21st Century Coal

Advanced Technology and Global Energy Solution

Report by the IEA Coal Industry Advisory Board

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Coal Industry Advisory Board

The IEA Coal Industry Advisory Board (CIAB) is a group of high-level executives from coal-related industrial enterprises, established by the IEA in 1979 to provide advice to the IEA Executive Director on a wide range of issues relating to coal. The CIAB currently has over 40 members from around 20 countries, contributing valuable experience in the fields of coal production, trading and transportation, electricity generation and other aspects of coal use.

For more information about the IEA Coal Industry Advisory Board, please refer to www.iea.org/ciab, or contact Carlos Fernández at the IEA (carlos.fernandez@iea.org) or Brian Heath, CIAB Executive Co-ordinator (mail@ciab.org.uk).

The Electric Power Research Institute, Inc. contributed to the technical content of this publication as an independent and unbiased entity and does not necessarily endorse the conclusions made herein.

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Executive Summary

In 2009, the term “21st Century Coal” was jointly coined by the governments of China and the United States to describe the importance of strategic international partnerships to advance development of near-zero emissions (NZE) technology enabling clean energy solutions from coal (OPS, 2009). Coal industry leaders have embraced the concept of “21st Century Coal”, viewing the term in an even broader context as a term which symbolises the future of coal in the world. This future rests on a foundation of several elements, including an uncompromising commitment to safety, modern cutting-edge mining techniques, world-class land restoration practices and a technology path to NZE.

This report’s focus is on the latter element of “21st Century Coal”: the technology path to NZE. It addresses the progress of high efficiency and other advanced coal-fuelled generation technologies, the promise associated with enhanced oil recovery in restoring momentum for carbon capture, and the dynamism of coal-fuelled power plants in ensuring stable electricity supply. Coal will continue to be a global energy solution through this century, and this report demonstrates the compelling reasons for confidence in coal’s ability to provide a solution to the global objectives of economic sustainability, energy security, and NZE.

The report is organised around the following topics:

- *Coal and the CO_2 challenge*

  discusses the benefits of and the need for coal, issues associated with coal use especially related to carbon dioxide (CO_2) emissions, and roadmaps to improve coal use and continue on a path toward zero emissions.
- *Evaluation of advanced coal-fuelled electricity generation technologies*

  provides insights into groundbreaking technology innovations for advanced coal plants to improve efficiency and reduce emissions including CO_2.
- *Carbon capture, utilisation, and storage (CCUS)*

  focuses on the exciting potential for enhanced oil recovery (EOR) to enable the economic viability of carbon capture and storage (CCS), together with the need for and status of CCUS demonstrations.
- *Flexibility of coal-fuelled power plants for dynamic operation and grid stability*

  assesses the essential features of fossil-fuelled power plants to operate dynamically on grids with intermittent wind and solar.

Box 1 • Key messages of the report

- Advanced coal with CCS is essential: Any plan for reducing greenhouse gas (GHG) emissions significantly must include advanced coal generation with CCS. The time window for technology investments to potentially reconcile the policy objectives of secure global energy supply and the mitigation of growth in GHG emissions is closing, requiring renewed focus on coal. In particular, significant efforts should be made to make certain that CCS demonstration projects move forward.
- Higher Efficiency Is a Key First Step in Lowering CO_2 Emissions: An estimated 59 Gtonnes (65 Gtons) of reduced CO_2 emissions from coal power could have been achieved, had new coal units over the past 50 years used the highest efficiency technology available when built. This is a significant amount of CO_2, equivalent to the world not producing any CO_2 over the next two years, and illustrates the importance of efficiency gains in reducing CO_2 emissions.

Box 1 • Key messages of the report *(continued)*

- Significant Advancements in Coal Technology: Multiple technologies are being developed for coal power designed to improve efficiency, lower emissions, and reduce both costs as well as the energy penalty associated with CCS. Current best-in-class efficiencies for coal power plants are over 40%. In the 2020 timeframe, efficiencies could be as high as 42% and by 2030 up to 46–48%. More advanced future coal-based power cycles could achieve efficiencies near 60%. Similarly advances in environmental controls for emissions and capture of CO_2 under development are providing a path toward NZE for future coal-fuelled power plants.
- Game-Changing Promise of EOR: CCUS-EOR holds transformational potential in terms of both GHG emissions reductions and global energy security. Worldwide application of EOR could recover over one trillion additional barrels of oil, with associated permanent storage of 320 Gtonnes (350 Gtons) of CO_2. Furthermore, EOR needs CCUS and vice versa since: a) large-scale realisation of EOR needs CO_2 from power generation and b) revenues from the sale of CO_2 for EOR provide significant benefit to CCUS economics.
- Coal Power Plants Are Highly Flexible: A case study on the German electricity market demonstrates that coal-fuelled units have considerable flexibility needed to follow dynamic grid operation caused when intermittent renewables are added to the electricity portfolio. This flexibility is critical to ensuring grid stability during extended use of intermittent wind and solar energy sources. Optimised coal-fuelled power plants are shown to be able to achieve part-load levels of less than 20% with ramp rates of approximately 3 percentage points per minute, allowing changes in the mode of operation between full and part load in under 30 minutes. These results indicate that coal units exhibit as much flexibility as other units in power systems, including natural gas combined cycle ones.

Coal and the CO_2 challenge

- Worldwide, over 30% of the total energy demand and over 40% of the electricity generated comes from coal.
- Global energy demand is projected to grow significantly and, under the existing mix of generation technologies, would contribute to increased CO_2 emissions.
- Maintaining the benefits of electricity generated from coal is essential in improving the human condition, particularly in the developing world; the challenge of maintaining these benefits while addressing CO_2 emissions is surmountable through technology.
- Studies show that a full portfolio of technologies must be available to reduce GHG emissions at least cost, starting with advanced coal power generation with CCS; studies further show that achieving ambitious climate goals is significantly less expensive with CCS than without CCS.
- Lowering CO_2 emissions from fossil-fuelled power plants requires a two-step approach: 1) increasing thermal efficiency, which provides a modest but significant reduction in CO_2 emissions; and 2) adding CCS, which brings more dramatic reductions.
- Increasing energy efficiency, much of which can be achieved through lower-cost options, offers the greatest potential for reducing CO_2 emissions over the period to 2050.
- The IEA roadmap for achieving advanced coal with CCS currently envisages just under 280 GW of CCS-equipped power plants globally by 2030 and 630 GW of CCS-equipped coal-fuelled power plants by 2050. Delays in project development may require an update of this objective, however.

- The development and deployment of advanced coal with CCS technologies that is needed to achieve substantial CO_2 emission reductions will require sustained and significant research, development, and demonstration (RD&D) investment.
- Financial incentives and greater regulatory certainty are required to accelerate RD&D on advanced coal with CCS.

Evaluation of advanced coal-fuelled electricity generation technologies

- Multiple types of coal-fuelled power plant technologies exist or are being developed, each with its own potential advantages and challenges. At this point there is no "clear winner" and therefore all technologies need to continue to be advanced.
- Similarly, several techniques for CCS are being developed with a limited number of demonstrations ongoing worldwide. While the energy penalty (and cost) of CCS is still prohibitive, gains are being made towards reducing it to 20%.
- Current coal power plants are capable of achieving net thermal efficiencies of ~40%[1] and very low emissions.
- Improvements in materials will allow higher steam and gas-firing temperatures, with correspondingly higher efficiencies and lower CO_2 production.
- State-of-the-art environmental controls can achieve NZE.
- More advanced, future technologies are capable of further improving efficiency; fuel cells in particular hold the potential of achieving 60% efficiencies.

Carbon capture, utilisation, and storage

- Since the power industry is among the major sources of CO_2 emissions, CCS demonstrations on power plants are needed. It is also necessary to demonstrate storage at sufficient scale.
- CCS demonstrations will only proceed with significant government support.
- Several dozen large-scale CCS demonstrations have been proposed or are ongoing throughout the world, capitalising on government funds; however, several CCS demonstrations have recently been cancelled or postponed.
- The inclusion of China and India will be of vital importance in achieving the necessary progress in advancing CCS deployment.
- The majority of projects moving forward are CCUS projects utilising EOR, which provides an additional revenue stream that assists the commercial viability of the projects.
- EOR has been profitable for 40 years under existing regulations in the United States.
- Nearly 100% of the CO_2 used for EOR operations will be stored at the end of active injection.
- All current EOR uses either natural CO_2 or CO_2 from natural gas processing or chemical plants.
- A sizeable percentage of the existing EOR sites are within 50 km (31 miles) of the CO_2 source itself.

[1] All thermal efficiencies in this report are net plant efficiencies and are on an HHV basis. Although the relationship between efficiencies on the HHV and NHV bases depends on the coal quality, as a rule of thumb, net efficiencies on a NHV are around 5% higher. For example, 40% on an HHV basis corresponds approximately to 42% on a NHV.

- Approaches to increase CO_2 storage in conjunction with EOR may further increase storage capacities, even to the point of storing more CO_2 than is associated with the life cycle of the incremental oil produced from EOR.
- Without the opportunities for CO_2 storage that EOR can facilitate, CO_2 storage at commercial scale is unlikely to occur.

Flexibility of coal-fuelled power plants for dynamic operation and grid stability

- In order to ensure grid stability, growing usage of intermittent resources requires conventional units, including coal-fuelled ones, to be increasingly flexible to handle more dynamic operation;
- The need to improve the flexibility of current and future coal plants can be achieved with a portfolio of strategies involving both technical and operational improvements including:
- Implementing coal plant flexibility early during design, when it is most effective
- Making greater use of the capabilities of existing control systems
- Collecting and using lessons learned to establish better operating practices.
- In the future, plant designers will face the requirement to balance high thermal efficiency with improved flexibility in the operation of future coal-fuelled power stations; as such, it is essential that operational flexibility be considered early in the design phase – as is the case in Germany – so that advanced technology can be incorporated into new plant layouts
- For coal power plants with CCS and future advanced cycles, limits on flexibility will not be fully understood until the operation of such plants is demonstrated
- A case study based on the German power market concludes that existing coal power plants can operate flexibly in response to the dynamic market required by increased renewables on the grid; as a result, early replacement of these plants would have negative consequences.

1. Coal and the CO_2 challenge

It is hard to find a single aspect of life that has not been transformed by electric power. Nearly all advancements in medicine, transportation, manufacturing, communications, and information technology were attainable because of electricity. Indeed, the availability of reliable and affordable electricity has been shown to have a strong positive impact on standard of living, poverty eradication, health, education, and regional economies.

Around the world, requirements for energy and electricity are largely met by fossil fuels, and coal is often the predominant fuel choice because it is a secure and low-cost energy source, and because coal resources are abundant and broadly distributed geographically. Coal also is relatively easy to mine, ship, and store. These qualities make coal-fuelled power plants important electricity price stabilisers and reliable power producers, especially in electricity systems using more price-volatile or intermittently available resources.

Worldwide, based on 2009 figures, almost 30% of the total energy demand – 3 294 million tonnes of oil equivalent (Mtoe) – and over 40% of the electricity generated – 8 200 terawatt hours (TW-hr) – comes from coal (see Table 1).

Table 1 • 2010 World energy demand and electricity generated

Fuel type	Demand Mtoe	Demand	Generation TW-hr	Generation
Coal	3 474	27%	8 687	40%
Oil	4 113	32%	1 000	5%
Natural gas	2 740	22%	4 760	22%
Nuclear	719	6%	2 756	13%
Hydro	295	2%	3 431	16%
Non-hydro renewables	1 389	11%	776	4%
Totals	***12 730***		***21 408***	

Source: IEA, 2011.

Coal remains the fastest growing source of fossil fuel, adding more to the absolute world energy supply in the last decade than almost all other forms of energy combined. The most significant rise in coal consumption is in the rapidly developing economies of China, India, and other Asian nations, where large supplies exist or are readily obtainable through expanded seaborne trade. Forecasts predict that these countries will continue to build and strengthen their economies and improve living conditions by largely using coal for electricity generation. For example, the IEA has estimated that China alone will commission about 600 GW[2] of new coal-fuelled generating units by 2030, more than doubling its coal-fuelled capacity (IEA, 2011).

Given the large investment in coal-based power plants in service and under development around the world, it is clear that many nations will continue using coal for electricity generation for decades to come. This is exemplified by a statement from Xiao Yunhan, a leading energy expert in the Chinese Academy of Sciences: "Even if China utilises every kind of energy to the maximum level, it is difficult for us to produce enough energy for economic development. It's not a case of choosing coal or renewables. We need both." (WCA, 2011). Many countries also view their indigenous coal resources as an essential element of their plans for national economic development and security.

[2] All numerical references to power in this report are on a net electrical output basis unless indicated, e.g., if the power is on a thermal basis, a "th" label is used.

As is the case with any fuel, maintaining the benefits of electricity generated from coal presents challenges, particularly related to environmental issues. For example, since electricity generation from coal has had increasingly strict emission regulations enacted on its emissions (particulates, sulphur dioxide [SO_2], nitrogen oxides [NO_X], and mercury) over time, producers of coal-based electricity have needed to respond by significantly improving emission controls. Reducing water use is also emerging as a priority for the power industry, including for coal-fuelled power plants, due to shortages in and competing demands for water in some regions.

One of the principal challenges faced by coal is CO_2 emissions. This is exemplified by the recently proposed United States Environmental Protection Agency's (EPA) rule on GHG emissions for new sources, which states that new fossil-fuelled units greater than 25 MW must meet an output-based standard of 455 kg CO_2/MW-hr (1 000 lb/MW-hr) (EPA, 2012) – a standard that current coal-fuelled plants cannot attain.

The power industry has risen to challenges in the past and has progressively improved coal power plant designs to meet increasingly tougher emission limits. Successive technology advances also have leveraged thermodynamic principles and economies of scale to increase net efficiency (which simultaneously reduces CO_2 emissions by lowering fuel use) and reduce the cost of electricity. As shown in Table 2, using the United States market as an example, new pulverised coal (PC) plants are far cleaner and more efficient than plants built in the past.

Table 2 • Progression of coal power technology development in the United States

Year	19211	1960s-1970s Subcritical PC	2007-08 Supercritical PC2	Ultra-supercritical (USC) PC3	Advanced USC (A-USC) PC4
Net output, MW	40	350-1 300	540-790		
Net efficiency, %	24	34	38	39.2	42.7
Main steam temperature, °C (°F)	322 (611)	541 (1 005)	570-585 (1 057-1 085)	604 (1 120)	680 (1 256)
Main steam pressure, bara (psia)	21.6 (315)	179 (2 600)	254-262 (3 680-3 800)	276 (4 000)	352 (5 100)
SO2, kg/MW-hr (lb/MW-hr)	37.9 (83.6)	27 (59)	0.41 (0.9)		
NOx, kg/MW-hr (lb/MW-hr)	4.1 (9.1)		0.27 (0.6)		
Mercury, kg/MW-hr (lb/MW-hr)			0.73x10-6 (1.7x10-6)		
CO2, kg/MW-hr (lb/MW-hr)	1 290 (2 850)	910 (2 010)	853 (1 880)	834 (1 840)	767 (1 690)

1. Fleet average values for Illinois #6 coal with heating value of 25 500 kJ/kg (11 000 Btu/lb) and 3.2% sulphur.
2. Values for Powder River Basin (PRB) coal with heating value of 19 400 kJ/kg (8 340 Btu/lb) and 0.3% sulphur.
3. Estimated and published values for newly commissioned supercritical PC units firing PRB coal.
4. Values for A-USC PC unit firing PRB coal, assuming technology available for commissioning in ~2015.

Source: EPRI, 2011.

The CO_2 challenge, however, exceeds that for other air emissions because CO_2 is a primary product of combustion, not the product of side reactions involving coal's minor constituents. As shown in Table 2, the quantity of CO_2 to be removed dwarfs that of SO_2 and NO_X. However, the industry's documented ability to overcome previous challenges gives confidence to the proposition that reduction of CO_2 emissions can also be successfully addressed, although the level of effort to do so will be unprecedented. The path for rising to this challenge and achieving the goal of NZE is based squarely on the advancement and implementation of technology.

The challenge of reducing CO_2

The challenge of reducing GHG emissions comes at a time when global electricity demand growth and concerns about economic recovery are placing a premium on new, cost-effective power generation. Innovative technology approaches will be required for the electricity sector to substantially reduce GHG emissions while minimising negative economic impacts.

The IEA has detailed the following three potential scenarios based generally on expected increase in global temperatures by 2050 (See Table 3 for scenario descriptions). The significant difference in their outcomes underlines the critical role that governments have in defining the objectives and implementing the policies necessary to shape the future path of energy use.

Table 3 • IEA policy scenarios

Scenario	Description
6°C Scenario (6DS)	Assumes no new policies are added to those currently in place. In the absence of efforts to stabilise atmospheric concentrations of GHGs, average global temperature rise is projected to be at least 6°C (10.8°F) in the long term.
4°C Scenario (4DS)	Assumes recent government policy commitments are to be implemented in a cautious manner – even if they are not yet backed up by firm measures. In many respects, this is already an ambitious scenario that requires significant changes in policy and technologies. Moreover, capping the temperature increase at 4°C (7.2°F) requires significant additional cuts in emissions in the period after 2050.
2°C Scenario (2DS)	Sets out an illustrative energy pathway for meeting the goal of limiting the increase in average global temperature to 2°C (3.6°F) by 2050 a temperature rise deemed to be relatively low-risk.

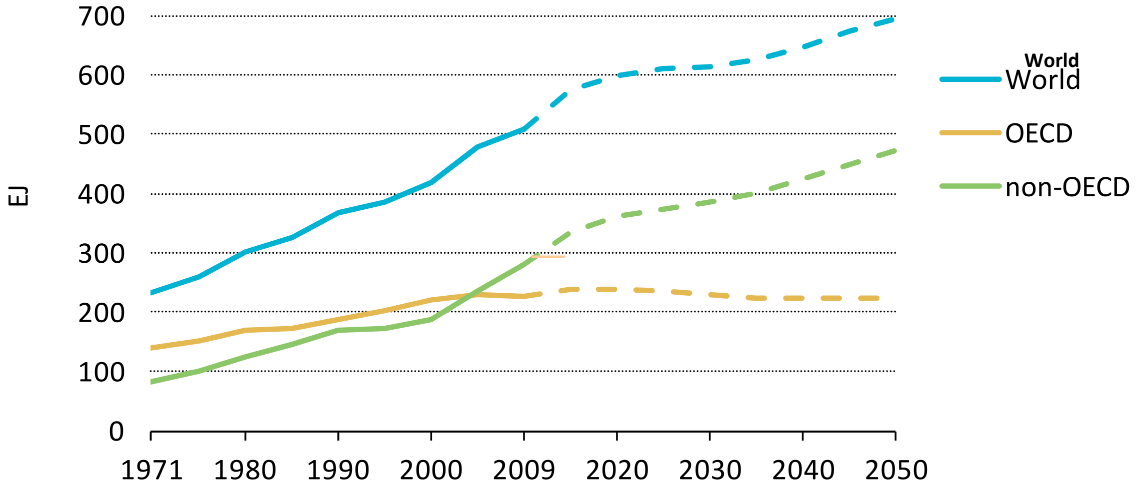
Source: IEA, 2012.

It is important to note that these are scenarios and not projections. The IEA states that the 2DS will be impossible to achieve without "… significant decoupling of energy use from economic activity, which requires changes in technology development, in economic structure and in individual behaviour" and that "Without this decoupling, achieving the 2DS becomes very costly if not impossible." Many of these changes are unprecedented.

The projected world energy demand through 2050 in the 2DS is shown in Figure 1. Total world energy supply increases by 39% between 2009 and 2050, largely in countries not part of the Organisation for Economic Cooperation and Development[3] (OECD) as they increase their economic activity and standard of living. (In the 6DS, world energy demand in 2050 is 76% above 2009 demand).

[3] OECD refers to 34 member countries grouped in an international economic organisation founded in 1961 to stimulate economic progress and world trade. Countries include Australia, Austria, Belgium, Canada, Chile, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Sweden, Switzerland, Turkey, the United Kingdom, and the United States.

Figure 1 • World energy demand, IEA 2DS global temperature rise scenario



Source: IEA, 2012.

Similarly, when looking at world electricity production, the 6DSshows the largest increase from 20 043 TW-hr in 2009 to 49 232 TW-hr in 2050, an annual growth rate of 2.2%, driven by economic and population growth. The 4DS projects a slightly lower growth to 44 087 TW-hr in 2050 and the 2DS a growth to 41 565 TW-hr. Again the differences are largely due to a greater implementation of efficiency improvements, but also include major shifts away from coal use in scenarios 4DS and 2DS.

In all cases, China and India account for over half of the increase in electricity generation, with OECD countries making up less than one-fifth. Non-OECD countries account for the vast majority of the growth with a three times larger average annual growth rate in electricity demand compared to OECD countries.

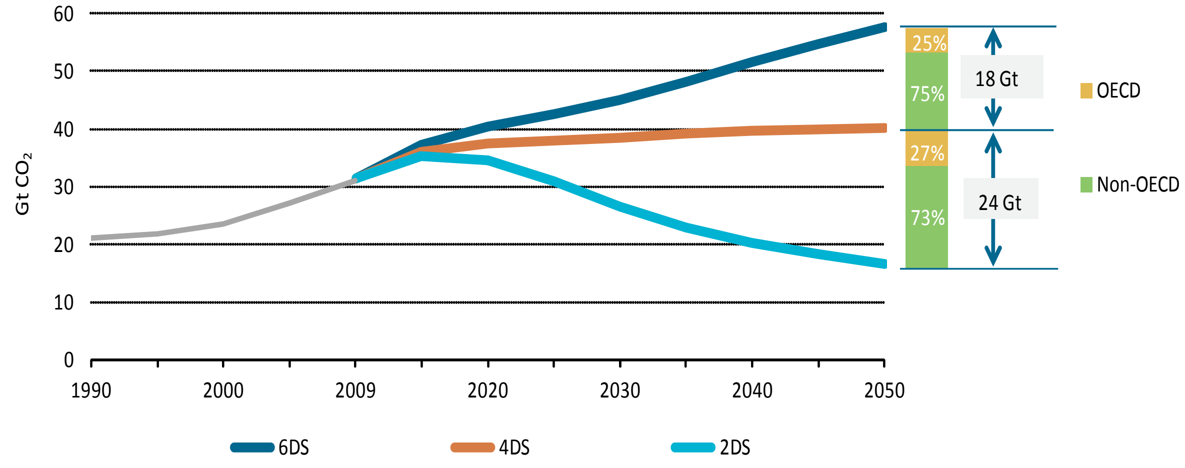
Box 2 • Projected growth in global population and gross domestic product

The world's population is assumed to increase by 26%, from 6.8 billion in 2009 to 8.6 billion in 2035, with over 90% of the increase in non-OECD regions (IEA, 2011).

Global gross domestic product (GDP) is projected to increase from USD 70.8 trillion in 2009 to USD 176.2 trillion in 2035 with an average annual growth rate of 3.6%. Non-OECD countries account for a significant portion of the overall economic growth, increasing their share of global GDP from 44% in 2009 to 61% in 2035 (JEDH, 2005).

Meeting future energy demand with the existing mix of power generation technologies would cause a significant rise in CO_2 emissions. The IEA predicts a rise of CO_2 emissions originating from energy production from 31 Gtonnes (34 Gtons) to 58 Gtonnes (64 Gtons) by the year 2050 in the 6DS (see Figure 2), which, according to computer models, would cause the average global temperature to rise 6°C (10.8°F), substantially above the low-risk 2DS scenario of 2°C (3.6°F). To reduce these potential risks, ways must be found to reduce the world's carbon intensity while still promoting productivity and maintaining the benefits of affordable electricity.

Figure 2 • World energy-related annual CO_2 emissions



Source: IEA, 2012.

The simplest conceptual approach for reducing power plant CO_2 – switching to lower carbon intensity fuels or energy sources – is unrealistic and subject to the following limitations:

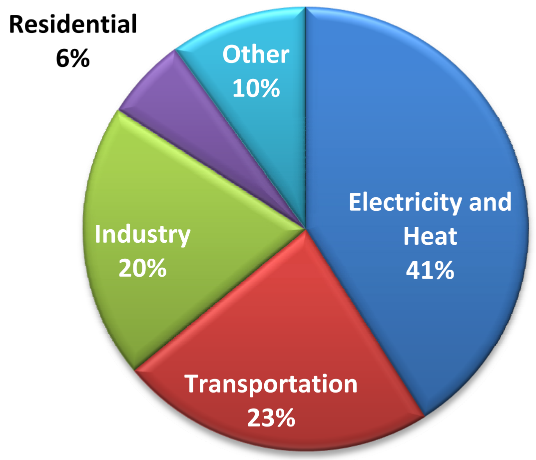
- Renewables-based electricity, even at aggressive build-out rates, will not be sufficient to solely meet the world's need for energy in the foreseeable future. The cost, distribution, and intermittency of key renewable sources such as solar, wind, and hydroelectric generation limit their applicability and use.
- Public concerns related to the safety and cost of nuclear power, which have been exacerbated by the tragic events in March 2011 at the Fukushima plant in Japan
- The carbon content of natural gas, which results in significant CO_2 emissions from this fuel even with efficiency improvements, especially when the full life cycle is considered
- The historically volatile cost of natural gas and non-CO_2 GHG emission rates during production and transportation of gas from some sources (*i.e.*, fugitive emissions of methane)
- Financial, political, and technological limits on the siting, construction, and renovation of power facilities
- Trade-offs between competing environmental concerns.

It should be noted that while electricity production is the largest source of anthropogenic GHGs, it represents less than half of the overall GHG production worldwide (as seen in Figure 3).

Reducing GHGs from these other sectors, transportation in particular, will also be a necessary part of the overall strategy for achieving global emissions goals. One of the many potential solutions (which include improving efficiency and the electrification of transportation) that has relevance here is the recent push for reducing short-lived climate pollutants such as methane and black carbon (OS, 2012). While methane has a shorter atmospheric lifetime, it is a GHG that is 20 to 25 times more potent than CO_2. Another short-lived atmospheric pollutant, black carbon (which is basically soot resulting from incomplete combustion of fossil fuels largely from transportation, agricultural, and residential sources), while not a GHG, contributes to potential climate change by absorbing light increasing the GHG phenomena and exacerbating polar icecap melting.

Measures to reduce methane and black carbon production in the short term include the recovery of methane from coal, oil, and gas extraction and transport; methane capture in waste management; use of clean-burning stoves for residential cooking; diesel particulate filters for vehicles; and the banning of field burning of agricultural waste (UNEP and WMO, 2011).

Figure 3 • World GHG emissions by sector



Note: Other includes commercial/public services, agriculture/forestry, fishing, and energy industries other than electricity and heat generation.

Source: IEA, 2012.

Fast action to implement these measures can lower GHG concentrations expected by 2050 by as much as 0.5°C (0.9°F), effectively helping to buy time for research and development (R&D) for longer-range measures like advanced coal generation with CCS, as well as advanced non-coal options.

Full portfolio approach

An important supplement to increasing energy efficiency is to reduce the carbon intensity of fossil fuels by reducing CO_2 emissions produced when those fuels are used.

The primary approach to accomplish this is through CCS whereby the CO_2 is captured from the process and then compressed for storage in deep geologic formations potentially requiring transmission via pipelines. While other potential CO_2 sequestration methods exist, including biological and mineralisation techniques, CCS is considered to be the primary vehicle for accomplishing the largest share of CO_2 reductions required from fossil plants under the IEA 2DS.

Capture technologies produce CO_2 that in some locations can be used for EOR. EOR uses supercritical CO_2 to effectively remove residual oil or gas from underground reservoirs to be withdrawn by production wells. EOR has the potential for storing significant amounts of CO_2 and has been a commercial practice for 40 years.

When the captured CO_2 is used for a useful process, such as increasing oil production from a site as in the case of EOR, the term CCUS is used. For CCUS applications, the CO_2 can provide a revenue stream for the CCS project, which can help offset the significant costs associated with CO_2 capture, compression, and transportation. Combining state-of-the-art lower-cost capture technology with EOR would serve to produce the best economics for CCS applications and is potentially the only recourse for CCS, at least in the short term, without CO_2 regulation in place.

Therefore, particularly in the near future, CCUS will likely be implemented first. More details on EOR and CCUS are provided in Chapter 4.

Analyses by several groups have concluded that the most economical electricity generation strategy to reduce CO_2 emissions entails developing and deploying a "full portfolio" of low-carbon technologies. Advanced coal power generation with CCS plays an integral part in such a portfolio, which also includes renewable energy resources, nuclear, efficiency improvements throughout the chain, and fuel switching amongst other potential technologies. Without timely implementation of advanced coal power including CCS, and other components of the full portfolio, substantial reductions in CO_2 and other GHG emissions likely would come at a much greater cost. As Norway's prime minister Jens Stoltenberg stated at the opening of the Test Centre Mongstad CCS demonstration plant in May 2012: "With nine billion people expected on the planet in 2050, there is no way we can choose between increased energy production and reduced CO_2 – we have to achieve both. Without CCS, we cannot do it (Carrington, 2012)."

The full portfolio approach to lowering CO_2 emissions is essential because no single low-carbon technology has clear-cut advantages in all circumstances. Power producers employ different generation strategies to match local resources, needs, and markets in different regions of the world. As the substantial investments being made in coal power generation in India and China continue, while in other areas of the world coal power is growing slowly or declining, the dichotomy of views on coal power requires a diversity of approaches to limit CO_2 emissions.

Energy economics studies of CO_2 reduction

IEA projections

The IEA estimates that in the 6DS, global energy use will increase 85% between 2009 and 2050 with an accompanying 56% increase in CO_2 emissions. The increase in CO_2 emissions associated with this increase in energy use comes largely from the non-OECD countries as these populations increase their economic activity and standard of living.

The IEA's least-cost strategies for the 2DS result in a 50% reduction of energy-related GHG emissions by 2050 (compared to 2009 levels). Achieving this level of CO_2 emissions reduction will require: reduction in energy demand (efficiency and conservation), increased use of nuclear and renewable resources, and CCS from stationary fossil fuel uses. The IEA concludes that CCS will need to contribute at least 20% of the necessary emissions reductions to achieve stabilisation of GHG concentrations in the most cost-effective manner.

Removing CCS from the list of options to reduce emissions in electricity generation increases the required capital investments necessary to meet the same emissions constraint by at least 40% and in the electricity sector relative to the incremental capital investment required to reach the 2DS target. Moreover, because the IEA analysis covers the entire world, where many countries are tied to coal without an option for natural gas or effective renewable energy (*e.g.,* China and India), it reflects the strong relationship between coal and the worldwide economy. Other relevant highlights include:

- A full portfolio of low-carbon technologies will be necessary to halve CO_2 emissions by 2050. No one technology can deliver the magnitude of change required. If CCS is not widely deployed in the 2020s, an extraordinary burden would rest on other low-carbon technologies to deliver lower emissions in line with the global climate objectives represented by the 2DS.
- CCS is a key CO_2 emissions reduction option, but it faces regulatory, policy, and technical barriers that must be overcome or its deployment is uncertain

- If CO_2 emissions peak later than 2020, achieving the 50% reduction target by 2050 will become much more costly. Attempting to do this at a later point in time would require more rapid CO_2 reductions, entailing much more drastic action on a shorter time scale and significantly higher costs.
- Increasing energy efficiency, much of which can be achieved through low-cost options, particularly for end use improvements, offers the greatest potential for reducing CO_2 emissions over the period to 2050

- CCS technology must also be adopted by biomass and natural gas power plants in the fuel transformation and gas processing sectors, and in emissions-intensive sectors like cement, iron and steel, and chemicals manufacturing.

Additional studies

Additional studies corroborate the need for CCS, echoing IEA's analysis showing that reducing CO_2 without including advanced coal generation with CCS will increase costs and electricity prices:

- The Global CCS Institute (GCCSI) was formed by the Australian government in 2008 to work collaboratively to build and share the expertise necessary to ensure that CCS can make a significant impact towards reducing the world's GHG emissions. One focus of the GCCSI is to monitor the overall progress of CCS and CCS projects. GCCSI states in its recent update on worldwide efforts on CCS that a large-scale demonstration effort is needed in order to prove CCS technology at full scale. Such large-scale demonstrations, across a range of technologies and in different operating environments, are a necessary precursor to commercial deployment of CCS, and to help drive cost reductions that are expected as technologies mature (GCCSI, 2012a).
- Another Australian entity, the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), states that a full portfolio approach that includes CCS and takes every opportunity to reduce GHG emissions will be required to meet the challenge of minimising potential risks of global climate change. Global modeling performed by CO2CRC indicates that widespread deployment of CCS would result in atmospheric concentrations of CO_2 being at least 100 ppm lower than would otherwise be the case (CO2CRC, 2011).
- An interdisciplinary study published in 2007 by the Massachusetts Institute of Technology examined the viability of coal power under scenarios in which mandated GHG reductions imposed an added cost on its use for power generation (MIT, 2007). The report concluded that despite cost premiums for GHG controls, coal would continue to play a "large and indispensable role" in supplying electricity for a growing world population. The report further identified CCS as "the critical enabling technology that would reduce CO_2 emissions significantly while also allowing coal to meet the world's pressing energy needs."
- The Electric Power Research Institute (EPRI) has conducted several analyses that examine the technical feasibility and potential economic impact of achieving large-scale CO_2 emissions reductions in the United States while meeting growth in United States electricity demand (EPRI, 2009d). EPRI's analysis suggested that the technical potential exists to reduce 2030 annual CO_2 emissions from the United States electricity sector by 41% relative to 2005 emissions, based on an assumption of a balanced full portfolio of increased performance and deployment of eight key electricity sector technologies. CCS technologies applied to advanced coal-based power plants coming online after 2020 play a critical role in this portfolio. The limited portfolio scenario, without availability of CCS and without any expansion of nuclear power, results in projected 2050 wholesale electricity production costs that are nearly double projections associated with the full portfolio of technologies.

- The Canadian organisation Integrated CO_2 Network (ICO2N) studied the potential supply, timing, and cost of GHG emission reductions from a variety of alternatives in the Canadian context. The findings produced by the Delphi Group showed that CCS (for the chemical industry, coal power, and oil sands production) has the most significant potential for annual reductions, based on an analysis of current and future drivers for installation/adoption in each sector and is closely followed by nuclear, wind power, and vehicle fuel efficiency improvements (in that order) (Delphi Group, 2009).
- The Intergovernmental Panel on Climate Change's CCS Special Report found that CCS would provide 15% to 55% of the cumulative mitigation effort up to 2100 (IPCC, 2005).
- The Stern Review found that omitting CCS would, on average, increase overall GHG abatement costs (Stern, 2005).

Research, development, and demonstration to prepare coal generation for a low-carbon future

Economic analyses show that the dual strategy of improving efficiency and CO_2 capture system performance is the optimal path to competitive advanced coal power systems with CCS. This section provides a high-level review of these topics.

Ultimately, power generators plan for additions to their system based on providing the lowest life-cycle levelised cost of electricity (LCOE) to their consumers, while meeting all applicable environmental standards potentially including CO_2. When CCS is included, the "least-cost" option for an advanced coal plant is based on the projected LCOE being lower than that for competing lower-CO_2 emission technologies (including natural gas combined cycles [NGCC], nuclear, and renewable energy) in order for the plant to be selected.

In the two-step approach for lowering CO_2 emissions from fossil-fuelled power plants, increasing the thermal efficiency of the power plants provides a meaningful reduction in CO_2 emissions (and the lowest-cost reductions on a kg/MW-hr or lb/MW-hr basis) (EPA, 2009). Figure 4 shows how improvements in efficiency as technology advances get implemented can reduce CO_2 significantly. Pursuing efficiency improvements buys time for improvements in CCS technology and reduces its cost by lessening the amount of CO_2 to be captured.

However, ultimately if the dramatic reductions in CO_2 emissions that are needed to reach the goals in the IEA's 2DS are pursued, they can only be obtained by also implementing CCS. It should be acknowledged that different countries will likely pursue different options depending on their particular regional circumstances, *e.g.*, some will make the switch from the efficiency step to CCS at different times.

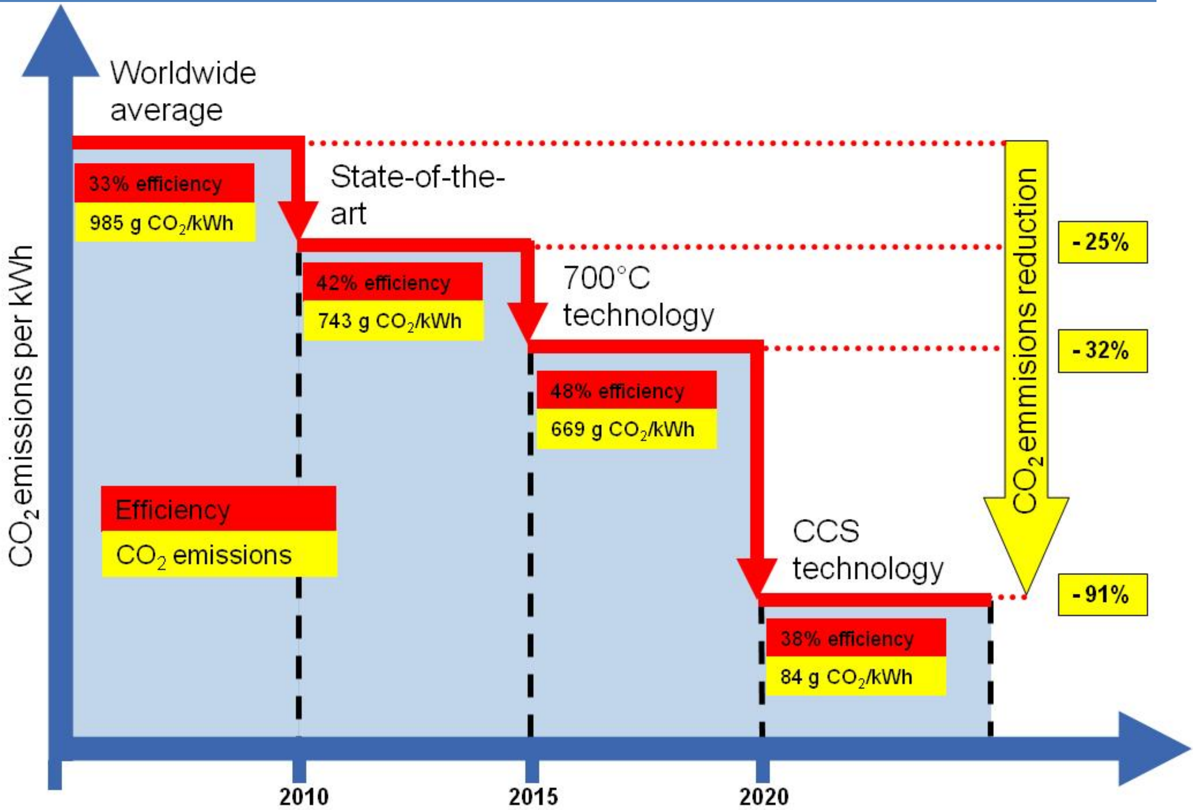
Step one: improving power plant efficiency

Increased thermodynamic efficiency reduces the amount of CO_2 generated per unit of plant output; plants that are more efficient can use smaller, less-expensive CO_2 capture systems. Other emissions also are reduced, as are the size, cost, and water consumption of cooling systems.

