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The European Coal Market:
Will Coal Survive the EC's Energy and Climate Policies?

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October 2012

Gouvernance européenne
et géopolitique de l'énergie

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ISBN: 978-2-36567-081-4

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Executive Summary

Introduction

The European coal industry is at a crossroads. The European Commission (EC) Energy Policy by 2020, *the 20/20/20 targets,* is not favourable to coal:

a 20% decrease in CO_2 emissions does not favour coal compared with natural gas, its main competitor in electricity generation;

a 20% increase in energy efficiency will lead to a decrease in energy/coal consumption;

a 20% increase in renewables will displace other energy sources, including coal.

The recent EC Energy Roadmap to 2050 targets a cut in GHG emissions by 80-95%. Under such a tough emissions reduction target, the future use of coal is tied with CCS technologies for which public acceptance and an adequate CO_2 price are crucial.

The Large Combustion Plants Directive has already had a huge impact on EU coal-fired electricity generation. In UK, a third of coal-fired power capacity will be closed by the end of 2015 at the latest.

Phase III of the EU Emissions Trading Scheme requires CO_2 allowances to be auctioned from January 2013, adding a new burden on fossil fuel power plants.

The end of state aid to European hard coal production by 2018, in line with EC Council Decision 2010/787/EU, means that domestic production is going to decrease.

Does this mean the end of coal in Europe? Maybe not, and certainly not by 2020, although its future after that date is quite uncertain.

Coal provides 17% of the EU's primary energy supply, and represents 25% of electricity generation. With the phasing out of nuclear energy in some countries (mainly Germany), coal has gained a period of grace before the transition to a less-carbonised economy. Its consumption by European power utilities increased by 7% in the

first half of 2012, boosted by low CO_2 prices and relatively high gas prices.

European production still accounts for 60% of the total coal supply in the EU. Coal therefore gives the EU a certain degree of independence and contributes to its security of supply. Hard coal and lignite represent approximately 80% of EU conventional reserves of fossil fuels.

Coal contributes to the economic activity and employment in the region. The EU mining industry employs 260,000 workers (direct jobs) and the turnover of the whole coal industry is estimated at €25 billion a year.

Coal prices, despite their rising trend in the past few years, are much lower than competing fuels: half the price of natural gas imported in Europe.

As coal ensures safe, reliable, affordable and sustainable energy for all, it will be very much needed in the years to come. However, coal is proscribed in a CO_2-free environment. Its combustion in thermal power plants – its main outlet in Europe – emits twice as much CO_2 as gas plants.

Although a lot of R&D work is done to capture CO_2 emissions from coal plants and store it, no zero emission commercial plants have yet started operation. Several CCS projects have been delayed, or even cancelled, in the past few years due to regulatory uncertainties, a lack of funding and public opposition to CO_2 storage. The current European economic crisis and the large sovereign debts have also reduced public funding in CCS projects.

The future of coal in Europe is therefore very uncertain. Will CCS development allows it to remain a fuel of choice, given large available reserves at low prices, compared with competing energy sources? Or will coal disappear from the European energy mix? How fast will the decline in European coal production be?

This report looks at these issues and highlights some facts, trends and regulation that may affect the supply and demand of coal in the future. The analysis concentrates on steam coal used to generate electricity, since the power generation sector is by far the largest user of coal in Europe.

Key findings

European domestic production is projected to decline following the end of public subsidies to the hard coal mining sector by 2018 at the latest. The decline is particularly sharp in Germany and Spain. In the latter country, recent cuts in coal mining subsidies have led to violent protests against government austerity measures. In the longer term, in the New Policies Scenario of the International Energy

Agency, EU coal production is expected to fall by 28% in 2020 and 63% in 2035, both compared to 2009. Demand from international trade is however limited, given the expected drop in consumption. Hard coal production in the EU generally suffers from largely depleted deposits, declining coal quality and excessively high production costs. Its production therefore has difficulty in competing with international coal. The picture is different for lignite. Its production is cost-competitive with hard coal imports. It could therefore continue providing a degree of **security of supply for the EU**. Reserves however are concentrated in four countries (Germany, Poland, the Czech Republic and Greece) and Germany alone accounts for 72% of EU reserves, so future EU lignite production will be essentially driven by development there. The decline in EU coal production will lead to a similar decline in coal employment and turnover of the coal mining sector.

Import steam coal prices are cheaper than competing fuels. Volatility of oil and gas prices due to the political situation in the Middle East and North African countries has reinforced this competitiveness. The overwhelming share of the Pacific basin in international coal trade – China and India particularly – means that international coal prices are driven by events and policies in Asia.

Coal use in European electricity generation is projected to decline during the decade following **stricter environmental standards on air pollution and CO_2 emissions**. The Large Combustion Plants Directive has a huge impact on ageing coal plants in Europe. By the end of 2015, around 35 GW of coal-fired capacity will be closed. The Industrial Emissions Directive tightens the emission limits of pollutants from 2016 onwards, and an additional capacity of 20 GW to 25 GW may close by 2023. Phase III of the EU ETS will oblige power utilities to auction CO_2 allowances above a pre-determined cap. CO_2 emissions therefore will have to be reduced drastically and the auction price of CO_2 incorporated into power generation costs. This new burden does not favour of coal plants. However, much depends on the price of CO_2 allowances. Its collapse in 2012 has allowed coal to be the most favoured fuel to generate electricity in Europe.

The EC policy on energy and climate and the new EU energy Roadmap to 2050 clearly define a **decarbonisation of the EU energy/electricity mix**. The goal is ambitious with a reduction in GHG emissions of 80-95% by 2050, a large development of renewables in the electricity mix and a drastic reduction in energy demand. **The future use of coal in Europe therefore appears intrinsically linked to the commercial development of CCS technologies.** They are the only currently available technologies to cap directly coal-based CO_2 emissions and reconcile the use of high CO_2 emitting fossil fuels with a low-carbon electricity mix. Although CCS technologies are proven, they currently face significant barriers to their widespread commercial deployment. Costs remain too high and public funding is insufficient. Regulatory uncertainties and public

opposition limit their development. And the current price of CO_2 does not give the price signal necessary for their deployment.

Given these uncertainties, the future use of coal is foreseen to fall in all scenarios analysed. In the New Policies Scenario of the International Energy Agency, **European coal demand halves over the period 2009-2035**. In the EC scenarios, **the share of coal in electricity generation shrinks from 25% in 2010 to between 2% and 13% by 2050**, displaced by renewables and natural gas.

The future of coal after 2020/2030 therefore depends on CO_2 prices, technological progress on CCS and financial commitments and regulations that governments take today in order to demonstrate the commercial viability of the technology.

Government response so far has been mixed, as shown in the analysis of four major coal markets.

In **Germany**, public opposition to CO_2 storage and distribution of political power between the federal state and the *Länders* make the establishment of a proactive policy in favour of CSS very difficult. However, the phase-out of nuclear energy, the slower-than-expected development of offshore wind and electricity security of supply issues will lead to an increased use of coal until 2022 at least.

In **Poland**, the scientific community is mobilised so that CCS technologies become a reality and enable the country to continue ensuring a degree of energy independence thanks to its abundant coal reserves. The new energy policy, to be announced by the government in 2012/13 and government support provided to CCS projects in the country will determine the future of Polish coal and its place in the electricity mix.

The **United Kingdom** intends to be a leader in CCS technology. Its CCS Roadmap to 2050 and the financial commitment made by the government reflects this willingness. The private sector is also committed to this development, since no less than 16 companies have expressed interest in participating in the new CCS competition launched by the government in April 2012. The future of coal in the country is however seriously compromised by new European and national regulations and its role is expected to decline sharply during the decade.

In **Spain**, the future of coal is mixed. Cuts in hard coal mining subsidies lead to a rapid fall in domestic production which is replaced by coal imports. Coal miners' protests have so far been unable to change the situation although miners have become a symbol of social resistance to government austerity measures. The serious economic and financial crisis in the country does not help with the financing of CCS projects, which may stay in their pilot stage.

Ultimately, the question is whether technological breakthroughs in CCS, including public acceptance, overcome stringent CO_2 regulations and allow coal to survive. Or will breakthroughs in other areas of the energy sphere (offshore wind,

photovoltaic power) spell the death of coal in the electricity mix? As nobody can answer these questions, investment in new power plants is a challenging issue, at a time when back-up facilities to intermittent renewables are much needed.

Structure of the report

The first part of this report looks at the European coal market region-wide. Chapter 1 describes the EU coal market in the global context. Chapter 2 analyses the significance of the European coal mining industry and its future after the end of state aid. Chapter 3 looks at international coal prices and their competitiveness compared with competing fuels. Chapter 4 provides an overview of EC regulations that are likely to shape the future demand of coal. Chapter 5 gives an overview of CCT and CCS development in Europe, while Chapter 6 presents the outlook of future coal demand and scenarios developed by the International Energy Agency and the European Commission.

The second part of the report gives a detailed picture of the three largest European coal markets (Germany, Poland and the United Kingdom). It also looks at the Spanish coal market. Although coal in this country accounts for a small share of total energy consumption, recent austerity measures and their social impact put the sector into the public spotlight.

A description of the coal market is given for each country. Then, key developments and issues pertaining to each country and its coal market are discussed. Chapter 7 analyses the impact of the phase-out of nuclear energy in Germany. Chapter 8 provides an overview of Poland's energy policy to 2030 and the CCS Roadmap prepared by the Bellona Foundation. Chapter 9 focuses on market reform of electricity in the United Kingdom and its impact on coal-fired power generation. Chapter 10 looks at coal subsidies in Spain and the impact of the drastic cut in coal mining subsidies decided by the government in May 2012.

Annex 1 explains what the nature coal is and the main differences between steam coal (mainly used in power generation) and coking coal (used in the iron and steel industry). Annex 2 briefly analyses the use of coal in the steel industry. Annex 3 provides some useful unit conversions.

Abbreviations and Acronyms

ARA	Amsterdam/Rotterdam/Antwerp
BGR	*Bundesanstalt für Geowissenschaften und Rohstoffe* (Federal Institute for Geosciences and Natural Resources), Germany
BMU	*Bundesministeriums für Umwelt, Naturschutz und Reaktorsicherheit* (Federal Ministry for the Environment, Nature Conservation and Nuclear Safety), Germany
BNA	*Bundesnetzagentur* (German Energy Regulator)
BOF	Basic Oxygen Furnace (steel)
CCOO	*Comisiones Obreras*, the Workers' Commission, Spain
CCR	Carbon Capture Ready
CCS	Carbon Capture and Storage
CCT	Clean Coal Technologies
CFBC	Circulating fluidized bed combustion
CHP	Combined Heat and Power
CIF	Cost Insurance Freight
CPF	Carbon Price Floor
CPI	Current Policy Initiatives (EU Energy Roadmap)
DECC	Department of Energy and Climate Change, UK
DOE	Department of Energy, USA
EAF	Electric Arc Furnaces (steel)
EAU	European Allowance Units
EEFA	Energy Environment Forecast Analysis, Germany
EEPR	European Energy Program for Recovery
ELVs	Emissions Limit Values
EMR	Electricity Market Reform, UK
EPP	Energy Policy of Poland
EPS	Emissions Performance Standard
ETS	European Trading Scheme
EWI	*Energiewirtschaftliches Institut an der Universität zu Köln,* Institute of Energy Economics at the University of Cologne, Germany
FGD	Flue Gas Desulphurization
FiT CfD	Feed-in Tariff with Contracts for Difference
GHG	Green House Gas
GSI	Global Subsidies Initiative
GVSt	*Gesamtverband des deutschen Steinkohlenbergbaus*, Association of German Hard Coal Producers)

GWS	***Gesellschaft für Wirtschaftliche Strukturforschung mbH*****,** Institute of Economic Structures Research, Germany
HCC	Hard coking coal
IEA	International Energy Agency
IED	Industrial Emissions Directive
IGCC	Integrated Gasification Combined Cycle
JSW	*Jastrzebska Spolka Weglowa* , Poland,
LCPD	Large Combustion Plant Directive
NBP	National Balancing Point, UK
NER	New Entrant Reserve
NO_X	Oxides of Nitrogen
OECD	Organization for Economic Co-operation and Development
PC	Pulverized coal- fired combustion
PCI	Pulverized Coal injection
PGE	*Polska Grupa Energetyczna*, Poland
PKE	*Poludniowy Koncern Energetyczny*, Poland
RAG	*Ruhrkohle* AG, Germany
REE	*Red Electrica de España*, Spanish transmission system operator
RES	Renewable Energy Sources
SC	Supercritical
SCR	Selective Catalytic Reduction
SO_X	Sulphur Oxides
SSCC	Semi-soft coking coal
TNP	Transitional National Plan
TPES	Total Primary Energy Supply
TSOs	Transmission System Operators
UGT	*Unión General de Trabajadores*, the General Union of Workers, Spain
USC	Ultra- supercritical
VDKI	*Verein der KohlenImporteure*, German Coal Importer Association
VDMA	*Verband Deutcher Maschinen und Anlagenbau,* **German Engineering Federation, Mining Equipment Association**
VGB	***V****erband der* ***G****roßkessel-* ***B****esiter e. V.,* Federation of the owners of large boilers, Germany
WEO	World Energy Outlook, IEA
ZEP	Zero Emission Platform

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Part 1

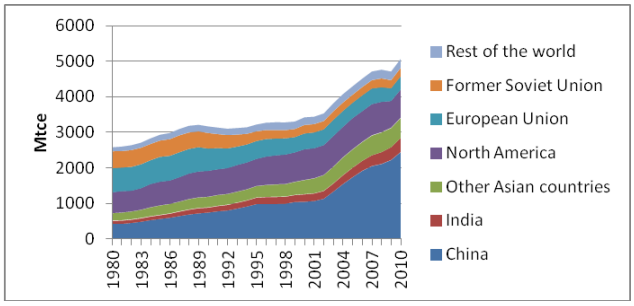
The European Coal Market

The European Coal Market in a Global Context

European coal demand: the fourth largest coal market in the world

Global coal demand has increased very quickly in the past decade. It now stands at 6.7 Gt (all types of coal: hard coal and lignite),[1] the equivalent of 5.1 Gtce.[2] China has been the driver of this growth, increasing its consumption by 400% over the past decade and now accounting for half of world consumption. Europe is the fourth largest coal market, after China, the United States and India (Figure 1). The EU consumed 721 Mt, the equivalent of 382 Mtce in 2010. Coal, which fuelled the industrial revolution in the region, still accounts for 17% of the primary energy mix (Figure 2), compared to 28% worldwide.

Figure 1: The evolution of coal consumption in the world by major coal consuming countries/regions

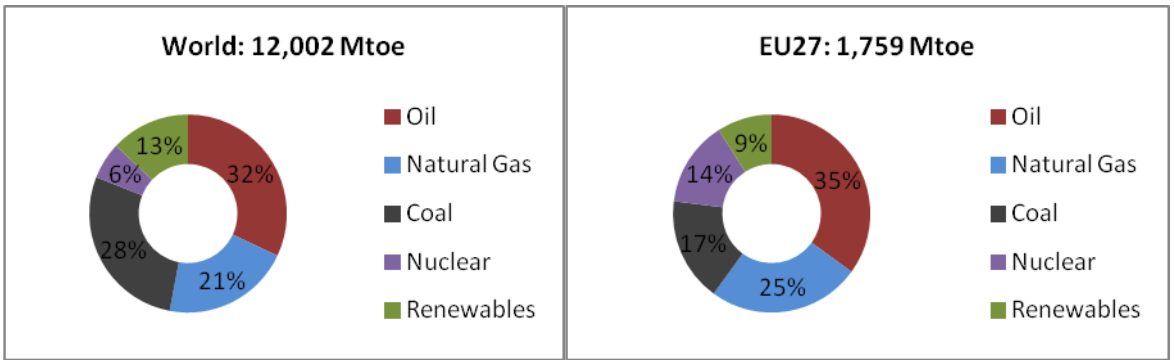


Source: BP (original data in toe converted into tce on the basis 1tce=0.7 toe)

1 "All types of coal" means hard coal and lignite in volume (tonnes), without taking into account their different calorific value. Hard coal is the sum of steam coal and coking coal (see Annex 1).

2 Tce (tonne coal equivalent). All coal volumes are converted to a common energy unit, tonnes of coal equivalent (tce). The conversion is done by multiplying the calorific value of the coal in question by the total volume of hard and lignite coal used, measured in physical units (tonnes). One tce has an energy content of 29.3 Gigajoules (GJ) or 7000 kcal and corresponds to 0.7 tonnes of oil equivalent (toe). Source: IEA, Coal Information, 2011.

Figure 2: Primary energy consumption, World vs. EU27 – 2010



Source: IEA, BP, VDKI.

For many European people these figures are quite surprising. This fuel is supposed to have disappeared from the energy mix a long time ago. This is true in France, where the share of coal in the energy/electricity mix is almost zero. However this is not true for some European countries where coal still plays a major role (Table 1).

Table 1: Share of coal in TPES and power generation in EU27 countries, 2010

	TPES (Mtoe)	Coal (Mtoe)	Share of coal in TPES (%)	Gross electricity production (TWh)	Share of coal in electricity production (%)
EU (27 countries)	**1759**	**280**	**17%**	**3346**	**25.7%**
Austria	35	3	10%	71	9.4%
Belgium	62	3	5%	95	6.3%
Bulgaria	18	7	39%	47	48.5%
Cyprus	3	0	1%	5	0%
Czech Republic	45	18	41%	86	58.3%
Denmark	19	4	20%	39	43.8%
Estonia (a)	6	4	64%	13	89.3%
Finland	37	7	19%	81	26.5%
France	269	12	4%	569	4.6%
Germany	336	77	23%	628	43.4%
Greece	29	8	27%	57	53.7%
Hungary	26	3	11%	37	17,0%
Ireland	15	2	14%	29	22.3%
Italy	176	14	8%	302	14.6%
Latvia	5	0	2%	7	0%
Lithuania	7	0	3%	6	0%
Luxembourg	5	0	1%	5	0%
Malta	1	0	0%	2	0%
Netherlands	87	8	9%	118	21.8%
Poland	102	55	54%	158	87.7%
Portugal	24	2	7%	54	13.1%
Romania	36	7	20%	61	34.2%
Slovakia	18	4	21%	28	14.6%
Slovenia	7	1	20%	16	32.2%
Spain	130	8	6%	303	8.7%
Sweden	51	2	5%	149	1.8%
United Kingdom	213	30	14%	381	28.5%

(a) oil shale

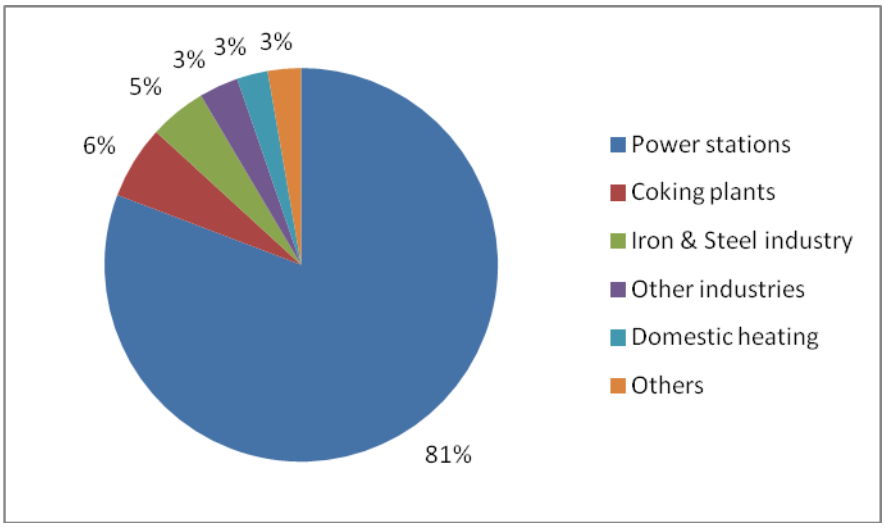
Source: Eurostat .

Almost 60% of EU coal demand is consumed by three countries: Poland, Germany and the United Kingdom.

The use of coal in Europe is mainly destined to the power sector (Figure 3). Its use for domestic heating has almost disappeared (3% of total coal demand in 2010), displaced by more modern sources of energy. In the iron and steel industry, coal plays a

major role as a raw material in producing coke (see Annex 2). European coal consumption in this sector is shrinking as several blast furnace plants are either idle or closed down in face of competition from other regions (China and India, in particular).

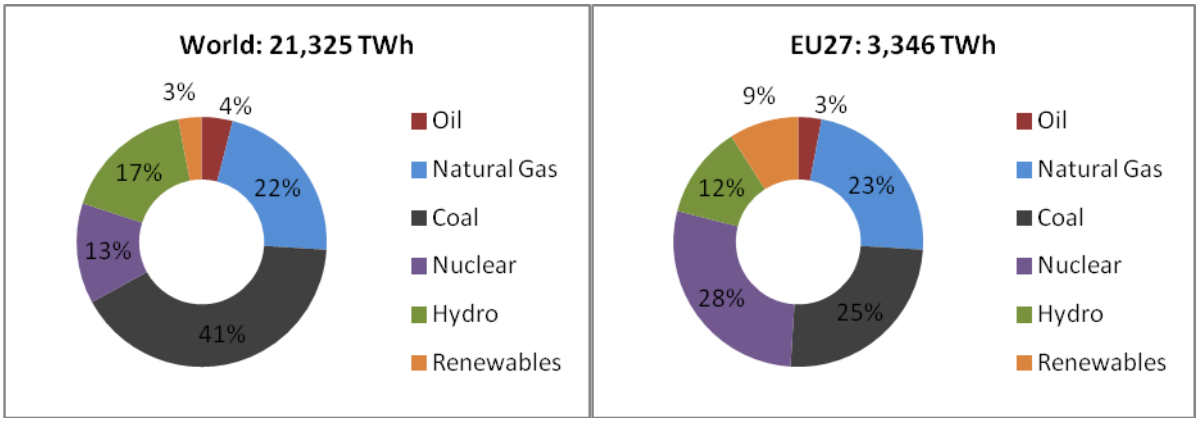
Figure 3: The breakdown of coal use in Europe, 2010



Source: Eurostat.

The use of coal in electricity generation varies widely across the EU Member States (Table 1). In some countries, Poland, for instance, coal still accounts for 88% of electricity generation and 43% in Germany. Even in Greece, where one could suppose that renewable energy sources have taken the lion's share in electricity generation, lignite still generates 54% of total electricity. On average, coal is the fuel used to generate 25% of EU electricity, compared to 41% for the world as a whole (Figure 4).

Figure 4: Gross power generation, World vs. EU 27 - 2010

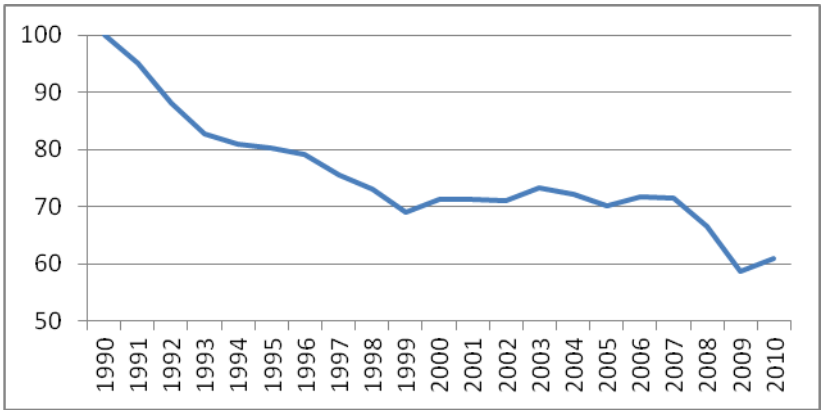


Source: IEA, BP, EURACOAL.

A decreasing trend since 1990, except in recent years

EU coal consumption decreased steadily in the 1990s (Figure 5). Then, from 2000 to 2007, it remained relatively stable at about 450 Mtce. Further large decreases in consumption were observed once again in 2008 and, above all, in 2009, when consumption reached its lowest level at 371 Mtce, 41% less than in 1990. Recent figures show that the decrease in coal consumption is not continuing, since a slight increase (in the order of 4%) was recorded in 2010 compared with 2009 and a 5% increase in 2011 and again a 7% rise in the first half of 2012, compared with same period in 2011 (preliminary data).

Figure 5: Evolution of EU coal consumption, 1990-2010



1990=100 (original data in toe). Source: BP

Whereas the economic crisis in the Eurozone has reduced total electricity demand and cut output at industrial facilities, coal consumption is increasing. This paradox is due to the falling price of CO2 to around €7-8/t since the beginning of 2012, 50% below 2011 levels (see Figure 15, Chapter 4). The recession has reduced CO2 emissions in sectors covered by the EU ETS (an estimated fall by 2% in 2011) and lowered demand of European Allowance Units (EAU). As demand for EAUs decreases, the price of CO2 has collapsed. At the same time, the price of natural gas in Europe remains high compared with coal (almost twice the price of coal on an equivalent energy basis, see Figure 14, Chapter 3). This has led power utilities to favour coal in generating electricity as profitability from coal burning is higher than for gas, even taking into account the higher efficiency of gas-fired power plants and their lower CO2 emissions per KWh. This explains the resurgence of coal consumption across Europe in the first half of 2012, a trend that is expected to continue for the whole year.

European coal production: 60% of total consumption

European coal production totalled 134 Mt of hard coal and 397 Mt of lignite in 2010, 2% and 40% of worldwide production respectively (Table 2).

Around 60% of coal consumption is covered by indigenous production, which makes coal a major contributor to EU security of supply (Figure 6).

