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International Gas Report

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Gazprom keen to build pipes

Putin visit to strengthen EU ties, but analysts doubt wisdom of more pipes

Russia's gas giant Gazprom and Dutch gas system operator Gasunie are expected to sign a memorandum of understanding on a planned expansion of the 55 billion cubic meters/year Nord Stream gas pipeline to northern Europe. The UK major BP has also expressed interest in taking a stake in two more Nord Stream lines.

Russia's president, Vladimir Putin, is due to visit the Netherlands on April 8 and an agreement with Anglo-Dutch Shell relating to exploration work in Russia's Arctic is also a possibility, say reports.

Doubling Nord Stream to 110 billion cubic meters would make Ukraine unnecessary as a transit country well before the end of this decade, by giving Russia over 200 Bcm/year of alternative export capacity, even excluding the Blue Stream to Turkey.

This is at a time when Europe's gas demand is uncertain, owing to a host of environmental objectives enshrined in law. Even if Gazprom sold as much every month to Europe as it did in March, that would still only be 173 Bcm.

Nevertheless, Gazprom CEO Alexei Miller and the CEO of its Yamal parter EuroPolGaz, Miroslaw Dobrut, have also signed an MoU to build a second line of

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Russia makes hay as snow falls

Russia's gas giant Gazprom sent 14.4 billion cubic meters to Europe in March, up 26% year on year as cold temperatures gripped the region.

In the first quarter, Gazprom's gas exports totalled 41.4 Bcm, up 6% year on year, a company source said, using preliminary data. Unusually cold temperatures, coupled with high spot prices, sparked greater use of Gazprom's gas in March. Russia's total gas exports, including to the former Soviet republics, amounted to 18.475 Bcm in March, up 17% year on year, according to data published April 3 by the energy ministry.

Despite the increase in gas exports, Gazprom's gas output reduced 6.8% year on year to 43.682 Bcm in March.

The drop surprised analysts, given increasing exports and the fact that March was one of the coldest in Russia in the last 60 years. "We were quite surprised to see these negative production dynamics in March," analysts at VTB Capital said April 3.

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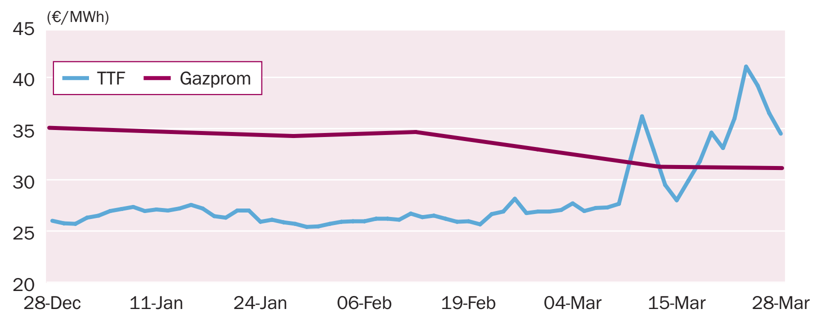
Dutch TTF (D+1) vs Gazprom equivalent (estimate)



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the Yamal-Europe gas system, which would bring capacity to some 220 Bcm/year.

The first Yamal line can carry up to 33 Bcm/year and the second, 15 Bcm/year Yamal-2 line would run in parallel to the first line up to the Belarus-Poland border, from where it would divide to carry gas to Slovakia and Hungary.

The first line flows across Poland into Germany, linking up with the Jagal line, owned by Gazprom and Wintershall.

Poland's gas importer PGNiG and the government in Warsaw – which is trying to reduce the country's dependence on Russian gas imports – were quick to distance themselves from the MoU.

Analysts have suggested the agreement was part of Russia's current war of words with Ukraine over gas transit and pricing, and that Yamal-2 would likely never see the light of day.

UBS and Russia's VTB estimate the projected Yamal-Europe line project would add more than $5 billion to Gazprom's already significant capital expenditure program.

Representatives of Gazprom and national energy company Naftogaz Ukrayiny are due to meet later in April to discuss joint operation of the Ukrainian network.

The third Nord Stream line is expected to deliver first gas in 2017 and the fourth line, if there is a decision to build it, in 2018, Nord Stream said in January.

Gazprom controls a 51% stake in the first two lines of Nord Stream. The other shareholders are BASF/ Wintershall and E.ON Ruhrgas, each with 15.5%, as well as Gasunie and GDF Suez, each with a 9% stake. — *Dina Khrennikova, Adam Easton*

Russia makes hay as snow falls

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Lower temperatures, however, supported production by Russia's second biggest gas producer Novatek, which increased its daily output last month by 5.9% year on year to around 4.43 Bcm, they noted.

The analysts believe that the cut in Gazprom's output could be explained by three factors: a decline in domestic gas consumption although given the weather in March, they did not see this as likely; a substantial decrease in Gazprom's market share in Russia; and gas being extracted from underground storage instead of higher production.

"The first two developments would be negative for Gazprom, while the third would be quite an unusual change from common practice, in our view," the analysts added.

Domestic gas use in Russia rose 1.8% year on year to 50.801 Bcm, the energy ministry's data showed. Russia's total gas production in January-March amounted to 183.511 Bcm, down 0.9% year on year. This includes Gazprom's overall production at 135 Bcm, down 4% year on year.

Russia's largest independent gas producer Novatek increased its total gas production in the first quarter by 9.7% year-on-year to 16.1 billion cubic meters, a company spokesman said April 3, citing preliminary results.

The increase was a result of production growth at the West Siberian Yurkharovskoye field following the launch of the fourth stage of its phase two development in October 2012, the spokesman said.

Launch of the second phase at the Samburgskoye license area in late 2012 also contributed to Q1 production growth, he said. The Samburgskoye license area includes the Urengoyskoye, North-Esetinskoye and East-Urengoyskoye oil and gas condensate fields.

Novatek increased its 2012 natural gas production by 6.3% year on year to 50.51 Bcm, the company said earlier. — *Nadia Rodova, Dina Khrennikova*

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Tamar eases Israel's prices

Israel has begun producing its own gas once more, with the start-up on the Tamar field in April. The effect on consumers – no longer forced to pay up for refined products – could mark a turning point in their fortunes.

Israel's huge Tamar offshore field began supplying much-needed natural gas to the country's domestic market on April 1. It is expected to be the sole source of gas for the domestic market at least until 2015, and consumers are already looking forward to lower fuel bills.

Initial volume from the Tamar field will be 1 billion cubic feet a day. Capacity is expected to be increased to 1.2 Bcf/d by late 2014 or early 2015 with the addition of four compressors at the Ashdod receiving terminal.

According to partner Delek Group, production at the field, which is some 90 km west of Haifa off Israel's northern Mediterranean coast, will peak in 2016 at 11.88 billion cubic meters, and that is expected to coincide with the beginning of production at the even larger Leviathan field.

The Tamar consortium, comprised of Noble Energy and its Israeli partners Delek Drilling, Avner Oil and Gas, Isramco and Alon Gas Exploration, has signed eleven supply agreements with local customers with a commitment to supply up to 170 Bcm of gas over the next 15 years.

Last month an updated report by Netherland, Sewell & Associates revised upwards estimated resources in the Tamar field to 283 Bcm. The report said that the size of the reserves may continue to grow by a further 44 Bcm.

Based on Israeli government projections total revenues from the sale of gas from the Tamar field will rise from $1.184 billion in 2013 to double that figure in 2015 and then rise gradually to around $3 billion annually. Over the next 30 years the Tamar field is expected to generate $76 billion in revenues of which $37 billion will go to state coffers from royalties, income tax and the special tax on the gas sector.

The largest customer will be Israel Electric Corp which has committed to purchase 42.5 Bcm with an option to buy as much as 99 Bcm. In the past two years IEC has been forced to switch to gasoil and fuel oil as a result of the severe shortage of gas supplies following the cut off of deliveries of Egyptian gas and the faster than expected depletion of the Mary-B reservoir off of Israel's southern Mediterranean coast.

Last year natural gas accounted for only 14% of IEC's fuel mix, down sharply from nearly 40% in 2010. Gasoil and fuel oil accounted for 22% of the utility's fuel mix. IEC used nearly 2 million mt of gasoil and 1 million mt of fuel oil to replace the shortage of gas supplies in 2012. IEC has said that it expects to discontinue use of fuel oil this year and substantially reduce gasoil demand.

IEC predicts that gas will account for about 30% of the fuel mix this year and rise to 80% in 2020.

Big savings from gas

After IEC, the next largest customers are three private power producers: Dalia Power Energies, Dorad Energy and OPC Rotem.

Their three power plants will have a combined capacity of over 2 GW and are due to come on line in the next two years and will represent the first real competition for the state owned utility.

The other local customers that have signed contracts are primarily industry. The savings for industrial clients will run into the tens of millions of dollars a year.

Bazan Group, which holds a majority interest in the country's largest oil refinery in Haifa and a large petrochemical complex, estimates it will save $130 million in energy costs annually by completely switching over to natural gas.