Numerous techniques are being developed and pursued for improving coal-fuelled power plant efficiency as will be described in Chapter 3. Principal amongst these is developing higher-temperature materials that can withstand higher steam temperatures, which in turn improves thermal efficiency. As shown in Figure 5, for the case of using a bituminous coal, increasing steam temperatures from the average subcritical range found in the United States up to A-USC conditions (760°C [1400°F]) improves net efficiencies by 14 percentage points with an associated 30% reduction in CO_2 production. Even moving from the state-of-the-art subcritical units to A-

USC produces a 9 percentage point improvement in efficiency and a 20% reduction in CO_2.

Figure 4 • CO_2 reductions at coal-fuelled steam-electric power plants from higher efficiency / CCS technologies (hard coal, 26 GJ/kg HHV, North Sea cooling water)



Source: RWE.

Box 3 • Estimating the impact of higher efficiency on lowering CO2 production

Installing the highest efficiency coal power plant possible has not always been the compelling concern for power generators:

- Where fuel costs are low, the incrementally higher capital cost of higher-efficiency power plants may not be justified by reduced fuel operating costs
- In many markets fuel costs may be passed through to the consumer, reducing the benefits (to the power generator) of lowering fuel costs through higher efficiency
- Higher efficiency plants are also riskier (since the technology is less mature), and plant owners are generally reluctant to accept higher risks for an investment financed over a 30 – 40 year life.

For these reasons, opportunities to reduce CO_2 production over time through higher efficiency have not been consistently exploited. An analysis was performed to estimate how much less CO_2 would have been produced from the world's coal fleet if the highest efficiency coal-fuelled plant designs (and hence the lowest CO_2-producing ones) available at the time were universally deployed whenever new coal generation was built.

The current global fleet of coal power plants produces ~1610 GW of generation. Of these, approximately 77% employ subcritical steam cycles, 20% supercritical steam cycles, and only about 3% use the highest efficiency USC steam conditions (IEA, 2012). The annual global production of CO_2 from coal power is ~13.3 Gtonnes (14.6 Gtons) based on 2010 numbers (IEA, 2011).

The first coal power plant, a low-temperature subcritical unit, was put into operation in the 1920s; the first supercritical coal-fuelled power plant was installed in the 1960s and the first USC plant was installed in the 1990s. However, since the first supercritical plants were constructed, ~1160 GW of new subcritical power has been put into place. Similarly, since the first USC unit went online, 570 GW of subcritical and 48 GW of supercritical power have been installed.

Box 4 • Importance of early deployment of advanced coal technologies *(continued)*

For purposes of the analysis, a database was used that listed the age of each unit in the world and rough assumptions were made on the CO_2 production for that plant over its lifetime based on given steam conditions (WEPP, 2011). Newer units were then artificially replaced with higher efficiency ones when the technology was available and the reduction in CO_2 was calculated as a result.

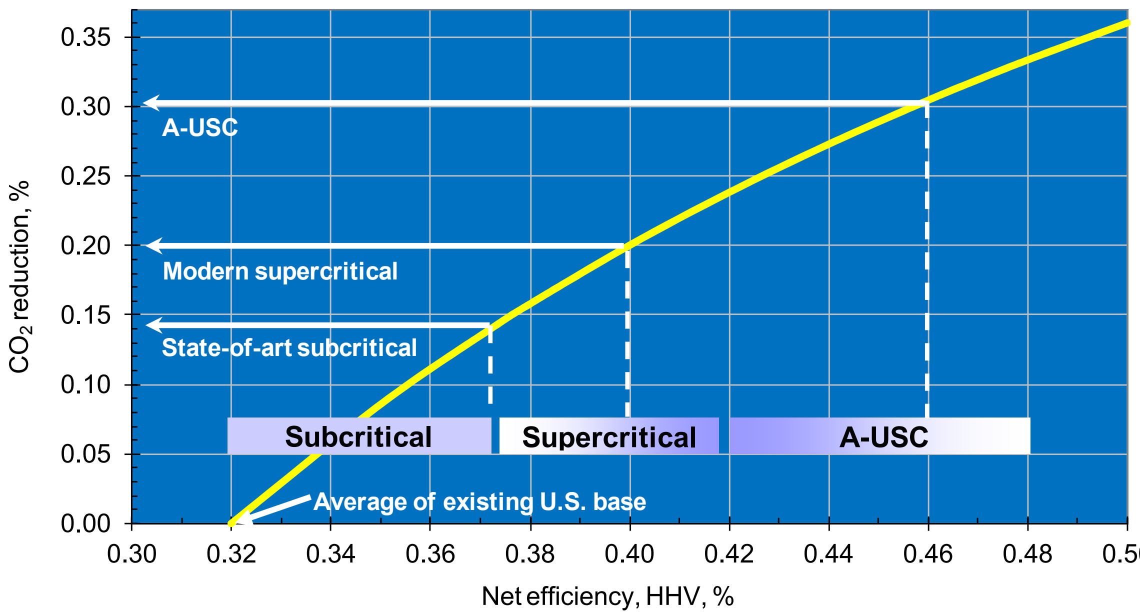
As an example, in the 2000–2010 time period, new coal-fuelled capacity amounting to ~350 GW of subcritical and 152 GW of supercritical power was installed in addition to 45 GW of USC power. Assuming the average CO_2 production for these plants was:

- Subcritical: 0.90 tonnes/MW-hr (1.0 tons/MW-hr)
- Supercritical: 0.84 tonnes/MW-hr (0.93 tons/MW-hr)
- USC: 0.80 tonnes/MW-hr (0.90 tons/MW-hr).

Replacing all of the subcritical and supercritical units with USC would have reduced cumulative CO_2 production in that decade by ~ 1.8 Gtonnes (2 Gtons), an 8% drop. Prior to the year 2000, coal power plants were even less efficient and consequently CO_2 production per MW-hr was higher, creating even more meaningful reductions had the highest efficiency power cycles available been deployed.

Based on these assumptions, the analysis estimated that the total cumulative reduction in CO_2 emissions from coal power that might have been achieved by the use of the best technology available was ~59 Gtonnes (65 Gtons), which is equivalent to 5 years aggregate of global CO_2 emissions from the current coal fleet, or total worldwide CO_2 emissions from all sources for 2 years. This illustrates the impact of efficiency on reducing CO_2 emissions and emphasises the need to pursue the highest efficiency plant designs going forward.

Figure 5 • High-efficiency coal power plants substantially reduce CO_2 emissions (bituminous coal)



Source: EPRI, published with permission from Babcock Power.

Step two: advancing CCS technology to commercial scale

It is technically possible today to incorporate equipment to capture CO_2 in all types of new coal-fuelled power plants. Depending on available space and other considerations, such equipment also can be retrofitted to existing coal-fuelled plants. The importance of retrofit should not be underestimated based on the large number of new coal units being added (especially in China and India).

Unfortunately, today's CO_2 capture technology is very costly. A recent review by the IEA of an array of engineering studies conducted by a range of organisations that showed the cost of electricity from a new coal power plant with CO_2 capture was estimated to be from 40 to 89% higher than a new coal plant without CO_2 capture (and this excluded the cost of transporting and storing the captured CO_2) (IEA, 2011a). Note that these costs represent "nth-of-a-kind" (NOAK) costs, meaning the costs after the technology has matured and multiple installations have occurred. The costs of capture and power from initial first-of-a-kind (FOAK) plants are typically significantly greater (NETL, 2012a).

Ultimately, in order to get over the hurdle and achieve the cost reductions brought by technology maturity, it will be necessary for governments to specifically support CCS demonstration projects with capital grants as well as support for the power prices. Even if additional revenues can be obtained from the sale of CO_2 for EOR, they may not be sufficient to allow full financing in all cases.

Box 4 • Importance of early deployment of advanced coal technologies

The historical record of technology development shows that costs, which tend to be highest at the start of the demonstration phase, subsequently begin to decline due to:

- Experience gained from "learning by doing"
- Increasing economies of scale in design and production as order volumes rise
- Removal of contingencies covering uncertainties and FOAK costs
- Competition from second- and third-to-market suppliers.

An IEA study conducted by Carnegie Mellon and others observed this pattern for power plant emission controls. The research team predicted a similar reduction in the cost of CO_2 capture technologies as their installed capacity grows**. RD&D of specifically targeted technology refinements can lead to greater cost reductions in the deployment phase. Once a technology reaches maturity, its NOAK costs often are relatively close to those originally projected.

Of the coal-based power and carbon storage technologies shown in Figure 7, only supercritical PC technology has reached commercial maturity. If all technologies in the portfolio can reach the stage of decli

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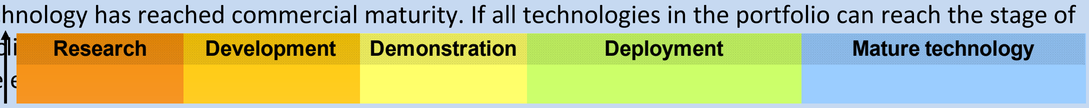
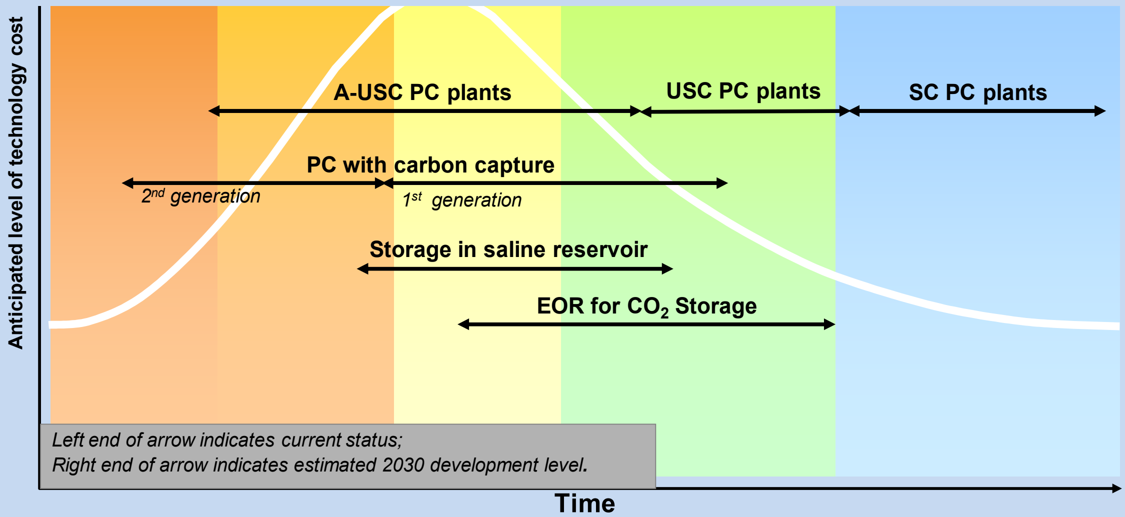


Figure 6 • Development status of major advanced coal and CO2 capture and storage technologies



Source: EPRI, 2012a.

Beyond the added cost, drawbacks to adding CO_2 capture to a given generating unit can include a reduction in plant output and efficiency, an increase in water consumption, increased control complexity, and decreased reliability and availability. For this reason, research into less expensive, less energy-intensive, and more flexible CO_2 capture technologies is a principal focus going forward.

CO_2 capture and/or reduction is only part of the CCS chain. Worldwide, important work is ongoing to assess infrastructure needs for pipelines to transport CO_2 from capture sites, reduce cost and improve the efficiency of CO_2 compression required for storage, identify CO_2 storage sites and their capacities, and assess the cost and performance of monitoring.

Storage of captured CO_2 in deep geologic formations in particular remains a significant issue for implementing a large-scale CCS programme worldwide. In fact, while storage work has been ongoing in various regions throughout the world for decades, several proposed large-scale CCS projects that had substantial funding from government sources have failed to move forward in this decade because of their inability to find a suitable site for storing the CO_2.

However, significantly more demonstration is likely required to prove that the technologies are safe and reliable at the scales required for capturing fossil-derived CO_2. Finally, attempting to overcome and address regulatory, legal, and long-term liability issues associated with CO_2 storage represents a significant issue.

At present, there is only a limited number of larger-volume CO_2 storage demonstration projects connected to coal-fuelled power stations. In 2009, American Electric Power (AEP) commissioned the first pilot project that integrated geologic storage with CO^2 capture (utilising Alstom's chilled ammonia CO_2 capture process) from a coal-fuelled power plant at its Mountaineer Station in West Virginia. The pilot ran for over two years successfully capturing approximately 50 000 tonnes (55 000 tons) of CO_2 and storing 30 000 tonnes (33 000 tons). In 2010, Southern Company Services started capturing 500-tonnes CO_2/day (550 tons/day) from Alabama Power's Plant Barry (utilising Mitsubishi Heavy Industries' [MHI] advanced amine CO_2 capture process). In late 2012, this site became the second integrated coal-fuelled CCS demonstration when it began storing the CO_2 in the nearby Citronelle oilfield.

Multiple organisations, including the IEA, EPRI, GCCSI, and government agencies throughout the world, agree on the need for demonstrations as the crucial link to commercialisation. However, while dozens of CCS demonstrations of various scales and types are planned, the first large-scale demonstration is not expected to operate until 2014 at the earliest.

Building a full portfolio of competitive advanced coal technology options

The development of advanced coal technology is proceeding, although at a pace hindered by a variety of policy, technical, and funding roadblocks. While it is technically feasible to reduce CO_2 emissions from coal-fuelled power generation, cut other emissions to near-zero levels, and reduce power plant water use and discharge, many of the necessary technologies are not yet at the level of developmental maturity required for affordable widespread deployment, and time and funding are needed to test and validate new technologies.

Achieving these goals, in particular mitigating the increase in GHG emissions, will require a broad programme of aggressive public- and private-sector RD&D to accelerate the commercial introduction and deployment of advanced coal-fuelled power generation technologies. Industry, government, and other stakeholders must play crucial roles in working together on collaborative RD&D programmes to develop self-sustaining, commercially-viable technologies.

Developing and deploying the advanced coal power and CCS technologies needed to achieve substantial CO_2 emission reductions within foreseeable economic constraints will require *sustained* RD&D investment at nearly unprecedented levels.

- The IEA estimates that OECD governments will need to increase funding for CCS demonstration projects to an average annual level of USD 3.5–4 billion between now and 2020. However, CCS technology must spread rapidly to the rest of the world through expanded international collaboration and financing for CCS demonstrations in non-OECD countries at an average annual level of USD 1.5–2.5 billion between now and 2020, bringing the worldwide total of required annual funding to USD 5–6.5 billion (IEA, 2009a). Note that in comparison, government subsidies for renewable energy sources worldwide were over USD 66 billion in 2010 (REN21, 2011).
- EPRI and others have estimated that over the next 25 years, a total RD&D investment of USD 30 billion will be required for coal-based technologies in the United States alone (MIT, 2007).

CCS roadmaps

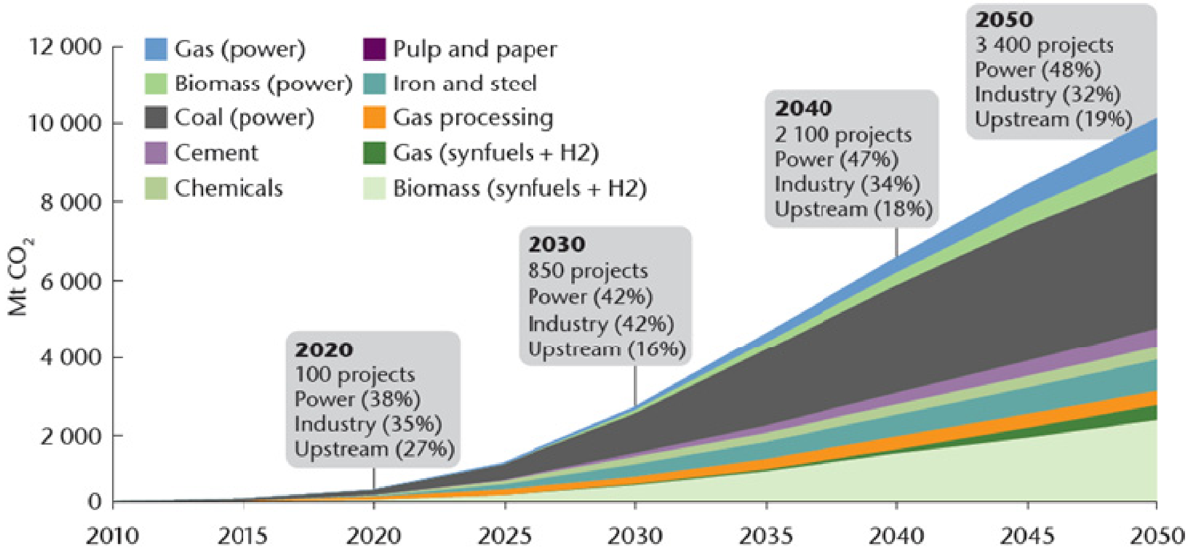
In addition to RD&D investments, an overall plan needs to be implemented for advanced coal generation with CCS technologies. Several organisations have put forward detailed plans for how to best achieve the multiple goals required.

The IEA CCS roadmap

The IEA developed a comprehensive roadmap for implementing CCS worldwide that was published in 2009. It provides a plan to cut GHG emissions back to 2005 levels by 2050 (a 50% reduction) by implementing CCS on multiple sectors including power, industry (*e.g.*, cement, chemicals, iron and steel, and pulp and paper), and upstream (*e.g.*, gas processing and fuels transformation). Key highlights include:

- IEA's roadmap envisages 100 CCS-related projects globally by 2020, 38% of which are in the power sector, and over 3400 total projects across all sectors by 2050 as shown in Figure 7 as a function of time and annual CO_2 emissions. The roadmap calls for virtually all fossil-fuelled (including natural gas) and biomass power plants to be using CCS by 2040.
- Beyond the funding required for CCS demonstration projects stated earlier, this roadmap's level of project development requires an additional investment of over USD 2.5–3 trillion from now to 2050, which is about 6% of the overall investment needed to achieve a 50% reduction in GHG emissions by 2050.
- To accomplish the roadmap's goals, particularly in the shorter term, mechanisms need to be established to incentivise and accelerate commercial-scale CCS deployment beyond the demonstration phase in the form of GHG reduction incentives, tax credits, or other financing mechanisms.
- Public engagement and education on CCS are cited as an important priority that requires additional government resources.
- The report emphasises the importance of the review of existing legal and regulatory frameworks for their ability to regulate CCS, identification of barriers or gaps, and creation of a comprehensive CCS regulatory framework, if required, by 2020.
- The report states that the roadmap will only be achievable via expanded international knowledge transfer, particularly on lessons learned during demonstrations.

Figure 7 • IEA CCS roadmap for deploying CCS



Source: IEA, 2009a.

It should be noted that the roadmap was described as ambitious when it was published in 2009. In the interim, a lack of worldwide progress on its stated goals is evident. While the original roadmap was vague on exactly what constituted a CCS project, clearly the world is not currently on a path to achieve anything like the degree of adoption of CCS technology recommended, especially in the short term. Current estimates are for an additional 10 larger-scale power-related CCS projects at most being achievable globally by 2020 nowhere near the 38 called for by the IEA. Similar concerns surround the likelihood that governments will provide the funding needed for CCS demonstration and commercialisation, particularly given the current state of the worldwide economy.

Maria van der Hoeven, Executive Director of the IEA, was reported as stating: "The current state of affairs is unacceptable precisely because we have a responsibility and a golden opportunity to act. Energy-related CO_2 emissions are at historic highs, and under current policies, we estimate that energy use and CO_2 emissions would increase by a third by 2020, and almost double by 2050. This would be likely to send global temperatures at least 6°C higher within this century (Harvey & Carington, 2012)."

Coal Utilisation Research Council-EPRI roadmap

The Coal Utilization Research Council (CURC)-EPRI coal technology roadmap initially produced in 2000 was most recently updated in 2012 (CURC and EPRI, 2012). The roadmap describes technologies needed to acquire a set of benefits from coal that are viewed as important and achievable through advancements in technology. In general, those benefits fall into the familiar categories of environmental quality, energy security, and economic prosperity. While this roadmap is intended to apply only to the United States, it has overarching themes that are generally applicable elsewhere.

Key highlights from the 2012 CURC-EPRI roadmap include:

- The roadmap presents an array of gasification-related and combustion-related technologies that are expected to be developed under the roadmap from now to 2035. Included amongst these are advances in turbines, gasifiers, CO_2 and acid gas clean-up, and oxygen production for integrated gasification combined cycles (IGCC); improved CO_2 capture solvents, alternative working fluids, and high-temperature materials for PC units; and more far-reaching technologies such as chemical looping, pressurised oxy-combustion, and hybrid cooling systems. Details on these technologies are provided in Chapter 3.

- The roadmap's goal is to have a first commercial demonstration unit for advanced coal generation with CCS with a net efficiency between 43% to 44% and a cost reduction from current estimates of USD 75–80/tonne (USD 68–72/ton) CO2 avoided for NOAK plants down to USD 17–20/tonne (USD 15–18/ton) CO_2 avoided by 2035.
- The roadmap recognises that the near-term and medium-term industry may feature CCUS, rather than CCS. With the combination of technology development and EOR, coal-based power plants designed and constructed in 2025 can provide lower-carbon electricity at a price competitive with natural gas and other fuels, and with 75% less CO2 emissions than today's new natural gas-based power plants.

Carbon Sequestration Leadership Forum roadmap

The Carbon Sequestration Leadership Forum (CSLF) has recently updated the roadmap it first developed in 2004. This roadmap was the first to provide a plan for CCS with a primary focus on transportation and storage (CSLF, 2010). Key goals of the roadmap include:

- Reduce CO_2 capture cost and efficiency penalties.
- Develop an understanding of global storage potential, including matching CO_2 sources with potential storage sites and infrastructure needs.
- Demonstrate sufficiency of CO_2 storage capacity.
- Address risk factors to increase confidence in the long-term effectiveness of CO_2 storage
- Build technical competence and confidence through sharing data and experience from demonstrations.
- Validate monitoring for safety and long-term security of storage sites.
- Improve understanding of and verify environmental impact of CO_2 storage.
- Create the ability to optimise transport infrastructure to accept CO_2 from different sources and reduce the risks and costs.
- Demonstrate, by 2020, fully-integrated commercial-scale CCS projects.

Other roadmaps

Multiple other organisations have also put together roadmaps related to CCS or aspects of CCS, often relative to a particular region in the world. Some key ones are:

- **Department of Energy and Climate Change (DECC) Roadmap –** Presents an overview of the shared challenge for the government, industry, and the wider CCS community in the United Kingdom (UK) to create the right market conditions to deploy CCS technology that can contribute significantly to reducing GHGs (DOECC, 2012).
- **Department of Energy (DOE)/National Energy Technology Laboratories (NETL) Roadmap –** An overview of United States RD&D efforts to supply cost-effective, advanced CCS technologies for coal-based power systems (DOE/NETL, 2010).
- **National Coal Council –** A study requested by the DOE on the United States market focusing on the capture of CO_2 emissions from the combustion of fossil fuels for power generation and from processes using coal to make alternative fuels, chemicals, or synthetic natural gas. In addition, the study addresses the storage of CO_2 and its use for EOR or the production of other products. The study was released on June 22, 2012 (NCC, 2012).

Conclusions

Coal remains an important and prevalent fuel for the production of electricity. Its low cost, abundance, and broad distribution make it attractive for power production, particularly in emerging countries such as China and India, where coal-fuelled power has increased dramatically in recent years as demand for energy and the higher standard of living it brings have grown along with the population.

While coal use remains significant, its continued use has been challenged by growing environmental concerns, particularly related to increases in anthropogenic CO_2 emissions. Adding technologies that can reduce CO_2 emissions from coal (primarily by using CCS or CCUS) is possible but adds considerable cost, risk, and complexity to coal-fuelled power plants, particularly at their current stages of maturity.

Developing economies such as China have pinned social and economic growth goals on coal-fuelled power generation and are unlikely to moderate their use of coal regardless of regulations and policy signals introduced in OECD countries. Moreover, multiple organisations have formulated detailed studies showing that, even if CO_2 restrictions are implemented, advanced coal with CCS will still play an important role in providing the world's electricity at competitive prices.

In contrast to concerns about potential climate change, coal and electricity have been and continue to be linked to people's well-being, poverty eradication, and increasing standard of living through energy access and affordable power. A step change in electricity prices on the basis of CO_2, or for that matter any reason, will have deleterious impacts on the economy as well as on both current electricity consumers and the approximately 1.3 billion people (IEA, 2012b) who do not have access to electricity. Policy makers must be careful to address both environmental concerns and the need for affordable electricity, particularly with the developing world's desire to lift itself out of energy poverty.

In the interim, the issue of CO_2 cannot be ignored. Power plant efficiency improvements and the implementation of more advanced coal generation, which also serve to reduce other coal-related environmental concerns, should be pursued. Additionally, short-term actions to reduce global warming impacts from sectors other than fossil-fuelled electricity generation should be pursued. These programs need to be advanced now as further research on CCS demonstrations proceeds.

Regardless, the time window for technology investments to potentially reconcile the policy objectives of secure global energy supply and the mitigation of growth in GHG emissions is closing, requiring renewed focus by policy makers on the challenges and opportunities for coal. To do this, financial incentives and greater regulatory certainty are required to accelerate the pace of investment in RD&D and overcome barriers to the deployment of advanced coal and CCS technologies; and potentially to the use of CCS on other fossil energy sources. In particular, significant efforts should be made to make certain that current proposed CCS demonstration projects move forward, and do not join the growing list of cancellations.

Steps forward have been identified in detailed roadmaps that, while aggressive in some cases, are well thought out and technically sound. Following them expediently is critical for the world community to continue to advance on a path toward NZE and achieve the vision of "21st Century Coal".

2. Evaluation of advanced coal-fuelled electricity generation technologies

Introduction

The goal of this chapter is to review coal technologies designed to improve efficiency and reduce emissions (both CO_2 and other emissions) that are either commercially available or near-commercially available. This review will be grouped around the three forms of coal power: PC and fluidised bed combustion (FBC), oxy-combustion, and IGCC. A review of more far-reaching technologies that could produce larger improvements in the future will also be presented.

Coal power systems

Pulverised coal and fluidised bed combustion

In PC boilers, coal is ground to the consistency of flour and air blown into a furnace for rapid combustion. PC technology is the most prevalent type for coal-based generation and is used in steam boilers around the world operating with subcritical, supercritical, and USC steam conditions.

Another type of combustion-based coal power plant is FBC (which can be operated at atmospheric or pressurised furnace conditions). Coal is burned in a more coarse form and potentially other solid fuels are burned in a bed of hot sorbent particles suspended in motion (fluidised) by combustion air. The chief benefit of FBC technology is its ability to use almost any combustible material as fuel.

PC and FBC power plants have a high-pressure turbine (HPT), an intermediate-pressure turbine (IPT), and a low-pressure turbine (LPT). HPT exhaust steam typically is reheated to the same steam temperature or higher before it enters the intermediate-pressure turbine (IPT). Steam power cycles can be categorised by the "main steam" conditions – the thermodynamic state of steam entering the HPT:

- ***Subcritical*** steam cycles have a main steam pressure that is below the critical point of water. The steam conditions used in current subcritical units are up to ~179 bar/541°C/541°C (2600 psia/1100°F/1100°F). Although subcritical steam cycles are not considered "advanced" technology for Rankine cycle plants, many "advanced" technology coal plants (*e.g.*, IGCC and oxy-combustion) may incorporate subcritical steam cycles.
- ***Supercritical*** steam cycle technologies became fully commercial in coal plants in the early 1960s. Current supercritical steam cycles typically have main steam pressures of about 240 bar (3500 psig) or higher and main steam and reheat temperatures around 565°C (1050°F). Supercritical plants are more economical at larger boiler and turbine sizes; typical units are >500 MW.
- ***USC*** steam conditions are defined as a main steam temperature around 600°C (1110°F) and main steam pressure greater than 300 bar (4365 psig). While not common, these plants represent the highest efficiency PC plants available today (up to 40% net).

PC and FBC typically use post-combustion capture for reducing CO_2 emissions, which will be discussed in more detail later in this chapter.

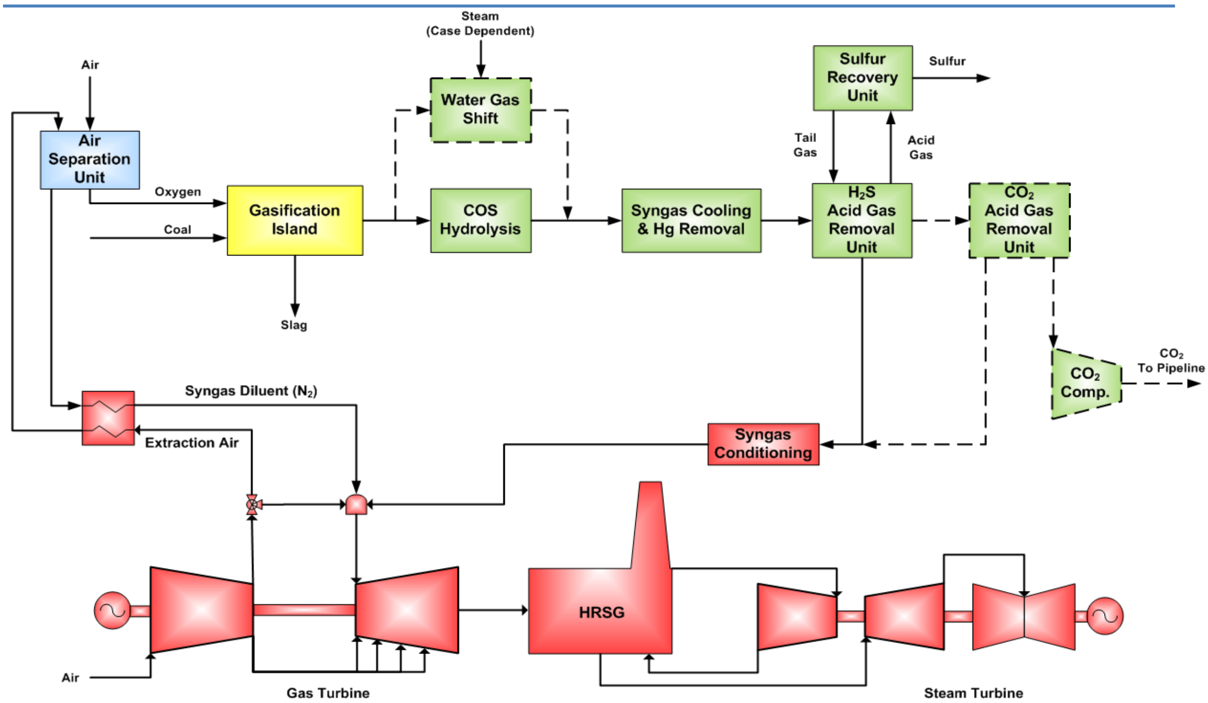
Box 5 • Co-firing with biomass

Most PC boilers and CFBs are flexible enough to allow co=firing with biomass by as much as 20% of the the total energy input (the amount is limited primarily by the inability of fuel feed systems to handle larger volumes of biomass). Co-firing with biomass can reduce the net CO_2 production of the coal power plant (since biomass is considered a carbon-neutral fuel) as well as other emissions including NO_x and SO_x with typically only a minor reduction in efficiency (Biopower, 2000). While limitations on biomass availability in some regions exist, the co-firing concept is well proven and is being used extensively in Denmark, the Netherlands, and the U.K. for retrofit and new-build coal power plants. An example is the Eemshaven Power Station, currently being built by Essent (an RWE company), which is a 2x765-MW net USC coal-fuelled power plant located in the Netherlands that can co-fire biomass. The plant is planned to come on line in 2014 (RWE).

Integrated gasification combined cycles

IGCC power plants use a gasifier to gasify coal and other carbon-based fuels into a gas, which subsequently can be burned using a gas turbine. IGCC technology allows the use of solid and liquid fuels (typically coal, petroleum coke, biomass, or a blend of these fuels) in a power plant that leverages the environmental benefits and thermal performance of a gas-fuelled combined cycle. In an IGCC gasifier, a solid or liquid feed is partially oxidised with air or high-purity oxygen. The resulting hot, raw "syngas" consists of CO, CO_2, hydrogen, water, methane (and sometimes heavier hydrocarbons), hydrogen sulphide (H_2S), carbonyl sulphide (COS), other sulphur compounds, and nitrogen and argon. After it is cooled and cleaned of particulate matter (PM) and undesired species, the syngas is fired in a gas turbine. The hot exhaust from the gas turbine passes to a heat recovery steam generator where it produces steam that drives a steam turbine. A block flow diagram of a typical oxygen-fired IGCC system is shown in Figure 8.

Figure 8 • Block flow diagram of an IGCC power plant with CO_2 capture



Source: EPRI, 2012a.

State-of-the-art IGCC configurations for bituminous coal normally achieve overall net thermal efficiencies in the range of 38–41% – comparable to supercritical PC units (DOE, 2011). By removing the emission-forming constituents from the pressurised syngas prior to combustion in the power block, IGCC plants can meet extremely stringent air emission standards. IGCC uses pre-combustion capture for reducing CO_2 emissions, which will be discussed in more detail later in this chapter.

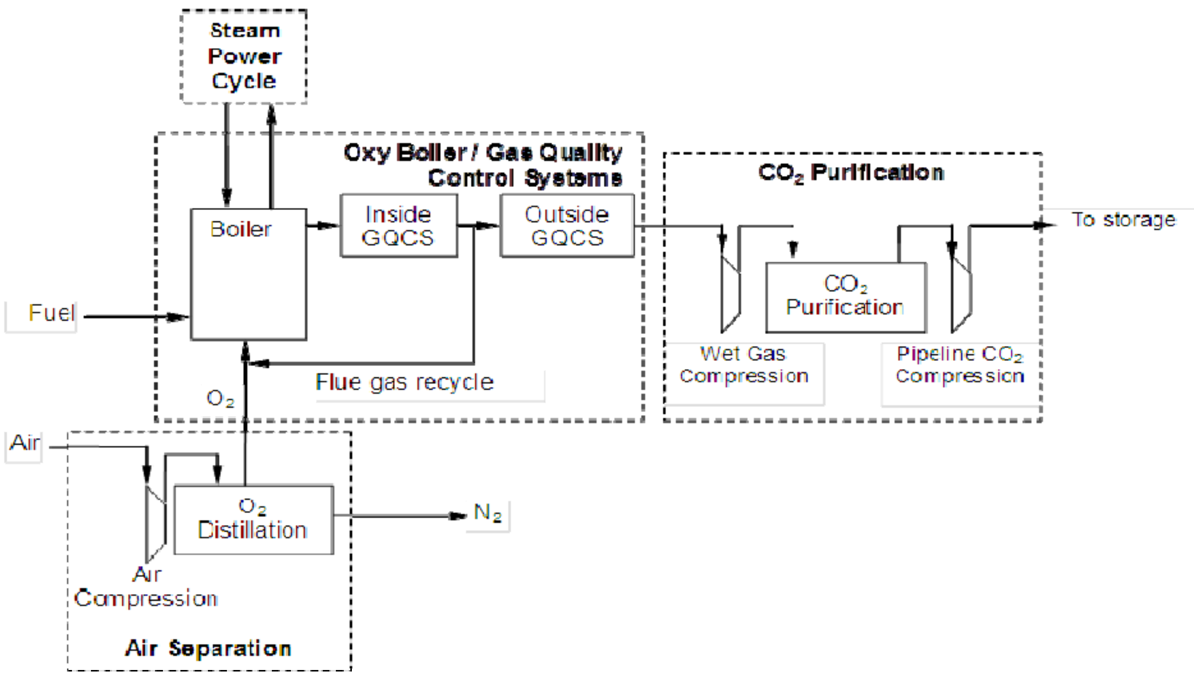
Oxy-combustion

Oxy-combustion is the combustion of fuel with oxygen separated from air. Oxy-combustion systems have many similarities to PC systems, and the fuel handling systems, steam cycles, and other balance of plant systems, will be nearly identical to their air-fired counterparts.

Figure 9 is a simplified block diagram for a typical, near-term oxy-combustion power plant. Oxy-combustion plants piece together technologies that are mature in other applications and include the following major component systems:

- **Air Separation Unit (ASU) –** technology that removes nitrogen and other trace species from air cryogenically to produce a high-quality stream of oxygen.
- **Oxy Boiler –** large system that combusts coal with oxygen separated from air. The oxy-fired boiler is in many ways similar to a traditional air-fired one, consisting of similar technology. The primary difference is the oxidant: in the case of an oxy boiler, air is simulated by diluting nearly pure oxygen with recycled flue gas (RFG) to attempt to achieve a similar excess oxygen level in the exiting flue gas of ~3–5% and keep temperatures under control.
- **Gas Quality Control System (GQCS) –** contains the environmental controls, which are typically far less extensive than in PC systems.
- **CO_2 Purification Unit (CPU) –** at a minimum, the CPU will include a flue gas drying sub-system and compressors to deliver the product CO_2 to a receiving pipeline or geological storage site. If required, it will also include a partial condensation process to clean the product CO_2 and remove impurities to specified levels.

Figure 9 • Oxy-combustion power plant simplified block diagram



Source: EPRI, 2012a.

While oxy-combustion power plants have a lower net efficiency than air-fired power plants without CO_2 capture when using the same steam power cycle due to the added auxiliary power loads associated with the ASU, RFG, and CPU (typical efficiency penalty is in the range of 15% – 25% incremental), when compared to a PC plant with CO_2 capture, oxy-combustion plants can be two to three percentage points higher in efficiency.

Commercially or near-commercially available coal power systems

This section presents a high-level review of coal power system technology related to efficiency or emission control that is either already existing or in the final stages of development and demonstration. The technologies described here are near to being made commercially available (by 2015) with predictable performance and vendor warranties/guarantees similar to power plant components in common use. Many local fuel/power market conditions will be such that the technologies identified here will meet economic requirements to justify their deployment.[4]

Pulverised coal and fluidised bed combustion

Efficiency: installing upgrades for ultra-supercritical steam conditions

Japan and Europe have taken the lead in the development and manufacture of the key materials for the new USC generating units. The newer high creep strength ferritic/martensitic steels with 9 to 12% chromium, such as P91, P92 (NF616), and P122 (HCM12A), used for thick section boiler components and steam pipes, have driven current USC technology. Efficiencies as high as 42% net have been achieved when additional reheat and cold condenser temperatures are used, which also reduces CO_2 production compared to conventional subcritical units by 10%.

As many of the world's PC plants do not use USC steam conditions, these existing subcritical PC plants could significantly raise their plant efficiencies by repowering their boilers to achieve USC steam conditions and adding a topping turbine (ASME International, 2008), (EPRI, 2010b). Note that while retrofitting an existing unit with USC steam conditions is possible, at this time, all USC plants have been new build.