The fall in EU coal production since 1990

Coal production decreased almost continuously from 1990 to 2010: in 2010, it was less than half that of 1990 (Figure 7).

Hard coal has been mined longer and more extensively in Europe than elsewhere, and most of the economically obtainable, high calorific value reserves have been tapped. As hard coal in Europe is recovered mainly from underground deposits, European coal miners are forced to work in deeper and in more difficult conditions to recover reserves of poorer quality coal, which increases costs. European indigenous hard coal production is about two times more expensive than imported coal. Some EU countries have therefore ceased hard coal production. In the countries where hard coal production still exists (mainly for socio-economic reasons), it is subsidised, but the subsidies are gradually being phased out (see Chapter 2).

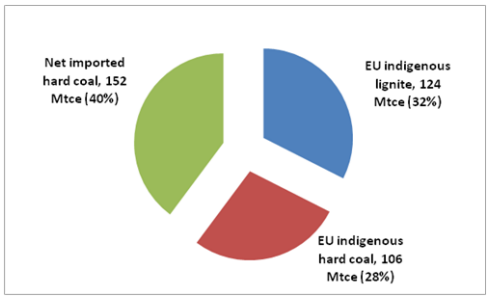
Table 2: Evolution of coal production, World and EU

	Annual production (Mt)				2010 share of global production (%)
	1990	**2000**	**2005**	**2010**	
World	4690	4512	5878	7229	
Of which lignite	1158	893	905	1043	14%
Of which hard coal	3532	3619	4973	6186	86%
EU	1036	631	637	531	7%
Major producers					
China	1051	1231	2226	3162	44%
United States	934	972	1028	997	14%
India	225	336	429	571	8%
Australia	205	307	371	420	6%
Indonesia	11	77	140	336	5%
Russia	372	240	297	324	4%
South Africa	175	224	240	255	4%
Germany	434	205	206	182	3%
Poland	215	163	160	133	2%
Kazakhstan	131	74	83	111	2%
Colombia	21	38	61	74	1%
Canada	68	69	65	68	1%

All types of coal measured in volume terms.

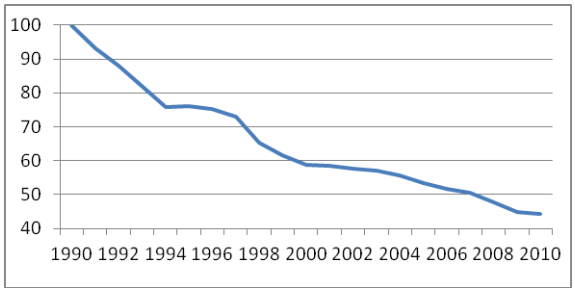
Source: IEA, BP, EURACOAL.

Figure 6: EU coal balance, 2010



Source: EURACOAL

Figure 7: Evolution of EU coal production, 1990-2010



1990=100

(original data in toe). Source: BP.

The case of lignite is different. The EU has greater reserves of lignite than of hard coal, and reserves are available and exploited in a larger number of countries (Table 3). Lignite in Europe is typically mined in open-cast sites, which keeps extraction costs low. European lignite production is generally cost-competitive with imports of hard coal without subsidies. Consequently, lignite production in the EU will most likely survive, unlike hard coal production. Lignite represents an important energy source for the EU, as it helps to reduce its energy import dependence.

Table 3: Hard coal and lignite production in EU, 2010

Mtce	Hard coal	Lignite	Total
Poland	66	17	83
Germany	11	50	61
Czech Republic	10	13	23
Greece	0	17	17
United Kingdom	16	0	16
Bulgaria	3	8	11
Romania	2	8	10
Spain	7	0	7
Hungary	0	3	3
Slovakia	0	1	1
Slovenia	0	1	1
Italy	<1	0	<1
EU 27	**115**	**118**	**233**

Source: EURACOAL, VDKI.

EU coal reserves: dominated by lignite

Coal is an abundant energy source worldwide and has the largest reserves and resources of all fossil fuels.[3] Global coal reserves

[3] Definition of Reserves and Resources
Reserves are energy resources which have been accurately recorded and which can be economically extracted using the current technical possibilities. Synonymously used expressions are recoverable (coal) as well as proved recoverable amounts/resources. The definition mentioned above means that the amount of reserves depends on the level of knowledge about the deposit, on commodity prices and on the present state of the technology.
Resources are those amounts of an energy resource, which have been geologically proven, but which cannot be extracted economically at that time and the amounts, which have not been proven, but which can be expected for geological reasons in the areas concerned. For coal these are, generally, in-situ amounts, i.e. the total amounts independent of their recoverability.
The remaining potential is the still extractable amount of energy resources, i.e. the sum of reserves and resources. For coal the term “total resources” is used as a synonym. It has to be noted that reserves are not part of the resources.
Source: BGR (*Bundesanstalt für Geowissenschaften und Rohstoffe*, Federal Institute for Geosciences and Natural Resources), Hannover.

amounted to 1,004 Gt at the end of 2010, of which 728 Gt are of hard coal and around 276 Gt of lignite (Table 4). This represents a ratio Reserves on Production (R/P) of 115 years for hard coal and 275 years for lignite.

Global resources are huge (17,204 Gt for hard coal, 4,154 Gt for lignite). Unlike oil and conventional natural gas, coal deposits are found in all continents, except the Middle East (Figure 8). Their production sites are located in many countries and exploited by many companies.

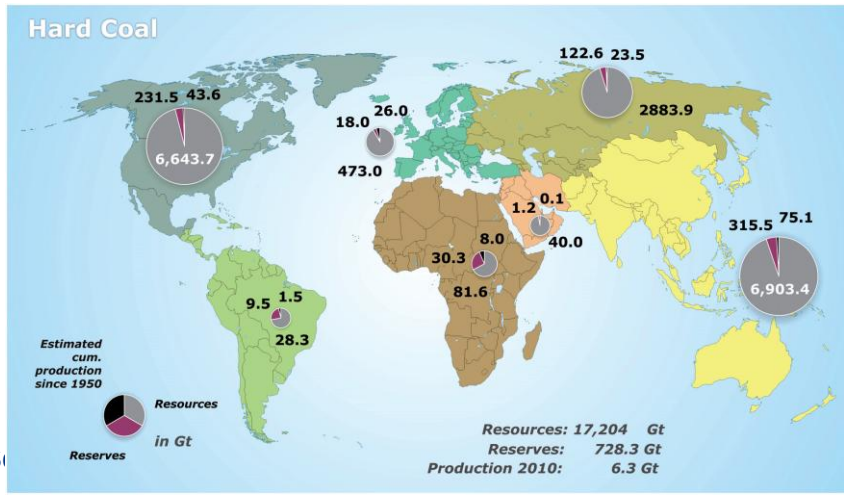
Europe holds 16.6 Gt of hard coal reserves (representing 124 years at current production levels), and 56 Gt of lignite reserves (142 years of production). The region accounts for 20% of global lignite reserves and 2% only of hard coal reserves. Five countries dominate: Germany (mainly lignite), Poland, Greece, UK and the Czech Republic. Lignite reserves are predominantly concentrated in four countries (Germany, Poland, Greece and the Czech Republic). Germany alone accounts for 72% of EU lignite reserves. The future production of lignite in the EU will therefore be tied to developments in Germany.

Table 4: Coal reserves and resources at end 2010, World and EU

	Reserves (Mt)		Resources (Mt)	
	Hard coal	Lignite	Hard coal	Lignite
United States	225 845	30 775	6 457 242	1 367 588
China	180 600	11 000	5 010 000	307 000
India	74 629	4 858	171 861	34 760
Russia	68 655	91 350	2 662 155	1 279 680
Australia	43 800	37 100	1 573 700	174 000
Ukraine	32 039	2 336	49 006	5 381
South Africa	27 981	0	ns	0
Kazakhstan	18 750	ns	129 966	ns
Poland	13 070	4 579	163 868	223 604
Indonesia	9 317	7 838	71 335	12 474
Colombia	4 945	0	9 928	0
Canada	4 346	2 236	183 260	118 270
Vietnam	3 116	244	3 519	199 876
Brazil	1 547	5 049	4 665	12 587
Uzbekistan	1 425	ns	9 910	ns
Iran	1 203	ns	40 000	ns
Chile	1 181	ns	4 135	7
Mongolia	1 170	1 350	39 854	119 426
Mexico	1 160	51	3 000	ns
Czech Republic	1 152	2 348	15 475	7 598
United Kingdom	371	0	186 700	1 000
Germany	59	40 500	82 962	36 500
Greece	0	2 876	0	3 554
Total selected countries	716 361	244 490	16 872 541	3 903 305
WORLD	**728 278**	**275 510**	**17 203 972**	**4 153 625**
EU27	**16 581**	**56 239**	**471 297**	**288 729**
EU27/WORLD	**2%**	**20%**	**3%**	**7%**

Source: BGR.

Figure 8: The regional distribution of hard coal potential (data in Gt)



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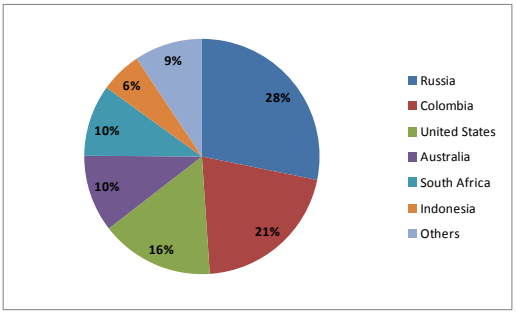
European coal imports: a decreasing role in international trade

Although Europe is a large coal producer, it supplements its coal production with rising coal imports. These reached 212 Mt in 2010 (47 Mt of coking coal and 165 Mt of steam coal), corresponding to net imports of 165 Mt. Steam coal imports are rising due to the decline of European production, mainly in Germany and Poland. However they decreased sharply in 2009, following the economic and financial crisis, which curtailed coal demand by power and steel plants. In 2010, despite a slight recovery, they had not yet reached their pre-crisis level.

As shown in Figure 9, Russia and Colombia are the two leading sources. The U.S. comes third. The country, which almost disappeared from the international steam coal scene at the beginning of the 2000s when coal prices were low, is actively developing its coal exports to Europe.

Figure 9: Coal imports by origin, 2010



Source: Eurostat.

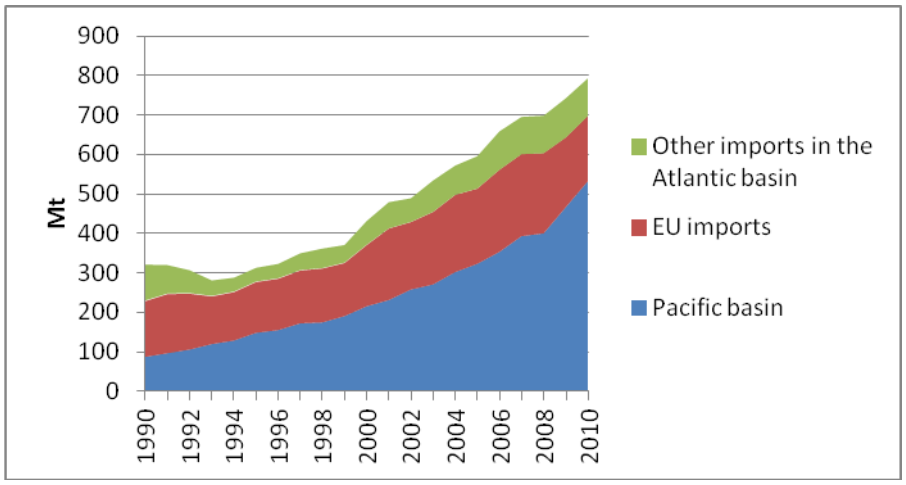
Competition from gas – mainly shale gas produced in abundance in the United States – is revolutionising the coal market and the future of coal in the U.S. The country's production of gas, up 6% in 2011, lowered the price, making coal uncompetitive and limiting its use in the electricity sector. Although coal still accounts for 49% of electricity production in the United States, demand for coal fell by 3% in 2011. To offset the loss in the internal market, U.S. companies are turning to the export market. They set a new record for exports in 2011: over 100 Mt, an increase of 30% compared to 2010.

This new source of supply brings additional liquidity to the international coal market. Competition between suppliers to the EU has been fierce over the past two years, as US coal has tried to displace Colombian and South African coal.

Although Europe is still a major player on the international coal scene, its role is shrinking from year to year. Today, it accounts for 21% only of global steam coal imports (Figure 10), compared with 44% in 1990.

The growing role of the Pacific basin (Chinese and Indian imports) means that international trade and prices are now dictated by Asia.

Figure 10: The evolution of international steam coal imports by basin



Source: VDKI, Eurostat, IEA.

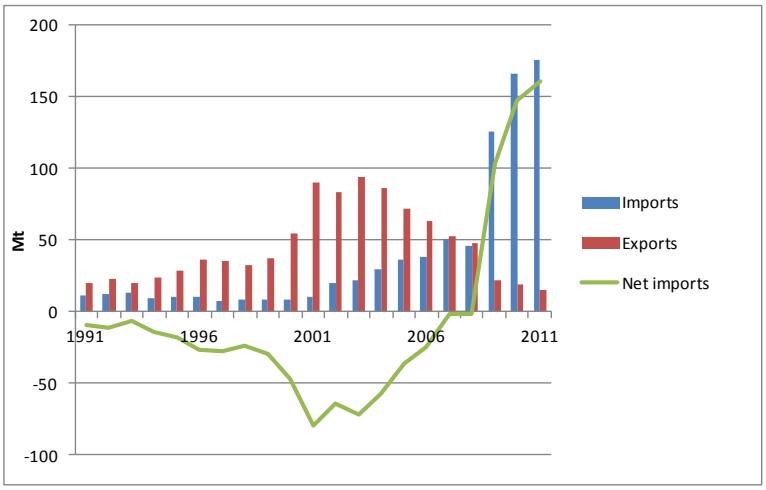
International coal trade: driven by the Pacific basin

The international coal trade is only a small fraction of world production: 16% in 2010, while for oil it is over 60% of production which is traded internationally, and over 30% for natural gas. However, the coal trade continues to grow (1,089 Mt in 2011). Whereas Japan and the European Union have long been the world's

largest hard coal importers, China and India are now emerging as top importers. This surge has shifted the centre of gravity in international coal trade to the Pacific basin market.

China, which in 2008 was still a net exporter, has become a net importer since 2009 and in significant quantities: over 160 Mt in 2011 (Figure 11). Rising prices of domestic coal (encumbered by high transport costs) compared to international prices made imports more attractive, especially for the southern provinces of the country. Yet China remains the world's largest producer of coal (3.5 Gt produced in 2011, nearly half of world production). Its imports are only a small part of its supply, 5%, but on the narrow international coal market, it now represents nearly 16% of world trade. It thus has considerable power in the international market, and policy decisions taken in Beijing affect the price of coal delivered to Europe!

Figure 11: Chinese international coal imports/exports



Source: IEA, 2011 data: International Coal Report, provisional.

India is also increasingly turning to the international market. In 2011, its imports increased by 31% to 118 Mt. Although the country is the third largest producer of coal (550 Mt in 2011), domestic production is not enough to cover the staggering needs of the country. India – where half the population lacks access to electricity! – has embarked on an ambitious national programme of electrification and plans to add 100 GW of electricity capacity over the next five years, mainly powered by coal. Moreover, the poor quality of its coal and its location far away from consumption centres favour imports. Thus, India is taking a major role in the international coal market. Its imports could reach or exceed 250 Mt in 2016/17 and it could then be the decisions taken in Calcutta that are crucial on the international coal scene.

The Significance of the European Coal Mining Industry

Employment and turnover

The coal industry in Europe is a significant employer (Table 5), with around 430,000 employees (direct and indirect) all together.[4] It makes an important contribution to the prosperity of Europe's mining regions and national economies in regions which lack industrial development. This is particularly the case in Silesia (Poland and the Czech Republic) where there are more working coal miners than in the rest of the European Union combined.

Table 5: Manpower in the European coal industry: direct jobs in 2010

	Hard Coal	Lignite	TOTAL
Bulgaria	4 600	8 200	12 800
Czech Republic	13 700	10 200	23 900
Germany	24 200	16 700	40 900
Greece		8 400	8 400
Hungary		2 400	2 400
Poland	114 100	16 300	130 400
Romania	8 800	13 500	22 300
Slovakia		3 900	3 900
Slovenia		1 800	1 800
Spain	5 400		5 400
United Kingdom	6 000		6 000
TOTAL	**176 800**	**81 400**	**258 200**

Source: EURACOAL.

4 Based on studies by the German Energy Environment Forecast Analysis (EEFA), Berlin, 2011, one direct job in the lignite mining industry creates 2.47 indirect jobs. In the hard coal mining industry, it creates 1.3 indirect jobs, according to the German Institute Prognos.

The turnover of EU hard coal and lignite production is estimated at €25 billion, based on its calorific value and average international hard coal price in 2011.

Beyond Europe, the technologies developed by the European mining equipment manufacturing industry for the coal industry also contribute to improving the efficiency of coal production and preparation in other regions of the world. Furthermore, such manufacturing also contributes to employment in Europe and sale revenues. For instance, Germany's mining trade association, VDMA, reported a 32% increase in turnover in 2011 to €5.14 billion, representing a new annual record for the country's mining equipment manufacturers.[5] In Europe, there are more than 1000 suppliers of mining equipment, most of them in Germany, the UK, Poland, France and the Czech Republic.[6]

State aid to the coal sector

Several EU hard coal mines are not economic and are subsidised. The Council Regulation (EC) on State aid to the coal industry N° 1407/2002 of 23 July 2002 expired on 31 December 2010. It was succeeded by a new Decision adopted by the Council on State aid (Council Decision 2010/787/EU of 10 December 2010) to facilitate the closure of uncompetitive coal mines, which provides for aid within a closure plan, under certain conditions. The uncompetitive mines must be closed by 31 December 2018, and the coal production progressively reduced over the period. Initially the Commission had proposed the 1 October 2014 as the cut-off date for State aid. This was met with strong opposition especially, by Germany and Spain.

The new regulation provides for only two categories of aid: (i) operating aid for the closure of mines (Article 3) and (ii) aid for exceptional costs (Article 4). The latter includes redundancy payments, re-training costs, and site cleaning-up or safety costs. Subsidies will have to be lowered by at least 25% until 2013, by 40% until 2015, by 60% by 2016 and by 75% by 2017.

The amount of production aid paid to support uncompetitive hard coal mines totalled €2.9 billion in 2010 (Table 6). These mines produced around 27 Mt, a very small share of total production (5% on a tonnage basis). These subsidies are far less than those paid to renewables (€26 billion). They do not apply to Bulgaria, the Czech Republic, the UK, nor to lignite mines (ortho-lignite, <15,000 kJ/kg) which offer competitive yields and revenues.

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[5] Engineering & Mining Journal, German Equipment sales go from strength to strength with record export demand, January 2012, p. 88-89

[6] Mining 1.com, international website for the worldwide mining industry. http://www.mining1.com/

Table 6: State aid to coal mining by Member States, 2005-2010

€ million	2005	2006	2007	2008	2009	2010	Yearly average 2005-2007	Yearly average 2008-2010
EU-27	**4565**	**3690**	**3539**	**2940**	**2748**	**2873**	**3931**	**2854**
Bulgaria	9	6	-	-	-	-	5	0
Germany	2879	2471	2413	1818	1752	1758	2587	1776
Spain	1224	874	843	819	776	816	980	804
Hungary	42	34	41	37	31	29	39	32
Poland	252	168	108	154	97	194	176	148
Romania	76	102	112	88	71	59	96	72
Slovenia	16	17	18	18	17	12	17	15
Slovakia	4	6	4	4	5	5	5	5
United Kingdom	63	12	1	2	-	-	25	1

Source: EU DG Competition.

State aid to EU hard coal mining companies is decreasing and will be phased out by the end of 2018, according to the above mentioned Council Decision. The Member States concerned continue to finance measures related to restructuring and consolidation of their subsidised coal sectors. A large part of the support is directed to environmental clean-up measures or early retirement schemes. Under present policies, about 27,000 mine workers still employed in Germany and Spain in 2010 will lose their jobs in the absence of production aid. In Romania, Hungary and Slovakia, a further 15 000 mine workers' jobs may be threatened by the end of subsidies. When taking into account jobs in related industries, up to 100,000 jobs – 42,000 jobs in the coal industry and more than 55,000 jobs in related industries – may be at stake.

On a national basis, the end of State aid has various consequences for hard coal production. Germany will substantially increase its imports to cover the loss of all domestic hard coal production: up to 13 Mt over the next five years. In Spain, around 60% of Spanish coal production could be competitive. However, the sector has to fight against the government's decisions to cut mining subsidies brutally and limit domestic coal production (see Chapter 10). Poland's imports have been rising and will likely continue to rise as inefficient mines are closed. However, privatisation will boost productivity and output at the remaining mines, so hard coal production should stabilise (see Chapter 8). In the other European countries, the majority of hard coal and lignite production is competitive with imports and State aid is relatively limited. At EU

level, coal production is expected to decrease from 230 Mtce in 2010 to 89 Mtce in 2035.[7]

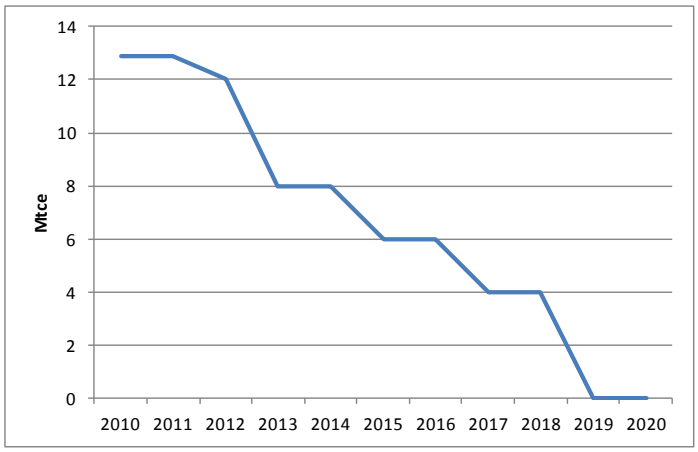
Prospects for German hard coal production after the end of state-aid

The cost of producing hard coal in Germany (lignite mining is not subsidised) is far higher than the price of imported coal: €180/tce compared with €107/tce on average in 2011.[8] The difference is made up by a subsidy to Ruhrkohle AG (RAG), the dominant producer. The cost of these subsidies peaked at $8.5 billion in 1996 and was €1.758 billion in 2011, in line with decreasing production.

In December 2007, the Federal Government issued the German Hard Coal Financing Act on State aid to the coal industry, which gave a detailed road map to end all subsidies by 2018. Under the Act, production is being gradually scaled back. Subsidies will continue to be paid jointly by the Federal and State governments until 2014, after which time the Federal Government will pay all subsidies. Liability costs that remain after the closure of the pits will primarily be paid out of a fund which will be financed by the proceeds of a public sale of shares in RAG. Another programme, in place since 2001, provides older coal miners with early retirement payments until they become eligible for regular pension payments.[9] The new legislation has a major impact on future hard coal production in Germany. In 2010, the Ost coal mine was closed. In 2012, the Ensdorf coal mine in the Saar region will be closed and the West mine in 2013. Hard coal production is expected to decrease from 12.9 Mtce in 2010 to 4 Mtce in 2018 (Figure 12) and to cease after that date, to be replaced by imports. The reduction in coal production leads to a similar decrease in coal employment in the hard coal mining industry.

[7] IEA (International Energy Agency), *World Energy Outlook 2011*, OECD/IEA, Paris, 2011. New Policies Scenario.
[8] VDKI (Verein der KohlenImporteure), *2011 Report, Facts and Trends 2010/11,* Hamburg, 2011.
[9] IEA, op cit.

Figure 12: Future hard coal production in Germany



Source: VDKI, EURACOAL.

Affordable Coal Import Prices in Europe

Fundamentals and recent trends

International prices for steam coal are mainly determined by market forces (domestic prices may include subsidies).[10] Supply constraints make coal vulnerable to sudden shocks. At the same time, decreasing demand may lead to a collapse in international coal prices. Whereas prices were cheap and stable in the 1980s and 1990s, essentially determined by mining and transportation costs, the situation has changed since the beginning of the 2000s.

International coal prices nearly doubled from 2003 to 2004 in USD. At that time, increased domestic demand in major exporting countries (China, Russia) and decreased production (the USA) tightened the market. China's economic development absorbed coal and steel, among other commodities, turning the nation from an exporter into a net coal importer. Furthermore temporary supply/demand imbalances occurred. On the demand side, unusually warm weather in Europe drove the need for electricity and at the same time reduced the availability of alternative energy sources (hydro and nuclear power) in favour of coal. Several nuclear power plants in Japan were closed for maintenance. High oil and gas prices also contributed through a shift in demand and higher transportation costs for coal. On the supply side, logistical bottlenecks in ports and railway systems in South Africa and Australia increased Capesize vessel rates to levels never experienced on the market over the last 25 years ($26 /t on average in 2006 for the route from Gladstone to Europe).

In 2007/08, the imbalance between supply and demand of the Pacific basin and the sudden rise in Chinese coal imports had pushed the coal production and transport infrastructure to the limit, and provoked a strong increase in international coal prices, accentuated by a spike increase in freight rates. In July 2008, CIF ARA coal

[10] This section only relates to steam coal prices. Coking coal has a different market and its pricing is determined by other factors.

prices reached an historical peak at $217/t.[11] Maritime transportation ($60 to 70/t for most typical routes to Europe) represented 30 to 35% of the delivered price.

