The Role of Coal in the Energy Supply of the EU-28

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Benjamin Sporton  
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Coal in Europe

The European Union’s recent ratification of the Paris Agreement and the road ahead to mitigate CO₂ emissions will be a challenging task for Europe without recognizing the key role coal plays. Coal is one of the major pillars in power generation for Europe’s 500 million inhabitants. The European Union’s 28 member-states have the third largest energy market in the world. In 2015, coal provided a quarter of the power generated in the EU-28 and remains a secure and affordable energy source.

Historically, coal was the stepping stone to the creation of the European Union. The establishment of the European Coal and Steel Community (ECSC) in 1951 created a common market for coal and steel among its founding members: the Netherlands, Belgium, France, West Germany, Italy, and Luxembourg. Ultimately, the ECSC led the way to the creation of the European Union.

Our cover story, written by a long-time member of the World Energy Council (WEC), explores the role of coal in the energy supply of the EU-28. There is also discussion about a study undertaken by the WEC on future energy use in Europe using three different energy scenarios. In all three scenarios coal plays a key role in providing a prosperous, stable, and secure supply of energy. The study also explores the importance of carbon capture and storage (CCS) technologies to enable a long-term future for coal-fired power generation in Europe.

In this issue we also examine the world’s first 460-MW supercritical circulating fluidized bed boiler (CFB) at Łagisza power plant in Będzin, Poland. After over six years of operation, the decision to build the first supercritical CFB unit in Łagisza appears to be economically and environmentally successful. The experience and knowledge gained from its design, construction, and operation has been a valuable step in further developing the technology and implementing it in other countries.

Several articles explore how lignite plays an important role in providing energy security, stable energy prices, and employment for many countries in Europe, such as Poland. Turkey is also promoting coal for economic and energy security reasons with the construction of 8.2 GW of new coal-fired power generation in order to utilize domestic lignite.

CCS remains a key technology for the coal and industrial sector. Although Europe has lost the position as a leader in the deployment of large-scale CCS projects to which it aspired several years ago, some countries are going forward with CCS research projects—including Norway, the Netherlands, and the UK. Achieving the targets set by the Paris Agreement will require widespread deployment of CCS. Alternative applications for CCS other than coal power exist and are recognized as vital in the long term by analysts, and we explore how vital the use of CCS is for achieving net zero emissions.

This issue of Cornerstone offers a wide range of articles on the continuing important role of coal in Europe. I hope it informs and encourages readers to understand the exciting developments happening within the coal sector in Europe.

On behalf of our team, I hope you enjoy this issue.
The Role of Coal in the Energy Supply of the EU-28

Hans-Wilhelm Schiffer

The European Union (EU-28) is one of the largest economies in the world, with a gross domestic product (GDP) of €14,635 billion in 2015. It has 508 million inhabitants, or 7% of the world’s population. Coal has played, and still plays, an important role in covering the energy needs of the EU-28. This article reflects on the role of coal within Europe in the past, at present, and in the future.
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Jinder Jow, National Institute of Clean-and-Low-Carbon Energy

GLOBAL NEWS
Covering global business changes, publications, and meetings
The European Union (EU-28) is one of the largest economies in the world, with a gross domestic product (GDP) of €14,635 billion in 2015. It has 508 million inhabitants, or 7% of the world’s population. Coal has played, and still plays, an important role in covering the energy needs of the EU-28. This article reflects on the role of coal within Europe in the past, at present, and in the future.

“**The prosperity and security of the EU depend on a stable and adequate supply of energy.**”

**STRUCTURE OF THE EU ENERGY SUPPLY**

In 2015 the total primary energy consumption of the EU-28 was 2332 million tonnes of coal equivalent (Mtce). That ranks the EU as the third largest energy market worldwide—after China and the U.S. Table 1 gives the total primary energy consumption of the EU by energy sources in comparison with the global average energy mix.
A significant difference is the lower share of coal in primary energy consumption. In contrast, there is a higher contribution of nuclear energy in comparison to the global average. The share of non-hydro renewables, particularly wind and solar, in total primary consumption exceeds the global average by a factor of three.

The energy production within the EU-28 by energy sources in 2015 was:2

- Oil: 103 Mtce
- Natural gas: 155 Mtce
- Coal: 208 Mtce
- Nuclear energy: 278 Mtce
- Hydro power: 109 Mtce
- Other renewables: 194 Mtce

The share of production (including nuclear energy) in the total primary energy consumption was 45%. The energy import dependence of the EU was 55% accordingly.

Globally, the EU-28 has become the largest energy importer. The EU’s energy import was one-fourth the total worldwide trade in oil, gas, and coal. In contrast, the EU’s share in global primary energy consumption was only 12.4% in 2015. The import dependence in the case of oil and gas is particularly high, 88% and 70%, respectively. The share of imports in total coal consumption was 45%.3

The import dependence of the EU’s energy supply has increased over the last decade. The main reasons for this were the halving of EU oil and gas production and a decline in the production of coal by 17%. The trend of increasing import dependence would have been even stronger were it not for a doubling in the consumption of renewables.

The lack of diversification in the supply sources for oil and gas are concerning from an energy security point of view. Russia is the largest supplier of oil and gas imports. Four EU member-states procure their entire supply of natural gas exclusively from Russia: Estonia, Latvia, Lithuania, and Finland. The countries of Central and Eastern Europe, such as Poland, Czech Republic, Slovakia, and Hungary, cover between 50 and nearly 100% of their annual gas consumption via imports from Russia. Because some of the region’s gas comes via Ukraine, it risks transit disruptions due to Ukraine’s situation as well as Russia-related risks. This high dependence on a single supply source makes some EU countries susceptible to supply disruptions. Ten years after Russia cut off gas supplies to Ukraine and Europe in the winters of 2006 and 2009, and in the midst of the 2014 Ukraine crisis, concerns about a potential politically motivated disruption of gas supplies from Russia, and especially those that pass through Ukraine, triggered a discussion on creating an Energy Union to counter this threat.4

In fact, Russia is also the most important single supplier of coal. However, the supply options for coal are numerous, and thanks to the existing infrastructure, even the loss of the largest supplier could be offset with deliveries from other sources—unlike the situation for gas.

### THE EU REGULATORY FRAMEWORK AND ITS EFFECTS ON THE ENERGY MIX

At the beginning of 2015, the EU Commission presented plans for a European Energy Union based on the strategic framework of the Commission and featuring five closely connected dimensions: energy supply security, solidarity, and trust; single energy market; energy efficiency; reduction of CO₂ emissions from economic activities; research, innovation, and competitiveness. The Energy Union has the following specific objectives:

- Energy dependency is to be reduced and investors are to be given planning security by the EU’s efforts to develop new sources, especially natural gas sources. Coal as a domestic energy source found in abundance in Europe is...
not mentioned specifically. The European Council wants to improve “the utilization of domestic sources”, however, and coal is one of these sources.

- A strategy for the import of more liquefied natural gas (LNG) and for increasing energy efficiency is to be prepared with the aim of making the energy system “fit for a society low in carbon”.  

The prosperity and security of the EU depend on a stable and adequate supply of energy. Consequently, the Commission has developed a strategy for a secure European energy supply that fosters resilience against energy supply disruptions in the short term and reduces dependency on certain fuels, energy suppliers, and supply channels in the long term.

The energy mix of EU countries differs markedly, due not only to differing resources but also to the wide variety of national energy policies adopted over the years.

Thus, power generation in France is based on nuclear energy. In contrast, Germany has decided to phase out nuclear energy by the end of 2022. As a result of political support in Germany, the share of renewables in total power generation reached 29.0% in 2015. This represents a fivefold increase since 2000. Hydropower has the highest share in power generation in Austria and in Sweden. Wind energy has a strong position in Denmark. In the Netherlands, gas is the most important energy source for power generation. Coal dominates power generation in Poland with a share of more than 80%. Of the UK’s electricity generation in 2015, coal accounted for 22.6%—a decrease of 7.1 percentage points on 2014 due to plant closures and conversions. In 2015, the British Secretary for Energy and Climate Change proposed a consultation on the closure of all coal-fired power plants without CCS by 2025. A week later, the UK government cancelled its £1 billion funding of the flagship White Rose CCS project.

Figure 1 shows the total coal supply breakdown in 2015 for Europe. The total production of hard coal in the EU-28 was 100.3 Mt in 2015. Poland was the most important producer with 72.2 Mt, followed by the United Kingdom with 8.7 Mt, Czech Republic with 8.2 Mt, Germany with 6.7 Mt, Spain with 3.0 Mt, and Romania with 1.5 Mt. The total brown coal production in the EU-28 was 398.1 Mt in 2015. Germany is the most important producer of brown coal within the EU. The production of brown coal, classified as lignite, was 178.1 Mt in 2015. Other major producers of brown coal in the EU are Poland (63.1 Mt), Greece (45.4 Mt), the Czech Republic (38.1 Mt), Bulgaria (36.8 Mt), Romania (22.4 Mt), Hungary (9.2 Mt), Slovenia (3.2 Mt), and Slovakia (1.8 Mt).

The coal supply of the EU-28 was supplemented by 191.6 Mt of hard coal imports (including anthracite) in 2015. In 2015, the most important such importers were Germany (55.5 Mt), the United Kingdom (27.1 Mt), Italy (19.5 Mt), Spain (19.0 Mt), France (14.3 Mt), the Netherlands (12.4 Mt), and Poland (8.2 Mt).

Domestic production and consumption of coal has declined in the EU over the past two decades. However, domestic production of hard coal and lignite represent a significant share in total coal supply, 55% in 2015—after conversion of the different categories of coal into energy quantities using standardized heating values.

Imported coal can also be classified as secure in supply as the import sources are well diversified. Global coal reserves remain plentiful and are found around the world. On an energy basis, proven reserves of coal, essentially an inventory
of what is currently economic to produce, are much greater than those of oil and gas combined, and are sufficient to supply more than 100 years of production at 2015 levels.  

**ROLE OF COAL IN THE ENERGY SUPPLY MARKET**

The power and heat sector dominates coal demand in the EU, accounting for more than 75% of the total coal demand. Another 10% is used in blast furnaces and coke ovens for iron and steel production. Other industries, such as cement making, accounts for 9% of coal use, the residential sector for 3%, and commercial and other services for 1%. Coal demand has been declining slowly in all sectors.

Despite being the main source of coal demand, coal’s share in power generation in the EU-28 has decreased substantially since 2000, from roughly 32% in 2000 to 25% in 2015. Although the German nuclear phase-out temporarily led to some increases in coal’s contribution after 2011, the share of coal in total electricity generation was 42% in 2015 compared to 50% in 2000.

The share of coal in total power generation varies from country to country. The highest share of coal in power generation exists in Poland with more than 80%. In Germany, the Czech Republic, Greece, and Bulgaria coal is the most important fuel for power generation with shares between 40 and 50%. Indigenous lignite plays a major role in these countries. Coal covers 10–30% of power generation in the UK, Spain, Denmark, the Netherlands, Romania, Portugal, Hungary, Ireland, and Slovenia. Coal continues to make a major contribution to energy security in approximately half of the member countries.

**IMPACTS OF COAL ON KEY EU CLIMATE AND ENERGY POLICIES**

In recent years, sustainability—notably, mitigating climate change—has been the key driver for EU energy policies. However, concerns about energy security and industrial competitiveness have become more pressing in recent years.

Coal is one of the main pillars for power generation. “But the European Union does not have a specific coal policy, even though its policy affects coal use, including the European Union Emissions Trading Scheme (EU-ETS), air pollution directives and renewable energy targets. There is still substantial competitive indigenous coal production in the European Union and well diversified secure international coal supply at low (hard) coal prices; this fuel has clear security benefits. A continued contribution from coal in a low-carbon economy is however compromised by its high CO₂ intensity. Considerable improvements in power plant efficiency and the use of carbon capture and storage (CCS) technologies will therefore be required.”

Over the last decade, the EU has embarked on three major actions in energy and climate policy: (1) the progressive liberalization of the internal energy market package, the so-called “Third Package”; (2) ambitious climate and energy targets and policy measures as part of the so-called “2020 Climate and Energy Package”; and (3) a new “2030 Climate and Energy Policy Framework” that prepared the EU position for international climate negotiations in 2015.

At their October 2014 European Council meeting, leaders from EU member-states reached an agreement on their ambitions for the 2030 Climate and Energy Policy Framework together with key conclusions on EU energy security:

- A binding EU target of a domestic reduction in greenhouse gas emissions of at least 40% by 2030 compared with 1990—with reductions in the emissions-trading sector amounting to 43% and in non-ETS sectors to 30% by 2030 compared with 2005.
- An EU-wide target of at least 27% for the share of renewable energy consumed in the EU in 2030.
- An indicative target at EU level of at least 27% for improving energy efficiency in 2030 compared with projections of future energy consumption based on current criteria.

Energy security is also part of the 2030 Climate and Energy Policy Framework. In this context, the European Council recognized that the EU’s energy security can be increased by
exploiting indigenous resources, as well as using safe and sustainable low-carbon technologies.

The EU-ETS remains the central instrument for reaching cost-effective emission reductions. In 2015, the EU-ETS was strengthened with the introduction of a market stability reserve and a steeper annual reduction in the number of ETS emission allowances issued: The 1.7% linear annual reduction will be raised to 2.2% from 2021.12

“The import dependence of the EU’s energy supply has increased over the last decade.”

PERSPECTIVES FOR COAL IN THE EU

The World Energy Council (WEC) has prepared a study, World Energy Scenarios 2060. Presented at the World Energy Congress in October 2016, the paper comprises three scenarios. These scenarios, which are characterized in Table 2, are designed to help a range of stakeholders address the energy trilemma of achieving environmental sustainability, energy security, and energy equity.13

TABLE 2. WEC: Three scenarios and key attributes

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Key attributes</th>
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<tr>
<td><strong>Modern Jazz</strong></td>
<td>A market-driven approach to achieving individual access and affordability of energy through strong technological development and rapid deployment of new technologies, leading to a fast transition to a sustainable world, which addresses climate targets and handles well the economic and geopolitical shift in Asia. Developments on the energy supply-side, and in the mid-stream, reduce energy costs and enable greater access to energy for all. The outcome in 2060 is a shift to a resilient, integrated, global low-carbon energy system.</td>
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<tr>
<td><strong>Unfinished Symphony</strong></td>
<td>A world of strong states and strong state direction, with energy policy priorities focused on security, public health, and climate change. This underpins an extensive network of “green subsidies” and carbon pricing. There is strong demand-side innovation with high levels of infrastructure development, smart cities, strong regulation, and their enforcement, of buildings, industry, and transport, with the aim for rapid and enduring large-scale improvement of energy efficiency. This world moves a long way to meet environmental targets while maintaining resilience. The scenario is indicated as “unfinished”, because the targets of the Paris Agreement are not met despite the assumed strong climate policies.</td>
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<tr>
<td><strong>Hard Rock</strong></td>
<td>A fragmented world with a weak economy that does not handle low growth and aging population well. There is increasing disparity in wealth and income and multiple challenges to the authority of the state, whether from internal regional jurisdictions, or new and powerful networks. In the shorter term, a collapse in debt markets leads to financial crises in the U.S. and China, with strong nationalism and isolationist government policy as emergent features. Energy policy focuses on energy security with tight regulation and bureaucracy, at times frustrating private investment. Over time, we see weakening resilience of the energy system, for example, regulation struggles to keep up with technology, leading to a wide range of cyber-attacks. There is strong growth in fossil fuel use, nuclear, and large-scale hydro—the world is on a path to exceed a 4°C temperature rise.</td>
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Symphony scenario (see Figure 2). The share of coal in total primary energy supply will be 5% or even less in 2060.

Coal’s share in EU’s electricity generation will diminish to approximately 2% in Modern Jazz and to 3% in Unfinished Symphony and in Hard Rock by 2060. Carbon capture and storage (CCS) is seen as a technology that will be implemented after 2030, in particular in the Unfinished Symphony scenario. In this scenario, 81% of electricity generated by coal within the EU-31 will use CCS by 2050, and this share is expected to grow to 95% in 2060.

“The deployment of clean coal technologies equipped with CCS, should be a priority to reduce CO₂ emissions…”

The share of fossil fuels in the EU’s total power generation will be reduced to approximately 42% in Hard Rock, to 25% in Modern Jazz, and to only 16% in Unfinished Symphony by 2060. Renewable energies will contribute approximately 43% of the total electricity generation in 2060 in the Hard Rock scenario, 63% in Modern Jazz, and 67% in Unfinished Symphony. The remaining share will be covered by nuclear energy.

CONCLUSIONS

The use of coal in the EU has clear energy security benefits, given the low international coal prices and well-diversified supplies as well as EU indigenous production potential in lignite. The deployment of clean coal technologies, equipped with CCS, should be a priority to reduce CO₂ emissions alongside the expansion of renewable energies and increasing energy efficiency. Furthermore, the total discounted mitigation costs for the long-term achievement of the 450 ppm CO₂ eq. target would be 138% higher globally if CCS was not used. Thus, policy backing and a corresponding legal framework for the implementation of CCS in power generation (on the basis of coal, gas, and biomass) and in industry are necessary in order to secure investments that lead to a cost-efficient reduction of greenhouse gas emissions. Taking such a sensible framework into account, a stronger role for coal than anticipated in the WEC scenarios would be compatible also with the ambitious climate targets of the European Union.

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The Need for Increased Momentum for CCS After COP21

By Andrew Purvis  
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As a result of the 21st Conference of the Parties (COP21) in Paris in 2015, 178 parties to the UN Framework Convention on Climate Change (UNFCCC) adopted a goal to hold the increase in global temperature to “well below” 2°C, “pursue efforts” to limit the temperature increase to 1.5°C above pre-industrial levels, and further achieve a balance between anthropogenic sinks and sources of greenhouse gases in the second half of the century. To achieve these targets, all emissions-mitigating measures and mechanisms will be needed. Efforts to decarbonize will be needed from both the parties to the agreement and the energy and industrial sectors. This will require increased momentum for energy efficiency and a continuing transition from fossil fuels to renewables. It also highlights the critical role of carbon capture and storage (CCS).

CCS is broader than just a contribution to emissions abatement for energy production. The industrial process sector accounts for 25% of global emissions and CCS is the only technology that can achieve deep emissions reductions in industries such as steel, cement, and fertilizer production. Recently completed CCS feasibility studies in Norway, complemented by work carried out in potential CCS capture hubs such as Teesside (northeastern England) and Rotterdam (southern Netherlands), highlight the necessity of CCS for the industrial sector.

Decarbonization requires the application of many different technologies according to circumstance and economics. CCS is vital, in terms of costs and necessity, to achieve emissions targets. Delaying CCS implementation will result in a significant increase in costs. Rather than being an expensive option, independent studies have shown that CCS in power generation applications is already cost competitive with many renewables, when the subsidies provided to renewables are removed.

“CCS is a technology that will help deliver continued access to affordable energy while reducing emissions in both developing and developed countries.”

CCS FOR POWER

CCS is relevant and crucial for a wide range of industries. Application of CCS to electricity production and many industrial processes is key to meet both emissions reduction objectives and the reality of continued fossil fuel use.

Global consumption of fossil fuels continues to increase, driving increases in CO₂ emissions. Forecasts of global energy demand growth indicate this reliance will continue for decades to come. The energy sector accounts for around two-thirds of greenhouse gas emissions and, according to the International Energy Agency (IEA) in its 2015 World Energy Outlook, coal, oil, and gas will remain important fuel sources for electricity generation for the foreseeable future.

In power production, renewables will be increasingly important, but with over 2000 new coal-fired power stations as well as many gas-fired plants planned to be operating before 2040, CCS is also vital. Energy demand is growing continuously, with the biggest growth in non-OECD countries in which 59%
of the electricity was generated by coal in 2013. Despite the decrease in demand for coal in several large economies, like China which went from a 74% to a 70% share in 2014, world demand and consumption is still increasing. It is therefore unrealistic to expect fossil energy production and consumption to cease overnight. CCS is a technology that will help deliver continued access to affordable energy while reducing emissions in both developing and developed countries. This increases the importance of large-scale deployment of CCS.

SOME RECENT EUROPEAN DEVELOPMENTS

Europe has lost the position as a leader in the deployment of large-scale CCS projects to which it aspired several years ago. However, the importance of CCS technologies at large scale is recognized and robust R&D efforts by a number of European bodies continue, as do efforts to enhance the European policy and regulatory framework governing CCS. Below, we detail some projects, developments, and countries’ efforts that are worth accentuating.