Efficiency: low temperature economisers

Additional back-end heat recovery from the flue gas stream leaving the air heater and prior to the wet flue gas desulphurisation (FGD) could result in efficiency improvements in these older assets. This heat can be used to pre-heat the boiler feed water reducing extraction duty and allowing more steam to pass through the turbine and could potentially raise efficiency by one percentage point. The heat recovery may condense water, depending on how deeply the gas is cooled, and that can be used by the plant after suitable treatment. In any case, lowering the temperature of the flue gas entering the wet FGD lowers the amount of water lost through evaporation and reduces the make-up requirement. Rather than putting the waste heat into the steam circuit it might be used to dry the high moisture fuel and raise boiler efficiency.

[4] Power plant efficiency will also depend on project features which are determined by geography and resource availability rather than engineering design. Chief among these are the fuel characteristics (largely moisture content), and coolant temperature. Lower fuel moisture content generally results in higher efficiency. Lower-temperature coolant, (cold ocean water, for example) results in higher efficiency than warmer dry cooling in arid environs.

Efficiency: steam turbine upgrades

An alternative to upgrade and retrofit to supercritical conditions, could be simply upgrading the steam turbines with the use of "dense packs" that improve on the efficiency of older turbine designs with modern day materials, blading advances, and engineering improvements. Such upgrades can increase the output of a steam turbine by up to 5% without increasing fuel consumption.

Emissions: mercury

Activated carbon injection (ACI) in boiler flue gases, which is processed to be extremely porous and therefore capable of adsorbing mercury, has been applied to reduce mercury emissions by up to 90%. For boilers using some coal types, modifications to the selective catalytic reaction (SCR) reactor and SO_2 scrubber can also remove substantial fractions of mercury without ACI.

Emissions: NO_X

State-of-the-art NO_X controls in boilers combine low-NO_X firing techniques that limit NO_X formation with chemical reduction technology that destroys NO_X after it has formed. In a boiler furnace, staged-combustion processes can reduce NO_X formation by 35 – 55% in comparison to conventional burner technologies. SCR systems, which flow flue gas through a catalyst bed along with a reagent (typically ammonia) to reduce NO_X chemically to molecular nitrogen and water, can reduce flue gas NO_X concentrations to 85 – 90% below SCR inlet levels. These technology combinations yield a net overall reduction in NO_X of 90 – 95% for PC boilers.

FBC boilers operate at lower combustion temperatures, which inhibit the formation of NO_X. Because the heavy particulate loading could plug the passages of an SCR catalyst, FBC boilers typically use selective non-catalytic reduction (SNCR) systems (which also use an ammonia-based reagent, but are located in regions after the furnace exit where the higher temperature window causes the reduction reactions to proceed without the need for catalysis).

Emissions: particulate matter

Options for PM control are a fabric filter ("baghouse") or an electro-static precipitator (ESP), which uses high-voltage electrodes to impart a negative charge to the particles entrained in the flue gas. The particles are then collected by and removed from a positively charged surface, which can reduce PM to less than 15 mg/Nm^3 (0.015 lb/MBtu), a reduction of more than 99%. In some units, a wet ESP is used for further removal of additional fine particulate and sulphuric acid (H_2SO_4) mist.

Emissions: sulphur species

Sulphur oxides ($SO_{X)}$ emissions from boilers are controlled by wet or dry FGD systems or "scrubbers". These systems use injected reagents in a slurry, solution, or solid form (typically finely ground limestone, lime, or sodium compounds) to react with flue gas SO_2, reducing emissions by 95–98% or more. A substantial portion of sulphur trioxide (SO_3) and H_2SO_4 also is removed by the FGD system.

Oxy-combustion

While oxy-combustion may not be "commercially available" by 2015, it is included here to provide a complete view of advanced coal technology developments.

Several major boiler vendors have undertaken oxy-combustion development programmes to establish the requirements for oxy-combustion and test the technology at pilot-scales up to 40-MWth in size. The first fully operational oxy-combustion system is a 30-MW demonstration at CS Energy's Callide A Station in Australia that began commissioning in April 2011 (IEAGHG, 2011).

Front-end engineering design (FEED) studies are underway or have been completed for new build and repowering oxy-combustion projects at larger scales, but no project has progressed to construction to date. A number of engineering and economic evaluations of full-scale (600–800 MW) oxy-combustion plants have been published but it is unlikely that a full-scale plant will be built until the technology has been demonstrated as a fully integrated plant at the 200–250-MW scale, which is the primary reason why oxy-combustion may not be commercially available by 2015.

Efficiency: installing ultra-supercritical steam conditions

USC steam power cycles with turbine inlet conditions of 600°C (1100°F) and 260 bar (3785 psig) similar to those deployed with air-fired steam generators could also be built with an oxy-fired steam generator. With these steam conditions, oxy-fired combustion with CO_2 capture could realise efficiencies similar to USC PC plants with post-combustion CO_2 capture.

Integrated gasification combined cycles

Efficiency

The most important parameter impacting IGCC efficiency is the firing temperature of the gas turbine. The five coal-based IGCC demonstration plants now in operation have 1990s vintage gas turbines with firing temperatures ranging from 1100–1260°C (2010–2300°F). Some gas turbines developed more recently have firing temperatures on natural gas that range up to 1500–1600°C (2730–2910°F). While turbine firing temperatures are typically derated by 50–100°C (90–180°F) when firing syngas, these so-called "G" and "H" class turbines could deliver an improvement of two to four percentage points in IGCC thermal efficiency. A G-class turbine is currently being offered by one supplier for IGCC applications and an H-class turbine could be offered in the 2015 timeframe. On-going gas turbine improvements will be discussed in more detail later in this chapter.

Variations on the basic IGCC flowsheet such as the design of the gasifier and syngas clean-up systems and the degree of integration between the power block and the gasification and air separation units can impact plant efficiency. Engineering-economic evaluations show that different design characteristics are beneficial with different feed properties, different degrees of CO_2 capture, and different economic assumptions.

The best gasifier design for an IGCC unit with CO_2 capture may be different from the optimal gasifier for a unit without capture. A gasifier design with some degree of water quench generally is the least-cost and most efficient approach to providing the moisture content required for the water-gas shift (WGS) reaction in units with CO_2 capture, but a gasifier with full water quench instead of waste heat boiler will yield the lowest overall efficiency for IGCCs without CO_2 capture.

The degree of integration of the gas turbine with the ASU represents a tradeoff between higher efficiency and the complexity and time requirements for unit startup. Also, availability may be slightly lower for highly-integrated units.

Emissions: mercury

In IGCC units, activated carbon beds, which are processed to be extremely porous and therefore capable of adsorbing mercury, can remove 95% or more of the mercury in syngas prior to combustion.

Emissions: NO_X

Fuel-bound nitrogen is almost non-existent in IGCC syngas as the nitrogen in the coal is typically converted to molecular nitrogen or ammonia. The ammonia is removed in a water wash step upstream of the acid gas removal (AGR). Consequently the only NO_X mechanism in an IGCC is thermal NO_X, which is formed in high flame temperature zones of the gas turbine. State-of-the-art NO_X controls in IGCC gas turbines combine low-NO_X firing techniques to limit thermal NO_X formation with chemical reduction to destroy NO_X after it has formed. In syngas-fired gas turbines, low NO_X combustors typically reduce NO_X production by 70–90%. SCR systems can reduce flue gas NO_X concentrations to 85–90% (or more) below SCR inlet levels. These technology combinations yield a net overall reduction in NO_X of 95–99% for gas turbines.

Emissions: particulate matter

PM in syngas can be removed by "dry" processes such as a pulse-cleaned, rigid barrier filter or by "wet" processes using venturi scrubbers (referred to as "gas scrubbing"). Both methods achieve over 99% particulate removal. In the wet process, the solids also can be recovered and recycled to the gasifier if warranted by the carbon content. In the dry process, solids can be sold for use in cement if low in carbon, or recycled to the gasifier if high in carbon. The particulate control approach is selected to match the properties of the raw syngas from the specific gasifier design. Particulate formation in the gas turbine and heat recovery steam generator (HRSG) are minimised by sulphur removal and by combustor designs that achieve thorough fuel burnout.

Emissions: sulphur species

In the gasifier of an IGCC plant, the sulphur compounds in coal are converted primarily to H_2S and a small amount of COS. Regenerable solvents with engineered chemical and physical properties are used to remove H_2S and other "acid gas" species from the syngas prior to combustion. Such processes are very effective, often removing 99.5% or more of the H_2S. A hydrolysis catalyst converts most of the COS to H_2S upstream of the AGR process.

Advanced technologies for existing systems

Achieving commercial availability, meaning routine consideration of the technology during power plant project development, will require technical maturity as well as the technology being suitable for meeting emission regulations (some not yet adopted) and acceptable cost performance in comparison with alternative technology options. Achievement of commercial availability is likely to lag achievement of technical maturity by several years.

This section reviews a number of advanced technologies for increasing efficiency or reducing emissions for each type of coal power system. The advanced technologies described here are still in R&D or in the early stages of demonstration and will require further demonstration, at a suitable scale, of their technical and commercial maturity before being available commercially. The technologies were selected in the expectation that they will be viable options for power plant planning initiated in 2020. The actual deployment timing of these technologies will depend on a number of factors that are likely to be unique to individual projects and are difficult to anticipate including the cost of deployment, specific environmental regulations, and the local fuel/power markets.

Coal beneficiation

A technology that could assist all types of coal power generation is coal beneficiation. Coal beneficiation refers to those technologies that go beyond conventional coal cleaning and dewatering and may include thermal, mechanical, or chemical treatment of the coal to remove emission precursors including mercury and other hazardous air pollutants (HAPs). Estimates show that coal beneficiation can improve efficiency for coal power plants by 0.5 percentage points. Coal beneficiation may also more cost-effectively enable NZE[5] levels. The challenge is to assess how coal beneficiation technologies would be deployed in concert with other environmental controls to significantly reduce the overall cost of NZE compliance, and then initiate the development and demonstration of those technologies.

Pulverised coal

Efficiency: improvements from upgrading to higher ultra-supercritical steam conditions

Significant advances in developing high-temperature alloys and welding techniques have recently taken place. The Advanced Materials Program, funded by the United States DOE through the NETL with significant co-funding from the Ohio Coal Development Office and under EPRI's technical leadership, is characterising the properties and developing the fabrication procedures for the nickel alloys required to accommodate up to A-USC steam conditions in the boiler, turbine, and interconnecting piping (DOE, 2011b).

Alloys with high nickel content have better strength and corrosion resistance than stainless steels at very high temperatures, but are considerably more expensive and have a reputation of being more difficult to weld. Nonetheless, researchers are working to qualify nickel-based alloys for use in high-temperature boiler and steam turbine components. The nickel-based alloys Haynes 230 and Inconel 617 are American Society of Mechanical Engineers (ASME) Code approved and would allow a plant to be built with main steam conditions of 700°C (1290°F) and 344 bar (5005 psig).

Momentum is growing for the application of USC conditions on coal plants, particularly on fleets that rely primarily on lower-efficiency units. For example, the IEA recently announced their support for widely applying USC technology in the United States (IEA, 2011b). Multiple countries have programmes underway that are aimed at developing and eventually deploying boiler and steam turbine metallurgy that will allow USC steam temperatures to reach 700°C (1300°F).

A recent EPRI survey of boiler and steam turbine suppliers concluded that the material development programme should be completed by 2014 after which a demonstration could be initiated (EPRI, 2011e). Such demonstration projects have already been proposed in India and China.

For main steam conditions of 760°C (1400°F) and 344 bar (5000 psig), age-hardenable nickel alloys such as Inconel 740 and Haynes 282 would be required. Inconel 740 recently received ASME Code Approval, and data are being developed for Haynes 282 that could lead to its approval by 2015-2016.

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[5] Although there is no precise definition of NZE, typical NZE target values for coal-based plants are SO_2 and NO_X levels of ~10 mg/Nm³ (0.01 lb/MBtu), filterable particulate levels of ~2 mg/Nm³ (0.002 lb/MBtu), and mercury levels less than ~0.1 µg/Nm³ (0.01 ppb). Actual values achieved may vary depending upon the coal quality being used.

Ultimately, these materials are expected to enable net generating efficiencies as high as 48% with bituminous coals. This nominal ~11-percentage-point improvement over the efficiency of a new subcritical PC plant would equate to a per-MW-hr relative decrease in CO_2 and other emissions of about 22%.With sustained R&D and financial support for a demonstration, the A-USC technology could be commercially proven by 2025. The overall budget to bring A-USC technology to fruition would be on the order of USD 700 million with USD 600 million being allocated to subsidise the construction of a 500-MW demonstration power plant.

Emissions: mercury

Active research is ongoing to develop a suite of control options to allow for cost-effective compliance with mercury regulations (NETL, 2009). One such option is the sorbent activation process (SAP), a technology that involves the on-site production of activated carbon at the power plant using site coal and then direct injection into the flue gas to capture mercury (EPRI, 2010c). If successful, SAP will reduce the cost of mercury control by 50%.

Emissions: NO_X

With additional capture or conversion of NO_X with multi-pollutant control technologies, achieving NO_X levels of 10 mg/Nm^3 (0.01 lb/MBtu) appears to be within reach for some fuels and boiler designs. For units firing high-sulphur bituminous fuels, NZE for NO_X may only be achievable in new boilers designed specifically for low-NO_X emissions. Consistently achieving this low-NO_X emission level for more typical supercritical PC plant applications will require the resolution of operational issues, along with technological advancements for in-furnace and post-combustion NO_X controls.

Emissions: particulate matter

A wet ESP is used as a "polishing" control device to further reduce levels of fine particulate and "condensable particulate" (primarily sulphuric acid mist) downstream of a wet FGD absorber potentially reducing PM to an NZE target level in the range of ~2–10 mg/Nm^3 (0.002 – 0.01 lb/MBtu).

Emissions: sulphur species

The path to NZE levels is expected to include the following SO_2 removal process improvements:

- More sophisticated monitoring and control of moisture, temperature, and reagent levels
- Advanced flow analysis techniques to ensure that gas/liquid contact is uniform and sufficient throughout the absorber vessel, without channeling or chimneying, and to minimise pressure drops and the resulting auxiliary power demands
- Fine-tuning of reagents through more precise purchase specifications and carefully designed additive packages
- Redundancy in sprays and pumps to achieve required availability.

Emissions: towards multi-pollutant control systems

Progress in lowering emission levels for PC power plants is expected to continue in response to the demand for NZE. Some ongoing research programmes are focused on extending the limits of current emission control technologies, while other efforts seek to develop new sorbents and alternate technologies that show promise in meeting NZE targets. These include multi-pollutant control technologies that remove all emissions of interest in a single train, with potentially lower cost and plot space requirements.

Oxy-combustion

Advances in oxy-combustion technology are likely to occur in three general areas: 1) increasing net plant capacity/efficiency, 2) lowering capital costs, and 3) improving emissions reduction performance by exploiting the unique features of the partial condensation CO_2 purification process to achieve NZE and/or reduce the scope/cost of conventional emission control equipment (Capture, 2011). Technology advances in these areas are not coupled and may be achieved independently, but are unlikely to be aggressively pursued in the absence of market signals that oxy-combustion is a viable CO_2 capture technical option.

Efficiency: air separation

The incumbent technology for separating oxygen from air is cryogenic distillation at moderate pressure. Compression of the entire air flow from which the oxygen is separated (roughly equivalent to the air used in an air-fired steam generator) reduces net plant output by approximately 15% with a corresponding reduction in net efficiency.

The use of ceramic ionic membranes, through which oxygen ions (O_2^-) are exclusively conducted (Dyer, Richards, Russek, & Taylor, 2000), is a leading technology for reducing the costs associated with supplying oxygen to an oxy-combustion plant. Air Products has developed this ion transport membrane (ITM) separation technology and testing at 4.5 tonnes-O_2/day (5 tons/day) scale began in January 2006. Testing at a 90 tonnes-O_2/day (100 tons/day) scale began in late 2012 with elements associated with oxy-combustion The first units suited for a commercial-scale oxy-combustion power plant are anticipated in the 2015 timeframe. Preliminary studies indicate that the technology can reduce costs and improve overall efficiency for an oxy-combustion plant that utilises a traditional ASU (Matuszewski, Woods, & Brasington, 2012).

Efficiency: improvements from upgrading to advanced-ultra-supercritical steam conditions

A-USC steam cycles of up to 760°C (1400°F) that are being developed for air-coal combustion power plants will also be directly applicable to oxy-combustion steam generators and associated turbines. Use of an A-USC steam cycle would increase the efficiency of an oxy-combustion plant by approximately 3–4 percentage points over a typical 600°C (1110°F) steam cycle in common use for new steam plants today.

Emissions: partial condensation process

In the partial condensation process, the flue gas is cryogenically cooled and gases with a dew point lower than CO_2 are separated and vented. These include the diluents O_2, N_2, and argon, and any residual PM and mercury. It is likely that an oxidation catalyst can also be employed to reduce CO emissions to negligible levels.

It may also be possible to incorporate bulk SO_2 and NO_X removal into the CPU wet-gas compression process, at modest cost, with a dramatic reduction in the scope and cost of conventional GQCS required to remove emissions (Matuszewski, Woods, & Brasington, 2012).

The end result is that the unique features of the partial condensation process produce nearly negligible emissions. The potential result is a full-scale coal-fuelled power plant with emissions that are negligible for air permitting purposes (EPRI, 2009b).

Note, however, that this process is the least mature technology block in the oxy-combustion process and testing at scale is required. It is generally anticipated that the cooling required for the partial condensation process can be accomplished by using the liquid CO_2 as the refrigerant. While this "auto-refrigeration" process is likely to result in significant capital cost savings, it also has yet to be implemented at industrial scale.

Lower capital costs

If the amount of RFG could be decreased, this would lead to an increase in the gas temperatures within the boiler. Hotter gas temperatures would provide a larger driving force for heat transfer that would lead to less surface area being required in the boiler. While there are limits to how hot the gases can be without impacting the integrity of the boiler tubes, the use of nickel alloys could allow hotter temperatures. This would allow the size of both the boiler and particulate removal systems to be reduced without negatively impacting the thermal efficiency of the boiler. The DOE Advanced Materials Program has been investigating the feasibility of lower flue gas recycle designs for oxy-combustion boilers (EPRI, 2011f).

Integrated gasification combined cycles

Efficiency: advanced gas turbines

Syngas is a relatively low-energy-density fuel with a heating value of about 9.314 MJ/m^3 (250 Btu/ft^3), roughly one-quarter that of natural gas. As a result, operation on syngas requires a higher volumetric fuel flow through the gas turbine combustors to achieve the same turbine-section heat input as operation on natural gas. In addition, the products of combustion from syngas contain more water vapor than they do from natural gas, and water vapor enhances heat transfer from the hot gases to the turbine's metal parts. Consequently, operating gas turbines on syngas requires turbine inlet temperatures to be lower than those used when firing natural gas because of differences in mass flow, aerodynamics, heat transfer, and erosion issues (DOE/NETL, 2005).

Gas turbine designs have been developed to accommodate the higher fuel mass flow and lower flame temperatures associated with firing syngas. In many cases, the higher mass flow allows an increase in gas turbine power rating, despite the lower firing temperature. Some turbine designs are modified with stronger drive shafts and larger generators to take advantage of this capacity (Turbo Expo, 2007).

IGCC plant development will benefit from new gas turbine models with higher firing temperatures, greater efficiencies, and larger power outputs, which will allow a significant reduction in the cost of electricity. Projects now in or close to construction typically have been selecting syngas versions of state-of-the-art F-class turbines with firing temperatures at 1370°C (2500°F). For plants coming online after 2015, the larger size G-class turbines, which operate at higher firing temperatures relative to F-class machines (1430°C [2600°F]), may provide the option to improve efficiency by 1 to 2 percentage points while also decreasing capital cost per kW capacity. H- or J-class gas turbines, coming online later, will have firing temperatures as high as 1480°C (2700°F) and will provide a further increase in capacity and efficiency (by another one to two percentage points).

Syngas that consists primarily of hydrogen has combustion properties significantly different from those of CO-rich syngas or natural gas. Although there is extensive commercial experience with firing hydrogen-rich fuel gas in gas turbines, most of this experience is with older, lower-firing temperature gas turbines that fire refinery fuel gas in which methane is the other main component (IPCC, 2005). However, GE, Siemens, and MHI will supply large hydrogen-fired gas turbines with guarantees at reduced firing temperatures.

DOE's Turbine Technology RD&D Program is supporting two projects (one by GE (Workshop, 2006) and one by Siemens (GT Conference, 2007)) to design large-scale, high-temperature turbines capable of firing hydrogen-rich fuels (NETL, 2005). Performance goals include the ability to integrate new systems into IGCC, fuel flexibility for operation using hydrogen and syngas, low-NO_X emissions, and IGCC net efficiencies of 45–50%. Japan also has initiated a similar programme for the development of larger advanced gas turbines that aim to raise the firing temperatures to 1700°C (3092°F).

Efficiency: air separation

The air separation technology discussed for oxy-combustion developed by Air Products that uses ceramic membranes to ionically separate oxygen from air at relatively high temperature and pressure can also provide benefits when used for IGCC. Largely because of its reduction in auxiliary power compared to conventional ASUs, this technology can improve efficiency by over one to one and a half percentage points.

Efficiency: liquid CO_2 coal slurry

Liquid CO_2 coal slurrying has been proposed to replace water-based slurry in future IGCC plants. Liquid CO_2 has a lower heat of vaporisation than water and is able to carry more coal per unit mass of fluid – potentially yielding dry-fed gasifier performance with slurry-fed simplicity (EPRI, 2009c). The liquid CO_2-coal slurry will flash almost immediately upon entering the gasifier, providing good dispersion of coal particles. Potential cost savings in other sections of the plant appear to offset expected cost increases in the feed preparation system.

CO_2 coal slurry improves IGCC efficiency by an estimated 2 percentage points. It also requires less oxygen to maintain gasifier temperature and is expected to foster better carbon conversion at the same gasifier temperature.

Emissions

Note that for the most part, environmental controls required for IGCCs to attain NZE are already mature technologies.

Technology options for carbon capture and storage

This section discusses the status of ongoing R&D efforts related to all the integrated parts of CCS: CO_2 capture, compression, transportation, and storage.

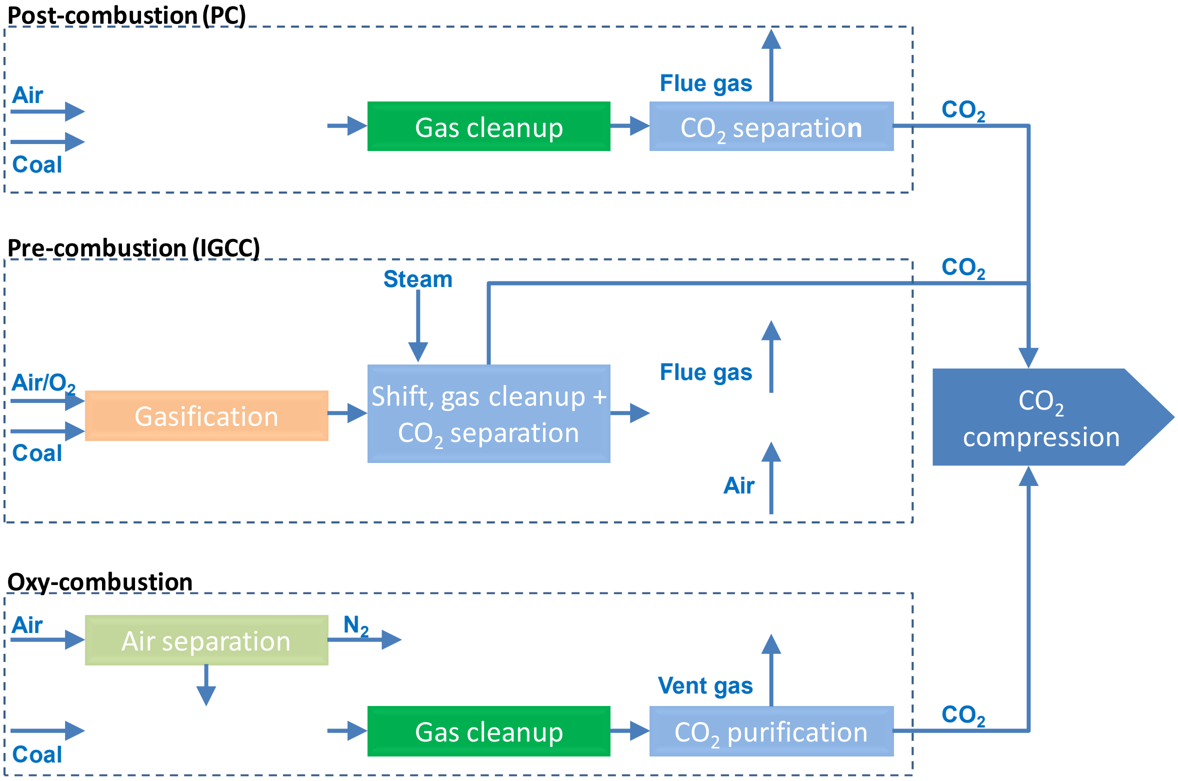
Description of major technologies for CO_2 capture

There are currently three primary approaches to CO_2 capture from fossil fuel usage being investigated:

- **Post-combustion capture** absorbs CO_2 from the flue gas produced by PC-fired boilers, FBC, and other combustion systems
- **Pre-combustion capture** is applied to the pressurised syngas prior to combustion in the gas turbine of an IGCC unit
- **Oxy-combustion** combusts the coal in oxygen and recycled flue gas, thereby producing a resultant flue gas containing primarily CO_2 and water, allowing relatively simple purification by cooling and condensing.

These three approaches are shown diagrammatically for coal-power systems in Figure 10.

Figure 10 • Technical options for CO_2 capture from coal power plants



Source: EPRI.

Absorption processes are currently the most advanced of the PCC technologies. A typical process passes flue gas through a packed-tower type absorber, where a chemical solvent selectively absorbs CO_2. The CO_2-laden solvent passes to a regenerating column (also called a stripper in some designs), where it is heated to release a nearly pure CO_2 stream, then returned to the absorber.

PCC at near atmospheric pressure can be applied to newly designed plants or retrofitted to existing coal and natural gas power plants after suitable flue gas clean-up. PCC technologies can also be used in other industries besides power, *e.g.*, cement, oil refining, and petrochemicals.

Pre-combustion capture in the IGCC power application comprises gasification of the fuel with oxygen or air under high pressure and the use of the water-gas shift (WGS) reaction, producing a gas mixture consisting primarily of CO_2 and hydrogen. CO_2 is subsequently removed from the mixture using acid gas removal (AGR) processes and the resulting hydrogen-rich syngas is supplied to the gas turbine-based power block. Pre-combustion capture can be added to existing IGCC plants, but in the future IGCC plants will almost certainly be designed with capture from the start. The pre-combustion capture of CO_2 using AGR processes is also practiced commercially in natural gas processing, natural gas reforming, and coal gasification plants.

Oxy-combustion represents the simplest and most cost-effective CO_2 separation process (although the overall LCOE for the full system may be higher than PC or IGCC plants with CCS), which is the primary reason it has been developed. For PC boilers, due to the large amount of nitrogen in air, the resultant flue gas CO_2 content is less than about 15%. Hence, PCC processes are designed to separate the relatively dilute CO_2 from the bulk flue gas nitrogen. In oxy-combustion processes, the bulk nitrogen is removed from the air before combustion. The resulting flue gas contains primarily CO_2 and water, and CO_2 is removed simply by dehydration along with the cleaning of any remaining impurities (predominantly oxygen, nitrogen, and argon) by reducing the flue gas (at moderate pressure) to a temperature at which the CO_2 condenses and the impurities do not. Note that if regulations and geochemistry permit, the raw, dehydrated flue gas from oxy-combustion may be stored directly without purification.

Within each of the three major capture categories there are multiple pathways using different technologies that may find particular application more favourably in certain climate conditions, locations, elevations, and coal types.

Advantages, challenges, and potential for improvement of CO_2 capture technologies

This section discusses the pros and cons of the three major types of capture processes. It also presents, at a high level, the potential for CO_2 capture technology improvements for each coal-based power plant to which the capture technology can be applied. Note that efficiency improvements will be important for potentially recouping some or all of the energy penalties associated with CCS.

Post-combustion capture advantages

- Can be retrofitted to existing plants allowing the continued operation of valuable assets with well established infrastructures.
- In either new build or retrofit applications it enables the continued deployment of the well-established PC technology familiar to power industries worldwide.
- Widespread R&D on improved solvents and capture equipment should reduce the energy penalty of PCC.
- Several sub-scale demonstrations of PCC have already successfully taken place.

Post-combustion capture challenges

- Most solvent processes are commercially available at relatively small scale and considerable re-engineering and scale-up is needed.
- Addition of capture with current solvent technologies results in a loss of net power output of about 30% and a reduction of about 11 percentage points in efficiency. In the case of retrofit, this would imply the need for replacement power to make up for the loss.
- Most solvents need additional flue gas clean-up to minimise usage and cost. Typically < 10 ppm or as low as 1 ppm of SO_2 and nitrogen dioxide (NO_2) is required depending on the particular solvent.
- If steam extraction for solvent regeneration is taken from the plant, flow is reduced to the LPT with operational impact on its efficiency and turndown capability. Providing steam using alternate means such as adding a separate power source can increase cost and reduce efficiency.
- Water use is increased significantly with the addition of PCC particularly for water-cooled plants where water consumption with capture is nearly doubled per net MW-hr. For air cooling, the water consumption is also increased with capture by about 35% per net MW-hr.
- Plot space requirements are significant, a particular concern for retrofitting CCS. The back-end at existing plants is often already crowded by other emission control equipment. Extra costs may be required to accommodate PCC at more remote locations.

Post-combustion capture improvements

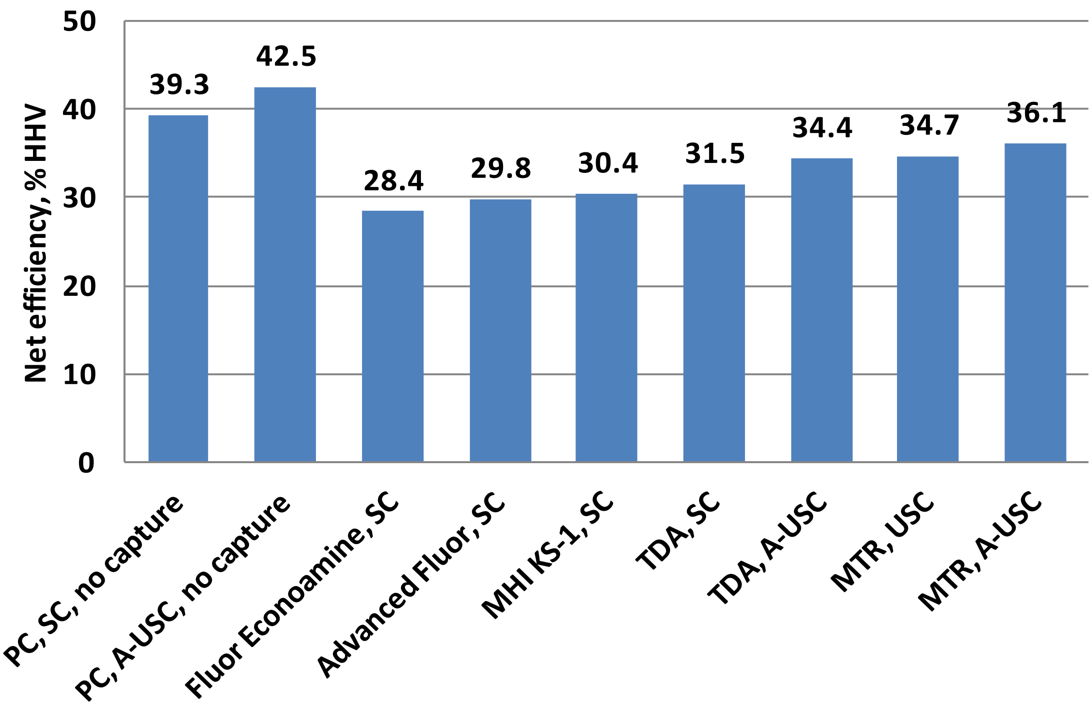
Since the global research community has only been focused on developing effective PCC solvents during the past decade, it should not be surprising that the technologies developed so far are nowhere near the theoretical optimum. Today's commercially available PCC solvents require approximately four times the theoretical minimum energy to capture 90% of the CO_2 from flue gas and compress it to 152 bar (2200 psig).

Researchers today are already working on PCC technologies that could reduce the energy requirement to less than three times the theoretical minimum (NETL, 2012), and it is not unreasonable to expect that continued R&D efforts could drive this down further. Several key areas of research on PCC processes include:

- Absorption – Research focuses on developing novel solvent processes that reduce the overall energy penalty
- Adsorption – Novel designs of packed and fluidised beds are being investigated in parallel with new solid sorbent materials that can absorb CO_2, such as those based on carbon or metal organic frameworks
- Membranes – Developers are working on polymer membranes that remove CO_2 from flue gas with both high selectivity and permeability. While still largely untested for this application, membranes have potential to lower the energy penalty.

The projected performance of PCC with improved capture technologies together with higher temperature steam cycles is shown in Figure 11. For this figure, absorption solvents are represented by Fluor and MHI, adsorption processes by TDA Research, Inc., and membranes by Membrane and Technology Research, Inc. (MTR).

Figure 11 • Efficiency improvements with better PCC capture technology[6]



Source: NETL, 2012.

[6] Illinois #6 coal used (27 135 kJ/kg [11 666 Btu/lb], 11% moisture, and 10% ash). SC steam conditions: 593°C/593°C/241.4 bar (1100°F/1100°F/3500 psig). A-USC steam conditions: 732°C/760°C/344.7 bar (1350°F/1400°F/5000 psig)

With sustained R&D and financial support for a demonstration, the most advanced PCC technologies identified in Figure 12 could be commercially proven by 2025.

The overall budget for bringing advanced PCC technologies to the market is a function of the number of technologies that are brought through the demonstration phase. SaskPower has stated that their 110-MW PCC project required a 240 million CAD subsidy from the Canadian government to make it economically viable. In addition to the cost of a commercial-scale demonstration, R&D money would be required at the earlier stages of development.

Pre-combustion capture advantages

- Uses the WGS reaction and removal of the CO_2 with AGR processes that are commercially practiced worldwide.
- Capture of the CO_2 under pressure incurs less of an energy penalty (~20%) than current PCC technology (~30%) at 90% CO_2 capture.
- Ongoing R&D on improved CO shift catalysts, higher temperature gas clean-up, and membrane separation technology for hydrogen and CO2 has the potential to produce a step-change reduction in the energy penalty of capture.
- Water use, while still substantial, is lower than with PCC. Similarly, plot space requirements, while still significant, should be lower than for PCC.

Pre-combustion capture challenges

- While the energy loss for pre-combustion capture is lower than for PCC, it is still significant
- Commercial demonstration of large F- or G-class gas turbines firing hydrogen, which will be required for >65% CO_2 capture, has yet to be demonstrated
- In the event of a need to vent the CO_2, additional purification may be needed
- IGCC is not yet widely used in the power industry and the gasification plant is therefore unfamiliar technology to most power generation companies
- Capital costs of IGCC without capture are much higher than PC plants without capture. The IGCC costs need to be reduced, largely through lessons learned from upcoming commercial-scale and further design improvements, to compete more effectively.

Pre-combustion improvements

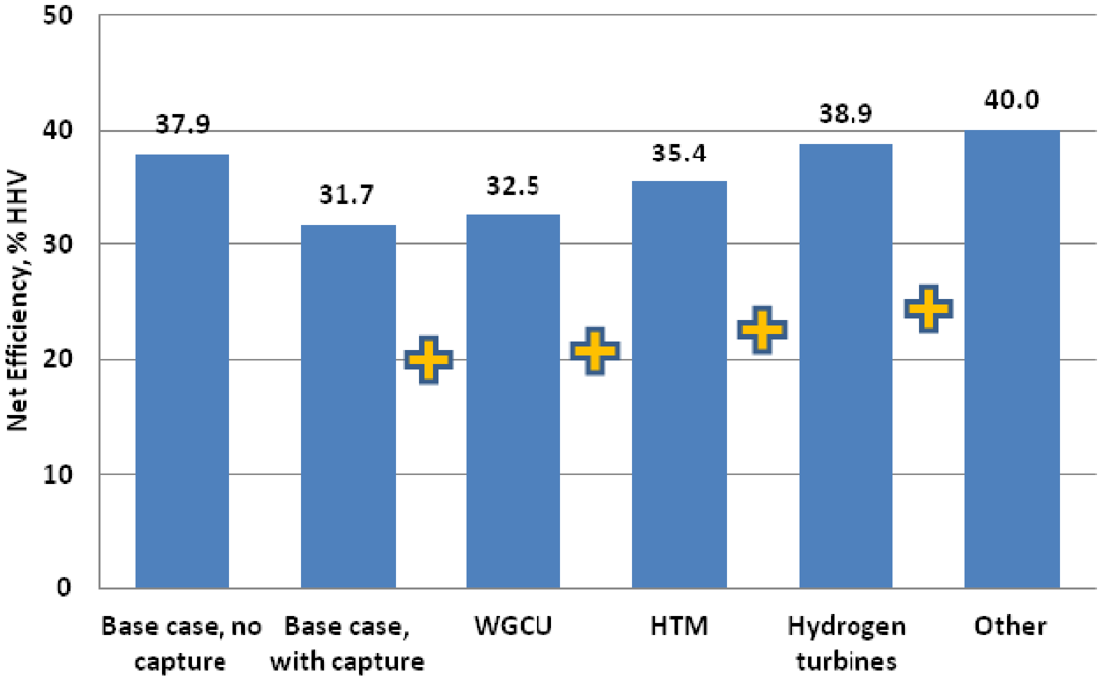
Pre-combustion capture of CO_2 already has been demonstrated at commercial scale in coal gasification plants used in non-power applications. The improvement plan for pre-combustion capture on IGCCs primarily focuses on syngas processing techniques that reduce the energy penalty (CCT Conference, 2011). Technologies include:

- **Hydrogen Transport Membranes (HTM) –** Have the potential to significantly reduce the cost and improve the efficiency of CO_2 capture from IGCC. A United States DOE technology evaluation showed that using HTM could increase efficiency by 2.9 percentage points (NETL, 2010). The HTM process avoids thermodynamic penalties incurred in conventional technology because the syngas is not cooled before separation and the CO_2 product is produced at relatively high pressure.
- **Improving WGS –** Various efforts are in place to reduce steam requirements
- **Warm-Gas Clean-up (WGCU) –** Pre-combustion capture would be more efficient with separation systems that operate at temperatures closer to those of the WGS reaction (260–370°C [500–700°F]) rather than at ambient temperature. WGCU removes contaminants such as sulphur and heavy metals at high temperatures, eliminating the need for syngas

cooling and expensive heat recovery systems. Studies show a potential improvement in efficiency of one percentage point with WGCU and up to 4 percentage points when combined with HTM (Hornick and Gardner, 2011).

The potential cumulative improvement in efficiency from these pre-combustion capture technologies is shown in Figure 12.

Figure 12 • Efficiency improvements with better pre-combustion capture technology



Source: EPRI, 2011a.