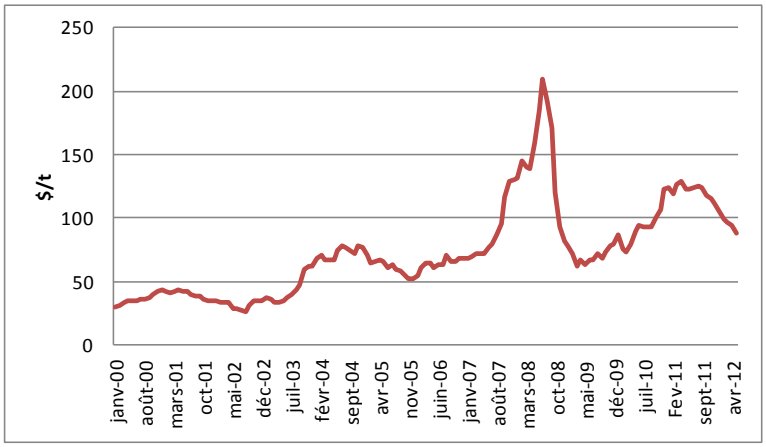
The collapse in coal prices in the second half of 2008, caused by the economic and financial crisis, was followed by a continued drop in 2009. On average, European import prices amounted to $70.5/t in 2009, against a record average of $147 in 2008. In 2010, prices rose again to $92/t mainly due to the combination of a recovery in coal demand in Asia and supply constraints in coal exporting countries (Colombia, Indonesia).

In 2011, the CIF ARA price was largely influenced by the events shaking the energy and economic scene. In early January 2011, prices rose to nearly $130/t due to cold weather and heavy snowfalls in Europe, as well as production cuts in Australia and Colombia following torrential rains. Warmer weather in February allowed prices to ease to around $120/t. When the Fukushima accident occurred and Germany announced the closure of seven nuclear reactors, prices rose to nearly $130, with the markets anticipating a shortage of coal in Europe, although paradoxically European demand was weak. They stayed at a fairly high level ($120-125/t) throughout the spring and summer of 2011, although European demand was low. But the uncertainties weighing on the oil market and the rising price of crude oil impacted on the price of coal, adding to the feeling of possible shortage. It was not until the last quarter of 2011 that the price resumed a downward trend, accentuated by economic uncertainties and the sovereign debt crisis. Prices of steam coal imported into Europe increased 32% to $122/t on average in 2011.

At the beginning of 2012, they were still above $100/t. However, weak demand in Europe coupled with economic uncertainties pushed coal prices below 100/t. At the end of May 2012, they settled at $86/t (Figure 13).

[11] CIF ARA prices: Cost Insurance and Freight, Amsterdam, Rotterdam and Antwerp. Coal prices delivered at major European coal terminals.

Figure 13: European Steam Coal Marker Price, 2000-2012

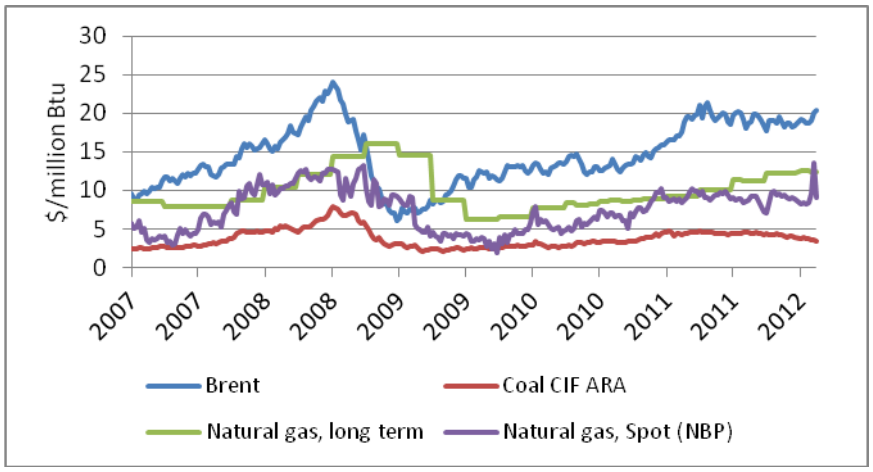


(Spot CIF Price, NW Europe, $/t basis 6,000 kcal/kg NAR - Net As Received) Source: International Coal Report

Coal vs. competing fuels

Although coal prices are on a rising trend, the increase in natural gas prices (its main competitor), makes coal more competitive. On an energy basis, coal consolidated its position as the cheapest fuel in 2011: coal imported to Europe is 4.6 times cheaper than oil (Dated Brent) and half the price of natural gas (Figure 14).

Figure 14: Comparison of fossil fuels prices imported in Europe



Crude Oil: Brent Spot Prices FOB
Coal: Platt's Coal Industry Marker CIF ARA (6000 kcal/kg, NAR)
Natural Gas Long Term: Average German Import Price
Natural Gas Spot: UK National Balancing Point
Source: US DOE, World Gas Intelligence, International Coal Report.

Coal in the Context of the EU Energy Policy

The European Commission has adopted ambitious targets to curb EU air pollutants and CO_2 emissions. The Large Combustion Plant Directive has already a huge impact on coal-fired power plants, forcing power utilities to close old, inefficient coal-fired power plants. The EU ETS and the CCS Directives have so far been unable to achieve their goal. The low price of a tonne of CO_2 has not discouraged coal burning. It has not given the right signal to stimulate investment in low/zero emissions power plants.

The backbone of EU energy policy: the 20/20/20 targets and the energy roadmap to 2050

In March 2007, the EU's leaders endorsed an integrated approach to climate and energy policy that aims to combat climate change and increase the EU's energy security while strengthening its competitiveness. They committed Europe to transforming itself into a highly energy-efficient, low carbon economy. To kick-start this process, the EU Heads of State and Governments set a series of demanding climate and energy targets to be met by 2020, known as the "20-20-20" targets which were adopted by the European Parliament and Council in December 2008 (Climate and Energy Package). These are:

- A reduction in GHG emissions of at least 20% below 1990 levels;
- A 20% reduction in primary energy use compared to projections for 2020, to be achieved by improving energy efficiency;
- 20% of EU energy consumption to come from renewable resources.

Coal, although not directly mentioned in the 2020 targets and the following EU strategy, could loose from the attainment of these targets by EU Member States:

- a 20% decrease in CO_2 emissions does not favour coal compared with natural gas, its main competitor in electricity generation;

- a 20% increase in energy efficiency will lead to a decrease in energy/coal consumption;

- a 20% increase in renewables will displace other energy sources, mainly coal.

In December 2011, the EC presented its *Energy roadmap to 2050* with a goal to cut GHG emissions by 80-95% by 2050 (40% by 2030, 60% by 2040 and 80% by 2050 compared with 1990).[12] The Roadmap explores how this goal can be achieved while at the same time improving EU competitiveness and security of supply. This goal would have serious implications for the EU energy system, which needs to be far more efficient and must be completely transformed by 2050. According to the Roadmap, about two thirds of energy should come from renewable sources. Electricity production needs to be almost emission-free by 2050, despite higher demand (see Chapter 6).

Achieving the 20/20/20 targets already puts a high burden on the electricity/energy sector. Reaching even more ambitious targets does not seem feasible in the current European economic context. It should be asked whether power utilities/European citizens have the ability and willingness to comply with these goals. The Euro zone crisis has shifted priorities from environmental policies to a more pragmatic approach: how to generate electricity at the lowest cost. With the collapse of CO_2 prices, this has led to a resurgence in coal burning throughout Europe.

It should be noted however that the Large Combustion Plant Directive has a huge impact on old inefficient power plants (coal and gas-fired), leading to the closure of numerous plants and their replacement by more efficient capacities.

The Large Combustion Plant Directive and the Industrial Emissions Directive

The Large Combustion Plant Directive (LCPD) was introduced by the European Parliament and Council in October 2001. The Directive introduced measures to control the emissions of nitrogen oxides (NOX), sulphur dioxide (SOX) and particulates from large combustion plants (i.e. plants with a rated thermal input of equal to or greater than

[12] European Commission, *Energy Roadmap 2050, COM(2011) 885*, Brussels, December 2011.

50 thermal megawatts). The aim of the Directive is to take steps to reduce the emissions of these pollutants, as they are known to damage human health and contribute to acid rain.

Existing operators were given the option either to meet the requirements of the Directive by accepting the Emissions Limit Values (ELVs) for the three pollutants, or to be exempted from compliance with the emission limits on condition that they undertake not to operate plants for more than 20,000 hours between 1 January 2008 and 31 December 2015. Plants authorised after 27 November 2002 have to comply with the emission limits set out in the Directive.

The Directive has a strong impact on the oldest coal plants with low thermal efficiency, for which it is not economic to invest in Flue Gas Desulphurization (FGD) equipment. The only solution is to take the second option and close such plants by the end of 2015 at the latest. For instance, E.ON announced in 2011 that it is going to close its five coal plants in France: all of them have operated for more than 30 years and have a low efficiency, meaning that investment in FGD is not economic.[13] The impact is also quite significant in UK where 10 GW of coal-and oil-fired capacity will be closed by the end of 2015. All in all, the LCPD leads to the closure of around 35 GW of coal plants by 2015. The challenge for the power system is enormous, in particular in Germany, as the rising share of intermittent energy requires a similar increase in back-up facilities. This role should have been taken by gas power plants. But the early retirement of nuclear plants leaves a capacity shortage which may not allow the flexible operation of gas plants. New coal-fired power plants are therefore necessary and need to be built in Germany (see Chapter 7). They were planned to replace old inefficient coal-fired power plants but will actually replace lost nuclear capacity, rising coal consumption in the country.

The LCPD is one of the seven existing EU directives on industrial emissions that were recast under the **Industrial Emissions Directive** (IED), endorsed by the European Parliament in July 2010. The IED proposes a further tightening of emissions limits, in comparison to the LCPD for SO_X and NO_X and particulates. For NO_X in particular the limits will be significantly tightened. All coal plants which have opted into the LCPD (and which will therefore remain open from 2016 onwards) have already installed FGD equipment. For this reason, it is the need to comply with the NO_X limits in the IED (from 2016 onwards) which will be the major reason for further expenditure in Selective Catalytic Reduction (SCR) equipment. Plants which opt-out of the IED will be allowed to run a limited number (17,500) of hours between 2016 and 2023, without complying with the new ELVs. Although plants which opt-out can exceed the IED ELVs, they will continue to be subject to the ELVs limits defined in the

[13] It is not yet clear if these plants are going to be closed as a purchase offer was recently put on the table for four of them.

LCDP. Plants which opt-in to the IED will be required to comply with the new ELVs. However some flexibility in early years is allowed through a Transitional National Plan (TNP), which gives power plants until July 2020 to meet the requirements. Member States must communicate their draft TNP to the Commission by 31 December 2013. For the oldest coal-fired power plants, this will result in more closures, as investment in SCR is not justified.

The EU ETS

The **EU Emission Trading Scheme** was launched in 2005. It works on a "cap and trade" principle. This means there is a limit on the total amount of CO_2 emissions that can be emitted by factories, power plants and other installations in the system. Within this cap, companies receive free emission allowances (European Allowance Units, EAU) which they can sell to or buy from one another as needed. Phase III of the EU ETS (2013-2020) builds upon the previous two phases (2005-2007 and 2008-2012) but has been significantly revised to make a greater contribution to tackling climate change. The EU-wide cap on emissions is much more ambitious. The number of allowances is reduced over time so that total emissions in 2020 will be 21% lower than in 2005. Auctioning is the rule for the power sector, which means that electricity generators will need to purchase all their allowances up to their emissions cap, for a particular year, through auctioning. There is also reduced access to project credits from outside the EU.

The Directive includes a temporary derogation to full auctioning for New EU Member States which may receive a proportion of their allowances free of charge if:

- in 2007, their electricity network was not interconnected with the EU system; or
- in 2007, their electricity network was connected to the EU system through a single line with a capacity of less than 400MW; or
- in 2006, more than 30% of their electricity was produced from a single fossil fuel and the GDP per capita in relation to the EU average did not exceed 50% of the average GDP per capita of the EU.

The auctioning rate for Member States benefiting from this derogation will be set at a minimum of 30% of an installation's emissions' cap in 2013, increasing to 100% in 2020.

For the power sector (and Western European coal generators mainly), this means that CO_2 emissions have to be reduced drastically and the auction price of CO_2 incorporated into the

generation cost. This new burden does again favour coal, which emits more CO_2 than its main competitor, natural gas.

However, the burden depends on the price of CO_2. Since the middle of 2011, CO_2 prices have collapsed and settled at around €7-8/t (Figure 15). At this level, coal is the most economic way of generating electricity, taking into account the relative price of coal compared with natural gas (see Figure 14, Chapter 3). This situation explains the big rise in European coal consumption observed in the first half of 2012.

Figure 15: Evolution of CO_2 prices (European Allowance Units): spot prices

Source: BlueNext

Aware of the failure of the EU ETS, the European Commission is currently trying to fix it by imposing a reduction in the number of EAUs.

The CCS Directive

Another piece of regulation is Directive 2009/31/EC on the geological storage of CO_2 (the so-called "**CCS Directive**"). It establishes a legal framework for the environmentally safe geological storage of CO_2 to contribute to the fight against climate change. It covers all CO_2 storage in geological situations in the EU, and lays down requirements covering the entire lifetime of a storage site. Existing legal frameworks are used to regulate the capture and transport components of CCS.

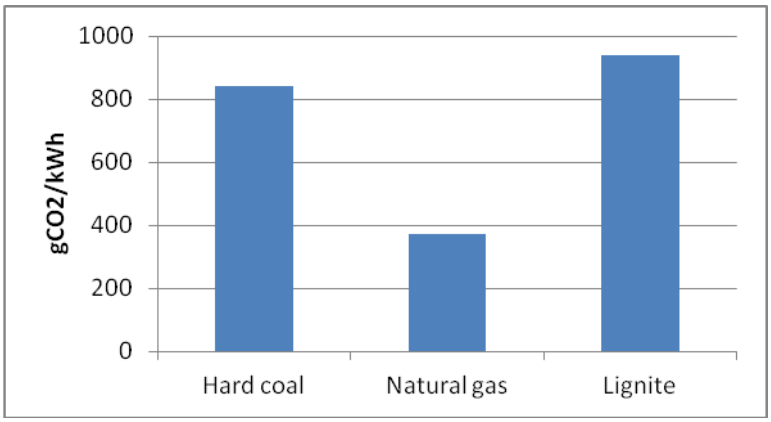
The CCS Directive also includes an article on new fossil fuel power plants which requires that any new plant with a capacity of 300 MW or more is built, so that CCS can be retrofitted at a later stage: the so-called Carbon Capture Ready (CCR) requirement.

All Member States were required to transpose the obligations included in the CCS Directive into their national legislation by 25 June 2011. Only Spain fully implemented the Directive by December 2010. The other Member States encountered various difficulties in implementing the Directive, such as public opposition to the technology or a complex division of powers between regional and central governments. As of February 2012, another seven Member States have implemented the Directive (Denmark, the Netherlands, Italy, France, Lithuania, Malta and Slovenia), meaning that 19 states are still struggling with regulatory issues. Again, the low price of EAUs coupled with the Euro zone crisis and technology challenges (see Chapter 5) do not encourage private and public investment in CCS. This makes the adoption of new legislation on CCS a less urgent priority.

CTT/CCS in Europe

Although the EC recognises the significance of coal as a major contributor to security of supply and its affordable price, it also stresses that the future use in coal-fired power stations depends on the development of clean coal technologies (CCT). Indeed of all fossil fuels, coal emits the most CO_2 when burnt (Figure 16). Coal is responsible for 25% of total EU CO_2 emissions (Table 7) and two-thirds of the emissions of the power sector.

Figure 16: CO_2 emissions by fossil-fuel power plants



Average values of emission factors for OECD countries. Source: IEA.

Table 7: EU CO_2 emissions, major emitters

Mt of CO_2	1990	2010	% change	Emissions from coal (2009)
Belgium & Luxembourg	140	167	20%	11
Czech Republic	170	111	-35%	70
France	412	403	-2%	44
Germany	1031	828	-20%	290
Greece	80	98	22%	35
Italy	435	439	1%	47
Netherlands	220	276	25%	28
Poland	387	324	-16%	194
Spain	237	334	41%	41
United Kingdom	622	548	-12%	113
Other EU countries	747	612	-18%	172
European Union	**4481**	**4143**	**-8%**	**1045**
World	**22613**	33158	47%	12493
EU/World	20%	12%		8%

Source: BP, IEA.

In order to reduce the environmental impact of coal-fired power stations, the EU is strongly promoting research and development of CTT in three main areas:

- Reduction of the traditional pollutants emitted by coal combustion (SO_X, NO_X and particulates) though the implementation of the LCP Directive.
- Improving the energy efficiency of the conversion of coal into electricity;
- CO_2 capture and storage (CCS).

Improving the efficiency of coal-fired power plants[14]

The major coal-based power generation technologies available today, and/or under development, include:

- Supercritical (SC) and ultra-supercritical (USC) pulverised coal-fired (PC) combustion;
- Circulating fluidized bed combustion (CFBC); and
- Integrated gasification combined cycle (IGCC).

Considerable progress has been made in the development of highly efficient supercritical (SC) and ultra-supercritical (USC) (PC) technology. While the current average efficiency of the European coal plant fleet is 38% (LHV, net), today's technologies allow efficiency of up to 46% for new hard coal plants and 43% for lignite plants.[15] New coal-fired power plants built in Europe reach this target (Table 8). They allow for a reduction in CO_2 emissions of 33% compared with the worldwide fleet (Figure 17).

[14] This section is based on IEA, Power generation from coal, Ongoing Developments and Outlook, IEA/OCDE, October 2011.
[15] Efficiency reported on the basis of a fuel's lower heating value (LHV) and net electricity sent-out (net), i.e. LHV, net.

Table 8: Recent SC and USC plants commissioned and planned in Europe

	Status	Capacity (MWe)
Eemshaven, Netherlands	under construction, 2013	2x800
Niederaussem, Germany	in operation, 2003	1 000
Walsum, Germany	in operation, 2010	750
Neurath, Germany	under construction, 2012	2×1100
Hamm, Germany	under construction, 2012	2x800
Lagisza, Poland, CFB	operating, 2009	460
Belchatow, Poland	operating, 2010	833
Torrevaldaliga Nord, Italy	operating, 2010	3×660
Porto Tolle, Italy	Planned by 2015	3×660
Saline Joniche, Italy	Planned by 2015	2x660

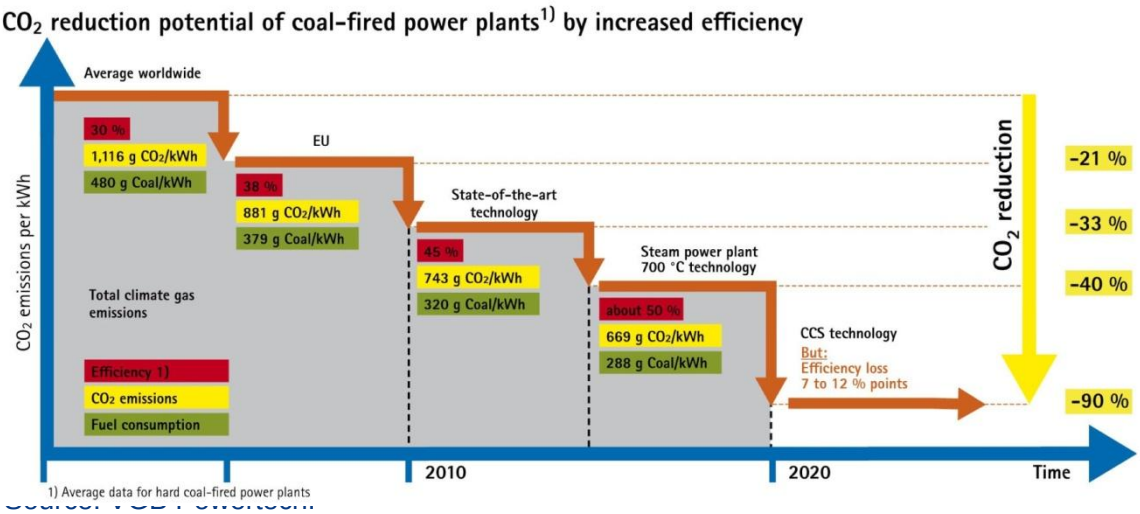
Source: IEA, Assocarboni.

At the same time, progress is being made in the development of circulating fluidized bed combustion (CFBC) plants. These can use low-rank fuels like lignite better. The first supercritical CFBC plant of 460 MWe size was commissioned at Lagisza (Poland) in 2009. Designed by Foster Wheeler, this plant has a design efficiency of 43.3%.

As far as integrated gasification combined cycle (IGCC) power generation is concerned, there are only six coal-based units in the world, three of them in Europe (the Buggenum plant in the Netherlands, the Elcogas plant in Puertollano, Spain, and the SUV/EGT plant in the Czech Republic). Other plants are planned in China, the United States and the United Kingdom.

Projections on progress in efficiency and emissions for coal-fired power generation show steady improvement to 2020 and beyond (Figure 17). If ongoing research in highly resistant materials (able to cope with temperatures of 700°C and pressures over 300 bar) is successful, the efficiency of the best PC plants may exceed 50% in the next 10 to 15 years. This would allow a reduction in CO_2 emissions by 40% compared with the current fleet.

Figure 17: The CO_2 reduction potential of coal-fired power plants



Coal-fired power plants are not only becoming more efficient, they are also becoming more flexible, providing essential grid services and back-up capacities. Modern coal plants can change from full load capacity to 50% in less than a quarter of an hour.

CCS development

As Figure 17 shows, these improvements however are not sufficient to comply with the ceiling of 500g CO_2/kWh proposed by the Environmental Commission of the EU Parliament for new power plants built in the EU after 2015. As no ceiling has been adopted at EU level so far, several countries – Germany and Poland in particular – are continuing to build coal-fired power plants (see Figure 18, Chapter 5, Tables 15 and 16, Chapter 7 and Table 17, Chapter 8).

When an Emissions Performance Standard (EPS) is set, for instance at 450g CO_2/kWh in the case of the UK, the only solution is to develop CCS. This would allow coal to become an ideal source in electricity generation, which abundant and affordable, and with low CO_2 emissions.

CCS technology

CCS technology involves:

- Capturing the CO_2 emitted at power plants and large industrial plants using fossil fuels;

- Transporting it to a suitable storage site; and finally,

- Injecting it in deep geological formations to be securely and permanently stored away from the atmosphere in rock.

There are three technologies to capture CO_2: pre-combustion, post-combustion and oxyfuel. All of these technologies can capture at least 90% of the CO_2 emitted. However, capture technologies reduce the efficiency of the plant by 7 to 12 percentage points. It is therefore crucial to start with improving the efficiency of the plants. The three technologies are demonstrated in pilot plants and current research programmes aim at halving the cost of capture.

CO_2 is preferably transported by pipeline, with ships being used when a source of CO_2 is too far from a suitable storage site. The transportation of CO_2 has been practiced by the oil and gas industry for over 30 years to maintain or increase production by injecting CO_2 into oil fields. However, the EU will need to build an extensive CO_2 pipeline network. Its complexity and lead-time should not be underestimated.

There are three means for storing CO_2: depleted oil and gas fields, deep saline aquifers and unmined coal seams. The largest storage capacities are in saline aquifers. As CO_2 has to be stored permanently, the CCS Directive demands that CO_2 storage is closely monitored.

EU support to CCS

Europe has been one of the first movers in the use of CCS. It is home to numerous projects on various scales which have been initiated over the past 20 years, including some of the first operational projects (Sleipner and Snovhit in Norway). In 2009, the EU established both a legal framework for CO_2 storage (the CCS Directive) and funding to support up to 12 CCS demonstration projects, since CCS is not yet economically efficient. In December 2009, a total of €1 billion of the funds of the European Energy Programme for Recovery (EEPR) were granted to 6 CCS demonstration projects in Poland, Germany, the Netherlands, Spain, Italy and the UK.

Funding is also available through the Commission's *NER300 programme*. The programme provides for the allocation of emission rights (300 million tonnes of CO_2) from the New Entrant Reserve (NER) for supporting CCS demonstration projects. The first call for proposals was published in November 2010. A total of 22 project developers filed their applications in February 2011, of which 13 were supported by the Member States and passed on. As Table 9 shows,

the vast majority of projects were submitted by the UK. Six other countries submitted applications for a single CCS project.

Recent developments, however, have shown that CCS technology is progressing more slowly than expected and regulatory issues, mainly for CO_2 storage, are difficult to overcome. Two major European projects were cancelled before the due diligence assessment carried out by the European Investment Bank:

- the Longannet Project (Scotland) was cancelled in October 2011, following a decision by the UK Government not to fund the construction of the project.

- the Vattenfall Jänschwalde (Germany) project was cancelled in December 2011, due to a lack of progress in resolving regulatory issues concerning CCS in Germany, particularly with respect to the permanent sequestration of CO_2 underground.

In addition, one further project was withdrawn at the end of June 2012, the Peel Energy post-combustion project in UK.

These cancellations are a major setback for the deployment of CCS technology in Europe. In addition, the collapse in EUAs price (€7 to 8/t in summer 2012, see Figure 15, Chapter 4) means that the NER 300 mechanism may collect only half the money it was expecting when the tender was launched. At that time, the price of CO2 was around €30/t and the prospect of a 10-12 project demonstration programme was very real. Today, the picture is different. A 10-12 project demonstration programme is no longer possible under these conditions.