Peak shaving plans

In addition, Israel's energy and water ministry granted the use of the nearly depleted Mary B reservoir for storage.

This would enable the consortium greater flexibility for deliveries to the domestic market during off peak hours. The ministry estimates that the additional capacity will enable volumes to go up to 1.5 Bcf/day in 2015. Additional receiving terminals are being planned but they are not expected to be on line before 2015 or 2016 at the earliest.

Israel's prime minister Benjamin Netanyahu said as the gas flowed: "This is an important day for Israel's economy and an important step towards independence in the field of energy." He added that the gas will benefit Israel's economy and its citizens in the years to come.

Israel's finance ministry estimated that the gas from Tamar would lead to an annual savings of $2.5 billion in energy imports and in indirect benefits to the economy. The Bank of Israel estimated that GDP would increase by an additional percentage point in 2013 as a result of the Tamar offshore field.

In addition to the domestic market the Tamar consortium is looking to export some of the gas. In March the consortim signed a letter of intent with Gazprom for the sale of 3 million mt/year for 20 years (*IGR 719/29*). However exports will be dependent on approval of the recommendations of a government panel that called for allowing foreign sales of up to 500 billion cubic meters of gas through 2040.

Israel's new government announced just after taking over in mid-March the setting up of a task force to decide on the fate of gas exports and deal with speeding up the delivery of natural gas to the domestic market. The government which took office in early April is expected to take up the issue of gas exports in the next few weeks. In August a government appointed panel recommended the approval of exports of 500 Bcm through 2040 and retaining 450 Bcm for domestic use. The previous government delayed a debate on the recommendations until after the January elections and the new one will now have to determine whether to accept the recommendations or amend them. — *Neal Sandler*

US Cove Point signs up Asian customers

A gas liquefaction terminal in the US northeast could be operational by 2017, providing two Asian companies with a tolling service that is well placed to take gas from the prolific Marcellus and Utica shale.

Dominion, which owns the Cove Point LNG import terminal in Maryland's Chesapeake Bay, said it plans to file an application April 8 with the US Federal Energy Regulatory Commission seeking approval to build a 5.25 million mt/year LNG liquefaction and export facility at the site. The Richmond, Virgina-based company also said it had signed 20-year terminal service agreements with Pacific Energy Summit, a US affiliate of Japan's Sumitomo, and Gail Global (USA) LNG, the US unit of Gail. Each company has agreed to take half of the export terminal's planned capacity.

Sumitomo said it had signed agreements to provide regasified LNG to Tokyo Gas and Kansai Electric Power. Gail is India's largest gas processor and distributor.

Gail's chairman, BC Tripathi, said the deal would "enhance Gail's scale of operations in the US, where we already have a presence through our participation in a shale gas asset in the Eagle Ford basin." He said Gail was enthusiastic about Henry Hub indexed LNG exports from US, hence the signing of a second LNG terminal service agreement with a US-based company.

"The contracts signed with Cheniere and Dominion make Gail one of the largest Henry Hub LNG portfolio holders and provide us an opportunity to market about 6 million mt/year of LNG from the US."

Gail in 2011 signed a 20-year LNG sale and purchase agreement with Cheniere Energy Partners for 3.5 million mt/year of LNG supplies from the Sabine Pass LNG terminal in Louisiana.

Dominion has also awarded an engineering, procurement and construction contract for new liquefaction facilities to IHI/Kiewit Cove Point, a joint venture between IHI E&C International Corporation of Houston and Kiewit Corporation of Omaha, Nebraska. The project has an estimated cost of $3.4-$3.8 billion.

"Japan and India are important allies and trading partners of the US that are in need of secure sources of natural gas and Sumitomo and Gail are high-quality companies working to meet those needs," Dominion CEO Thomas Farrell said.

Access to shales

While the gas liquefied at Cove Point may be sourced from a wide variety of areas, Farrell said the facility would have direct access to the Marcellus and Utica shale plays, two of the most prolific natural gas basins in North America.

"No other proposed liquefaction facility can provide the strategic value in terms of supply and location," Farrell said. "We believe that having achieved these milestones of signed terminal service agreements, an EPC contract and our FERC filing, we are well positioned to obtain permission from the US Department of Energy to move forward with this vital infrastructure project," he said.

If it receives required regulatory approvals, Dominion said it plans to start construction of the facility in 2014 and put the liquefaction facilities in service in 2017. Dominion also said Sumitomo and Gail have signed precedent agreements for service on the 88-mile Cove Point pipeline, which connects the facility to a interstate pipelines in northern Virginia.

The customers will procure their own natural gas and deliver it to the Cove Point pipeline. Dominion will liquefy the gas, store it and load it into tankers brought to the facility on the Chesapeake Bay. Dominion will provide a tolling service, and will not take title either to the natural gas or the LNG.

The Department of Energy has already approved Cove Point's application to export 1 Bcf/d of LNG to free trade agreement countries. Its application to ship LNG to non-FTA countries is still pending at DOE.

Sumitomo signed heads of agreements to supply 1.4 million mt/year of LNG to Tokyo Gas and 800,000 mt/year of LNG to Japan's Kansai Electric, priced off the US Henry Hub, the companies said.

Tokyo Gas gas established a wholly owned subsidiary, TG Plus, which signed the heads of agreement with Sumitomo. Tokyo Gas will enter into an LNG sale and purchase agreement with TG Plus to import LNG to Japan.

"We have established this company to [allow ourselves] a degree of freedom in selling LNG [to other markets] when the company cannot bring LNG to Japan," Kunio Nohata, executive officer and senior general manager at the gas resources department at Tokyo Gas, said at a joint press conference.

For Tokyo Gas, this deal is part of its ongoing strategic efforts to increase its flexibility, Nohata said. The Cove Point LNG would not have any destination restrictions, he added.

In an interview with Platts in September 2012, Nohata had said that Tokyo Gas aimed to import "more or less than 1 million mt/year" out of the proposed 2.3 million mt/year of LNG from the Cove Point project (*IGR 707/1*).

He added then that Tokyo Gas and Sumitomo were in talks with its prospective customers for marketing the remaining 1.3 million mt/year of Cove Point LNG.

A senior Kansai Electric official told Platts March 22 that the Osaka-based power utility was in talks with the Cove Point project to buy LNG as it tried to not only diversify its supply sources, but also pricing benchmarks in a bid to cut import costs.

With its expected LNG sales to Tokyo Gas and Kansai Electric, Sumitomo has sold "almost all" liquefaction volume from Cove Point LNG. Sumitomo and Tokyo Gas aim to conclude by June details on establishing a tolling agreement company, which will be jointly operated by the two companies, Nohata said.

Nohata told Platts that he understood Dominion was "in the final stages" of a final investment decision on the project, but declined to elaborate.

Barnett Basin

Separately, Tokyo Gas March 29 concluded a sales and purchase contract with New York Stock Exchange-listed independent oil and gas producer Quicksilver Resources to acquire a 25% stake in US Barnett Basin in Texas, marking its foray into shale gas development in the US.

Tokyo Gas March 29 said it acquired the 25% stake at $485 million through TG Barnett Resources, a wholly owned subsidiary of Tokyo Gas America Ltd.

These assets, operated by QRI, produce 275 million cubic feet/day equivalent of shale gas and natural gas liquids marketed in the US market.

TGBR's share of gas production, which is forecast to be some 350,000-500,000 mt/year in terms of LNG volume, will be marketed in the US, the company said.
— *Takeo Kumagai*

Statoil's fast-track field program succeeds

Norway's Statoil has caught the oil and gas industry's attention with its new fast-track program designed to bring new, smaller and previously uneconomic fields online at twice the pace of bigger resources.

Norway has managed to defeat the pessimists with its strategy for squeezing more value out of its offshore oil and gas reserves. Some analysts say other countries might benefit from copying Norway's fast-track techniques developed offshore. "In some ways this is evolution," Arctic Securities analyst Trond Omdal told Platts. "Improving project management, parallel activities, standardization, improved integration with suppliers – some of these principles can definitely be applied to other places," he said.

S&P analyst Christine Tiscareno said Statoil also had first-mover advantage in fast tracks on sector rivals. "I think Statoil is technologically more advanced than other companies and the advantage is that it has the skill and resources of a big company but it is not as constrained as a company like ExxonMobil," she said.

"It's only recently that they went global. Their emphasis was always 'let's make the most of what we have.' So if they applied that in the Gulf of Mexico and other places, then yes indeed I do think that others will follow," she said.

"If oil prices stay at these levels, everyone is beginning to try to extract as much as possible of what they have got.

It's a new trend in the industry. It's just that Statoil started earlier," says Tiscareno, who rates fast-tracking as a big success even though it's still early days in the program. S&P, like Platts, is part of the McGraw-Hill Companies.

Smaller critical mass

On March 25, Statoil announced production had begun at its new $920 million Stjerne oil and gas field, 13 km southwest of the Oseberg South platform in the North Sea.

