Integrating intermittent renewable energy technologies with coal-fired power plant

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CCC/189 ISBN 978-92-9029-509-9

October 2011

Abstract

Historically, coal-fired power plants have faced competition from other forms of power generation such as nuclear, natural gas and oil. Like most coal-fired plants, many of these were designed to operate primarily on base load. However, competition is now increasingly coming from a range of renewable energy sources that include biomass, geothermal, hydro, solar, and wind. Unlike conventional power plants, several of these (particularly wind and solar power) are wholly dependent on prevailing weather patterns and consequently only generate electricity on an intermittent/variable basis. Changes in operating patterns mean that many existing coal-fired power plants no longer operate solely on base load, but are now subject to two-shifting or some other irregular form of operation. Switching a plant originally designed for base load can have implications in a number of areas that include plant economics, operation and performance. Environmental performance may also be impaired. This report discusses the growing level of intermittent renewable energy in the global power sector and examines the potential impact on associated coal-fired plants that have been obliged to change their mode of operation.

Acknowledgements

The contribution, comment and input of the following individuals and organisations is gratefully acknowledged:

Robert Giglio and Jim Utt, Foster Wheeler Global Power Group, USA
Ton Duijn and Hans de Jong, NUON, The Netherlands
Hans-Joachim Meier, VGB PowerTech e.V., Germany
Barry MacColl and Nalini Pillay, ESKOM, South Africa
John Davison, IEA GHG R&D programme, UK
Fedir Woskoboenko, HRL Technology, Australia
Michelle Aguayo, Xcel Energy, USA
Steve Pascoe, TruEnergy, Australia

Acronyms and abbreviations

ASU	air separation unit
ABS	automated sequential control system
BPA	Bonneville Power Authority
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CFBC	circulating fluidised bed combustion
CLFR	compact linear Fresnel reflectors
CM	condition modelling
CSP	concentrated solar power
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
EU	European Union
EWEA	European Wind Energy Association
FGD	flue gas desulphurisation
HP	high pressure
ICMS	integrated control and monitoring system
IEA	International Energy Agency
IEA GHG	International Energy Agency Greenhouse Gas R&D Programme
IGCC	integrated gasification combined cycle
LNG	liquefied natural gas
LP	low pressure
O&M	operation and maintenance
MCR	maximum continuous rating
MSW	municipal solid waste
NDRC	National Development and Reform Council (China)
NREL	National Renewable Energy Laboratory (USA)
NTPC	National Thermal Power Company
OECD	Organisation for Economic Cooperation and Development
OEM	original equipment manufacturer
PCC	pulverised coal combustion
PV	photovoltaic
RE	renewable energy/energies
RPS	Renewable Portfolio Standards
SC	supercritical
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
UHV	ultra-high voltage
USC	ultra-supercritical
VRE	variable renewable energy technology

Contents

1 Introduction

Recent years have witnessed significant changes in the make-up and operation of the global power sector, changes that continue. As a result of widespread deregulation in the electricity market, power generators have entered a far more competitive marketplace. Some of the biggest changes have been (and, are being) felt by the operators of coal-fired generating capacity. Historically, coal-fired power plants have faced competition from other forms of power generation such as nuclear, natural gas and oil. Like most coal-fired plants, many of these were designed to operate primarily on base load. However, competition is increasingly coming from a range of renewable energy sources that include biomass, geothermal, hydro, solar, and wind. Unlike conventional power plants, several of these (particularly wind and solar power) are dependent on prevailing weather patterns and consequently only generate electricity on an intermittent/variable basis.

All nations rely heavily on an adequate and accessible supply of electricity and for many years, in most countries, demand has continued to rise. However, concerns have recently increased over the depletion of energy resources and possible climate change linked to the use of fossil fuels. The preferred response of western governments has been a supply-side strategy, namely to raise the share of renewables in the energy mix toward 20% and beyond (Boccard, 2010). To date, wind power generation has emerged as the leading contender for this task although levels of solar power are also growing steadily.

Renewable energy technologies have obvious features that make their use attractive. Compared with conventional fossil fuel-based energy production, ‘fuel’ costs may be negligible or even zero, as may be emissions generated during day-to-day operation. Although initial capital outlay for renewables-based systems can be high, operating costs may be low. Despite the umbrella term often employed, there are significant differences between individual renewable energy technologies; some can have a significant environmental impact. For instance, when examined on a life cycle analysis basis, large-scale hydro and tidal power installations can be expensive to construct and/or environmentally damaging. Likewise, biomass for heat or power generation requires harvesting, transport and preparation, all stages that require energy input and have environmental consequences. No renewable system is entirely free from environmental impact of some kind although much of this may be associated with the initial construction phase, as opposed to daily operation. However, even where this is the case, in an integrated generating system relying on a portfolio of technologies that includes thermal plants, where a proportion of electricity generation comes from intermittent renewable sources, there are likely to be other indirect consequences that may, at first, be less obvious.

Most types of renewable energy technology have experienced significant growth during the past few years. Part of the rationale behind this has been the desire by many governments to achieve a more secure, diverse and sustainable energy mix and to limit emissions of CO_2. On this basis, levels of deployment will continue to increase for the foreseeable future. The IEA suggests that by 2035, around 45% of global electricity will need to come from renewable sources if the level of CO_2 in the atmosphere is to be limited to 450 ppm, roughly consistent with a global temperature rise of no more than 2°C. Under this scenario, around 17% of electricity would need to come from variable renewables (predominantly wind and solar) up from 1% in 2008 (OECD/IEA, 2011).

Within many major electricity systems, when available, output from renewables is now taken first (a ‘must-take’ resource) in preference to that from fossil fuel-fired stations. The global wind (and to a lesser extent, solar) generation sector has been growing at a remarkable rate for some years and looks set to carry on expanding for the foreseeable future. In some countries, the contribution of renewables is considerable and whilst some types are both controllable and predictable, others, such as wind and solar power, are not. With both of the latter, output is dependent on natural forces and thus, at the mercy of uncontrollable and sometimes unpredictable changes in weather patterns. Thus, for instance, output from a wind farm can change from 100% to zero in a short period of time.

Even though this is not the only factor to determine a plant's mode of operation, inevitably, this type of fluctuating, intermittent generation has an impact on other forms of power plant that may also supply electricity to a particular system. In the case of coal-fired plants, because of changes in demand and competition from nuclear, gas-fired plant, and now renewables, many existing stations no longer operate solely on base load, but are now subject to two-shifting or some other irregular form of operation. Many are now required to operate on a more flexible basis, with load variations and two-shift operation increasingly becoming the norm. However, a significant proportion of older coal-fired plants, the majority of which are based on conventional subcritical pulverised coal combustion (PCC) technology, were originally designed and built with steady base load operation in mind.

Such major changes in operating patterns can have an impact in several areas of coal-fired plant operations. Some of the impacts associated with switching to cyclic operations are now reasonably well understood; globally, there is extensive experience of regular two-shift operation. In some parts of the world, non-base load operation has long been a fundamental aspect of the electricity supply industry, particularly in mature markets where supply capacity exceeds base demand. Because of the nature of this competition, where cycling operations have been deemed appropriate, they could be planned with a degree of certainty, and suitable plant strategies and operating regimes developed and optimised. However, the growing input from intermittent renewable sources has meant that changes required in plant operations are now often more abrupt and less predictable.

On a localised basis, electricity demand can vary considerably. Various factors influence the demand profile and to some extent, this can be manipulated through demand management efforts. However, fluctuating supply from intermittent sources can make demand planning difficult. Because of such fluctuations, it is necessary to have spare capacity available to meet peak demand and to step in when generation from intermittent sources falls. In some countries, much of this spare capacity takes the form of coal-fired plant.

In order to survive in this new commercial marketplace, many coal-fired generators are having little option but to adapt to more flexible operation, although inevitably there are various commercial, engineering, environmental and financial implications that result from changing to new, less predictable and controllable operating patterns. This is a global phenomenon and some countries appear to be adapting better than others. There is little doubt that for many operators of coal-fired plants, these changes are a major concern, the full consequences of which may not become apparent for some time. Furthermore, the current picture will continue to change as more intermittent capacity is added.

In the future, many new coal-fired units will be expected to cycle, even from the first day of operation. This will have a major impact on the cost of power from such plants. Discounting the increased maintenance and extra fuel costs, capital costs will have to be spread over a reduced output of electricity.

2 Renewable energy sources

'Renewable energy' is an umbrella term often used to describe energy obtained from natural resources such as sunlight, wind, rain, tides, and geothermal sources that are naturally and continually replenished. Renewable energy technologies convert these 'fuels' into usable forms of energy. Predominantly, they are used to replace conventional fuels in four main areas, namely hot water and space heating, transport fuels, off-grid energy supply, and grid-connected power generation. This report concentrates on the impact that selected renewable systems are having on the latter sector.

Some renewable energy technologies are best applied to small localised applications, whereas others are suitable for use up to utility scale. Some are long established and have been used throughout much of human history, whereas others have been developed more recently. Increasingly, in recent years, economic and environmental concerns associated with the use of fossil fuels have helped accelerate the development and deployment of a range of renewables-based energy production systems.

Not all renewable energy systems are applied to power generation and, of those that are, not all can be harnessed to generate electricity on a continuous basis; the output from some is more intermittent/variable than others. Thus, renewable energy technologies not considered in the present report include large-scale hydro, tidal, and geothermal power. Although these can be affected by natural forces, in general, output and operation of these can be relatively predictable. Thus, the report focuses mainly on the impacts from the two biggest intermittent players, namely wind and solar power. Furthermore, compared to most other renewables-based generating systems, the level of deployment for both technologies looks set to carry on increasing significantly for the foreseeable future.

The rationale behind the use of renewable energies for power generation usually focuses on a need for more electricity, to reduce fossil fuel use, to reduce classic pollutants from fossil fuel combustion (SO_2, NOx and particulates), and to minimise CO_2 emissions. Most renewable technologies are generally perceived as being benign in that, although output is usually more expensive than that from conventional generators and initial capital costs may be considerable, during day-to-day operations, they may not release any emissions directly to air. However, where they form part of a system that also includes fossil fuel fired plants, their operation can have a number of significant indirect impacts. These are reviewed later in the report (*see* Section 3).

2.1 The growth of renewable energies

All countries now employ some form of renewable energy technology to varying degrees. Understandably, the degree of application varies, often reflecting individual local or national circumstances. Thus, one country may have access to geothermal resources whereas another may not, or a nation may have large indigenous supplies of biomass available, that its neighbour lacks, and so on. However, globally, the use of such technologies has grown significantly in recent years, with many indicators showing dramatic gains (Table 1). During recent years, annual renewable energy investment has increased hugely, reaching US$130 billion in 2008, rising to US$150 billion in 2009 (REN21, 2010).

Globally, the most important market for renewable energy technologies is for electricity generation. During the past five years, for some systems, worldwide capacity has increased at rates of 10–60%/y. This has been a global phenomenon, affecting both developed and developing nations. Some of the biggest gains have been in the area of wind power and most countries now have some wind-based generating capacity. Significant capacity is now operating throughout Europe, the Asia-Pacific region, and North America. During the same period, although on a smaller scale, the deployment of grid-connected solar-based technologies has also been increasing. The top ten global producers of

Table 1 **Selected renewable energy indicators** (REN21, 2010)			
Selected global indicators	2007	2008	2009
Investment in new renewable capacity, US$ billion	104	130	150
Existing renewable power capacity, including large-scale hydro, GWe	1070	1140	1230
Existing renewables power capacity, excluding large hydro, GWe	240	280	305
Wind power capacity (existing), GWe	94	121	159
Solar PV capacity; grid-connected, GWe	7.6	13.5	21

Table 2 **Global top ten renewable electricity producers (TWh/y)** (BP, 2010; UN wind data, nd)				
Country	Year	Total from REs	Wind power	Solar power
China	2009	682	26.9	0.14
EU-27	2007	525	104.3	3.8
USA	2009	413	70.8	0.81
Brazil	2008	386	0.6	–
Canada	2008	370	2.5	0.017
Russia	2008	179	0.007	–
India	2008	137	14.7	---
Norway	2008	121	0.673	---
Japan	2008	95	1.75	0.002
Germany	2009	93	37.5	6.0
Venezuela	2008	83.9	–	–

electricity from renewables, plus the respective contributions from wind and solar power are noted in Table 2. In all but Germany, the bulk of generation from renewable sources is accounted for by large-scale hydropower. The installed capacity of the world's ten biggest wind-based generators is show in Table 3.

In some countries, the contribution from renewable energies in general has grown significantly, often as a result of various incentive schemes. For instance, in Germany, during the last decade, the amount of electricity generated from wind, solar and biomass-based systems has risen. By 2007, more than 14% of the country's electricity was being generated from renewable sources (Figure 1). In 2000, the share of renewables of gross electricity consumption was 6.3%. By 2009, it had risen to 14.2% (Busgen and Durrschmidt, 2009).

Similarly, since 2005, in the USA, the use of all forms of renewables for electricity generation has increased (*see* Table 4 and Figure). For much of the past decade, the overall capacity growth rate for renewable energies has been ~13%/y, although between 2009 and 2015 it is expected to be ~19%/y (McGranaghan, 2010). The most striking gains have been made in the area of wind power; between

Table 3 Top ten cumulative wind power capacities (December 2009) (EWEA, 2010)

Country	GW	% of world total	New capacity installed in 2009
USA	35.2	22.3	9.9
Germany	25.8	16.3	1.9
China*	25.1	15.9	13.0
Spain	19.1	12.1	2.5
India	10.9	6.9	1.3
Italy	4.9	3.1	1.1
France	4.5	2.8	1.1
UK	4.1	2.6	1.1
Portugal	3.5	2.2	0.7
Denmark	3.5	2.2	0
Rest of world	21.4	13.5	4.0
World total	157.9	100	37.5

* In 2010, China's installed capacity surpassed that of the USA, making it the biggest producer

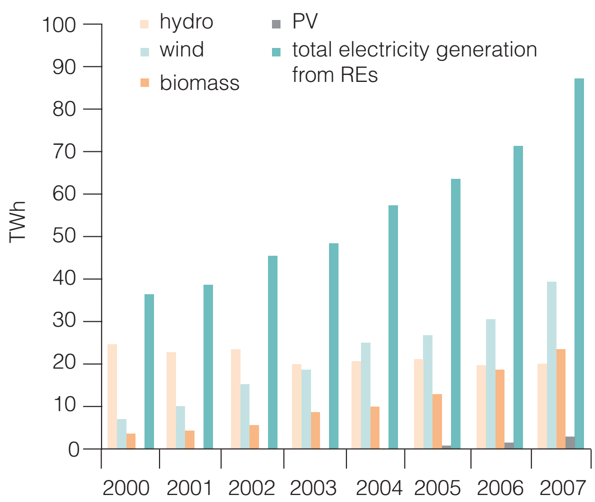

Figure 1 Contribution of renewable energy sources to German electricity generation (2000-07) (Busgen and Durrschmidt, 2009)

2005 and 2009 net electricity generation from wind power increased from 17.8 GWh to 70.8 GWh (EIA, 2009).

In the USA, more than 30 states now have Renewable Portfolio Standards (RPS) in place. The RPS mechanism generally places an obligation on electricity supply companies to produce a specified fraction of their electricity from renewable energy sources such as wind, solar, biomass, and geothermal. For different states, the timescale for implementation varies, mainly between 2015 and 2030, and suggests individual total renewable energy contributions of between 15% and 33% (at 33%, California is the highest, to be implemented by 2020). In the power generation sector, for 2030, projected US generation using renewables is expected to be around 750 GWh. The predicted make-up of the renewables-based power sector for 2030 is shown in Figure 3.

The USA has great wind power potential, especially offshore. However, recently, the lack of reliable energy policy, coupled with the recession, has slowed development of the sector. The installation rate for 2010 was relatively low; in the third quarter, only 395 MW of wind capacity was added, the lowest quarter since 2007. During the year, total installation amounted to 1634 MW, down 72% on 2009 (Silverstein, 2010). However, several major projects are in the pipeline; for instance, the 1 GW offshore Deepwater Wind Energy Center was announced in late 2010. The first turbines should become operational in 2015 and will supply several East Coast states (Energy Central, 2010). It is

Table 4 US electricity capacity (MW, net, summer) (EIA, 2010)

Source	2005	2006	2007	2008	2009
Total	978,020	986,215	994,888	1,010,171	1,027,584
Non renewable total	879,274	884,281	886,934	893,747	901,785
Renewable total	98,746	101,934	107,954	116,423	125,800
Biomass	9802	10,100	10,839	11,050	11,353
Waste	3609	3727	4134	4186	4405
Landfill gas	887	978	1319	1429	1514
MSW	2167	2188	2218	2215	2215
Other biomass	554	561	598	542	676
Wood and derived fuels	6193	6372	6704	6864	6948
Geothermal	2285	2274	2214	2256	2351
Hydroelectric conventional	77,541	77,821	77,885	77,930	77,951
Solar/PV	411	411	502	536	603
Wind	8706	11,329	16,515	24,651	33,542

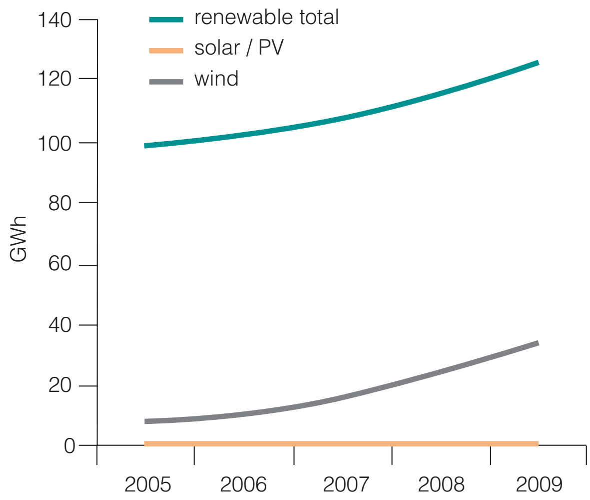

Figure 2 US intermittent renewables-based electricity capacity (net, summer) (IEA, 2010)

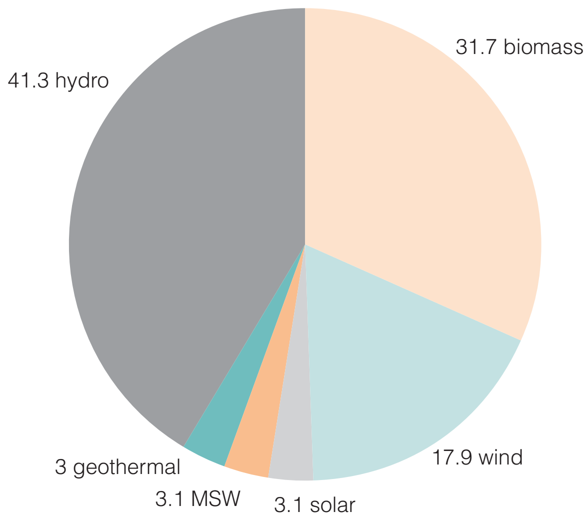

Figure 3 Projected US generation using renewables, 2030 (McGranagham, 2010)

expected that wind will be the primary technology for meeting RPS targets in the USA, as it has lower capital costs than solar thermal and photovoltaic technologies, the other politically acceptable 'green' technologies (Hutzler, 2010).

Within the European Union, the rationale for increasing the share of electricity from renewable energy sources has been to improve energy security, mitigate greenhouse gas emissions and other pollutants from the fossil fuel fired power sector, and increase the EU's competitiveness in renewable energy technologies. In 2007, the European Commission brought forward a target to increase the share of renewables in final energy consumption to 20% by 2020. Given the limited scope for renewables deployment in other sectors, it is likely that the power sector will bear a disproportionate share of this,

Table 5 EU targets for the share of energy from renewable sources (Most and Fichter, 2010)

	Directive 2001/77/EC	Directive 2009/28/EC	
	National indicative targets for the contribution of electricity produced from RES-E to gross electricity consumption (%) 2010	Share of energy from renewable resources in gross final consumption of energy (%) 2005	Target for share of energy from renewable resources in gross final consumption of energy (%) 2020
Austria	78.1	23	34
Belgium	6.0	2.2	13
Denmark	29.0	17	30
Finland	31.5	28.5	38
France	21.0	10.3	23
Germany	12.5	5.8	18
Greece	20.1	6.9	18
Ireland	13.2	3.1	16
Italy	25.0	5.2	17
Luxembourg	5.7	0.9	11
Netherlands	9.0	2.4	14
Portugal	39.0	20.5	31
Spain	29.4	8,7	20
Sweden	60.0	39.8	49
UK	10.0	1.3	15

such that the 2020 target will translate into a share of 30–40% of renewables in the electricity generation mix by this date (Roques and others, 2010). Each EU Member State has a national indicative target for electricity generated using renewable technologies to contribute towards the overall target, and is required to support production from such sources. In addition to the specific goals for each State (already set in Directive 2001/77/EC for 2010), more ambitious targets have been set for the share of renewable sources in final energy consumption (not only electricity) for 2020 by Directive 2009/28/EC (Table 5).

Different strategies and policies are being implemented in each Member State, often tailored to specific aims and requirements. Thus, the mix of renewables being pursued varies between individual countries. For instance, in order for the UK to meet its targets, a large amount of wind power capacity (both onshore and offshore) will have to be installed (Green and Vasilakos, 2010). Similarly, in Germany, there is a growing focus on offshore wind. In 2010, wind power provided around 5.9% of total energy share. German goals are for 65% from renewable sources by 2040, rising to 80% by 2050. However, because so much wind capacity is planned, and as guaranteed wind output is only ~5–10%, it is forecast that German power generation capacity will need to be doubled by 2050 (Altman, 2011).

Major developments are also taking place in the Asia-Pacific region. In China, currently the region's biggest individual user of renewable energy, recent years have seen the rapid promotion of sources such as hydro, wind, solar and biomass, primarily for electricity generation. China is now the world's largest producer of hydropower (with a capacity of ~150 GW, plus a target of 300 GW by 2020) and recently,

Table 6 Projected Australian electricity generation by fuel (2007-30) (Syed and others, 2010 – citing ABARE data)

Renewable type	2007-08, TWh	2029-30, TWh	2007-08, %	2029-30, %
Hydro	12	13	5	3
Bioenergy	2	3	<1	<1
Geothermal	<1	6	<1	2
Wind	4	44	2	12
Solar	<1	4	<1	1
Total renewables	18	69	7	19
Total generation	247	366	–	–

passed the USA to become the world's leading installer of wind capacity. The country has increased its renewables-based generating capacity at a remarkable rate. In particular, the Government views the development of wind energy as a key priority, with forecasts suggesting that by 2020, capacity will have increased to at least 150 GW, possibly as high as 230 GW. Although the country still relies on coal to produce more than two thirds of its total energy, currently, ~7% of the total comes from renewable sources (ChinaFAQs, 2010). Official targets aim to increase this to at least 15% by 2020.

The use of renewable energy is also growing rapidly in India, with the amount used for power generation forecast to double over the next ten years. India's total renewable capacity is expected to reach 128 GW by 2020. Of this, some 68 GW will be hydro-based. Excluding large-scale hydro, the country currently has an installed renewables-based capacity of 13.2 GW; this accounts for 9% of its overall power generation capacity. Currently, India's renewable energy sector comprises 43.5 GW hydro, 13.75 GW wind, and 3.19 GW biomass. Smaller contributions are made by solar PV (540 MW), solar thermal (25 MW), and biogas (124 MW). The overall total amounts to 61.2 GW (MPS BRIC, 2011).The Government has set a target for renewables to contribute 10% of total capacity and 4–5% of the electricity mix by 2012. For the period 2008-12, the objective is to add 14 GW of renewable generation capacity, 10.5 GW of which will be wind (Global Wind Energy Council, 2010). Within the next decade, wind capacity is forecast to reach 32.2 GW.

In some other countries, intermittent renewables look set to make significant headway in the next few years, although current levels of deployment may be low. For instance, the Russian energy scene is currently dominated by oil, coal and natural gas. The country's huge geography includes every type of condition favourable to renewable generation, but so far, apart from large hydropower, most of this potential remains untapped. Excluding large hydropower (currently 47 GW), only ~1% of Russia's power is currently generated from renewables. However, within the next decade, Russia's renewable installed capacity is projected to increase to 61.5 GW, of which nearly 60 GW will be hydro-based; hydro will produce ~99% of the country's renewables-derived electricity. Of the other renewables, only wind is set to increase significantly. In 2010, installed capacity was only 54 MW. This is forecast to increase to 396 MW by 2015, rising further to 1422 MW in 2020 (MPS BRIC, 2011).

Similarly, at the moment, the bulk of Australia's electricity is currently generated from hard coal and lignite. However, forecasts suggest that the use of renewables is set to increase significantly. At the moment, wind power is the main intermittent source contributing to grid electricity supply although this is currently only around 1% of total electricity generated. However, a significant increase is expected in the future (Wibberley and others, 2008). There is now a government target for 20% of electricity to be generated from renewable sources by 2020, with a Mandatory Renewable Energy Target of 45 TWh/y. This target represents a major increase in the use of renewables. Projected electricity generation from renewable sources is shown in Table 6.

Thus, for power generation in general, there are a number of renewable energy technologies available. Some can be harnessed to generate electricity in a controllable, stable manner, whereas others produce on an intermittent/fluctuating basis. The biggest two players in the latter category comprise wind and solar power; these, and their associated impacts, are explored in the following sections.

2.2 Wind power

2.2.1 The technologies

Winds are created by uneven heating of the Earth's atmosphere by the sun, irregularities of the planet's surface, and its rotation. As a result, winds are strongly influenced and modified by local terrain, bodies of water, weather patterns, and other factors. Wind flow can be harvested by wind turbines and used to generate electricity.There are numerous designs of turbines available commercially, ranging widely in output. Larger units have a rated output of around 5 MW, although those in the range 1.5 to 3 MW are the most commonly encountered. However, several US, Norwegian and Chinese technology suppliers are known to be actively developing individual units of between 6 and 10 MW (Rajgor, 2010).

Figure 4 Wind turbine, UK. A 500 kW gearless Enercon turbine. Annual output clearly depends on prevailing weather conditions (photograph courtesy of Russell Mills Photography)

The most commonly encountered type of unit used commercially is the horizontal axis type, in which the shaft is parallel to the ground, and the blades are perpendicular to the ground (Figure 4). There are also various types of vertical axis turbines produced, where the rotating shaft is perpendicular to the ground, and the cups or blades rotate parallel to the ground. Development of wind turbine technology is continuing, with major technology suppliers investing heavily. For instance, in March 2011 both Siemens and GE launched new variants.

2.2.2 Market developments

In 2009, global wind power capacity increased by a third, often encouraged by various incentives.

In the EU, the climate and energy package (RE Directive of December 2008) has a goal of having 20% of renewable energy in the European energy mix by 2020. This could equate to 35% of European electricity coming from renewable sources (IEA Wind Energy, 2010). A significant proportion would comprise wind power capacity. In recent years, wind power has dominated new generating capacity additions made in the EU, a trend that continues. During 2010, further additions included over 300 new offshore wind turbines.

Table 7 Installed European wind power capacity (2008-09, MW) (EWEA, 2010)

	End of 2008	New in 2009	Total (end of 2009)
Germany	23,903	1917	25,777
Spain	16,689	2459	19,149
Italy	3736	1114	4850
France	3404	1088	4492
UK	2974	1077	4051
Portugal	2862	673	3535
Denmark	3163	334	3465
Netherlands	2225	39	2229
Sweden	1048	512	1560
Ireland	1027	233	1260
Greece	985	102	1087
Austria	995	0	995
Turkey	458	343	801
Poland	544	181	725
Belgium	415	149	563
Rest of Europe	1313	304	1614

In 2009, wind turbines produced 12.2% of renewables-derived electricity within the OECD as a whole. Amongst the regions, production was the highest in OECD Europe, accounting for nearly 70% of total OECD production. Between 1990 and 2009, OECD wind power increased from 3.8 TWh to 215.6 TWh, achieving an annual average growth rate of 24%. This was the second largest growth rate of renewable energy after solar PV. The biggest growth was seen in OECD Europe, where wind energy has been heavily subsidised by a number of national governments. The highest growth rate was in Portugal, with 60%/y between 1990 and 2009, increasing from 1 GWh to 7573 GWh. In absolute terms, the USA, Germany and Spain are the largest OECD wind-based generators, producing 71.2, 37.8 and 36.6 TWh/y respectively (IEA, 2010). European wind power capacity is shown in Table 7.

