Squaring the circle

Stephen Bush and **David MacDonald** outline the UK's gigantic hurdles towards a green economy

THE challenge of maintaining energy security while cutting greenhouse gas emissions is driving a fundamental change in the way countries around the world produce their energy.

In the UK, the Climate Change Act 2008 has set the country the challenging target of reducing emissions of CO_2 and CO_2 equivalents by 34% from 1990 levels by 2020, 50% by 2027, and 80% by 2050, though the 2027 target is subject to review in 2014. Coupled with rising demand and the already painful impact of higher energy prices, meeting this target will be challenging indeed, leaving some engineers to wonder what it will take to square this circle.

For electricity alone, the official target is to raise the proportion generated from low carbon sources from around 20% in 2009 (essentially nuclear and hydroelectricity) to 40% by 2020. These targets are not only the biggest proportionate changes for total energy of any Western nation; they are also the most difficult. In 2009, the UK had the highest dependency on hydrocarbon sources of any large Western economy at 92% of total energy, or 230m toe (tonnes of oil or its thermal equivalents for gas, coal, nuclear, hydroelectricity, wind, sea and solar). In 2008, 188m toe (or 2200 TWh) were consumed as electricity and fossil fuels in the UK's five sectors of economy (see Figure 1).

In the following analysis, the source data is to be found in the paper by the authors to the National Grid Consultation 2010 at the link shown at the end of the article.

Table 1 shows the CO_2 emitted from each type of fossil fuel combusted. In terms of emissions reductions for the same electricity produced, the combined cycle gas turbine (CCGT) system emits only about 37% of CO_2 that a standard coal-burning station does and just over 50% CO_2 of an oil-fired station. These figures reflect the fundamental laws of chemical combination and heats of formation and the thermodynamics of the steam and gas turbine cycles.

reducing emissions

Using fossil fuel combustion figures (see Table 1) and given the 2008 mix of power stations as currently deployed (coal 36%, gas 36%, oil 6%, nuclear 14%, others 8%), annual emissions from the fossil-fuelled stations amount to around 30% of the UK's total, ie 190m t CO_2 equivalent out of the 2008 total of 633m t. Table 2 also gives the emissions targets for 2020, 2027 and 2050 and the required replacement capacities (assuming no change in energy demand).

Figure 1: Energy users (million toe per year)

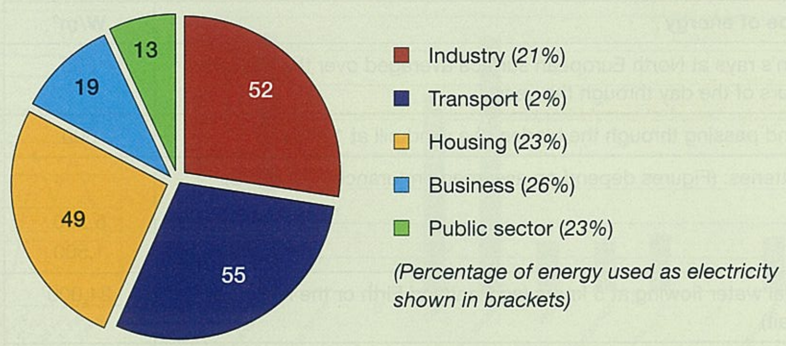


Table 1: Fossil fuels and CO_2 emissions

	Tonnes of CO_2 per tonne of fuel burnt	Tonnes of CO_2 per toe of fuel burnt	Tonnes of CO_2 per MWh (heat)	Thermal efficiency to electricity (η)	Tonnes of CO_2 per MWh (electricity)
"High hydrogen" coal	3.43	3.96	.336	0.35 (standard boiler)	.96
	3.43	3.96	.336	0.45 (supercritical boiler)	.75
Octane (liquid)	3.09	2.9	.247	NA	NA
Fuel Oil	3.14	2.95	.25	0.35	.71
Methane (gas)	2.75	2.34	.198	0.55 (CCGT)	.36

Table 2: Removal of fossil fuel burning installation and replacement by electricity production

		2008	2020	2027	2050
Millions of tonnes of CO_2 emitted (targets in brackets)		633	(512)	(390)	(155)
Fossil fuel plant retained in millions of toe of energy input on assumption that coal is removed before oil and gas, and that electricity stations are removed before heating processes	*Coal*	40	9	0	0
	Oil	80	80	51	0
	Gas	110	110	110	74
New build of electricity in increments of TWh between dates			140	288	653

It needs to be appreciated that the fossil fuel removed has to be replaced by electricity because this is what nuclear, wind, wave, solar deliver. On these figures, by 2027 we would need to build 140 + 288 = 428 TWh of new electricity output; by 2050, 428 + 653 = 1081 TWh. These figures should be compared with the total UK electricity production in 2008 of around 360 TWh.

The number of installations required to generate the electricity to replace fossil fuels (see Table 2) depend on their capacity and availability. A 1,600 MW Areva-type nuclear reactor working at 80% availability generates 11 TWh/y, so around 13 would need to be built to meet the 2020 target; an impossible task. A 3 MW wind turbine with 75 m blades on an 80 m mast onshore has achieved average availability of around 24%, while for offshore 30% future availability is claimed yielding 6.3 GWh/y and 7.9 GWh/y respectively. To meet the 2020 target would require 20,000 and 16,000 turbines respectively; an equally impossible task over the next nine years (six to be built every day). The 2027 target is even further out of reach.

Besides wind and nuclear, much consideration has also been given to solar, wave and tide, and CCS to replace hydrocarbons as primary energy sources for electricity generation and biofuels as a substitute for gasoline and kerosene in land and air transport.

