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Iran eyes nuclear power as international dispute continues

Kamalvandi, Deputy Head of the AEOI, says China will "enter the arena soon"

Iran is yet to finalise a deal over its nuclear programme but this has not stopped it from securing deals with Russia and now China for the construction of new nuclear power plants.

Junior Isles

Iran has set its sights on increasing its nuclear generating capacity, despite ongoing talks regarding its fuel enrichment programme.

While commenting on a framework agreement struck in Lausanne on April 2, Deputy Head of the Atomic Energy Organization of Iran (AEOI) Behruz Kamalvandi said China would cooperate with the Islamic Republic on building new nuclear power plants.

"The Islamic Republic of Iran plans to produce at least 190 000 SWUs (Separative Work Units) of nuclear fuel at the industrial scale, while we also think about one million SWUs, which will be needed to fuel five power plants like Bushehr (nuclear power plant)," Kamalvandi said, addressing a meeting dubbed as 'an Analysis of the Lausanne Statement'.

Iran has already reached an agreement with Russia on building two new nuclear power plants and Kamalvandi said: "… the Chinese will also enter this arena soon". He also said other countries will cooperate with Iran on constructing nuclear power plants.

Iran and the 5+1 (US, UK, France, Russia, China, and Germany) reached a framework agreement after eight days of intensive talks in Lausanne over the Islamic Republic's disputed nuclear programme.

The deal would see Iran reduce its nuclear programme, and in return the P5+1 would lift certain sanctions imposed on Tehran. However, a final deal has yet to be signed. Iran and the P5+1 have set June 30 as the deadline for a final deal.

The first round of talks on pushing forward the final Iran nuclear deal ended after three days of discussions in Vienna on April 24, but disputes between the US and Iran still remain unresolved.

At the top of the agenda for the talks was the timing of sanctions relief, which could have a major impact on oil and gas markets. The US and Iran continue to hold different or even opposite opinions on the procedures for

Continued on Page 2

Areva may consider nuclear sell-off

The sale of Areva's nuclear operation has been put forward as part of a solution to help end the struggling French nuclear engineering firm's financial difficulties.

Jean-Pierre Bachmann, the representative of the CFDT union, said Areva's Chief Executive Officer Philippe Knoche told union representatives that the government was evaluating a partial or total sale of Areva NP, which handles the company's core business, to Electricité de France (EDF) for an amount still to be determined. Knoche also said other options were discussed at the meeting last month.

The French engineering giant has been struggling to stay afloat as a result of plant construction delays and a slowdown in the nuclear sector following the accident at Fukushima in Japan.

The meeting between Knoche and the unions was held after French Economy Minister Emmanuel Macron said he was asking EDF – the operator of France's fleet of nuclear power stations, which provide most of the country's electricity – to rescue Areva by deepening their industrial and possibly financial ties.

EDF and Areva, which are both majority-owned by the French state, have to cooperate better over the construction of nuclear reactors and tendering for international business, Macron said.

Areva is currently working on a plan to sell assets, cut costs, reduce capital expenditure and start talks with unions over possible job cuts.

The unions oppose the sale of the nuclear reactor business, which represented almost 40 per cent of its overall revenues in 2014.

"Areva would be left without its core business, it wouldn't be able to make reactors or even design them," Bachmann claimed. "Additionally, the company provides equipment and services to some of EDF's competitors. How would that be possible after a sale?" he added.

According to its latest annual financial statement, Areva lost around €5 billion ($5.3 billion) in 2014, compared with a €500 million loss the year earlier because of delays in projects around the world, most notably at its EPR units being built at Olkiluoto in Finland and Flamanville in France.

The company is now looking to Asia and in particular China for future growth.

Remy Autebert, Areva's senior executive vice-president for the Asia-Pacific region, recently told *China Daily* that China will play an important role in the company's global strategy as a source for future growth.

He said Asia accounts for just 15 per cent of its total revenue, with the biggest growth in China.

"We plan to increase the Asian share to 20 per cent and even 30 per cent in the long term," he said. "The major part of the growth in China is new nuclear reactors. It has the largest number of nuclear reactors under construction, and that will continue for some time."

Areva's plans for Asia received a boost last month when it signed a pre-engineering agreement (PEA) with Nuclear Power Corporation of India (NPCIL) to set up two evolutionary pressurised reactors (EPR) at the Jaitapur Nuclear Power Project in Maharashtra, a state in India.

The PEA will also try to localise the components of the power plant, to increase India's domestic capabilities according to the 'Make in India' campaign.

It is expected that the PEA will bring down time and cost during the implementation of the project.

Areva also signed a memorandum of understanding with Larsen & Toubro (L&T), for cooperation to maximise localisation for the Jaitapur plant.

■ Following an Areva GmbH Supervisory Board meeting in April, the management will begin discussions with its social partners regarding a project to relocate the activities currently based at the Offenbach site (700 employees) to the Erlangen and Karlstein sites by mid-2016, at the latest. The objective of this project is to optimise the industrial footprint of Areva in Germany by improving cooperation between the teams and providing structural savings.

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sanctions relief.

So far Iran has accepted few limitations on its Research and Development programme, which will come to an end after a 10-year period. Following the Lausanne deal, Kamalvandi also said the Fordo uranium enrichment facility in central Iran will be kept intact and over 1000 centrifuges will remain at the facility.

Tehran and Moscow recently announced that they would jointly produce fuel for Iran's nuclear power plants. Russia and Iran signed an agreement on March 2 to supply services to the Bushehr nuclear power plant, the head of Rosenergoatom said. According to

Vladimirovich has struck a five-year cooperation deal with Iran

Rosenergoatom's CEO Romanov Yevgeny Vladimirovich, the firm agreed on a five-year cooperation deal with Iran.

Iran's only nuclear power station, the 1000 MW Bushehr plant, was inaugurated in September 2013. Construction of the two new Russian plants, also at Bushehr, is expected to kick off in the current Iranian fiscal year (ending March 21, 2016).

Under the agreement, the new 1000 MW facilities will be built next to the first Bushehr unit, said Kamalvandi, adding that the deal also includes the construction of two desalination units.

Kamalvandi also announced the country's plans to build small nuclear plants on the rims of the Persian Gulf to desalinate water.

While stressing that the country is seriously pursuing large scale nuclear plants, he noted: "At present, the world is moving towards the construction of small power plants since they can have different applications."

Kamalvandi said that two or three small nuclear power plants could be built beside each other to form a mid-size power plant.

Iran is looking to become a major regional exporter of electricity. It is currently trading electricity with Armenia, Pakistan, Turkmenistan, Turkey, Azerbaijan, Iraq, and Afghanistan.

The country's generating capacity stands at nearly 70 000 MW, of which 57 541 MW is generated by thermal power plants, 9686 MW is generated by hydroelectric power plants, 1020 MW is generated by nuclear power plants, 466 MW is generated by distributed generation power plants, and 219 MW is generated from renewable energy sources.

Power generation capacity has grown by seven per cent annually over the past 10 years.

Countries gear up for COP21

■ US and Mexico submit targets ■ Network of cities adopt action plan

Junior Isles

The global community is ramping up efforts to tackle climate change as countries continue to submit their emissions targets ahead of the Conference of Parties (COP) 21 meeting in Paris in December.

A new binding global climate agreement is due to be signed at the meeting that should finalise post-2020 emissions reduction targets. To help the negotiations, countries that are ready had been asked to submit their emissions targets and climate plans by March 31.

Following the EU's submission of its target in early March, several major emitters have now also put forward their targets.

On March 31, the US submitted its Intended Nationally Determined Contribution (INDC), committing to reduce greenhouse gas (GHG) emissions by 26-28 per cent below 2005 levels by 2025. The proposal also indicates this target is consistent with a trajectory to economy-wide reductions of 80 per cent or more by 2050.

Commenting on the plan, the World Resources Institute (WRI) stated: "The US proposal to reduce emissions by as much as 28 per cent represents a significant commitment through 2025. But the country will need to continue to accelerate its efforts over time to help the world get on track to limit global warming to 2°C (3.6°F) and reach the goal of deep decarbonisa-tion by mid-century."

Mexico became the first developing country to submit its INDC, which includes a plan to peak its emissions by 2026, and reduce GHG emissions by 22 per cent and emissions of black carbon or soot by 51 per cent by 2030.

Mexico said its pledge could rise to as much as 40 per cent if broader international agreements are reached at the Nov. 30-Dec. 11 COP 21 meeting or subsequent rounds of talks.

"While the devil is in the details, Mexico's plan to peak its emissions by 2026 is particularly encouraging and should inspire others to follow a similar course," said Jennifer Morgan, global director of the WRI's climate programme.

The INDC follows passage of a national climate change law in 2012, and low carbon growth is a key part of Mexico's ongoing structural reforms.

Mexico and the US have also agreed to form a new high-level bilateral clean energy and climate policy task force, co-chaired by the US energy secretary and Mexican environment secretary.

Elsewhere, major emitters India and Japan said they will submit targets in June.

Meanwhile at a congress held in South Korea in mid-April, the world's largest network of cities adopted an action plan to tackle climate change.

The plan calls for close cooperation between cities worldwide through three major global networks – ICLEI – Local Governments for Sustainability, United Cities and Local Government and C40 Cities Climate Leadership Group – to address greenhouse gas emissions.

Cities also pledged to more effectively implement the Compact of Mayors that was established at the United Nations Climate Summit in September 2014. The pact focuses on the commitments of cities to bolster their pledges to reduce GHG emissions by 454 Mt by 2020.

Shell's takeover of BG could mark start of mega-mergers

Royal Dutch Shell's planned takeover of oil and gas exploration firm BG Group could be the start of a new wave of mega-mergers in the sector.

Last month the company said it has agreed to buy BG in a deal that values BG's equity at £47 billion ($69.5 billion), plus net debt of £8 billion. Completion is expected in early 2016. It could be one of the biggest deals of 2015 and could produce a company a valued at more than £200 billion.

Analysts at global investment banking firm Jefferies said that by 2018 the combined company of Shell and BG would produce more oil and gas than ExxonMobil, currently the world's biggest non-state oil group.

Christian Stadler, an Associate Professor of Strategic Management at Warwick Business School, who has researched and worked with Shell for the last 15 years commented: "…with cost pressures, acquisitions are an obvious way to maintain growth; there has been some M&A activity in the oil service sector already. For Shell an acquisition to replace reserves makes sense as attempts to join the US shale boom did not deliver much and exploration budgets are being cut.

"If Shell takes over BG it could be the beginning of a new wave of mega-mergers in the sector. Quite a few oil companies are under cost pressure with no sense of the oil price recovering. Companies had got used to $100 a barrel, and many need $40 to $60 to break even so we could see more of these deals."

According to Wood Mackenzie, Shell "has made a compelling first move" on the M&A market.

It says the real prize for Shell is the oil in deepwater Brazil. By 2025 Brazil will be delivering 550 000 barrels per day of oil – 13 per cent of BG/ Shell's total production and the biggest single country position in the combined portfolio.

In addition the combined entity will control sales of 44 million metric tonnes per annum of LNG by 2018, making it the largest LNG seller globally. Wood Mackenzie also noted that post-BG, Shell will remain under-exposed to unconventionals relative to its peers.

The deal comes at a time of uncertainty for oil and gas companies. In the past six months the price of oil has fallen by about 50 per cent. Meanwhile, analysts have warned that investment in North Sea oil exploration has all but dried up, threatening the entire industry.

Shell and BG Group expect to make annual savings of £1.7 billion following the deal. But Shell chief executive Ben van Beurden said he remained committed to North Sea oil and expected to invest £4 billion between 2016 and 2018.

This will be welcome news to the UK, which is desperate to maintain domestic supplies of oil and gas.

■ Last month UK Oil & Gas Investments announced a discovery of huge reserves near Gatwick airport in southern England. The company said, however, that estimated volumes of 158 million barrels per square mile "should not be considered as either contingent or prospective resources or reserves".

Banks weigh-in on climate change

A crucial step towards reaching a climate deal in Paris this year was taken last month when a group of leading development banks finalised a set of climate finance parameters.

The banks issued a set of "Common Principles", which are backed by the World Bank, International Development Finance Club (IDFC) and Agence Francaise de Developpement and specify investments that can qualify as 'climate friendly'.

Signatories include the top development banks in China, India, Brazil, South Africa, Japan and Mexico who control assets worth a combined $2100 billion, with financing commitments of $390 billion in 2010.

The new document calls for banks not to exaggerate the investment being channelled into clean energy projects, and to only report investment that directly enables emissions reduction.

In a separate announcement the World Bank called for a new carbon tax and for subsidies for fossil fuels to be scrapped.

The World Bank also said that, in addition to introducing a carbon tax and scrapping fossil fuel subsidies, it is aiming to boost spending on energy efficiency, sustainable agriculture and pollution reduction in cities.

According to Bloomberg New Energy Finance global investment in clean energy was $50.5 billion in the first quarter of 2015, down 15 per cent from Q1 2014.

The Q1 figures show that investment in Europe slipped 30 per cent compared to first quarter 2014, to $9.7 billion, while that in China fell 24 per cent to $11 billion. Investment in the US edged up 2 per cent to $9.6 billion, but Brazil slid 62 per cent to $1.1 billion and the rest of the Americas fell 17 per cent to $2 billion. South Africa saw the strongest performance, where investment in Q1 surged to $3.1 billion from almost nothing in the same quarter a year earlier.

Michael Liebreich, chairman of the advisory board at Bloomberg New Energy Finance, commented: "The big question, of course, is whether and how hard clean energy investment would be hit by the slump in oil and gas prices. These figures indicate the answer is not so much."

According to recent figures from the UN Environment Programme, global clean energy investments grew 17 per cent in 2014, reversing two years of continued decline.

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US solar sector races ahead

The US solar sector is on track for continued growth after a record 2014.

Siân Crampsie

Major energy companies have announced plans to build almost 1 GW of solar power capacity across the USA.

Duke Energy Corporation says it will add up to 500 MW of utility-scale solar in Florida by 2024, while plans for an innovative 750 MW natural gas and photovoltaic (PV) power plant in New Mexico have been outlined by Western Energy Partners.

In southern Utah, SunEdison has signed agreements to build three new solar power plants with a combined output of 262 MW.

The plans indicate another year ahead of strong growth for the US solar energy sector following a record year in 2014.

California showed the strongest levels of growth last year, adding 4316 MW of solar electric capacity, bringing total installed capacity in the state to 9977 MW. California has also become the first US state to generate more than five per cent of its annual electricity from utility-scale solar power.

Duke says that construction of the first solar power plant – outlined in its latest ten-year site plan – would start later this year and that it expects to complete around 35 MW of solar capacity by 2018.

The projects would enable the company to monitor the effects of solar energy on the grid as well as evaluate costs, Duke said.

Western Energy Partners says it expects to complete construction of its $1 billion solar-combined cycle plant in mid-2019. The combined cycle plant would produce 680 MW and solar panels the remaining 70 MW.

SunEdison last month signed agreements with PacifiCorp for the sale of energy from three solar farms in Utah. The projects are the 63 MW Granite Mountain Solar West plant, the 100 MW Granite Mountain Solar East plant and the 99 MW Iron Springs Solar plant. Construction of the power plants is expected to begin in the fall of 2015 with commercial operations expected in 2016.

Overall the USA installed 6201 MW of solar capacity in 2014, according to the Solar Energy Industries Association (SEIA). Solar accounted for 32 per cent of the USA's new generating capacity in 2014, beating both wind energy and coal for the second year in a row. Only natural gas constituted a greater share of new generating capacity.

GTM Research forecasts that the US PV market will grow 31 per cent in 2015, adding 8.1 GW of new capacity. The utility-scale segment is expected to account for 59 per cent of additions.

- Dong Energy has entered the US offshore wind sector through the purchase of the rights to develop up to 1000 MW off the coast of Massachusetts. The project area covers 760 km^2 located 90 km from the coast with water depths of 40-50 m.

Sun shines on Chilean solar

- EDF EN enters Chilean solar market
- Rame grows wind plans

Siân Crampsie

A 146 MW solar power plant in Chile's Atacama Desert region will help the country to meet its renewable energy objectives, say its developers.

