Modern Energy

Tuesday June 24 2014

www.ft.com/reports | @ftreports

Technology drives shift to smarter thinking

Utilities are reinventing their business models as high street retailers and telecoms companies move into their territory, reports *Guy Chazan*

The world of energy used to be fairly straightforward. Big state-owned utilities generated power and fed it through wires and pipes into customers' houses. It was a well functioning system that seemed to be set in stone.

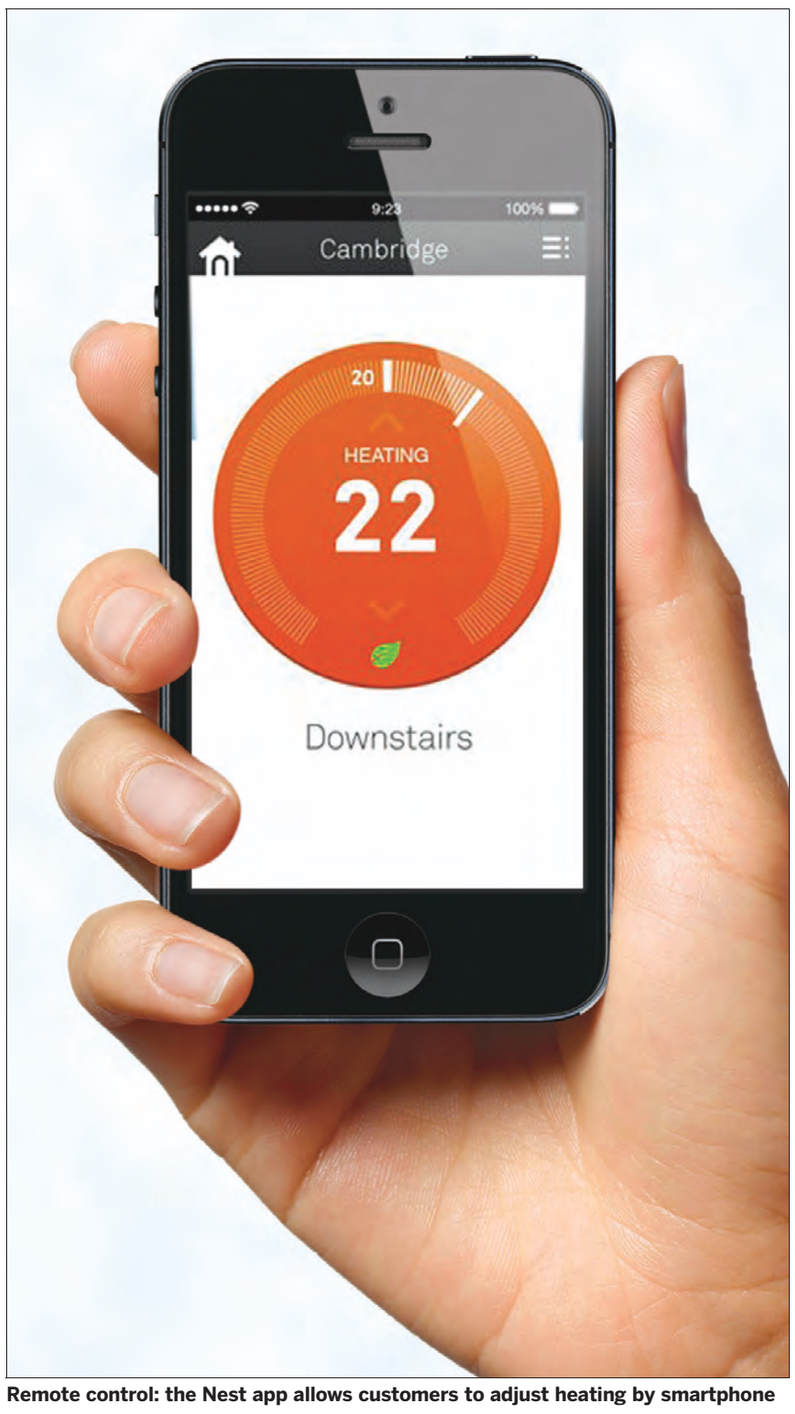
But this centralised, "command and control" model is under pressure as never before. Energy is changing fast, as technological innovation disrupts the old paradigms. Smart grids, smart meters and smart home appliances embedded with sensors that connect them to the "internet of things" promise to revolutionise our approach to energy use.

Nothing better highlighted these changes than Google's $3.2bn acquisition in January of Nest Labs, a four-year-old start-up that makes smart thermostats and smoke alarms for the home. Users can turn up or switch off their heating from anywhere using a smartphone app.

Others are following suit. Apple is working on a software platform that will turn the iPhone into a remote control for lights, security systems and other appliances. Samsung recently unveiled its Smart Home range of washing machines, refrigerators and TVs that can be controlled from its mobile phones and watches.

Suddenly, big technology providers are focusing on energy as a potentially lucrative sector. High street retailers and telecoms companies are also waking up to the opportunities of retail energy provision.

This presents a huge challenge to the traditional utilities – the big power companies such as RWE and Eon in Germany, Centrica in the UK and Enel in Italy. For decades, these vertically integrated monoliths, which both generate power and supply it to millions of homes and businesses, dominated their markets. But the changing economics of the energy industry have depressed their returns and constrained their balance sheets.



Remote control: the Nest app allows customers to adjust heating by smartphone

Some, especially the "big six" suppliers in the UK, are facing mounting public anger over rising fuel bills and complaints about poor service. They are being subjected to much greater scrutiny from regulators, while a growing number of politicians are calling for them to be broken up.

"The big six are finding retail very painful," says Omar Abbosh, senior managing director of Accenture, the consultancy. "It's not in sync with their core competence, which is big capital formation and asset stewardship." That contrasts with companies in the retail, telecom and technology space, who "have brands that consumers relate to" and "are better at managing customer relationships".

For Google, buying Nest does not necessarily mean it will become a big energy player. "But," says Mr Abbosh, "it realises it can use Nest's technology to learn more about its end consumers, what those consumers need, and how it can profit from them."

Already, there are some examples of new entrants into the supply business. Hungary's Magyar Telekom sells gas and electricity to residential and business customers. UK retailer Marks and Spencer has teamed up with SSE, one of the big six, to offer energy packages, with the promise of M&S vouchers to those who make the switch.

Some big utilities are meeting the challenge head on, offering more services to their huge fixed installed base of customers. There is a big incentive for them to do so.