While all of these systems may find uses at some scale of operation, for supply to the national grid on an industrial scale (approximately 10 TWh/y), three fundamental factors: power intensity,

Table 3: Typical power intensities

	Type of energy	W/m²
1	Sun's rays at North European surface averaged over the daylight hours of the day through the year	200
2	Wind passing through the blades of a windmill at 10 m/s	600
3	Batteries: (Figures depend on assumed endurance - 20 hours)	
	Lithium-ion	5,200
	Lead-acid	1,500
4	Tidal water flowing at 5 knots (eg Pentland Firth or the Islay-Jura strait)	24,000
5	120 HP engine in a medium-sized saloon car	400,000
6	Steam passing through the blades of a 500 MW steam turbine in an electricity power station	400,000,000

Table 4: Energy storage potential of different energy sources

Fuel	MJ/m³	KJ/kg
Coal (anthracite)	36,000	26,000
Natural gas at 10 bar pressure	390	55,300
Gasoline/kerosene/diesel	31,000	44,200
Hydrogen at 10 bar pressure	107	118,700
Uranium fuel (enriched to 2% U-235)	26,300m	1,650m
Water stored at 1,000 m	10	10
Lead-acid battery	400	150
Lithium-ion battery	1,440	990

energy storage density and energy source intermittency, determine land use, system reliability and cost per unit of electricity delivered.

problems with space

Power intensity in W/m² determines the space needed to capture and use natural and synthetic energy sources for electricity generation or transportation (see Table 3). The gigantic differences between windmill power and steam power show why windmills have to be so tall, and why wind farms and solar panels occupy so much land space to generate the output of a conventional power station (1,000 MW).

Because of intermittency or variation in its source of energy and the need to cope with interruptions due to maintenance and breakdown, energy systems will generally need some form of storage or redundancy. In the transport field, cars and planes have to carry their energy with them, so the energy density either in joules per unit volume or weight is of crucial importance (see Table 4).

The order of magnitude differences between batteries and fossil fuels is due to the order of magnitude differences between the breaking of covalent bonds in combustion, and the formation of ions in the case of batteries.

sources may vary

Along with solar, wind power poses the greatest problem of intermittency. The problem will become acute when wind makes up more than a few percent of supply as government policy clearly intends it should. The day-by-day load factors obtained for our eight nuclear stations and wind generation supplied to the grid in the month of February 2010 is a good example of this intermittency (see Figures 2 and 3).

Lest the volatility shown in February 2010 be thought to be unusual, the monitoring exercise has recently been repeated in March 2011. This showed that on 28 March that the entire 3226 MW wind capacity connected to the National Grid, spread over 77,700 km², was reduced to 9 MW at one point (0.27% of nominal capacity). Three days later, output was 2,618 MW (81%), a switch of 25 GW – even greater than in February 2010.

Taken over a whole month, February 2010, one of the coldest on record, the recorded usage factors for each of the ten systems connected to the grid were substantial (see Figure 3). The removal of even one third of the 32 GW nominal wind capacity would therefore result in widespread blackouts. The reality is that wind power can efficiently only supply relatively scattered populations, where there is backup from local diesel generation, or from the national grid.

In principle, intermittent supply can be mitigated by buffer storage. For a national supply system, however, the numbers are very adverse. To store a week's supply of electricity from the current 3,226 MW grid-connected wind capacity working at the annual average 25% load factor (see Figure 2) would require 4.5m m³ of hydrogen stored at 10 bar, or a lithium-ion battery stack 100 m² by 34 m high (see Table 4). Extrapolated ten times to the 32 GW of wind capacity proposed in National Grid's Gone Green scheme, it can be seen that this buffer storage concept to use wind power on this scale is another blind alley.

cost and carbon

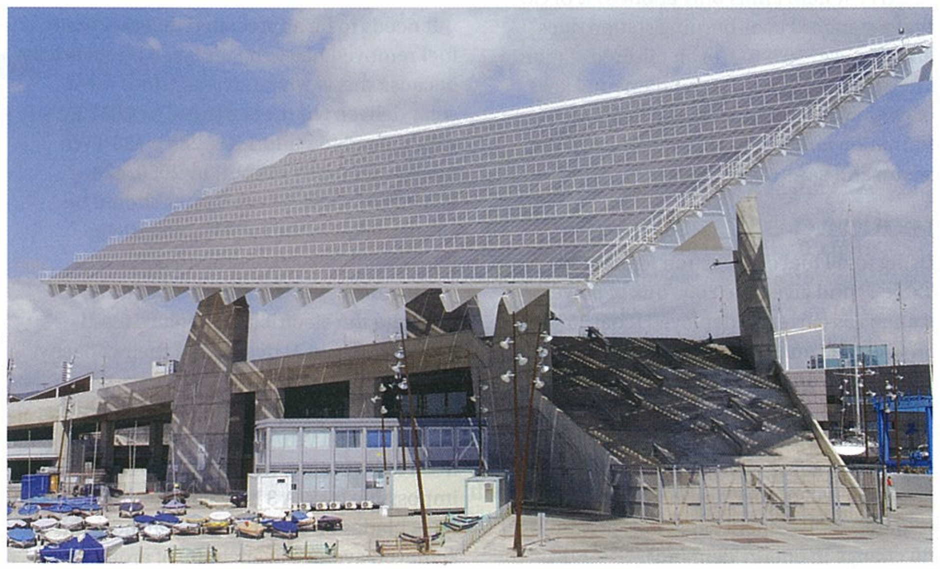
With the huge expansion of electricity required (Table 2), minimising the cost of generation and distribution is vital for the competitiveness of the process industries which are the major fossil energy using sectors of industry, which overall is responsible for nearly a quarter of all UK energy consumption (see Figure 1).