Marubeni Corporation and EDF Energies Nouvelles have signed a partnership agreement to invest in the planned photovoltaic (PV) plant, known as Labertino. The project will be owned equally by Marubeni and EDF EN, which says it has secured long term project financing from a pool of local and international banks.

The Labertino project will be one of the world's largest solar plants selling its electricity output on a merchant basis, and also marks EDF EN's entry to the Chilean market.

"By expanding into Chile just after Brazil lately in the South American continent, EDF Energies Nouvelles has achieved one of its objectives to develop its activities in emerging markets with a high development potential," said Antoine Cahuzac, CEO of EDF EN.

He added: "Laberinto, a sizable solar project, is a perfect example. We are proud to see that the quality of this project… is recognised by a pool of high profile lenders and by a co-investor like Marubeni."

Labertino will be connected to the Northern Interconnected System (SING) of Chile, which has set a goal of generating 20 per cent of the country's power from renewable resources by 2025.

Other solar projects planned in the country include two solar farms with a combined capacity of 34 MW being developed by Colombian construction firm Grupo Odinsa. One of the projects will have a capacity of 14 MW and will be built in the Atacama region in conjunction with Chinese firm TBEA Co.

- Rame has announced plans to increase the capacity of its wind projects in Chile by a net 15 MW to 133 MW. It has added a new 24 MW wind project to its portfolio to improve cost efficiencies and economics, and as a result will not go ahead with the construction of the 9 MW Punta Chome wind project. The rights to develop Punta Chone have been sold to EREN Developpement (EREN), it said.

Climate plans face legal test

US President Barack Obama's plans to implement rules to cut greenhouse gas emissions last month survived a major legal challenge.

A panel of three federal judges for the US Court of Appeal for the District of Columbia heard arguments in April against government plans to reduce carbon emissions but said that it could not take action because the proposed regulations were not yet finalised.

The court heard two challenges to the Environmental Protection Agency's (EPA's) proposed rules to put strict emission limits on both new and existing coal fired power plants. The lawsuits – one from a coalition of 15 states and another brought by Murray Energy Corp., the USA's largest privately held coal mining company – are part of a growing political attack from opponents who say the move is illegal and will kill jobs, cripple demand for coal and drive up electricity prices.

During arguments, two of the three judges on the panel appeared highly skeptical of the plaintiffs' efforts to stop the regulation before it is complete, according to reports. However, the panel made it clear they would be willing to review the regulation once it is finalised.

The rule proposed by the EPA last year requires states to cut carbon emissions by 30 per cent by 2030 and is a key part of Obama's commitments to combat climate change. It gives customised targets to each state, leaving it up to them to draw up plans to meet the targets.

EPA officials say the rule would protect public health, fight climate change and lower electricity costs by 8 per cent by 2030.

Cap and trade pledge in Canada

Ontario and Quebec have signed an agreement to implement a cap-and-trade emissions trading system but have revealed few details about the initiative.

Ontario Premier Kathleen Wynne visited Quebec last month to sign the deal with Quebec Premier Philippe Couillard ahead of a climate change summit in Quebec City but said that the details of the scheme, including the mechanism and costs, would be worked out at a later date.

The agreement comes seven years after Quebec, Ontario and California signed the Western Climate Initiative (WCI) and means that 75 per cent of the Canadian population will live in a province that has some form of carbon pricing.

British Columbia has a carbon tax that includes a seven-cents-a-litre levy on gasoline. Alberta's version of carbon pricing targets large industrial emitters, requiring them to reduce their carbon intensity by 12 per cent relative to their baseline level.

Reform boosts Mexico investment

Mexico's ambitious electricity market reforms are helping the country to meet growing electricity demand.

Last month engineering group Sener and OHL Industrial said they had won a contract from national electricity utility CFE to build a major new combined cycle power plant in the north of Mexico.

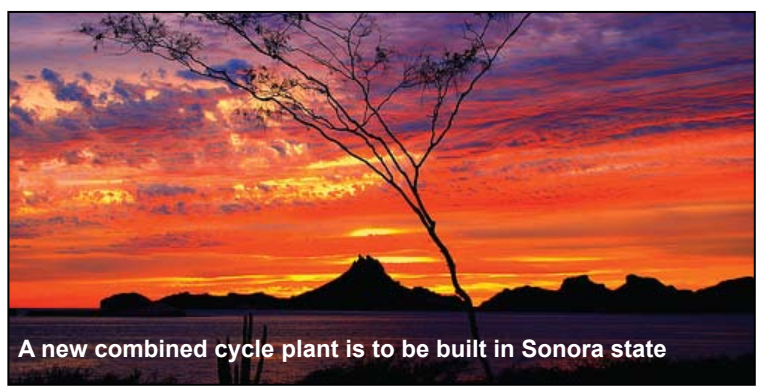
The project will be the third major power plant contract to be executed by the two Spanish firms in Mexico and follows the outlining of plans by other major private energy firms to invest in Mexico's electricity sector.

OHL and Sener will build the 770 MW Empalme I combined cycle plant in Sonora state under a turnkey contract worth $477 million. The plant will use two Siemens H-class gas turbines and will supply electricity from November 2017 to northern Mexico, where energy demand is growing at 3.6 per cent per year.

Earlier this year, Iberdrola, Gamesa and Acciona announced that they would invest a combined $14 billion in Mexico's energy industry between 2015 and 2018. Another Spanish firm – Abengoa – was awarded a contract by CFE to build Norte III, a 924 MW gas-fired combined cycle plant.

The plans were announced after energy reform legislation was passed in 2014. Further reforms affecting the electricity sector are planned in 2016.

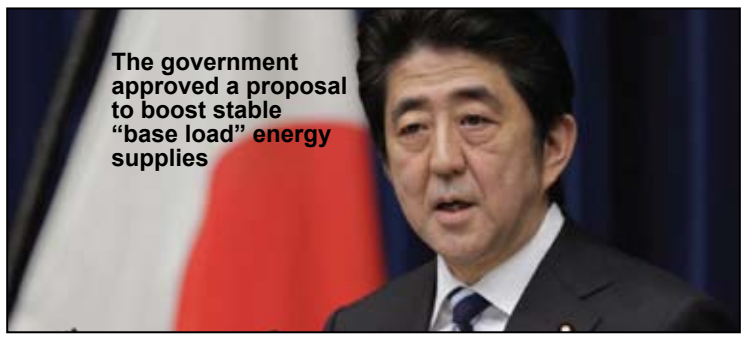
These reforms are likely to include a long-term auction process, improved grid access and some level of competition in generation, transmission and distribution. A means of encouraging more investment in renewable energy could also be included, and there have been calls for the introduction of retail competition.



A new combined cycle plant is to be built in Sonora state

Uncertainty clouds Japan's GHG emissions targets

Japan is coming under fire for what some think are unambitious emissions targets, writes **Syed Ali**



The government approved a proposal to boost stable "base load" energy supplies

Japan is considering setting a target of reducing greenhouse gas emissions by at least 20 per cent by 2030 from 2005 levels. However, the target is causing concern at home and abroad, being labelled by some as unambitious.

Japan is planning to announce its emissions reduction targets in June as part of efforts to reach a new international deal to fight climate change later this year.

The target, still a source of conflict within the government, is being considered following an estimate by the International Energy Agency that Japan can reduce its carbon dioxide emissions by 24 per cent.

Samantha Smith, Leader of WWF's Global Climate and Energy Initiative, reacting to media reports said: "The target of 20 per cent reduction compared to 2013 is equivalent to only 10 per cent reduction compared to 1990 levels. A 20 per cent cut below 2013 levels by 2030 would be unacceptably unambitious, given Japan's historical responsibility and its capacity to drive action on climate change."

The debate continues as Japan revealed its latest emissions figures. Last month the Environment Ministry revised the country's greenhouse gas emissions in fiscal 2013, saying the amounts totalling an equivalent of 1408 million tons of carbon dioxide were the second worst on record.

Preliminary figures released by the ministry in December showed that the emissions totalled an equivalent of 1395 million tons of CO_2, the worst since fiscal 1990, the earliest year for which comparable data are available.

The rise in emissions has been caused by the shutdown of the country's nuclear reactors following the Fukushima accident.

Japan's ruling party wants to revive nuclear power and see it eventually make up a fifth of electricity generation, a move that is widely opposed by the public.

A panel of Prime Minister Shinzo Abe's Liberal Democratic Party approved a proposal in a closed-door session last month that would boost stable "base load" energy supplies – nuclear, coal, hydroelectric and geothermal – to about 60 per cent by 2030 from 40 per cent now, according to reports. The *Asahi* newspaper said this could only be achieved by getting nuclear back up to 20 per cent of the energy mix.

The news that the government is continuing to support coal is also likely to cause some concern at home and abroad. Internationally there have been mounting protests, as Japan continues to finance the building of coal-fired power plants with money earmarked for fighting climate change. In April the *Associated Press* revealed that two new projects financed by Japan were under way in India and Bangladesh.

Meanwhile, last month it was reported that Kansai Electric Power Co. will build a large coal-fired power plant in Chiba Prefecture, east of Tokyo, jointly with oil company Tonen-General Sekiyu K.K. Although base load capacity is needed, the plant will do little to curb soaring emissions.

Sources familiar with the matter said Kansai's foray into the capital region has been made possible by market liberalisation. Japan's retail electricity market, which has been monopolised by 10 regional power companies, is set to open up to competition in April next year.

In preparation for the competitive market, the government recently established a nationwide grid management body.

The entity, called the Organization for Cross-regional Coordination of Transmission Operators, is aimed at coordinating power supply with demand across the country and ensuring stability of electricity supply even in the event of emergencies.

The organisation will oversee plans to enhance the national transmission grid to facilitate power interchange among suppliers.

Yoshitsugu Kanemoto, President of the organisation said improving the power system to promote renewable energy is also one of the body's most important missions. Plans to increase clean energy as much as possible following the Fukushima disaster have been hampered due to transmission capacity problems.

A ministry official said last month that Japan must move to both conserve more energy and tap more renewable energy in response to the latest figures for GHG emissions.

According to a new study from the Ministry of Environment, Japan has the potential to triple the amount of electricity it gets from renewable sources by 2030 depending on energy policies.

According to the document, renewable energy from solar, wind, hydro, geothermal and biomass could provide between 241.4 and 356.6 TWh by 2030. Wind energy (onshore and offshore) has the potential to reach 64.6TWh by 2030.

■ Toshiba Corp. said it aims to boost sales of its hydrogen energy business to 100 billion yen ($840 million) by fiscal 2020 from 15 billion to 20 billion yen expected in fiscal 2014. The Japanese electronics maker said it will put into practical use a system that stores hydrogen extracted from water through methods powered by renewable energy sources, such as solar and wind, and use it to create electricity when necessary.

Companies seek renewables opportunities

International project developers and corporations alike are increasingly seeking to invest in Asia's renewables sector.

In April Enel Green Power (EGP) S.p.A. and Marubeni Corporation signed a two-year memorandum of understanding (MoU), to cooperate in evaluating potential business opportunities in renewable projects mainly in the Asia-Pacific region.

The MoU will address geothermal, wind, solar and hydro projects mainly located in the Philippines, Thailand, India, Indonesia, Vietnam, Malaysia and Australia as well as other areas that may be identified at a later stage.

Only projects in the development phase will be considered, therefore projects under construction and operating assets will be excluded from the scope of the cooperation.

Meanwhile RE100, a global initiative that recruits and supports major companies to use 100 per cent renewable power across their operations, announced a partnership with the China Renewable Energy Industries Association (CREIA) as part of a major new drive to help companies in China adopt renewable energy.

The report titled, 'RE100: China's Fast Track to a Renewable Future', identifies areas of greatest growth and proven opportunities available to corporations looking to invest in clean energy.

Published by The Climate Group, the report says corporate demand for renewable energy is quickly growing in China. It stated that the country is already the largest investor in the renewable energy market, noting that 2014 alone saw an increased investment of $89.5 billion.

Thailand to move away from gas

The proportion of natural gas for power producing will be cut from 70 per cent to 40 per cent under Thailand's new power development plan (PDP) 2015-36.

New generating capacity will come from renewable energy and clean coal, as well as purchasing power directly from neighbouring countries.

The new PDP targets an additional 57 500 MW by the end of 2036, taking the country's power capacity to 70 400 MW. This excludes 24 670 MW produced by ageing generators that will be retired at the end of the plan.

The plan is based on GDP growth averaging 3.94 per cent during the course of the plan, slightly below the 4.41 per cent GDP growth used in the previous PDP in 2010.

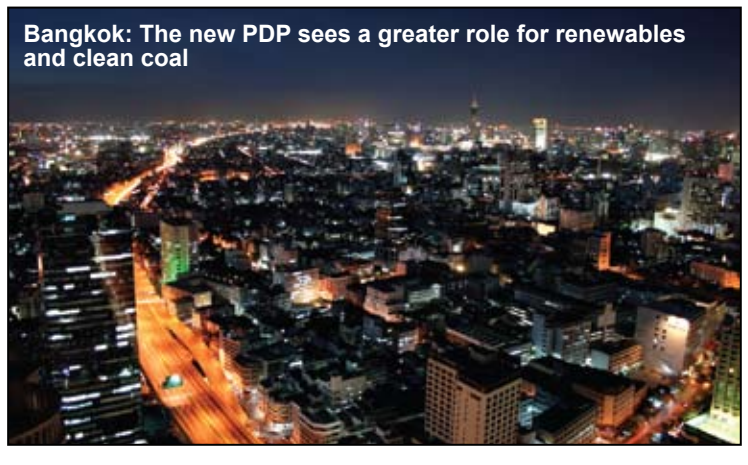
By the end of the PDP, the proportion of renewable energy will rise to 20 per cent from the current 8 per cent. Clean coal will provide 25 per cent, up from 7 per cent, while imported power will rise to 20 per cent from 7 per cent.

Permanent Energy Secretary Areepong Bhoocha-oom urged the private sector to participate in the PDP by investing in renewables when the government opens up licences for up to 12 000 MW over the next 20 years.

Under the Plan, 6000 MW will come from solar, 5500 MW from biomass, 3000 MW from wind, 600 MW from biogas and another 500 MW from waste-to-energy projects.

Clean coal projects will be assigned to the Electricity Generating Authority of Thailand, which will generate an additional 8000 MW from coal.

Separately, a study published last month by researchers from Thailand and Canada shows that the Bay of Bangkok has a technical wind potential of 3000 MW, which could generate 6 TWh/year. The whole Gulf of Thailand has a potential of 7000 MW that could generate 15 TWh/year.



Bangkok: The new PDP sees a greater role for renewables and clean coal

Solar firms ride UK's "rollercoaster" policies

UK Solar developers have welcomed the removal of barriers to investment in the rooftop sector, but face a dearth of opportunity in the utility-scale project segment thanks to the end of RO funding.

Siân Crampsie

Solar companies in the UK have welcomed plans by the government to remove barriers to investment in rooftop solar schemes by property owners and developers.

The government announced at the end of March that it will be possible, from 2019, for building-mounted solar panels to be moved from one property to another without the loss of feed-in tariffs (FITs).

In addition, it has announced that schemes of up to 1 MW in size will no longer require full planning approval.

The inability to move solar panels from one building to another – in the event of a homeowner or business moving premises, for example – has been a major barrier to investment in rooftop solar in the UK, especially in the commercial rooftop segment.

The government also hopes that relaxing planning permission requirements will kick-start development in the commercial rooftop sector, which is underdeveloped compared with the domestic rooftop and large-scale ground-mounted segments.

"These changes represent a vital recognition on the part of the government of the role solar PV has to play in helping the UK to meet its renewable targets," said Giles Hanglin of planning consultants Savills Energy. "In easing both the planning and building transference involved in the process, these amendments are set to make a huge difference in driving greater commercial use of this renewable energy."

The Renewable Energy Association (REA) said that the "simple but effective" changes would "make it much easier" for commercial properties to self-generate using solar PV. "Solar installed on commercial buildings has the potential to generate significant amounts of clean electricity, yet it is a considerably underdeveloped area, and the rigidity of the planning system has long been a major barrier to its progress," said REA Chief Executive Dr Nina Skorupska

Solar developers hope that the changes will provide them with new opportunities following other changes to government policy that brought the end of renewables obligation (RO) funding for large-scale ground-mounted solar projects at the end of March.