The backbone of their business – thermal power generation – has become a lot less profitable in recent years, undercut by weak energy demand in Europe, the rise of renewables such as wind and solar, and low power prices. Burdened by debt, they are largely unable to invest in new plants and have instead been cutting

Continued on Page 2

Inside »

Industry's new milestone on the road to making fuel from waste

Biofuels

Science, logistics and regulations still temper expectations, writes *Ed Crooks*

The history of the advanced biofuels industry resembles nothing so much as the alchemists' pursuit of the Philosopher's Stone: a procession of false promises and broken dreams. But, in a modest way, some of those expectations are at last being realised.

Over the next 12 months, three plants producing cellulosic ethanol, one of the most heralded of the next generation of biofuels, are set to start production in the US. Yet while the arrival of cellulosic ethanol on the US market is a big step forward, the industry has a long way to go to make a material difference to fuel supplies. Technical, commercial and regulatory challenges still present significant barriers to the widespread adoption of advanced biofuels.

In principle, the new generation of biofuels could be vital for sustaining road and air transport in the face of declining oil production and emissions concerns.

The new fuels avoid the problems of first-generation products such as US corn-based ethanol, including competition with food production, because they are produced from agricultural or municipal waste, or from special energy crops.

Realising that potential is difficult. The energy locked up in plant cellulose – or in algae, another focus for research – is hard to unleash on a useful scale.

At last, though, at least three projects are about to get under way in the US. Two are in Iowa: one from Poet, the US ethanol group and Royal DSM, a Dutch biotech company; and one from DuPont, the US chemicals group. Abengoa, the Spanish renewable energy group, plans to open a plant in Kansas soon.

Beta Renewables, backed by the private equity firm TPG, started operations at a plant in Italy last year.

These facilities generally take corn stover – leaves and stalks left after maize harvesting – or other agricultural waste and break it down to make ethanol. Manuel Sánchez Ortega, Abengoa's chief executive, is also bidding for contracts with three US cities to turn their municipal solid waste into ethanol. That technology is less well developed, he adds, "but it's something that is happening".

Other advanced biofuel technologies are further behind. Attempts to use algae, sometimes proclaimed as the long-term future of fuel, have suffered multiple setbacks.

Royal Dutch Shell, the European oil group, stopped its efforts with algae. ExxonMobil of the US is continuing research with Synthetic Genomics, but shifted to "a basic science effort" focused on genetically modified algae after, in the company's words "it became clear that economically producing suitable quantities of oil from naturally occurring or conventionally modified algae would be technically difficult".

San Francisco-based Solazyme is one of the more successful companies producing oil from algae, but is not having much impact because its costs are still too high.

Jonathan Wolfson, its chief executive, told a recent Goldman Sachs conference: "The reason we started the company was to disrupt fuels." Instead, he said, the company's oils are going for higher-value uses in cosmetics, soap and foods, and are used for fuels only as an additive to conventional crude. "We're only selling blends, because we can't compete yet with a barrel of oil," he said.

Shell's remaining efforts with advanced biofuels are concentrated on two processes: using a thermal process to make petrol from waste wood, and a cellulosic ethanol process similar to that used by the companies starting production this year. It has a test plant in Houston for the petrol from wood technology, and plans to expand it and add cellulosic ethanol production.

Although Shell seems to be making progress, it overpromised and under-delivered on cellulosic ethanol and algae in the 2000s, and is now cautious about making promises on how quickly its work will bear fruit.

> A new generation of biofuels could be vital for sustaining transport in the face of declining oil production

Matthew Tipper, Shell's vice-president of alternative energies, says there is a fundamental problem with many advanced biofuels.

The logistics of delivering the feedstock to the plant mean each individual facility has to be relatively small: perhaps producing 6,000 barrels of ethanol a day, compared with a large refinery that could produce 500,000 b/d.

At small scales it is hard to make the process efficient enough to compete with conventional oil-based fuels, which is Shell's ambition. The regulatory framework of the US Renewable Fuel Standard (RFS) and similar programmes in other countries today support biofuels, especially advanced ones, but Shell does not expect that support to last forever, and wants any fuels it produces to be able to compete.

The RFS was established in 2005, and in 2007 was set on a path for a steadily rising volume of biofuels to be blended into US road fuel.

As that number has risen, ethanol has faced the growing problem of the "blend wall". Because 10 per cent is the maximum amount of ethanol that can be blended into fuel used by cars in the US, that share sets a limit for how far volumes of ethanol sold can grow.

Faced with that problem, the US Environmental Protection Agency (EPA) has proposed cutting back the mandated biofuels volumes, to the fury of the ethanol and biodiesel industries.

DSM accuses the EPA of capitulating to pressure from the oil industry, and says the proposal had "a massive chilling effect" on investor interest.

Abengoa's Mr Sánchez Ortega agrees, saying the administration should have compelled retailers to make a higher proportion of ethanol available for customers that can use it. Still he adds, this is nothing new for the renewables industry, where companies always feel they are the underdog.

"In the renewables sector, it's always a fight against the big boys," he says. "Some days you feel like saying you give up, but on most days you feel like fighting on. And that's what Abengoa will do."


Eco warrior: waste left after harvest can now be used to make ethanol

Japan revisits pre-Fukushima past

Nuclear Three years on, there are moves to restart the reactors, writes *Sylvia Pfeifer*

Impact: visitors to a shrine in Namie remember those lost in the tsunami Getty

The 21,000 townspeople of Namie, 231km northeast of Tokyo, are allowed to go home once a month, but never to stay overnight. Their houses lie in the 20-mile evacuation zone around the Fukushima Daiichi nuclear plant, torn apart by explosions after an earthquake and tsunami hit Japan in March 2011.

Their continued exile is a reminder of the deep impact of the disaster. Japan almost immediately turned its back on nuclear power, which had produced nearly a third of the country's electricity before the accident.

Namie is just one of several ghost towns and tens of thousands of people are still unable to return to their homes. While there is no certainty that its residents will ever be allowed home permanently, Japan is again starting to embrace atomic power.

This spring, the government of Shinzo Abe declared its long-term commitment to nuclear energy, reversing the previous administration's decision to shut all reactors.

The U-turn is a fillip for the nuclear industry, which was hard hit by a global change of attitude towards atomic power. After the disaster Germany, Switzerland, Italy and Belgium moved to close down or phase out their nuclear programmes.

Meanwhile in the US, reactors have struggled to compete with gas-fired power plants riding the shale gas boom. Four nuclear plants closed in the US in the past 18 months.

