THE ENERGY INDUSTRY TIMES

October 2013 • Volume 6 • No 8 • Published monthly • ISSN 1757-7365 www.teitimes.com

Special Supplement

Korea bets on high efficiency gas turbines

Not smart enough

Will Europe ever get there on its transition to a new, smarter energy system? *Page 13*

Final Word

Miliband is dreaming The Impossible Dream, says Junior Isles.
Page 16

News In Brief

MHI joint venture buoys Vestas
Struggling Danish wind turbine manufacturer Vestas received a lifeline in its fight to stay afloat following the agreement of a joint venture with Japan's Mitsubishi Heavy Industries.
Page 2

SMR grant delayed
The US Department of Energy has missed a target for announcing the recipient of government funds for the development of small modular reactor designs.
Page 4

High Asian LNG prices beyond 2020
Energy research and consulting company, Wood Mackenzie says policy and regulatory uncertainty in Japan and South Korea could result in less new liquefied natural gas supply being developed, perpetuating higher spot prices.
Page 6

Energy firms step up pressure on European policy
Energy companies and industry associations from around Europe are stepping up the pressure on lawmakers to establish concrete measures on energy policy.
Page 7

Geothermal growth
Some 70 countries around the world are moving forward with plans to build new geothermal energy capacity.
Page 8

Energy Outlook: Regulating for commercial realities
Offshore wind farms can progress more easily with the right approach to regulation and legislation, as Triton Knoll demonstrates.
Page 14

Technology: Making a case for battery storage
A trial project in Orkney will help determine whether an energy storage system can make technical and commercial sense.
Page 15

Still strong interest in UK nuclear programme

UK Energy Secretary Ed Davey is said to be in talks with China

Despite the ongoing deadlock between EDF and the UK government over Hinkley Point, other overseas suppliers are still showing a strong interest in Britain's nuclear power programme.

Junior Isles

China and Russia are pushing strongly to be part of the UK's planned nuclear power programme.

According to the *Sunday Times* newspaper UK energy secretary Ed Davey was planning to travel to Beijing to lay the groundwork for a new partnership that could lead to Chinese-designed nuclear reactors being built in Britain.

Davey's talks with China are aimed at striking a deeper relationship, which could be formalised in a memorandum by the end of the year, the newspaper said.

The government has been locked in talks with French utility EDF over the price that would be paid for electricity generated by two nuclear units to be built at Hinkley Point in Somerset. According to the latest reports, the government is refusing to offer more than about £90/MWh, while EDF wants a minimum of £93. The deadlock has dragged on for a year.

EDF is also currently in negotiation with China General Nuclear Power Group (CGN) on sharing the cost of building the £14 billion Hinkley Point units. EDF is looking for a partner in the project after Centrica pulled out.

CGN, however, has made it clear that it will only go ahead if it is given more of a say in other projects the companies might build together in the UK.

EDF is also hoping to build two reactors at Sizewell and CGN could be looking to become a joint operator of the new plant.

One source told the *Financial Times* newspaper: "CGN is using Hinkley as a stepping stone. In the next project they'll want greater control. This is likely to create unease within the UK government, which has concerns over the national security of allowing a Chinese state-backed company to have a role in running a nuclear plant. Last year it insisted that Chinese companies could only take a minority stake in the Horizon consortium, which was eventually acquired by Hitachi of Japan.

Another Japanese owned company is also believed to be close to gaining a stake in the Nugen consortium that owns the right to construct a new reactor at Sellafield.

US-based manufacturer, Westinghouse, which is owned by Toshiba, is near to finalising the acquisition of a 50 per cent stake in the business owned by Spain's Iberdrola. It is also keen to

Continued on Page 2

Czech Republic abandons renewables in favour of coal

The Czech Republic is set to go against a trend in the rest of Europe that has seen countries support renewables over large centralised fossil fuelled plants.

Last month the upper house of parliament, or Senate, voted 56 in favour with only one opposing a bill to eliminate subsidies for new photovoltaic power plants while quickly winding down support for other types of renewable power production. Instead it approved a bill that directs support to centralised power production at plants burning fossil fuels.

The bill put forward by the country's caretaker government has been approved by the lower house of parliament and only needs the signature of President Milos Zeman to become law, which is expected this month (October).

The approval of the bill signals that the central European country – where manufacturing and industry are key sectors of the economy – is breaking from the European mainstream, which supports renewable energy.

"Definitely we welcome it; it's a step in the right direction, to gradually limit the spiral of support for renewable energy which has deformed the entire market," CEZ spokesman Ladislav Kriz said immediately after the vote.

The Czech Republic has seen a surge in renewable power production over the last four years due to large cash payouts to investors in the sector. Public outrage over fast-rising power prices has, however, forced politicians to put the brakes on subsidies. They also say the payouts have been a drain on the economy, creating uncertainty in energy markets and preventing utilities from investing.

"To maintain the country's [international] competitiveness we had to act," said Senate Vice-chair Alena Gajduskova after the vote.

The new bill will certainly be welcomed by major power producers such as 70 per cent state-owned CEZ, which primarily produces its electricity from large, centralised power plants.

Some former central European countries such as Poland have long resented pressure from Brussels forcing them to decrease dependence on domestic coal for power generation.

While stopping subsidies for clean renewable energy, the Czech Republic pledged to double its use of fossil fuels. This follows Poland's announcement that it would use its abundant domestic coal supplies for power generation rather than invest in what it sees as more costly renewable energy facilities.

Poland and the EU are already at loggerheads over the country's plans to build a 2 GW coal plant on the Vistula River.

■ Last month German utility E.On agreed to sell an opencast lignite coal mine and a power plant to a wholly-owned subsidiary of Czech energy investor EPH for an undisclosed price. The EPH unit Mibrag will take over the business, which comprises the Buschhaus lignite fired power plant and the opencast mine in Schoeningen, eastern Germany. The lignite-fired power plant has a capacity of around 390 MW and was commissioned in 1985.

E.On had originally planned to cease operation of the Buschhaus power plant once the deposits in the adjoining Schoeningen opencast mine were exhausted around 2017. Following the transaction with E.On, Mibrag will continue to operate the power plant, supplying it with lignite from one of its other mines.

THE ENERGY INDUSTRY TIMES is published by Man in Black Media • www.mibmedia.com • Editor-in-Chief: Junior Isles • For all enquiries email: enquiries@teitimes.com

Continued from Page 1

buy part of the other half owned by France's GDF Suez.

Westinghouse is waiting for the final nod from Toshiba but a deal is believed to be close.

The prospect of a deal comes as nuclear continues to gain political support. In mid-September Davey gained the backing of his Liberal Democrat Party in overturning its longstanding opposition to nuclear power.

Earlier, UK Business and Energy Minister Michael Fallon signed a memorandum of understanding (MoU) to co-operate on civil power with Russian state atomic monopoly Rosatom.

Rosatom also announced that it was joining forces with Finnish utility Fortum and UK engineering company Rolls-Royce to assess whether Russian VVER-type reactors could be introduced into the UK market. The MoU between Rosatom and the government will allow the company to familiarise itself with the UK market and forge links with British firms.

Fallon signed an MoU with Russia's Rosatom

Fallon said Russian and British companies already played a "significant part in the global nuclear industry" and so are well placed to co-operate in civil nuclear programmes around the world.

Under the terms of the MoU, the government will organise seminars to help Rosatom understand Britain's nuclear regulatory and planning regimes and the approval process for its reactor design. Approval of reactor designs by UK regulators could take as long as four years.

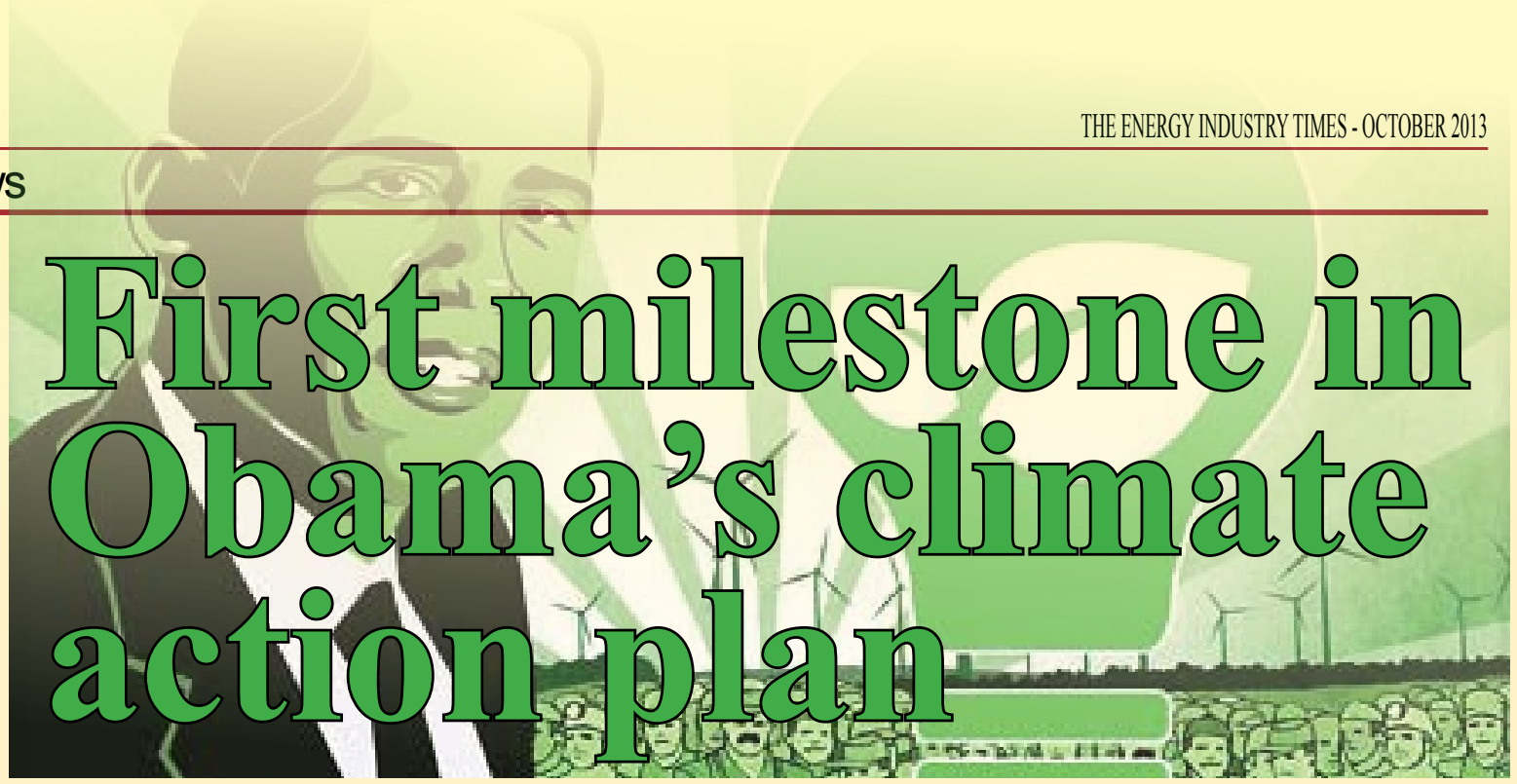
Under the three-way company agreement, Fortum, Rosatom and Rolls-Royce will begin preparatory work with a view to getting the VVER reactor into the UK's Generic Design Assessment, or GDA, programme, which is the first step in a wider approval process for new nuclear reactors. Regulators at the Office for Nuclear Regulation and the Environment Agency use the GDA process to assess the safety, security and environmental implications of new reactor designs.

Although no investment decision has yet been made by the three companies, Matti Ruotsala, Fortum's executive vice president, described the UK as "a really interesting opportunity."

Fortum is involved because the UK government stipulates that any technology provider submitting plans to build a reactor in the UK must team up with a credible operator. Fortum operates nuclear plants in Finland and Sweden.

Rolls-Royce, meanwhile, will undertake engineering and safety assessment work for Rosatom ahead of GDA.

Fallon commented: "Inward investment into our energy sector will depend upon all reactor technologies meeting the stringent and independent regulatory standards required in the UK and European Union."



First milestone in Obama's climate action plan

A proposal to limit emissions from new power plants is being seen as the first milestone in the US' plan to tackle greenhouse gas emissions. **Junior Isles**

The proposed emissions standards for new power plants recently announced by the US Environmental Protection Agency (EPA) marks the first milestone outlined in President Obama's June 25 Memorandum to the EPA on "Power Sector Carbon Pollution Standards," a major part of the President's Climate Action Plan.

According to the EPA, electricity generation represents one-third of US greenhouse gas emissions. The rules are therefore a major step for the US in its goal to reduce greenhouse gas emissions by 17 per cent below 2005 levels by 2020.

Under the proposal, new large natural gas fired turbines would need to meet a limit of 454 kg (1000 lbs) of CO_2 per MWh, while new small natural gas fired turbines would need to meet a limit of 500 kg (1100 lbs) of CO_2/MWh. New coal-fired units would need to meet a limit of 500 kg of CO_2/MWh, and would have the option to meet a tighter limit if they choose to average emissions over several years, giving those units additional operational flexibility.

Following the news, Kevin Kennedy, Director, US Climate Initiative at the World Resources Institute (WRI) said the announcement "delivers a strong signal" that the administration will use its authority to tackle climate change.

"These new rules will limit carbon pollution from all future US power plants. That's good news for people and the environment," he said.

In anticipation of expected resistance from Republicans, Energy Secretary Ernest Moniz assured a House energy panel that fossil fuels would remain significant sources of energy for years to come.

EPA Administrator Gina McCarthy, who was questioned with Moniz at a House hearing, said: "The rule will provide certainty for the future of new coal moving forward, and in terms of existing facilities, coal will continue to represent a significant source of energy for decades to come."

Nevertheless, the proposal is another blow for coal fired generation. Market dynamics, including the emergence of low price natural gas, have been driving US generators away from coal. According to the US Energy Information Administration, over the next three years, utilities plan to build only eight new coal fired generators compared with 91 new gas fired plants.

"In some sense, it closes a door preemptively," said Julien Dumoulin-Smith, an analyst at UBS in New York who follows Western Pennsylvania's biggest power companies. "The reality is low natural gas prices are going to do in coal much more significantly than any new regulations are going to."

While the new standards are relatively strict, they provide power plants with options for compliance, including phasing in carbon capture and storage (CCS). While not yet widely used due to unfavourable economics, CCS is technically feasible and could be further deployed under the right conditions.

James Van Nostrand, a West Virginia University energy law professor said an EPA mandate would allow a utility to "make a much stronger case" to recover the costs of installing CCS, although companies still would have to show that such an investment makes sense compared to other options for providing power to their customers.

Smart grid investment under threat

- Replacing Germany's meters would have generated €6 billion
- Situation will worsen if others follow

The potential German rejection of smart meters could pose a threat to $44billion (€33 billion) of smart grid investment, says Frost & Sullivan.

Frost & Sullivan Energy Analyst, Neha Vikash explained: "The EU Energy Efficiency Directive mandates for 80 per cent of households in Europe to have smart metering by 2020. The exception to the Energy Efficiency Directive is if a country can prove that smart metering would not pass a cost benefit analysis."

In August, Germany's Economy Ministry published such a report, carried out by external consultants, rejecting smart meters as too expensive to deliver economic benefits.

"The report has shocked the industry and could have major ramifications, although it should be pointed out that the report could still be rejected by the German government," said Vikash.

Germany has 48 million meters and the replacement of them over a 5-7 year period would have generated an estimated €6 billion ($8 billion) in revenues for smart meter and communications manufacturers.

According to numbers based on Frost & Sullivan's internal forecasts made for the upcoming Global AMI report to be published in the autumn, this amount does not include the estimated €7.5 billion that would be spent on supporting infrastructure, project management and installation.

"If Germany instead decides to install smart meters only when existing meters need replacing, this would be a massive blow to the industry," said Vikash.

The situation for meter manufacturers could worsen if other countries follow Germany's lead. "If a country with the political strength of Germany opts out," adds Ms Vikash, "it could embolden EU countries to follow suit. Prior to the German announcement, the UK government had already announced it would delay its rollout by one year to allow further consultation – could this be scrapped or delayed further?"

According to Frost & Sullivan, excluding Germany there are an estimated 180 million residential meters in the EU, and of these approximately a third are either already smart or in countries with smart rollouts that are underway and unlikely to be stopped. This leaves 120 million meters. Assuming 80 per cent of the 120 million meters in Europe were to be replaced by 2020, this would mean an estimated 96 million meters being replaced at an estimated €9 billion, and this does not take into account the support infrastructure and installation costs which would be an estimated €10.5 billion.