PV projects over 5 MW in size in the UK must now compete with onshore wind energy for contracts for difference (CFDs), the new support mechanism for large-scale renewable energy projects.

As the end-March deadline loomed, the large-scale ground-mounted segment saw a boom resulting in an estimated 1.5 GW of PV capacity being added in the first quarter of 2015 alone.

This compares to 1.3 GW added in the year to the end of March 2014. The year to the end of March 2015 saw a total of 2.2 GW added, according to IHS Technology.

In the next financial year, however, no new PV projects over 5 MW will be built, except for about 150-200 MW allowed under an extended deadline for projects delayed by grid connections.

The Solar Trade Association (STA) said that it was a "tragedy" that no new large-scale farms would be built in the next year. "As we predicted these types of projects could be cheaper than gas in just 3 years with stable policy support," said STA head of external affairs Leonie Greene.

STA believes that the developers active in the UK's solar energy sector would have to "rewrite their business plans" because of the government's "rollercoaster" policies. Many will focus on solar farms in the sub-5MW category while others will look for opportunities in the commercial roof-mounted sector.

According to the European Photovoltaic Industry Association (EPIA), the UK was the "only bright spot" in Europe's PV sector in 2014.

Europe installed around 7 GW of PV capacity last year, with the UK leading with around 2 GW, up more than 50 per cent on the previous year. EPIA has called for a more stable policy framework for solar energy across Europe so that the region can take advantage of the resource.

Network links boost UK connections

- NSN link starts construction phase
- France-Spain interconnector commissioning

National Grid and Statnett have signalled the start of the construction phase of the world's longest interconnector, a 730 km link between the UK and Norway.

The two transmission firms have signed the ownership agreement for the NSN link, which will be the first electricity link between the two countries and will have a capacity of 1400 MW.

The move comes just weeks after National Grid and Belgium's Elia signed a joint venture agreement to build the Nemo link, the first electricity interconnector between Belgium and the UK.

Both projects have been awarded Projects of Common Interest (PCI) status by the European Commission, indicating their significance for the development of Europe's electricity grid and for Europe's other key energy sector goals.

PCI projects can benefit from accelerated licensing procedures, improved regulatory conditions and access to financial support. Nemo and NSN will help to improve energy security in the UK, Norway and Belgium and enable the countries to share resources such as hydropower and offshore wind energy.

"Not only is this a technically impressive project where we will set a new world record, it is also an important contribution to the increase of renewable energy production on both sides, and thereby an essential part of the future electricity system," said Auke Lont, Statnett CEO, of the NSN link. "In addition it will contribute to security of supply and value creation for both Norway and the UK."

NSN will be built at a cost of €2 billion and will start operating in 2021. The UK already has connections with France, the Netherlands, Ireland and Northern Ireland totalling around 4 GW of capacity – equivalent to 5 per cent of its total generating capacity.

The European Commission is proposing that countries should attain an interconnection level of ten per cent in order to achieve a single market with closer cooperation and greater sharing of resources.

Elsewhere in Europe, Siemens has started commissioning the converter stations for a high voltage direct current (HVDC) link between France and Spain.

The link is due to enter operation in mid-2015, when it will double the current exchange capacity between the two countries from 1400 MW.

Commission approves German wind plans

The European Commission has given its approval to plans in Germany to build 20 offshore wind farms.

The Commission said in April that the country's plans to support the development of 17 wind farms in the North Sea and three in the Baltic Sea were in line with state aid rules and that they would also further EU energy and environmental objectives.

The wind farms will be supported by a premium paid to operators on top of the market price for electricity. With a combined capacity of up to 7 GW, the projects are a key element of Germany's transition to renewable energy.

However last month it emerged that consent applications for around 30 far offshore wind farms in the North Sea had been put on hold.

According to *ReNews* magazine, the offshore wind projects were not included in Germany's latest offshore grid development blueprint drafted by the network agency, BNA. The projects, which lie some 130 km from shore, are not necessary to meet the country's 2030 target for offshore wind of 15 GW.

Data in Germany shows that the country's switch to clean energy is having an effect on carbon emissions.

The Umweltbundesamt (UBA) environment agency has reported that carbon emissions fell for the first time in three years, by 41 million tonnes, or 4.3 per cent. Renewable energy accounted for 27.8 per cent of power consumption in 2014, up from 6.2 per cent in 2000, while the closure of fossil fuel-fired power plants has also had an impact on emissions.

At the end of March, E.On, the owners of the Irsching 4 and 5 gas-fired power plants announced plans to close the units because they "have no prospect of operating profitably". The two combined cycle plants came into operation in 2011 and 2010, respectively, and supplied no merchant power at all in 2014 because of low wholesale power prices and an increase in subsidised renewable energy.

Offshore support: wind farms will be supported by a premium paid to operators on top of the market price for electricity

Carbon policies make their mark

The use of tools such as carbon permits and carbon taxes to limit emissions of greenhouse gases is having a significant impact on industries around the world, according to Moody's, the investment rating firm.

The firm says that the impact of carbon reduction policies is not only rising globally, but is also driving innovation and change across many industrial sectors as companies adapt to new risks and liabilities.

"An increase in 'direct carbon liabilities', such as carbon permits and/or carbon taxes, as well as the emergence of disruptive technologies, such as solar power, are already having a tangible impact on rated companies in select carbon-intensive industries," said Brian Cahill, the Managing Director for Moody's Fundamental Group in Asia Pacific.

"But such policy action is also driving innovation and change across many industrial sectors; for example, technological innovation is very advanced in power generation where renewable energy, especially in parts of Europe, is established," said Raffaella Altamura, a Vice President and Senior Analyst based in Moody's Corporate Finance Group in Europe.

However even the most affected sectors enjoy some mitigating factors, says Moody's. For example, in the power generation sector, regulated utilities are likely to experience some protection through adjustments to regulation, and thermal coal producers will continue to enjoy the growth of demand in emerging markets such as China and India.

Turkey marks Akkuyu construction

■ Parliament approves Sinop ■ Blackout hits Turkish cities

The consortium proposing to build a new nuclear power plant at Sinop in Turkey is to move forward with a feasibility study after the country's parliament approved the project.

The Japanese-French-Turkish consortium says that it will carry out a number of assessments, including geological surveys, seismic hazard and environmental impact assessments in order to determine the suitability of the proposed construction site.

The news came as Turkish Energy Minister Taner Yildiz reaffirmed the government's commitment to the development of three nuclear power plants in the country.

He made the comments at a ceremony to mark the start of construction of Turkey's first nuclear power plant in Akkuyu, Mersin province.

Yildiz and Sergei Kiriyenko, head of Russian firm Rosatom, laid the foundation stone at the Akkuyu project, which is due to be completed by 2020 and will have four power units with a capacity of 1200 MW each.

The $20 billion project is being built by Rosatom but has been criticised by environmentalists who have raised concerns about safety issues and the plant's impact on local wildlife. Greenpeace says that the seismic assessment of the Akkuyu site had been "totally inadequate".

Yildiz said that Akkuyu will meet 28 per cent of Turkey's demand for electricity. "Development cannot happen in a country without nuclear energy," said Yildiz. "If we had built this power station 10 years ago, we would have saved $14 billion in natural gas purchases."

The Sinop plant is due to be completed by 2023 and will consist of four ATMEA1 reactors on Turkey's Black Sea coast. ATMEA1 is a generation III+ pressurised water reactor (PWR) designed by Areva and Mitsubishi Heavy Industries (MHI). The other project partners are Itochu, GDF Suez and Turkey's EUAS.

The Sinop units are likely to be the first ATMEA1 units built.

The government has not yet decided on the location for the proposed third nuclear plant, but says that it is needed in order to improve energy security.

At the end of March, dozens of Turkish cities and provinces were hit by a power outage that disrupted transportation, services and businesses. Turkey's electricity transmission company, TEIAS, said that a problem with the power network was to blame for the blackout.

■ French renewable energy company Akuo Energy has agreed up to $100 million in World Bank financing for the construction of a wind farm in Turkey. The 77.5 MW Baglar RES park near Konya, Central Anatolia region, will comprise 24 GE wind turbines. The project loan will be extended by the International Finance Corporation.

GWEC data shows recovery in wind

Markets in non-OECD countries have once again led growth in the global wind energy industry, according to the Global Wind Energy Council (GWEC).

In its latest Global Wind Report publication, countries such as China, Brazil, Mexico and South Africa outstripped the traditional markets in Europe and North America in terms of growth in 2014.

Global installed capacity of wind energy reached 370 GW at the end of 2014, according to GWEC, with a record 51.5 GW of new capacity added in that year. The figures show a "solid sign" of recovery in the market after a slowdown in 2013 and stable growth is projected for at least two years.

"Wind power is the most competitive way of adding new power generation capacity to the grid in a rapidly increasing number of markets around the world, even when competing against heavily subsidised incumbents," said Steve Sawyer, GWEC Secretary General. "Wind is a rapidly maturing technology, with proven reliability and competitiveness. Not only the low prices but also the cost-stability of wind power makes it a very attractive option for utilities, independent power producers and companies who are looking for a hedge against the wildly fluctuating prices of fossil fuels."

China installed 23 GW of new wind power last year, bringing its cumulative total to more than 114 GW, and Brazil was the world's 4th largest market in 2014, and entered the top 10 in cumulative rankings for the first time. The African market took off in 2014, and Germany, Chile, Canada and Turkey also had record years.

The US market also recovered in 2014, while Europe grew marginally with nearly 13 GW of new capacity additions. Germany added 5.2 GW of capacity in 2014, cementing it as the leading market in the region.

Looking ahead, GWEC expects the market to top 50 GW again in 2015, and reach 60 GW per year by 2018. Growth will continue to be led by China, which seems on track to meet its 200 GW well ahead of the government's target of 2020; and the Indian market is expected to grow substantially in the years ahead. Latin America is becoming a strong regional market, led by Brazil, but with Mexico catching up quickly.

Strike action hits Medupi

Unrest at Eskom's flagship coal fired power plant project will cause further delays.

Siân Crampsie

Industrial action at the Medupi coal-fired power plant in South Africa could cause further delays at the project.

A stand-off between Eskom contractors and workers means work at the site has effectively ground to a halt.

Local reports indicate that workers have defied a court order obtained by Eskom contractors in April forcing them to return to work. The National Union of Metalworkers of South Africa (NUMSA), one of the unions representing workers at the site, says that their members should be paid a bonus for completing the power plant's unit six, and is also demanding improved accommodation.

The disruption comes as state utility Eskom grapples with a strained grid. The firm is implementing regular load shedding events because of a low reserve margin and the need to carry out essential maintenance on power plant units.

Statistics South Africa said last month that the country produces less electricity than it did a year ago.

In its latest report on electricity generation, the statistics body notes that electricity generation dropped by 2.1 per cent year-on-year in February 2015. Eskom itself produced 2.6 per cent less electricity.

In April the South African government said it would accelerate and expand the country's Renewable Energy Independent Power Producer Procurement Programme in order to boost generating supplies.

Tina Joemat-Pettersson, Minister of Energy, said that this would be achieved by allocating additional capacity in the fourth bid window of the programme and issuing a request for further proposals for an expedited procurement process of 1800 MW.

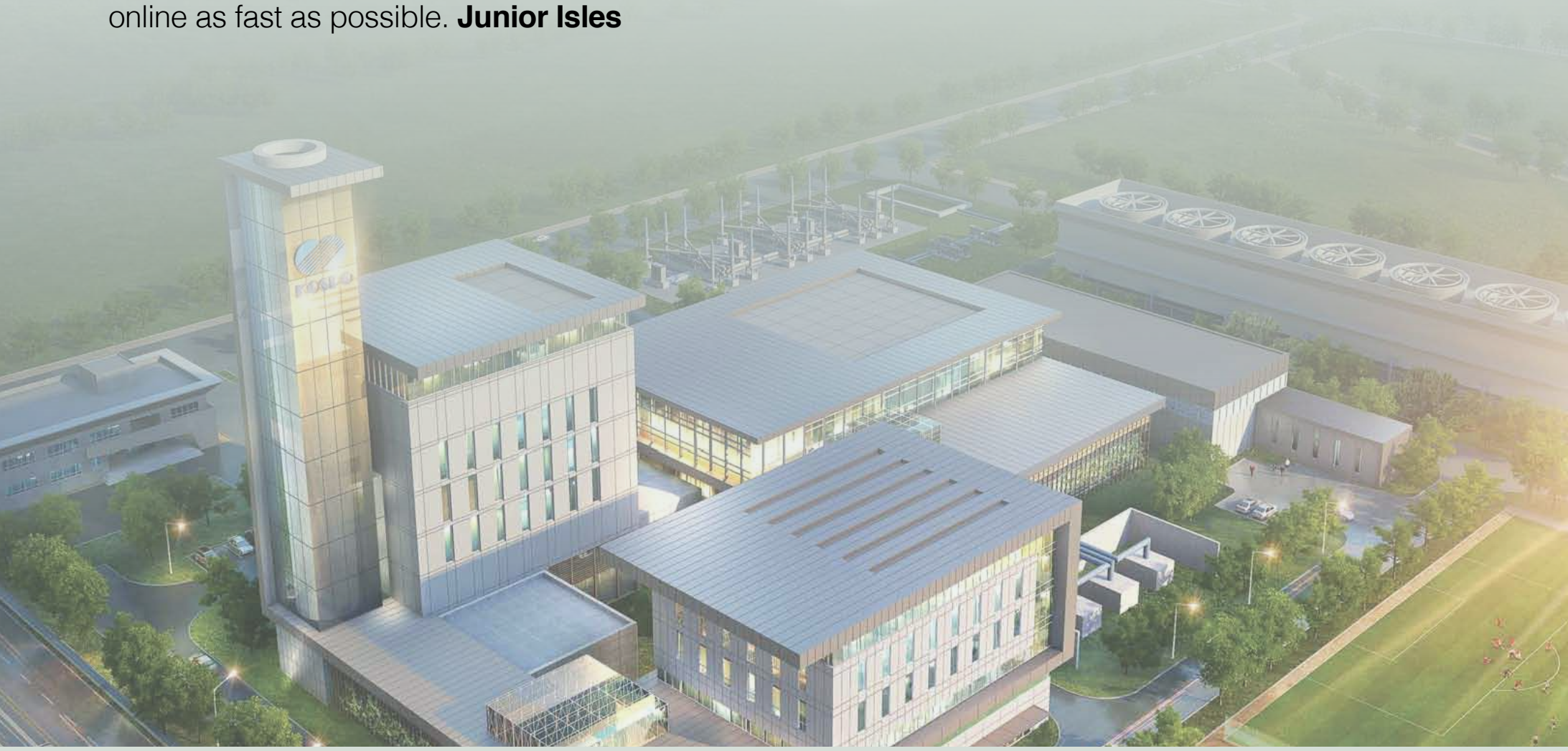
Medupi is one of the firm's flagship power plant projects but was originally due to start operating in 2013. The first 800 MW unit at the 4764 MW plant was synchronised to the grid at the end of March, but the industrial action at the site is likely to delay commissioning of the remaining units, adding to Eskom's woes.

The industrial action started at the end of March, when around 1000 workers went on a one-day strike in protest over poor living conditions and pay. Eskom said that property was damaged during the strike and closed the site for a day to assess the damage. Some of the striking workers were then dismissed, leading to further protests.

Special Project Supplement

Fast track to high efficiency

The recent start of commercial operation of the Ansan advanced gas turbine combined cycle power plant marks another milestone in South Korea's drive to bring new highly efficient generating capacity online as fast as possible. **Junior Isles**



November last year saw the start of commercial operations at the Ansan project in South Korea – the fourth combined cycle power plant based on Siemens' 8000H advanced gas turbine technology to begin operation in the country.

The 834 MW plant, which was one of the fastest to be built to-date, represents another milestone in the deployment of H-technology in the country. It also illustrates Siemens' excellent project management and execution capabilities.

Siemens has enjoyed tremendous success with the 8000H in South Korea, highlighting the fact that although state-of-the-art, it is now proven technology.