Stjerne is the fifth of Statoil's fast-track projects in production so far: new fields which have a smaller critical mass that would be uneconomic as stand-alone units, but when tied back to infrastructure of nearby existing bigger fields become viable. More are set to be rolled out offshore Norway.

"This is a good example of how to make smaller discoveries profitable," said Halfdan Knudsen, chief of Statoil's Norwegian fast-track development portfolio.

Discovered in 2009, Stjerne has recoverable volumes of 49.2 million barrels of oil equivalent and will produce just 7,800 boe/d or so.

While Stjerne may be a small pebble comparatively in Statoil's universe, the company says it is symbolic of its larger change in mindset to refocus on previously neglected and forgotten smaller resource nuggets in mature areas as part of its overall development strategy.

S&P analyst Tiscareno says Statoil's birthplace as a producer offshore Norway, which led to decades of intensive production in the North Sea, where until only recently new discoveries were failing to replenish mature fields, created the pre-conditions for fast track.

"They have one advantage that other companies don't have, which is they have their major production concentrated in one area, an area they know very well," she said.

"They are taking advantage of the fact that, with these high oil prices, it's silly to leave anything behind. If you pick up all the bits and pieces it adds up and it does make an impact. The infrastructure is there and it adds to the mix."

Oil from Stjerne, earlier known as Katla, is being piped to nearby Oseberg South, with the gas used as pressure support in Oseberg Omega North to boost output from that reservoir.

Faster development still needed

Big new fields from discovery to first oil normally take about 6-7 years and cost billions of dollars. One of the biggest discoveries ever made offshore Norway, Johan Sverdrup, with estimated recoverable reserves of up to 3.3 billion barrels, was discovered in 2011 and first oil is not expected until late 2018.

Stjerne, by contrast, once added to Statoil's fast-track portfolio, came onstream in 39 months, and the company says that is still not good enough.

It says its ambition is to cut this timeframe to an average of 30 months for new fast-track fields as it gains experience.

Only the week before Stjerne, Statoil announced another production start at its $1.7 billion Norwegian Sea Skuld oil and gas field, with recoverable reserves of 90 million boe. Skuld is connected to production vessel Norne, which is also producing for the Norne, Urd, Alve and Marulk fields.

A fortnight before that Statoil announced first oil at its new $750 million Vigdis north-east oil field located in the southern part of the North Sea, with volumes of about 37 million boe.

Globally, Statoil can now count on massive new discoveries like Sverdrup, as well as major resource purchases such as the North American shale oil and gas interests. It can also count on new exciting discoveries in new areas offshore Brazil and Africa as it evolves into becoming a more global player and less Norway-centric, as well as a general push to better oil recovery rates. But if Statoil is going to meet its stated target of achieving a 25% increase on 2012 output of 2.004 million boe/d to 2.5 million boe/d in 2020 then it says the fast-track fields program will also play a key role.

The program started early in 2010 and by the following year it had mapped out a shopping list of planned fast track projects: Visund South, Katla, Vigdis North-East, Gygrid, Fossekall and Dompap, Vilje South, Visund North, Gamma/Harepus and the Snorre B template.

Statoil said at the time that it aimed to have close to five fields in operation at the turn of the year 2012 to 2013 and to "maintain this level in the years ahead." Analysts say it has comfortably met that brief.

They also say it is indisputable that Statoil has become perhaps the foremost industry exponent of fast tracking small fields into production quickly and efficiently.

Replica model

But others are not so sure whether the lessons learned and the techniques gained from that experience can be rolled out wholesale internationally by other oil and gas groups.

"[Statoil] sits on so many of these small, satellite fields that are close to home for them. No one else among the

European majors has that," said one analyst who did not want to be identified. "You had BP a few years ago talking about the same technique used in say the Gulf of Mexico, but it just cannot go as far as what Statoil is doing, because there is simply not as much infrastructure there than in the North Sea," the analyst said.

"So the North Sea is the best basin where you could apply that tactic, by using mature infrastructure that would be shut down anyway in five or 10 years' time, on satellite fields," the analyst added.

Arctic Securities' Omdal agrees some conditions are particular to Norway for fast track, where there are many mature fields running down to the end of their productive lives, but he said the techniques Statoil was developing still had wider relevance.

"Some of it is specific to Norway in terms of infrastructure, a competent and co-operative supply industry and the Norwegian government making it easier with its development requirements," Omdal said.

"But Statoil has the advantage in that they are so dominant in Norway ... they can be an industry architect. Because they are so dominant in Norway, can they apply it globally? Maybe, yes," he said.

"You have to remember that techniques vary according to the geology," said S&P's Tiscareno.

"So even one technique used in the south [of the North Sea] might not be applicable in the Bering Sea, but the concept is applicable." — *Patrick McLoughlin*

US exports must be 'unfettered'

The US energy industry must vigorously oppose efforts to restrict exports of liquefied natural gas if the country is to retain its repuation for consistency, but the petrochemicals industry wants to keep its advantage.

Major US chemicals producer ExxonMobil has warned that any attempts to limit exports of liquefied natural gas would be seen as a betrayal of the country's free trade principles.

"These proposals to block LNG investments justified by artificial price caps represent a selective and harmful departure from the free market and free trade principles," its chemicals president Stephen Pryor told the IHS World Petrochemical Conference, speaking hypothetically as so far no caps have been imposed.

Calling them an affront to US trading partners, Pryor said such protectionist measures would undermine efforts to build closer trading ties and hurt domestic markets as well.

"For example: Why should the EU block tariffs on American chemicals made from advantaged natural gas, if the US blocks exports of that gas in liquefied form?" Pryor said.

"Likewise, how can the US secure sanctions against China for restricting exports of rare-earth minerals, without inviting sanctions on the US for restricting exports of natural gas? And how can the US ask Japan, a close ally still suffering from energy shortages, to stop importing oil from Iran, if we prevent Japan from importing gas from the US?"

ExxonMobil is one of several oil and gas majors planning to export LNG as a way to relieve the glut of natural gas in the US caused by increased production from shale plays. US proven reserves of natural gas have increased nearly 50% since 2005, Pryor said.

Other companies seeking to export LNG include Anglo-Dutch major Shell, French Total and UK major BP, although exports from Alaska, where BP is considering a share in a 17 million mt/year plant with US majors ConocoPhillips and ExxonMobil belong in a different category from exports in the lower 48 states. Alaska as very little alternative market for its vast gas reserves. DOE has received more than two dozen export applications.

ExxonMobil wants to export natural gas through the Golden Pass LNG Terminal, a joint venture in Sabine Pass, Texas, that also includes Qatar Petroleum as the majority partner and ConocoPhillips. The terminal, now an import-only facility, has a capacity of 2 Bcf/d.

Pryor pegged the cost of retrofitting it by installing up to 2.6 Bcf/d of liquefaction capacity, at $10 billion.

Restricting LNG exports would go beyond affecting trade relationships, Pryor said. It could return the US to the days of price controls in the 1970s and 80s, which caused drops in production and supply shortages, he said.

"Protectionist pleas are often wrapped in pious appeals to nationalism, but the real agenda is to unlevel the playing field and stifle the competition," Pryor said. "As an industry we must vigorously oppose protectionist measures that limit access to markets around the world. We must also promote free-trade initiatives.

"Likewise, we must oppose protectionism in our home markets, such as calls to restrict natural gas exports," he said.

New Anga boss seeks conciliation

The newly named head of America's Natural Gas Alliance has his work cut out for him: shepherding coming federal regulations on LNG exports while seeking to end the feud between gas producers and some of the country's largest end-users.

Dow Chemical and the National Association of Manufacturers have left the American Chemistry Council over the ACC's endorsement of US LNG exports.

Martin Durbin, executive vice president of the American Petroleum Institute, will become president and CEO of Anga on May 1, the gas producer trade group announced late March.

He will replace Regina Hopper, the founding CEO who resigned after three years.

Before lobbying the government for API, Durbin directed political programs and lobbying for the ACC.

"These are important customers for this industry," Durbin told Platts. "There is going to be enough of this resource."

The nephew of the second-ranking Democrat in the US Senate, Illinois Democrat Dick Durbin, also plans to get Anga more deeply involved in Congress' and the Department of Energy's policymaking process for LNG exports.

"Anga wants to help make policy," he said, noting that he also plans to engage the Republican-controlled House and the Obama administration. "I see this as a great time" to move the LNG export debate ahead.

The market, not the government, should determine how many LNG terminals are permitted to export gas overseas and "DOE should move on the permits," Durbin said

DOE is still studying how many permits it should issue for exports to non-free trade agreement countries, which include major gas consumers such as Japan.

It has granted only one non-FTA permit, to Houston-based Cheniere Energy's Sabine Pass, Louisiana, terminal.

Durbin's lobbying efforts will take him near his uncle's Capitol Hill turf, the Senate Energy and Natural Resources Committee, where newly named chairman Ron Wyden, an Oregon Democrat, and ranking member Lisa Murkowski, an Alaskan Republican, have jointly said they intend move LNG exports to the top of the legislative agenda.

