperature



Source: Edison Electric Institute, National Oceanic & Atmospheric Administration

Figure 20: Tracking Coal Stockpiles at Utilities

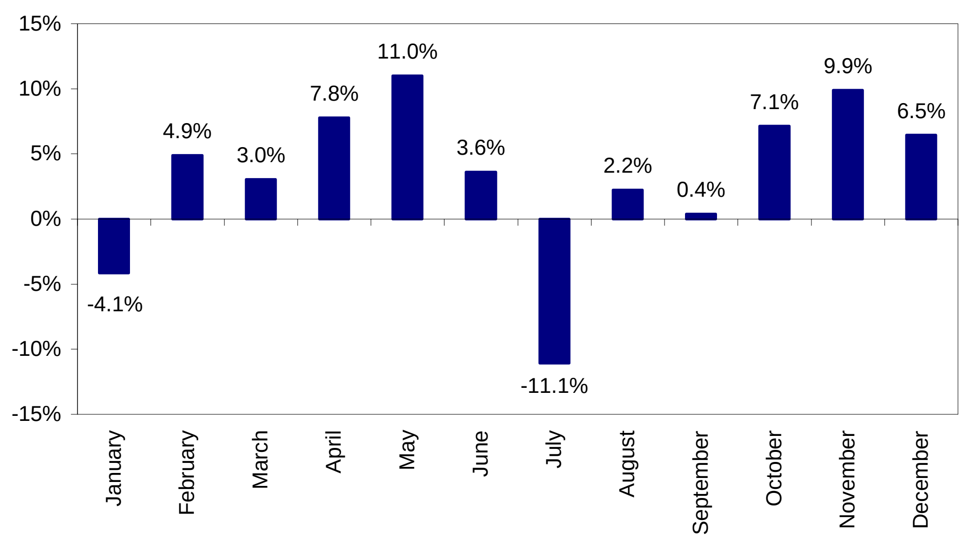


Source: EIA, Dundee Securities

May and November are good months to hold coal stocks.

Coal consumption seasonality results in a clear signal for investment in coal stocks. This seasonal demand for coal will directly impact revenue of coal producers. The change in share prices of the Dow Jones US coal index components is highly correlated to the seasonal change in the stockpiles of the coal-fired power plants (Figure 21). Historically, share prices of U.S coal producer's have generally peaked in May and November. July is the weakest month with shares dropping by an average of 11% during the month (Figure 21). This suggests that short-term investors should consider buying coal company shares in February, selling them in June, buying them back in September, and selling in December.

Figure 21: Monthly Returns of Dow Jones US Coal Index (2002-2008)



Source: Dundee Securities, Bloomberg

Dwindling Stockpiles at Utilities – Positive Implications for Coal Prices

Utilities keep coal stockpiles at the plant for two reasons: security of supply and as a hedge against rising prices. Excessive coal in stockpiles increases working capital, while low stockpiles run the risk of impact from supply shortfalls and forcing a utility to go to the open market. In the current market, utilities around the globe are carrying lower than average coal inventories, largely a result of supply constraints.

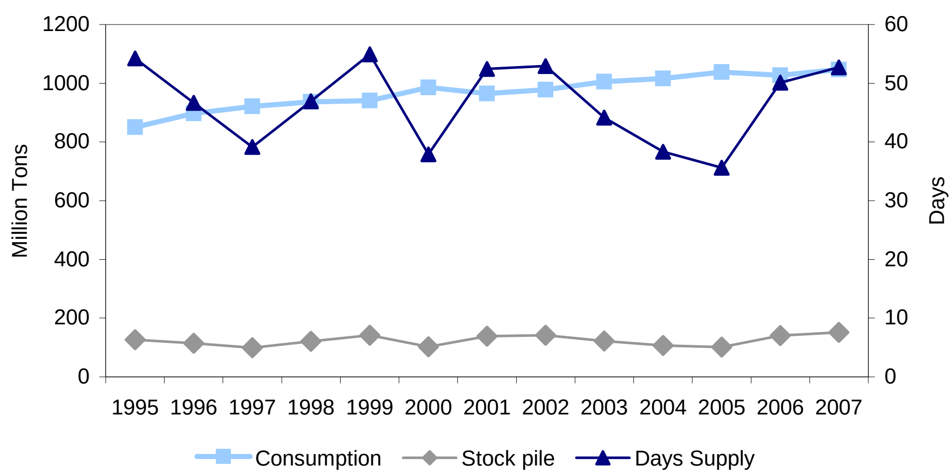
Global coal stockpiles are considerably below their average sizes.

The situation in South Africa looks bleak. Eskom, the country's largest power producer is struggling to bring coal stockpiles to a 20-days supply at its power stations. Some of its plants recently have seen alarming levels, falling to as low as a 5-day supply. Plants in India have coal stockpiles lower than their mandated 21-day supply. In May 2008, the Indian Ministry of Coal indicated that about 27 power units held less than seven days worth of coal in stockpiles. China has a bigger issue in its hands. A continued sixth year of electricity shortages has prompted local governments to limit electricity consumption and issue warnings on possible blackouts. According to the State Grid Corp of China, the current stockpile can meet up to 10-days supply.

The US power sector ended 2007 with 151 million tons of stockpiled coal, representing a 53-day or above average supply (Figure 22). Increased global demand for coal and higher global prices are attracting US coal producers to export coal and has been placing a strain on the stockpile position so far in 2008. While not yet at critical levels, it has created concern for the utilities. The global stockpile situation suggests that the market may remain in tight balance for some time. Supply shortages in the near term will likely be positive for global coal prices.

The global stockpile situation clearly indicates that coal market may remain in tight balance and global shortages may worsen in the near term, a positive for global coal prices.

Figure 22: US Electric Power Sector Coal Consumption, Stockpile and Days of Supply



Source: EIA, Dundee Securities

DYNAMICS OF THE METALLURGICAL COAL MARKET

Metallurgical coal or coking coal is an essential input in 65% of the world's steel production manufactured using Basic Oxygen Furnaces (BOF). BOF's consume about 11% of total coal demand.

World Demand for Metallurgical Coal is Accelerating

Metallurgical coal consumption reached 706 million tonnes in 2006 with 222 million tonnes being transported across political borders. The largest consumers, China and Japan, represented 46% and 10% of demand, respectively (Table 5). The largest metallurgical coal importers are Japan, South Korea, India and Brazil. Although China is the largest producer, Australia is the world's largest metallurgical coal exporter at 55% (121 million tonnes) of world exports in 2006 (Table 6). Transportation costs are a significant factor in the metallurgical coal market.

Australia is the world's largest metallurgical coal exporter with 55% market share.

Table 5: Top Metallurgical Coal Producers and Consumers

Top Met Coal Producers		Top Met Coal Consumers	
Country	**MM t**	**Country**	**MM t**
China	323	China	327
Australia	132	Japan	73
Russia	64	Russia	53
USA	45	India	42
Indonesia	25	Ukraine	30

Source: World Coal Institute, International Energy Agency, 2006

Table 6: Top Metallurgical Coal Exporters and Importers

Top Met Coal Exporters		Top Met Coal Importers	
Country	**MM t**	**Country**	**MM t**
Australia	121	Japan	73
Indonesia	25	South Korea	20
USA	25	India	19
Canada	25	Brazil	13
Russia	10	China	9

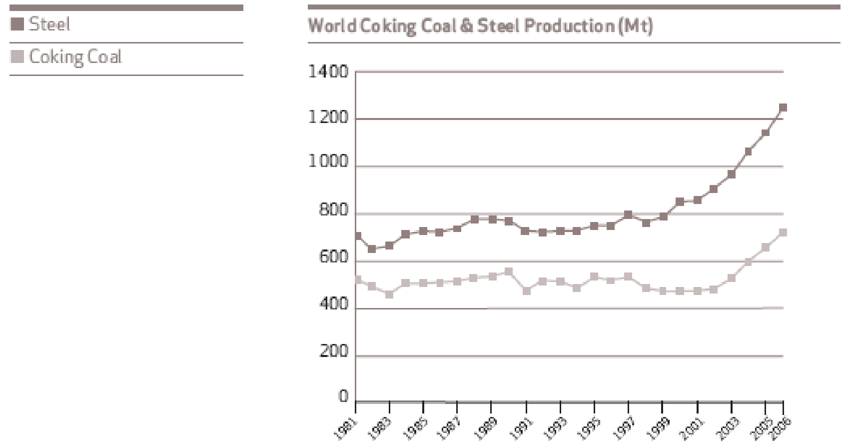
Source: World Coal Institute, International Energy Agency, 2006

Steel production is rising.

New steel capacity is coming on line.

Worldwide steel production has almost doubled over the past 30 years. The last seven years has seen unprecedented growth, with global production rising over 58% to 1,344 million tonnes from 848 million tonnes (Figure 23). In China, new capacity of 54 million tonnes per year is expected by the end of 2008. The Middle East and Latin America are also expected to significantly increase capacity, with some 34 million tonnes per year planned in Brazil alone.

Figure 23: World Coking Coal and Steel Production



Source: World Coal Institute

Per capita steel consumption is growing in China and India.

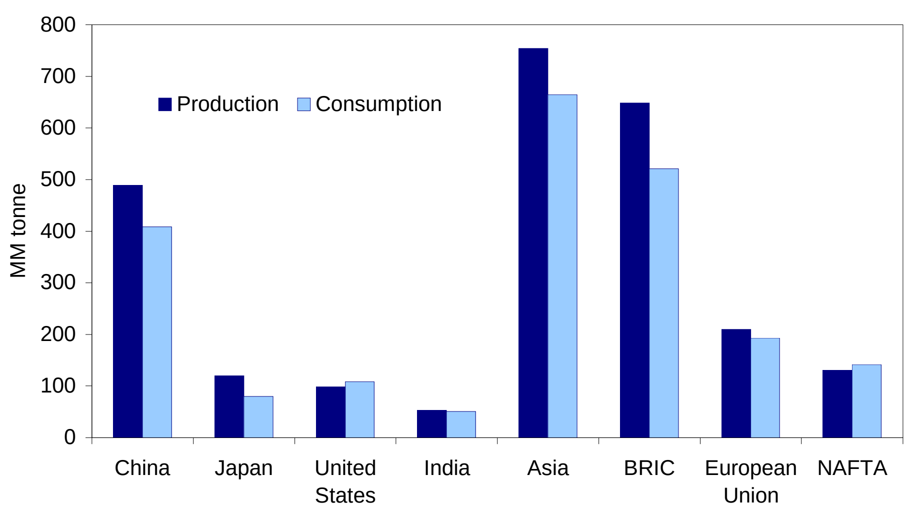
Steel demand in BRIC nations is expected to grow by 11% in 2008 and 10% in 2009.

The world consumed 1.21 billion tonnes of steel in 2007, up 7.5% from 2006. Much of the demand for steel is being driven by the strong and rapid economic growth of China and India. Both together consumed over 459 million tonnes of steel in 2007, representing 38% of global consumption (Figure 24). Per capita steel consumption in China and India has grown 149% and 62% since 2001 respectively (Table 7).

Chinese consumption has nearly reached US consumption on a per capita basis. According to the International Iron and Steel Institute, steel demand in BRIC (Brazil, Russia, India and China) countries is expected to increase 11% in 2008 and 10% in 2009. We estimate global metallurgical coal demand of approximately 1 billion tonnes per year by 2012 using a conservative 6% annual growth rate for global steel consumption. This is 30% higher than 2006 levels.

Global metallurgical coal demand is estimated to reach 1 billion tonnes per year by 2012.