Starting with the Dangjin 3 (formerly Bugok 3) project in 2013, the company has so far sold 15 of these SGT6-8000H gas turbine models for eight projects in the country. This corresponds to an installed power generating capacity of 6.3 GW. Five projects – Dangjin 3, Andong, Ansan, Daegu, and Posco Units 7, 8 and 9 – have now been completed, with the other three scheduled to begin operation in the course of 2016 and 2017.

Korea's decision to put such faith in high efficiency gas turbine-based power plants is being driven by a combination of limited domestic resources, falling electricity reserve margin and a growing demand for district heating.

Due to its lack of energy resources, imported high priced liquid natural gas (LNG) has become popular over the last few years as the fuel to power its efforts to supply clean energy. Korea is one of the top energy importers in the world and relies on fuel imports for about 97 per cent of its primary energy demand. According to the Energy Information Agency (EIA), in 2013, the country was the second-largest importer of LNG.

The EIA also notes that South Korea's power generation has increased by an average of 5 per cent annually over the past decade, and the Korea Energy Economics Institute (KEEI) expects demand to grow by 3.7 per cent annually through 2017.

Capacity additions, however, have not kept pace with demand and power reserve margin has therefore 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 in 2012. According to Korean Power Exchange (KPX), the reserve margin dropped to a minimum of 3.8 per cent in 2012.

"In the last years, there has therefore been a need for a huge amount of new capacity on the market said Erik Zindel, Siemens' Director of Marketing Asia & Middle East. "This is why the government has moved to significantly increase the number of projects, many of which are now coming on line."

The government is aiming to increase the reserve margin to 22 per cent of the total capacity by 2027 and has therefore been adding around 3-4 GW annually of capacity for the last several years. 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 2013, 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.

During the last few years, a significant portion of new thermal generating capacity has been based on Siemens H-class technology due to its high combined cycle efficiency and therefore lower running cost per installed megawatt, especially when considering the high price of LNG. And with many of these projects being built as cogeneration plants, even greater fuel efficiency is achieved in line with Korea's drive to maximise energy efficiency.

> "The Ansan project illustrates Siemens' excellent project management and execution capabilities"

Ansan is one of these projects that produce both heat and power.

The Ansan plant is owned and operated by S-Power, a special purpose company formed by Samchully, Kosep and Posco E&C with Samchully as the majority shareholder.

The contract to deliver the project's power island was awarded to Siemens in 2012 by South Korean Posco Engineering & Construction Co. Ltd. (Posco E&C), an affiliate of Posco, one of the largest steel companies in the world. Posco E&C was responsible for the construction of the plant; Siemens delivered the core equipment in a 2+1 configuration.

The Ansan CHP project is located in the city of Ansan in Gyeonggi-do province southwest of the capital Seoul. Running on LNG, the plant has an electrical efficiency of more than 60 per cent. In addition to generating electricity, it also provides district heating for the inhabitants of Ansan. Combined heat and power production raises the overall fuel utilisation factor to over 75 per cent.

This makes the plant one of the most efficient and eco-friendly fossil-fuel-fired electricity generating plants in South Korea.

Under its contract scope, Siemens delivered the power island main equipment: two SGT6-8000H gas turbines, an SST6-5000 steam turbine, three SGen6-2000H hydrogen-cooled generators, and two Benson type heat recovery steam generators, as well as the entire instrumentation and control technology, SPPA-T3000. Siemens is also providing long-term servicing for the two gas turbines.

The project is based on what are widely recognised as the most advanced gas turbines currently operating in the world. The SGT6-8000H gas turbine – like the original SGT5-8000H 50 Hz version that broke the record for electrical efficiency in 2011 at the Ulrich Hartmann plant near Irsching in Germany – is a single-shaft turbo train design.

Since breaking the world record for combined cycle plant efficiency a significant number of operating hours

have been clocked up worldwide. The fleet of Siemens H-class gas turbines has achieved more than 150 000 cumulative equivalent operating hours. Siemens has now sold 46 H-class gas turbines worldwide. Sixteen of these machines are currently in successful commercial operation with a high degree of flexibility, starting reliability and operational availability, making this the most successful gas turbine of this efficiency class on the global market.

The gas turbine uses air as coolant as opposed to steam and requires no other external equipment such as coolers or boosters. This offers greater plant flexibility, as the gas turbine cooling system is fully decoupled from the water/steam cycle.

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. This built-up disc type rotor is yet another feature to increase the allowable load ramps and reduces start up time.

The 60 Hz version of the turbine is designed to generate 274 MW in simple cycle operation and around 410 MW in combined cycle – single shaft – 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 fully 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, identical in design to the 50 Hz version, 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.

According to Siemens, Ansan's NOx emissions of 7 ppm, achieved with a downstream SCR, are among the lowest in Korea. At the same time CO is kept to below 10 ppm, while CO_2 is about 310 g/kWh – the lowest in the market.

The 8000H has a four-stage turbine section and 13 compressor stages

Due to its high efficiency, Ansan, like all the other Siemens H-class projects in Korea has been operating in baseload for the last several months to meet the specific high demand in winter time. As the country brings more capacity on line, in the future some of these projects might operate in more of an intermediate regime. This, however, will not be a problem for these combined cycle units, as they are especially designed for this.

Hot gas from each gas turbine exhaust enters an associated three-pressure Benson (once-through) boiler to generate steam at 585°C. Benson technology avoids the use of a thick-walled, slow warming HP drum. When combined with the 8000H gas turbine, it enables fast start times compared with conventional combined cycle plants. This gives the plant the flexibility to cycle up and down quickly and reach full load in 30 minutes from a hot start.

Steam from the boilers is fed to the 280 MW steam turbine which has district heat extraction fed from the cross-over pipe connecting the steam path of the HP/IP section to the double flow LP section at 3.6 bar[a]/250°C.

Notably, Ansan is the first H-class 2+1 multi-shaft power plant in Korea. The decision to opt for this configuration was taken by Posco E&C after careful discussion with Siemens.

Lothar Balling, VP of global project management for Siemens Energy Solutions said: "Although we were supplying the power island, the choice of configuration was mainly the customer's decision.

"They believed it was the best option in terms of footprint and cost. Their plan is to run it mainly in base load, and so felt they would not see value from the benefit of the single-shaft configuration."

Balling explained that the merits of the single-shaft configuration versus multi-shaft is a "very old debate".

He noted that the three recently completed units for Posco Energy are single shaft as is the Dangjin 3 unit, Andong, Daegu and several others. At the same time, while Ansan is the first 8000H multi-shaft project in Korea, the upcoming Dangjin 4 and Jangmoon projects will also be multi-shaft.

"What is clear is that where there is a high requirement for flexibility in the market, i.e. operators have to shut down or ramp up quickly and frequently, the single shaft has an advantage.

"I think the customer saw the multi-shaft configuration as a better investment – considering he might not have to cycle up and down so frequently. For projects with single units it still remains the preferred choice.

"In terms of time for construction, there is little difference; perhaps slightly more time is needed for the second train in a single shaft design."

For Ansan, the time taken from ground breaking to first commercial operation date (COD) was just 24 months.

The project serves as a good example and reference of Siemens' project management and execution capabilities, which will be expanded to the region and to Korea as well.

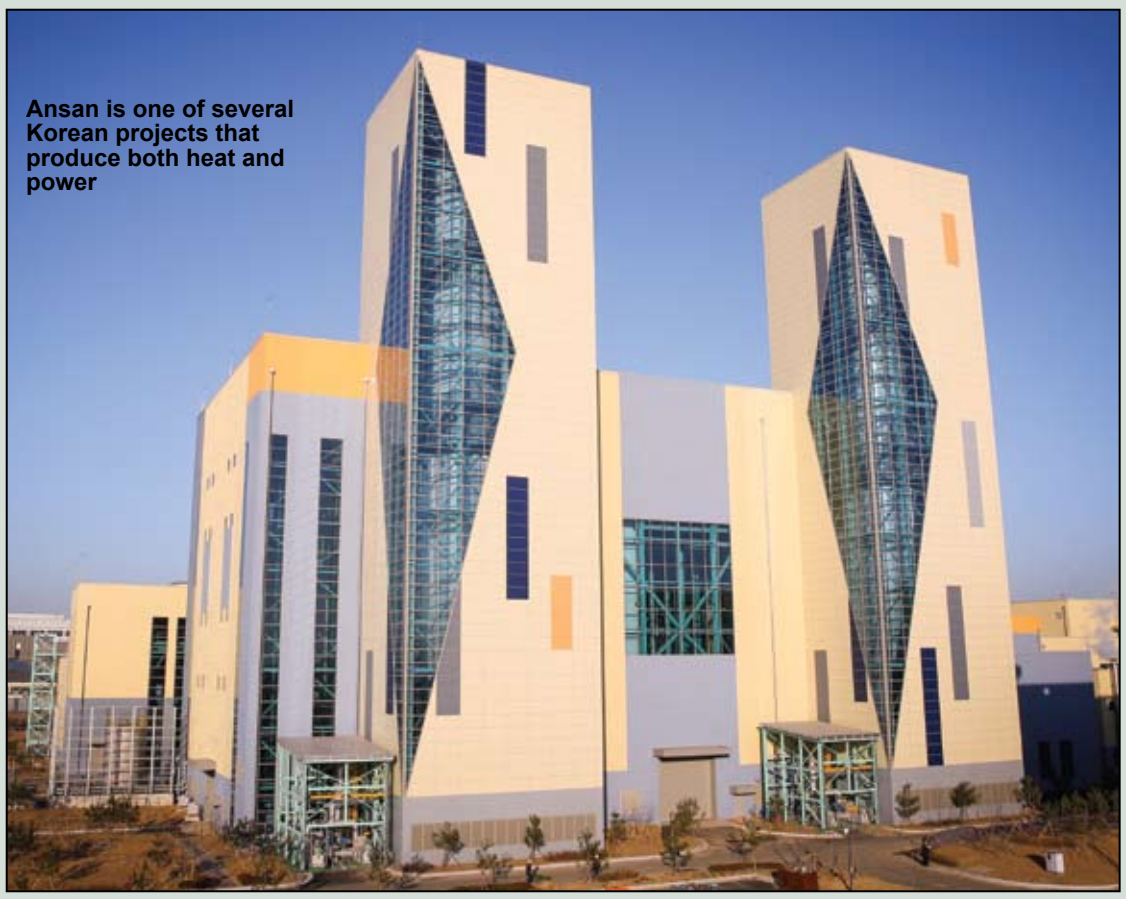
"Andong is the yardstick in terms of efficiency, constructability, quality, health and safety during construction, and operational reliability for the upcoming new projects," noted Balling.

Siemens attributes much of the speed with which these plants have been built to its special cooperation with the Korean customers and local arm of the EPC contractor. Siemens delivered the equipment, and civil and erection work was carried out by Posco E&C. Siemens then performed the full commissioning in close cooperation with owner and operator.

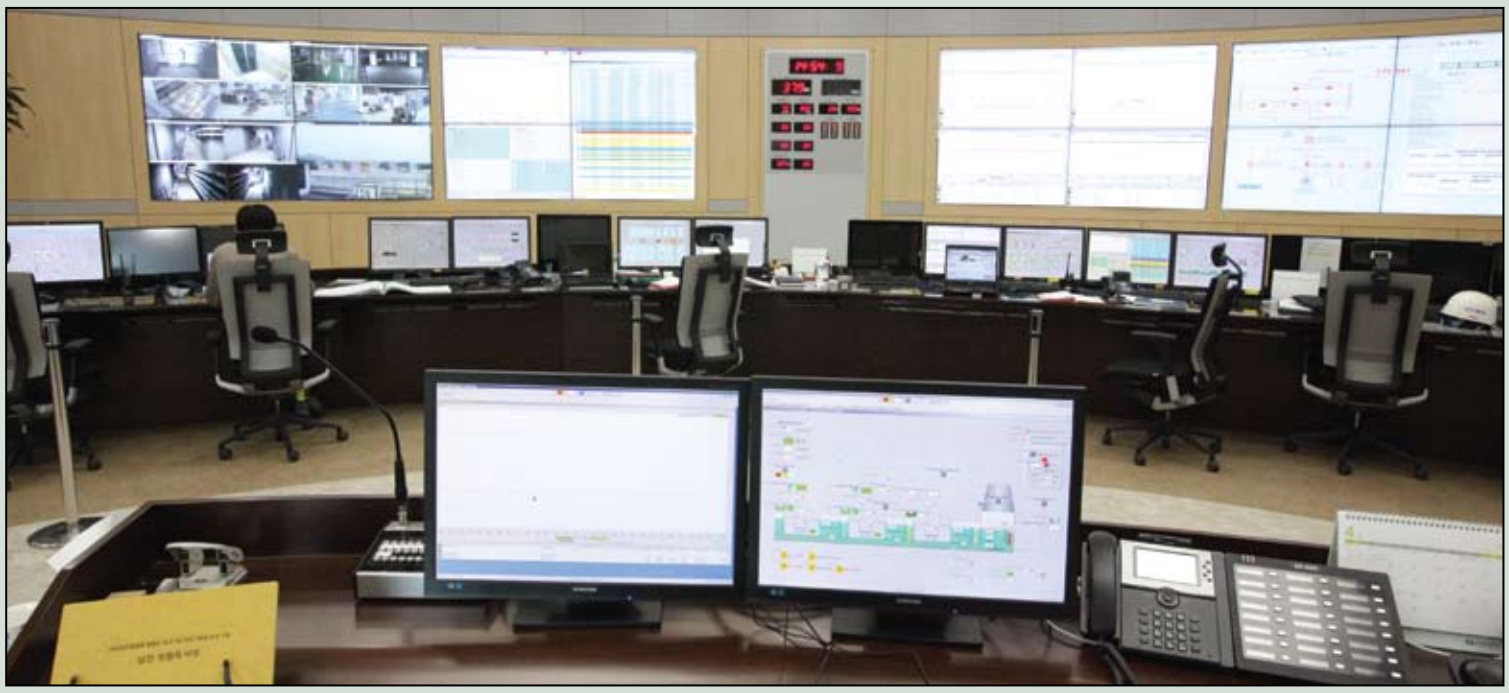
"Korea has a well-proven track record in construction – all the labour and tools are readily available for the civil and erection works. We worked have closely with Posco E&C on several projects now, which allowed very fast design or interface freeze [when needed]," said Balling.

There was also an improvement in the commissioning process. "Commissioning in Korea is done a little bit different than in the rest of the world. Hot commissioning could be achieved in a short period of time because the customer was extremely cooperative – accepting of tests, supporting with manpower and having a quick decision-making process."

Choosing Siemens as a partner for the power island, providing full performance guarantee wrap, site



Ansan is one of several Korean projects that produce both heat and power



Andong control room: Of the 10 units ranked highest in the dispatch order, seven of them are Siemens H-class units

support and handling commissioning integrated with customer and EPC, has proved to be a successful formula in Korea.

Zindel pointed out: "All of the projects were solutions sales, not just equipment sales. We worked with the EPCs to come up with the right and most effective solution."

Siemens says that working with Posco E&C on this basis has allowed Ansan, Andong and Posco Units 7, 8 and 9 to be constructed in a short period of time as well.

The contract for Ansan was signed on January 31, 2012 and site works began in October 2012. Erection of the boiler started in April 2013. The first gas turbine arrived on site in August 2013 and the second in September 2013.

Ignition of the first gas turbine took place in July 2014 and in August 2014 for the second gas turbine. Commissioning of the plant started in June 2014 with first steam to the steam turbine in October 2014.

The plant has been in commercial operation since early November 2014 and Siemens received the PAC in December 2014 (with hand over at the same time).

"It was all fairly straightforward – the two gas turbine generators, HRSGs with a steam turbine on the back end," said Balling. "The fancy part was the architecture."

Although a cooling tower is used for plant cooling, the plant has been styled to blend in with the environment.

Commenting on the importance of the architectural design, Zindel said: "There is a high sensibility in the country and people don't want to see a power plant built next to their property. This makes it very difficult for power plant owners to get permits for new plants. The only way to solve this is to either build on a brown field site or make a special effort on architectural design. We have also seen this at the Andong, Daegu and Posco projects as well."