It therefore remains to be seen what will be the outcome of the due diligence assessment carried out by the European Investment Bank on the remaining 10 projects. This will form the basis of the final selection of three demonstration projects by the EU's Climate Change Committee.16 Award decisions are envisaged by the end of 2012, and projects are to be operational four years afterwards. However, funding from the NER programme will be limited (less than €1 billion for the three projects) and their promoters may be disappointed.

[16] Latest number announced by the European Commission in July 2012.

Table 9: NER300 CCS projects

Project	Technology	Location	Country
Alstom Limited Consortium	oxyfuel new supercritical coal-fired power station	Drax, North Yorkshire	United Kingdom
C.GEN	new IGCC power station (pre-combustion with CCS on the coal-feed)	Killingholme, Yorkshire	United Kingdom
Peel Energy CCS Ltd	post-combustion amine capture on new supercritical coal-fired power station	Hunterston in Ayrshire, Scotland	United Kingdom
Don Valley Power Project (formerly known as the Hatfield Project)	new IGCC power station	Stainforth, Yorkshire	United Kingdom
Progressive Energy Ltd	pre-combustion coal gasification project	Teesside, North East England.	United Kingdom
Scottish Power Generation Limited	post-combustion amine capture retrofitted to an existing subcritical coal-fired power station	Longannet, Scotland	United Kingdom
SSE Generation Limited	post-combustion capture retrofitted to an existing CCGT power station	Peterhead, Scotland	United Kingdom
Air Liquid hydrogen project	capture and storage of CO2 released in the production process of hydrogen from hydrocarbons	Rotterdam	Netherlands
ENEL	post-combustion CCS project	Porto Tolle	Italy
ArcelorMittal	steelwork project	Florange	France
Vattenfall	oxyfuel coal-based project	Jänschwalde project	Germany
Alstom for Elektrownia Belchatow	amines-based capture technology	Belchatow	Poland
Turceni Energy Complex	post-combustion capture on a newly modernised lignite-fired unit of 330MW	Turceni	Romania

Source: after Bellona.
http://www.bellona.org/news/news_2011/NER300_applications

Box 1: the ZEP platform

Several European groups are working on CO_2-free electricity generation by 2020. The most well-known one is the research centre "Zero Emission Fossil Fuel Power Plants" (ZEP) European technology platform.

Founded in 2005, ZEP is a unique coalition of stakeholders united in their support for CCS as a key technology for combating climate change. ZEP serves as an advisor to the EC on the research, demonstration and deployment of CCS. The European utilities, petroleum companies, equipment suppliers, scientists, academics and environmental NGOs that together form ZEP have three main goals:

1. To enable CCS as a key technology for combating climate change.

2. To make CCS technology commercially viable by 2020, via an EU-backed demonstration programme.

3. To accelerate R&D into next-generation CCS technology and its wide deployment post-2020.

ZEP has developed a research and market launch strategy in order to commercialise CCS by 2020. First, it provided the roadmap necessary to commercialise CCS by 2020, including the 10-12 demonstration projects. ZEP then carried out an in-depth study into how such a demonstration programme could work in practice, from every perspective – technological, operational, geographical, political, economic and commercial – backed up by robust R&D activity.

ZEP has also undertaken a detailed study on the costs of CCS for existing pilot and planned demonstration projects. It concludes that post-2020 and following the EU CCS demonstration programme, CCS will be cost-competitive with other sources of low-carbon power, including on-/offshore wind, solar and nuclear power. The costs of post demonstration CCS with coal are estimated at €70-90/MWh and €70-120/MWh for CCS with gas. The associated EUA break-even-cost compared to power plants without CCS corresponds to a price of €37/t CO_2 for hard coal; ~€34/t CO_2 for lignite; and ~€90/t CO_2 for gas.

ZEP recently published a new strategy aiming at securing the business case for CCS as a key enabler for the decarbonisation of Europe. The strategy states that "While confidence in the (CCS) technology remains high, the fall in the carbon price could have a severe impact on both CCS demonstration and deployment: not only is significantly less funding available for the *NER 300* scheme, but the long-term business case for CCS has been seriously undermined. It means CCS has now reached a "tipping point" in Europe, where its success or failure depends on what measures are taken to counteract these developments and ensure the window of opportunity is not missed".

Source: ZEP Platform. `http://www.zeroemissionsplatform.eu/`

The key role of CCS in meeting EU climate targets remains indisputable, as confirmed by the EU Energy Roadmap 2050 which states that: "For all fossil fuels, Carbon Capture and Storage will have to be applied from around 2030 onwards in the power sector in order to reach decarbonisation targets". The International Energy Agency

goes even further in its 2011 World Energy Outlook, warning that: "If CCS is not widely deployed in the 2020s, an extraordinary burden would rest on other low-carbon technologies to deliver lower emissions in line with global climate objectives". The costs of achieving such objectives without CCS would be over 70% higher.

However, CCS seems much more difficult to apply than previously expected. Without CCS deployment, the future of coal in Europe is rather uncertain. When the price of CO_2 increases or CO_2 regulation tightens, there will be a switch from coal to natural gas. The first coal to disappear out of the mix will be the more expensive hard coal – possibly domestically produced coal. This will have implications for security of supply. Lignite will probably stay longest in the mix because of its low fuel costs. But eventually, its lower efficiency and higher emissions per kWh mean it will also become too expensive to sustain, especially as renewables and gas plants will be given priority in power generation and dispatching.

Given these uncertainties, the scientific community is mobilised so that Europe remains at the forefront of the CCS technology. The recent policy statements from the major institutions involved are clear. Markets alone are unlikely to bring forward investment in CCS before 2020, particularly given the volatility that carbon prices have displayed. The commitment of governments and industries must be strengthened and accelerated. For Europe, CCS is a major industrial challenge: while the contribution of coal is being reduced in the European electricity mix, it is instead growing in the world, particularly in emerging Asian economies. The impact of GHG emissions is not regional but global. If GHG emissions reduction in Europe is accompanied by a greater increase in GHG emissions in other parts of the world, the net global GHG balance will be negative. Hence the rapid deployment of commercial CCS in Europe would not only benefit the region (and coal) but offers huge export opportunities. Moreover, even on the most optimistic scenarios for nuclear power, gas and renewables ramped up by 2030/50, it seems likely the EU may struggle to deliver the desired level of abatement of CO_2 emissions, unless CCS is part of the low-carbon future. With regards to security of supply, there is a perceived EU need for fuel diversity (including coal) both to provide security of supply and to enable the EU to react to changing fuel market conditions. CCS is one way of achieving this objective.

The Future Demand for Coal

Faced with all these uncertainties, what could be the role of coal in the future European energy mix? This section presents two outlooks:

- The World Energy Outlook 2011 published by the International Energy Agency.[17]

- The scenarios developed by the European Commission in its EU Energy Roadmap to 2050.[18]

World Energy Outlook 2011

WEO2011 defines three scenarios:

- The New Policies Scenario (central scenario) which takes into account current commitments to protect the climate and improve security of supply;

- The Current Policies Scenario (previously called Reference scenario), with no change in government policies on energy and the climate (business as usual);

- The 450 ppm Scenario which sets out an energy pathway to achieve the objective of limiting the global rise in temperature to a maximum of 2°C compared with pre-industrial levels.

Under the New Policies Scenario, European coal demand halves over the Outlook period, from 381 Mtce in 2009 to 200 Mtce in 2035 (Table 10). Most of this decline results from reduced coal burning in power generation. Coal demand continues to be depressed as a result of a combination of factors: an expansion of natural gas and renewable-based generating capacity; the phase-out of subsidies to hard coal production, carbon pricing; and increasingly stringent local environmental regulations. By 2035, the share of coal in the energy mix falls to 8%.

[17] IEA, op. cit.
[18] European Commission, op. cit.

Table 10: The EU coal balance under the New Policies Scenario

Mtce	2009	2015	2020	2025	2030	2035
Coal production	238	201	171	142	117	89
Hard coal imports	143	170	155	140	116	111
Coal Demand	381	371	326	282	233	200

Source: WEO2011

Under the Current Policies Scenario, coal demand by 2035 amounts to 316 Mtce (12% of the energy mix). In the 450 ppm Scenario, coal demand plunges to 131 Mtce (6% of the energy mix). The price of CO2 under the EU ETS is assumed to reach $30/t in 2020 (in 2010 dollars) and $50/t in 2035 in the New Policies and Current Policies Scenarios; and $45/t in 2020 and $120/t in 2035 in the 450 ppm Scenario.

ExxonMobil's scenario to 2040 presents a similar trend. Coal consumption in the whole of Europe is expected to decrease by an average 3% per year over the period 2010-2040, from 431 Mtce in 2010, to 319 Mtce in 2025 and 180 Mtce in 2040 (original data in BtU).19 Europe continues to shift towards less carbon-intensive sources of energy for electricity generation. Today, Europe gets about half its electricity from nuclear power and renewable energies. This percentage rises to nearly 65% by 2040, mostly because of strong growth in wind power, which is estimated to expand from its current share of 5% to 20% in 2040. Integral to these forecasts is an expectation that the cost of CO2 emissions rises. ExxonMobil sees OECD CO2 costs reaching $60/t by 2030 and about $80/tonne by 2040.

The EU Energy Roadmap to 2050

In its Roadmap, the Commission has outlined seven different potential scenarios, illustrating possible evolutions of the energy system in Europe by 2050. These scenarios are split into two current trend scenarios, which are not ambitious enough to achieve the EU's 2050 decarbonisation goal, and five other possible decarbonisation scenarios. Among the current trend scenarios, the first reference scenario includes current trends in accordance with policies adopted by March 2010, and long-term projections on economic development, while the second current policy initiatives scenario (CPI) takes into account the recent measures adopted, especially after the nuclear catastrophe at Fukushima. This latter scenario serves as the basis of

[19] ExxonMobil, 2012 The Outlook for Energy: A View to 2040, Irving, Texas, 2012.

all decarbonisation scenarios. While the current trend scenarios are insufficient, the five other scenarios show that decarbonisation is possible. All decarbonisation scenarios achieve an 80% GHG reduction and an 85% energy-related CO_2 reduction by 2050, compared to 1990, as well as equal cumulative emissions over the projection period.

They each represent a main route to achieve the energy transition, focusing respectively on:

- high energy efficiency, where there is a commitment to very high energy savings, leading to a 41% decrease in energy demand by 2050 compared to the 2005-2006 peaks;

- diversified supply technologies, in which all energy sources compete on a market basis with no specific support measures;

- high renewable energy sources (RES), with strong support measures for renewables resulting in a share of 75% in gross final energy consumption, and of 97% in electricity consumption;

- delayed CCS with the share of nuclear energy in primary energy consumption amounting to 18%;

- and low nuclear power with higher shares of CCS, around 32% in power generation.

The major tendency emerging from the Roadmap is that a large share of energy production will come from renewables, fossil fuels (mainly natural gas) playing a complementary and transitional role towards exclusively low-carbon energy production, and nuclear energy facing a potential decline. Energy efficiency is set to play a major role in all cases. The development of CCS could also significantly change the transition pathway.

As for coal, the Roadmap recognises its advantages in terms of energy security and competitiveness. However, as the most polluting energy source, its share in the EU energy mix progressively decreases. Coal demand differs greatly according to these contrasting scenarios. Table 11 shows the outcome of the CPI scenario.

Table 11: European coal balance under the CPI scenario

(Mtce)	2010	2015	2020	2025	2030	2035	2050
Coal production	254	240	204	191	155	146	139
Hard coal imports	146	165	136	138	123	102	79
Coal Demand	400	405	340	329	278	248	218
Share of coal in primary energy supply (%)	16	15.7	14	13.7	12	10.7	9.4

Original data in koe, converted in Mtce and rounded.
Source: EU Energy Roadmap to 2050.

Table 12 shows the outcome of the five decarbonisation scenarios on the future demand of coal (2035 and 2050), and its share in energy supply and electricity mix.

Table 12: European coal demand under the five decarbonisation scenarios

	2035			2050		
	Coal demand (Mtce)	Share of coal in primary energy supply (%)	Share of coal in electricity generation (%)	Coal demand (Mtce)	Share of coal in primary energy supply (%)	Share of coal in electricity generation (%)
High efficiency	124	6.4	5.8	63	4.1	4.8
Diversified Supply Technologies	146	6.9	7.1	110	6.3	8.1
High RES	100	4.9	3.5	33	2.1	2.1
Delayed CCS	90	4.4	3.7	81	4.6	5.1
Low nuclear	186	9.3	11.5	165	10.2	13.1

Original data in koe, converted in Mtce and rounded.
Source: EU Energy Roadmap to 2050.

The share of coal in EU primary energy mix could drop to 4.4-9.3% by 2035 and to 2.1-10.2% by 2050. Even in the Low nuclear scenario, which is the most favourable to coal, the demand for coal is drastically reduced from 400 Mtce in 2010 to 186 Mtce by 2035 and 165 Mtce by 2050. The share of coal in electricity generation shrinks from 25% currently, to between 2% and 13% in 2050.

Coal plants with CCS will have to contribute significantly in most scenarios with a particularly strong role of up to 63% in the case of constrained nuclear production and shares ranging from 29% to 53% in other scenarios (Table 13).

Table 13: Installed coal capacity in 2050

	Coal-fired capacity (GW)	Coal CCS capacity (GW)	% of total capacity equipped with CCS
CPI	104	33	32%
High efficiency	70	28	40%
Diversified Supply Technologies	94	50	53%
High RES	62	18	29%
Delayed CCS	73	30	41%
Low nuclear	125	79	63%

Source: EU Energy Roadmap to 2050.

The shrinking use of coal use by 2050

While WEO2011 and EU2050 scenarios are not directly comparable, they conclude with the same trend: a shrinking share of coal in the future, even if CCS is deployed on a large scale. Coal is displaced by renewabled (mainly wind power), and gas is used as a back-up fuel.

Again, CCS appears as the only possibility in enabling coal use in the EU power mix.

The EU transition to a free-carbon world poses many challenges for the power sector. At least four of them must be addressed:

- Investment,
- Electricity prices,
- Security of supply,
- Regional or worldwide approach to GHG emissions reduction.

As the power system becomes more and more dependent on intermittent energies, back-up facilities need to be built. In addition, more than half of current installed fossil generation capacity in the EU will reach the end of its lifetime within the next twenty years and must be replaced. This requires massive new investment in the power sector: for power generation and transmission alone the Roadmap analysis estimates a €1.3 trillion investment over the next 15 years, or roughly a doubling of the historic investment rate in the power sector. In the Roadmap, the back-up role is mainly given to natural gas which appears as the bridge fuel to low-carbon future. The Roadmap also states that CCS must be applied to all fossil fuels from around 2030 onwards, in order to reach the decarbonisation targets. For fossil fuels plants (whether gas or coal), operational costs in the future will

be higher and power plants might run for fewer hours, at lower load factors providing lower revenues from electricity sales. This leads to concerns for investors about their ability to raise project finance and to recover capital and fixed operating costs. Already today, financing of new fossil fuel power projects is difficult because banks assume a much higher future CO2 price (€50/t CO2 or more), based on their assessment of EU policy. Under this environment, it is difficult to see how investment in back-up capacity will take place, leaving the EU with a vulnerable energy system. It is important that long-term decarbonisation goals do not deter the necessary investments in fossil fuel options in the next 10/20 years. It is also crucial that back-up facilities are incentivised through some remuneration of capacity and availability, and not only from the actual electricity produced.

Shifting to a decarbonised energy system will result in a higher electricity price, particularly in the next 20 years when many of the high-capital investments in the system are made. The extension of renewables will entail significant costs/subsidies above lower-cost alternatives for many years. In the longer run, over the 40 year period up to 2050, the Roadmap analysis shows that price levels are roughly of the same order in all modelled pathways. A key challenge will be to create acceptance for higher energy prices in the next 20 years. The big risk to power investment is that consumers will not pay for all of the decarbonisation costs or that the costs will make the European Union uncompetitive.

Security of supply is an important component of the EU energy policy. However, a shrinking share of coal in the energy mix does not play in favour of increased security. Relying only on one back-up fuel in the future leaves the power system dependent on external risks and infrastructure risks, which may be avoided by keeping the coal option opened. In this way, coal and lignite would add to power system stability and robustness. Point source emissions from gas use are lower than from coal, but the whole environmental impact of importing gas from distant suppliers must be taken into account. If Russia uses more coal to free up natural gas for export to the EU, then the climate benefit will be negative.

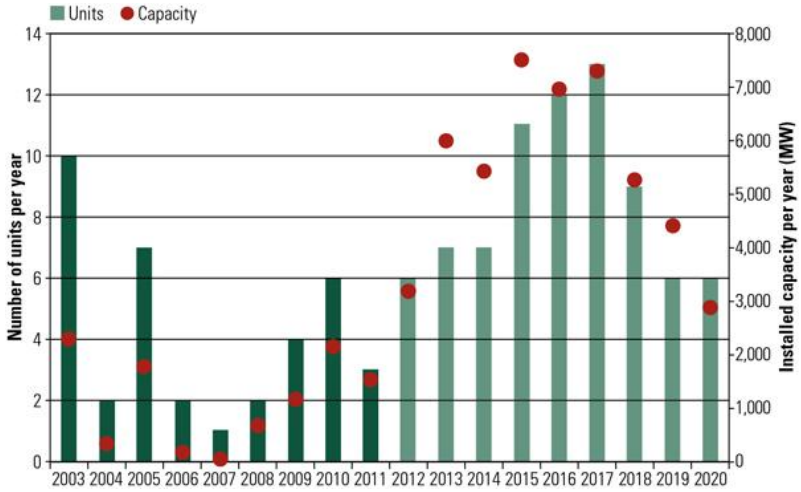
By adopting this position, the EC is at the forefront of a new energy world. However, it remains to be seen what the position of non-EU countries will be. The issue of global warming is not a regional issue. It must be addressed in the global context. If global climate targets are not harmonised with the ambitious European targets on CO2 reduction, Europe will face carbon leakage: the migration of energy-intensive industry outside Europe and importation of cheap – but CO2-intensively-produced – power from non-EU countries. The latest OECD environmental outlook shows that if nothing is done at global level, GHG emissions will reach 80 Gt by

2050.20 The 80-95% reduction in EU GHG by 2050 would represent a 6% saving in forecasted global emissions at that date.

A possible surge in new coal capacity in the next few years

At the end of 2011, Europe had about 330 coal-fired power plants with a combined capacity of 200 GW from almost 950 units.[21] Between 2012 and 2020, approximately 80 new coal units, with a capacity of about 50 GW, are under construction or planned (Figure 18). From 2003 to 2011, by comparison, only 40 units totalling 10 GW were built.

Figure 18: Coal-fired power plants under construction and planned in Europe



Source: Ecoprog GmbH.[22]

The main driver for this surge in new construction is the need to replace lost capacity due to the LCPD and ageing coal, gas and nuclear plants. The LCPD alone will account for a loss of 35 GW by 2016. The average age of Europe's coal power plants is 34 years, and by 2020 another 20 GW to 25 GW of coal capacity will have reached the end of its operating life and must be replaced. The loss of nuclear power plants in Germany and Switzerland, oil-fired plants

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[20] OECD, OECD Environmental Outlook to 2050: The Consequences of Inaction, Paris, March 2012.

[21] Butcher Charles, *Europe: More Coal, Then Less*, Powermag, 1 May 2012 .http://www.powermag.com/coal/Europe-More-Coal-Then-Less_4597_p1.html

[22] Ecoprog GmbH, The Market for Coal Power Plants in Europe, Köln, April 2012 in Powermag, op.cit.

in Italy, and old gas plants in the UK will further add to the pressure. A large part of lost capacities will be replaced by gas. About 160 gas-fired power plants will be constructed or extended between 2011 and 2015. The capacity of the European gas-fired power plants will increase by 66 GW – from about 176 GW to 242 GW. However, the uncertain development of gas prices and security of supply concerns (see Chapter 7) will obstruct an overly larger extension. The growth of renewables will also add a considerable amount of new capacities. But their intermittent operations and delays in building the necessary transmission lines may limit their role. Eventually, some countries plan to construct new nuclear plants. However, their implementation is also uncertain at present.

In light of these uncertainties, the large power utilities aim at maintaining electricity generation from coal to diversify their electricity mix and risks. Furthermore, coal is still the largest domestic fossil fuel in some major EU countries: this is true for lignite in Germany and hard coal in Poland. Imported coal also contributes to security of supply with large quantities of US coal available on the market, since the development of shale gas in the country and the subsequent decrease in coal consumption.

Indeed, not all projects shown in Figure 18 will be built. Local opposition in several countries will reduce considerably the number of projects, as has been observed in Germany, the UK and Italy in the past few years. However, even assuming a 50% success for new projects, coal-fired power capacities would still amount to 165 GW-170 GW by 2020, a decrease of 15% to 17.5% compared with the end of 2011.

The kinds of plants which are built today are either supercritical (SC) power plants or co-firing plants. The SC plants will allow a drastic reduction in CO_2 emissions when they replace old coal-fired power capacities. The new, highly efficient coal-fired power plants reach efficiencies of 45-46%, and some are built with combined heat and power (CHP), increasing the overall efficiency futher. Another strategy adopted by utilities is the construction of co-firing plants that can burn coal and a combination of fuels. In Denmark, for instance, the Danish energy company Dong Energy is refurbishing its 375 MW coal-fired cogeneration plant in Aarhus, in a way that makes it possible to shift from biomass to coal at very short notice. The plant is expected to continue operating until 2030. In UK, RWE's 750 MW Tilbury coal plant has been converted to 100% biomass. The 4,000 MW Drax plant in Yorkshire, which already includes 500 MW of biomass co-firing capacity, is being upgraded to increase biomass burning. Several plants in the Netherlands, Belgium, Germany, Italy and Poland already use biomass or are upgraded to co-fire coal and biomass. Indeed, biomass co-firing is an attractive solution: it offers renewable energy generation with the smallest capital cost, taking advantage of the high electrical efficiencies of today's coal power stations. It offers a opportunity to

replace up to 20% of the coal fuel with biomass fuel. This represents a substantial volume of avoided CO_2 emissions.

The phasing out of nuclear plants in Germany and the need to replace ageing plants in several EU countries have created an opportunity for building new efficient coal power plants. This period of grace however is limited. The share of coal-fired power generation will decline rapidly after 2020/30, unless CCS is deployed on a large scale.

Part 2

Looking at Key European Coal Markets

Germany

Germany has always been a traditional coal producer and consumer. Coal still accounts for 23% of the energy mix and 44% of electricity generation. However, the importance of coal has been declining over the past decades. In 1990, about 37% of total primary energy supply came from coal. In the long term a further decline of coal demand is expected.

KEY COAL INDICATORS. 2010 DATA	GERMANY
Coal market	
Coal production (Mtce)	**64.12**
of which hard coal (Mtce)	12.1
of which lignite (Mtce)	52.02
Coal imports (Mtce)	**46.2**
Coal exports (Mtce)	-1.4
Stock changes (Mtce)	0.2
Primary coal supply (Mtce)	**109.2**
of which electricity (%). data for 2009	85%
of which iron and steel industry (%). data for 2009	8.6%
Coal reserves and resources	
Hard coal reserves (Mt)	59
Lignite reserves (Mt)	40 500
R/P hard coal (years)	**4**
R/P lignite (years)	**240**
Hard coal resources (Mt)	82 962
Lignite resources (Mt)	36 500
Employement	
Direct employement in the coal mining industry	**40 900**
State aid to the coal sector (M€)	**1 758**

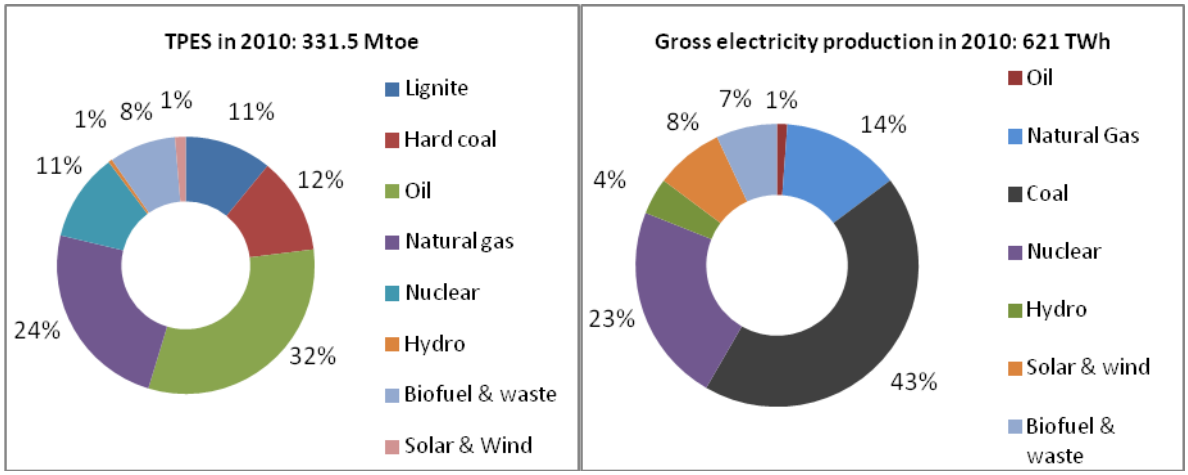
This country profile first gives some key data on the German coal market, and then analyses:

- How the Fukushima accident and the following decisions by the German Government impact on future coal demand in the country.
- What the long term future of coal in the context of the *Energy Concept* is.
- What the current status of CCT and CCS in Germany is.

The Coal market

Coal is one of the most important primary energy sources in Germany. In 2010, it accounted for 23% of total primary energy supply (TPES) and 43.6% of gross electricity generation (Figure 19).

Figure 19: TPES and gross electricity generation in Germany, 2010



Source: IEA.