The level of wind energy penetration (usually defined as the fraction of energy produced by wind compared with the total available generation capacity minus installed wind power capacity (MW) divided by peak load (MW)) varies widely throughout EU Member States. Penetration levels are the highest in Denmark, Spain, Portugal, Ireland and Germany (EWEA, 2010). For the EU-27 as a whole, the figure is around 3.8%, although there is a target of ~12–14% by 2020. In specific areas, the maximum share of wind power is already considerable; for example, in West Denmark (57%) and the German state of Schleswig Holstein (44%).

The member countries making up the IEA Wind Implementing Agreement host around 70% of the world's total wind capacity. In 2009, the cumulative total wind generating capacity for these countries amounted to ~111 GW (Figure 5). Wind power produced 2.5% of the total electricity demand in the reporting member countries (Table 8) (IEA Wind Energy, 2010).

Around the world, many developed countries have set ambitious targets for renewable energy use, particularly wind power. For instance, in Australia the Renewable Energy Target (RET) scheme mandates 45,000 GWh (~20% of the country's electricity supply) to be provided by renewable energy

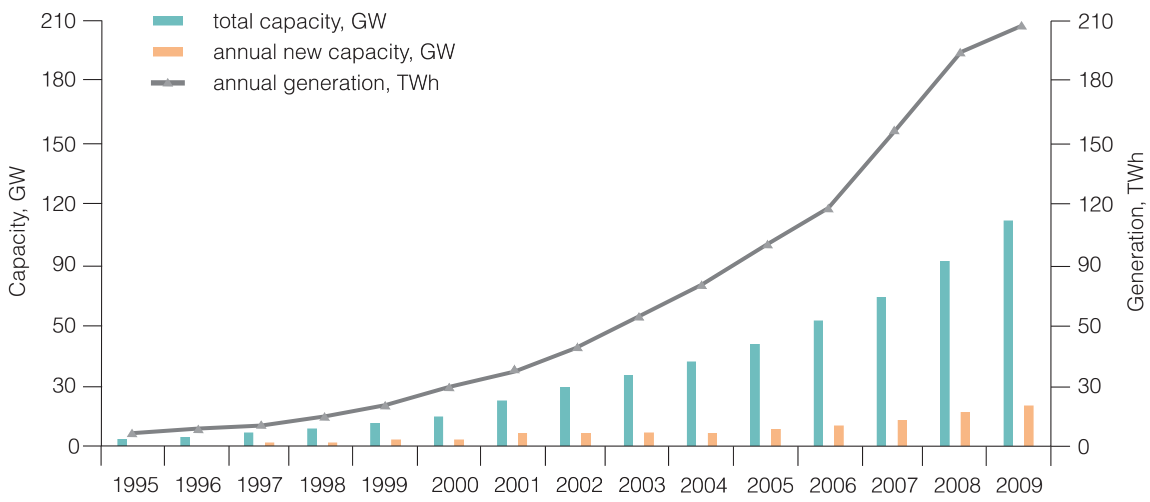

Figure 5 Annual installed capacity, cumulative installed capacity, and annual generation as reported by IEA Wind member countries (1995-2009) (IEA Wind Energy, 2010)

by 2020. In Canada the wind power sector is pursuing a strategic vision for wind energy to supply 20% of the country's electrical demand by 2025, or an installed capacity of 55 GW, and in South Korea there is a goal of 7.3 GW of wind power by 2030. There are many other similar proposals in the pipeline.

Rapid growth in the wind power sector is also being experienced in several of the major developing economies. For instance, China has identified wind power as a key growth component of the country's economy and, boosted by the application of green energy polices, has effectively doubled its wind capacity each year since 2006 (Power Technology, 2010). During 2009, China added 13.8 GW of new wind power, averaging one new turbine every hour (Renewable Energy, 2010b). Reportedly, in 2010, the country's total capacity reached ~45 GW, overtaking the USA and Germany to make it the biggest global wind generator. It is estimated that globally, half of all new wind turbines that came on line in 2010 were in China (Tong and Warren, 2010). At the end of 2008, China overtook India in having the highest installed wind energy capacity in Asia. The National Development and Reform Council (NDRC) has set a goal for wind power to surpass nuclear power, by 2020, becoming China's third largest source of electricity after thermal and hydropower. Recently, there have been indications that the rate of wind power build-up in China may be slowing. However, despite investor support having weakened during the past year, policy changes that are reducing subsidies, and stricter measures for project approval (Global Times, 2010), the outlook for wind power in China remains the strongest of any individual economy.

Major developments have also continued in India. The country has a rapidly developing and growing renewables energy sector, of which, wind power forms the largest segment. It is now the world's fifth largest wind power producer and, by early 2010, had an installed capacity in excess of 11.8 GW. As elsewhere, the short construction period and the increasing reliability and performance of wind turbines have made the technology a favoured choice for capacity addition. The highest concentrations of facilities are in the states of Tamil Nadu, Maharashtra, Gujarat, Karnataka and Rajasthan. Annual generation for individual Indian states is shown in Table 9. Forecasts by the Indian Wind Turbine Manufacturers' Association suggest that a further 5 GW will be added by 2015. The Government estimates that the country has a total wind power potential of 48.5 GW, although other estimates suggest between 56 and 100 GW. However, these goals may be over-optimistic. Figures released (December 2010) by the Ministry of New and Renewable Energy indicate that the country is likely to miss its new wind power capacity targets for the third year in a row. Only 205 MW was installed in the first financial quarter (April-June 2010) compared with the annual target of 2 GW.

Table 8 National statistics for IEA wind member countries for 2009 (IEA Wind Energy, 2010)

Country	Total installed wind capacity, MW	Offshore wind capacity, MW	Annual net increase in capacity, MW	Total number of turbines	Average new turbine capacity, kW	Wind generated electricity, TWh/y	National electricity demand, TWh/y	% of national electricity demand from wind
Australia	1712	0	406	984	2000	4.28	267.0	1.6
Austria	995	0	0	618	2000	2.10	70.7	3.0
Canada	3319	0	950	2130	2000	9.98	549.9	1.8
Denmark	3480	665	319	5108	2200	6.72	34.8	19.3
Finland	147	24	4	118	2000	0.28	80.8	0.3
Germany	25,777	72	1880	21,164	2013	37.50	582.5	6.5
Greece	1109	0	116	1270	1339	2.55	57.0	4.4
Ireland	1264	25	237	939	2230	2.96	27.4	10.5
Italy	4850	0	1114	4237	1715	6.50	316.8	2.1
Japan	2056	11	176	1609	1680	3.14	846.1	0.4
Korea	392	0	88	152	1579	0.68	446.1	0.2
Mexico	415	0	330	366	1136	0.50	204.0	0.2
Netherlands	2216	228	67	1978	1982	4.59	114.0	4.0
Norway	431	0	2	200	2310	0.98	121.5	0.8
Portugal	3616	0	797	1976	1900	7.49	49.9	15.0
Spain	19,149	0	2459	18,400	1854	36.19	251.5	14.4
Sweden	1448	133	363	1359	1830	2.52	144.0	1.8
Switzerland	18	0	4	30	2000	0.02	58.7	0.04
UK	4051	883	1077	2490	2060	6.96	406.0	1.7
USA	35,086	0	10,010	33,000	1750	70.76	3741.0	1.9
Totals	111,531	2041	20,399	98,128	1994	206.70	8369.7	2.5

Table 9 Indian states currently generating electricity from wind power (Indian Wind Energy Association, 2010)

State	Generation 2009-10, GWh	Cumulative generation, GWh
Andhra Pradesh	106	1451
Gujarat	2988	8016
Karnataka	2687	9991
Kerala	63	110
Madhya Pradesh	82	554
Maharashtra	2625	11,790
Rajasthan	1045	3938
Tamil Nadu	8146	41,100
Total	17,742	76,950

The scale of individual Indian wind farms varies between 10 and ~500 MW, with the majority falling between 10 and 30 MW. The largest individual project is the 513 MW Muppandal wind farm in Tamil Nadu. In the future, there are plans for several major wind turbine manufacturing plants to be built in India. Spanish manufacturer Gamesa has announced that by 2012, it plans to invest €60 million in production facilities in Gujarat. Other production units are also planned at locations in Gujarat and Tamil Nadu.

Despite the widespread deployment of wind power seen in recent years, not all countries have yet adopted the technology to a significant degree. For instance, even though the country has huge potential, the application of wind power in Russia is currently very limited (at only ~11 MW). However, several feasibility studies are in hand and reportedly, there are more than 1.7 GW of wind projects under development, or for which the development phase has been completed. Another 3–3.5 GW has been announced for the longer term. The Russian Wind Energy Association forecasts that by 2020, some 7 GW of wind energy will be in place, although in recent years, there appear to have been be few incentive schemes to drive this forward (Vestas, 2009). According to the state programme on the use of renewables, green energy should make up 4.5% of the country's energy balance by 2020. Presently, the figure is only around 1%.

2.2.3 Offshore wind developments

For a number of reasons, many developers are now shifting their focus from the development of onshore wind facilities to offshore locations, despite the higher costs entailed. Currently, countries with significant offshore capacity either operational or under development include the UK (1341 MW), Denmark (854 MW), The Netherlands (249 MW), Portugal, Sweden, Germany and Italy. The largest individual European offshore operators are DONG Energy, Vattenfall, and E.ON. Focus on offshore locations is also increasing in the USA and China.

The EU as a whole has ~30 GW of offshore wind capacity under development and a number of countries have set ambitious targets. The Netherlands aims to have 6 GW by 2020, and, as a result of the increasing saturation of onshore sites, Germany is looking to build significant offshore capacity. Forecasts suggest that by 2020, total German wind capacity will be ~50 GW, with offshore capacity possibly up to 28 GW (including 18.7 GW in the North Sea and 1.7 GW in the Baltic Sea) (Ziems and others, 2009; Haase and others, 2009). An estimated €75 billion investment will be needed to increase offshore capacity to ~25 GW by 2030. Under the German government's new energy plan of 2010, the share of renewable energy sources in power generation will increase from the current level of 16% to 80% by 2050.

In the future, China is forecast to become a major offshore player. Currently, most of the country's wind capacity is onshore, with only a single offshore facility (a 102 MW facility near Shanghai) in operation. The municipal government of Shanghai plans to build four additional offshore wind farms with a combined generating capacity of 1 GW (Tong and Warren, 2010). China's offshore potential is very large, and in 2009 coastal provinces each produced an 'Offshore Development Plan to 2020'. Under this, Shanghai, Shandong and Fujian hope to have a combined offshore installed capacity of

10 GW by 2015, rising to 30 GW by 2020 (Rajgor, 2010). Current forecasts suggest an offshore wind potential of ~200 GW, based on deploying turbines at water depths of between 5 and 25 metres.

2.3 Solar power

2.3.1 The technologies

Solar power is the conversion of sunlight into electricity. Solar radiation varies with changing atmospheric conditions (mainly cloud cover) and the changing position of the Earth relative to the Sun. At the moment, solar power systems are actively deployed in over a hundred different countries. Where suitable conditions exist, many plan to increase their deployment of solar-based generating systems.

There are a number of competing technologies available, some more effective than others. These convert sunlight into electricity directly using photovoltaics (PV) or indirectly using concentrated solar power (CSP) systems.

Photovoltaics (PV)

PV devices function by converting sunlight into direct current electricity using semiconductors that exhibit the photovoltaic effect. A growing range of materials and devices (more than 30) is being developed or used, although the three main technologies in commercial production comprise monocrystalline cells, polycrystalline cells, and thin-film cells. At the moment, monocrystalline (or single crystal) solar cells, manufactured from a wafer of high-quality silicon, are generally the most efficient. Other variants being developed include cells based on amorphous silicon, cadmium telluride, and copper indium selenide/sulphide.

Currently, global installed PV capacity now exceeds 21 GW. Output from most individual facilities remains at best modest, although a gradual upward trend is apparent. Output from typical commercial units falls in the range 40 to 80 MW. Many of these are located in Canada, Spain, Germany, and Portugal. Two larger PV plants (550 MW and 250 MW) have been proposed for California. In recent years, the application of grid-connected PV has increased significantly. Reportedly, the capacity of utility-scale solar PV plants (larger than 200 kW) tripled during 2009 (REN21, 2010). Globally, more than 90% of photovoltaic systems are grid-connected. However, for obvious reasons, electricity output from PV systems can be highly weather-dependent.

Concentrating solar thermal (CSP) systems

Four main approaches are adopted with concentrating solar power. These are the parabolic trough, power tower, linear reflector, and Sterling dish. Currently, >90% of installations use parabolic troughs for electricity generation. Most CSP systems use lenses or mirrors and tracking systems to focus a large area of sunlight into a small beam. The concentrated heat is then used as a heat source for a conventional power generating system. Parabolic trough technology can generate temperatures of up to ~370°C. In a heat exchanger, water is preheated, evaporated, and superheated into steam, which runs a steam turbine. The water is cooled, condensed, and reused in the heat exchangers. Higher operating temperatures would increase overall efficiency although this is currently limited by available heat exchange media. CSP systems require a heat transfer fluid and, in some cases, a thermal energy storage medium; essentially, these form the interface between the solar energy input and the power block. To date, some CSP plants have used synthetic oils as heat transfer fluids and molten salts for thermal energy storage (Skumanich, 2010).

It is claimed that a major potential advantage of CSP systems (compared to PV or wind) is their potential (under some circumstances) of providing dispatchable power. By storing solar energy in thermal reservoirs and releasing it when needed, it may be possible to reduce the drawbacks associated with intermittency (Lew and others, 2010). Compared with other technologies, CSP-derived electricity is expensive; it can cost double that generated by gas- or coal-fired plants. Despite this, the CSP sector is expanding; in 2009, over 1.2 GW of new capacity was under construction and, globally, a further 14 GW has been announced for completion by 2014. The largest individual facility (354 MW) is in the Mojave Desert of California. Spain also hosts a number of larger plants (100–150 MW). Like PV technology, CSP systems are often capital-intensive and highly weather-dependent.

Certain CSP systems can form part of a hybrid source of electricity (*see* Section 5.2.1).

2.3.2 Market developments

In 2010 global solar PV market installations reportedly, exceeded 21 GW, with the industry generating US$82 billion in global revenues, up 105% from US$40 billion in 2009. In 2010, global solar cell production reached 20.5 GW, up from 9.86 GW the previous year (Solarbuzz, 2011).

It is expected that by 2015 the major areas of market growth will be North America and Asia, although in Europe the deployment of solar power continues to grow. In 2009, 16 GW of installed PV capacity was in place in Europe, representing a significant portion of the global total. Europe has the highest PV level, followed by Japan and the USA. During 2010, a further 1 GW of grid-connected PV capacity was added in Europe (Fenwick, 2010) and there are plans for the introduction of even larger amounts. As part of this, in 2008 the Mediterranean Solar Plan was announced, whereby up to 20 GW of solar electricity would be produced in the Saharan region of North Africa, with a quarter of the output directed to Europe by 2020. At the moment, the highest individual levels of solar-based generating capacity in European countries are in Germany, Spain and Italy, although markets continue to grow in other countries such as Austria, France, Portugal, Belgium and the Czech Republic.

At around 430 MW, European CSP-based capacity is more modest, although the European Solar Industry Initiative estimates that up to 30 GW could be installed by 2020. In terms of new installations, PV and CSP represented 21% and 0.4% of the new generating capacity installed during 2009 (Fenwick, 2010).

A number of European utilities are actively developing new solar power capacity. For instance, E.ON has identified solar power as a major growth area and made it a focus of its renewables growth strategy. The company currently has 50 MW of PV projects under construction, with a further 450 MW of capacity being developed in France and Italy. In Spain, a new 200 MW CSP project is being developed by Spanish company Acciona Energia in conjunction with Mitsubishi Corporation, making it the first Japanese company to own CSP plants in commercial operation. Acciona already operates four CSP plants in southern Spain.

Solar projects are also increasing in the USA, with some analysts predicting a rise of up to 60% in the number of installations during the next few years, driven partially by falling equipment prices. According to the Solar Energy Industries Association, US solar energy capacity more than doubled in 2010. Total capacity of PV and CSP power plants installed during the year amounted to 956 MW (878 MW PV-based systems), compared to 441 MW in 2009. California has the highest PV capacity installed (259 MW), followed by New Jersey (137 MW), Nevada (61 MW) and Arizona and Colorado (both with 54 MW). In March 2011, work commenced on the country's largest individual PV plant, Sempra Generation's 48 MW Copper Mountain Solar project. Here, electricity is produced using 775,000 thin-film PV solar panels. The project could eventually be increased by a further 200+ MW. There are currently 700 MW of PV projects scheduled for completion in the USA during 2011 (PowerGenWorldwide, 2011), plus around 40 more CSP projects in the pipeline (total of 9 GW) under development, mainly in the southwest. This includes several projects of between 250 and 390 MW.

The developing nations are also making increasing use of solar technologies. Until relatively recently, Chinese activity in this sector was limited. However, reportedly, there are at least 12 GW of large projects in the pipeline and the country looks set to become a major player in the industry. Under its 2009 stimulus plan, China has also announced a target of 20 GW of solar power by 2020, up from the 1.8 GW installed at present (Renewable Energy, 2010a). China is currently the world's leading manufacturer of solar photovoltaic cells, in 2008, accounting for nearly 40% of global output. In 2009 this reached 50%, and in the third quarter of 2010 increased further to 66%. Chinese and Taiwanese firms comprise eight of the world's twelve top cell manufacturers. Prices for solar panels (and wind turbines) in China are on average 30% lower than equivalents produced elsewhere.

India also has significant potential for PV installations. In 2009, installed capacity was only 30 MW although the government expects the market to expand significantly in the coming years (Fenwick, 2010). Governmental encouragement will be important in driving this forward. As part of this, in 2010 the Ministry of New and Renewable Energy announced its National Solar Mission, which aims to generate 20 GW of grid-connected solar power by 2022, of which 50% will be based on CSP technology (Gallego, 2011; Global Wind Energy Council, 2010). The target for the first phase (up to March 2013) is to set up 1100 MW of grid-connected solar capacity. There is also a government aim to add a further 1.1–1.3 GW of grid-connected capacity by 2013, increasing to 10 GW by 2017. However, reaching the target of 20 GW by 2022 will require an estimated US$70 billion. Some of this new capacity will be developed by Indian organisations such as the state-owned power producer NTPC, although interest from overseas suppliers is increasing rapidly. For instance, Kyushu Electric of Japan is forming a renewable power joint venture (with the Asian Development Bank and NTPC) in India. This aims to develop 500 MW of renewables-based generating capacity (wind and solar) within three years. NTPC intends to generate an additional 1 GW from renewable energy sources by 2017 (PowerGenWorld, 2010). There is also a proposal for a 13 GW project in Karnataka that will combine wind and solar power; Phase I will comprise 100 MW solar plus 200 MW wind. As part of its plan to increase the uptake of solar systems, the Indian government has selected 37 companies to construct solar power projects, each of 50 or 100 MW (Renewablesbiz, 2010).

Globally, falling prices in 2010 for solar equipment boosted installation rates in many countries. For instance, in the USA the average installation cost fell to less than 6 US$/watt (Hsu, 2010). However, despite lower prices, it is expected that in some parts of Europe, the industry will see slower growth as a result of policy changes (such as the reduction of feed-in tariffs in Germany, Italy and Spain).

2.4 Power generation using renewable energies

Electricity can be generated using a number of different renewable energy-based technologies. Understandably, the ratio between alternative systems varies between countries, often reflecting national circumstances and preferences. In many, however, the overall general trend in the use of renewables remains resolutely upwards.

In terms of integration into existing power generation systems, some renewable energy technologies such as biomass, geothermal and large-scale hydropower generally present no greater challenge than conventional power technologies. However, others such as wind and solar are based on resources that can fluctuate widely with time – these are sometimes referred to as Variable Renewable Energy (VRE) technologies. Integration of these can be much more complex and challenging. The extent of the challenge is one of the most disputed aspects of sustainable energy supply. Some observers are concerned that, at high levels of deployment, such systems introduce a level of uncertainty that makes it very difficult to balance electricity supply and demand across a power system. However, variability (and the need for flexible resources to balance them) is a well understood characteristic of the power sector; fluctuating demand, on all timescales, has always been a fundamental characteristic of power systems. They all include a range of flexible resources to manage this fluctuation, mainly dispatchable power plants (plants that can be turned on quickly to a desired level of output, generating more or less

Figure 6 Gas-fired combined cycle plants are often used to respond quickly to changes in electricity demand (photograph courtesy of E.ON UK)

power on-demand). Dispatchable plants can include coal- and gas-fired plants, and some hydro facilities. Wind power plants are not dispatchable (OECD/IEA, 2011).

Most operators of power systems have had significant experience in responding to changes in electricity demand; this varies frequently and is normally addressed by ramping flexible resources up or down. When a fast response is needed, the operator will call upon the most flexible resources available. Where available, these will be power plants designed for peaking (such as open-cycle gas plants, and pumped hydro facilities). In many circumstances, changes in demand occur on a regular, predictable daily basis and these changes will be addressed by the dispatch of mid-merit power plants such as combined-cycle gas plants (Figure 6) (OECD/IEA, 2011). Base load plants (such as nuclear and some coal and gas-fired plants) are designed to accommodate demand that is more or less constant around the clock. Most were designed to operate at near full power for much of the time; usually, they are more constrained in their ability to respond as quickly or to such an extent.

Globally, renewable energies currently provide around 18% of total electricity generation, with renewable-based generators located in many countries. However, the generating characteristics of different systems can vary significantly. For instance, large-scale hydro-based systems are generally controllable and predictable in their mode of operation, as are plants based on geothermal technologies. Other technologies, predominantly wind and solar power, are at the mercy of the elements and hence, generate electricity in a more random (intermittent) less controllable manner. A detailed analysis of the different renewable energy technologies is beyond the scope of the present report, and these have been discussed widely elsewhere. Thus, this report concentrates exclusively on the impacts resulting from the use of wind and solar power and examines the particular aspects relevant to electricity generation.

Often, there is a perception that there are few drawbacks with the widespread application of technologies such as wind and solar power. They are generally perceived as being problem- and emission-free. However, there are a number of important factors that require consideration when deploying such systems. Some reflect the type and scale of operations attainable, and others, the impact that their use has on other types of power plants connected to the grid. These issues are examined below.

2.4.1 Intermittent/variable output

Intermittency is a major consideration as, unlike thermal and nuclear power plants, daily output from wind and solar facilities can fluctuate widely. Such intermittent operation can have an impact on the performance of other power plants on the system, and on grid management and stability.

In the context of electricity generation systems, 'intermittency' indicates the non-continuous (starting and stopping at irregular intervals) output of power plants. By their very nature, technologies such as wind and solar invariably produce output that fluctuates and is intermittent/variable on all timescales.

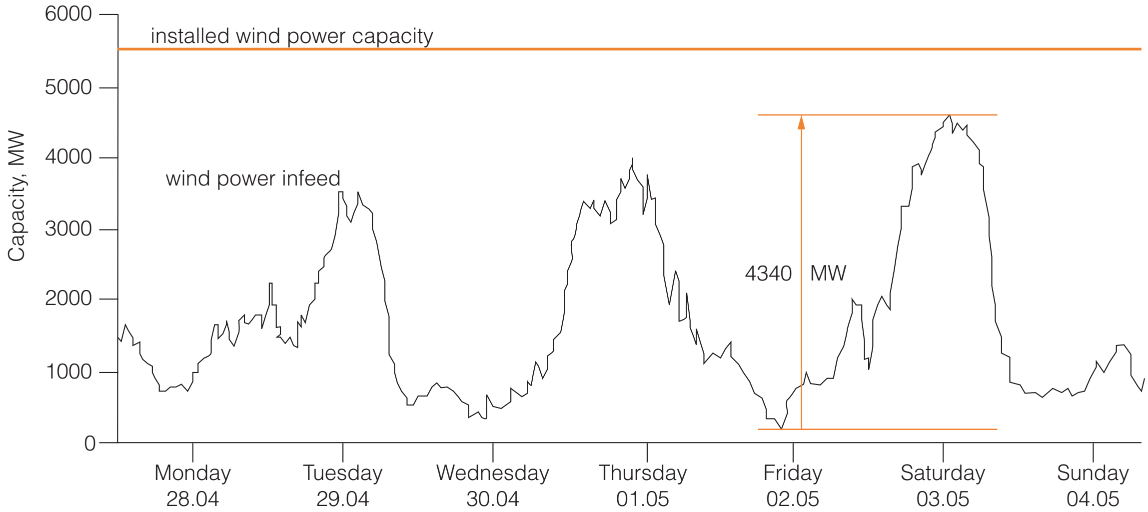

Figure 7 Example fluctuations in German wind generation (Wibberley and others, 2008)

This can affect the continuity of supply (ability to meet peak power demands) and quality (voltage drops, etc). There are obvious difficulties in predicting accurately the behaviour of the wind and weather patterns, especially in the longer term, and forecasting difficulties increase dramatically with time. Thus, the magnitude and timing of variable generation output is much less predictable than for conventional generating plants. Even over a short time, output can be highly variable, with rapid swings. An example of short-term wind variations over the course of a week is shown in Figure 7. As elsewhere, depending on the whims of the prevailing weather, swings in wind generation of over 80% of installed capacity can occur over just a few hours. Storms can arise unexpectedly, then just as suddenly abate; this can occur almost anywhere on the planet. For example, in the USA, during a single day in 2010, wind-generated power supplying the Bonneville Power Authority ramped up 1580 MW in a single hour, 756 MW of that in only ten minutes. Just previously, wind-generated power had dropped by 1160 MW in a single hour (Palmer, 2011).

An obvious, but nevertheless, important point is that wind (and solar) power may not be available when most needed. Peak energy demand is usually highest during the day, often peaking in late afternoon or early evening. This may not align with peak wind flow. Unlike a conventional thermal power plant, wind cannot be switched on or its output increased at will. Most of the time that wind generation is available it replaces output from gas-fired facilities (assuming that this is available and that such plants are not supplying electricity at a cheaper rate). If there is a low amount of gas generation in the system, then coal plants may be backed out to make room for wind. When this happens, coal plants are cycled, reducing their effectiveness in various ways (*see* Section 3.6).

Improved forecasting of wind availability enables better use of this resource. In Germany, it is claimed that wind generation output can be predicted with 90% certainty 24 hours ahead, meaning that it should be possible to deploy other generating plant more effectively. However, as wind output can be unpredictable, for planning purposes its potential output is discounted to the level of power that can be relied upon for 90% of the time. For instance, in Australia this amounts to 7% and in Germany 8% of installed wind capacity – this is all that can be included as securely available. Similar issues are also encountered elsewhere. For instance, in the USA, the Sawtooth Wind Project in Idaho is capable of producing up to 21 MW of electricity. However, because of wind's inconsistency, only 10 MW can be guaranteed. Furthermore, during periods of low demand and/or high wind output, the local utility will not purchase excess power above this figure. On the 90% availability basis, competing generation technologies can be counted on for much higher reliability. Hence the investment cost per kilowatt available reliably is much lower (World Nuclear, 2010).

In Europe, Denmark is often cited as an example of a country producing a high percentage of its electricity from wind power. It has the highest wind power capacity in the Nordic power system and in 2009 had more than 5100 wind turbines with a total installed capacity of 3169 MW. In 2007, the Danish government issued a New Energy Plan, with the aims of reducing fossil fuel consumption by 15%, and at least doubling the share of renewable energy supply to 30% by 2025. A major component of this strategy is to double the country's installed wind capacity (Jacobsen and Zvingilaite, 2010). However, a significant proportion of Denmark's wind-generated electricity is often unavailable at peak times and when domestic demand is low it has to be exported at low value. Furthermore, the country is forced to import power (mainly generated by hydro facilities) from Norway and Sweden, to provide back-up when wind output is low. Reportedly, this costs more than the income generated from exported wind power. Some observers (for instance Hutzler, 2010) have suggested that Denmark would benefit by eliminating its wind plants and simply buying the hydro-produced electricity when needed.