At Posco Units 7, 8, and 9, however, designing the plant so it was not an eyesore was not the only challenge. The Posco plant, which consists of nine Siemens units in total, is built in an area between Incheon Airport and downtown, where there are a number of Siemens gas turbines.

The usual approach is to have a powerhouse for each single-shaft unit but space restrictions called for a tailor-made design for Posco 7, 8 and 9. "We had to specially design a single powerhouse for all three single shafts units," said Balling. "The powerhouse was essentially turned around so that overhead cranes run across the shafts instead of along the shafts."

According to Siemens, this was one example of how it has worked with customers in Korea to develop the right solution. "With most of the projects the customers have noted our adaptability to the requirements in Korea, the engineering, planning and quality of execution with a focus on EHS, and the good experience with commissioning," said Balling.

The high efficiency and reliability of the H-class combined cycle units is proving economically attractive for plant owners selling power in the Korean electricity market. Of the 10 units ranked highest in the dispatch order, seven of them are Siemens H-class units, with Posco Units 7 and 8 ranked first and third, respectively, and Ansan ninth, according to Siemens.

In the last 20 years, Siemens has sold more than 15 GW of capacity into the South Korean market and more than 12 GW of this is in operation. Notably, more than 6 GW of this total is based on Siemens' 8000H advanced gas turbine.

All the units in operation have run reliably and there have been no issues or need for major downtime since the start up of the first unit at Dangjin 3.

Commercial operation of Posco Unit 9 on January 17, 2015 has been the most recent milestone in Siemens' activities in Korea, which were boosted with the opening of its Asian and Middle East headquarters in Seoul in October 2013.

Since the opening of Siemens Energy Solutions Limited (SESL), the local staff and employees from the HQ have been gradually integrated into the projects, providing site support and commissioning support. Now the most recent projects – Jangmoon, Wirye and Dangjin 4 – are being solely executed from Seoul in terms of project management, engineering, purchasing and later on, commissioning support.

Seoul office will continue to be a big asset for the Asian and Middle East region, even as the market slows down in Korea.

Indeed the gas turbine boom that has been seen in recent years is expected to fade in the next couple of years.

According to a report issued by Moody's last year, power reserve margins in Korea are expected to surpass 15 per cent in 2015-16, as generation capacity additions outpace electricity demand growth. In addition, new coal and nuclear power plants will likely displace more expensive natural gas- and oil-fired units over the next two to three years.

This was echoed by Siemens, which sees less of a need for IPP projects in the coming years.

"We don't expect too many projects after the current ones are finished," said Zindel. "There will be some CHP projects cropping up but with reserve margins reaching double digit levels, the system marginal price will decrease significantly, making IPP projects less profitable."

Nevertheless, the Asian and Middle East HQ in Seoul will continue to serve other projects elsewhere in the region with its engineering, construction and commissioning capabilities.

"Being in the same time zone is also very useful on the sales side. Being in the same region means it's easier to communicate with customers because of the smaller time difference. Also we can now make decisions more quickly without needing permission from Germany," said Balling.

With Ansan now in operation, the Korean HQ will be firmly focused on completing the remaining projects – the experience gained at Ansan and the other projects will stand them in good stead.

Andong is the yardstick in terms of efficiency, constructability and operational reliability for the upcoming new projects

SIEMENS

Proven EPC and OEM expertise for cutting-edge integration

If you're planning a power plant project, there is no other EPC partner in the world that can provide you with such extensive, in-depth expertise and experience in the electricity market.

Reliability, honesty and trust – the guiding principles for partnership

As your partner, we run a trustworthy and reliable business. We create lasting value by helping you to achieve a compelling return on investment as well as managing every facet of your project. By respecting the value of strong partnerships, we have built up an extensive track record of satisfied customers around the globe.

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Keeping pace with competition also necessitates a continuous stream of innovative ideas along the entire process chain. With Siemens at your side, you benefit from an international team with decades of experience in integrating mechanical, electrical and chemical processes for fossil power plant installations. It's no wonder that we are constantly setting world records in efficiency, flexibility, reliability and execution excellence. With one common goal: your sustainable success and increased profitability.

Superb project management

Designing and building power plants to provide superior performance over the entire lifecycle is what we do. On average, our general project managers possess some 22 years of experience in the power generation industry. With their unique expertiswe, they bring an unmatched dimension of quality and security to your investment – including time schedules, project management as well as health and safety standards you can rely on.

All reasons that have earned us a reputation as your most trusted partner delivering cutting-edge integrated solutions at highest quality.

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New alliance focused on microgrids market


Spiesshofer: microgrid applications are expanding rapidly

ABB and Samsung SDI say that their new alliance will enable accelerated growth in the microgrid market.

The two firms have signed a memorandum of understanding to promote microgrid solutions around the world, using Samsung's lithium-ion battery technology and ABB's expertise in the grid sector.

In a statement ABB said that they would establish a global commercial alliance to develop and market modular and scalable microgrid solutions using lithium-ion batteries for energy storage. Such technology will broaden access to electricity in emerging markets and remote areas as well as improve grid reliability and resilience in developed markets, it added.

"Microgrid applications are expanding rapidly, both in emerging and developed markets, and are a key growth area in ABB's Next Level strategy," said ABB CEO Ulrich Spiesshofer.

"This strategic alliance allows us to combine our complementary capabilities and will enable us to bring optimised solutions to our customers," he added.

ABB will provide technologies for electrification, control optimisation, stabilisation and expert consulting services. Samsung SDI will provide the batteries and the battery management system.

"The alliance with ABB provides Samsung the basis to expand our global No. 1 position into the microgrids market," said Namseong Cho, President and CEO of Samsung SDI. "Together with ABB we will make our utmost effort to develop new products and to pioneer new markets to keep on being the world's best ESS company."

GDF speeds up growth strategy

- Energy transition spurs new structure
- Region-centred approach

Siân Crampsie

GDF Suez has launched a new project designed to speed up its growth strategy.

The so-called enterprise project will also help the energy giant to meet the demand of a rapidly changing energy environment, said its CEO Gérard Mestrallet, and will be based on the creation of 24 decentralised operational business units.

GDF Suez said that the energy transition towards renewable energy, natural gas, energy efficiency and network solutions had taken root in developed and developing countries, and that the company had to change in order to maintain its leading position and take advantage of new business opportunities.

The new business units will be based on geographical lines and have responsibility for controlling the company's operations in the region in question. France will have eight business units because of its size and level of regulation, and there will be five global steering business units for E&P. LNG, EMT, Tractebel Engineering and GTT. The last business unit will cover thermal generation in Europe.

Conergy targets Turkey

Conergy is expanding its operations into Turkey through a new joint venture partnership with Turkish CO Group.

The co-owned venture, RKT Conergy, will provide project development, financing, engineering, procurement and construction (EPC) as well as operations and maintenance (O&M) services to the Turkish market with a focus on commercial rooftop and ground-mount segment.

It will be well positioned to be a leading player in the Turkish market, Conergy said in a statement. The CO Group is part of the Cenay Group, which has extensive operations in various market sectors in Turkey.

"We look forward to expanding our global business to the Turkish market," said Alexander Gorski, Chief Operating Officer of Conergy. "Further, we are pleased to have the CO Group as our partner in this promising market."

"Conergy with its many years of solar experience and its high quality engineering standards is an ideal partner for us to grow a solar business in Turkey with," said Cengiz Guldamlası, owner of the CO Group. "We expect RKT Conergy to grow very rapidly."

Turkey is one of the most attractive emerging solar markets because of its increasing energy demand, high irradiance levels and FIT programme for renewables. RKT has already developed more than 800 MW of wind parks in Turkey to date.

In 2014, Conergy developed and installed 300 MW of utility scale projects, bringing its total installed capacity to nearly 1 GW and placing it among the largest solar companies globally. It also recently celebrated a return to profit, bringing in nearly $0.5 billion in revenue in 2014.

In the UK Conergy said it built and connected 12 large-scale solar PV projects in the first quarter of 2015, bringing its UK total to 22 solar farms with a combined installed capacity of 230 MWp.

It also announced last month that it had reached financial close on a 28 MW portfolio of solar projects in North Carolina, USA.

The deal "marks Conergy's focus on growing its US market share", said the firm in a statement. It collaborated with North Carolina-based Holocene Clean Energy on the projects, which are located across five locations within the state.

RWE purchase targets energy efficiency market

- RUMM roll-out in 2015
- Admin cut backs planned

RWE will roll-out a new energy efficiency solution to some of its largest clients in the UK later this year.

The company's UK subsidiary, RWE npower, will offer an innovative energy management service to British businesses after announcing the acquisition of Welsh tech firm RUMM last month.

RUMM, which was spun out of the University of South Wales, uses cloud-based data analytics to help businesses to monitor and control their energy in real-time. RWE says that it hopes to start offering the service in Q2 2015 with the goal of delivering energy efficiency at scale.

With energy prices in Europe remaining at low levels amid slack demand, RWE's move echoes that of other utilities looking to the energy efficiency sector to boost revenues.

In April the German firm told German media that it is planning to s hrink its administrative functions across the business as part of a cost-cutting programme.

RWE is aiming to make efficiency gains of €2 billion annually by 2017. *Handelsblatt* newspaper reported that RWE would make cuts in human resources, compliance, controlling, risk management and other areas.

RUMM said that working with RWE would enable it to "help some of the UK's biggest companies cut energy, cost and carbon".

RUMM's proprietary software is designed to capture and store energy usage data every half-hour to identify potential inefficiencies on customers' sites.

The software provides the basis for enabling significant energy reduction, has the capability to offer switch-off measures and also enables RUMM to offer a behavioural approach to energy management.

Capstone alters structure

Capstone Turbine Corporation says that a change to its organisational structure will lead to more innovation and creativity in the tech firm.

The microturbine manufacturer has flattened its organisational structure, a move that it believes will also help to reduce operating costs and increase adaptability.

The new structure will eliminate three executive positions and will also pass on greater responsibility to lower level employees. Its workers will be more motivated to help the company achieve its goals and the flat structure will also cultivate accountability, better communication, promote organisational flexibility and improve response times to project deadlines.

Capstone's Executive Vice President and Chief Financial Officer (CFO) Edward Reich will be leaving the company to seek other opportunities. Jayme Brooks has been newly promoted to Chief Financial Officer and Chief Accounting Officer from her long-standing role as the company's Vice President of Finance and Chief Accounting Officer as the two positions are being merged into one leadership role.

"In light of the macroeconomic headwinds in oil, currency exchange and geopolitical issues affecting our business over the past year, I felt all the more compelled to flatten our organisation and centre our focus on improving our current products, broadening our aftermarket services and leaning our internal operations to achieve our short-term goal of EBITDA breakeven," said Darren Jamison, President and CEO at Capstone.

"Open communication and collaboration should improve under this new organisational structure since more responsibility will now be placed upon each individual; creating a situation where innovative and collaborative self-starters will excel. In addition, we can attract the type of employees who are encouraged by a work structure that requires self-motivation and cross-functional teamwork," added Jamison.

Americas

Grand Ben orders Siemens units

Siemens has received an order for the supply, installation and commissioning of 40 wind turbines for the Grand Bend wind farm in Canada.

Siemens will supply its SWT-3.2-113 direct drive wind turbines to the 100 MW project, which will be built 220 km southwest of Toronto in Ontario province. Construction at the site is already under way and commercial operation is scheduled for the first half of 2016.

B&W wins emission control contract

A consortium that includes Babcock and Wilcox Power Generation Group (B&W PGG) has won a contract from Colorado Springs Utilities to engineer, procure, construct and commission an emissions control project for the Ray D. Nixon Power Plant in Colorado.

Colorado Springs Utilities is installing emissions controls to comply with Colorado's Regional Haze State Implementation Plan, which requires compliance with new sulphur dioxide (SO_2) emission levels by Dec 31, 2017. B&W PGG will design, manufacture and construct a spray dryer absorber (SDA) to control SO_2 emissions from the plant's 208 MW coal-fired unit.

B&W PGG's portion of the contract is worth approximately $40.3 million.

CMI equips Chilean CSP

CMI Energy has been awarded orders for the supply of molten salt solar receivers for a 110 MW power plant to be built in the Atacama desert in Chile.

Designed by CMI Energy within the frame of a joint development agreement with Abengoa Solar, the molten salt solar receiver was chosen by Abeinsa EPC. It will have a 110 MW, 17-hour storage capacity.

The Atacama power station will be the largest molten salt power plant worldwide and South America's most powerful solar plant. It will include a 32 m-high CMI receiver installed at the top of a 217 m-high tower.

Vestas to supply Passadumkeag

Wind turbine manufacturer Vestas Wind Systems, has received an order from Passadumkeag Windpark LLC, an affiliate of Quantum Utility Generation, LLC, for 13 V112-3.075MW turbines for the Passadumkeag wind farm in Penobscot County, Maine.

The project's scope includes supply and commissioning of the wind turbines as well as a five-year Active Output Management (AOM 4000) service agreement. The project will benefit from a long-term utility power purchase agreement and a consistent wind resource, said Vestas.

Alstom to deliver Colombia substation

Alstom Grid has been awarded a €23 million contract to supply the first 500 kV substation for Empresa de Energía de Bogotá (EEB) in Colombia.

The substation will be located at Gachanzipa, 30 km north from Bogota, capital city of Colombia. It will connect the Hydro Sogamoso power plant to Bogota, improving the reliability of the city's energy system. The project is due to be completed by mid-2017.

The substation is essential to support the national programme of energy improvement in Colombia, which focuses on projects that will reduce power loss, meet the environmental standards of the country and also guarantee that the substation operates at optimum efficiency.

Asia-Pacific

Gamesa wins Chinese order

Hebei Construction & Investment Group (HGIC) and Fujian Energy have placed orders with Gamesa for a combined 98 MW of wind turbines.

Under the contract with HGIC, Gamesa will supply, install and commission 25 of its G97-2.0 MW turbines at the Senjitu II wind farm located in the province of Hebei, in southwest Peking. The wind turbines are scheduled for delivery this year.

The agreement reached with Fujian Energy encompasses the supply, installation and commissioning of 24 of Gamesa's G97-2.0 MW turbines at the Dingyanshan wind farm in the province of Fujian. These turbines are custom-designed to withstand the extreme winds typical of this coastal area, which is often hit by typhoons.

They are due for delivery in the fourth quarter of 2015.

Trina lands Toyo deal

PV module firm Trina has signed a supply agreement with Toyo Engineering Corporation to supply 116 MW of solar modules for the largest solar power project in Japan.

The 231 MW Setouchi solar farm will be built on 260 ha of city land on a former salt field in Okayama Prefecture. It will include 446 000 pieces of Trina's TSM-260PC05A high efficiency modules.

The solar farm will be commissioned in the second quarter of 2019.

BARC orders substation

India's Bhabha Atomic Research Centre (BARC) has ordered a substation for its Challakere unit in Chitradurga, Karnataka, from Alstom T&D India.

The equipment will serve as the main receiving substation to cater for the power supply needs of the Chitradurga unit. Alstom will build a 220/11 kV, 25/31.5 MVA master receiving substation on a turnkey basis. It will also provide six units of 220 kV bays, two units of 25/31.5 MVA, 220/11 kV power transformers and other associated equipment.

Doosan inks Vietnam contract

Doosan Heavy Industries & Construction said it has won a contract to build a coal-fired thermal power plant worth Won1 trillion ($936 million) from Vietnamese government-funded corporation Petro Vietnam.

The 1200 MW plant, Song Hau 1, will be built in Hau Giang Province, about 200 km southwest of Ho Chi Minh to ease the power shortage in the country's southern regions.

The power plant is slated to be completed by October 2019 and will use coal imported from Australia or Indonesia.

Twelve compete for Mindanao

Twelve investor groups are bidding for the contract to build the 200 MW Mindanao coal-fired power plant, the Power Sector Assets and Liabilities Management Corporation (PSALM) of the Philippines has said.

The bidders include SPC Power Corporation, Meralco Powergen Corporation, GDF Suez Energy Philippines, FirstGen Northern Power Corporation and Vivant Energy Corporation.

A pre-bid conference has been scheduled for early May and the bidding will take place in September 2015.

Toshiba wins Myanmar hydro bid

Toshiba Hydro Power Hangzhou Co. Ltd. has received an order from Myanmar Electric Power Enterprise to supply four 77 MW turbine generators for the Upper Yeywa hydropower plant.