Figure 24: Major Steel Producers and Consumers



Source: International Iron and Steel Institute

Table 7: Per Capital Steel Consumption

Country	2001 (kg)	2007 (kg)	% Change
South Korea	814	1135	39%
Japan	575	626	9%
Canada	491	532	8%
Germany	398	463	16%
United States	**368**	**354**	**-4%**
Australia and New Zealand	268	341	27%
China	**124**	**307**	**149%**
Russia	183	280	53%
France	291	268	-8%
United Kingdom	228	212	-7%
Brazil	95	115	21%
India	**27**	**43**	**62%**

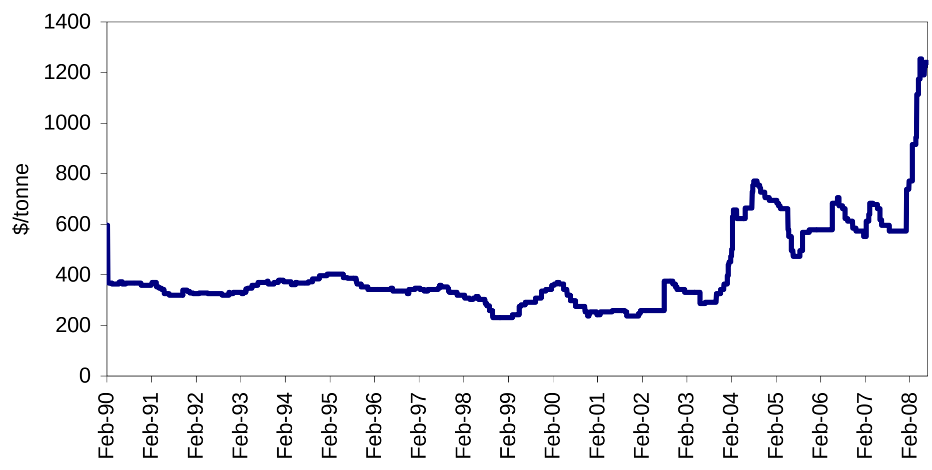
Source: International Iron and Steel Institute, Dundee Securities

Steel Prices are Up!

Iron ore and coal together account for 50% of the total manufacturing cost for steel.

US steel prices have more than doubled since the beginning of 2008, from $575 per tonne to a record high of $1,254 per tonne in May (Figure 25) on the back of strong global steel demand and rising coal and iron ore prices. The intense infrastructure and construction activity in the BRIC nations will likely keep demand for steel strong in the near future. Increased steel demand should translate into higher metallurgical coal demand.

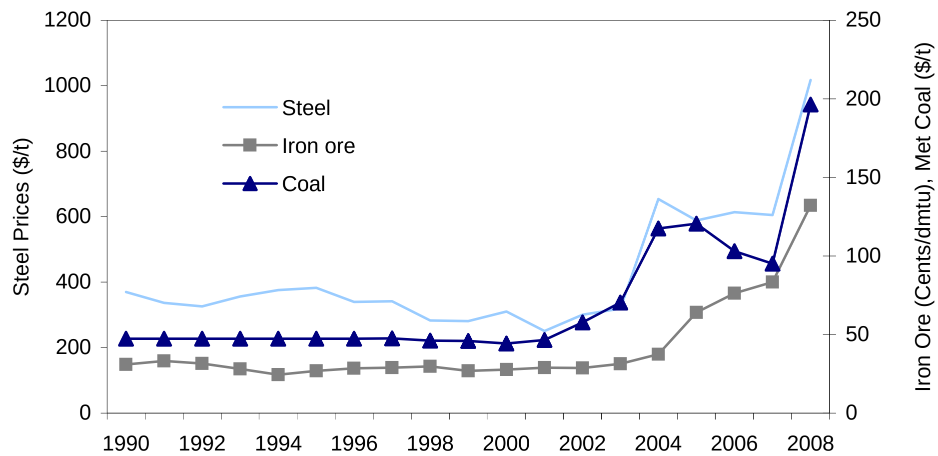
Figure 25: US Hot Rolled Steel Prices



Source: Bloomberg, Dundee Securities

The rise in steel prices can be explained by both higher input costs and higher demand. Higher iron ore and metallurgical coal prices account for more than 50% of the total manufacturing costs of steel (Figure 26).

Figure 26: Steel Prices vs. Iron Ore and Metallurgical Coal Prices



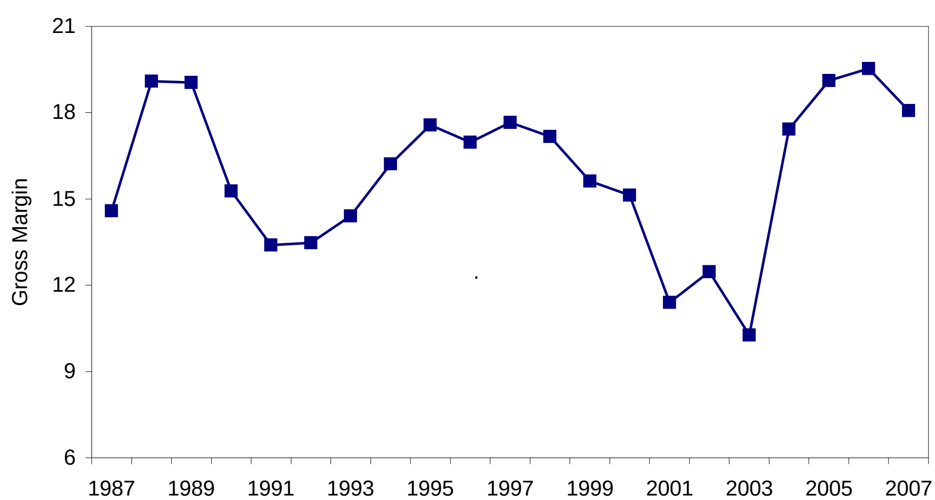
Source: Bloomberg, econstats.com

Steelmakers have the ability to maintain healthy gross margins on the back of strong steel demand.

The strong demand for steel due to the growth in developing nations has helped steelmakers to successfully raise steel prices and more than maintain their profit margin. Steelmakers have raised their prices and passed rising input costs on to the end users. The strong demand for steel has improved gross margins of major US steelmakers from lows of 10.3% in 2003 to 18.1% in 2007 (Figure 27).

Metallurgical coal prices have topped $350 per tonne. In our view, these prices will likely hold up in current market conditions unless we have additional supply disruptions. However we do not foresee the current pace of steel demand to drive up met prices significantly further – especially if cheaper, yet high quality thermal coal is made available.

Figure 27: Gross Margins of Dow Jones US Steelmakers Index



Source: Bloomberg

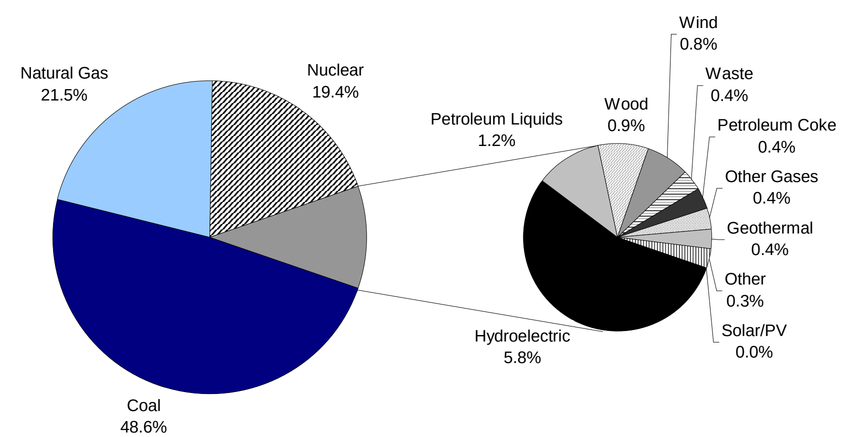
ROLE OF COAL IN THE US

Coal continues to play a vital role in the US energy mix – it accounted for 49% of total electricity production, generating 4,160 billion kWh of electricity (Figure 28). US coal consumption increased 1.5% YOY to 1.13 billion tons in 2007. Almost 93% of all coal consumed in the US is used to generate electricity.

Coal fuels 49% of all electricity generation in the US.

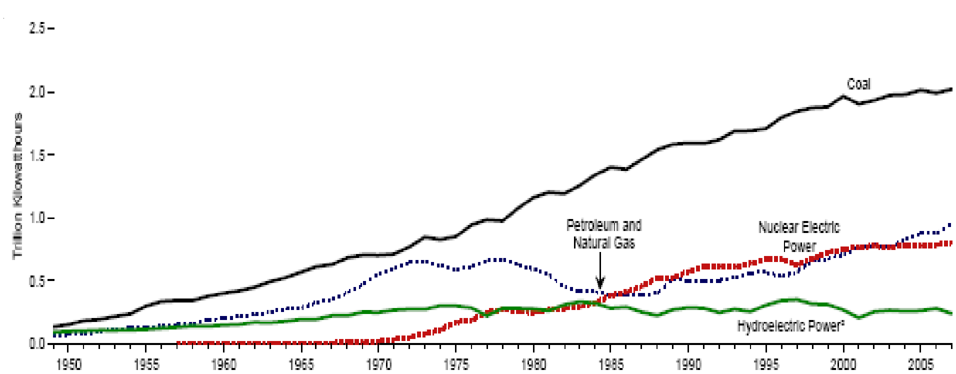
Increased security of energy supply issues coupled with higher natural gas prices have peaked interest in further investment in coal-fired and nuclear power plants, Renewable energy sources, including wind, solar, and geothermal together, account for just over 1% of total electricity generation in US.

Figure 28: US Electricity Generation in 2007



Source: EIA, Dundee Securities

Figure 29: Electricity Generation by Major Sources



Source: EIA

Coal plants are working overtime . . .

The US has in excess of 1,075 GWe of installed generation capacity. Natural gas-fired plants account for only 22% of electrical production, despite having 41% of the country's generating capacity. The overcapacity is a function of higher gas prices, inducing a higher percentage of natural gas-fired capacity to operate as the marginal reserve (operating only at peak-time). Meanwhile, utilities prefer to keep the coal plants burning – they provide 49% of the electricity, despite only a 31% share of total installed capacity.

Natural gas produces only 22% of US electricity despite its 41% share of installed capacity.

Table 8: US Existing Electricity Generation Capacity

Energy Source	Number of Generators	Nameplate Capacity (MW)	Share in %
Coal	1,493	335,830	31%
Natural Gas	5,470	442,945	41%
Nuclear	104	105,585	10%
Hydro	3,988	77,419	7%
Petroleum	3,744	64,318	6%
Other Renewables	1,823	26,470	2%
Others	302	23,108	2%
Total	**16,924**	**1,075,677**	**100%**

Source: EIA, 2006

Most emerging American electricity capacity is fueled by traditional sources.

According to the American Public Power Association, over 180,000 MWe of new capacity is under some degree of development – a 16% increase over current capacity. Although there is a strong focus on expanding the renewable portfolio, most of the emerging capacity will be fueled by traditional resources: coal, natural gas and nuclear (Table 9, Figure 30).

Plants that are permitted or under construction and projected to be online by 2012 account for 52,000 MW or less than 30% of the total planned new capacity. Units pending application account for an additional 50,000 MW. Proposed plants suggest another 85,000 MW of capacity or 45% of the total, although there is an increased level of uncertainty surrounding the latter projects.

Table 9: Proposed US Electricity Generation

Fuel Type	Plants Under Construction		Permitted Plants		Pending Application		Proposed Plants	
	Capacity (MW)	**% Total**	**Capacity** (MW)	**% Total**	**Capacity** (MW)	**% Total**	**Capacity** (MW)	**% Total**
Coal	7,863	31%	13,437	50%	24,285	48%	26,628	31%
Natural Gas	10,728	42%	8,937	33%	15,084	30%	11,216	13%
Nuclear	1,541	6%	165	1%	2,613	5%	19,940	24%
Wind	2,980	12%	4,068	15%	5,506	11%	20,278	24%
Other Renewable*	420	2%	189	1%	2,072	4%	4,785	6%
Others	1,788	7%	182	1%	1,290	3%	1,714	2%
Total	**25,319**	**100%**	**26,978**	**100%**	**50,850**	**100%**	**84,560**	**100%**

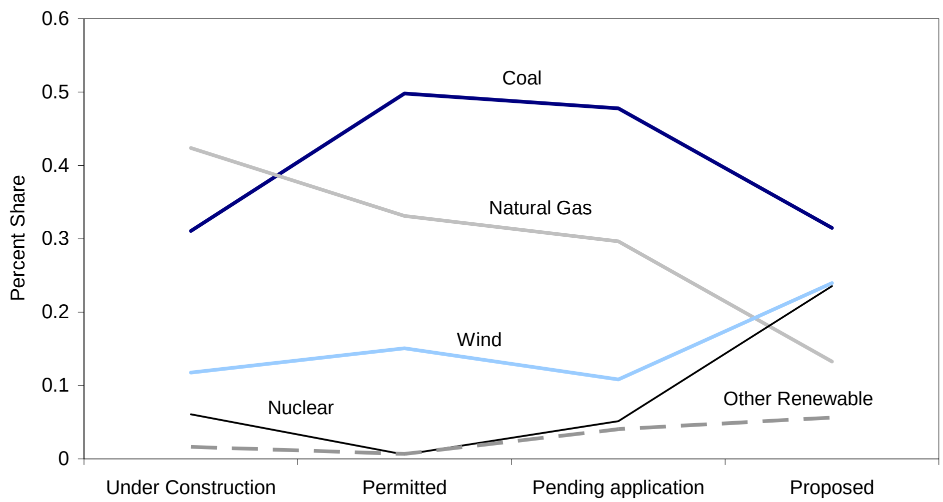
* Hydro, Solar, Geothermal

Source: American Public Power Association, Dundee Securities

Except for gas plants well into the construction stages, coal is the primary fuel of choice in almost all development stages (Table 9). The preference for natural gas is trending downward. Nuclear and wind both trend upwards significantly. Hydro and renewables still account for a very small proportion of future energy mix.