"This may be the only committee in the Senate that can get something done," Durbin said, citing Wyden and Murkowski's good working relationship. "The good news is that they are going to be very focused on this issue."

Senator Durbin does not sit on the energy committee. — *Bill Holland, Bernardo Fallas*

UK stresses renewables, fossil fuels

The UK has replaced its energy minister – an outspoken opponent of wind farms – with a keener advocate of renewables. But government has also stressed the importance of the North Sea for revenues and jobs.

To the delight of many environmentalists, the UK government replaced its energy minister John Hayes in late March after seven months in the job.

At the same time it pledged to secure "billions of pounds" of future investment for the country in a new oil and gas strategy.

In a mini cabinet reshuffle by the UK prime minister David Cameron, Hayes was replaced by Michael Fallon, a Conservative MP who will expand his existing role as the UK's business minister at the Department for Business, Innovation and Skills. Hayes will become Cameron's parliamentary adviser as Cabinet Office minister, with a remit to act as a link man with backbench lawmakers, the government said.

In his short career within Department for Energy and Climate Change, Hayes was dogged by national press reports that showed he had independence of thought where wind farms were concerned.

He told the UK's *Daily Telegraph* that "enough is enough" for onshore wind; and before joining DECC he had been outspoken in his opposition to any onshore wind generation subsidies.

Hayes also had high-profile differences at the DECC with his boss, the Liberal Democrat Energy Secretary Ed Davey, and has voiced criticism of European Union's climate targets.

Fallon, who is also deputy chairman of the Conservative Party, will help to "join up" the government's work on low-carbon industries like nuclear and offshore wind, the DECC said.

"Energy policy has a key role to play in securing sustainable future growth in the economy, strengthening supply chains, keeping people's bills down and tackling climate change," Fallon said.

Upstream oil, gas still supported

Fallon's appointment also came within hours of the government announcing a new "oil and gas strategy" aimed at promoting billions of pounds worth of new investment in the aging North Sea.

The long-term strategy, which does not include any new policy measures or targets, largely reaffirms offers to encourage North Sea investment, boost supply chains and promote engineering exports from the sector.

The strategy seeks to underpin investor confidence to fully exploit the UK's remaining oil and gas resources with a a pledge to maintain fiscal regime and tax breaks on more costly field developments.

Announcing the strategy, Fallon's business ministry said it wants to further promote innovation to boost supply chains, exporting skills to other countries and bringing new skills to the industry, while tackling a growing engineering skills gap in the sector.

The UK oil and gas industry expects it will require an additional 15,000 staff over the next 4-5 years across a range of disciplines, the ministry said. It said it is looking at a possible program to retrain ex-military personnel to redeploy them in the oil and gas industry.

The government's so-called "business bank" will help small and mid-sized businesses access finance, it said, noting that GBP7 million has been granted to Newcastle University to set up a subsea and offshore engineering research center.

"This is an expanding industry. We can either help create more jobs and opportunities across the UK if we get this right. Or see work going overseas if not," UK Business Secretary Vince Cable said.

Gas production boost

North Sea oil and gas operators welcomed the publication of the strategy as "one more step in the right direction" to secure investment and create jobs in the sector.

"The strategy fosters strong and meaningful collaboration between the government and industry and will help to focus efforts on addressing particular areas such as skills, technology and exports," the CEO of Oil & Gas UK Malcolm Webb said.

Webb noted that record investment in the offshore industry is forecast this year followed by a brief upturn in North Sea production from 2014 as a number of new projects come on stream.

The industry association last month estimated that UK offshore oil and gas investment rose to its highest level in 30 years in 2012 thanks to recent tax breaks but noted that oil and gas output fell to 1.55 million b/d of oil equivalent.

OGUK said, however, it still expects combined oil and gas production to reach some 2 million boe/d in 2017, unchanged from its forecast this time last year.

The UK government has extended a number of tax breaks for North Sea producers and removed doubts over offshore decommissioning costs in recent year to help extend the life of the North Sea's aging oil and gas industry.

Including estimates of reserves yet to be found in the UK, the government estimates that the country's remaining recoverable oil and gas resources are close to 20 billion boe.

Last year, UK oil production fell by more than 14% to less than 1 million b/d as natural field declines in the North Sea and a number of outages continued to shrink output.

UK oil production has fallen steadily since reaching a peak of 2.84 million b/d in 1999 when the country's net exports were 972,000 b/d. The country became a net importer of crude oil on an annual basis in 2005 and a net importer of oil and products in the following year.

OGUK told Platts that it had found that 11 dry gas projects had been approved since the start of 2011, which, combined, will produce around 45 billion cubic meters of gas over time. Three quarters of this future gas production has been enabled as a result of a field allowance.

"Furthermore, there will be associated gas production from oil and condensate fields approved since 2011, the majority of which also receives a field allowance," it said. — *Staff*

Europe's winter puts spot gas at premium

The cold weather in northwest Europe this winter pushed spot prices above oil indexed prices, giving utilities some relief against their take-or-pay exposure and revealing differences in storage provision across Europe.

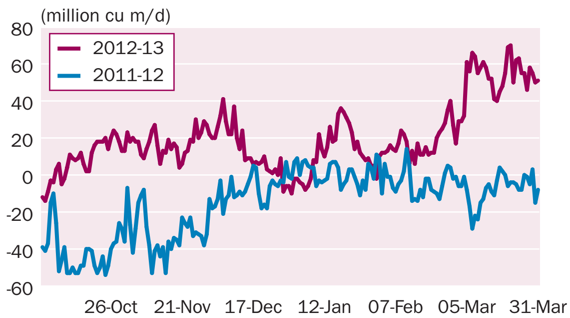
Spot gas prices over the last few months have overtaken oil indexed prices for prompt deliveries in northwest Europe, according to Platts' estimates.

And in the UK, where oil indexation still has a strong effect by virtue of its physical links with the continent, the prolonged cold spell has raised many questions of policy and markets.

Comparisons with the winter before, which was much milder, also show unexpected trading patterns as Latin America entered the spot market, outbidding Asia (*IGR 715/1*), Qatar fixed more deliveries to Asia, and Nigeria had supply problems. And Angola LNG remained obstinately out of commission. The end result was much less LNG to Europe as a whole and the UK in particular.

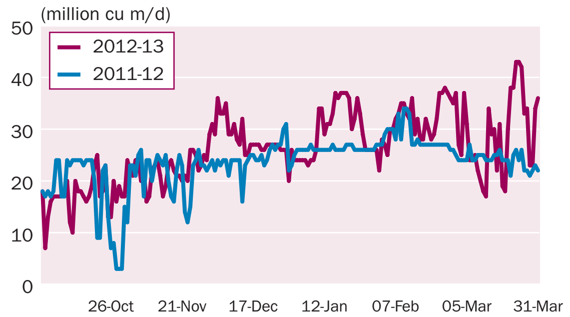
The UK-Belgium Interconnector stepped up to compensate, carrying much more gas this year into the UK than last year (*see graphs*). Incidentally, only Russian Gazprom remains of the original shareholders in the pipeline company. Following regulatory unbundling of supply and transport, Gazprom still has 10%, the other shareholders all being either pipeline companies linked to Belgian Fluxys, or pension funds.

Interconnector flows



Source: Bentek Energy

BBL flows



Source: Bentek Energy

Companies oppressed by take-or-pay conditions and oil indexation will have had the chance to catch up on some of their shortfalls, finally able to sell contracted gas at the even more expensive hubs.

Normalized relations between Ukraine and Russia as well as new capacity in the form of the second Nord Stream line have allowed flows to Europe from Russia to rise (*see page 1*).

British energy regulator Ofgem is doing some analysis of the operation of the Interconnector and the Balgzand Bacton Line, and is not commenting yet on its findings. However so far this year, the market has functioned as it should: without as much LNG coming in, pipeline deliveries have been running at or near capacity from those two sources.

Ofgem's CEO Alistair Buchanan often claims that continental markets do not always act commercially and therefore pose a risk to the import-dependent UK. In support, he quotes evidence from 2005, rather in the way that the European Commission uses the threat of a dispute between Russia and Ukraine as its perpetual justification for new pipelines and LNG terminals.

In fact the biggest supply failures occurred right on the UK's doorstep: the failure of some onshore facilities at Bacton led to an eight-hour stoppage of flows through the Interconnector. And less spectacularly, but with a more prolonged effect on prices, was the cut in Norwegian flows following problems at Nyhamna, where Ormen Lange gas is processed (*see below*).

UK storage shortage

The cold snap came at a critical point for the UK government too. The giant seasonal storage asset, Rough, had practically run out of gas by the end of March as withdrawals seemingly ate into cushion gas and leaving it facing the new injection season with a ravening appetite.

Much has been written about the eventual decarbonizing of the European energy mix and the apparent effects of global warming, combining to reduce the need for more infrastructure to store and transport gas in the future.

But also there is the need, as the UK runs out of swing production capacity, to ensure gas is available to meet the intermittency of renewables as well as heat homes.