Norway

Norway is well known for its petroleum industry, but also for basing most of its own electricity production on hydropower. Thus, while exporting large quantities of oil and gas, Norway has also emerged as a strong supporter of CCS—thereby aligning concern for energy security with consideration of the consequences for climate of economic growth, and the government’s goal of securing an efficient and climate-friendly energy supply. In 1996, Statoil began injecting CO$_2$ on the Norwegian continental shelf, as part of the natural gas production process at the Sleipner field. Later, the company also started injecting CO$_2$ at Snøhvit in northern Norway. These two projects have established Norway as a leader in Europe on CCS. The country has reinforced this position with new feasibility studies initiated by the Norwegian Ministry of Petroleum and Energy (MPE) on behalf of the government and the Mongstad CO$_2$ Technology Centre (the world’s largest test laboratory for capture technologies, in operation since 2012). Also, Statoil has recently submitted plans to Norwegian and UK authorities to develop the Utsira field, which foresee gas and condensate being piped to Sleipner and processed using CCS technologies.

On 4 July, the MPE published a report on the newly conducted Norwegian CCS feasibility studies. The overall goal of the study was to examine the technical feasibility and total cost of at least one full-chain CCS project. Three industrial stakeholders have conducted feasibility studies examining CO$_2$ capture as part of the study. Different ship transport options were also examined, adding variables such as location, amounts of captured CO$_2$, and replicability into the assessment. Studies of CO$_2$ storage at three different sites on the Norwegian continental shelf also were carried out.

The MPE report concludes it is technically feasible to realize a full-chain CCS project in Norway. Further, the studies demonstrate that all of the alternatives studied have the potential to significantly reduce barriers to deployment and costs for future projects.

There are several positive outcomes from the study, beyond the feasibility of a full-chain CCS project. Norwegian authorities are actively maintaining momentum with their national policies for CCS and have identified and engaged competent private industry stakeholders, emphasizing that CCS is necessary for the delivery of climate targets at the lowest cost possible.

“...the importance of CCS technologies at large scale is recognized and there continues to be robust R&D efforts by a number of European bodies.”

United Kingdom

CCS in the UK has not come to an end. Despite cancellation of the UK CCS competition, which was to make available £1 billion capital funding, and additional operational funding to support the design, construction, and operation of the UK’s first commercial-scale CCS projects. While this resulted in the termination of the White Rose and Peterhead projects last year, several activities continue.

The UK government is undertaking an ongoing examination of a reoriented approach to CCS for both power and industrial processes, and the government is considering advice from Lord Oxburgh’s CCS Parliamentary Advisory Group. While awaiting the results of these ongoing processes, three CCS projects under development are worth highlighting: the Caledonia Clean Energy Project, the Don Valley Power Project, and the Teesside Collective Project.

The Caledonia Clean Energy Project has received £4.2 million in joint funding from the UK and Scottish governments. The plan is to construct a new coal-fired power plant equipped...
with carbon capture technology to capture 3.8 million tons (Mt), or 90% of the total CO₂ emissions per year. The Don Valley Power Project, co-funded through the European Energy Programme for Recovery, has been seeking to develop CCS on a new power station. Up to 1.5 Mt of CO₂ per year would be captured.

A CCS hub and cluster network brings together multiple CO₂ emitters and/or multiple storage locations using shared transportation infrastructure. The Teesside Collective is such an infrastructure project developed by a cluster of industries in northeastern England, partially funded by the UK government, that aims to prevent the emission of up to 5 Mt of CO₂ per year in the 2020s. These ongoing projects prove that private stakeholders are willing to move forward, and that both the power and industrial sectors are willing to innovate and engage on CCS development and deployment. The cluster approach will further be an important aspect of driving down costs in the future.

The Netherlands

In the Netherlands, the Rotterdam Capture and Storage Demonstration (ROAD) project is widely known as Europe’s most advanced CCS project in progress. The project involves the retrofit of a 250-MWd post-combustion capture and compression unit to a newly constructed 1070-MWd coal-fired power plant located within the Rotterdam port in the industrial Zuid-Holland area. The ROAD project plans to capture 1.1 Mt of CO₂ per year and store it in a depleted gas reservoir under the North Sea. Co-financed by the European Commission, the government of the Netherlands, and the Global CCS Institute, the project is in the define stage of development planning and its next step is to make a Final Investment Decision, which is expected by the end of 2016.

A related project is examining developments in the Port of Rotterdam. This is the largest seaport in Europe and, as part of the ambitious Port Vision for 2030, seeks to develop an integrated industrial cluster with Antwerp to become a leading European hub for cargo. Although CCS is not a specific goal under the Port Vision, the Port of Rotterdam will be interconnected to the CCS industry through projects like ROAD and CO₂ infrastructure already in use delivering CO₂ from industrial sources in Rotterdam to greenhouses. ROAD is among the first CCS projects in Rotterdam’s port and industrial complex, which plan to use the port as their gateway to storage sites in the North Sea, and there are expectations that more of the industry located in the cluster will implement CCS in their activities over time.

EU DEVELOPMENTS ON POLICY AND REGULATORY ISSUES

In the EU, several efforts are underway after COP21 to maintain the momentum the Paris Agreement gave to global emission reductions efforts. These include both proposals to reform the Emissions Trading Scheme (ETS) and the development of the integrated European Strategic Energy Technology Plan (SET-Plan). Part of the ETS reform has been finalized, through the establishment of a new market reserve, to gradually decrease the number of allowances in the system and therefore increase prices. Remaining elements of the reform include reducing the number of emission allowances permitted to be issued, revising the system of free allocation to focus on sectors at highest risk for carbon leakage, and launching a new Innovation Fund to support low-carbon innovation, including CCS.

The ETS Reform and Reforming the Innovation Fund

One of world’s largest carbon markets, the EU-ETS represents an important element in the implementation of EU climate policy. The scheme works as a cap-and-trade system, in which a cap on emissions is imposed with opportunities to trade emissions allowances. The carbon price, the price per ton of CO₂ being emitted or traded, associates a financial value with reducing or avoiding emissions. A sufficiently high carbon price would create an incentive to invest in low-carbon technologies like CCS.

In July 2015, the European Commission proposed legislation to revise the EU-ETS, and on 31 May 2016, Ian Duncan, Member of the European Parliament (MEP) and EU-ETS rapporteur, published a draft ETS reform proposal. The goal of the reform is to revise the EU-ETS for the period 2021–2030. For the EU to reach its targets for emissions cuts, the overall emissions cap
will need to significantly decrease. The Commission’s proposal recommends that the overall number of emissions allowances decline at an annual rate of 2.2% from 2021 onward, compared to the current 1.74%.

The proposal also aims to revise the system of free allocation to focus on sectors at highest risk of relocating their production outside the EU (so-called “carbon leakage”), as well as urging member-states to implement policies and financial measures to avoid carbon leakage within the legal limits of state aid. The proposal suggests a model for compensation to the industry if the carbon price reaches certain levels, and emphasizes that more harmonized rules for indirect cost compensation are needed. Strong, predictable policy action is needed urgently to stimulate CCS deployment in order to fulfill EU’s climate targets.

As part of the EU-ETS, 300 million allowances were included in a New Entrants’ Reserve (NER300) and monetized to raise money to support the deployment of low-carbon technologies such as renewables and CCS. White Rose, based in the UK, was the only CCS project to be awarded funding through the NER 300 mechanism. The legislative proposal further suggests the establishment of an Innovation Fund (extending NER300), which would be funded through the sale of 400 million allowances. However, the process on ETS revision is not finalized, and is expected to be voted on in February 2017 as part of the EU-ETS reform.

**The Market Stability Reserve**

Since 2009, the EU-ETS has built up a surplus of emissions allowances, which risks undermining the orderly functioning of the carbon market in the short term. This led to a reduction in the carbon price, and thus a disincentive to invest in technologies to reduce emissions. Long term, this could limit the ability of the ETS to cost effectively meet more demanding emissions reduction targets and the deployment of critical technologies such as CCS would be delayed. As part of a long-term solution, the Commission decided in 2015 to introduce changes to reform the ETS by establishing a market stability reserve that would be operational by January 2019. This would allow the supply of allowances to be flexible based on economic conditions and would be expected to set a more stable and predictable carbon price.

**The SET-Plan Process**

“Research, innovation, and competitiveness” were collectively identified as one of the five dimensions of the EU Energy Union Strategy, a project of the European Commission to coordinate the transformation of European energy supply.

The SET-Plan aims to accelerate the development and deployment of low-carbon technologies, and demonstrating CCS is explicitly included as one of 10 identified actions to transform the energy system, creating growth and new jobs in the EU. SET-Plan Action 9, which aims to demonstrate CCS in the EU and to developing sustainable solutions for carbon capture and use (CCU), is currently subject to a public consultation process that began in Spring 2016. As a result of the process, stakeholders have agreed on a number of draft targets for CCS and CCU. The next step is for the stakeholders to develop a detailed implementation plan for the delivery of these targets.

**CONCLUSION**

Reports of the death of CCS in Europe have been greatly exaggerated, with projects in continued operation in Norway, and projects in development in Norway, the UK, and the Netherlands. Nonetheless more needs to be done if CCS is to make the contribution that it must if secure, affordable, and climate-friendly energy and industrial production are to be delivered. Policy action is needed urgently to facilitate CCS deployment or else the Paris Agreement temperature targets are at risk of not being achieved.

Governments must continue efforts to develop strong and stable policies, and in response industry needs to advance R&D and new projects.

**NOTES**

A. According to leaked information from the Norwegian draft national budget, the Norwegian government recommends the projects to continue into a FEED phase, and will support the process with substantial funding; www.e24.no/makro-og-politikk/statsbudsjett-2016/regjeringen-satsser-videre-paa-tre-co2-fangstprosjekter-sproeyter-inn-360-mill/23807295

B. In April 2016 the White Rose Project was canceled following the UK Secretary of State’s decision not to grant the Development Consent Order for the project.

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Lessons from the “Golden Decade” of Coal for China’s Energy Revolution

By Qian Minggao
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China is abundant in coal resources, but holds limited oil and natural gas resources. In the past decade, China’s GDP has grown 8–10% annually, and it is the second largest economy in the world. Nearly 70% of its economic growth and primary energy demand has been met by coal. The consumption of coal increased from 1 billion tons in 2000 to nearly 4.2 billion tons in 2014. This four-fold increase within 15 years is known as the coal sector’s “golden decade” (2000–2010).1

The extensive production and consumption of energy during this golden decade brought about many advances and improvements in the quality of life for hundreds of millions of people. However, this rapid advancement has also created problems. As a result, in recent years the extensive consumption of coal has been criticized, and there has been debate about better “coal control” and even “decarbonization” with proposals for a low-carbon economy. In 2014, China proposed a national plan for an “energy revolution” in terms of consumption, supply, and technology.2 The dominant position of coal is being reevaluated as the country moves toward adjusting the energy mix and reducing coal production capacity.

The increasing consumption of fossil energy in China to meet energy demand has resulted in greater environmental challenges. The construction and development of some coal mines has resulted in environmental problems. China is working to resolve these problems, but issues remain. Internal costs become easily converted into social costs, and only part of the costs of coal mining can be absorbed by the mining company.

“China will continue to rely on coal for the foreseeable future, with alternatives such as renewable energy remaining relatively small in scale.”

China will continue to rely on coal for the foreseeable future, with alternatives such as renewable energy remaining relatively small in scale. Given the country’s extensive consumption of coal, enormous challenges exist in the areas of safety, mining, and clean utilization, requiring more studies on planning and the efficient use of resources. A key element in sustainable coal mining is to seek to maximize the economic and social benefits of coal, coal-bed methane, water, and other useful resources. The coal industry in China is part of the energy revolution undertaking reform and innovation. Companies and research institutes are studying methods and technologies to improve the efficient utilization of coal in mining and power generation.

ISSUES ARISING IN THE GOLDEN DECADE

During the rapid development of the coal industry in the golden decade, there arose production safety, environmental, and economic issues.

Production Safety

Geological conditions, technological standards, and levels of safety and protection vary in different mines. During the last few years, several major mining accidents have occurred in unsafe mines. In 2002 the output of township and village coal mines accounted for 39% of national coal output, the fatality rate per million tons was as high as 4.64, and the number of deaths occurring under these two kinds of ownership accounted for...
“In order to achieve scientific and sustainable development, the coal industry must reinvest profits in clean coal technologies.”

Environmental Capacity Exceeded

Coal mining activities alter the environment, impacting air quality as well as land and water resources. China’s coal industry grew rapidly, at the rate of 200 million tons annually, to meet the energy demand of economic development (2004–2014) (Figure 1). It was a challenging task to improve coal production technologies and meet the national energy demands. The rapid expansion did not allow an opportunity for resource planning. China’s coal fleet expanded quickly and was not equipped with modern emissions control technology.

Carbon dioxide emissions, particulates, dust, and other emissions from increasing coal usage have resulted in environmental issues. The international community has called for more policies and measures to mitigate CO₂ emissions. A further air quality issue is mitigation of smog formation from coal-fired power stations.

Resource Economy Issues

Chinese coal mines operate under different financial conditions, depending on whether they are state or privately owned. Some private mines may cut costs, which can result in environmental and safety problems. Coal mining costs are a part of the total economic and environmental costs. In several cases the external costs are not fully met. Consequently, prices are kept low in exchange for profits, while the losses from external costs are borne by society. For instance, in some township and village coal mines (mainly privately owned) and poorly financed state-owned coal mines, resources are obtained improperly, and low production costs (55 yuan/ton) are achieved. As a result, these mines have higher mortality rates due to lack of investment in resource planning and safety measures. Internal costs are thereby converted into social costs. Some state-owned coal producers have invested in the establishment of a specialized research institution and in research and development of clean coal technologies. However, other coal companies do not have those resources, especially for smaller township and village coal mines. Due to a lack of regulations these companies do not reinvest in solutions to the industry’s technological issues or invest back into the local economy.

Resource Advantages Are Not Converted Into Economic Advantages

During the life cycle of a coal resource, there will be high costs at the beginning of the mine and at the end of its life when reclamation and environmental remediation take place. Regions rich in resources should reinvest their profits into the rehabilitation of the mine at the end of its economic life. However, there are currently no regulations concerning this. The issue of lack of investment into long-term sustainable solutions was highlighted at the fourth session of the 12th National People’s Congress held in January 2015 in Shanxi province: “Shanxi’s development is inseparable from coal, but due to the prolonged, massive, high-intensity and extensive mining of coal (that provides for a quarter of the national coal output), and especially when restoration and treatment are not in place after mining, Shanxi, which is already an ecologically fragile province, has had to pay a huge price; consequently, it has become one of the provinces with the worst environmental issues in China.” In the national ranking for GDP growth, Shanxi slipped to last place in 2014 and finish second to last in the first half of 2015. The economic benefits from coal mining are not being invested within the province to resolve environmental issues.
In order to achieve scientific and sustainable development, the coal industry must reinvest profits in clean coal technologies. A portion of the profits could be invested in training staff to study resource and environmental economics and sustainable coal mining management. In the long term, this investment also would aim to improve the coal industry’s public image with the wider community. This is an issue worth considering for those who are involved in coal technology, economics, and management work.

**ENERGY REVOLUTION AND COAL**

In June 2014, the Chinese government proposed an energy revolution in terms of consumption, supply, technology, and system management. The energy revolution approach was in response to concerns over high CO$_2$ and other emissions.

In 2012, China’s GDP exceeded Japan’s for the first time; however, Japan only consumed 660 million tons of standard coal equivalent in that year compared to China’s 3.25 billion tons of standard coal equivalent. This is related to China’s rapid development, economic model optimization, and lack of innovative technologies. Therefore, it is necessary to improve the economic model, encourage scientific and technological innovation, and grow economically through high-tech products with low energy consumption in order to reduce energy consumption. Coal will remain the primary energy source in China and to address the long-term sustainable use of coal must be part of the proposed energy revolution.

**Coal Mining Equipment**

Equipment manufactured for the coal sector provides a high level of mechanization and automation with fewer miners on site. For example, China Coal Technology and Engineering Group provided a complete set of fully mechanized mining machinery to a Russian company in 2015. Consequently, productivity in the mine increased, with fewer accidents. It is mandatory for mines to provide equipment to ensure the safety of miners. Coal companies must also provide comprehensive training and research to improve employer’s safety and environmental protection.

**Emissions Control**

Historically, major industrial countries have had a severe impact on the environment; in many developed countries, coal is no longer a major part of the energy mix. China produces annually around 4 billion tons of coal—more than half of the world’s coal output. The installed capacity of coal-fired units is close to 800 million kW, and coal-fired power generation accounts for 75% of the total power generated in the country; coal also accounts for more than 40% of cargo transported by rail.

Analysis of geographical regions in China shows a close correlation between the presence of haze and coal usage. Hence it is necessary to ensure more efficient use of coal usage in order to better control the haze issue.

Without restructuring its energy mix, it is likely that the consumption of coal in China will continue to rise in order to meet the target of doubling the GDP from 2010 to 2020. Therefore, it is important to undertake further scientific research in order to formulate policies and regulations to improve energy use and reduce emissions.

In recent years, some large coal-fired power plants in China have achieved excellent environmental results through the use of ultra-low emissions technology in their coal-fired power generators. With supercritical and ultra-supercritical high efficiency low emissions (HELE) technologies, coal-fired units can achieve “ultra-low emissions”. For instance, in 2015, Unit 2 at Shenhua Group’s Luoyang Guohua Mengjin Power Station was modified with supercritical technology. This resulted in improvement in several areas: smoke control technology reduced emissions by about 319 tons/year, sulfur dioxide control technology by about 267 tons/year, and nitrogen oxide control technology by about 267 tons/year.

Other examples of improvement in emissions control after modifications include Unit 4 (300,000 kW) at Guohua Sanhe Power Plant (Figure 2) in 2015. Unit 4 set a new record in China for ultra-low emissions by coal-fired units, with only 0.23 mg/m$^3$ emitted. Unit 3 passed through a 168-hour test run and achieved 2 mg/m$^3$ of emissions in December 2015; Waigaoqiao No. 3 Power Plant’s coal consumption was 273 g/kWh from January to May 2015. The average concentration of sulfur dioxide emissions was 14.95 mg/m$^3$, and the average desulfurization efficiency was above 98%; the actual concentration of flue gas emissions was below 1 mg/m$^3$; and the concentration of nitrogen oxide emissions was only 15.9 mg/m$^3$.

The Chinese government’s recent energy directive states: “We will implement the State Council’s Action Plan on Air Pollution Prevention and Control in accordance with the

The Chinese government’s recent energy directive states: “We will implement the State Council’s Action Plan on Air Pollution Prevention and Control in accordance with the
requirements of green development, and fully promote ultra-low emissions and world-class energy consumption standards across the country by speeding up the upgrading and modification of coal-fired power plants; these are important measures to promote clean fossil energy, improve air quality and ease resource constraints.”

The government has decided to implement ultra-low emissions and energy-saving modifications on all coal-fired units by 2020. As a result, all operating coal-fired power plants will have an average coal consumption of less than 310 g/kWh. New power plants will have an average coal consumption of 300 g/kWh. Those that fail to meet the mandatory standards will be closed. In eastern and central China, these standards are to be met earlier, in 2017 and 2018. Upon completion of the modifications, about 100 million tons of coal can be saved every year. CO₂ emissions can be reduced by 180 million tons, and the total discharge of major emissions in the power industry can be reduced by about 60%.1

CONCLUSION

In response to the “energy revolution”, the coal industry in China should focus on reform in the areas of technology, economics, and management, with support from government leadership and the wider community. First, the coal industry should propose its own ideas on development, seeking consensus in the industry with formulation of top-level scientific and technological designs that are compatible with national demand. To improve research in the economics and management of coal mines, the industry should establish several high-level research institutions in eligible companies as well as at colleges and universities. Second, coal companies need better resource planning during both the opening and closing of a coal mine. To ensure the long-term sustainable use of coal requires consultation with the local community to gain their support. Improved government planning and coordination are also necessary to efficiently produce coal throughout China. The ongoing consumption of coal provides challenges in development of methods to improve mining, transport, and utilization of coal in a sustainable manner. Support to better understand the coal life cycle will allow China to better manage its coal resources.

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North Dakota is part of the interior of the United States. Sometimes called the Peace Garden State because it shares a peaceful border with the Canadian province of Saskatchewan, the state is known for its sparse population and its abundant resources—productive farms and energy sources that help feed and power a vast region. However, its most important resource is the perseverance and ingenuity of its 750,000 residents.

North Dakota’s history is filled with examples of how its citizens rallied together to make decisions for the betterment of its farms and cities. A couple of examples are the state-owned Bank of North Dakota, which lends money to farmers who are just getting started or are expanding their operations. Another example is the state-owned North Dakota Mill and Elevator that added value to the state’s grain crops without transporting the wheat out of state to the Minneapolis-based flour mills. Both have been huge successes and annually return millions of dollars to the state’s general fund.

A similar success story took place in June 1990 when the voters in North Dakota passed a constitutional measure to increase revenues for a North Dakota Lignite Research and Development (R&D) program with a 10-cent tax on every ton of lignite mined.