Under some circumstances, excess electricity can be produced from renewable sources such as wind and hydro, and this can cause problems. In 2010, in the US Pacific Northwest region, as a result of the prevailing weather patterns, excess renewables-based generation occurred and during a three-week period electricity produced exceeded demand. To deal with the excess the authority offered free hydropower to local gas- and coal-fired utilities if they would temporarily shut down their power plants. The federal agency covering this area (BPA) is now seeking the option of turning off wind turbines (and discharging excess water from hydro facilities) to keep its system from overloading (Palmer, 2011). Reportedly, this would only happen when other measures, such as briefly shutting coal and natural gas plants, fail to balance the system. The area's biggest wind generator, Iberdrola Renewables, has agreed that under these circumstances, it will temporarily shut down its gas-fired generators. Some other local coal and gas generators have agreed to accept free hydropower from BPA and shut down their plants. Similarly, in the UK, during April 2011, a number of Scottish wind farms were disconnected by the National Grid. Excess wind power was generated and system overloads occurred as a result of a combination of high winds and the availability of additional hydro power caused by heavy rain. The grid was unable to absorb all the electricity generated, hence wind turbines were taken off line to compensate.

A high level of electricity generated from intermittent sources can make it difficult for planners to determine future capacity requirements, particularly where estimates are often made for some considerable time in the future. In particular, the large swings in output, often experienced when using wind power, can cause difficulties. For instance, the UK government wants to have ~30 GW of peak capacity wind power by 2020, enough to supply a third of the UK's electricity. Potentially, this could lead to power excesses of 23 GW when the wind blows strongly and demand is low, or shortages of 10 GW during periods of calm (ENDS, 2011). The National Grid has noted that if the UK meets its 2020 renewable energy targets, it will need 8 GW of reserve to manage intermittency, up from 3.5 GW today. About 15% of that current level is provided by pumped hydro, with the rest mainly from diesel, gas and managing industry's electricity demand. Forecasts for how much extra reserve will be needed in 2030 have not yet been released, although it will be higher.

It is sometimes argued that issues of intermittency can be largely overcome through improved interconnections between neighbouring countries and other grids. However, the effectiveness of this cannot be guaranteed as periods of high and low wind can often affect several countries at the same time.

2.4.2 The requirement for back-up capacity

As output from intermittent renewable sources can sometimes be unavailable or restricted, there clearly remains a requirement for back-up power supply. This needs to be capable of reacting quickly in order to balance fluctuations in electricity demand and supply. The scale and nature of a back-up system requirement depends on the level of penetration of intermittent generation, the technologies involved, the specific electricity system, and many other factors.

Back-up capacity is sometimes referred to as 'spinning reserve', although depending on the source, spinning reserve can be described in different ways in different locations. However, in essence it describes a generator that is online and ready at very short notice to contribute power to the system. It is the spare capacity in the grid needed to ensure security of supply and is provided by individual units operating at reduced output. Generally, a system's operating reserve comprises spinning reserve and non-spinning (supplemental) reserve. Thus, spinning reserve is the extra generating capacity that is available by increasing the power output of generators that are already connected to the power system. The non-spinning reserve is extra capacity that is not currently connected to the system but can be brought quickly online. Where coal-fired plants comprise part of the spinning reserve, they usually operate at lower thermal efficiency. To accommodate input from intermittent renewables, spinning reserve often requires very low load operation. As the input from intermittent sources rises, coal-fired stations will increasingly require dynamic and flexible response to accommodate new operating regimes (Rieck, 2011). Invariably, provision of such reserve increases the cost of electricity.

As noted, the scale of back-up requirement depends on many factors. Most wind (and solar) facilities usually operate at considerably less than their rated capacity (*see* ***Capacity factor***). This is because the rated capacity of a wind turbine is its maximum output, which is typically associated with wind speeds in excess of 15 m/s. Based on a 30% capacity factor, a 100 MW wind farm delivers the same energy as a 35 MW fossil fuel fired station, allowing for a an 85% capacity factor. The amount of capacity required to back up a particular wind farm can vary significantly (Wibberley and others, 2008). Depending on local and other factors, back-up capacity can take various forms.

Capacity factor

This is the ratio of the actual energy produced in a given period, compared to the hypothetical maximum possible (running full time at rated power). All power plants have capacity factors; these vary depending on resource, technology, purpose, and cost of electricity produced. Generally, within a given technology or a given plant, a higher capacity factor is better and in particular, more economical. In the case of a wind turbine, it is an indicator of how much energy a particular unit produces in a particular place.

Examples of typical capacity factor for different types of (US) power plants (University of Massachusetts, nd)

Technology	Capacity factor, %
Wind	20–40
Hydro	30–80
PV	12–15
Nuclear	60–>100
Coal (base load)	70–90
CCGT	60

The need for spare capacity is not unique to systems with intermittent generation as no type of generation is available with 100% certainty; conventional units close down for planned and unplanned maintenance. However, large-scale penetration of intermittent generation is giving rise to a much greater requirement (Moselle, 2010). Increasingly, alongside regular two-shifting (*see* Section 3.1), there are more random fluctuations superimposed. With the increasing reliance on intermittent sources, new forms of cycling are emerging – increasingly, thermal plants are required to adopt strategies that allow increased operational flexibility, rapid load response, and frequent start/stops. Operational flexibility thus forms a major focus for modern power plant design. In this respect, some fossil fuel fired plants are more flexible than others. A gas-fired combined cycle plant usually has a faster response time and is more easily and quickly started up than a coal-fired equivalent. For instance, Siemens has recently developed a new optimisation concept for a CCGT start-up process, claimed to be less than 30 minutes for a hot start (Balling and others, 2010). However, even in some major economies, relying heavily on gas-fired plant is not an option. For instance, China is rapidly becoming the world's largest producer of wind energy with an ambition to create 'green cities' powered by large wind farms; however, the country is also adding considerable coal-fired capacity as back-up. Officials require sufficient coal-fired capacity in reserve so that demand can be met when output from wind generators is unavailable. Unlike some other countries, little use is made of gas-fired facilities for back-up or peaking duties. China is now the world's biggest energy consumer (20.3%). Its coal consumption constitutes 48.2% of the world total; however, natural gas consumption only amounts to 3.4%.

China may not be alone in having to increase its thermal power capacity as it develops more wind-based facilities. Any country with a combination of rapidly growing energy demand, an old and inflexible grid, an existing reliance on coal for power, and ambitious renewable energy expansion plans is likely to face a similar dilemma. However, what marks China out as different is the amount of new coal-fired capacity that will be required. For instance, by 2015, the city of Jiuquan in the province of Gansu will have wind turbines with a combined capacity of 12.7 GW, although the Jiuquan government also plans to build 9.2 GW of new coal-fired capacity as back-up. There are also plans for six other wind farms in China, each with a capacity of more than 10 GW; at least several GW of new thermal power capacity is expected to be required for each of these (Yang, 2009).

The scale of back-up capacity required is an issue that continues to be debated. In reality, this will be dependent on a number of individual factors specific to a particular portfolio of generating plants, grid structure and so on. Historically, it has sometimes been proposed that for a system to operate successfully, wind power requires an equivalent amount of back-up/reserve generation. However, this may not always be the case. A study commissioned by the IEA Wind Implementing Agreement and undertaken by VTT of Finland concluded that the size of back-up needed will vary greatly according to the system's characteristics. The size of the system and the correlation of wind production with peak demand are two major and decisive factors. The study noted that some electricity grids already operate with high levels of reserve in the form of conventional power plants connected; these are capable of absorbing the incrementally added variability resulting from wind power (IEA, 2005). The study suggested that the level of back-up required is unlikely to ever be 100%. In areas where wind production is high during periods of peak demand and the share of wind is no more than 30% of production, around 60% back-up will suffice. However, in other situations, bigger back-up capacities could be required, possibly up to 95% (De Wachter, 2010). An example of where a suitable level has been arrived at by practical experience is that of ELTRA, the West Danish Grid Operator. Here, it has been determined that each GW of wind power installed required between 300 and 500 MW of system resources for ramping up and ramping down (Etherington, 2004).

Table 10 Contribution from wind (UK)

Contribution from wind, % of 400 TWh	Wind capacity, GWe	Conventional capacity, GWe	Spare capacity, GWe
2%	0.5	59	9.5
5%	7.5	57	14.5
20%	25	55	30

In the UK, modelling of spare capacity requirements was carried out by the National Grid Company to determine the level of generating plant necessary for the country to achieve a 20% renewables target, based largely on wind power (*see* Table 10). The study concluded that building 25 GW of wind capacity (approximately equivalent to almost half of UK peak demand) would only reduce the need for conventional fossil and nuclear plant capacity by 6.7%. Furthermore, some 30 GW of spare capacity would be needed to be on immediate call continuously to provide a normal margin of reserve and to back up wind's intermittency; around two thirds would be for the latter (World Nuclear, 2010). The level of back-up for other forms of power generation that can be called upon on demand is much lower. Particularly on smaller electricity systems, it is important that adequate conventional plant remains online to ensure the dynamic stability of the system (Doherty and others, 2004).

In the USA, several studies have concluded that a wind plant would not need to be backed up with an equal amount of dispatchable power generation (University of Massachusetts, nd). Even at moderate wind penetrations (5–15%), the need for additional generation to compensate for wind variations was determined to be less than the installed capacity of wind generation (Wibberley and others, 2008). Thus, within a US context, it was concluded that the balance does not need to be exact; not every movement in wind generation needs to be matched one-to-one by another conventional generator.

Studies carried out by E.ON have addressed the UK's proposed 20% renewable targets by 2020, plus the associated back-up requirements. It was concluded that even if 13,000 turbines (40 GW total capacity) were built to meet EU renewable energy targets, they could be relied on to provide only 7% of the country's peak winter electricity demand; this equates to only 3.6 GW. It noted that during the coldest days of winter, so little wind blows that 92% of installed wind capacity would have to be backed up by conventional power plants (Haworth, 2010). To achieve this, the UK's installed power base would need to increase from 76 GW to more than 100 GW, at an estimated cost of £100 billion. In a further development (January 2011) the UK government proposed the introduction of 'capacity payments' to encourage the operation and construction of back-up power plants. Under this proposal, generators will be paid to maintain power stations that are not generating electricity to ensure the availability of back-up capacity to deal with sudden surges in demand or fluctuating input from intermittent sources. In a similar move (July 2011), the Spanish government submitted an order to the energy regulator to increase the amount power generators are paid to build and operate gas- and coal-fired plants. An increase in incentives has been proposed for the construction of generating capacity as well as capacity payments for combined cycle gas- and coal-fired back-up plants. Over the past two years, both have seen reduced operating hours resulting from increased input from the renewables sector. In the case of gas, plants have been running at only 30–40% of total capacity, and average operating hours have fallen from 3600 between 2007 and 2009, to around 2500 in 2011.

A number of studies and policy reviews have indicated that, in different locations, there is not necessarily a strong connection between the availability and quality of the natural resource (mainly wind) and the achievement of particular targets for renewable energy. It has been suggested that where electricity being generated by a system matches (reasonably well) the demand being placed on it, wind penetration can be in the range of 30-40% without compromising the reliability of the system. However, in less matched or isolated systems, the percentage may be as low as 10%. This suggests that the barriers to the development of wind energy are likely not only to be related to natural characteristics, they also reflect the different policy approaches adopted (Decker, 2008). In reality, the situation is different in different countries and the scale and composition of a back-up system will vary. Where gas-fired CCGT plants are available, these will often be the first choice. However, as noted, there are a number of major economies where this is not a realistic option, and where much of the necessary back-up will comprise coal-fired units.

2.4.3 Energy imports required for back-up systems

Renewable energy sources are frequently cited as enhancing a country's energy security by reducing the use of indigenous reserves and/or minimising imported energy supplies. In many parts of the world where the use of intermittent renewables is increasing, natural gas fired plants are often used for rapid response when input from such sources falls suddenly. Some countries rely heavily on the use of imported gas supplies, often from relatively unreliable suppliers, thus calling energy security claims into question. For instance, a recent examination of the situation in Germany (Schmidt and others, 2009) noted the intermittent nature of wind and solar power and the need for fossil fuel fired back-up systems. Maintenance of these is expensive (the study cites €590 million for Germany in 2006) and, in addition, any increased energy security afforded by wind and solar power is undermined by reliance on fuel sources (principally gas) imported to meet domestic demand. With 36% of gas imports to Germany in 2007 originating from Russia, a country that has not proven to be a reliable trading partner in recent years, the notion of improved energy security is further called into doubt.

2.4.4 Limited output from individual generating units

Multiple units are required to achieve a meaningful output from wind (or solar) power, even when working at full capacity. A wind farm is a group of turbines in the same location, interconnected with a medium voltage (usually 34.5 kV) power collection system and communications network. At the upper end of the capacity spectrum are individual units with a rated output of around 5 MW, although those in the range 1.5 to 3 MW are the most commonly encountered. These often need to be spread over a wide geographical area so that if the wind abates in one part, it may not decrease in another. Forecast uncertainty is also reduced with wider geographic spread of plants. Wind projects can be sited onshore, nearshore (within 3 km of the coast), or offshore (10 km or more). With the latter, the average wind speed is usually considerably higher. Capacity factors (utilisation rates) are also higher than for onshore and nearshore locations. Despite this, a large number of individual turbines are generally needed. Examples of the largest individual wind farms currently operating include a 782 MW facility in the USA, a 640 MW project at Dhule in India, and a 500 MW facility in Albania. Globally, there are many others that fall between 200 and 500 MW. Thus, even the largest individual wind facilities currently operating at full power only have a maximum output that can be produced consistently by one or two conventional coal-fired generating units.

To make a significant contribution to national energy supply, large numbers of individual wind turbines are required. For instance, Australia produces much of its electricity from a combination of black and brown coal fired stations. Here, there are plans for a greatly increased level of renewables to be deployed. It has been calculated that to replace a single 1.6 GW power station, it would require placing a wind turbine every 250 metres from Melbourne to Sydney, a distance of ~1000 km (ACA, 2009). Capital investment would be enormous and additionally, visual intrusion would be extensive and not necessarily welcomed by the local population.

Although the output from individual facilities is slowly increasing and larger units are being developed, the output from the vast majority of individual solar power facilities is even lower. The largest PV units currently operating (located in Canada, Spain, Germany, and Portugal) are only between 40 and 80 MW. The largest CSP facility (354 MW) is in the Mojave Desert of California, and Spain also hosts a number of larger plants (100–150 MW). But again, output remains relatively meager compared to an average thermal unit.

2.4.5 Grid and electricity storage issues

Power systems must be actively managed to maintain a steady balance between supply and demand. This is a complex task as demand varies continually. In some places, it is becoming more complicated as a consequence of the growing levels of intermittent sources being deployed. To take best advantage of wind and sunshine, both types of facilities may need to be located in remote or relatively inhospitable regions. This raises issues of cost and grid connection. For instance, in parts of China, as a consequence of their geographical remoteness, significant wind power capacity is not yet connected to provincial or state grids.

The optimal conditions for integrating large amounts of intermittent energy such as wind at an acceptable cost include a robust, well interconnected electric grid. In essence, a grid is an interconnected network for delivering electricity from suppliers to consumers. The term may be used to describe an entire continent's electrical network, a regional transmission network, or a sub-network, such as a local utility's transmission or distribution grid. For example, the UK grid comprises a high-voltage transmission network that connects power stations and major substations. Much of the electricity is carried by a network of more than 7000 miles of 275 kV and 400 kV overhead lines. In other countries, grid infrastructure is different and the make-up of a grid can vary considerably, depending on geography, budget, requirements for system reliability, and the load and generating characteristics.

The integration of a significant amount of electricity from intermittent sources into existing power grids can create operational problems and impose a number of new requirements, especially with older grids. A number of issues are likely to become apparent, particularly where a country has a combination of rapidly growing energy demand, an inflexible grid, a heavy reliance on coal, and ambitious renewable energy expansion plans. Reliably integrating renewable energy resources into the bulk power system requires significant changes to traditional methods used for system planning and operation (Moura, 2010). Currently, various strategies are being used to accommodate such changes in grid make-up and performance.

In recent years, based on predicted increases in the capacity of intermittent renewables, various national and international studies have addressed grid expansion requirements. An example of the former is the German DENA (Deutsche Energie-Agentur) studies that examined the integration of onshore and offshore wind energy generated by 2020 (Lehner and Schlipf, 2011). These studies concluded that in order to achieve the Federal Government's goal of at least 20% of renewable energy in power generation between 2015 and 2020, around 400 km of existing 380 kV grid would require upgrading, and 850 km of new lines adding.

On a wider basis, the European Wind Integration Study (EWIS) – Towards a Successful Integration of Wind Power into European Electricity Grids was undertaken. This joint investigation for the system integration of wind power was initiated by the European Transmission System Operators and supported by the EU. Within the EU, there is a general consensus that significant grid improvements will be required to fully accommodate the growing level of intermittent renewables (Nies, 2011). A number of measures to improve national and trans-border grids are being pursued. Transmission systems can be upgraded in a number of ways. This can be accomplished by installing additional power lines or improving/upgrading existing ones. This can be via replacement of conductors with larger versions, increasing the voltage carried, or increasing the line rating by operating at a higher temperature. Based on several studies, the European Commission has concluded that European grids need to be extended and upgraded in order to foster market integration and maintain existing levels of system security, but especially to transport and balance electricity generated from renewable sources, expected to more than double in the period 2007-20. A significant proportion of such generating capacity will be concentrated in locations distant from major centres of consumption. Up to 12% of renewable generation in 2020 is expected to come from offshore installations, most notably in the Northern seas. However, some existing renewable capacity lacks permanent grid connections and efforts continue to provide suitable connections to, for instance, a number of new offshore wind farms feeding into UK and Belgian grids. Alongside offshore wind, significant shares are also forecast to come from land-based solar and wind parks in Southern Europe and biomass installations in Central and Eastern Europe.

Increasingly, a more harmonised approach in the pursuit of greater renewables capacity is being considered within Europe. Based on their particular advantages, certain regions could advantageously become 'specialised' in different forms of renewable technology. Thus, solar power could be developed predominantly within Mediterranean countries, and wind power concentrated more in Northern Europe (Lindenberger, 2011). This will influence investment costs. Amongst the priorities identified to address these issues, and to ensure the timely integration of renewables generation capacities in Northern and Southern Europe, the European Commission has proposed (European Commission, 2010):

- an offshore grid in the Northern seas and connection to Northern and Central Europe. This would link energy production facilities in the Northern seas with consumption centres in Northern and Central Europe, and hydro storage facilities in the Alpine region and in Nordic countries;
- interconnections in south western Europe to accommodate wind, hydro and solar power, in particular between the Iberian Peninsula and France, and further connections within Central Europe, to make best use of North African renewable energy sources and the existing infrastructure between North Africa and Europe;
- connections in Central Eastern and South Eastern Europe – strengthening of the regional network

in North-South and East-West power flow directions, in order to assist market and renewables integration, including connections to storage capacities and integration of energy islands.

In some locations, the growing input from intermittent renewables has already resulted in grid-related problems. In Italy, in 2009, on a number of occasions, the transmission system operator required wind generators to shut down their wind farms because of temporary overloads on electrical lines. An estimated 500 GWh of wind production was lost in this way during the year (IEA Wind Energy, 2010). Similar problems have also been reported in India, the UK and parts of the USA.

In the USA, 33 states currently have some kind of renewables obligation (Renewable Portfolio Standards – RPS). If creation of a national RPS proceeds, estimates suggest that incremental capacity additions of more than 300 GW will be needed. However, transmission capacity for this new (and mostly remote) generation, is lacking and it could take to beyond 2025 to install the transmission lines required (Gross, 2011). The requirement to expand and increase grid capacity to handle the expected renewable generation growth has been highlighted by a number of US organisations (such as the North American Electric Reliability Corporation). Although multiple major transmission projects are under way or approaching construction, they will be insufficient to support all RPS requirements. Transmission capacity increases to accommodate the growing renewables output are not being helped by the regulatory approval process, and the absence of an integrated renewable generation and transmission strategy.

Studies undertaken by the US Department of Energy's National Renewable Energy Laboratory (NREL) concluded that, on technical, operational and economic grounds, up to 20% of the country's electricity could theoretically be produced by wind by 2024. However, substantial investments in additional transmission lines will be needed. The Eastern Wind Integration and Transmission Study (NREL, 2010), the largest of its kind to date, focused on the bulk of utilities in the Eastern Interconnection system; essentially, this covers the eastern two thirds of the country. The study concluded that there were no fundamental technical barriers to the integration of 20% wind energy into the electrical system, but transmission planning and system operation policy and market development need to continue to evolve in order for these penetration levels to be achieved. At the moment about 4% of the region's electricity comes from wind.

The study further noted that without additional transmission capacity, the development of wind power is likely to be hampered. There is evidence to suggest that the lack of capacity is already limiting the growth of wind power in some locations (Smart Grid, 2010). Several other studies have confirmed that it will be critical to co-ordinate transmission expansion growth with building infrastructure to accommodate generation from wind and solar. The costs required to bring large amounts of intermittent renewables onto a grid are likely to be considerable. For instance, a study of wind integration issues undertaken by the Western Governors Association Clean and Diversified Energy Advisory Committee determined that a 'high renewables' case would require an additional 3578 miles (5758 km) of transmission line, above the 3956 line miles (6367 km) required in the reference case; total cost would be US$15.2 billion (Gramlich, 2008).

Texas is the leading US producer of wind power. By 2008, an estimated 4.5 GW of wind generation was operating and an additional 3.6 GW was under interconnection agreements. A goal of the state's RPS policy is for a further 10 GW of renewables-based generation to be added by 2025. It is estimated that some US$1 billion investment in new and upgraded transmission will be required to support this target (Decker, 2008). A recently-completed analysis undertaken by EPRI addressed the costs and benefits of modernising the US electricity system and deploying Smart Grid technology; a cost of between US$338 and US$476 billion was estimated, a significant increase over 2004 estimates of US$165 billion. Thus, the costs associated with grid upgrades needed to support a growing level of intermittent renewables can be significant.

In a recent development, Alstom Grid was awarded a contract for the first stage of the Tres Amigas

SuperStation project located in New Mexico. The SuperStation power transmission hub will eventually interconnect America's three primary electricity grids, the Eastern (Southwest Power Pool), Western (Western Electricity Coordinating Council) and Texas (Electric Reliability Council of Texas) networks. It is expected to strengthen reliability, transmission efficiency and grid capacity and will also help ensure stability for intermittent power sources such as wind, solar and geothermal. Commercial operations are expected to begin in 2014.

Other US studies have confirmed the importance of having adequate flexible generators on the grid. Wind integration studies have determined that grid systems with more flexible generators tend to have lower integration costs. For example, systems with large amounts of flexible hydroelectric or natural gas generation have lower integration costs than systems with a high proportion of less flexible generators such as nuclear and coal power plants. In fact, a study of California's grid calculated that the load following cost for integrating wind energy would be essentially zero, in part because of the large available stock of flexible generators in the state (Gramlich, 2008).

Like many other countries, China is also increasing its dependence on renewable energy sources, most notably, wind power. In recent years, investment in wind power has continued to grow and the government has set a goal for it to surpass nuclear power, becoming the country's third-largest source of electricity after thermal and hydro power by 2020. As elsewhere, although grid companies are obliged to buy the output from wind farms, this strategy is not problem-free as some are being hindered by ageing grid infrastructure (Renewable Energy, 2010b). Reportedly, in the first half of 2010, China lost about 2.8 GWh of power due to insufficient transmission capabilities and poor grid connectivity. During this period, on-grid power generated by wind and solar facilities accounted for only 0.7% of the country's total power generation (Energy Central, 2011).

Many Chinese wind facilities are remote from major centres of energy demand and industry observers suggest that the country's power grid will require extensive upgrades in order to support large-scale wind farms. At the moment, some of the country's provincial grids are not fully connected to the main grid (Minchener, 2011). China's geography means that many major wind facilities are concentrated in remote provinces in the far northwest, such as Inner Mongolia, Gansu and Xinjiang, although the greatest requirement for electricity is along the coastline. For instance, Xinjiang province is around 4000 km from Shanghai, hence the transport of wind-generated energy from west to east will require high investment in the latest generation of ultra-high voltage (UHV) transmission lines. One of the largest projects so affected is a geographically remote 10 GW wind project at Jiuquan in Gansu. Here, as elsewhere, major transmission upgrades are needed. In view of these issues, the State Grid, China's largest power distributor, plans to spend more than US$75.9 billion on grid upgrades during the current 12th Five-Year Plan (2011-2015). Investment in UHV transmission lines between 2006 and 2010 amounted to ~US$3 billion. In February 2011, the world's first 660 kV transmission system began supplying energy from northwest China's Ningxia Hui Autonomous Region to the eastern Shandong Province. This forms part of the US$1.58 billion West-East Power Transmission Programme.

The stability of China's grid is already problematical because of weak inter-regional interconnections, resulting in power shortages that hamper grid efficiency in different parts of the country. In the short term, until these issues are fully resolved, large-scale wind power deployment will remain difficult. To overcome this, as in other parts of the world, China hopes to develop a 'smart grid' system, an enhanced method based on an intelligent monitoring system for delivering electricity using information technology and communication systems between suppliers, consumers, storage systems, and the components of the grid (Crossley and Beviz, 2010), potentially operational by 2020. Smart grid technology should be capable of improving the prediction of potential electricity loads and adjusting generating needs, reducing the likelihood of rolling blackouts caused by greater reliance on renewables (Rutowski, 2010). However, upgrades to the grid continue to lag behind the expansion of wind capacity, leaving many of China's existing wind farms unconnected and unused. Reportedly, only 72% of the country's total wind power capacity is currently connected to the grid.

India already has a significant wind power capacity in operation and various initiatives are driving the technology forward. However, limitations imposed by grid and transmission bottlenecks and other grid-related issues sometimes force curtailment of wind generation to ensure reliable system operation. For instance, recent years have seen the state of Tamil Nadu lose up to 15% of total wind generation as a result of congestion and a shortage of power evacuation facilities (Banunarayanan and Altaf, 2009). A major constraint in harnessing the full potential of wind is the inability of the Indian grid to absorb the power generated by the country's wind turbines. Many wind farms are located in remote areas, with limited transmission capacity and limited local power demand. The Indian transmission infrastructure is the responsibility of the state transmission utilities; however, many lack the funds for upgrades needed for the integration of the planned large-scale increases in wind capacity. Here, as elsewhere, transmission planning needs to be in tandem with generation, as the time required to develop and build new transmission systems is much longer than for the construction of wind turbines. Wind developments can be built within a short timeline (within six months), while the lead time for the development of transmission lines is estimated to be between 3 and 15 years (Decker, 2008).

Electricity storage

A major potential drawback when generating electricity from intermittent renewables is that peak production may not correspond with periods of high demand. Excess electricity cannot be stored easily in readiness for the next increase in demand, although potentially, there are a number of technologies that could be deployed. However, most are better suited to smaller-scale applications and the only system currently finding large-scale use is pumped-storage hydroelectric. This type of system is useful for 'storing' the fluctuating output from wind and helps provide grid stability, although for obvious reasons its availability may be limited. Germany, for example, has 7–9 GW of pumped storage capacity but this is insufficient to fully compensate for the country's growing wind capacity (Frohne, 2011; Rieck, 2011).

A further drawback with most storage systems is that they can only operate for short periods. In prolonged periods of low wind coinciding with high demand, gas-fired peaking plants can continue to meet that demand for as long as necessary. This does not necessarily apply to storage systems; if there are no periods of excess production, systems cannot be recharged (ENDS, 2011).