"The German government may reject this report and go ahead with the rollout. Other countries may ignore Germany and install smart meters regardless. But with €33 billion in the balance, this development has got everyone in the industry concerned," concluded Ms Vikash.

MHI joint venture buoys Vestas

Struggling Danish wind turbine manufacturer Vestas received a lifeline in its fight to stay afloat following the agreement of a joint venture (JV) with Japan's Mitsubishi Heavy Industries (MHI).

Shares in the embattled company soared 12 per cent on the news that it is offloading its lossmaking offshore turbine division into a JV with MHI.

Although its offshore business only represented 7 per cent of Vestas' order backlog at the end of June (measured by MW of generating capacity), it has been a financial drain on the company's balance sheet.

The JV will combine Vestas' and MHI's current capabilities within offshore wind turbines. Vestas will transfer the development of the V164-8.0 MW wind turbine, the V112 offshore order book, existing offshore service contracts and approximately 300 employees to the JV.

It also said at a later date it may seek to incorporate the hydraulic technology used in MHI's 7 MW SeaAngel turbine into the Vestas machine. The SeaAngel turbine will not be part of the joint venture and will continue to be developed independently by MHI.

MHI will inject €100 million in cash into the JV and will inject another €200 million based on certain milestone achievements reflecting the natural early product life cycle of the V164 turbine.

Each company will own 50 per cent of the JV although there is an option for MHI to change the ownership ratio to 51 per cent for MHI and 49 per cent for Vestas in April 2016.

The transaction is subject to the normal approvals from relevant competition authorities in Europe and Asia but closing is expected around the end of March 2014.

The JV will not have any impact on Vestas' annual accounts for 2013 and is only expected to have a marginal impact on its 2014 revenues and earnings. Any capital expenditure related to the development of the V164-8.0 MW turbine after September 1, 2013 will be reimbursed to Vestas by the JV after closing.

Vestas and MHI had been in talks for over a year and the deal is the first by Vestas' chief executive Anders Runevad, who joined in August.

SMR grant delayed

Applicants for the second funding opportunity are waiting to hear of the DOE's decision.

Siân Crampsie

The US Department of Energy last month missed a target for announcing the recipient of government funds for the development of small modular reactor (SMR) designs.

The March 2013 funding opportunity announcement indicated that the $226 million award would be announced in mid-September but the DOE says that it is still working on the bids solicited.

The funding award is part of a wider programme by the US government to assist the design, development and commercialisation of SMRs in order to help kick-start the stagnant US nuclear energy industry and boost exports of the country's nuclear expertise.

The DOE has so far awarded $79 million to Babcock & Wilcox mPower, which is aiming to bring an SMR-based power plant on-line at Clinch River, Tennessee by 2022.

The B&W mPower reactor is an advanced integral pressurised water reactor designed to generate 180 MW of electricity. Like other SMR designs, its small size should make it cheaper and faster to build compared with large, conventional nuclear power plants, as well as make it more flexible to operate.

Other SMR designs on the drawing board and seeking DOE funds include General Atomics' Energy Multiplier Module (EM2), a helium-cooled high temperature reactor, NuScale's 45 MW self-contained pressurised water reactor and generator set, Westinghouse's 225 MWe integrated pressurised water reactor, Holtec's 160 MWe design and a hybrid fossil fuel-nuclear design from Hybrid Power Technologies.

The delay has cast further doubt on the government's plans for SMR development following a report published by the Institute for Energy and Environment Research (IEER) over the summer, which criticised the economic case for SMRs.

The IEER report said that that companies building SMRs are more likely to use established nuclear energy supply chains in China than develop new supply chains in the USA, resulting in limited economic benefit to the US. Additional federal subsidies to the tune of billions would be required to set up the domestic supply chain, it said.

"SMRs are a poor bet to solve nuclear power's problems and we see many troubling ways in which SMRs might actually make the nuclear power industry's current woes even worse," said Arjun Makhijani, Ph.D., nuclear engineer and president of IEER. "SMRs are being promoted vigorously in the wake of the failure of the much-vaunted nuclear renaissance. But SMRs don't actually reduce financial risk; they increase it, transferring it from the reactor purchaser to the manufacturing supply chain."

Firms boost Brazilian wind investments

- GE to expand nacelle production
- Alstom to deliver Pontal wind turbines

Siân Crampsie

Wind turbine manufacturing firms are turning their attention to Brazil as growth in the country's wind industry continues apace.

GE is to expand its nacelle production facility in Campinas, São Paulo, and last month said it had installed its 500th wind turbine in the country.

Alstom says it has signed a contract worth around €25 million with Enerplan to supply wind turbines for the Pontal wind project in the south of Brazil.

According to GE, wind energy is one of Brazil's fastest growing energy sources and manufacturers are keen to take advantage of this as growth in more established markets in Europe and North America has stumbled. The US firm has also announced plans for two service centres for the wind sector in Brazil.

"Last year the country added 1077 MW of wind to the grid – 40 per cent of which were GE installations. The Campinas facility expansion will enable GE to continue to provide high quality wind technology while enabling our customers to have access to Brazil's BNDES financing lines," said Jean-Claude Robert, general manager of Latin America for GE's renewable energy business.

GE's Campinas facility is co-located with Brazilian manufacturer and GE subsidiary Gevisa and produces nacelles for GE's 1.7-100 and 1.85-82.5 wind turbines.

The two wind energy service centres, to be located in Bahia and Rio Grande do Norte states, will support operational wind farms by monitoring turbines as well as weather conditions.

GE's 500th wind turbine in Brazil was a 1.6 MW unit installed at DESA's 38 MW Eurus project in João Camara in the state of Rio Grande do Norte.

Alstom announced in September that it will supply ten of its ECO 122 wind turbines for the Pontal facility in Viamão. The nacelles will be manufactured at Alstom's plant in Bahia State and the towers will be produced at its new facility in Canoas.

Since 2010, Alstom has signed contracts in Brazil to provide more than 2000 MW in wind projects, including the supply of over 600 ECO 122 wind turbines.

Flexible CCGTs gain momentum

Flexible combined cycle gas turbine plants are continuing to gain momentum in the US off the back of increasing intermittent renewable generation and cheap, abundant, natural gas resources.

NRG Energy recently inaugurated a 550 MW combined cycle power plant in California, while GE Energy Financial Services, ArcLight Capital Partners and Competitive Power Ventures have closed financing on a 700 MW combined cycle facility in New Jersey.

Advanced, flexible technology with fast-start and fast-ramping capability will be a feature of both plants.

In California, Siemens technology is being used to power a 'Flex Plant' for the El Segundo Energy Center to serve the needs of 450 000 households and provide reliable support for the state's growing renewable energy sector. This is the second Flex-Plant to open in California after the first in Lodi began operation just over a year ago.

The plant features two Flex-Plant 10 combined cycle blocks. At the heart of each is an SGT6-5000F gas turbine, integrated with a single-pressure, non-reheat bottoming cycle. Notably, the El Segundo Energy Center is the first to feature NEM's new Drum+ fast start heat recovery steam generators. According to Siemens, the plant is able to deliver 300 MW in 10 minutes.

Meanwhile, in New Jersey, the CPV Woodbridge Energy Center will turn the site of a former chemical plant into a productive power generation site, selling its capacity through 15-year Standard Offer Capacity Agreements (SOCA) with New Jersey utilities and energy through a hedge.

It will generate enough electricity to power 700 000 homes. Construction of the project begins this quarter, and it is expected to enter commercial operation as soon as the first quarter of 2016.

GE's Power & Water business is supplying its FlexEfficiency 60 combined-cycle technology as well as engineering services for the project.

Bolivia signs accord for lithium future

Bolivia could become an important producer of lithium-ion batteries for electric vehicles following the signing of a framework agreement with the government of the Netherlands.

The two countries finalised an accord in La Paz in late August that outlines plans for a lithium battery plant as well as for training and technology and knowledge transfer.

Bolivia is thought to hold as much as half of the world's lithium resources in Salar de Uyuni, a dried-up salt lake in the southwestern province of Potosi. President Evo Morales' government has set up a semi-industrial plant there to produce potassium chloride and another pilot plant to make 40 tons per month of lithium carbonate, the main component of the rechargeable, lithium-ion batteries that power electronic devices such as laptop computers and cellphones, as well as electric vehicles.

Bolivian authorities have rejected various proposals for developing Uyuni's lithium reserves submitted by would-be foreign partners, arguing that none of them has offered to industrialise the metal on Bolivian soil.

The accord with the Netherlands not only foresees the development of a battery production facility, but also the creation of research programmes and research placements for Bolivian professionals at Delft University of Technology in the Netherlands.

Bolivia is thought to hold half of the world's lithium resources

Jamaica selects preferred bidder

Jamaican Energy Minister Phillip Paulwell says that the country is taking concrete steps towards reducing the cost of energy after the regulator named the preferred bidder for a major new power plant.

The Office of Utilities Regulation (OUR) has picked a joint venture of New York-based Azurest Partners and Miami-based Cambridge Project Development Inc. as preferred bidder for the construction of a 360 MW facility.

Ansord Hewitt, Director of Regulation, Policy, Monitoring and Enforcement said that the Azurest-Cambridge joint venture topped the bidding based on its technical proposal and price.

OUR will carry out due diligence and further negotiations with Azurest-Cambridge before the signing of a power purchase agreement for the project.

OUR says it received five final proposals from four entities for the supply of baseload generating capacity.

Moves to curb solar manufacturing may prompt consolidation

■ Policy will slow efforts to expand production capacity ■ Ban on coal plant may benefit solar

Syed Ali

China's decision to limit the construction of new photovoltaic (PV) manufacturing plants in an effort to curb excess capacity may spur consolidation within the industry, according to analysts.

Last month, the world's biggest maker of solar panels said new PV panel production plants that "purely" expand capacity would be strictly banned. In a statement on its website the Ministry of Industry and Information Technology said annual spending by companies for research and development and upgrading equipment must total at least 3 per cent of revenue and must exceed Yuan10 million ($1.6 million).

The policy will slow efforts to expand production capacity in favour of mergers and acquisitions as a growth strategy for the biggest companies, according to Angelo Zino, an analyst with S&P Capital IQ in New York.

"They may be able to add capacity without actually building it," Zino said. "The Chinese government would be more than OK with companies if they joined forces or capacity gravitated toward the tier-one manufacturers."

Chinese solar companies have more than enough capacity to supply the entire industry. According to data compiled by Bloomberg, if they ran at full capacity, China's factories could produce 49 GW of solar panels a year, 10 times more than in 2008 and 61 per cent more than installed globally last year.

"You still have so much capacity out there that is just not being used," said Wang Minnan, a Bloomberg New Energy Finance analyst. "It will help stabilise the whole pricing environment."

According to Bloomberg, a global oversupply of solar panels led to a 20 per cent plunge in prices last year.

Panel prices are about 84 cents/watt, compared with $2 at the end of 2010. The slump forced dozens of producers into bankruptcy, including the main unit of Suntech Power Holdings Co., once the industry's biggest supplier.

Chinese solar panel manufacturers are also being affected by anti-dumping duties imposed by the US and Europe. Last month, China hit back at the US saying it would impose duties on some imports of US solar-grade polysilicon. China's Commerce Ministry said it would slap US imports of the material used to make solar panels with duties of up to 6.5 per cent.

The country's struggling solar industry may, however, benefit from the government's recent decision to ban new coal-fired power plants in three key industrial regions around Beijing, Shanghai and Guangzhou.

In a move to improve air quality the State Council, China's Cabinet, also aims to cut coal's share of total primary energy use to below 65 per cent by 2017 and increase the share of nuclear power, natural gas and renewable energy.

According to government statistics, coal consumption accounted for 68.4 per cent of total energy use in 2011. The government aims to increase the share of non-fossil fuel energy such as solar and wind power to 13 per cent by 2017. It was 9.1 per cent last year.

Indonesia steps up transmission capacity

The government of Indonesia, with assistance from the Asian Development Bank (ADB), will build a cross-border power transmission line linking West Kalimantan with Sarawak, Malaysia.

State-owned electricity company Perusahaan Listrik Negara (PLN) currently uses expensive oil for power generation in West Kalimantan but the new link will bring cheaper, greener hydroelectricity from Malaysia to West Kalimantan and add 8000 households to its power grid.

"This is a win-win-win situation," said ADB Energy Specialist Sohail Hasnie. "West Kalimantan gets renewable energy and will have the ability to exchange power; Sarawak starts its first export of hydropower; and the region moves one step closer to establishing a regional power transmission link that crosses Brunei Darussalam, Indonesia and Malaysia."

The link is expected push down the price of power in West Kalimantan from $0.25/kWh to $0.18/kWh, while carbon dioxide emissions from fossil fuel-based generation could be cut by 400 000 tons each year by 2020.

The project will build a 145 km distribution line, distribution feeder extensions, and a new substation to improve the reliability of power in West Kalimantan. An 83 km cross-border high-voltage transmission line and substation will connect the West Kalimantan power grid to that of neighbouring Sarawak. An estimated 230 MW of power could be exchanged every hour between the two systems.

Both countries have agreed to complete the link by December 2014 and power will start flowing from the start of January 2015.

■ Avantha Group Company CG has produced its first batch of 500 kV transformers from its state-of-the-art manufacturing and testing facility located in the industrial area of Cileungsi, Bogor, Indonesia. The CG is the first company in southeast Asia to design, manufacture and test 500 kV transformers locally.

Boost for Indian hydro and wind

The Indian government is attempting to boost wind and hydropower generation through the extension of incentive schemes.

The Ministry of New and Renewable Energy plans to extend the scheme for generation-based incentives for grid connected wind power projects for the 12th Plan period. The objective is to broaden the investor base, to incentivise actual generation, and to facilitate the entry of large independent power producers and foreign direct investors to the wind power sector.

Under the scheme, wind power generators will receive 50 paise per unit of electricity fed into the grid for a period of 4-10 years, with a cap of $153 000. The total disbursement in a year will not exceed 25 per cent of the maximum limit of the incentive.

Meanwhile, to speed up the growth of hydropower generation capacity, India plans to extend the so-called 'cost-plus' tariff regime for setting up these capital-intensive projects.

The regime allows utilities to charge a price that factors in their cost and a certain return. The current cost-plus model, applicable till 2015, promises assured returns over the investment made.

"The cost-plus model is up to December 2015. We are trying to extend it up to the 13th Plan period (2017-22). Nobody is calling tariff bids for purchasing electricity generated from hydropower projects," a government official said. "This [proposed extension] will promote hydropower."

High Asian LNG prices beyond 2020

High LNG prices could persist longer than expected, and possibly increase, due to power sector uncertainty in Japan and Korea.

Energy research and consulting company, Wood Mackenzie says policy and regulatory uncertainty in Japan and South Korea could result in less new liquefied natural gas (LNG) supply being developed. According to the company, this will result in continued tightness in the Pacific LNG market beyond 2020 and perpetuate relatively high spot prices.

The prediction is contrary to general market consensus that the market will see relief around the 2018 timeframe. While the governments of Japan and South Korea are actively promoting greater competition between new LNG suppliers to encourage lower priced LNG, uncertainty regarding nuclear generation and market liberalisation may have the opposite effect and increase the cost of LNG procurement, said the energy analysts.

Gavin Thompson, Head of Asia Pacific Gas & Power Analysis, said: "Both governments recognise their influence on the global LNG market and are actively pursuing initiatives aimed at reducing overall LNG supply costs through increasing competition between global LNG suppliers. However, a lack of clarity around the timing and extent of market liberalisation as well as ongoing uncertainty around nuclear power in their domestic markets could have the opposite effect."

Thompson says that power market liberalisation could erode the regional monopolies of traditional power utilities and enable other players such as gas utilities, industrials and downstream companies to enter the market. He also noted: "Uncertainty about the future regulatory and competitive environment could result in all players delaying firm LNG procurement decisions."

Similarly in South Korea, gas market liberalisation, contract renegotiations and the potential for new entrants able to procure LNG at prices below the weighted average supply cost of Korea Gas Corporation (KOGAS) is restricting the company's ability to procure new long-term LNG supply. Furthermore, optimistic government expectations on future coal and nuclear generation build, amongst other issues, consistently underestimates the country's actual LNG requirements.

Thompson concluded: "The governments of Japan and South Korea are rightfully looking to reduce overall energy costs to maintain competitiveness within their broader economies. However, the uncertainty that these policies have introduced could be counter-productive.

"Projects need some security of contracted volumes in order to be assured of commercial viability. Without this security, these projects will not be developed in line with market demand. The wave of supply expected to come online around 2018 will likely be delayed as a result, and risk LNG procurement costs rising."