The R&D program was advanced by the Lignite Energy Council, a regional trade association representing the power plants and lignite mines in North Dakota. The Council was established in 1974 and has provided a single voice, regionally and nationally, for the industry on most issues in North Dakota.

“...the Allam Cycle, is projected to match or lower the current cost of electricity from natural gas combined cycle plants, while also inherently capturing all CO₂ and other air emissions.”

The lignite industry is one of North Dakota’s five largest industries and is generally regarded as its most stable. Since 1988, the industry has produced about 28 to 32 million tons of lignite annually. The industry provides some of the best paying jobs in the state with coal miners and power plant operators earning about twice the state’s average income. The industry also provides the state with about $200 million in tax revenue every biennium.

John Dwyer, then president of the Lignite Energy Council, wrote: “Through technological development efforts, these (lignite) resources also represent tremendous potential for future economic growth. Not only can research and development programs discover new and better uses for lignite, but they can also find cleaner, more efficient methods of using lignite in today’s markets.”

These words seem even more prophetic today, given the challenges the industry faces following the August 2015 release of the Clean Power Plan (CPP), the CO₂ emissions limit the U.S. Environmental Protection Administration (EPA) is attempting to impose. Although the CPP is currently under a stay order by the U.S. Supreme Court, the rule is a harbinger that CO₂ will be regulated in the future.

NORTH DAKOTA’S LEADERSHIP

As the U.S. and the world seek to reduce anthropogenic CO₂ emissions while assuring adequate supplies of the affordable...
and reliable electricity needed to ensure strong economies, the state of North Dakota stands uniquely situated to be a leader in finding technical solutions for low-rank coals such as lignite.

North Dakota’s distinctive characteristics include:

- A state–industry funded R&D partnership with a 30-year track record of success. These funds are distributed based on evaluations and recommendations through the Lignite Research Council, a governor-appointed advisory council made up of representatives of key stakeholders in the lignite industry;
- Home to the Energy & Environmental Research Center (EERC), known internationally as a top lignite R&D organization;
- Existing CO\(_2\) infrastructure including a pipeline and compressor facilities from the coal fields through the oil fields of western North Dakota. The lignite industry has been providing CO\(_2\) for enhanced oil recovery (EOR) since 2000.
- The state’s enormous lignite resources. Only Australia has a larger known lignite reserve. At current production levels, North Dakota reserves would last more than 800 years.
- A history of outstanding lignite mine reclamation and meeting all federal ambient air quality standards.
- An energy-rich, business-friendly state that promotes all sources of energy including coal, oil, natural gas, hydro power, wind, ethanol, and other renewables.

Since its beginning in 1987, the North Dakota Lignite R&D Program has provided $63.5 million in state funds for more than 200 lignite R&D projects. The total investment to date for all projects is more than $650 million. So for every state dollar invested, more than nine dollars comes from other sources,—including industry, research entities, and the United States Department of Energy, demonstrating the truly collaborative nature of the research.

The North Dakota Lignite R&D program has three primary goals:

1. Preserve the state’s existing lignite resources by concentrating on ways to increase efficiency and lower emissions.
2. Expand the industry by looking at both traditional and novel uses of lignite and coal-combustion by-products, such as using fly ash as a substitute for Portland cement or converting lignite into activated char.
3. Invest in marketing efforts that help expand the sales of lignite products, while also informing the public about the industry through active public affairs and public education programs.

**BUILDING ON DECADES OF SUCCESS**

North Dakota’s R&D program has yielded dramatic results over the years. The North Dakota lignite industry was a leader in identifying technologies to reduce mercury emissions from lignite-based power plants in the 2002–2005 timeframe. Over $27 million was invested in R&D activities that led to a reduction in the cost of retrofitting existing plants to comply with the EPA’s new mercury regulations.

Pilot projects originally funded through the North Dakota Lignite R&D program have also grown into major research projects that have been subsequently supported by the U.S. Department of Energy (DOE) and partnering utilities. An example is a $161,000 coal-drying study at the Coal Creek Station that resulted in a $13.5 million cooperative agreement from the DOE. Eventually, Great River Energy invested $182 million to retrofit the Coal Creek Station with coal dryers that lowered emissions and increased efficiency.

**FOCUSING ON NOVEL TECHNOLOGIES**

The Lignite Research Council has also been actively searching for a technology that would be used in near-zero CO\(_2\) power plants for more than a decade.

As part of the search, several North Dakota lignite industry representatives attended a project review briefing at the Power System Development Facility (PSDF) in Wilsonville, Alabama, in 2004. The PSDF is a DOE-sponsored advanced integrated gasification combined-cycle (IGCC) test facility operated by Southern Company Services.

The lignite industry engineers were given a briefing on the performance of moderate and high-sodium lignite from the Coteau Properties Company’s Freedom Mine, near Beulah, North Dakota, using an advanced pilot-scale transport gasifier. A previous test in May 2003 evaluated the performance of lignite from the Falkirk Mine in an air- and oxygen-blown operational mode. The transport gasifier, when incorporated into an IGCC configuration with a combustion turbine, provided high efficiencies and very low emissions and operated particularly smoothly with North Dakota lignite.

The technology is now employed by Southern Company at its Kemper County Project in Mississippi. Despite many challenges with cost and schedule, the new plant is expected to begin operations later this year. The facility will use a Gulf Coast lignite as its fuel source.

In the exploration for new technologies, North Dakota lignite interests began researching a first-of-its-kind natural gas power generation technology being built in Texas.
In October 2014, NET Power, LLC, the developer of the new technology, announced the funding sources for a first-of-its-kind natural gas power plant. The 50-MW demonstration plant would validate the world’s first natural gas power generation system that produces no air emissions and includes full CO₂ capture without requiring expensive, efficiency-reducing carbon capture equipment. This is accomplished because the natural gas is combusted in oxygen and recycled CO₂. The combustion occurs at supercritical CO₂ conditions, meaning the CO₂ behaves like a liquid and is nearly pure after combustion.

The $140 million project, which broke ground in March 2016, includes ongoing process engineering, plant engineering, procurement and construction, a full testing and operations program, and commercial product development. Commissioning is expected to begin in late 2016 and be completed in 2017.

This novel supercritical CO₂ power cycle, known as the Allam Cycle, is projected to match or lower the current cost of electricity from natural gas combined-cycle plants, while inherently capturing all CO₂ and other air emissions. The cycle produces CO₂ as a pipeline-quality by-product, as opposed to conventional power plants, where CO₂ is produced as an exhaust-gas mixed with other gases and emitted through a stack.

North Dakota energy companies are interested in this technology because the Allam Cycle can work with North Dakota lignite if it is gasified on the front end of the plant.

A preliminary technical and economic study indicates that the owners of power plants using this technology could derive two revenue streams: one stream from the power generation and the other from the sale of CO₂, which is valuable to enhance the oil production from partially depleted oil-bearing formations. This combination means that electricity produced from a new Allam Cycle plant could be competitive with electricity produced from conventional coal-based power plants.

North Dakota is an ideal place to build a lignite-based power plant using the Allam Cycle for several reasons:

1. The state has a history of successfully gasifying Fort Union lignite on a commercial basis that dates back to the opening of the Great Plains Synfuels Plant near Beulah, North Dakota, in 1984. A 205-mile pipeline to transport carbon dioxide from the Synfuels Plant to the oil fields near Weyburn, Saskatchewan, was completed in 2000. To date, more than 32 million tons of CO₂ have been stored in the partially depleted oil fields and used for EOR. The pipeline runs through western North Dakota oil fields and has six taps that can be used for additional domestic EOR.
2. The EERC in Grand Forks, North Dakota, has undertaken two separate studies examining how North Dakota lignite can be gasified and integrated into the Allam Cycle design. The Lignite Research Council with the EERC has twice funded studies, which are known as Phase I and Phase 2 of the Pathway to Low-Carbon Lignite Utilization.
3. North Dakota’s electric demand is expected to grow along with the oil fields in North Dakota. Projections for electricity demand growth are estimated to be between 2.5 and 5 GW. This demand is for stable baseload generation, the kind typically furnished by lignite-based power plants. The CO₂ produced by Allam Cycle generation can also be marketed to oil companies in the nearby Williston Basin.

**PART OF THE SOLUTION**

The Lignite Research Council is committed to finding a CO₂ solution for our industry and supporting a development pathway for the Allam Cycle—or other low-carbon emission footprint technologies—benefiting both the North Dakota lignite industry and the oil and gas industry. The Allam Cycle is one example of the many technologies holding much promise economically and environmentally. The Lignite Energy Council will support this research and other projects that continue to carve out a role for North Dakota’s vital lignite industry.

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Lignite, a low-grade fossil fuel in geological transition from peat to hard coal, is a mainstay of power generation and heating services between Central Europe and the Mediterranean Sea. Germany is the world’s largest lignite producer with an annual output of 178 million metric tons (Mt) in 2015, covering nearly a quarter of electricity demand. Although mining declined significantly after 1990 in the former East Germany and Czechoslovakia, most other countries have increased usage. Foremost is Turkey, with lignite power generation expected to increase by over 80% within three years.

BROAD LIGNITE AVAILABILITY

Lignite deposits between Germany and southeastern Europe constitute 45% of the EU’s domestic energy reserves. Mined lignite exhibits an energy content (heating value) considerably below that of wood pellets (17 MJ/kg) due to high water permeation and non-combustible ash and sulfur. The shallow deposits nevertheless permit surface extraction at a lower final energy cost than imported gas and coal.

At highly efficient power stations connected by conveyor belt to adjacent mines, Germany has achieved fuel expenses below 15 € per MWh of electricity. Even when transported to distant plants by rail, lignite provides lower and more predictable pricing than natural gas.

Lignite grid power costs vary significantly in the EU and Turkey due to differences in mining operations and thermal quality. The particularly low energy content of local deposits in Greece (3.8–9.6 MJ/kg at EURACOAL country profiles) makes lignite-fired electricity generation the most expensive at 59.9 €/MWh. Romania achieves 54.2 €/MWh, followed by 53.6 in Germany, 52.7 in Turkey, 40.3 in Serbia, 39.0 in the Czech Republic, 38.6 in Poland, and 31.6 in Bulgaria.

HISTORICAL GERMAN DOMINANCE

Before 1990, East Germany (the German Democratic Republic) was the world’s largest lignite producer with over 300 Mt per year (18 t per capita) mined in Lusatia (near the Polish border) and in Central Germany. About 50 Mt/a of low-moisture briquettes were pressed from crude lignite for domestic and industrial heating.
a combined 51.1 Mt, compared with 31.7 Mt at the end of the 1970s. Both Greece (48 Mt) and Poland (63.9 Mt) doubled annual tonnage, while lignite usage in Turkey more than quadrupled to 61.5 Mt in the same period.

Lignite reliance is increased by auxiliary energy services (see Figure 2). For instance, total primary energy consumption in the Czech and German economies approaches six metric tons of coal equivalent per inhabitant. However, lignite is responsible for over 30% of overall energy demand in the Czech Republic due to greater heating utilization.

As indicated in the ranking diagram of Figure 3, district heating invariably incurs a higher level of dedicated fuel usage. In the case of Poland, heating demand is only partially covered by lignite due to the threefold reliance on hard coal that satisfies 43% vs. 12.9% of total energy requirements.

**CLIMATE POLICY IMPLICATIONS**

Burning a ton of mined lignite emits about a ton of CO₂. At below 900 Mt/a, global lignite combustion equates to less than 3% of accountable CO₂ emissions that totaled 35.7 Gt in 2015. Lignite provides particular logistical and geological benefits compared with other energy sources. Locating large power

plants adjacent to mines precludes transport energy losses. Combined heat and power generation increases net fuel utilization. Unlike gas and hard coal, lignite deposits release only negligible methane effluents. Biomass combustion, on the other hand, contributes significantly to climate change with CO₂ emissions that persist in the atmosphere.

Following nuclear phase-out legislation enacted in 2011, Germany has been deviating from its 2020 greenhouse gas reduction target of 40% referred to 1990 (see Figure 4). Emissions of 908 Mt in 2015 would need to be reduced by another 159 Mt to meet this obligation, roughly equivalent to all lignite emissions in the electricity sector.

The Central German lignite miner MIBRAG (Mitteldeutsche Braunkohlengesellschaft mbH) estimates that switching to gas generation under the EU Emissions Trading Scheme (ETS) would entail a 10-fold price increase, resulting in a doubling of electricity rates.® In contrast with imported fuels, domestic lignite enables calculated costs to be maintained while providing the revenue streams required for post-mining landscape reclamation.

**RELATIVE LIGNITE USAGE**

There are several countries in the eastern Mediterranean region that consume over four tons of lignite per capita annually.
The lower heating value of southern European lignite requires greater quantities of lignite to be burned. The Czech Republic, however, uses the most lignite energy per inhabitant. Tonnage is comparable to that of Balkan countries, but heating values are in the range of 10.9–18.2 MJ/kg under current contracts. Prehistoric volcanic activity has resulted in both high carbon density and the imbued sulfur formerly responsible for forest mortality (Waldsterben) in the absence of SO₂ emission filters. Central German deposits north of the intervening Ore Mountains exhibit similar geological characteristics.

GERMAN LIGNITE SUSTAINS NUCLEAR PHASE-OUT

Lignite with thermal grades between 7.8 and 11.3 MJ/kg is used in Germany to generate nearly a quarter of the country’s electricity (155 TWh/a in 2015). Together with heating services, lignite covers 12% of overall energy demand. Renewable power provides the same amount of primary energy. However, it is dedicated chiefly to supplanting Germany’s remaining eight nuclear reactors that are being phased out by 2022 in compliance with the 2013 federal coalition agreement.

Nuclear generation accounts for 7% of primary energy and 14% of grid electricity. Renewable power exceeding 30% (196 TWh) must attain a commensurately higher post-nuclear level before lignite generation could be appreciably diminished. Due to ongoing delays in transmission line construction from offshore wind farms, that objective is unlikely to be achieved for another decade.

Licensed lignite reserves in the lower Rhine valley (currently 95 Mt/a) were recently reduced by 400 Mt in the RWE Garzweiler II mine, but without revising the final 2045 production date. A proposed power plant in Central Germany, a flexible 660-MW two-turbine design, was canceled by MIBRAG in April 2014.

The corporation’s Czech owner, Energetický a Prumyslový Holding (EPH), together with PPF Investments has instead bought all four Vattenfall lignite mines and three power stations in Lusatia plus one Central German 934-MW block at Lippendorf. The combined capacity of approximately 8.1 GW includes the 2575-MW Boxberg site with a variable-fired 310–675-MW generator dedicated in 2012.

Two nearby Lusatian 500-MW units (of six blocks total) at Jänschwalde are being relegated to reserve status in 2018–2019 under a federal subsidy agreement. The MIBRAG 392-MW Buschhaus plant in Lower Saxony and five other RWE blocks in the Rhineland are also included in the staged retirement program, comprising 2.7 GW of overall capacity, which is intended to avoid 12.5 Mt CO₂ annually.

The recent reorganization of RWE and EPH will enable the German lignite industry to maintain high grid dependability standards as nuclear power is superseded by renewable energies.

MINING EXPANSION IN POLAND

Domestic lignite and hard coal currently meet 56% of energy demand in Poland and account for nearly 90% of electrical power generation. Although particular coal operations are being terminated, lignite deposits extending below the Neisse River from Germany will enable new plant capacities to be added. A 100-km² surface mining site is undergoing preliminary licensing at Gubin-Brody to produce 17 Mt of lignite annually over 49 years from seams 140 m deep. PGE Polska Grupa Energetyczna intends to erect three 830-MW generation blocks for operation beginning in 2030.

In southwest Poland at Turów, PGE began construction of a 450-MW lignite plant in May 2015 to complement the existing six 250-MW turbines at this location. The close proximity of Germany and the Czech Republic could promote the international development of reduced-emissions lignite technologies.

Europe’s largest lignite power station at Bełchatów with 5354-MW generation capacity has been modernized for extended operation. All major lignite sites are prepared for CCS retrofits if warranted by EU decarbonization strategies, with CO₂ storage proposed under the Baltic Sea.

MINING LIMITS LIFTED IN THE CZECH REPUBLIC

Since the 1990s, the Czech semi-state energy corporation ČEZ has upgraded its power plant fleet, beginning with the desulfurization of 6462 MW of installed lignite capacity. The Tušimice II (4 × 200 MW) and Pruněrov II (5 × 210 MW) power stations have been completely refurbished for generation until at least 2040.
Restrictions imposed in 1991 by Parliamentary Resolution 444 for Northern Bohemian lignite mining have been successively lifted.

Mining operations are being prolonged from 2036 to 2049 at Bílina to supply an additional 100 Mt of lignite to the newly constructed Ledvice 660-MW plant. The single-generator design expands the existing 330 MW of electrical capacity, providing heat to 300 commercial customers and 20,000 private households.

During 2014–2015, over 1 Mt/a of Central German lignite was shipped by rail from MIBRAG mines to the Opatovice and Most-Komňany power plants, which are likewise owned by EPH. While these imports have since been discontinued, briquettes manufactured by MIBRAG with low-sulfur RWE lignite continue to be delivered to the Czech domestic heating market.

Ongoing lignite dependency is sustained by district heating services. Nuclear generation capacities may be expanded in future decades at Dukovany and Temelin.

**BULGARIA: LIGNITE ECONOMIC STABILITY**

Over 95% of Bulgarian lignite is mined in the Maritsa East (Iztoń) Basin. The 240-square-mile expanse is the largest mining site in southeastern Europe, making its operator, Mini Maritsa–Iztoń EAD, the most important employer in Bulgaria. The local lignite exhibits a 16–45% proportion of ash with heating values ranging from 6.5 MJ/kg for steam grades to 7.3 MJ/kg for briquette manufacturing. The 1.95–2.4% sulfur content is higher than in northern European deposits.

In addition to two successively modernized power stations with 2365 MW, the AES Bulgaria 600-MW Galabovo plant completed in 2011 constitutes about 5% of the country’s installed power capacity. The € 1.3 billion installation uses approximately a quarter (5 Mt/a) of the lignite mined at this location.

**ROMANIAN ENERGY DIVERSITY**

Romanian lignite with 7.2–8.2 MJ/kg has a comparatively low moisture content of 41–43%. Lignite accounts for nearly one-fourth of primary energy consumption and about half of electricity generation, with demand at around 30 Mt/a. However, oil, gas, and coal contribute to broad domestic supply diversity. Romania also has the highest installed wind power capacity in southeastern Europe with over 3.1 GW.

**SECONDARY LIGNITE ROLE IN HUNGARY**

The Visonta and Bükkabrány surface mines operated by Mátrai Erőmű ZRT northeast of Budapest provide about 90% of Hungarian lignite. The overburden-to-lignite ratio of 9:1 indicates high expenditures for earth-moving. Lignite is used to supplement the country’s natural gas resources. The Mátra Visonta power station comprises five lignite-fired boilers with 876-MW total generation along with two gas turbines of 2 × 30 MW. Biomass is also co-fired up to 10%. Lignite in combination with non-fossil generation therefore serves to cushion the power market against price volatility.

**GREECE AND THE FORMER YUGOSLAVIA**

Lignite significantly contributes to domestic energy security in Greece and the former Yugoslav states (see Figure 6). Mining has been terminated in Croatia, but the remaining Balkan countries are using their lignite resources. The thermal qualities available in Slovenia (11.3 MJ/kg) and Serbia (7.8–8.2 MJ/kg) are comparable with northern European grades. Lignite provides half of Serbia’s total primary energy (see Figure 7).

New power plants in the region are dependent on external financing, such as the 660-MW Ptolemaida V expansion in Greece co-funded by the KfW German Development Bank. Although the underlying decisions have been criticized by environmental organizations such as the WWF, economic stabilization takes priority over climate policies. Plant expansions await approval at Kolubaru (2 × 375 MW) in Serbia and near Přistina (2 × 300 MW) in Kosovo, where Europe’s fourth-largest lignite resources (after
Poland, Germany, and Serbia) are located. Future generation may be developed with greater reliance on renewable energies.

**LIGNITE EXPANSION PLANS IN TURKEY**

In 2015, Turkey met 12% of overall electricity demand with lignite plant capacity of 8.1 GW. According to research by the Institute for Energy Economics and Financial Analysis, the most recent energy legislation will raise lignite power generation from 31.2 TWh in 2015 to 57 TWh by 2018. Newly constructed plants would receive guaranteed revenues of 8 cents per kWh, necessitating a 3.5 cent subsidy at current power trading prices.

Tentative Chinese financing of US$ 10–12 billion was announced in 2014 to expand the existing 2795-MW AfSin-Elbistan generation site to 8 GW. Overall, more than 80 coal and lignite plants have been variously listed in planning and construction.