Myanmar Electric Power Enterprise is building the 308 MW project northeast of Mandalay. Deliveries to the project's EPC contractor, Zhejiang Orient Engineering Co. will start in March 2016.

The project will be the second equipped by Toshiba Hydro Power in Myanmar following an order for the 28.4 MW Sedawgyi in 1989.

ABB to strengthen China grid

ABB has won orders worth over $100 million to supply converter transformers and components including wall bushings and circuit breakers for the Lingzhou-Shaoxing ultra-high voltage direct current (UHVDC) transmission link in China.

The link will be the seventh 800 kV UHVDC transmission system in the country and will help to deliver more electricity from remote power plants in China's interior to growing urban areas, over longer distances with fewer losses.

The long-distance Lingzhou-Shaoxing (LingShao) +/-800 kV UHVDC transmission project will transfer 8000 MW of power from Lingzhou in the northwestern Ningxia region to Shaoxing in the eastern Zhejiang province, stretching over a distance of more than 1700 km.

This will be the world's first 750 kV ultra-high-voltage alternating current (UHVAC) to 800 kV UHVDC connection, an innovation that enhances the efficiency and capacity of long-distance UHV electricity delivery systems necessary for China's growing economy. The products provided by ABB are scheduled to be commissioned in 2016.

Europe

Steag orders Nordex units

Nordex SE has won a contract for the delivery and installation of a wind farm in France for Steag New Energies GmbH.

Nordex will start installation of the seven N100/2500 turbines at the Cormainville project in January 2016 and the 17.5 MW wind farm will go into commercial operation in the summer.

Senvion seals UK deals

Senvion SE has signed four new contracts totalling 45 MW with Blue Energy for the supply of wind turbines for UK projects.

The contracts are the first signed by Senvion with Blue Energy and involve the Grange wind farm in North Lincolnshire, Kelmarsh wind farm and Winwick wind farm near Northampton and Chiplow wind farm in Norfolk.

All the projects are due to enter operation in 2016.

Amec FW assists EDF Energy

Amec Foster Wheeler has been awarded a contract by EDF Energy to provide project management services to all of its UK nuclear power stations and technical offices in Gloucester and East Kilbride.

The nine-year agreement is currently one of the largest project management contracts within the UK nuclear industry and is worth up to £15 million a year.

Clive White, President of Amec Foster Wheeler's Clean Energy business, said: "This framework agreement further reinforces our long-standing relationship with EDF Energy."

In addition to EDF Energy's Generation offices at Barnwood in Gloucester and East Kilbride near Glasgow, Amec Foster Wheeler will provide these crucial services to the nuclear stations at Dungeness in Kent, Sizewell in Suffolk, Hunterston in North Ayrshire, Torness in East Lothian, Heysham 1 and 2 in Lancashire, Hartlepool on Teesside and Hinkley Point in Somerset.

International

EGP heads for South Africa

Enel Green Power (EGP) has won licenses in South Africa to build three wind farms with a total capacity of 425 MW.

The firm won contracts in South Africa's Renewable Energy Independent Power Producer Procurement (REIPPP) programme and will build the three wind farms through vehicle companies in which it has majority shareholdings.

The three wind farms are the 142 MW Oyster Bay project, the 141 MW Nxuba wind farm and the 142 MW Karusa project. Oyser Bay and Nxuba will enter operation in 2017 and Karusa in 2018.

The projects will require a total investment of €500 million. Energy from the wind farms will be sold to Eskom through power purchase agreements (PPAs).

Kathu wins in REIPPP

A consortium including GDF Suez, Acciona and Sener has won a contract to develop the Kathu solar thermal power plant in South Africa.

The firms have been selected by the South African government as part of its Renewable Energy Independent Power Producer Procurement (REIPPPP) programme to build the 100 MW plant.

The Kathu plant will have a parabolic trough design with thermal energy storage and will cost over €500 million to build. It will start operating in 2018.

PW gas turbine package for Guinea

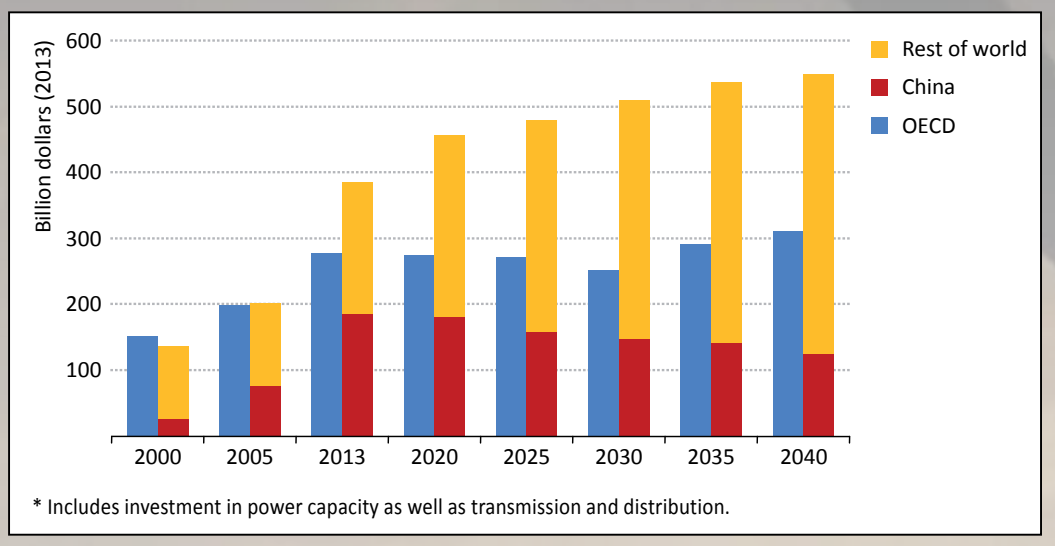
PW Power Systems has signed a contract with Miami Capital Holding Corporation to provide three mobile gas turbine generator packages for installation in Conakry, Guinea.

The units will be the first PW Mobilepac units delivered to Guinea and will boost the country's power supplies. MKH Engineering will install the equipment on site with engineering and technical support from PW Power Systems.

Jordan attracts solar bids

Jordan has prequalified 15 local and international companies to build a $150 million solar power plant, the Ministry of Energy and Mineral Resources said last month. The 65-75 MW solar plant will be located in Qweira in the southern Governorate of Aqaba and has attracted bids from First Solar, Elecnor, SunEdison Italia Construction srl, China Gezhouba Group International Engineering and Isolux, among others.

World investment in the power sector* by region in the New Policies Scenario



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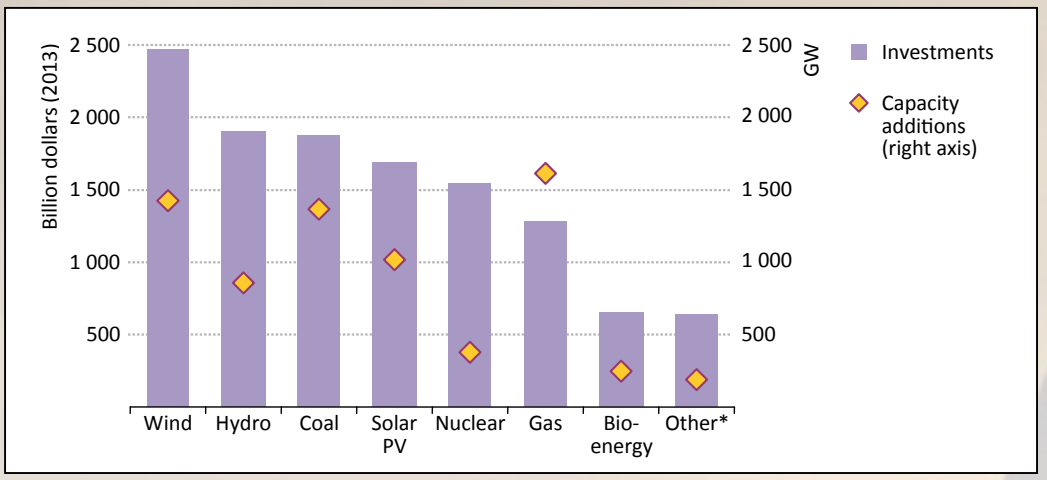
Cumulative world investment in the power sector by generating type, 2014-2040



World Energy Outlook 2014, © IEA/OECD, Figure 6.11, page 220

Cumulative investment in the power sector by region and type in the New Policies Scenario ($2013 billion)

	2014-2025						2026-2040						2014-2040
	Fossil fuels	Nuclear	Renewables	Total Plant	T&D	Total	Fossil fuels	Nuclear	Renewables	Total Plant	T&D	Total	Total
OECD	**476**	**261**	**1 381**	**2 119**	**1 282**	**3 401**	**468**	**450**	**1 908**	**2 827**	**1 404**	**4 231**	**7 632**
Americas	196	90	503	789	569	1 359	246	178	739	1 163	646	1 809	3 168
United States	158	87	387	632	460	1 093	197	159	571	927	495	1 422	2 515
Europe	174	102	605	881	468	1 348	162	202	863	1 228	502	1 730	3 078
Asia Oceania	106	70	273	449	245	694	60	70	306	436	256	691	1 385
Japan	70	14	196	280	130	410	26	22	191	239	143	382	793
Non-OECD	**1 002**	**354**	**1 570**	**2 925**	**2 479**	**5 405**	**1 294**	**468**	**2 517**	**4 279**	**3 521**	**7 799**	**13 204**
E. Europe/Eurasia	202	83	80	364	234	598	164	143	164	471	292	763	1 361
Russia	100	71	41	212	101	313	87	84	90	260	127	387	700
Asia	586	239	1 080	1 905	1 606	3 511	843	249	1 525	2 617	2 217	4 834	8 345
China	255	193	700	1 148	982	2 129	218	152	726	1 096	1 034	2 130	4 260
India	176	29	194	400	289	688	321	67	440	827	499	1 326	2 015
Southeast Asia	112	2	89	203	247	449	220	16	178	414	502	915	1 365
Middle East	83	21	52	156	117	273	74	32	216	323	156	479	751
Africa	93	-	151	245	282	527	160	27	344	531	566	1 097	1 624
Latin America	37	12	207	256	240	496	53	16	268	337	290	627	1 123
Brazil	11	5	126	143	145	288	21	11	155	186	172	359	646
World	**1 478**	**615**	**2 951**	**5 044**	**3 761**	**8 805**	**1 762**	**918**	**4 426**	**7 106**	**4 925**	**12 030**	**20 836**
European Union	155	104	557	815	413	1 228	139	198	802	1 139	439	1 578	2 806

World Energy Outlook 2014, © IEA/OECD, Table 6.5, page 219

Source: Source: World Energy Outlook 2014

EU ETS: where evolution and adaptation matter

Power utilities and industrials participating in the EU Emissions Trading Scheme are not on equal footing in the face of rising CO_2 prices, warns **Yann Andreassen**

In March, the Council of the EU agreed on a common position on the Market Stability Reserve (MSR) paving the way for a potential passage of legislation by summer 2015. The two main groups in the EU Emissions Trading Scheme (ETS), – power utilities and industrials – positioned themselves at opposite ends of the policy spectrum broadly supporting and opposing (or conditionally supporting) the MSR, respectively.

To understand these different stances, it is pivotal to grasp that not all EU ETS participants have the same carbon position profile nor do they have access to the same tools to manage that position, especially in the context of rising CO_2 prices.

While utilities and industrials evolve in the same CO_2 compliance environment, their carbon position – long or short – makes them very different animals. Since 2013, most power utilities must purchase EUAs (EU emissions allowances), as they no longer receive free allocations. This means the power sector has been short and will continue to be in the third trading period (2013-2020).

In contrast, industrials continue to receive free permits via regular and carbon leakage free allocations, leaving some players with a surplus. So a key question is: why would utility players, with the biggest short allowance positions in the market, support the MSR and want higher carbon prices while industrial players, with the longest position in the market oppose the scheme and want lower carbon prices? The answer comes down to availability of tools.

When managing the carbon price risk in the context of potentially rising carbon prices, utilities and industrials have access to a very different set of tools. Firstly, utilities have partially passed through their carbon costs to consumers. This means that utilities could compensate for higher input costs, due to rising carbon prices, with higher output revenues through higher power prices.

Secondly, utilities have flexibility in the technologies used to produce their output, i.e. through fuel switching. Depending on the power production portfolio mix and attractiveness of the clean dark and spark spreads, rising carbon prices would increasingly allow utilities to switch from coal to gas.

In contrast, industrials in, for example, the steel sector, face competition from those outside the EU not facing carbon regulation, which means carbon pass-through is not a viable option. Industrials have therefore been compensated through free allocations to offset additional carbon input costs under the EU ETS and thus avoid 'carbon leakage'.

While some utilities can employ fuel switching, industrials do not have this option. Some companies can pursue efficiency projects but nothing comparable with the speed and emissions saving of switching from coal to gas. One available option to industries in the case of high carbon prices is obviously the temporary or permanent interruption of production but this is probably unattractive.

Historically, utilities and industrials have pursued very heterogeneous carbon management strategies. Most European utilities evolved in fully liberalised energy markets. Companies had to implement long-term sophisticated hedging strategies to mitigate their output price risk on the power side and input price risks, e.g. coal and gas as well as carbon. On average, Central European power utilities have hedged their power production three to four years in advance, securing the related inputs including carbon at the same time. But the hedging horizon of companies is not homogeneous and can differ greatly between regions. For instance Mediterranean utilities tend to have a two-year hedging horizon.

The comfortable level of freely allocated permits has allowed most industrial companies to take a short-term "wait-and-see" approach for the management of their carbon position. Selling behaviour was not homogeneous between and within sectors. We saw small cash-strapped cement players in recession-hit countries like Spain or Italy selling most or all of their freely allocated permits in 2014 and other companies piling up massive surpluses due to a muted selling strategy.

Despite their short position, European power utilities look better equipped to face higher carbon prices than European industries. Power generators actually welcome a higher carbon price, as this would mean higher power prices for them. It is therefore no surprise that Eurelectric, which represents the EU power industry, supports an ambitious MSR starting in 2017.

For most utilities, higher EUA prices will not warrant a fundamental shift in their long-term carbon hedging strategies as any increase in carbon input costs will be partially reflected in power output revenues. With that said, all utilities will not be equal in the face of higher carbon prices. Indeed, those with a "dirty" power plant fleet resulting in higher carbon intensity than that of the average power price setting plant would be worse off. This situation would result in those companies having lower output revenues/input costs ratio than their lower carbon emitting competitors.

In terms of strategy, some high carbon intensity companies will choose to acquire a 'strategic reserve' of allowances today in the expectation of higher EUA prices in the future.

This scenario materialised in 2013 when RWE, based on power sales, announced the purchase of allowances for the third trading period. ICIS Tschach Solutions analysts estimated this to be about 50 million EUAs.

Looking forward, it will be harder for industrials to ignore their carbon obligation when EUA prices reach €20-40 per tonne. Sectors such as the oil and gas industry are increasingly taking a short position in the run-up to 2020. In parallel, the EU ETS Cross Sectoral Reduction Factor (CSRF) will ensure that even the most efficient companies, at the top of the carbon leakage benchmark will not get 100 per cent free allocations. This results in more and more companies, which were long in the past, becoming short in the future and being forced to purchase allowances on the market.

Furthermore, there is currently uncertainty on post 2020 rules on free allocations. We know that the EU ETS linear reduction factor will increase from 1.74 per cent to 2.20 per cent after 2020 and that the Council has agreed that the volume of auctions sold will not be touched – meaning that the linear reduction factor will reduce the pool of free allocation allowances available.

Overall, this means that those companies with a surplus of allowances will have to assess the viability of selling EUAs today at €7/t versus keeping them for the future when EU ETS reforms kick-in and higher carbon prices materialise. In principle, there is nothing precluding short industrials from following higher carbon intensity utilities and securing a buffer of EUAs today at "low" prices.