A restart of atomic power in Japan could also have implications for world energy markets. Japanese imports of liquefied natural gas (LNG) shot up after it closed its nuclear plants, pushing up the price of LNG in Asian and European markets.

The country's volte face – despite many Japanese opposing the restart – should not have come as a surprise. The loss of nuclear power and the increasing reliance on imports of LNG have come at a considerable cost.

In January, the country revealed its worst annual trade deficit on record. In 2013, the gap between imports and exports was Y11.5tn ($111bn), widening from the Y6.9tn and Y2.6tn deficits recorded in 2012 and 2011 respectively. Several utilities have turned to government-owned banks for bailouts to cover losses. Households too have paid a price, with electricity prices jumping by a fifth in the 18 months after the earthquake.

So far, Mr Abe's efforts have focused on the short term. The prime minister is supporting efforts by electricity utilities to restart about a dozen of the 50 still-usable reactors, all of which are shut pending safety reviews. That effort, however, still faces considerable hurdles and any restarts must be approved by safety regulators and local governments.

Laszlo Varro, head of the gas, coal and power division at the International Energy Agency (IEA), predicts the process will be gradual. Nor does he expect all plants to be restarted. The agency predicts nuclear power to recover to about half its pre-Fukushima level by the end of this decade.

Bringing nuclear back into the energy mix would be good news for Japan's trade balance. Restarting five reactors over the next 12 months would mean lower imported energy costs and "would reduce the trade deficit by Y400bn a year", according to John Vail, chief global strategist at Nikko Asset Management.

Mr Vail also identifies some indirect benefits of a restart. "It's hard to overestimate how frustrated companies are at high electricity costs in Japan and how it affects plans to expand capital investments there," he says.

> After the disaster, Germany, Switzerland, Italy and Belgium all moved to phase out nuclear power

Whether a restart will have a big impact on the use of gas remains to be seen. Mr Varro thinks that nuclear restoration will first reduce oil-powered generation in Japan, which is even more expensive than liquefied natural gas. The impact of the restart will therefore "not be a game changer for global gas markets", he adds.

Strong demand from China for LNG over the next two years, driven by tighter environmental regulation, will have a bigger impact on the global gas market, he suggests.

Japanese demand for LNG increased by 20m cubic metres in two years after the disaster, in a global market of between 340m and 350m cubic metres.

"Even if Japanese nuclear comes back, other parts of Asia can compensate for less gas demand from Japan," says Mr Varro. "New supply of LNG from Australia and North America will be a bigger game-changer than Japanese nuclear coming back."

For supporters of nuclear energy, Japan's decision underlines that despite its potential risks, atomic power has a role to play, as it provides a low-carbon, domestic source of supply without reliance on costly imports of gas.

Turkey, for example, another country with a large energy import bill, is planning to build nuclear reactors as well as coal plants in an attempt to cut its reliance on foreign supplies.

Some observers note that countries in favour of atomic power before the crisis have remained committed.

Keith Parker, chief executive of the Nuclear Industry Association in the UK, says: "Clearly, Fukushima had an impact but we are now building more reactors than we have done for the last 20 years."

Britain is one of a number of European countries pursuing a fleet of new reactors. Fukushima sparked a global safety review of reactors and in terms of new-build designs, any lessons from the crisis will be incorporated, says Mr Parker.

In Japan, the government's recent announcement, he adds, is "just the start of the process". The key challenge will be "extensive public consultation to rebuild national trust".

UK consumers resist calls to shop around

Competition

Nearly 40 per cent have never changed supplier, says *Michael Kavanagh*

How can consumers be persuaded to shop around for domestic electricity and gas supplies?

In much of the world this is not an issue. Local or national utilities typically act as monopoly suppliers, with regulators left to set prices and ensure customers get a fair deal.

But in the UK, domestic customers have been free to choose their supplier since 1999, under a liberalisation designed to let the threat of switching squeeze the profits of energy retailers.

Since the formal scrapping of price caps in 2002, retail competition has been left as the main market lever to protect consumer interests.

Growing anger among consumer groups and politicians about rising fuel bills has led the UK's opposition Labour party to threaten to reimpose the policy of price caps that it abandoned when in government, amid claims of profiteering among the country's leading energy retailers.

The willingness of suppliers to let retail markets rip has been stoutly defended throughout the protracted political debate by Angela Knight, chief executive of Energy UK, the industry body.

Ms Knight accepts the process of switching suppliers can be improved, but argues there is little to stop consumers voting with their feet, aided by online price comparison sites.

"Switching is simple: just pop in your postcode; how much gas and electricity you use – which is on every bill; and Bob's your uncle. It's as simple as that, as more than a quarter of a million customers find every month," she says.

Ms Knight nonetheless recognises that many consumers do not shop around for energy suppliers in the way they do for other products. "While many of us like to hunt for a good bargain, we rarely apply this to searching for a better energy deal," she concedes.

The two-tier nature of the UK energy retail market is shown by recent customer numbers from Centrica, which owns market leader British Gas, and SSE, the UK's next biggest operator.

The two companies, alongside Npower, EDF Energy, Scottish Power and Eon, comprise the so-called big six, which last year held 98 per cent of the household market.

But a wave of unpopular price increases last autumn, blamed on increased wholesale costs and the growing burden of environmental levies, caused a surge in switching to new market entrants as well as between the big six, according to the market leaders.

Last month, SSE – the first of the big six to announce tariff increases – blamed the rises and competition from alternative suppliers for the loss of 370,000 customers, as it ended its year to March with 9.1m accounts.

Centrica, which leads the pack with 15m customers, also conceded in a profit warning last month that it has lost 180,000 residential accounts in the year to date. Sam Laidlaw, Centrica chief executive, said the fall demonstrated that "competition remains fierce, particularly from smaller suppliers that are benefiting from an exemption from some environmental obligations".

Encouragement of new entrants has drawn more than two dozen alternative suppliers into the marketplace, keen to portray themselves as more keenly priced or more ethically concerned Davids ranged against the big six Goliaths.

These include Good Energy, which offers customers the chance to source electricity solely from renewables such as wind, solar and hydro power, and Ovo Energy, which also offers a range of fixed, cut-price and "green" tariffs.

Yet in spite of a surge in entrants and rule changes imposed by regulator Ofgem aimed at making switching easier, enthusiasm for shopping around remains patchy and the big six still dominate.

A survey commissioned by Ofgem from Ipsos Mori, the market researcher, shows a continued pattern of a small minority of customers happy frequently to seek out the best deals. Many others, while unhappy with their suppliers, do not move.