Despite the carbon footprint inherent to increased fossil fuel usage, Turkey’s Intended Nationally Determined Contribution (INDC) statement, submitted on 30 September 2015 for climate negotiations in Paris, has established that greenhouse gas emissions could be reduced by up to 21% below business as usual (BAU) in 2030 by including land use, land use change, and forestry (LULUCF). Comprehensive mitigation plans are intended to abate up to 255 MtCO₂eq by that time over BAU.

**DURABLE PROSPECTS FOR LIGNITE USAGE**

Lignite remains a reliably calculable domestic energy resource in most countries between Germany and Turkey. Heating services in combination with power generation provide highest fuel utilization. The retirement of aging power plants additionally contributes to fulfilling CO₂ reduction obligations.

The increasing deployment of renewable power technologies challenges the competitive advantage of conventional fuels in electricity generation. Established district heating networks, however, depend widely on low-cost lignite extracted as needed from surface mines. There are no comparable biomass resources in Europe.

Significantly, Turkey is expanding lignite utilization despite having twice the solar irradiation of Germany, where 16% of worldwide photovoltaic capacity is currently installed. Since renewable energy deployment entails particularly high technology outlays, adequate infrastructure prerequisites have yet to be established in the Mediterranean region.

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Turkey opened its energy industry to the private sector as part of an overall shift toward a market economy in 2001, and, in that context, liberalization and restructuring studies in the energy sector were initiated. Prior to 2001, several models including BOT (Build-Operate-Transfer), BOO (Build-Own-Operate) and TOOR (Transfer of Operating Rights) were implemented to increase private-sector participation in the power sector. Since 2001 under the Electricity Market Law state-owned companies are allowed to finish ongoing construction of power plants and can continue to intervene and build additional new power generation plants if there is a threat to security of supply. As a result of the new law, the private sector has commissioned significant new generation capacity. In particular, new renewables-based generation has been built with support provided by the Renewables Law enacted in 2005. Figure 1 shows the different new generation capacity built since 2002.

As shown in Figure 1, during 2002–2015, 41.3 GW of new capacity were commissioned, mostly built by the private sector. Turkey has become increasingly reliant on private-sector power generation investments. In 2002, electricity generation by the private sector made up 40% of Turkey’s total, compared to 79% by the end of 2015.

The compound annual growth rate (CAGR) of installed capacity during the same period was 6.6%, and was 5.5% for electricity demand. Due to this difference, low wholesale prices, and increased renewable energy capacity in recent years, some domestic coal-fired and natural gas-fired power plants are unable to sell their electricity into the market.

“To improve energy security, the Ministry of Energy and Natural Resources (MENR) has set a goal to increase the utilization of domestic coal in the energy sector.”

During the 2002–2015 period, 8.6 GW of coal-fired power plants were commissioned with nearly 6 GW of that using imported coal. Coal’s share in the generation mix increased from 24.8% to 29.1%, whereas the share of domestic coal dramatically decreased from 23.7% to 13.8% in the same period (see Figure 2). To improve energy supply security, the Ministry of Energy and Natural Resources (MENR) has set a goal to increase the utilization of domestic coal in the energy sector.

In 2014 Turkey’s net energy imports were approximately 75% of total primary energy needs. Primary energy production in 2014 was 31 million tonnes of oil equivalent (Mtoe), compared to 24 Mtoe in 2002. Since 2002, there has been a 28% increase with the share of domestic primary energy production...
decreasing from 31.6% to 25.1%. In contrast, over the same period the share of domestic coal (lignite, domestic hard coal, and asphaltite) in primary energy production increased from 46.9% to 52.7%.²

“…MENR believes that import dependency can be decreased by increasing the share of domestic coal and renewables.”

COAL UTILIZATION

Figure 3 depicts the increase in lignite production since 1973; however, it is still low compared to the level of reserves in Turkey (see Table 1). Due to the development and utilization of natural gas in the late 1990s, lignite production decreased

Since 1973 hard coal production in Turkey has been decreasing (see Figure 4). In 2004, after the allowance of the private sector in hard coal fields by the TTK, hard coal production trended upward, but subsequently began decreasing again and was only 1.4 million tonnes in 2015.² Hard coal imports, however, have been increasing steadily since 1980 and exceeded 33 million tonnes in 2015, with an increasing number of coal-fired power plants relying on imported coal. Figure 5 indicates the breakdown of hard coal imports by country.³

With regard to the electricity sector, as of June 2016 the total capacity of coal-fired power plants in operation is 16.6 GW, 9.8 GW of which is domestic coal-fired (see Table 2).³

FIGURE 2. Coal’s share in Turkey’s electricity generation¹

FIGURE 4. Hard coal production and imports² until 2004; since then private-sector involvement has resulted in an increase.

FIGURE 3. Lignite production in Turkey²

FIGURE 5. Hard coal imports in 2015 by country³
According to the January 2016 “Progress Report” of the Energy Market Regulatory Authority (EMRA), 13 coal-fired power plants are under construction with a total capacity of 8.2 GW, of which 2.1 GW will be domestic coal-fired.

INCENTIVES

Coal, especially domestic coal, has a great importance for MENR and the Turkish government. Although Turkey is not rich in oil and natural gas reserves, MENR believes that import dependency can be decreased by increasing the share of domestic coal and renewables. In several official documents, the government has set targets for increasing the utilization of coal.

For example, Turkey’s High Planning Council (headed by the Prime Minister) endorsed the “Electricity Market and Security of Supply Strategy Paper” in May 2009. Electricity generation and capacity targets were set by sources, to 2023. Regarding coal and hydro, the document calls for all known lignite, hard coal, and hydro resources to be utilized for electricity generation by 2023. For wind and geothermal capacity, the targets were set as 20 GW and 0.6 GW, respectively. Additionally, the document sets target shares of 30% for renewables and for gas and at least 5% for nuclear in electricity generation.

The government’s Tenth Development Plan (2014–2018) sets a target of 60 billion kWh of electricity generation from domestic coal by 2018, compared to the 39 billion kWh generated in 2012. Moreover, the plan has 25 Priority Transformation Programs targeting several sectors. One is the Domestic Resource Based Energy Production Program (1.13), which includes the following elements:

- Developing and implementing a special financing method to utilize coal reserves in large coal basins, such as Afşin-Elbistan and Konya-Karapinar
- Transferring the major fields to private sector
- Identifying new coal reserves by accelerating exploration activities
- Focusing on R&D activities that increase the quality of domestic coals or increase their calorific values
- Monitoring and, if needed, updating incentive programs regarding investments in domestic coal-fired power plants
- Rehabilitating lignite-fired thermal power plants owned by the state

MENR’s Strategic Plan (2015–2019) sets similar targets for the utilization of domestic coal.

<table>
<thead>
<tr>
<th>TABLE 1. Coal reserves* in Turkey (billion tonnes)</th>
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<tr>
<td>Lignite</td>
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<tr>
<td>Hard Coal</td>
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<td>TOTAL</td>
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*No official data are available about coal reserves belonging to the private sector.

<table>
<thead>
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<th>TABLE 2. Coal-fired capacity (GW)</th>
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<td>Table 2. Coal-fired capacity (GW)</td>
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<tr>
<td>Domestic Lignite</td>
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<tr>
<td>Hard Coal</td>
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<tr>
<td>Asphalitite</td>
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<tr>
<td>Imported Coal</td>
</tr>
<tr>
<td>TOTAL</td>
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</table>
INVESTMENT INCENTIVE PROGRAM

Since 2012, the Investment Incentive Program has been active in Turkey. Designed to achieve Turkey’s 2023 vision as well as to advance the production and export-oriented growth strategy, the program supports investments through four different incentive schemes: general, regional, large-scale, and strategic.

Coal exploration, coal production, and domestic coal-fired power plant investments are eligible to apply in the general and regional investment incentive schemes, and are recognized as priority investments. Regardless of the province of the investment, such investments are supported with the 5th Region incentives, under the regional investment incentive scheme.

INCENTIVES UNDER THE RECENTLY PASSED LEGISLATION

The Turkish government introduced a new law in June 2016 to encourage the utilization of domestic coal. A new financial model aims to decrease the bureaucratic processes and speed up investments in the energy sector.

The first step in the new model is to establish related companies for each large-scale coal area belonging to EUAS or TKI. The first company established was Çayırhan Energy and Mining Corporation (ÇEMPAS Co.), which is part of EUAS. The Çayırhan region has ~250 million tonnes of lignite reserves suitable for a ~800-MW capacity power plant.

All the necessary expropriation, Environmental Impact Assessment, zoning approval, and other required procedures will be undertaken by ÇEMPAS Co. A power purchase agreement (PPA) has been signed between ÇEMPAS Co. and EUAS for 15 years. ÇEMPAS Co. will then be privatized by a tender by the end of 2016. The bidding will start from US$72/MWh, the bidder with the lowest price in US$/MWh will win the tender. The tender is expected to identify a suitable bidder that will develop the mine, build the coal-fired power station, and operate it.

"The Turkish government introduced a new law in June 2016 to encourage the utilization of domestic coal."

The new legislation also aims to further incentivize use of domestic coal. Turkish Electricity Wholesale and Contracting Co. (TETAS), a state-owned enterprise, has long-term PPA contracts with BOT, BOO, and TOOR types of power plants. Moreover, TETAS purchases all the electricity produced by EUAS and sells it to distribution companies, which in turn sell it to end users. If TETAS needs additional electricity to meet its obligations, it can purchase electricity from domestic coal-fired power plants by tender. The Council of Ministers (CoM) decided that TETAS may purchase up to 6 billion kWh of electricity by tender in 2016 and 18 billion kWh of electricity in 2017 with the price of 185 TL/MWh (~US$60/MWh). Under this decision, TETAS announced a tender in August, and has started purchasing electricity from domestic coal-fired power plants.

The share of coal-fired power plants using imported coal has been increasing steadily compared to those using domestic coal. This can be attributed to several reasons, such as lower cost and higher calorific value. In August 2016 the CoM decided to slow down imported coal-fired power plant investments by setting a purchase limit of US$70 per ton of imported coal used for power generation. If an investor purchases imported coal less than a price of US$70/ton, they must pay the difference to the Ministry of Economy as a tax. However, if they purchase the coal for over US$70/ton then no tax is applicable.

CHALLENGES TO INVESTMENTS

The Turkish government aims to increase the share of domestic coal in the electricity mix. According to MENR’s unofficial target, the envisaged electricity generation mix will be 30% renewables, 30% coal (half will be domestic coal), 30% natural gas, and 10% nuclear. Although the government has taken several significant steps, it will not be easy to achieve its targets, especially for coal, due to both national and international developments.
For example, the State Council requested an overall Environmental Impact Assessment for imported coal-fired power plants located in the eastern Mediterranean region of Turkey. The rationale was that these plants are located in close proximity and the government wanted to better understand the possible environmental effects and impacts of the power plants to the region.

In addition, after COP21 and the resulting Paris Agreement, business as usual for fossil fuel-based power plants, including those in Turkey, is unlikely. Turkey signed the Paris Agreement in April 2016. According to its Intended Nationally Determined Contribution (INDC), 70.2% of the total emissions expressed in CO₂ equivalent (CO₂e) are generated by the energy sector. The INDC is aiming for a 21% reduction in greenhouse gas (GHG) emissions from a business-as-usual scenario by 2030 (from 1.175 million tonnes to 929 million tonnes of CO₂e). Achieving that target will require 10 GW solar and 16 GW wind capacity, utilizing all hydro potential (around 36 GW), and commissioning a nuclear power plant (4.8 GW) by 2030. The separate goal of increasing the share of domestic coal will make the INDC target even more difficult to achieve and will require renewable investments to be implemented without delay.

Since 2013 the OECD export credit committees have been reviewing export credit rules for coal-fired power plants. As a result, a program was introduced in November 2015 with new rules for official support of coal-fired power plants, including restrictions on official export credits for the least efficient coal-fired power plants.

There are many challenges to coal-fired power plant investment in Turkey. The government’s current policy seeks to provide a stable investment environment to increase domestic coal production and utilization, thus securing the country’s supply of energy. In the medium term, the share of coal is expected to reach 30%, which is currently around 20% in terms of installed capacity. In this way, the system will be reinforced and baseload needs will be fulfilled, providing the delivery of both sufficient and good-quality electricity to consumers.

"The government's current policy seeks to provide a stable investment environment to increase domestic coal production and utilization..."

NOTES

A. All the comments and the opinions in this article are the author’s and do not reflect the official opinion of the Republic of Turkey Ministry of Energy and Natural Resources.

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Present State of and Prospects for Hard Coal in Poland

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The modern economy and the development of civilization are closely related to energy consumption. Fossil fuels (hard coal, lignite, oil, and natural gas) account globally for about 80% of the demand for primary energy sources. The dynamics of changes in the structure of the global fuel and energy balance in the past, present, and foreseeable future indicates continuing dependence on fossil fuels as a primary energy source. The share of coal in primary energy supply of the world has increased in recent years, influenced primarily by increased consumption in China, reaching its highest level since 1971: 29% in 2013 and 2014. Despite these facts, its role as a fuel of the future is often questioned. This is mainly due to climate change and emissions generated from the use of coal.

In Europe, the trend is toward closing coal mines and switching to alternative energy sources. Only a few member-states of the European Union (EU) are still producing coal. The EU produced 99.9 million tonnes of coal in 2015, of which 72% (72.2 million tonnes) was from Poland. Other EU countries produced small quantities of coal (see Table 1).

“Coal plays a major role in Poland’s energy security, providing the secure, reliable, and affordable energy supply that is fundamental to Poland’s economic stability and ongoing development.”

A downward trend in production is occurring in most European countries. However, the volume of coal imports to the EU remains high. In 2014, the total imports of hard coal amounted to 204.9 million tonnes, decreasing to 190.6 million tonnes in 2015.

STATUS OF THE POLISH ENERGY SECTOR

In contrast to other EU countries, the Polish energy and heating sector is reliant on coal. Figure 1 depicts the energy mix in 2015. The hard coal and lignite shares in electricity generation in the energy sector totaled 53.9% and 35.2%, respectively. Meanwhile, wind power accounted for 6.6% of electricity.

<table>
<thead>
<tr>
<th>Producing Country</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poland</td>
<td>72.5</td>
<td>72.2</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>11.5</td>
<td>8.5</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>8.7</td>
<td>8.2</td>
</tr>
<tr>
<td>Germany</td>
<td>7.6</td>
<td>6.7</td>
</tr>
<tr>
<td>Spain</td>
<td>3.9</td>
<td>3.0</td>
</tr>
<tr>
<td>Romania</td>
<td>1.5</td>
<td>1.3</td>
</tr>
<tr>
<td>Total</td>
<td>105.7</td>
<td>99.9</td>
</tr>
</tbody>
</table>

FIGURE 1. Poland energy mix in 2015

TABLE 1. Hard coal production in the European Union in 2014 and 2015, million tonnes

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"Coal plays a major role in Poland’s energy security, providing the secure, reliable, and affordable energy supply that is fundamental to Poland’s economic stability and ongoing development.”
natural gas provided 2.8%, hydropower 1.5%, and the remainder came from other renewable energy sources. Electricity production from hard coal has decreased in recent years from 61.6% in 2007 to 53.9% in 2015. This decrease is a result of increased lignite usage (which is less expensive than hard coal) and the development of wind energy.

In 2014, installed capacity for power generation was 39.4 GW, of which 22.2 GW were hard coal-fired units and 9.2 GW were lignite-fired units. The total capacity installed for units based on solid fuels is 80%. There are additionally 0.9 GW of gas-fired units, 2.2 GW in hydropower plants, and 4.2 GW utilizing other renewable energy sources.

The modernization of the Polish coal fleet has resulted in improvements in efficiency. \( \text{SO}_2 \) and \( \text{NO}_x \) emissions have also been reduced with the installation of flue gas cleaning. However, older power units still operate at a lower efficiency. There are plans to decommission older plants, with 18 GW of existing coal-fired power station units to be closed by 2050. Several existing coal-fired stations have also been replaced with modern, high-performance boilers and turbines with supercritical parameters (i.e., temperature of 600/620°C and pressure of 25–30 MPa). Supercritical lignite-fired power plants are operating at Pątnów (460 MW) and Belchatów (858 MW), as is a hard coal-fired power plant at Łagisza (460 MW). Poland is also constructing new supercritical plants in Kozienice (1075 MW), Opole (2 x 900 MW), Jaworzno (910 MW), and Turów (lignite-fired, 496 MW).

COAL IN SUSTAINABLE ENERGY DEVELOPMENT

Coal plays a major role in Poland’s energy security, providing the secure, reliable, and affordable energy supply that is fundamental to Poland’s economic stability and ongoing development. Throughout the economy, coal is used for not only electricity but also heating and industrial activities. It is a key driver for multidimensional government initiatives, among which the most important are those related to: raw materials, infrastructure, and political and international affairs.

The energy policy of a country must ensure a balance between the three elements of sustainable development: energy security, energy affordability, and limiting the impact of energy on the environment. There are no simple solutions in the quest to achieve sustainable development. The interests of the private and public sectors, governments and regulators, international pressures, economic, social, and environmental factors, and the behavior of individual consumers are mutually intertwined.

Energy security and independence in meeting energy demand are important elements in creating Poland’s energy policy. Energy imports to Poland contribute only 25.8% of the energy consumed, well below the EU average of around 53%.

Poland will continue to use its large coal reserves for the foreseeable future in meeting energy demand and ensuring security of supply. The challenge lies in maintaining low energy costs while meeting sustainable development and environmental protection goals despite the high cost of producing domestic coal per tonne at US$76 compared to US$50–52 for imported coal.

HARD COAL RESOURCES IN POLAND

Poland’s hard coal resources are located in the Upper Silesian Coal Basin and the Lublin Coal Basin. The size of the resource base of hard coal changes annually as a result of exploitation and new exploration. It is also a consequence of changes in the definition of proved reserves due to fluctuating economic and operating conditions.

The documented balance resources of hard coal deposits at the end of 2015 totaled 56 billion tonnes. Steam coal represents 71.6% of the total resources base, that is, over 40 billion tonnes, while the remainder (16 billion tonnes) is coking coal.

The recoverable reserves are estimated at 1.8 billion tonnes, of which 1.3 billion tonnes are in existing coal mines possessing valid licenses for exploitation. Operating mines may extend and expand the areas with new production licenses. This would result in an additional 5.4 billion tonnes of balance resources, which translates to an additional 1.6 billion tonnes of recoverable reserves in already-developed areas.

The potential lifespan of the currently active mines, determined by dividing the volume of recoverable reserves as of the end of 2015 by the average annual coal production in 2013–2015, varies from a few years to several decades. The
potential lifespan of mines depends on the output volume and numerous other factors, including economic conditions, which can result in significant changes. However, it can be stated that the reserves of hard coal in existing coal mines will last for many years.

Documented balance resources in undeveloped deposits (58 deposits) amount to 31.2 billion tonnes. The ratio between the balance resources and recoverable reserves is around 0.17, which means 170,000 tonnes of extracted coal per one million tonnes of documented balance resources. Extrapolating this ratio to the total balance resources in undeveloped deposits means a possible 5.3 billion tonnes of coal production. However, it would be expensive to develop them. The major challenge to utilize these coal resources is finding sufficient investment.

THE STATE OF HARD COAL MINING

The end of the communist era in Poland in 1989 and the introduction of market rules were quite difficult for the country’s entire economy, and especially for the coal mining sector. Previously, the most important function for coal mining was to produce as much coal as possible regardless of costs. Under the new economic criteria and with competition, rules introduced into the Polish economy and coal mining sector made the previous model uneconomic.

However, efforts have been undertaken to restructure coal mines to work more efficiently. One of the most difficult tasks was to reduce the number of miners employed in coal mining. In 1989, 415,900 people employed in the industry produced 177.4 million tonnes of coal, whereas by 2011 the number of people employed had dropped to 114,200 and the output decreased to 75.7 million tonnes. This has resulted in some success, with a profit of more than 3 billion PLN (about US$1 billion) reported by the sector in 2011.

In 2011 steam coal prices began to trend downward. The demand for Polish coal also diminished and contributed to the deterioration of the mining industry. In 2007, the mining industry sold 86.9 million tonnes compared to 73.6 million tonnes in 2015 (i.e., 13.3 million tonnes less). Domestically, 64.6 million tonnes were sold and 9 million tonnes exported. The main customers are in the power industry sector, with 36.6 million tonnes sold, totaling almost half (49.7%) of sales. Other domestic sales include coking plants (10.7 million tonnes), heating plants (4.3 million tonnes), other industrial customers (0.4 million tonnes), and households and small recipients outside industry (12.5 million tonnes).

Due to adverse economic and market conditions, the coal mining sector has been incurring large financial losses since 2012.