Energy firms step up the pressure on European policy


Mestrallet: subsidies not needed

Europe's energy companies want clear policies on climate change but are split over the role of renewables.

Siân Crampsie

Energy companies and energy industry associations from around Europe are stepping up the pressure on the region's lawmakers to establish concrete measures on energy policy.

Last month over 60 companies and associations joined forces to call for stronger targets for renewable energy, while a group of nine major European utilities said that a lack of clear policies had put investments and energy security in the region at risk.

The actions of the groups comes ahead of the expected publication later this year by the European Commission of proposals for a climate framework to 2030.

While both groups want Europe's climate ambitions to be reinforced, the group of nine utilities – which includes GDF Suez, Enel and E.On – believe that the recent rush to build wind farms and solar power plants is not sustainable.

Speaking in front of a European Parliament in September, GDF Suez CEO Gérard Mestrallet said that one of Europe's biggest issues was over-generous renewable energy subsidies that had pushed up the price of energy for consumers. He argued that some technologies no longer required subsidies and that public support for some renewables should be adjusted.

The voice of Mestrallet and his counterparts from other utilities, including RWE, GasTerra, Iberdrola, Gas Natural and Vattenfall, will put pressure on the Commission as it ponders future climate policy.

The group of nine utilities do not favour a binding renewable energy target for 2030 but would like to see the region's carbon market strengthened with ambitious emission reduction targets.

But a second group of companies and associations – including the European Renewable Energy Council (EREC), Dong, EnBW, Vestas, EDP Renewables, SSE and Alstom – has written to the European Parliament President Martin Schulz, EU Energy Ministers and the EU Energy and Climate Commissioners to call for a legally binding 2030 target for renewables as part of "a strong and ambitious regulatory framework for the years to come".

Their letter notes the success of Europe's 2020 targets in setting a clear direction for the energy industry and calls urgently for 2030 targets in order to provide investors with certainty.

"Such a framework bears the opportunity to reduce the current costs of uncertainty, mobilise the needed funding, help to protect the environment, decrease the costs of decarbonisation, facilitate the creation of new jobs and enhance the EU's technology leadership," say the signatories in the letter.

They continue: "However, 2030 is already at our doorstep. Given the long investment cycles in the energy sector and the fact that investment decisions in the EU's liberalised energy markets strongly depend on reliability, certainty about the regulatory framework of the next 17 years is needed."

But the nine utilities are concerned that the rapid rise of renewable energy in Europe is already undermining the economic competitiveness of conventional power generation plants using natural gas and coal. RWE and E.On have recently been forced to mothball some capacity and Mestrallet indicated in the Parliamentary hearing last month that Europe's security of supply is at risk.

He said that 30 000 MW of gas fired capacity had been closed down or mothballed in Europe in recent years and called for a system of capacity payments that would provide an incentive for such plants to stay on-line and serve as a back-up to renewable capacity.

The nine utilities have called collectively for all existing power capacity to be used "rather than subsidising new capacity construction that may undermine a level playing field between competitive technologies".

They have also called for gas supplies to be diversified in terms of both routes and sources, "notably, through domestic energy production (including unconventional sources), whilst always taking into account environmental concerns".

Siemens reaches HelWin milestone

Europe's offshore wind sector has reached major milestones in two key grid connection projects.

Siemens says it has installed the HelWin1 offshore platform in the North Sea that will connect two major wind farms to the German grid, while ABB has successfully commissioned the transmission link connecting the Thornton bank project to the Belgian grid.

These two projects will not only allow the connection of over 900 MW of wind capacity to the European mainland, but have also enabled the wind energy industry to gain experience in building offshore connections.

ABB executed the Thornton Bank link for Belgium's C-Power NV. It constructed a transformer station platform 30 km from the Belgian coast to collect the energy from the 325 MW Thornton Bank project and transmit it to the mainland.

HelWin1 will link the 200 MW Nordsee Ost wind farm and the 288 MW Meerwind wind farms to TenneT's grid in Germany, with operations starting next year. Siemens says that it anchored the HelWin1 platform in its final position northwest of the island of Helgoland on August 23, 2013, after seven days of transport at sea and four days of installation.

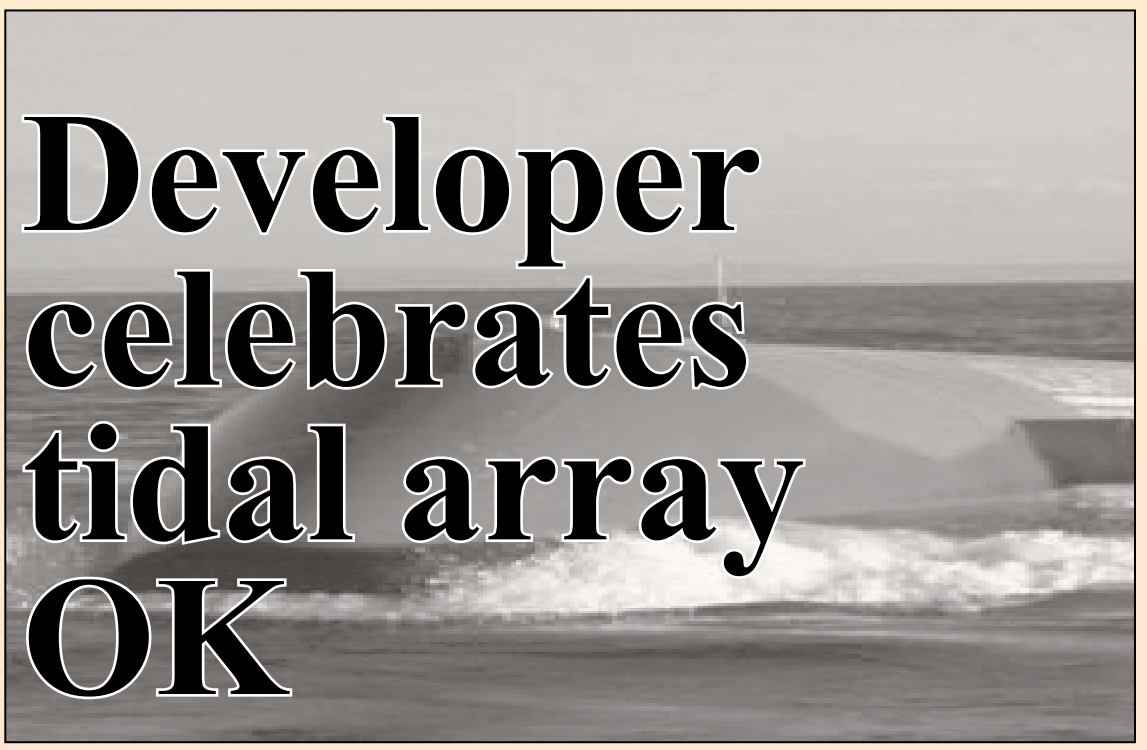
HelWin1 is an HVDC converter platform that uses Siemens' HVDC Plus technology. Siemens and Italian cable specialist Prysmian are implementing three other North Sea grid connection projects for TenneT: HelWin2, BorWin2 and SylWin1.

"Installation of the platform for HelWin1 constitutes reaching a key milestone in our series of grid connection projects," said Karlheinz Springer, CEO of the Power Transmission Division within the Energy Sector of Siemens AG. "With the installation of our platform at sea we have successfully mastered the most critical part of this project and are now in the final stretch for commissioning in 2014."

At 12 000 tons, the HelWin1 platform weighs more than 20 loaded and fully tanked Airbus A380 super airliners. The surface area of the platform, at 75 m by 50 m, is more than half the size of a soccer field. The platform's seven decks, spanning a total height of 27 m, accommodate 16 cabins for crewmembers with a total of 24 berths, a galley, sanitary facilities, a multi-purpose room equipped with sports equipment and a day room with satellite TV, in addition to housing all the technology and equipment required for HVDC transmission.

The technical challenge of building such structures in the North Sea led to significant delays for some European offshore wind energy projects. Last year TenneT said that it could not carry the financial burden of connecting all of Germany's planned offshore wind farms to the electricity grid alone and that it would not start the construction of new connections until the delayed connections including BorWin2 and HelWin1 – were back on track.

Developer celebrates tidal array OK



The construction of the largest tidal array energy project in Europe can now go ahead after Scottish ministers gave the go-ahead for the project.

MeyGen Ltd. has been given consent to build the 86 MW project in the Pentland Firth off the north coast of Scotland, and says that the site could eventually yield up to 398 MW of capacity.

MeyGen – a joint venture between investment bank Morgan Stanley, GDF Suez and tidal technology firm Atlantis Resources – will build an initial demonstration array of up to six turbines, with construction starting in 2015 and commissioning slated for 2015. It says that the project will be an important "stepping stone to commercialising tidal energy".

Scottish Energy Minister Fergus Ewing said that the project was "a major step forward for Scotland's marine renewable energy industry". It would be the first commercial tidal project in Scotland, he added.

Ewing also said that wave developers Aquamarine Power Limited and Pelamis Wave Power would share a slice of a £13 million support programme – part of the Scottish government's Marine Renewables Commercialisation Fund.

"The tide is also turning for the wave sector," commented Ewing. "Both wave and tidal technologies need support if we are to maintain our leading position in marine energy. The Scottish government's awards to Aquamarine Power Limited and Pelamis Wave Power will enable them to develop their technologies further so they can successfully deploy the first wave arrays."

The Carbon Trust has estimated that wave and tidal resources could provide 20 per cent of the UK's electricity if fully developed.

Geothermal growth

■ 27 GW under exploration ■ EGS making its mark

Gawell says "so many projects" are moving forward

Siân Crampsie

Some 70 countries around the world are moving forward with plans to build new geothermal energy generation capacity.

According to the Geothermal Energy Association (GEA), some 11 766 MW of new capacity are in the early stages of development or under construction, and global installed geothermal capacity is expected to reach 12 000 MW by the end of 2013.

In addition, developers are actively engaged with and exploring 27 GW of geothermal resource globally that could develop into operational capacity within a decade.

"The number of geothermal projects continues to grow as more and more countries recognise the potential economic and environmental benefits that geothermal power can bring," commented Karl Gawell, Executive Director of GEA.

"There are so many projects moving forward that just a year or two ago were ideas on paper. This demonstrates how quickly the geothermal industry is growing internationally," noted Ben Matek, the author of GEA's latest report on the outlook for the industry.

Growth in the market is seen by the number of countries that are taking up geothermal energy for the first time, including Uganda, France, Tanzania, Chile and Rwanda. In addition, advanced technologies such as enhanced geothermal systems (EGS) are making their mark, with the first demonstration projects getting underway this year in the United States and Australia.

GEA notes that a growing middle class in many emerging economies is driving demand for energy, and some nations are looking increasingly to geothermal resources to help them to meet demand. Kenya is one of the fastest growing geothermal markets in the world, with around 1000 MW in development, of which nearly 300 MW is under construction.

Japan is also looking to boost geothermal energy capacity as part of plans to replace nuclear capacity.

Other key markets include Indonesia and Costa Rica, says GEA. However both of these markets have regulatory issues to resolve before geothermal growth can get under way.

In Indonesia – the world's largest geothermal market by installed capacity – major projects have been stalled by regulatory issues. No new plants are likely to come on line this year in the country in spite of there being 860 MW under construction and 4000 MW in the development pipeline.

In Costa Rica, most of the geothermal resources are in national parks, but the government is making moves to remove obstacles to development, says GEA.

Turkmenistan boosted by Japanese cooperation

Turkmenistan and Japan have signed an accord that will see the two countries increase trade and cooperation in the energy and infrastructure fields.

Japan has pledged to assist the central Asian country in developing its natural resources and provide assistance with technology and human resource training.

A key area of cooperation will be natural gas liquefaction, and the development of associated infrastructure in Turkmenistan such as ports, power plants and pipelines.

Japan is increasing its international trade efforts – particularly in the energy industry – in the wake of the Fukushima nuclear energy disaster of 2011. It needs to secure supplies of energy and is also looking for export markets for its energy technology, including nuclear.

Japan has already increased import of natural gas from Turkmenistan to help meet increased domestic needs

Prime Minister Shinzo Abe recently signed nuclear energy cooperation pacts with Turkey and the United Arab Emirates, and the country has also approached Brazil, South Africa and India.

■ The Japanese government has agreed a long term loan to Uzbekistan for the Navoi thermal power station modernisation project. The $354 million facility is being provided through the Japanese government's Official Development Assistance programme.

Uganda to invest $500 million in grid

Uganda says it will double the size of its power grid within four years in order to reduce transmission losses and boost both energy production and economic growth.

The plan to expand the length of transmission lines from 1700 km to 3400 km will cost $500 million. There are currently six major power transmission projects underway, according to state minister for energy Simon D'Ujanga.

Uganda is expanding its power production base to help support economic growth ahead of plans to start producing and exporting crude oil in 2017. In June, the government signed a contract granting China's Sinohydro Group Ltd a tender to build the 600 MW Karuma dam on the Nile River at a price of $1.65 billion.

Work on the Karuma dam has already started. Uganda is also planning the construction of two smaller hydropower plants on the Nile, and to expand a number of smaller, existing hydropower plants. Bagasse – sugarcane waste – is also expected to play a role in expanding energy supplies.

In the transmission sector, Uganda is building new domestic power lines as well as interconnections with Kenya and Rwanda.

Economic growth in Uganda is expected to reach six per cent this year and could reach double-digit rates once crude oil production starts, according to government projections.

Saudi Arabia advances nuclear programme

Saudi Arabia is tying up with international companies as it moves forward its plans to build 16 nuclear reactors by 2032. **Junior Isles**

Saudi Arabia moved forward its civil nuclear programme with the recent signing of two agreements with US and Japanese companies to collaborate on future projects.

Exelon Nuclear Partners (ENP), Westinghouse Electric Company and Toshiba Corporation last month signed a memorandum of understanding (MoU) to create a joint proposal for the construction of nuclear power plants for King Abdullah City for Atomic and Renewable Energy (K.A.CARE). K.A. CARE is the government body established to develop alternative energy sources in Saudi Arabia.

Toshiba and Westinghouse will provide nuclear expertise related to their advanced reactors. ENP will provide operations and associated services for the project. ENP is wholly-owned by Exelon Generation, the largest operator of nuclear generating stations in the US.

Toshiba and ENP were partners in an earlier team formed in July 2010. The new partnership, adding Westinghouse, will be strengthened by its ability to draw on Westinghouse's AP1000 reactor technology and engineering expertise, and will target winning multiple orders for nuclear power plants in Saudi Arabia.

Amir Shahkarami, CEO of ENP said: "Exelon Nuclear Partners is excited about the prospect of collaborating with Toshiba and Westinghouse to help Saudi Arabia achieve its goals of developing alternative energy resources that will help the Kingdom to reduce its reliance on oil and strengthen its position as a regional energy supplier."

ENP also announced the signing of a MoU with GE Hitachi Nuclear Energy (GEH) to discuss the feasibility of collaborating on future nuclear power projects in the Kingdom.

The MoU will see the companies explore the feasibility of providing Saudi Arabia with GE Hitachi's advanced boiling water reactor technology, engineering, procurement and project management expertise combined with Exelon's operational skills.

In May last year KA-CARE said that Saudi Arabia aims to build 16 nuclear power reactors with a capacity of around 18 GWe over the next 20 years at a cost of more than Riyals 300 billion ($80 billion).

Russia freezes tariffs in bid to boost economy

Russian President Vladimir Putin is hoping that plans to freeze energy tariffs will help boost the country's economy.

The economy ministry put forward plans to freeze tariffs on state-regulated utilities – including gas, electricity and railways – for one year starting in 2014. The move is designed to help slow inflation and enable the central bank to stimulate the economy by lowering interest rates.

Tariffs would be raised in 2015 and again in 2016, economy minister Alexei Ulyukayev said.

The tariff freeze would be the first in Russia since the 1998 financial crisis.

Russia's economy is struggling to recover from the global economic slowdown, and the World Bank recently cut the country's economic growth forecast for 2013 to 1.8 per cent from 2.4 per cent. The Bank has indicated that the dependence of the Russian economy on fuel exports has left it exposed to price and demand volatility on the global commodity market.

Special Project Supplement

Betting on high efficiency gas turbines

The Daegu combined cycle power plant, currently under construction in Korea, is one of a growing number of projects that will use advanced gas turbine technology as part of the country's plan to shore up its falling reserve margin. **Junior Isles**

The Ulrich Hartmann plant in Irsching, Germany, has set new standards for efficiency. Since its start-up, several SGT6-8000H gas turbines have been sold to Korea

In 2011, E.On's Ulrich Hartmann plant in Irsching, Germany, became the first combined cycle power plant to break the 60 per cent barrier for electrical efficiency. It was also the first project to feature Siemens' 8000H advanced gas turbine.