Just 12 per cent of those surveyed last year had switched electricity suppliers in the previous 12 months, while 11 per cent changed gas company – a fourth year of decline in switching.

Nearly two-fifths of those surveyed said they had never switched suppliers. These consumers tend to be poorer, less inclined or able to pay by direct debit to secure better deals, rent their homes, and are more likely to be in Scotland than England and Wales.

> 'We compare prices for many things, yet we don't do the same with our energy bills'

Consumer groups argue that established suppliers have been happy to compete for low-margin business among the minority of customers who chase the best deal, but know that their margins are secure among their core customer bases who rarely, if ever, switch suppliers.

Yet it is often the latter customers who are most at risk of "fuel poverty".

With a root-and-branch investigation of the UK energy retailing market under way, led by the Competition and Markets Authority, Dermot Nolan, Ofgem's chief executive recently conceded that nearly half of Britons did not prioritise shopping around for the best deal.

"We shop and compare prices for many things in life, yet we often don't think to do the same when it comes to our energy bills, even when we could be saving in the region of £200 a year," he said.

"Previously, people found it difficult to compare tariffs and the process was too time consuming," he conceded, "but the recent reforms have changed things for the better."

Smart meters deliver benefits – and costs

Technology

Savings for suppliers and consumers come at a price, writes *Michael Kavanagh*

If you live in Europe and do not already have a smart meter, the chances are one is coming your way soon.

Smart meters allow for real-time measurement and analysis of consumption, remote connection and disconnection of supplies, and more accurate billing.

In Italy and Sweden they are the norm, while in Spain, Endesa, Iberdrola and Gas Natural Fenosa are ordering the devices for an installation programme that should see 70 per cent of households equipped by 2016 and universal adoption by 2018.

The UK and France are next among the 20 European countries that have finalised – or are about to finalise – plans for smart meter adoption.

The digital technology will become part of the fabric of domestic energy use by the end of the decade.

Analysts are predicting that penetration rates across Europe will catch up with the 80 per cent expected in North America by the end of the decade, with further strong growth in Japan and China likely to fuel demand for meter manufacturers.

However, who pays and who gains from the adoption of smart meters remains controversial.

In the UK, the installation of 53m electricity and smart meters in 30m homes and businesses by the end of 2020 is expected to cost £10.9bn. Much of the benefit will accrue to energy suppliers, which will no longer need to absorb the costs of inspection of old analogue meters.

Households, meanwhile, at a time of growing political tension and protest over rising energy costs, will see their annual bills rise later this decade to pay for the rollout.

Changing behaviour: smart meter displays can help customers cut their bills

Last July, RWE Npower calculated that the cost would add £24 to average household bills by 2020.

Nevertheless, the UK's National Audit Office (NAO) is broadly satisfied by the benefits that will be generated by the investment. "The economic case for the programme remains positive," concluded a report published in May by Amyas Morse, head of the public spending watchdog.

The NAO gave broad support for estimates provided by the Department of Energy and Climate Change (DECC) that savings could total £17.1bn, resulting in a net economic benefit of £6.2bn by 2030.

The DECC estimates that energy suppliers will be the biggest winners, saving £8.3bn – half of the gross saving – through reducing site visits and cutting the cost of customers switching contracts.

But the DECC also argues that £5.7bn will be saved by customers. This is expected to come largely from reductions in demand, as better information on their energy use prompts consumers and businesses to change their behaviour.

Policy makers' confidence that smart meters can provoke a genuine shift in consumer behaviour – rather than simply bring cheaper revenue collection for utilities – is yet to be tested.

Though Germany has not implemented plans for the compulsory installation of the devices, Eon has been piloting their introduction in Bavaria ahead of widespread adoption over the next decade.

The company says that experience suggests smart meters can help consumers quickly identify "energy guzzlers" and that greater awareness of patterns of usage can reduce bills by 5 to 10 per cent. Eon points to the potential of smart meters to allow more flexible tariffs, for example, offering cheap rates for recharging electric cars overnight.

Sacha Deshmukh, chief executive of the Smart Meter Central Delivery Body, which advocates adoption of the technology in Britain, says the assumptions underpinning the UK rollout are modest.

The DECC's cost-benefit analysis of its $10.9bn programme is based on an assumed 2.8 per cent fall in electricity consumption and 2 per cent in gas.

But Mr Deshmukh points to a recent assessment of pilot schemes across Europe led by Philip Lewis of VaasaETT, an energy industry consultancy. This research suggested smart meters combined with displays offering real-time monitoring of a building's usage may reduce consumption by 7-9 per cent.

For now, UK policy makers are maintaining their modest assumptions. A best-case scenario could deliver more than £22bn in total benefits, nearly doubling the net gain. But a pessimistic assessment of £12bn would deliver almost no return on the high-profile project.

Mr Deshmukh predicts further gains for consumers as a global rollout will trigger a wave of smart household devices. It will be possible to monitor and control these remotely, allowing for more efficient operation of hot water, heating, refrigerators and other energy-draining appliances.

Some campaigners are concerned that the proliferation of digital information concerning the use of household appliances raises privacy issues.

But Mr Deshmukh says the meshing of smart meters, smart devices and smart grids will benefit consumers with the emergence of "real time of use tariffs", allowing households to trim bills by reducing overall consumption and also shifting energy use away from times of peak demand.

It will be the emergence of radical tariff deals and smart household devices that will "make smart meters really worth having", he says.

Technology drives shift to fresh thinking about business models

Continued from Page 1

costs and divesting assets.

"There's a strategic necessity for them to find new models of business development that are less capital-intensive," says Roger Reynolds, managing director for utilities at Exane BNP Paribas. Hence the attraction of "capital-lite" services, such as advising customers on managing consumption, or installing energy-efficient boilers or batteries in their homes, he says. "They don't want to just roll over and let Google and Apple take over that business."

Instead of trying to beat the technology companies at their own game, some are forming partnerships with them. Eon, Germany's biggest utility, is working with rooftop solar developer Sungevity to sell co-branded panels to customers in the Netherlands. Npower, the UK subsidiary of RWE, has teamed up with Nest, offering customers its thermostat for £99 – down from £279 – if they agree to fix gas and electricity prices at current rates until 2017.

Similarly, British Gas, a subsidiary of Centrica, recently launched Hive Active Heating, a service that lets people control their heating and hot water remotely from a smartphone, tablet, SMS, or via a website. The company says it can save households up to £150 a year.

Such innovations may be relatively minor, but they show that some companies are using technology in ways that could redefine their relationships with customers.