Although there are a number of (non-hydro) storage techniques available or being developed, most have technical issues to be resolved, and all have significant cost implications. Few are yet ready or cost-effective for utility-scale application. The main alternatives are:

- **Batteries** – these are expensive, have high maintenance requirements, and have limited lifespans although some small-scale use is being made. For instance, Duke Energy of the USA is installing a 36 MW energy storage and power management system at a 153 MW wind power project in Texas. In the UK, ABB has commissioned its first lithium-ion battery-based DynaPeaQ dynamic energy storage installation; some of the wind power generated is stored on site and the remainder fed to the grid. Battery modules are continually charged and discharged, and can store up to 200 kWh. Rated power and storage capacity is ~20 MW for ~15–45 minutes, although the technology can reportedly be scaled-up to 50 MW for >60 minutes.
- Compressed air systems – air is compressed and stored in some form of geological feature. When electricity demand is high, the air is released, heated with a small amount of natural gas then passed through turboexpanders to generate electricity. Several utilities are also looking at compressed air storage to provide backup. E.ON has operated a 320 MW plant near Bremen in Germany since the 1970s and is looking to build another. RWE also intends to build a 200 MW/1 GWh pilot plant in Germany in partnership with General Electric (ENDS, 2011).
- **Off-peak cryogenic storage** – in the UK, a small-scale device (300 kW/4 MWh peak capacity) has been installed at a major cogeneration plant (Slough Heat & Power). This uses off-peak electricity to liquefy nitrogen. When electricity is needed, ambient temperature or waste heat from the power plant is used to turn it back into a high-pressure gas that can drive a turbine.
- **Flywheels** – a heavy rotating disc is accelerated by an electric motor. On reversal, this acts as a generator, slowing down the disc and producing electricity. Electricity is stored as the kinetic

energy of the disc. In June 2011, a 20 MW unit was completed in Stephentown, New York. Its primary function is to provide grid-stabilising commercial frequency regulation services to the New York State electricity grid.

- **Hydrogen** – there are proposals to produce hydrogen using off-peak electricity and/or heat. This would then be compressed or liquefied and stored. It could be used as a gas turbine fuel.
- **Thermal storage** – it has been suggested that molten salts could be used to store heat collected from solar power systems; this could then be used on demand to produce electricity. In Denmark, recent changes in the law now permit the electric heating of water in some of the country's cogeneration plants. Thus, when excess wind energy is available it can now be used instead of natural gas for district heating; this can be viewed as 'storing' the electricity in the form of hot water.
- **Electric vehicles** – if plug-in hybrid and/or electric cars are mass-produced, there may be the potential of using their batteries to help meet peak demand. A parked and plugged-in electric vehicle could potentially sell the electricity from its battery during peak loads and recharge either during the night or off-peak (Gramlich, 2008). In Germany the federal government has an objective of having roughly a million electric vehicles on the road by 2020.

Other possible 'storage' alternatives continue to be proposed and developed. For instance, in April 2011, US patents were issued for a novel system designed to use intermittent, off-peak wind power to generate radio-frequency heating. It is claimed that this would be used to heat heavy oil deposits, producing liquid fuels without the production of CO_2.

Not all markets may need to adopt storage techniques, at least in the near term. For instance, studies carried out by the US DOE have determined that the country should be able to accommodate as much as 20% wind power generation without requiring storage (DeCesaro and Porter, 2009). If this is the case, it may be many years before the levels of wind generation will be significant enough to require large-scale storage systems; during the intervening period, changes in resource mix, market rules, and other factors may ease large-scale wind integration without the need for storage technologies.

In the long term, further development could potentially make some storage techniques suitable for larger-scale application, particularly to help balance grid requirements. There could be periods when significant commercial opportunities may arise whereby stored electricity could be sold at a high price. For instance, a 2009 study addressing the UK situation suggested that there are likely to be periods when UK wholesale electricity prices will be zero due to the availability of excess wind power, while at other times prices will spike to 1300 £/MWh due to sudden power shortages. By 2030 there could actually be periods of negative prices and short spikes of up to 8000 £/MWh (ENDS, 2011, reporting data produced by Pöyry in 2009). Despite these opportunities, the opinion of much of the power sector seems to indicate that electricity storage will not play a significant role in filling the reserve gap. More likely, interconnection will be used to deal with excess generation (by selling power overseas). Thermal plants (probably mainly gas fired) will deal with shortfalls. Both options will cost less than large-scale storage.

2.5 The growing use of intermittent renewable sources – summary

Across the world, the use of renewable energies continues to increase. The preceding sections have examined the rationale for this and discussed some of the main areas associated with their use, particularly for power generation.

The issue of the cost effectiveness of using grid-connected intermittent renewable sources for electricity generation is beyond the scope of the present report, hence has not been examined in depth.

However, what is apparent is that without subsidies electricity produced by some forms of renewable energy will remain much more expensive for the end-user. For instance, it is suggested that in the UK, offshore wind may require subsidies until at least the mid-2020s, a situation mirrored elsewhere (Derbyshire, 2010). Despite issues of cost, the use of most forms of renewable energy looks set to carry on increasing for the foreseeable future. Greater deployment is predicted in both developed and developing nations, particularly for power generation applications.

Proponents of competing electricity generating systems frequently dispute the findings of others, particularly where process economics are concerned. Opinions are often highly polarised. For instance, in March 2011 the Irish Wind Energy Association suggested that by 2020, wind energy could save Irish consumers up to €100 million per year in electricity costs. In direct contrast was a report from the Irish Academy of Engineering predicting that consumers would face higher bills (under government targets to generate at least 40% of electricity demand) from such renewable resources by 2020 (McDonald, 2011). This remains an area that continues to be the focus of much analysis and debate.

Analysis continues into the most effective ways of accommodating future increases in the amount of intermittent renewable-generated electricity into individual national systems. Potentially, impacts could be considerable. As a consequence of greater wind- and solar-generated electricity, thermal power plants (both coal and gas) will be expected to operate more dynamically and at lower loads. The best options for integrating these different generating technologies is the focus of a number of ongoing research projects (for example, the German VGB PowerTech eV project 283) (Ziems and others, 2009).

Like most parts of the energy sector, renewable energies have not been immune to the recent turmoil in the global economy. During 2010-11, some projects stalled or were abandoned as a result of issues ranging from global economics, the state of government finances, difficulties in funding, and regulatory uncertainty. Where project funding remains available, this is often on more onerous terms.

The environmental advantages of renewable energy sources over fossil fuel fired plants continue to be promoted widely. Once built, technologies such as wind power are often perceived as being emission-free. However, whilst this may be true in that their day-to-day operation generates no direct emissions, where wind (and solar) power forms part of a system that also includes thermal power plants, their intermittent input means that increasingly, these thermal units (designed to operate mainly on base load) are now repeatedly cycled or relegated to load following. Inevitably, this impacts negatively on various aspects of plant economics, environmental performance, operation, and maintenance. These issues are examined in the following chapters.

3 Impact of intermittent energy sources on operation of coal-fired power plants

According to most estimates, the use of regenerative generators based on wind and solar power is set to continue increasing for at least the next 20 years. The installed capacity of both energy sources is forecast to increase dramatically during this period. The growth of these systems is already imposing significant changes on how many conventional coal-fired power plants are operated. Not all are well suited for these new tasks as, to date, a significant proportion have only been required to operate on base load (Lehner and Schlipf, 2011). Even though many regularly adjust their output to meet variations in demand, historically this has often been a relatively regular and predictable process. However, the growing input from intermittent energy sources is changing plant requirements and working patterns, even though this is not the only factor. Many conventional power plants are now being deployed more flexibly to accommodate the variable input from wind and solar power.

This means that their output range changes more often and the proportion of hours operating on part load is tending to increase. As part of their response, plant operators continue to pursue different routes to achieve stable operation at very low load levels, and to increase the maximum speed of load change attainable. Plants are also being started up and shut down more frequently than before. It is expected that in the future, at least some electricity markets will require less base-load plants and more flexible mid-load and peak-load power plants.

Although this chapter considers primarily the impacts on coal-fired plants, many of the issues discussed also apply to gas-fired facilities, often used to provide back-up supply when generation from intermittent renewable sources is unavailable. Most existing combined cycle plants were not designed for cycling service, hence will incur similar penalties when operating off base load.

3.1 Different modes of power plant operation

A conventional coal-fired power plant can, potentially, be operated in a number of ways, depending on market requirements and other factors. At one extreme it can operate continuously at or near full output, whilst at the other it can be run at part load or turned on and off repeatedly. The main modes of operation encountered are:

- **Base load** – a base load power plant is one that generates at or near maximum output on a more-or-less continuous basis and is only shut down to undertake maintenance operations. Generally, they produce electricity at the lowest cost of any type of power plant, and so are operated most economically at maximum capacity. Base load plants include coal, oil, nuclear, geothermal, hydroelectric, biomass and combined cycle natural gas plants.
- **Peaking** – a peaking plant generates electricity only at periods of peak demand during the day. The extent of operation of some peaking plants can vary significantly throughout the year.
- **Load following** – a load following plant adjusts its power output as demand for electricity fluctuates throughout the day. Changes may be greater than 50% MCR (maximum continuous rating). Such a plant is often on for more than 48 hours at a time, but varies its output to follow the daily pattern of electricity demand. In terms of efficiency and speed of start-up and shut-down, they generally fall midway between base load and peaking plants. Load following plants often run during the day and early evening, and their output is curtailed during the night when electricity demand is lower. However, exact hours of operation depend on various factors that include the cost of electricity generated. The most efficient plants, which are almost invariably the least costly to run per kWh produced, are brought online first. Load following capabilities can depend on many factors.
- **Two-shifting** – here, the plant is started up and shut down once a day. There is also double two-shifting where the plant is started up and shut down twice a day. Economic two-shift operation requires that units are brought back on load and taken off load as quickly as possible to

minimise off-load heat costs. Two-shifting is sometimes referred to as daily start/stop (DSS) operation. To be able to two-shift effectively, plants need to be ‘flexible’. Gas-fired (and some hydroelectric) plants are well suited to two-shifting as they can be brought quickly on line and synchronised rapidly to the grid. Coal-fired power plants are less suitable because of the longer time periods required to bring their boilers up to steam (Vinter and Price, 2006).
- **On-load cycling** – in which, for example, the plant operates at base load during the day and then ramps down to minimum stable generation overnight.
- **Weekend shut-down** – in which the plant shuts down at weekends. This may be combined with load-following and/or two-shifting.

Depending on the mode of operation and how long a coal-fired plant has been off line, different start-up procedures are adopted. Once a unit is on, load following is the least damaging of the cycling activities. Starting a unit is much more damaging, with a cold start the most damaging of all (Denny and others, 2007). Start-ups are usually categorised as:
- hot start – refers to a unit starting up within a few hours (<8h) of shutting down, while the materials in the unit are still hot (often >350–400°C);
- warm start – takes place when the unit has been off for slightly longer (>8–48 h) and the materials have begun to cool but are not yet cold (150–350°C);
- cold start – occurs if the unit has been off for a long period (>48 h) and the materials have cooled completely (typically <200°C).

The precise definitions adopted vary between utilities and units and are influenced by the extent to which heat is retained in the plant and its controllability.

Start-up and shut-down times can vary significantly between individual units and type of technology deployed (for instance, the start-up time for a PCC unit will differ from that of a CFBC). Times suggested for typical base load units (usually based on guidance from the original equipment manufacturers) are likely to be very conservative, probably with a suggested cold start time for a large unit of 12 to 15 hours, and a hot start time of three hours. However, globally, many utilities have developed procedures to reduce these times and some newer plants are considerably faster. For instance, in South Korea, the supercritical Yonghung power plant achieves a cold start to full load in seven hours, a warm start in just over three hours, and a hot start in 90 minutes (Peltier, 2005). Experience has shown that (depending on unit size and configuration) with the adoption of suitable measures, start-up times can often be more than halved from original base load times (Gostling, 2002).

The speed at which a power plant can be brought on and off the grid is referred to as the ‘ramp rate’. It is the rate of change of specific parameters and is generally applied to boiler pressure or temperature, turbine speed or temperatures, or generator output.

3.2 Switching from base load operation

For the purpose of this report, base load operation is considered to mean the operation of plant on a reasonably continuous basis, at or near the plant or unit MCR. Conversely, non-base load or cyclic operation covers all other operating modes.

Owing to their high capital cost and high capacity factors, some technologies (such as coal and nuclear power) were designed to operate more or less continuously, meeting base load demand. With lower capital costs but higher fuel costs, many natural gas-based plants (combined cycle and gas turbine plants) were designed primarily to meet intermediate and peak electrical load. Coal-fired power plants may not necessarily respond well when switched from base load to some form of cyclic or less regular operations (Haase and others, 2009). However, in recent years, at least in some parts of the world, the requirement for this type of operation has increased significantly as competition from alternative generating sources has increased.

Conventional steam plant is often constrained in various ways. Rapid load changes may be difficult because of limited thermal storage, thermal stress limitations, and firing system inertia (Rieck, 2011). Many issues that affect coal-fired plant also apply to gas-fired units. Particularly during rapid start-ups, major plant components can experience temperature excursions significantly above design. If such thermal transients are not controlled, then key plant items become susceptible to failure due to mechanisms such as thermal fatigue, creep, creep-fatigue and corrosion-fatigue (*see* Section 3.3). A switch from base load to start-stop or cyclic operation can affect many areas of plant operation, including operation of boiler, steam turbine, emission control systems, electrical, and numerous auxiliary components. Potentially, it can result in:

- higher forced outage rate and reduced availability due to the increased component failure frequency, plus high associated replacement costs;
- increased operation and maintenance costs needed to keep the unit functioning efficiently;
- increased wear and tear of components due to additional overhauls and maintenance required;
- increased costs for operating personnel and automation systems needed to manage the more complex operation of a plant experiencing a greater number of cycles;
- increased fuel costs and higher emissions per kW as a consequence of reduced plant efficiency and operation under non-optimum conditions.

The type and scale of such factors is often highly plant-specific and can be influenced by the overall design of the plant (boiler type, layout, and so on), its size and age, the individual design of major components (types of materials used and their thickness), the way the plant is operated, the quality of the water chemistry, and previous maintenance quality and philosophy (MMU, 2010). Each of these will influence or even determine the degree to which cycling will impact on the overall capital, operating and O&M costs.

When a coal-fired plant is switched to cycling, the number of thermal transients can greatly exceed those experienced by utility boilers operating on base load. This can result in the fatigue of pressure parts. Hence major plant components need to be appropriately designed to cope with this mode of operation. Ideally, this is best facilitated at the plant design stage, based on the application of comprehensive data on operational scenarios, both historical and expected. Furthermore, plant problems can be better controlled via the adoption of optimised, standardised start-up and shut-down procedures. Much of the damage experienced by plant components occurs during these phases, hence the importance of developing and adopting appropriate procedures. These can help reduce the magnitude of, for instance, thermal gradients across thick-walled components. The provision of data from the OEM suppliers of major components such as steam turbines can be crucial for the development of practical and accurate start-up procedures (de Pijper, 2002). By application of these, the life of the equipment, and subsequently the plant, can often be extended significantly, even when cycled.

The switching of coal-fired plants from base load to more irregular forms of operation has prompted a number of major industry investigations into the possible repercussions. For instance, recent German studies analysed and modelled the expected demands on conventional thermal power plants resulting from changes in operating patterns caused by the growing integration of wind energy. Areas examined included minimum load attainable, controllability, ramp rates, and control strategies. Although within a German context, data generated are expected to contribute towards improved design of new coal plants (Haase and others, 2009). Investigations and modelling are continuing (under, for instance, VGB project 333) (VGB, 2011).This remains an area of ongoing examination and a number of similar studies are under way in different parts of the world.

When operating on base load, the amount of energy consumed within a coal-fired plant itself may be negligible (<0.5% of total energy). For other modes of operation, such as two-shifting, it can represent 5% or more of total energy consumed and result in reductions in efficiency of around two percentage points, even if the average output during the on-load period remains high (OECD/IEA,2010). A major factor that affects on plant efficiency is the number of perturbations (transients) from steady state operating conditions. During each of these, the plant does not operate at peak performance, thus, the more transients, the greater the overall reduction in efficiency.

Despite the various issues that can potentially arise when coal-fired plants are switched from base load to some form of cyclic operation, its incidence has increased substantially in recent years, driven largely by market changes and requirements, and technological developments. Historically, particularly where units have been switched to regular two-shifting patterns, few unexpected operational problems appear to have been encountered (Fernando and others, 2000). Two-shifting is generally focused around fairly regular daily hours of operation, with plants being put on and taken off load at roughly the same times. Consequently, it can involve a consistent, fairly straightforward set of actions that are repeated regularly. This mode of operation has been well established in many plants, although more recently the situation has been changing as a consequence of the growing input from intermittent energy sources.

Figure 8 Part of the 4.1 GW Castle Peak power station, Hong Kong (photograph courtesy of CLP Power)

Where a unit was designed with cycling in mind from the outset, appropriate features can be incorporated at the build stage. For example, four 680 MW subcritical units of the Castle Peak B plant in Hong Kong were intended for regular cycling duties and have operated successfully for more than 15 years (*see* Figure 8 and box on page 38). Similarly, in South Korea, two 500 MW units of the Taen power plant were designed for two-shifting and have been cycled continuously since 1995. Where not designed for cycling, there are ways in which existing coal-fired plants can be modified to improve their response and effectiveness when operated in this manner; these are examined later in this report.

Internal industry surveys and practical experience has confirmed that with due diligence regular two-shifting of coal-fired plants can be achieved successfully although generally, at some cost. These surveys have noted that there is now extensive experience of two-shift operation worldwide. Whilst there are potential risks and added wear and tear associated with the practice, they conclude that with due care and application of sound engineering and operational practice, economic two-shifting of at least some plants (even when designed initially for base load) can be achieved (Gostling, 2002). Clearly, where a plant is designed for cycling from the outset, appropriate features can be incorporated at the design stage. For instance, several 800 MW SC sliding pressure units of the Yonghung power plant in South Korea came on line in 2004. These were designed accordingly and incorporated a 'European-style' HP/LP turbine bypass system in order to shorten start-up times and ease cycling operations (Peltier, 2005).

3.2.1 Frequency of start-up and shut-down

For some years, in order to meet changing market requirements, some coal-fired plants in countries such as the UK, Germany and Italy have been shut down and started up on a fairly regular basis. Depending on the individual national and local circumstances, the extent of the cycling and start-stop frequency has varied significantly between and within different countries and regions. Although in some, base load operation still dominates, many plant operators expect to begin cycling their

Castle Peak Power Station, Hong Kong

Four of the station's coal fired units (built between 1985 and 1989) were specified for extensive two-shifting application from the outset and designed accordingly. Despite subsequent changes in their operating regimes and the increasingly demanding conditions imposed over 15 years of experience of two-shift operation, the four units have recorded acceptable standards of performance. Much has been attributable to the careful optimisation of plant start-up and shut-down procedures and the fact that they were designed with this type of operation in mind (Chow and others, 2002). Boiler and turbine designs were based on those that had evolved to meet the standard requirement for 200 cold starts, 1000 warm starts and 5000 hot starts, as defined by the UK's former Central Electricity Generating Board.

During initial plant operations, co-ordinated two-shift start-up procedures were developed as part of the final acceptance trials. This included the participation of boiler and turbine designers and plant start-up specialists. Priority actions during this initial phase concentrated on identification and elimination of design and equipment weaknesses that could adversely affect availability, reliability, and consistency of start-up. This stage was followed by evaluation of the impact of transient conditions measured during two-shift starts on the rate of cyclic life expenditure in critical parts of the boiler and turbine. Subsequent changes in the makeup of the CLP generating fleet (increased use of natural gas and nuclear power) resulted in an increase in the number of hot start-ups (6–8 hours off). The length of shut-down periods also increased to 10–12 hours.

Over more than 15 years of continuous two-shift plant operations, there has not yet been a requirement for early replacement of major components such as boilers, turbines or main balance of plant. This has been due partly to careful attention to thermal and operational flexibility at the design stage, and a sound understanding of the influence of methods of operation on the conditions developed during boiler and turbine start-ups and shut-downs. This has helped to minimise the more damaging thermal transients that can occur. Thus, successful operation was attributed to:

- parts of the boiler and turbine resulting from frequent fast start-ups;
- optimised operation during start-ups, based on start-up tests and thermal-mechanical stress analysis of extensive measurements of transient temperatures in critical boiler components;
- preventative maintenance focused where condition monitoring and accumulated experience indicated it was likely to be most beneficial.

The only problems linked directly to two-shifting have occurred in HP and IP turbines and generators. These were managed by repairs at minimal additional maintenance cost during major turbine inspections (performed at intervals of ~100,000 Equivalent Operating Hours). It is expected that boilers and turbines will be capable of at least 200,000 operating hours with 5000 hot starts,1000 warm starts and 200 cold starts before some major components may require replacement.

The success of stations such as Castle Peak can be attributed in large measure to the fact that the plant was specified for two-shifting at the design stage and designed and built accordingly.

respective coal-fired plants in the foreseeable future. At least some of this cycling will result from the increasing input from intermittent renewable sources.

Europe

Cycling experience varies across Europe. Some plants have been cycled regularly for a decade or more, whereas others, so far, have worked exclusively on base load.

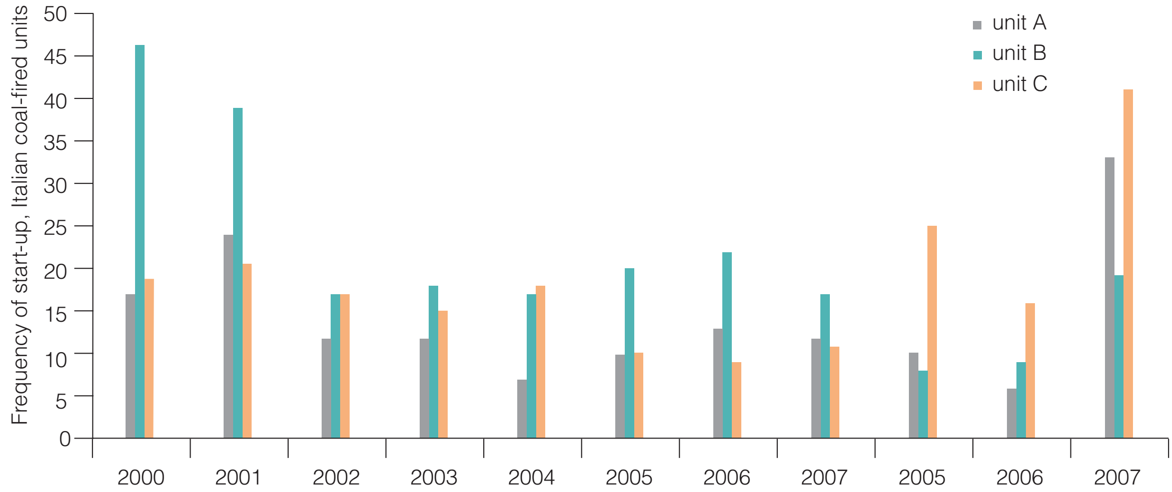

Figure 9 Frequency of start-up – examples of Italian coal-fired units (Meier, 2011)

In the **UK**, all major coal-fired stations are two-shifted or part loaded for at least part of the year. Some operate on base load during the winter and switch to cycling during the summer months. Most stations, originally designed for base load, have been refurbished with cycling in mind; this has extended the governed load range at partial loads, shortened start-up times, decreased start-up costs, and reduced labour requirements (Leizerovich, 2008). Major stations now cycled regularly include Drax, Eggborough, Ratcliffe, West Burton, Fiddlers Ferry, Ferrybridge, Ironbridge, Rugeley, Tilbury, Longannet, Cockenzie and Didcot. Some have been cycled more than others; for example, Didcot A has spent much of its life two-, three-, or four-shifting. The plant has had 720 starts in one year, and over 400 in another (Starr, 2010).

In **Italy**, some coal-fired units have been cycled regularly for more than a decade. Historically, the extent of start-stop operation has varied widely between units. Data (where available) for coal-fired units indicate that yearly start-ups can vary between 6 and 46 (Figure 9) (Meier, 2011).

In **Germany**, a number of plants are also two-shifted or low loaded. These include some larger facilities such as those at Sholven, Wilhelmshaven and Mehrum, plus many smaller units (Leizerovich, 2008). A 500 MW supercritical unit at the Rostock station is cycled on a daily basis; it apparently achieves an availability of more than 90%. Similarly, the supercritical Bexbach plant has reportedly averaged more than100 start-ups a year since coming online in 1983 (Schimmoller, 2011). However, detailed cycling data for most German stations are not available. Of those reporting (to VGB PowerTech), most hard coal fired units experienced only three or four start-ups during 2010, apart from two that underwent 102 (Meier, 2011). However, these data are not comprehensive and some other stations are also known to be cycled frequently.

Most of the German units being cycled appear to be hard coal fired. However, the country also has a significant generating capacity based on domestic lignite. It is anticipated that in the future, as the level of intermittent energy input increases, the extent of cycling of both hard coal and lignite fired units will increase. During 2010 (although based on incomplete data) of the lignite fired units reporting, some experienced only a minimal number of start-ups of between three and sixteen. At the moment, many lignite-fired power plants operate over 7500 hours per year. If the proposed levels of intermittents become a reality, the yearly full-load schedule of existing lignite plants is predicted to decline to 3900 hours by 2030, falling to 3200 hours by around 2050 (Michel, 2010). In order for German lignite-fired plants to retain their major role, it will be important that different modes of operation are achievable. RWE Power has noted that this can be achieved using its BoA technology (lignite-fired power plant with optimised plant engineering). Through the application of advanced performance control systems, the technology allows rapid temporary part-load operation without a major loss in efficiency. The associated I&C (instrumentation and control) technology controls individual plant components and thereby adjusts steam and water temperatures, and combustion air with a high degree of precision. Using this advanced control technology allows newer larger units to part-load down to ~50% of their rated output. Many older 300 MW units can only operate successfully down to ~66%. BoA technology allows output to be ramped up or down by some 38 MW/min. In comparison, a new gas-fired plant (for example, the Lingen facility) can ramp at 30 MW/min (Lambertz, 2010).

In some situations, there may also be the possibility of individual facilities combining coal-fired base load with gas-fired capacity; such a combination is operating at Vattenvall's Hamburg-Tiefstack cogeneration plant. This relies on coal-fired capacity to meet base load requirements, coupled with two combined gas and steam turbine plants integrated into the existing plant for peaking duties, a configuration that is also deployed elsewhere.

At the moment, there is only limited experience of cycling in **The Netherlands**. However, at some point in the future, operators expect to adopt this mode of operation. In readiness, Nuon/Vattenfall has undertaken studies to identify components of its 630 MW Hemweg 8 supercritical plant that, potentially, could be affected by a switch to cycling. The main areas of concern identified were the possible reduced lifetime of boiler and turbine components resulting from increased rates of thermal fatigue, and the influence of regularly changing plant water chemistry (from oxygenated treatment to All Volatile Treatment, and back) (de Jong, 2011). Currently, Hemweg operates solely as a base load station within the Nuon/Vattenfall production portfolio. It is thought that, at present, all other coal-fired plants in The Netherlands also operate solely on base load.

In **Spain**, most of the larger stations (such as As Pontes, Compostilla, Abono, Litoral and Los Barrios) operate predominantly on base load although some small-medium capacity (150–500 MW) plants operate on a more irregular basis. Their extent of use can be influenced significantly by the level of hydro power available within the country.

France has an installed generating capacity of 110 GW. Some 63 GW of this comprises nuclear power (58 units) used primarily for base load. Thermal capacity (27.5 GW, 34 units – mainly coal) is used for some base load operation but also for load following duties. The country's 25.4 GW of hydropower is used mainly for peaking applications.

Asia-Pacific

Although the incidence of cycling coal-fired plants is increasing in many parts of the world, its adoption is not universal, as in several major economies electricity remains in short supply and coal-fired plants are not regularly cycled but continue to operate predominantly on base load. For instance, **in China**, most coal-fired power plants are not currently subject to two-shifting or other forms of cyclic operation; most are contracted to run for an agreed number of hours of base load operation. Although there are plans to introduce a merit order, this is not yet in operation (Minchener, 2011). However, at least some newer Chinese units are being installed with the possibility of cycling and/or load following in mind. For example, the supercritical Taishan plant has been designed to be capable of cycling down to 25–30% load (Schimmoller, 2011).

In India, the shortage of electricity and the country's growing demand dictates that the majority of coal-fired Indian power plants continue to run predominantly on base load. However, even where electricity is not in short supply, coal-fired plants are not necessarily cycled.