Since this landmark project, a number of 8000H turbines have been sold worldwide, with a total of 24 machines being ordered in Asia, Europe and the US. Most notably around one third of these advanced gas turbines will be installed in South Korea, where market conditions have made the 8000H the preferred choice for several projects. No less than eight turbines have been sold into Korea, and according to Siemens more will be announced soon.

One of the most recent of the South Korean orders is for a combined heat and power (CHP) plant for the Daegu Innovation City project to be built in Daegu Metropolitan City.

The Daegu Innovation City DHPP demonstrates the country's drive to boost its reserve margin while at the same time focusing on high energy efficiency. Fired on natural gas, the plant will produce about 415 MW of power at an electrical efficiency of around 61 per cent. It will also be capable of delivering 190 MWth of district heating. When producing both heat and power the plant will have an overall fuel efficiency of 80 per cent.

Commenting on the project, Thomas Hagedorn, Head of Gas Turbine Power Plant Solutions, Asia Pacific said: "Korea is putting a lot of emphasis on energy efficiency, so it is applying the latest gas turbine technology and is also looking to cogeneration."

Korea has limited energy resources and imported liquid natural gas (LNG) has become popular over the last few years as the fuel to power its efforts to supply clean energy. According to the Energy Information Agency, in 2011 the country was the second largest importer of LNG worldwide. Like most of Korea's gas fired projects, Daegu DHPP will be supplied by LNG imported by gas supplier Korea Gas Corporation (Kogas).

Power demand has been increasing over the last decade, and at the end of 2012 the country's peak power demand hit nearly 76 GW. Korea experiences peak electricity demands in winter for heating and in summer for air-conditioning.

According to the Korea Energy Economics Institute an installed generating capacity of 81.8 GW is needed to meet this peak demand. However, this figure is still is well below the industry's normal reserve generation buffer of 10 per cent and barely above the country's 4000 MW safety threshold.

Indeed the power reserve margin has been falling steadily over the last decade. Asian Development Bank figures show that reserve margins have fallen from 17.1 per cent in 2003 to 10.5 per cent in 2006, and 7.9 per cent in 2009 to 5.5 per cent last year.

To address the situation, the government has taken steps to increase the reserve margin to 22 per cent of the total capacity by 2027. In 2011-12, the construction of about 9 GW of gas fired power plants was started. In addition, a government plan issued at the end of January this year, includes the construction by 2027 of thermal power plants fuelled by coal and LNG with a total capacity of 15.8 GW. Renewable energy sources, especially wind, are also targeted to generate 12 per cent of total electricity supplies by 2027 – almost double the seven per cent previously planned.

South Korea, and especially the region around Daegu Metropolitan City, is currently experiencing a high level of economic growth. More and more power generation units are being built at existing power plant sites in cities throughout the country in order to satisfy the growing demand for electricity.

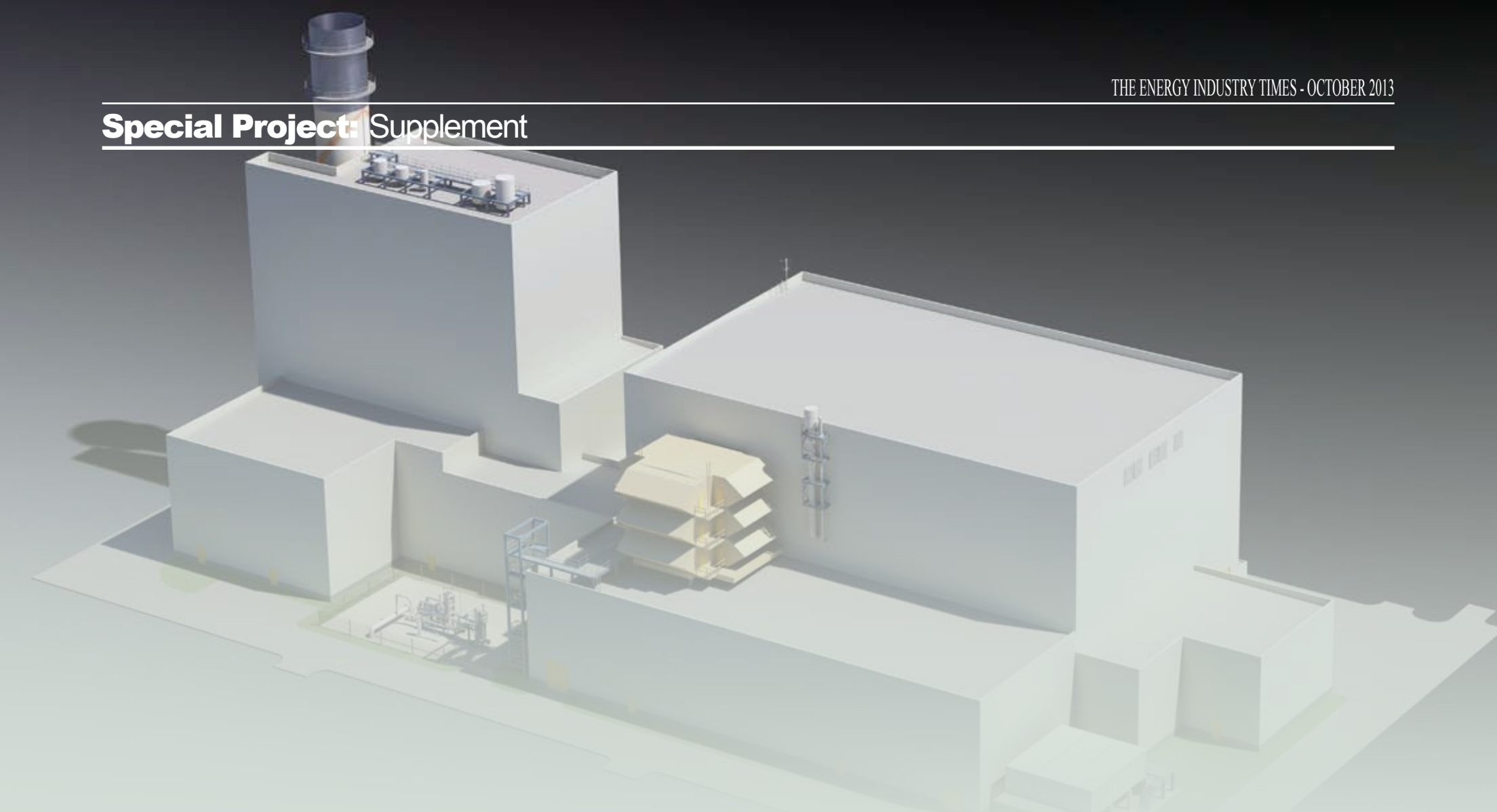
At the same time it is becoming increasingly necessary to ensure the most economic supply of heat to the growing number of people living in cities as the country goes through significant urban development.

South Korea has an extensive district heating network, and a cogeneration plant that supplies heat to a city via a heating network is a far more efficient and cheaper way of providing heat during the cold Korean winter than the electric heating that is widely used.

Therefore when a new town or city is developed, or an existing city is being extended, it is quite common to build a local cogeneration plant. The Daegu Innovation City DHPP is one of these plants.

The plant will be built in Daegu Metropolitan City, about 240 km southeast of the capital city of Seoul.

It is being developed by independent power producer (IPP) Daegu Green Power (DGP), a joint venture company comprising Korean utility Southern Power Company (KOSPO), Lotte Engineering and Construction (E&C), BHI and Daegu National Gas. Siemens' customer for the project is Lotte E&C, which has been contracted to build the plant. This



Model of the Daegu Innovation City DHPP

represents the fifth of a total of eight H-class turbines that Siemens has sold to South Korea.

Siemens' scope of supply comprises a power island, which includes an SGT6-8000H gas turbine, an SST6-5000 steam turbine and condenser, an SGen6-2000H hydrogen-cooled generator and a heat recovery steam generator (HRSG). Siemens will also supply the electrical system and the SPPA-T3000 instrumentation and control system as well as parts of the auxiliary and ancillary systems.

Siemens will be responsible for the complete design of the power plant and will supervise assembly and commissioning. A 10-year long term maintenance contract has also been signed.

The Daeugu DHPP is a project that Siemens was involved in at a very early stage. "We were contacted by the customer to support them in finding a technical solution," Hagedorn recalled. The fact that Siemens had a turbine that was the right size for the project and the ability to deliver the right CHP solution within a very short time schedule, led to it being awarded the contract in September 2012.

Power plants with high power density are becoming increasingly important as the country attempts to optimise the use of its limited space. H-class power plant technology has a distinct advantage over other gas turbines in terms of power output to footprint.

Hagedorn said: "Due to high land costs in Korea's urban areas, the site is quite small. It is an interesting site; more or less triangular in shape, which we could accommodate by adapting our standard design to the site requirements."

Adaptions included placing the main step-up transformer in a different location compared to a typical Siemens plant and routing the bus duct differently. The power train and location of the steam extractions also had to be made to fit the district heating equipment i.e. the heat exchangers and heating condensers.

"Finding solutions for the right layout was quite important," noted Hagedorn. "The customer also had quite a challenging timescale, which we were also confident we could meet."

Although the Ansan project has CHP capabilities, Daegu Innovation City DHPP is the first 8000H, single shaft configuration to be implemented as a cogeneration plant from the outset for the 60 Hz market.

The project is similar to another 8000H-based cogeneration combined cycle project being constructed for the 50 Hz market in Lausward, Germany. Lausward, described by Siemens as the most modern CHP power plant worldwide, is located in the port of Düsseldorf.

Siemens says the plant will be a landmark for future power generation in Germany and emphasises the role of CHP combined cycle power plants as an engine for the country's energy system transition.

According to Siemens, the plant will achieve another world record in terms of efficiency for pure power generation – over 61 per cent – and its fuel utilisation factor will be more than 85 per cent. In addition it will have high plant availability with long maintenance intervals, and will feature a flexible operation regime.

Flexibility is something that is critical at the Daegu DHPP. South Korea experiences extremes in weather, which puts special demands on power plant flexibility. For the Daegu site the plant is designed for ambient temperatures that can range from -12°C to +38°C. Thus the standard Korean procedure is to define certain operating modes in order to build a boundary performance enclosure for evaluating the performance of a power plant.

Hagedorn noted: "In a CHP plant, the optimisation of electrical efficiency is not the main aim. It is more important to find the best operating points for the various modes of operation. In winter it's all district heating, in spring it is a mixture [of heat and power]. In summer they will also want to run it as a pure combined cycle, which then has to compete with all the other combined cycle plants. The challenge is therefore to find the right balance for the various operating modes."

The plant is designed to operate in several modes, depending on DGP's requirements.

Mode 1 is maximum district heat supply operation. The amount of heat produced depends on the size of the heat network to be supplied or the anticipated number of new inhabitants in the city district.

Mode 2 is steam turbine bypass operation. Here the steam generated by the HRSG will be routed to the condenser bypassing the steam turbine.

Mode 3 is for maximum electricity generation (full condensing mode). In this mode, all the steam from the HRSG is utilised in the steam turbine for generating electricity.

Mode 4 is open cycle operation (no steam generation). If electricity has to be produced quickly the gas turbine alone is turned on, bypassing the HRSG.

Mode 5 is for part load district heat generation. This is the closest one to the "real" operation of the Daegu plant. A certain amount of steam will be produced to supply the district heating network while highly efficient electricity generation is maintained.

The two bypass operation modes, Mode 2 and 4, are normally not used. Although the steam bypass system for Mode 2 is designed for 100 per cent continuous load it is intended more as an emergency mode to keep the plant running while the steam turbine is out of operation. Mode 4 requires a bypass stack, which has been omitted, however. This has been the standard design for Korean combined cycle plants for the last couple of years, as high fuel prices make it uneconomical to run a gas turbine in simple cycle mode.

A key contributor to this high level of flexibility is a specially designed HRSG. The H-class HRSG is based on the proven Siemens Benson HRSG design but sets a new benchmark, exceeding F-class HRSG technology in all aspects. Compared to the F-class HRSG, the steam temperature and pressure are 35 per cent higher, while steam mass flow has been increased by 30 per cent.

Benson technology avoids the use of a thick-walled, slow warming HP drum. When combined with the 8000H gas turbine, it also enables fast start times compared with conventional combined cycle plants. The plant is designed to reach full load in 30 minutes from a hot start.

The use of air-cooling in the gas turbine as opposed to steam offers greater plant flexibility because it means the gas turbine cooling system is decoupled from the water/steam cycle.

"With a steam-cooled machine, steam quality has to be strictly controlled, which becomes more difficult as soon as you introduce more complicated condensing and heat exchanging equipment into the water steam cycle," explained Hagedorn.

Daegu CHP performance in mode III (electricity only)

Gross power output (MW)	>415
Electricity gross efficiency (%)	>55 (based on HHV)
NOx emissions (incl. SCR, ppmvd)	<10 (@ 15 per cent O_2)
Noise level at 1 m from equipment (dB[A])	85

Plant start-up times

Conditions	**Typical plant start-up time [min]**
Cold start (plant shutdown for < 72h)	87
Warm start (plant shutdown for < 48h)	78
Restart (plant shutdown for < 2h)	39
Hot start on the fly with	
ST start on the fly (plant shutdown for <8h)	30
Shutdown	50

Special Project Supplement

Under construction: the Daegu DHPP project is being built to a challenging schedule

The SGT6-8000H gas turbine, like the original SGT5-8000H 50 Hz version, is a single-shaft machine of single-casing design. Its high efficiency makes the turbine attractive for South Korean plant owners. With LNG imports being the sole source of gas, gas prices are high, which means fuel efficiency is extremely important.

In combined cycle condensing operation the turbine can achieve a plant electrical efficiency of more than 60 per cent. Notably, the 50 Hz unit installed in Irsching broke the world record for power plant combined cycle efficiency when it was connected to the grid in 2008.

The basic design, adopted from previous gas turbine models, includes: a disc-type rotor with central tie-bolt and radial serrations; two journal bearings and one thrust bearing; generator drive at the compressor intake end; and axial exhaust diffuser.

The 60 Hz version of the turbine is designed to generate 274 MW in simple operation and around 410 MW in combined cycle operation depending on ambient conditions.

The turbine section of the machine has four stages with air-cooled blades and vanes on the first three stages, and thermal barrier coatings on the first and second stages. Stage-four is uncooled.

The machine has 13 compressor stages operating at a pressure ratio of 19.2:1. It has four inlet guide vanes, which further increases its operational flexibility.

The combustion system consists of 12 low-NOx burners and baskets with air-cooled transitions. An annular combustor arrangement provides excellent uniformity of exhaust-gas temperature field. The result is significantly reduced emissions per kWh, which is especially important in urban environments. NOx emissions will be as low as 25 ppm NOx, CO is kept to 10 ppm, while CO_2 is less than 325 g/kWh.

The gas turbine is connected to a two-pole SGen6-2000H generator that has direct radial hydrogen cooling for the rotor winding and indirect hydrogen cooling for the stator winding. A start-up frequency converter is provided for starting the turbine generator unit. The generator then acts as a motor in converter mode to start the gas turbine set.

As it is a single shaft configuration, the generator is also driven by the steam turbine via a synchro-self-shifting (SSS) clutch. The clutch is disengaged only when the gas turbine is in operation (for example, during start-up). When the steam turbine is accelerated and its speed overtakes the generator, the clutch is engaged and transfers the steam turbine's torque to the generator. The clutch's location between the generator and steam turbine supports flexible plant operation.

The steam turbine is specially designed to allow for continuous extraction of steam. It consists of a combined high- and intermediate-pressure casing (HP-IP) and a double-flow low-pressure (LP) section. These two turbines are coupled on one shaft and the steam will be guided from the IP turbines exhaust via a crossover pipe to the LP section.

In order to supply heat to the local distribution system, low-pressure (LP) steam will be tapped off the crossover pipe. Via a large bore piping system, the steam will be transferred to the district heat exchangers first section. Here the steam's heat is used to warm the secondary section, which is filled with high-pressure district heat water.

This water is transferred to the consumers. The steam itself is condensed to water during this process. Since it is a closed cycle, the condensed water, or condensate, is pumped back into the HRSG. A hydraulically activated throttle valve is installed inside the crossover pipe to regulate the amount of steam that is routed to the district heating heat exchanger.

In order to achieve optimum alignment of the components and to reduce the number of terminal points, the district heating system is seen as part of the steam turbine. The Daegu CHP plant therefore has two sides – a "producer side" for electricity and heat, and a "consumer side" where the consumers attach their district heating water system or receive electricity.