Oxy-combustion advantages

- Should be able to deploy conventional, well-developed, high-efficiency steam cycles without the need to remove significant quantities of steam from the cycle for CO_2 capture
- Added process equipment consists largely of rotating equipment and heat exchangers; equipment familiar to power plant owners and operators
- Ultra-low emissions of conventional emissions can be achieved largely as a fortuitous result of the CO_2 purification processes selected, and at little or no additional cost
- On a cost per tonne CO_2 captured basis, it should be possible to achieve 98+% CO_2 capture at an incrementally lower cost than achieving 90% CO_2 capture
- While there is currently no geological or regulatory consensus on what purity levels will be required for CO_2 compression, transportation, and storage, oxy-combustion costs may be reduced if purity requirements are relaxed
- The best current information is that oxy-combustion with CO_2 capture should be at least competitive with pre-combustion and PCC and may have a future cost advantage.

Oxy-combustion challenges

- It is not possible to develop smaller-scale or “slip-stream” oxy-combustion at existing power plants. Oxy-combustion needs an integrated plant and oxy-combustion development requiring the commitment of the entire power plant to the technology. Thus, the technology development path for oxy-combustion may be more costly than for pre-combustion or PCC, which can be developed on slip-streams of existing plants.

- Auxiliary power associated with air compression in a cryogenic ASU will reduce net plant output by up to 15% compared to an air-fired power plant with the same capacity (without CO_2 capture); this is the trade-off of paying to separate the oxygen to produce a concentrated CO_2 flue gas stream to reduce CO_2 capture costs
- Air-fired combustion is commonly anticipated for start-up of oxy-combustion power plants. The very low emissions achieved by oxy-combustion with CO_2 purification cannot be achieved during air-fired start-up without specific flue gas quality controls that are redundant during steady-state oxy-fired operations. If a significant number of annual restarts are specified, either these added flue gas quality controls will be required or provisions must be made to start-up and shutdown the unit only with oxy-firing and without venting significant amounts of flue gas.
- Plot space requirements are significant for the ASU and CPU and overall should be comparable to PCC
- Water consumption, while less than that for PCC, is still increased compared to a coal power plant that does not capture CO_2.

Oxy-combustion improvements

In terms of improvements on the CO_2 capture process itself on an oxy-combustion plant, there is less R&D ongoing compared to PCC and pre-combustion as the technology used is relatively straight forward. However, one key area of research is related to capturing the CO_2 contained in the vented inert gas (which typically has about 10% of the total CO_2) from the CPU. Technologies include:

- Both Linde and Praxair have developed pressure-swing absorption bed processes used to capture CO_2 from the vent gas stream and recycle it back to the inlet of the CPU compressor. It is projected that these systems would raise overall CO_2 capture efficiency to ~99% (Linde, 2011), (IEAGHG, 2011b).
- The vent gas leaving the flash stages is at pressure and contains 25 vol% CO_2 and 20 vol% oxygen. Air Products proposes using a polymeric membrane selective for CO_2/O_2 to separate and recycle the majority of these gases back to the boiler. This increases CO_2 capture efficiency to over 97% and reduces the size and power demand of the ASU by 5% (IEAGHG, 2011a).

Description of CO_2 compression, transportation, and storage

Compression

Most commercial storage applications pressurise CO_2 to inject as a supercritical fluid. Compressors required to raise CO_2 pressure to such a state consume significant amounts of power. With current technology, compression of the CO_2 produced by a PC plant may require as much as 8% of the plant's net power output and may add USD 150 million to the capital cost. Reducing capital costs and improving compression efficiency are major R&D issues.

Transportation

Storage of CO_2 from some power plants may require transportation for longer distances to suitable injection locations, possibly in other jurisdictions. Although CO_2 may be transported by various means, for the large quantities of CO_2 involved in CCS, pipelines are likely to be the only economic mode of transportation.

The technical, economic, and permitting aspects of CO_2 pipeline transport are generally well-understood. However, pipeline transport of CO_2 may require a minimum purity specification to prevent pipeline corrosion and reduce hazards in the event of an accidental release. This may have a significant impact on the cost of CO_2 capture as higher purity standards require more CO_2 purification.

A regulatory framework to provide structure and oversight for CCS activities will be necessary to ensure that CCS fulfills its promise of lowering CO_2 emission levels in a manner that is safe and long lasting.

Storage

Storage of captured CO_2 in underground or undersea locations remains a significant issue for implementing a large-scale CCS program worldwide. Options for geologic storage include oil- and gas-bearing formations, saline formations, and deep, unminable coal seams as well as EOR. EOR will be discussed in more detail later in Chapter 4.

Four large-scale geologic projects have been in place for some time and have successfully stored significant amounts of CO_2. The Weyburn-Midale project in Saskatchewan, Canada began in 2008 and stores ~2.4 Mtonnes (2.7 Mtons) CO_2/year (IEA, 2007). The Sleipner Saline Aquifer CO_2 Storage project, in the North Sea off of Norway, began injecting CO_2 from natural gas purification in 1996 and has an injection rate of ~1 Mtonnes (1.1 Mtons) CO_2/year (IPCC, 2002). The Snøhvit project began injection in the Barents Sea in 2008, with a capacity of ~0.7 Mtonnes (0.77 Mtons) CO_2/year (Storage, 2008). The In Salah Project in Algeria began injection in 2004 and stores ~1.2 Mtonnes (1.33 Mtons) CO_2/year (BP, Sontrach and Statoil, 2004).

However, significantly more storage demonstration is required to further calm public fears on this topic. Also, while storage opportunities are present in many areas in the world, some regions do not have suitable storages sites, which may require developing pipeline transportation networks.

To adequately qualify a site for CO_2 storage, characterisation studies must confirm the site's storage capacity and ability to safely store CO_2. Site characterisation and monitoring are critical to successful storage operations; oil-field technology and experience give researchers a good head start.

Unresolved barriers include regulatory, legal, and long-term liability issues associated with storage; addressing these will be critical to timely commercialisation.

Future technologies

This section reviews more advanced future technologies, several of which represent different platforms for coal power generation, that are in earlier stages of development (available commercially in the 2025–2030 timeframe) but may ultimately represent significant improvements in performance.

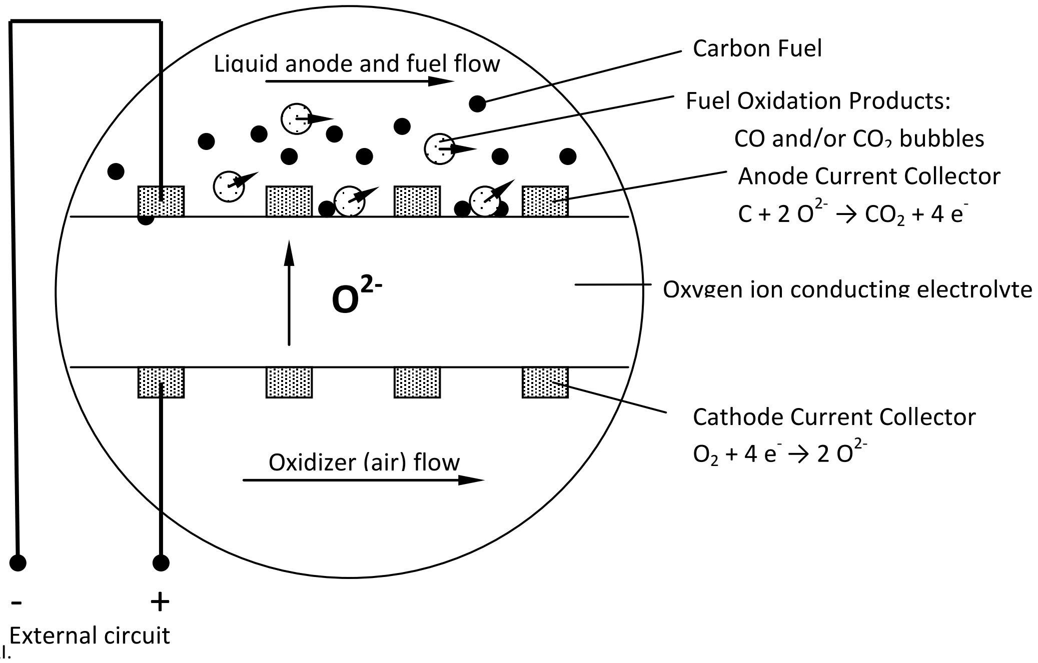
Advanced fuel cells

Fuel cells, which have been the focus of a decades-long development process, hold the promise of providing a step change in thermal efficiency for coal-based power plants.

Direct carbon fuel cells

Direct carbon fuel cells (DCFC) employ anode systems that consume powdered coal. Cathode systems consume oxygen from ambient air. The low-voltage cells (0.6–0.9 volts DC) are stacked to achieve high DC voltage and current that is then inverted to produce standard AC power. The anode exhaust is rich in CO_2. The cells are at temperatures in the range of 650–1000°C (1200–1830°F). A generic implementation of DCFC technology using a solid oxide electrolyte is shown in Figure 13. DCFCs using molten carbonate electrolyte are also being investigated. Full-scale implementation is expected to include a steam-bottoming cycle to make use of high-quality heat emanating from the DCFC system.

Figure 13 • Generic coal direct carbon fuel cell with solid oxide electrolyte



Source: EPRI.

The primary attraction of DCFCs is that a very high coal-to-electricity conversion efficiency might be achieved (potentially in excess of 60%) in an integrated, full-scale power plant at a cost comparable to conventional PC plants (EPRI, 2008). At present, DCFC technology is being developed at lab scale, at less than 1-kW electricity output. A full-scale power plant based on this technology will require scale-up by a factor of ~100 000. A significant amount of time and effort will therefore need to be undertaken to field this technology.

The concept of DCFC electrochemistry has been proven but significant challenges remain, among them:

- Developing economical systems for pre-processing the coal feed to meet DCFC inlet quality specifications
- Achieving a targeted cell/stack life of 5 years. Looming large in this effort is the ability to economically handle potential contaminants in coal that are not removed in pre-processing, including sulphur, reduced nitrogen, halogens, and ash constituents.
- Economical, durable, and maintainable designs for supplying air and coal to individual cells without leakage/bypass, electrical connections between cells and between stacks, and the inverters that are durable at the high cell temperatures.

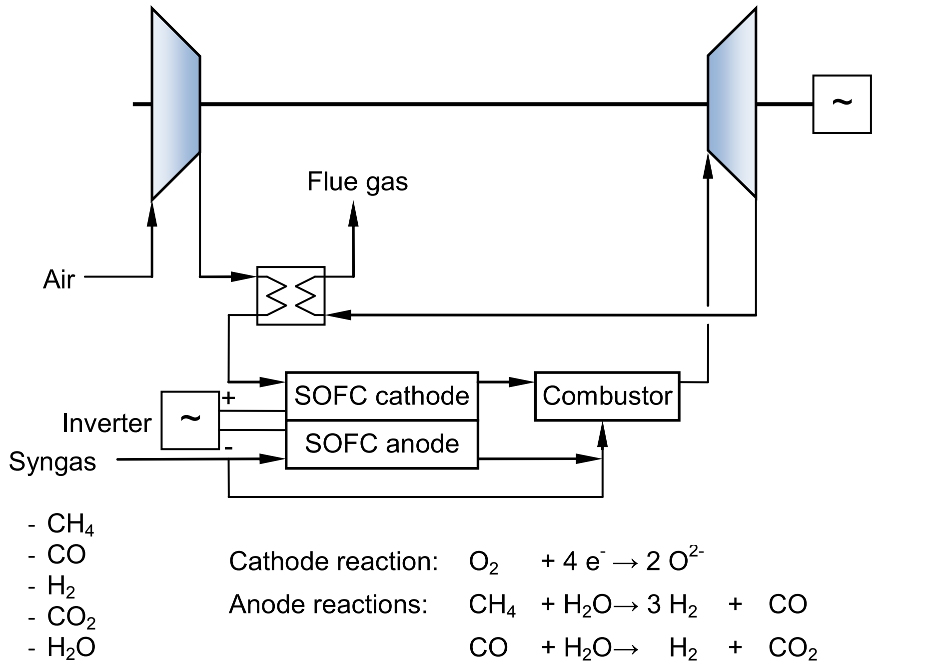
The critical path in development of DCFC power plants is to show that durable single cells can be fabricated and operated to achieve the target cell life while fuelled with coal. Bench-scale work continues to address this challenge. Once this is shown, the follow-on challenges of economical fabrication, durable mechanical stack assembly, and the associated mechanical durability questions commonly encountered with fuel cell power plants can begin to be addressed.

Integrated gasification fuel cell

An integrated gasification fuel cell (IGFC) power plant is an advanced concept for coal power generation for which the gas turbine is replaced with a fuel cell that converts the syngas directly into electricity while also producing residual heat. There are several types of fuel cells under development, but solid oxide fuel cells (SOFC), as shown in Figure 14, appear to the best choice for applications that include CO_2 capture because SOFCs can convert clean, unshifted syngas (CO & H_2) to a stream of CO_2 and water. After condensing out the water and using polishing to remove impurities, this stream is ready for compression and storage.

IGFCs offer the promise of a major step change in thermal efficiency for coal power systems with CO_2 capture. The DOE has estimated that an IGFC with CO_2 capture could achieve a net thermal efficiency of 56.3% (NETL, 2010). In addition to this dramatic increase in thermal efficiency, because the IGFC would not require a WGS reactor and would not have a steam turbine, the water consumption of the plant would be an order of magnitude less than an IGCC with CCS.

Figure 14 • Solid oxide IGFC power plant schematic



Cathode reaction: $O_2 + 4e^- \rightarrow 2O^{2-}$

Anode reactions:

$CH_4 + H_2O \rightarrow 3H_2 + CO$

$CO + H_2O \rightarrow H_2 + CO_2$

$H_2 + O^{2-} \rightarrow H_2O + 2e^-$

$CO + O^{2-} \rightarrow 2CO_2 + e^-$

Source: EPRI.

SOFCs operating on syngas are still an immature technology. The DOE goal is to have a 5-MW system operating by 2015 (Vora, 2010). A successful 5-MW system would need to be scaled up by a factor of ~100 for a full-scale power plant based on this technology. This is unlikely to be accomplished before 2025. Remaining challenges include:

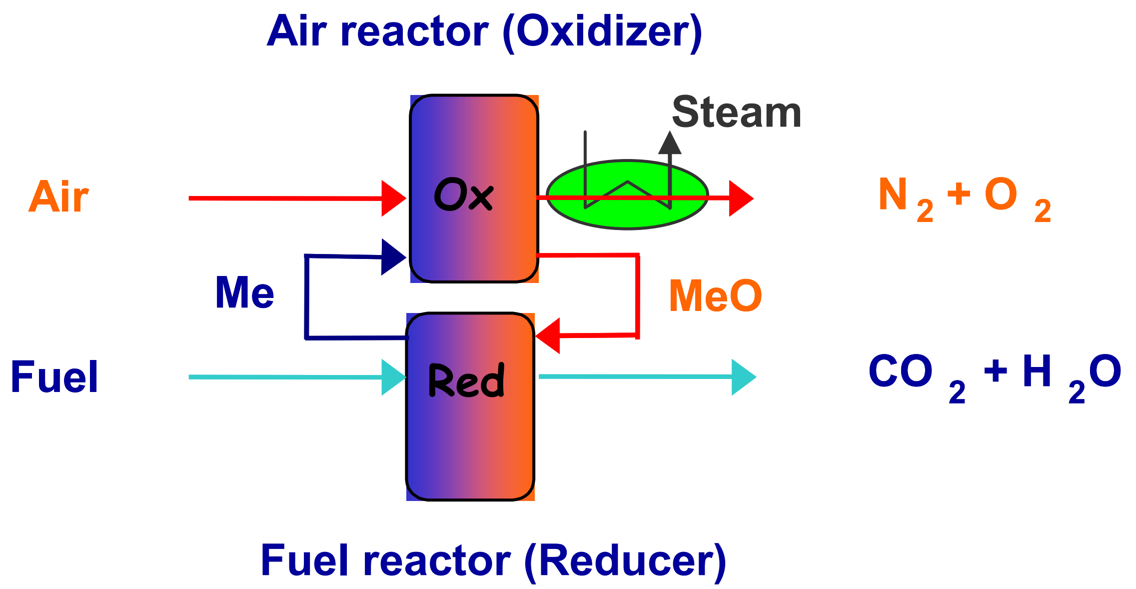
- Achieving a targeted cell/stack life of 5 years. Similar to DCFC, the ability to economically remove potential contaminants in coal-derived syngas including sulphur, reduced nitrogen, halogens, and ash constituents to SOFC inlet specifications will be a major task.
- Again similar to DCFC, developing economical, durable, and maintainable designs for air and syngas supply to individual cells without leakage/bypass, electrical connections between cells and between stacks, and the inverters that are durable at the high cell temperatures.

Chemical looping combustion

Chemical looping combustion (CLC) is, broadly speaking, an oxy-combustion technology that uses a reversible chemical reaction to separate oxygen from air. CLC uses suitable solids in an "air reactor" that are then transferred to a "fuel reactor" where the solid-oxygen reaction is reversed and the fuel burned. The process is shown schematically in Figure 15. Circulating fluidised bed (CFB) reactors are commonly used. Gas flow out of the air reactor is vitiated air. Gas flow out of the fuel reactor is predominantly CO_2 which may be sent to a CPU similar to that envisioned for conventional oxy-combustion power plants.

A successful CLC process would dramatically reduce auxiliary power use in air separation by replacing the air compressors in a cryogenic ASU with fluidising blowers in the CLC process. The use of A-USC steam conditions in a CLC steam-electric plant with CO_2 capture could achieve net efficiencies near 41% (GCCSI, 2012), which is significantly better than the 39% net typical of USC PC plants being built today without CO_2 capture. This potential for very high efficiency with CO_2 capture is the motivation for pursuing CLC technology.

Figure 15 • Simplified schematic for chemical looping using a metal oxide carrier



Source: EPRI.

Bench-scale activities are underway worldwide to identify suitable solids. Leading candidates are metal oxides and calcium sulphide/calcium sulphate. The largest coal-based chemical looping process development unit deployed to date is Alstom's 3-MWth prototype in Windsor, Connecticut, in operation since early 2011 (CL Conference, 2010). It is being used to develop solids handling schemes and to characterise overall process performance of the calcium sulphide/sulphate system. Pilot-scale facilities might be deployed in the 2015 time frame. A number of process challenges that must be addressed by pilot-scale CLC facilities are:

- The ability to manage the large solids flows associated with the process
- Solid oxygen-carrier deactivation, attrition, and replacement cost (the calcium sulphide system has an advantage here in that it can be supplied by relatively inexpensive limestone that will also affect capture of sulphur emissions produced during combustion)
- Carbon leakage from the fuel reactor to the air reactor will result in CO_2 emissions from the air reactor.

Closed Brayton power cycles

The steam-Rankine cycle is the backbone of the electricity industry in most of the world. It has been deployed in unit capacities exceeding 1400 MW and thermal-to-electric efficiencies over 40%. Efforts continue to increase cycle efficiency by designing for steam temperatures up to 760°C (1400°F).

Over the last 10 years, a number of organisations have conducted analytical and process development work to advance closed Brayton power cycles using supercritical CO_2 (SCO_2) as the working fluid in lieu of the Rankine cycle (Wright, Conboy, Parma, Lewis, Rochau, & Suo-Anttila, 2011), (Johnson & McDowell, 2011). Variations of the SCO_2 closed Brayton cycle have been proposed for generating electricity from nuclear, fossil fuels, solar thermal, geothermal, heat sources, and as an alternative to the Rankine bottoming cycle commonly deployed in NGCC plants. The technology might also be suitable for repowering as a topping cycle[7] added to existing subcritical Rankine cycles to increase plant output and efficiency.

Primary motivation for considering this power cycle for coal-fuelled applications is the prospect of higher efficiency. As fuel is the major operating cost of a coal-fuelled power plant, any technology that can increase efficiency (with correspondingly reduced fuel costs) commands attention.

A simple version of a closed Brayton power cycle is shown schematically in Figure 16. In a Brayton cycle, the working fluid does not change phase (boiling/condensation); it is compressed, heated, and expanded through a turbine. Combustion turbines operate as open Brayton cycles using air as the working fluid. In a closed Brayton cycle the working fluid exiting the turbine is cooled and sent to the compressor and heating the working fluid is done by indirect heat exchange rather than by direct combustion. Supercritical carbon dioxide (pressure greater than 73.9 bar [1086 psig]) is readily available at modest cost, does not change phase and has high density, which minimises compression power, making it an attractive candidate for the closed Brayton cycle.

This cycle offers the prospect of 2–3 percentage points higher efficiency (at comparable turbine inlet pressures and temperatures), an associated reduction in CO_2 emissions, and lower turbo-machinery costs as compared to the incumbent Rankine power cycle. Achieving the promising high efficiencies in actual deployments will require pilot-scale technology development in the following areas:

- **Fired Heater –** Feed water enters a fired steam generator at a temperature near 340°C (644°F). In the closed Brayton cycles being investigated, pre-heated SCO_2 enters the fired CO_2 heater at a temperature nearer 450°C (842°F). Fired heat exchanger designs with efficiencies comparable to those achieved in steam generation will need to be developed.
- **Power Cycle Optimisation –** There are a number of cycle modifications to the simple cycle shown in Figure 3-9 that will improve efficiency and cycle management. These include reheat (commonly practiced in steam-Ranking cycles), recompression, separate power and

[7] In a topping cycle, the fuel is burned in a device that generates electricity and thermal energy is recovered from the exhaust. In a bottoming cycle, fuel is first burned in a boiler or other device to generate thermal energy, a portion of which is extracted to generate electricity.

compressor turbines, variable pressure, etc., all with varying cost impacts. The economically optimum power cycle has yet to be identified.

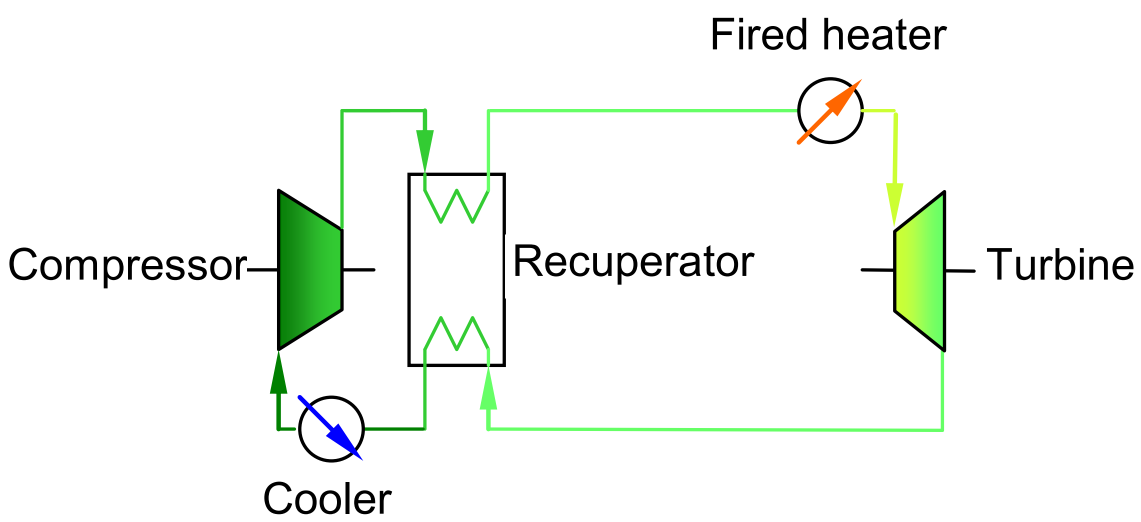
- **Recuperative Heat Exchanger(s) –** High efficiency will only be achieved with the use of recuperative heat exchangers to transfer residual heat in the turbine exhaust to the gas leaving the compressor. Highly effective heat exchangers with acceptable cost must be developed.
- **Turbomachinery –** SCO_2 turbines with the requisite performance specifications have not been deployed in other applications. In addition, in order to compete with advanced steam cycles, the SCO_2 turbine inlet temperatures will need to be comparable to those achieved in A-USC steam cycles; a materials challenge. SCO_2 compressors with the requisite performance specifications will differ in detail from those commonly deployed for pipeline CO_2 compression.

Note that demonstration and commercial use at partial scale in non-coal applications could validate the full-scale application of Brayton cycles to coal power.

Pressurised oxy-combustion

Conducting oxy-combustion under gas pressure (typically at ~10–15 bar [160–230 psig]) has been proposed to improve net efficiency and potentially reduce plant costs. A schematic typical of pressurised oxy-combustion power plants being considered is shown in Figure 16.

Figure 16 • Simplified closed Brayton cycle

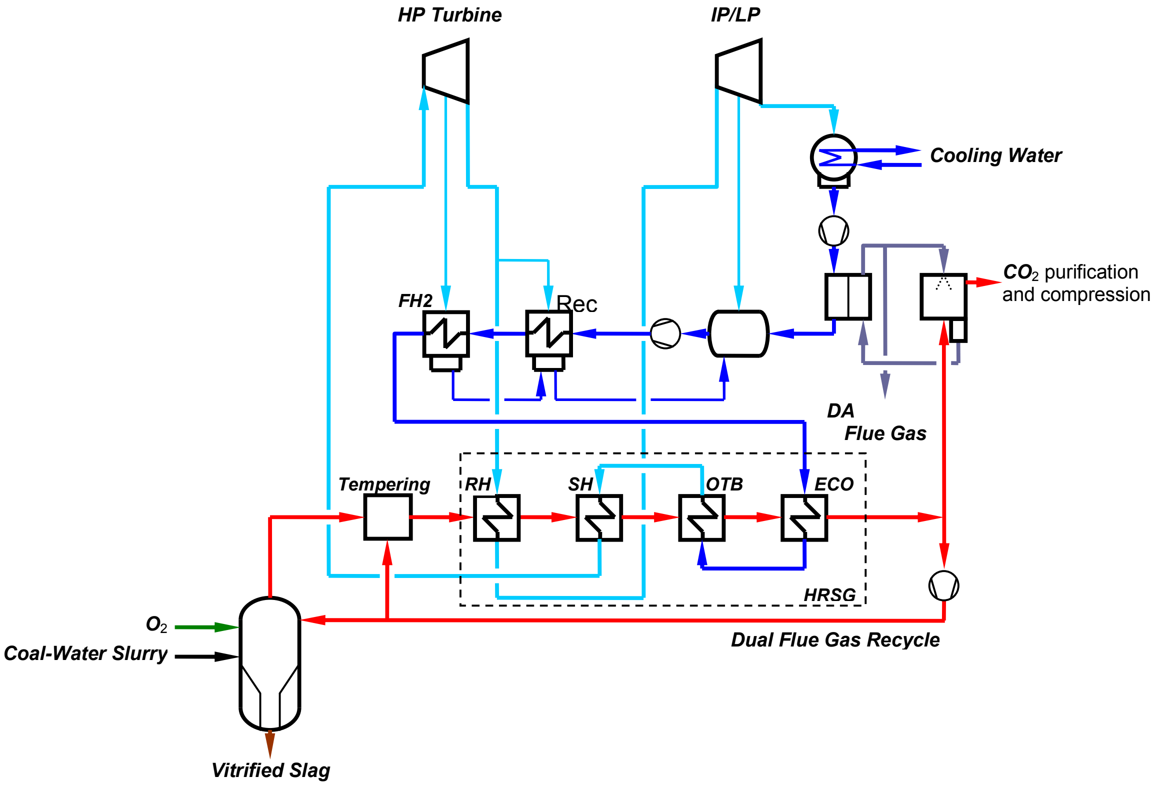


Source: EPRI.

The major efficiency benefit from pressurised oxy-combustion is the reduction of latent heat losses in the flue gas (higher boiler efficiency) by recovering the heat of flue gas moisture condensation at a temperature usable to the power cycle (Bindemann, 2012). A marginal reduction in auxiliary power use, primarily in the RFG fan, could also be realised. Operating the combustion and heat transfer under pressure will offer opportunities to reduce the size/cost of the steam generator through a variety of mechanisms. The elimination of air ingress (diluting the flue gas) will reduce CPU performance requirements.

Pressurised oxy-combustion process development has been conducted at the 5-MWth level. There are a number of developers proposing pressurised oxy-combustion operations at pilot scale but none of these have been deployed yet. There is relevant pressurised air-coal combustion experience up to 250 MWth, which might be applicable to pressurised oxy-combustion.

Figure 17 • Pressurised oxy-combustion power plant schematic



Source: EPRI.

A parallel challenge to pressurised oxy-combustion is the development of the associated gas-pressurised boiler design. Capital costs for pressurised oxy-combustion power plants with uncertainty comparable to atmospheric pressure oxy-combustion power plants await more detailed component designs, particularly the gas-pressurised boiler.

Conclusions

Table 4 summarises the various technologies discussed in this chapter that are not yet commercial by listing their benefits, the time to technical maturity, the estimated level of R&D spending required to bring them to commercial readiness, and the level of technical risk of achieving the described benefits.

In total there is a vast array of options available to improve the cost-effectiveness and environmental performance of coal power plants.

In the Appendix, Table 14 contains a timeline for several of the key technologies described in this chapter. The dark blue shading in the timeline indicates project steps that are already funded. The light blue shading represents project steps that are partially funded. Unshaded blocks are steps that are not currently funded at any level.

Table 4 • Overview of coal technology review

Technology	Benefits	Timing to technical maturity[8]	R&D spending needed	Technology risk
Advanced cycles				
Advanced fuel cells	▪ High efficiency with CCS; DCFC at 60% and IGFC at 56.3% ▪ Very low water use	>15 years	USD 50 million per year through 2020; larger amounts for demos in 2020s	High
Chemical looping combustion	▪ Higher efficiency with CCS ~41%	10-13 years	Pilot plant: USD 60 million	High
Closed Brayton Power Cycle	▪ Higher efficiency by 2-3 percentage points ▪ Incrementally lower cost	8-10 years	Pilot plant: USD 20-40 million	Moderate
Pressurised oxy-combustion	▪ Incrementally higher efficiency and lower cost	8-10 years	Pilot plant: USD 50 million	Moderate
IGCC				
Advanced gas turbines	▪ Higher efficiency ▪ Lower capital cost	10-12 years	Turbine development: USD 20 million/year for 6 years, 400 MW demo: USD 1 billion	Moderate
Air separation membranes	▪ Higher efficiency ▪ Smaller footprint	5-8 years	1800 tonnes/day (2000 tons/day) of oxygen demo: USD 100 million	Moderate
HTM	▪ Lower compression power ▪ Eliminates low temperature colling of syngas	5-8 years	Pilot plant: USD 70 million	Moderate
Improving WGS	▪ Improves efficiency ▪ Incrementally lower cost	<8 years	Most research done privately	Low
Liquid CO_2 coal slurry	▪ Improved efficiency with CCS ▪ Potentially lower capital cost	8 years	Flow test loop: USD 4 million, Pilot gasifier test: USD 5 million	Moderate
Warm-gas clean-up	▪ Higher efficiency by 3 percentage points	5-8 years	Pilot plant already in place	Moderate

[8] Technical maturity is indicat3ed by predictable engineering performance at full scale accompanied by availability/reliability and vendor guarantees/warrantees comparable to other power plant components in common use. Commercial availability, defined as acceptance by the market as a technology option for routine consideration, will typically lag technical maturity by several years.

Table 4 • Overview of coal technology review *(continued)*

Pulverised Coal				
A-USC steam conditions (700°C [1290°F])	▪ Raises net efficiency to 44%	8 years	Demo plant (500 MW): USD 600 million	Moderate
A-USC steam conditions (760°C [1400°F])	▪ Raises net efficiency to 46-48%	13 years	USD 20 million to complete lab tests, USD 50 million for component test, USD 600 million for demo plant	Moderate
Mercury control	▪ Reduce mercury capture costs by 50%	5 years	Pilot plant: USD 10 million	Low
Multi-pollutant control	▪ NZE NO_x and PM levels	5-8 years	Pilot plant: USD 50 million	None
Oxy-Combustion				
Near-commercial	▪ No steam extraction or chemical processes and less cost for CO_2 capture ▪ Lower water consumption	4-6 years	Incremental costs for a commercial pilot plant (150-250 WM): USD 1.5 billion	Low
Advanced	▪ Incrementally higher efficiency ▪ Negligible emissions	6-8 years	Will leverage R&D investments in A-USC programmes	Moderate

Note: maturity = 600–800 MW
Source: EPRI.

3. Carbon capture, utilisation, and storage

Implementation of CCS in coal-fuelled power plants will have major technical and economic impacts on the way electricity is produced from coal. The business decision to deploy a given CCS technology will generally require that the technology be sufficiently mature such that the technology: 1) Meets specified performance; 2) does not adversely impact routine delivery of electricity to market and has a reliability/maintainability comparable to other power plant components; and, 3) meets commercial acceptability criteria. The first two requirements can only be met by deployment of CCS technologies at commercially relevant scales. These demonstration deployments will entail risks greater than those that might be acceptable for commercially mature deployments.

While it might be possible to anticipate the technology development path to full-scale deployment specific CO_2 emissions reduction options will take, it is much more difficult to anticipate which technologies will meet the third criteria indicated above: commercial acceptance. This follows largely from the fact that CCS has such a major impact on the engineering and economics of coal-fuelled power generation. It is not possible at this point to anticipate which CO_2 emission reduction technologies will predominate in a commercial market 10–15 years hence. It is very likely, however, that those options that are most competitive will achieve commercial acceptance in a time gap of years after acceptable full-scale technical performance is demonstrated.

As will be discussed in this chapter, CCS projects that utilise EOR, or CCUS projects, are likely to be the first CCS demonstration projects implemented, since the CO_2 provides a revenue stream that improves project economics. Moreover, in the time window when CO_2 capture costs are high and there is no value for CO_2 related to pure geologic sequestration, CCUS, while not universally applicable, will provide the opportunity and experience to improve CO_2 capture, compression, and transportation technology. In this way, CCUS can help all future CCS projects, even those without EOR opportunities, by reducing the overall cost of CCS.

Critical need for integrated CCS demonstration projects

Although current CCS technology requires significant technology improvements and cost reductions, it is important to demonstrate CCS on a commercial scale (>1 000,000 tonnes CO_2/year [1 111 111 tons/year] stored) as soon as possible. Since the power industry is a major source of CO_2 emissions, demonstrations of capture technology operating in integrated power plant mode and in real power grid environments are urgently needed. It is also necessary to demonstrate storage at sufficient scale that has credibility for further deployment. Neither the public nor financial entities such as banks and insurance companies will accept CCS as a commercial option until the technology has been successfully demonstrated at commercial scale.

Commercial-scale CCS projects are also needed to remove legal and regulatory uncertainties associated with deep geologic storage of CO_2. Unless progress is made at the commercial CCS demonstration scale to answer these basic issues, it will become increasingly difficult to justify continued R&D funding on potential improvements to CCS technologies.

The need for CCS demonstrations has been acknowledged for some time. At the 2008 G8 Summit in Japan, major economies agreed that there was an urgent need to dedicate funding and begin construction of at least 20 large-scale CCS demonstration projects before 2015 and that CCS should begin broad deployment by 2020 (IEA, 2010). The United States Interagency CCS Task force has called for 5–10 CCS United States-based demonstration projects to be in operation by

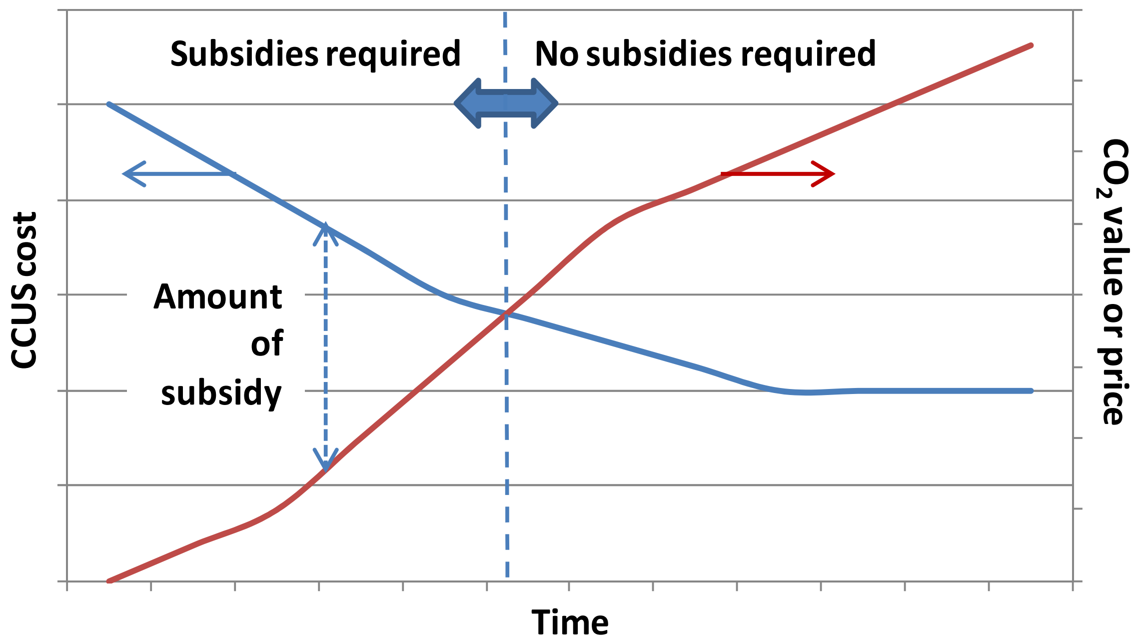
2016. An interim report on the progress towards the G8 goals was prepared for the Muskoka 2010 G8 Summit by IEA and the CSLF (IEA/CSLF, 2010). This report acknowledged some progress but also emphasised that a sense of heightened urgency and much greater effort will be required to achieve the G8 and IEA goals.

While Australia, Canada, European Union (EU), and United States have all dedicated funding to investigate and initiate CCS demonstrations, several projects have recently been cancelled and the FOAK costs have been very high. Government funds available so far only partially cover the CCS costs. Those projects that can obtain an additional revenue stream from the sale of CO_2 for EOR can provide some of the best early prospects for CCUS demonstration. The United States and the North Sea area of Europe offer opportunities for CCUS demonstration, but such opportunities will not be universally available.

Meanwhile China and, to a lesser extent, India are building new coal plants at a fast pace and CO_2 emissions from the world's coal fleet will continue to increase. China is the largest source of CO_2 worldwide and growing. Therefore, CCUS should be most relevant to China, a large importer of crude oil. China's huge investment in a coal-to-chemicals industry provides multiple sources of captured CO_2 that could be used for Chinese EOR projects, thus increasing domestic oil production, reducing expensive oil imports, and partially offsetting the cost of Chinese CCS demonstration projects (Minchener, 2011).

Because the cost of implementing CCS today far exceeds the cost of emitting CO_2 everywhere in the world, the initial commercial-sized, coal-based CCS demonstration projects will only proceed with significant government support. While integrated commercial CCS demonstration projects are clearly needed, improvements in the technology and a higher value on CO_2 emissions reduction (or revenue from EOR) will also be needed in order for CCS to eventually make economic sense without relying on government subsidies as depicted in Figure 18.