Replacing coal with offshore wind electricity amounts to about £50/t ($77/t) of CO_2 not emitted, or around £6b/y in additional generating cost just to meet the 2020 target for emission cuts (see Table 2). The capital cost of building the wind capacity to deliver 140 TWh per annum must also be added. These figures are estimated at £47b onshore and £168b offshore (see Table 5).

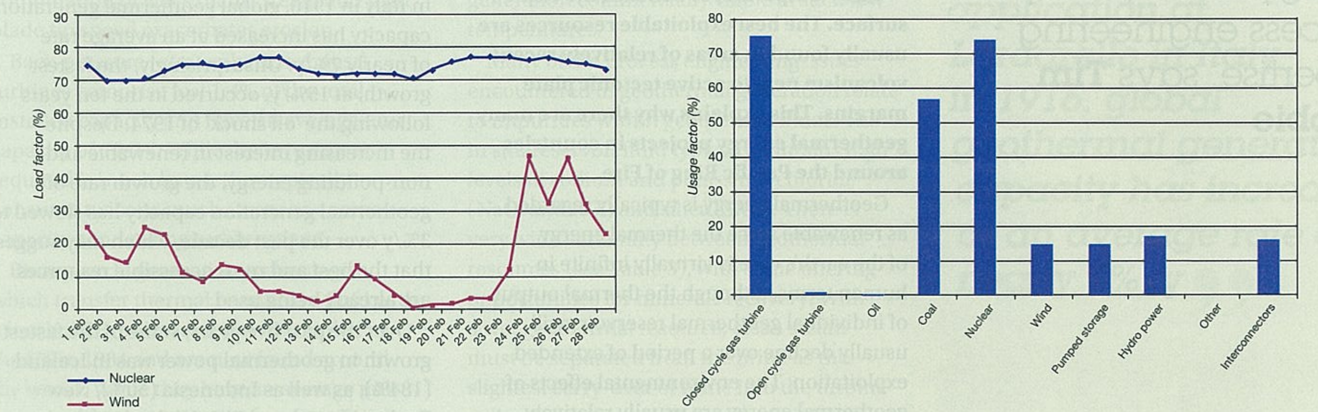
Separating CO_2 from nitrogen and other boiler exhaust gases, compressing and storing have been considered as an alternative to closing fossil fuel plants on emission grounds. Here again, the basic numbers will rule as follows. Applied to a 4 GW, 29 TWh/y coal-burning station, (comparable with Drax power station in Yorkshire) around 27m t/y of CO_2 is generated (see Table 1). In the liquid state, this would require about 14m m³/y of secure storage. This corresponds to 18,000 km of 1 m diameter pipe (which would be enough to go four times around the UK) every year. Besides pressurised CO_2 storage, there is also the separation of 27m t of CO_2 from about 80m t of nitrogen and 3m t of steam in the exhaust. These numbers greatly exceed even the largest ammonia plant, which would be several times the size of the power station itself, and would absorb a large part of the power generated. Overall, the proposal seems completely impractical.

averting catastrophe

Readers will draw their own conclusions from the inexorable figures above, but for these authors, only a system with its baseload provided by nuclear power, supplemented by gas for peak demand, and retaining the existing wind investment, can possibly supply the UK long-term with the huge amounts of secure and reliable, predominantly electrical energy, it needs. To actually achieve a changeover to a largely non-fossil fuel economy without wreaking catastrophe on our industries, the targets set by the Climate Change Act 2008 (see Table 2) will have to be pushed back no matter whatever combination of electricity generating technologies is built. **tce**



Figures 2 & 3: Load factors, nuclear and wind, February 2010 and usage factor, February 2011



Bottom left: Solar panels require more land than a conventional power station to generate the same amount of power

Table 5: Cost assumptions for different strategies

System	£m of capital cost (2008) per GW delivered	Total cost in 2008 pence per kWh (units)	CO_2 emissions in '000s tonnes per GWh delivered
Biomass	1,250	4.0	.15
Wave and tidal	11,400	9.0	.01
Offshore Wind	10,500	8.0	.01
Onshore Wind	2,960	4.7	.01
Oil	1,250	4.0	.70
Closed cycle gas turbine	810	3.0	.37
Coal	1,320	3.4	.96
Nuclear	2,100	3.2	.037

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data sources

Maintenance of UK Electricity Supplies to year 2020 and proposals for a secure energy strategy to 2050 by the authors at www.nationalgrid.com/uk/Electricity/Operating+in+2020/ Consultation response by Prosyma Research

At the core of an industry

Harnessing geothermal energy takes plenty of process engineering expertise, says **Tim Dobbie**

GEOTHERMAL energy is most often derived from the high temperatures beneath the earth's surface. The best exploitable resources are usually found in areas of relatively recent volcanism next to active tectonic plate margins. This explains why there are many geothermal energy projects in countries around the Pacific Ring of Fire.

Geothermal energy is typically regarded as renewable since the thermal energy of the earth's core is virtually infinite in human terms, although the thermal output of individual geothermal reservoirs will usually decline over a period of extended exploitation. The environmental effects of geothermal energy are usually relatively benign in that the brine that is often associated with the resource is typically re-injected deep into the reservoir. Although the geothermal fluid contains non-condensable gases (NCGs) – mostly CO_2 with lesser amounts of H_2S and other gases – which are released to the atmosphere, the amounts are usually significantly lower than hydrocarbon fuel emissions.