"This industry is leaving a world where customers were just meter numbers," says Peter Terium, RWE's chief executive. Companies such as RWE can no longer just "sell kilowatt hours", he says. They have to present a much broader offer, reflecting the rapidly changing world of energy.

RWE is being forced to change by the "Energiewende", Germany's radical shift from fossil fuels to renewables. The transition has given rise to a new phenomenon – "prosumers" with solar panels on their roofs and wind farms in their fields who both produce and consume energy.

Germany now has 6.5m energy producers, many of them households.

"What renewables have been able to bring is the miniaturisation of the equipment needed to produce electricity," Gérard Mestrallet, chief executive of GDF Suez, said in a recent interview. "A wind turbine is a thousand times smaller than a power plant." This allows for distributed generation – production in small quantities near the point of use, rather than in vast amounts in a few locations.

With the rise of the prosumer, houses are gradually turning into small power plants that produce and store electricity. Mr Terium says the utility of the future will form partnerships with prosumers, helping them sell excess energy to the grid when their batteries are full and buy it in if grey or windless days leave them short of power.

They will also advise them on reducing their consumption, which is one reason why so many are involved in smart meters that show customers how much energy they use and how much they pay for it.

6.5m

German energy producers, many of them households

"We want to offer bundled products, where all those functions can be combined under one contract," Mr Terium says.

The smart meter revolution comes at a time when pressure on household budgets from rising energy bills and concerns about global warming have underlined the importance of energy efficiency, sometimes referred to as the "invisible fuel".

The growing realisation that the energy we do not use can have almost as much impact as the energy we do has had a huge impact on everything from building designs to street lighting.

Mr Reynolds says the move by companies such as RWE into such energy services is inevitable. But he is sceptical. "I think it's going to be difficult for them to build up a meaningful business," he says.

Meanwhile, some say that by telling customers how to cut their energy use, utilities are shooting themselves in the foot, reducing demand for their chief product.

Mr Terium's responds: "If I don't shoot myself in the foot, someone else will. I'd rather be in the front row of that than wait and let others take it away."

Utilities grapple with Germany's big switch to greener power

Renewables There is new hope for struggling traditional providers, writes *Jeevan Vasagar*

On a bright but windy weekend in Germany last month, renewables set a new record. For an hour at lunchtime on Sunday May 11, wind and solar energy accounted for 70 per cent of the national electricity supply, illustrating the transformation brought about in Germany's energy system.

The record reached that day also highlighted the challenge facing conventional power generators, as the glut of clean energy in the system pushed electricity prices into negative territory. On the intraday energy spot market, prices ranged as low as minus €48.19/MWh. For a brief period, utilities were paying grid operators to take their energy.

The renewable energy law which came into force in 2000 set guaranteed prices for 20 years and provided clean energy with favourable access to the grid, sparking a scramble to install solar power, wind and other renewable energy sources.

The consequences of the Energiewende, as Germany's ambitious transition to green energy is known, are now visible across the country. Photovoltaic panels speckle the roofs of Bavarian farmers and community wind farms dot the windswept plains of northern Germany.

While established utilities were slow to respond, new businesses seized the opportunity. Renewables have gone from being the province of idealistic "*Grüne Spinner*" – crazy greens – to being firmly anchored in the mainstream, says Tim Loppe, a spokesman for one such business, Naturstrom.

The company, founded in 1998, has 240,000 customers across Germany and has signed a partnership deal with BMW to offer clean energy to buyers of the carmaker's electric vehicles.

In March, Audi offered a similar deal to buyers of its electric A3. The Volkswagen-owned brand teamed up with Hamburg clean power provider LichtBlick, which has 600,000 private and business customers across Germany, to recharge its electric model with hydroelectric power.

For investors, the news from Germany's traditional power providers has been bleak. Last year, RWE reported an annual loss for the first time since the Federal Republic of Germany was established. Germany's second biggest utility is crossing a "vale of tears", its chief executive Peter Terium told the Financial Times recently.

Eon, Germany's biggest utility by market value, suffered a 46 per cent drop in underlying net income in 2013. Income fell from €4.2bn in 2012 to €2.2bn last year. The hit to the utilities' profits had made it tougher to adapt their business models.

"The government forced significant losses on the utilities' businesses and on their market values, which limits their ability to invest," says Ralph Trapp, managing director of Accenture's German utilities practice.

It was an indication that the pace of the Energiewende was too fast, Mr Trapp says. "It was not a coherent solution."

But the tide may be turning in favour of the big power providers. Reforms to Germany's renewable energy law, due to come into force in August (see below), pose a challenge to the prospects of smaller players. "Politicians are giving the big energy concerns space to breathe," says Mr Loppe, of Naturstrom.

He suggests three reasons why the reforms to Germany's Energiewende will cramp smaller developers. First, a tendering model for new clean energy projects that is due to be introduced by 2017 will raise the risks for smaller businesses. Such companies are less likely to be able to afford early investment in a project that does not win a tender.

Second, annual caps on new installations of renewable energy mean there is a possibility that by the time a project comes to fruition, the annual limit will have been reached. Again, bigger companies are more able to bear such a risk, he says.

Third, the higher feed-in tariffs for offshore wind projects, compared with other forms of clean energy, favour a market from which smaller players are excluded because of its scale and technical difficulty.

The traditional model of power generation in vast plants outside big cities has been squeezed hard by the Energiewende. Eon plans to shut more than a quarter of its conventional generating fleet in Europe.

Both Eon and RWE are seeking to expand instead in areas that require greater interaction with customers. These include helping customers to optimise their energy consumption, or working with customers who also generate their own power using sources such as rooftop solar panels or combined heating and power plants.

Price guaranteed: government subsidies sparked a scramble to generate solar and wind power Dreamstime

Wind and solar energy briefly accounted for 70 per cent of supply

"Utilities need to develop agility," says Mr Trapp of Accenture. "That is not the way they have been used to working."

The utilities are waking up to a world in which selling electricity is no longer enough. In the UK, RWE's Npower has teamed up with Google's recent acquisition Nest to sell a thermostat that tracks household energy usage and uses the data to set temperatures automatically, saving energy.

"What helps [the utilities] is they have so much experience," Mr Trapp says. "If you combine that with new technology, they are certainly in an advantageous position."

It remains to be seen whether gains in new technology will make up for declines in utilities' core competence. The extent to which customers are willing to pay for the extra convenience and bespoke solutions offered by digital technology is open to question.