Figure 18 • Trends for CCS costs vs. cost of emitting CO_2 over time



Source: EPRI.

Status and costs of large-scale coal-based CCS demonstration projects

While improvement in CCS technology is clearly needed in order to decrease the cost of implementing CCS, there is still a vital need to demonstrate the CCS concept on coal power plants at commercial scale using today's technology. Numerous larger-scale coal projects with capture are currently in development around the world. Several major economies have created significant government funds to support CCS projects. Details on existing projects broken out by regions of the world follow. Table 13 in the Appendix gives high-level details on each project that is still possible or is already moving forward. As these projects change frequently, several on-line sources can be found that provide current status updates to keep up-to-date (GCCSI), (CCST, 2012).

As has already been noted, multiple proposed CCS projects have been cancelled or put on hold. In the last year alone, half-a-dozen large-scale projects have been cancelled and over a dozen have been cancelled worldwide in the last several years. Even some CCS projects that had been selected for significant subsidies under a government programme have elected not to proceed. Project hosts cite the lack of CO_2 emissions regulations with cost incentives or the inability to find a qualified storage location as typical reasons. In addition, the funding support in some cases has been insufficient to justify the full project cost in the absence of power price incentives.

This exemplifies the difficulty in getting CCS demonstrations done, with finances and CO_2 storage being the primary reasons, and further illustrates the importance of CCUS in the short term. In fact, the majority of the proposed or existing demonstration projects throughout the world that are moving forward are CCUS projects with EOR, which have been favoured for selection due to the greater chance of success.

Canadian projects

With the April 2012 announcement that the Project Pioneer PCC at Keephills near Edmonton is not going forward, the only remaining large-scale CCS project in Canada is the Boundary Dam PCC project in Saskatchewan – but it is a very important one. Boundary Dam is the only larger-sized near-commercial-scale PCC actually under construction anywhere in the world. The retrofitted PCC will capture one Mtonnes (1.1 Mtons) per year of CO_2 from one of Boundary Dam's refurbished coal units, which has a net generating capacity of around 110 MW. The captured CO_2 is to be sold for EOR (Sask, 2010).

Chinese projects

By the year 2020, according to a recent IEA Clean Coal publication (IEA, 2012a), the Chinese aim to reduce their carbon intensity to 40–45% of their 2005 levels and meet 15% of their total energy demand with non-fossil fuel. Even with such goals in place, Chinese coal use will continue to dominate the power sector, as much of their existing power plant capacity is new, having only been introduced in the last decade, and will clearly be operating well into the middle of the 21st century.

Under the current Chinese Five-Year Plan for 2011 to 2015, all new coal-fuelled power plants built within this period will not include CCS technology. This is because China does not currently perceive CCS as a viable way forward, citing high costs and lack of maturity of the first generation of CCS technologies. Nevertheless, developing CCS is considered a Chinese R&D priority with a near-term emphasis on CO_2-driven EOR to essentially help limit China's growing oil imports. The Chinese are therefore aiming to reduce the energy penalties and high costs of first-generation technologies while implementing very significant levels of research at universities and institutes towards the development of second-generation systems. The most significant large industrial pilot-scale CCS trials are being led by major state companies. The Huaneng Group is one of the biggest players in the Chinese CCS arena to date and is involved directly in the following pilot projects:

- The recent pilot-sized capture systems operated in Beijing (2008) and Shanghai (2010) each capturing 3 000 and 120 000 tonnes (3 300 and 132 227 tons) of CO_2 on an annual basis for the food and beverage industry
- Phases 1 and 2 of the GreenGen IGCC capture project (incorporating a 40 000 to 60 000 tonnes [44 000 to 66 000 tons] CO_2/year EOR trial).

The next stage in Chinese CCS development recognises the need for construction of one or more large-scale CCS demonstration units to enable potential users to gain experience with all aspects of the process including construction, commissioning, and operation. From a technical perspective, it would appear that China is poised to move forward on several potential large demonstration projects such as:

- A proposed 1 Mtonnes (1.1 Mtons) CO_2/year capture project to be led by the Huaneng Group, which builds on the capture and utilisation pilot at their advanced coal-fuelled power plant near Shanghai
- Phase 3 of the GreenGen project, which would include the construction of a 400-MW IGCC with 90% CO_2 capture and EOR
- The China Datang Corporation's collaboration with Alstom on two 1 Mtonnes (1.1 Mtons) CO_2/year projects in Heilongjiang province and Shandong province, utilising oxy-combustion and PCC technologies, respectively
- The Sinopec Shengil 1 Mtonnes (1.1 Mtons) CO_2/year PCC unit in Shangdong province
- The 2 Mtonnes (2.2 Mtons) CO_2/year Shanxi International Energy Oxyfuel project in Shanxi province
- The highly ambitious Energy Power Research Centre (EPRC) of the Chinese Academy of Sciences clean coal energy demonstration project in Jiangsu Province. Intended to include a 1 200-MW IGCC power plant built alongside two 1 300-MW USC PC power plants and a 10-MW solar unit to maximise heat integration between the IGCC, USC PCs and solar heat collector to improve the efficiency. It is also intended to demonstrate the capture of up to 1 Mtonnes (1.1 Mtons) CO_2/year from the plants to be used directly in EOR projects.

However, the Chinese Government has indicated the state-owned enterprises would not undertake such demonstrations of commercial prototype CCS systems without significant financial support. The global CCS community will therefore need to fully engage with China to determine how such potential projects can be best financed and how information can be disseminated.

From a storage perspective and in parallel to any capture EOR activities, the IEA also indicated in their 2011 review that China requires a national CO_2 storage capacity map, covering oil and gas reservoirs in all regions as well as a rigorous assessment of saline aquifers. In addition, a requirement to develop in-house Chinese experience with CO_2 storage monitoring and verification was acknowledged.

Finally, based on the current Chinese initiative to export advanced SC coal-fuelled boilers in Asia and nearby markets, China poised to become a serious supplier of CO_2 capture technologies. For example, the Huaneng Power Group claims that their cost for capturing CO_2 is below 200 RMB/tonne (USD 30/tonne), which is 30% of the costs quoted for other OECD intended projects. However, at present it remains to be seen whether this difference is merely a reflection of China's lower equipment cost base or whether Huaneng has made some significant CCS process improvements.

EU projects

The EU is planning to support multiple large CCS demonstration projects through several different government-based funding programmes.

European Energy Program for Recovery

In October 2009, the EU identified CCS projects for support totalling EUR 1.08 billion under the European Energy Program for Recovery (EEPR). Eleven applications were submitted by the mid-July 2009 deadline. The six selected power projects were:

- **Belchatów (Poland) –** PCC on a 33% slip-stream from a new 858-MW supercritical PC plant. Compressed CO_2 will be transported by pipeline for storage in a saline reservoir. An estimated 1.8 Mtonnes (2 Mtons) of CO_2 will be stored annually. Engineering studies of the capture plant have been completed, along with storage site selection.
- **Compostilla (Spain) –** Capture on a CFB oxy-combustion system. The proposed technology has been tested on a 30-MWth pilot plant at CIUDEN that will be scaled up for the demonstration plant of 242 MW. Captured CO_2 will be stored in a nearby saline reservoir. It is estimated that 1 Mtonne (1.1 Mtons) of CO_2 will be stored annually.
- **Don Valley (England) –** Pre-combustion capture on 800-MW IGCC of slightly more than 90%. CO_2 will be compressed and transported by pipeline to the North Sea, where it will either be used for EOR or stored in a saline reservoir. Up to 5 Mtonnes (5.6 Mtons) of CO_2 will be stored annually.
- **Jänschwalde (Germany) –** Oxy-combustion and PCC on a 300-MW demonstration unit integrated into the existing Jänschwalde lignite power plant capturing 90% and storing one Mtonne (1.1 Mtons) of CO_2 annually underground. In 2011, Vattenfall announced that they were not going forward with the project after completing FEED work.
- **Maasvlatke (Netherlands) –** PCC from 25% slip-stream of a 1070-MW PC plant. 1 Mtonne (1.1 Mtons) of CO_2 annually will then be transported and permanently stored in an off-shore hydrocarbons field – although several options are being investigated.
- **Porto Tolle (Italy) –** PCC on the entire flue gas from a 250-MW PC plant that co-fires coal with biomass (up to 5% of thermal input). The CO_2 capture is expected to be over 90%. CO_2 will then be transported to an off-shore saline reservoir and injected underground.

Note that one additional project was selected (capture from a steel mill at the Alcatel-Mittal facility in France), which will not be discussed here as it is a non-power project.

Most of these projects are planning CO_2 storage in a saline reservoir primarily because EOR opportunities are limited in Continental Europe.

New Entrants Reserve 300

Additional funding for CCS projects is to be made available from the New Entrants Reserve (NER) 300 initiative (NER300, 2012), whereby 300 million CO_2 credits from the planned auctioning of CO_2 allowances are to be made available for CCS and renewable installations. The actual value is unknown and dependent on the price of a CO_2 credit. The original announcement envisaged that up to 8 CCS and 34 renewables projects could be demonstrated by 2020.

Each EU member state solicited proposals and then selected those to be forwarded to the European Investment Bank (EIB) as candidates for funding under NER 300. The EIB will rank the projects and provide a recommendation to the European Commission, who will consult the EU Climate Change Committee before finally allowing the EIB to sell allowances and disburse funds. Full details of the programme are available on the European Commission Climate Action website. EIB has retained two engineering consulting companies to assist in the evaluation of CCS projects. The selection will probably be announced around year end 2012 or early 2013.

The following thirteen CCS projects were originally submitted to NER 300 by 9 May 2011:

- Post-combustion
  - Belchatów, PGE Elektownia S.A., Poland, lignite, on-shore storage (also EEPR funded). May be cancelled.
  - Longannet, Scottish Power, Scotland, coal, off-shore storage. Cancelled.
  - Peel Energy CCS, Ayrshire Power, Scotland, coal, off-shore storage. Cancelled.
  - Peterhead, Scottish & Southern Energy (SSE), Scotland, gas, off-shore storage (note this project was originally proposed by a British Petroleum-led consortium, so significant prep work has already been undertaken on it)
  - Porto Tolle, Enel, Italy, coal, off-shore storage (also EEPR funded)
  - Turceni, Getica, Romania, lignite, on-shore storage.
- Pre-combustion
  - Don Valley, 2CoEnergy, England, coal, off-shore storage (also EEPR funded)
  - Killingholme, CGen, England, coal, off-shore storage
  - Teesside Low Carbon, Progressive Energy, England, coal, off-shore storage.
- Oxy-combustion
  - Jänschwalde, Vattenfall, Germany, lignite, on-shore storage (also EEPR funded). Cancelled.
  - White Rose CCS Project, Drax Power, England, coal, off-shore storage.
- Industrial
  - Florange, Arcelor Mittal, France, steel, on-shore storage
  - Green Hydrogen project, Air Liquide, Netherlands, off-shore storage.

Note that neither the Compostilla nor Maasvlatke projects submitted proposals for NER 300 funds. Also, the Scottish Power Longannet, Ayrshire Power Peel Energy, and the Vattenfall Jänschwalde projects were subsequently cancelled and withdrawn leaving ten remaining candidates. Sixty-five renewable energy projects were also submitted.

Some of the projects submitted by other European countries to NER 300 already received some funding under the earlier initiated EEPR as noted above.

On 12 July 2012, NER 300 listed the candidate projects for award decisions and a reserve list (NER300, 2012). The rank order of candidates for award decisions was Don Valley, Belchatów, Green Hydrogen, Teesside Low Carbon, White Rose CCS Project, Killingholme, Porto Tolle, and Florange. The reserve list was Turceni and Peterhead. Note that PGE Elektownia S.A. stated in May 2012 that the Belchatów project would not go forward without further government support, although this may be reversed with its subsequent high ranking on the NER 300 list (Bakewell, 2012).

In case a project drops out from the candidate list, *e.g.,* if it is deselected due to insufficient funds or decides to drop out of its own accord as potentially is the case with the Belchatów project, the next-highest ranked project from the reserve list would ascend into the candidate list.

NER 300 is due to announce awards from its first round of funding at the end of 2012. In order to do that EU member states need to state which projects they are prepared to support from the list that NER 300 has selected. No more than 2 or 3 CCS projects total will receive funding in this round. The maximum support available for CCS projects is around GBP 250 million per project.

However, since the project cost estimates for large CCS projects are mostly over USD 1 billion and some as high as USD 6 billion, the contribution from NER 300 is likely to be only a percentage of the funding required. It would appear that the decision to proceed would primarily be driven by the ability of the project sponsors to achieve financial closure from other sources (banks, investors) rather than any award from the EIB.

UK Department of Energy and Climate Change Carbon Capture and Storage Demonstration Initiative

The UK DECC (DECC, 2012a) has re-launched a programme for CCS projects. Proposals developed under the previous solicitation were either withdrawn (*e.g.,* E.ON UK's Kingsnorth) or were rejected / cancelled due to high costs *(e.g.*, Scottish Power's Longannet). The DECC initial focus is to be the power sector since it is the largest source of CO_2 emissions in the United Kingdom.

On 2 April 2012, UK DECC announced a GBP 1 billion CCS competition. Potential entrants notified DECC by 13 April 2012 and applications were submitted 3 July 2012. Eight total projects submitted applications, several of which also applied to NER 300.

On 30 October 2012, DECC announced that four projects had been selected for the short list that would enter into a negotiations phase leading to decisions in 2013 on which projects would be supported further (Davey, 2012):

- **Captain Clean Energy Project –** A new 570-MW IGCC pre-combustion project in Grangemouth, Scotland with storage in offshore depleted gas fields. Led by Summit Power and involving Petrofac (CO_2 Deepstore), National Grid, and Siemens.
- **Peterhead –** Also applied for NER 300 funds
- **Teesside Low Carbon Project –** A pre-combustion coal gasification project (linked to a 330-MW plant fuelled by syngas with 90% of CO_2 removed) on Teesside, North East England with storage in depleted oil field and saline aquifer. The project has a consortium led by Progressive Energy and involving BOC, GDF SUEZ, and Premier Oil.
- **White Rose Project –** Also applied for NER 300 funds.

The selected projects are to be financed by a combination of capital grants and revenue from sale of low-carbon electricity in a reformed electricity market.

The timing of project selection for the UK DECC solicitation is similar to that planned for selection of NER 300 projects. It is not clear if there is any dialogue or coordination between the two organisations; however, the EIB expects that any projects selected under NER 300 should also get financial support from the host member states.

United States projects

A total of six large coal-based CO_2 capture projects are in development in the United States. With the exception of the Tenaska Trailblazer project, all have funding support from the DOE either under the Clean Coal Power Initiative (CCPI) or the American Recovery and Reinvestment Act (ARRA).

It should be noted that all of the active United States projects – save for FutureGen 2.0 – plan to sell captured CO_2 for EOR thereby providing a revenue stream rather than an additional cost that would be incurred for storage in a geologic site (*e.g*., saline reservoir). Several also will produce chemicals for sale in addition to electricity.

The only project under construction is Mississippi Power's Kemper County 524-MW IGCC project located near Meridian, Mississippi. At a CO_2 capture rate of 67% (about NGCC equivalency), which would conform to EPA's proposed standard for new coal plants[9].

The only other two United States IGCC projects in development (Summit Power's Texas Clean Energy Project [TCEP] and SCS Energy's Hydrogen Energy California [HECA]) plan on co-production of urea fertiliser and the sale of CO_2 for EOR. Both projects received USD 450 million from the CCPI programme.

NRG Energy's Parish Unit 7 project in Texas that is planning to use the Fluor Econamine FG Plus^{SM} technology is the only large United States PCC project in development. This project was originally to be on a flue gas slip-stream equivalent to 60 MW of the 565 MW total, but the design was recently increased to 240 MW. The costs for the larger project are still being evaluated.

The 168-MW (gross) FutureGen 2.0 oxy-combustion project at Ameren's Meredosia plant in Illinois has USD 1 billion in funding from ARRA. The status of this project has been in flux as Ameren has dropped out, but it is still active and is being led by the FutureGen Alliance, a non-profit organisation formed from funding received from several utility and coal companies interested in the project moving forward. The project has planned from inception that the CO_2 be stored in a saline reservoir and has selected a geologic site in nearby Morgan County. A characterisation well was successfully drilled and data are currently being analysed for suitability for CO_2 storage.

Tenaska Trailblazer has proposed doing a PCC project on a commercial-scale PC plant with 90% capture on the entire flue gas, not just a slip-stream. This project is still in the design phase and has not yet secured any sizeable governmental financial support.

Major challenges faced by CCS demonstration projects

The following challenges faced by CCS demonstration projects will be reviewed and contrasted between those that include EOR and those with other CO_2 storage plans where applicable.

Environmental advocacy opposition to coal

Many environmental action organisations are against the continued use of coal and are pursuing opposition to projects that include CCS regardless if it is geologic storage or EOR. The Kemper IGCC with CCS project is a current example where pressure from such organisations has resulted in the Mississippi Supreme Court requiring that the public utilities commission re-examine their approval of the project. The Sierra Club is aggressively trying to halt construction but currently this has been allowed to continue. This is an important case to monitor. So far the progress of the other United States CCS projects has not been significantly affected by opposition to the use of coal. As of this date it does not appear that the opposition to coal has dramatically affected the plans for the CCS projects submitted under NER 300 or the UK DECC CCS initiative.

China, India, and other countries in the Asia Pacific region (with the exception of Australia) are proceeding with major coal plant expansions without much opposition.

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[9] However, this plant would be exempt from the EPA rule since it started construction before the proposed rule was published.

Public opposition to storage

Although concerns about on-shore storage in saline reservoirs are discussed in the United States, so far they have not been a key cause of CCS project delays or cancellations. The majority of proposed CCS demonstrations in the United States plan to use EOR and public opposition do not seem to be a rate-limiting step in moving forward.

In contrast, continental Europe has experienced marked public opposition to on-shore storage ("NUMBY": not under my backyard). This opposition was almost certainly a factor in the cancellation of the Vattenfall Jänschwalde oxy-combustion and RWE IGCC with CCS projects. Germany's parliament has blocked a law permitting CCS; however, the government must now come up with a new law that conforms to an EU directive on the CCS technology.

All of the UK CCS projects and the Maasvlatke project in the Netherlands plan to either store the captured CO_2 in depleted gas fields or use it for EOR in the North Sea. This has not been particularly controversial. However, as discussed later, the costs for off-shore storage or use appear to be much higher than earlier estimates and the high cost of transporting and storing the CO_2 off-shore was cited as one of the reasons for the cancelation of the Longannet CCS project.

No (or low) value for CO_2

Even in those locations where there is a price for CO_2 emissions (*e.g.*, Europe), the current value (USD 8–10/tonne [USD 7.2–9/ton]) is insufficient to incentivise large-scale development and deployment of CCS. As an example of the impact on advancing CCS demonstration, the lack of value for reducing CO_2 emissions was one of the cited reasons for AEP's cancellation of the larger-scale Mountaineer CCS demonstration project despite the provision of partial DOE funding (AEP, 2011). Beneficial uses of CO_2 (*e.g.*, for EOR) and the associated revenue stream can financially offset CCS implementation costs in some locations but will not be universally applicable. CCS demonstration projects will need both capital cost support and subsidy for the power price to move forward.

Continued uncertainty on climate change and weak CO_2 value, relatively low power costs in areas of the world, and low natural gas prices are major inhibitors for CCS demonstration projects. For CCS retrofit projects, there is also the loss of net power output that must be replaced by other generation. Currently most of the proposed CCS demonstration projects are from OECD countries, but the inclusion of China and India will be of vital importance in achieving the necessary progress in advancing CCS deployment.

Ultimately, a value for CO_2 is clearly needed for widespread commercial deployment of CCS. In the context of getting some CCS demonstrations funded, the costs of CCS will likely need to be reflected in the revenue stream, which will require consumers to pay a premium on the price for the power, as can currently be the case for renewable energy.

High cost of storage or lack of storage sites

In many regions in the world, there is no easy access to storage sites either underground or undersea. Even in regions where storage opportunities exist, there can be significant technical and regulatory barriers both of which can dramatically drive up the cost associated with finding, researching, permitting, operating, and monitoring a storage site. These have contributed to a low success rates of CO_2 storage projects.

The generalised cost of USD 10/tonne (USD 9/ton) for transportation, monitoring, and storage (TMS) may apply in the United States where some CO_2 pipeline infrastructure exists and the terrain is well characterised. However, in many parts of the world, these costs are likely to be much larger. For example, the TMS costs of the UK projects planning storage or EOR off-shore in the North Sea are very high.

Higher cost estimate for CCS

The CCS project cost estimates are much higher than had been anticipated a few years ago when many of the CCS projects were initiated. There has been a general capital cost escalation but there has also been a major increase as a result of the completion of engineering studies that have defined in greater detail what is necessary to build such projects.

One area of major cost increase has been CO2 transportation and injection. These costs are very site specific with short on-shore transportation being generally the lowest cost and off-shore more expensive. In the United States, many CCS projects plan on-shore transportation via pipelines to connect to CO2 networks previously established for EOR. FutureGen 2.0 plans a short pipeline for storage in the Mount Simon saline reservoir. In Europe, it currently appears that the only sites for CO2 storage or EOR are off-shore in the North Sea (proposed CCS projects in Italy, Poland, Romania, and Spain are at very early stages of development with regard to storage).

Although a complete breakdown of costs is not available, it is interesting to compare the FOAK cost estimates for three PCC plants: Scottish Power's Longannet, E.ON UK's Kingsnorth, and AEP's Mountaineer CCS projects as shown in Table 4-1. All are cost estimates for the addition of CO_2 capture to PC plants.

However, the distance to CO_2 injection sites are very different. AEP has only a short on-shore pipeline to the injection site. Longannet, located in Scotland, has some on-shore pipeline to the St. Fergus transfer station and then an off-shore pipeline to the injection wells in the North Sea. Kingsnorth, located in southeast England, needs a much longer pipeline both on-shore and off-shore to get to the injection site.

Table 5 • Estimated FOAK cost for PCC projects – Kingsnorth, Longannet, and Mountaineer*

Site	Kingsnorth (as reported)	Kingsnorth (adjusted)	Longannet	Mountaineer
Plant Size and Type	800-MW supercritical PC (planned)	800-MW supercritical PC (planned)	600-MW supercritical PC (existing)	1300-MW supercritical PC (existing)
Equivalent amount of CO_2 capture	300 MW_{eq}	300 MW_{eq}	300 MW_{eq}	300 MW_{eq}
CO_2 Stored, Mtonnes/year (Mtons/year)	2.0 (2.2)	2.0 (2.2)	2.0 (2.2)	1.5 (1.7)
Cost Category – USD Million				
Steam and power	NA	NA	179	NA
CO_2 capture plant	400	400	771 (including Owner's Engineer and Balance of Plant)	665
CO_2 compression	129	129	262 (74 on site and 188 at St. Fergus transfer)	665
CO_2 pipeline	748	304	250	160
CO_2 Injection in wells	277	113	324	160
Risk and contingency	332	178	304	103
Total	**1 886**	**1 124**	**2 090**	**928**

* An exchange rate of 1.56 USD/GBP has been assumed. The costs in the Kingsnorth (as report) column are as reported in the FEED report for the larger pipeline. The costs in the Kingsnorth (adjusted) column are recalculated costs using a smaller diameter pipeline and fewer injection wells.

Source: Mountaineer data based on AEP, 2012; Kingsnorth and Longannet data from DECC, 2012.

The overall plan for Kingsnorth was for two new 800-MW (rating without capture) supercritical PC units and to add 50% capture from one 800-MW unit. This would be equivalent to about 300-MW net with capture. However, the CO_2 pipeline was sized for the CO_2 output of the full 2 x 800 MW units with capture whereas a pipeline with half the diameter would have been sufficient for the 300-MW demo unit. A preliminary attempt has been made to estimate the cost effect of a smaller pipeline. In this design, the solvent regeneration energy is taken from the steam cycle and in this regard these costs should be more comparable to other studies that use the same approach for addition of PCC to supercritical PC plants.

The Longannet design was a retrofit to a much older subcritical unit. ScottishPower decided not to modify the older steam cycle and instead took the approach of adding a NGCC unit to supply the steam for solvent regeneration and the power for the CO_2 compression. However, CO_2 compression at the plant was only 34 barg (493 psig) in order to be able to use an existing feeder line owned by National Grid. The connection to the feeder line needed new pipeline including one under the Firth of Forth. A new compressor station near the end of the feeder line compresses the CO_2 to 80–120 barg (1160–1740 psig) for off-shore transport in an existing pipeline to the Goldeneye platform. Despite the use of existing infrastructure (albeit with considerable modification), the overall site and project specific transport costs are very high and are believed to have been a significant factor in the project cancellation.

No information is available on the base plant costs without capture so that it is not possible to calculate the CO_2 avoided costs for the projects. However, using these capital costs the annual revenue requirements to service such investments can be estimated and related to a cost/tonne of CO_2 stored. These projects were designed for about a 20-year life (or less). For the capital component factor based on a 20-year life, an approximate rule-of-thumb estimate is to use 0.15 and then add 0.04 to account for O&M. The resulting cost/tonne of CO_2 stored that would be required to service the capital investment in these projects is shown in Table 6.

Table 6 • Cost of CO_2 stored required to recover capital investment and O&M

Site	Kingsnorth (as reported)	Kingsnorth (adjusted)	Longannet	Mountaineer
Capture and Compression, USD/tonne (USD/ton)	60 (66)	60 (66)	113 (125)	94 (104)
Pipeline and Injection, USD/tonne (USD/ton)	119 (131)	47 (52)	85 (94)	22 (24)
Total, USD/tonne (USD/ton)	**179 (197)**	**107 (118)**	**198 (219)**	**116 (128)**

Source: EPRI.

High power loss from CO_2 capture

This is a major issue for those CCS demonstration projects that retrofit PCC to existing PC power plants. This typically results in a loss of about 30% of the electricity sent out from a power station due to steam and power from the plant being used for solvent regeneration and CO_2 compression. This loss of power and its associated loss of revenue – in addition to the capital cost of installing CO_2 capture equipment – need to be addressed to make the projects economically viable. In the United States, for example, this is one reason why the majority of United States CCS demonstration projects that are still in development plan to sell the CO_2 for EOR.

Low revenue from power sales in current markets

In the United States, natural gas prices in 2012 have been low, ranging between ~USD 1.8–2.7/GJ (USD 2–3/MBtu), and power prices are low because of the large number of low-fuel cost gas turbine-based generating units. For PCC and oxy-combustion projects, sale of the CO_2 for EOR is the only other potential revenue source.

However, IGCC projects that include co-production of other chemicals and fuels can also derive additional revenues from the sales of these products. The TCEP and HECA projects in the United States are based on IGCC with co-production of fertiliser (urea and urea-ammonium nitrate) and these projects would then have three revenue streams. The TCEP project estimates that about 45% of its revenues will come from the sale of 721 000 tonnes/year (800,000 tons/year) of urea products, 30% from power sales of 195 MW, and 20% from the sale of 2.25 Mtonnes/year (2.5 Mtons/year) of CO_2 for EOR.

Current prices of natural gas are higher in Europe at USD 6–10/GJ (USD 5.7–9.5/MBtu) and much higher in the Asia Pacific region at USD 12–15/GJ (USD 11.4–14/MBtu). Coal and associated power prices in those locations are also much higher than United States prices. However, they remain insufficient to justify the high capital cost and lower efficiency of CCS plants.

The UK DECC CCS initiative is considering both capital assistance and revenue assistance from the sale of low-carbon electricity from CCS projects in a reformed electricity market. The GreenGen project in China was also able to negotiate a special tariff for the sale of its electricity in order to make the project financeable by the Asian Development Bank (LRC Symposium, 2012).

Using EOR to make CCS projects financially viable

In the absence of special tariffs for electricity such as proposed in the United Kingdom and China, CCS projects that rely only on power sales for their revenues are not going to be able to achieve financing and will only proceed with major government assistance. Hence, CCUS projects are at the forefront in regions that can use CO_2 for EOR.

In several locations there is an opportunity to obtain additional revenues from the sale of CO_2 for EOR. Currently this is mainly practiced in the United States where 6276 km (3900 miles) of pipelines transport over 60 Mtonnes/year (66 Mtons/year) of CO_2 for EOR producing an additional 352 000 barrels/day of domestic crude oil. This practice has been operated over four decades with no major accidents, serious injuries, or fatalities reported. The National Coal Council reported that 18 to 31 Gtonnes (19.8 to 34.1 Gtons) of additional CO_2 could be used in United States for EOR over the next 40 years or more, potentially yielding an additional 3.5 million barrels of oil (MMBO) a day (NCC, 2012).

The National Enhanced Oil Recovery Initiative (NEORI) was launched on 17 July 2011 to help realise EOR's full potential in the United States as a national energy security, economic, and environmental strategy. In a report published in February 2012 (NEORI, 2012), NEORI recommends a federal production tax credit (that could be funded from additional tax revenues from increased oil production) for capturing and transporting CO_2 from industrial and power plant sources. The deployment of CO_2 capture and pipelines for EOR will establish a national infrastructure that can eventually be utilised by many industries for long-term CCS in geologic formations beyond oil and gas fields. However, if EOR is going to be expanded significantly, monitoring and verification of larger quantities of injected CO_2 above that required for current EOR projects will be needed to demonstrate long-term storage security. NEORI represents an innovative funding mechanism that could fill the gap left by governments facing tightening fiscal limits.

Over the past decade, China has made large investments in coal to chemicals plants that provide large sources of captured CO_2, some of which is used but most is vented. China now uses about 3 billion tonnes (3.3 billion tons) of coal a year and is the largest producer of CO_2 emissions worldwide (and growing). If CCS is to make the major contribution to the international goals of GHG reductions then it must be demonstrated and deployed worldwide but particularly in China. CCUS demonstration projects in China using captured CO_2 from existing coal gasification plant clusters would be the least cost, most relevant CCUS projects worldwide. This concept has been recently highlighted by a report from the IEA Clean Coal Centre (Minchener, 2011) and previously by the National Resources Defense Council (NRDC, 2009). Support from government, international banks, and major energy organisations for this concept is growing.

The following section provided by Advanced Resources International, Inc. (ARI) gives more information on the worldwide potential for EOR.

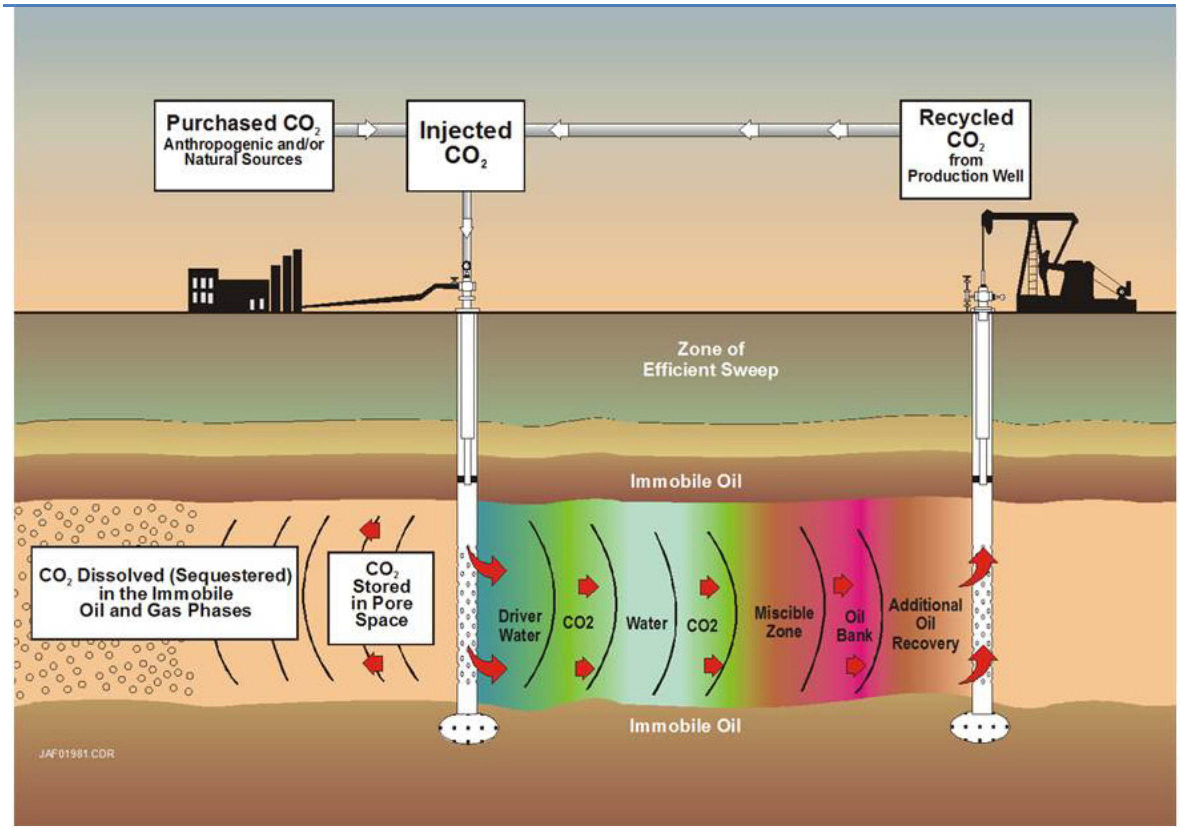
Opportunities for EOR

EOR involves injecting CO_2 into a (often) depleted oil reservoir, where it dissolves in the oil, lowers its viscosity, and improves its flow. This allows for additional oil to be pushed to a production wellbore. Oil displacement by CO_2 injection relies on the phase behaviour of CO_2/oil mixtures, which are strongly dependent on reservoir temperature, pressure, and oil composition.

There are two main types of EOR processes:

- Miscible EOR is by far the most dominant form of EOR deployed. In miscible EOR, the CO_2 vaporises the lighter oil fractions into the injected CO_2 phase and CO_2 condenses into the reservoir's oil phase, leading to two reservoir fluids that become miscible (mixing in all parts), with favorable properties of low viscosity, enhanced mobility, and low interfacial tension, with the objective to remobilise and produce the residual oil in the reservoir's pore space after water flooding as shown in Figure 19.

Figure 19 • Schematic showing the miscible EOR process



Source: ARI, 2012.

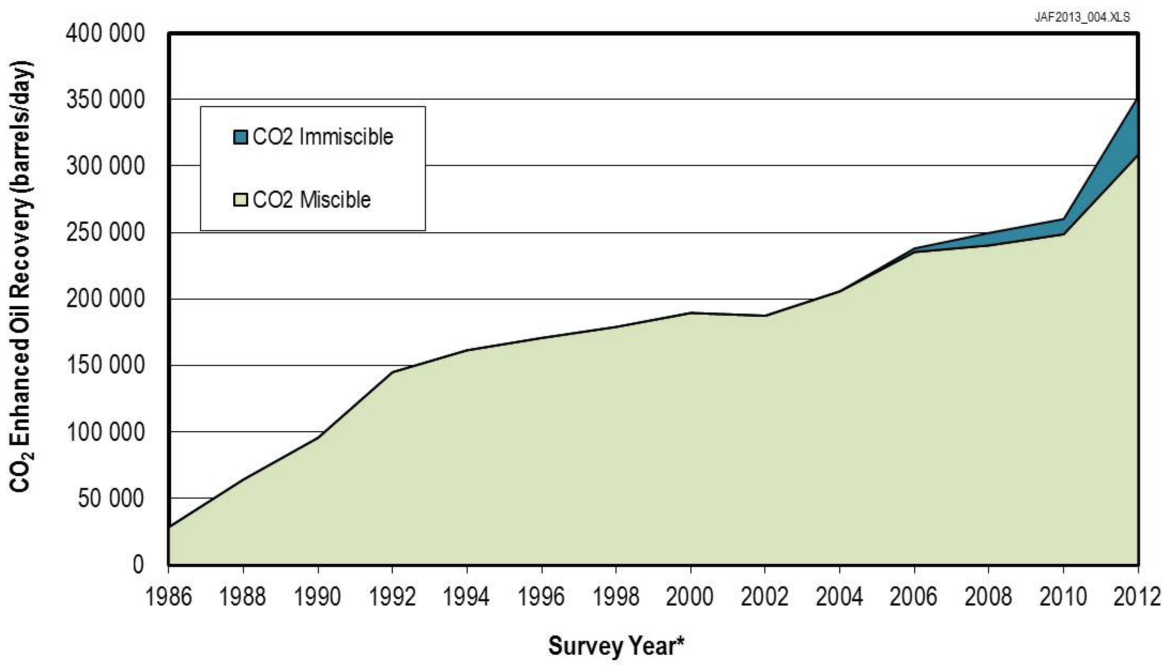
- Immiscible EOR occurs when insufficient reservoir pressure is available or the reservoir's oil composition is heavier. The main mechanisms involved in immiscible CO_2 flooding are: (1) oil phase swelling, as the oil becomes saturated with CO_2; (2) viscosity reduction of the swollen oil and CO_2 mixture; (3) extraction of lighter hydrocarbons into the CO_2 phase; and, (4) fluid drive plus pressure. This combination of mechanisms may enable a portion of the remaining oil to be mobilised and produced, and can be commercial in many instances.

EOR operations have traditionally focused on optimising oil production, not the storage of CO_2. However, EOR can result in very effective storage. In general, nearly 100% of the initially acquired/purchased CO_2 for EOR operations (not that which is recycled) will be stored at the end of active injection.

Current production from the application of EOR

EOR technologies have been demonstrated to be profitable in commercial-scale applications for nearly 40 years. The most comprehensive review of the status of EOR around the world is the biennial EOR survey published by the *Oil and Gas Journal*; the most recent issue was published in April 2012 (OGJ, 2012). The survey shows that oil production from fields undergoing EOR in 2012 amounts to over 352 000 barrels per day, with over 284,000 barrels per day directly attributable to EOR, from over 120 projects, and represents 6% of total United States crude oil production as seen in Figure 20.

Figure 20 • United States EOR production (1986-2012)



* Data is for EOR production rate at end of prior year; United States crude oil production of 6.02 MMB/D in 2012.
Source: ARI and Oil and Gas Journal, 2012.

Natural CO_2 fields are the dominant source of CO_2 for the United States EOR market, providing CO_2 supplies amounting to an estimated 48.9 Mtonnes/year (53.8 Mtons/year) as shown in Figure 20. An extensive CO_2 pipeline network has evolved, and continues to evolve, to meet the CO_2 requirements for EOR. Industrial sources account for a much smaller but steadily increasing share of this CO_2 supply, currently providing 13.3 Mtonnes/year (14.7 Mtons/year).

The largest source of industrial CO_2 used for EOR in the United States is captured from ExxonMobil's Shute Creek natural gas processing plant at the La Barge field in western Wyoming (Thomas, 2009). This is followed by the capture of about 3 Mtonnes / year (3.3 Mtons/year) from the Northern Great Plains Gasification plant in Beulah, North Dakota and its transport, via a 330-km (205 miles) cross-border CO_2 pipeline, to two EOR projects (Weyburn and Midale) in Saskatchewan, Canada (GPDGC).