Coal is expected to dominate future US electricity capacity build.

Figure 30: Share of US Proposed Electricity Generation



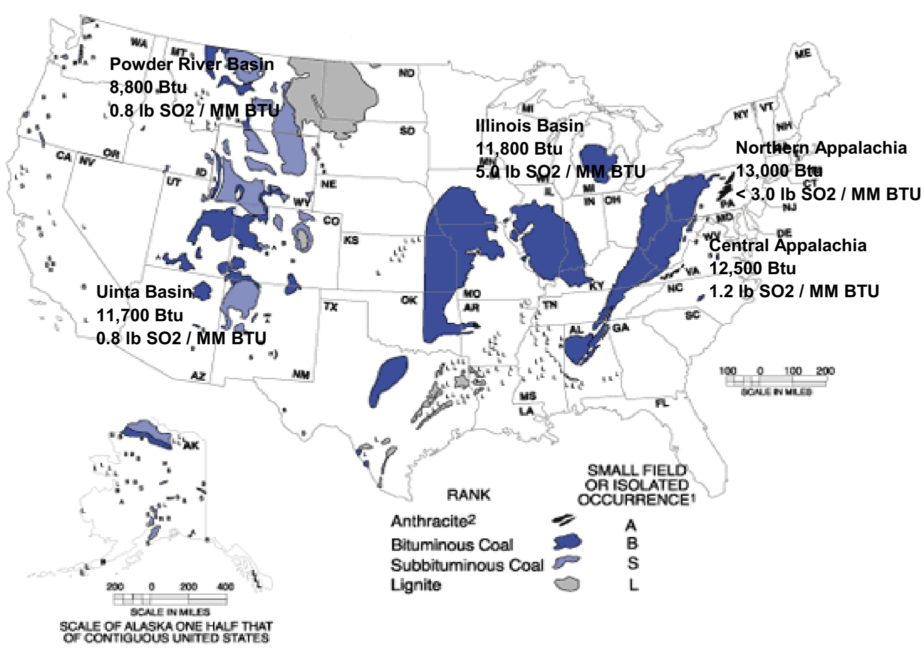
Source: American Public Power Association, Dundee Securities

Distribution of Coal in USA

The US has the largest reserve base of coal in the world.

It is estimated that the US contains 243 billion tonnes of coal, enough to sustain the country for more than 234 years at current consumption rates. Five areas predominate – Northern and Central Appalachia, and the Illinois, Powder River and Uinta Basins (Figure 31).

Figure 31: Various Coal Bearing Areas of the US

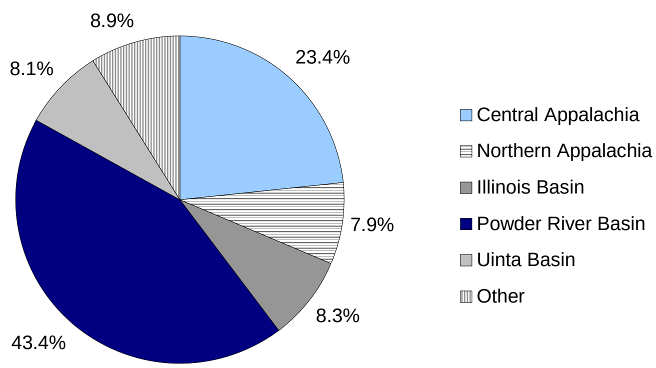


Source: USGS, EIA

The US is the second largest coal producer after China.

The US is the second largest producer of coal after China, and produced 1.04 billion tonnes of coal or 19% of total global production in 2007. The Powder River Basin accounts for 43% of total US coal production, whereas the Central Appalachian region produced 23% (Figure 32). Based on EIA estimates, production from high-BTU Appalachian coal will likely trend downwards as low-BTU production from the Powder River Basin picks up the slack. Increasing scrubber installation at power plants will likely drive significantly more demand for high to medium-BTU, high-sulphur Illinois Basin coal.

Figure 32: Regional Distribution of US Coal Production



Source: EIA, Dundee Securities

Appalachian Region – Northern and Central Appalachian

High quality Appalachian coal production is flat or declining.

The Appalachian regions host higher quality (high-BTU, lower-sulphur) bituminous coal and high quality metallurgical coal. Production from the Appalachian region has leveled off and is likely in decline. Northern Appalachian accounted for 9% (90 million tonnes), and Central Appalachian accounted for 23% (268 million tonnes) of total US coal production in 2007.

Illinois Basin – Interior region

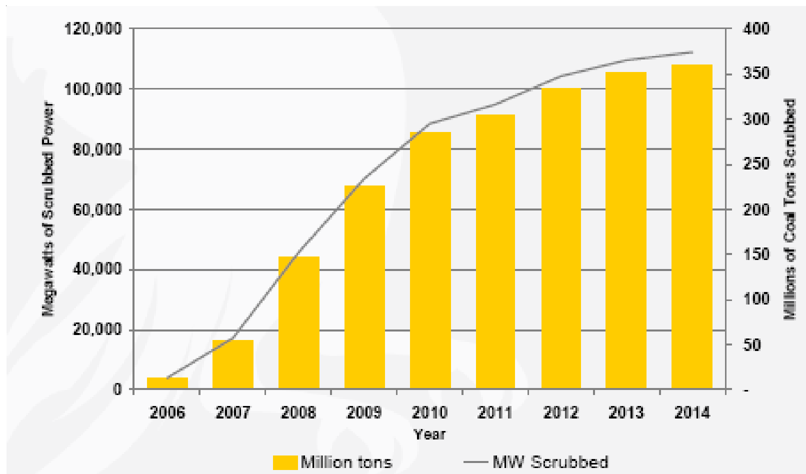
The Illinois Basin has large reserves of medium to high-BTU bituminous coal; however, this coal generally has a high sulphur content (up to 5%). Illinois Basin coal ran afoul of the 1990 Clean Air Act which limited SO_2 emissions and the coal industry in this area was decimated. Higher prices, the exportation of Appalachian coal, and scrubber installation have since provided a boost to high-sulphur Illinois coal. Illinois basin production totalled 96 million tonnes representing 8.3% of the total US production in 2007. Production from the rest of the Interior region was 37 million tonnes.

Increased scrubber installation gives Illinois Basin coal new marketability.

Plants retrofitted with SO_2 scrubbers can burn cheaper, high-sulphur coal, giving Illinois Basin coal a new marketability. Currently about 30% of total US coal-fired plants are retrofitted with scrubbers but another 70 GW of new scrubber retrofits are expected by 2015. According to Hill and Associates, this addition of scrubbers could allow for the use of over 350 million tonnes of high-sulphur coal (Figure 33). Given time this new demand should help reduce the price gap between Appalachian and Illinois Basin coal.

Chlorine is a corrosive element which impacts coal-fired boilers and scrubbers at varying degree. The chlorine content of the coal in the Illinois Basin ranges from 0.00% to more than 0.60%. Mean concentration of chlorine in coal from US is reported to be 0.02%, with worldwide mean concentration of 0.10%. US boiler manufacturers and utility operators consider coals containing more than 0.3% chlorine to be potentially corrosive. All else being same, high chlorine coal (>0.3%) should trade at a discount to low chlorine coal (<0.3%).

Figure 33: Announced US Scrubber Capacity



Source: Hill and Associates

Western Region – Powder River Basin and Uinta Basin

Production from the western region is dominated by the Powder River Basin (PRB). PRB reserves consist of low-BTU, low-sulphur sub-bituminous and lignite coal. Total production from PRB was 497 million tonnes in 2007, accounting for 43% of total US coal production.

PRB coal accounts for 43% of US production.

Powder River Basin coal remains amongst the cheapest coal with prices only reaching as high as $16/ton. This lower price is due to both transportation costs and that coal-fired plants have yet to adapt to burn lower-BTU coal. As higher quality coal in the east is depleted, additional demand for PRB coal will likely lead to higher prices. With low-BTU coal sources in mind, we believe that new coal-fired plants will be built in the eastern US to operate using this fuel. An upgrade of the railways to transport coal through Wyoming and South Dakota has already begun.

US Export Market

Exports to Europe may significantly increase in the near term.

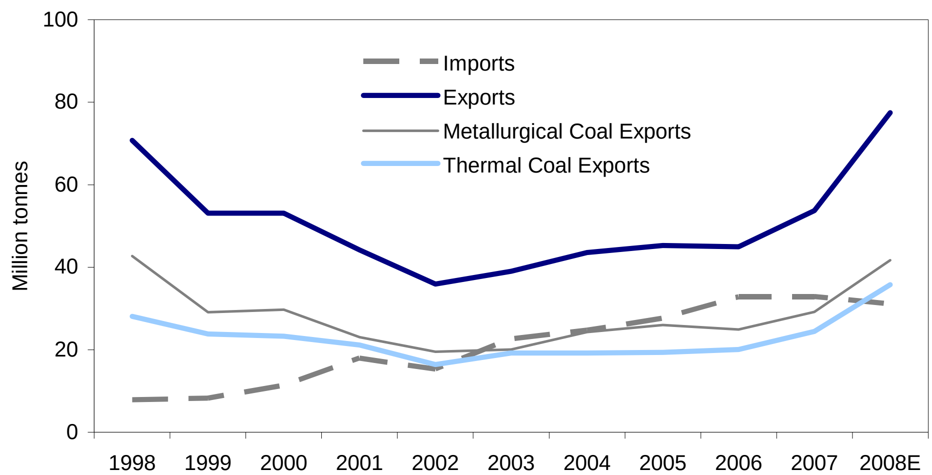
The US exported 54 million tonnes coal in 2007, or 5% of total coal production, up 19% YOY (Figure 34). Metallurgical coal accounted for 54% (29 million tonnes) and thermal coal accounted for 46% (25 million tonnes) of the total exports.

Canada is the largest thermal coal importer, accounting for 55% of US thermal coal exports. Europe ranks second, accounting for 32% (8 million tonnes). With the global shortages in the coal supply, significant reduction in exports from South Africa and China, and the shipping cost advantage from eastern US ports, we believe that exports to Europe may significantly increase in the near term.

US is exporting more coal to Europe.

Metallurgical coal exports to Europe rose significantly in 2007, accounting for 57% of total metallurgical coal exports. This is followed by Brazil and Canada. US metallurgical coal export to Asian markets accounted for only 3% of exports – the Asian market continues to be serviced by Australia.

Figure 34: US Export and Import Trends



Source: EIA

The US imported 33 million tonnes coal or 3% of total coal consumption in 2007. Colombia accounts for 74% of total imports, followed by Indonesia, Venezuela and Canada. These four countries accounted for 99% of total US coal imports. Metallurgical coal accounts for only 5% of the total imports and this comes entirely from Canada. Coal imports typically occur when transportation costs make domestic production delivery impractical.

CHINA AND INDIA – DRIVING THE COAL MARKETS

45% of Chinese rail capacity is devoted to coal transport.