While the first geothermal power plants were sited on high temperature resources, strong demand for renewable and low-carbon energy have driven R&D so that today electricity can be generated from geothermal energy across a much wider temperature range. This includes hot rock resources and medium-temperature aquifers in Europe and Australia, away from tectonic plate margins. Many of the issues mentioned here also apply to these hot dry rock, hot fractured aquifer and hot saline aquifer resources, even if they're not specifically dealt with here in any detail.

slow rise

From its pioneering application at Lardarello in Italy in 1916, global geothermal generation capacity has increased at an average rate of nearly 7%/y. Unsurprisingly, the fastest growth, at 15%/y, occurred in the ten years following the 'oil shock' of 1974. Despite the increasing interest in renewable and non-polluting energy, the growth rate of geothermal generation capacity has slowed to 3%/y over the past decade, which may suggest that the best and most accessible resources are already being used.

Over the past five years, some of the fastest growth in geothermal power was in Iceland (184%), as well as Indonesia (50%), New Zealand (44%) and El Salvador (35%).

powering through

Almost 88% of geothermal power is generated using condensing steam turbine generators. Direct contact condensers and induced-draft, wet cooling towers are standard in the industry, along with air-cooled generators. The average geothermal steam turbine has a net capacity of almost 38 MW, though the maximum capacity has steadily risen over the years and over the past couple of decades there have been several units exceeding 100 MW. A shining example of a modern steam turbine plant is New Zealand's Nga Awa Purua geothermal power plant, with a capacity of 140 MW (see Figure 1).

With geothermal power plant, however, the usual economies of scale are balanced by the high steam consumption and high specific volume of low pressure steam, resulting in physically very large turbines and associated piping. Also, the use of saturated inlet steam results in high exhaust steam wetness. This constrains the back-end blade length, and therefore the capacity of the turbine, as the combination of wet exhaust steam and high blade tip speed exacerbates erosion.

Back-pressure (atmospheric exhaust) turbines comprise just 1.4% of the total installed capacity and have an average unit capacity of 6 MW. While the investment required is much lower, they typically consume twice as much steam as a same-capacity condensing turbine plant.

Binary-cycle generation technologies, which transfer thermal energy to a fluid with a low boiling point, entered the market in the US in 1984 and are now found around the world. While they have an average unit capacity of only 6 MW, they account for nearly 9% of total geothermal generation.

The relatively high capacity factors achievable with geothermal plants (see Table 1) invite comparison with other renewable energy resources (see Table 2). The Wairakei plant, which has been operating for 53 years, has maintained an annual capacity factor of over 90% for many years.

engineering hurdles

The hot spots preferred for electrical generation typically range from 230°C to over 300°C and resources may be either 'wet', delivering a two-phase mixture of steam and brine, or 'dry', delivering only steam. New Zealand's Wairakei steam turbine plant was the world's first wet geothermal development and pioneered many of the technologies that are in use today. The development of binary cycle technologies has widened the range of exploitable temperatures to as low as around 100°C, although it would require rather particular circumstances to make geothermal generation commercially viable at such low temperatures.

Many of the process engineering issues encountered in geothermal generation relate to impurities within geothermal fluids. The in situ reservoir fluid typically contains high levels of sodium and potassium chloride (NaCl and KCl) and silica (SiO_2). There is very wide variability between geothermal resources (see Table 3), with some offering opportunities for minerals recovery. With a wet geothermal resource, clean steam must be separated from the brine as the slightest carry-over of brine into the turbine will cause salts and silica to deposit inside the turbine, typically around the first stage nozzles. Traces of chlorides can lead to stress corrosion cracking, requiring the use of special alloys for blades and nozzles.

The most important part played by process engineers is the selection of the most economically and technologically appropriate energy conversion cycle. For typical reservoirs the economically optimal steam/brine separation pressure is likely to be 5-10 bar above atmospheric pressure. Turbines operating at these low temperatures and pressures consume very large volumes of steam, requiring large

> "from its pioneering application at Lardarello in Italy in 1916, global geothermal generation capacity has increased at an average rate of nearly 7%/y"

Figure 1: Nga Awa Purua geothermal power plant.

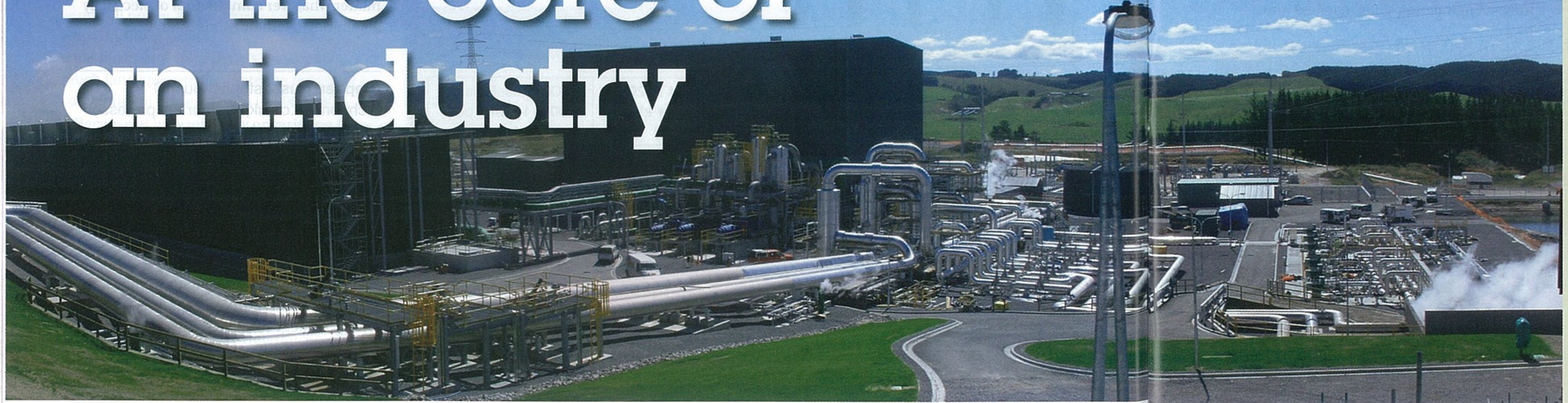

Table 1: Installed Geothermal Generation Capacity and Annual Generation (2010)