When the Daegu DHPP begins operation, consumers will benefit from efficiently produced heat and power. According to the planned schedule, this will be in a little over a year from now. The project's 26-month timeline will see start-up in late 2014.

Currently the plant is in the middle of execution. Site activities are ongoing and the main equipment should be delivered before the end of this year. The next major milestone will be commissioning, which will start during the spring of 2014.

The plant's start-up will help improve the country's dangerously low reserve margin and further demonstrate the value of gas fired power plants based on the 8000H turbine.

South Korea is certainly proving to be a lucrative market for Siemens and the H-Class gas turbine.

The first order for the 400 MW Dangjin 3 (formerly Bugok 3) combined cycle plant, secured in January 2011, was handed over to the South Korean power utility GS EPS Co. Ltd in August this year. The plant, the most efficient in the country, is now supplying electricity to more than 300 000 people.

This order was followed in March 2012 by the award of a contract for the 834 MW Ansan combined plant in Gyeonggi-Do province. Here, Siemens is supplying the power island consisting of two SGT6-8000H gas turbines, one steam turbine, three generators, and two heat recovery steam generators as well as the entire instrumentation and control technology. In addition to generating electricity, the plant will also provide district heating for the inhabitants of the city of Ansan.

Just a month after it signed the deal for Ansan, a third order was received for a 415 MW combined cycle power plant to be built at Andong in the north of Gyeongsangbuk-do province. Like Danjing 3, under a turnkey EPC contract Siemens is supplying and building the entire power plant comprising one H-class gas turbine, a steam turbine, one generator, a HRSG, as well as the balance-of-plant (BoP), and I&C technology in a single shaft configuration.

Then in July 2012 three identical 420 MW combined cycle units known as Incheon 7, 8, and 9 were sold to POSCO Energy. The new POSCO power units are being built on an existing site in the Metropolitan City of Incheon approximately 30 km west of Seoul.

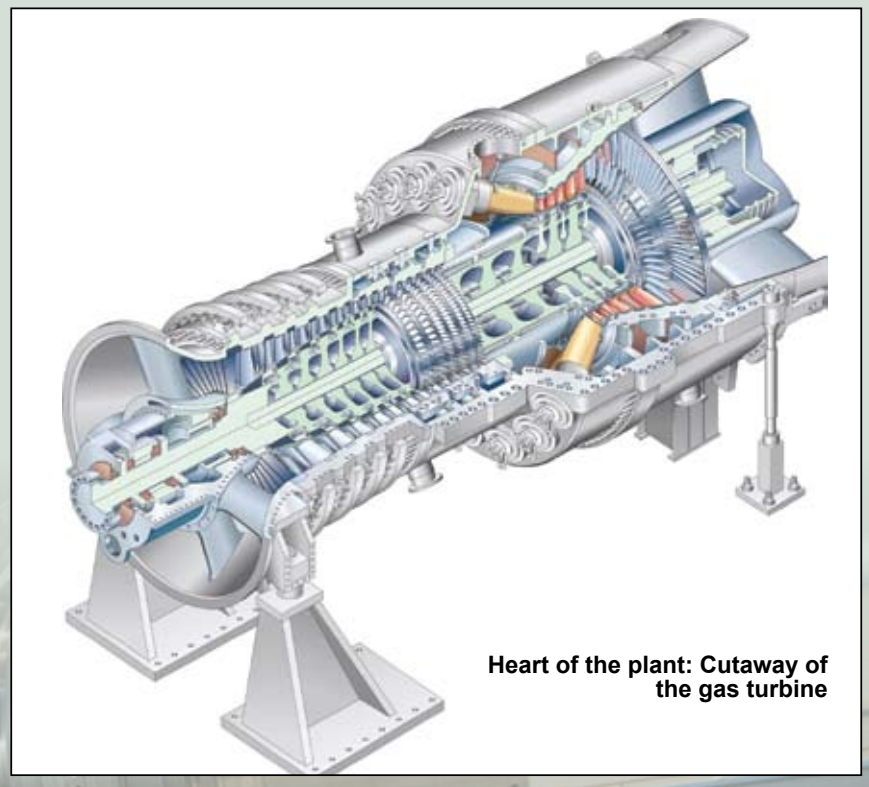
With the exception of Dangjin 3, all of these projects are scheduled to start up in 2014. Such a high level of activity in the country has led to Seoul being chosen as the location of a new Siemens Asia Pacific headquarters.

Michael Suess, CEO of Siemens Energy Sector, said: "Siemens has already been working jointly with Korean companies in the construction of domestic and overseas power plants. We will strengthen cooperation with Korea through power engineering solution business investment."

Hagedorn added: "Seoul can cover Asia Pacific as well as the Middle East. It provides us with a good EPC base in that it has good human resources – subcontractors and sub suppliers – which is quite unique for this region. The government is also very supportive of the idea."

According to the schedule, the new regional HQ will be inaugurated this month (October). Over the next 12 months, staff numbers will be ramped up to reach 100 people and continue to reach around 500 by 2017.

Clearly Siemens will be busy in Korea for the next few years as it continues to help the country provide energy cleanly and efficiently for its growing urban population.



Heart of the plant: Cutaway of the gas turbine

The SGT6-8000H has a four stage air-cooled turbine section and features a 13- stage compressor

SIEMENS

World record efficiency requires world-class technology.

Siemens H-class technology: designed for a reliable power supply and a plant efficiency of more than 60 percent in combined cycle mode.

siemens.com/energy

Today many countries face the challenge of how to meet the imbalance between power demand and power supply. The Siemens solution is the highly flexible H-class gas turbine technology. With extremely fast ramp-up and ramp-down times, these gas turbines are ideally suited to balance grid fluctuations, thus contributing to a reliable energy system. Furthermore, the Siemens H-class gas turbine is the world's first with a certified plant efficiency of more than 60 percent in combined cycle duty. The Seoul-based GS Electric Power & Services Ltd. is the first supplier in Asia to benefit from the H-class technology. Their Dangjin 3 power plant can generate enough electricity to supply power to more than 300,000 people in the Republic of Korea.

To learn more about our trailblazing technology, visit **siemens.com/energy**

Answers for energy.

Suzlon sells Chinese subsidiary

- Retains presence in China
- Wins European orders

Siân Crampsie

Suzlon Group has formed a joint venture partnership with Chinese firm Poly LongMa Energy (Dalian) Ltd after selling a majority stake in its China-based manufacturing subsidiary.

The India-based wind turbine firm had been trying to sell a 75 per cent stake in Suzlon Energy Tainjin Limited (SETL) for more than a year as part of plans to divest non-core assets and tackle its debts.

It has retained a 25 per cent stake in SETL and will be Poly LongMa's technology partner, responsible for manufacturing and quality, it says.

"This is an important step forward for our future business in China," said Tulsi Tanti, Suzlon's Chairman. "With this joint venture, we monetise an asset we have built up from 2006, and through our partner, Poly LongMa Energy (Dalian) Ltd, maintain our strong presence in the world's largest market, which remains strategically important for us.

"With the combined strength of both groups, the new joint venture will be very well positioned in China, and offer the potential to explore exports as well."

Suzlon sold the 75 per cent stake to Poly LongMa for $28 million. Poly LongMa will lead sales and marketing operations in China for Suzlon's S66-1.25 MW, S82-1.5 MW and S88-2.1 MW turbines.

Suzlon had expected a valuation of $60 million for SETL when it put the asset up for sale, according to the Indian press. Stiff competition in the Chinese wind turbine market made trading conditions hard and Suzlon identified it as one of 15 or so non-core assets to be sold.

Suzlon is ranked as the world's fifth-largest wind turbine supplier, with operations across 30 countries and an installed capacity of over 22 500 MW. Last month in Europe, Suzlon Group Subsidiary REpower announced new contracts in the UK and France.

In the UK REpower will be supplying turbines for wind power projects in Aberdeenshire, Suffolk, Yorkshire and Cumbria, adding 58 MW to the firm's UK project pipeline.

In France, REpower signed a contract with Valorem to supply 24 of its 2 MW MM92 wind turbines to be deployed at four separate wind farms.

RWE tightens its belt

RWE has announced plans for a cut in its dividend and for further savings in a bid to turn its financial fortunes around.

The German utility is one of Europe's top five gas and power companies but says that Europe's debt crisis, falling energy demand and Germany's renewable energy plans have eroded its earnings prospects.

RWE said that it would propose to shareholders that the dividend payment for 2013 will be halved to €1 per share compared with €2 per share paid out a year earlier.

Dow Jones newswires said last month that sources familiar with RWE's plans indicated that thousands of jobs would be shed and a salary freeze implemented at the utility in a bid to save €800 million over the next five years.

According to *Dow Jones*, RWE is considering cutting 3400 jobs from its power plant business, the majority of which would be in Germany.

RWE's new plans are further evidence of the struggles in the European utility sector. Its main rival, E.On, has already idled thermal power plants because of overcapacity and muted energy demand.

In August RWE said that it would close around six per cent of its total power generating capacity in Europe because of the difficult trading conditions.

So far, RWE had pledged to cut costs by around €1 billion through 2014. Profits in its European power generation business – which operates nuclear, gas, coal and lignite fired power plants – fell by 60 per cent in the first half of the year, RWE said in August.

RWE posted a 28 per cent drop in net profit for last year because of write-downs on the value of its power plants in Europe.

Under pressure: dividend payments will be halved to €1 per share

Smart grid team from Toshiba and Tepco

- Developed and emerging economies drive demand
- GE, XD create T&D partnership

Tokyo Electric Power Co (Tepco) and Toshiba are hoping to capitalise on the rising demand for power transmission and distribution systems around the world through a newly established joint venture.

T. T. Network Infrastructure Japan Corp will have a capitalisation of ¥100 million and will provide next-generation smart grid technology solutions to both developed markets and emerging economies.

It will be 85.1 per cent owned by Toshiba and 14.9 per cent by Tepco, which has been looking for business opportunities overseas that will help it to build its business in the wake of the 2011 Fukushima nuclear disaster.

Both firms believe that the uptake of renewable energy is driving demand for network infrastructure upgrades in North American and European markets, while emerging markets are looking to strengthen their weak electricity infrastructure.

The new business will combine Toshiba's technologies with Tepco's expertise in grid planning and system design and will provide engineering support for overseas transmission and distribution infrastructure projects.

Toshiba's global organisation includes the Swiss-based metering firm, Landis+Gyr.

Earlier this year GE and XD Electric announced that they would combine their technologies and capabilities to create a global partnership aimed at the transmission and distribution sector.

GE and XD said in August that the partnership had been officially created, with GE acquiring a 15 per cent stake in XD.

The partnership combines GE's grid automation capabilities with XD's high voltage power equipment portfolio. Its creation was driven by strong growth prospects in the $100 billion transmission and distribution industry, says GE.

The companies say that growing energy demand and urbanisation in emerging economies are straining energy infrastructure, while in developed countries ageing grids are in need of modernisation.

E.On expands in energy efficiency

E.On wants to capitalise on energy savings opportunities in Europe's business and industrial sector.

Siân Crampsie

E.On has purchased a UK-based energy management firm as part of plans to diversify away from the stagnant European power generating business.

The Germany-based utility has bought Matrix, which manages energy for commercial buildings and which counts UK telecoms firm BT and retailer Marks & Spencer among its clients.

Like other European utilities, E.On's power plant business has been hit by falling demand and the increased use of renewable energy. It is thought to have paid around £85 million for Matrix and will operate the company within its Connecting Energies energy efficiency brand.

E.On says that the Matrix purchase will allow it to provide its customers across Europe with much greater control of their energy costs and will improve E.On Connecting Energies' expertise in data-analytics based energy efficiency services.

"This transaction is an important strategic move for us, allowing us to expand our position in the fast growing energy efficiency market," said Hervé Touati, CEO of E.On Connecting Energies. "It adds a sophisticated, innovative offering to our existing services portfolio. We see tremendous opportunities from the combination of Matrix's deep data-led building energy expertise with our capital-led energy efficiency and on-site generation capabilities."

Matrix offers data-led energy efficiency solutions and energy management services, based on its metering and building energy management technologies.

The company has a track record of delivering energy savings of up to 40 per cent for its customers, says E. On.Matrix has customers in 22 countries.

Americas

Vestas secures US deal

Vestas could supply Renewable Energy Systems Americas Inc. (RES Americas) with up to 610 MW of wind turbine capacity after finalising an agreement with the project development firm.

Vestas will initially supply 60 MW of its V100-2.0 MW turbine to RES Americas for projects scheduled for commissioning in 2014 and 2015. The companies have not disclosed the locations of the projects.

Gamesa's low wind speed turbine debuts in USA

Gamesa has signed an agreement for the supply of 20 MW of turbines to the Big Turtle wind farm being developed by Heritage Sustainable Energy in northeast Michigan, USA.

The contract marks the first sale of the company's new G114-2.0 MW wind turbine in the USA. The deal includes a 12-year operation and maintenance services agreement.

The ten G114-2.0 MW turbines are scheduled for delivery in mid-2014, with the facility slated for commissioning towards the end of that year. Heritage has already secured a Power Purchase Agreement (PPA) with DTE Energy under which the latter will buy the power produced by the new wind farm for the next 20 years.

The G114-2.0 MW wind turbine is designed to operate at medium and low wind speed sites.

ABB to enhance Brazil's infrastructure

ABB has won an order worth around $30 million from Furnas Centrais Elétricas S.A. to construct a new indoor transmission substation in downtown Rio de Janeiro to power the renowned Maracanã soccer stadium and the adjacent neighbourhood.

Brazil is boosting its power capacity and enhancing its transmission and distribution infrastructure to ensure that its electricity grid can meet the needs of its expanding economy as well as the 2014 FIFA World Cup and the 2016 Olympic Games.

Asia-Pacific

Voith celebrates Asia success

Voith has announced that it is to supply the Nam Hinboun hydropower project in Laos with two 15 MW bulb type power generating units.

The turnkey project includes engineering and components, the complete electromechanical equipment as well as automation systems, transformers and switchyards.

The firm is targeting southeast Asia as a major market for growth. Laos in particular has the potential to become the "battery of Asia", says Voith.

NTPC orders solar plant

India's National Thermal Power Corporation (NTPC) has placed an order with Bharat Heavy Electricals Ltd (BHEL) to build a 15 MW solar power plant in Uttar Pradesh.

The engineering, procurement and construction (EPC) order is for the design, manufacture, testing, erection and commissioning of the 15 MW grid-connected plant at Singrauli.

Vestas to supply 100 MW to China

Vestas has received two orders totalling 100 MW from Ningxia-based Hanas New Energy (Hanas), the leading regional natural gas supplier in China's Ningxia Hui Autonomous Region (NHAR).

The two orders consist of 50 units of the new V100-2.0 MW turbine model for installation in the Yanchi wind farm. The orders include turbine supply and delivery but does not include towers.

Delivery of the first turbine is expected for the second quarter of 2014.

Europe

E.On selects Jenbacher for CHP plant

E.On Hanse Wärme GmbH is to use GE's new 10 MW J920 FleXtra gas engine for a planned combined heat and power (CHP) plant in northern Germany.

The new, €6.8 million plant will be the largest of its kind in the region and is part of an energy cooperation project between E.On Hanse and the city of Hamburg. It will be the second J920 installation in Germany.

GE's J920 FleXtra is designed to achieve an industry leading electrical efficiency of 48.7 per cent and about 90 per cent efficiency in cogeneration mode.

Landis+Gyr lands BG deal

Landis+Gyr says that it will supply the majority of the 16 million smart meters that British Gas is planning to install in UK homes by 2020.

The technology firm has sealed a £600 million deal with British Gas and expects to double its UK workforce as a result.

The project is part of a UK government initiative to roll out smart meters as standard in UK homes and businesses by 2020. The meters will enable consumers to see how much energy they are using and will bring estimated savings to consumers of around five per cent per year.

Alstom, Scottish Power sign tidal MOU

Alstom and ScottishPower Renewables have signed a Memorandum of Understanding (MOU) to incorporate Alstom's tidal power devices in the Sound of Islay project.

The tidal array, between the islands of Islay and Jura on the west coast of Scotland, will include up to four of Alstom's 1 MW tidal devices, one of which is currently on test at the European Marine Energy Centre in Orkney.

The Sound of Islay project is expected to be the world's largest tidal array when fully completed, with an installed capacity of 10 MW. It is on track for the first unit to be deployed in late 2015, and for full site deployment during 2016.

Nordex wins Italy bid

Eolsiponto Srl, a special purpose vehicle set up by Capital Riesgo Global SA, a company of Banco Santander, and Alerion Clean Power, has awarded Nordex a contract to build the Manfredonia wind farm in Italy.