The UK government is planning to bring out a strategy on storage this spring, and its job has become a lot harder: another mild winter and relatively low spot prices would have let it off the hook.

But the press ran numerous reports in late March about Rough only having enough gas to meet a few more hours' demand. A former energy and climate change minister Charles Hendry told the flagship Radio 4 *Today* program late in March that there was no need for a "national panic" and said that compulsory construction of additional storage facilities, paid for by consumers and used very rarely, was not the answer.

But the BBC found someone to take the opposing view: "If we put in as much storage as the Germans and the French, we would have no problem and I'm very surprised the government continues not to do that – it is a first step to getting real energy security," the chair of the Kings Policy Institute at Kings College London, Nick Butler, told the program, ignoring the large amount of gas production in the UK compared with the countries he mentioned.

Utilities on the continent have done doubly well out of the cold spell: the storage businesses have seen demand for withdrawals at record levels in order to meet UK demand; while their unbundled supply arms have finally seen the spot price first hit, and then greatly exceed, the oil indexation price, on days of high demand.

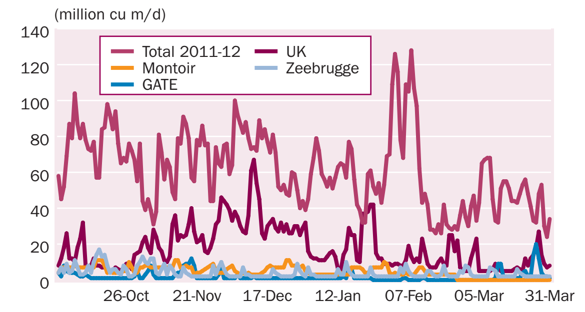
The depletion at Rough was hastened by an outage at the Norwegian Nyhamna gas processing plant that caused losses of 53 million cubic meters/day of production and pushed prompt NBP gas prices to their highest level since 2006.

While the outage only lasted a few days, the storage concerns continued. "It's the mixture of flow disruption and the low level of flexible supply – be that storage or LNG – that can come on to make up the shortfall," a trader said of increased risk premium in week 11.

He said he expected prices to stay strong: "It looks like we are pricing in gas from German gas storage. The cold over next week is a big risk, so I think the basis premium could remain quite high to make sure we attract gas to flow into the country. If it's cold in Germany as well then they will probably want a bigger premium as they will also be pricing in risk, too," he said.

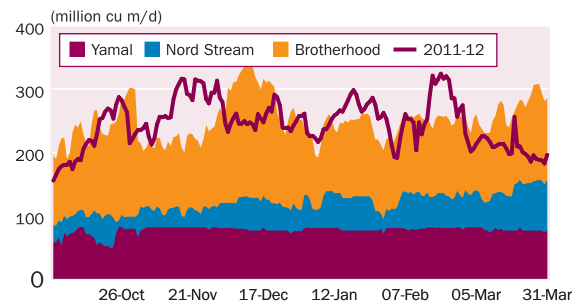
One German storage operator told Platts in mid-March that he had never seen his facilities working so hard, and that France and the UK were the destinations. Last year's cut in Russian flows to Europe led to a spike in German

LNG sendout



Source: Bentek Energy

Russian-contracted gas flows to Western Europe



Source: Bentek Energy

withdrawals and plenty of days of injection (see graph) while this year the the trend has been more downwards.

By early March, storage levels at the UK's long-range Rough storage facility were at 575 million cubic meters, allowing just 13 days of withdrawals at its maximum flow rate of 45 million cu m, although in the event it kept producing gas to the point where even the cushion gas might have been broached. There was about half as much in the UK's medium-term storage at that point.

Last year, Rough had already started reinjecting by the start of March (*see graph*). By contrast, German gas storage levels were still 50% full at 8.3 billion cubic meters at that time.

Other offshore problems

Also affecting supply was the closure of the UK's Brent oil pipeline system which impacts gas flows into the St Fergus gas terminal.

The Cormorant Alpha platform in the northern part of the UK North Sea and all related pipeline infrastructure were shut down as a precaution after oil was discovered in one of the legs of the platform, owner TAQA said.

On the other hand, the restart of Elgin/Franklin has been slow to contribute gas, as it expects to take months to reach pre-leak levels.

UK gas and power traders expressed concern over supply, especially in light of the potential colder weather could have on already depleted stocks. "If more cold weather comes, I don't know where the additional supply will come from," a UK-based power trader told Platts.

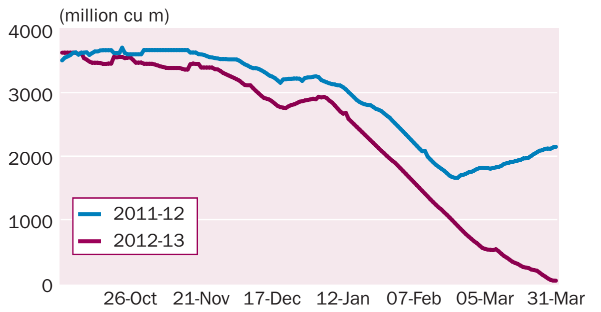
"We are maxed out on all local and nearby supply. LNG is our only hope but the Qataris are focusing on their long-term customers [and we] haven't seen anything for a while," he added.

Peakload power on the OTC market climbed £12/MWh to £68.85/MWh on the Nyhamna outage. Although coal-fired power makes up the majority of the UK's electricity production, gas-fired power output typically contributes around 30% of the generation mix, leaving power prices sensitive to pricing levels.

However, the market did not spike as dramatically as the NBP because alternative supply options elsewhere in the market remained stable.

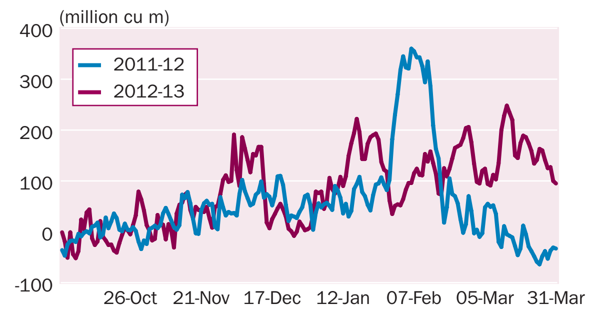
"It's a slightly different shock [for the power market]," a UK power trader told Platts. "It's just the fuel price of marginal plant which has gone up – we haven't lost any plants or experienced a weather-related price spike... so we're not needing to move to next marginal plant, such as oil-fired power," he said.

UK storage inventories



Source: Bentek Energy

Withdrawals from German storage



Source: Bentek Energy

Interconnector fails

Data collected by National Grid showed an average of about 54 million cubic meters (1.9 Bcf)/dayof gas came to the UK from Belgium via the Interconnector pipeline.

Throughout March 2012, daily shipments via the pipeline were around 14 million cu m, but in the opposite direction.

Until its brief failure the line had been flowing at maximum – equivalent of 25.5 billion cubic meters/year –taking gas from continental Europe through Belgium into the UK.

But a pump in the UK terminal suddenly malfunctioned, halting flows and trapping gas in the Belgium grid. "End of day [nominations] will not be met," the company said in an ominous statement early one morning.

Initially, the imbalance was absorbed by the linepack, the Belgian grid operator Fluxys said. Some quantities were also put into the Loenhout storage facility, which had until then been in withdrawing mode.

At the same time, action was taken to reduce flows into the area that covers the Interconnector terminal, the Norwegian Zeepipe terminal and LNG terminal.

Flows that were directly nominated from the virtual Zeebrugge trading point and the LNG terminal were very quickly rebalanced, resulting in a reduction of LNG and ZPT flows into the Fluxys grid.

As far as the physical Zeebrugge Beach hub was concerned, in order to avoid disruptions in the trade supply chain, the operator Huberator initiated the so-called automatic back-up and offtake service, whereby excess gas between the Zeebrugge Beach and the Interconnector Zeebrugge terminal was sold on to the APX-Endex Zeebrugge Trading Point market.

Shippers who bought these quantities from Fluxys, on the exchange, in turn reduced their flows from other entry points such as the French and Dutch border points to rebalance their portfolio.

As a net result of these measures, the Fluxys grid encountered no physical balancing problem, nor was there ever any safety issue, Fluxys said. Most of the market players did not even notice that there was an Interconnector problem, Fluxys, said, concluding that it had been a good test for the new entry-exit system.

Dutch market close to UK

The day-ahead price at the Dutch market was very closely aligned with the UK, owing to the connection through the Interconnector and the BBL. "When a great price difference occurs the market participants have the opportunity of arbitrage; buy gas on the hub where the price is the lowest and/or sell gas on the hub with the highest price, taking the costs for transport into account. The consequence is that the prices will be balanced," said dominant Dutch trader Gasterra.