Country	Installed capacity [MWe]	Annual energy generation [GWh/yr]	% of national capacity [%]	Annual capacity factor [%]
Costa Rica	166	1,131	8.4	78
El Salvador	204	1,422	14	80
Guatemala	52	289	1.7	63
Iceland	575	4,597	20.5	91
Indonesia	1197	9,600	2.2	92
Italy	843	5,520	1	75
Japan	536	3,064	0.2	65
Kenya	167	1,430	11.2	98
Mexico	958	7,047	1.9	84
New Zealand	628	4,055	4.9	74
Nicaragua	88	310	11.2	40
Papua New Guinea	56	450	10.9	92
Philippines	1904	10,311	12.7	62
Russia	82	441	N/A	61
Turkey	82	490	N/A	68
USA	3093	16,603	0.3	61
Other	84	486	N/A	66
Total / average	**10,715**	**67,246**		**58**

Source: World Geothermal Congress, 2010

Table 2: Comparison of renewables generation capacity, annual generation and nominal capacity factor, 30 OECD countries

Resource	Installed capacity (MWe)	Annual generation (GWh)	Annual capacity factor (%)
Geothermal	5,400	38,100	80.5
Solid biomass	22,500	115,900	58.8
Hydro	344,600	1,286,300	42.6
Tide, wave, ocean	300	550	20.9
Wind	63,700	116,200	20.8
Solar PV	4,100	2,626	7.3

Source: OECD, 2007

diameter pipelines and vessels.

Geothermal steam separators, the largest delivering up to 700 t/h, are most often based on the Webre vertical axis centrifugal design (see Figure 2) and have been developed to provide very high separation efficiencies while imposing relatively low pressure losses. It is usually possible to achieve steam quality (dryness) of at least 99.98% at the separator exit, thus minimising the carry-over of dissolved solids.

Even at a steam purity of less than 1 ppm, however, geothermal steam will carry more than 6 t of solids per year into a nominal 100 MW steam turbine, so steam usually needs to be cleaned to prevent solids from accumulating. This can be achieved by using the large diameter pipelines downstream of the separator and/or specific steam scrubbing and de-misting vessels (see Figure 3), sometimes with injection of scrubbing water.

It is no longer acceptable to discharge the separated brine to rivers and streams, particularly since the water tends to contain arsenic and boron along with the aforementioned chlorides and silica. The preferred approach is reinjection at depth, adjacent to or below the identified reservoir. This, however, involves pumped or gravity-flow transport of the hot brine, probably super-saturated with amorphous silica, which introduces an additional raft of technical challenges.

Because of the NCGs found in geothermal reservoir fluids, the steam typically contains 1-5% of NCGs by weight, but this can be as high as 20%. Gas extraction systems are needed to remove the NCGs from the turbine condenser in order to achieve a low turbine exhaust pressure. For low to moderate NCG levels, two or three stages of steam jet ejectors and liquid ring vacuum pumps are sufficient. Rotary gas compressors are sometimes used, usually where NCG levels are particularly high but, although efficient, are expensive to purchase and maintain.

The biggest concern for NCGs is hydrogen sulphide, which is typically around 5% by weight but can be up to 10%. This is not only a significant hazard, but also restricts the use of copper-based alloys around geothermal plant and can contribute to sulphide cracking of steels.

Some jurisdictions require the elimination of all atmospheric emissions of H_2S, involving the use of expensive surface condensers and even more expensive H_2S abatement technologies, typically adapted from the sour natural gas industry. Unless H_2S abatement is mandated, however, most geothermal plant uses direct contact condensers and ejects the gases into the buoyant plume above the cooling towers.

binary advent

Binary-cycle power plants, which transfer heat to a low boiling point fluid such as butane or pentane, were initially developed to take advantage of low-grade waste heat from industrial processes.

The ability to commercially exploit low temperature resources is not the only advantage of binary-cycle plants: these units are much less sensitive to impurities in the steam, and the requirement for efficient steam separation is minimal. Condensate and brine are often recombined to reduce the silica super-saturation, and there is no requirement to extract the NCGs from a low pressure condenser. Many proprietary versions of binary-cycle plant use fin-fan coolers as condensers, with the thermodynamic penalty of dry rather than wet cooling being balanced by the ability to operate in dry areas. The lack of economies of scale is balanced by the modular nature of the plant, rapid installation on simple foundations and their ready adaptability to a wide range of resource and ambient conditions.

A particular variant known as the Kalina Cycle, which is currently at the prototype stage, uses a mixture of water and ammonia. It did not take long before binary-cycle units were installed at the many low-temperature geothermal resources around the world.

world of opportunity

There is a very wide range of chemical and process engineering skills that feed into the design and operation of geothermal power plants, including thermodynamics, steam and brine transport, solid-liquid and gas-liquid equilibria, exotic materials of construction, control systems etc. The major challenge is how to optimise the power plant operating parameters in the face of many varying factors including temperature, pressure, and the gas and solids content of produced fluids.