Currently, in **Australia**, a high proportion of the country's electricity is generated in large black coal fired stations in New South Wales, Queensland and Western Australia, and important lignite-fired stations operate in Victoria's Latrobe Valley. Although some plants marginally modify load in response to pool price, until recently most coal-fired units operated solely on base load. This included nearly all of the country's subcritical and supercritical plants; all of the latter (Callide, Kogans Creek, Millerman, Tarong, plus the proposed Galilee Power project) operate primarily on base load. It has only been the recent addition of significant wind generating capacity in South Australia that has seen two plants operated by Flinders Power starting to cycle regularly (Northern – 540 MW, and Playford – 240 MW) (Woskoboenko, 2011). Even though the incidence of cycling is currently low, plant operators anticipate that in the future, the growing application of intermittent renewables will have an impact on at least some plants. Australia has a target to generate 20% of its electricity from renewable energy sources by 2020.

In **Japan**, most coal-fired plants operate mainly on base load and do not contribute much to peak demand. At peak hours, much of the non-base load requirement is met by oil or LNG. All newer stations such as the Isogo New No 1 USC unit operate predominantly on base load, excluding time operating on a weekly partial load regime called ‘clinker pattern’ (OECD/IEA, 2007). In 2010, Japan set a goal of producing 20% of its electricity from renewable sources by 2030. Coal and LNG were each to make up 10%, and oil less than 10%. Nuclear power was to provide the balance. Renewables (including hydropower) currently make up ~10%, although their share is expected to increase, encouraged by government subsidies. However, in the wake of the 2011 problems at the Fukushima Daiichi nuclear plants, it seems inevitable that the country will increase its reliance on fossil fuels such as oil, coal and LNG in order to replace the lost capacity. As part of this, estimates suggest that the country will import an additional 4–8 Mt of coal to compensate for the lost nuclear capacity. It is unlikely that in the foreseeable future, significant cycling will be adopted by coal-fired facilities because of the current shortage of generating capacity.

North America

Even in some countries where generation from intermittent sources is increasing rapidly, not all coal-fired plants may necessarily be cycled regularly. In the USA, some thermal power plants were two-shifted during the 1970s and 1980s, but currently, most are not subjected to regular start-stop operation. Variations in demand are usually met by part loading, although some individual units may be shut down over weekends. Reportedly, some are able to operate successfully at a minimum load of ~25% or less (Leizerovich, 2008).

In the **USA**, there are a number of projects operating or being developed based on sliding pressure SC PCC technology. It is expected that unlike Europe, much of this new capacity will operate predominantly on base load and will not be frequently shut down or repeatedly load-cycled. Parts of the US market are different from that of Europe (which includes the requirement for shut-downs and rapid and continual load ramping). This fosters different priorities and operating practices.

It is widely considered that continual load cycling of new US coal-fired units (beyond controlled nightly reductions) will be limited to a relatively small number of plants. These will be strategically determined for each grid region. The significant operating advantage of new supercritical units will give these units preference for load dispatch (Vitalis, 2006). In addition, the country has a significant amount of natural gas-fired capacity (~200 GW) well suited for peaking duties and bringing quickly on line when input from intermittent renewable energy sources falls.

Most recent SC projects have been developed primarily for base load operation. These include projects such as the 1600 MW Prairie State Energy Campus in Missouri, the 790 MW Walter Scott Jr (formerly Council Bluffs) plant in Iowa, the 750 MW Trimble County Station in Kentucky, the 850 MW Iatan 2 plant in Montana, the 760 MW Cliffside Steam Station in North Carolina, the 1600 MW Oak Grove Expansion project in Texas, the 700 MW Longview plant in West Virginia, and the 600 MW John W Turk Power Plant in Arkansas. In some cases, as in Germany, gas-fired peaking capacity has been added to existing coal-fired plants. For instance, SWEPCO’s 600 MW John W Turk coal-fired plant generates on base load but has added two natural gas-fired units to accommodate intermediate and peaking capacity.

Where cycling of US coal plants becomes part of normal operation, the extent will be influenced by a number of factors, one of which will clearly be the amount of intermittent generation available in the region.

In **Canada**, several provinces rely at least partially on coal for their electricity. Reliance varies, but coal is particularly important for base load operations in Saskatchewan, Nova Scotia, Ontario and Alberta. This is expected to continue in some, although Ontario plans to reduce its dependence on coal, focusing more on nuclear power and increased renewables. The intention is to replace imported coal from the USA by 2030, using increased nuclear and hydro power for base load.

South Africa

The biggest segment of Eskom's plant mix comprises 13 coal-fired base load power stations with an installed capacity of 37.76 GW. The remainder comprises a single base load nuclear station (1930 MW), plus 2 GW of hydro capacity used for peaking duties.

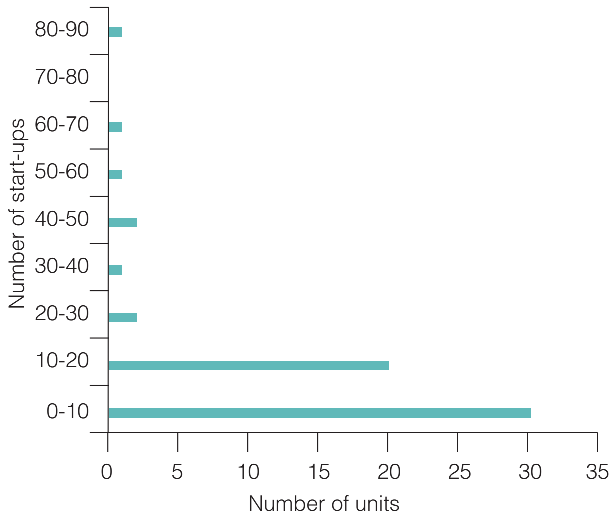

Figure 10 Number of start-ups experienced by South African coal-fired units, 2010) (Meier, 2011)

Figure 11 Eskom's Majuba power station, South Africa (photograph courtesy of Eskom)

At the moment, electricity is generally in short supply and coal stations operate primarily on base load, although some experience a reasonable number of start-ups/shut-downs each year. In 2010, of the 58 units reporting, start-ups varied between 2 and 86 (Figure 10). There are also periods when plants are put into 'Emergency Level 1- EL1' to address capacity shortfalls, which pushes them temporarily past the steady state rated power (McColl, 2011).

Although cycling is not a regular feature of daily operation at the moment, Eskom has undertaken a number of studies examining issues that may arise under these conditions. These focused mainly on the Majuba station (Figure 11). Areas examined included materials performance issues, economics of cycling, risk analysis of multiple start-stop operation of the turbo-generator plant, process control requirements for two-shifting, and impacts on emission control equipment and plant chemistry (Pillay, 2011).

3.3 Impacts of non-base load/cyclic operation

In some parts of the world, cycling has long been a feature of daily operation for coal-fired power plants. The requirements are generally well understood and can be anticipated with a degree of certainty, allowing the appropriate strategies to be adopted and measures to be taken. However, more recently, the increasing addition of intermittent power sources to generating systems has changed the situation. Less regular and unplanned fluctuations inevitably impose different requirements that can impact in various ways on plant requirements, operation and performance.

The scale and extent of impacts resulting from intermittent energy-induced cyclic operations will depend on a number of factors, although a major one will be the extent and frequency of coming off base load. Where the level of input from intermittent sources remains low, the impact on coal-fired plants may be minimal. However, at higher penetration levels, impacts can become far more significant as stations are switched increasingly to start-stop or load following operations. As wind penetration rises beyond ~1–2% (in energy terms, MWh) problems are likely to increase. This has been confirmed by, for example, experience in Germany, Denmark, Spain, Texas, the US Pacific Northwest, Alberta, and Ireland (Hutzler, 2010).

Where a plant was designed for base load but is now being cycled, repeated on-off start-up/shut-down operations and on-load cycling can be very damaging to plant equipment, and wear and tear can increase significantly (de Groot and le Pair, 2009). The magnitude of these impacts is largely design-dependent, with some designs being inherently more tolerant of cyclic operation than others. Analysis conducted on more than 150 coal-fired units has shown that the financial implications associated with cycling operations can potentially be very high, although some older coal-fired plants have been found to be more rugged and cost effective to cycle than the newest combined cycle units (Bentek Energy, 2010). Conversely, other industry analysis has suggested that many older plants originally designed for base load are actually less tolerant. Some were designed with heavy section headers and pipework that have a poor response to thermal fatigue. There are also a number of other major issues that can result from repeated start-stop operation.

The decision whether to cycle a coal-fired unit may not be straightforward, as a number of issues require consideration. When a plant is switched from base load, there are likely to be impacts on cost, efficiency and environmental performance (Lefton and Besuner, 2006). However, studies have concluded that some impacts may not become apparent for some time and may not become a serious issue until three or more years after switching from base load. After this time, cyclic effects can begin to cause significant component damage (Starr and others, 2000). Some plant operators are seriously concerned about the effect of increased cycling on plant life (Woskoboenko, 2011). This remains an area of investigation and modelling. However, because of the variety of coal-based generating technologies available, coupled with the fact that each individual power plant is essentially unique, accurate prediction and modelling often proves difficult (Bentek Energy, 2010).

The actual and potential impacts associated with a switch from base load to cyclic operation are reviewed in the following sections.

3.3.1 Thermal and mechanical damage

Historically, most conventional coal-fired units have been designed for continuous rather than variable operation, and when operating within their normal range can function for long periods with relatively low risk of failure and loss of equipment life.

Power plants operating in volatile or competitive markets, or operating as marginal providers of power, may be required to shut down frequently or load follow. When a generating unit is required to vary its output to meet demand, major components can experience large thermal and pressure changes and become subject to additional stresses and strains. In turn, this can lead to deterioration in physical conditions that affect plant efficiency (OECD/IEA, 2010). When turned on and off, the boiler, steam lines, turbine and auxiliary components undergo large temperature and pressure stresses that cause damage (Denny and others, 2007). This accumulates over time and can eventually lead to accelerated component failures and forced outages. The impact on components may not be uniform across the station; some can be seriously compromised by non-base load operations (unless significant design changes are incorporated) whereas others are likely to experience only minimal detrimental impacts. However, increased start-stop/cycling operation can be extremely damaging to thermal plants and result in stress damage that can take several forms (MMU, 2010). Particularly where older units designed for base load operation have been switched, increasing incidents of failures have been reported. The main mechanisms involved are:

- **Creep-induced damage** – this is the change in the size or shape of a material due to constant stress or force. In power plants, it arises from continuous stress generated in a component by constant high temperature and pressure. This type of damage is both time- and temperature-dependent. Two-shifting and low-load operation would be expected to reduce the incidence of damage resulting from long-term creep. However, operational experience has shown that this may not necessarily be the case.
- **Creep-fatigue** – fatigue is a mechanism whereby materials fail when subjected to repeated, varying levels of stress, usually caused by changes in pressure and temperature. Repeated cycling exacerbates this effect. Often, damage or premature failure results from a combination of both creep and fatigue processes. The degree of susceptibility is dependent on the particular component and its material(s) of construction; different materials (or combinations of) behave differently. With base load operations, the predominant mechanism is likely to be creep, although if exposed to increased fatigue working life can be shortened considerably. These two phenomena are not independent, but act in a combined manner to cause premature failure. Creep-fatigue interactions can cause the cracking of thick walled components, and can be of particular importance for plant parts such as superheater and reheater headers, evaporators, economiser headers, and feedwater heaters. Studies have noted that cracks have initiated and propagated to more than 50% of wall depth in as few as 300–500 starts.
- **Expansion-related issues** – thermal movement caused by repeated expansion and contraction resulting from large temperature changes in some plant components can be significant. Such movements can have a detrimental effect on components such as boiler structures, pipework systems, and steam turbine rotors and casings.

Base load fossil-fired units are designed to operate in the creep range during steady-state operation and some major plant components may be highly susceptible to failure when forced to cycle regularly. A power plant component can withstand considerable fatigue damage before it fails. However, a material that has already gone through 50% of its design creep damage during base load operation can fail if only a further 15% of its design fatigue damage is also expended. The combination of creep and fatigue damage has caused many failures at ageing power plants that have been forced from base load into cyclic operation (Lefton and others, 2002).

Cycling can cause damage (usually cracking) to various thick-section components such as boiler and turbine stop valves, governor valves, loop pipes, and HP turbine inlet belts. These are all prone to thermal fatigue cracking resulting from temperature differences experienced during start-up and shut-down. Thermally-induced cracking and/or distortion can be experienced by a number of major plant components that include superheater and reheater header ligaments and welds, evaporator header stubs, economiser headers, and feedwater heaters. There may also be an increase in corrosion- and fouling-related issues with various plant components such as economisers, feedwater heaters, and evaporators. In an effort to overcome some of these problems, many stations have installed drainage systems. However, sometimes design and operational alterations have resulted in thermal quenches, temperature swings and so on, giving rise to new types of failure. These effects, their causes and possible remedies have been examined in detail by several studies (such as MMU, 2010; Fernando and others, 2000; Fleming and Foster, 2001) hence are not considered in further detail here. The main areas that can be affected and the mechanisms that can be involved, resulting from a switch from base load to some form of cyclic or intermittent operation are summarised in Table 11.

Various models and modelling systems have been developed to help monitor and predict the impacts on plant components when cycled repeatedly. However, detailed thermo-mechanical analysis on, for instance, steam turbine components, has confirmed that stress levels and degradation rates resulting from repeated start-stop operation can sometimes be much higher than expected. For instance, Nowak and Rusin analysed measured data collected from several plant components during actual start-ups (Nowak and Rusin, 2004). Comparison with OEM recommendations discovered significant

Table 11 Main impacts on plants as a result of cyling (MMU, 2010)

Components	Possible effects
Mechanical, thermal and expansion-related issues	
Boiler structures	Support structures incorporate various expansion joints, attachments and supports that are required to allow for considerable expansion and contraction. Repeated thermal and mechanical cycling can weaken or distort these, leading to failure
Steam pipework systems (boiler-turbine)	Damage to constant load supports. Development of high stresses leading to creep and fatigue damage and weld failure
Steam turbines	Thermal fatigue and associated creep-fatigue of turbine parts (such as blading) resulting from load and speed variations. Development of high stresses leading to creep and fatigue damage and weld failure. Differential expansion of turbine rotors and casings may cause problems. Increased wear and tear on turbine governor valves and stop valves. Localised overheating under low/no steam flow conditions. Carryover of oxide in boiler tubes and steam mains into the HP or IP turbines, leading to erosion
Corrosion- and fouling-related issues	
Waterside corrosion in economisers, feedwater heaters and evaporators	Increased aqueous-related corrosion due to interruption in condenser/condensate polishing and in water treatment plant operation. Two-shifting creates a need for increased supplies of feedwater (additional draining etc). Condenser problems resulting from leakage of air and cooling water during shut-down, leading to contamination During start-up, oxygen ingress can lead to corrosion-fatigue in the evaporator sections of boilers. This can be one of the most serious problems with two-shifting Leakage of air into deaerators poses an additional risk
Steam turbine erosion, corrosion, and fouling aspects	
Steam turbine	Two types of steam turbine blade erosion can be encountered: – erosion by particulates caused by oxide scales (turbine front end); erosion by water droplets (back end). Fouling and stress corrosion resulting from the carryover of boiler water salts and impurities that are deposited on turbine blades and rotors. Stress corrosion of turbine blades and rotors is likely to increase with two-shifting as a result of greater steam contamination
Fireside corrosion	
Superheaters and reheaters	Largely confined to some UK and US plants operating with high (>565°C) steam temperatures
Furnace wall	Two-shifting can exacerbate furnace wall problems. Furnace wall corrosion is caused by a combination of oxidation and sulphidation. Problems can be made worse by stress and fatigue effects
Emission control systems	
ESP	EPSs usually perform better at low loads, but precipitator temperature must be kept above dew point as moisture can result in a build-up of difficult-to-remove dust. Acid gases also increase corrosion at lower temperatures
FGD and NOx control systems	Possible range of impacts and limitations (*see* Section 3.6.1). It may take some time to re-establish optimum operation following cycling
Pumps and auxiliaries	
	Many auxiliaries (such as boiler start-up and standby pumps) are subject to increased wear and tear during two-shift operation. Steam-driven main boiler feed pumps subject to increased thermal cycling. Fans, vacuum-raising plants, lubricating oil systems, and condenser extraction pumps are similarly affected. Valves are subject to more frequent operation
Electrical equipment	
General	Damage to electrical equipment from cyclic operation not generally a problem
Motors	Not usually affected by number of starts apart from increased general wear
Generators	Not usually affected by number of starts apart from increased general wear. But additional wear and tear on switchgear

disparities. It was determined that the degradation produced by a single start-up can differ from the original design by up to three times, meaning that the allowable number of work cycles must be changed in a similar ratio. The problems increase with the frequency of cycling. Such findings highlight the possible limitations of some modelling systems and the importance of relying on data derived from actual operation where possible.

3.3.2 Corrosion and ash accumulation

Potentially, cycling-related corrosion can impact on several areas of plant operation and can extend as far as the main stack. For instance, like many others worldwide, a major UK power plant (West Burton) operates on base load during the winter but reverts to two-shifting with daily starts and stops at other times of the year (around 200 start-ups and shut-downs each year). During each start-up, its two stacks remain relatively cool. In the initial phases of operation, flue gas volumes are still small and while the internal flue surfaces are heating up there can be significant formation of acid condensate within the chimney (Hadek, nd). A cool chimney can also reduce the temperature of the exit plume, affecting dispersion during start-up (Bruggendick and Benesch, 2011). It is claimed that the application of proprietary acid-resistant insulating linings (some based on foamed borosilicate glass) to stack steel or concrete flues, can reduce corrosion problems and allow the exit plume to reach its full operational temperature within a few minutes. Similar systems have also been adopted in a number of plants worldwide. In this respect, some newer proprietary linings are claimed to be more effective than traditional refractory-based materials.

On-off plant operation can also cause problems of ash accumulation in stacks. When the power plant is off, rain water can enter the stack causing fine dust particles present to accumulate and harden. When full load resumes, this can produce problems of cracking. This phenomenon has been reported by a number of plant operators and solutions are currently being sought (Bruggendick and Benesch, 2011).

3.3.3 Operation and maintenance (O&M) activities associated with plant cycling

As noted above, where a coal-fired plant adopts cycling, it is important for suitable operating procedures to be developed and applied, particularly during start-ups and shut-downs. The application of these can help minimise some of the more detrimental impacts that can result from non-base load operation. When cycled, there is likely to be a significant additional maintenance cost penalty, even where replacement of major components such as the boiler or steam turbine is not anticipated within the design lifetime of the plant. Increased maintenance can take many forms and experience suggests that a comprehensive O&M programme is vitally important. Frequent inspections and other maintenance-related procedures can reduce the impact of cycling-related failures by keeping the plant operator aware of impending failures and thus prevent unplanned unit downtime. A well-defined inspection programme will permit anticipation and scheduling of maintenance or repairs prior to a catastrophic failure.

Operational issues

When a plant if first started up, there may be a delay where steam flow through the boiler may not have been fully established or be at a low rate. Under these conditions there is the potential for a number of problems. In particular, care is required to ensure that local overheating is avoided. A number of common concerns have been identified, centred mainly on the evaporative sections, superheater platen bottom loops, and reheater elements (Gostling, 2002).

Some problems can be minimised via systematic operation of the plant. For instance, typically, a rapid start-up can be achieved through a combination of changes in procedure and plant modifications, although clearly, the precise strategies adopted depend on the individual circumstances. Equipment modifications and improvements that can help reduce the impacts of cycling can encompass a number of areas. Modifications made to plant, for instance in Europe and the USA, have included the installation of high capacity bypass systems, modified steam valves, and pre-warming systems (Fernando and others, 2002; Starr, 2002; MMU, 2010). Such changes have significantly improved the performance of many plants. A major part of this improvement has been achieved through analysing the limitations of critical components and optimising operating procedures so as to control stress and damage accumulation. Actions may also involve replacing components with improved designs; for example, replacement of headers with a more stress-resistant ligament design. Although many of these actions have helped improve cycling capabilities, limitations remain and in some cases remedial actions have created new problems. For instance, some plant operators have installed drainage systems to deal with condensate removal during cycling and there are reports that some are now experiencing cracking and failures in such systems.

Remedial actions identified as having the biggest potential to minimise the impacts created by a switch from base load to cycling include (Starr and others, 2000; Lefton and Besuner, 2006):
- increased drainage capacity to promote steam flow through the boiler and pipework;
- improved thermal insulation to increase heat retention, thus minimising thermal cycling;
- improved oil burner reliability, stability and turndown to facilitate rapid and controlled boiler warming;
- boiler off load and economiser recirculation to reduce temperature differentials;
- boiler hot filling to avoid thermal quenching, especially in the economiser region;
- inter-stage drains to enable progressive warming of the boiler;
- modification of tube attachments to reduce failures;
- HP turbine bypass to promote steam flow through steam pipework and into the reheat circuit;
- improved condenser air extraction and vacuum raising;
- provision of auxiliary steam supplies to facilitate rapid warming from cold conditions;
- improved reliability and accuracy of plant control and instrumentation systems. When appropriate, some (normally) automated controls may need to be operated manually, enabling plant operators to take direct control of certain functions.

Based on practical experience, the precise strategies adopted may take some time to develop and it is not unusual for operating strategies adopted to vary considerably between individual plants and countries.

Maintenance and repair issues

Experience indicates that, if maintenance programmes are not managed correctly when cycling, costs increase and reliability falls as the plant slides into a reactive mode of maintenance. With cyclic operation, the main focus is often on the management of plant performance. However, it is equally important to understand and monitor the impact on plant materials in order to avoid failures and to optimise the reliability of components. This can be achieved via a combination of advanced analytical techniques, online condition monitoring, and critical engineering assessment. The impact of cyclic operation must also be reflected in maintenance planning. Historically, maintenance has been planned on a time basis, although under cyclic conditions the outage frequency is much less predictable. Thus, it may be appropriate for plant operators to adopt a maintenance regime based on the number of cycles, rather than the total number of accumulated hours of operation.

Even where a component may not require replacement, there may be areas that now require addressing on a more regular basis. For instance, a major UK power plant experienced steam turbine blade erosion as a result of cycling. Although, this is currently controlled, turbines now require refurbishment on a regular four-yearly basis as a consequence of imposed cycling (Starr, 2010).

The application of impact modelling can be useful in helping monitor and predict component behaviour and lifetime although, where possible, it is important for utilities to determine such impacts based on data collected during plant operation. The assessment of actual plant temperatures, pressures and unit chemistry during cycling can be critical in analysing correctly cycling-related impacts. Actual plant data can be very useful in assessing damage per cycle, calibrating damage models, diagnosing problems and making cost saving recommendations.

Particularly for some older plants, cycle water chemistry can also be an important issue. Corrosion and/or corrosion products or contaminant transport can impact in various ways on the boiler circuit. Impacts can include hydrogen damage or stress corrosion cracking of turbine components, increased corrosion fatigue in boiler waterwall tubing, pitting in reheater tubing, long-term overheating of waterwall tubing, and a greater requirement for regular chemical cleaning of the boiler water circuit (Fernando and others, 2000). However, where appropriate measures are taken as part of a comprehensive maintenance schedule, many corrosion problems can be avoided.

Coal storage

Increased electricity input from competing generating systems can mean fewer operating hours for coal-fired power plants. Thus, coal may remain in plant stockpiles for longer than anticipated. Extended storage can create problems, particularly where high volatile coals are stored as there is potential development of hot spots and self-ignition. For instance, longer than expected storage periods in Germany have required the application of remedial actions such as compacting, mixing, and building stockpiles with appropriate geometry (Bruggendick and Benesch, 2011). Protracted storage can also result in weathering and oxidation which affects coal characteristics; low temperature oxidation can significantly influence and alter some inherent coal properties.

3.4 Financial impacts of switching from base load to cyclic/irregular operation

The introduction of intermittent renewable energy sources into an existing portfolio of power plants can have financial implications in many areas of generation and can be a complex (and often controversial) area to address. Some of the additional costs involved are obvious and easily calculated, whereas others are less so. Many of these elements are beyond the scope of this report and continue to be debated elsewhere. Numerous studies addressing the cost of electricity generated by different renewable energy systems have been undertaken in many parts of the world. However, it is often difficult to compare these directly and in isolation. The impacts and costs of intermittent generation can be assessed only in the context of the particular type of system in which they are embedded (Gross and others, 2006).

The impacts that result from introducing intermittent renewables into existing power systems depend on a variety of issues that include the ‘quality’ of the renewable source (such as wind strength and variability), grid capabilities, the regulatory and operating practices in place, the accuracy of forecasting of intermittent output, and the degree of geographical dispersion (such as wind turbines). Some of these do not impact directly on coal-fired power plant costs and a full discussion of these issues is beyond the scope of this report; thus, cost-related issues discussed are limited mainly to those linked directly to the operation and maintenance of coal-fired power plants, and the changes that result from a change from base load to more irregular modes of operation.

Despite difficulties in comparing different studies, there is general agreement that electricity generated by intermittent renewable sources is more expensive than that produced by conventional thermal plants. For instance, a recent report produced by the UK Energy Research Centre examined generating costs and concluded that it currently costs nearly twice as much to generate electricity from an offshore wind farm as it does from a conventional power station (Derbyshire, 2010). It further noted that the construction costs of offshore wind power, instead of falling over the past five years as predicted, have in fact increased by more than 50%. Alongside construction costs, US studies note that wind power imposes additional operating costs on a system, but suggests that these costs will be

Table 12 Additional costs resulting from increased plant cycling (Fleming and Foster, 2001; Chow and others, 2002; Lefton and Besuner, 2006; Denny and others, 2007; Starr, 2010)

Extra start-up costs
Increased power consumption by auxiliaries such as boiler feed pumps, condenser cooling water pumps and boiler fan groups
Increased fuel oil support and consumption. At the start of each cycle, extra oil is needed to bring equipment up to operating temperature and to raise steam
Increased use of chemicals required for unit start-up
Additional manpower needed
Increased maintenance and overhaul capital expenditures
Costs for ongoing condition modelling and monitoring
Increased staffing costs
Increased ongoing maintenance requirements
Replacement of damaged components due to shortened unit life
Forced outages
Forced outage effects, including forced outage time, replacement energy, and capacity
Long-term generation capacity cost increase due to a shorter unit life
Loss of revenue from lost electricity sales – the cost of electricity production lost during a repair outage generally exceeds the cost of the repair
Major repairs carried out during times of peak production. Planned outages are normally conducted during a period of low demand
Low/variable load operation
Increased heat rate. There is significant degradation in unit heat rate when power plants cycle extensively. It can result from fouled heat exchangers, worn seals, wear/tear on valves and controls and so on
Reduced operating efficiency. Poor efficiency due to low load operation, load following, unit start-ups and shut-downs
Less electricity generated per tonne of coal
Emission control equipment
FGD, SCR and other emissions control systems operating under non-optimal conditions
Additional chemicals and reagents may be required
Additional staffing requirements

'moderate' at penetration levels expected over the next 5–10 years. It does, however, comment that wind integration costs are likely to increase with the degree of penetration (Parsons and others, 2006). Many aspects concerning the true cost of electricity produced from sources such as wind and solar continue to be disputed and debated and often, opinions remain highly polarised.

Industrial experience has confirmed that when a coal-fired plant is switched from base load to some form of cyclic operation, there will be a net cost penalty. The scale of this will depend on various factors, many of which are highly site-specific. Additional cycling-related costs can arise from a number of sources; the main ones are summarised in Table 12.

Where units experience reduced lifetime of major components as a consequence of cycling, there can be substantial capital costs required for replacement, plus associated cost penalties that may arise from a lengthy outage (Chow and others, 2002). For example, as a result of extensive shifting operations, a major UK power plant was forced to replace a steam drum and superheater as a consequence of cracking (Starr, 2010). Cost implications were significant.

Where an electricity system comprises a combination of coal-fired units and other types of generating plant, there may be a number of operating strategies available (two-shifting, part loading, or running above Maximum Continuous Rating) when attempting to accommodate variable input from intermittent sources such as wind. For instance, it may be appropriate to keep the maximum number of coal units in service at periods of low demand, although operating above their minimum load capability, with stable combustion without oil support. Thus, a balance may need to be struck between operating several units (burning coal only) at lower load, or shutting down one (or more) and operating another at higher load. The heat cost saved by operating one unit at higher load comprises savings from reduced coal consumption by operating under more efficient conditions, plus the auxiliary power consumption saved by not running boiler feed pumps, boiler fans and condenser cooling water pumps overnight on the shut-down unit. Each option has its own set of cost implications which depend on the individual circumstances.