China and India are the emerging giants of the world economy and international energy markets. The staggering pace of Chinese and Indian economic growth in the past few years has driven their energy needs. Domestic capacity has been exceeded and now a growing share of China's coal requirements have to be imported. The fundamental change in the world's coal markets has led to supply shortages in several regions and helped contribute to higher coal prices. Despite this price increase, higher oil and gas prices are still making coal a more attractive option. China and India already account for 45% of world coal use. They are projected to account for over 57% of the incremental demand in world coal through 2030.

China Has Become a Net Coal Importer

Coal output in China rose to 2.54 billion tonnes in 2007 from 1.30 billion tonnes in 2000, making China by far the world's largest coal producer. The country is also the largest producer of metallurgical coal, producing 323 million tonnes in 2006. China's coal resource is extensive. More than 90% of Chinese coal is located in inland provinces, although most demand is from the coastal region. The cost of internal transportation has resulted in more competition from coal imports. Approximately 45% of China's national railway capacity is devoted to the transport of coal, if its capacity does not keep up with coal demand, the effective domestic coal supply is estimated to continue to fall short. With improving safety standards, the Chinese government is shutting down more illegal and unsafe coal mines, further exacerbating the issue.

China became a net importer of coal in the first half of 2007 for the first time, and may have to import 250 million tonnes/year coal by 2010.Snowstorms in early 2008 caused a serious domestic coal shortfall and the government banned exports. This put Japan and Korea in a bind as they had to source fuel on the world market.

Rapid economic development is changing the lifestyle and energy needs of China. Coal already accounts for approximately 79% of China's electricity generation and most of the generation growth is also being fueled with coal. According to a MIT study, China is building the equivalent of two coal-fired 500 MW power plants every week. Recent growth rates of over 12% in electricity consumption may moderate in coming years, but this growth trend is likely to continue for some time.

Indian Coal Imports are Increasing

Like China, India has extensive coal reserves, and it is the world's third largest coal producer after China and US. India produced 478 million tonnes of coal in 2007. Once again domestic production could not meet demand and India imported 45 million tonnes of coal (22 million tonnes of coking coal and 23 million tonnes of thermal coal).

Thermal coal imports have increased rapidly over the last couple of years. We expect the trend to continue for reasons of quality of coal (Indian coal has high ash content) and for economic reasons for power plants located a long way from mines but close to ports. Indonesian and South African exports provide approximately 70% and 30%, respectively, of India's thermal coal needs.

India consumed 40 million tonnes of metallurgical coal in 2007 and imported more than 50% all of its metallurgical coal needs, mainly from Australia. Due to relatively poor quality of domestic supplies, India is likely to remain heavily dependent on imports for metallurgical coal. With an average annual growth rate of 8%, India's metallurgical coal imports are predicted to rise to 70 million tonnes per annum by 2025.

India is set to become a large driver of global coal imports.

Coal currently accounts for about 69% of India's electricity generation. A large fraction of future growth in the electricity sector will be coal-based. Indian National Electricity Policy estimates per capita electricity consumption to rise to over 1,000 kWh by 2012 from 500 kWh today. As a result, the plan calls for installed capacity to increase from 115 GW in 2005 to 780 GW in 2030. This translates to coal demand rising from 460 million tonnes per year in 2005 to about 2.0 billion tonnes per year in 2030. At this rate India would match current US coal consumption by 2020.

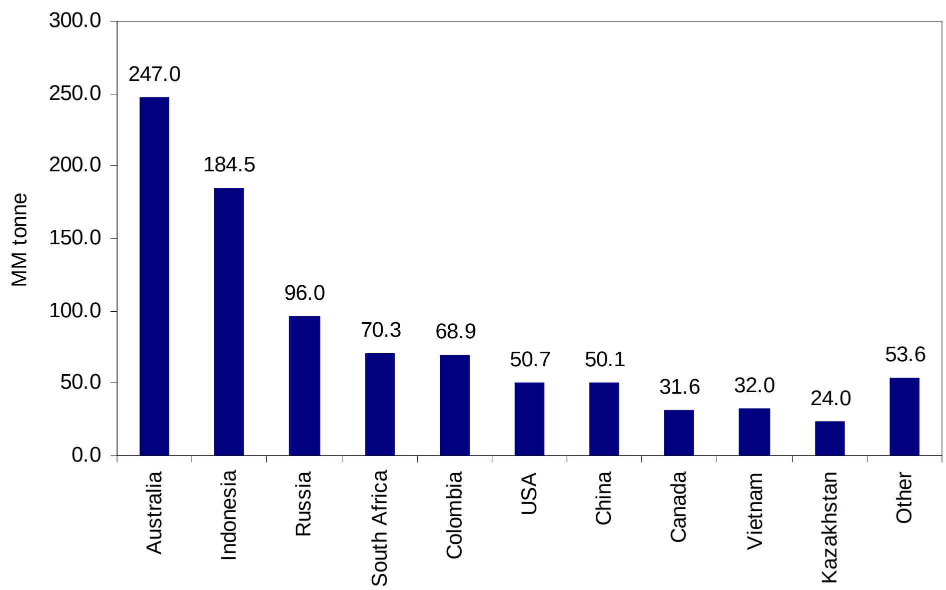
INTERNATIONAL COAL TRADE

About 14% of global coal production is traded internationally. This is large enough to cause a supply and demand imbalance that impacts global prices. The export market has grown 72% since 1998 from 530 million tonnes to 909 million tonnes by last year.

Australia is the largest coal exporter.

Australia is the largest exporter of coal, accounting for 27% of global exports, followed by Indonesia, Russia and South Africa (Figure 35). European buyers are now favoring thermal coal with lower sulphur and nitrogen content following adoption of the EU Large Combustion Plant Directive in 2008.

Figure 35: Global Coal Exporters

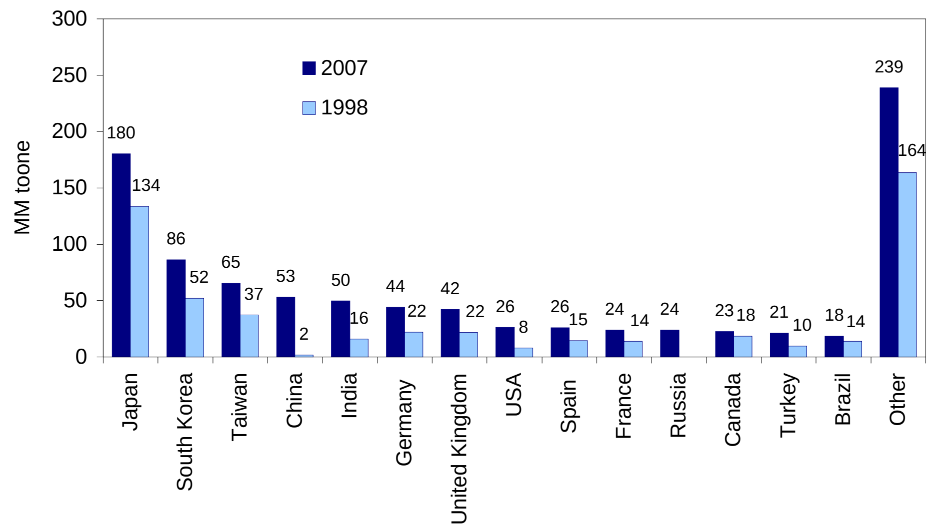


Source: Coal Portal, Dundee Securities, 2007

Japan is the largest coal importer.

Japan is the largest coal importer accounting for 20% of the market, followed by South Korea and Taiwan (Figure 36). China has become a net importer and India is steadily increasing their reliance on imports due to lower coal quality and unreliable domestic supply. However, European demand is driving the growth of global coal exports.

Figure 36: Global Coal Importers



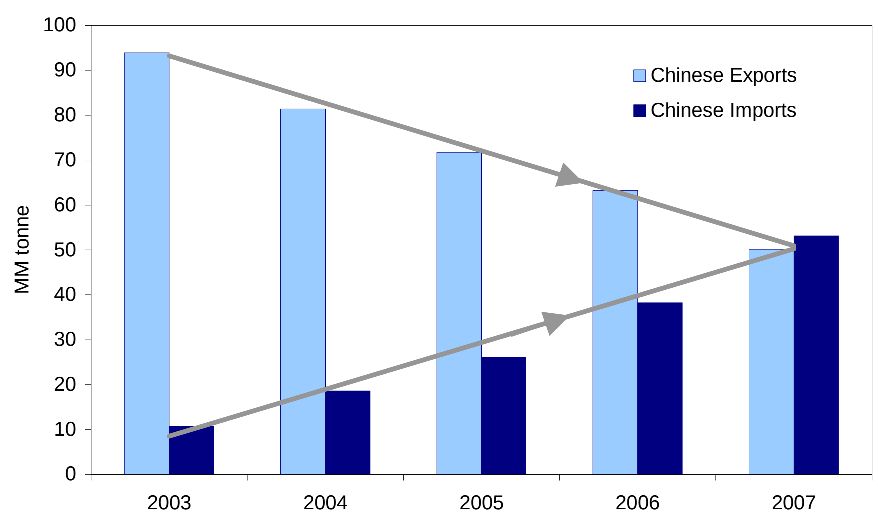
Source: Coal Portal, Dundee Securities

China became a net importer of coal in 2007.

There are relatively few exporters of coal as compared to a diverse group of importers. This provides leverage to the exporters for price setting. Supply disruptions also tend to significantly affect the trade balance which can be reflected in coal prices.

As we noted earlier, China became a net importer of coal for the first time in 2007 (Figure 37). As it seeks more coal to cover its strongly growing demand, it will increase competition in the already strained export markets.

Figure 37: Chinese Coal Imports and Exports



Source: Coal Portal, Dundee Securities

Transportation Costs Play a Key Role

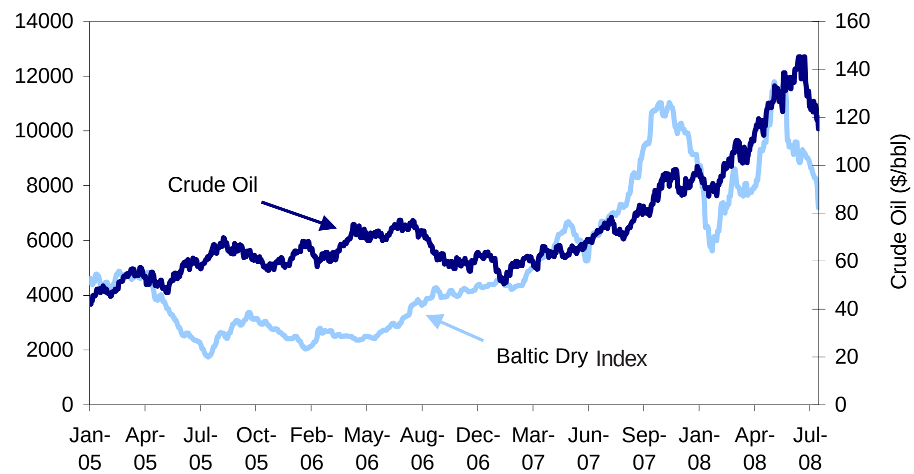
In the Coal business cost of shipping is KEY – You WIN when you can gain a cost advantage in shipping. Transportation constraints have an impact of setting coal prices, and this cost may be significant.

Selling price at Mine Mouth + **Shipping Costs** = **Cost of Coal at Power Plant**

If a utility is willing to pay a certain price for its thermal coal delivered to its plant, transportation costs are factored into the equation. Current cost of shipping by rail is about 4 cents per ton mile in North America. Given strong demand for bulk commodities and skyrocketing oil prices, shipping costs have risen significantly (Figure 38).

Global shipping costs have skyrocketed on the back of rising oil prices.