THE FUTURE OF THE POLISH COAL MINING SECTOR

Coal mining in Poland is expensive due to difficult geological conditions. It costs approximately 285 PLN (US$76) to produce one tonne of coal. The World Bank forecasts that, for the next few years, the price of steam coal internationally will be around US$50–52 per tonne. Low coal prices and too much
production will challenge the economic viability of Polish mining companies. Therefore, adaptation to the changing conditions is a major task for the mining industry. The key is to maintain competitiveness, especially with the low price of imported coal.

Coal companies are undergoing restructuring. The program aims to reduce extraction costs, increase production efficiency, improve organizational measures, and identify sales opportunities. A key priority is innovation and continuous improvement and to apply more efficient management methods in how miners are employed, such as subcontracting, number of shifts per day, and the type of training and skills required.

Coal will remain a significant contributor to power generation in Poland up to at least 2050. Factors such as its low cost, ongoing investment in new coal-fired power plants, and maintaining existing and new coal mines will ensure its future. Even if Polish coal mines reduced production, the new coal-fired power stations would still operate with imported coal.

Coal mining is also a significant source of income for the state and local budgets. The mining enterprises’ obligatory payments required by Polish law have a direct impact on the net profit of mining companies. The payments are elements of the costs of coal production. These are both general taxes (the same as for any other enterprises) and special taxes connected with mining, such as royalties, environmental fees, and other special charges resulting from exploitation deposits, which are very high. One-third of the total revenues from coal sales are allocated in state and local budgets in the form of public payments. It is therefore expected that the government could support mining activity by lowering the level of those payments.

In order to allow the future use of coal in the energy sector and the wider economy, the government aims to accelerate the implementation and further development of clean coal technologies and is currently funding several research initiatives, including:

- Development of coal gasification technology for highly efficient production of fuels and electricity
- Production of hydrogen-rich gas in a process of chemical looping combustion of coal
- Coal gasification processes with CO₂ absorption

Currently no cost-effective alternative for coal-based electricity production exists in Poland. The country possesses large domestic reserves of hard coal and lignite, and other energy sources are limited. Gas might become an option in the case of the development of shale gas reserves currently undergoing exploration. Outside of this scenario, expensive imports would limit the expansion of gas power plants. The deployment of nuclear power has been delayed due to various obstacles. A recent study shows that building new nuclear power plants is not a cost-effective option before 2040, as it has higher CO₂ abatement costs than coal with CCS, wind, or hydro. Development of renewables also encounters greater
difficulties in Poland than in other European countries, as the potential for exploiting renewables is lower due to less favorable climatic and geographical conditions. It is therefore planned to continue to use coal and to build high-efficiency coal-fired power stations to reduce CO₂ emissions.

CONCLUSIONS

Coal companies face many challenges with low coal prices and an oversupply of coal. The closure of unprofitable mines, where capital expenditures are limited, is inevitable. Mining requires more prior preparation to identify production capacity in the future, even for those mines where efficient production is expected.

Investment in the development of new coal mines is being considered despite difficult geological and mining conditions in several mines. There are several projects at different stages of development, indicating that coal remains an integral part of the Polish energy mix. Those projects include:

• Kopex, a manufacturer of mining machinery and equipment, wants to build a coal mine in Przeciszów. The investment will reach 1.7 billion PLN. The mine’s lifespan is expected to be 30 years.
• The Coal Holding Sp. z o. o., part of the Australian Balama-ra Resources Limited group, is planning to invest in some mining projects in Poland, including opening a coking coal mine near Nowa Ruda.
• The PDCo Sp. z o.o., subsidiary of the Australian company Prairie Downs Metals, wants to build a mine in the Lublin Coal Basin.
• The Silesian Coal Company (Jan Kulczyk) is planning to build coal mines in Orzesze and Suszec.

The future of coal mining in Poland will strongly depend on adjusting production to meet demand. Improvements in mining production are key, as is closure of unprofitable mines.

Poland’s 20 GW of coal-fired power plants and the additional 2.8 GW under construction will create the future demand for coal. Although diversification of the energy mix is planned, including commissioning nuclear power plants, coal will continue to play the leading role in Poland’s energy mix up to 2050.

A final decision on future energy policy is urgently needed to speed the recovery process of the coal mining industry. Governmental promises to support the process should be confirmed by legal acts, which would create stable conditions for economic restructuring of the sector.

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Net-Zero Emissions: New Climate Target and New Chance for Coal

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DELIVERING PARIS: WHY IT MATTERS FOR COAL

At the Paris climate summit in December 2015, world leaders agreed to work to limit global climate change to 2°C and to try to achieve 1.5°C. To put the necessary cap on total cumulative greenhouse gas (GHG) emissions, leaders also agreed on net-zero emissions; that is, there must be “a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second half of this century”.

Net-zero emissions will require carbon capture and storage (CCS) for all fossil fuels and other technologies (e.g., biomass with CCS or direct air capture) for residual emissions from fossil fuel extraction and from other anthropogenic sources such as agriculture. This is radically different from the current position wherein CCS has been mainly identified with coal use and considered unnecessary for other fossil fuels. Coal-fired power generation with partial CCS is competing with unabated natural gas power plants—an impossible challenge economically unless gas and oil prices are very high. If, however, coal with CCS has to compete with gas with CCS then the situation is more balanced, particularly in markets such as China where the capital costs for coal power plants and coal prices are relatively low compared to natural gas.

WHERE IT ALL BEGAN: CCS AND THE DASH FOR COAL

Following earlier CCS initiatives such as the Sleipner injection project, the IEA GHG program, the Greenhouse Gas Technology conferences, the planning for CCS as part of the Gorgon LNG mega-project, and early SaskPower planning for coal CCS projects, CCS gained international prominence in the mid-2000s. Key events included the inaugural 2003 meeting of the Carbon Sequestration Leadership Forum (CSLF) in the U.S., the 2005 Gleneagles Conference in Scotland, and the launch of the Global Carbon Capture and Storage Institute (GCCSI) in 2009.

“Net-zero emissions will require carbon capture and storage (CCS) for all fossil fuels and other technologies.”

Subsequently, plans for CCS deployment expanded rapidly, driven by increasing demand and high natural gas and oil prices prior to the 2009 recession (see Figure 1) and continuing beyond 2009 because of commitments and established positions and, in the U.S., because of support for CCS in the so-called Stimulus Package (American Recovery and Reinvestment Act of 2009).

New CCS projects were expected to be placed on coal power plants, with major coal-build programs anticipated in the U.K., Europe, U.S., and Canada. Strong environmental protests were a driver for CCS on many of these proposed new coal-fired power plants. There was also an expectation that coal+CCS+EOR (enhanced oil recovery) would be competitive with natural gas with no CCS (e.g., SaskPower’s BD3 plant in Canada and the Petra Nova Project in Texas). However, the collapse of high natural gas and oil prices due to the recession resulted in a rethink of “peak oil”, and hence lower CO₂ sales prices for EOR, and also of the need for a “dash for coal”.

FIGURE 1. Historic and future North American natural gas market prices
POST-RECESSION COAL BLUES IN COUNTRIES CHAMPIONING CCS

The current CCS position follows on from the changes after the recession and also from shale gas developments in North America. Minimal numbers of new coal plants have been built in CCS-championing countries (e.g., U.S., UK, Australia, Canada, and the Netherlands) with limited prospects for future construction. Electricity demand reduction is a partial reason for this in some markets (e.g., the UK) as is the growing output from intermittent, subsidized renewable generation sources. The Waxman-Markey climate legislation in the U.S., which contained incentives for CCS, failed to pass in the Senate in 2009, meaning coal+CCS+EOR in North America cannot compete with unabated natural gas, even with government capital support (such as from the U.S. stimulus incentives).

Without countries that champion CCS deploying it at scale, neither other developed economies (e.g., Germany, Poland) nor developing economies (e.g., China, India) are under much pressure to deploy CCS, even for coal—especially when there is no economic incentive or immediate global GHG emission reduction imperative to drive it.

“ The idea of building new fossil infrastructure to be CCS ready is becoming more accepted in both developed and developing countries.”

CCS: A TECHNOLOGY FOR ALL FOSSIL FUEL USE

Alternative applications for CCS other than coal power exist and are recognized as vital in the long term by CCS-championing countries. However, there is currently no immediate GHG constraint nor public opinion driver to make CCS as imperative as it was for coal pre-recession. Globally important applications for meeting net-zero targets include:

- Energy-intensive industries: usually grouped together, but in practice a heterogeneous range of applications (in terms of technology, scale, cost, location, etc.) and are almost always exposed to global competition. Therefore, production costs cannot be raised unilaterally by a country without import controls.
- Natural gas CCS: limited new natural gas plants in many places, with construction under pressure from intermittent renewables; reluctance by some stakeholders to get CCS associated with natural gas power because it may then become effectively impossible to build; also U.S. Department of Energy (DOE) CCS funding is specifically for coal.
- Biomass and waste combustion: of interest for negative emissions, but no developed proposals to incentivize negative emissions have been made anywhere yet.
- Hydrogen: being discussed for heat in buildings, industry, and also, with interim storage, for electricity production in markets where (subsidized) zero-dispatch-cost renewables make CCS plant load factors uncertain.

THE IMMEDIATE WAY AHEAD FOR CCS

The idea that CCS should be supported in ways analogous to renewables appears to be gaining traction in some countries, such as the UK (Feed in Tariffs with a Contract for Difference for electricity14) and the U.S., but has received little attention elsewhere.

There are also some suggestions in the U.S. and UK that coal should be supported for political reasons, but coal+CCS would inevitably be more expensive than unabated gas. Coal+CCS versus natural gas+CCS would be more favorable to coal, but coal probably would still be more costly (particularly with large amounts of renewables in the system and hence uncertain load factors). The uncertainty in the timing and quantity for new nuclear power plants also makes the scope for CCS deployment and the strategic value of coal uncertain in the U.S. and UK.

CCS is therefore currently in a regrouping phase. Old plans either have almost all been completed or are defunct. New major projects and concepts for CCS are still nascent. This does not mean, however, that the CCS field should be inactive, rather the reverse. Major new projects take around a decade to develop and so work on them needs to be urgently advanced. The time available while this happens is a priceless resource that can be used to reduce costs and risks for the next tranche of major projects, as described below.

Making CCS Readiness More Widespread

The idea of building new fossil fuel infrastructure to be CCS ready is becoming more accepted in both developed and developing countries. Examples include the UK’s capture-ready guidelines used for power plant permitting15 and the Guangdong “CCS Ready Province” initiative16 in China. However, anecdotal evidence suggests that in some cases, where it is not a legal requirement, the fact that new facilities have been designed and located so as to be capture ready is deliberately not stated to avoid pressure to undertake CCS before competitors.
Establishing Proven CO₂ Transport and Storage Infrastructure Options

Storage sites need to be further de-risked for prospective storage applications, with potentially significant costs, especially for offshore storage. Measures to make new plants CCS ready require some thought to be suitable for specific infrastructure and also to adapt to changes as CCS technology develops. Defining future shared pipeline routes (or CO₂ shipping options) would benefit CCS readiness plans greatly in some places.

Fast-track Small-Scale Projects

Successful small-scale projects (including on coal) could help to raise the profile of CCS and to partially rebuild industry confidence, and also could be used (in conjuction with other activities; see below) as part of a program of cost and risk reduction for future projects. Small-scale, modular CCS units could also have direct applications in some markets, not least for flexibility to cope with intermittent renewable outputs.

Raising Commercial Readiness of Post-combustion Capture

It seems unlikely that many (any?) new technology concepts will be brought to commercial readiness by the next stage of CCS deployment since this would require major speculative, funding for a reference plant. NET Power’s Allam Cycle is a possible exception. Recent large gasification-based pre-combustion capture trial plants (e.g., the Kemper plant in Mississippi) have not gone well. Post-combustion capture (PCC) projects, SaskPower and Petra Nova, are going largely as planned. When the next large-scale CCS projects are built, PCC may be the only commercially proven choice available for coal and gas power, and quite possibly the most competitive. PCC is also the only capture technology with full-scale experience available that can be used, with design studies and pilot-scale testing (see Figure 2), to produce improved second-generation PCC technologies for the next stage of CCS deployment.

Developing CCS Policy, Regulations, Incentives, and Business Models

Ways to meet the cost of CCS need to be in place, as well as the organizations (private, possibly regulated, and/or public) with the necessary expertise and financial resources to undertake projects. National and international laws and regulations need to allow CCS. For example, the London Protocol amendments to allow cross-boundary transfer of CO₂ for sub-seabed storage are not yet ratified. CCS treatment in GHG accounting

Acceptance of CCS as a Means of Delivering Clean Electricity Targets

Low-carbon electricity from fossil-fired power plants with CCS needs to be given equal treatment with nuclear and renewables in new policies to meet the Paris Agreement objectives. An example of this is the recent “Three Amigos” initiative by the U.S., Canada, and Mexico that includes producing 50% of electricity from clean sources. The calculation for the fraction of CCS plant output counted as zero carbon output needs to be rigorous environmentally, but it is essential that it is based on actual plant performance to encourage innovation in plant design and operation and to take advantage of the inherent flexibility of CCS for reducing costs.

CCS Uses in Energy-Intensive Industries

The cement, iron and steel, and chemicals industries are all major users of coal and other fossil fuels and are large GHG emitters in many countries. Effective utilization of the time between now and the beginning of the more widespread, commercially driven deployment of large-scale CCS facilities can be based on fast-tracked small-scale work as well as larger industrial projects where CO₂ storage or EOR markets are
already available (e.g., the Decatur Project, Shell Canada’s Quest Project, Air Products’ Port Arthur project).

**CCS TRAINING AND OPPORTUNITIES FOR WORK IN THE CCS INDUSTRY**

One important challenge in establishing and rolling out CCS as a global option for reducing CO₂ emissions is ensuring sufficient numbers of trained people are available at all stages of the project life cycle. Particularly for early projects, it is likely that most contributors to project design and delivery (and supporting policy and regulation) will be applying skills normally used for other applications.

A range of initiatives are underway to develop and support a cohort of CCS professionals. For example, most universities with CCS research interests include course material on CCS in their undergraduate and MSc programs. Several MSc programs are dedicated to CCS and PhD-level programs with significant CCS content are also available. Some graduates from such programs are developing careers in CCS R&D and consultancy, while others are using the skills developed during their studies in other energy-related roles.

It is important to ensure that individuals who are early in their career are able to gain as much practical experience as possible and also to learn from more experienced practitioners who may retire before widespread deployment of CCS. In this context, “learning by doing” at pilot-scale facilities (see Figure 3) and through targeted international collaboration is particularly important in the next decade as part of a broader effort to ensure that necessary expertise is grown to facilitate effective global rollout of CCS in the longer term.

“Several efforts are underway to develop and support a cohort of CCS professionals.”

CCS projects are operating in many countries, but prospective workers and researchers should look at a variety of scales and different fuels and applications. The range of disciplines required is growing, with specialists in areas other than CCS.
becoming more important as technologies are deployed at pilot scale or larger in “real” applications, and a range of new issues are discovered and addressed. Strong cooperation between industry and researchers is also needed for cost reduction. It may appear that there are not many job opportunities now, but CCS worker numbers will have to grow rapidly if net-zero emissions are to be achieved. With exponential growth in CCS deployment during the next two or three decades, experienced workers in all aspects of CCS development, design, and construction will be in short supply. Once a significant number of CCS installations are in place a large workforce of operators will be required. Experience with power plants and other long-lived major infrastructure investments also suggests that in-service modifications, improvements, and maintenance will be a continuous and major business.

The drive to achieve net-zero emissions from all fossil fuel use within perhaps 50 years or less will be a challenging but vital job for the current generation, and many future generations, of CCS workers and researchers.

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The Role of Fracking in the U.S. Utility: Battle of Gas vs. Coal

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For decades, coal was the dominant fuel for electric power generation in the U.S. Although advances in natural gas generation technology allowed natural gas to become increasingly competitive with coal and other generation options, regulatory constraints and market influences drove coal to remain the overwhelming source for baseload power throughout most of the 20th century. However, in the early 21st century the advent of horizontal drilling as an adjunct to hydraulic fracturing (fracking) significantly reduced the price as well as the price volatility of natural gas. These changes, combined with increased environmental regulation for coal-fired generation, have led to natural gas surpassing coal in terms of net U.S. generation.

THE HISTORY OF ELECTRICITY GENERATION IN THE U.S.

Historically, the dominance of coal-fired power generation was enabled by two factors: (1) the increasing efficiency of power plants over time and (2) the abundance of local coal supply. Generating units were no larger than 150 MW from the 1930s through to the mid-1950s. By 1975, however, due to technological advances, 1300-MW generating units were developed and installed — increasing in generating capacity magnitude by almost a factor of 10 as well as significantly improving energy efficiency. The costs of electricity production declined as each new generating unit was installed. With coal basins located throughout the continental U.S. and Alaska, coal was easily accessible, available, economically priced, and readily stockpiled.

The Middle East oil embargo in the early 1970s, ensuing economic conditions including rampant inflation, the Powerplant and Industrial Fuel Use Act of 1978, and the accident at the Three Mile Island nuclear plant in 1979 meant that the installation of new electric generating facilities no longer led to decreases in electric rates. In addition, electric consumption stopped growing at a dependable annual rate of 7%. These events in the 1970s laid the foundation for the changes in electric generation mixes that are now observed in the 21st century.

According to data from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), coal provided about 47% of the total electricity generated (see Figure 1) in 1949. Coal reached its peak level of power production in 1988, providing almost 57% of all electricity produced. In 1949, power that was not produced using coal as a fuel source was primarily generated by conventional hydroelectric power, petroleum and its derivatives, and natural gas. Nuclear power made its debut for electric power generation in 1957. Other sources — including wood, waste, geothermal, solar/photo-voltaics (PV), and wind — generated electricity at significantly lower levels than coal, natural gas, or nuclear.

“As the 21st century unfolds, the roles of natural gas and coal may well take unforeseen twists due to developments in areas such as clean coal technology...”
USING COAL AS A FUEL SOURCE

During the 19th century, coal was the major fuel that enabled the U.S. to evolve from an agricultural society to a world economic power. In the early 20th century, coal was used primarily as a raw material to power the nation’s industrial and transportation sectors and for home heating, although Thomas Edison used coal to fire the first electric power generation station in 1882 in New York City.¹

The major expansion of the U.S. electric utility systems occurred from the 1960s through the 1980s. During that time, coal was the primary fuel for baseload generation and coal production nearly doubled from 1970 to 1990.² For a long period, larger, more efficient coal additions were aligned with efforts to improve both the economy and the environment. Coal as a fuel for electricity generation remains plentiful. The EIA estimates that, at the 2014 consumption rate of about one billion tons, known coal reserves in the U.S. will last for more than 250 years.³

NATURAL GAS AS A GENERATION FUEL

As demand for electricity grew throughout the late 1900s, natural gas was not the preferred fuel choice for several reasons. The 1978 Powerplant and Industrial Fuel Use Act (FUA) prohibited the use of natural gas and oil as the primary fuel in electric utility power plants or large industrial boilers. Although these restrictions were eliminated with the repeal of the FUA in 1987,⁶ the price level of natural gas, restrictions on its availability during the winter season, and its significant price volatility precluded its use for baseload generation.

The first public use of natural gas for electric power generation occurred in 1939/1940 in Switzerland. The first natural gas combined-cycle unit began operating in 1961 in Austria.⁷ Advances in materials and technology included the development of aeroderivative gas turbines that significantly improved operational efficiency versus previous gas turbine models.⁸ Aeroderivative gas turbines are compact, using lighter weight designs (originally developed for aviation use); with high efficiency and fast-start capabilities, they are well suited for power generation.⁹ Pairing these turbines with heat recovery steam generators led to today’s natural gas combined-cycle units, some of which offer among the highest efficiencies of any fossil-fuel-sourced generation.

“…coal was the major fuel that enabled the U.S. to evolve from an agricultural society to a world economic power.”

21ST CENTURY CHALLENGES

Increasingly, public and regulatory attention has focused on the environmental impacts of coal-fired generation and coal mining in the years since the passage of the Clean Air Act in 1970 and its later amendments. In fact, some in the U.S. point to a “war on coal”.¹⁰ Owners of coal-fired generation have retrofitted or retired power production facilities as a result of actions taken by the U.S. Environmental Protection Agency (EPA). In addition, the global focus on climate change and concomitant efforts to reduce coal-fired power plant emissions have resulted in all decisions concerning coal-based electric generation receiving significant scrutiny.

The regulations issued by, or actions of, the EPA affecting ozone, sulfur dioxide (SO₂), nitrogen oxides (NOₓ), particulate

T. A. Smith Natural Gas Station (Courtesy of Oglethorpe Power Corporation)
matter (PM), ash disposal, water, mercury, and carbon dioxide (CO₂) emissions have impacted the cost competitiveness of coal-fired units more than natural gas-fired units, as emissions from natural gas are significantly lower than from coal. Many coal-fired generating units were retrofitted to comply with these regulations and experienced associated increases in capital, operating, and maintenance costs, while the additional cost requirements pushed other units into retirement. The Clean Power Plan (CPP), currently being adjudicated, would further reduce coal’s competitiveness and accelerate the retirement of additional coal facilities.