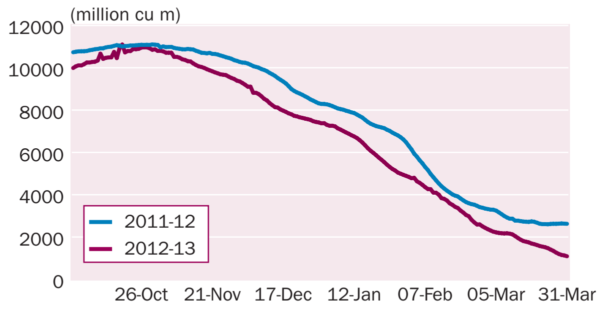
The strong coupling of prices is a consequence of the great connectivity of the markets. If there is a serious shortage in the UK, as seen on March 22, then the prompt prices on the NBP will rise and the prices on the continental hubs will follow, Gasterra said.

This backs up the view that UK shale gas production will not necessarily bring lower prices, if prices elsewhere are high. The Netherlands is a net exporter of gas, but even that is not enough to protect its consumers from price spikes in neighboring markets that rely on its exports.

Total LNG sendout between October and March was 2.99 billion cu m (105.5 Bcf), compared with 7.25 Bcm during the same period in 2011-12 and 11.86 Bcm in 2010-11, according to Bentek data.

The average price for day-ahead gas in March was 86.51 pence/therm ($13.05/MMBtu) compared with 58.46 p/th a year earlier. The UK's Met Office said provisional statistics showed March to be the coldest since 1962. "From 1 to 26 March the UK mean temperature was 2.5 degrees Celsius, which is three degrees below the long term average."

French storage inventories



Source: Platts

Average daily gas demand for the month was 329 million cu m, compared with 267 million cu m in March 2012. — *Staff*

Australia nears gas shortage

Much has been written about the plans to export gas from Australia, less about the problem that this will create for the continent's residents, contemplating shortages as rules lock away trillions of cubic feet.

Australia's most populous regions face either gas shortages in the next few years, or much higher prices – a paradox when compared with the almost unlimited potential of their coalbed methane gas reserves.

Even in the west of the continent – the heart of an LNG industry that is expected to be the world's leading supplier in the next few years – there are concerns that the exporters will soak up most of the gas. This is despite a state government measure which reserves 15% of reserves for domestic use.

Graeme Bethune, of the energy analysts EnergyQuest, says future east coast gas supply will rely on the ability of companies in the Cooper Basin, in central Australia, to produce more; and on growing production in NSW (*IGR 720/17*).

However there are possible impediments in both regions – technical in the Cooper Basin, and technical and political impediments in NSW.

There is a powerful group of farmers who are opposed to CBM in NSW and Queensland and they are making it more difficult for the emerging industry to drill and develop deposits.

CBM projects already developed in Queensland are dedicated to the rapidly developing LNG industry, which might need more reserves than have been so far committed to its long-term needs. Even if enough gas is found to satisfy both export and local demand, there is a concern that the international pricing of LNG will push up tariffs in Australia – which have already risen sharply in recent years.

Ever more stringent regulations in NSW and Queensland make it harder for CBM developers to move forward and some companies are questioning whether projects will be viable.

Governments claim they are highly supportive of the industry and that they are trying to strike the right balance between the need for more gas and the concerns of farmers.

Given the traditional political power of rural communities the outcome may not be what the gas industry wants.

Forecasts of domestic gas demand throw up another paradox: although shortages are likely, they will be in a market that will be growing at a much slower rate than was expected only a short time ago.

Several authorities have forecasts growth of only 0.5%/year, involving striking reductions on figures prepared two years ago.

EnergyQuest agrees with this figure, suggesting there will be slow growth in the mass market and for power generation for the next seven years, before it takes off once more.

Industrial demand for gas will remain flat. However even these conservative forecasts include concerns over supply.

EnergyQuest says demand for gas in the eastern part of Australia was 722 PJ last year and it asks that if this is the same figure in 2020, how will it be met?

The research firm notes that the Cooper Basin produced 94 PJ last year. By 2020 most of this will be flowing into LNG plants, with only 24 PJ remaining for domestic markets if there is no growth in production.

EnergyQuest says that it might be assumed production will be stable from Queensland fields (254 PJ) and from NSW (5 PJ), Gippsland, in Victoria (265 PJ) and Bass Strait (20 PJ).

The crunch comes in production from the Otway fields, which could fall by more than half, to about 50 PJ. There have been no significant discoveries in this basin for a decade.

Thus the total available for the eastern regions would be 618 PJ or 104 PJ less than even conservative estimates of demand.

Graeme Bethune says that “with some luck” it may be possible to meet around half of the gap from increased Cooper Basin production and the other half from NSW (in the Gloucester and Gunnedah areas).

“However there are challenges in achieving this, primarily technical in the Cooper Basin but both technical and political in NSW.”

For domestic users there remains that potential for high gas prices, even if there is an adequate supply, because to some degree there will be competition from LNG – unless governments mandate proportions of local production for local use.

However some industry sources say that this could distort markets, and discourage exploration – a theory can be tested in Western Australia, where the 15% rule is already in place.

2016 a crunch year

Spiralling gas prices and shortages could appear even earlier, by 2016, according to the Australian Energy Market Operator, which forecasts investment requirements for the gas and electricity industries.

It said the gas market was entering a transition period as gasfields in production decline, long-term contracts expire and LNG exports from central Queensland begin in 2014.

AEMO’s Gas Statement of Opportunities report says the LNG export market based around Queensland’s Gladstone was having a significant impact on the domestic market.

“If possible reserves are not developed in a timely way, potential supply shortfalls to the LNG export and domestic market may be seen towards the end of the period of increasing LNG demand in 2016,” the report says.

AEMO has not forecast how much gas prices will rise, but other studies have predicted gas prices will double over the next four years.

The AEMO report also found projected gas demand exceeds the capacity of pipelines to supply gas in several business hubs. Shortfalls are expected in Gladstone next year, Brisbane in 2020 and Townsville in 2021.

Some companies, including Dow Chemical, want state governments to limit how much Australian gas is sold overseas. In the US, Dow is also urging the government to limit the amount of gas exported, as it sees its competitive advantage escaping to where the US LNG goes.

Large industrial customers are finding it hard to secure long-term domestic prices at levels they are willing to pay.

The CEO of global aluminium giant Alcoa’s Australian operations, Alan Cransberg, recently called for governments to set aside gas for domestic industry.

However, Santos CEO David Knox said a domestic gas reservation policy would be counter-productive. The federal government’s energy White Paper also rejected the plan. AEMO’s CEO Matt Zemo said he would prefer the market to sort out the potential shortage.

“There are enough reserves, it just depends on whether people want to develop them and bring them to the market,” he said.

"Gas prices have been creeping up over the last few years but the real crunch will come near 2015-16 when all the LNG stuff ramps up."

Inpex has no spare

Perhaps the most surprising example of domestic consumers being ignored came from the Japanese company Inpex, which has pointed out that all of the gas from its Ichthys fields off the coast of north-western Australia has already been forward-sold and none is available for domestic use in the Northern Territory.

The Territory Government – a quasi state under the Australian federal structure – had suggested the company may be able to provide some gas from the fields for local demand.

Inpex responded that all the gas to be processed at its Darwin LNG plant will be committed to sales contracts. The $33 billion Inpex project will produce about 8.4 million mt/year of liquefied natural gas from the Darwin plant.

Paradoxically, Inpex originally expected to have its gas processed in Western Australia, which controls the offshore tenements where the Ichthys fields are.

It chose to pipe the gas a considerable distance to Darwin because of difficulties it faced in WA, especially related to the environment.

Inpex and its French partner Total have signed long-term sales agreements with Japanese and Taiwanese utility companies.

These cover the total projected LNG production from the Ichthys fields for 15 years from 2017.

In January, the NT government agreed to provide gas for the Rio Tinto-owned alumina refinery at Gove, about 850 km east of Darwin, from the Territory's domestic gas supplies. This gas comes from the Blacktip field, operated by Italian energy giant Eni.

At the time of the agreement, the government said alternative supplies of gas for domestic use in the Territory would be sought but there is obviously the prospect of a shortfall unless new fields are found.

Western Australia has negotiated deals on LNG projects in that state for the supply of some gas for domestic use, up to 15% of reserves.

However both the consumers and suppliers have some concerns about the ruling.

There is the hope that gas prospects close to the populated areas in the south of the state may provide reserves dedicated the domestic markets, making the issue less urgent.

Battle lines drawn in NSW

But the debate over the use of gas and other energy sources is at its most fierce in NSW, Australia's most industrialized state.

There a consortium of organizations in the energy industry has attacked the government's "knee-jerk" reaction on CBM gas legislation.

Among industry groups that have launched campaigns to protect the domestic supplies is DomGas, a group of 12 Australian utilities and major manufacturers, which produced a paper in arguing that some reservation should be placed on new gas projects, to ensure Australian consumers did not face shortages – or at the very least, soaring prices.

Other major industry players, the Australian Industry Group, Australian Petroleum, Production and Exploration Association, the Clean Energy Council, and the Energy Supply Association have united to call on the government to assess the drawbacks of its policy.