Table13 Cost benefit of part-loading two 680 MW units instead of shutting down one unit (Chow and others, 2002)

	Cost, HK$/cycle
Non-heat cost	
Maintenance cost	13,000
Heat cost overnight	–23,500
Start-up costs	
Makeup water	1000
Fuel – oil	20,000
Fuel – coal	4000
Auxiliary power	1400
Total part loading cost	15,900
Overall savings	7600

In some cases, the start-up costs for make-up water, fuel oil, coal and auxiliary power consumed while returning a unit to service may not be recovered by the fuel cost savings from more efficient operation of the units that remain synchronised, unless the duration of the shut-down exceeds eight hours (Chow and others, 2002; Starr, 2010). Thus, there can sometimes be advantages in part-loading several units rather than shutting one down. For instance, Castle Peak B in Hong Kong is able to achieve stable combustion of several 680 MW units (without oil support) down to 220 MW, allowing more coal-fired units to remain in service overnight. Indicative cost implications of part-loading are shown in Table 13.

High MW ramp rates on plants not specifically designed for cycling can produce high temperature and/or pressure rates of change, resulting in component damage and increased maintenance costs. Appropriate control of ramp rate can have a significant impact on both areas. For instance, Lefton and Besuner cite the case of two identical 550 MW units, operated by two different utilities. Analysis revealed that one unit had associated cycling costs for typical starts that were half that of the other's. This resulted from gentler MW and temperature/pressure ramp rates. They also noted that in a European unit (designed for cycling, with a turbine bypass), the majority of tube failures, and significant costs resulting from rapid starts, could be attributed to a single component, the reheater. Again, the cause was found to be excessively fast temperature changes during start-ups. Calculations showed that correcting this operational problem would result in a cost reduction of at least 20% per start and a similar, or greater, reduction in forced outages.

Under some circumstances, although potentially costly, the decision may be made to run a unit above its MCR (Lefton and Besuner, 2006). Frequently, steam boilers and other plant equipment may be operated beyondthe MCR capacity. It is usual for boiler manufacturers to rate their equipment to have a specific MCR on a continuous operating basis, with a 2–4 hour peak rating, often 110% of MCR. At the design stage, margins are built into the peripheral equipment of the boiler and other major items of equipment to ensure the capability of meeting performance guarantees. These margins include items such as additional fan volume and static capability, pump capacity, oversized material handling systems, and so on. In some situations (for instance, in the USA) the conservative design of all equipment results in the capability of overfiring the boiler above and beyond the peak 110% MCR rating. Operating peripheral equipment at their physical limits does not necessarily create problems.

However, operating a steam generator continuously above MCR may create long-term maintenance issues, resulting in associated costs not easily detectable in the short term. The impacts of severe overfiring can include (Reeves, 2008):

- overheating damage to refractories;
- changes in tube metallurgy;
- erosion of boiler tubes and particulate collection devices;
- corrosion of furnace walls and superheater tubes;
- steam moisture and solids carryover. This causes problems with superheater tubes, steam turbine blades, and other process equipment.

However, there may be situations where the production demand or a high-profit opportunity warrants overfiring the steam generating equipment, and it may be an appropriate business decision to suffer the short- and long-term increased maintenance costs to obtain the extra production. In South Africa, Eskom often puts plants into ‘Emergency Level 1 – EL1’ – this pushes the plant temporarily past its MCR in order to address capacity shortfalls (MacColl, 2011). Because of the often significant differences between generating systems, the decision to two-shift, part load, or exceed MCR can only effectively be based on individual circumstances.

3.4.1 Costs per cycle

The real costs of irregular plant operations and repeated cycling are not always known or fully understood. Even where a particular unit was designed for cycling from the outset, there are a variety of external effects (such as balance of plant design, water chemistry, pulveriser operation, coal type, and so on) that can influence overall cycling costs. In order to optimise plant performance and determine the true cost of each operation, an individual in-depth analysis of plant operations is required. This can help clarify the levels of cycling damage and costs. Because of the large number of variables, it is difficult to compare costs directly between individual units. However, such analysis is often beneficial for in-house plant planning and operation purposes.

In the USA, in-depth cost analysis has been undertaken by a number of utilities to quantify the increase in capital and O&M costs of increased cycling resulting from higher wind power penetration brought about by state RPS mandates. For reasons of commercial confidentiality, much of the detailed data has not been published. However, indicative figures have been made available from the analysis carried out by several US utilities. For instance, Florida Power Corporation recognised that cycling was increasing its maintenance, capital, and forced-outage rate expenses, and decided to determine the total cycling costs. As part of this, the utility examined two 500 MW coal-fired units at its Crystal River plant. Although precise data was not made public, it was determined that total cycling costs for individual hot starts fell between US$30,000 and US$110,000 (for comparison, a 330 MW SC gas-fired unit had cycling costs of between US$15,000 and US$70,000 per hot start). For cold starts the figures were between US$70,000 and US$240,000. When the data were incorporated into the company’s system planning and dispatch models, the resulting savings amounted to between US$10 and US$25 million per year. Using the same analysis methods, Public Service Corporation of Colorado reported comparable results for two of its similarly-sized coal-fired units.

A major internal US industry survey undertaken in 2002 (Gostling, 2002) suggested somewhat lower figures and that the average cold start cost for a 1 GW nominal output coal-fired plant was around US$70,000; a warm start cost US$ 4000, and a hot start US$ 3500. However, individual estimates apparently ranged widely about these figures. European studies have indicated a similarly wide range (depending on the type of unit) with the cost for a single on-off cycle falling in the range €200 to €50,000. Studies concluded that the cycling costs depend mainly on the type of boiler used in the unit, rather than the fuel type (Denny and others, 2007).

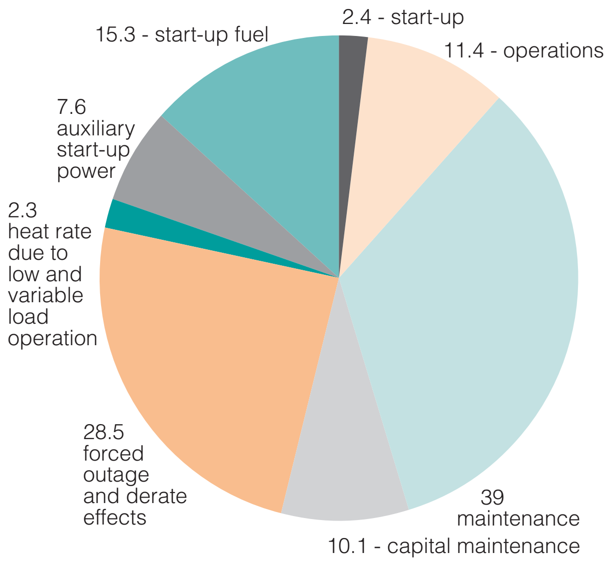

Figure 12 Example of cycling costs US$ thousand) (Puga, 2010; Agan and others, 2008)

Table 14 Start-up-shut-down cost per cycle for different generating technologies (Puga, 2010; Agan and others, 2008)	
Unit type	Potential range of total cost (US$ thousand)
Coal – small drum	3–100
Coal – large supercritical	15–500
Gas turbine	0.3–80

Another US study examined several coal-fired power plants operated by Xcel Energy. Here, an analysis (undertaken by APTECH Engineering Services) was based on the actual operating statistics and costs of the 30-year-old 500 MW Pawnee power plant over a 10-year period (1997-2008). Cycling costs were dominated by fixed and variable cost of maintaining and repairing resultant wear and tear (42%). The results of one such analysis (for a typical start-shut/down cycle) are summarised in Figure 12.

In this case, the overall cost per cycle of US$116.6 k (in 2008 values) falls at the lower end of the range for 'typical' coal-fired plants. However, estimates can vary widely; examples for selected systems are shown in Table 14. The increase in the cost of electricity of 0.21 US$/MWh resulting from increased cycling reported by Xcel is relatively low as the plant in question underwent a relatively low number of cycles and had a high capacity factor during the analysis period. However, both such operating conditions are unlikely to exist for many coal plants as additional wind generation comes on line. Thus, after long-term operational impacts and shortened plant life are considered, the true cost of cycling a large coal generating plant are likely to be significant (Puga, 2010; Agan and others, 2008).

Studies also examined the cost impact of integrating wind power into Xcel's system, focusing mainly on the effects on three of its coal-fired plants (Pawnee Unit 1 in Colorado, Harrington Unit 3 in Texas, and Sherburne County Unit 2 in Minnesota) as a result of enforced cycling. The purpose of the study was to attempt to quantify the increase in capital and O&M (including fuel costs) for the three plants. It was suspected that the addition of wind power to the generation mix would affect significantly the cost of maintaining the integrity of the overall fleet. Although largely confidential, a public domain overview was made available (APTECH, 2008). A summary of the analysis of the Harrington plant follows (*see opposite*). A similar report also addressed the Pawnee unit (Agan and others, 2008).

The development of sound cost data will help determine how to operate a particular combination of power plants most effectively. Knowing the extent of damage (and associated costs) per cycling event can help determine whether particular units are shut down, ramped down to minimum output, or two-shifted. In the longer term, it may prove less expensive to maintain operations at a low level than to cycle a unit. Not cycling on-off or going to two-shift operation for specific units with low cycling

Harrington Unit 3, Texas, USA

Table 15 provides a summary of the best estimates of the total cost of cycling the unit for the year 2000, adopted as the baseline year. Prior to 2001, the unit was used for base load, operating at >80% for much of the time. During the baseline year, there was little wind generated power coming into the system. These historical baseline results were then compared with the forecast cost results for a year in which significant wind generated power was produced. The impact of the latter was expected to increase plant operating costs.

The total cost of cycling analysis was examined using nine different cost categories:

- cost of operation – including operator non-fixed labour, general engineering and management cost (including planning and dispatch); excludes fixed labour;
- cost of maintenance – including maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components;
- cost of capital maintenance – includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components;
- cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity;
- cost of long-term heat rate change due to cycling wear and tear;
- cost of heat rate change due to low load and variable load operation (process-related);
- cost of start-up auxiliary power;
- cost of start-up fuel;
- cost of start-up (operations – chemicals, water, additives, etc)

These were then totalled to determine the cost of each type of cycle (hot start, warm start, cold start, and significant load following) (Table 15). Of the nine cost factors, plant wear and tear costs were the highest. Although these estimates give some idea of the scale of costs that can be involved, they are only relevant to the particular plant and are not easily compared with those for other units. Nevertheless, they do provide helpful data on the potential cost implications associated with different forms of operation and can be very useful for internal planning and scheduling purposes.

Table 15 Cost elements for different types of cycles at Harrington Unit 3 (in 2008 US$'000/cycle) (APTECH, 2008)

Cycle type	Baseline data cycle Best estimate	Low estimate	High estimate
Hot start-shut-down	131.5	97.8	158.4
Warm start-shut-down	167.2	131.8	214.1
Cold start-shut-down	293.9	217.2	333.5
Hot shut-down-start	155.7	119.0	184.5
Warm shut-down-start	198.2	160.0	248.5
Cold shut-down-start	349.0	266.4	391.4
Significant load following	2.33–2.73	1.38–1.71	3.85–4.36

For hot starts, the average peak ramp rate was 152 MW/h, for warm starts it was 102 MW/h, and for cold starts it was 140 MW/h costs may provide an effective competitive strategy when cycling costs are analysed. Through such analysis, a power plant should be able to improve cost control and operational flexibility, improve response time, and boost profitability. It may also help determine whether equipment is maintained on the basis of total operating time, or on the number of accumulated cycles.

A rapidup time is advantageous in a number of ways. This includes the amount of fuel consumed during the process. It has been calculated that each minute longer for start-up consumes ~0.08–1 tonne of equivalent fuel per 100 MW of the unit's rated capacity (Leizerovich, 2008).

3.4.2 Procedures to minimise cycling costs

Industry experience has shown that under some circumstances, certain types of coal-fired power plants can be cycled successfully. However, this mode of operation is acknowledged as being more complex and requiring greater investment than steady-state working, resulting in higher operating costs (Bruggendick and Benesch, 2011). A number of studies have examined these issues and suggested ways to minimise the cost impacts associated with cyclic operations. For instance, Lefton and Besuner (2006) recommended a number of strategies on plant operation and chemistry and suggested various possible improvements and hardware additions and/or modifications. Many focused on operational changes to control/decrease the temperature ramp rates of key components during start-stop operations. This has been identified as a major factor influencing the speed of unit response and the extent of damage and costs entailed. Suggested plant hardware modifications to minimise these impacts have included the addition of comprehensive monitoring equipment to measure temperatures of specific boiler areas and steam lines, particularly during critical shut-downs.

Plant chemistry during start-up, shut-down and unit lay-up can have a major impact on component damage and cost. However, even when remedial actions are taken to correct imbalances in plant chemistry, there may be a delay before optimum conditions are regained. This can increase the risk of, for instance, localised pitting and stress corrosion cracking of some turbine components (Zhou and Turnbull, 2007), phenomena reported by a number of plant operators. This has occurred mainly in plants undergoing frequent start-up and shut-down and has been attributed to conditions created during standstill phases. In some cases, costly rehabilitation measures have been required. To overcome the problem of corrosive attacks during outages, various remedial strategies have been developed, such as the adoption of modified turbine shut-down procedures that help reduce relative humidity inside the LP turbine casing (Leidich and Klein, 2006).

Different strategies for minimising plant impacts and controlling costs have been suggested (see, for instance, MMU, 2010). This particular study included recommendations for improving hot start procedures. Although each unit needs to be assessed on its own merits and limitations, the following procedures are fairly typical of units currently operating successfully on a two-shift regime:

On boiler shut-down:
- de-load the unit to 50% load (using sliding pressure control if available) and follow with rapid shut-down whilst maintaining maximum superheat and reheat temperatures;
- top up boiler level (drum type boilers) before burners removed;
- box up the boiler to maximise heat retention. Avoid air purge of boiler.

On boiler start-up:
- commence boiler light-up sequence fans in service (purge boiler). Light up burners in service;
- begin to raise condenser vacuum (air pumps in service);
- open boiler stop valve or bypass early to facilitate turbine gland steam sealing;
- open turbine bypass if fitted;
- initial firing with boiler drains closed to raise the temperature as quickly as possible to match

metal temperatures and to begin to raise steam;
- fire in a balanced pattern to promote boiler circulation (natural circulation boilers);
- increase firing rate to raise boiler gas temperature to match final steam temperature as soon as possible;
- open superheater bypass if fitted;
- open drains progressively starting from the primary superheater and moving towards the final superheater (fit inter-stage drains) so that flow is established in final superheater when gas temperatures are matched. Delay opening of turbine steam drains to avoid cooling of main steam pipework;
- fire on coal as soon as possible (just prior to steam if bypass fitted or just after if not fitted). Steam to set and run up to speed;
- synchronise unit and raise load at prescribed rates (typically 3% MCR/m up to 50% MCR and then 5% MCR/m up to full load);
- close turbine bypass and close superheater bypass (where fitted);
- commission mill burner groups as required.

As input from intermittent renewable sources continues to rise, it will become necessary in future, for some coal-fired stations to adopt a dynamic and flexible response to accommodate new operating regimes. Where used as back-up (spinning reserve), low load levels of operation are likely to be required (Rieck, 2011). Thus, coal units will need to be capable of turning down to their lowest stable operational level. On some, stable low load combustion is achieved by firing light oil with the coal input; this technique can be applied to both subcritical and supercritical boilers. A number of new proprietary burner configurations aimed at easing operation at lower load levels have been introduced in recent years, and in some cases the requirement for oil support has been greatly reduced.

Various means continue to be developed in order to allow successful low load operation to be achieved successfully without oil support. These include measures to increase burner turbulence, the use of more finely milled coal particles, and improved unit air control. The technical minimum output of most power plants is in the range 35–50 % of the nominal output (Lehner and Schlipf, 2011). Although testing on a German coal-fired unit has managed to achieve plant operation (using a single burner) down to 15%, 20% was considered to be the safe stable lower limit. At low levels of operation, boiler efficiency falls and levels of CO produced tend to increase. There may be environmental legislation limits for CO in force, hence this may influence the lowest load level achievable (Bruggendick and Benesch, 2011). Low load operation may be preferable to adopting two-shifting or other irregular modes of operation, helping to keep plant on line and avoid costly ramping and shut-downs.

Plant start-up and load following can sometimes be eased and optimised through the use of advanced control systems. For instance, a number of South Korean power plants were designed for cycling duty and two-shift operation. Here, an automated sequential control system (ABS) was adopted for two-shift operation. This system also controls automatic starting and loading of the units from initial light-off of the steam generator to full unit load of 500 MW. With the balance of plant auxiliaries stopped and the steam generator empty of water, the ABS is capable of automatically starting and loading the unit up to its full load. Newer Korean units have benefitted from recent further advances in control technology. For example, four units at the Yonghung supercritical plant (which came on line in 2004 and 2008) use a sophisticated centralised automatic integrated control and monitoring system (ICMS) that manages operational and emission reduction systems (Peltier, 2005; OECD/IEA, 2007). Supplied largely by Emerson Process Management of the USA, the ICMS manages all major plant systems.

3.5 O&M – predictive failure and condition modelling

Damage resulting from cycling or high load operations affects future maintenance requirements and capital replacements, forced outages and deratings. The time to failure from the start of significant cycling operations in newer plants can vary between five and seven years, and in older plants between nine months and two years (Lefton and Besuner, 2006).

The lifetime of major plant components is often monitored on the basis of cumulative hours of operation. However, a switch from base load to cycling may mean that other factors need to be taken into account. O&M suppliers generally recommend a specified time period (total number of hours of operation – Equivalent Operating Hours – EOH) for major inspection outages. Typically, for a steam turbine this is around 50,000 hours. However, for each start-up cycle additional hours need to be added (for example 30 hours) to the unit's cumulative time (Chow and others, 2002).

Predicting the costs and impacts of cyclic operation in all of its possible combinations requires modelling capabilities that are capable of determining with reasonable accuracy the overall impact of any given cycle on both the short- and long-term costs that will result. A comprehensive damage model takes into account the damage that results from different modes of plant operation (cycling, base load, and above MCR) for key plant components. Such models are usually calibrated with plant temperatures and pressures ('signature data') collected from major (stressed) components during a typical load transient. These transients can be converted to 'equivalent hot starts' (EHS) to determine the cyclic fatigue and creep damage (Lefton and others, 2002). Data collected and analysed can give an indication of the scale and scope of cycling-related creep and fatigue damage and can be useful in helping to determine the expected useful lifetime of specific plant components under different modes of plant operation. Various models have been developed to address these areas (Gostling, 2002). Although they vary in their degree of comprehensiveness and scope, their main elements generally comprise:

- establishment of historical cycling pattern at a high level (for instance, hourly MW data);
- collation and analysis of available historical operational data;
- establishment of a base cycle to compare and relate to actual cycles;
- introduction of a damage accumulation model that includes terms covering steady state (creep), cyclic (fatigue) and off-load (corrosion) conditions.

Such systems can be used to estimate the cost of each type of start or load change. However, there are a large number of possible variants in terms of unit types, equipment manufacturers, balance of plant types, and operational regimes that make it difficult to determine cycling costs precisely; a range may be the best that can be achieved.

A number of damage models have been developed that include creep and fatigue (plus their interaction) for different unit types, and different pressure and temperature ranges, under base load and non-base load operation. Typically, they are calibrated using plant temperature and pressure signature data for key unit components that operate during typical load transients. Critical components where detailed plant data are analysed are likely to include (where appropriate) the steam drum, water wall/evaporator tubing, first/second pass water wall tubing, superheater and reheater tubing and headers, economiser inlet, start-up system components, and turbine/generator-related components (such as valves, cases, generator windings and steam chests). The maximum temperature ramp rate and the overall range of temperature change experienced by a component during each transient are key indicators of cycling-related creep and fatigue damage. Such parameters are used to quantify the severity of each unit's load, start-up, and shut-down transients (Lefton and Besuner, 2006). The use of such plant data and modelling capabilities can be useful in helping to establish a reasonable cost estimate for each cycle, as well as determining the remaining useful life of particular components. It can also enable plant operators to determine the optimum temperature for the ramp rate during all types of start-up, shut-down, and cooling. This information helps plant operators minimise damage, maximise unit life and reliability, and better control maintenance costs.

Potentially, there are a number of techniques that can be applied, one important variant being Condition Modelling (CM). This is a useful tool when applied to power plant maintenance, and

Table 16 Summary of Mirant Mid-Atlantic's equipment monitored and estimated savings (Smith, 2010)

Rotating equipment		Valves/coal pipes/boiler		High-voltage motor control		Totals	
Number of points surveyed	Number of problems	Number of points surveyed	Number of problems	Number of points surveyed	Number of problems	Number of points surveyed	Number of problems
5559	123	5726	578	1331	43	12,616	744
Estimated savings (US$ – 2006 data)							
Vibration-related problems							1,708,101
Valves/coal pipes/boiler tubes/conveyers							3,315,408
Motor control centres/electrical systems							43,000
Total for year							**5,066,509**

utilities have developed a number of predictive forms in order to improve control of O&M requirements and costs and increase unit availability. These can cover aspects such as:

- vibration monitoring and analysis and in-place dynamic balancing – applicable to virtually all rotating equipment such as motors, pumps, fans, compressors, turbines, and generators;
- infrared thermography –surveys of valves, motor control centres, load centres, transformers, boiler casings, boiler tubes, coal conveyors, and motors;
- ultrasound – ultrasonic leak detection, performed routinely on valves, tanks, piping and other equipment.

The use of such techniques and the data produced can form the basis of a cost-benefit analysis of estimated future cost savings. For instance, through its programme of plant condition monitoring, the US generator Mirant Mid-Atlantic calculated the savings made when plant problems were identified prior to failure. An average figure per problem was produced; for each potential fault identified the utility saved US$13,887. The total included savings of US$5736 for valves and coal piping, and US$1000 for each motor control centre/electrical problem detected. Table 16 shows the estimated savings produced by the company's system, delineated by equipment type. Estimated savings exceeded US$5 million per year (Smith, 2010).

Although, clearly, the situation will differ according to different circumstances and individual units operating under different conditions, it is apparent that condition monitoring and other similar techniques, used as part of a comprehensive plant O&M programme, can generate significant savings and reduce unplanned outages by predicting failures before they happen. This is of particular importance where plant cycling has increased and become part of normal operations.

3.6 Impact of cycling on coal-fired plant emissions

Renewable energy sources such as wind power are often perceived as being substitutes for fossil fuel-based energy production, and thus a strategy for reducing pollutant emissions and CO_2. However, what is not always fully understood is that gas- and coal-fired units are usually needed to compensate for the issue of intermittency, a role that creates incremental fuel usage and emissions compared to a situation where the conventional capacity operates on a steadier basis (Hawkins, 2010a). As the day-to-day operation of wind (and solar power) generation does not itself create any harmful emissions, it is often promoted as a means for achieving national emissions targets. However, it is often unclear whether policy makers consider the impacts that large amounts of, in particular, wind power, can have on overall system operation and other associated forms of generation.

It is commonly supposed that, as part of the rationale for replacing fossil fuel fired capacity with renewable technologies such as wind power, pollutant emissions and CO_2 will be reduced significantly. However, studies have shown that this may not necessarily be the case. As conventional coal and/or natural gas plants are reduced to make room for wind generation, and are then subjected to stop-start conditions or ramped up as wind generation subsides, the heat rate rises; this reduction in efficiency increases fuel consumption and emissions. Although the type and scale of these impacts are dependent on many site-specific factors, it is likely that at least some of the environmental benefits of introducing wind generation onto an electricity system will be negated by an increase in emissions from any back-up combustion plants (Denny and O'Malley, 2006; MMU, 2010; Bentek Energy, 2010). To date, only a few studies have addressed these issues directly. However, several have concluded that the effect of wind integration on both fuel consumption and emission reductions can in fact be negative.

In some countries, current levels of wind power are modest at present, although in a number of locations (such as parts of Europe and some US states) there are proposals for this to be increased beyond the 20% level. As such additions are made, more comprehensive data should become available on the possible impacts of integrating high levels of wind power into conventional energy systems, and the effect on the operation of associated coal-fired plants should become clearer (Hutzler, 2010). However, practical experience has already shown that cycling coal-fired power plants can have a negative impact in a number of areas. Boilers are generally designed to run most efficiently on base load, within a narrow, steady-state range of operating conditions, and operation outside these parameters invariably has an impact. Optimum boiler operations are obtained using a precise and steady flame temperature, coupled with carefully controlled levels of air and coal. Varying these operating conditions can create significant challenges. Plant efficiency is reduced and the operation of emission control systems impaired, increasing plant emissions per unit of electricity generated. Crucially, such disruptions often extend well beyond the immediate time period of reduced output, resulting in non-optimum operation for many hours.

If lower output is required from a coal-fired unit, the coal feed rate is reduced. This allows the boiler to cool down, thus producing less steam and therefore, less power. During this period of reduced operation, plant emissions may decrease, simply as less coal is being consumed. However, the emission rate (emission/MW output) actually increases as the plant is operating less efficiently. Furthermore, when the plant is required to come back to full output, the coal feed is increased and the boiler temperature is again raised, increasing the emission rate further (Bentek Energy, 2010).

Cycling plants can also impact directly on the operation of emission control equipment such as FGD units, and to regain optimal control such systems may require recalibrating and adjusting. To effectively control plant efficiency and emissions can involve a combination of computer-based technology and manual intervention. There may be more than 50 individual adjustments required in order to respond to changing generation output, a process that can be both complex and time-consuming. Studies have confirmed that where cycling has been imposed on coal plants, it can take up to 24 hours for some emission control equipment (such as bag-houses and FGD units) to settle back to the pre-event emission rates. During these periods, emission rates normally exceed what would be experienced if the plant were operating under stable conditions. Thus, the incorporation of intermittent renewable energy sources into some power systems can have an adverse impact (in terms of efficiency and emissions) on any associated coal-fired plants. This is particularly so where a system relies heavily on coal-fired back-up plants and has a relative lack of gas-fired capacity. The production of ever-larger amounts of intermittent renewable energy will only exacerbate this problem.

These unintended consequences are not necessarily disclosed by proponents of renewable energies nor taken into account when calculating system-wide emissions. For instance, recent studies suggest that the Netherlands government failed to take full account of the reduction in coal plant efficiency once wind was introduced into the system, and thus overestimated the scale of CO_2 reduction. Dutch researchers (de Groot and le Pair, 2009) determined that when the efficiency of coal back-up plants was reduced by more than 2% as a consequence of wind generation-induced cycling, fuel use and emissions increased accordingly (Hutzler, 2010). This somewhat negated expected savings in fuel and reduced CO_2 emissions.

One of the main reasons given for the adoption of wind power is that it displaces fossil fuel CO_2 emissions. The ongoing debate between renewables and fossil fuel proponents addressing this issue is often highly polarised, with each frequently disputing the conclusions of the other. For instance, the effectiveness of West Denmark's large wind powered generating capacity in mitigating CO_2 emissions has been questioned by some observers (for instance, Mason (2004) who suggested that the increased development of wind turbines has done little to reduce overall Danish CO_2 emissions). Here, much of the wind power produced has to be exported at prices below the cost of production. Despite the installation of a significant amount of wind power, until recently Denmark's CO_2 emissions were still increasing (Cohen, 2010). Similarly, calculations produced by Etherington (in 2004, addressing the UK situation) disagree strongly with figures for CO_2 savings produced by some UK-based wind power proponents.

The nature of back-up systems used is an important factor within this debate. Studies by Hawkins (2010b) analysed a series of heat rate simulations representing the cycling of coal plants when wind power was introduced into a system. To assess the impact on overall CO_2 emissions, one set of simulations evaluated wind energy replacing coal power, with different technologies serving as back-up power. It was determined that if coal alone were used as back-up, overall CO_2 emissions would increase as a consequence of cycling. Thus, under circumstances where wind is integrated into a system that is primarily coal-based, it does not necessarily produce an offset in CO_2 emissions but could actually result in an increase. China, for example, relies on coal for 80% of its electricity generation and natural gas for only 2%. Thus, paradoxically, as a number of studies have confirmed, the displacement of fossil fuel fired generating capacity with a significant level of intermittent renewables may not necessarily produce the emissions reductions expected, but may actually result in an overall increase. For instance, studies such as those carried out by Bentek Energy (2010) (*see* Case Study on page 60).