FRACKING

The advent of fracking significantly increased the amount of economically recoverable natural gas and oil. Very similarly to coal basins, shale deposits are widespread in the U.S. with significant formations now etched into the public’s mind in North Dakota (Bakken), Pennsylvania (Marcellus), and Texas (Barnett and Eagle Ford). 

The Marcellus Shale and Bakken Formation became producers of oil and natural gas through the advancement of fracking. As a result, domestic crude oil and natural gas production has increased significantly in the U.S. in the last decade, as shown in Figure 2. In conjunction with that increase, the price of natural gas has also decreased to a level that makes it competitive with coal for baseload generation.

This increase in production and domestic availability has also reduced the volatility historically associated with natural gas prices. Of geopolitical importance, the U.S. is now an exporter of oil, can produce enough natural gas for energy independence, and is exporting liquefied natural gas.

LOOKING TO THE FUTURE

Much current rhetoric touts that renewable energy (generally referring to solar and wind but ignoring hydroelectric power) will become the primary energy source for electricity in the near future. However, electric professionals as well as the U.S. federal government forecast that nuclear, coal, and natural gas resources will be required to provide a reliable electricity grid for the foreseeable future. These are so-called “dense” energy sources and the spinning turbines associated with these generation technologies provide the inertia that the power system needs to be stable, especially as renewable resources become a larger percentage of the generation mix.

The EIA’s 2016 Annual Energy Outlook forecasts that coal will provide 21% of total electricity in 2030 and 18% in 2040, with total coal production of approximately 640 million tons in 2040 (see Figure 3). In the face of slowing growth in electricity use (less than 1% per year), natural gas is projected to provide 38% of the total electricity produced in 2040, while nuclear will provide about 16%.

FIGURE 2. U.S. dry shale gas production

FIGURE 3. Electricity net generation
Projections for the future need to be made with humility and interpreted with caution. In the not-too-distant past (the 1970s), there was a belief that the world was entering a new Ice Age. Around that same time, it became illegal to build electric power generation fueled primarily with natural gas or oil. Also in that era, solar and wind technologies were in development but much too expensive for either utility-scale or individual consumer application. In the 1990s, it was accepted that the “gas bubble” would break and that natural gas, besides being unable to support baseload generation, would become too costly to power intermediate generation. There were serious concerns that natural gas combined-cycle plants would become far too expensive to operate. Justifications for natural gas combined-cycle plants were supported by backup plans showing that they could be converted and powered by gasified coal when natural gas became too costly.

“The availability and infrastructure for natural gas generation is lacking in many other parts of the world...”

Today, concerns about global climate change have led to calls for the reduction of emissions from fossil fuels, including coal. The results of the earthquake and tsunami affecting the Fukushima Daiichi nuclear power plant in Japan have led to projected and actual changes in the use of nuclear power around the world. Utility planners have learned that their crystal balls can be quite cloudy. The forecast is always wrong—the only issues are in which direction and by how much—and these factors only become obvious in retrospect. Planning for future generation sources thus requires flexibility that reflects mindfulness of the abrupt changes that can take place underlying pricing and availability of any fuel source. Good planning results in solutions robust enough to adjust to the differences between forecasts and reality.

As the 21st century unfolds, the roles of natural gas and coal may well take unforeseen twists due to developments in areas such as clean coal technology or environmental regulations impacting natural gas, nuclear power, or renewable technologies. Lastly, it should be noted that this article has focused on U.S. generation. The availability and infrastructure for natural gas generation is lacking in many other parts of the world, particularly some developing countries. Under current conditions worldwide, coal-based generation in many cases will be the superior option considering developmental needs, economics, and the environment.

CONCLUSION

Although coal-fired generation dominated the electricity market for many decades, the advent of fracking has led to an abundant domestic natural gas supply with low and stable prices that are competitive with coal prices. With the
technological advances in gas turbines and combined-cycle units, natural gas-fired generation has become economically competitive with coal and produces lower emissions. Increasing regulations associated with clean air, clean water, and global climate change are also increasing the costs to build, operate and maintain, and fuel coal-fired generation. Nevertheless, both electric utility professionals and the U.S. federal government project that, by 2040, coal will still be providing about 20% of the total electricity requirement in the U.S. That level of generation will require the mining of over 600 million tons of coal. Although natural gas will replace coal as the dominant fuel, coal and nuclear power will still be required to supplement the baseload demand requirements of customers throughout the U.S. With demand for electricity increasing in other countries around the world, many of which may not have the infrastructure to support natural gas generation, coal-based generation may still be required globally due to the economic and environmental needs of the developing world.

"...by 2040, coal will still be providing about 20% of the total electricity requirement in the U.S."

NOTES

A. The denser the energy resource the more energy that can be produced in a smaller space. Example power densities include: wind – 1 watt per square meter; solar – 6 watts per square meter; natural gas – 28 watts per square meter; nuclear power – 50 watts per square meter.16

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Effect of Coal Beneficiation on the Efficiency of Advanced PCC Power Plants

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Pulverized coal combustion (PCC) dominates power generation and will continue to do so for the foreseeable future.¹ Due to aging of the existing fleet of PCC plants and global increase in electricity demand, especially in emerging economies, a fleet of new highly efficient PCC plants is likely to be deployed.

Thermal efficiency of a power plant is one of the key parameters affecting the fuel cost, emissions (both non-greenhouse (GHG) and GHG), and capital cost. An increase in plant efficiency reduces coal consumption and fuel costs and lowers the amount of flue gas treated by the flue gas cleaning system, thus resulting in lower emission compliance cost. The published data concerning performance of advanced PCC generation is almost exclusively for the bituminous (hard) coals with no or very little information available for lower rank coals. Addressing this information gap and quantifying the effects of fuel quality on efficiency of USC and A-USC plants are the main goals of the study discussed in this article.

“Infiltrated coal combustion (PCC) dominates power generation and will continue to do so for the foreseeable future.”

Increasing steam parameters with the resulting increase in turbine cycle efficiency is one of the most effective ways of improving plant efficiency. The state-of-the-art ultra-supercritical (USC) technology can reach a steam temperature of 600°C at the superheater outlet and net efficiency of 47% (LHV) for bituminous (hard) coals. The new target for advanced ultra-supercritical (A-USC) technology is a main steam temperature in excess of 700°C and net unit efficiency estimated at 50% (LHV) for hard coals.¹

In addition to increasing steam parameters, improvement in coal quality is an effective method to increase the efficiency of PCC plants. This is particularly important for the advanced PCC technologies (USC and A-USC) operating at high steam parameters. The negative effect of high coal-moisture content on efficiency rises as steam parameters increase, reducing the operating benefits of the USC and A-USC.

Low-rank, high-moisture coals constitute about 50% of the world coal reserves.² Given such coals’ abundance and low cost, a significant portion of advanced PCC generation built in the future will be fueled by low-rank coals. To achieve the highest operating efficiency, capacity, and availability, smallest equipment size, and lowest CAPEX and OPEX will require reducing coal moisture.
The effects of coal quality improvement achieved by thermal dewatering of high-moisture coals on net efficiency and capital cost of the USC and A-USC plants are discussed below. The results were obtained by predicting performance of a reference 860-MW_{gross} plant for four high-moisture coals.

**EFFECT OF COAL QUALITY ON EFFICIENCY**

The use of high-moisture coals with a low HHV (higher heating value) results in higher coal and stack flue gas flow rates, higher station service power, and lower net plant efficiency compared to that of hard coals (see Figure 1). In addition, the mill, coal pipe, burner, and coal-handling equipment maintenance requirements are higher. The properties of coals used in our analysis are summarized in Table 1.

As shown in Figure 1, coal quality significantly impacts plant efficiency—for low-quality coals, plant efficiency is significantly lower compared to the bituminous (hard) coals. This negative effect is higher for plants with high steam parameters, thus reducing the benefits of advanced PCC operation. For example, an USC PCC plant firing high-moisture German lignite will have 7.3%-points lower net efficiency compared to the same plant using hard coal. Considering the high capital cost of the advanced PCC technology, such a reduction in performance is highly undesirable.

**Pre-drying of High-Moisture Coals**

Given that HHV increases as the total coal moisture (TM) is reduced (the average improvement in HHV is in the range of 100–120 Btu/lb per 1%-point reduction in TM), countries with large resources of high-moisture, low-quality coals are developing coal dewatering and pre-drying processes to improve unit efficiency, plant operation, and economics, as well as to reduce emissions from existing and future-built power plants firing low-rank coals. However, many thermal drying processes are either highly complex or require high-grade heat to remove moisture from the coal. This significantly increases the process cost, which represents a major barrier to industry acceptance of this technology.

Two previous IEA Clean Coal Centre (CCC) studies identified two low-energy-based coal pre-drying technologies: the U.S.-developed DryFining™ and German-developed WTA (Wirbelricht-Trocknung mit interner Abwärmenutzung, fluidized bed drying with internal waste heat utilization) as commercially available and suitable for implementation at power plants burning high-moisture coals.$^{3,4}$

**TABLE 1. Properties of the coals used in our analysis**

<table>
<thead>
<tr>
<th>Coal</th>
<th>Units</th>
<th>North Dakota lignite</th>
<th>Sub-bituminous (Wyoming PRB)</th>
<th>Bituminous (hard) coal Illinois No. 6</th>
<th>Indonesian (Wara)</th>
<th>German brown coal (Niederlausitz)</th>
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<td>13.58</td>
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</tr>
<tr>
<td>N</td>
<td>%, wt</td>
<td>0.64</td>
<td>0.70</td>
<td>1.12</td>
<td>0.63</td>
<td>0.30</td>
</tr>
<tr>
<td>H₂O</td>
<td>%, wt</td>
<td>40.00</td>
<td>30.24</td>
<td>11.12</td>
<td>40.76</td>
<td>55.80</td>
</tr>
<tr>
<td>Ash</td>
<td>%, wt</td>
<td>11.72</td>
<td>5.33</td>
<td>9.99</td>
<td>2.03</td>
<td>3.90</td>
</tr>
<tr>
<td>HHV</td>
<td>Btu/lb</td>
<td>6147</td>
<td>8340</td>
<td>11670</td>
<td>6937</td>
<td>4457</td>
</tr>
<tr>
<td>LHV</td>
<td>Btu/lb</td>
<td>5603</td>
<td>7722</td>
<td>11143</td>
<td>6269</td>
<td>3704</td>
</tr>
</tbody>
</table>
DryFining™: A Low-Temperature Coal Drying and Refining Process

DryFining™ is a novel low-temperature coal drying and cleaning process that employs a multistage moving bed fluidized bed dryer (FBD). The process uses low-grade heat rejected in the main steam condenser and sensible heat from the flue gas leaving the boiler to decrease moisture content of the high-moisture coals, such as North Dakota (ND) lignite. The technology was developed by a team led by Great River Energy (GRE). The DryFining system has been in continuous commercial operation at Coal Creek Station in North Dakota since December 2009 and has processed in excess of 40 million tons of raw ND lignite.

Implementation of DryFining™ at the Coal Creek lignite-fired power plant has improved unit heat rate by more than 5%, simultaneously achieving 30% reduction in SO₂ and Hg emissions, 20% reduction in NOₓ emissions, improving plant availability, and lowering plant water usage. Pre-combustion Hg removal is currently a topic of considerable interest.

APPLICATION OF DRYFINING™ TO ADVANCED PCC POWER PLANTS

There is significant interest in coal quality improvement through thermal pre-drying in markets experiencing high electrical load growth combined with local resources of low-rank coals. A number of lignites and sub-bituminous coals from North America, Europe, Indonesia, and other regions have been tested using the GRE pilot dryer in Underwood, ND. Drying kinetics of tested coals was similar, starting with the removal of surface moisture, followed by progressive removal of intrinsic moisture.

Process models of the reference plant and DryFining fuel enhancement process were thermally integrated to determine the effect of reduced coal moisture content and system integration on net plant efficiency ṅnet, fuel feed, flue gas flow rate, and CO₂ emissions. Table 1 lists the coals that were analyzed. Table 2 lists steam conditions over a range of coal moisture contents for subcritical (SUBC), supercritical (SC), ultra-supercritical (USC), and advanced ultra-supercritical (A-USC) operations.

We performed an economic analysis for each of the cases to determine the capital investment needed for the coal drying system, reduction in plant capital cost due to improved coal quality (higher HHV), and resulting capital cost savings. The results are presented as overnight $/kW. The overnight capital cost of $2933/kW for the A-USC firing Powder River Basin coal published in a recent EPRI study, “Materials for Advanced Ultrasupercritical Steam Turbines”, was used in the analysis.

Table 2. Steam conditions

<table>
<thead>
<tr>
<th>Gross Power Output: 860 MW</th>
<th>Main Steam/Reheat Steam Temperature</th>
<th>Main Steam Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>°C</td>
<td>bar</td>
</tr>
<tr>
<td>Subcritical (SUBC)</td>
<td>538/538</td>
<td>168.9</td>
</tr>
<tr>
<td>Supercritical (SC)</td>
<td>538/538</td>
<td>241.3</td>
</tr>
<tr>
<td>Ultra-supercritical (USC)</td>
<td>600/600</td>
<td>262.0</td>
</tr>
<tr>
<td>Advanced Ultra-supercritical (A-USC)</td>
<td>700/700</td>
<td>379.2</td>
</tr>
</tbody>
</table>

Results

The results for the high-moisture coals presented in Table 1 are depicted in Figures 2 to 4. For clarity, only the results for the USC and A-USC steam conditions are shown here. The improvement in ṅnet relative to the subcritical steam conditions and raw coal is shown in Figure 2 as a function of the reduction in TM. For all analyzed coals, ṅnet increases as TM is reduced (coal quality is improved). The efficiency improvement is higher for the higher moisture coals and higher steam conditions; the largest improvement with the lowest TM is achieved with A-USC steam conditions.

For the decrease in coal moisture of 25%-points, high-moisture German lignite, and A-USC steam conditions, the improvement in ṅnet is 12 %-points; for identical conditions and lower moisture PRB coal, the efficiency improvement is approximately 10.5%-points.

![FIGURE 2. Improvement in net efficiency as a function of reduction in TM for USC and A-USC steam conditions](https://example.com/figure2.png)
TM can be reduced by approximately 15%-points using exclusively the power plant waste heat. To achieve deeper coal drying requires process heat. In this study, the low-pressure (LP) steam extracted from the LP turbine was used as a source of the process heat. Because this steam extraction lowers the steam turbine power output, the achieved improvement in unit efficiency is smaller and the efficiency curves change slope at ΔTM greater than 15%.

The reduction in CO₂ emission intensity EFₐₑ₂ relative to the subcritical steam conditions and raw coal is presented in Figure 3 as a function of ΔTM for the USC and A-USC steam conditions. The magnitude of the reduction in EFₐₑ₂ increases with the reduction in TM and improvement in steam conditions. For the ΔTM of 25%, high-moisture German lignite, and A-USC steam conditions, the reduction in the CO₂ emission factor exceeds 28%. For identical conditions and lower moisture PRB coal, the reduction in EFₐₑ₂ is lower, approximately 22%. As the figure shows, improvement in coal quality by thermal drying results in significant reduction in CO₂ emissions.

The results of the economic analysis performed for the USC and A-USC steam conditions are presented in Figure 4. The capital cost (CAPEX) savings for all analyzed coals are given as functions of the reduction in coal moisture content.

For a new plant, the CAPEX savings increase with the reduction in TM and are higher for the A-USC conditions compared to the USC due to the smaller size and lower cost of the DryFining™ system. The highest CAPEX savings from the analyzed coals were achieved by the Indonesian WARAK coal, followed by the U.S. lignite and PRB coals. For these coals, A-USC steam conditions, and ΔTM of 25%, CAPEX savings are in the US$170–220 per kW range, or 6–7.5% of the plant capital cost. For the USC steam conditions, the CAPEX savings are approximately US$75–85 per kW lower.

As the results show, thermal drying of high-moisture coals provides significant capital cost savings for the USC and A-USC steam conditions, and should be considered for all new advanced PCC plants.

"...improvement in coal quality by thermal drying has a significant positive effect on the power plant efficiency and reducing CO₂ emissions."

CONCLUSIONS

An effective method of increasing net efficiency of PCC plants is to increase steam parameters and improve coal quality. This is particularly important for advanced PCC technology (USC and A-USC), which operates at high steam parameters. The negative effect of high coal-moisture content on efficiency increases as steam parameters increase, reducing the benefits of USC and A-USC operation.

Analyses applying DryFining™ to advanced PCC power plants were carried out to determine the effect of reduced coal moisture content on plant performance, CO₂ emissions, and capital
cost. Results indicated that plant efficiency increases as TM is reduced and steam conditions are increased; the largest improvement can be achieved with combustion coal having the lowest moisture content at A-USC steam conditions. The efficiency improvement from coal drying increases with higher moisture coals in comparison to lower moisture coals. Plant efficiency is improved due to reduction in fuel moisture from thermal drying, resulting in decreased flow rates of coal, flue gas, and emitted CO$_2$.

"Thermal drying of high-moisture coals provides significant capital cost savings..."

In conclusion, improvement in coal quality by thermal drying has a significant positive effect on the power plant efficiency and reducing CO$_2$ emissions. Economic analysis results show that CAPEX savings increase with the reduction in TM. The savings are better for higher steam conditions due to the smaller size and lower cost of the DryFining™ system.

Thermal drying of high-moisture coals provides significant capital cost savings, especially for the USC and A-USC steam conditions, and should be considered for all new PCC plants.

REFERENCES


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Improving Flexibility of Hard Coal and Lignite Boilers

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The EU energy strategy for 2020 and 2050 sets specific targets for the transition of the current European energy system and energy market. The aim of the strategy is to encourage a low-carbon energy system with decreased greenhouse gas (GHG) emissions (by 50% compared with 1990 levels until 2050), increased energy efficiency, and a larger share of renewable energy sources (RES).¹ All these developments set new challenges in the conventional thermal power sector. Under these new market conditions, modern, highly efficient natural gas combined-cycle (NGCC) power plants cannot be competitive in several countries and lose market share. Hard coal and lignite power plants are often requested by grid operators to stay in operation as the backbone of the electricity generation system and to increase their operational flexibility, in order to cover the increasing fluctuations of the residual load due to the intermittent RES.²

“Most efforts to improve flexibility in existing hard coal and lignite plants begin with measures taken to improve the flexibility of firing systems.”

Most efforts to improve flexibility in existing hard coal and lignite plants begin with measures taken to improve the flexibility of firing systems. Indirect firing systems may play a key role through utilization of pulverized coal dust or pre-dried lignite dust that can be stored in intermediate silos. In addition, the development of new ignition systems without expensive auxiliary fuels enables successful ignition and stable combustion conditions using only electricity. This reduces start-up costs and increases flexibility. This article discusses new developments in firing system technologies. Additional information can be also found in the literature.³⁻⁶

FLEXIBILITY REQUIREMENTS AND CHALLENGES

Increasing flexibility in coal power plants is not a straightforward task, because several operating parameters must be optimized under a high number of constraints. In general terms, the key targets toward increasing flexible plant operation are:

- reduction of minimum load
- increase of ramp up/down rates
- reduction of start-up cost and start-up time
- increase of maximum load period

In parallel, the above-mentioned targets must be achieved under the following conditions:
• lowest investment and operating costs
• highest plant efficiency rate and lowest CO₂ emissions, and
• by always keeping within flue gas emission limits

A graphical representation of these parameters is depicted in Figure 1. Several of these targets are not fully complementary to each other. Hence, new design principles need to consider a broad range of plant operating modes, so that plant operating parameters can be adjusted and optimized based on system operators’ and market demands.

An overview of the current state-of-the-art technical parameters related to flexible operation of coal plants is provided in Table 1 for (1) older plants commissioned in the 1990s, (2) newer plants commissioned after 2000 representing the state of the art, and (3) future plants following highly flexible design characteristics.