Nordex will build the 17.5 MW wind farm in Apulia near the Adriatic coast. It will consist of seven N100/2500 wind turbines and will generate almost 40 GWh per year.

Areva to build bioenergy plant

Renewable power producer neoen has selected a consortium of Areva and Leroux & Lotz technologies to build a biomass cogeneration power plant in Commentry, France.

Using wood chips as fuel, this power plant will generate around 15 MW of electrical power and 50 MW of thermal power. Areva and Leroux & Lotz Technologies will supply all the equipment and services required for the construction and commissioning of the plant, scheduled for the first quarter of 2015.

Scottish Hydro orders Nexans cable

Scottish Hydro Electric Transmission plc (SHE Transmission) has awarded Nexans a contract to supply and install a subsea power link to upgrade the electricity transmission network between the Kintyre peninsula and mainland coast in Southwest Scotland.

The upgrade, which is part of SHE Transmission's wider plans to invest up to €6 billion in its electricity network between 2013 and 2021, will release up to 150 MW of additional grid capacity for renewable projects and signal a significant boost for the Kintyre economy.

Nexans will create a twin subsea cable link, rated at 230 kV and 240 MVA, from a new substation on the peninsula to the mainland coast. The project includes the supply and installation of two 41 km 3-core submarine cables together with six 5 km single core underground cables for the land element. A fibre optic cable for control of the cable link will be integrated within the subsea cables and supplied separately for the land cables. Nexans will also supply a range of accessories.

International

Acciona orders JinkoSolar modules

JinkoSolar has won contracts to supply 274 MWp of solar photovoltaic (PV) modules to Acciona for projects being developed by the Spanish engineering firm.

JinkoSolar is to supply 94 MWp of modules to Oakleaf Investment Holdings, a joint venture between Acciona and its local partner, for a solar farm in Northern Cape province, South Africa.

It will supply a further 24 MWp to Acciona Energy Oceania for the Royalla PV plant in the ACT territory of Australia, and says that it will also supply 156 MWp to Acciona, subject to further discussion and final supply agreements.

The solar farm in Northern Cape province will be one of the three largest solar farms on the African continent. The project will use approximately 319 600 high-efficiency JinkoSolar PV modules and will produce approximately 206 GWh per year.

The solar farm in ACT territory will be one of the biggest PV plants in Australia. The project will use approximately 81 600 PV modules and will produce energy for 4500 households in Canberra.

Alstom secures Shuqaiq order

Hyundai Heavy Industries (HHI) has selected Alstom to supply four 720 MW steam turbine generator sets for the Shuqaiq project in Saudi Arabia.

Alstom's €170 million contract includes the engineering, manufacturing, supply and field services for all four steam turbines and generators, and also includes all direct control and auxiliary systems. The plant is scheduled to start operating in 2017.

The 2650 MW power plant will be located on the Kingdom's western Red Sea coast and will be among the world's most efficient facilities run on heavy fuel oil.

GE wins $2.7 billion Egypt contract

GE has won three contracts totalling approximately $2.7 billion with SPE, an affiliate of Sonelgaz, Algeria's national electricity and gas company. The contracts are among the largest power agreements signed in GE's history.

GE is to supply heavy-duty gas turbine combined cycle and aeroderivative gas turbine technology for nine power plants with a total capacity of nearly 9 GW.

The three agreements include six new combined cycle power plants based on 9F 3-series gas turbines that will add more than 8 GW of capacity, increasing Algeria's generating capacity by 70 per cent; two fast-track projects that add 528 MW for this summer's peak demand; and a new simple cycle power plant to add 370 MW to Algeria's electricity grid.

The nine Sonelgaz power plants are located in northern Algeria and will begin simple cycle duty in 2015 and combined cycle operation in 2017.

Additionally, GE announced plans for a long-term joint venture with Sonelgaz for the development of a new production facility in Algeria that will eventually produce more than 2 GW of power generation equipment per year.

CESI wins innovative projects

Technical consulting and engineering company CESI Middle East (CESI), is growing its portfolio of smart grid and HVDC projects with three new contracts.

CESI has been selected by the Electricity & Co-Generation Authority of The Kingdom of Saudi Arabia (ECRA) to develop policies, specification requirements and an implementation plan for a smart metering and advanced metering infrastructure. This mandate is the first kingdom-wide project of its kind to be undertaken in Saudi Arabia.

CESI has also been selected by Uzbekenergo as a technical advisor for the development of a smart metering installation project in Uzbekistan. The metering infrastructure forecasts one million smart meters as a first step of installation in households and industrial locations in three local regions, and will be followed by similar projects for a total investment of $1 billion and four million meters.

The complete smart metering installation project is expected to be finalised by 2015.

In the third contract, CESI has been selected by the Ethiopian Electric Power Corporation (EEPCO) and Kenya Electricity Transmission Company (KETRACO) as the technical consultant for the Power System Interconnector Project between Ethiopia and Kenya.

The project will contribute to the integration of the electricity markets of the East African Power Pool through the interconnection of the two countries' power systems. It will increase the supply of power and reduce the cost of electricity in Kenya while generating additional revenues for Ethiopia through the export of electricity to Kenya.

CESI's work will mainly focus on advising on the design, supply, installation on-site, testing and commissioning of about 1040 km, ±500kV HVDC bipolar overhead transmission lines.

Oil

Middle East turbulence remains key price factor

- Syrian conflict unsettles prices
- Production falls with Libyan protests

David Gregory

The continuing civil war in Syria and ongoing social unrest in Libya were significant factors in keeping crude oil prices high during the last month.

The prospect of US military action against Syria's President Bashir al-Assad for his alleged use of chemical weapons against civilians sent the price of West Texas Intermediate (WTI) above $110/b and Brent crude over $116/b. As nerves cooled and Washington agreed to a yet-to-be formulated plan by Moscow to bring Syrian chemical weapons under control, crude prices by mid-September had eased slightly.

Meanwhile, strikes and blockades at Libya's oil production and export facilities have removed more than 1 million b/d from the market. An announcement by Libya's government that a deal was afoot to restart production from the Sharara and El Feel (Elephant) field and send it to the Zawiya export terminal also eased prices.

Syria has never been a big oil player and its production has never had an important market role. Before the civil war the country produced around 380 000 b/d and exported around 130 000 b/d, earning it about $3 billion per year.

Last month it was reported that Libyan crude production (capacity around 1.6 million b/d) had fallen to 150 000 b/d and exports were down to 80 000 b/d. The National Oil Corporation (NOC) declared *force majeure* at the country's six main export terminals (Es Sider, Ras Lanuf, Zueitina, Marsa el-Hariga, Zawiya and Mellitah) which have a total export capacity of 1.13 million b/d. Libya's total production capacity is 1.275 million b/d.

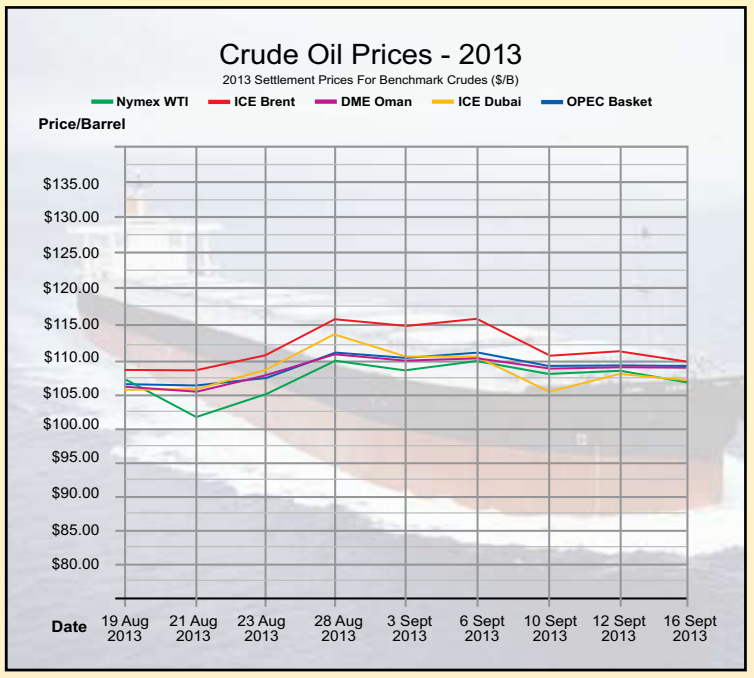
The government said that Libya was losing $130 million per day due to the protests. Its crude exports account for 95 per cent of the country's export earnings and 75 per cent of government revenues.

Concern has been expressed that circumstances in Libya are such that terrorist groups could take control of some facilities and sell oil on the black market for their own purposes.

At one point the government threatened to fire on unauthorised ships entering its ports and also threatened force to end the strikes and blockades. But Prime Minister Ali Zeidan, speaking at a conference in London in mid-September, expressed his hope that the disruption in Libya's oil industry would be resolved peacefully.

The removal of Libyan crude from the market has moved Saudi Arabia to raise crude production to more than 10 million b/d. Rising US production brought on by its shale revolution has helped to take some pressure off the market with output above 7 million b/d.

When Libyan crude disappeared from the market in 2011 during the civil war, Saudi Arabia and other Gulf producers stepped in to make up the shortfall. There was little damage to Libya's oil industry infrastructure during the war and the country was able to return quickly to its previous production and export levels of some 1.2 million b/d.



Speaking at a regional energy conference in South Korea last month, Saudi Arabia's Minister of Petroleum Ali Naimi said that Opec detected no shortage of crude oil on the market. Saudi Arabia produced 10.19 million b/d in August, its highest production rate in 32 years.

According to the Paris-based International Energy Agency (IEA) global supplies in August fell by 775 000 b/d to 91.59 million b/d, with both non□Opec and Opec registering monthly declines. Opec crude oil supplies declined slightly in August with a sharp downturn in Libyan production only partially offset by near record output from Saudi Arabia, the IEA said. In August Opec output was pegged at 30.51 million b/d, down by 260 000 b/d, it added.

"For the record, oil fundamentals are good. The market is well supplied," Naimi said. "I repeat the message that Saudi Arabia and other producers remain committed and capable of meeting any international demand. Saudi Arabia will continue to meet all demands placed upon it."

Opec Secretary General Abdullah el-Badri told the same conference: "If you see there is a shortage in the market, shortage of supply, we will act," he said, adding: "Stocks are healthy."

Opec has been saying that for a very long time now, yet it seems to have little impact on prices.

Gas

China expands gas deals with central Asian producers

China's energy relationship with the former Soviet republics of Central Asia is growing, as demonstrated in September during a tour of the region by China's President, Xi Jinping.

Mark Goetz

China's new President Xi Jinping last month signed a number of agreements that will see natural gas and oil shipments to China climb in the coming years and will also expand the region's infrastructure – notably the Central Asia-China gas pipeline.

While in Turkmenistan, China's largest supplier of natural gas, Xi met with President Gurbanguly Berdymukhammedov to inaugurate production at the giant Galkynysh gas field, which is considered the world's second largest gas reservoir with reserves estimated as high as 26 trillion cubic m^3.

China has been involved with Galkynysh since development began in 2009. Work was carried out by a group of contractors from China, South Korea and the UAE and required an investment of $9.7 billion that covered exploration, development and construction of three processing facilities. A new agreement with China will see Beijing providing second phase financing for Galkynysh and phase-two development undertaken by China National Petroleum Corporation (CNPC).

Turkmenistan, which holds the world's fourth largest natural gas reserves, already has natural gas sales agreements with China to supply 40 bcm/year. During Xi's visit, another agreement was signed for an additional 25 bcm/year, bringing total future shipments to 65 bcm/year. The plan calls for shipments to reach that volume by 2020 and the Galkynysh gas field will cover supplies for this new accord.

China and Turkmenistan launched what will be a long-term energy partnership in December 2009 with the opening of the Central Asia-China gas pipeline, known also as the Trans Asia Gas Pipeline (TAGP). According to media reports citing figures released by the China National Petroleum Corporation (CNPC), Turkmenistan has shipped some 60.22 bcm of gas to China since the pipeline opened. Turkmenistan provides 51 per cent of China's gas imports, making it Beijing's largest foreign supplier.

Since the gas pipeline came into operation, Turkmenistan has supplied China with an average of 20 bcm/year. The *BP Statistical Review of World Energy June 2013* reports that Turkmen gas exports to China for 2012 amounted to 21.3 bcm.

The two countries signed in 2007 their first gas deal, which called for 30 bcm/year over 30 years. In 2008, the volume of that agreement was boosted to 40 bcm/year.

The new agreement, to boost supplies to 65 bcm/year, will see further expansion for the Central Asia-China gas pipeline with a fourth pipeline that will pass through Uzbekistan, Tajikistan and Krygyzstan.

Two pipelines – Lines A and B – are currently operating and have a combined capacity of 30 bcm/year. A third pipeline – Line C – with a capacity of 25 bcm/year is under construction. The fourth will have a 30 bcm/year capacity, an obvious indication that China is taking Central Asian gas supplies seriously.

China has covered financing and construction of the Central Asia-China pipeline and will continue to do so.

Uzbekistan began to export gas to China in 2012 and Kazakhstan gas exports started in July of this year. Eventually both countries are likely to direct the bulk of their gas exports eastward. Kazakhstan is already supplying China with crude – about 200 000 b/d – most of which comes from China's oil assets in Kazakhstan. China has also recently purchased an 8.33 per cent of Kazakhstan's giant offshore Caspian oil field, Kashagan, where initial production began last month.

While in Kazakhstan, President Xi and Kazakh President Nursultan Nazarbayev marked the inauguration of the Kazakhstan-China gas pipeline. A 1140 km section of the pipeline is now ready to ship gas and when complete with a total length of 1454 km, the pipeline will stretch from Beyneu in the northwest to Bozoy and then to Shymkent, where it will hook up with cross-continent system. The Kazakh branch of the pipeline has a 10-15 bcm/year capacity.

China is clearly prepared to purchase as much gas as Central Asia can supply, but it calls to question whether Central Asia wants to rely entirely on China as its main market. This applies particularly to Turkmenistan, which has been considering other export projects that have yet to make any headway.

Europe is keen to purchase Turkmen gas but Caspian region politics stands in the way. And a plan to export gas through Afghanistan to Pakistan and India is struggling with questions of security.