However, once they have discovered and tested the right technology, the ability to roll it out on a big scale is an advantage, says Mr Trapp.

With wholesale power prices predicted to fall further in the next few years, the outlook remains tough for utilities. But there are a few glimmers of hope.

Reforms aim to contain cost of ambitious clean energy targets

Germany

New rules will still protect industry but increase the burden on consumers, says *Jeevan Vasagar*

As Sigmar Gabriel, Germany's economy and energy minister, made a speech about significant reforms to the country's renewable power subsidy scheme, a red light began to blink on the lectern. Without missing a beat, the minister glanced at the warning signal and quipped: "That'll be the biomass people."

It was not only the biomass industry that had cause to worry.

Germany continues to set itself ambitious targets for its shift to renewables, the Energiewende. By 2035, Europe's biggest economy will generate up to 60 per cent of its electricity supply from clean sources, according to government plans. Last year, about 23 per cent of Germany's electricity came from renewables.

But the government is anxious to contain the cost of the transition. The coalition of Angela Merkel's conservatives and the Social Democrats is determined to curb a subsidy scheme that costs businesses and consumers €24bn a year.

Mr Gabriel's speech in January outlined a bill that was approved by the German cabinet in April. It aims to curb rising costs by scaling back renewable energy subsidies and placing upper limits on new installations. Feed-in tariffs paid to renewable power generators will be cut to an average across all technologies of €0.12/kWh by 2015, down from a current average of €0.17/kWh.

The revamped Energiewende will focus on solar power and onshore wind farms, the most cost-effective sources. Upper limits of 2,500MW of new capacity annually each will be placed on onshore wind power expansion and photovoltaic generation.

The expansion of offshore wind plants, one of the newest and most expensive types of clean energy, will be limited to a total of 6,500MW through to 2020.

An annual limit of 100MW has been put on biomass, which produces energy from municipal waste and plant matter and can be expensive because of the need to harvest and transport the raw material.

The new rules, due to come into force by August 1, come alongside reforms to the system of exemptions that spare heavy industry from the full cost of clean energy subsidies.

Germany has shielded its energy-intensive industry from the cost of the switch to renewables to protect jobs. Under a deal agreed between Berlin and the European Commission in April, the number of exempted companies will fall from 2,100 to 1,600, although the overall value of the exemptions will remain about €5.1bn a year.

German households, which pay a surcharge on bills to finance the Energiewende, will continue to face high prices. The surcharge rose to €0.0624 a kilowatt-hour this year, adding about €220 a year to an average family bill.

Jörund Haartveit, European power markets analyst at Thomson Reuters, says: "The big burden is going to fall on the household consumers, because there will still be exemptions for energy intensive industry, though moderated from what they are today."

Despite the rebates, industry remains concerned about the costs of energy. The energy price differential between Germany and its five leading trade partners cost the nation's manufacturing sector €52bn in net export losses from 2008 to 2013, consultants IHS says in a February report.

The US shale gas boom and anxiety over Germany's energy dependence on Russia has added urgency to the debate on energy policy.

German business has put pressure on the government to allow hydraulic fracturing for shale gas, and it emerged recently that Berlin is drawing up a legal framework to allow applications for fracking. The IHS report suggests domestic shale gas production could keep costs down.

The reforms outlined have left some questions unanswered. The shift to renewables was accompanied by a withdrawal from nuclear energy, which left Germany in need of a back-up source for days when wind or solar power fail to deliver.

This has led to reliance on highly polluting brown coal (lignite), which is more profitable for utilities to burn than cleaner natural gas – a perverse outcome for a green energy reform.

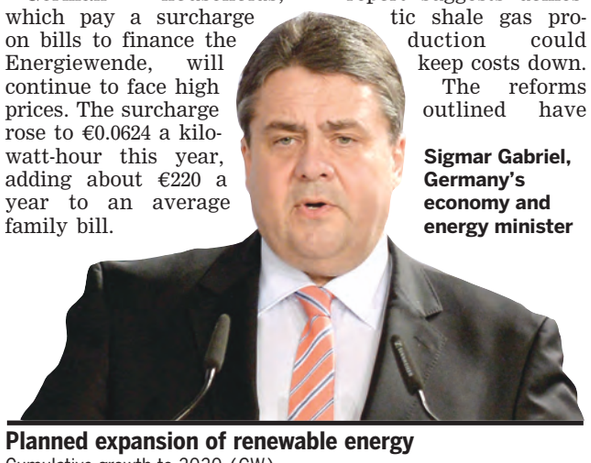
Brown coal provided 26 per cent of Germany's electricity supply last year, according to the BDEW, the German association of energy and water companies. Rewarding utilities for the cost of generating power rather than the amount they supply could solve this. The government has raised the prospect of regional solutions to prevent a loss of capacity, but is wary of imposing an additional burden on German households.

Crucially, Germany still lags behind in building the power lines vital to taking electricity from wind parks on the North Sea and the Baltic coasts to the manufacturing heartlands of the south. Construction plans have been challenged by protesters who say the "energy arteries" destroy the landscape and bring down property prices. The government is looking at burying power cables to address public concern.

The biggest change for the German renewables industry is yet to come. The country will phase out its feed-in tariffs under EU rules that require competitive bidding for green power facilities by 2017.

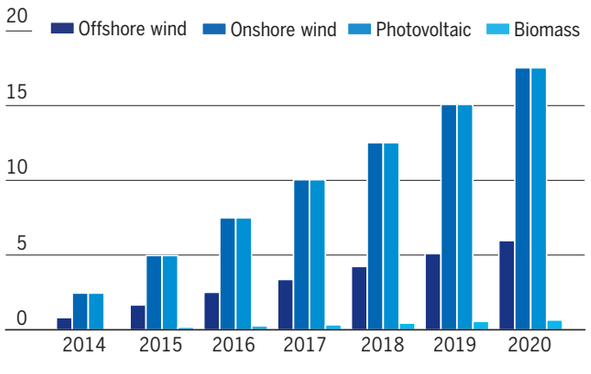
"The implementation will be challenging, as the German renewables industry has no experience with such a competitive tendering procedure," says Holger Kraft, a partner specialising in energy affairs at law firm CMS Hasche Sigle,

"The Bundesnetzagentur [federal network agency for electricity] has authority to regulate certain details of this new auction model, but nothing is certain yet," he adds. "The legal framework is still rather misty."