Figure 38: Shipping Cost Trends

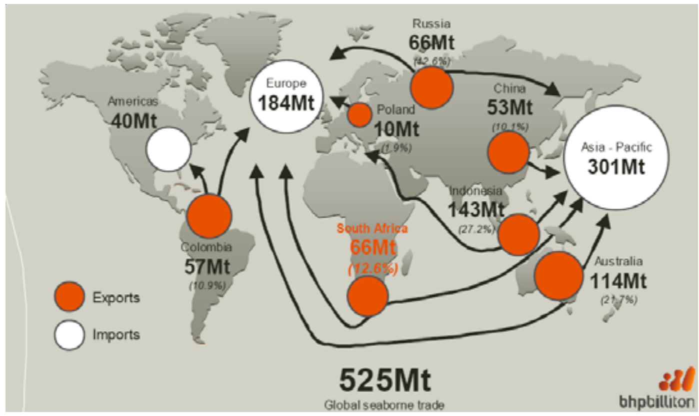


Source: Bloomberg, Dundee Securities

Shipping is also subject to supply-demand pressures.

Seaborne thermal coal trade has increased an average of 7.5% per annum since 1986. Figure 39 shows the favourable routes of seaborne coal trade – almost all routes lead to the Asian Pacific coast and Europe. North American imports are relatively small in comparison.

Figure 39: Global Seaborne Thermal Coal Trade



Source: IEA, BHP Billiton, 2006

Shipping costs have risen eightfold since 2001.

Table 10 outlines trends in selected global coal shipping routes. The shipping cost component as a percentage of delivered coal prices is rising, again due to the same demand pressures. We have seen a significant increase in shipping costs since 2001 – in fact shipping costs from the US to Europe have gone up roughly eight fold. As a result, we are seeing a shift in trading patterns – Australian producers would prefer to ship to Japan over Europe as they will likely see more cash for its product with a smaller proportion going to the shipping companies.

Table 10: Current Global Seaborne Transportation Costs

From	To		Historical Data (Avg.)		2008
			2001	2007	YTD
Hampton Road, **USA**	Rotterdam, **Europe**	$/tonne	5.4	31.5	39.30
Bolivar, **USA**	Rotterdam, **Europe**	$/tonne	5.3	32.8	40.96
Richards Bay, **South Africa**	Rotterdam, **Europe**	$/tonne	6.7	32.4	39.36
New South Wales, **Australia**	Rotterdam, **Europe**	$/tonne	10.5	46.0	56.32
Queensland, **Australia**	Rotterdam, **Europe**	$/tonne	9.5	42.6	51.65
Rizhao, China	Rotterdam, **Europe**	$/tonne	9.0	33.2	40.25
Indonesia	Rotterdam, **Europe**	$/tonne	na	42.6	44.86
Richards Bay, **South Africa**	**Japan**	$/tonne	12.3	78.1	103.64
New South Wales, **Australia**	**Japan**	$/tonne	5.8	33.3	42.44
Queensland, **Australia**	**Japan**	$/tonne	5.6	30.7	39.15
New South Wales, **Australia**	**South Korea**	$/tonne	5.5	35.8	45.73
Richards Bay, **South Africa**	**South Korea**	$/tonne	6.8	40.4	50.24
Roberts Bank, **Canada**	**Taiwan**	$/tonne	6.6	41.4	54.38

Source: Bloomberg, Dundee Securities

The US is gaining a shipping advantage.

US is gaining a shipping advantage to Europe at the cost of its competition.

At these high oil prices, the US is gaining a competitive advantage getting an advantage in shipping to Europe due to its closer proximity. Increased US exports may affect the traditional exporters including Australia, Indonesia and South-Africa, although strong world demand will likely mitigate the impact. As a result, we will likely see further appreciation in US coal prices versus global coal prices going forward as demand for American product increases.

DUNDEE'S COAL PRICE FORECASTS

Coal prices are a factor of supply-demand fundamentals, mining costs and transportation costs. They are also dependent on other factors – type of coal, heat content (BTU), and impurities such as sulphur, chlorine, ash, etc.

About 20-25% of coal trading occurs in the spot market. Prices are quoted as either port of origin (FOB = freight on board) or port of destination (CIF = cost + insurance + freight). There is currently no organized commodity market for metallurgical coal. Metallurgical coal is traded entirely through contracts between suppliers and consumers.

Long term contract pricing typically follow the spot market's lead. Again, long term contracts are priced through agreements between suppliers and consumers. Once lasting for several years, producers are now reluctant to sign contracts for long periods. Most offers to steelmakers or utilities now supply coal for less than a year (three months is common) and have embedded escalation clauses built in.

Thermal Coal Price Forecast

Thermal coal prices typically track its closest competing fuel – natural gas. China, India, East Asia and Europe continue to import coal. With continued demand and regional supply shortages and disruptions, global coal prices will likely stabilize close to current levels. However, a pull back in overall global energy markets (leading to declining oil and natural gas prices) would negatively impact coal prices. We would expect the domestic US coal prices to move upwards towards global coal prices as demand for American coal increases.

Table 11: Dundee's Thermal Coal Price Forecasts

		2006	2007	2008 YTD	2008E	2009E	2010E	2011E	2012E	Long-term Estimate
Northern Appalachian	**US$/short ton**	42	46	91	100	120	100	90	90	65
Central Appalachian	**US$/short ton**	na	52	94	105	125	100	90	90	65
Illinois Basin	**US$/short ton**	36	32	51	65	80	75	70	65	50
Powder River Basin (8800)	**US$/short ton**	13	10	14	15	20	20	18	18	18
Global Thermal Coal*	**US$/metric tonne**	64	89	159	175	180	170	150	125	75

* Europe Thermal Coal (CIF); Rest FOB

Source: Dundee Securities Estimates, Bloomberg

Metallurgical Coal Price Forecast

The demand of metallurgical coal by the steel industry, coupled with the supply disruptions in Australia has helped the price of metallurgical coal reach current prices near the $350 per tonne level. Metallurgical coal supply remains constrained. With limited potential for new supply and ongoing demand by the steel industry, this market will likely remain tight for years. In our view, metallurgical coal prices should hold up in the current steel market. However we do not foresee any significant price increases, believing that metallurgical coal is fairly priced at these levels.

Table 12: Dundee's Metallurgical Coal Price Forecasts

		2006	2007	2008E	2009E	2010E	2011E	2012E	Long-term Estimate
US Met Coal (FOB)	**US$/short ton**	91	89	250	275	225	200	170	100
Global Met Coal*	**US$/metric tonne**	–	–	290	300	275	250	200	120

* Japanese Met Coal (CIF)

Source: Dundee Securities Estimates, Bloomberg

RISKS

There are several risk factors that may negatively impact the coal industry

- Legislative, regulatory and judicial developments, environmental restrictions, changes in energy policy and energy conservation measures that would adversely affect the coal industry, such as legislation limiting carbon emissions (carbon taxes).
- Competition for production of electricity from non-coal sources, including the price and availability of alternative fuels, such as natural gas and oil, and alternative energy sources, such as nuclear, hydroelectric, wind and solar power.
- Project risk and cost overruns may delay or cancel new projects.
- Transportation costs and other input costs.

APPENDIX I: ENVIRONMENTAL CONSIDERATIONS

Kyoto Protocol

The US is responsible for ¼ of the world's CO_2 emissions.

Kyoto covers emissions of the six main greenhouse gases (GHGs): Carbon dioxide (CO_2), methane (CH4), nitrous oxide (N20), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF6). Rather than placing a specific target on each of the gases, the overall emissions targets for all six is combined and translated into CO_2 equivalents.

Under the Kyoto Protocol signed in December 1997, 38 industrialized countries were required to reduce their emission of GHG to an average of 5.2% below 1990 levels in the 2008-2012 time frame. The number of industrialized countries that ratified the Kyoto treaty increased to 169 by December 2006. However, the US, responsible for a quarter of the world's carbon emission, has yet to ratify Kyoto. The US and Australia remain the only countries that have signed, but not ratified the Protocol.

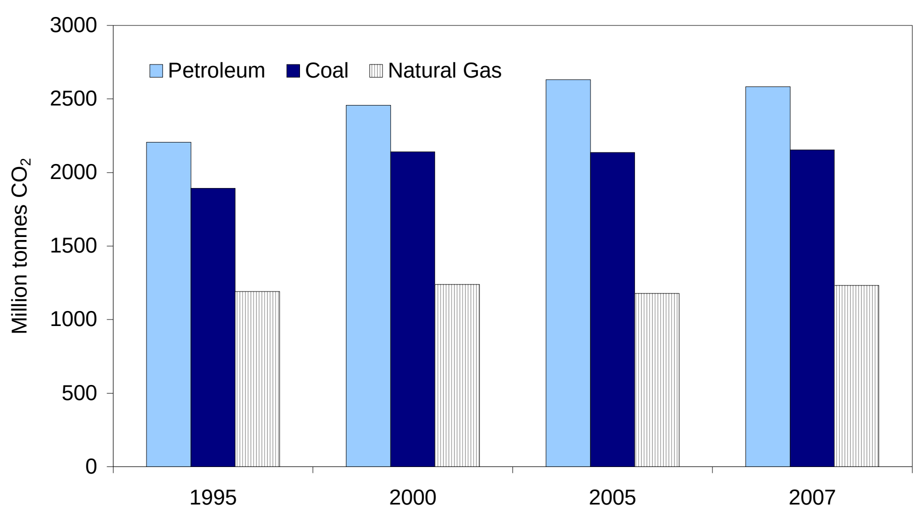
CO_2 Emissions and Carbon Trading

Petroleum continues to be the biggest emitter of CO_2 in US, accounting for 43% of total energy related CO_2 emission in 2007. Coal and natural gas contribute roughly 36% and 21%, respectively (Figure 40).

There is a risk that coal users could be hit harder by possible emission regulations than other fuel users due to the high emission levels per BTU. This may lead to government imposed carbon taxes which are likely to be passed on to customers through rising electricity prices.

Petroleum is the leading CO_2 emitter.

Figure 40: US Energy-Related Carbon Dioxide Emissions by Fuel



Source: EIA

The US is resisting CO_2 trading.

The European Union has been operating the world's largest emissions trading system and the first system to limit and trade carbon dioxide emissions. While the US government has not legislated carbon limits or carbon trading plans, some companies are taking steps toward creating and trading carbon dioxide credits in hopes of eventually entering a larger world market. The most recent attempt is a voluntary carbon trading market project on the Chicago Climate Exchange (CCX).

The cap-and-trade approach to controlling emissions is hardly unprecedented. For years, the US has operated highly successful cap-and-trade systems for emissions of sulphur dioxide and nitrogen oxides. Despite such success, setting up a US cap-and-trade system for CO_2 emissions has proved challenging. Carbon emissions are so central to energy consumption that the idea of imposing a policy to limit them raises serious concerns.

Sulphur Dioxide Trading

SO_2 emissions are trading at its all time low levels.

Under an existing Clean Air Act Amendment, a sulphur dioxide (SO_2) allowance has a vintage-year for which it can be used to meet SO_2 emissions. If unused, it may be banked and used at a later date. There are plenty of SO_2 emissions allowances (6.75 million tons) to meet SO_2 emissions. Actual SO_2 emissions in 2007 were approximately 500,000 tons below the annual cap. This gap is likely to grow in future years with the scrubber retrofit projects underway. The value of SO_2 allowances fell to nearly an all-time low and as of August 1, 2008 it is now trading at $141/ton after reaching an all time high of $1,600 per ton in late 2005.

In July 2008, the U.S. court's decision struck down the Clean Air Interstate Rule, including the provision requiring the Eastern states to relinquish 2 SO_2 allowances for every 1 ton of SO_2 emissions in 2010 and 2.86 allowances for every 1 ton of SO_2 emissions starting in 2018. Instead the status quo requirement remains of 1 SO_2 allowance for every 1 ton of SO_2 nationwide under the existing Clean Air Act Amendment passed by Congress.