Hard coal

Consumption in the hard coal market totalled 56.3 Mtce in 2010. 42.1 Mtce were used for power and heat generation (steam coal) and 14.8 Mtce were coking coal. Most of the hard coal used in Germany was imported (79% in 2010). The main suppliers were Russia, Colombia and Poland for steam coal and Australia, the United States and Canada for coking coal.

Germany produced 12.1 Mtce of hard coal in 2010 (5.03 Mtce of steam coal and 7.07 Mtce of coking coal). Hard coal is produced in three areas: the Ruhr area, the Saar area and the Ibbenbuehren area. Indigenous hard coal production has been declining (71 Mtce produced in 1990) and this trend is expected to continue with the end of State aid by 2018.

Lignite

Germany has the largest reserves of lignite within the EU and is the world's largest producer of lignite (17% of global output in 2010). The country produced 52.02 Mtce of lignite in 2010. Lignite production has been constant over the past decade. There are four areas of production: the Rhineland, the Lusatian mining area, the Central German mining area and the Helmstedt mining area. In these areas lignite is produced in opencast mines and its production is not subsidised. Lignite is mainly used for electricity generation and heating (92% in 2009).

Reserves

Hard coal and lignite are the most important domestic fuels. According to BGR, Germany's coal reserves amount to 59 Mt of hard coal and 40,500 Mt of lignite. Hard coal reserves have been

downgraded to reflect the amount that is to be produced with government funding until 2018. The minable amount is higher.

Coal (mainly lignite) is the only major domestic contributor to fossil fuel production as natural gas and oil reserves are negligible and these fuels have to be imported, making Germany a large energy importer. Coal therefore plays an important role for security of supply in Germany.

Power generation

Germany is both the largest electricity generator and consumer in Europe, ranking sixth worldwide. Its annual electricity consumption has stagnated over the past decade at around 520/540 TWh (2010: 541.1 TWh). More than 65% of Germany's electricity is generated from fossil fuels (43.6% from coal). In 2010, lignite had a share of 23% and hard coal accounted for 19%. 22% of electricity generated came from nuclear power plants. The share of renewables (16% in 2010) has been increasing rapidly since 2000, and played an essential role in 2011 (see the next section).

Electricity capacities amounted to 160.5 GW at the end of 2010. Hard coal capacities made up 23.3 GW, while lignite capacities were 21.3 GW. Nuclear capacity amounted to 20.8 GW, and natural gas to 20.6 GW. Installed electricity generating capacity has been rising fast over the past decade, as wind and solar capacities have been added intensively to the network: from 0.1 GW in 2000 to 17 GW in 2010 for solar and from 6.1 GW to 27 GW for wind. In 2011, this trend continued: 2 GW of wind and 8.5 GW of solar capacity were added to the system.

The short and long-term views of coal in the energy mix

The short-term impact of Fukushima: a review of power generation in 2011

In March 2011, the announcement of the temporary closure of the seven oldest nuclear plants (8.4 GW taking into account the Krümmel plant which was already closed) led to the feeling that steam coal imports were going to increase fast to replace nuclear capacity losses. This was not the case. Steam coal use decreased by 1 Mtce in 2011 to 39 Mtce. Most of the lost nuclear capacity was replaced by renewables (mostly wind and solar), which accounted for 20% of electricity generation (+ 4 percentage points compared with 2010, Table 14), by a larger use of lignite plants and by a changing pattern in electricity trade (increasing imports from neighbouring countries and decreasing exports, although Germany was still a net electricity

exporter in 2011: it exported 6 TWh, which was much less than the 17 TWh in 2010). It should be noted that in 2011 weather conditions were favourable, with a warm winter and a lot of wind. The system was therefore not really tested under more difficult, but possible, conditions.

Table 14: German electricity generation by fuel, 2011 vs. 2010

	2010		2011	
	TWh	%	TWh	%
Total gross electricity generation	**628.1**	**100**	**612**	**100**
Hard coal	119	19	116.3	19
Lignite	144.5	23	153	25
Nuclear	138.2	22	110.1	18
Natural gas	88	14	86	14
Oil. pumped storage and others	37.7	6	30.6	5
Renewables	100.5	16	122.4	20
of which wind	37.6	6	46	7.5
of which phtovoltaic	11.7	2	19.5	3

Source: BDEW, AG Energiebilanzen, AGEE/ZSW, McCloskey Report (provisional figures).

Recent developments in the winter of 2011/2012

These more difficult conditions were encountered in the very cold month of February 2012, when an unexpected shortfall in gas supplies coupled with an exhaustion of the system balancing energy reserves put the electricity grid under severe strain.[23] The unexpected interruption of gas deliveries from Russia and the fact that several natural gas–fired power plants could not produce at full capacity, due to interruptible capacity contracts between power plant operators and gas Transmission System Operators (TSOs), required additional measures to be taken by electricity TSOs to maintain system security. During this period, there was not only a very high load on the power lines, but also a massive short portfolio in balancing groups. This means that significantly more electricity was consumed than had been forecast and thus actually produced. Given this shortfall in the system balance, the TSOs had to exhaust temporarily the system balancing energy, which is kept in reserve and is meant to provide short-term balancing capability for load fluctuations and power plant outages. In order to avoid disconnecting electricity consumers from the grid, the system balancing energy was supplemented using back-up power plants. To cover the generation shortfall of 6.2 GW, TSOs had to use all normal German reserve capacity (3,824 MW), to call upon cold reserves in Germany (360 MW) and Austria (985 MW), and

[23] BNA (Bundesnetzagentur), Status report on grid-based energy supply in winter 2011/2012, Bonn, May 2012 and McCloskey Coal Report, 18 May 2012.

to take emergency measures with TSOs in neighbouring countries (1,350 MW).

This shortage challenges the decommissioning of old coal-fired power plants. BNA, the energy regulator stated in its report that "the back-up reserves will be required to a similar degree in the winter of 2012/13".[24] BNA also states that "Decommissioning of further conventional power plants cannot be currently justified in Germany" and adds that "regulatory and legislative measures are required to prevent decommissioning of conventional generation plants." To ensure sufficient reserve power station capacity exists, BNA recommends that power station operators should be legally obliged to announce planned power station closures at least 12 months in advance, otherwise closure should be forbidden. BNA also recommends postponing closure of power stations that are due for decommissioning because they no longer comply with emission limits. This new outlook could mean that coal plants designated for closure in 2012 (3 GW) may be required to stay on line at least in the winter of 2012/2013. The situation should improve in 2013 when around 5.7 GW of new coal capacity comes on line (Table 15). A new 2.2 GW lignite-fired power plant was already commissioned in Cologne in August 2012. This new plant confirms the resurgence of coal/lignite burning in Germany. The plant operated by RWE has a high efficiency (43%) compared with old plants.

Table 15: German conventional power station capacity developments, 2012-2014[25]

	2012			2013			2014		
Net Capacity in MW	**Increase**	**Closure**	**Balance**	**Increase**	**Closure**	**Balance**	**Increase**	**Closure**	**Balance**
Coal	0	-1110		5665	-520		2365	0	
Waste	7	0		26	0		0	0	
Lignite	2740	-1960		0	-60		0	0	
Gas	509	-160		875	-1037		0	-383	
Hydro	10	0		0	0		0	0	
Several fuels	0	-110		126	-50		11	0	
Oil products	0	0		0	0		0	-772	
Pumped storage	0	-40		195	0		0	0	
Total	3266	-3380	-114	6887	-1667	5220	2376	-1155	1221

Source: Bundesnetzagentur, McCloskey Report.

The long-term *Energy Concept*

In September 2010, the Federal Government adopted the *Energy Concept* which sets out Germany's energy policy until 2050. The *Energy Concept* paves the way for the *"age of renewable energies"* and sets out very ambitious goals for the future energy mix:

[24] BNA, ibid.
[25] The longer term view to 2022/32 is presented in Table 16.

- The intention is to increase the share of renewables in power generation to at least 35% in 2020, a figure that should rise to 80% by 2050.

- Correspondingly, an ambitious climate protection goal aims at reducing GHG emissions by 40% by 2020, and by 80% to 95% by 2050, with respect to their 1990 levels.

- Energy efficiency increases by an average of 2% per year to cut Germany's total energy consumption by half by 2050 (compared with 2008).

In the first version, nuclear power had a bridging role to the "age of renewable energies". The Energy Concept included the extension of the operating lives of the 17 nuclear power plants by an average of 12 years. Against the backdrop of the nuclear meltdown at Fukushima in March 2011, the role assigned to nuclear power in the Energy Concept was reassessed and the seven oldest nuclear power plants and the one at Krümmel were shut down permanently. On 6 June 2011 the Federal Government adopted the Energy Package which supplements the measures of the *Energy Concept* and speeds up its implementation. The centrepiece was the legislative package adopted for a further amendment of the Nuclear Energy Act – the intention now being complete withdrawal from nuclear energy by 2022. Other provisions included the earlier than scheduled revision of the Renewable Energy Sources Act (EEG), acceleration Acts for power grid expansion and the planning of new power stations and storage capacity, along with adjustments to the Energy Industry Act.

To meet the *Energy Concept* targets in the power sector, Germany's entire power supply system must be overhauled. Investments must be made in modernising the power plant fleet, adding back-up fossil-fuelled capacities, building new power grids, extending interconnections with neighbouring countries, and above all expanding renewables. Most of the *Energy Concept* – as far as the power sector is concerned – is based on an enormous development of offshore wind in the Baltic Sea. Linked with this development, new high-voltage transmission lines have to be built across the country to transport electricity from the north to the south of the country. These are particularly expensive and, in addition to the financial burden, create environmental issues and provoke local opposition. Investment required to meet the *Energy Concept* targets is expected to total approximately €20 billion annually, i.e. € 250 billion over the period. The early retirement of nuclear energy is estimated to add €16.4 billion to costs from 2010 to 2030 (or much more according to industry figures).[26]

[26] Prognos, EWI, GWS, *Energieszenarien 2011*, Basel/Köln/Osnabrück, July 2011.

Prospects for the coal industry

From a coal perspective, the first version of the *Energy Concept* was fatal in the long term. According to the lead scenario, hard coal consumption would drop by about three quarters by 2050, to a residual amount of approximately 15 Mtce. Already by 2020, it was to halve to just 31 Mtce, all of which was imported. Indigenous lignite use was to be stable until 2020, but drop drastically after that date. Its contribution to electricity generation would fall drastically to less than 1% in 2050.

The new *Energy Package* changes the situation. Although it has not changed the direction of the German energy policy towards a drastic reduction in GHG emissions, more renewables and increased efficiency, nuclear power can no longer be the bridging energy to the *new age of renewables*. This role has to be taken by thermal capacity (or electricity imports in case of shortages). In addition back-up capacities will be necessary to support intermittent electricity production, this role could either be given to gas or coal-fired power plants. Although gas-fired power plants offer more operational and economic flexibility, it is not sure that only these considerations will be taken into account. Coal-fired electricity generation in Germany offers another advantage as lignite is a domestically-produced energy source, whereas natural gas has to be imported from Russia mainly. The problems encountered by TSOs in February 2012 will certainly influence the electricity mix, at least during the nuclear phase-out period.

When the government announced the phase-out of nuclear power by 2022, it estimated that at least 10 GW, and more likely, 20 GW of new fossil-fired power plants will be required in Germany over the next decade, in addition to the roughly 10 GW currently under construction for commissioning by 2013.[27] No breakdown was given of how the capacity could be divided between coal, gas and lignite.

In July 2011, Prognos/EWI/GWS released a report on the consequences of the nuclear power phase-out on the energy system.[28] The study, commissioned by the Germany Ministry of Industry, is based on political targets: (i) a complete exit from nuclear power by 2022, (ii) significant energy demand reductions (total primary energy consumption is reduced by 34% over the period 2008-2030, Figure 20) and, (iii) a high share of electricity generation from renewables (the share of renewables reaches 55% of electricity generation by 2030, Figure 21). The goal of the study was to assess the impact of the exit from nuclear energy by 2022 compared with scenarios developed in 2010, in the context of the *Energy Concept*. The study therefore compares the energy/electricity mix and associated costs under the exit scenario with that of the extended

[27] Germany's Chancellor Angela Merkel in her address to parliament on "the path to energy of the future", McCloskey Coal Report, 17 June 2011.
[28] Prognos, EWI, GWS. op. cit.

lifetime of nuclear power plants. The key findings of the study are: first, nuclear capacities are mainly replaced by longer lifetimes of existing coal-fired plants and the construction of new gas-fired plants. Second, fossil fuel-based generation and power imports increase, while power exports are reduced in response to the lower nuclear generation. Third, despite the increased fossil generation, challenging climate protection goals can still be achieved. Finally, system costs and electricity prices are clearly higher. The challenge of transforming the energy system really occurs after 2020, when the time comes to replace the energy production from fossil fuels and to prove the feasibility of an energy mix with a predominant share of renewables.

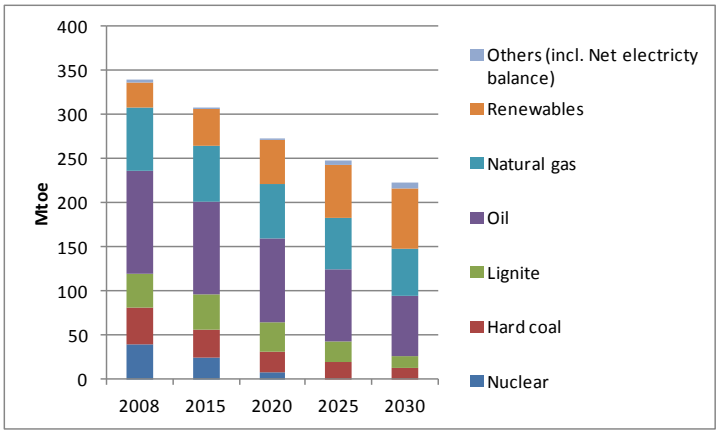
The decommissioning of nuclear plants causes an additional need for conventional generation capacity which is to be satisfied in a cost-minimal way. Firstly, economic lifetimes of 5.4 GW of old coal-fired plants are extended. Secondly, in addition to the conventional power plants currently under construction (+12.3 GW, of which 0.7 GW based on natural gas, 8.7 GW on hard coal and 2.9 GW on lignite), significant new-built gas-fired generation capacities are to come online between 2015 und 2025. Yet, under the assumption of an increasing role of renewables, total conventional capacity decreases while renewable capacity increases over time (Figure 22). Additional renewables capacity mainly comprises wind power onshore (+11.9 GW until 2030), offshore (+16.7 GW) and photovoltaics (+37.1 GW). Apart from plants currently under construction, no additional hard coal or lignite-fired capacities are installed in the decade. From 2025, coal with CCS is an alternative. Finally, the European power trade is influenced. Power imports increase while power exports are reduced in response to the lower nuclear generation. In 2015 Germany is still a net electricity exporter. In contrast, Germany becomes a net importer by 2020. German electricity imports increase after 2020 to 44 TWh in 2030.

From a coal perspective, the scenario leads to a shrinking share of coal in the electricity mix, particularly after 2020. Installed coal-fired capacities are reduced from 53 GW in 2008 to 47 GW in 2020 and to 22 GW in 2030, of which 1.4 GW are equipped with CCS (Figure 22). Electricity generation from coal decreases by 26% in 2020 and by 68% in 2030, both compared with 2008.

The study concludes that an accelerated phase-out is feasible but challenging: it is subordinated to the realisation of political assumptions: firstly, the realisation of a 36% share of renewables in electricity generation in 2020; secondly, energy efficiency improvements and hence substantial energy demand reductions. Failure in either of these two will result in additional needs for investments in conventional power plants and additional electricity imports. Other key challenges and risks involve the extension of the grid, security of supply of electricity and the construction of

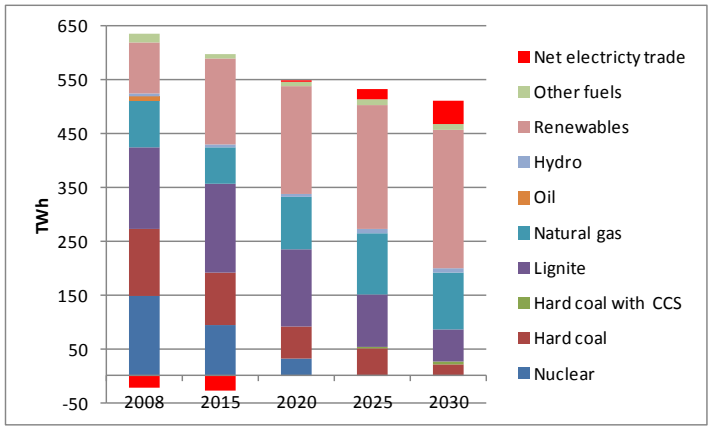
conventional back-up facilities. The recent report of BNA indicates that additional regulatory measures are going to be taken to reinforce grid and electricity supply security.29 This may not change the long term use of coal in Germany. However the contribution of coal plants in securing electricity supplies will certainly be strengthened in the decade ahead, as well as their role as security reserves in the longer term.

Figure 20: Primary energy consumption after the from nuclear power, 2008-2030



Source: Prognos, EWI, GWS.

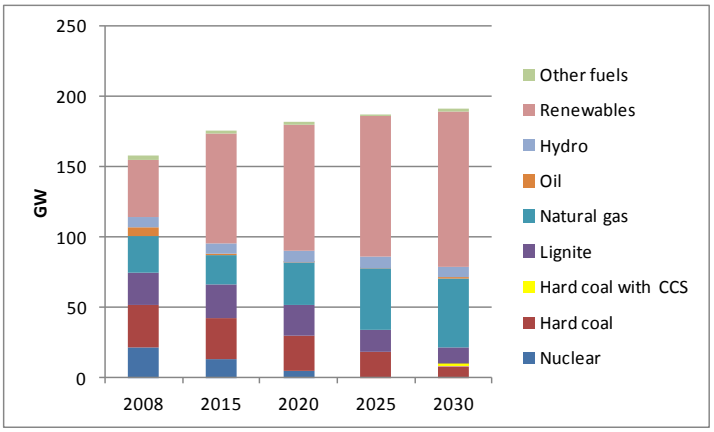
Figure 21: Gross electricity generation by energy source, 2008-2030



Source: Prognos, EWI, GWS .

[29] BNA, op.cit.

Figure 22: Gross electricity power capacity after the exit from nuclear power, 2008-2030



Source: Prognos, EWI, GWS

In December 2011, the German Energy Regulator BNA issued new scenarios for the development of the power system by 2022/32.[30] The scenarios create the basis for the national Network Development Plan which TSOs would present for the first time in June 2012.

The lead scenario (Scenario B) is based on an ambitious expansion of renewables and combines them with the assumption that in the area of conventional electricity generation, only those coal-fired power plants under construction and gas power plants, which currently exhibit a high degree of planning, will be completed. Scenario A foresees a slower expansion rate of renewables combined with a stronger increase in coal-fired power plants. Plants with a high degree of planning are taken into account. Scenario C foresees a sharp rise in plants generating electricity from renewables, as announced by the individual Federal States, combined with only modest contributions of fossil-fuelled generation.

Under the lead scenario B, coal still plays an important role in future electricity generation: hard coal-fired capacities in 2022 are on a par with the 2010 level of 25 GW, falling to 21 GW in 2032 (Table 16). Lignite capacity drops to 18.5 GW in 2022 from 20.2 GW in 2010, and falls to 13.8 GW in 2032. This scenario shows that coal might gain a period of grace and should still play a significant role in electricity generation in 2022. Its assumptions seem to reflect recent developments in the power system.

[30] BNA (*Bundesnetzagentur*, German Energy Regulator), *Szenariorahmen 2011*, Bonn, December 2012

Table 16: BNA's scenarios for the development of the German power system by 2022/32

	2010	2022			2032
Fuel (GW)		**Scenario A**	**Lead scenario B**	**Scenario C**	**Lead scenario B**
Nuclear	20.3	0	0	0	0
Hard coal	25	30.6	25.1	25.1	21.2
Lignite	20.2	21.2	18.5	18.5	13.8
Natural gas	24	25.1	31.3	31.3	40.1
Pumped storage	6.3	9	9	9	9
Oil	3	2.9	2.9	2.9	0.5
Others	3	2.3	2.3	2.7	2.3
Total conventionnal power stations	**101.8**	**91.1**	**89.1**	**89.1**	**87.3**
Hydro	4.4	4.5	4.7	4.3	4.9
Wind onshore	27.1	43.9	47.5	70.7	64.5
Wind offshore	0.1	9.7	13	16.7	28
Photovoltaic	18	48	54	48.6	65
Biomass/biogas	5	7.6	8.4	6.7	9.4
Other renewables	1.7	1.9	2.2	2	2.9
Total renewables	**56.3**	**115.6**	**129.8**	**149**	**174.7**
Total generation	**158.1**	**206.7**	**218.9**	**238.1**	**262**

Source: BNA.

On the one hand, wind energy may not expand as swiftly as expected, because the existing transmission network is unable to absorb the power and the new cables are slow in being built. The transmission system operator Tennet stated in November 2011 that the nine cable connections to German offshore wind stations underway, are " no longer desirable or possible" due to lack of staff, materials and finance.[31] The cable projects were designed to carry electricity to shore from 5.2 MW of offshore wind projects. Offshore wind farms are also delayed as the licensing and permitting process has turned out to be more complex than planned. The start of the first offshore wind farm platform will be delayed by about a year, until May 2013.[32]

On the other hand, there are still a lot of new hard coal and lignite plants under construction or planned in Germany.

- A total of 8.2 GW will come on line from 2011-2013. This is 59% of total new power station capacity (13.8 GW) due on line over the three year period, according to the latest BNA Monitoring Report.[33] Over the same period, 3.1 GW of coal capacity will be decommissioned, resulting in an overall increase of 5.1 GW of coal burning plants. This means that by 2014,

[31] Windpower Monthly, November 2012.
[32] The HelWin converter platform (a 576 MW grid connection for wind parks) is the first grid connection for offshore wind farms in the eastern North Sea.
[33] BNA (Bundesnetzagentur, German Energy Regulator), Monitoring Benchmark Report 2011, Bonn, 2012.

coal and lignite-fired power capacity would total 50 GW.

- Over the period 2014-2019, the BNA report states that another 10.4 GW of coal and lignite capacity was reported by generators as due for commissioning. 4.9 GW of capacity will be decommissioned between 2014 and 2020, resulting in an overall addition of 5.5 GW of coal plants over the period.

All in all, over the period 2011-2020, an overall increase in coal capacity of 10.6 GW is expected by 2020, compared to 2010. BNA points out, however, that a number of new coal plants due to be commissioned after 2013 are not fully licenced. This is echoed by a recent report by the Federal Association of the Energy and Water Industry (BDEW), which states that legal insecurity is an issue for the planned 17 coal-fired power plants.[34] Although many projects have been granted the necessary permits in full or at least partially, law suits are often pending.[35] The supply shortage of February 2012 will certainly influence either the licencing process of new plants or the extension of operating lifetimes of power plants due for decommissioning in the decade.

The rapid development of CCT, but no development of CCS

Germany is an innovative technology developer. Its electricity companies are at the forefront of new technologies and innovation. Ageing power plants are either closed or retrofitted with the latest available technologies. CTT technologies have been adopted for all new coal-fired power plants built in the last few years or under construction. Thermal efficiencies are up to 45% for all new built plants. This results in significant reductions in CO_2 emissions, about 33%, when new efficient coal plants replace old coal plants.

CCS has also been an important component of the R&D done by major power utilities. Since 2007, several pilot plants have been launched. A small pilot programme for CCS exists in Ketzin in the

[34] BDEW, Regardless of billion-euro investments, power station construction cannot be proclaimed fine, 23 April 2012.
www.bdew.de/internet.nsf/id/en_press-release

[35] From July 2007 to the end of 2011, seventeen new coal plant projects (with a capacity of 15 GW) were cancelled. These plants are not included in the BNA/Prognos scenarios. However the figure shows how it is difficult to build new coal-fired power plants in Germany. Plants which have passed the permitting stage may not be built due to local opposition.

federal state of Brandenburg. Vattenfall operates an oxyfuel pilot plant (30 MW) located near its existing lignite-fired power plant in Schwarze Pumpe. The company also works on **oxyfuel and post-combustion at Jänschwalde.** E.ON and Siemens also launched a pilot plant that tests post-combustion at E.ON's hard coal-fired power plant near Hanau in September 2009. Furthermore, E.ON started a small-size pilot plant at Wilhelmshaven in 2010 to test post-combustion capture. RWE operates a pilot-scale CO_2 scrubber at the lignite-fired Niederaussem power station.

The next step, the development of CCS demonstration plants (above 300 MW, integrating capture, transport and storage) is much more difficult to implement in Germany. The technology is new and there is widespread opposition, above all against carbon storage, throughout large sections of the population. The necessary legal framework is therefore not yet in place. In July 2011, the German Parliament approved a bill for a CCS Act that regulates CCS demonstration projects. However, the Bundesrat, the parliament's upper chamber that represents Germany's federal states or *Länder*, rejected the bill in September 2011. Without clear legislation on CCS, projects are being delayed, or in the worst case cancelled. In December 2011, Vattenfall, which was the only remaining utility proceeding with plans for a large scale CCS plant **at Jänschwalde, cancelled it.**

Clearly, the extensive use of coal stands in contrast to Germany's ambitious climate targets. If coal-fired power stations are to remain in the energy mix after 2030, the development of power stations with high efficiencies and CCS is crucial. One important prerequisite for the deployment of CCS in Germany is the acceptability of storage capacities. Raising public awareness and providing sufficient information will be pivotal in the coming years if CCS is to be implemented in Germany. For the time being, there are no longer any CCS projects planned in the country.