Sigmar Gabriel, Germany's economy and energy minister

Planned expansion of renewable energy
Cumulative growth to 2020 (GW)



Source: German Economics Ministry

Pressure: a worker checks a Sinopec appraisal well in Sichuan province, China. Some estimates suggest China has the world's largest shale gas resources Reuters

Costs hamper shale extraction

China

Companies face challenges from geology, monopolies and water, says *Lucy Hornby*

When Jianfeng, the Chinese chemical fertiliser maker, announced last September that it would switch to shale gas as its feedstock base material, it was the first Chinese company to do so.

But instead of claiming the pioneer's crown, Jianfeng became embroiled in a national debate over the viability of Chinese shale gas, as higher-than-expected prices took the shine off its decision.

Nine months after its initial announcement, the fertiliser company has yet to reach an agreement with Sinopec, the state-owned oil company, on the price of gas from China's first commercial shale development.

The shale revolution in the US has reduced the country's energy costs and imports. China hopes for similar benefits but is finding the US momentum hard to match.

By some estimates, China boasts the world's largest shale resources, with 68 per cent more technologically recoverable than the US, according to the US Energy Information Administration (EIA).

Shale has been touted as a game changer for China, the world's largest crude oil importer and consumer of half the world's coal.

However, a top-down mandate to develop shale in China has so far failed to yield the competitive volumes or low costs of the privately developed industry in the US.

Shale beds in China tend to be deeper and more geologically complex than the deposits of North America. "The geology was always going to push the cost of development higher than in the US," says Elliot Brennan, a researcher with the Sweden-based Institute for Security and Development Policy.

Other costs arise from the less-developed pipeline infrastructure and the dominant role of state monopolies. Producing Chinese shale gas will cost more than double the biggest US projects by 2015, Bloomberg New Energy Finance warned in a recent report. Boosting shale gas production therefore requires increased tariffs or higher subsidies, it said.

Beijing aims to produce 6.5bn cubic meters (bcm) of shale gas by 2015 and between 60 bcm and 100 bcm by 2020. The standard bearer so far is Sinopec, which is expanding drilling at Fuling, 20km from Jianfeng's fertiliser plant near the southwest city of Chongqing. It has pledged to produce 5 bcm of shale gas from the Fuling deposit by the end of 2015.

Sinopec is also lobbying fiercely for continued subsidies for shale gas – now at Rmb0.4/bcm – without which it says it cannot break even. China's current subsidies expire in 2015. The company is spending about Rmb80m ($1.2m) for each well it drills in Fuling, according to Chinese media reports, nearly four times the cost in the US.

China is keen to exploit shale as an alternative to dirtier coal, as part of efforts by the government to reduce unrelenting air pollution. The Chinese leadership also sees shale as a way to develop domestic energy sources and reduce vulnerability to imports. "Energy security is a top priority for China," Mr Brennan says.

Lin Boqiang, an energy expert at Xiamen University, believes the price problems will eventually be fixed after production picks up. He says it is China's industrial structure that is holding back the fledgling business.

> Producing Chinese shale gas will cost more than double that of US projects

Beijing, impatient with the pace of shale development by Sinopec and CNPC, the state oil majors, opened the second round of shale tenders to private companies.

But drilling in those blocks has been constrained by lack of funds and state oil companies' control over pipelines. A third round of tenders is planned this year.

Smaller companies, if they find shale gas, would either have to sell it to oil companies at unattractive prices or fund their own pipelines to reach distant markets where gas prices are higher.

Even if companies overcome technological barriers posed by geology and the underdeveloped pipeline system, further challenges remain.

"Something should be done about the pipeline monopoly of Sinopec and CNPC, or else it will be hard for other companies to get the gas they extract to the market," says Mr Lin.

Another challenge is water scarcity. The Tarim Basin in the deserts of Xinjiang, near China's restive border with Central Asia, holds some of China's more promising shale deposits, according to EIA estimates. But there is not enough water for fracking, a process that involves large amounts of water being injected at high pressure to free gas trapped in shale rock formations.

Areas with more water also have more people. Chongqing and neighbouring Sichuan, where CNPC is partnering with Shell to drill shale wells, are some of China's most densely populated regions, with villages clustered thickly in the mountain valleys.

These factors mean it could be a while before signing up for shale gas is an easy decision for customers such as Jianfeng.

As Accenture concluded in a recent report: "The country's above-ground non-technical factors pose the biggest challenge for investors."

Additional reporting by Owen Guo

Hydropower under scrutiny over value

Renewables

Study comes amid new push to build more mega-dams, writes *Sylvia Pfeifer*

Harnessing water: there are plans to expand schemes on the Congo river

Shortly before emptying into the Atlantic, the Congo river, which drains the world's second largest rainforest, twists and dips into a sharp, narrow bend and falls 100m in just 15 kms.

The rapids, in the Democratic Republic of Congo, are the world's most powerful, with about 42,000 cubic metres of water – 17 Olympic-sized swimming pools' worth – racing through each second.

Two hydropower schemes have been built at the Inga Falls, as the series of rapids is called. Planning is well advanced on a much bigger project that would harness the falls' full might and create the world's largest dam and hydroelectric power station. If it happens, Grand Inga would produce 40,000MW, double the output of the previous largest hydro scheme, the Three Gorges in China, and enough, in the words of its proponents, to "light Africa".

Last year, South Africa and the Democratic Republic of Congo signed a treaty to develop the project jointly. It is an ambitious and expensive scheme, with estimates that it will cost as much as $100bn. Great Inga may be unique in terms of scale, but countries including Brazil, China and Indonesia, have in recent years begun to build large hydropower projects after a lull of more than a decade.

In part, the new push is aimed at providing renewable energy to meet soaring demand. Dams can also be a way of storing water and managing river flows to avoid droughts and floods. Yet these giant projects have their critics. They often trigger opposition because they can disrupt ecosystems and require thousands of people to be uprooted.

A recent report from Saïd Business School at Oxford university – one of the most comprehensive analyses in years – says many of these projects have a poor record in terms of cost and time and are likely to saddle developing countries with large debts. Instead, governments should look into smaller, more flexible projects, it says.

Hydropower is no newcomer. It is the biggest renewable electricity generation technology worldwide, with 1,000GW installed. This is equivalent to the total electricity capacity installed in Europe and 74 per cent of the world's renewable generating capacity – enough to supply 740m people. In the past five years, about 30GW of power has been installed annually, a large amount in China, the rest in Asia, Africa and Latin America.

Hydropower has unique attributes, as it can store energy and be switched on and off quickly. It is also highly efficient; schemes can obtain up to 95 per cent of the potential energy in the water and turn it into electricity.