The group is highlighting the constantly contracting gas supply on the Australian east coast that is expected to cause energy prices to skyrocket. They estimate cost increases of $2 billion and losses of $3 billion in declining economic activity.

It claims planning for a future supply shortage has to be taken into account when the government makes policy decisions.

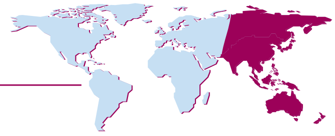
"The Commonwealth and the states face real community disquiet in relation to energy development," the letter says. "These worries can and should be addressed.

"However, the restrictions that are being imposed have not been underpinned by adequate evidence or consultation, and threaten serious consequences for the economy and Australians' quality of life."

With energy prices already rising, the bans could set the states back even further.

"We believe it is urgent that all governments take the wider consequences for energy affordability, security and sustainability into account when considering planning and development."

An example was the small company Metgasco, which in March suspended its exploration for CBM owing to the regulatory uncertainty in New South Wales. — *John McIlwraith*



ASIA-PACIFIC

Newfield finds big Malaysia field

US Newfield Exploration has made what it called a “significant” natural gas discovery in the Block SK 310 production-sharing contract area 80 km offshore Sarawak, Malaysia.

The B-14 well, in about 250 feet of water, is the The Woodlands, Texas-based company’s second pinnacle reef gas discovery in the region, Newfield said April 2. The well encountered about 1,800 feet of gross column and 1,585 feet of net gas pay in the main carbonate objective.

“This is the largest conventional exploratory success that Newfield has made in its 25-year history,” said Newfield CEO Lee Boothby. “Recent amendments to gas terms in Malaysia make natural gas developments economically competitive with oil developments. We have multiple ‘reef’ prospects to test along trend.”

Additional drilling should resume in the third quarter with drilling of the B-17 prospect, Boothby said.

A recent drill stem test confirmed commerciality of B-14, while company officials project gas in place at 1.5-3 Tcf of resource, Newfield said.

B-14 is less than three miles from Newfield’s first pinnacle reef gas discovery, B-15, also on Block SK 310. Recoverable reserves at B-15 are projected around 265 Bcf; it will be developed jointly with B-14, the company said.

The company operates Block SK 310 with 30% interest. Its partners are Diamond Energy Sarawak, a wholly-owned subsidiary of Japan’s Mitsubishi Corporation and Malaysia’s state-owned Petronas Carigali, which hold respective stakes of 30% and 40%.

Meanwhile, Newfield said it has identified additional prospects on roughly 1.1 million acres that Block SK 310 covers, with multi-Tcf of remaining gas resource potential. Newfield has committed to drill one remaining exploration well (B-17) on the acreage.

Boothby noted that Newfield signed a new production sharing contract in December 2012, for Block SK 408 and also completed farming into Block SK 319. Both PSCs are offshore Sarawak, and nearly double the company’s offshore Malaysia position with a total 1.7 million acres. The blocks extend the pinnacle reef trend and provide “dozens” of high-potential exploration targets around producing fields with existing infrastructure and pipelines in place, said Boothby.

Block SK 408 covers 1.1 million acres in water depths of 200-400 feet and 16 discoveries have been made on the block so far. Infrastructure and production hubs are located less than 10 miles from dozens of potential Newfield-identified prospects. The company has a 10-well commitment on the block over an initial three-year exploration period. Newfield operates the block with 40% interest; other partners are Anglo-Dutch Shell (30%) and state Petronas (30%).

Block SK 319 covers 580,000 acres and is adjacent to Block SK 408 in water depths of 300 feet or less. Newfield has identified several exploration prospects on it and has a five-well commitment over an initial three-year period. Shell operates Block SK 319 with a 50% stake, while Newfield and Petronas Carigali each hold 25%.

At the same time, Newfield said its Malaysia and also China operations are still on the sale block. A data room for those international businesses is projected to open in second quarter 2013. Goldman, Sachs & Co. will lead the sale process, Newfield said. — *Starr Spencer*

Barclays’ firm makes splash

An upstream company backed by UK bank Barclays’ private equity arm has acquired 15 licenses in the gas-rich Carnarvon Basin offshore western Australia.

Hydra Energy said its haul includes six retention leases which each contain an undeveloped oil or gas discovery, one production license with an undeveloped oil field and four exploration permits with multiple discoveries and prospects. It has also obtained the rights for four pipeline licenses, it said April 4.

Stakes in six of the licenses was acquired from fellow Australian minnow Pan Pacific Petroleum last October.

The undeveloped discoveries include the Corowa, Sage, Tusk, Okapi and Oryx prospects. The blocks are in water depths ranging from 40 meters to 85 meters. Hydra said it will operate seven of the leases and has started development planning.

Hydra Energy was set up in 2010, via partnership between Barclays Natural Resource Investments and a team headed by CEO Paul Nimmo. Hydra is focused on offshore oil and gas assets across Australia and Southeast Asia.

The company said it is looking for opportunities in undeveloped and small oil field discoveries, which have proven resources, but remain undeveloped.

BNRI was established in 2006 and has committed over $2 billion to more than 20 portfolio companies around the world. It typically commits $50-$100 million to each venture. The other Asia-focused oil and gas company it has funded is Nio Petroleum, which has marginal projects offshore Malaysia, partnering Sweden’s Lundin Petroleum. — *Song Yen Ling*

Bangladesh to improve terms

Bangladesh received bids for just three of the nine shallow water blocks it offered in the latest bidding round, with only ConocoPhillips and India’s ONGC Videsh making submissions by the April 2 deadline.

Assuming approval from the government, state-owned Petrobangla will make the terms more attractive for the deepwater bids, in the hope of avoiding a repetition, the state-owned company's director for production sharing contracts, Muhammad Imaduddin, told Platts.

Petrobangla had been expecting bids for at least four to five blocks, Imaduddin said.

Measures include a higher ceiling price for high sulfur fuel oil – $220/mt, rather than $200/mt – which will equate to a gas price of $6.50/'000 cu ft instead of $5.50/'000 cu ft.

In addition, Petrobangla is now also considering a tax holiday, allowing direct sales of hydrocarbons to third parties and raising the cost recovery limit.

Petrobangla has also proposed raising the cost recovery limit to a maximum 70% per calendar year, up from an earlier 55%, and allowing contractors to sell 50% of their output from a block directly to domestic third parties bypassing Petrobangla. Contractors will also enjoy a tax holiday for the entire duration of the contract.

Conoco, ONGC Videsh the winners

In the shallow-water round, ConocoPhillips submitted a bid for oil and gas exploration in block SS-04, while ONGC Videsh bid for blocks SS-07 and SS-09.

State-owned Bangladesh Petroleum Exploration and Production Company, or Bapex, will have a 10% carried interest stake in all three blocks.

The area of these blocks ranges from 4,463 to 7,692 sq km and the water depths range from 3 to 200 m.

In Bangladesh's previous 2008 bidding round, the floor price for HSFO in the formula was fixed at $70/mt and the ceiling price at $180/mt. Gas exports have been prohibited from all these blocks.

If awarded its block, ConocoPhillips will have the right also to explore Bangladesh's first discovered offshore gas field, Kutubdia, Imaduddin said. Kutubdia was offered under a "special package" that obliges the operator to give Petrobangla an additional 5% profit gas.

The field has recoverable gas reserves of around 45.50 Bcf. — *M Azizur Rahman*

Russia, China defer price

Russia's gas giant Gazprom has set yet another deadline for reaching an agreement on the price of its gas supplies to China: the latest target is June.

That will pave the way for a deal by the end of this year, Gazprom chairman Viktor Zubkov said March 27.

"I think that some time in June, the final price [of gas to be supplied to China] will be determined, and by year-end, all the documents regarding the agreed supply volumes and the price will be signed," Zubkov said.

Gazprom and China National Petroleum Corporation, or CNPC, signed on March 22 a memorandum of understanding on Russian pipeline gas supplies via the eastern route from east Siberia.

Under the 30-year deal, supplies are expected to start in 2018 at a rate of 38 billion cubic meters/year, with a possibility to increase volumes to up to 60 Bcm/year, Gazprom CEO Alexei Miller said at the time, adding that there is a possibility of pre-payment for the gas supplies.

Ratings agency Fitch said the gas deal "will dramatically improve [Gazprom's] position in Asian gas markets, which is currently represented only by a 50% share in the 9.6 million mt/year Sakhalin-2 project."

Gazprom had previously expected to sign a final contract on supplies of 30 Bcm/year of pipeline gas over 30 years via the so-called western route, from West Siberia to western China, in mid-2011, but that project was repeatedly delayed as the parties failed to agree on a gas price.

Earlier this year, Gazprom also approved a decision to build a three-train, 15 million mt/year LNG plant in the Russian Far East near Vladivostok, with the first train to be commissioned in 2018, and plans to supply LNG from there to Asian markets.

Third Australian FLNG plan

US major ExxonMobil has sought Australian government approval to install the world's largest floating LNG production facility at the Scarborough natural gas field.