The experience gained since 1958 from the Wairakei plant, as well as the exploration and drilling of a large number of prospective resource areas has enabled New Zealand companies to export their geothermal expertise to the world. Their involvement in the development of geothermal resources in the Philippines and Indonesia from the mid-1970s culminated in major power plants being commissioned in the early 1980s. **tce**

(left) Figure 2: Steam/brine separator with high level two-phase fluid entry from the right, brine exit to brine drum through loop-seal to left. Steam exit to right at mid-level.

(top, opposite page) Figure 3: Steam piping from left into steam scrubbers and demisters with steam vent piping to right.

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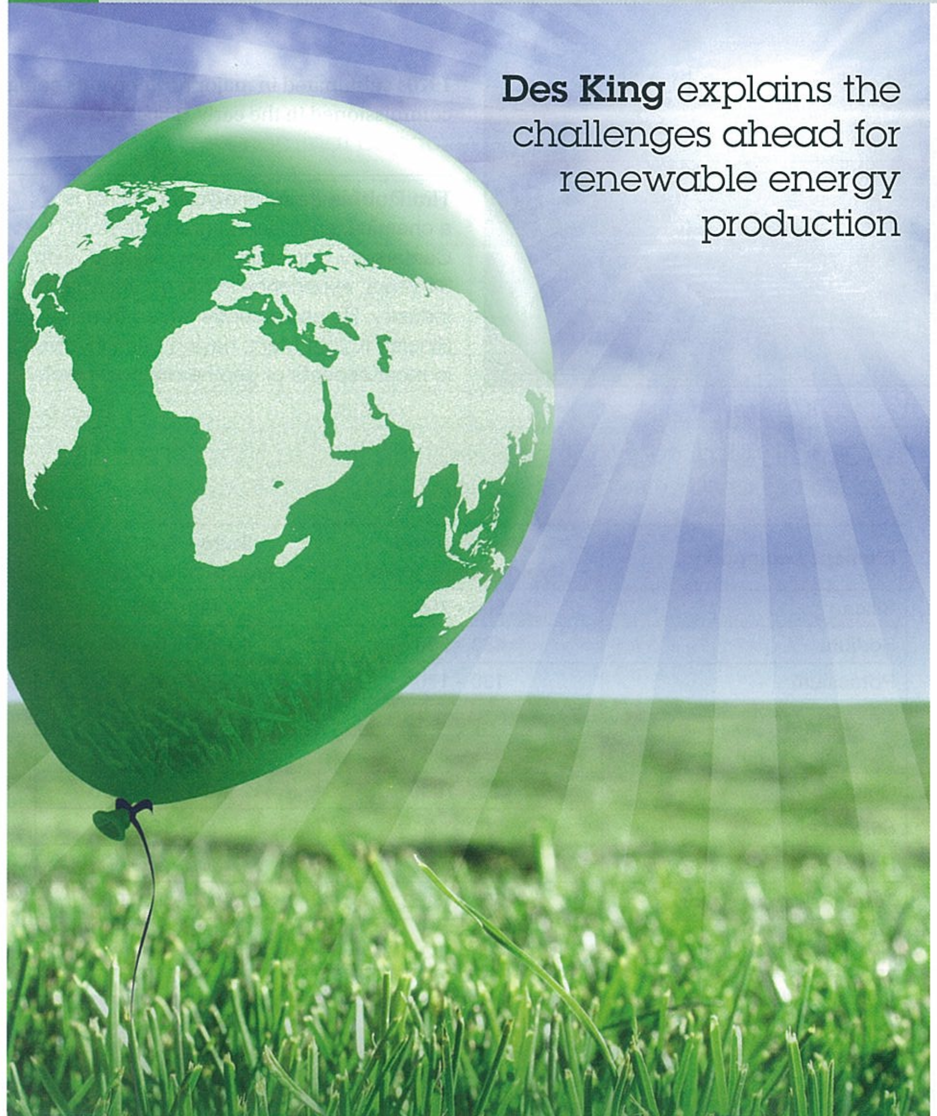
Table 3: Typical composition of reservoir fluid in New Zealand (moderate) and Salton Sea, US (high mineralisation)

Element / compound	New Zealand typical range (ppm)	Salton Sea, US typical range (ppm)
Silica	500 - 700	420 - 480
Sodium	480 - 580	40,000 - 50,000
Potassium	130 - 170	11,000 - 16,000
Calcium	0.31 - 1.1	22,000 - 29,000
Fluoride	2.35 - 2.61	15 - 25
Chloride	420 - 1000	125,000 - 165,000
Sulphate	3.9 - 13	50 - 150
Boron	16 - 25	300 - 350
Total dissolved solids	**1553 - 2492**	**200,000 - 260,000**



Des King explains the challenges ahead for renewable energy production

Renewables

and the world's energy demand

TS ELIOT once wrote: "Anxiety is the hand maiden to creativity." Perhaps that explains the proliferation of energy technologies that have surfaced or resurfaced over the last ten years.

People are increasingly anxious about the world's energy supply. Is there enough? Where will it come from? How much is it going to cost? It's an environment that has given birth to a lot of new ideas in energy technology and we're just starting to learn which may have more potential for integration into the world's energy mix.