In 2012, the International Energy Agency predicted hydropower could double its contribution by 2050. It could prevent "annual emissions of up to 3bn tonnes of carbon dioxide from fossil fuel plants", the agency said.

Most of the growth will come from large projects in emerging economies and developing countries, the IEA predicted. Yet research such as the Saïd Business School survey of 245 large dams built in 65 countries since 1934 is raising questions about the viability of huge dams.

The study found that large dam construction costs were on average more than 90 per cent higher than initial budgets, while eight out of 10 suffered a schedule over-run. It concluded that the Brazilian Belo Monte dam in the Amazon and the Gilgel Gibe III dam in Ethiopia, and similar projects elsewhere, are likely to face "large cost and schedule over-runs seriously undermining their economic viability".

Developing countries often have to borrow heavily for imported goods or services to build big dams, putting pressure on public finances. The Itaipu dam, built on the border of Brazil and Paraguay in the 1970s, suffered a 240 per cent cost over-run that affected Brazil's finances for three decades, the authors of the study say.

Dam proponents argue that the industry has learnt from past mistakes. The IEA identified several challenges if hydropower were to meet its potential, including overcoming barriers relating to the environment, public acceptance and finance.

Richard Taylor, executive director of the International Hydropower Association, a non-profit group working to advance sustainable hydropower, disagrees with several of the Oxford study's findings, including the assessment of the Itaipu dam. He points out that it has generated revenues of $63bn so far – six times the cost of construction.

The project, he adds, will operate for 60 more years and is therefore "difficult to criticise on an economic basis". Hydropower projects have high initial costs, but what matters, says Mr Taylor, is whether they are an investment worth undertaking.

"You need to look at the value of services from the project and its lifespan – a dam will last 100 years or more and will therefore provide services for many generations," he says.

Contributors »

Guy Chazan
Energy editor

Ed Crooks
US industry and energy editor

Lucy Hornby
China correspondent

Michael Kavanagh
Energy and utilities reporter

Sylvia Pfeifer
Freelance journalist

Jeevan Vasagar
Berlin correspondent

Jerry Andrews
Commissioning editor

Steven Bird
Designer

Andy Mears
Picture editor

For advertising details, contact:
Liam Sweeney on +44 (0)20 7873 4148,

or liam.sweeney@ft.com or your usual FT representative.

All FT reports are available on FT.com at ft.com/reports

Follow us on Twitter at:
@ftreports

All editorial content in this supplement is produced by the FT.

US shows how to conquer peaks

Demand management

Users get better deals for accepting supply interruptions, writes *Michael Kavanagh*

Grid operators around the world are grappling with how to ensure generating capacity is available to meet peaks in demand.

In Europe, the encouragement of renewable but unpredictable wind and solar power has made guaranteeing supply more complicated. Amid warnings of the looming threat of power outages and dips in voltage, debate has centred on how to incentivise operators of power stations – whose output might be needed only intermittently – to top up supplies to the grid.

However, regulators are also looking at ways of encouraging customers to curtail usage at peak times to curb unnecessary investment in new power plants.

Brett Feldman, an analyst at Navigant Research, says lessons can be learned from North America, the largest market for "demand-response" programmes.

These are designed to attract households and businesses willing to trim consumption at peak times for a financial incentive.

"At the same time, technology advances in metering, controls and end-use devices are making it easier for customers to participate in demand-response programmes and manage their energy usage," he adds.

Mr Feldman predicts that global demand-response capacity will grow from 30.8GW this year to nearly 200GW in 2023, which translates into a market of $1.6bn rising to nearly $10bn. The bulk of the market is in the US, but interest in Europe and elsewhere is growing.

The potential savings to utilities are enormous. Each 250MW shaved from peak demand may remove the need for a new average "peaking" power station that might sit idle off-peak.

PJM Interconnection, operator of the world's largest competitive electricity market – 60m customers in 13 states in the Midwest and eastern US – last month procured 11,000MW of demand-response capacity, compared with a total 167,000MW of supply it secured.

PJM's capacity auctions allow demand-response programmes to compete on cost with generators offering peak-time output. Encouragement of a market willing to accept interruptions has avoided the need to finance and build 40 peaking power stations in the region, says Mr Feldman.

The shift leaves PJM with an aggregate reserve margin of more than 25 per cent over predicted peak demand this summer – well above the 16 per cent required by regulators, said Michael Kormos, PJM's executive vice-president of operations.

In the US, domestic customers typically get $20-$25 for interruptions to air conditioning during summer peaks, controlled by timed switches. The rollout of smart meters and improved technology will allow less noticeable interruptions.

Aggregator companies such as EnerNOC and Comverge are offering industrial customers technologies that allow them to cut peak and overall demand as well as benefit from lower bills through the direct incentives from demand-response programmes.

EnerNOC points to the example of Great Lakes Cold Storage, a frozen and refrigerated warehouse operator. The installation of new systems enabled refrigeration to be interrupted without risk to stock and led to the receipt of $33,000 in direct payments for contracting into a PJM demand-response scheme through EnerNOC – part of wider savings estimated at $250,000 in the company's power bill.

> Cutting use at key times is shown to reduce the need for new power stations

Mr Feldman suggests that at nearly 10 per cent of capacity in some US regions, demand response "is getting towards the limit for customer satisfaction and grid reliability".

However, he predicts that curtailment of coal plants and growth of intermittent wind and solar power will see demand response grow in Europe.

National Grid, the UK grid operator, is extending its demand-response programmes, prompted by a short-term squeeze on generating capacity. The company already has deals with large users such as steel works that involve short interruptions to supply. The deals allow for the use of sources such as back-up generators at hospitals.

But the recent retirement of a range of coal and gas-fired power stations has raised concerns at Ofgem, the UK energy regulator, about whether enough capacity remains to guarantee the country's needs in the middle of this decade.

In response, National Grid said it would tender for up to 330MW of demand side balancing reserve – in which large energy users reduce their demand during winter weekday evenings in return for payment – for the coming winter, plus up to 1,800MW of combined demand response and additional peak power capacity for the following winter.

Dermot Nolan, Ofgem chief executive, described the contracts as "the right levers to keep the lights on for households this winter".

Before confirmation of the tendering, Steve Holliday, chief executive of National Grid, said he was satisfied with initial interest from customers willing to constrain their use, thus helping to guarantee supply to others in the "shortest, darkest days of winter".

Financially motivated enthusiasm for – rather than panic about – planned power interruptions to office, factory and household equipment may soon become more commonplace.