World: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2035	2020	2030	2035	2035		2010-2035	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**29 194**	**36 492**	**40 364**	**26 497**	**29 841**	**31 748**	**100**	**100**	**2.6**	**1.6**
Coal	12 048	15 015	16 814	9 105	5 483	4 364	42	14	2.7	-2.7
Oil	827	687	673	695	405	332	2	1	-1.6	-4.3
Gas	6 273	8 247	9 342	5 652	6 306	5 791	23	18	2.7	0.8
Nuclear	3 397	3 885	3 908	3 601	5 218	5 968	10	19	1.4	3.1
Hydro	4 390	5 055	5 350	4 658	5 816	6 263	13	20	1.8	2.4
Bioenergy	668	1 021	1 212	750	1 529	2 033	3	6	5.3	7.5
Wind	1 148	1 841	2 151	1 442	3 316	4 281	5	13	7.6	10.6
Geothermal	118	183	217	150	345	449	1	1	4.7	7.8
Solar PV	282	451	524	376	985	1 371	1	4	11.8	16.2
CSP	39	94	141	61	398	815	0	3	19.7	28.4
Marine	3	13	32	6	38	82	0	0	17.6	22.1

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2035	2020	2030	2035	2035		2010-2035	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**7 184**	**8 717**	**9 481**	**7 048**	**8 589**	**9 512**	**100**	**100**	**2.4**	**2.5**
Coal	2 265	2 747	3 005	1 905	1 394	1 220	32	13	2.4	-1.2
Oil	359	276	265	345	230	205	3	2	-2.0	-3.0
Gas	1 861	2 308	2 544	1 765	2 036	2 148	27	23	2.6	1.9
Nuclear	476	526	524	495	699	796	6	8	1.1	2.9
Hydro	1 311	1 498	1 580	1 395	1 742	1 875	17	20	1.7	2.4
Bioenergy	128	183	211	143	264	338	2	4	4.4	6.4
Wind	527	781	890	655	1 337	1 658	9	17	6.2	8.9
Geothermal	18	27	32	23	51	65	0	1	4.2	7.3
Solar PV	227	341	384	303	720	966	4	10	9.7	13.8
CSP	11	25	38	17	107	219	0	2	14.6	22.9
Marine	1	3	8	2	10	22	0	0	14.7	19.1

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2035	2020	2030	2035	2035		2010-2035	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**36 281**	**41 177**	**44 090**	**31 449**	**24 861**	**22 055**	**100**	**100**	**1.5**	**-1.2**
Coal	16 663	19 104	20 515	13 205	7 556	5 620	47	25	1.8	-3.3
Oil	12 100	13 129	13 788	11 355	10 291	9 645	31	44	0.9	-0.5
Gas	7 518	8 943	9 786	6 889	7 014	6 790	22	31	1.8	0.4
Power generation	**15 556**	**18 329**	**20 112**	**12 183**	**6 696**	**4 704**	**100**	**100**	**1.9**	**-3.8**
Coal	11 767	13 990	15 334	8 810	3 722	2 144	76	46	2.1	-5.6
Oil	728	575	551	620	356	292	3	6	-1.8	-4.3
Gas	3 061	3 764	4 227	2 754	2 618	2 268	21	48	2.0	-0.5
TFC	**18 963**	**20 969**	**22 020**	**17 622**	**16 625**	**15 854**	**100**	**100**	**1.3**	**-0.1**
Coal	4 536	4 733	4 792	4 074	3 557	3 220	22	20	1.0	-0.6
Oil	10 698	11 868	12 536	10 094	9 363	8 815	57	56	1.2	-0.2
Transport	*7 617*	*8 732*	*9 396*	*7 234*	*6 684*	*6 251*	*43*	*39*	*1.4*	*-0.2*
- Bunkers	*1 215*	*1 389*	*1 497*	*1 181*	*1 234*	*1 258*	*7*	*8*	*1.3*	*0.6*
Gas	3 728	4 369	4 692	3 454	3 705	3 819	21	24	1.8	1.0

TCF: Total Final Consumption

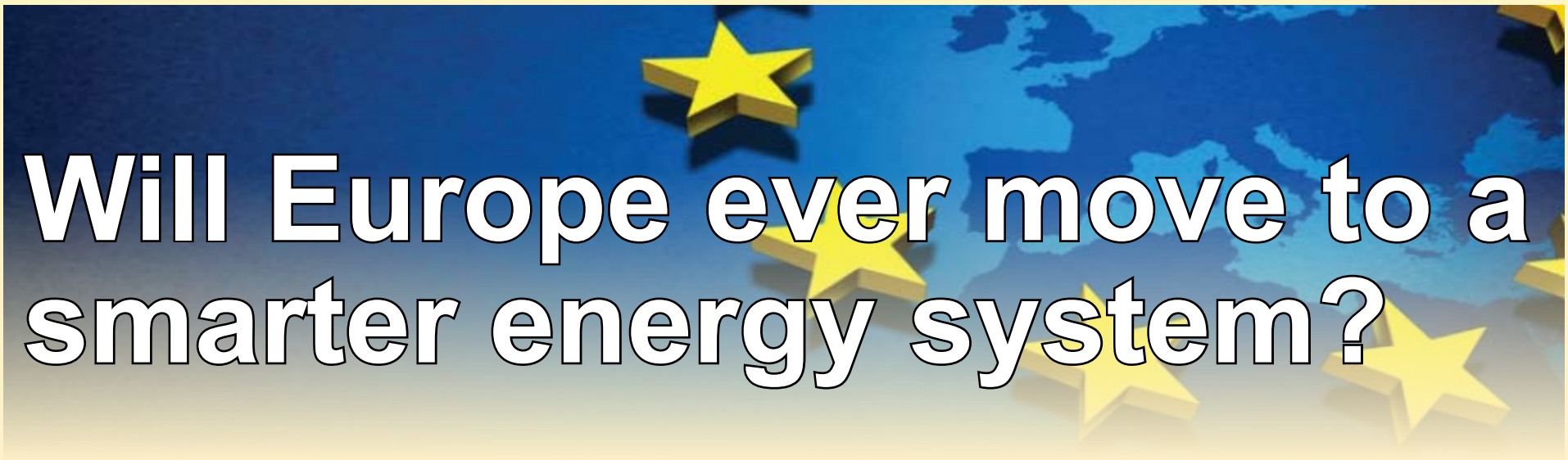
World Energy Outlook 2012 © OECD/IEA 2012, Annex A, page 555

For more information, please contact:

International Energy Agency
9, rue de la Fédération
75739 Paris Cedex 15
France.

Email: bookshop@iea.org
website: www.iea.org

Source: World Energy Outlook 2012



Will Europe ever move to a smarter energy system?

If Europe wants to achieve its energy policy and environmental goals, have an energy market characterised by competition as well as develop the smart grid, it is going to have to find a way to square the circle.
John Harris

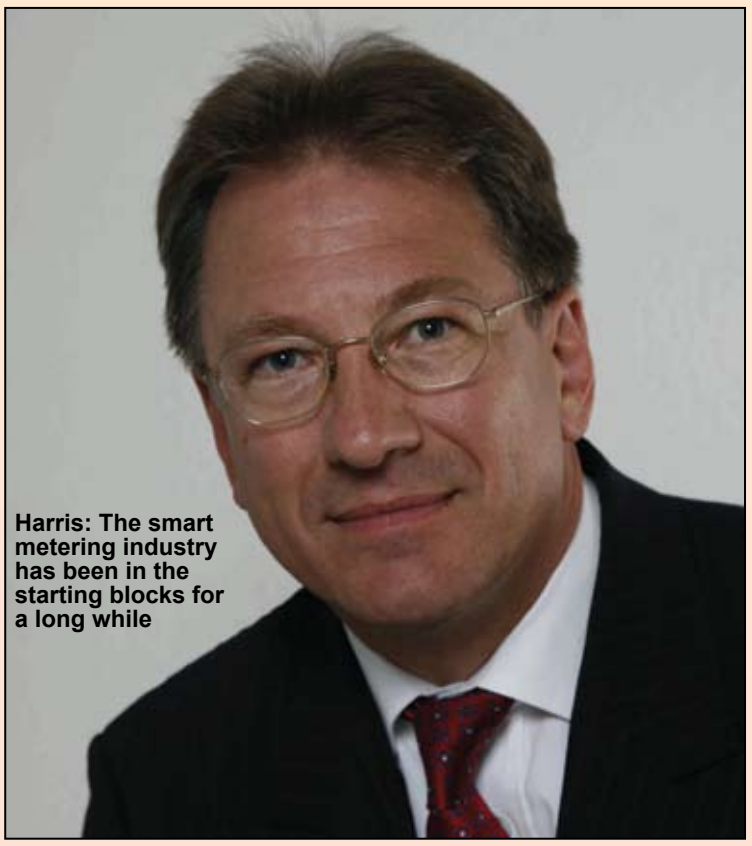
In the traditional energy supply system, there is already a great deal of "intelligence" in the transmission grid, and some in the distribution network, but absent smart metering, there is none between the substation and the point of consumption. In order to know that an outage has occurred and the extent of the outage, the distribution system operator (DSO) has to rely on the 'tried and true' method of people calling in, to say they have no electricity.

This 'blind spot' in the network is exactly the gap smart metering would fill. Intelligence can certainly be enhanced in the transmission and distribution networks, but without filling the communications gap between the substation and the point of consumption (and increasingly also a point of generation), we cannot truly speak of a "smart grid".

The energy system is already in transition. The revolution in the generation mix – away from centralised thermal power plants to decentralised and small generation such as wind power and photovoltaics – makes it imperative that non-dispatchable generation be complemented by variable load. That means that load/consumption should increase when there is an abundance of renewable energy and consumption should be reduced when either generation or network capacity is tight.

But this can only happen when the data on generation and consumption is readily available to all market actors. This is the crucial information provided by smart meters. Moreover, the smart meter plays an operational role: based on the information it provides, both generation and consumption can be adjusted to specific circumstances. The electricity from solar panels on the roof of a house can be throttled, if need be, or a heat pump and hot water heater activated to make maximum use of the availability of that renewable energy.

Moreover, the smart meter provides invaluable information for the network operator on voltage and power quality as well as detailed information needed for investment decisions.



Harris: The smart metering industry has been in the starting blocks for a long while

> If the smart meter is so central to the development of the energy supply system in the 21st century why don't we already have complete coverage?

If the smart meter is so central to the development of the energy supply system in the 21st century, however, then why don't we already have complete coverage from Finland to Portugal and from Scotland to Greece? The problems are not technical. Despite what some say, standardisation is not an issue nor is the technology questionable. It is tried, tested and mature.

Many smart metering and smart grid providers have the required technology "sitting on the shelf". The investments in the technology necessary to realise both the goals of market liberalisation and the transition of the generation system are not taking place.

The European Union's 3rd Energy Package foresees 80 per cent coverage of European households with smart meters by 2020. We, in the industry, do not see that happening.

In the mid-1990s the European Union decided to liberalise the supply of electricity and gas. No longer would consumers be tied to their local monopoly, but could choose from a number of suppliers. At the same time, the generation of electricity became competitive, and energy exchanges were created which set wholesale prices. Only the grid remains a natural monopoly. This policy decision still casts a long shadow as Europe tries to develop smart grids.

In almost all EU member states, the metering system is part of the network infrastructure and therefore part of the "natural monopoly" of the distribution system operator. Investments in smart metering are therefore, the subject of negotiations between the network operator and the national regulatory authority. Both of these two are well versed in negotiating over "copper and steel". But the development of the smart grid depends on adding intelligence to the system, not more hardware.

But that is exactly the point: the industry does not want to invest in more of the same, i.e. enhance the grid with hardware to cover any and all eventualities. It wants to be "smarter". By adding intelligence to the network – particularly in the area between the substation and the point of consumption, where it is blind today, the network can be run more effectively and sounder investment decisions can be made.

One way of getting around this problem – and one that the European regulators themselves have brought into the debate – is to base regulation on operational performance goals. In other words, describe what the network must be able to do and handle in respect to this energy transition: incorporation and dispatch of large amounts of small, decentralised generation, ancillary services, etc. So instead of solely discussing network reinforcement, as we have always known it, work "backwards" from how we want the network to be able to perform.

To add to this complication is that some regulators have thrown in the notion of a "smart market". The idea is that the investment in certain technologies belongs in the competitive part of the value chain rather than in the regulated infrastructure.

The unbundled, liberalised energy market foreseen in the 2nd Energy Package of 1996 makes investments in smart grids technology more difficult. In 26 of 28 EU member states (the UK being the most notable exception, and Germany somewhere in between), the DSO, a natural monopoly, is responsible for metering.

In this configuration, the smart metering system is part of the regulated infrastructure, and the smart meter is the last point of that infrastructure: it is where the smart grid meets the smart home and the "smart consumer". The smart market should then be built upon the information provided by and the control capabilities enabled by the smart metering system.

For instance, information on consumption patterns would allow suppliers to make offerings available to consumers based on their individual usage. Likewise, aggregators could collect individual households, decentralised generation and small business into virtual power plants which could aggregate micro-generation or decrease load depending on the circumstances. These services have a price and are made possible by a smarter infrastructure.

The beauty of smart metering is that it brings benefits all along the value chain. The problem lies therein, that the benefits are spread out and longer term but the costs of making the investment are concentrated (usually with the DSO) and immediate. An unbundled, liberalised electricity market makes dividing this "cost pie" much more difficult. The smart metering industry in Europe is looking at a flat growth rate in at least the next two to three years.

Other regions of the world, such as Australia, Asia and North America have already surpassed Europe in the deployment of smart metering and smart grids technology. With few exceptions they all have not liberalised nor unbundled their energy markets or at least have gotten past the politics of "who pays for what" vs "who benefits from what", and have found a way to deploy smart metering technology to the benefit of all stakeholders. A vertically integrated energy company derives all the benefits of smart metering, from supply upwards, and therefore is willing to make the investment. Further, the benefits provided from smart metering are usually greater and at lower cost.

It would be difficult to argue for a complete reversal of European energy market policy of the last 15 years but the hurdles to investment that this market design causes have to be recognised: by regulators, the member state governments and most particularly by the European Commission.

For all the grand plans the European Union has, they all depend on a transformation of the grid from a one-way, centralised flow to a multi-directional, dynamic, living organism. The distribution network will bear the brunt of most of these changes, and the metering system is the keystone to this new smart grid.

The fact that the European Union has an almost unbroken record of setting goals and then failing to meet them notwithstanding, if smart metering technology is not in place at least according to the timeframe foreseen in the 3rd Energy Package, the other goals will melt away like an ice cream cone in the July sun.

If Europe wants to achieve its energy policy and environmental goals, have an energy market characterised by competition as well as develop the smart grid, it is going to have to find a way to square this circle.

The smart metering industry has been in the starting blocks for a long while, and will provide constructive contributions to the debates, as well as develop state-of-the-art technology for the benefit of Europe's consumers and utilities. But the policy-makers and regulators have to do their part. The question of smart metering deployment is not technical, but political and regulatory.

Let's get on with it.

John Harris is the Vice President and Head of Regulatory Affairs for Europe at Landis+Gyr.

Regulating for commercial realities

Offshore wind farms can progress more easily with the right approach to regulation and legislation, as Triton Knoll demonstrates. **Chris Williams**

As wind power generation continues to develop as a vital contribution to UK renewable energy targets, and projects grow in scale and complexity, the regulatory and legislative context has needed to evolve in parallel. Four recent examples illustrate how the commercial realities of wind power have been reflected in decisions, legislation, government policy, and regulatory coordination.

The first relates to a decision made on the Triton Knoll wind farm, showing how offshore wind projects can be approved if grid connection and transmission elements remain uncertain during the application and examination stages.

The project, which is being promoted by Triton Knoll Offshore Wind Farm Limited (TKOWFL), was approved for development on July 11, 2013 and will comprise up to 288 wind turbines, with a capacity of up to 1200 MW.

The wind farm application did not include subsea export cabling or onshore grid connection infrastructure because the prospective grid connection points had changed during the pre-application stage. The developer decided to proceed with the wind farm application and environmental assessment with reference to an indicative grid corridor to avoid significant delay. The offshore/onshore transmission and grid connection elements would be the subject of subsequent applications.

The decision required the Secretary of State to consider the approach to three issues: environmental assessment, subsequent applications for different elements of an overall project and any linking of the wind farm development to the subsequent transmission/connection works.

The national renewable energy policy says that where the precise location of cabling routes/substations is not known, a cabling/substation corridor should be identified and the environmental assessment should assess the effects of including this infrastructure within that corridor.

The Secretary of State decided it was "not necessary or indeed possible for [the developer] to submit detailed information about the anticipated grid connection for the proposal as part of the application or to assess this in the supporting ES". He concluded the Environmental Statement provided adequate assessment of the effects of the wind farm development and "on grid connections to the extent necessary for this offshore proposal".

The national renewable energy policy also recognises that a wind farm applicant may not have received or accepted a formal offer of a grid connection from the relevant network operator at the time of the application, and that in some cases applicants may decide to put in an application that seeks consent only for one element but contains some information on the second.

This is a commercial risk the applicant may wish to take for a variety of reasons. Here, the applicant should explain the reasons for the separate application, and the Secretary of State must be satisfied there are no obvious reasons why the necessary approvals for the other elements are likely to be refused. The Secretary of State restated these requirements of policy and concluded "there are no obvious reasons why the connection elements of the project would be likely to be refused, given the applicant would be able to bring forward a number of alternative routes or solutions to those indicated".

The Secretary of State rejected the suggestion that there should be a restriction that no works on the offshore generating station should commence until the Secretary of State had confirmed in writing that all the necessary consents for the later connection and transmission works had been obtained. On cumulative assessment of onshore and offshore elements, the Secretary of State noted that any impacts of further development will normally be dealt with in the consenting process for that development, and in particular: "any subsequent supporting EIA assessment for grid connection infrastructure would also need to consider cumulative impact with the offshore wind farm development". He also rejected the suggestion of a requirement linking the offshore and onshore elements for the purpose of assessing overall project mitigation.

In the second example, we examine new policy issued by DECC in relation to variation procedures for s.36 consents. In July 2013, DECC issued new guidance and regulations (effective from 31 July 2013) for England and Wales on a procedure for varying consents granted under s.36 of the Electricity Act 1989 for construction, extension, and operation of electricity generating stations ("section 36 consents"). Equivalent regulations for Scotland will appear towards the end of 2013.

The previous problem was that the Electricity Act had no process for varying section 36 consents, and since March 2010 (when the Planning Act replaced the Electricity Act for most generation projects, with the exception of offshore generation below 100 MW) it has not been possible to apply for a new section 36 consent for updated plans. The Planning Act allows changes to be made to schemes approved under it, but this does not cover previous s.36 consents.

The new variation procedure appears in the Electricity Act as Section 36C, and the July regulations bring this into operation. It is now possible for design or operation of generating stations to be modified in ways that the existing section 36 consent would not permit.