Table 7 • Significant volumes of anthropogenic CO_2 are being injected for EOR

Existing CO_2 Supplies for United States EOR operations (average 2010)				
Location of EOR/storage	Source type and location	CO_2 Supply, Mtonnes/year (Mtons/year)		
		Geologic	Anthropogenic	Total
Texas-Utah-New Mexico-Oklahoma	Geologic (Colorado-New Mexico) Gas processing (Texas)	30.9 (4.0)	3.7 (4.1)	34.6 (38.1)
Colorado-Wyoming	Gas processing (Wyoming)	0.0	5.8 (6.4)	5.8 (6.4)
Mississippi-Louisiana	Geologic (Mississippi)	18.0 (9.8)	0.0	18.0 (19.8)
Michigan	Ammonia plant (Michigan)	0.0	0.2 (0.2)	0.2 (0.2)
Oklahoma	Fertiliser plants (Oklahoma)	0.0	0.7 (0.8)	0.7 (0.8)
Saskatchewan	Coal gasification (North Dakota)	0.0	2.9 (3.2)	2.9 (3.2)
Total, Mtones/year (Mtons/year)		**0.0**	**2.9 (3.2)**	**2.9 (3.2)**

Source: ARI, 2012.

The Weyburn field in Canada is a combined EOR and geologic storage project. This Cenovus Energy (formerly EnCana) CO_2 flood has been expanded to over 60% of the unit, and oil production from the field has continued to increase. The implementation of the EOR project, along with the continued infill well development programme, has resulted in a 65% increase in oil production (OGJ, 2008). According to recent reports, 18.5 Mtonnes (20.5 Mtons) have been injected to date (Whittaker, 2010). The ultimate plan is to inject a total of 55 Mtonnes (61 Mtons); much of which will be injected solely for purposes of CO_2 storage (PTRC, 2004). The nearby Midale field has been operated by Apache Canada since 2005 using the same CO_2 source as Weyburn; 2.8 Mtonnes (3.1 Mtons) have been stored to date in the Midale field.

Outside of North America, only a few (mostly immiscible) EOR projects are underway (in Brazil, Turkey, and Trinidad), according to the *Oil and Gas Journal* survey (OGJ, 2012). In Brazil, CO_2 injection for EOR has been carried out by Petrobras since 1987 in the Recôncavo Basin (Bahia) oil fields, where Petrobras have been injecting CO_2 for the purposes of EOR into a number of oil fields for 24 years. In Trinidad, four immiscible EOR pilot floods were implemented by Petrotrin at its Forest Reserve and Oropouche fields over the period 1973 to 1990. In Turkey, an immiscible EOR project was initiated in the Bati Raman field. In the North Sea, five hydrocarbon gas injection projects have been initiated with some success (Alvarado & Manrique, 2010).

A number of EOR pilots are underway in China, though for some the injection stream is flue gas or other waste stream, often with a relatively low concentration of CO_2 (Dahowski, Li, Davidson, Wei, Dooley, & Gentile, 2009), (Meng, Williams, & Celia, 2007),[10] (Liang, Shu, Li, Shaorah, & Qing, 2009), (NETL, 2008). A number of pilots are also underway and/or planned in the Middle East.

[10] What is often referred to as the Liaohe oil field is actually a complex of many oil fields within close proximity. This observation applies to all of the major "oil fields" discussed as EOR candidates in this report.

Global potential for technically recoverable resources from EOR

In a study performed by ARI and published by IEA GHG (IEA, 2009), a database of the largest 54 oil basins of the world (that account for approximately 95% of the world's estimated ultimately recoverable [EUR] oil potential) was developed. Defined technical criteria were used to identify and characterise world oil basins with potential for EOR. From this, a high-level, first-order assessment of the EOR oil recovery and CO_2 storage capacity potential in these basins was developed using the United States experience as analogue (NETL, 2009a). This methodology is outlined in Table 8.

These basin-level, first-order estimates were compared with detailed reservoir modeling of 47 large oil fields in six of these basins, and these estimates were determined to be acceptable. In all cases, the basin and field-based results agreed within $\underline{+}$50% for estimated recovery efficiency for EOR, and within $\underline{+}$16% for the CO_2/oil ratio.

Accurately estimating the actual performance of EOR can be a complex and data intensive effort, often taking months or years to perform on a single candidate field. Moreover, it requires substantial amounts of detailed field- and project-specific data, most of which is generally only available to the owner and/or operator of a field. While data access and time constraints prevented the application of this level of rigor to estimating the worldwide performance of potential future EOR projects, this methodology was developed which builds upon ARI's large volume of data on United States crude oil reservoirs and on existing EOR operations in the United States. However, it is not a substitute for a more comprehensive assessment when investing in such projects.

Table 8 • Overview of methodology for screening-level assessment of EOR potential and CO_2 storage in world oil basins

Step	Basin-level average data used	Basis	Result
1. Select World Oil Basins Favourable for EOR operations	Volume of oil cumulatively produced and booked as reserves	Basins with significant existing development, and corresponding oil and gas production expertise, will likely have the most success with EOR	List of 54 (14 United States, 40 in other regions) oil basins favourable for EOR
2. Estimate the Volume of Original Oil in Place (OOIP) in world oil basins	American Petroleum Institute (API) gravity; ultimately recoverable resource	Correla5tion between API gravity and oil recovery efficiency from large United States oil reservoirs	Volume of total OOIP in world oil basins
3. Characterise oil basins and potential fields within these basins amendable to EOR	Reservoir depth in basin, API gravity	Characterisation based on results of assessment of United States reservoirs amendable to miscible EOR	OOIP in basins and fields amenable to the application of miscible EOR
4. Estimate EOR flood performance/recovery efficiency assuming "state-of-the-art" technology	API gravity; reservoir depth	Regression analysis performed on large dataset of United States miscible EOR reservoir candidates	EOR recovery efficiency (% of OOIP)
5. Estimate volume of oil technically recoverable with EOR assuming "state-of-the-art" technology	OOIP, EOR recovery efficiency	Regression analysis performed on large dataset of United States miscible EOR reservoir candidates	Volume of Oil recoverable with EOR
6. Estimate volume of CO_2 stored by EOR operations assuming "state-of-the-art" technology	Technically recoverable oil from EOR	Ratio between CO_2 stored and oil produced in ARI's database of United States reservoirs that are candidates for miscible EOR	Volume of CO_2 used and ultimately stored during EOR operations

Source: IEA, 2009.

The results of the application of this methodology in the above-referenced IEA GHG study are shown in Table 9. This assessment applies just to the largest fields within each basin and does not apply to resources that remain to be discovered (within either new or existing fields) or smaller oil fields. Fifty of the largest oil basins of the world have reservoirs amenable to the application of miscible EOR, and have the potential to produce nearly an additional 470 000 MMBO and store nearly 140 Gtonnes (155 Gtons) of CO_2 with the application of "state-of-the-art" EOR technology.

Table 9 • Estimated CO_2 storage potential from application of "state-of-the-art" EOR in world oil basin

Region Name	EOR oil recovery, MMBO	Miscible basin count	CO_2 oil ratio, tonnes/barrel, (tons/barrel)	CO_2 stored, Gtonnes (Gtons)
Asia Pacific	18 376	6	0.27 (0.3)	5 (5.6)
Central and South America	31 697	6	0.32 (0.36)	10.1 (11.2)
Europe	16 312	2	0.29 (0.32)	4.7 (54.2)
Former Soviet Union	78 715	6	0.27 (0.3)	21.6 (24)
Middle East and North Africa	230 640	11	0.3 (0.33)	70.1 (78)
North America/Non-United States	18 080	3	0.33 (0.37)	5.9 (6.6)
South Asia	-	0	N/A	-
Sub-Saharan Africa and Antarctica	14 505	2	0.3 (0.33)	4.4 (5)
United States	60 204	14	0.29 (0.32)	17.2 (19)
Total	**468 529**	**50**	**0.3 (0.33)**	**139 (154.6)**

Source: IEA, 2009.

If EOR technology could also be successfully applied to smaller fields, the additional growth in reserves in discovered fields, and resources that remain in fields yet to be discovered, the worldwide application of "state-of-the-art" technology could recover over one trillion additional barrels of oil, with associated CO_2 storage of 320 Gtonnes (355 Gtons).

However, it is important to note over half of this storage potential exists in basins in remote locations, with low population densities, little existing industrial infrastructure, or the likely demand for construction of new power plants with CO_2 capture. Thus, it may be difficult to have affordable, accessible CO_2 necessary to realise this full storage potential.

A compilation of the estimates of original oil in place, ultimate primary and secondary oil recovery, incremental technically recoverable oil from EOR, and the volume of CO_2 stored in association with EOR is provided in the Appendix in Table 15 for the 50 world oil basins considered.

More CO_2 supplies needed to capture the potential for EOR

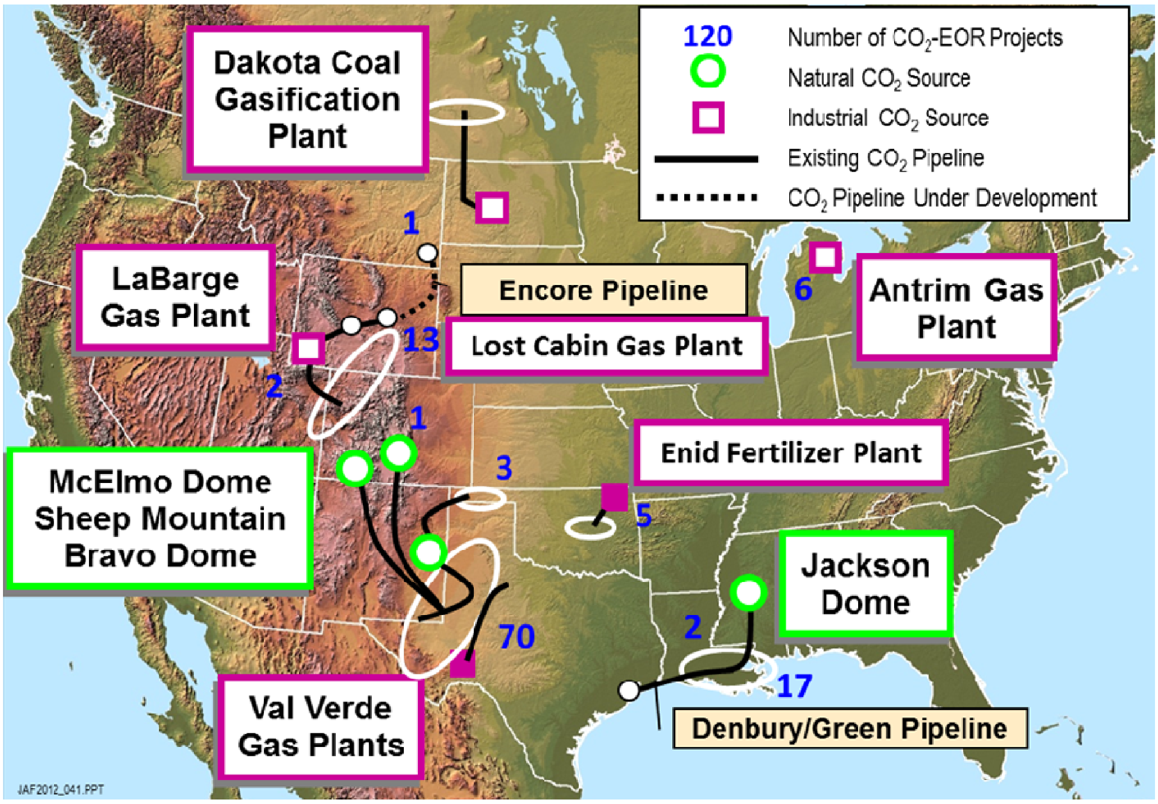
Today, the main barrier to reaching higher levels of EOR production, both in the United States and worldwide, is insufficient supplies of affordable CO_2 (Hargrove, Melzer, & Whitman, 2010). The establishment of CO_2 sources and the growth of CO_2 flooding in West Texas, Wyoming, and Mississippi in the United States provide three independent case histories as support. Today, in all three areas, EOR expansion is constrained by CO_2 supply, and current CO_2 supplies are fully committed. While all current EOR employs either natural CO_2 or CO_2 from natural gas processing plants, both of which currently provide less costly CO_2 than power plants, the lack of CO_2 supply for EOR will eventually provide an opportunity for it to come from anthropogenic sources.

New CO_2 pipelines and refurbished gas treating plants have recently been placed on-line to augment United States CO_2 supplies for EOR as shown in Figure 21. In the Permian Basin, three pump stations have been added to the Cortez CO_2 pipeline from the McElmo Dome natural CO_2 field to upgrade throughput to enable transport of up to 25 Mtonnes/year (28 Mtons/year) of CO_2. At the Doe Canyon CO_2 source field, just north of McElmo Dome, wells were drilled and CO_2 volumes from that field were added to the enhanced volumes at McElmo Dome to keep the CO_2 pipeline full (Wells & Mills, 2007). A new area of Bravo Dome was developed by the Hess Corporation, called West Bravo Dome, and some upgrades at Bravo Dome were completed by Oxy Permian to keep their CO_2 supplies from these natural source fields from declining, and to keep the CO_2 pipeline from this region full. However, these new supplies were absorbed quickly in the market.

Legislative and regulatory activity in Texas is evolving to support increasing CO_2 supplies from anthropogenic sources to serve its EOR market (EORI, 2009). This combination of unmet demand for CO_2 and a supportive political/regulatory climate has stimulated several new projects to increase anthropogenic CO_2 supplies for West Texas EOR:

- The SandRidge/Oxy gas separation plant in Texas plans to provide more than three Mtonnes per year of by-product CO_2 to be utilised by Oxy for EOR (SandRidge, 2009);
  - Summit Power's 200-MW IGCC power/poly-gen plant in the Permian Basin plans to provide 3 Mtonnes/ year (3.3 Mtons/year) for EOR (CCJ, 2010); and
  - Tenaska's Trailblazer plans to generate 600 MW to provide EOR operations as much as 4.5 Mtonnes/year (5 Mtons/year) of CO_2 (TTEC, 2008).

Figure 21 • Current United States EOR activity and CO2 supply sources



Source: ARI, Inc. based on Oil and Gas Journal, 2012 and other sources.

In the Rockies, efforts to expand CO_2 supplies through the proposed 360-km (224 miles) Encore Pipeline include ExxonMobil's expansion of the Shute Creek gas processing plant, the refurbished Lost Cabin gas plant, and the soon-to-be-developed Riley Ridge CO_2 reserves.

In the United States Gulf Coast, CO_2 supply expansions include Denbury's 512-km (318 miles) Green Pipeline from its Jackson Dome natural CO_2 source along with potential new anthropogenic sources, and Southern Company's Kemper County 582-MW IGCC plant, which has plans to sell 1.1–1.5 Mtonnes/year (1.2–1.7 Mtons/year) of CO_2 for EOR.

But despite all of this activity in the United States, growth in production from EOR remains limited by the availability of reliable, affordable CO_2. The economic demand from EOR is estimated to be on the order of 25 Gtonnes (28 Gtons) of CO_2; while remaining natural and gas processing-sourced CO_2 supplies can only provide about 3 Gtonnes (3.3 Gtons). And elsewhere in the world, even more significant efforts will be needed to link CO_2 supplies from industrial and power generation sources to where they can most effectively be utilised for EOR, which in some regions will require the development of pipeline infrastructures to connect anthropogenic CO_2 sources to EOR.

In summary, there are more prospective EOR projects than there is cost-effective CO_2 to supply them. If increased volumes of CO_2 do not result from CCS, then increased oil production from EOR cannot be realised. Thus, not only does CCS need EOR to ensure viability of CCS, but EOR needs CCS to ensure adequate CO_2 to facilitate EOR growth.

Relative location of industrial CO_2 sources to basins amenable to EOR

A high-level assessment was previously performed by ARI for IEA GHG (IEA, 2009) of the relative contribution that industrial sources of CO_2 could make in facilitating the recovery of the worldwide resource potentially recoverable through the application of EOR technologies. Since location information for individual fields within each oil basin was not universally available, this assessment was performed based on the proximity of industrial sources of CO_2 emissions to basins containing fields that were amenable to miscible EOR.

Data on global anthropogenic CO_2 emissions were gathered from the 2010 version of the IEA GHG CO_2 Emissions Database (IEAGHG, 2010). The IEA GHG emissions database contains information on annual CO_2 emissions from 16 types of sources. Table 10 shows which categories of sources were considered high and low CO_2 concentration (or high and low purity), respectively, in this study. Using GIS techniques, data from the IEA GHG CO_2 emissions sources were compared to the location and spatial extent of the hydrocarbon basins identified as having EOR potential.

Table 10 • List of categories of high- and low-purity CO_2 emissions sources

High-purity CO_2 sources	Low-purity CO_2 sources
Ammonia	Aluminium processing
Chemicals	Biomass production
Ethanol	Cement
Ethylene oxide	Ethylene
Fertiliser	Iron and steel
Gas processing	Paper mills
Hydrogen	Power
Oil and gas extraction	
Refineries	

Source: ARI.

Two scenarios were assumed for identifying viable sources of CO_2 near each oil basin: those within 50 km (31 miles) of the boundary of a basin, and those within 100 km (62.1 miles) of the boundary of a basin.

The results by region are provided in Table 11. The table summarises the number of oil basins in the region that may contain fields that are amenable to miscible EOR, the potential volume of incremental oil production that could result from the application of EOR in the basins in the region, and the volume of CO_2 that would be required to be purchased and ultimately stored to achieve this volume of incremental oil production. The table also shows the portion of that demand that could be met from current industrial sources of CO_2 emissions according to the categories of industrial sources considered – high-purity sources, low-purity sources, and all industrial sources (the sum of the high- and low-purity sources).

Table 4-7 shows that in all regions, the supply of CO_2 from industrial sources is not sufficient to satisfy the potential demand for CO_2 for EOR in all regions. For example, in aggregate, CO_2 from high-purity industrial emission sources within 50 km (31 miles) of the oil basins can meet only 4% of the CO_2 requirements for EOR; and all CO_2 emissions from industrial sources can meet only 14% of the CO_2 requirements for EOR. These numbers increase only slightly if all sources within 100 km (62.1 miles) are considered.

Table 11 • CO_2 requirements for EOR supplied by industrial sources

50 km (31 miles) Case									
Region	Number of basins	EOR potential, MMBO	CO_2 demand, Mtonnes (Mtons)	High-purity CO_2 emissions		Low-purity CO_2 emissions		Total industrial emissions	
				Mtonnes (Mtons)	%	Mtonnes (Mtons)	%	Mtonnes (Mtons)	%
Africa	6	35 642	10 474 (11 521)	28 (31)	0%	581 (639)	6%	609 (670)	6%
Australia	1	1 286	324 (356)	0	0%	0	0%	0	0%
Canada	2	5 747	1 763 (1 940)	646 (711)	37%	1 069 (1 176)	61%	1 714 (1 887)	97%
China Region	3	14 022	3 838 (4 222)	361 (397)	9%	530 (583)	14%	890 (980)	23%
Commonwealth of Independent States	5	73 018	19 897 (21 887)	254 (279)	1%	854 (939)	4%	1 108 (1 218)	6%
East Asia	2	3 068	837 (921)	0	0%	13 (14)	2%	13 (14)	2%
Eastern Europe	1	1 939	621 (683)	121 (133)	20%	340 (374)	55%	462 (507)	74%
Latin America	6	40 959	13 167 (14 484)	194 (213)	1%	606 (667)	5%	800 (880)	6%
Middle East	8	215 200	65 783 (72 361)	475 (523)	1%	1 562 (1 718)	2%	2 037 (2 241)	3%
OECD Europe	1	14 373	4 031 (4 434)	383 (421)	9%	39 (43)	1%	422 (464)	10%
South America	1	3 072	1 095 (1 205)	0	0%	26 (29)	2%	26 (29)	2%
United States	14	60 204	17 205 (18 926)	2 667 (2 934)	16%	8 678 (9 546)	50%	11 345 (12 480)	66%
Total	**50**	**468 530**	**139 034 (152 937)**	**5 129 (5 642)**	**4%**	**14 298 (15 728)**	**10%**	**19 427 (21 370)**	**14%**

Table 11 • CO_2 requirements for EOR supplied by industrial sources *(continued)*

100 km (62.1 miles) Case

Region	Number of Basins	EOR Potential, MMBO	CO_2 Demand, Mtonnes (Mtons)	High-Purity CO_2 Emissions		Low-Purity CO_2 Emissions		Total Industrial Emissions	
				Mtonnes (Mtons)	%	Mtonnes (Mtons)	%	Mtonnes (Mtons)	%
Africa	6	35 642	10 474 (11 521)	28 (31)	0%	656 (722)	6%	684 (752)	7%
Australia	1	1 286	324 (356)	0	0%	0	0%	0	0%
Canada	2	5 747	1 763 (1 940)	675 (743)	38%	1 169 (1 286)	66%	1 844 (2 028)	105%
China Region	3	14 022	3 838 (4 222)	433 (476)	11%	569 (626)	15%	1002 (1102)	26%
Commonwealth of Independent States	5	73 018	19 897 (21 887)	267 (294)	1%	905 (996)	5%	1 172 (1 289)	6%
East Asia	2	3 068	837 (921)	83 (91)	10%	25 (28)	3%	108 (119)	13%
Eastern Europe	1	1 939	621 (683)	131 (144)	21%	430 (473)	69%	561 (617)	90%
Latin America	6	40 959	13 167 (14 484)	194 (213)	1%	754 (829)	6%	948 (1 043)	7%
Middle East	8	215 200	65 783 (72 361)	824 (906)	1%	1 807 (1 988)	3%	2 632 (2 895)	4%
OECD Europe	1	14 373	4 031 (4 434)	394 (433)	10%	47 (52)	1%	441 (485)	11%
South America	1	3 072	1 095 (1 205)	0	0%	26 (29)	2%	26 (29)	2%
United States	14	60 204	17 205 (18 926)	3 031 (3 334)	18%	9 976 (10 974)	58%	13 007 (14 308)	76%
Total	**50**	**468 530**	**139 034 (152 937)**	**6 062 (6 668)**	**4%**	**16 363 (18 000)**	**12%**	**22 426 (24 669)**	**16%**

Source: ARI.

Regions containing the more economically developed countries – like North America, Australia, and Europe – have the largest portions of industrial emissions that could be a CO_2 supply source for EOR, especially from high-purity sources. Nonetheless, all of the regions have large volumes of CO_2 emitted from industrial sources that are in relatively close proximity to basins containing fields that are amenable to the application of EOR.

For concentrations of large-scale EOR operations, the long-distance scenario can be viable, because it can take advantage of economies of scale in transporting large volumes of CO_2 through pipelines that connect multiple sources, perhaps to areas that contain multiple fields that can be used for EOR and CO_2 storage. In the United States, there is already precedence for this type of scenario, given the fact that CO_2 is already transported through approximately 6600 km (4100 miles) of pipeline infrastructure to the major areas where EOR operations are currently underway.

Environmental impacts of EOR based CO_2 storage

Oil field storage vs. saline reservoirs

The relative environmental merits of storage of CO_2 in saline reservoirs compared to CO_2 storage in depleted oil fields in association with EOR has been the subject of considerable debate. Deploying CCS in association with EOR can help accelerate, perhaps significantly, the public acceptance and implementation of CO_2 storage. Oil fields provide CO_2 storage options that can be permitted under existing (or slightly modified) regulatory regimes, thereby avoiding the large delays inherent when waiting on new regulations to be developed for permitting commercial-scale storage of CO_2 in saline formations. The pore space, mineral rights and long-term liability issues of oil fields are already well established and thus would not be impediments to an integrated CO_2 storage and EOR project. Finally, the early reliance on EOR for storing CO_2 would help build the regional pipeline infrastructure for future CO_2 storage projects in saline formations.

Consequently, without the opportunities for CO_2 storage that EOR can facilitate, CO_2 storage at commercial scale is unlikely to happen. Moreover, if substantial changes are made to existing regulatory frameworks that impose excessively burdensome regulatory requirements on CO_2 storage with EOR, CO_2 storage at commercial scale may also be put at risk.

Oil fields operations have generally acquired a large amount of subsurface data over the course of field development. Historical production operations provide a baseline of reservoir data and production history to use for characterising storage capacity, CO_2 injectivity, and reservoir heterogeneity. An oil or gas field also, by definition, has a known trap and seal integrity that has been proven over geologic time. Relative to storage in saline reservoirs, the oil production associated with EOR can lower storage technical risk because of lower reservoir pressure requirements for CO_2 storage in a depleted reservoir. Because of this lower pressure in a depleted reservoir, the footprint of the CO_2 plume within an oil field would be several times smaller than within a saline formation, and could be as much as an order of magnitude smaller in area.

A number of other conditions favour the use of oil fields for injecting and storing CO_2. First, oil fields are located in areas with an accepted history of oilfield activities, contributing to public acceptance for storing CO_2. Second, oil fields provide an existing "brown field" storage site versus having to establish a new "green field" site when preparing a saline formation for CO_2 storage. Finally, substantial usable infrastructure such as injection wells, surface facilities, and gathering systems exist in developed oil fields, which can be utilised for EOR and CO_2 storage, resulting in considerable cost savings relative to storage operations deployed in saline reservoirs.

On the one hand, a key issue for gauging the appropriateness of CO_2 storage in an EOR context is the verifiable permanence of CO_2 storage. Tertiary recovery obviously implies that the reservoir has already been produced through many wells over a considerable period of time, calling into question the integrity of the CO_2 confinement if CO_2 could leak from these existing wells. Clearly, any potential future monetisation of the stored CO_2 will require development of both well integrity standards and an adequate and affordable monitoring system and verification protocol, with particular focus on these existing wells.

On the other hand, lighter organics like benzene found in the oil can be entrained in the CO_2 stored in a depleted oil field and could potentially be transported into shallow groundwater if the wells leak. While there have been no known reported cases of this occurring, it has been raised by some regulatory agencies such as the EPA.

Moreover, the EOR process entails repeated recycling of the CO_2, as a substantial fraction of the injected amount can accompany the produced oil, is separated from that oil, and then reinjected. Thus, CO_2 "accounting" will be necessary throughout the entire operation. However, experience shows that EOR can result in very effective storage; nearly 100% of the initially acquired/purchased CO_2 for EOR operations (not that which is recycled) likely will be stored at the end of active injection.

Producing oil from EOR vs. other oil production options

Consideration should also be given to the advantages of producing oil using EOR operations in a depleted field, relative to oil produced using other technologies in other settings. EOR contributes to permanently storing CO_2 that would otherwise be emitted to the atmosphere. In most cases, alternative sources of oil supply would have greater net emissions than that associated with EOR. A critical choice for society, at least in the near term, will be between a barrel of crude oil produced through the application of EOR, and that produced by other means.

EOR operations also have other environmental benefits over oil produced by most other means. Preparing an existing oilfield for EOR operations does not require as large an energy (and capital) investment, since a significant portion of the infrastructure – such as existing wells, surface equipment, and gathering network – is already in place. EOR produces incremental oil from fields that have already been explored and developed, and are producing. The incremental development activities associated with EOR include installing additional infrastructure necessary for CO_2 injection and recycling, and some additional new wells. The incremental environmental impacts associated with this additional development would be minimal, however, compared to producing these same volumes of oil from areas that are not currently under development, which would require full-scale prospecting, project siting, infrastructure installation, and field development.

Accounting for CO_2 emissions from EOR operations

Some believe that the emissions associated with consuming the incremental volume of oil produced from EOR operations should not be considered in life cycle emissions analyses of EOR projects. They believe project life cycle emissions attributed to EOR should include only fugitive emissions directly related to the EOR project and not include downstream emissions common to all sources of oil supply. They believe oil not otherwise produced using EOR would just get supplied to the market, as demanded, by other sources of crude oil (Faltinson & Gunter, 2010).

A more appropriate perspective should recognise that it is likely that the oil produced via EOR will replace oil produced using traditional technologies (or unconventional technologies like shale oil). In this case, there is no increase in emissions from the EOR oil, and there may be a large reduction in overall CO_2 emissions related to oil production. Assuming that increased oil production from EOR does not result in increased demand for crude oil and/or petroleum products, and that it instead reduces oil produced from other more CO_2-intensive processes, then EOR should be given additional credit for reducing global emissions of CO_2.

One of the questions surrounding EOR operations is whether there can be, in fact, an overall net reduction in CO_2 emissions over the life of a strategically planned and executed EOR project. Such strategically planned and executed EOR projects would strive to optimise the volume of CO_2 stored, not just the volume of incremental oil produced. Other approaches to increase CO_2 storage in conjunction with EOR may further increase storage capacities. These primarily involve approaches that inject CO_2 earlier, inject CO_2 longer, and inject CO_2 instead of water (including producing residual water in oil reservoirs to "make more room" for CO_2). Additionally, after the injection and permanent storage of CO_2 from EOR, CO_2 can be injected into and stored in other geologic horizons that can be accessible from the same CO_2 injection wells and surface infrastructure used for EOR, allowing for the utilisation of additional storage capacity. In fact, some approaches for EOR development that maximise CO_2 storage could permanently store more CO_2 than the CO_2 emissions associated with the incremental oil produced, when considered over its entire life cycle (DECC, 2010).

However, even with EOR projects that are not optimised for storage, 50% to 60% of the total volume of emissions associated with oil production (from operations, transport, refining, and the ultimate combustion of the products refined from the produced crude) could be permanently stored. In other words, even if only half of the emissions resulting from incremental oil production from EOR are stored, this is still considerably better than none, which would be the case otherwise.

Conclusions

The need for CCS demonstration projects is acknowledged by many countries and organisations. While numerous demonstrations have been proposed for all three current types of capture technologies worldwide and significant government funding has been set aside, progress has not been rapid enough and several proposed projects have been cancelled – and more may follow. There are serious roadblocks to getting sufficient projects in place to move CCS to maturity so that it can cost effectively address CO_2 emissions from fossil plants. CCS needs direct policy support for developing and demonstrating FOAK plants to bring down their cost.

The government funds available so far only partially cover the CCS costs. Those projects that can obtain an additional revenue stream from the sale of CO_2 for EOR can provide some of the best early prospects for CCUS demonstration. As discussed in the ARI analysis, considerable opportunities exist for EOR throughout the world particularly in the United States, the North Sea area of Europe, and China but such opportunities will not be universally available. For the United States, UNITED KINGDOM, and China the additional production of domestic crude oil will be of great benefit in promoting greater degrees of national energy security and self sufficiency.

EOR has been profitable in commercial-scale applications for over 40 years under current regulations. The majority of the applications have been in the United States with natural CO_2 fields being the dominant source of CO_2 for the United States EOR market. However, CO_2 reserves from natural sources have the potential to support the production of only a small fraction of the oil resource potential achievable with the application of EOR. Therefore, growth in oil production from the application of EOR requires significantly expanded access to industrial sources of CO_2.

The potential global capacity for storage of CO_2 in association with EOR can be substantial. Fifty of the largest oil basins of the world have reservoirs amenable to the application of miscible EOR with the potential to produce 470 billion barrels of additional oil, and store 140 Gtonnes (156 Gtons) of CO_2. If EOR technology could also be successfully applied to smaller fields, the additional anticipated growth in reserves in discovered fields, and resources that remain in fields that are yet to be discovered, the worldwide application of EOR could recover over one trillion additional barrels of oil, with associated CO_2 storage of 320 Gtonnes (356 Gtons).

Since significant expansion of oil production utilising EOR will require volumes of CO_2 that cannot be met by natural sources alone, industrial sources of CO_2 will need to play a critical role. Thus, not only does CCS need EOR to help promote economic viability for CCS, but EOR needs CCS in order to ensure adequate CO_2 supplies to facilitate growth in the number of and production from new and expanded EOR projects.

Some approaches to increase CO_2 storage in conjunction with EOR may further increase storage capacities, and could, under certain circumstances, store more CO_2 than is associated with the CO_2 emissions over the life cycle of the incremental oil produced from EOR, including emissions from consumption of the products of the incremental oil produced. These primarily involve approaches that inject CO_2 earlier, inject CO_2 longer, or inject CO_2 instead of water. Additionally, after the injection and permanent storage of CO_2 from EOR, CO_2 can be injected and stored into other geologic horizons that can be accessible from the same CO_2 injection wells and surface infrastructure used for EOR, allowing for additional storage capacity.

Even if only half of the emissions resulting from incremental oil production from EOR are stored, and thus offset, this is still considerably better than none, which would be the case otherwise. In traditional EOR projects, 50% to 60% of the total volume of emissions associated with the incremental oil production (from operations, transport, refining, and the ultimate consumption of the products refined from the produced crude) can be permanently stored. In other words, non-EOR oil production processes, when netting out the CO_2 stored with EOR, produce twice the GHG emissions as EOR projects.

EOR contributes to permanently storing CO_2 that would otherwise be emitted to the atmosphere, and has other environmental benefits over oil produced by most other means. Achieving these benefits will require that governments continue to work to ensure a policy, regulatory, and legal environment that encourages the application of EOR in conjunction with CCS, as well as encouraging a long-term, viable market for CO_2 in EOR applications.

While CCUS projects are important for advancing CCS demonstrations and technology, since EOR is not universally applicable (*e.g.*, in Southeast Asia) or may not be able to be used to store enough CO_2 even in regions where it can be applied, emphasis and R&D funding must still be placed on demonstrating geologic storage in saline formations.

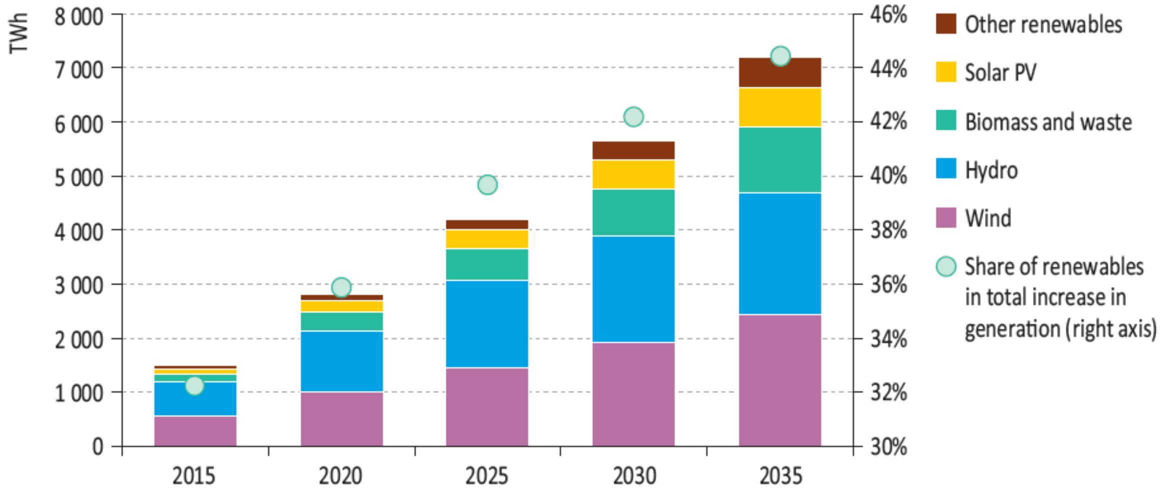
4. Flexibility of coal-fuelled power plants for dynamic operation and grid stability

The status of intermittent power sources

In 2009, renewable energy accounted for 3902 TW-hr of the world's electricity generation, or 19.5% of the total. The majority (>83%) of this "green" electricity came from hydro, but the amount of both renewable energy and non-hydro renewables is projected to grow significantly.

In the IEA's New Policy scenario, from 2009 to 2035, 44% of the increase in electricity generation comes from renewables as shown in Figure 21. Mainly driven by government policies, generation from non-hydro renewables is projected to increase from 3% of the total in 2009 to over 15% in 2035.

Figure 22 • Incremental global renewables-based electricity generation relative to 2009



Source: IEA, 2011.

The increasing contribution of renewables to meeting rising electricity demand has important implications on other generating units on the electricity grid – both existing and future ones – because of the variable nature or intermittency of the output of several renewables-based technologies, such as wind and solar. The increasing penetration of intermittent renewable generation generally requires non-renewable units to operate more flexibly to ensure grid stability. Grid stability is a major issue as the population wants electricity generators to be able to respond to varying demand – meaning that electricity is always available whenever the public wants it in whatever amount. Grid instabilities can cause blackouts (a worst-case scenario of this happened in India in late July 2012, when over 600 million people went without power for several days) and incur significant repair cost.

The impacts of renewable energy sources are region-specific, and depend on how a market can change in response to a specific set of drivers. For example, in limited cases, automated demand response or energy storage could absorb some of the variability associated with wind and solar, negating the need for the different operation of more conventional power plants. Increased transmission could also spread the variability over a larger region to mitigate the need for any one generating unit to modify its operations.

In general, however, increased amounts of intermittent resources require conventional units, including coal-fuelled ones, to be increasingly flexible. The ability of coal power plants to be more flexible in response to the changing electricity market is a major question. While most coal power plants are capable of some dynamic operation and are designed to be able to cycle with moderate ramp rates and potentially even handle two-shift operation (where the plant is started up and shutdown daily), the increased need for flexibility will impact costs, maintenance, and reliability. Most notably, higher cycling will increase wear and tear while the number of operating hours decreases, resulting in an increase of specific maintenance costs/MW-hr over time. Moreover, as coal power plants add more complex environmental control systems such as CCS in the future, their ability to operate dynamically may be reduced (IEACCC, 2011).

This chapter is intended to look at the flexibility of coal plants first by presenting a real-world case study from the German market that shows the possibilities for coal being flexible in a growing renewable energy source market, followed by a more general technical review of coal-fuelled power plants' current ability to operate dynamically and issues associated with increasing its ability to do so in the future.

Introduction

The need to improve the flexibility of current and future coal plants can be achieved with a portfolio of strategies involving both technical and operational improvements. Countries or regions that are committed to increased renewable generation understand the importance of reliable coal generation for load balancing. The industry can look to these areas to better understand how the challenges associated with flexible coal generation can be met.

One such region is Germany, which has several factors in its favor regarding handling intermittent resources and reducing their potential impact on the grid. Germany has a diverse portfolio of generation with a significant fraction of intermittent renewables and units having the necessary sophistication to handle dynamic operation. Also, electricity prices are higher in Germany than most OECD countries, so that any increased costs due to the fluctuating operation of conventional power plants is somewhat less significant, hence reducing concerns associated with doing so. Add everything together and Germany provides a unique opportunity to provide lessons learned from practical and relevant experience garnered in the field. As a result, the German market has made significant strides in the transition associated with accommodating more renewable energy sources as discussed in the following case study.

Case study on the flexible use of conventional power plants in Germany

This section presents a real-world case study based on actual data taken from the German electricity market in an attempt to show how fossil-fuelled power plants respond to a more dynamic grid caused by increased intermittency from a growing amount of renewable energy.