However, an opposing view is taken by others. For instance, reviewing the UK situation, Gross and others (2006) agree that as a consequence of wind power integration, some thermal power plants will be operated below their maximum output to facilitate this, but argue that fuel (and CO_2) savings not realised because of the reduced efficiency are 'generally small'. It concluded that there was no evidence to suggest that efficiency was reduced to such a degree as to significantly undermine fuel and CO_2 savings. This study also suggested that the introduction of significant levels of intermittent renewable energy generation into the UK electricity system would not necessarily lead to reduced reliability of supply, at least for the foreseeable future. In the longer term, much larger penetrations may also be feasible given appropriate changes to electricity networks, although this is not considered (Gross and others, 2006). Other studies (such as Denny and O'Malley, 2006) have analysed the impact of systems with large penetrations of wind power on the operation of conventional plants and the resulting emissions of CO_2, SO_2 and NOx. These concluded that wind generation could be used as a tool for reducing CO_2 emissions but it would not be effective in curbing emissions of SO_2 and NOx.

The ongoing debate over possible impacts on emissions is sometimes characterised by highly divergent views, and the topic is likely to remains under discussion for some time. As further additions are made to wind (and solar) power capacity around the world, new operational data, operating experience and further studies should make the true impacts on plant emissions clearer and ease system planning and operation.

Public Service Company of Colorado (PSCO) and the Electric Reliability Council of Texas (ERCOT) study (2010)

This study (undertaken by Bentek Energy) considered operational data accumulated over a four-year period and focused specifically on the energy markets of Colorado and Texas. It examined how wind, coal, and natural gas-based generating systems interact. In both cases, state policymakers hoped that the integration of renewable energy sources would reduce overall emissions of CO_2 from their respective systems, and by displacing conventional fossil fuels, would reduce smog and other air pollution by reducing levels of SO_2 and NO_x.

A major component of the study was an examination of how the addition of wind power to the energy mix had displaced coal-fired capacity, resulting in its irregular cycling. Wind power is mandated by US state Renewable Portfolio Standards as a 'must take' resource. As a result, when wind power is available, output from coal- and gas-fired plants must be ramped down. Colorado has an RPS that requires 3% of the electricity generated by investor-owned utilities to come from qualifying renewable technologies; this will increase to 30% by 2020 (Hutzler, 2010).

PSCO operates a significant amount of coal-fired capacity, with 3.76 GW of coal-fired plants, 3.24 MW of gas-fired combined-cycle and gas turbine capacity, 405 MW of hydro and pumped storage capacity, and 1.06 GW of wind power capacity. The introduction and integration of 775 MW of wind power in 2007 meant that coal-fired plants were increasingly being cycled. It was generally assumed that overall emissions would be reduced by this addition to PSCO's portfolio. However, as elsewhere, PSCO's coal-fired plants operate most efficiently when operating on base load and are not necessarily well-suited to accommodating the load variability imposed by the integration of wind generation.

The Bentek study determined that the cycling imposed on PSCO's coal plants by the integration of wind power into the system negated the emission benefits of the latter. Cycling of the coal plants decreased their overall efficiency and increased emissions of SO_2, NOx and CO_2 emissions per unit of electricity generated. The loss of efficiency also reduced the effectiveness of their environmental control equipment, driving up emissions. Thus, the enforced cycling of these units actually resulted in higher emissions of SO_2, NOx and CO_2 than would have occurred if wind energy input was limited and the coal plants were not cycled. Between 2006 and 2009, individual PSCO coal-fired plants experienced emissions increases of between 17% and 172% higher for SO_2, up to 9% higher for NOx, and up to 9% higher for CO_2. One plant switched to a lower sulphur content coal, but still suffered from an overall increase in SO_2 emissions of 18%. Also, between 2006 and 2009, these plants reduced their generation by over 37%, exacerbating the situation further (Hutzler, 2010).

Generally, when coal plants are cycled the heat rate rises, resulting in higher emissions. This problem can persist for up to 24 hours after cycling the facility. Contrary to the stated goals, implementation of RPS in Colorado appears to be adding to the air pollution problem. Similar findings were found for ERCOT, which also operates under an RPS mandate to utilise wind power. Bentek Energy concluded that unexpectedly, the addition of wind power has not allowed these utilities to reduce emissions, but has been directly responsible for creating more.

As part of the study, the direct impact on overall emissions of several specific 'wind events' were analysed in detail. The definition of time period of the event can significantly affect the findings. Thus, when a very narrow definition is used (the time between when the wind build-up begins and when it falls off) using wind energy appears to create a net emissions savings. However, when the definition is broadened to include the balance of the day after the wind dies down, the emission impacts become much more significant. The difference between the two approaches is the fact that cycling coal plants often results in the destabilisation of the emission control equipment, thereby reducing its effectiveness and producing additional emissions for a far longer period than just the actual wind event itself. The entire day (or longer) requires analysis to understand fully the impact of cycling on overall emissions. The study concluded that enacting RPSs that require more than 5–10% of wind energy for electricity generation is likely to add significantly to emissions unless adequate (more flexible) natural gas generation is utilised in order to avoid the cycling of any associated coal plants.

3.6.1 Operation of emission control equipment

When coal plants are subjected to rapid start-ups, shut-downs and low load operation, all plant systems are affected in some way. Like the boiler and other component parts that make up a coal-fired generating facility, there are emission control systems that can lose their effectiveness as a consequence of variable plant operation. Some can be particularly affected during start-up and shut-down periods. When the plant is returned to full output, emission control systems such as FGD units and some particulate control devices require recalibration and adjustment in order to regain optimal control. Industry experience suggests that it can take up to 24 hours for full operational capability to be restored (Bentek Energy, 2010).

SO_2 control

FGD units, like most other emissions control systems, operate best under stable controlled conditions. However, increasingly, changes in power plant operations means that many now have to cope with more irregular working. In the UK, a typical coal-fired plant equipped with FGD operates on base load during the winter months, but reverts to two-shifting at other times of the year. For instance, West Burton power station undergoes around 200 start-stops each year; this also includes the plant's four (MHI/FLS miljø) wet limestone FGD units. Similar modes of operation are also encountered in other parts of the world, with FGD operation now expected to adapt to the changing circumstances.

FGD maintenance costs are usually taken to be independent of plant operating hours or operating regime although, in reality, there is likely to be some impact when cycled. In particular, the number of start-ups can have a significant impact on the rate of degradation of some plant components, due to the mechanical and thermal stresses that the start-up procedure imposes on the plant (UK DTI, 2000). Specific examples include the effects of thermal cycling on FGD absorber linings and the additional rotational loads on motors and pumps as they are accelerated to operating speed (Wu, 2001). In some types of FGD unit spray density may need to be increased when operating at reduced load in order to minimise the risk of encrustation.

During normal operation of a coal-fired power plant, bulk SO_2 emissions are generally directly proportional to the load, although in concentration terms they should be relatively constant. Generally, coal mills are not operated at less than 50% of their capacity because of the irregularity of discharge at low feed rates. As a result, oil or gas burners sufficient to provide 15–20% of the boiler's MCR are required for boiler start-ups to avoid bringing mills on and off line at low loads. Some oil can contain higher sulphur levels than coal, hence can increase start-up SO_2 levels. In addition, it may take some time before mills are operating fully, during which time the burners need to operate at much greater air-to-fuel ratios than normal (Fernando and others, 2000). As a consequence, SO_2 levels are likely to increase during start-up periods. The overall amount of SO_2 produced is proportional to the number of starts experienced.

With some types of FGD, repeated start-ups and shut-downs can cause problems with system foaming. Accurate control of liquid levels is crucial for effective operation, and foaming during start-up makes this difficult. Under some start-up conditions, there is the risk of FGD liquid flowing through ductwork and into the booster fans, damaging fans and other equipment. Remedial actions such as the use of antifoam reagents, operational changes, and frequent ductwork draining may be required (Hoydick and others, 2008). All impose a cost penalty.

Frequent unit start-ups and shut-downs can also increase the risk of corrosion-related impacts. Materials designed for base load operation may deteriorate more rapidly when subjected to repeated thermal cycling or cycling through the acid dew point, and liners and expansion joints may have to be replaced or upgraded periodically. Due to the nature of their operation, FGD units employ a range of corrosion-resistant materials in their construction. Units may incorporate combinations of carbon steel lined with rubber, vinyl ester, epoxy, and high alloy steels to counter/control corrosion issues. Alloys such as stainless steel or nickel-rich alloys may also be used either as solid plate or 'wallpapered' over carbon steel. Depending on the particular design, there are a number of regions of an FGD unit that are particularly prone to corrosion. These can include the air preheater outlet, particulate collection device, FD and/or ID fans and various sections of ductwork. Corrosion normally results from cool spots on the unit's walls, expansion joints, access doors, or air in-leakage. During normal operation, under typical operating conditions, flue gas temperatures range between 150°C and 200°C. Where temperatures outside these limits are encountered, problems can be exacerbated (Jaworowski and Langeland, 2008). Temperatures outside the design specification (more likely to be encountered during start-up and shut-down) can increase the rate of corrosion of various components. Fatigue of metal components can also increase as a result of the expansion and contraction of the metal substrates.

Under cyclic or low load operation, there may be the option of operating two (or more) FGD units at low load, as opposed to shutting one down and running the other at higher load. Depending on the type of FGD, there may be the option of operating with perhaps just one of a plant's two absorber modules and associated equipment at moderate-full load, with the other(s) taken off line. This may be preferable to operating multiple absorbers at reduced load. The full operation of a single module ensures that the gas flow through the unit and the reagent feed rate can be close to the full-load rate. Alternatively, where multiple FGD units are deployed, there may be the option of shutting down some whilst maintaining others at full load. For instance, this strategy is adopted at Drax power station in the UK. When the station is operating at reduced load, some FGD units are also maintained at full load with others off-load, rather than all the units operating at reduced capacity. The SO_2 removal efficiency is around 97% at reduced load although during cycling, the effective efficiency is cut to 80–85% as the FGD plant only comes on stream for loads greater than 50%.

Some FGD variants are equipped with a bypass system. This allows flue gas to be diverted past the FGD unit, directly to the stack and helps provide operational flexibility during boiler start-up and shut-down. However, like a power plant, many site-specific factors can influence the decision of how best to operate a particular plant's FGD system(s). Ideally, where cycling is to form a regular part of plant operations, the FGD units should be capable of working under low load conditions, and designed with this in mind. Cycling of an FGD unit not designed in this way can result in heavy wear on components such as plant pumps, motors and switchgear. Furthermore, some FGD variants designed for full load use may be oversized and hence, unsuitable for operation at reduced loads or in a cyclic manner.

Thus, potentially, there can be a range of cycling-related impacts on FGD system operation. Repeated cycling can impose a number of extra tasks and procedures on operators (such as opening system drains), as well as increase wear and tear on plant components through both fatigue and corrosion (Hoydick and others, 2008). However, industry experience suggests that even with increased cycling, most effects can be minimised with due diligence, through the use of suitable precautions and procedures.

NOx control

The principal oxides of nitrogen emitted during coal combustion are nitric oxide (NO) and nitrogen dioxide (NO_2), generally referred to as NOx. Potentially, NOx emissions can be controlled in a number of ways. Emissions can be prevented by measures such as the adoption of primary measures (combustion control) and the deployment of low NOx burners, or controlled by selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) systems. These are explored in depth elsewhere (Nalbandian, 2009; Wu, 2002) so are not considered here in further detail.

Like SO_2 control technologies, systems for controlling plant NOx emissions operate most satisfactorily under steady stable conditions. Under cyclic operation, particularly during periods of rapid load increase, NOx emissions can increase and are likely to remain at an elevated level until steady loading has been re-established. Considerable fine tuning of control systems can be required in order to regain optimum emission performance and some systems are effectively inoperable under part load conditions. Such increases due to cyclic operation are not restricted to coal-fired plant, and NOx emissions can also increase significantly from modern CCGT facilities during start-up (Bass and others, 2009). As noted above (*see* Public Service Company of Colorado (PSCO) and the Electric Reliability Council of Texas (ERCOT) study, 2010) on a system-wide basis, where a portfolio of generating technologies are used, increased cycling resulting from intermittent generating sources can produce an overall increase in NOx emissions from coal-fired plants.

Depending on the individual circumstances, some SCR systems can be operated under part load conditions. Some may also be operated during start-up and shut-down, but only whilst gas temperature is adequate for SCR operation (Staudt and others, 2004). However, not all systems are operable during periods of start-up or shut-down. As coal-fired boilers are cycled between low and full load operations, the SCR unit temperature also fluctuates; however, there is a minimum operating temperature below which it should not be operated. The optimum temperature is usually between 300ºC and 400ºC (normally the flue gas temperature at the economiser outlet) although a recent development on low/part load operation in Germany allowed SCR unit operating temperature to be reduced from 320ºC to 280ºC without jeopardising plant operation (Bruggendick and Benesch, 2011). If the operating temperature is too low, there is the possibility of ammonium bisulphate forming in the catalyst, causing deactivation. This phenomenon can be avoided by the use of an economiser bypass which can increase the SCR operating temperature during low load operations. However, for units firing high-sulphur coals, the minimum operating temperature can be relatively high. In this case, even with an economiser bypass, the required SCR operating temperature may no longer be maintained (Nalbandian, 2006). Sometimes a partial bypass system may be used. Some European units were designed without a bypass, unlike many power plants in the north-eastern part of USA that are equipped with a SCR bypass; here, legislation requires NOx reduction only during the ozone season (May to October).

Overall, increased plant cycling, as opposed to base load operation, often requires increased operator input and control. There may also be increased emission levels when not operating in a steady state.

Particulates

Most coal-fired units now incorporate some method for controlling particulate emissions. ESPs are the most common industrial devices for particulate control, with an estimated 70% share of the total particulate control market. There are a number of commercial variants available. These are available for a wide range of gas temperatures, typically from 120–180°C for cold-side ESPs (located after the air preheater) and 300–450°C for hot-side ESPs (located before the air preheater). ESPs are very efficient at removing most of the particulates from a gas stream, with collection efficiencies exceeding 99%. Globally, ESPs (cold side, dry) are the most widely-used technology for particulate matter control on coal-fired power plants. Particulate control technologies have been well explored (*see* Zhu, 2003; Nalbandian, 2006).

The main alternative to an ESP is a fabric filter that generally operates in the temperature range 120–180°C.The choice between ESP and fabric filtration depends on coal type, plant size, boiler type and configuration. However, their application to pulverised coal fired steam generators has been somewhat limited because of considerations relating to flue gas temperature. If this falls below the dew point of water vapour, the fly ash collected on the bag filter is moist and tends to adhere to the filter bags, increasing pressure drop. Insulation needs to be of high quality to maintain heat and bags should be kept ‘dirty’ so that fibres are protected from dew point transitions (Fantom, 2005). Furthermore, if flue gas temperature entering drops below the condensation point of sulphuric acid, the flue gas becomes corrosive to all but prohibitively expensive bag fabrics and bag life is greatly reduced. For these reasons, use of fabric filters on pulverised coal fired units is generally avoided during start-up and low load operation.

Capture systems operate better under constant process conditions. Where boilers are cycled repeatedly, such as in the UK, the gas cleaning equipment can be subject to many stops and starts.

Potentially, this can cause problems for ESPs and fabric filters. Like many plant systems, an ESP will operate best under stable steady conditions and, depending on the particular variant, may not respond well to changes in gas temperature, pressure or flow rate, conditions that may be encountered during on-off operation or operating at varying load. However, when operating at reduced load under certain conditions, the reduction in gas flow can increase the specific collection area and hence collection efficiency may rise.

Generally, ESPs cannot be brought into operation until the flue gas temperature entering is above the dew point of water vapour in the flue gas stream, as fly ash in the flue gas will have a relatively low resistivity if moisture in the flue gas condenses. Failure to maintain the temperature above the dew point can result in moisture contributing towards the build-up of difficult-to-remove dust. For cold side ESP units, optimum performance is obtained with a flue gas temperature of 135–163°C, the range of maximum fly ash resistivity. For many pulverised coal fired applications, the minimum flue gas temperature required at the electrostatic precipitator is ~93°C.

ESP efficiency can be reduced by the presence of even small amounts of condensed sulphuric acid mist in the flue gas; even very low concentrations passing through the unit can significantly reduce collection efficiency. Acid gases also increase the risk of corrosion at lower temperatures. For these reasons, ESP operation is sometimes precluded during start-up and low load operation.

For most boilers, oil or natural gas is fired during start-up, with pulverised coal not being fired until the required minimum flue gas temperature is reached. This helps meet stack opacity and particulate emission requirements. However, in practice, there do not appear to be many severe operational ESP problems associated with cyclic operation although if this causes the residual carbon-in-ash level to increase beyond specified limits, it may preclude its subsequent sale.

Start-up and shut-down procedures must always be given close consideration to avoid or minimise the effects of going through the dew point, causing condensation and corrosion. Such procedures may include pre-heating the unit and monitoring its temperature to prevent moisture condensation. Filter bag cleaning may also need to be continued for some after unit shut-down.

4 Cyclic operation of advanced coal-fired power plants

The cycling of conventional PCC subcritical power plants and issues associated with this type of operation have been discussed above. In the following section, the practicality of cycling plants based on other forms of coal-based technology is examined.

4.1 Supercritical (SC) PCC-based plants

There has been a growing push towards the adoption of supercritical (SC) and ultra-supercritical (USC) PCC technology in a number of major economies for some years. Compared to conventional subcritical systems, the higher steam conditions provide greater efficiency, better economy and lower emissions. For some time supercritical technology has been deployed in Europe, Japan and China – and in the USA it has seen something of a renaissance, being adopted for a number of new projects. It is also making headway in the dynamic Indian economy, with significant new capacity under construction or planned (Blue Wave/IEA, 2007; Mills, 2007). It is likely that, at least in some parts of the world, new coal-fired power plants (including SC and USC plants) will be expected to accommodate cycling from the first day of operation, although in others plant will remain predominantly on base load. However, where a growing level of intermittent generation forms part of a system, some form of cyclic operation and/or load following is likely to become the norm. Industry experience has shown some designs of plant to be inherently more tolerant than others.

Steam boilers are distinguished by water circulation design, which impacts load following and other capabilities. There are two main types of boilers for utility-scale power plants: drum and once-through. Typically, drum boilers are used in subcritical plants and require thick walled steam drums, with a large thermal mass to hold the cycle's steam. Alternatively, supercritical plants are based on a once-through design that does not recirculate fluid. Without a heavy steam drum, the once-through design has less thermal mass, allowing faster load response and shorter start-up times (Buhre and others, 2002). However, once-through load response adjusts both fuel firing and steam flow rates, and may introduce stresses not present in drum boilers. Despite the more responsive dynamic performance of a once-through unit, the durable drum boiler is sometimes regarded as more suitable for dynamic and two-shift operation (Lindsay and Dragoon, 2010). In many situations, the efficiency advantage of the SC cycle over the subcritical cycle will dictate that it remains at base load (Schimmoller, 2011) although this will not always be the case.

An advantage of SC boilers is that their variable evaporation endpoint enables achievement of high main steam temperatures over a large output range, independent of operating conditions. Main steam temperatures are independent of load, resulting in higher process efficiency over a wide load range. Minimum output in once-through operation at high main steam temperatures is typically 35–40% for furnace walls with smooth tubes, but can be as low as 20% where rifled tubes are used (Siemens Power Generation, nd). The smaller thermal storage mass (compared to drum-type boilers) aids flexible plant operation, allowing shorter start-up times and bigger load transients over a comparatively wide output range. The use of thin-walled separators instead of a thick-walled drum produces lower thermal stresses that can result from temperature changes. However, some supercritical units can have high start-up losses as large quantities of steam, and therefore heat energy, must be dumped to the condenser during the start-up process (OECD/IEA, 2010).

Start-up can be relatively rapid for some types of unit, dependant on the rate of heat transfer into major plant components – this often dictates the rate of the start-up process, and some technology suppliers have developed technical solutions to shorten the process. For example, Siemens has a novel feature for its HP turbine modules whereby a small amount of cooling steam passes through radial bores into the small annulus between the inner and outer HP casing (effectively protecting the inner surface of the outer casing which would otherwise be exposed to main steam temperature). This internal bypass cooling system has made it possible to reduce the wall thickness of the outer casing and thus enable faster heat-up (Siemens Power Generation, nd; Cziesla and others, 2009).

Some suppliers claim that their SC PCC designs are inherently suited to cyclic operation, with rapid response times. For instance, Alstom suggests that its once-through boilers can respond quickly and adjust to changes in load demand while maintaining tight control of steam temperatures. Alstom's design uses a sliding pressure mode, where pressure is reduced with load. This allows the maintenance of relatively constant first-stage turbine temperature, reducing the thermal stress on components as the unit is cycled. This is claimed to be beneficial in terms of maintenance requirements and allowing higher availability. Plant efficiency at low load is also better than older conventional plant designs and there is now industry experience to confirm that regular two-shift operation can be undertaken without experiencing major plant problems. For instance, KEPCO's Taean plant in South Korea is one of a number of the country's plants based around standardised 500 MW sliding pressure units (Alstom, 2007). Since 1995, the two Taean units (and others) appear to have operated in daily regular two-shift operation with a high degree of reliability.

It is claimed that some of the newer SC units currently in operation or being developed can actually react more quickly and are more flexible in terms of load change gradients than some older natural gas fired plants. For instance, RWE Power is currently building such a plant at Hamm (2 x 800 MW) in Westphalia, Germany, due for start-up in 2012 (Frohne, 2011). The new units are expected to be able to operate at low loads of ~25% of rated output. They will also be able to reduce output from 800 MW to about 200 MW in less than 30 minutes and be capable of reverting to full load.

The use of the very high pressures and temperatures proposed for some newer SC/USC developments will impose arduous operating conditions on plant materials and there are some concerns that cycling may increase the prospect of mechanical and thermal fatigue. Some materials and components utilised in these systems may be less tolerant to temperature cycling than those used currently. Where some newer materials are concerned, creep-fatigue, repair welding and cyclic oxidation remain pertinent issues (Starr and others, nd). There may be further concerns where cycling of USC units is envisaged, as some of the more advanced alloys used in their construction are not well suited to cycling, potentially making them more prone to creep and fatigue damage. Thus, it has often been assumed that the majority of USC plants will operate predominantly on base load (Susta and Boo Seong, 2004). However, in the light of changes taking place with much of the global generation sector, this may not necessarily be the case. Materials development is an area in which R&D efforts and investigations are continuing globally (Blue Wave/IEA, 2007).

A number of advanced alloys have been in widespread use for some years (for example, ferritic alloy steels such as P91) and have been shown to be capable of withstanding these increasingly arduous conditions. In the case of P91 alloys, these exhibit high strength and high oxidation resistance up to temperatures of ~600°C. Advantageously, this allows smaller wall thicknesses to be used in the manufacture of components such as superheater coils, headers and steam piping, helping contribute towards a tenfold higher thermal fatigue life (Zactruba, 2010) and making it well suited for some plant components that operate on a cyclic basis. However, these steels can be relatively sensitive to heat treatment (through changes to their micro structure). Hence any plant repairs that involve forming and/or welding will require close control of cooling rate, both pre- and post-welding.

Due to the once-through nature of SC boilers, increased erosion-related problems have been reported for some SC PCC units that have been cycled repeatedly. Solid particle erosion (SPE) is caused by deposits, such as magnetite, that have exfoliated from boiler tube surfaces. The worst erosion has been associated with particle impingement on the high pressure control stage and the first reheat stage. Industry experience has shown that nozzle and bucket repair/replacement are about one and half times more frequent than subcritical units and SPE has been flagged up as the major cause of heat rate degradation in supercritical turbines. The degree of erosion has tended to increase with the extent of cycling. The situation is reportedly worse for once-through SC units in the USA, not equipped with a steam bypass (PowerClean, 2004).

4.2 CFBC plants

The steam cycle of most CFB units is similar to that of a conventional pulverised coal plant. Many are subcritical although some newer units are now operating with temperatures and pressures close to supercritical designs. The first plant to adopt SC steam conditions is in operation in Poland and a second is nearing completion in Russia. Many coal-fired CFB units are of moderate capacity and operate predominantly on base load, although new projects are being developed globally both for cycling and base load operation. For instance, an example of the latter is at Naga, in the Philippines, where a 200 MW CFB-based project is under construction which will provide base load power to the Visayas grid. As far as can be ascertained, many of the larger units currently operating are predominantly on base load, even though some have been designed with both base load and cyclic capabilities; for instance, KEPCO's 2 x 200 MW Tonghae CFBC-based power facility in South Korea is just one of many.

Some CFB units are viewed as having good turndown, with load following capabilities similar to those of PCC units. Part loads down to 25% of MCR and load change rates of up to 7%/min are possible. For comparison, typical PCC plant rates are often in the range 2–2.5%/min (Lehner and Schlipf, 2011). However, start-up times for some CFB units can be longer than for similarly sized PCC plants.

As the steam cycle is similar to that of conventional PCC plants, repeated cycling can potentially affect various plant components in a similar manner. However, additionally, there is also potential for refractory damage when CFBC plants are cycled repeatedly. Wide or rapid refractory temperature changes occurring during start-up, shut-down or load following can cause thermal shock-related problems, particularly in the combustor and loop seal areas. Thus, compared to conventional PCC plants, CFB cyclic operation is likely to incur some different costs and stresses (Lindsay and Dragoon, 2010).

There are little published data on issues that arise during CFB cycling. However, a number of units have been cycled repeatedly for some years, apparently without problems. For example, Japan's largest coal-fired CFB facility is the 149 MW Itoigawa plant. This IPP generation facility has been operating flexibly for over a decade. During most of the day it operates at full capacity, and in load-following mode at other times. At night, it is turned down to 40% of its capacity (Yokogawa, nd). Automatic (CENTRUMS CS) systems are used for start-up, shut-down and load following, minimising the need for manual input.

As when cycling conventional PCC plants, there are various plant modifications that can be made to minimise the impacts associated with CFB start-stop operations. For instance, Foster Wheeler offer for their Compact CFB boilers a patented reheat steam bypass system for reheat steam temperature control. The design also provides in-duct start-up burner systems, used in combination with over-grid burners to shorten start-up times and save fuel (Goidich, 2001). To accommodate cycling, steam bypass systems have been adopted on a number of CFBC units. For example, in the USA, the Spurlock Generating Station in Kentucky incorporates a steam turbine bypass system that allows the boiler to start up independently of the steam turbine. This reduces turbine thermal stresses and unit start-up time. Similar systems are also installed on several coal-fired Compact units at Tha Toom in Thailand.

Globally, apart from one, all CFBC units currently in use operate with subcritical steam conditions. The exception is the supercritical 460 MW Łagisza plant in Poland. As this has only entered commercial service relatively recently, no operational issues have yet been reported. A second supercritical CFBC power plant (330 MW) is being developed at Novocherkassk in Russia.

4.3 IGCC plants

To date, where used for commercial operation, the handful of coal-based IGCC plants have operated predominantly on base load. There are a number of reasons for this:

- turndown characteristics of IGCC units are limited and somewhat complex;
- start-up from cold is time-consuming (longer than for conventional plants) because of the need to avoid the formation of explosive mixtures and the necessity of bringing the reaction chamber up to temperature;
- flexibility in terms of load-following is more limited;
- high capital cost; this reduces the attractiveness of running on part load;
- potential for downtime corrosion;
- there are also a number of ancillary systems needed for gas and wastewater purification that need to be brought on line, causing additional problems for operating staff (Starr, 2002).

Because of their highly integrated nature, there have been concerns about the ability to two-shift plants based around entrained flow gasifiers economically. Others, particularly those of the fixed bed type, appear more amenable to shutting down overnight and restarting the following day. It is suggested that, two-shifting may be difficult for some types of plant, although load following may be easier. A major concern appears to be the syngas gas exchanger where there is the potential for corrosion-assisted fatigue. This potential problem could increase if more corrosion-resistant coatings are used, as these tend to be less ductile than current alloys.