Energy companies are taking extensive efforts to deliver today's energy reliably and affordably while also identifying, developing, and commercialising new forms of energy. Today, hydrocarbons account for more than 80% of the world's energy supply and according to the International Energy Agency (IEA), that ratio will not change substantially in the next 20 years. At first glance, that may seem grim for renewable energy technologies. But consider this: overall energy demand is expected to increase 25% as more countries modernise over the next two decades.

So while renewables will remain relatively small in size compared with other fuel sources, they will grow tremendously over the next 20 years in absolute terms, albeit from a small base. But which renewable energy sources and which technologies hold more promise?

growth in gusts

In the near term, we will continue to see growth in familiar renewable sources, such as wind and solar. The IEA predicts that in a business-as-usual case, electricity generation from wind power will reach 4.5% of total electricity generation by 2030 worldwide, compared with less than 1% in 2008. It is projected to soon become the second-largest source of renewable electricity after hydro power.

Wind power is indeed growing in popularity and penetration, but it has three key challenges. First, it is intermittent, which means it cannot be counted on to provide baseload power. Second, it has a large geographic footprint. Some estimate that, on average, wind power needs about 20 hectares to generate one megawatt (MW) of electricity. Third, even when enough land is available, siting wind facilities can be difficult because of complaints about aesthetics and noise.

One solution to locating the sizeable land mass needed is to repurpose old industrial sites, often referred to as brownfield sites. Chevron has done this near Casper, Wyoming. Using a former refinery site, Chevron has installed an 11-turbine wind power facility that has 16.5 MW production capacity.

In 2008, the U.S. Environmental Protection Agency (EPA) began an initiative to encourage renewable energy development on brownfields and, according to the agency; there are 15m acres in the United States with the potential for developing solar, wind, biomass and geothermal facilities.

solar challenges

Like wind, the solar industry is growing as well. Electricity from solar photovoltaics is still small, but growing rapidly. Germany, Japan, and the United States are among the leading users of solar photovoltaic technology. It is predominately used as distributed power generation on buildings instead of to power central grids.

Solar is projected to continue to make headway, but it has two primary challenges. First, like wind power, it is intermittent, so it cannot be relied upon for large amounts of baseload power. Solar's other big challenge is its cost. The IEA says that solar photovoltaic without subsidies has the highest investment cost of all commercially deployed renewable energy resources. As a result, solar is heavily dependent on government subsidies to compete.

There are several efforts under way to reduce the cost of solar photovoltaics by advancing thin-film technology. Key research and development areas include:

- Reducing the amount of silicon consumption in wafer development;
- Improving device structures and substrates;

• Advancements in nano-structured materials and devices; and
• Improvements in thermal storage technologies.

There are also promising developments under way in the area of concentrating photovoltaic (CPV) technology and concentrating solar power (CSP). With CPV, lenses are used to concentrate the sun's rays onto a small area and make solar collection more efficient compared to conventional photovoltaics. With CSP technology, mirrors are used to direct sunlight onto a boiler, generating steam. Many manufacturers of both CPV and CSP technologies incorporate computer-programmed tracking systems that allow the lenses or mirrors to follow the sun and potentially capture more energy throughout the day. The software is just as critical as the panels or lenses in the success of solar technology.

Chevron sees potential for solar power applications for reducing long-term energy usage at our facilities and keeping up our record of energy efficiency gains. In Questa, New Mexico, we have one of the largest CPV installations in operation built on the tailings facility of the molybdenum mine. The facility has the capacity to produce about 1 MW of power, which goes into the local grid.

Near Bakersfield, California, we have repurposed another former refinery site by installing various thin-film photovoltaics to determine which hold the most promise for wide deployment.

biofuel boost

Another area with intense activity worldwide is advanced biofuels. The United States Energy Information Administration shows that the expected 2010-2030 compounded annual growth rate for biofuels worldwide is 5.8%, outpacing many other renewables and other fuel categories.

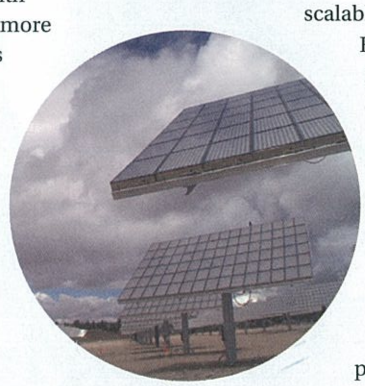
According to IEA, the share of biofuels in the total supply of road transport fuels worldwide is projected to rise from 1.5% in 2006 to 4% in 2030. Many energy companies are taking their expertise in advanced engineering and manufacturing techniques to convert biomass into transportation fuels.

The key to the growth of biofuels is matching the right feedstock with the right conversion technology, and then working out the relevant logistics to ensure that the production of commercial levels of advanced biofuels is feasible. It's a complex effort with many variables. The technology also needs to be economic at small scale. Since biomass has low energy density and contains about 50% water, it is not efficient from a greenhouse gas standpoint to transport the biomass too far – so the conversion facilities need to literally be "in the field" no more than about 100 km from the biomass source if the produced biofuel is to have a greenhouse gas footprint 50-60% lower than conventional fuel.

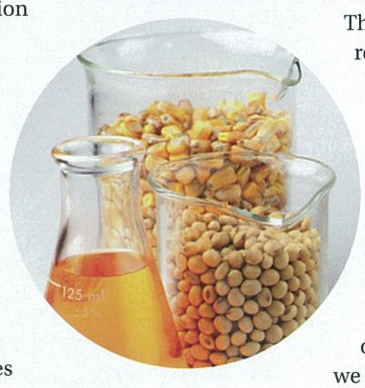
One of the tallest hurdles is the issue of growing enough biomass at the huge scale required in the timeframe to meet some of the biofuels mandates that exist. For example, the US federal mandates call for over 1m barrels of advanced cellulosic biofuels *per day* by the year 2022. Today, there is almost zero produced in the US.