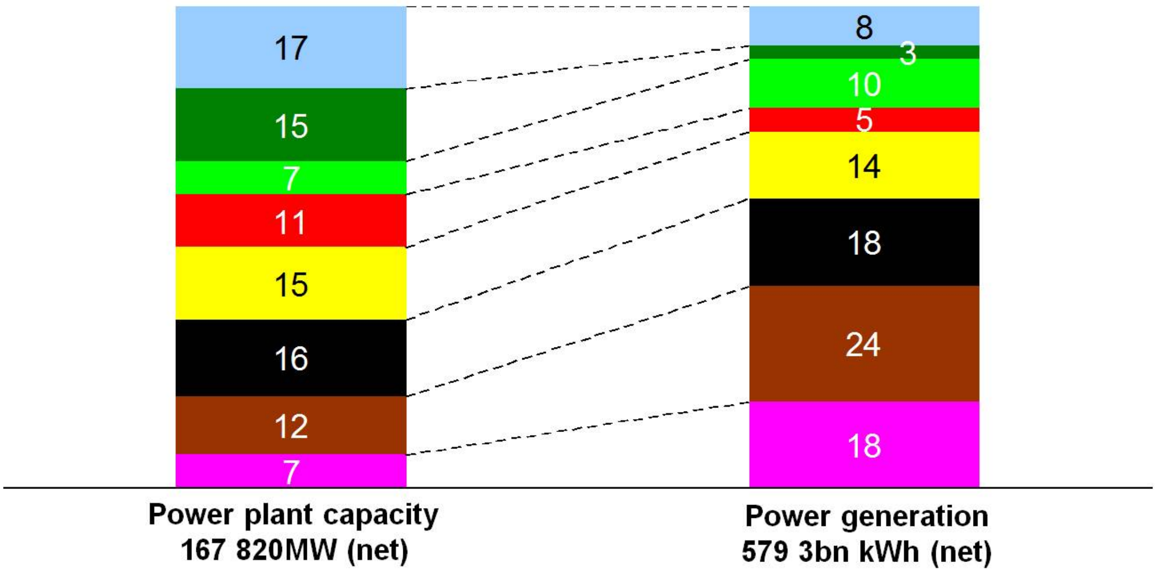
Power generation supply on the German electricity market

The German electricity market is characterised by a huge variety of providers and by a broad energy mix in terms of generation. By the end of 2011, the installed net capacity of the German power generation portfolio totalled approximately 168 GW. 103 GW of this amount comprises conventional power plants (fossil, nuclear, and pump-storage) and 65 GW of renewable energy.

For the coal-fuelled units, approximately 25% of the existing German coal units, based on the installed capacity, are of supercritical design and the remainder are of subcritical design.

The installed capacity and the power generation by energy source in Germany are shown in Figure 23.

Figure 23 • Percentage of power plant capacity in Germany on 31 Dec 2011 and % net power generation in 2011



Source: BDEW (German Association of Energy and Water Industries).

Of the 103 GW arising from conventional power plants, some 11 GW account for industrial power plants that basically produce for their own consumption (mostly combined heat and power [CHP]) and are, therefore, not totally integrated into the electricity trading market. The remaining 92 GW of conventional power plant generation is subject to market competition.

Since 1998 the German electricity market has been completely liberalised. This applies to generation, trading, and retail. Only the value-added element of transport and distribution remains subject to regulation; access to the power supply grid is granted on a non-discriminatory basis.

In the electricity market, competition prevails between large and small providers, private internationally-orientated groups, and public utilities and regional companies and the market is balanced using a least-cost merit order.

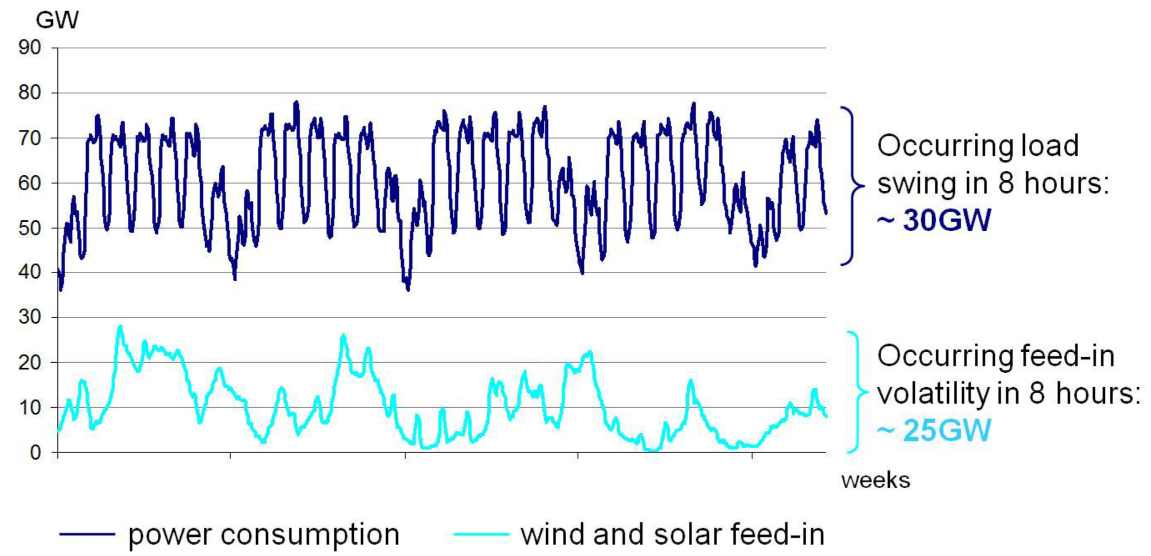
However, electricity generated from renewable energy benefits from a legally-based feed-in priority and a guaranteed feed-in tariff based on the full costs of the respective type of generation. Since 2009, new renewable energy capacity is also obligated to be technologically capable and participate in the feed-in management of grid operators. This feed-in tariff considerably exceeds the wholesale market price and the additional costs are charged to consumers by the grid operators via an allocation on the grid fees, the so-called "EEG" renewable charge. In 2012, this allocation is approximately EUR 36/MW-hr.

Fluctuations in demand and feed-in

The peak demand on the German electricity grid is approximately 80 GW. Considerable demand fluctuations have been common for decades. Nuclear and lignite-fuelled power plants predominantly meet the base-load, coal-fuelled power plants operate in mid-merit, and gas-fuelled power plants are used to meet peak loads and CHP requirements.

Load fluctuations result from different day/night, weekday/weekend, and summer/winter demand levels. Demand usually fluctuates by approximately 30 GW within one day as seen in Figure 24.

Figure 24 • Volatility of power consumption vs. feed-in from wind and solar in Germany, January 2012



Source: ENTSO-E, EEX.

Typically, the highest increase in demand can be seen every Monday early in the morning, when the increase in private household consumption and industrial demand after the weekend coincide. In fact, industry accounts for more than 45% of the overall demand in electricity in Germany and private households almost 30% of the demand. The remaining 25% can be allocated to trade/commerce/services.

The tenfold increase of wind and photovoltaic capacity in Germany since the year 2000 (from 6 GW to 30 GW for wind and from 0.1 GW to almost 30 GW for photovoltaic by mid-2012) has resulted in a second "feed-in" load fluctuation, in addition to the traditional consumer demand fluctuation. For instance, in 2011, wind-power feed-in varied by almost 23 GW (maximum of 22.7 GW on 4 February 2011 and a minimum of 0.1 GW on 5 July 2011) and photovoltaic power varied by about 13 GW (maximum of 13.1 GW on 9 May 2011 at noon and a minimum at the same time of 0.6 GW on 1 January 2011). At the time of peak load, which usually occurs around 6 PM on a winter work day, photovoltaic feed-in can continuously be zero.

The feed-in fluctuation of wind and solar generation can amount to 30 GW within an 8-hour period; currently it is equal to the consumer demand fluctuation and likely will become the dominant fluctuation in the German electricity market over the next three years.

These demand and renewable energy feed-in fluctuations must be continuously balanced to provide electricity grid stability and this is putting pressure on the conventional power generation portfolio. Power generation from conventional plants has to be able to flexibly adjust to the residual load at any time, *i.e.,* to compensate for the difference between consumption and fluctuating renewable energy.

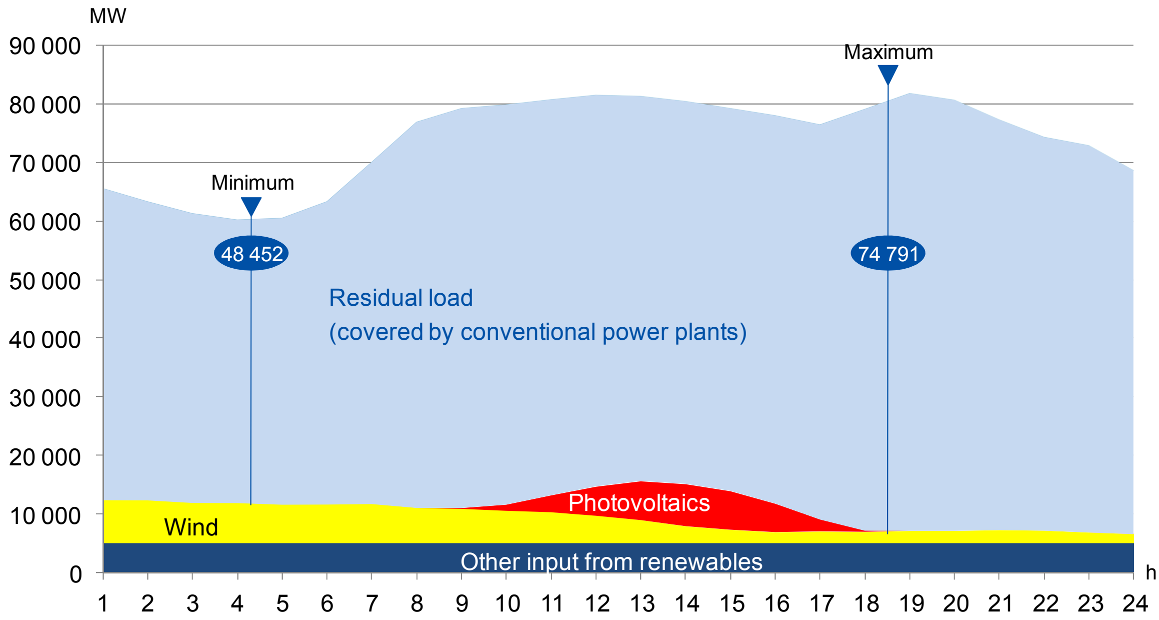
In addition, grid operators must balance the electricity grid dependent on the location of the renewable energy source. In Germany, the majority of installed wind capacity is in the north. With increasing frequency, grid operators are forced to "redispatch" thermal units during the day to keep the energy feed-ins in balance with demand by location. An example of this is when wind feed-ins are extremely high in the north, forcing the grid operator to ramp down output from a northern coal unit, while a more expensive gas plant may still be operating in the south.

The need for load adjustments by flexible power plants is particularly high when an increase in electricity demand occurs at the same time as the feed-in from wind power plants dramatically decreases.

Currently, the requirement for load adjustments of >50 GW within an 8- to 10-hour period has occurred *(i.e.,* >60% of the peak load). This sort of demand fluctuation occurs more or less at random, but can be forecast to some extent approximately two days in advance (*e.g.*, via a weather forecast).

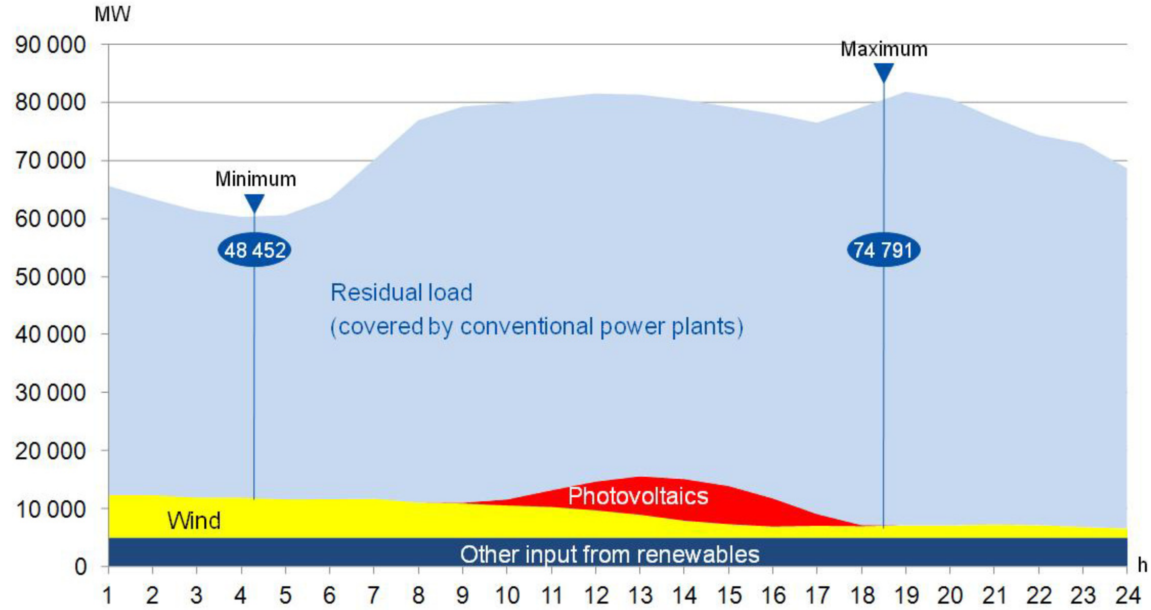
Figure 25 and Figure 26 present examples of the residual load in Germany covered by conventional power plants (nuclear, coal, and gas) in comparison to the load covered by renewable energy sources during two different days in 2012. Due to high peak demand and low renewable generation on 8 February 2012, up to 75 000 MW had to be covered by conventional power plants as shown in Figure 25. As a consequence of weak demand and high renewable generation on 27 May 2012, the minimum residual load to be covered was reduced to 17 000 MW as shown in Figure 26.

Figure 25 • Load curve and load coverage in German electricity market on 8 February 2012



Source: ENTSO-E, RWE (load); EEX (input from renewables).

Figure 26 • Load curve and load coverage in German electricity market on 27 May 2012



Source: ENTSO-E, RWE (load); EEX (input from renewables).

Flexibility to meet load fluctuations

The German electricity transmission network is part of the European synchronous zone and is connected with European neighbour markets. A regular exchange of electricity takes place with all adjacent countries, including France, the Netherlands, Denmark, Poland, the Czech Republic, Austria, and Switzerland. However, since these markets are also expanding wind capacities and consumer behaviour in all markets shows substantial similarity, the capacity to adjust imports and exports to meet German electricity market fluctuations is limited.

Therefore, the required flexibility to meet load fluctuations must be predominantly managed by existing national power plants. Existing power plants currently in Germany are all designed to cater to flexible operation and these requirements are equally met by new NGCC plants and new coal-fuelled power plants.

Many of the conventional power plants available in Germany today were built before expansion targets for wind and photovoltaic plants had been adopted (in the 1980s and 1990s). In many plants, measures to allow greater flexibility have been implemented subsequently, so that power plants can meet increased requirements for market load adjustments. As a result, there are very few dedicated base-load power plants that do not allow for flexible operation.

Example 1: High fluctuation of wind power feed-in in January 2012 – how flexible operation of coal- and gas-fuelled power plants was used to balance the grid

On Sunday, 1 January 2012, power demand was relatively low due to low industrial demand and mild temperatures of approximately 8°C (46°F). Around the evening peak, a temporary daily maximum consumption of 56 GW was reached in the German power grid, after which demand decreased to a minimum value of less than 41 GW until late at night.

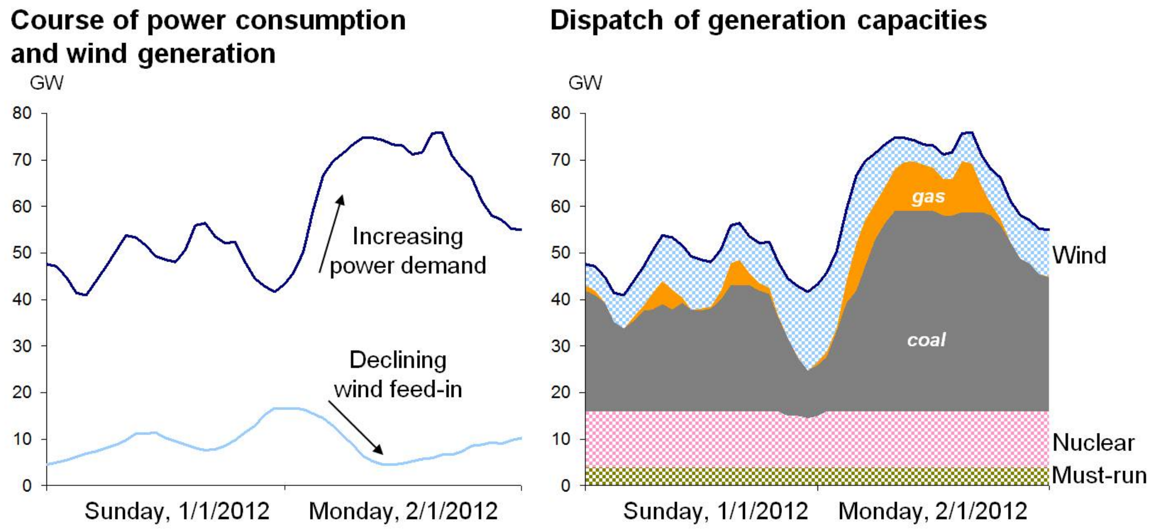
At the same time, the amount of wind feed-in temporarily reached a very high level of more than 16 GW. Further feed-ins that day came from other renewable energy sources, including run-of-the-river hydro and biomass power plants, which also benefit from feed-in priority. The feed-in from those plants continuously amounted to about 5 GW. The power generation from photovoltaic plants was negligible due to the season as well as the cloudy weather conditions over that weekend.

On Sunday night, after renewable energy feed-ins, only a residual load of 21 GW had to be temporarily covered by other power plants available according to schedule.

At 4 AM on Monday, power consumption markedly increased and reached a demand level of approximately 73 GW at around noon. This corresponds to an increase of 32 GW within 8 hours.

At the same time the feed-in from wind power plants decreased in the early hours of the morning due to declining wind speeds and intermittently amounted to only 4 GW at around noon. In parallel, a decrease in feed-in of about 12 GW was registered on the supply side. Thus, overall, an additional power output of nearly 45 GW had to be provided by the conventional power plant portfolio within those 8 hours.

Figure 27 • Power consumption and deployment of power plants in Germany on 1st and 2nd January 2012



Source: ENTSO-E, EEX, RWE.

Figure 27 displays on the left-hand side the parallel development of power consumption and intermittent wind feed-in, requiring a high degree of load adjustment from the conventional power generation portfolio.

Power generation from German nuclear power plants contributed almost without interruption a supply of about 12 GW. There is a degree of flexibility available from the German nuclear power stations, although their low variable power generation costs ensures that this is only used once the load adaptability of the fossil-fuelled power plants is exhausted. As seen in the right-hand side of Figure 26, the necessary load adjustment of about 50 GW on Monday morning was almost completely provided by the coal- and gas-fuelled power plants.

On Sunday night, almost 40% of the coal-fuelled power plants were still in operation; although the system requirements for coal-fuelled power plants at that time reduced to about 20-60% of their installed output. Overall, their contribution was only about 10 GW.

The conventional gas-fuelled power plants were almost completely off the grid on Sunday night, since part-load operation of gas-fuelled power plants is considerably more expensive than it is for coal-fuelled power plants.

In the early hours of Monday morning the increase of residual load was initially covered by coal-fuelled power plants supporting the grid by means of part-load operation. In parallel, further coal-fuelled power plants went into operation that had previously been off the grid. Subsequent to the grid synchronisation, which takes approximately 1-4 hours, newly started coal-fuelled power plants met the required load increase until midday.

Available gas-fuelled power plants are typically returned from downtime to meet the load peaks on Monday. The first feed-ins from gas-fuelled plants are normally in the early hours of the morning from 5 AM onwards. Over the course of the day, load balancing is mainly regulated by gas-fuelled power plants, and the coal-fuelled power plants remain on full load until the evening.

On that particular Monday load adjustments were made by a combination of available coal-fuelled and gas-fuelled power plants. In doing so, the coal-fuelled power plants provided, all in all, about three-quarters of the required flexible output.

Example 2: Fluctuations of photovoltaics feed-in during the day and flexible use of hard coal- and gas-fuelled power plants to balance the grid

The average cycle between strong and low wind phases corresponds to 3 to 5 days in northwest Europe. Even in the event of short-term changes, as portrayed in the first example, the conventional power plant portfolio has several hours in which to adjust load.

Short-term feed-in fluctuations are also triggered by the output of widely developed photovoltaic plants in Germany. The effects can be seen from the beginning of spring as the daily level of solar radiation increases.

The timing of the increase in solar radiation in the morning does not coincide with the increase in power consumption. Whilst electricity demand increases between 4 and 8 AM, the increase in photovoltaic feed-in occurs between 8 AM and 1 PM. Similarly, photovoltaic feed-in decreases in the evening some hours before the decline in power consumption. Consequently, conventional thermal power plants have to kick in at short notice twice – in the morning and in the evening – on days with a high photovoltaic generation.

16 March 2012 was one of the first days in 2012 with intensive solar radiation in Germany. The feed-in from photovoltaic plants increased by about 16 GW between 8 AM and 1 PM. Between 2 and 6 PM, it decreased again. On that day, wind levels were extremely low.

To cover peak consumption in the morning, coal- and gas-fuelled power plants started operation. In order to accommodate the temporarily high photovoltaic feed-in around midday, and afterwards provide full load to cover the evening peak, the coal- and gas-fuelled power plants were intermittently reduced to part-load operation.

In the regular configuration of two gas turbines and one steam turbine, the minimum load of a new NGCC plant is typically around 60% of its installed capacity. An even lower minimum load is achievable by switching off one gas turbine, although this causes a substantial loss in efficiency, so this mode of operation is rarely used.

In contrast, a new coal-fuelled power plant has a lower minimum load capability of approximately 40%, with further potential to reduce this to 20–25%. The reason for this is that the output of the coal boiler is controlled via direct fuel combustion and not, as is the case with an NGCC power plant, via a HRSG with an upstream gas turbine. It was possible to reduce the minimum load at existing power plants in Germany by optimising the boiler-turbine system using modern control systems. Optimised coal-fuelled power plants are now able to achieve a part-load level of less than 20%.

The change between part-load and full load at power plants involves load changes of approximately 3 percentage points per minute (Table 12); and the change in mode of operation can therefore be achieved at all plants in less than half an hour.

Table 12 • Typical flexibility parameters for coal- and gas-fuelled power plants

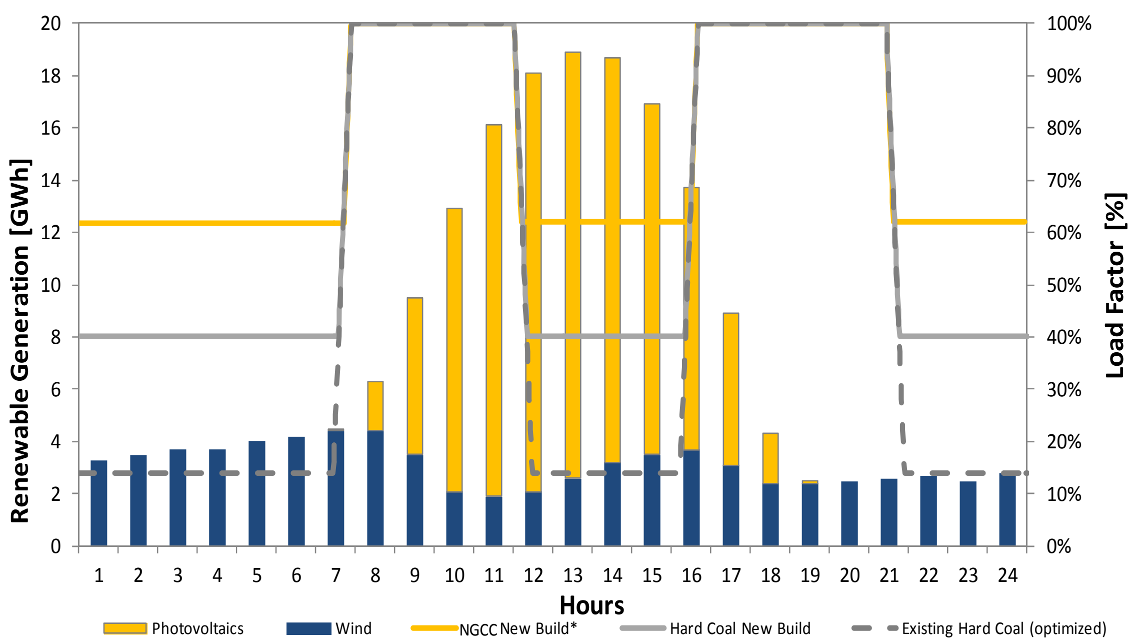
Parameter	Units	NGCC new build*	Hard coal new build	Existing hard coal (optimised)
Capacity	MW	800	800	300
Minimum load/nominal load	%	~60%	~25-40%	~20%
Mean load change rate**	%/min	~3.5	~3***	~3

*Standard operation of two gas turbines and one steam turbine
** With respect to nominal load
*** In the lower load range (25 to 40%) the load change rate differs from this value
Source: EEX, RWE.

Figure 28 shows the course of intermittent feed-ins and the adjusted operation of conventional power plant (new NGCC plant, new coal-fuelled power plant, and an existing coal-fuelled power plant with optimised flexibility parameters), following changes in demand and available generation from renewable energy sources.

On 16 March 2012, German coal- and gas-fuelled power plants were able to accommodate photovoltaic feed-in variations mutually because of their short-term flexible operating capability.

Figure 28 • Renewable generation (16 March 2012) and exemplary flexibility of coal- and gas-fuelled power plants under normal operation conditions



* Standard operation of two gas turbines and one steam turbine
Source: EEX, RWE.

Summary

- The increased need for flexibility in the German power market is fulfilled just as well by coal-fuelled as by gas-fuelled power plants.
- New coal-fuelled power plants are specifically designed for flexible operation. Pure base-load power plants are no longer being built.
- Existing coal-fuelled power plants can be optimised and made flexible so they meet the new requirements. Early replacement of the plants is not necessary.

Cycling of coal-fuelled plants

This section provides a detailed review of issues and solutions related to the potential need for more cycling of coal-fuelled plants.

Coal assets worldwide will remain a critical element of the generation portfolio mix for decades. Reliable and dispatchable generation will be required to balance increased deployment of must-take variable renewable energy resources. Traditional coal plant design focused on economical base-load operation, which has led in some markets to an evolution in unit size and main steam conditions that challenge the ability of many existing plants to operate flexibly in the future. With demands to extend operating life of these current assets to beyond forty years, affordable strategies must be found for improving the cycling capability of existing coal plants. Lessons learned from these efforts to operate current plants more flexibly, together with advances in materials and control schemes, can form a basis for improved design of future plants to assist meeting their load balancing role.

Challenges for coal assets with increased renewables penetration

As more renewable energy sources come on-line, particularly intermittent ones, the role of coal- and gas-fuelled generation will likely need to change in response. A reverse correlation exists between the daily and monthly trends in renewable generation and the demand trends. Morning and evening demand peaks do not generally align with peak output of renewable energy resources. Optimal load balancing using coal and gas will likely evolve with coal supplying an increasing level of spinning reserve and load following, and gas supplying power during peak demand. Regional coal-gas price dynamics will influence this trend in a particular market, for example more gas plants supplying bulk power in essentially base-load operation. Studies indicate that spinning reserve requirements will increase with increasing renewable penetration, which could be primarily supplied by coal (GE Energy, 2010).

Even with continued uncertainty in fuel prices and regulatory constraints, it is evident that many coal assets must improve performance in the following key areas: 1) increased turndown, 2) faster and less damaging startups, 3) faster load changes, and 4) reserve shutdown at minimal cost. These desired operational attributes can conflict with the traditional design objectives of existing high-merit coal plants, which favored high thermal efficiency base-load operation. Operational constraints on NO_X and SO_X control equipment, depending on how they are integrated into the plant, can also result in reduced flexibility of coal assets.

In regions like North America, much of the flexibility of the existing coal fleet is supplied by relatively small, subcritical units operating without environmental control equipment. With the long-term future of these units in question due to their lower efficiency, and capital spending required for emissions compliance, the emerging challenge to coal in these markets will be to attain flexibility with the remaining larger units.

Cycling impacts on existing coal assets

Increased rates of component life consumption due to thermal fatigue, mechanical fatigue, and wear caused by differential thermal expansion comprise the bulk of cycling impacts on thermal plants. Ultimately, these will manifest themselves on the LCOE of the system, although estimating the cost addition is difficult as the impacts are cumulative and complex to evaluate. The following paragraphs summarise the cycling impacts on major plant systems.

Boilers and piping

Boiler thermal fatigue in both drum and supercritical units primarily affects the superheat, reheat, and economiser sections. In each case, the source of fatigue is temperature mismatch between the fluid and the pressure boundary wall. Supercritical boiler waterwalls are also subjected to thermal fatigue due to temperature stratification. In addition to thermal cycles associated with starts and load following, header fatigue cracking can be caused by repeated quenching of header internal surfaces due to inadequate condensate draining (EPRI, 2010). The extent of thermal fatigue in cycling units can be reduced through increased efforts to control steam temperature, attemperator sprays, and condensate draining.

Corrosion fatigue damage, which can occur on riser tubes in drum units (EPRI, 2012) and waterwalls (EPRI, 2009), is increased by the operational challenges associated with maintaining boiler cycle chemistry under cycling operation. Increased levels of dissolved oxygen in feedwater during cycling can be the result of condenser leaks, aggravated by more frequent shutdowns. Other factors affecting cycle chemistry include increased need for make-up water and the interruption in operation of the condensate polishers and deaerators (EPRI, 2009a). These operational factors can be controlled or eliminated with increased attention to plant material condition and staff expertise.

Steam turbines

Steam turbines and control/stop valves are affected by a number of damage mechanisms due to flexible operation (EPRI, 2004). The most costly damage is increased thermal fatigue of thick-section pressure boundaries (casings and valve bodies), as well as HPT and IPT rotor forgings. Valve bodies tend to cool quicker during shutdowns, resulting in more warm-starts and cold-starts as opposed to less-damaging hot-starts. Thermal fatigue cracking of casings is common, even prior to undergoing increased cycling operation. The risk associated with increased cycling is the potential for more rapid fatigue crack propagation. Spare casings are not easily procured, so casing life consumption must be managed through a program of inspections and weld repair.

HPT and IPT rotor forgings under cycling operation are subjected to thermal and mechanical low-cycle fatigue. Allowing HPTs and IPTs to retain as much heat as possible during brief shutdowns will reduce low-cycle fatigue damage due to frequent starts. Plants with rotors that have already experienced 20–30 years of operation may have bore defects that require monitoring more frequently using ultrasonics.

Cycling impacts on the LPT include greater risk of corrosion-related crack formation, and risk of blade vibration and fatigue associated with reduced minimum load operation. A reduction in steam reheat temperature associated with low-load operation results in an upstream shift in the steam phase transition zone in the LPT. The associated deposition and concentration of corrosive salts over a larger extent of the steam path can contribute to increased risk of disk rim stress corrosion cracking and corrosion fatigue of blading. Greater attention to maintaining steam purity under dynamic operation and more frequent LPT steam path inspections will be required to manage risk in cycling operation.

Electrical generators

The primary cycling-related damage mechanism in generators is associated with repeated differential thermal expansion of the copper-insulation system, and the surrounding rotor steel and/or core iron (EPRI, 2004). The three materials involved (copper, insulation, iron/steel) each have different coefficients of thermal expansion, resulting in strain at the interface of bonded connections, or rubbing at the interface of tight sliding connections. In both cases, accelerated mechanical wear of the insulation material takes place as a result of even small temperature variations if occurring continuously. The repeated relative motion at these material interfaces can reduce the design life of the windings from a nominal twenty years under base-load operation. Periodic monitoring of winding condition is possible and is the subject of ongoing research (EPRI, 2006), (EPRI, 2006a). Consequences of undetected insulation damage include winding short circuits and ground faults.

Generator cores consist of a compressed laminate of iron plates separated by thin dielectric material. Continuous mechanical movements of the core assembly associated with frequent starts, and generator load (torque) changes, will accelerate dielectric wear and reduce the required time interval between core restacking.

Selective catalytic reduction systems

Operational parameters that are critical to control of SCR operation are: 1) maintaining flue gas temperature above a minimum required for the catalyst to function, and 2) achieving optimum proportions and mixing of ammonia and flue gas.

SO_3 and H_2SO_4 present in the flue gas can combine with the injected ammonia to form ammonium bisulphate, $(NH_4)HSO_4$, on the catalyst surface. This occurs primarily when the flue gas temperature drops below the ammonium bisulphate (ABS) formation temperature of approximately 285–305°C (545–580°F) (EPRI, 2010d). Liquid ABS fouls the catalyst pores and reduces its effectiveness in NO_X removal. From an operational perspective it is imperative that economiser exit temperature remains above the ABS formation temperature for that unit. The impact of these temperature restrictions for units without economiser bypass is to limit minimum load level for long-term operation to a range of approximately 40–60% of unit maximum continuous rating. Large fleets of units with NO_X control equipment will therefore have limitations on turndown due to the need to avoid costly ABS fouling of the catalyst. Ongoing research is exploring ways to incrementally reduce the ABS formation temperature on a unit-specific basis, thus allowing greater unit turndown (EPRI, 2011d).

Flue gas desulphurisation systems

Wet FGD systems involve complex chemical reactions in which control of the reagent process flow is critical to achieving SO_X removal. Typically the process is tuned to design load and design fuel characteristics, so that unit cycling and load-following necessarily requires more advanced process control functionality. Cycling impacts FGD systems in two key areas: water balance and oxidation-reduction potential.

Prolonged low-load operation affects the overall water balance by lowering the amount of evaporative losses. This reduces the fresh water available for the mist eliminator and filter cake washing. If the makeup water is not adjusted at low load, it can result in lower recycle solids, potentially changing gypsum crystal formation, resulting in lower-quality gypsum.

The more serious cycling impact discovered recently is the resulting change in the oxygen/sulphur ratio and resultant oxidation air requirements. The consequence of variations in oxygen/sulphur ratio in units not designed to adjust oxidation air with load is to change the process chemistry by increasing oxidation of other species such as mercury, selenium, or manganese and the formation of higher oxidation states of sulphur. This effect is indicated by a high oxidation-reduction potential (ORP) measured in the scrubber liquid. High ORP operation keeps more mercury in solution phase and increases potential to re-emit mercury. High ORP also oxidises selenite to selenate which is more difficult to remove in downstream wastewater treatment systems. Another detrimental effect of high ORP operation is the formation of MnO_2 scale and potential crevice corrosion attack of the FGD vessel. The formation of higher oxidised states of sulphur compounds make it more difficult to reduce the ORP level when the unit increases load, continuing these other detrimental effects discussed.

Overall plant operational impacts

Although the boiler and turbine-generator experience the greatest component damage in cycling operation, other operational impacts deserve mention. Some examples are highlighted below:

- Cycling units require increased attention to human factors issues that affect operators. Alarm management, human-machine interface, and documented procedures need to be in place. New distributed control systems provide the capability to significantly improve human-machine interfaces and reduce cycling impacts.
- Uncertainty in the future dispatch scheduling may result in coal bunkers being filled at the start of an economic reserve shutdown. For some fuels with high volatility, this represents a significant fire hazard, resulting in the need to empty the bunker (an example of this occurred at Xcel Energy’s Black Dog Plant (Nelson & Dunbar, 2010)).
- Two-phase flow-assisted corrosion (FAC) is a potentially dangerous condition in which pipes and vessels experience wall thinning over time. Prolonged part-load operation can cause FAC to appear in areas of the plant that have not previously been affected.
- Increased maintenance required on boiler ignitors, precipitator fouling due to increased oil firing, increased condensation/corrosion in air pre-heaters, and reliability issues with ash-handling systems caused by intermittent operation.

Future plant design considerations

Designers will continue to face the requirement to balance high thermal efficiency with improved flexibility in future coal-fuelled plants. It is essential that operational flexibility be considered early in the design phase so that material selection and features such as bypass systems can be incorporated into the plant layout. As described later in this chapter, in Germany, all new thermal plants are designed primarily for flexible operation.

Lessons-learned from the existing fleet, combined with new research on advanced materials (Viswanathan, *et al.*, 2008), leads to the following list of recommended considerations for achieving future plant flexibility:

- Use of advanced creep strength enhanced ferritic steels such as P92, and new nickel alloys such as Inconel 740 and Haynes 282. These materials for piping, headers, and casing components provide good creep-life characteristics at the higher temperatures. Additional advantages include reduced wall thickness and a reduction in the level of thermal stresses under cycling operation.
- Design boiler headers, piping systems, valve casing, and turbine rotors/shells with both creep life and thermal cycling as a requirement. Existing commercial analysis tools can assist in this process (Payten, Bendiech, & Snowden, 2009).

- Consideration of a broader range of unit load when designing the furnace, burner systems, and controls. Seeking to attain a lower minimum load below which oil firing is necessary for stable furnace operation.
- Installation of a main steam turbine bypass to improve temperature matching during start-ups
- Installation of an economiser bypass to extend the load range over which the SCR system will operate without catalyst fouling.
- Incorporation of partial-arc admission for the steam turbine to improve part-load efficiency
- Improve measures to retain heat in the boiler-turbine systems during brief shutdowns, particularly in the turbine valve bodies and steam chests which typically lose heat faster
- Consideration of long-term cost advantages of employing variable speed motors as prime movers for large pumps and fans
- Installation of adequate condensate drains in all boiler header and piping systems, with instrumentation to detect presence of condensate. Enable remote actuation of these drains in the control room.
- Incorporate the latest advanced human-machine interface technology in the control room. Operator situational awareness is critical in cycling operation and is greatly influenced by screen layouts, trending, and strict adherence to alarm management standards.

Cost-effective cycling impact mitigation strategies

Many plants are successfully instituting cycling impact mitigation efforts by initially employing low-cost operational and controls strategies rather than costly whole-component upgrades. One European power producer has used a “toolbox” approach to reduce cycling impacts, which includes the following elements (powermag, 2011):

- Flexible operation studies on those key components that either limit flexibility or accrue damage during cycling. This includes additional instrumentation to monitor key thermal transients followed by repeated operational trials using this new data to reduce startup times and equipment damage.
- Identification and elimination of any hot surface quenching caused by inadequate drain capacity/control as well as at temperature spray control
- Continuous operator coaching using simple component damage algorithms to instill a focus on reducing cycling related equipment impacts. One current example of commercial cycling damage assessment tools is REMLIFE, now in use by Australian power plants (Payten, Bendiech, & Snowden, 2009).
- Institute a more aggressive equipment inspection regime to seek and proactively address new component degradation modes. Plants need to adopt a formal maintenance basis, and continuously adapt this basis with input from observed component degradation.
- Where design changes are cost-justified, seek to “design-out” the failure modes rather than simply replace in-kind.

Improved controls strategies have emerged as perhaps the most effective overall approach to improving coal plant flexibility. The capability of new distributed control systems to optimise over wider operating ranges is generally under-utilised; however, some successful case studies have been documented recently (powermag, 2011).