Figure 13 The Willem Alexander IGCC plant at Buggenum in The Netherlands (photograph courtesy of NUON)

However, there is some industry experience of load following; for instance, reportedly, the Buggenum IGCC (Figure 13) is turned down to 57% of peak load at off-peak periods; Shell suggests that 50% is viable. Here, plant load-following capabilities are limited by the ASU. The gasification island can change at >5% load/min, and the total IGCC with SCGP (Shell Coal Gasification Process), >3% load/min (de Graaf, 2008).

In Japan, Nippon Petroleum Refining's 431 MW (refinery residue-fuelled, oxygen-blown, GE direct quench gasification) Negishi IGCC plant in Yokohama is routinely turned down by 25% over a 30-minute period. It operates at 75% of full capacity to accommodate lower power demand at night and weekends. It can be ramped up to full capacity over a 30-minute period when electricity demand increases again (Ansolabehere and others, 2007). Some proposed plants, although not yet built, will be expected to achieve significant turndown in order to operate satisfactorily under cycling conditions. For instance, in the USA, AEP has suggested that several proposed coal-fuelled IGCC projects will have target turndown to 40% of full load, and be capable of load following operation (Zando and others, 2006).

In the Netherlands, NUON is developing its coal/biomass/gas fuelled Magnum IGCC project (Figure 14). The plant will comprise between three and five combined cycle units and three

Figure 14 Artists impression of the proposed NUON/Vattenfall Magnum plant (photograph courtesy of NUON)

gasification units, with a total net power output of 1200 MWe. About 60% of the fuel input will be supplied by the gasification units and the remaining 40% by natural gas. NUON suggests that this multifuel plant will operate on coal for base load and gas for peak load, and will be well placed in the Netherlands as well as in the merit order of northwest European plants as a whole. However, it is acknowledged that future increased generation from renewables such as wind and solar power could lead to a greater need for load following (de Kler, 2007). The Magnum design will combine the fast ramp-up and ramp-down capabilities of gas turbine technology (for peaking) with the virtues of a base load generation on coal, biomass and other secondary fuels. The coal-based portion of the plant is expected to come on line post-2020.

4.4 CCS-equipped plant

In some parts of the world, the impact of renewables on the next generation of fossil fuel plants will be significant. The irregularity of demand is likely to have an even greater effect on efficiency, maintenance and reliability than current two-shift operation, for which there is now much experience. Problems caused by two-shifting and other forms of cycling are likely to be greater with more advanced designs of power plant, particularly those equipped with some form of carbon capture system. However, in some situations, the successful deployment of CCS may help secure stable base load for some coal-fired plants in the face of the growing impact of intermittent generating technologies.

Where a coal-fired plant is equipped with CCS and operates within a contestable electricity market, capital and operational costs will be influenced significantly by the way in which it is operated (base load, two-shifting or load following). Particularly at times of high demand and/or power prices, commercial returns may take precedence over CO_2 capture and the decision may be to turn down or turn off any energy-intensive capture plant (Campisi and Wokoboenko, 2010). Cyclic operation, as opposed to base load, will place additional requirements on plant design and plant life that will need to be considered. Much of the discussion of the economics of CCS-equipped coal-fired plant concludes that it will be important for CCS units to operate at a high load factor in order to recoup the higher capital costs. However, due to their higher operating costs (relative to wind and nuclear) some may be forced to run as mid-merit rather than base load units.

There are a number of advanced coal-based technologies that can be used for power generation, some potentially more amenable to carbon capture than others. However, with most, development continues and deployment has so far only reached pilot scale. Thus, at the moment, data from extended utility-scale operation is lacking. Hence experience of operating these systems under real conditions is limited. Therefore, there remain a number of unknowns such as how much extra fuel might be consumed in the start-up of an advanced CCS-equipped generating plant (compared to a conventional PCC plant), or indeed whether such plant can be started up and shut down in response to rapid changes in demand. Similarly, it is not yet clear how flexible large-scale oxyfuel plants will be (Burchhardt, 2011).

A major factor for CCS units is the amount of energy consumed by the capture process. This can take several forms such as provision of steam for a water-shift reactor in a pre-combustion process, regenerating amine in a post-combustion process, or operating an air separation unit (ASU) for either a pre-combustion or oxyfuel process. Under appropriate circumstances, this energy could temporarily be directed to providing more power to the grid, rather than applied to the capture process. This would give CCS units the ability to engage in spot, balancing and reserve markets (Ladbrook and Pearce, 2010). There may be a number of possible options to provide additional grid power. One would be to turn off the capture facilities and vent the CO_2, although this may not be practical because of carbon and electricity prices, and any emission limits in force. Alternatively, in the case of a post-combustion process, the captured CO_2 could be stored in the form of the CO_2-rich amine. This could be regenerated later, when electricity prices had fallen.

In a pre-combustion process, coal-derived syngas is fed through a water-shift reactor where it is mixed with steam under high pressure to produce hydrogen and CO_2; these are then separated. It should be possible to tailor operating conditions such that excess hydrogen could be produced. This could be stored and, when electricity prices were high, used to fire gas turbines or substituted for the hydrogen produced in the water-shift reactor, allowing steam required for this process to be diverted to power generation. At times of low electricity prices, it may also be possible to divert power to the ASU supplying oxygen to a gasifier or oxyfuel process. If the oxygen produced was stored it could be fed to the process when electricity demand warranted it, avoiding the power requirements of the ASU.

The IEA GHG R&D Programme has recently examined several possible options whereby flexible operation of coal-fired plant equipped with CCS might be achieved (Davison, 2010a). Davison noted that power generation processes with CCS capable of operating at variable load will be needed to achieve deep reductions in emissions (to near-zero levels) of CO_2 to the atmosphere. This will need to be achieved against a background of increased cyclic activity for many coal-fired plants. Operational flexibility will be needed to cope with the variability in power demand; this need will be greater if intermittent renewable generators, such as wind, are deployed on a large scale. Costs of power generation with CCS will depend greatly on fuel costs, the type of electricity system, and the required CO_2 reductions. For operation at high load factors, power plants with integrated CCS (such as post-combustion capture) have the lowest costs. However, it is not possible to achieve deep reductions in emissions by abating only base load plants – in some countries, a significant amount of electricity is generated by non-base load plants and to achieve major CO_2 cuts these will also need treating. For instance, in 2009, around 40% of the UK's generation was non-base load, a situation mirrored elsewhere. Flexible power plants with near-zero emissions will be needed to decarbonise this electricity. There could also be issues associated with the high cost of CCS-equipped plant as some coal-fired units may not be operating full time. Hence investment costs will take longer to recoup.

CCS operational flexibility requirement will depend on a variety of factors that include the variability of power demand, the amount of renewables and nuclear on the grid, and the overall CO_2 emissions target. Davison considered several ways in which coal-fired plants with CCS could possibly achieve flexible and economic operation under conditions of varying demand, and addresses both integrated and non-integrated systems (Davison, 2010b).

To date, most work on coal gasification-based processes with CCS has concentrated on IGCC. Most systems proposed are highly integrated and potentially this could constrain the flexible operation of any associated CO_2 capture plant. Possible areas of concern include the thermal cycling of equipment, liquid distribution in columns, and process materials reaching steady state. However, an alternative with greater operating flexibility has been proposed whereby a gasification hydrogen plant would be capable of operating independently to the main power plant; thus, the gasification, CO_2 capture, transport and storage equipment could be operated at full load while the power plant operated flexibly in response to the electricity demand. This would be made possible by underground buffer storage of hydrogen. The concept of storing hydrogen in salt caverns has already been undertaken at a commercial scale in the UK and USA (Davison, 2010a). If required, the gasification and power plants could even be on separate sites.

In the case of post-combustion capture, the degree of integration with the power plant will be less than some competing systems, possibly offering increased scope for flexible operation. Thus, if the capture plant shuts down, the power plant could still operate. It may also offer the option to allow for increased capacity by temporarily curtailing the capture process during periods of peak power demand. Some technology developers are known to be addressing the issue of flexibility, but to date, little information has been made public. However, there are suggestions that some capture technologies may be able to react relatively quickly to changing requirements. For example, the Siemens-developed post-combustion capture process (PostCap – based on amino acid salts) has been developed for both new build and retrofit applications. It is claimed that the process is very flexible and can respond quickly, allowing it to follow the cyclic operation of the power plant. A response time of less than 30 minutes from start-up to full capture capacity has been claimed (Kremer, 2011). Some capture processes may be more flexible than others and may be affected in different ways. In the case of capture processes based on chilled ammonia, modelling studies suggest that when the power plant is operating at low load, the reduced heat input to the capture plant will result in a reduced CO_2 capture rate. A 10% drop in heat input for 20 minutes will reduce capture efficiency to an estimated 91.5% (Rode and Meyer, 2011).

Where there is a significant degree of integration between the power plant and CCS unit, there may be operational issues where the capture plant is expected to mirror the cycling of the power plant. Such cycling duties are likely to increase where the level of intermittent energy sources continues to grow. As with cycling of conventional plants, almost inevitably there will be effects on overall plant efficiency, maintenance, and reliability of the capture plant. However, it is not yet fully clear what types of issues may arise when CCS-equipped plants are operated under cyclic conditions. These issues may not be understood until sufficient data has been accrued from practical experience of their operation under varying actual conditions.

5 Coal-renewables hybrid plants

A possible alternative option currently being explored is to combine a coal-fired plant directly with some form of intermittent renewable energy source such as wind or solar. Under some circumstances, this could provide a more effective way of accommodating energy produced by intermittents, without recourse to two-shifting/cycling of the coal plant and the undesirable impacts that this can have. Several studies have examined the potential for integration in this manner, although to date only a few have progressed to pilot/small commercial-scale testing. Efforts have been concentrated largely on combining wind and solar power with coal- or gas-fired plants.

5.1 Coal-wind hybrids

Several studies in the USA have examined the possibility of supplanting gas-fired power plants with combined wind and coal facilities. Encouragement comes from the fact that a significant proportion of US high quality coal and wind resources are co-located in remote regions such as the Upper Great Plains and the Rocky Mountains. Typically, these are transmission-constrained and located far from load centres. This suggests the possibility of developing new transmission capacity to deliver both resources to the market simultaneously. New transmission investments associated with combined coal-wind development could be made economically feasible by the high utilisation rates associated with the delivery of base-load coal, coupled with emissions-free wind energy. Coal and wind generated power could be co-dispatched, delivering bundled non-intermittent energy. To achieve this, coal plants would need to be capable of dispatching inversely in response to variations in wind power output. Analysis carried out suggests that the ramp rates achievable by newer coal-fired plants (5–15 MW/min for a 500 MW unit) would be capable of matching variations of wind-produced output for much of the time. A key feature would be in matching the wind capacity relative to the coal plant to ensure that wind output variations did not exceed coal plant ramping capabilities. In these particular circumstances, it is likely that wind's share in a joint coal-wind system would be less than 10% of total system output (Owens, 2004).

Also in the USA, a techno-economic analysis was carried out examining an Advanced Coal Wind Hybrid (ACWH) concept. This explored the feasibility of combining wind farms with advanced coal generation facilities and operating them as a single generation complex (to be located in Wyoming). A major question was whether such a hybrid would provide sufficient advantages through improvements in the utilisation of transmission lines and the capability to firm up variable wind generation for delivery to load centres to compete effectively with other supply-side alternatives in terms of project economics and emissions footprint. The ACWH considered comprised a 3 GW IGCC power plant equipped with CCS, a fuel production or syngas storage facility, and a 1.5 GW wind plant. The plant was connected to load centres by a 3 GW transmission line and operated in such a way that the transmission line was always utilised at its full capacity by backing down the combined cycle power units to accommodate wind generation. Studies suggested that operating the facility in this manner would result in a constant power delivery of 3 GW to the load centres, in effect firming-up the wind generation at the project site (Phadke and others, 2008). The study concluded that the concept was technically feasible and could be economic under certain circumstances (Phadke, 2007).

The developers (Summit Power Group) of a 400 MW coal-fuelled IGCC (the Texas Clean Energy Project) in the USA have proposed integrating the plant's operations with electricity generated by wind power. Instead of shutting down the plant when excess wind energy is available to the grid, operations will switch to the manufacture of urea, using the plant's unwanted base load power. Urea is used widely for the production of fertilisers. The plant will also incorporate a CO_2 capture plant. Summit anticipates that income from the project will be from three streams: electricity generation, urea sales, and CO_2 sold on for enhanced oil recovery.

In Europe, several advanced hybrid concepts for combining coal- and wind-based technologies continue to be considered. For example, Siemens is examining the use of intermittent renewable sources such as wind power to provide electricity that would be used to electrolyse water. This would produce oxygen and hydrogen; the latter could be used for power generation or combined with coal gasification, shift and methanation, then used for power generation or SNG production (Kremer, 2011). These concepts are being looked at by Siemens and a number of universities, although developments are still at an early stage.

5.2 Coal-solar hybrids

Efforts to develop coal-solar hybrids are being pursued in several parts of the world. A potential advantage of adding a solar thermal module to an existing coal-fired power plant is that much of the necessary infrastructure (steam cycle, etc) and plant requirements already exist. This can make the economics more attractive than those of a stand-alone solar thermal generating unit (Grunweld, 2011). Clearly, the appropriate location and weather conditions are a major prerequisite for the application of any solar-based project.

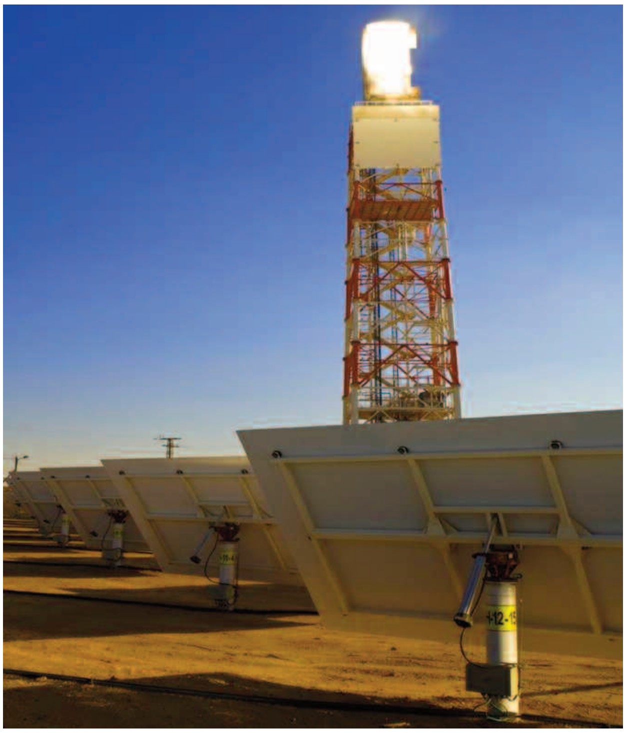

Figure 15 Solar thermal plant steam generator (photograph courtesy Foster Wheeler Power Group)

Solar energy input can be harnessed by parabolic troughs, compact linear Fresnel reflectors (CLFR), or power towers (Figure 15). As part of a hybrid, this would raise steam that would be fed into the fossil fuel plant, reducing the amount of coal (or gas) required. In the USA, EPRI has been examining the concept of combining solar energy with natural gas or coal plants. Such thermal hybrid projects may be the most cost effective option for large-scale use of solar energy. According to EPRI calculations, a solar trough system could potentially provide 20% of the energy required for the steam cycle. The analysis concluded that it was economically beneficial to create an integrated solar steam cycle rather than to use an isolated solar thermal plant. It was proposed that the development of such hybrid plants could reduce the amount of coal or gas consumed, decrease CO_2 emissions, and help some US states meet Renewable Portfolio Standards.

Currently, there are around 15 hybrid solar thermal plants being developed, with a total capacity of 460 MW. EPRI is currently engaged with two demonstration projects, expected to commence operation by 2014 (Renewable Energy, 2010c). These comprise an 1100 MW natural gas combined cycle plant with 95 MW of solar energy (NV Energy, Nevada), and a 245 MW coal plant with 36 MW of solar energy (Tri State G&T, Escalante, New Mexico). Florida Power and Light is also developing a 75 MW solar plant to supply heat (via a concentrating solar thermal power trough) to one of the two 800 MW steam turbines of its gas-fired Martin Power Plant. The Martin Next Generation Solar Energy Center uses ~190,000 mirrors over 500 acres on the existing site and came on line in March 2011.

Near Palisade in Colorado, USA, a US$ 4.5 million project is under way on Unit 2 of Xcel Energy's

Figure 16 The Cameo Generating Station, Colorado, USA. This coal-solar hybrid uses parabolic trough solar collectors to collect sunlight (photograph courtesy of Xcel Energy)

coal-fired Cameo Generating Station (Figure 16). This is using parabolic trough solar collectors and is intended to decrease coal use, increase plant efficiency, lower CO_2 emissions and test the commercial viability of combining the two technologies. It is expected that coal use will decrease by 2–3%. The hybrid plant will produce the equivalent of just one MW (of the plant's 49 MW) from solar power. The parabolic trough system uses glass mirrors to concentrate the sun's energy into a series of tubes filled with a heat transfer fluid (mineral oil). When this reaches 300°C, it is fed to a heat exchanger where the heat is transferred to water, bringing it to near boiling point, before being fed into the existing plant steam system.

Elsewhere, solar integration projects are also being developed on gas-fired generating facilities in Morocco and Algeria. The former comprises a 470 MW plant, with the solar system providing 20 MW of this total. The solar output is estimated at 1.13% of the annual production or some 40 GWh/y. The second project is at the 150 MW Hassi R'Mel project in Algeria, where the solar contribution to the total output is estimated at ~20 MW. It will work in conjunction with a 130 MW CCGT plant and 80 MW steam turbine. A new solar-natural gas project (Agua Prieta II) is also being developed in Mexico where a CSP plant will contribute 12 MW to a 464 MW combined cycle facility. Some major technology developers consider that there may be considerable benefits in combining solar technology with conventional thermal plants in this manner. Recently, General Electric announced that it has entered into an investment and licensing agreement with a CSP provider with a view to combining its FlexEfficiency 50 combined cycle gas technology with CSP.

Other studies have also examined the potential for coal-solar hybrids based on a linear Fresnel collector added to hypothetical 350 MW coal-fired power plants in Australia and the USA (de Lailing and others, 2011). A main focus was an investigation of the entry point of the solar-produced steam into the water-steam cycle. The study noted that the optimum means of integrating a CSP application into an existing power plant was best achieved with a direct steam generating system. This enables direct connection to the steam cycle, thereby avoiding the requirement for additional heat transfer media and heat exchangers. In the proposed system, the solar collector is divided into three different sections, similar to a regular steam boiler. In the pre-heating section, feed water is heated close to the evaporation point at the operating pressure, then sent to a steam drum. In the evaporation section, feed water from the drum is gradually evaporated. Liquid water is separated and the steam heated further in a superheating section. Several possible plant configurations were examined. The overall aim of the project is to reduce plant fuel use and lower CO_2 emissions.

In a recent development (April 2011) it was announced that the Australian utility CS Energy plans to add a 44 MW solar thermal add-on to its coal-fired 750 MW Kogan Creek plant in Queensland. This US$110 million project (Kogan Creek Solar Boost Project) will use Compact Linear Fresnel Reflector technology. The add-on will allow increased electricity production and will avoid an estimated 35,600 t/y of CO_2. Construction is expected to be completed by 2013.

In Chile, GDF Suez and German renewable energy company Solar Power Group is developing a 5 MW concentrated thermal solar power plant. The facility will provide steam to the 150 MW Mejillones coal-fired plant in the northern part of the country. The finalisation of permits is under way, with the intention for the pilot plant to be operational in early 2012 (GDF, 2010; Rojas, 2011).

6 Conclusons

Intermittent renewable sources and integration issues

As a consequence of on-going changes in the make-up and operation of the global power sector, coal-fired power plants are facing growing competition from alternative generating technologies. Historically, much of this has come from nuclear power, natural gas and oil. However, increasingly, it is now also coming from renewable energy technologies that include intermittent sources such as wind and solar power. Deployment of such systems is being driven largely by the growing global demand for electricity and concerns over the use of fossil fuels.

The global wind (and to a lesser extent, solar) generation sector has been growing at a remarkable rate for some years and looks set to carry on expanding for the foreseeable future. In some countries, the contribution of renewables is considerable, although whereas some types are both controllable and predictable, others, such as wind and solar power, are not. Output from both is dependent on natural forces and therefore at the mercy of uncontrollable and sometimes unpredictable changes in weather patterns. For instance, output from a wind farm can change from 100% to zero in a short time.

A significant drawback when generating electricity from intermittent renewable sources is that peak production may not correspond with periods of high demand. Excess electricity cannot be stored easily in readiness for the next increase in demand. Although there are a number of potential storage technologies that could be deployed, most are better suited to smaller-scale applications, and the only system currently finding large-scale application is pumped-storage hydroelectric. Most of the storage techniques available or being developed have technical and scale-up issues to be resolved, and all have significant cost implications. None are ready or cost-effective for utility-scale application.

The integration of a significant amount of electricity from intermittent sources into existing power grids can create operational problems and impose a number of new requirements, especially where the grid is old. Integrating intermittent renewable energy resources reliably into the bulk power system requires significant changes to traditional methods used for system planning and operation. Currently, various strategies are being used to accommodate such changes in grid make-up and performance. Integration issues are likely to increase as the amount of electricity generated by intermittent renewable sources continues to grow.

An often-asked question is what level of intermittent renewables is economic and practical in a particular power system? Recent investigations by the IEA have concluded that there is no simple answer and that a range of strategies will need to be adopted to accommodate the differing individual circumstances – there is no 'one-size-fits-all' (OECD/IEA, 2011). Power systems differ widely in many aspects with some being better able than others to manage large inputs from intermittent sources.

Renewable energy technologies have obvious features that make their use attractive. Compared with conventional fossil fuel-based energy production, 'fuel' costs may be negligible or even zero, as may be emissions generated during day-to-day operation. Within many major electricity systems, output from renewables is now taken first (a 'must-take' resource) in preference to that from any associated fossil fuel-fired stations.

Impacts of intermittent renewables on thermal power plants

Where intermittent sources form part of a portfolio of generating technologies that includes fossil fuel fired plants, their variable output can have a significant impact on the operation of the latter. Many coal-fired stations no longer operate solely on base load, but are now subject to two-shifting or some other form of irregular operation. Often, they are required to operate on a more flexible basis, with load variations and two-shift operation increasingly becoming the norm. However, many plants (based mainly on conventional subcritical pulverised coal combustion technology) were originally designed and built with steady base load operation in mind.

Changing the operational patterns of coal-fired plants can affect a number of areas. Some of the impacts associated with a switch to cycling are reasonably well understood and there is now extensive experience of regular two-shift operation. In some cases, where coal-fired units have been switched to two-shift patterns, relatively few unexpected operational problems appear to have been encountered. Two-shifting is generally focused around regular daily hours of operation, with plants being put on and taken off load at roughly the same times. Consequently, it involves a consistent, fairly straightforward set of actions that are repeated regularly, allowing the development and optimisation of suitable plant strategies, operating regimes, and planned operation. Industry surveys and practical experience have confirmed that, with due diligence, two-shifting of some coal-fired plants can be achieved successfully, although generally at some cost. However, the growing input from intermittent renewable sources has meant that operational changes are now often more abrupt and less predictable. The full consequences of such changes may not become apparent for some time. Furthermore, the current situation will continue to evolve as more intermittent capacity is added to energy systems around the world.

On a localised basis, electricity demand can be influenced by a variety of factors and can vary considerably. To some extent, the demand profile can be manipulated through demand management efforts, although fluctuating supply from intermittent sources makes planning more difficult. Because of this variable output, it is necessary to have spare capacity available to meet peak demand and step in when generation from intermittent sources falls. In some countries much of this spare capacity (‘spinning reserve’) takes the form of coal-fired plant. For instance China is building considerable coal-fired capacity as back-up for its growing wind-based generating capacity. Where coal-fired plants comprise part of a back-up system, they may now be started up and shut down more frequently than in the past. They may also be required to operate at low load, hence with lower thermal efficiency. The industry is trying to achieve stable operation at very low load levels and to increase the maximum speed of load change attainable.

Where a plant designed for base load is now being cycled, repeated on-off start-up/shut-down operations and on-load cycling can be very damaging to plant equipment, and wear and tear can increase significantly. The magnitude of these impacts is largely design-dependent, with some designs of power plant being inherently more tolerant of cyclic operation than others.

Conventional steam plant is often constrained in various ways. Rapid load changes may be difficult because of limited thermal storage, thermal stress limitations, and firing system inertia. Particularly during rapid start-ups, major plant components can experience temperature excursions significantly above design. If such thermal transients are not controlled, then key plant items become susceptible to failure due to thermal fatigue, creep, creep-fatigue and corrosion-fatigue. A switch from base load can affect many areas of plant operation; start-stop or cyclic operation can affect the boiler, steam turbine, emission control systems, electrical, and numerous auxiliary components.

Areas currently with large existing shares of intermittent renewable capacity can experience heavily depressed electricity prices when wind power output is high because this low-cost electricity displaces generation from (higher-cost) fossil-fuel powered plants. Unless compensated in some way, this will mean reduced revenues to those conventional plants that are called upon to operate for less time than intended when they were built. Increased cycling-related wear and tear resulting from responding to a more variable net load may make such plants uneconomic and result in their early retirement (OECD/IEA, 2011).

In the future, many new coal-fired units will be expected to cycle, even from the first day of operation. This will have a major impact on the cost of power from such plants. Discounting the increased maintenance and extra fuel costs, capital costs will have to be spread over a reduced output of electricity and hence will take longer to recoup.

Environmental issues

As the day-to-day operation of wind (and solar power) generation does not itself create any harmful emissions, it is often promoted as a means for achieving national emissions targets. It is commonly supposed that pollutant emissions and CO_2 will be reduced significantly. However, a number of studies have shown that this may not necessarily be the case. As conventional coal and/or natural gas plants are reduced to make room for wind generation, and are then subjected to start/stop conditions or ramped up as wind generation subsides, the heat rate rises. This reduction in efficiency increases fuel consumption and emissions. Although the type and scale of these impacts will be dependent on many site-specific factors, it is likely that some of the environmental benefits of wind generation will be negated by an increase in emissions from the back-up combustion plants. Several studies have concluded that the effect of wind integration on both fuel consumption and emission reductions can in fact be negative.

Cycling of advanced coal-fired systems

At present, the majority of coal-fired plants being cycled are based on conventional subcritical pulverised coal combustion systems, although some supercritical plants are also being cycled. Most CFBC plants in operation appear to operate mainly on base load, although some have cyclic capabilities and are cycled regularly. CFB units are viewed as having good turndown and load following capabilities. Part loads down to 25% of MCR are sometimes possible. As the steam cycle is similar to that of conventional PCC plants, repeated cycling can potentially affect various plant components in a similar manner.

Because of their highly integrated nature, the handful of commercial coal-based IGCC plants work predominantly on base load. However, there is some industry experience of load following; for instance, the Buggenum IGCC plant is reportedly, turned down to 57% of peak load at off-peak periods. Load-following capabilities are limited by the ASU. Some future IGCC plants proposed will be expected to achieve significant turndown in order to operate satisfactorily under both base load and cycling conditions.

Problems caused by two-shifting and other forms of cycling are likely to increase with more advanced designs of power plant, particularly those equipped with some form of carbon capture system. However, the successful deployment of CCS in this way may help secure stable base load for some coal-fired plants in the face of the growing competition from intermittent generating technologies. Experience of operating commercial-scale coal-fired plants equipped with CCS has yet to be established and various strategies for successful, flexible plant operation are being considered or developed.

Coal-renewables hybrids

There is potential for integrating directly coal-fired power plants with either wind or solar power in some locations. Under certain circumstances, this may provide a more effective way of accommodating energy produced by intermittents, without recourse to two-shifting or cycling of associated coal plants. Several studies have examined the potential for integration in this manner, although only a few have progressed to pilot scale so far. Efforts have been concentrated largely on combining wind or solar power with existing coal- or gas-fired plants. A number of new projects are being developed in countries with suitable conditions.

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