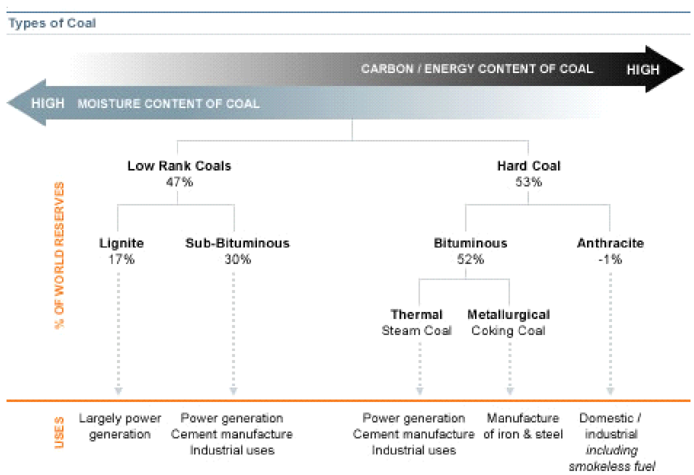
APPENDIX II: COAL, MINING AND PREPARATION

Coal is a fossil fuel. It is a combustible, sedimentary, organic rock, composed mainly of carbon, hydrogen and oxygen. Coal formation began during the Carboniferous period; also known as the first coal age which spanned 360 million to 290 million years ago. Coal is the altered remains of prehistoric vegetation that originally accumulated in swamps and peat bogs. The build-up of silt and other sediments, together with tectonic movements of earth's crust buried these areas. With burial, the plant material was subject to high temperatures and pressures. Over many million years, this caused physical and chemical changes in the vegetation, first transforming it into peat and then into coal.

Types of Coal

There are four major ranks of coal in the US classification scheme. It is classified according to its organic maturity, heating value, its fixed carbon and volatile matter content. The coal ranks from highest to lowest in heating value are: Anthracite, Bituminous, Sub-bituminous and Lignite. Its organic maturity is dependant on temperature and length of time in formation (Figure 41).

Figure 41: Organic Maturity of Coal



Source: World Coal Institute

Higher quality coals are generally harder and often have a black vitreous luster. They have high carbon content, lower moisture levels, and produce more energy. The prices of such coals are typically higher than low quality coals. Low quality coals, such as lignite and sub-bituminous coals are softer, friable and its colour can range from dark black to various shades of brown. They have low carbon content and high moisture levels, and therefore have low energy content (Table 13).

Table 13: Coal Ranks of US Coal

Type of Coal	Avg Energy Content (Btu per lb.)	Carbon Content (%)	Sulfur Content (%)	Known U.S. Reverses (%)
Anthracite	12,500	86-98	0.4-1.9	1.5
Bituminous	12,000	50-86	0.8-5.0	53
Sub-bituminous	9,000	40-0	0.6-1.8	37
Lignite	7,000	40	1.6	9

Source: U.S. Department of Energy, EIA

Coal Mining Methods

Geology of the coal deposit determines the mining method. Depth, thickness, and configuration of the coal seams influence this choice. Worldwide, underground mining accounts for 60% of production with 40% coming from surface mining. Surface mining is predominant in Australia (80% of its coal mining) and the US (67% of its coal mining).

Underground Mining

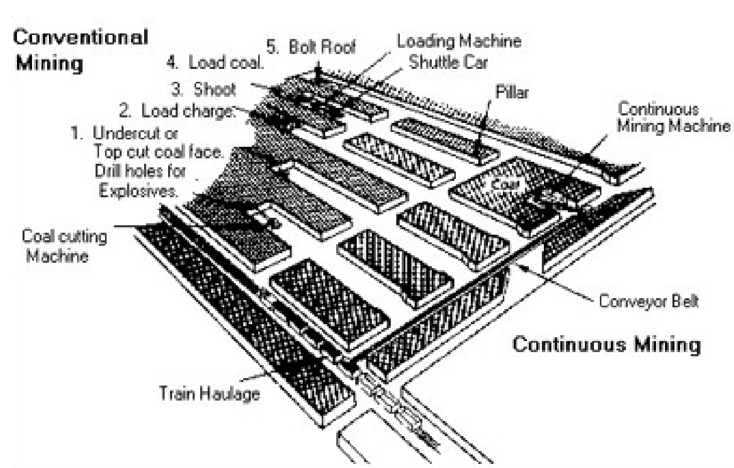
Room-and-pillar and longwall mining are the two main methods used in mining coal underground. The choice of mining technique is site specific but always based on economic considerations. Longwall section typically have production rates of 1,000 to 20,000 tonnes per shift while room-and-pillar mines usually have lower production rates of 600 to 1,000 tonnes per shift per miner unit. The main advantage of room-and-pillar mining over longwall mining is that it allows coal production to start earlier, using smaller and cheaper mobile machinery. Longwall mining requires specialized machinery (mechanized shearer) which can cost up to $50 million each.

Underground mining accounts for 60% of global coal production.

Room-and-pillar mining is the most common underground mining method (Figure 42). The deposits are mined by cutting a network of rooms into the coal seam and leaving behind pillar of coal to support the roof of the mine. There are two types of room and pillar mining – conventional mining and continuous mining. In conventional room-and-pillar, the coal seam is cut, drilled, blasted and then loaded into cars. In the more prevalent continuous mining, a machine known as a continuous miner cuts the coal seam and simultaneously loads the coal on to a shuttle. The coal eventually is placed onto a conveyor belt that moves the coal to the surface.

As coal is being left in the ground as pillars, using this mining method normally results in only up to 60% recovery. To increase recovery, under special circumstances pillars may be mined towards the end of mining in a process called “retreat mining”. The roof is then allowed to collapse and the mine is abandoned.

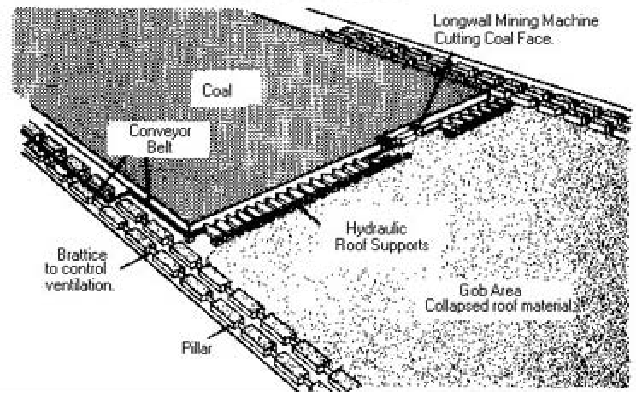
Figure 42: Room-and-Pillar Mining Method



Source: United Mine Workers of America

Longwall mining involves the extraction of coal in large blocks or panels (up to 100 to 350m long) using a mechanized shearer. Self-advancing, hydraulically-powered supports hold up the roof while coal is extracted, after which the roof is allowed to collapse behind the machine. This method typically recovers about 75% of the coal (Figure 43).

Figure 43: Longwall Mining Method



Source: United Mine Workers of America

Surface Mining

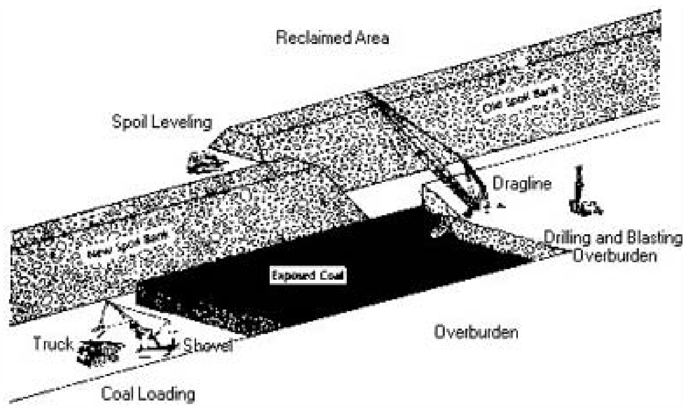
Surface mining accounts for 40% of global coal production.

Surface mining is often used when coal seams are located near the surface. In this method the overburden is first broken up by explosives, it is then removed by dragline or by shovel and truck. Once the coal seam is exposed, it is drilled, fractured and systematically mined in strips.

Surface mining is safer than underground mining because the miners are not exposed to such potential hazards as, roof falls, explosions caused by methane gas or dust ignitions. Productivity is often greater and recoveries may reach over 90%.

There are three general methods of surface mining: **contour mining**, area mining, and open-pit mining, with variations of each. The contour mining method is practiced commonly in rolling or mountainous terrain where the seams of coal outcrop on the mountain slopes. The **area mining** method is favored where the terrain is flat or only slightly rolling and where the mine site includes large stretches of land. The first cut, often referred to as a box cut, results in a long pit with a highwall on both sides of the cut. Overburden from the first pit is placed in a convenient hollow or else stored to be available later for filling the final cut. A second cut is started adjacent to the first cut into which the second cut's overburden is placed. Strip by strip, the mining thus proceeds across the property. This type of mining is usually conducted with giant draglines or shovels. The **open-pit mining** method is most often used where the coal beds are extremely thick. Open-pit operations generally use the bench-mining approach, in which a series of benches or terraces forms the open pit (Figure 44).

Figure 44: Area Surface Mining

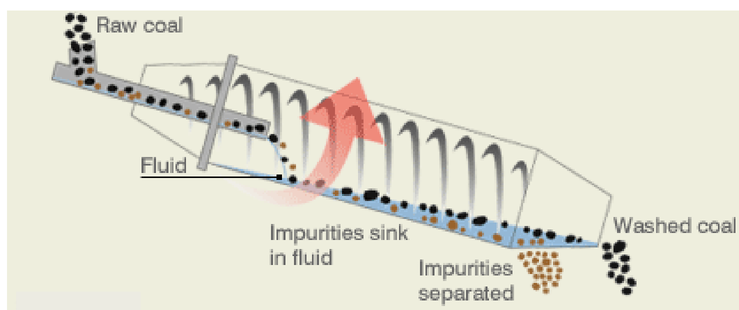


Source: United Mine Workers of America

Coal Preparation

Coal preparation – also known as coal beneficiation or coal washing, refers to the treatment of run-of-mine (ROM) coal to ensure a consistent quality for particular end-uses. This process involves grinding the coal into smaller pieces and passing it through a gravity separation process. Systems include hydrocyclones, heavy media separation, and froth flotation technologies (Figure 45).

Figure 45: Coal Washing Facility



Source: DTI

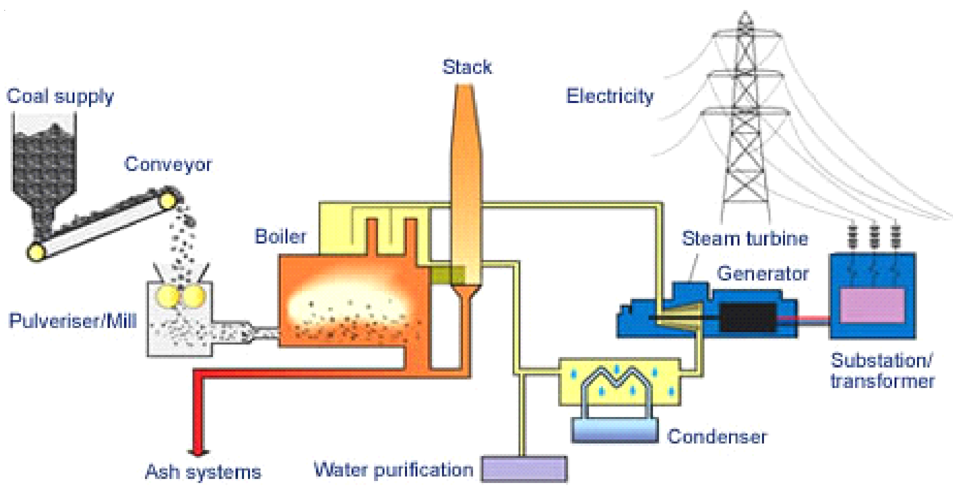
Coal washing/cleaning is performed for two main reasons. It removes impurities and boosts the heat content of the coal, thereby improving power plant capacity. Secondly, it reduces potential air pollutants, especially sulphur dioxide. Washing works to remove ash and inorganic sulphur (such as pyrite) which accounts for up to half of the total sulphur found in the coal.

APPENDIX III: USES FOR COAL

Thermal Coal – Electricity Generation

Earlier conventional coal-fired power stations used lump coal, but modern plants now tend to use fine powdered coal. This increases the surface area of the fuel and allows it to burn quickly. In pulverized coal combustion (PCC) systems, the powered coal is blown into the combustion chamber of a boiler where it is burnt at high temperature. The hot gases and heat energy produced coverts water into steam. The high pressure steam is passed into a turbine which intern rotates the generator to produce electricity. Modern PCC technology is well-developed and accounts for over 90% of coal-fired capacity worldwide (Figure 46).