**OVERVIEW OF FLEXIBILITY INCREASE MEASURES**

Mitsubishi Hitachi Power Systems Europe (MHPSE) has presented a comprehensive overview of possible technical measures for retrofit and flexibility increase in existing boilers in several papers.⁵⁻⁷ A short list of the key measures is provided in Table 2 with an ascending order from the “simpler” or “limited” measures to the more “advanced” or “extensive” measures. Similarly, the measures presented on the top of each class are the most “limited” ones within this class. The classification provides only initial guidance and may differ between cases. Furthermore, additional checks on low-load operation are required before undertaking any retrofit measure. The checks have to be carried out within the framework of a comprehensive study-and-measurement campaign and include checking:

- current instrumentation and control system installed in each plant and the upgrade possibilities
- the boiler’s static and dynamic stability with different load changes and the planning of retrofit measures
- all other main plant components apart from the boiler (steam turbine, condenser) as well as the balance of the plant (fans, pumps)
- flue gas emissions performance in low-load and dynamic operation (NOₓ, SO₂, CO, particulates)

**FLEXIBILITY INCREASE MEASURES (SELECTED EXAMPLES): INDIRECT FIRING**

A key bottleneck to increasing the flexibility in existing hard coal and lignite boilers is the firing systems. A possible retrofit through installation of additional indirect firing systems can contribute to overcoming limitations and extending the operating range of existing boilers. Indirect firing systems can include an additional pulverized fuel storage (Figure 2). During...

![Figure 1. Overview and comparison of flexibility measures and impact on the operating mode](image-url)
normal boiler operation the pulverized fuel produced can be partly stored in an additional coal dust silo. The dried fuel dust can be used (1) as supporting fuel for combustion stabilization in low-load operation, (2) as supporting fuel in case of very low-quality fuels, and (3) as a start-up fuel alternative to oil or natural gas during start-ups and shut-downs.

In indirect firing systems the fuel dust is directly injected into the boiler via a special burner. For these applications MHPSE developed the DST-burner (Figure 3), suitable for indirect firing of different pre-dried fuels. Due to the high turn-down ratio, the DST-burner may be used in a broad load range during start-up and shut-down, leading to savings in conventional start-up fuels of up to 95%. Furthermore, in lignite power plants the potential integration of an external pre-drying system may be used for the production of pre-dried lignite, which can be utilized as start-up and supporting fuel in existing and future lignite power plants (Figure 4).

DEVELOPMENT ACTIVITIES: ELECTRIC IGNITION SYSTEMS

To reduce the consumption of costly auxiliary fuels such as oil and natural gas, MHPSE is evaluating the possibility for ignition

FIGURE 2. Indirect firing system

FIGURE 3. DST-Brenner® burner for dried fuel dust (1-core air, 2-fuel, 3-secondary air, 4-tertiary air, 5-fuel nozzle, 6-swirler)

TABLE 1. State-of-the-art and future targets in operating parameters related to plant flexibility

<table>
<thead>
<tr>
<th>Parameters/characteristics</th>
<th>Currently operating PP fleet (PPs erected in 80s–90s)</th>
<th>Current BAT (PPs erected after 2000)</th>
<th>Targets</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum load for continuous operation, %</td>
<td>15–20 for hard coal &gt;50 for lignite&lt;sup&gt;a&lt;/sup&gt;</td>
<td>15–25 for hard coal&lt;sup&gt;b&lt;/sup&gt;</td>
<td>~15 (considering alternative &amp; low-carbon solid support fuels and their blends)</td>
</tr>
<tr>
<td>Ramping rate, %/min</td>
<td>2–3</td>
<td>5</td>
<td>~10</td>
</tr>
<tr>
<td>Frequent start-up/shut-down ability (cold/warm/hot)</td>
<td>Specific no. of start-ups/shut-downs foreseen per year (limited to few cold start-ups)</td>
<td>Possible daily start-up for hard coal PP (usually hot/warm daily, cold over the weekend)</td>
<td>Possible daily variations of 15–100% to avoid daily start-ups</td>
</tr>
<tr>
<td>Emissions and plant efficiency must be kept during part load</td>
<td>Optimum design for high efficiency &amp; lowest emissions at full load</td>
<td>Optimum design for high efficiency &amp; lowest emissions at full load and some low loads</td>
<td>Optimum design for high efficiency &amp; lowest emissions (IED) for load following operation</td>
</tr>
</tbody>
</table>

Notes. *Best possible known, and documented.
<sup>a</sup>Usual minimum load operation for recent new-built plants is around 30–35% due to lowest marginal cost of all hard coal units. Certain operational restrictions also arise from ultra-supercritical design of new units when switching to min-load operation below those limits.
<sup>b</sup>Oil/gas may be required as supporting fuel for lignite.
<sup>c</sup>Plants existing in Germany or being retrofitted with dry lignite firing to operate in the range of 20–30% load.
of solid fuels by electric start-up technologies. Two technologies are currently in development: the electrically heated burner nozzle and the plasma ignition system. The electrically heated burner nozzle is designed for start-up of further burner levels when increasing the boiler load; the plasma ignition system is designed for cold, warm, and hot start-up. The concept is to induce ignition of pulverized fuels through the radiation heat from and through contact with the burner nozzle, which is electrically heated (Figure 5). The proof of concept was successfully demonstrated in 2013 with industrial-scale experiments. The first prototype, modified DS® burners with electrically heated burner nozzle and the plasma ignition system.

TABLE 2. Possible measures to increase flexibility in existing power plants and expected impact

<table>
<thead>
<tr>
<th>No.</th>
<th>Measures</th>
<th>Possible Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>decrease of minimum load</td>
</tr>
<tr>
<td>1</td>
<td>Comprehensive study-and-measurement campaign of the current plant operation</td>
<td>√</td>
</tr>
<tr>
<td>2</td>
<td>Upgrades in I&amp;C and flame monitoring</td>
<td>Instrumentation and Control (I&amp;C)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Flame monitoring system</td>
</tr>
<tr>
<td>3</td>
<td>Retrofit measures in firing system (incl. mills)</td>
<td>Retrofit mills for improved low-load operation (“one mill” operation)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Install additional indirect firing system with dedicated burners/install dedicated “electric ignition” systems for start-up</td>
</tr>
<tr>
<td>4</td>
<td>Boiler retrofit measures</td>
<td>Replace thick-walled with thinner walled components using optimized materials</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Change 2-line to 4-line arrangement</td>
</tr>
<tr>
<td>5</td>
<td>Overall plant cycle retrofit measures</td>
<td>Improve short-term load flexibility by “condensate stop” concept</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reduce auxiliary power consumption variable-speed-controlled fans (ID, FD)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Retrofit at flue gas path (in SCR and FGD)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Gas turbine repowering</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Integration of energy storage concepts</td>
</tr>
</tbody>
</table>

*By improved control of stoichiometry and thus increased boiler efficiency /lower NOx in part load.

FIGURE 4. Lignite pre-drying system can aid increase in flexibility of current and new power plants.

FIGURE 5. (a) Bituminous coal ignition with electrically heated burner nozzle: proof of concept; (b) installation of DS® burner with electrically heated nozzle in PP Hannover
nozzles, has been installed in a 300-MW CHP plant providing electricity and heat to the city of Hannover and nearby industries (Gemeinschaftskraftwerk Hannover). Ignition using a plasma flame (Figure 6) is possible given that plasma is a highly reactive blend of electrons, radicals, atoms, and molecules. Development aims to optimize the plasma flame in low NOx swirled burners for safe ignition of a wide range of fuels while minimizing the necessary plasma power. The implementation of such electric ignition systems aims to reduce supporting fuels and maintenance costs of the complex infrastructure and/or storage of heavy fuel oil, light fuel oil, and gas start-up systems, which require regular safety inspections.

CONCLUSIONS

This article summarizes recent developments and state-of-the-art technology using firing systems to increase flexible plant operation on hard coal and lignite boilers. Depending on coal quality and market conditions, today’s boilers and combustion systems can be optimized for maximum flexibility with reasonable capital investment. If necessary, coal-fired power plants can be designed for fast-load ramps as well as minimum load operation at 15–20% or lower independent of fuel type. For this application, indirect firing systems are already considered as state-of-the-art technology. Electrical ignition concepts are also currently under development and in a prototype stage. Additionally, the article provides a list of measures toward plant flexibility and provides a ranking of these measures from the simpler concepts to the concepts with the higher complexity. All flexibility options have to be evaluated case by case and take into account the particular technical and economic boundary conditions of each considered case.

REFERENCES


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The Łagisza Power Plant: The World’s First Supercritical CFB

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Author and Analyst, IEA Clean Coal Centre

The Łagisza power plant in Będzin, Poland, is home to the world’s first 460-MW supercritical circulating fluidized bed boiler (CFB), which remains the largest of its kind outside China. Since beginning commercial operation in June 2009, the plant has attracted considerable interest from all over the world. Experience gained from its design, construction, and operation has been a valuable stepping stone in further developing the technology and implementing it in other countries.

PLANT HISTORY

The power plant is currently owned by Tauron Wytwarzanie S.A., the second largest energy company in Poland. The first subcritical units at Łagisza were built in the 1960s. At the turn of this century, when Łagisza consisted of seven 120-MW pulverized coal-fired boilers, the decision was taken to build a new, larger coal-fired unit to replace the smaller, less efficient ones. As described by Szymon Jagodzik, Łagisza’s Deputy Director and Chief Energy Generation Engineer, various options were initially considered, including both pulverized (PC) and CFB combustion designs. All the possibilities were carefully evaluated before the company decided to build a supercritical CFB unit—even though, at the time, no such boilers were operating anywhere in the world. A number of factors influenced the decision. First, it was calculated that the total plant investment cost for the CFB was approximately 15% lower than for a comparable pulverized coal-fired boiler. Second, a CFB would not require the installation of expensive wet flue gas desulfurization (FGD) and selective catalytic reduction (SCR) systems as both sulfur dioxide (SO₂) and nitrogen oxides (NOₓ) could be removed from within the boiler. Third, CFB units have greater fuel flexibility than pulverized coal combustion units.

“Łagisza’s operating experience has provided a good knowledge base for further development of CFB units all over the world.”

Foster Wheeler Energy Polska and Foster Wheeler Energia OY (currently Amec Foster Wheeler) designed and built the boiler. To keep costs down, a number of suppliers and contractors were chosen, both locally and from abroad. Alstom Power supplied the turbine set and Elektrobudowa S.A. Katowice provided the electrical system. The ash handling and limestone sorbent systems came from Mostostal Kraków and the Energo–Eko-System Katowice consortium. The Ciepło–Serwis Będzin and PURE Jaworzno consortium provided the coal-feed system, and the distributed control systems (DCS) came from the consortium of Metso Automation Finlandia and Metso Automation Polska. This strategy was successful as the unit was completed below the budget price; the total cost was about 1.9 mld zl (€0.422B, $0.594B). The money was raised by the company, bonds, and various Polish government environmental funds. It took three and a half years from the start of construction in January 2006 to commissioning of the unit in June 2009. Between 1500 and 2000 people were involved in its design, construction, and commissioning.

THE CFB UNIT

The design of the Łagisza unit was based on Foster Wheeler’s second-generation CFB technology, which features solids separators (cyclones) constructed from water- or steam-cooled panels integrated with the furnace combustion chamber. Prior to Łagisza, Foster Wheeler’s largest second-generation...
CFB boilers were the 262-MW units at the Turów power plant, also in Poland. The main design parameters of the boiler are listed in Table 1 and a schematic is shown in Figure 1.

Although CFB boilers have considerable fuel flexibility and can fire many low-grade fuels, including low-rank coals, biomass, and different types of waste, the boiler at Łagisza plant was designed specifically for locally mined hard coal and the limestone used for desulfurization. In 2015, the average parameters of the fired coal were as follows: calorific value 20,522 kJ/kg; 19.21% ash; 1.03% sulfur; and 14.49% moisture content.

The most significant design features of the Łagisza CFB unit are the boiler’s compact size, its once-through operation mode, the single fluidizing grid, the integrated steam-cooled solids separator, the INTREX™ fluidized bed heat exchanger, and the flue gas heat recovery system.

The parameters of the coal and limestone to be used were analyzed extensively, which led to the design of a compact boiler 27.6 m wide, 10 m deep, and 28 m high. In fact, it is only slightly larger than the boilers designed for Foster Wheeler’s subcritical 235-MW CFB units at Turów power plant (22 m wide, 10.1 m deep, 42 m high).

The unit uses a single fluidizing grid in the bottom of the boiler, with four separate air plenums for the primary air flows. The primary air flow to each plenum is measured and controlled separately to ensure equal air flow to all sections of the grid and uniform fluidization as well as simple control.

The application of vertical Benson tubing (low mass flux once-through technology) and Siemens supercritical steam flow technology allows steady operation of the boiler at variable load conditions (40–100% load).

Table 1. Main design parameters of the Łagisza 460-MW CFB boiler

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Unit Electrical Output</td>
<td>460 MW&lt;sub&gt;e&lt;/sub&gt;</td>
</tr>
<tr>
<td>Gross generation efficiency at 100% load</td>
<td>45% (LHV)</td>
</tr>
<tr>
<td>Steam flow</td>
<td>361 kg/s</td>
</tr>
<tr>
<td>Steam pressure on the turbine inlet</td>
<td>27.5 MPa</td>
</tr>
<tr>
<td>Primary steam temperature on the turbine inlet</td>
<td>560°C</td>
</tr>
<tr>
<td>Secondary steam temperature on the turbine inlet</td>
<td>580°C</td>
</tr>
<tr>
<td>Flue gas temperature at the boiler outlet</td>
<td>130°C</td>
</tr>
<tr>
<td>Flue gas temperature after heat recovery/at the cooling stack</td>
<td>85°C</td>
</tr>
</tbody>
</table>

The unit has eight integrated steam-cooled solids separators arranged in parallel, four separators on two opposite furnace walls. This arrangement allows a high collection efficiency with low flue gas pressure loss. The inlet is tall and narrow in shape to provide a uniform flow of flue gas and solids, thus avoiding high local velocities. The result is a collection efficiency equal to the best conventional cyclones with substantially lower loss of pressure. To minimize the required amount of refractory material, the separators are designed with panel wall sections and have a thin refractory lining anchored with dense stud. The separator tubes are steam cooled, forming a third superheater stage.

Foster Wheeler’s integrated recycle heat exchanger (INTREX™) incorporates the heat exchanger water wall with the furnace water steam system and the return channel. As well as cooling the externally circulated solids, openings in the furnace’s rear wall provide access for additional solids to circulate internally through the heat exchanger tube bundles, ensuring sufficient hot solids to the INTREX™ heat exchanger at all loads. As the system is located in the solids return part of the solids separator, corrosion from high temperature and the acidic flue gas component is avoided.

The flue gas heat recovery system (HRS) cools the flue gas from 130°C to 85°C and improves the total efficiency of the unit by around 0.8 %. The HRS operates in the clean gas after the electrostatic precipitator (ESP) and induced draft fans. The flue gas is cooled in a heat exchanger made of PFA tubing.
to avoid corrosion problems. After HRS cooling, the flue gas is conducted to the cooling tower via a fiberglass duct. The recovered heat is transferred by a primary water circuit to the combustion air system of primary and secondary air. As the combustion air temperature before the rotary air preheater is increased, the incoming cold combustion air flow is not able to absorb all the heat from the flue gases. Hence part of the flue gas is directed to a separate low-pressure bypass economizer that allows the heat from the flue gas to be used to heat the main condensate.\textsuperscript{7}

The temperature of the flue gas after heat recovery is relatively low and would cause problems for a traditional stack. Thus a decision was made to construct a 133.2-m-high “cooling stack”. This was more economical than constructing a cooling tower and a separate stack. More importantly, it allows higher and better dispersal of the flue gas than would be achieved with a stand-alone stack.\textsuperscript{1}

The advantages that resulted from these applied solutions include significant fuel flexibility and a low combustion chamber temperature of 800–900°C. This means that screen tube slagging is avoided, as well as high-temperature corrosion.

Łagisza’s CFB unit operates with much greater efficiency and emits significantly less carbon dioxide and other air pollutants than the 120-MW pulverized units it replaced (see Table 2).\textsuperscript{7}

**OPERATION OF THE BOILER**

Currently, Łagisza power plant consists of the 460-MW CFB and two subcritical 120-MW pulverized coal-fired units. The plant employs 326 people, of which approximately 60 are required to operate the CFB unit. In 2015, the unit was in operation for 6000 hours, used 905,000 tonnes of local coal, and generated 2.3 TWh of electricity. It operated at 65–100% load, with an average load of 85% (392 MW). Obviously, variations in the load translate to variation in the boiler’s efficiency.\textsuperscript{7} As shown in Figure 2, when operating at full load, net efficiency is in the

Table 2. Operating efficiencies and emissions levels of the 460-MW CFB and replaced 120-MW pulverized coal-fired units at 100% load operation\textsuperscript{7}

<table>
<thead>
<tr>
<th>Operating Parameters</th>
<th>460-MW CFB</th>
<th>120-MW Units</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Gross efficiency</strong></td>
<td>45%</td>
<td>36.4%</td>
</tr>
<tr>
<td><strong>PM</strong></td>
<td>0.09 kg/MWh</td>
<td>0.22 kg/MWh</td>
</tr>
<tr>
<td><strong>SO(_2)</strong></td>
<td>0.6 kg/MWh</td>
<td>8.51 kg/MWh</td>
</tr>
<tr>
<td><strong>NO(_2)</strong></td>
<td>0.6 kg/MWh</td>
<td>2.23 kg/MWh</td>
</tr>
<tr>
<td><strong>CO(_2)</strong></td>
<td>750 kg/MWh</td>
<td>950 kg/MWh</td>
</tr>
</tbody>
</table>

**Figure 2. Gross and net efficiency (LHV) of the unit in relation to the load**

region of 43% (lower heating value, LHV) and net power output is 439 MW.

Sulfur dioxide emissions are controlled by feeding limestone into the boiler; last year, 62,500 tCaCO\(_3\) were used for that purpose. NO\(_x\) emissions from a CFB combustion unit are only around one fifth of those produced by pulverized coal combustion as the combustion occurs at lower temperature and thus less NO\(_x\) is formed.\textsuperscript{8} Hence, NO\(_x\) emissions are effectively controlled by staged combustion as well as the addition of ammonia as part of a selective non-catalytic reduction process. In 2015, 2885 tonnes of ammonia were used.\textsuperscript{1} An ESP system is used to control PM emissions. Consequently, in 2015 the emissions were as follows: 17,000.2 kg PM (<30 mg/Nm\(^3\)); 454,962.3 kg SO\(_2\) (<200 mg/Nm\(^3\)); 521,274.3 kg NO\(_x\) (<200 mg/Nm\(^3\)); and 721,367 tCO\(_2\). These pollution control options enable compliance with the relevant EU legislation.

Fuel is delivered to the boiler by 14 screw-type feeders, as reported by Jagodzik.\textsuperscript{7} Coal is crushed to 1–30 mm; 80% of it to between 1 and 10 mm to allow seamless combustion. About 40–50 kg of coal is delivered each second to the boiler, corresponding to around 4000 tonnes of fuel being used per day. When in operation, the total mass of solids (fuel, sand, sorbent, ash) in the boiler is about 200 tonnes. Although the CFB boiler can fire different types of fuel, unsurprisingly it is most efficient when using the fuel for which it has been designed: local hard coal.

It is worth noting that the Łagisza CFB unit also has the Dual-Reflux Vacuum-Pressure Swing Adsorption (DR-VPSA) CO\(_2\) capture pilot installation in place. The installation is operated by Częstochowa University of Technology and Eurol Innovative Technology Solutions Sp. z o.o. with the participation of Tauron staff. When in operation, the installation utilizes a slipstream of the CFB flue gas (100 m\(^3\)/h) to investigate two adsorbents (activated carbon and zeolite types) for their potential to remove CO\(_2\).\textsuperscript{8}
STEPPING STONE FOR FURTHER DEVELOPMENT OF CFB

As noted by Lockwood, despite attaining the status of “cleaner” coal technology because the emissions of NO, and SO, emissions are more easily controllable, the use of CFB combustion at the utility scale has been limited by smaller boiler sizes than those used in pulverized coal combustion. However, scale-up and optimization over recent years have allowed CFB boilers to benefit from economies of scale. Larger units have been built since the commissioning of the Łagisza CFB unit, and CFB combustion is beginning to provide a viable alternative to pulverized coal combustion for utility power generation, especially where low-grade fuel will be used. The successful operation of the world’s first supercritical CFB boiler at Łagisza power plant in Poland has been crucial to this progress. Łagisza has validated Foster Wheeler’s supercritical CFB design platform, providing a solid base for its development of units of up to 600–800-MW capacity.

“…CFB combustion is beginning to provide a viable alternative to pulverized coal combustion for utility power generation.”

Tauron Wytwarzanie S.A. has generously shared its knowledge and experience gained during the operation of the world’s first supercritical 460-MW CFB unit. The company has hosted many tours and provided training and learning opportunities for plant operators from around the world. This included training for a team from KOSPO, South Korea, which is expected to commission four 550-MW units in Samcheok later this year. And as Szymon Jagodzik noted, as Tauron staff train others during such interactions, they are also open to suggestions because they never stop improving operation of their coal-fired fleet.