Poland

Poland is not only the largest coal producing country within the EU, but was once one of the world's leading suppliers. At the beginning of the 1990s, Poland began a major restructuring of its coal industry, which resulted in a dramatic fall of hard coal production. Nevertheless, coal continues to play a substantial role, making a 55 % contribution to the country's primary energy supply and accounting for 88% of its electricity generation.

KEY COAL INDICATORS, 2010 DATA	POLAND
Coal market	
Coal production (Mtce)	**80,05**
of which hard coal (Mtce)	62,83
of which lignite (Mtce)	17,22
Coal imports (Mtce)	**11,9**
Coal exports (Mtce)	-16,2
Stock changes (Mtce)	4,4
Primary coal supply (Mtce)	**80,1**
of which electricity (%), data for 2009	72%
of which iron and steel industry (%), data for 2009	2%
Coal reserves and resources	
Hard coal reserves (Mt)	13070
Lignite reserves (Mt)	4 579
R/P hard coal (years)	**170**
R/P lignite (years)	**81**
Hard coal resources (Mt)	163 868
Lignite resources (Mt)	223 604
Employement	
Direct employement in the coal mining industry	**130 400**
State aid to the coal sector (M€)	**194**

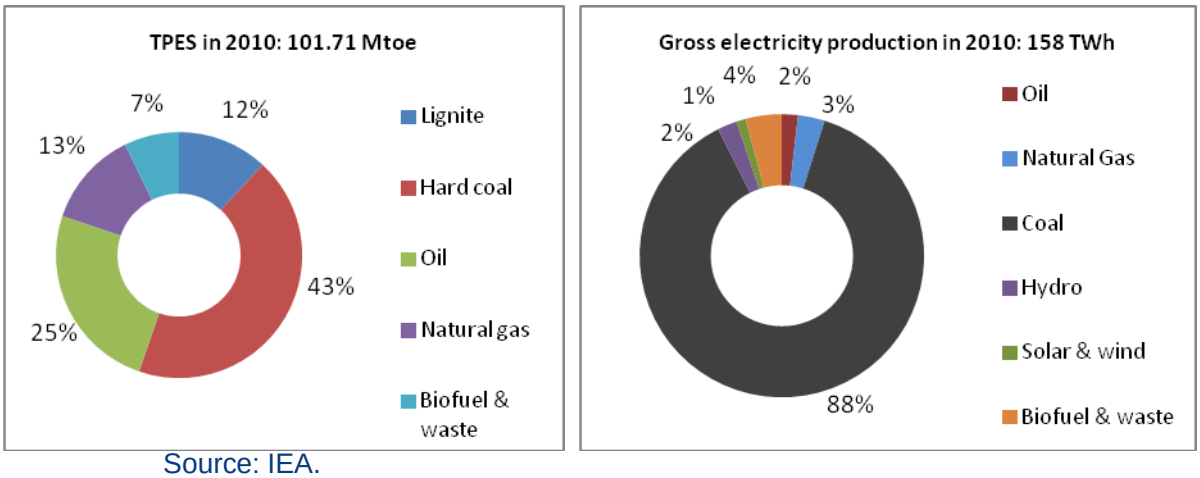
This country profile first gives some key data of the Polish coal market and then analyses:

- The restructuring of the hard coal mining industry and its impact on production and employment;
- Uncertainties surrounding future coal demand;
- The Bellona CCS Roadmap to 2050.

The coal market

Coal is one of the most important primary energy sources. It accounted for 55% of total primary energy supply in 2010 and 88% of electricity generation (Figure 23).

Figure 23: TPES and gross electricity production in Poland, 2010



Source: IEA.

Hard coal

The hard coal market totalled 58.48 Mtce in 2010. 51.96 Mtce of steam coal was used for power and heat generation and 6.52 Mtce were coking coal. Poland produced 62.83 Mtce of hard coal in 2010 (51.06 Mtce of steam coal and 11.77 Mtce of coking coal). It accounted for 62% of EU hard coal production. Hard coal is produced in two areas: the Upper Silesian Basin and the Lublin Basin. Operations in the Lower Silesia Coal Basin ceased in 2000. All hard coal is deep mined at an average working depth of some 600 metres.

Indigenous hard coal production has been declining and is supplemented by increasing imports (11.89 Mtce in 2010). These imports, mainly steam coal, are primarily supplied by Russia and used in Northern Poland. In contrast, coal exports are declining (9.61 Mtce in 2010) so that Poland is now a net importer.[36] The largest importer of Polish coal is Germany and most shipments are transported by rail.

Lignite

Poland produced 17.22 Mtce of lignite in 2010. It is the third-largest lignite producer in the EU, after Germany and Greece. Lignite production has been fairly stable during the last decades. There are four main lignite mines in Poland: Adamow, Belchatow, Konin and Turow. All of the lignite mines in Poland are opencast mines. Lignite is mainly used for electricity generation (98% in 2009).

[36] Poland also exported 6.6 Mtce of coal products derived from coal (mainly coke).

Reserves

Hard coal and lignite are the most important domestic fuels as Poland does not have significant reserves of oil and only modest natural gas reserves, although it may have great potential to exploit unconventional gas resources (shale gas and CBM). According to BGR, Poland's coal reserves amount to 13,070 Mt of hard coal and 4,579 Mt of lignite.

Power Generation

Coal is the most important source for electricity generation: 88% in 2010. Lignite has a share of 32%, hard coal provides 56%. Natural gas and biomass are the two other energies generating electricity. There are no nuclear plants in Poland, although the government plans to build one.

Gross electricity capacity amounted to 33.3 GW at the end of 2010, with coal accounting for 28.5 GW. Installed electricity generating capacity has been relatively stable over the past decade.

Restructuring the hard coal mining sector

20 years of reforms

In 1989, when Poland's economic transition began, the hard coal mining sector was entirely state-owned and in very bad straits, characterised by over-employment, low productivity and poor economic conditions. It required immediate restructuring, which meant closing inefficient mines, as well as reducing employment at mines that were kept in operation.[37]

The government's first attempt to address this issue was made in September 2011 through a restructuring programme, later amended in 1992. Coal mines were transferred to commercial enterprises owned by the State Treasury. In 1993, they were merged into seven companies. The programme however was a failure due to the continuation of the government's policy to control the domestic price of coal at very low level, and the strong bargaining position of the trade unions. Despite the State aid, nearly all mines experienced an increase in liabilities. The next reform programmes were launched in 1993, 1996 and 1997, but were not successful either, mainly because the funds for mine closures were insufficient and the miners regarded the social programmes as relatively unappealing. The

[37] Suwala Wojciech (Prof.), *Lessons learned from the restructuring of Poland's coalmining industry*, Global Subsidies Initiative (GSI) of the International Institute for Sustainable Development (IISD), Geneva, March 2010.

sector had a significant outstanding debt ($6 billion at the end of 1999).

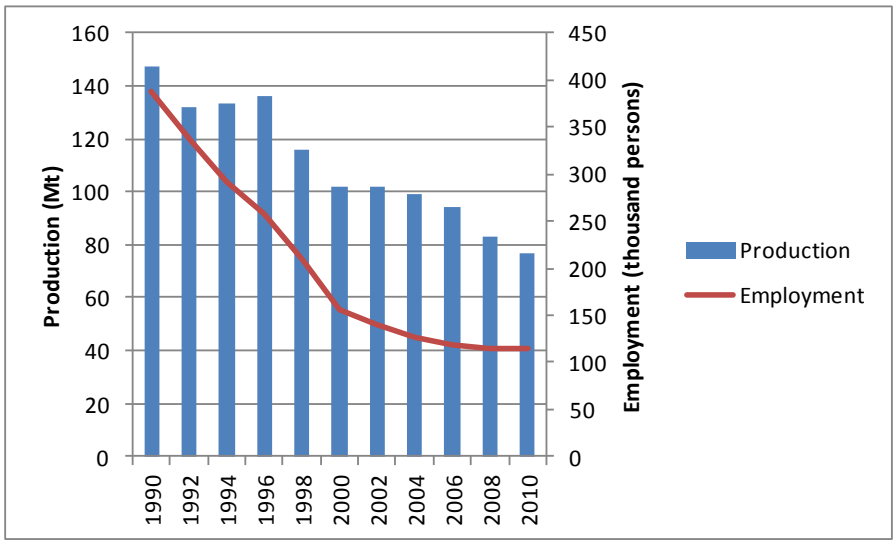
In 1998, the new government formulated a new restructuring programme formalised by a parliamentary bill. The five-year programme (1998-2002) was much more ambitious than the previous ones. It included large subsidies ($2.4 billion over the 5 year-programme) to finance social programmes for redundant miners and mines' closing costs. The programme was more successful than the previous ones. More than 53,000 workers left the coal mining sector over the period, of which 33,000 received some form of help. The number of mines operating was reduced from 71 at the end of the 1990s to 41 in 2002.The third pillar of state support for mines, debt management, was however not sufficient and although the sector's debt was stabilised, it was still about $5.9 billion at the end of 2002.

The financial problems of the industry were finally addressed by the Act of 28 November 2003 which ordered the forgiveness of debt incurred before September 2003 in the form of unpaid taxes, payments to the pension fund, environmental charges and others. The amount of debt forgiven equalled $4.9 billion. Other debts from 2004 onward were to be paid before 2010. Since 2004, amendments to the restructuring programmes have put off repayment of these debts, with a 2007 amendment putting off repayment until 2015. In 2003, the seven coal companies merged into three: Kompania Węglowa SA, Katowicki Holding Węglowy SA and Jastrzębska Spółka Węglowa SA.

Since Poland's accession to the European Union in 2004, its coal-mining subsidies have been regulated according to EU law. There are only two kinds of subsidies being paid at present: one for investment; and one to settle historic liabilities. No State aid is given to support operating costs or to maintain access to coal reserves already exploited. Since 2007, the costs of mine closures have been met by a dedicated fund, established for this purpose by the remaining mining enterprises.

Production and employment have been cut dramatically over the period (Figure 24). Over 270,000 jobs have been lost. Today, approximately 115,000 persons are directly employed in the hard coal mining sector. The hard coal industry is undergoing further restructuring to ensure its future competitiveness and the process of privatisation has commenced.

Figure 24: Coal production and employment in the hard coal mining industry, 1990-2010



Source: IEA, Global Subsidies Initiative (GSI).

Privatisation

The first mine was privatised in 2009. Lubelski Węgiel „Bogdanka" SA, which owns and operates a large hard coal mine in the Lublin coal basin, became majority privately owned in 2010, following a successful initial public offering in 2009. In December 2010, the Czech group EPH took over the hard coal mine KWK Silesia from Kompania Węglowa SA. The newly created company, PG Silesia will resume coal operation in 2012. In 2011, 30% of Jastrzebska Spolka Weglowa (JSW), the largest Polish coking coal producer was listed on the Warsaw Stock Exchange. The government maintains a 51% stake in JSW, but there is a possibility that future sales of shares will occur.

Future ownership changes may involve other key players in the Polish hard coal sector. Poland is planning to float Weglokoks, the state-owned hard coal exporter, on the Warsaw Stock Exchange in the autumn of 2012. The country's largest hard coal producer, Kompania Weglowa, could be listed in 2014.

The future of coal in Poland: he Energy Policy until 2030

- In November 2009, the Polish Government adopted an *Energy Policy of Poland* until 2030 (EPP)

which addresses the main challenges faced by the energy sector.[38] The key directions of EPP are:

- To improve energy efficiency;
- To enhance security of fuel and energy supplies;
- To diversify the electricity generation structure by introducing nuclear energy;
- To develop the use of renewable energy sources, including biofuels;
- To develop competitive fuel and energy markets;
- To reduce the environmental impact of the power industry.

The policy envisages a reduction in the energy consumption of the Polish economy and a 19 % share of renewables in total energy generation by 2020. However, primary energy demand is set to grow by 22% between 2006 and 2030, reaching 118.5 Mtoe in 2030. Most of this growth will occur after 2020. Coal demand is estimated to amount to 44 Mtoe in 2020, and 46.4 Mtoe in 2030 (39% of TPES). Coal is expected to be used as the main fuel for electricity generation in order to ensure an adequate level of energy security for the country. Its share in the electricity mix is nevertheless forecast to decrease with the rising share of renewables and the introduction of nuclear energy. By 2020, lignite and coal-fired capacity will amount to 30.3 GW (28.5 GW in 2010).

This poses major challenges to the Polish coal/electricity sector. Although the EPP foresees a slight reduction in coal-fired capacity, Poland's coal-fired generation fleet is very old, with more than 70% of power plants over 30 years old, 40% over 40 years old, and 15% over 50 years old. More than half are slated for retirement within 5 to 20 years. In order to comply with the LCPD and IED, several plants representing 11.2 GW have to be retired over the period 2010-20, and another 7.3 GW over the period 2020/30. Against this background, it is clear that huge investments will have to be made over the decade. Though there are several projects under construction or planned (Table 17), any delays in investment decisions may lead to electricity shortages in the near future.

In view of stricter environmental regulations, new coal-fired power plants face many challenges. From 2013, new rules for the

[38] This energy policy is going to be updated in 2012 and a new set of energy regulations is expected to come in force in 2013.

EU-ETS will apply. Poland will have temporary exemptions from the auctioning requirement for the power sector. In 2013, assuming the application for such derogation is accepted, Poland may allocate up to 70% of allowances to power producers for free.39 Between 2014 and 2019, the quantity of free allowances will gradually decrease, at the discretion of the government, leading up to the introduction of full auctioning in 2020. The exemption only applied to plants that were "physically initiated" by the end of 2008, meaning "where preparation work was already undertaken." Not all the plants listed in Table 17 will be allowed to apply the derogation. This led RWE in 2010 to shelve plans to build an 800 MW plant near Katowice.

[39] Poland is negotiating with the European Commission the introduction of a domestic system of benchmarks, based on the most efficient installations in a given fuel, to determine the free allocation of allowances to the power sector after 2013.

Table 17: Planned coal power plants in Poland

Location	Capacity (MW)	Start-up date	Investor	Fuel
Bełchatów	858	2011	PGE	lignite
Opole block 5	800	2015	PGE	hard coal
Rybnik	900	2017	EDF	hard coal + Biomass
Kozienice	2000	2015	ENEA	hard coal
Dolna Odra - Pomorzany	244	2016	PGE	hard coal
Turów	460	2016	PGE	lignite
Opole block 6	800	2016	PGE	hard coal
Jaworzno 3_B	900	2016	Tauron	hard coal + Biomass
Police	1432	2016	GDF Suez	hard coal
Lublin	1600	2016	GDF Suez/PGE	hard coal
Opalenie k. Gniewu	1600	2016	Vattenfall	hard coal
Puławy	1600	2016	Vattenfall	hard coal
Pelpino	2000	2016	Elektrownia Północ	hard coal
Ostrołęka	1000	2017	ENERGA	hard coal + Biomass
Gubin	2400	2018	ENEA	lignite
Siekierki	480	2020	Vattenfall	hard coal
Jaworzno 3	910	2020	Tauron + KGHM	hard coal
Kędzierzyn Koźle/Blachownia	910	2020	Tauron	hard coal
TOTAL	**20894**			

(only plants above 100 MW).
In addition there are 6,313 MW of gas-fired capacities planned for the decade.
Source: Bellona Foundation.

Poland also has to reduce its CO2 emissions by 20% by 2020 to comply with the Energy and Climate Package.40 The uncertainty surrounding future EUA prices and the perceived risk of more stringent future emission regulations make investors reluctant to invest in coal plants and may lead to additional fuel switching from coal to gas. Indeed, significantly much more investment in new natural gas-fired facilities has already been witnessed than was predicted in the EPP (6.3 GW are planned for this decade compared with 600 MW planned in the EPP). However, so far the potential of shale gas in Poland has not been clearly identified.41 Gas-fired power plants would therefore rely on gas imports, from Russia mainly, which the Polish Government does not want. As it still retains ownership of several major electricity generation companies, it may drive future development as a power sector investor.

Poland has also to reduce the energy intensity of its economy and power sector. Large possibilities exist to reduce electricity demand (losses in the electricity system are very high compared with other European countries). They could result in a much slower growth of electricity demand and fuel used in the coming years.

According to the EPP, CO2 emissions will decrease from 332 Mt in 2006 to 280 Mt in 2020. The decrease in emissions, when compared to emissions in 1990 amounts to 15%, which is not compatible with EC regulation. If Poland therefore is to continue using large quantities of indigenous coal, then it will have to continue to improve the environmental performance of coal use and develop CCS.

The CCS Roadmap to 2050

Poland has many research institutes working on coal conversion, in-situ gasification and CCS. These programmes have the support of the Polish Government and enable the country to be at the forefront of coal R&D. Before 2020, two CCS demonstration projects are

[40] Poland has also agreed to the EU's longer-term target of reducing emissions by 80-95% by 2050, but in March 2012, Poland vetoed proposals setting out milestones to achieve that goal on the grounds they would harm its economy.

[41] The Energy Information Administration of the U.S. Department of Energy estimates that Poland has huge shale gas deposit, stretching from the northern Baltic Sea coast to the eastern borders with Ukraine and Belarus. Resources are estimated at 5.3 trillion cubic meters, equal to more than 300 years of the country's annual gas consumption. The government has issued over 90 licences for shale gas exploration. Many oil giants, such as ExxonMobil, Total, and smaller companies, are drilling test wells in Poland to assess whether and how they could extract shale gas there on a commercial scale. Reliable assessments are expected to be presented in 2012. If it turns out to be economically viable to extract, shale gas would reduce Poland's natural gas supply dependence on Russia and would radically change the fuel mix of the country.

expected to be operating in Poland as part of the wider EU demonstration programme. They represent an investment of €2 billion. The Bełchatów project has already received European Commission's EEPR grant and is carried out in Poland as a flagship of European demonstration projects, while the Kędzierzyn-Koźle project is in the planning phase.

CCS projects in Poland

Bełchatow

At the PGE Bełchatow power plant, the largest lignite-fired plant in Poland and also the largest CO_2 emitter in Europe, post-combustion CO_2 capture using amine scrubbers is proposed on the 858 MW unit now under construction. About one-third of the CO_2 produced (1.8 Mt CO_2 per year) will be captured from this lignite-fired unit, compressed to being a supercritical fluid and transported 60 to 140 km to a deep saline aquifer storage site. The total investment cost is in the order of EUR 600 million (PLN 2.6 billion), of which 30% (EUR 180 million) comes from the EEPR. As well as corporate investment, other funding may come via the *NER300* programme to which the project has applied, and from public funds and grants from Norway.

Kędzierzyn

A second pre-combustion CCS demonstration is planned by ZAK, one of the biggest Polish chemical companies, at a proposed polygeneration plant at the company's Kedzierzyn chemical works, in co-operation with PKE, Poland's second largest power producer. An integrated gasification combined cycle (IGCC) retrofit at the adjacent PKE Blachownia power plant will produce electricity (309 MW), heat (137 MW), methanol (0.529 Mt/year) and synthesis gas (0.703 Mt/year) using two gasifiers, with the possibility of hydrogen production. It is fuelled with hard coal and biomass, the aim is to capture 2.8 Mt CO_2 per year at the plant, assuming 90% capture. Such polygeneration plants are expensive and Kedzierzyn SA is expected to cost around €1.4 billion, with commissioning before 2020.

The Bellona CCS Roadmap to 2050: insuring energy independence

In March 2011, the Bellona Foundation published a CCS Roadmap to 2050 which presents CCS technologies as an insurance policy for Poland, putting the country in a position to choose freely between coal, lignite, gas, or renewables in its near and medium term energy mix.[42] It states that widespread CCS deployment in Poland is feasible, but immediate actions must to be taken to demonstrate the

[42] Bellona Foundation, Insuring energy independence; a CCS roadmap for Poland, Krakow, Poland, 2011.

technology, characterise potential CO_2 storage sites, and provide a stable regulatory framework.[43]

The Roadmap defines a CCS deployment scenario for the Polish power sector, responsible for more than 44% of GHG emissions. The scenario is designed as a tool to help answer the questions of how and when to deploy CCS, and as a guidepost for a Polish CCS deployment plan. It is applied to three possible development trajectories for the power sector, reflecting possible developments in Poland's energy mix and the demand for electricity:

- Energy Policy of Poland (EEP) which follows the government projections contained in the 2009 Polish Energy Policy until 2030;
- Gas Expansion (GAS) which assumes the same growth in electricity demand as in the EEP trajectory, but a greater share of gas-fired generation in the energy mix;
- Energy Efficiency (EE) which assumes a significantly slower 1% annual growth rate for electricity demand, due to the adoption of significant energy efficiency measures in Poland.

Specific figures are provided on costs, emissions and benefits. For instance, in the Full deployment scenario applied to the EEP and GAS trajectories, power sector emissions fall to 108 Mt and 106 Mt by 2030 respectively, and to below 26 Mt in both cases by 2050. These reductions represent a more than 80% reduction in total electricity-related emissions by 2050, as compared to 2010 levels.

Under all three trajectories, a power sector with CCS becomes less expensive than one without CCS in the 2030s, and even more so through to 2050. The Roadmap concludes that CCS gives Poland the power to ensure it can use its domestic energy resources, meet its internal energy demand, protect its energy independence, and guard against potentially unlimited future economic costs.

[43] Although the legislative process for implementing the EC Directive on CCS was initiated in November 2009, the legislation on CSS has not yet been transposed into national law. The Polish Ministry of Environment (MoE) submitted a bill proposal to the Council of Ministers on 25 November 2010. It is expected that the National Geological Institute will be the competent authority to oversee CO_2 storage regulation and enforcement. The legislative process is well-advanced and the law should be adopted in 2012.

The United Kingdom

The share of coal in the primary energy supply has declined significantly since the early 1970s. As domestic gas production has surged, electricity producers have switched from coal to gas. In 2010, coal accounted for 15% of the total primary energy supply and 29% of electricity generation.

This country profile gives a description of the coal market in the UK and analyses:

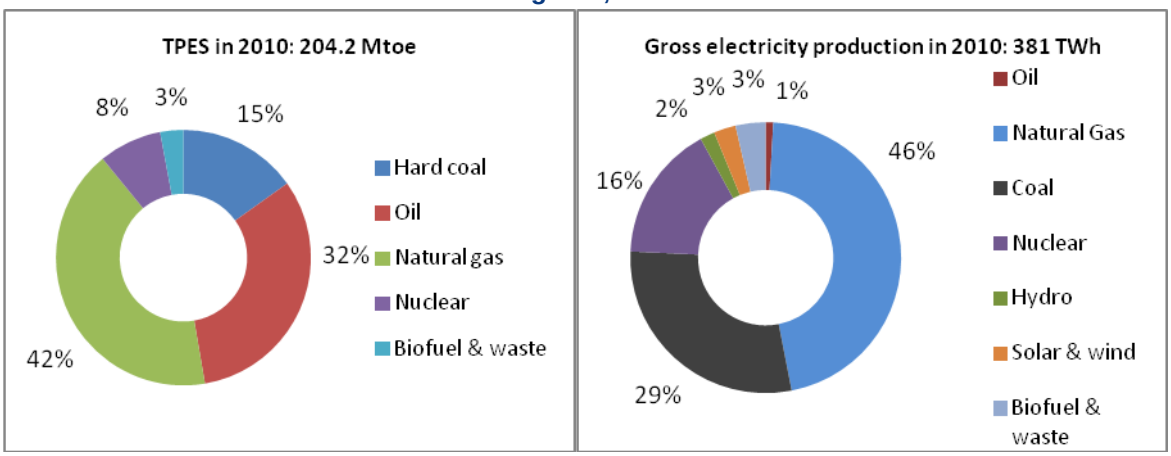
- The renewed interest and investment in hard-coal mining in the 2000s;
- The shrinking role of coal in the future electricity mix;
- The new CCS Roadmap to 2050.

KEY COAL INDICATORS. 2010 DATA	UNITED KINGDOM
Coal market	
Coal production (Mtce)	**15.6**
of which hard coal (Mtce)	15.2
of which lignite (Mtce)	0.4
Coal imports (Mtce)	**23.7**
Coal exports (Mtce)	-1.1
Stock changes (Mtce)	5.7
Primary coal supply (Mtce)	**43.8**
of which electricity (%). data for 2009	83%
of which iron and steel industry (%). data for 2009	8.6%
Coal reserves and resources	
Hard coal reserves (Mt)	371
Lignite reserves (Mt)	0
R/P hard coal (years)	**20**
R/P lignite (years)	**0**
Hard coal resources (Mt)	186 700
Lignite resources (Mt)	1 000
Employement	
Direct employement in the coal mining industry	**6 000**
State aid to the coal sector (M€)	**0**

The coal market

The significance of coal in primary energy supply has decreased sharply over the past decades, has it has been replaced by natural gas produced in the UK Continental Shelf. In 2010, coal accounted for 15% of total primary energy supply and 29% of gross electricity generation (Figure 25).

Figure 25: TPES and gross electricity production in the United Kingdom, 2010



Hard coal

The hard coal market totalled 43.8 Mtce in 2010. 37.3 Mtce were used for power and heat generation (steam coal) and 6.5 Mtce were coking coal. Imports of hard coal totalled 23.7 Mtce in 2010, a fall by 31% compared with 2009, mainly due to a destocking effect at coal plants. In 2011, they increased largely (+22.2% to an estimated 32 Mtce), mainly as a result of power stations using less coal from their stocks. These large fluctuations are explained by the arbitrage undertaken by power utilities between domestic and imported coal, as well as between gas and coal according to their relative price. The main suppliers were Russia, Colombia, the United States, South Africa and Poland for steam coal and Australia, the United States and Canada for coking coal.