Figure 46: Typical Coal-fired Power Station



Source: World Coal Institute

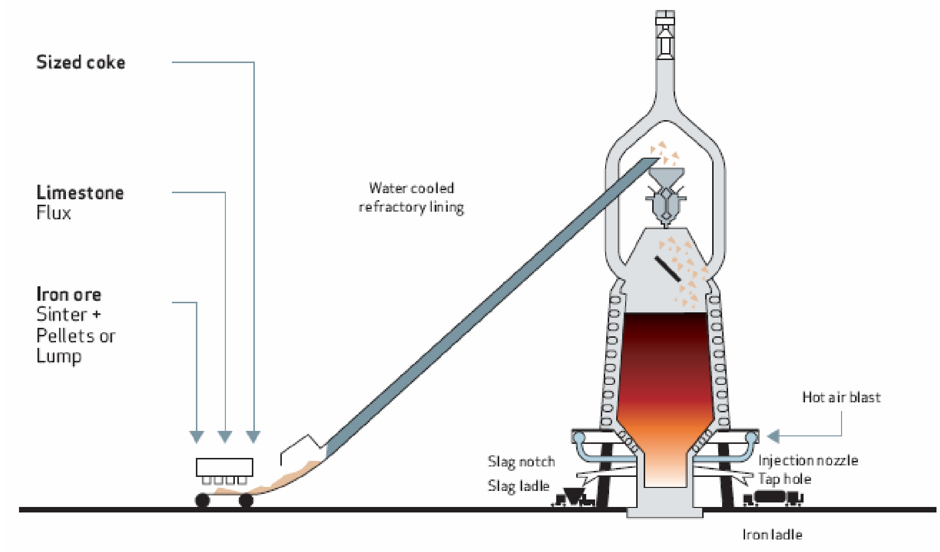
Metallurgical Coal – Input for Iron and Steel Production

Metallurgical coal, also known as coking coal, is essential for iron and steel production. Worldwide, 65% of steel production comes from iron made in blast furnaces which use metallurgical coal. Around 0.63 tonnes of coke is needed to produce 1 tonne of steel. Coke is made from metallurgical coal, which has physical properties that causes iron ore to soften, liquefy and then resolidify into hard but porous lumps when heated in the absence of air. Coking coals must have low sulphur and phosphorous content. Metallurgical coal is relatively scarce and thus more expensive than the thermal coal.

Iron and steel is produced in a blast furnace through a combination of iron ore, coke and small quantities of limestone (flux). These raw materials are fed into the top of the blast furnace, air is heated to about 1200 degree Celsius and blown into the furnace through nozzles in the lower section. The air causes the coke to burn producing carbon monoxide, which causes a chemical reaction. The iron ore is reduced to molten iron by removing the oxygen. A tap at the bottom of the furnace is periodically opened and molten iron and slag is drained. Developments in the steel industry have enabled 'pulverized coal injection' (PCI) technology to be used. This allows coal to be injected directly into the blast furnace and hence a wide variety of coals can be used in PCI including thermal coal (Figure 47).

Figure 47: Typical Blast Furnace

Coal Use in Steel Production

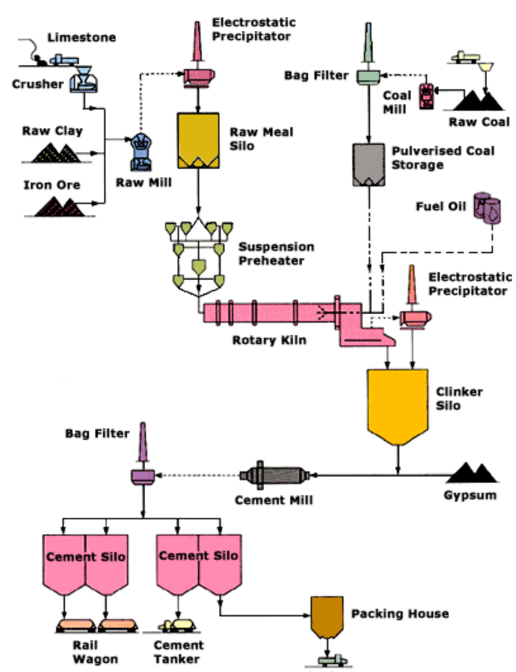


Source: World Coal Institute

Coal – Input for Cement Production

Cement is critical to the construction industry where coal is used as a primary energy source in cement production. With more than 1.35 billion tonnes of cement used globally every year, the cement industry is an energy intensive industry with energy typically accounting for 30-40% of production costs. Kilns usually burn coal in the form of powder and consume around 0.5 tonnes of coal for each 1 tonne of cement produced (Figure 48).

Figure 48: Typical Cement Production Process



Source: Tasek Corporation Berhad

APPENDIX IV: CLEAN COAL TECHNOLOGY

Coal is the most impure of all fossil fuels and contains carbon, hydrogen, ash, sulphur, and other components. In addition to CO_2, it produces SO_2 another air pollutant. A range of technologies are being used and developed to reduce emissions, reduce waste and increase the amount of energy gained from each tonne of coal used.

Sulphur Dioxide (SO_2) Reduction

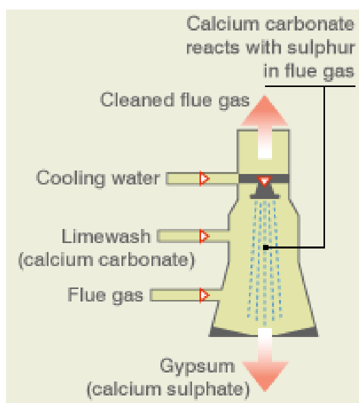
Flue Gas Desulphurization Systems

Flue gas desulphurization (FGD) systems are used to remove sulphur dioxide (Figure 49). There are two types of scrubbers: The "dry" scrubber, usually used with low-sulphur coal, is capable of about 90% SO_2 removal; and, the "wet" lime stone slurry scrubber, usually used with high-sulphur coal, is capable of about 98% SO_2 removal. Wet scrubbers are the most widespread method. A mixture of limestone and water is sprayed over the flue gas and this mixture reacts with the SO_2 to form gypsum (a calcium sulphate), which is removed and used in the construction industry.

Most coal-fired plants either have scrubbers or use coal with a maximum sulphur content of about 1%. Emissions of SO_2 from current coal-fired plants have been reduced by about one-third since 1970.

Figure 49: Wet Scrubber/ Flue Gas Desulphurization

Removing Sulphur Dioxide



Source: ZE PAK

NOx Reduction

Nitrogen Oxides are air pollutants mainly formed by the oxidation of elemental nitrogen during the coal combustion process.

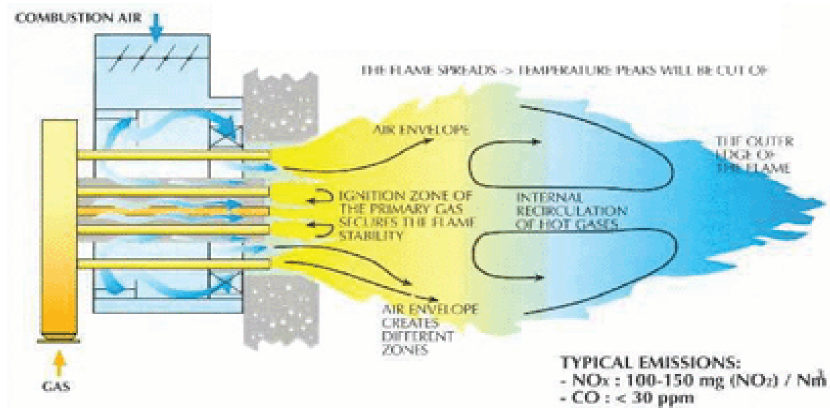
Selective Catalytic Reactor Systems (SCR)

SCR is a process where a reductant, most often ammonia, is added to the flue. The reductant then reacts with the NOx in the emissions and forms H_2O and N_2 (ambient nitrogen). This process may take place at anywhere between 500°F and 1200°F depending on the catalyst used. SCR may reduce NOx emissions by up to 90%.

Low NOx Burners

These specially designed burners restrict the amount of oxygen available in the hottest part of the combustion chamber where the coal is burned (Figure 50). Changing the shape and formation of the flame by using plates to control airflow, a more elongated flame is created in the burner. The temperature is decreased due to increased surface area, and the lower temperature reduces the amount of thermal NOx.

Figure 50: Low NOx Burners



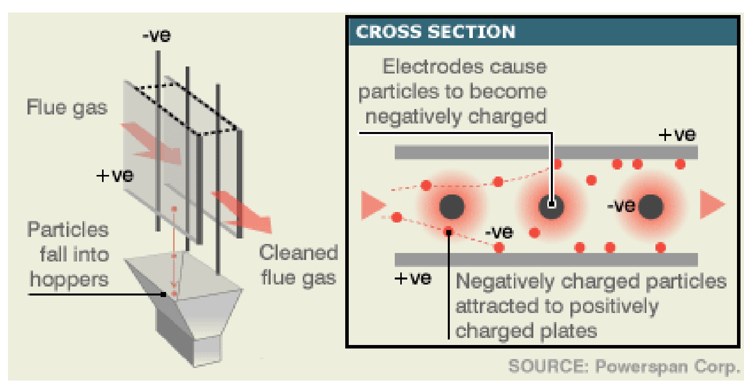
Source: E Instruments Group

Particulate Emissions

Electrostatic precipitators can remove more than 99% of particulate matter from the flue gas (Figure 51). The system works by generating an electrical field to create a charge on airborne particles which are then attracted by collection plates. Other less common removal methods include fabric filters and wet particulate scrubbers.

Figure 51: Electrostatic Precipitators

Electrostatic Precipitation



Source: Powerspan Corp.

Technological Innovation – CO_2 Reduction

An important method in reducing CO_2 emissions is through improved thermal efficiencies of coal-fired plants. Thermal efficiency is a measure of the overall fuel conversion during the electricity generation process. The higher the efficiency levels, the greater the energy being produced from the same tonne of coal.

Different technologies are often suited for different types of coal, and the choices often depend on a country's level of economic development. The developing world is unlikely to use the more expensive, highly advanced technologies.

Coal ugrading – up to 5% CO_2 reduction

Coal washing – also known as coal beneficiation or coal preparation – refers to the treatment of run-of-mine (ROM) coal. This treatment removes a proportion of the unwanted waste and ensures a consistent coal quality for the power plant. Coal washing leads to improved efficiency of coal-fired plant, which leads to a reduction in emission of CO_2 of up to 5%. The ash content of coal can be reduced by over 50%, helping cut waste from coal combustion.

Efficiency improvements of existing plant – up to 22% CO_2 reduction

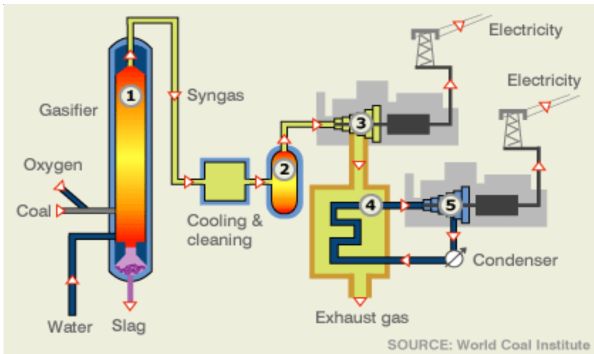
The current global average thermal efficiency of coal-fired power stations are around 30%, with organization for economic co-operation and development (OECD) averaging about 38% and China 27%. However, newer conventional coal-fired sub-critical generation have an improved efficiency of 38-40%. The technological advancement into supercritical and ultra-supercritical power plants offers thermal efficiency ranging from 43% to 50%. Supercritical plant operates at higher steam temperatures and pressures than conventional plant. There are more than 400 supercritical plants in operation worldwide. Improved efficiency reduces the amount of coal required, reducing emissions.

Integrated gasification combined cycle – up to 25% CO_2 reduction

Integrated Gasification Combined Cycle (IGCC) is an approach of producing a liquid gas from coal (Figure 52). In IGCC, coal is not combusted directly but reacted with oxygen and steam to produce a syngas composed mainly of hydrogen and carbon monoxide. This syngas is cleaned for impurities and then burned in a gas turbine to generate electricity.