CONCLUSIONS

After over six years of operation, the decision to build the world’s first supercritical CFB unit in Łagisza appears to have been both economically and environmentally successful. Łagisza’s operating experience has provided a good knowledge base for further development of CFB units all over the world. The Łagisza CFB unit is predicted to be in operation until 2046 and there are plans for it to produce heat as well as electricity. The amount of heat to be produced is not yet known, as it will depend on local demand. Nevertheless, the future of Łagisza CFB unit looks good.

REFERENCES

Resource Utilization and Management of Fly Ash

By Jinder Jow
National Institute of Clean-and-Low-Carbon Energy (NICE), Beijing, China

China’s primary energy resources are fossil-based fuels: oil, natural gas, and coal, with coal being the least expensive. From a material aspect, coal has both organic and inorganic components, quite different from oil and natural gas which have only organic materials. Figure 1 depicts the process of a coal-fired power plant and its by-products—from coal mine to electricity or heat. The by-products are (1) NOx, sulfur oxides, Hg, particulate matter (PM), and CO2; (2) wastewater; and (3) fly ash, bottom ash, and flue-gas desulfurized gypsum when an external desulfurization process is used. The solid by-product with the largest volume is fly ash. The fly ash retains the inorganic components of coal after combustion.

Three different coal combustion processes are used to produce energy: pulverized coal (PC), circulating fluidized bed (CFB), and integrated gasification combined-cycle (IGCC). The first two are the most commonly used by coal-fired power plants. The PC process typically has a higher combustion temperature and efficiency than the CFB process, and produces less fly ash with better quality. Fly ash is mostly used in low-end applications, such as buildings and constructions, due to significant property variations that strongly depend on how each coal-fired power plant operates. This article describes the approach taken by the National Institute of Clean-and-Low-Carbon Energy (NICE), a subsidiary of Shenhua Group, to utilize and manage fly ash as a resource to increase its utilization volume and value. The same concept and approach can be applied to the utilization of fly ash or any other by-product related to coal-based energy. Coal-fired power can be cleaner if its by-products can be reduced or utilized.

“**The development of options to make coal-fired power cleaner by reducing or utilizing more waste by-products is critical to maintain long-term sustainability.**”

FUNDAMENTAL PROPERTIES OF FLY ASH

Figure 2 depicts the three fundamental properties of fly ash: particle size distribution and morphology, chemical composition, and mineral composition. As noted, fly ash will differ in these properties, due to the operational differences of various coal-fired power plants. Factors that influence these properties include the coal type/source, pretreatment, combustion process, environmental control system, and the ash collection system.

Figure 3 shows how these three fundamental properties are linked with the operation of a coal-fired power plant. Several steps need to be taken to utilize fly ash as a resource. Identifying and understanding the properties of the fly ash is the first key step. Obtaining fly ash with consistent properties
FIGURE 2. Fundamental properties of fly ash

is the second step. Identifying suitable applications and development of specific products for different uses is the last step to maximize its properties and utilization value.

Particle size distribution of fly ash depends on the coal’s pretreatment, combustion process, and ash collection system. In general, fly ash has a particle size range of 0.1–600 μm. Fine coal particles produce finer fly ash. Higher combustion efficiency also tends to produce finer fly ash. Fly ash collected at the same plant using different electrostatic precipitators will have a different average particle size and distribution. Finer fly ash usually has a better utilization value due to its higher surface area and reactivity. The particle morphology depends on the combustion process. The PC process produces spherical particles due to natural cooling, whereas the CFB process creates irregularly shaped particles due to the fluidizing action. The images in Figure 4 show the differences in particle morphologies using a scanning electron microscope. A spherical shape has a better flow property but less aspect ratio effect than an irregular shape.

The chemical composition of fly ash depends on the coal type and the extent and temperature of combustion. The environmental control units used to remove NOx, sulfur, or Hg will also affect the composition. The major chemical compositions are dominated by SiO2 and Al2O3 as an aluminosilicate material followed by four secondary components, CaO, Fe2O3, or Fe3O4, SO3, and unburned carbon (loss on ignition, LOI). Combustion of lignite or subbituminous coal usually produces more fly ash, due to its high ash and CaO content, than does combustion of an anthracite or bituminous coal. The internal desulfurization

FIGURE 3. Fundamental properties of fly ash related to coal-fired power plant operation
process where lime is injected into the combustion process can also produce fly ash with high CaO content. Fly ash with more CaO tends to have higher cementitious reactivity. Typically, the PC process produces better fly ash quality with lower LOI, SO₄, and CaO contents than the CFB process.

Mineral composition depends on the coal type, coal particle size, and boiler temperature. In general, higher boiler temperatures and smaller coal particles produce fly ash with higher glass content. Fly ash typically has a glass content range of 35–70%. Fly ash with more glass and smaller particle size has a higher pozzolanic reaction. Fly ash with high aluminum content tends to have lower glass content but higher mullite content in its crystalline phase.

**FLY ASH UTILIZATION ISSUES**

Two key issues for fly ash utilization are significant property variation and local supply-demand issues. In China fly ash is used in various applications, such as cement and concrete, walls and building materials, aggregates in road pavement, agricultural use, mine filling, and mineral extraction. The building and construction sectors are major users of fly ash which can meet their low performance requirements. For example, China produced 540 million tons of fly ash in 2014 with a utilization rate of 70%, higher than the global average of 54%. The fly ash was used as follows: 60% for cement and concrete, 26% for bricks and walls, 5% for road pavement, 5% for agriculture and mine filling, and 4% for mineral extraction and other applications. The utilizations are categorized into three types as shown in Figure 5: local massive utilization, high-value utilization, and local ecologic utilization.

Fly ash from coal-fired power plants located near metropolitan areas or large industrial complexes can be utilized to meet local demand in building and construction applications. However, these local applications are typically of low value (low price-to-performance) and only economic within a 100-km distance due to the transportation cost. Coal-fired power plants located in remote areas have limited options for fly ash utilization. Both high-value (high price-to-performance) and local ecologic utilizations become critical to increase its usage. Utilization and management of fly ash must be economically viable in remote locations or regions. In order to increase current utilization value and volume, efforts are underway to identify new applications for high-value and local utilizations. This requires an understanding of materials science and knowledge of possible applications.

“China produced 540 million tons of fly ash in 2014 with a utilization rate of 70%...”

**APPROACHES TO ADDRESS FLY ASH UTILIZATION AND MANAGEMENT ISSUES**

To address fly ash utilization and management issues, the first step is to characterize its fundamental properties from individual coal-fired power plants and re-characterize when the operational conditions change. The second step is to obtain fly ash with consistent property qualities through a cost-effective particle control system, particularly for particle size, LOI, and Fe₂O₃ content. The third step is to select suitable applications based on consistent fundamental properties of fly ash and to develop core technologies and products for full utilization of fly ash to achieve the maximum value. Figure 6 shows how these three steps address both property variation and supply-demand issues.

The fly ash R&D team at NICE has adapted this approach to characterize different types of fly ash and establish a

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**FIGURE 5. Utilization types of fly ash**

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Coal Mine → Coal Mining & Refining → Coal → Coal Shipping → Coal-fired power → Electricity or heat → Fly ash → Local ecologic utilization → High-value utilization → Local massive utilization
cost-effective particle control system. This particle control system has obtained at least three grades of fly ash with consistent particle size distribution used to develop four products: hydraulic fracturing proppants, fillers, highly active supplemental cementitious (HASC) products, and river sand (RS) products (see Table 1). All products are based on at least one of these three fly ash grades, which are produced from the PC process. The processes of making fly ash-based products do not generate any by-products and consume less energy than the existing products to be replaced.¹

HASC products can replace up to 50% cementitious materials including cement used in concrete. Concretes using HASC products have higher compressive strengths, including three-day compressive strength which is one of the most important properties of concrete.² The RS product fully replaces ultrafine sand used in mortar. Fillers can fully replace CaCO₃ and other inorganic fillers (2500 mesh or above) used in polymers with better flow property. When the polymers are molten and pushed to flow, spherically shaped fillers help the molten polymer flow better than do irregularly shaped fillers. Fly ash-based proppant properties are either equivalent to or better than three commercially available bauxite-based proppants, identified as SG overseas, YT China, and CQ China, as shown in Table 2.⁴

The three cases described below demonstrate how these products increase the utilization rate and value in local massive and high-value utilisations. The fly ash reference case was obtained from a pulverized coal-fired power plant. The fly ash is rated as Class II according to Chinese National Standard GB1596-2005 for concrete and mortar uses. For the particle

### Table 1. Fly ash-based products developed by NICE

<table>
<thead>
<tr>
<th>Utilization Level</th>
<th>FA-Based Products</th>
<th>Existing Products to Be Replaced</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Local massive utilization</strong></td>
<td>HASC products</td>
<td>Cement and admixture used in concrete</td>
</tr>
<tr>
<td></td>
<td>RS products</td>
<td>Ultrafine sand used for mortar</td>
</tr>
<tr>
<td><strong>High-value utilization</strong></td>
<td>Fillers</td>
<td>Inorganic fillers, CaCO₃, BaSO₄, kaolin, etc.</td>
</tr>
<tr>
<td></td>
<td>Proppants</td>
<td>Bauxite-based proppants</td>
</tr>
</tbody>
</table>

Note. Proppants are solid materials designed to keep an induced hydraulic fracture open during oil and gas exploitation.

### Table 2. Performance comparison of four different low-density, high-strength proppants

<table>
<thead>
<tr>
<th>20/40 mesh size/test items</th>
<th>Chinese Standard SY/T 5108-2014 Performance Requirements</th>
<th>NICE Proppant</th>
<th>SG Overseas Proppant</th>
<th>YT China Proppant</th>
<th>CQ China Proppant</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sieve Analysis (wt.%)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>U.S. Mesh</td>
<td>µm</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>1180</td>
<td>≤0.1</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>20</td>
<td>850</td>
<td>≤8</td>
<td>1.2</td>
<td>2.5</td>
<td>0.0</td>
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<tr>
<td>25</td>
<td>710</td>
<td>≥90</td>
<td>32.5</td>
<td>26.9</td>
<td>43.4</td>
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<td>30</td>
<td>600</td>
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<td>30.0</td>
<td>38.9</td>
<td>46.6</td>
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<tr>
<td>35</td>
<td>500</td>
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<td>27.6</td>
<td>25.7</td>
<td>9.2</td>
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<tr>
<td>40</td>
<td>425</td>
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<td>8.8</td>
<td>5.6</td>
<td>0.7</td>
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<tr>
<td>50</td>
<td>300</td>
<td>≤1</td>
<td>0.0</td>
<td>0.4</td>
<td>0.0</td>
</tr>
<tr>
<td>Pan</td>
<td></td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Crush at 7500 psi (%)</td>
<td></td>
<td>2.84%</td>
<td>4.56%</td>
<td>3.19%</td>
<td>2.12%</td>
</tr>
<tr>
<td>Bulk Density</td>
<td></td>
<td>1.58</td>
<td>1.57</td>
<td>1.61</td>
<td>1.58</td>
</tr>
<tr>
<td>Apparent Density</td>
<td></td>
<td>2.73</td>
<td>2.83</td>
<td>2.87</td>
<td>2.93</td>
</tr>
<tr>
<td>Roundness</td>
<td></td>
<td>0.80</td>
<td>0.75</td>
<td>0.75</td>
<td>0.80</td>
</tr>
<tr>
<td>Sphericity</td>
<td></td>
<td>0.80</td>
<td>0.75</td>
<td>0.75</td>
<td>0.80</td>
</tr>
<tr>
<td>Acid Solubility (wt%)</td>
<td></td>
<td>5.85%</td>
<td>6.80%</td>
<td>6.60%</td>
<td>7.80%</td>
</tr>
<tr>
<td>Turbidity (NTU)</td>
<td></td>
<td>88.6</td>
<td>&gt;100</td>
<td>&gt;100</td>
<td>&gt;100</td>
</tr>
</tbody>
</table>

Note: Proppants are solid materials designed to keep an induced hydraulic fracture open during oil and gas exploitation.
size requirements, the GB 1596-2005 standard specifies fly ash with particle size greater than 45 μm and no higher than 25% by weight as Class II fly ash, while ASTM C618 specifies no higher than 34% by weight as Class F. The fly ash cost reference is assumed to be RMB50/ton from a coal-fired power plant and sold to a concrete producer at RMB150/ton, resulting in a gross margin of RMB100/ton.

Case I demonstrates two fly ash-based products used for concrete and mortar as an example of local massive utilization. Case II shows the viability of fillers for high-value utilization along with two products used for concrete and mortar for local massive utilization as a mixed example. Case III maximizes the utilization value and rate by making fillers and proppants using fly ash with an Al₂O₃ content of at least 35% as the example of high-value utilization only.

Case I: The reference fly ash is classified and converted into a highly active supplemental cementitious (HASC) product to replace 50% cement in concrete, Class II fly ash as an existing product, and a river sand (RS) product to fully replace ultrafine river sand used in mortar at a price of RMB350/ton, RMB150/ton, and RMB50/ton, respectively, under a product split ratio of 20%, 75%, and 5%. The average cost of conversion is RMB80/ton. The calculated gross margin is RMB105/ton. The market size of Class II fly ash used in concrete is assumed to be 71 million tons. The expected fly ash volume processed is 84 million tons to achieve a total extra gross margin of RMB420 million in China. The extra fly ash volume is 21 million tons used for HASC and RS products.

Case II: The same fly ash is classified and converted into fillers, Class II fly ash, and an RS product priced at RMB1000/ton, RMB150/ton, and RMB50/ton, respectively, under a product split ratio of 30%, 60%, and 10%. The average cost of conversion is still RMB80/ton. The calculated gross margin is RMB265/ton. The market size of fillers is assumed to be 1.8 million tons. The total fly ash volume processed is 6 million tons to achieve a total extra gross margin of RMB990 million. The total extra fly ash volume is 2.4 million tons used for filler and RS products.

Case III: Fly ash with high Al₂O₃ content is classified and converted into fillers and proppants priced at RMB1000/ton and RMB2500/ton under a product split ratio of 30% and 70%, respectively. The average cost of conversion rises to RMB800/ton. The calculated gross margin is RMB1250/ton. The market size of proppants is assumed to be 1.4 million tons in China. The extra fly ash volume is 2 million tons used for both proppants and fillers to achieve a total extra gross margin of RMB2300 million.
All prices stated are a reference for economic comparison and not necessarily the actual prices. Table 3 summarizes the extra fly ash volume and margin created by these three cases. As expected, high-value utilization creates more value and consumes less fly ash volume, while local massive utilization consumes more fly ash volume but creates less value.

CONCLUSIONS

The development of options to make coal-fired power cleaner by reducing or utilizing more waste by-products is critical to maintain long-term sustainability. Coal has the organic component used to generate heat or electricity while its inorganic component is converted into fly ash through the combustion process. This article discusses options to increase the utilization of fly ash from coal-fired power generation. The fundamental properties of fly ash are particle size distribution and morphology, chemical and mineral composition, and significant variability depending on the operational conditions of individual power plants.

This article demonstrates how to increase fly ash utilization volume and value based on understanding the fundamental properties of fly ash and their property-driven applications for high-value and local building materials uses. Local ecologic utilizations are other options to increase volume and add value to fly ash, including mine refilling, agricultural use, land reclamation, and road construction. These usages are of extremely low value but useful in achieving full utilization, particularly in remote regions. How to achieve positive economic benefits for any ecologic utilization is another important and challenging goal. Resource utilization and management of fly ash requires collaborative efforts among local coal-fired power plants, governments, R&D teams, and enterprises to achieve a full utilization with an overall positive economic benefit in each region.

NOTES

A. High-value utilization includes fillers, flame retardants, low-density foam for fire protection, thermal insulation, and industrial ceramics. Local massive utilization includes building materials for cement, mortar, and concrete, pre-cast, wall materials, and high-density foam. Local ecologic utilization includes mine refilling, aggregates for road pavement, land reclamation, and agricultural use.

REFERENCES

International Outlook

Canada

Canada’s Saskpower’s C$1.5 billion Boundary Dam Carbon Capture plant at Esteven in Saskatchewan announced in August the plant has captured more than 1 million tonnes of CO₂ since its start-up in October 2014. The company is on track to capture annually 800,000 tonnes of CO₂ by the end of 2016. Alberta Shell’s Quest carbon capture and storage (CCS) project has also achieved a significant one-year milestone, capturing and storing 1 million tonnes of carbon dioxide (CO₂) ahead of schedule.

China

Shenhua Group and SUEK the Siberian coal energy company, have held a meeting in Moscow to discuss areas of potential collaboration. SUEK is Russia’s largest coal company and Shenhua is the largest coal company in China. Both sides exchanged views on the global coal industry and market dynamics. Shenhua was represented by Vice President Wang Jinli and SUEK by CEO Vladimir Rashevsky with both saying they would find areas in which to cooperate including coal mining, processing, and supply.

U.S.

The Kemper County energy facility in Mississippi started production of syngas from its second gasifier using locally mined lignite. The project aims to utilize two commercial-scale transport integrated gasification (TRIG™) units to gasify locally mined lignite coal to produce syngas. The syngas will then be cleaned and used to fuel two combined-cycle power generating units each with a net output of 582 MW of electricity.

The WA Parish Carbon Capture Storage (CCS) project, also known as the Petra Nova Carbon Capture Project, is scheduled to be completed by the end of 2016. Globally, the Petra Nova Carbon Capture Project will be the largest post-combustion carbon capture facility on an existing coal plant. The project will use a carbon dioxide (CO₂) capture process developed by Mitsubishi Heavy Industries. Approximately 90% of the CO₂ will be captured from a 240-MW slipstream of flue gas from the power station’s existing 610-MW coal-fired Unit 8, and extract approximately 1.6 million tons (mt) of CO₂ annually. The CO₂ will be used for enhanced oil recovery (EOR) at the West Ranch Oil Field.

International

The Paris Agreement entered into force on 4 November 2016. The threshold for the entry into force of the Paris Agreement was achieved on 5 October 2016. The threshold was reached due to the ratification of the U.S. and China in September and in October the European Union. The key condition of 55 parties to the United Nations Framework on Climate Change Convention, accounting for 55% of total global greenhouse gas emissions, was achieved. In total, 74 countries have deposited their instruments of ratification, acceptance, or approval to the agreement, covering 58.82% of the total global greenhouse gas emissions.

Recent Select Publications

CO₂ Building Blocks: Assessing CO₂ Utilization Options — U.S. National Coal Council — The assessment was prepared in response to a request from U.S. Secretary of Energy Moniz that the federal advisory council “develop an expanded white paper assessing opportunities to advance commercial markets for carbon dioxide (CO₂) from coal-based power generation”. The NCC assessment concludes that CO₂-EOR currently represents the most immediate, highest value opportunity to utilize the greatest volumes of anthropogenic CO₂ with the greatest near-term potential to incentivize CCUS deployment. The full study is available at www.nationalcoalcouncil.org/studies/2016/NCC-CO2-Building-Block-FINAL-Report.pdf

Case Study on Glencore Land Rehabilitation Initiative in Australia — World Coal Association (WCA) — The WCA has published a new case study from Glencore which examines the company’s land rehabilitation initiatives in Australia. Glencore’s rehabilitation and restoration plans go beyond the mandatory requirements. The case study reviews the rehabilitation plans taking place at Mungoala, Liddell, Westside, and Mt Owen opencast mines. Each site develops and implements an Annual Rehabilitation Plan. This plan is incorporated into day-to-day operations. Among other aims, the annual rehabilitation planning process seeks to closely integrate rehabilitation with both short- and long-term (life of mine) mine planning and operations, and assist with quality implementation of rehabilitation works as planned and designed. The case study is available at www.worldcoal.org/file_validate.php?file=2016Glencore%20case%20study.pdf
Globally there are numerous conferences and meetings geared toward the coal and energy industries. The table below highlights a few such events. If you would like your event listed in Cornerstone, please contact the Executive Editor at cornerstone@wiley.com

<table>
<thead>
<tr>
<th>Conference Name</th>
<th>Dates (2016–2017)</th>
<th>Location</th>
<th>Website</th>
</tr>
</thead>
<tbody>
<tr>
<td>IEA GHG R&amp;D Programme 13th Greenhouse Gas Control Technologies Conference</td>
<td>14–18 Nov</td>
<td>Lausanne, Switzerland</td>
<td><a href="http://www.ghgt.info">www.ghgt.info</a></td>
</tr>
<tr>
<td>2017 8th International Conference on Clean Coal Technologies</td>
<td>8–12 May</td>
<td>Cagliari, Italy</td>
<td><a href="http://www.cct2017.org">www.cct2017.org</a></td>
</tr>
</tbody>
</table>

There are several other Coaltrans conferences globally each year. To learn more, visit www.coaltrans.com/calendar.aspx

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If you have a suggestion, email the editorial team at cornerstone@wiley.com (English) or cornerstone@shenhua.cc (Chinese)
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