Variation is likely to be allowed for: construction or extension of a generating station (not yet commenced or not yet completed) along different lines from the existing consent; operation of a generating station, whether or not already operational, in a way that is different from the existing consent.

The key point is that the variation procedure is not intended to allow any change that would result in development fundamentally different in character or scale from the existing consent. Changes in a plant's main fuel or other power source are unlikely to be allowed. Detailed examples in the guidance on permitted variations are:

- Less significant changes to the type or operation of technology may be allowed (for example different boiler or turbine designs).
- Changes in permitted power generation level for plants that are consented but not constructed are likely to be allowed, provided no major changes in the environmental impact of the plant.
- Changes in permitted power generation level at an existing plant could be allowed, provided there is no physical extension of the generating station, no relocation of generating plant, and no installation of new equipment that would amount to the construction of a new generating station.
- It should generally be possible to allow variations which only affect the operation of an existing station (and do not involve construction of a new generating station or extension of an existing one).

It is now possible for design or operation of generating stations to be modified in ways that the existing section 36 consent would not permit

Applications for variation must be made to whoever granted the existing s.36 consent (i.e. DECC or MMO). Applications for projects in Scotland will be dealt with by Scottish Ministers under separate regulations. Applicants must justify the changes in planning and energy policy terms, and the application must describe the whole of the development that would result if the section 36 Variation is granted, not just the change proposed. Variation applications will also need some form of environmental statement. Depending on the change proposed, this might range from only minor updating of a previous document, to undertaking new assessment of the impacts of any change in design that are likely to have significant effects on the environment.

The third example relates to new planning guidance published by the Department of Communities and Local Government in July 2013 on the planning issues associated with the development of renewable energy.

Local planning authorities are encouraged to promote the delivery of renewable and low carbon energy in local plans, and are incentivised to identify suitable areas for renewable development by advice that where they do so it should be possible to refuse planning permission in other areas: "... Where councils have identified suitable areas for onshore wind or large scale solar farms, they should not have to give permission outside those areas for speculative applications involving the same type of development when they judge the impact to be unacceptable".

There is an apparent shift away from a general presumption in favour of sustainable development in the new guidance which now states: "The expectation should always be that an application should only be approved if the impact is (or can be made) acceptable".

One important statement of general guidance is that local planning authorities should not rule out otherwise acceptable renewable energy developments through inflexible rules on buffer zones or separation distances to residential areas.

The guidance also identifies a range of questions specific to wind turbine schemes, aimed at improving understanding of what needs to be done in preparing and assessing these applications, which should lead to a more efficient and successful consenting process.

In the final example of how the commercial realities of wind power have been reflected in regulatory coordination, we examine coordination of offshore transmission infrastructure.

To date most transmission links from offshore wind farms to shore have been standalone connections serving individual projects. However, the Round 3 offshore wind projects are larger, more complex, and further offshore, so Ofgem believes there could be likely potential efficiencies from greater coordination of offshore transmission infrastructure. In July 2013, Ofgem published a statement setting out its views on the way forward for two categories of coordinated investment.

Generator Focused Anticipatory Investment is investment in offshore transmission infrastructure led by a developer to support the later connection of specific offshore developments. There is potential benefit of more efficient combined transmission costs for the generation projects served, but also risk for the developer if the later generation projects do not all connect. Ofgem believes the developer of the initial generation project is best placed to manage this risk.

Developer-led Wider Network Benefit Investment is investment by developers in transmission capacity to provide wider network benefit. It includes offshore transmission assets or capacity that go beyond what is needed by a single developer. Developer-risk could arise if the expected wider network need did not materialise, and previous feedback to Ofgem suggested that one barrier to their provision was lack of clarity on how assets will be treated during an offshore tender exercise.

Ofgem has now said that where it is convinced by the developer's rationale for including additional or oversized transmission assets, Ofgem will commit to not re-assessing the rationale during the subsequent tender exercise.

This would be conditional on continual monitoring of the needs case by the developer and the network operator; if the needs case changed Ofgem would expect these parties to review the design of the offshore assets and make any necessary changes where this would be economic and efficient. A change in the needs case may also mean that the wider investment is not taken forward.

This approach appears to balance risk to the developer with cost to consumer; whether it will be regarded by industry as unlocking the provision of wider network benefit will become clearer as major projects proceed.

Chris Williams is a Partner in the Energy Group at CMS, specialising in consenting issues.

Williams: the regulatory and legislative context has needed to evolve

Making a case for battery storage

A utility scale energy storage system has been energised in Orkney, Scotland. The trial project will help determine whether an energy storage system can make technical and commercial sense.
Junior Isles

The growing amount of intermittent renewable generation on the grid has made utility scale energy storage vital. Yet with the exception of pumped storage hydro, energy storage is still very much in its infancy.

Battery type storage systems, although small compared to pumped storage systems, have the advantage that they can be installed at any geographic location. Although the commercial case for their deployment is still a considerable way off, some utilities are still looking at how battery storage can make sense – both technically and commercially.

In one interesting development, Scottish Hydro Electric Power Distribution (SHEPD), the SSE group company that handles power distribution in Scotland, recently connected the UK's first large scale battery to the local electricity distribution network on the Orkney Islands in northern Scotland.

This trial project, funded by Ofgem's Low Carbon Networks Fund, will investigate how large scale batteries could play an important role in releasing capacity on the electricity distribution network and explore how the intermittency issues affecting renewable generation can be resolved.

The system, installed at Kirkwall power station, was energised in July this year. It uses a 2 MW, 500 kWh lithium-ion battery provided by Mitsubishi Power Systems Europe, Ltd. (MPSE), the European operation for Mitsubishi Heavy Industries, and operated by SSE Generation Ltd, the power generation unit of SSE group.

Explaining the rationale behind the latest project, Andrew Urquhart, SHEPD's project manager said: "Within SHEPD we have had a number of different storage projects varying from: flow battery cells for auxiliary power supplies; batteries for frequency response; and LV batteries for improving [power] quality on the network.

"But although we have trialled a different application with this project, we wanted to look at a different ownership model and in tandem with that, we wanted to get an understanding of the biggest question facing storage at the moment, which is: where does the business case lie?"

Making commercial sense of storage is certainly a dilemma for people wanting to install systems. This led SHEPD to look at a different ownership model. Instead of specifying its exact requirements, procuring and installing the equipment, and then operating and maintaining it, SHEPD put out a tender for a third party to provide the service.

"We decided to see if we could get someone else to provide us with the benefits of storage without the complications of buying and installing ourselves," said Urquhart.

Indeed the complications are significant. All distribution network operators use a 'Utility Vendors Database' as a procurement system. However, there is no category for large scale energy storage.

Urquhart said: "This meant we had to start by going out to 129 companies across many different categories to try and get someone willing to engage in this type of project. So your issues start right at the beginning of the project. The challenges are mainly procurement and understanding the safety of systems because there are no codes or standards that apply to lithium-ion, flow cells or sodium sulphur [batteries], so you have to go that whole extra step to make sure the systems are safe. And safety is our number one priority.

"There are also operational issues. Lithium-ion is a new technology, which we are not experts in. So why not pay somebody else who is an expert?"

However, companies with expertise of a new technology for a new type of application are few and far between. The list of 129 companies approached soon became just seven.

"Not a lot of companies have prior experience, which was one of the criteria we set," noted Urquhart.

The project, which officially kicked off in September 2011, ties in with another that was completed by SHEPD several years ago. In 2009 it began operating what it calls an 'Active Network Management' scheme. The project, claimed to be a world first, essentially increases the network capacity of Orkney without reinforcing the network. This is very beneficial in an area with a significant amount of latent wind capacity.

Urquhart explained: "The Active Network Management system essentially allows more generation to be squeezed into the grid. It monitors key constraint points on the network in real-time. It then looks at the output from the circuit breakers being fed from the wind farms. If those tight spots are about to be breached in any way, i.e. the thermal rating of the cable is about to be breached, a signal is sent from the local controller to the generator, which can then reduce its energy export.

Urquhart: looking for a commercial case for storage

"With the inclusion of a storage system, the controller will instead send a signal to the battery to import the energy. So rather than losing renewable energy from the network, it is instead saved for later."

SHEPD looked at all the energy storage technologies but finally opted for lithium-ion technology as it offered the cheapest overall project cost.

The energy storage system, which has the capacity to store approximately 800 kWh (nominal) or 500 kWh (normal usage), consists of two 12.2 m (40 ft)-long container units for the batteries and a 12.2 m-long container unit for the power conditioning system. Each battery container houses more than 2000 units of lithium-ion rechargeable batteries. The power conditioning system container houses a system for converting DC to AC, and the associated input/output controls.

The system is similar to a trial system that Mitsubishi has been running continuously for the past two years in Nagasaki, Japan.

Compared to other battery technologies, a lithium-ion battery has both pros and cons. On the plus side, it is compact and light, has high power output, longer life, can be charged and discharged quickly and does not suffer from memory effect. However, their costs need to come down and performance improved to widen their scope of applications.

According to Urquhart, when it came to selection SHEPD was "technology agnostic".

"We really didn't mind what the storage device was, as long as it met certain performance characteristics i.e. it responded within one or two seconds, had a certain minimum size and minimum transfer capacity."

It therefore became purely a commercial decision i.e. who could offer the cheapest price for the project duration.

A popular belief is that no single application will make a business case for storage deployment. SSE therefore says there will have to be a "stacking" of various market revenues to provide the business case.

"We believe a group of different markets will have to operate in tandem at different times of the day, offering different services," said Urquhart. "So the market mechanism we have put in place is a constraint management service. There is also the possibility SSE Generation would get into the national grid ancillary services markets – for example, short term operating reserves or frequency response."

The third market possibility, says Urquhart, is arbitrage i.e. realising profit by buying electricity at a lower price and selling at a higher price. The fourth market he sees would be a "miscellaneous" option. This would be random, bespoke applications such as supplying load or taking load from a nearby demand.

The idea is that if the project is successful, SHEPD will be able to identify at least one other market that is possible for such an installation to engage in and what value could be attributed to that market.

SHEPD will no doubt have a good idea of what is possible by the time the trial is complete in 2015. Over the coming two years, it will be monitoring whether the systems can operate for the constraint management market.

"We will look at how often it is dispatched and essentially how much capital expenditure it has deferred compared to installing a £30 million submarine cable [from Orkney to the mainland].

"On the generation side, the operators will engage in as many markets as possible and it is a requirement that they share what markets they have been involved in and what percentage of their revenue has been derived from each market," said Urquhart.

This, he believes, will give SHEPD more bargaining power with the energy storage supplier/operator when looking at other installations where storage is a potential solution. "If we know a similar asset can operate in three or four other markets, in the future when we go out for a procurement process, we can expect a lower price."

It will be interesting to see if SHEPD can make the business case for storage. If so, it will be another tool in helping operators deal with the network constraints that are becoming more common as the amount of grid connected renewables continues to grow.

The energy storage system is housed in two 12.2 m long container units

Junior Isles

Tilting at utilities

Some may describe Ed Miliband as a Quixotic character. But it is far more likely that his recent speech on UK energy is driven by politics as opposed to any pursuit of romantic but impractical ideals.

The leader of the UK's opposition Labour Party said that if elected he would freeze gas and electricity prices for 20 months. Miliband told delegates at a Labour Party conference: "We need successful energy companies and we need them to invest in the future but… there will never be public consent for that investment unless you get a fair deal. The system is broken and we're going to fix it."

Miliband claims that the 'big six' energy companies are overcharging consumers. "When wholesale prices go up, people end up paying more but when wholesale prices come down, people still pay more. A few years ago, we saw wholesale prices go down by 45 per cent but retail prices fell by just 5 per cent and have remained out of whack ever since," he said.

Miliband's heart may be in the right place but it is more likely that this is just another attempt at winning over voters ahead of the next election. If so, it is a dangerous game.

Perhaps he is forgetting that utilities are global public companies operating in an open market. Further, four of the big six suppliers are foreign owned. German shareholders of RWE and E.On for example, are unlikely to tolerate limits being imposed on the amount of money they are allowed to make, especially when already wrestling with challenging European market conditions. After all, they do not have to play ball here. If he is elected and follows through, Miliband may find he has simply contrived to score an own goal if they decide to pick up their ball and go home.

> "Miliband's plan to freeze utility bills is not just misguided, it is Quixotic. This will merely encourage energy firms to push up prices before any legislation can be passed"

Centrica has already suggested it would not be commercially viable to operate under the proposed conditions. It also said price rises over the last five years have been due to three factors: higher commodity prices; increases in regulated transportation and distribution charges; and environmental costs and taxes.

Whatever one's view on utilities and energy prices, there is no escaping the fact that utilties are needed to provide investment. If the price cap impacts their ability to invest, the UK seriously runs the risk of the lights going out.

According to EnergyUK, the trade association for the energy industry, no other industry is facing the investment challenge of the energy sector. It said last year alone the energy industry invested £11.6 billion and needs to invest £110 billion over the next ten years to build new power stations and energy infrastructure.

Angela Knight, Chief Executive of Energy UK said: "Freezing the bill may be superficially attractive, but it will also freeze the money to build and renew power stations… and make the prospect of energy shortages a reality, pushing up the prices for everyone."

Mark Powell, Head of A.T. Kearney's UK Utilities Practice, stressed: "This is an incredibly dangerous place to go with politics. Whatever you say about energy policy, people will not care when the lights go off. And there is no question that with the current capacity margins we are already running the risk of a real capacity crunch by 2017 or even sooner."

The Labour leader says the price freeze would last from June 2015 to January 2017. He gives no detail on what happens after the 20 months. Instead he only talks of putting in place a "new system for the future". Policy uncertainty has resulted in very little being built in the UK as it is, and the last thing potential investors need is the spectre of another market reform before the pending one is even finalised.

Michael Ware, a partner at BDO International, the fifth-largest accountancy network in the world, is also scathing of the proposal. "This is pantomime politics," he said. "Rhetorical attacks on the villains of energy companies may get a big cheer from the conference audience but this policy will probably inhibit investment in generating capacity at a time when it is most needed."

Ware added: "History shows very clearly that government attempts to fix prices in commodity markets rarely work in the long run and tend to reduce supply whilst increasing demand."

Indeed there is a precedent. The combination of liberalised wholesale markets with price controlled retail markets was one of the factors that resulted in soaring prices and blackouts in California in 2001. Further, government control over tariffs is also partly to blame for a tariff deficit that is now forcing the Spanish government to find a way to fill a €24 billion gap.

Yet Miliband remains adamant. He believes the energy companies are able to "absorb" the price freeze without putting investment at risk. "Less than half the profit the companies actually make go into investment. They go into dividends rather than investment. Secondly we have seen an increase in profits over the last few years but a collapse in investments."

Utilities probably could absorb a price freeze without going bust but it would be unrealistic to expect that they will not take steps to recoup profits by, for example, cutting jobs.

It is easy to vilify energy companies. Perhaps they have not done a great PR job of getting their message across to the general public. However, it is debatable as to whether they have made excessive profits. Electricity is often taken for granted but building and operating power plants is an expensive business

"If you look at the FTSE, they have been a bit above average but I don't think you will find real evidence that they have been 'coining it' and ripping everyone off, as is being implied. They are making sensible profits but relative to capex employed, the profits are not unreasonable. And, keep in mind that they are expected to make investments of tens of billions," said Powell.

It also should not be forgotten that over the last 20 years, the UK has enjoyed some of the lowest energy prices across Europe. The UK has a had a good run but is now beginning to see accelerated costs in order to hit decarbonisation targets and the need to build new infrastructure.

Powell said: "Costs are going to go up and it is going to be painful… you can tinker around with the system but the basic drivers will not change. You need a lot of capital to build new infrastructure and a lot of the costs are linked to decarbonisation – this is driven by policy, which is not going to change any time soon."

Powell believes that the government is actually pulling the wrong levers in trying to achieve its goals. "Why are we putting so much into a renewables target when it is actually about carbon?" he questioned.

Even some renewables proponents are not convinced by Miliband's proposal.

Renewables expert Sylvio Spiess said: "Miliband's plan to freeze utility bills is not just misguided, it is Quixotic. This will merely encourage energy firms to push up prices before any legislation can be passed. That does not even benefit householders in the short term, and does nothing to address the fundamental problems with energy costs in the UK."

Labour says the energy price freeze would save average households £120 a year and businesses £1800. No doubt we could all do with a little help but the plan is ill-conceived and risky for both Miliband and the public. And looking at it more broadly, if politicians start to tinker with energy markets, where does it end? Will they also start to intervene in telecoms?

This is an impossible dream. Miliband may see tilting at energy companies as championing the cause of the man on the street. It may be a great vote winner, but today's ardent supporters can soon become tomorrow's angry mob – especially if the lights go out.