The production of hard coal has declined dramatically over the last decades. The amount produced fell from 105 Mtce in 1980 to 24 Mtce in 2005. Since then, coal production has stabilised at around 15 Mtce (15.6 Mtce in 2010), thanks to new investment in hard coal mining.

Lignite

There is no lignite production or market in the United Kingdom.

Reserves

According to BGR, UK coal reserves amount to 371 Mt of hard coal.

Power

The United Kingdom is the third electricity generator and consumer in Europe. Its annual electricity consumption has stagnated over the

past decade at around 350 TWh (361 TWh in 2010). Most of the UK's electricity is generated from fossil fuels (46% from gas and 29% from coal). 16% of electricity generation comes from nuclear power plants. The share of renewables (8% in 2010) is increasing fast.

Electricity capacities amounted to 90.2 GW at the end of 2010. Hard coal capacities made up 30 GW (including dual-fired capacities), natural gas 35.5 GW, nuclear 10.9 GW, oil 5.4 GW while renewables capacity was 8.5 GW. Installed electricity capacity has been rising over the past two years as CCGT plants came on line (2 GW in 2009 and 5 GW in 2010).

Resurgence in UK coal mining

Despite a long history of extraction, remaining UK coal resources are extensive (186,700 Mt at end 2010) and there is still a sizeable domestic demand for coal. Increases in global coal prices have improved the economics of indigenous production and driven renewed interest in UK coal mining. In contrast with other European countries where coal mines are closing, some mothballed mines have been reopened, investment in existing mines has increased and new comers have appeared on the coal scene, alongside with the two major coal producing companies: UK Coal and Scottish Coal. Coal production, which declined sharply in the 1980s and 1990s, has stabilised since 2007 and is expected to grow to 20 Mt/year and remain at this level until the middle of the 2020s.

Deep mines

Recent investment in deep mine development has seen the reopening of abandoned operations. The Hatfield mine in Yorkshire has been reopened and recommenced production in January 2010. The mine, developed by Powerfuel, was sold in 2011 to ING-backed Entero. Output is expected to reach some 2 Mt a year. The Aberpergwm Colliery, one of the first to close in the 1980s, also reopened in 2010. Its operator, Energybuild Mining Ltd, expects to increase annual coal production to 750,000t by 2013. The Unity Mine, owned by Unity Mining Ltd, located in the Neath Valley, has also reopened and is expected to produce 1 Mt a year. Two further mines, Johnston and Gleison Collieries are under development in South Wales. UK Coal Plc, UK largest coal producer, which owns the Harworth colliery in Nottinghamshire, expects to reopen the mine with an investment of over £100 million. The mine was mothballed in 2006.

The sharp increase in international coking coal prices has also spurred interest in coking coal mining: a licence has been awarded to the Corus Group to develop of a new deep coking coal mine at Margam in South Wales, adjacent to Port Talbot steelworks.

Surface mines

The increase in international coal prices has increased the volume of reserves that can be economically extracted from the surface with some estimates putting them as high as 700 Mt. Whilst environmental restrictions may place some limit on accessible reserves, the reserve base exists to support an output of at least 15 Mt a year for several decades. The challenge is to gain access to these reserves. Recent success on the planning front, allied with increasing coal prices, means that UK surface mine output should also increase to more than 10 Mt a year, which is sustainable for many years. In 2006, ATH Resources commenced work on its new Laigh Glenmuir surface mine in East Ayrshire and obtained further consent to extract 800kt from an extension into Duncanziemere land in June 2010. Planning permission was also granted to extract up to 4 Mt of coal from the company's Netherton site near Cumnock, East Ayrshire in June 2010. Currently, the company produces around 2 Mt a year.

Future coal production

Output from both deep and surface mines may increase to a total of over 20 Mt a year, sustainable until the middle of the 2020s. Coal mining in the UK is an industry worth over £1 billion to the economy.

The future role of coal in electricity generation

Coal currently provides 29% of UK electricity, a proportion which rises to 50% or more at peak periods in winter. Although the current installed capacity is close to 29 GW, it is going to be reduced drastically over the next few years in order to comply with EC environmental regulation (LCPD and IED). The Electricity Market Reform (EMR) launched by the UK Government in July 2011 will also have a huge impact on coal-fired generation in the future.

The impact of EC regulations (LCPD and IED)

About a third of UK's coal-fired power stations (8.3 GW) and all large oil-fired plants (3.5 GW) have opted out of the LCPD and must close by 31 December 2015 at the latest. The remainder of the UK's coal-fired power stations have fitted FGD equipment to ensure that they comply with the SO_2 limits. Table 18 shows that 8.3 GW of coal-fired capacities have opted-out and therefore will close by the end of 2015 at the latest.

Some coal-fired power plants which have opted-out have already used a significant portion of their allowed hours and will close earlier than 2015. This is the case for E.ON Kingsnorth power station which is going to close in March 2013. Furthermore, from January 2013, all coal-fired power plants in UK will have to purchase EUA

under phase III of the EU ETS. Depending on the CO_2 price, some of the plants may close before the end of 2015.

When the LCPD ends, the Industrial Emissions Directive (2016-2023) will tighten regulation of SO_X and NO_X even further. The remaining coal-fired power plants (20 GW) will need either to: (i) invest in SCR equipment; (ii) limit operating hours to 17,500 over the period; or (iii) be subject to ever tightening standards for 4½ years under the 'Transitional National Plan', with an option to fit SCR later. Most of them would also have to invest in up-rated FGD installations to be able to burn high sulphur indigenous coals without restrictions. Power plant owners must declare their decisions to the UK Government by end-2013. To comply with the IED, the UK coal fleet will need about £2 billion of capex. Owners may not be prepared to invest such sums at these ageing plants. There is the potential therefore that more closures will happen in the period. It is estimated that just half of the remaining fleet will invest in SCR by the end of 2022 (only 6 GW has been committed so far, at Drax and Radcliffe).[44]

Table 18: Opted-in and opted-out power plants in the United Kingdom

Opted in			Opt out	
Power station	**Capacity (GW)**		**Power station**	**Capacity (GW)**
Aberthaw	1.5		Cockenzie	1.2
Cottam	2		Didcot A	2
Drax	4		Ferrybridge	1
Eggborough	2		Ironbridge	1
Ferrybridge	1		Kingsnorth	2
Fiddler's Ferry	2		Tilbury	1.1
Kilroot	0.5			
Longannet	2.3			
Radcliffe	2			
Rugeley	1			
Uskmouth	0.4			
West Burton	2			
TOTAL	**20.7**		**TOTAL**	**8.3**

Source: Association of Electricity Producers, October 2009.

The reform of the electricity market

In July 2011 the UK Government published its White Paper on 'Electricity Market Reform' (EMR) outlining how it intends to encourage investment in low carbon generation to meet its long term carbon reduction targets.[45]

[44] According to a Credit Suisse analysis, *UK power generators*, 2 March 2012
[45] DECC, Planning our electric future: a White Paper for secure, affordable and low-carbon electricity, July 2011

These targets are defined in the Climate Change Act 2008 which sets legally binding GHG emissions reductions targets for 2020 and 2050: a reduction of at least 34% in GHG emissions by 2020 and at least 80% by 2050 compared with 1990. The Act introduces five-yearly carbon budgets to help ensure that these targets are met. The first three carbon budgets, covering 2008-12, 2013-17 and 2018-22 were set in law in spring 2009 and require GHG emissions to be reduced by at least 34% by 2020. The level of the Fourth Carbon Budget for the period 2023-2027 was set in law at 1950 Mt CO2 at the end of June 2011. The level set equates to a 50% reduction in GHG on 1990 levels for each year over the Fourth Carbon Budget period. In addition, the Renewable Energy Directive sets a target for the UK to achieve 15% of its energy consumption from renewables by 2020.

For the power sector, the challenge is enormous: a fifth of generating capacity is shutting down over the next ten years as old coal and nuclear power stations close and a significant proportion of new generation is likely to be more intermittent and less flexible. It is estimated that more than £110 billion in investment is needed by 2020 to build the equivalent of 20 large power stations and upgrade the grid. In the longer term, by 2050, electricity demand is set to double, as the UK shifts more transport and heating onto the electricity grid. Electricity supply therefore may need to double, and will need to be decarbonised. A growing level of variable renewable generation increases the challenge of balancing the electricity grid.

The White paper states that the existing market does not deliver the scale of long-term investment, at the pace that is needed, so there is a need to reform the market now. The government then proposes four main principles to reform the electricity market:

- a Carbon Price Floor (CPF) from April 2013 to reduce investor uncertainty, putting a fair price on carbon and providing a stronger incentive to invest in low-carbon generation now. The CPF as announced in the 2011 Budget begins at around £15.70/t CO_2 in 2013 and follows a straight line to £30/t CO_2 in 2020, rising to £70/t CO_2 in 2030 (real 2009 prices). This equates a price of €35/t of CO_2 in 2020 and €80/t of CO_2 in 2030, a much higher level than envisaged in the EU ETS at these horizons. Power plants with CCS will be exempted from the CPF in proportion of the CO_2 captured and stored;

- the introduction of new long-term contracts (Feed-in Tariff with Contracts for Difference, FiT CfD) to provide clear, stable and predictable revenue streams for investors in all forms of low-carbon electricity generation. FiT CfD will replace the existing Renewables Obligation;

- an Emissions Performance Standard (EPS) set at 450g CO_2/kWh for all new fossil fuel plants, to reinforce the requirement that no new coal-fired power stations are built without CCS, but also to ensure that necessary short-term investment in gas can take place. Plants in the UK CCS Demonstration programme, or benefiting from European funding for commercial scale CCS, are exempted from the EPS, in order to provide flexibility for the UK to demonstrate the full range of CCS technologies; and

- a Capacity Mechanism, in the form of a market-wide Capacity Market (i.e. a mechanism which will establish contracts for the required volume of capacity needed to deliver security of supply), including a demand side response, generation and storage.[46] It is intended to ensure that sufficient generating capacity is available to meet demand during the transition to low-carbon electricity generation.

The White Paper sets out key measures to attract investment, reduce the impact on consumer bills, and create a secure mix of electricity sources including gas, new nuclear, renewables, and CCS. It does not prescribe any technologies or sources of energy: "New capacity will include renewables, CCS on gas and coal and new nuclear stations." The government's objective is to have competition between low carbon generation technologies in the 2020s with the market deciding which of the competing technologies delivers the most cost effective mix of supply and ensures a balanced electricity system.

Its impact on coal-fired generation may however be drastic. The carbon price support mechanism introduced in April 2013 reduces the competitiveness of coal-fired plants against other types of generation, meaning that further closures may happen in this decade. The emission performance standard will force all new coal power stations to fit CCS from the start of operations. The future of coal-fired generation in the UK is therefore entirely tied to the successful commercial development of CCS.

The UK CCS Roadmap to 2050

The UK Government has always been committed to making CCS a viable option as part of a low carbon generation mix and to facilitating

[46] The Technical Update, published in December 2011 by the Government, explains in detail this Capacity Mechanism. DECC, *Planning our electric future*. *Technical Update,* London, December 2011.

the development of CCS as a key technology for the decarbonisation of the energy sector. Already in November 2007, the then Department for Business, Enterprise and Regulatory Reform (the DECC's predecessor) launched a competition for industry to run a project to design, construct and operate the UK's first commercial-scale CCS demonstration project at a coal-fired power station, by 2014, with government funding. Although FEED was awarded to two developers (E.ON's Kingsnorth and Scottish Power's Longannet), this first competition was a failure. Regulatory uncertainty on CCS led E.ON to withdraw from the competition in October 2010. The second project was cancelled in October 2011, when the government announced that they were not going to proceed with the project but to pursue other projects with the £1 billion funding made available for CCS.

In April 2012, the government presented a new CCS Roadmap to 2050. The Roadmap states that there are three key challenges that must be tackled to enable commercial deployment of CCS in the UK:

- Reducing the costs and risks associated with CCS so that it is cost-competitive with other low carbon technologies;
- Putting in place the market frameworks that will enable CCS to be deployed by the private sector in a cost-effective manner; and
- Removing key barriers to the deployment of CCS.

The Roadmap includes a programme of interventions that aim to make the technology cost-competitive and enable the private sector to invest in CCS in the 2020s, without government capital subsidies. The programme includes:

- A CCS Commercialisation Programme with £1 billion in capital funding to support commercial-scale CCS, targeted specifically to learn-by-doing and to share resulting knowledge to reduce the cost of CCS, such that it can be commercially deployed in the 2020s;
- A £125m, 4-year, co-ordinated R&D and innovation programme;
- Development of a market for low carbon electricity through Electricity Market Reform (EMR), including availability of Feed-in Tariff Contracts for Difference for low carbon electricity tailored to the needs of CCS equipped fossil fuel power stations; covering fundamental research and understanding, through to component development and pilot-scheme

testing, to ensure that the best ideas – with a clear focus on cost reduction – can be taken forward to the market, and establishing a new UK CCS Research Centre;

- Intervention to address key barriers to the deployment of CCS including work to support the CCS supply chain, develop transport and storage networks, prepare for the deployment of CCS on industrial applications and ensure that a right regulatory framework is in place; and

- International engagement focused on sharing the knowledge generated through the programme and learning from other projects around the world to help accelerate cost reduction.

The aim is to create for the first time a market in which there is a clear commercial model for CCS in the UK, provided it can demonstrate the ability to compete with other low carbon technologies.

The scenarios modelled for the Carbon Plan suggest that around 40 to 70 GW of new low carbon electricity generating capacity will be needed by 2030, and depending on demand and the mix of generation that is built, CCS could contribute as much as 10 GW by 2030 and up to 40 GW by 2050.[47] The CCS Association, the representative body for the CCS industry, has set out their ambition for 20 to 30 GW of CCS to be deployed by 2030. The Roadmap is designed to enable this ambition to be achieved, subject to CCS demonstrating its effectiveness as a cost-competitive low carbon source of electricity generation in time to meet projected demand.

The government launched its new competition in April 2012 with £1 billion in direct funding support for the design and construction of CCS projects. The new CCS Demonstration Programme is ambitious as it requires projects to be operational by 2016 to 2020. Bidders have until July 2012 to submit proposals. In May 2012, the DECC published a list of 16 companies which have already expressed their interest in applying. Most of the projects developed by these companies are coal-fired power or industrial plants. The interesting development compared with the previous competition is that power utilities and equipment suppliers, the UK transmission operator National Grid, and oil/gas companies have formed consortia to develop these projects. This approach, where each industrial sector brings its skills in a specific component of CCS technology – capture, transportation and storage – could contribute to making

[47] DECC, The Carbon Plan: Delivering our low carbon future, London, December 2011.

faster progress. A revival of coal generation in the UK may therefore be possible if the projects demonstrate their economic viability compared with other low-carbon technologies.

Spain

KEY COAL INDICATORS. 2010 DATA	SPAIN
Coal market	
Coal production (Mtce)	**4.57**
of which hard coal (Mtce)	3.73
of which lignite (Mtce)	0.84
Coal imports (Mtce)	**11.01**
Coal exports (Mtce)	-1.6
Stock changes (Mtce)	-2.4
Primary coal supply (Mtce)	**11.58**
of which electricity (%). data for 2009	74%
of which iron and steel industry (%). data for 2009	8%
Coal reserves and resources	
Hard coal reserves (Mt)	868
Lignite reserves (Mt)	319
R/P hard coal (years)	**99**
R/P lignite (years)	**-**
Hard coal resources (Mt)	3 363
Lignite resources (Mt)	na
Employement	
Direct employement in the coal mining industry	**5 400**
State aid to the coal sector (M€)	**700**

Spain is neither a large producer nor consumer of coal. Coal, domestically produced and imported, accounts for 6% of total primary energy supply and 9% of electricity generation (2010 figures). However, the recent austerity measures and cuts in coal mining subsidies have shed light on the coal mining sector. More than 5,000 coal miners have been on strike since May 2012 and violent protests have developed within the country. The coal miners have become a symbol of social resistance to austerity measures. This country profile gives some key data on the Spanish coal market. It then analyses:

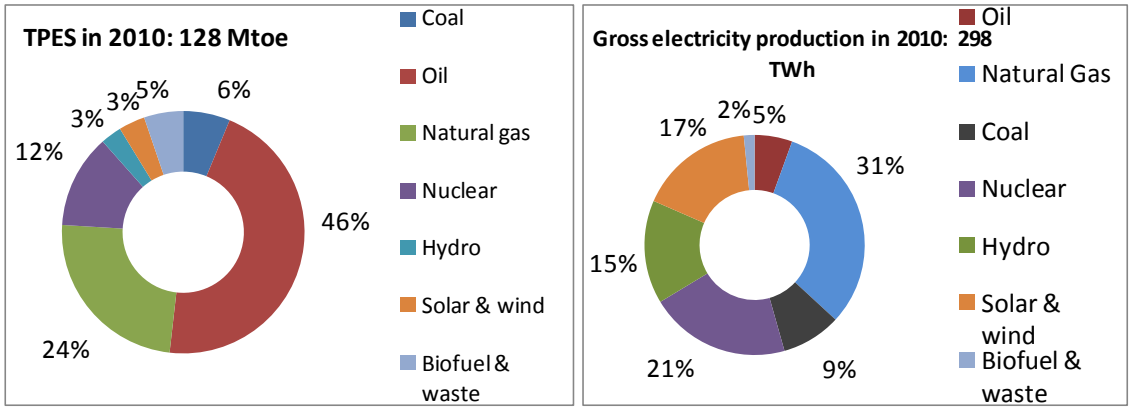
- Historical subsidies to the sector;
- Additional aid agreed in 2010;
- Cuts in coal mining subsidies decided in May 2012 and their social impacts;
- The status of CCS projects in Spain.

The market for coal

Total primary energy supply amounted to 128 Mtoe in 2010 (Figure 26). As in most other European countries, oil has the largest share accounting for 46% of primary energy consumption. The coal share has been shrinking since the beginning of the 1990s, whereas gas

and renewables are expanding fast. Nuclear power has a share of 12% and the government has decided to continue operating its nuclear plants, even after the Fukushima accident. Spain's primary energy consumption depends on imports to a large extent. The high import dependency (79% in 2010) is mainly due to the predominance of imported oil and gas in the Spanish primary energy mix.

Figure 26: TPES and gross electricity production in Spain, 2010



Source: IEA.

Hard coal

Coal consumption amounted to 11.5 Mtce in 2010, of which 4.6 Mtce were produced in Spain. Thus, 40% of primary coal output came from domestic coal production.

Spain only produces steam coal, as domestic coal reserves are of insufficient quality for coking coal. Hard coal mines are located in the region of Castilla y León, especially Palencia, in Asturias, in Puertollano near Córdena and finally in the northern part of the country at Teruel and Aragon. Over 60% of hard coal is mined in opencast mines where it is estimated that 80% of production is profitable compared with international coal. Other coal mines have problems competing with coal from other parts of the world, due to comparatively high production costs and inferior quality. By 2018, when it will no longer be possible for the State to aid uncompetitive mines, it is estimated that only 60% of coal production will be competitive.

Spain's coal-mining industry is consolidating and production is declining. Most companies have an annual production capacity below 500,000 tonnes, with some employing fewer than 25 miners. The largest is UMINSA, a privately owned company that resulted from the merger of 15 independent companies. The other major operator in terms of staff is the state-owned HUNOSA.

Hard coal production is supplemented by rising imports: 11 Mtce in 2010. Most of it is steam coal (8 Mtce), coming from Colombia, South Africa, Indonesia and Russia.

Lignite

At the end of 2007, Spain's last lignite mines located in Galicia on the north-west of the Iberian Peninsula had to be closed.[48]

Reserves

According to BGR, hard coal resources are estimated to be about 3,363 Mt, whereas lignite resources are negligible. Hard coal reserves amount to 868 Mt.

Power

In 2010, Spain's electricity production amounted to 298 TWh. The power generation mix is diversified. Gas provides the largest share with 31%. 21% of the Spain's electricity supply is generated by nuclear power. Hydroelectric power (15%) also contributes significant amounts. Renewables (mostly wind) are expanding fast (17%), while the shares of coal and oil are shrinking (9% and 5% respectively).

Domestic hard coal production is almost exclusively used for power generation. The share of electricity generation from coal-fired power plants has decreased drastically compared to the 1990s, when coal accounted to nearly 40% of power generation.

Power generation capacities totalled 100.6 GW at the beginning of 2012. Nuclear power capacity was 7.8 GW. Conventional thermal power plants amounted to 45.7 GW, of which 11.7 GW were coal-fired power plants. Installed capacities of hydropower were 19.6 GW, while those of wind power were 21.3 GW.

Spain has significant excess capacity, especially gas-fired power plants. Its isolated situation from the European power grid makes these extra capacities necessary, which do not even seem to be sufficient in case of special events. New investments in power capacity mainly focus on gas, wind and photovoltaic energy. Spain is one of the largest European producers of wind energy.

Domestic coal production and support mechanisms

The main source of support for the coal sector in Spain is the financial assistance to coal mining.[49] This assistance is subject to EU rules on state aid and approval by the European Commission. It is defined in

[48] It should be noted however that 0.84 Mt of coal production are classified as lignite production under the IEA classification.
[49] OECD, Inventory of estimated budgetary support and tax expenditures for fossil fuels, Paris, October 2011.

multiannual plans negotiated between the government, trade unions (the General Union of Workers (UGT) and the Workers' Commission (CCOO), to which 90% of coal miners in Asturias are affiliated) and Carbunion, the Spanish coal association. The latest plan, the National Plan for Coal 2006-12, sets out targeted reductions in production, staffing and subsidies, supply guarantees and economic restructuring policies for the coal-mining regions.

Total aid to the sector amounted to €700 million in 2010 (Table 19) and is estimated at €689 million in 2011. The principal form of aid comes in transfer payments by the government to the state-owned company HUNOSA and private coal companies, to compensate them for the difference between their operating costs and the prices at which they sell their output to local power plants (which are negotiated directly).[50] Under the Plan 2006-2012, operating aid is to be reduced by 1.25% per year for underground mines and 3.25% per year for opencast mines. Production is due to fall from 12.1 Mt in 2005 to 9.2 Mt in 2012, and employment from 8 310 to 5 302.

Private coal producers also benefit from budgetary transfers that support the transport of coal across basins, whenever local supply conditions meet certain criteria.

Table 19: Financial support to the coal sector in Spain (€ million)

Support element	Avg 2000-02	Avg 2008-10	2008	2009	2010p
1. Producer Support Estimate					
Support to unit returns					
Operating Aid to HUNOSA	100,43	80,56	85,3	80,38	76
Operating Aid to Coal Producers	334,75	256,34	266,5	252,53	250
Subsidy for the Interbasin Transport of Coal	3,13	12,73	11,35	14,04	12,8
Income support					
Adjustment Aid to Coal Producers	54,05	30,07	40	40	10,2
2. Consumer Support Estimate					
Funding for Coal Stockpiles	12,02	7,25	2,92	6,34	12,5
3. General Services Support Estimate					
Inherited Liabilities Due to Coal Mining	155,06	322,05	302,55	328	335,6
TOTAL	**659,44**	**709**	**708,62**	**721,29**	**697,1**

Source: OECD.

The second major form of aid is in the form of inherited liabilities. This aid can be used to pay benefits to former miners and cover the costs of mine closures. Aid is also available to finance industrialisation projects and for developing infrastructure in the affected mining regions.

[50] Use of Spanish coal at power plants, the principal market, is based on volume quotas set by the government. Power producers contract directly with mining companies for the volume and price of coal under their quota.

Another government measure provides funding to power plants for purchases of domestic coal for stockpiling. These stockpiles are meant to guarantee over 720 hours of power generation. The government also finances R&D to develop clean-coal technology, including carbon capture and storage.

During the period 2000-2010, €7 billion were distributed to the sector. A large part was supposed to be spent for re-industrialising regions affected by mine closures. The on-going economic and social crisis in the mining regions – and Asturias especially – shows how inefficient these subsidies were.

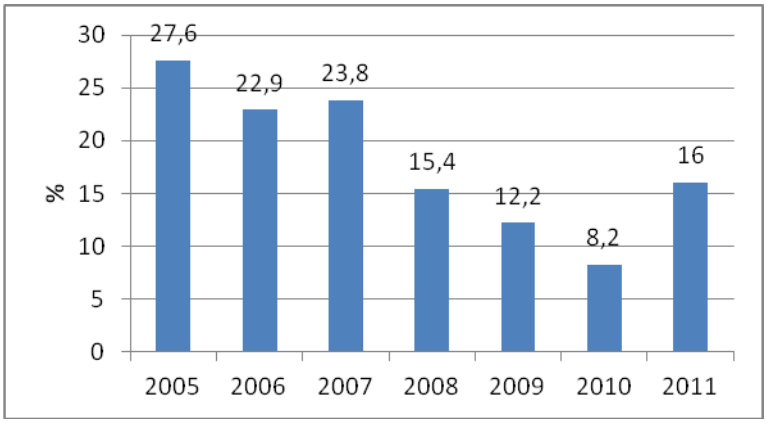
Additional aid in 2011: the Royal Decree guaranteeing Spanish coal supplies

In 2009, during the economic crisis, Spain suffered an unforeseen and sharp drop in electricity demand (about 5%), which displaced domestic coal. Coal production that year fell to 9.44 Mt (5.18 Mtce). Its share in electricity generation collapsed to 12%. This trend was aggravated in 2010 with coal-fired power generation amounting to 8% only of total generation (Figure 27). Overall, the share of coal in power generation almost halved between 2008 and 2010, and coal production declined by around 2 Mt.