Some large industrials could have a relatively short-term horizon in terms of investment returns so such strategic reserves might not fit the criteria. In parallel, small industrials often say that "they're not in the carbon business" to explain their passive carbon strategy. Higher carbon prices could drive them to realise that putting carbon management on the backburner at €20-40 price levels could very well put them out of business

Carbon price is a risk for both industrials and power utilities. To manage such risk, companies must understand it. If you are an oil refining company, how does a €1 or €30 increase in EUA prices impact the production cost of one unit of your product? Is that impact the same for your competitors? If you are a small cement company focused on a long-term strategy, at what EUA price level does a carbon efficiency project investment make sense? And when is that price level forecasted to materialise? If you are a utility with only old lignite and hard coal power plants, how much higher is your carbon intensity from the one priced in the power price? And what would it cost today to put you on par with your competitors' carbon intensity for the next five years?

After understanding the carbon price risk, companies must develop a long-term CO_2 strategy. There are no one-size-fits-all CO_2 strategies and differences exist beyond the utility/industry divide. Sectors within industries are different. Beyond that, a small family-owned German cement company is, for example, different than a publicly traded French cement company. In other words there are no shortcuts. Each company must develop its own long-term CO_2 strategy based on its own sector features, unique company characteristics, and carbon profile.

Finally, some companies might decide not to pursue a long-term carbon strategy at all. In that context, an appropriate step would be to understand the risk of not doing so. According to our base case policy scenario for the proposed MSR (start in 2019; back-loading and unallocated allowances transferred to reserve) EUA prices will increase to around €12 in 2015 due to back-loading, increase to €33 in 2020 after the MSR implementation, and finally reach €40 in 2030. Evolution suggests that only the species that are able to adapt to their changing environment will survive – EU ETS Phase 3 and 4 will tell.

Yann Andreassen is Senior Analyst, EU Carbon Markets at ICIS Tschach Solutions.

Andreassen: power utilities look better equipped to face higher carbon prices than industries

> When managing carbon price risk... utilities and industrials have access to a different set of tools

Capacity markets: the dawn of a new era?

Future electricity market design should not only value energy, but also flexibility and capacity. With capacity markets gaining traction, policymakers need to minimise implementation risks by following a set of fundamental design features, based on the principles of cost-efficiency and competitiveness.
Hans ten Berge

European wholesale markets for electricity are entering a new phase. Continued progress in completing the EU's internal energy market remains a fundamental no-regrets option. But the debate in many EU member states – and increasingly at EU level itself – has moved on. Concerns about sufficient capacity availability have come to the fore, amid the dawning realisation that markets might need adjusting to keep the lights on in the long run. Against this backdrop, capacity markets have repeatedly been proposed as a promising solution.

European power systems today are experiencing a paradox: they urgently need firm capacity to provide electricity when variable renewables such as wind and solar do not deliver. But many markets do not value firm capacity in a way that would allow such capacity to keep on running – or necessary investment in new capacity to be made. In effect, although everybody wants electricity available at their fingertips and nobody wants the lights to go out, the economic outlook for firm capacity is increasingly uncertain.

Why is this so? A combination of several factors is at work. Incentivised by the EU's targets for decarbonisation and renewables growth, and spurred on by a combination of subsidy schemes and declining production costs, renewable generation has experienced sustained growth in many European markets, displacing conventional generation as electricity demand has failed to keep up. Sustained downward pressure is placed on wholesale market prices as the share of low carbon generation grows, given its low variable cost structure. In addition, wholesale market prices are becoming more volatile and more difficult to predict. In a business with investment horizons that span several decades, such uncertainty makes it difficult to commit to large-scale investments with long investment horizons.

As a result, many providers of firm capacity today do not see the value of remaining online. The curious fact is that, while plants are working fewer hours, this does not imply that they are all less needed. Quite the opposite – firm capacity to back up power systems is more important than ever to prevent shortages in the long term.

Against this backdrop, the introduction of a capacity element is already a reality in many European markets. Faced with concerns about a medium term capacity shortage, France and the UK for example have decided to drastically reduce the chances of potential blackouts by ensuring, through two different forms of capacity markets, that enough assets are available. Other European countries are discussing introducing a capacity element – and at EU level, the European Commission is expected to publish further guidance on the issue in an upcoming market design communication.

The recognition is growing that market design will have to adapt to take these new realities into account. In contrast to today, the future market design should not only value energy, but also flexibility and capacity. All three – energy, flexibility and capacity – are interlocking elements of a more efficient market design to ensure continued security of supply in different time horizons. Flexibility should enable the system to respond to short-term variations in the supply-demand balance. In contrast, capacity should ensure long-term system adequacy in case of extreme load peaks or moments where capacity has to be available to back up intermittent renewable generation.

With capacity markets continuing to gain traction across Europe, Eurelectric firmly believes that the market design needs to be updated to make the market fit for an energy system that is increasingly dominated by renewables. In our view, a successful transition to a new market design provides customers with continued security of supply while simultaneously decarbonising the electricity sector – both in a way that is not unnecessarily expensive.

However, while the value of capacity needs to be recognised, capacity markets are not all born equal. In theory, capacity markets are market-based – and therefore cost-efficient – solutions that deliver long-term power system adequacy by properly valuing capacity, thereby providing signals for existing, necessary capacity to stay online or new capacity to be built. In practice, the way these markets are designed will critically determine how successful they are in achieving these objectives.

In our view, policymakers can minimise the risks of capacity market implementation by following a set of fundamental design features, based on the principles of cost-efficiency and competitiveness. What does this mean in practice?

First, capacity markets should be conceived of as a market-based way to put a price tag on a certain product, i.e. capacity. They are not subsidies or free cash handouts to prop up investments gone wrong. If a market experiences overcapacity, excess capacity should leave the market and not be artificially kept online. Poor investment decisions should not be rewarded. Rather, the aim of capacity markets should be to deliver only as much capacity as is needed to keep the lights on in the long run – as little as possible, as much as necessary.

Capacity markets should move away from today's national piecemeal approach, says Hans ten Berge

In determining where this capacity should come from, it is more sensible to let this play out on a competitive market rather than handing over wads of cash to individual plants – or, worse still, forcing lossmaking plants to stay on-line. Market-based mechanisms are more efficient and less costly. Nor should a properly designed capacity market interfere with the operation of the Internal Energy Market. This means that the capacity market should have no effect on the dispatch order: it should price availability, not production.

Second, once policymakers have decided to opt for a capacity market, they need to ensure that their chosen system is as open as possible to competition. This means that capacity markets should be open to existing plants and new investments, and open to both renewable and conventional forms of generation. They should also look beyond generation to equally include demand and storage. Taken together, these measures will make sure that the most efficient assets remain available in the system to keep costs down for customers while ensuring that their lights stay on.

Third, capacity markets should have a clear European dimension. Investment decisions might be distorted if different capacity market models are implemented without coordination and effective cross-border participation. This could lead to a sub-optimal use of capacity and higher prices for customers, as countries fail to take into account developments in neighbouring EU member states.

We therefore strongly believe that a European mind-set and a regional approach to market design – and in particular to capacity markets – are the best way forward in this debate. Capacity markets must allow capacity from neighbouring countries to participate.

The implementation of capacity markets should thus move away from today's national piecemeal approach. Instead, capacity markets should result from a coordinated effort to establish regional instead of national models. To guarantee this evolution, the European Commission should push for harmonised solutions and EU member states should, at the very least, coordinate and adopt mechanisms that allow cross-border participation. Ideally, the preferred approach would be to adopt the same model at regional level.

In addition, capacity markets should be taken into consideration when planning system operation across Europe. More and better cooperation of transmission system operators (TSOs) will be needed to make this happen.

So what are the most promising options for capacity mechanisms, taking these criteria into account? At Eurelectric we see centralised auctions or decentralised certificate schemes as Europe's best bet to cost-efficiently ensure security of supply in the long run. Both deliver a competitive marketplace that incentivises the most efficient actors to stay in the system. However, it seems likely that the debate among EU member states will continue for some time. As policymakers draw first conclusions from the UK and French experiments, maintaining a cross-border, European perspective will allow them to develop capacity markets that are fit for today's changing energy system.

Hans ten Berge is Secretary General of Eurelectric, the association representing Europe's electricity utilities.

Decentralised reliability options

Pöyry Management Consulting has considered some of the underlying features of existing and proposed Capacity Remuneration Mechanisms (CRMs) and offers a new model – decentralised reliability options – for consideration as a potential basis for a European CRM blueprint.

Stephen Woodhouse

For the first decade of liberalised energy markets in Europe; energy only markets have brought investment. New capacity was built assuming near-base load operation. Price risk arising from commodity price movements was hedged through forward trading, long-term power purchase agreements (PPAs), or vertical integration with a retail portfolio. Volume risks were low and manageable.

The situation has changed. Energy markets are being challenged by new uncertainties. Capacity margins in European countries are generally high, and base load operation for new thermal plants is no longer reality, under the pressure of an aggressive growth of out-of-market renewable generation and the lingering impact of the financial crisis on electricity demand.

Going forward, volume risks will be far higher, and thermal plants relying only on sales of energy will have to rely disproportionally on high prices at times of scarcity to recover fixed costs.

Scarcity pricing requires scarcity to occur. However, higher risk of brown outs and potential price spikes are often unacceptable from political and regulatory perspectives, and any resulting market intervention (real or threatened) can result in 'missing money'.

Traded markets have not adapted to deal with volume risk, and there are 'missing markets' for the new combination of price and volume risk faced by participants.

Recognising the importance of security of supply to individual states and the national inclination to implement a local solution, Capacity Remuneration Mechanisms (CRMs), are now being implemented in several European countries and seriously debated in many others. However, they are nationally based, each is different in design, and they have no arrangements yet in place for cross-border participation.

So while energy markets are integrating, capacity markets appear to be diverging and this could undermine the Internal Market for Electricity. Uncoordinated CRMs risk distorting spot electricity prices, especially over critical peak periods, and by extension may distort cross-border electricity trading and investments as well as damaging demand side response.

If CRMs damp scarcity energy prices, this could lead to inefficiency. This begs the question of whether to reward capacity or the right type of capacity.

Nearly all CRM schemes under construction fail to recognise the additional value that flexible capacity brings to the system, treating all available capacity alike. The focus of CRMs has traditionally been on generation adequacy, meaning ensuring that sufficient capacity is on the system to meet peak demand.

In order to incentivise the right type of capacity markets in a world with increasing levels of weather variable generation, CRMs will need to be able to cope with emergent system performance requirements, and in particular should consider flexibility as one of the parameters of their design.

A coordinated approach to CRMs could be highly beneficial to the overall energy system.

CRMs should not stand in the way of creating 'smarter' electricity markets with a more active role from the demand side. They should work with minimal distortions even at boundaries between markets with and without a CRM.

A common CRM blueprint, which allows a wide degree of freedom for changing design parameters to meet national needs, without causing distortions between markets, and requiring any country to adopt a CRM, could be beneficial.

Pöyry has considered some of the underlying features of existing and proposed CRMs and offer a new model – decentralised reliability options – for consideration as a potential basis for a European CRM blueprint.

Capacity schemes take various forms, often categorised into 'targeted' (paying specific types of capacity) or 'broad' (paying market-wide); and price-based (prices are centrally determined and paid to all) or quantity-based (prices arrived at through competition between providers). A decentralised reliability option scheme is a market-wide, quantity-based scheme.

At its simplest, a decentralised reliability options scheme introduces a set of contracts between capacity providers and (indirectly) consumers. Retailers are required to buy reliability options to meet their demand at critical times. Sellers of reliability options commit their availability at critical periods and forego revenue from price spikes, in return for which they receive a stable revenue stream.

The contracts are a hybrid between a call option (which is essentially commercial) and a physical commitment to make capacity available to the system at key times. The call option introduces a financial settlement (aside from the physical commitment and penalty arrangements), whereby the seller of the option returns the difference between the reference market price and the strike price, if any, to the buyer. Customers benefit from security of supply to an agreed standard, and their exposure to scarcity pricing is reduced in return for an up-front fee.

So what are the benefits of reliability options?

The physical commitment delivers security of supply and creates a supplementary revenue stream to deliver missing money, in the same way as other market-wide CRMs.

The commercial option has an important impact: it should protect customers from scarcity prices in the spot markets while allowing capacity providers to hedge price volatility. This means reliability options can reduce 'missing money' both directly and indirectly.

Protecting consumers against price spikes through an option contract means regulators can remove any underlying price distortions to reveal price volatility, which unlocks the potential for demand-side management, interconnection and flexible capacity.

The reliance on the physical commitment could be made transitional, leading to an improved version of the energy-only market in which investment risks could be managed through the sale of a combination of forward sales of call options and fixed volume energy contracts.

From a consumer perspective, reliability options remove any incentive for generators to exercise market power over periods of scarcity and offer a hedge to consumers through direct compensation over periods of short-term price spikes.

Capacity tickets, on the other hand, present the risk of overcompensation for generators at the expense of consumers as, in the absence of regulatory measures to limit price spikes, generators may attempt to exercise market power over periods of scarcity in addition to receiving the up-front capacity payment.

On the other hand, reliability options present a more complex solution when compared to capacity tickets and may be perceived as 'riskier' by investors as both a penalty and a commercial incentive for performance are in place.

Ultimately, the benefits of avoiding distortion of competition and trade, protecting consumers and better facilitating innovative technologies may outweigh the downsides of a reliability options scheme.

Operating on a decentralised basis has advantages.

A central agency for each country may tend to procure too much capacity at the expense of customers. So while security of supply is more assured, the process is likely to prove less efficient. Efficiency gains would be realised from a more decentralised approach in which the timing and the terms of procurement are determined by the market participants.

Central procurement of simple, standardised products means a common route to market for all and should naturally promote greater liquidity. A decentralised approach may raise concerns about liquidity, but it has other attractions.

The principal advantage of decentralised reliability options is that they can be struck against different markets and with different contract terms. This freedom allows for the value of different types of capacity to be revealed, with the market revealing the premium for flexibility, without undermining the trading of energy over different timeframes.

Overall, decentralised reliability options are more in line with the philosophical basis for most European electricity markets, which value bilateral trading and place responsibilities on market participants rather than central agencies.

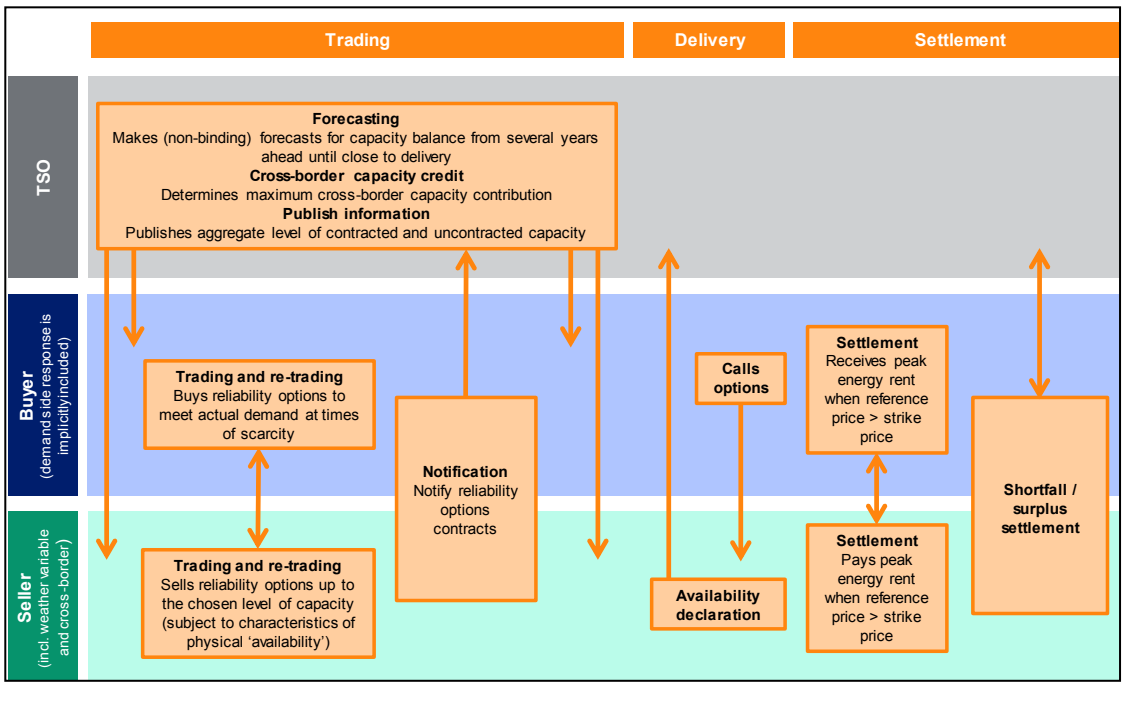
Pöyry has outlined a credible design for a CRM. Decentralised reliability options could provide the required adaptability to meet national needs, without threatening the Internal Market for Electricity.