To help illustrate the challenge, let's assume that hybrid poplar trees emerge as the feedstock of choice. To make 1m barrels per day of biofuels would require a 260,000 km^2 forest. That's larger than the UK.

There are infrastructure issues as well. The existing energy supply chain is large, integrated and complex, with an infrastructure that took more than 100 years and trillions of dollars to build.



For advanced biofuels to reach commercial scale in a reasonable timeframe, they must be developed to be compatible with this infrastructure. It may sound like a small thing, but virtually every ship, truck, pipeline, terminal, refinery, and refueling station was built to accommodate hydrocarbons. Developing a new infrastructure for a new type of transportation fuel could not be done easily, quickly, or inexpensively.



Each of the major energy companies is pursuing advanced biofuels in a way that makes sense for them and takes advantage of their unique strengths, capabilities, and commercial relationships. ExxonMobil and Synthetic Genomics are working together on biofuels from algae. Shell and Cosan have formed a joint venture, Raizen, focusing on ethanol from Brazilian sugar cane.

Chevron has formed a joint venture with forest products giant Weyerhaeuser, called Catchlight Energy, which is currently working to develop and commercialise forest-based biomass into biofuels. Weyerhaeuser provides the knowledge of biomass feedstock development and Chevron provides expertise in the manufacturing and distribution of transportation fuels.

> **"our challenge is finding the right combination which can become scalable, sustainable, and affordable"**

strategies ahead

There's a wealth of feedstocks and conversion technologies available. Our challenge is finding the right combination which can become scalable, sustainable, and affordable.

Resources are more easily integrated when we can leverage off of existing infrastructure or technology. For example, the same technologies and expertise needed for geothermal production are the same applied in oil production. Both involve drilling in high pressure and high temperature environments.

The research into various energy resources and technologies has been promising so far, but we still have far to go to gain a comprehensive understanding of how best to diversify and integrate our energy resources.

The energy industry understands this. It's taken hundreds of years to build our current infrastructure; we know we can't change it overnight.

We also understand the challenge of meeting increased energy demand; that's why we will continue to explore a variety of possibilities. When it comes to meeting the world's increasing demand for energy, we will need all the conventional and renewable forms of energy that can meet our needs reliably and affordably. tce

Desmond King is president of Chevron Technology Ventures and immediate past president of IChemE.

NNL Laboratories

Fuelling the coming era

Robin Taylor highlights the latest advances in nuclear fuel recycling

ACROSS the world there is a renewed interest in the prospects of nuclear energy to help address concerns with carbon dioxide emissions and energy security. Whilst events at Fukushima are causing some countries to reconsider the role of nuclear, there is still likely to be a major expansion in the use of nuclear energy over the next few decades and a consequent build-up of spent nuclear fuel in storage. Typically, 97% of spent nuclear fuel (SNF) can be recovered and recycled into new fuels. This process, known as reprocessing, has been widely used over the last 60 years to recover uranium (U) and plutonium (Pu), the reusable actinide elements.

However, with concerns around Pu proliferation, the costs of reprocessing (compared to interim storage) and the wastes generated, reprocessing at the commercial scale is currently only undertaken in the UK, France and Japan. This has led to the situation where approximately 250,000 t of SNF are currently in stores around the world, a figure that could rise to 1.25m t by 2100 if the expected new build of nuclear power plants happens. Eventually, decisions must be taken and these stored fuels must be reprocessed or disposed of in geological repositories designed for high-level radioactive wastes.

Internationally, there is now wide interest in the development of sustainable nuclear fuel cycles which would use generation IV reactors that utilise U and Pu fuels far more efficiently than current thermal (generation III) reactors and can also burn the transuranic actinides (Pu, neptunium (Np); americium (Am); and curium (Cm)) that pose difficult problems for nuclear waste repositories. To deal with the stocks of SNF in storage and to allow this transition towards sustainability, significant changes are needed to reprocessing technology to address the proliferation, cost and waste concerns and new processes are needed that can recover and recycle the minor actinides (Am; Cm). At the European level, the Sustainable Nuclear Energy Technology Platform has published a strategic research agenda outlining R&D needs (www.snetp.eu). Alternatively, there are advocates for fuel cycles based on thorium (Th) rather than U as the main fuel, but advances in reprocessing of Th-based fuels will still be required.

> **"whilst events at Fukushima are causing some countries to reconsider the role of nuclear, there is still likely to be a major expansion in the use of nuclear energy"**

new processes

In the national nuclear laboratories of France, Japan, the US, India, the UK and elsewhere, new separation processes are being developed that meet these challenges. Some of these processes are evolutionary, modifying established reprocessing methods to ensure Pu is always intimately diluted with U to reduce proliferation risks and intensifying the process to reduce costs and wastes generated. Some approaches are far more innovative, for instance a process that extracts all actinides (U – Cm) together in a group, and some lines of research move away from the dominant aqueous separation technologies, looking at whether ionic liquids, molten chloride salts or volatile fluorides could be used.

Currently, nuclear fuel reprocessing at the commercial scale uses the well-known Plutonium-Uranium Extraction (Purex) process to recover U and Pu products. First developed in the US in the late 1940s, this is a hydrometallurgical process in which SNF is initially dissolved in refluxing nitric acid and then solvent extraction (SX) is used to extract U and Pu from the fission product containing nitric acid solution into a kerosene