Bearing in mind the importance of coal regarding security of supply and the need to maintain the indigenous coal alternative as well as jobs in the sector, the former government passed a new regulation in order to promote the use of indigenous coal in power plants: the Royal Decree 134/2010 on security of supply constraints. After several amendments requiring EC approval of the new law, the regulation, which was first proposed at the beginning of 2010, was finally implemented in March 2011. It forced use of domestic coal by generators (10 coal-fired power plants). It also established a mechanism which allowed the market to set a marginal price for electricity, regardless of indigenous coal. Furthermore, once the price was set the more polluting technologies were substituted by indigenous coal power plants. The scheme was expected to involve about €2 billion-worth of government aid over the four-year period (2011-2014).

The new regulation was heavily contested by power utilities. However, it allowed indigenous coal mines to continue operating: in 2011, coal production increased to 9.8 Mt total (+1.4 Mt compared with 2010) and the share of coal in electricity generation almost doubled to 43.43 TWh, or 16% of the total generation of 264.50 TWh. At the same time, generation from gas-fired plants fell 21% to 13.5 TWh.

Figure 27: Share of electricity generation from coal in Spain, 2005-2011



Source: Ministry of Industry, Tourism and Commerce, REE (Spanish transmission system operator).

This new regulation was a transitory solution until the end of 2014 at the latest. The new government, elected in November 2011, strongly opposed the new law which cost €256 million in 2011 and decided to cut this aid in its emergency budget announced in April 2012.

Recent austerity measures and the drastic cut in coal mining subsidies

At the end of March 2012, the new government adopted emergency measures to reduce a budget deficit that reached 8.9% of GDP in 2011 (the Royal Decree Law 13/2012 adopted on 30 March 2012). In the coal/electricity sector, austerity measures included a cut in costs in the electricity sector by €1.7 billion, involving distribution, transmission, capacity payments, financing the regulator CNE, an interruptible tariff and a reduction of subsidies for coal. The government also increased tariffs (around 7% for the tariff of last resort), thus generating an additional income of around €1.4 billion.

In May 2012, the government announced additional austerity measures which included a cut in the subsidies to the coal mining industry by €450 million,51 from €703 million to €253 million,52

[51] To put this in perspective, this sum amounts to 0.45% of the €100 billion bailout for Spanish banks agreed in July 2012.

[52] Figures published at the time of the announcement differ from more recent official data: according to government data, €656 million are collected in the General State budget, of which €300 million are destined to pay inherited liabilities, €110 million for operating aid to coal mining, €100 million for infrastructure work in the affected regions, €40 million for CCS R&D and the rest for training and other mining related needs.

including a 60% reduction in operating aid to coal mining from €301 million in 2011 to €111 million in 2012. This drastic cut led coal miners to launch an indefinite strike. They famously marched on Madrid in July to take their protest directly to the government. They were subjected to brutal police repression, fighting back with home-made rockets and dynamite. Demonstrating miners had hoped to convince the government to reinstate mining subsidies to help save their jobs. Instead, Prime Minister Mariano Rajoy announced additional austerity measures amounting to €65 billion through to 2015, including new taxes and budget cut. At a meeting with trade unions and Carbunion at the beginning of August, the government reiterated that the cut in 2012 subsidies was not negotiable. Despite a lack of compromise with the government, the trade unions ordered return to work after more than a two-month strike. They stated that they were preparing further industrial actions as the new 2013-2018 Coal Plan was to be negotiated in September.

Although the mining sector employs 5,400 workers directly, according to EURACOAL (8,000 workers according to trade unions) in a country where the official unemployment rate is about 25%, the miners' struggle has been a major event. It has become a symbol of all who oppose austerity, and who will be ravaged by austerity. The Black March of the miners against cuts to subsidies recalls the Big Strike of 1962, when miners' strike in Asturias was widely supported by the rest of Spain. It was the first big labour conflict against Franco's dictatorship and met severe police repression. It also recalls the 1934 October revolution which took place in Asturias. Indeed, the current protests are driven by coal miners from the same province.

Ultimately, the miners' protest is not about a falling industry. It is about an economy which has been fundamentally altered by globalisation and whose government policies have been unable to achieve necessary structural adjustments. Funds earmarked to help the reindustrialisation of the mining areas did not meet their objectives, making coal miners hostages of their mines. Most of the funds were used to create museums, congress and sport centres, all of which are unable to provide alternative jobs to miners. The recent cut in subsidies – instead of their reform – again undermines the ability of the mining areas to develop the necessary infrastructure and incentives to encourage firms to set up new activities in these regions.

In all of this, the miners' struggle in Spain has become a symbol, and a national/European rallying point. At the end of August, in Sardinia, coal miners barricaded themselves inside the Carbosulcis mine, the only operating mine of the country, to prevent the government from closing it. The Italian Government reacted immediately with positive proposals.

The miners' fight also reveals the fragility of Spain's energy policy and its heavy reliance on inefficient energy subsidies driven by broader socio-political factors. The conflict with the miners is part of

the government's larger quandary of how to rein in energy subsidies. Coal subsidies are only the top of the iceberg: the main goal is to reduce a tariff deficit of €24 billion accumulated in paying for the cost of generating power in Spain.53

What could be the consequence for the coal mining industry in Spain? Does the end to subsidies mean the end of coal in the country and its substitution by less polluting fuels? Firstly, ending coal mining in Spain will not end its reliance upon coal power stations. As in Britain, which lost its mining industry in the 1980s, coal will simply be imported. So closing Spanish pits will in no way make Spain "greener", but it will make up to 30,000 people unemployed (direct and indirect jobs). It will increase dependence upon imported coal, sometimes mined with less environmental and safety regulation (e.g., Colombian coal), and shipped thousands of miles. This trend is already evident in recent statistical data. Since the start of the strike, coal consumption has increased as local coal has been replaced by imported coal. In the first eight months of 2012, the share of coal in power generation rose to 21%, with a jump by 83% of power based on imported coal. All utilities are burning more coal, which is boosted by expensive gas prices and low hydro generation. Traders (local and foreign) have profited from the misery of coal miners. Coal imports totalled 8 Mt in the first five months of 2012, a rise by 52% compared with the same period in 2011 (Figure 28).

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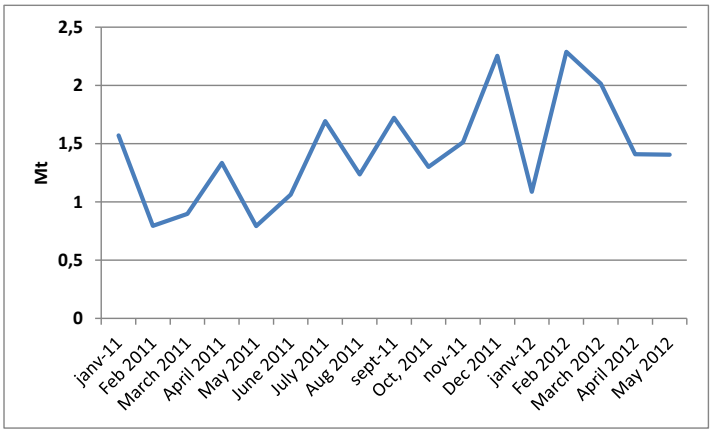
[53] Spain has traditionally capped end-user prices of electricity to several consumer groups under a regulated tariff system. The tariffs do not always cover costs, with the result that a so-called tariff deficit is generated within the system at the expense of utilities. With the costs of generation and the regulated costs (e.g. transportation and distribution) rising faster than the tariff, the deficit has significantly increased in recent years and stands at an accumulated amount of €24 billion (more than 2% of GDP). Two thirds of this amount (around €17 billion) is guaranteed by the government, which has allowed utilities to securitize it. In 2009, the government revised the whole tariff system with the aim of ensuring that electricity prices cover total costs. However, low-consumption households (representing 83% of consumers) were still allowed to pay electricity prices that did not fully reflect the overall costs of the system under the so-called 'last resort tariff'. As a result, the tariff deficit continued to build up. (European Commission, *Assessment of the 2012 national reform programme and stability programme for Spain, SWD(2012) 310 final*, Brussels, 30 May 2012).

In January 2012, the Government temporarily suspended renewable energy premiums paid to newly-built plants (wind, solar, biomass and hydro technologies) in an attempt to reduce electricity costs and thus the electricity tariff deficit. The Royal Decree Law 13/2012 adopted on 30 March 2012 also included measures to correct the imbalance in the electricity for 2012. Again in July 2012, the Government announced a new series of spending cuts and tax increases in the face of an ultimatum by the EU, as the country struggled to reduce its deficit while negotiating a bailout for its banks. The measures included a temporary abolition of energy subsidies designed to limit the runaway growth of the country's electricity tariff deficit.

Figure 28: Monthly coal imports in Spain



Source: Eurostat.

Besides the cut in subsidies in the 2012 budget, Spanish miners are right to be concerned about the longer term outlook of their industry. The Industry Ministry is due to hold a series of discussions with trade unions and company representatives later this year to establish the plan for coal for 2013-2018, given that the 2006-2012 plan is due to expire at the end of 2012. The government, pushed by the EC, is to continue implementing a strategy that could see all mines that have received subsidies or state aid close by the end of 2018 at the latest, in line with EC regulation on state aid (Council Decision 2010/787/EU of 10 December 2010). Although the new plan has not yet been published, it is estimated that the government plans to limit domestic production at 5 Mt already this year. Job retraining for coal miners will remain an issue and further industrial action can be expected in the coming months. It is important not to underestimate the unintended consequences of energy subsidies and how an energy policy based on subsidies is unsustainable, especially when these subsidies are removed suddenly, while their aim has not been achieved. The Spanish Government would have done better by auditing the spending of this public money to make sure that no private interests benefit from it, and that subsidies serve their defined objectives. Clearly, this has not been the case, as mining areas have not been re-industrialised. More transparency on the existing subsidies would have helped the dialogue with trade unions and representatives of the coal industry. The 2013-2018 plan for coal could be used to reform the inefficient subsidies and allocate money to the intended purpose, i.e. attracting new activities in the mining regions and ensuring a gradual restructuring of the coal mining industry in a socially acceptable manner. Spain's economic environment is maybe unfavourable, but cutting operating aid to coal producers by €200 million while at the same time than giving €100 billion to the banking system is just indecent.

The status of CCS projects

Although Spain was the first EU Member State to transpose the CCS Directive into national legislation, the new law may be left with nothing to govern in the short to medium term. The two CCS projects developed in the country have achieved little progress and may merely remain pilot plants.

The first project in Compostilla is promoted by a consortium between CIUDEN and Endesa (full chain demonstration supported by EU funding) and the second one, in Puertollano, is promoted by ELCOGAS (only capture). Both projects do not appear as a priority for public or private funding.

The CUIDEN project was divided into two phases. Phase I included the construction of a 30 MW oxy-firing Circulating Fluidised Bed (CFB) pilot plant in Compostilla (Leon), transportation of CO_2 and its storage underground. In Phase II (starting in 2011-2012), Endesa would construct a 300 MW CFB oxycombustion demonstration plant, and store the captured CO_2 in a deep saline formation, Hotomín near Burgos. This plant was intended to be operational in 2015.

The first phase of the project started to be implemented in 2009, as planned. The pilot plant received partial financial support from the European Commission's EEPR, with the rest to be financed by Spain. In December 2011, CUIDEN successfully completed the initial testing phase of oxycombustion. However, in May 2011, Endesa suspended the work for the construction of the 300 MW plant. It justified its decision on the grounds of the insecurity of the energy/carbon market and declared that a final decision would only be taken at the end of 2012.

The second CCS project is a pilot plant developed by ELCOGAS in Puertollano (Castilla-La Mancha). ELCOGAS was set up in 1992 to build and operate an IGCC plant and to commercialize its technology. It was the first demonstration plant with this technology in Spain, and at that time the largest in the world to use coal. The ELCOGAS CCS project is a 14 MW pilot plant integrated with the IGCC plant to test the potential of pre-combustion technology for CO_2 capture. The commissioning of the pilot scheme was completed in October 2010, and the tests were successfully carried out. The project has taken a lot longer than expected, and for financing reasons the project is not progressing. At present, no storage of the separated CO_2 is foreseen.

Annexes

Annex 1. The Nature of Coal

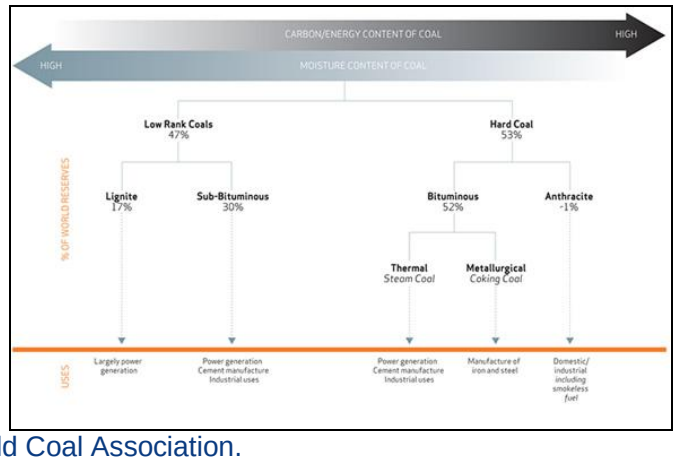
Coal formation

Coal is a fossil fuel formed from plant remains that have been consolidated between other rock strata and altered by the combined effects of pressure and heat over millions of years to form coal seams. Coal is a readily combustible black or brownish-black sedimentary rock that is composed primarily of carbon, along with variable quantities of other elements such as sulphur, hydrogen, oxygen and nitrogen.

Types (ranks) of coal

Based on its properties, coal can be classified by rank, from the lowest to the highest, into the categories of lignite, sub-bituminous, bituminous coal and anthracite. Lower rank coals contain less carbon, more moisture and have lower calorific values (Figure 26).

Figure 26: Coal ranks and uses



Source: World Coal Association.

Lignite, also referred to brown coal, is the lowest rank of coal. Used almost exclusively for power generation, lignite is a young type of coal. Lignite is brownish black, has a high moisture content (up to 45 %), and a high sulphur content. Lignite is more like soil than a rock

and tends to disintegrate when exposed to the weather. Lignite has a gross calorific value of less than 17,435 kJ/kg (4,165 kcal/kg).

Sub-bituminous coal, whose properties range from those of lignite to those of bituminous coal, contains 20-30% moisture. Sub-bituminous coal is used primarily for power generation. Its gross calorific value ranges from 17,435 kJ/kg (4,165 kcal/kg) to 23,865 kJ/kg (5,700 kcal/kg).

Bituminous coal is a soft, dense, black coal. Bituminous coal often has bands of bright and dull material in it. Bituminous coal is the most common coal and has moisture content less than 20%. It is used primarily as fuel in power generation, with substantial quantities also used for heat and power applications in manufacturing and to make coke (coking coal). Its gross calorific value is above 23,865 kJ/kg (5,700 kcal/kg).

Anthracite, the highest rank, is hard, black and lustrous. Anthracite is low in sulphur and high in carbon. Its moisture content generally is less than 15%. It is used primarily for the heating of residential and commercial buildings. It gross calorific value is very high, ranging from 27,000 kJ/kg (6,450 kcal/kg) to 34,000 kJ/kg (8,100 kcal/kg).

Most organisations (the IEA, Eurostat), when publishing statistical data, adopt a simplified classification of hard coal and lignite.

Hard coal is the sum of steam coal and coking coal.

- Coking coal is reported in the category coking coal.
- Anthracite and bituminous coal are reported in the category steam coal.
- Lignite (or brown coal) is reported in the category lignite.
- Sub-bituminous coal is reported in the category lignite (or brown coal) except for some countries where it is included in steam coal because of its relatively high caloric value (in Europe, this is the case for Belgium, Finland, France and Portugal).

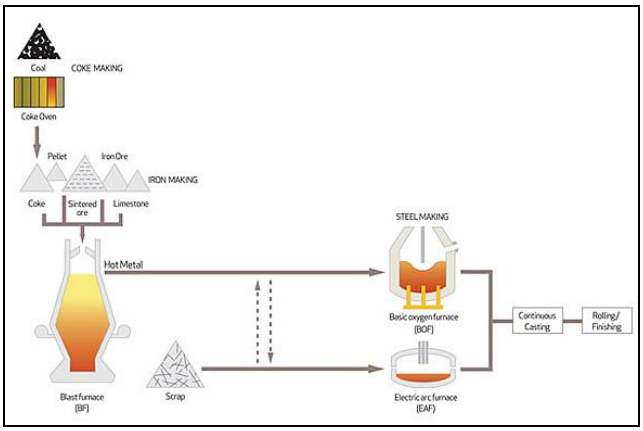
Annex 2. The Use of Coal in the Steel Industry

Steel-making routes

Steel is produced via two main routes (Figure 27):

- Integrated smelting involving blast furnace iron-making followed by a basic oxygen furnace (BOF);
- Electric arc furnaces (EAF).

Figure 27: Steel-making routes



Source: World Coal Association.

The majority of global steel production is made with coal via the BOF route: 68% of the steel produced today uses coal. The remainder is produced using scrap and electricity – often generated by coal.

The main categories of coking coal

There are three main categories of coking coal used by the steel industry:

- hard coking coal that forms high-strength coke;
- semi-soft coking coal that produces coke of lesser quality; and
- PCI coal. PCI (pulverized coal injection) coal is generally not considered to be a coking coal; rather it is used primarily for its heat value and is injected into a blast furnace to replace expensive coke.

Hard coking coals (HCC) are a necessary input in the production of strong coke. Only certain types of coking coal have the necessary characteristics required to make coke. These characteristics include caking properties (the ability to melt, swell and re-solidify when heated) and low impurity levels (e.g. moisture, ash, sulphur, etc.). Hard coking coals trade at a premium to other coals due to their importance in producing strong coke and because they are limited resources.

Semi-soft coking coal (SSCC) or weak coking coal is used in the coke blend, but results in a low coke quality with a possible increase in impurities. There is scope for interchangeability between thermal coal and SSCC, and thus SSCC prices have a high correlation with thermal prices.

Coal used for pulverized coal injection (PCI) reduces the consumption of coke per tonne of pig iron as it replaces coke as a source of heat and, at high injection rates, as a reductant. PCI coal tends to trade at a premium to thermal coal, depending on its ability to replace coke in the blast furnace. Integrated steel mills optimize the use of semi-soft and PCI coals in order to reduce overall costs. However, there are technical limits to the ability of integrated steel mills to substitute semi-soft and PCI coals for hard coking coal in their coking coal blend.

Coke Making

Steel is an alloy based primarily on iron. As iron occurs only as iron oxides in the Earth's crust, the ores must be converted, or 'reduced', using carbon. The primary source of this carbon is coking coal. Iron ore and coking coal are used mainly in the blast furnace process of iron making. For this process, coking coal is turned into coke, an almost pure form of carbon which is used as the main fuel and reductant in the blast furnace.

Coking coal is converted to coke by driving off impurities to leave almost pure carbon. The physical properties of coking coal cause the coal to soften, liquefy and then resolidify into hard but porous lumps when heated in the absence of air. The coking process consists of heating coking coal to around 1,000-1,100°C in the

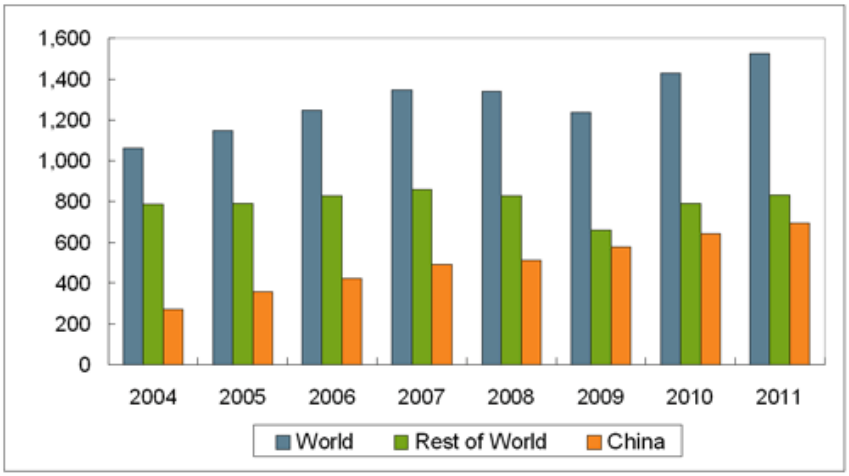
absence of oxygen, to drive off the volatile compounds (pyrolysis). This process results in a hard porous material: coke. Coke is produced in a coke battery which is composed of many coke ovens stacked in rows into which coal is loaded. Once pushed out of the vessel the hot coke is then quenched with either water or air to cool it before storage or is transferred directly to the blast furnace for use in iron making.

On average, around 600 kg of coke produces 1 tonne of steel, which means that around 770 kg of coal are used to produce 1 tonne of steel through the BOF route.

Crude steel production

World crude steel production reached 1,527 Mt in 2011, an increase of 6.8% compared to 2010 and a record level. Crude steel production is dominated by China, which produced 696 Mt (46% of global production). Around 800 Mt of coking coal and PCI were used, which is around 12% of total hard coal consumption worldwide.

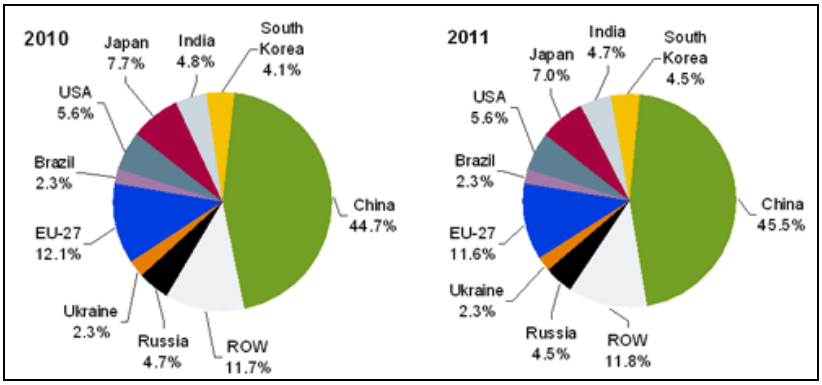
Figure 28: Global crude steel production



Source: World Steel Association

The EU recorded an increase of 2.8% compared to 2010, producing 177 Mt of crude steel in 2011. It accounted for 11% of world crude steel production (Figure 29).

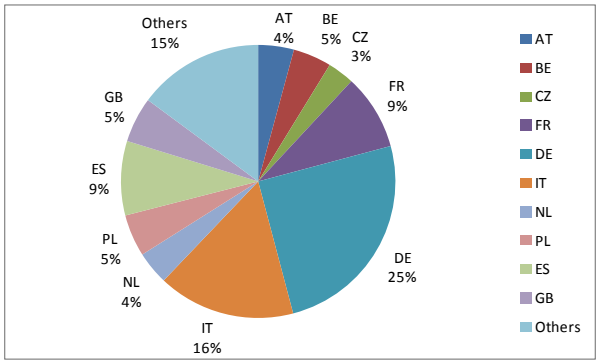
Figure 29: Share of crude steel production by region/country



Source: World Steel Association

The major producers are Germany, Italy, France, Spain, Belgium, United Kingdom and Poland (Figure 30).

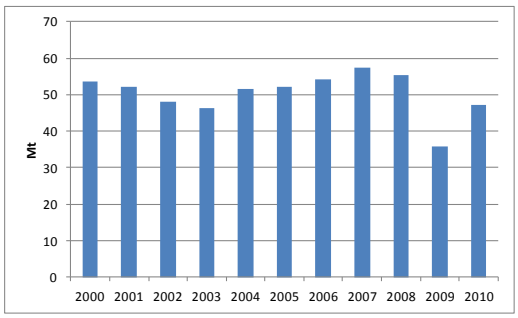
Figure 30: Share of EU crude steel production by country, 2011



Source: Eurofer

EU coking coal imports amount to around 50 Mt a year (Figure 31), except in 2009, when the collapse in EU crude steel production led to a similar fall in coking coal imports. Major suppliers are Australia, the United States and Canada.

Figure 31: EU coking coal imports



Source: Eurofer

Annex 3. Useful Conversions

Data in this study are given in metric tonnes.

For Total coal (Hard coal +lignite), data are measured in tonnes of coal equivalent (tce) **1 tce = 0.697 toe** (tonnes of oil equivalent)

1 tonne of coal = 23.9 GJ on average

from < 10 GJ for lignite to > 30 GJ for coking coal/anthracite)

1 kcal/kg = 4.1868 kJ/kg

One tonne of oil equivalent equals approximately:

1.5 tonnes of hard coal

3 tonnes of lignite

A 600 MWe coal-fired power station operating at 38% efficiency and 75% overall availability will consume approximately:

- Bituminous coal (CV 6000 kcal/kg NAR*): 1.5 Mt/annum
- Lignite (CV 2250 kcal/kg NAR*): 4.0 Mt/annum

* Net As Received

1 tonne of coal produces around 2.5 MWh of electricity

1 tonne of steam coal produces around 2.5 t of CO_2

to from	TJ Multiply by:	Gcal	Mtoe	Mbtu	GWh
Terajoule (TJ)	1	238.8	2.388×10^{-5}	947.8	0.2778
Gigacalorie (Gcal)	4.1868×10^{-3}	1	10^{7}	3.968	1.163×10^{-3}
Mtoe (Million tonne oil equivalent)	4.1868×10^{-4}	10^{7}	1	3.968×10^{7}	11630
Million Btu (million British Thermal Units)	1.0551×10^{-3}	0.252	2.52×10^{-8}	1	2.931×10^{-4}
Gigawatt-hour	3.6	860	8.6×10^{-5}	3412	1

Source: IEA, World Coal Association.

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