Such a concept follows EC guidance and has the potential to limit future regulatory and policy risk. It would be consistent with a more active role for market participants and customers in delivering the required level of security.

These ideas could be further considered and developed to support the efforts for a single European electricity market. Pöyry intends to continue discussing, developing and disseminating these concepts to inform and influence discussions on CRMs and the future of the European electricity markets, and we seek the support of a range of stakeholders to continue the work.

Stephen Woodhouse is Director at Pöyry Management Consulting. Pöyry's design for a CRM is published at www.poyry.co.uk/news/DRO. For further details email: stephen.woodhouse@poyry.com

Straw man design of decentralised reliability options scheme



Technology

Moerdijk goes "virtually energy-neutral"

Two new boilers were recently inaugurated at Europe's largest sewage sludge incineration facility in Moerdijk, the Netherlands. **Junior Isles** had a tour of the new power plant, which has been integrated into a cogeneration facility at the site with minimum downtime.

Just over an hour's drive from Amsterdam, Dutch company Slibverwerking Noord-Brabant (SNB) operates what is the largest sewage sludge incineration plant in Europe. Although it may be handling sludge, the facility can certainly be regarded as "clean" – a new cogeneration project, which recently began operating at the site, is now demonstrating that even a sewage facility can be "green".

At the start of April, two new boilers installed by NEM Energy B.V. and an associated Siemens steam turbine, were officially inaugurated. The boilers, a key part of the cogeneration plant, are now recovering residual heat from the sludge incineration to generate high pressure steam to significantly boost power output and produce enough electricity to meet almost all of the facility's needs. In addition, the cogeneration plant produces low-pressure steam that is used for pre-drying the sludge and for reclaiming raw materials.

With the new boilers, SNB will increase its production of green energy by a factor of nine. This will not only save SNB and its shareholders money, it will also benefit the environment. The new cogeneration power plant will contribute to satisfying agreements that the shareholding water boards made in the Climate Accords, one of which was to cut energy consumption by 30 per cent between 2005 and 2020.

SNB processes sewage sludge for six shareholding water boards (including three from the province of North Brabant), as well as several external clients. Sludge throughput of its Moerdijk facility is around 430 000t/y, delivered by on average 50 trucks each day.

Sewage sludge is the end product of the treatment of sewage water from water purification plants owned by the water boards. SNB is constantly working on initiatives to recover energy and valuable raw materials from sludge. For example, it sells CO_2, which is a byproduct of the incineration process, to a neighbouring company that uses it for paper production.

SNB also works with a partner firm to reclaim phosphates from the sludge. The ash produced from the incineration process contains 20 per cent phosphorus and SNB has signed an agreement with a Belgian company that will use SNB's incineration ash to produce fertilisers. Notably, SNB says this will be the first large scale application of phosphorus recovery in the world when it begins implementing production in 2017.

The use of the heat content in the sludge enables SNB to incinerate extremely wet sludge without using natural gas. Gas is only needed for starting up an incineration line after maintenance. Part of the energy from the sludge is also converted to electricity.

NEM was able to remove two existing boilers and replace them with the new boilers while the plant remained operational

The facility was first opened in 1997 and up until recently, used four low-pressure boilers (one per incineration line) operating at 10 bar to handle its steam requirements and produce a small amount of electricity. The new installation saw the replacement of two of these low pressure boilers with two NEM heat recovery steam generators that operate at 60 bar and 450°C. These produce steam to drive a new 3.2 MW steam turbine.

Extraction steam from the turbine is also combined with steam from the remaining low-pressure boilers to provide process steam via a new header at 3.5 bar. This steam is mainly used for sludge drying. Some also goes to an evaporation system to evaporate wastewater, and to a stripping system that removes ammonia from the dry vapour condensate formed when the sludge dries.

The four steam boilers produce around 46 t/h of steam: 30 t for sludge drying; 10 t to the steam turbine for electricity production; 3 t to the evaporation system and 3 t to the stripper system.

Marcel Lefferts, SNB's Director, says the combination of high-pressure and low-pressure steam boilers "is the optimal solution" in terms of energy production and the cost of electricity.

"The main reason for the new boilers was to increase electricity production and become more or less energy-neutral; we are now at around 95 per cent. When one of the boilers is shut down for maintenance, electricity is provided by the grid.

"The second reason was [electricity] cost. The cost of electricity is almost 10 per cent of the running cost of the facility. We have now reduced this to almost zero." said Lefferts.

While installation of the new boilers was important to the company, it was paramount that they be installed without causing significant downtime. When considering the amount of sludge processed each day, continuous operation is essential.

"The facility has to have a high availability – more than 95 per cent – otherwise there's a problem," noted Lefferts.

Gerard Van Dijk, CEO, NEM Energy B.V. added: "It was, therefore, essential to minimise the downtime during replacement of the boilers."

It was a complex operation. After a year's preparation, technicians began assembling the boilers at the SNB facility in September 2014. In the first instance, incineration line 3 was shutdown in order to replace the boiler. After completion, the facility returned to full capacity for two weeks before line 2 was shutdown for the boiler to be replaced.

Lefferts commented: "You could compare it to open-heart surgery. NEM was able to remove two existing boilers one after the other and replace them with the new boilers while the plant remained operational. That meant that the project had to be completed as quickly as possible."

NEM proved equal to the task, with the project being executed in about 70 days. At its peak, 250 people were on-site working on the project.

Van Dijk noted that although its core business is the supply of HRSGs, for NEM it was a special project. It was in its own backyard and had to be done in a limited time at an operating plant.

"Because you have a running installation, it means opening up the roof, taking out the old boilers, generating equipment, balance-of-plant, everything – because you want to touch as little as possible. Then replacing it – installing the new boiler, new turbine etc. – closing it up again, and bringing it all back into operation," he explained.

NEM says it has learned a lot from this project. Erwin Aalbers, NEM's Project Manager stressed the value of giving engineers hands-on site experience. "It is not always according to drawings… you don't always know what you are facing. We created a task force including a project and supply manager, mechanical engineer, process engineer etc. and sent them to and from the site, so that the same people who did the engineering were also involved in the site direction."

He concluded: "It was important having a customer that was willing to listen and learn from our ideas. But the key things we have learned are to understand the process. You should make a design that does not just optimise each Euro you spend on equipment but also considers the benefit of that piece of equipment so you can decide whether you actually have to install it or not."

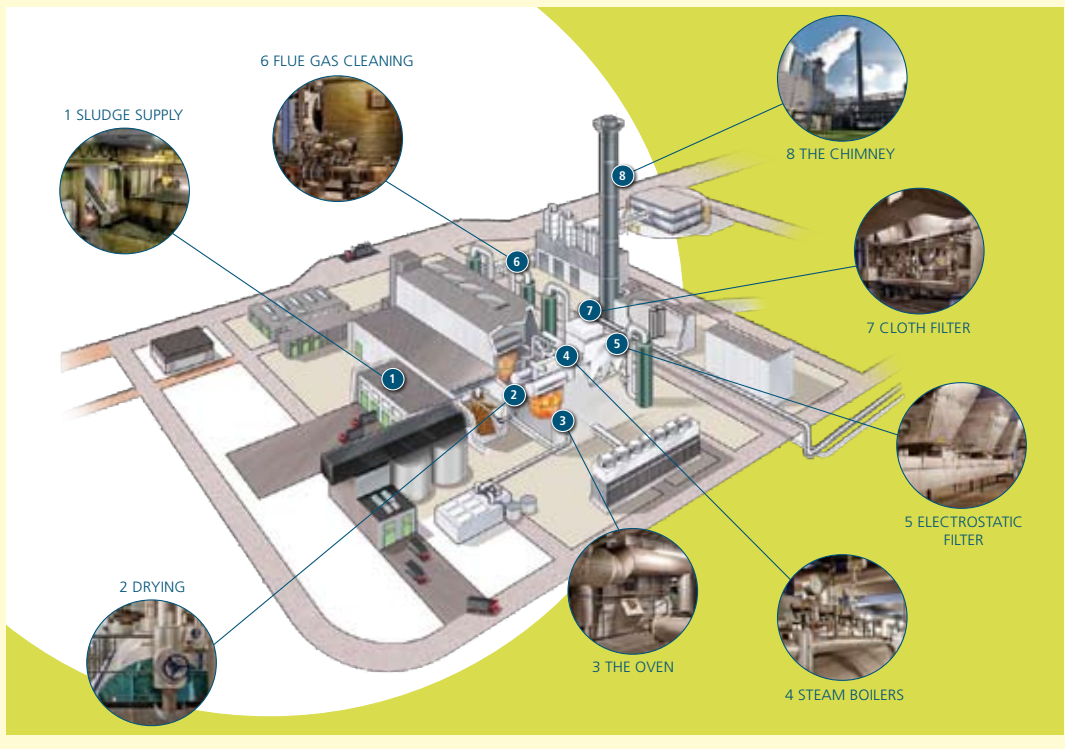
The sludge incineration process

Dutch households consume 800 billion litres of water annually. When treating this used water, an enormous amount of sludge is left behind.

Sludge is typically incinerated to ensure that dangerous substances such as remnants of medicines, organic contaminants and heavy metal are removed. This is usually done in a power station, cement oven or waste incineration plant. SNB's incinerator, however, not only removes dangerous substances. Its mono-combustion process offers possibilities for recycling of valuable components such as phosphates.

Before it is incinerated, sludge has to be dried to a level at which it can be combusted without the need for another fuel. The dried sludge is then transported to an oven where it is burned in circulated fluidised bed at about 900°C.

Flue gases from the oven enter a steam boiler where steam is generated. Ash particles in the flue gas are removed by an electrostatic precipitator and the flue gas is then washed and filtered to remove heavy metals, including mercury and other hazardous components.



Junior Isles

Patchwork quilts are not good security blankets

Patchworks may be nice for quilts (I can't say I'm a fan myself) but not much else.

Yet it was a term that was used more than once during the opening session of this year's *Platts 6th European Energy Summit*.

In 2011 EU member states agreed to set 2014 as the year to complete the internal the energy market. Unsurprisingly, 2014 has come and gone and still we are far from a harmonised internal energy market. More to the point, countries are adopting national policies in response to market pressures.

With sluggish demand and the growth in renewables, operators of conventional base load plants have been under so much pressure, that many have either closed or earmarked for closure a significant amount of capacity, which in turn is threatening security of supply.

Notably, at the end of April Vattenfall, which operates seven reactors, said it would shut the 881 MW Ringhals-1 and 865 MW Ringhals-2 nuclear reactors in Sweden between 2018 and 2020 instead of, as previously announced, around 2025.

The company blamed the early closures on difficult market conditions, with continued low electricity prices in the coming years, as well as increasing production costs.

Andreas Ragnell said at the conference: "It's a case of taking capacity off the market because the energy-only price is too low."

Commenting on the current design of Europe's energy market, Francesco Venturini, CEO and General Manager, Enel Green Power (EGP), said: "The target market is based on an energy-only model which is based on the idea that short term price resulting from a competitive market will suffice to remunerate the total costs of generators."

He told delegates: "This is not happening; clearly it is not working. The model is being challenged by depressed power prices and most of the stakeholders, including you poor guys, agree the model has to be reviewed to bring more predictability to revenue streams for investors.

"On top of the unclear market design that Europe insists on supporting, there are other issues that make the overall picture even more blurred and complex."

The unstable environment for investments caused by regulator changes at national level has increased the reluctance of operators like EGP to develop projects in Europe. According to Venturini, last year EGP invested €1.5 billion but 90 per cent of this was in other continents.

> Europe looks like a colour puzzle filled by a patchwork of policies that are the sum of a plurality of interests but satisfies no one

He added that member states are implementing diverging policies in an uncoordinated manner, which is leading to a re-nationalisation of European energy policy and thus hindering the functioning of energy markets.

"In particular," said Venturini, "I'm referring to the implementation of Capacity Remuneration Mechanisms (CRMs) at national level, which are often designed and still remain as an excuse for supporting dying conventional assets… From an international operator's point of view, such as Enel Green Power, Europe looks like a colour puzzle filled by a patchwork of policies that are the sum of a plurality of interests but satisfies no one."

His thoughts were echoed by Alberto Pototschnig, Director of ACER (Agency For The Cooperation Of Energy Regulators), who gave his view on the integration of renewables and related aspects. The agency had been called by the European Parliament to give its opinion on CRMs in early 2013. It presented a report entitled: 'Capacity Remuneration Mechanisms And The Internal Market For Electricity' in July that year.

"Since presenting our position," said Pototschnig, "We have in a sense been waiting for things to happen. We might come out with something else later this year if we see a blueprint [from the European Commission]. In this year's Market Monitoring report we may have a section on CRMs to update the picture from 2013.

"We can discuss whether a CRM is needed or not, under what conditions; there should be an assessment and then it should be designed one way or another. Hopefully we will agree with the blueprint. This is how we have proceeded in the past with other parts of the target model."

A common understanding or vision on CRMs would facilitate implementation across borders and minimise market distortions.

"We believe that completing the implementation of the target model we have at the moment, i.e. completing the energy market, is a pre-requisite and basis for any additional mechanism that has to be put in place to tackle the adequacy problem," said Pototschnig.

This is spelt out in the Energy Union communication and is still the political position of the European Commission.

However, a number of different mechanisms are being implemented or are already in place that are very diverse.

"These," said Pototschnig, "are being developed in an uncoordinated way and looking mostly at national conditions and national concerns."

With capacity mechanisms already achieving significant traction he said the question is not so much whether capacity mechanisms are needed. "The challenge," he said, "is that such a diversity in national schemes does not distort the single energy market."

Some argue that, theoretically, CRMs would not needed if prices were left free to vary without government intervention. But this is not how the market works and investors cannot be sure that ministers will not intervene if prices go very high. Further, to expect no interventions during the lifetime of an asset that runs for 30-40 years is somewhat unrealistic.

While investor certainty is important – and most investors would prefer that politicians do not interfere with energy markets – this is not the number one concern of governments. Their top priority is keeping the lights on.

Many industry observers therefore agree that some sort of capacity mechanism is needed in the current situation.

The problem, however, is, although all agree that harmonised policy is the best way forward, there is perhaps no one size fits all solution.

Ignacio Vizcaino, Director of Regulator Affairs at Iberdrola said: "You need a different answer for each different problem, so talking about a detailed blueprint for a capacity mechanism is not very realistic in our opinion. Of course the idea is to have a single market with more or less the same capacity mechanism but that is not the situation right now."

He emphasised that we should not miss the point that a capacity mechanism is put in place to counteract the effects of specific market failures and regulatory interventions. So if states do not have the same market failures and regulatory interventions, the same recipe cannot be applied to all.

Nevertheless, Vizcaino stressed that doing nothing is not an option. "There are no perfect solutions but you have to do something," he said

Stephen Woodhouse, Director, Pöyry Management Consulting put forward the concept of reliability options on CRMs as a possible blueprint.

Despite the challenge Pototschnig remains optimistic. "We have a good deal in place, and my sense is that we are slowly getting there. A few years ago you couldn't mention reliability options; today they have been mentioned again and again."

Woodhouse perhaps summed it up best in saying: "We are not living in times of 'Big Europe', we are living in times of nations fighting Europe. Even if they had the legal right to do so, I cannot envisage the Commission blocking a national capacity mechanism a government says is required for its security of supply. I don't think the Commission would want to even if they had the legal right to do it.

"But I also agree the national patchwork is a dreadful route forward; we need to set up some pathway to a harmonised scheme."

Few would disagree. But unfortunately the patchwork quilt is already in the making. It may be horrible and not truly fit for purpose but perhaps it is better than nothing.