IGCC systems operate at high efficiencies, typically from 45% to 50% with prospects of net efficiencies of 56% in the future. They also remove 95-99% of NOx and SOx emissions. There are around 160 IGCC plants worldwide.

Figure 52: Typical Integrated Gasification Combined Cycle



1. Coal burned to produce syngas
2. Syngas burned in combustor
3. Hot gas drives gas turbines
4. Cooling gas heats water
5. Steam drives steam turbines

Source: World Coal Institute

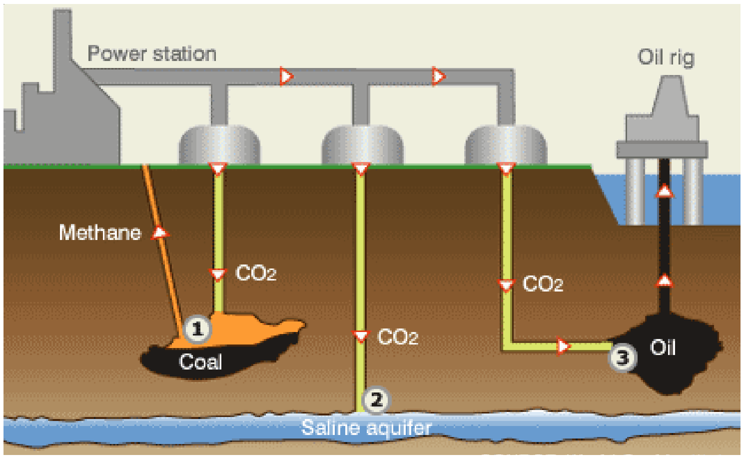
Carbon capture & sequestration (zero emission) – up to 99% CO_2 reduction

Carbon capture and sequestration/storage (CCS) involves capturing the carbon dioxide from the exhaust stream of coal combustion and dispose in such a way that the CO_2 does not enter the atmosphere. Underground storage may be one such disposal method.

Carbon capture is a realistic option for attaining zero CO_2 emissions.

Various approaches of CCS have been developed and have proven to be technically feasible (Figure 53). While further development is needed to demonstrate the viability of separating CO_2 from high volume, low CO_2 concentration flue gases from coal-fired power stations, carbon capture is a realistic option for the future.

Figure 53: Carbon Capture and Storage Technique



1. CO_2 pumped into disused coal fields displaces methane which can be used as fuel
2. CO_2 can be pumped into and stored safely in saline aquifers
3. CO_2 pumped into oil fields helps maintain pressure, making extraction easier

Source: World Coal Institute

COAL-TO-LIQUID – THE NEXT OIL SANDS!

Coal-to-liquids (CTL) involves transforming coal into liquids such as diesel by direct liquefaction, or by using the Fisher-Tropsch process whereby coal is gasified then liquefied by using a catalyst. Two or three barrels of crude oil can be made with one tonne of coal with efficiencies ranging from 60-70% for direct liquefaction and over 40% for indirect liquefaction.

Coal-to-liquid (CTL) technology was developed approximately 100 years ago, but has only ever been used by Germany and South Africa when confronted by critical fuel shortages. The current CTL industry comprises of one established producer in South Africa, a near producer in China, and over 30 projects under consideration.

The quadrupling of oil prices in the last decade has potentially made CTL appealing. While oil costs approximately $130/barrel, the Oil and Gas Journal has projected that CTL fuel can be produced for $67 to $82 a barrel. The ultimate cost would be determined by the availability of water and electricity as the process uses massive amounts of both.

Production costs for Coal-to-Liquid technology ranges from $67 to $82 a barrel.

In the US where the government and energy industry hope to capitalize upon abundant coal reserves to create more "energy independence," a CTL push is on in the Powder River Basin. Construction is due to start on a plant in Wyoming in 2009, in a partnership between DRKW Advanced Fuels and Arch Coal Inc. Companies developing CTL technology include General Electric and Exxon Mobil.

Sasol, a South African company is the only company in the world which operates a CTL facility and has demonstrated the viability of the Fisher-Tropsch process. This operation produced 160,000 bbl/day or 37% of the country's liquid fuel needs in 2007. Shenhua Group, China's largest coal company, is building a 20,000 bbl/day plant in Inner Mongolia that uses direct liquefaction with an option to expand to 100,000 bbl/day. This project is expected to commission in 2008.

Concerns that may slow CTL development include that the project can emit large quantities of CO_2, ample water is required, and capital costs are high. We believe the benefits of CTL in the high oil price environment outweigh the concerns and the potential of this nascent industry is significant. Growing demand from CTL projects in a tight oil market will support the coal industry as it takes about half a tonne of coal to produce a barrel of liquid product. EIA projects that by 2030, the world would have 3.9 MM bbl/day of CTL fuel production which would translate into 700 million tonnes of annual coal consumption or 15% of world coal production.

APPENDIX VI: DUNDEE'S ECONOMIC MODEL FOR COAL

Table 14: Cost of Fuel to Generate One kWh of Electricity

Key Assumptions:

	Efficiency	Quality
Coal	38%	12,000 Btu/lb
Natural Gas	58%	1,031 Btu/cu.ft

Key Convestions:

1 Therm = 100,000 Btu = 29.31 kWh

1 lb Coal = 12,000 Btu, 1 short ton Coal = 24.0 million Btu

1 cubic foot of Natural Gas = 1031 Btu

Coal		**Coal-Fired Plant**	
$/ton	**$/MM Btu**	**Efficiency**	**Cents/kWh**
10	0.42	38%	0.37
20	0.83	38%	0.75
30	1.25	38%	1.12
40	1.67	38%	1.50
50	2.08	38%	1.87
60	2.50	38%	2.24
70	2.92	38%	2.62
80	3.33	38%	2.99
90	3.75	38%	3.37
100	4.17	38%	3.74
110	4.58	38%	4.12
120	**5.00**	**38%**	**4.49**
130	5.42	38%	4.86
140	5.83	38%	5.24
150	6.25	38%	5.61
160	6.67	38%	5.99
170	7.08	38%	6.36
180	7.50	38%	6.73
190	7.92	38%	7.11
200	8.33	38%	7.48

Natural Gas	**Gas-Fired Plant**	
$/MM Btu	**Efficiency**	**Cents/kWh**
1	58%	0.59
2	58%	1.18
3	58%	1.76
4	58%	2.35
5	58%	2.94
6	58%	3.53
7	58%	4.12
8	58%	4.71
9	**58%**	**5.29**
10	58%	5.88
11	58%	6.47
12	58%	7.06
13	58%	7.65
14	58%	8.24
15	58%	8.82
16	58%	9.41
17	58%	10.00
18	58%	10.59
19	58%	11.18
20	58%	11.76

Source: Dundee Securities

Table 15: Cost of Electricity Produced by Natural Gas and Various Coals

Natural Gas		Europe (API2)		Central Appalachian		Illinois Basin		Powder River Basin	
		10,800 Btu/lb, <1% SO_2		12,000 Btu/lb, <1% SO_2		11,500 Btu/lb, <3% SO_2		8,800 Btu/lb, <0.3% SO_2	
$/MM Btu	**Cent/kWh**	**$/tonne**	**Cent/kWh**	**$/ton**	**Cent/kWh**	**$/ton**	**Cent/kWh**	**$/ton**	**Cent/kWh**
1.00	0.59	15	0.57	10	0.37	5	0.20	2	0.10
2.00	1.18	30	1.13	20	0.75	10	0.39	4	0.20
3.00	1.76	45	1.70	30	1.12	15	0.59	6	0.31
4.00	2.35	60	2.26	40	1.50	20	0.78	8	0.41
5.00	2.94	75	2.83	50	1.87	25	0.98	10	0.51
6.00	3.53	90	3.39	60	2.24	30	1.17	12	0.61
7.00	4.12	105	3.96	70	2.62	35	1.37	**14**	**0.71**
8.00	4.71	120	4.53	80	2.99	40	1.56	16	0.82
9.00	**5.29**	135	5.09	90	3.37	45	1.76	18	0.92
10.00	5.88	150	5.66	100	3.74	50	1.95	20	1.02
11.00	6.47	165	6.22	**110**	**4.12**	55	2.15	22	1.12
12.00	7.06	180	6.79	120	4.49	60	2.34	24	1.22
13.00	7.65	**195**	**7.35**	130	4.86	65	2.54	26	1.33
14.00	8.24	210	7.92	140	5.24	**70**	**2.73**	28	1.43
15.00	8.82	225	8.48	150	5.61	75	2.93	30	1.53
16.00	9.41	240	9.05	160	5.99	80	3.12	32	1.63
17.00	10.00	255	9.62	170	6.36	85	3.32	34	1.73
18.00	10.59	270	10.18	180	6.73	90	3.51	36	1.84

Note: Assumptions, Efficiency of Coal-Fired plant = 38%, Efficiency of Natural Gas-Fired plant =58%

Source: Dundee Securities

Table 16: Cost of Natural Gas and Various Coals in $/MM BTU

Natural Gas	Europe (API2)		Central Appalachian		Illinois Basin		Powder River Basin	
	10,800 Btu/lb, <1% SO_2		12,000 Btu/lb, <1% SO_2		11,500 Btu/lb, <3% SO_2		8,800 Btu/lb, <0.3% SO_2	
$/MM Btu	**$/tonne**	**$/MM Btu**	**$/ton**	**$/MM Btu**	**$/ton**	**$/MM Btu**	**$/ton**	**$/MM Btu**
1.00	15	0.63	10	0.42	5	0.22	2	0.11
2.00	30	1.26	20	0.83	10	0.43	4	0.23
3.00	45	1.89	30	1.25	15	0.65	6	0.34
4.00	60	2.52	40	1.67	20	0.87	8	0.45
5.00	75	3.15	50	2.08	25	1.09	10	0.57
6.00	90	3.78	60	2.50	30	1.30	12	0.68
7.00	105	4.41	70	2.92	35	1.52	**14**	**0.80**
8.00	120	5.04	80	3.33	40	1.74	16	0.91
9.00	135	5.67	90	3.75	45	1.96	18	1.02
10.00	150	6.30	100	4.17	50	2.17	20	1.14
11.00	165	6.93	**110**	**4.58**	55	2.39	22	1.25
12.00	180	7.56	120	5.00	60	2.61	24	1.36
13.00	**195**	**8.19**	130	5.42	65	2.83	26	1.48
14.00	210	8.82	140	5.83	**70**	**3.04**	28	1.59
15.00	225	9.45	150	6.25	75	3.26	30	1.70
16.00	240	10.08	160	6.67	80	3.48	32	1.82
17.00	255	10.71	170	7.08	85	3.70	34	1.93
18.00	270	11.34	180	7.50	90	3.91	36	2.05

Source: Dundee Securities

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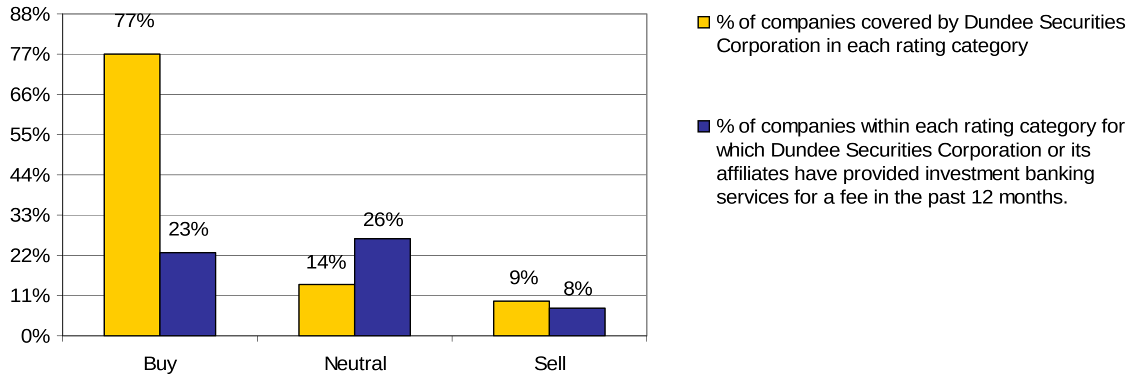

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