Protection of the boiler-turbine water circuit during layup periods of indeterminate duration has emerged as a major challenge to the industry. An effective new strategy to provide corrosion protection in these situations is the use of filming amines in the feedwater, which continuously coat the wetted surfaces during operation and provide a barrier against oxidation when exposed to air during shutdown. This new strategy has the potential to significantly reduce the cost and protection effectiveness over traditional layup practices.

Plant efficiency considerations under cycling operation

To reduce throttling losses in the turbine at part-load operation, partial-admission control stage designs should be incorporated. The efficiency gains at part-load can more than offset the increased losses at design-point operation.

Recent studies have outlined cost-effective strategies to incrementally reduce the roughly 10–20% part load heat-rate penalty (relative to full load). These strategies include the implementation of sliding pressure operation, in which the turbine inlet pressure is set using feedpump controls rather than through throttling of the turbine control valves. Sliding pressure has been accepted by many plants as the most cost-beneficial approach to reducing the heat rate penalty at low load. Additional actions to improve performance of cycling units include (EPRI, 2010a):

- Boiler combustion and air quality control system tuning over a range of unit conditions rather than just at design operating point (referred to as gain scheduling)
- Replacement of fixed-speed motors with variable-speed drives
- Use of heat rate monitoring systems that trend process parameters and apply algorithms to calculate recoverable losses in real-time
- Increased attention to improving cycle isolation, which improves heat rate across the entire load range
- Improved schemes for operation of condenser cooling system (pumps, fans) at part load operation to reduce auxiliary loads and avoid wasteful condensate sub-cooling
- Improved schemes for operation of boiler draft fan systems during startup and part load operation to reduce auxiliary loads.

  A new area of research on cycling impact is focusing on the effect of continuous load following on heat rate. Units that are never stabilised at constant load experience thermal hysteresis effects on even minor load swings that result in additional heat rate penalties due simply to the non-steady operation. Controlled testing has been conducted on commercial coal plants (EPRI, 2011b).

CCS impacts on plant flexibility

Much of the inherent flexibility of CCS plants will not be fully understood until such time as full-scale capture plants are demonstrated and new operators begin to become familiar with the potential bottlenecks and restrictions associated with startup, shutdown and varying plant loads. Currently, modeling activities are the tools to best understand the potential limitations of these evolving technologies.

Several issues of concern that could limit the flexibility of advanced coal plants with CCS:

- If the plant is capturing CO_2 for EOR, disruption or change in the supply of CO_2 might be detrimental for oil-field production impacting the plant's ability to turndown particularly if there is an existing contract for CO_2. Such plants may be required to be base-loaded as a result at least while EOR is occurring.
- In general, increased dynamic operation implies lower capacity factors, and with the capital intensity of advanced coal plants with CCS, lower capacity factors could pose a large cost barrier to running at lower loads.

Oxy-combustion flexibility

Essential to oxy-combustion startup is the requirement for its ASU to be up and running for nearly 48 hours in order to achieve acceptable oxygen purity from ambient conditions. This long startup time for the ASU is the rate limiting step for the entire oxy-combustion system start-up.

Once the ASU is close to achieving acceptable oxygen purity, the boiler startup can be initiated, which is essentially the same as for air firing. At about 40% load on air, the transition to oxygen firing and flue gas recycling will begin.

A full-scale oxy-combustion plant is envisaged to operate similarly to a conventional PC plant. The transition from the air firing to the oxy-fuel firing during startup and shutdown has been shown (at pilot scale) to be relatively simple and automatic. Load changing has been found to be essentially the same as for air firing with the addition of oxygen control.

With oxy-combustion there is no steam (heat source) required to be diverted from the plant's steam turbines. This has implications on its options in terms of flexibility.

Even if regulation was to allow a CCS plant to vent CO_2 at certain times at its owner's discretion, it seems unlikely that one would want to turn the ASU on and off given the long startup time requirement from ambient. However, one element of oxy-combustion flexibility that could be considered to reduce costs would be the storing of its oxygen. In this scenario, the ASU could come down in load and reduce the overall parasitic power loss of the oxy-combustion plant for peak periods yet still maintain the required oxygen flow to the boiler. Such flexibility would require pre-investments on an appropriate oxygen storage tank, but may prove cost effective in a competitive electricity bidding market. The disadvantage would be that it also requires some element of cycling of the ASU equipment, which may be deleterious for existing ASU systems that are historically not designed to cycle.

Likewise if the CO_2 compressors were to be turned off on the oxy-combustion plant and CO_2 vented for a period, this might allow an opportunity where the plant could fire at full MW capacity with a considerably lower parasitic load (albeit, venting its CO_2 for this short period).

Post-combustion capture flexibility

Unlike their oxy-combustion counterparts, amine capture systems require large amounts of heat to regenerate the solvent used in the CO_2 removal process (as opposed to large amounts of MW to power an ASU for oxygen supply in the oxy-combustion case).

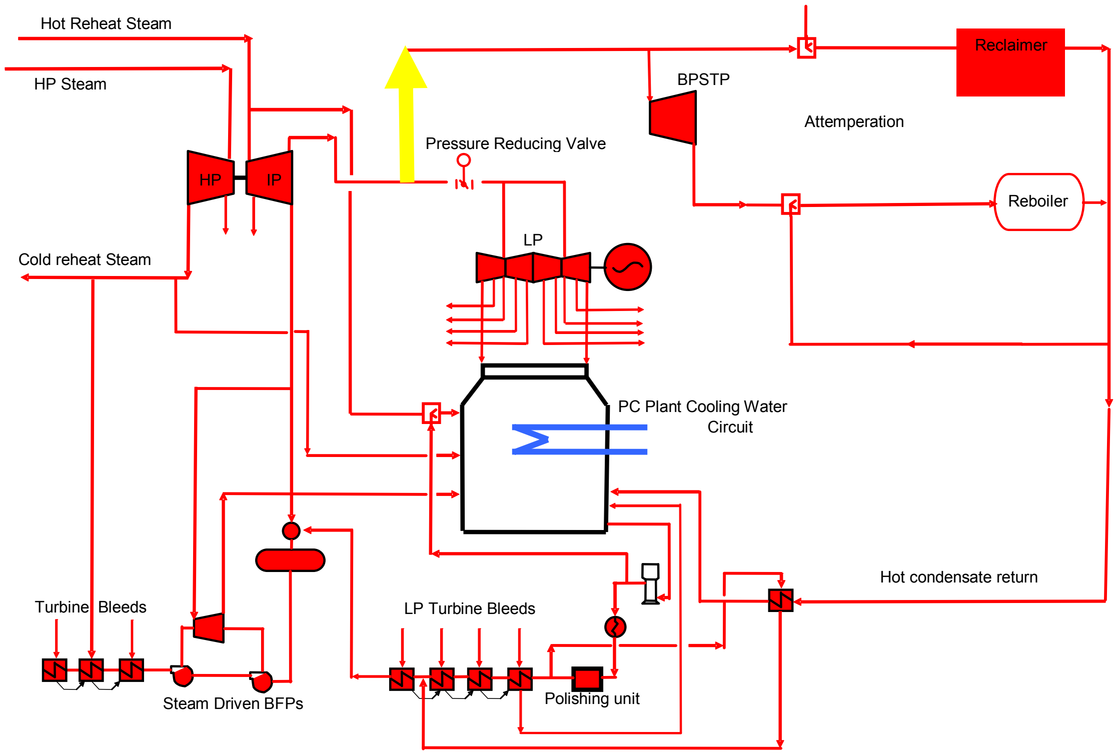
For both new-build and retrofit PCC plants, the heat source is commonly supplied from the steam generated in the PC plant. The steam is required to be at a certain condition as dictated by the capture solvent. The crossover steam between the IPT and LPT is the common place for extraction.

Obtaining appropriate source of heat for post-combustion capture systems

Studies on advanced amine PCC with commercial systems show that to achieve 90% CO_2 capture for an entire plant, significant amounts (40–50%) of the steam produced is required to be extracted from the steam turbine for solvent regeneration (EPRI, 2011c). This significant extraction has implications on the IPTs and LPTs in both normal operation and load following scenarios.

An approach intended to avoid major modifications to the IPT design is to add a pressure control valve downstream of the crossover extraction location as shown in Figure 29 (EPRI, 2011c). This valve will maintain IPT exhaust pressure at its normal value, and thus the IPT is unaffected. Controls will be implemented such that this valve modulates IPT exhaust pressure to the value appropriate to the loading of the IPT.

Figure 29 • Turbine and feedwater heater circuit for the PC plant with CO_2 capture added



Source: EPRI, 2011c.

Understanding the potential effects/limits on plant turndown operation

Extracting the large amount of low-pressure steam required for the PCC plant will cause a substantial reduction in LPT power output. Since the IPT exhaust pressure is maintained by the pressure control valve, the steam pressure available to the PCC plant will be much higher than required. A let-down back-pressure turbine (BPT) generator can be installed upstream of the PCC plant to recover some of the power. This turbine accepts steam from the crossover line and exhausts at the pressure required for the PCC plant. Because the IPT exhaust pressure, which is also roughly the PCC extraction pressure, decreases with turndown, eventually the difference between the PCC extraction pressure and the required PCC reboiler pressure will be too small to generate power efficiently from the BPT. Hence, a bypass line with shut-off valve is required around the BPT to allow the plant to operate with PCC during low turndown rate.

Therefore two major criteria that limit PCC turndown are:

1. Maintaining the minimum PCC extraction pressure for solvent regeneration
   - Usually around 4.14 bar (75 psig) for 30% monoethanolamine (MEA) systems, but different for other solvents systems.
2. Maintaining the steam flow through the LPTs for stable turbine operation.
   - Should not be less than the pre-PCC design flow.

Flexibility of IGCC plants with capture

In general, IGCC plants have been designed to operate at base-load and do not have a great deal of experience in cycling. The plants tend to be highly integrated and complex, especially those designed for carbon capture, so turndown of the unit is slow, making load-following difficult. In general, they have longer start-up times than a PC unit or NGCC, so single or two-shifting a unit becomes impractical.

However, several gasifiers do have experience operating in a load-following manner:

- The Nuon gasification project at Buggenum, the Netherlands, operated in load dispatch from 1999 to 2003. However, the plant reverted to base-load operation in 2004. The plant demonstrated that in an integrated mode it could vary load at better than 3% per minute.
- Nippon Petroleum Refining's Negishi IGCC plant reportedly operates at 75% load at night and weekends and then can be ramped up to full load over a 30-minute time period.

One advantage of IGCC over other technologies when it comes to cycling is that the technology has the ability to "poly-generate" or can make multiple products. During times of reduced electricity demand, the syngas produced by the IGCC could be used to make chemicals, which are typically stored in liquid form. This would allow the gasification portion of the process to operate at a constant load, while the combined cycle is operating at a reduced load (or even shutdown). Two IGCC projects currently in development in the United States plan to use this operating strategy (Summit Power's TCEP and SCS Energy's HECA).

Flexibility of advanced cycles

Chapter 2 presented several future advanced cycles for coal-powered electricity generation. As these cycles won't be in commercial use until after the 2020 timeframe, the status of the electricity grid and the impacts of intermittent resources will be less certain, potentially increasing the need for flexible operation. This need for flexibility may be tempered as the potential higher thermal efficiencies of the advanced cycles could increase the likelihood that these units will be more base-loaded.

A brief review of each cycle is presented here; much R&D remains to be done in this arena.

Advanced fuel cells

The dynamic control of fuel cells through startup, shutdown, emergency, and load-following has been identified as a critical issue primarily due to the complexity of the system (NETL, 2012b). Designing fuel cells for flexible operation is in its infancy, but one study has identified the need of a DC/DC converter for a SOFC to be used for load following applications (IEEE, 2007).

Chemical looping combustion

CLC is a complex system that requires balancing of multiple sub-systems each of which may have different startup and shutdown sequences and times as well as different operating characteristics at part-load operation. One study showed that CLC had a promising efficiency at part-load operation down to 60% of full load; however, it required an advanced control strategy. A combination of control strategies is required for startup and shutdown and for part load when airflow reduction is not practically possible with the current generation of compressors (Energy, 2007).

Closed Brayton power cycles

Closed Brayton power cycles are likely to have excellent flexibility. SCO_2 closed Brayton cycles have smaller weight and volume, lower thermal mass, and less complex power blocks versus Rankine cycles due to the higher density of the fluid and simpler cycle design. The lower thermal mass makes startup and load change faster for frequent startup/shutdown operations and load adaption than a steam-based system (NREL, 2011).

Pressurised oxy-combustion

The flexibility of a pressurised oxy-combustion plant is not envisaged to be significantly different from an atmospheric oxy-combustion plant discussed earlier in this chapter.

Conclusions

The amount of both renewable energy and non-hydro renewables is projected to grow significantly. Mainly driven by government policies, worldwide generation from non-hydro renewables is projected to increase from 3% of the total in 2009 to over 15% in 2035.

The increasing amount of intermittent renewables means that the generation portfolio must be increasingly flexible to handle more dynamic operation to ensure grid adequacy with an acceptably high probability.

The ability of coal power plants – both existing and future – to be more flexible in response to the changing electricity market has been questioned largely due to the perception that coal plants are designed to be base-loaded units and have a limited ability to respond dynamically.

A case study on the German electricity market provided relevant experience germane to this topic. The German market has a huge variety of providers and a diverse energy mix, including considerable renewable energy sources and both coal- and natural-gas-based units. The study showed that coal-fuelled units exhibited good flexibility in responding to dynamic operations caused by intermittent renewables.

Note that the conclusions of this study, while very positive on coal's ability to operate flexibly in a diverse portfolio, are partially tied to the particular circumstances in the German market. There will certainly be regional differences that will produce other outcomes, hence the need is still there to research and improve the ability of coal power plants to operate flexibly.

Coal assets must improve performance in the following key areas related to flexibility: 1) increased turndown, 2) faster and less damaging startups, 3) faster load changes, and 4) reserve shutdown at minimal cost. These can conflict with the desire for high thermal efficiency base-load operation for coal. Operational constraints on emission control equipment also impact the flexibility of coal power plants.

Much of the flexibility of the existing coal fleet is supplied by small, subcritical units operating without environmental control equipment. With the long-term future of these units in question due to their lower efficiency, and capital spending required for emissions compliance, the challenge to coal will be to attain flexibility with the remaining larger units. Improved controls strategies have emerged as perhaps the most effective overall approach to improving coal plant flexibility. For new coal plants, it is essential that operational flexibility be considered early in the design phase.

Advanced high-temperature materials and plant controls can be employed to improve flexibility. Conducting rigorous operational trials to optimise details of plant process changes during transient operation has also proven to be cost effective. The change in flexibility of advanced coal plants with the addition of CCS will not be fully understood until demonstrated and the resulting experience is accrued. However, it is not envisaged that adding CCS will substantially change the base plant's flexibility.

For advanced cycles such as CLC and fuel cells, the complexity of the system could impact its flexibility, requiring advanced control strategies. Pressurised oxy-combustion should behave similarly to atmospheric oxy-combustion. Closed Brayton cycles are likely to have excellent flexibility arising from their smaller size, lower thermal mass, and less complex power block.

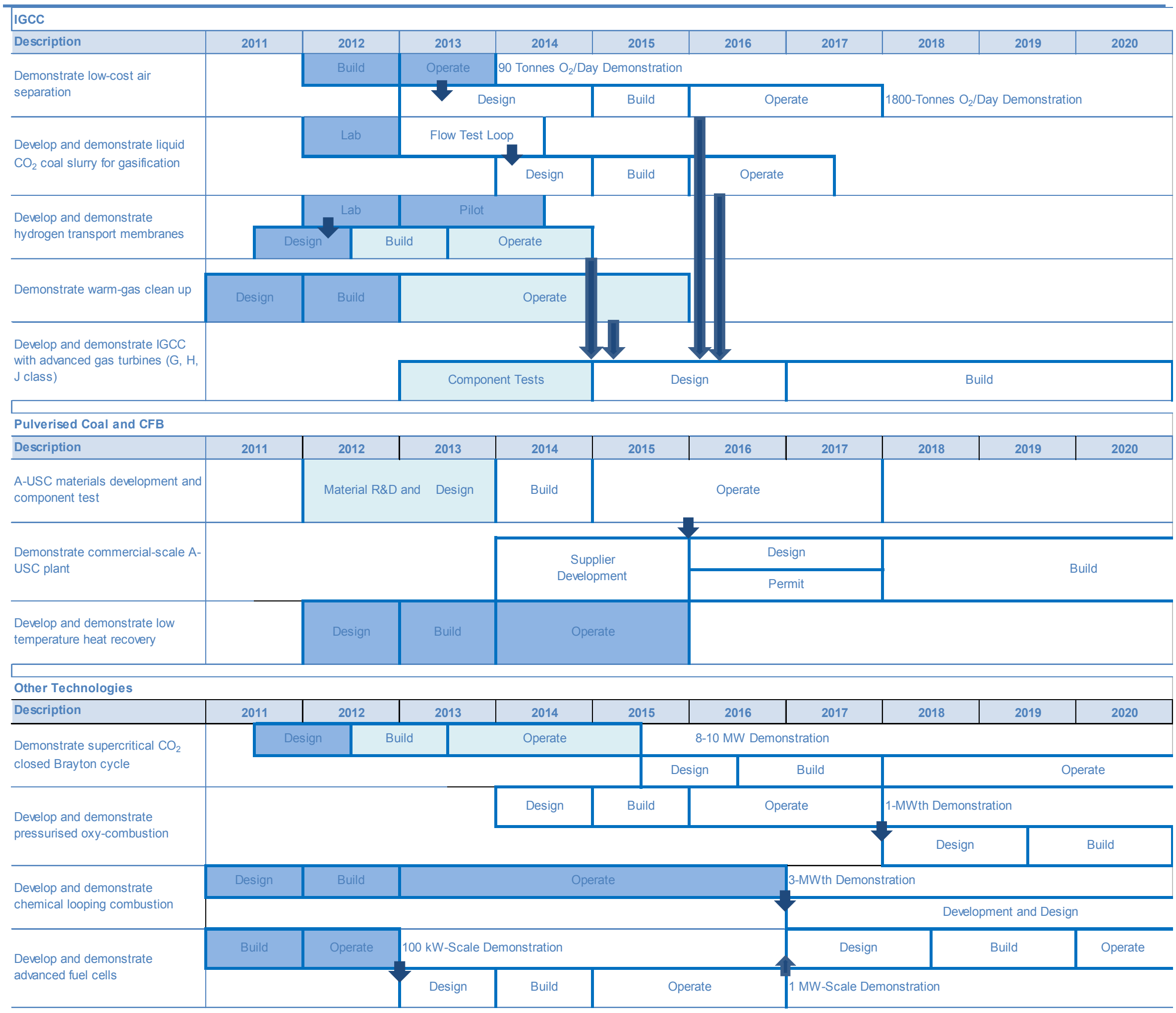
Recommendations

Based on findings presented in this report, the CIAB recommends the following:

- Coal will remain the cornerstone fuel in the global energy economy for decades to come. In 2013, the IEA should leverage its stature and undertake a special initiative to re-educate OECD leaders on this and other aspects of world energy. Such an initiative would be highly constructive by contributing to a greater understanding of crucial energy issues on the part of policymakers and the public they serve. In turn, such understanding would enhance prospects for consensus between developed and developing world leaders on balanced policy measures to achieve the dual benefits to human civilisation resulting from increased energy access and advanced emissions technology.
- World leaders should be guided by the history of technological development in approaching the issue of coal and the CO_2 challenge. The documented record of industry to overcome previous emissions challenges has rested squarely on the progression of new technologies, a fact which remains true today through continued advancements in coal-fueled generation technologies. The next generation of clean coal technologies – including CCUS – represents 21st Century Coal and now provides the path toward NZE, demonstrating coal's continuing role as a global energy solution.
- Energy Ministers from developed and developing countries that use coal should promote in earnest the building of more efficient supercritical and USC coal-fuelled generation. This approach is grounded in scientific and economic analyses that conclude that improved thermal efficiency is the essential first step in realising both meaningful and the lowest-cost reductions in GHG emissions, followed over time by the deployment of CCS technology. Efficiency improvements can deliver emission reductions of 20–30% followed by the application of CCS that can deliver emission reductions of 90%.
- Governments should collaborate with the petroleum industry to identify current and future demand for CO_2 for EOR and ensure that the opportunity to supply CO_2 for EOR is fully considered in strategies to support FOAK commercial-scale CCS demonstrations. These will generally be the lowest-cost CCS demonstration projects. EOR has been profitable for 40 years in the United States and is a technology that holds transformational potential in terms of GHG emissions reductions and global energy security. Likewise, the additional revenue stream associated with EOR provides integral financial support enabling the commercial viability of – and restored momentum for – CCS projects.
- Efforts should be made by all stakeholders to engage with China on CCS demonstrations and EOR. China possesses numerous EOR opportunities; however, information on the country's efforts in the field of CCS is not well-known outside China. Among the relevant stakeholders are private companies from the coal, power generation, and related industries, which can play a constructive role in broadening the extent of bilateral and multilateral cooperation with China through co-sponsorship with Chinese counterparts of joint scientific R&D initiatives relating to CCS and EOR. China is likely to be of vital importance in achieving cost reductions and other necessary progress to advance CCS deployment.

Appendix

Table 13 • Timeline for coal technologies to achieve technical maturity*



* The timeline continues on the next page to2025.

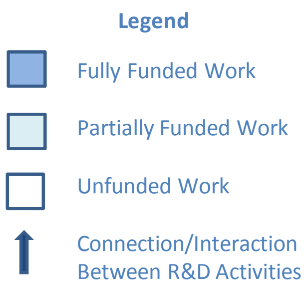


Table 13 • Timeline for coal technologies to achieve technical maturity *(continued)*

IGCC					
Description	**2021**	**2022**	**2023**	**2024**	**2025**
Demonstrate low-cost air separation					
Develop and demonstrate liquid CO_2 coal slurry for gasification					
Develop and demonstrate hydrogen transport membranes					
Demonstrate warm-gas clean up					
Develop and demonstrate IGCC with advanced gas turbines (G, H, J class)	Operate	Operate	Operate	Operate	
Pulverised Coal and CFB					
Description	**2021**	**2022**	**2023**	**2024**	**2025**
A-USC materials development and component test					
Demonstrate commercial-scale A-USC plant	Build	Operate	Operate	Operate	Operate
Develop and demonstrate low temperature heat recovery					
Other Technologies					
Description	**2021**	**2022**	**2023**	**2024**	**2025**
Demonstrate supercritical CO_2 closed Brayton cycle	Operate	50-250 MW Demonstration			
Develop and demonstrate pressurised oxy-combustion	Demo.	Commercial Design	Commercial Design	Commercial Design	
	Operate	Operate	Operate	Operate	100-MWth
Develop and demonstrate chemical looping combustion	Build	Build	Operate	Operate	Operate
Develop and demonstrate advanced fuel cells	Operate	10-MW Demonstration			
	Design	Design	Build	Operate	Operate

Source: EPRI.

Table 14 • Major CCS demonstration projects worldwide

Project /Location/ Owner	Fuel *	Size, Net MW	Capture Process % Capture	CO_2 Fate	Cost / Funding (Source)	Status / Startup
Canadian Projects						
Boundary Dam/ Saskatchewan SaskPower	L	110	PCC; Cansolv 90%	EOR and Saline	USD 1.4B / USD 245M (Saskatchewan government)	Construction / 2014
Chinese Projects						
Daqing / Heilongjiang China Datang Corp.	C	350	Oxy-combustion 90%	EOR	?	2015
Dongying / Shandong China Datang Corp.	C	1000	PCC; Amines or chilled ammonia 90%	EOR	?	2017
GreenGen / Tianjin City GreenGen	C	250/400	Pre-combustion 90%	Saline	USD 360M for 250-MW IGCC; USD 1B for 400-MW IGCC with CCS / ?	250-MW IGCC operating / 400-MW IGCC with 90% CCS in 2017
Lianyungang / Jiangsu EPRC	C	1200 IGCC; 2 x 1300 PC	Pre-combustion and PCC with solar integration 90%	EOR	?	2015 quoted but highly unlikely
Shanghai / Shanghai Huaneng Group	C	350	PCC / 90%	EOR	?	~2016
Shengli Oil Field / Shandong Sinopec	C	100	PCC retrofit to CFB / 90%	EOR	?	2014
SIEG / Taiyuan Shanxi International Energy Group Co., Ltd.	C	350	Oxy-combustion 90%		?	2015–16
European Union Projects						
Belchatów / Poland PGE Elektownia S.A.	L	250	PCC; Dow / Alstom Amine / 33%	Saline	? / €180M (EEPR)	FEED / 2015
Compostilla / Spain Endesa	C	242	Oxy-combustion, CFB / 90%	Saline	? / €180M (EEPR)	Pilot under testing / 2016
Don Valley / Yorkshire 2CoEnergy	C	650	Pre-combustion / 90%	EOR and Saline	€4.7B on land, €1.6B off shore / €180M (EEPR)	Pre-FEED / 2015
Jänschwalde / Germany Vattenfall	Li	250	Oxy-combustion / 90%		€1.5B / €180M (EEPR)	FEED / Project cancelled
Maasvlatke / Netherlands E.ON. ,Electrabel , GDF	C	250	PCC; MEA / 25%	Off-shore gas field	€1.2B / €280M for PCC / €180M (EEPR)	Pre-FEED / 2015
Porto Tolle / Italy Enel	C	250	PCC; Aker is one of the finalists / 90%	Saline	€2.5B / €100M (EEPR)	FEED / Needs approval before going forward
United Kingdom Projects						
Caledonia Clean Energy Project / Scotland Summit Power	C	200? + Hydrogen	Pre-combustion / 90%	EOR and Saline	?	Planning / 2018
Killingholme / England / CGen	C	450	Pre-combustion / 90%	Gas field	? / (also applied to NER 300)	Pre-FEED / 2015

Table 14 • Major CCS demonstration projects worldwide *(continued)*

Project /Location/ Owner	Fuel	Size, Net MW	Capture Process % Capture	CO_2 Fate	Cost / Funding (Source)	Status / Startup
United States Projects						
FutureGen 2.0 / Illinois FutureGen Alliance	C	168 (gross)	Oxy-combustion 90%	Saline	USD 1.65B / USD 1B (ARRA)	FEED / 2017
HECA / California SCS Energy	PC, C	288	Pre-combustion 90%	EOR	USD 4.5B / USD 450M (CCPI)	FEED / 2018
Kemper County / Mississippi Mississippi Power (Southern)	L	524	Pre-combustion 67%	EOR	USD 2.88B / USD 270M (CCPI)	Construction / 2014
TCEP / Texas Summit Power	PRB	200	Pre-combustion 90%	EOR	USD 2.5B / USD 450M (CCPI)	FEED / 2014
Trailblazer / Texas Tenaska	PRB	600	PCC; Fluor Econamine 90%	EOR	USD 667M for PCC; USD 3.8–4.6B for SC PC+PCC / ?	Received air permit in 2010
W.A. Parish / Texas NRG Energy	PRB	60/240 (25% CCS)	PCC; Fluor Econamine 90%	EOR	USD 339M / USD 167M (CCPI) for PCC only	FEED / 2015

* L = lighnite, C = hard coal, PC = Pet Coke
Source: EPRI

Table 15 • Summary of results for the 50 basins considered in the IEA GHG assessment

Basin Name/ Main Country/ Location (1 = On-shore, 2 = Off-shore)	Known Oil (MMBO)	Recovery Efficiency	Discovered Fields OOIP (MMBO)	OOIP in Large Fields for EOR (MMBO)	Large Field OOIP Favour-able for Miscible EOR (MMBO)	EOR Recovery Efficiency	Large Field EOR Oil Technically Recoverable (MMBO)	CO2/OIL Ratio (tonnes/ Bbl)	CO2 Stored in Large Fields (Gigatons)
Mesopotamian Foredeep Basin Saudi Arabia (1)	292 442	32%	908 501	663 206	449 559	20%	89 069	0.31	27.2
West Siberian Basin Russia (1)	139 913	34%	412 441	301 082	204 091	21%	43 683	0.27	11.7
Greater Ghawar Uplift Saudia Arabia (1)	141 700	36%	394 328	287 859	195 128	22%	43 348	0.30	13.2
Zagros Fold Belt United Arab Emirates (1)	121 601	33%	369 291	269 582	182 739	21%	39 274	0.30	11.8
Rub Al Khali Basin United Arab Emirates (2)	89 827	37%	245 615	179 299	121 539	23%	27 977	0.31	8.8
Volga-Ural Region Russia (1)	63 937	33%	193 683	141 388	95 841	20%	19 130	0.27	5.2
North Sea Graben United Kingdom (2)	43 894	34%	127 914	93 377	63 297	23%	14 373	0.28	4.0
Maracaibo Basin Venezuela (2)	49 072	31%	157 328	114 849	77 851	18%	14 307	0.32	4.5
Permian Basin United States (1)	31 131	33%	95 400	72 380	61 426	22%	13 428	0.31	4.1
Villahermosa Uplift Mexica (1)	35 022	34%	104 134	76 018	51 529	24%	12 333	0.34	4.1
Sirte Basin Libya (1)	37 073	34%	110 538	80 693	54 698	22%	11 765	0.29	3.4
North Slope United States (1)	20 848	33%	64 074	62 295	61 434	19%	11 373	0.27	3.1
Niger Delta Nigeria (2)	34 523	32%	106 913	78 047	52 905	20%	10 448	0.30	3.1
East/Central Texas Basins United States (1)	37 287	34%	109 000	67 372	44 024	21%	9 392	0.26	2.4
East Venezuela Basin Venezuela (1)	30 203	31%	96 942	70 767	47 970	18%	8 707	0.31	2.7
Bohaiwan Basin China (1)	24 554	33%	73 998	54 018	36 617	20%	7 443	0.27	2.0
Widyan Basin-Interior Platform Saudi Arabia (1)	17 435	27%	65 553	47 854	32 438	22%	7 068	0.32	2.3

Table 15 • Summary of results for the 50 basins considered in the IEA GHG assessment *(continued)*

Basin Name	Known Oil (MMBO)	Recovery Efficiency	Discovered Fields OOIP (MMBO)	OOIP in Large Fields for EOR (MMBO)	Large Field OOIP Favorable for Miscible EOR (MMBO)	EOR Recovery Efficiency	Large Field EOR Oil Technically Recoverable (MMBO)	CO2/OIL Ratio (tonnes/ Bbl)	CO2 Stored in Large Fields (Gigatons)
Mid-Continent Basins United States (1)	24 461	27%	89 600	53 133	28 005	23%	6 359	0.25	1.6
South Baspian Basin Turkmenistan (2)	17 439	34%	51 984	37 948	25 723	22%	5 697	0.30	1.7
Trias/Ghadames Basin Algeria (1)	15 203	35%	43 514	31 766	21 533	24%	5 185	0.29	1.5
Alberta Basin Canada (1)	15 279	36%	42 573	31 078	21 067	22%	4 724	0.31	1.4
LA Off-shore United States (2)	9 571	34%	28 100	22 251	22 055	21%	4 594	0.35	1.6
Songliao Basin China (1)	15 575	33%	47 592	34 742	23 550	19%	4 495	0.26	1.2
Gulf Coast Basins United States (1)	16 950	38%	44 400	26 413	19 978	21%	4 131	0.32	1.3
West-Central Coastal Gabon (2)	13 717	32%	43 459	31 725	21 505	19%	4 057	0.31	1.3
Timan-Pechora Basin Russia (1)	13 120	33%	39 404	28 765	19 498	20%	3 943	0.27	1.1
North Caspian Basin Kazakhstan (1)	10 809	43%	25 140	18 352	12 440	26%	3 226	0.34	1.1
Red Sea Basin Egypt (2)	9 860	32%	30 632	22 362	15 158	20%	3 072	0.32	1.0
Campos Basin Brazil (2)	10 056	31%	32 947	24 051	16 303	19%	3 072	0.36	1.1
Middle Caspian Basin Turkmenistan (2)	9 552	34%	28 507	20 810	14 106	22%	3 036	0.29	0.9
Rockies Basins United States (1)	10 437	31%	33 600	23 662	13 779	19%	2 625	0.28	0.7
San Joaquin Basin United States (1)	15 691	36%	43 861	39 595	8 792	25%	2 164	0.25	0.5
Junggar Basin China (1)	6 810	33%	20 809	15 191	10 297	20%	2 084	0.29	0.6
Putumayo-Oriente-Maranon Basin Colombia (1)	6 601	31%	21 050	15 367	10 416	19%	1 945	0.32	0.6
Carpathian-Balkanian Basin Romania (1)	5 908	33%	17 928	13 087	8 871	22%	1 939	0.32	0.6
Baram Delta/Brunei-Sabah Basin Brunei (2)	6 898	31%	22 213	16 215	10 992	17%	1 895	0.29	0.6
Llanos Basin Colombia (1)	5 403	33%	16 380	11 958	8 106	23%	1 867	0.35	0.6
Williston Basin United States (1)	3 739	28%	13 200	9 299	7 153	26%	1 827	0.27	0.5
Tampico-Misantia Basin Mexico (1)	6 895	30%	22 689	16 563	11 227	16%	1 799	0.30	0.5
Interior Homocline-Central Arch Saudi Arabia (1)	4 700	32%	14 616	10 670	7 233	20%	1 421	0.30	0.4
Fahud Salt Basin Oman (1)	4 473	35%	12 645	9 231	6 257	22%	1 346	0.29	0.4
Gippsland Basin Australia (2)	3 861	36%	10 832	7 907	5 360	24%	1 286	0.25	0.3
Coastal California Basin United States (1)	3 535	25%	14 008	12 646	4 786	25%	1 179	0.29	0.3
Malay Basin Malaysia (2)	3 608	36%	10 109	7 380	5 002	23%	1 173	0.24	0.3
Illizi Basin Algeria (1)	3 670	35%	10 608	7 744	5 249	21%	1 114	0.23	0.3
Los Angeles Basin United States (1)	7 019	28%	25 431	22 958	7 563	14%	1 096	0.27	0.3
Williston Basin Canada (1)	3 505	39%	9 011	6 578	4 459	23%	1 024	0.31	0.3
Appalachia United States (1)	1 144	8%	14 000	11 657	3 905	22%	856	0.34	0.3
Cook Inlet United States (1)	1 388	43%	3 226	3 137	3 026	22%	670	0.32	0.2
Illinois Basin United States (1)	6 170	35%	17 800	11 985	4 422	12%	512	0.27	0.1
Total	**1 503 509**	**33%**	**4 537 521**	**3 316 311**	**2 240 904**	**21%**	**468 530**	**0.30**	**139**

Source: IEA , 2009.

List of acronyms and abbreviations

Abbreviation	Meaning	Abbreviation	Meaning
2DS	2°C scenario	HRSG	heat recovery steam generator
4DS	4°C scenario	H_2S	hydrogen sulphide
6DS	6°C scenario	H_2SO_4	sulphuric acid
ABS	ammonium bisulphate	HTM	hydrogen transport membranes
ACI	activated carbon injection	ICO_2N	Integrated CO_2 Network
AEP	American Electric Power	IEA	International Energy Agency
AGR	acid gas removal	IGCC	integrated gasification combined cycle
API	American Petroleum Institute	IGFC	integrated gasification fuel cell
ARI	Advanced Resources International, Inc.	IPT	intermediate-pressure turbine
ARRA	American Recovery and Reinvestment Act	ITM	ion transport membrane
ASME	American Society of Mechanical Engineers	LCOE	levelised cost of electricity
ASU	air separation unit	LPT	low-pressure turbine
A-USC	advanced ultra-supercritical	MEA	Monoethanolamine
BPT	back-pressure turbine	MHI	Mitsubishi Heavy Industries, Inc.
CCPI	Clean Coal Power Initiative	MMBO	million million barrels of oil
CCS	carbon or CO_2 capture and storage	MTR	Membrane and Technology Research, Inc.
CCUS	CO_2 capture, utilisation, and storage	NEORI	National Enhanced Oil Recovery Initiative
CFB	circulating fluidised bed	NER	New Entrants Reserve
CHP	combined heat and power	NETL	National Energy Technology Laboratory
CIAB	Coal Industry Advisory Board	NGCC	natural gas combined cycle
CLC	chemical looping combustion	NO_2	nitrogen dioxide
CO_2	carbon dioxide	NO_X	nitrogen oxides
CO2CRC	Cooperative Research Centre for Greenhouse Gas Technologies	NOAK	nth-of-a-kind
COS	carbonyl sulphide	NUMBY	“not under my back yard”
CPU	CO_2 purification unit	NZE	near-zero emissions
CSLF	Carbon Sequestration Leadership Forum	OECD	Organisation for Economic Cooperation and Development
CURC	Coal Utilization Research Council	OOIP	original oil in place
DCFC	direct carbon fuel cell	ORP	oxidation-reduction potential
DECC	Department of Energy and Climate Change	PC	pulverised coal
DOE	Department of Energy	PCC	post-combustion capture

EEPR	European Energy Program for Recovery	PM	particulate matter
EIB	European Investment Bank	PRB	Powder River Basin coal
EOR	enhanced oil recovery	R&D	research and development
EPA	Environmental Protection Agency	RD&D	research, development, and demonstration
EPRI	Electric Power Research Institute, Inc.	RFG	recycled flue gas
EPRC	Energy Power Research Centre	SAP	sorbent activation process
ESP	electrostatic precipitator	SCO_2	supercritical CO_2
EU	European Union	SCR	selective catalytic reduction
EUR	estimated ultimately recoverable	SNCR	selective non-catalytic reduction
FAC	flow-assisted corrosion	SO_2	sulphur dioxide
FBC	fluidised bed combustion	SO_3	sulphur trioxide
FEED	front-end engineering and design	SOFC	solid oxide fuel cell
FGD	flue gas desulphurisation	SO_X	sulphur oxides
FOAK	first-of-a-kind	SSE	Scottish & Southern Energy
GCCSI	Global Carbon Capture and Storage Institute	TCEP	Texas Clean Energy Project
GDP	gross domestic product	TMS	transportation, monitoring, and storage
GHG	greenhouse gas	UK	United Kingdom
GQCS	gas quality control system	U.S.	United States
HAPs	hazardous air pollutants	USC	ultra-supercritical
HECA	Hydrogen Energy California	WGCU	warm-gas clean-up
HHV	higher heating value	WGS	water-gas shift
HPT	high-pressure turbine		

List of units

Abbreviations and Meaning (unit type, system)

a	Absolute
bar	bar (pressure)
Btu	British thermal unit
^oC	degrees Celsius (temperature, SI)
^oF	degrees Fahrenheit
ft	feet (distance)
g	gage; gram (mass, SI)
G	giga, 10^9
hr	Hour
J	Joules (energy, SI)
k	kilo, 10^3
lb	pound (mass)
m	metre (length, SI); milli, 10^{-3}
M	mega, 10^6
Mtoe	million tonnes of oil equivalent
MWe	megawatt electric (power, SI)
MWth	megawatt thermal (power, SI)
N	Newton (force, SI); normal
Pa	Pascal (pressure, SI)
ppm	parts per million (concentration)
psi	pounds per square inch (pressure, English)
T	tera, 10^9
W	Watt (power, SI)
ton	2000 lb
tonne	1000 kg
vol	volumetric

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