The ExxonMobil-operated Scarborough FLNG project would process around 1.1 Bcf/day of gas, producing an estimated 6 million to 7 million mt/year of LNG from five trains, the company said.

ExxonMobil submitted an application on April 2 with the Australian government's Department of Sustainability, Environment, Water, Population and Communities for project approval.

ExxonMobil and BHP Billiton each own 50% of the Scarborough field.

The vessel will be deployed and permanently moored at Scarborough. It is expected to be a massive 495 meters long, even bigger than the 488 meter FLNG facility under construction for Shell's Prelude project. That vessel is now being built in South Korea and will be moored in Australia's Browse Basin.

Prelude was the world's first FLNG project to be approved, with final decision reached in May 2011. It is expected to start producing 3.6 million mt/year of LNG from 2017. Since its approval, several other companies in Asia are seeking governmental approval for FLNG projects.

The Scarborough FLNG project is in the pre front-end engineering and design phase, and exact schedules are yet to be determined, ExxonMobil said. But the project is expected to progress to the FEED stage in 2013 and to a final investment decision in 2014-2015.

The development would involve the drilling of 12 wells in two phases, starting with seven over the period from 2018 to 2019. Offshore installation and commissioning of the FLNG facility would be expected to occur in 2019 and 2020, with production starting in 2020-2021.

In addition to the gas treatment and liquefaction facilities, the vessel would be fitted with up to 10 storage tanks inside the hull, with an onboard storage capacity of around 380,000 cubic meters. Around 80-110 cargoes would be offloaded from the facility each year.

The Scarborough field was discovered in 1979 in permit WA-1-R and holds about 8-10 Tcf of lean gas. The field lies about 220 km (136 miles) off the coast of Western Australia in around 950 meters of water.

Floating production technology was considered the most appropriate development method for Scarborough, given the field's remote location and reservoir characteristics, ExxonMobil said.

Following receipt of ExxonMobil's application, Australian environment minister Tony Burke has 20 working days to decide on whether approval for the project is required under the federal Environment Protection and Biodiversity Conservation Act 1999. That 20 days include a 10-day public comment period.

Since Shell approved its Prelude project, FLNG production technology has steadily gained traction in the Asia Pacific region. In June last year, Malaysia's Petronas approved an FLNG facility off Bintulu which it expects to get into production prior to Prelude's startup.

Burke has also already approved what would be Australia's second FLNG facility, the Bonaparte project off northern Australia which is being pursued by GDF Suez and Santos. That project has yet to reach a final investment decision, but is targeting a go-ahead in 2014.
— *Christine Forster*

China okays Shell shale PSC

The Chinese government has approved Shell's shale gas production sharing contract inked with state company PetroChina in the onshore Sichuan basin last year, the Anglo-Dutch company said April 3.

The PSC for the gas-rich Fushun-Yongchuan block was approved in March, a spokeswoman for Shell China said in an email.

The contract had been awarded in March last year and was the first – and to date only – shale gas PSC in the country.

The approval process was unusually lengthy and analysts said this was likely because the government needed to clarify the terms of the agreement given China's nascent shale gas sector.

The PSC award came following a joint assessment agreement with PetroChina for the block in 2010. No reserves estimate has been released for the block.

Shell had said it would apply its technology and operational expertise to develop the 3,500 sq km, but its CFO Simon Henry said last July that the company would not have a good idea of the right way to develop the field until the middle of this year.

China has been encouraging shale gas development to keep up with booming gas demand. The government is likely to unveil new incentives soon to address technology, research and infrastructure aspects of shale gas development to support continued investment.

The official target is to produce 6 billion cubic meters/year of shale gas by 2015, from nothing today.
— *Song Yen Ling*

EUROPE, MIDDLE EAST & AFRICA

Wintershall's Danish find

Wintershall, the energy unit of German petrochemicals giant BASF, has announced a large discovery offshore Denmark.

Together with other recent finds it could be of significance to the country's overall production profile, according to the Danish energy agency.

Operator Wintershall said it had successfully drilled the Hibonite-1 exploration well in Danish License 5/06 in the western part of the North Sea, with preliminary estimates indicating potential oil in place of 100 million barrels.

DEA said the find contained mostly oil with a smaller amount of gas, but did not want to discuss specific ratios.

The agency said cores were taken and a logging program carried out, with a production test producing oil and gas.

The Hibonite prospect is around 7 km north of Wintershall's Ravn field in the same license, which was successfully appraised in 2009 with the Ravn-3 well and which the company is considering developing.

The Ravn-3 exploration well confirmed the presence of hydrocarbons at a depth at 4,469 meters in 2009 and the seismic surveys carried out in exploration block 4/06 are now being evaluated. Ravn-3 is about 1.5 km south of the Ravn-1 well which discovered crude back in 1986.

The reservoir in both the Hibonite and Ravn structures is formed by Upper Jurassic Heno sandstones, the company said.

The Danish agency said license partners are now working on evaluation of results and the need for additional work is being considered to determine if the find is commercial.

It added that for a further evaluation of the extent of the oil discovery, two sidetracks were drilled, Hibonite-1A and Hibonite-1B.

"The oil companies will now evaluate the results of Hibonite-1 and make plans for the additional work that is necessary to determine if the oil discovery can be produced commercially," it said.

If commerciality is determined it would be a significant shot in the arm for the ailing Danish oil and gas industry. The overall picture for the Scandinavian country remains one of long-term production decline as new discoveries fail to fully replenish maturing and declining fields (*IGR 710/9*).

"I am sure that even if this discovery isn't as big as the ones made offshore Norway, that this, following other smaller discoveries made recently, could add up and positively affect Denmark's position," said DEA . Wintershall is operator of the license with a 35% stake, while other partners are Bayerngas (30%), EWE Vertrieb (15%) and the Danish government owned North Sea Fund (20%). — *Patrick McLoughlin*

Norway OKs Aasta Hansteen

The Norwegian government has approved the massive Aasta Hansteen gas field project in the Norwegian Sea as well as the major Polarled pipeline linking it to shore, which will cost an estimated NOK54.2 (($9.4) billion.

The energy ministry said the project had royal assent and would be sent to parliament for final ratification.

"The development of Aasta Hansteen field and Polarled pipeline opens up a new gas region in the northern part of the Norwegian Sea and will facilitate increased exploration and several developments in the area," energy minister Ola Borten Moe said.

The Aasta Hansteen field, in water depths of 1,300 meters, was discovered in 1997 and contains significant quantities of gas and condensate.

The 480 km Polarled pipeline, to be positioned about 300 km offshore Norway, will transport gas from Aasta Hansteen and future field developments in the Norwegian Sea to the onshore gas processing plant at Nyhamna. There will also be a 30-km spur to the Statoil-operated Kristin gas condensate field.

Norwegian papers have reported that other tie-ins to Polarled could be the Zidane and Linnorm fields with a connection to the Asgard Transport pipeline.Aasta Hansteen is expected to start production in the third quarter of 2017.

Investment in Aasta Hansteen is estimated at NOK30.1 billion, while investment in Polarled and the Kristin gas export project is estimated at NOK24.1 billion.

The Aasta Hansteen field has reserves of 46.5 billion cubic meters of gas and 900,000 cubic meters of condensate.

The operator is Statoil Petroleum with 75% and the other partners are OMV (15%) and ConocoPhillips (10%).

The Polarled pipeline operator is Statoil with 50.3%. The other partners are Petoro (11.9%), OMV (9.1%), Shell (9.0%), Total (5.1%), RWE Dea (4.8%), ConocoPhillips (4.5%), Edison International SpA (2.4%), Maersk Oil (2.4%) and GDF Suez E & P (0.5%).

The Aasta Hansteen field was formerly known as the Luva field while the Polarled pipeline was originally known as the Norwegian Sea Gas Infrastructure pipeline. — *Patrick Mcloughlin*

Sterling faces Breagh delay

Canada's Sterling Resources is expecting a "deeply disappointing" 90-day delay to the start up of its Breagh natural gas field in the UK, as the company again nears a financial crunch over the late launch of production.

But Sterling did give assurances that it had financing in place for much of the period until gas production provides cash flow from September.

"RWE Dea, as operator, has now completed a review of overall progress of works on the modifications being performed at the Teesside Gas Processing Plant and has reported further delays of [about] 90 days to finish the modifications before gas can be received for processing from the Breagh field," Sterling said in a statement April 3.

"The reported earliest estimate for first sales gas is mid-July, with a best estimate of early August and a late case of the final week of August, 2013," it said.

Sterling CEO Mike Anzacot said that "deep disappointment" notwithstanding, the "fundamentals of the whole Breagh project remain robust, with good well results so far and with the second phase of development now taking shape."

Meanwhile, the company made no specific mention April 3 of a proposed $192 million takeover offer from trader Vitol. Sterling's most recent communication on the offer – made in mid-February by the trading giant – was that it continued to review its strategic options but it has paid off its loan.

"We hope to announce soon our selection of a strategic solution aimed at refinancing the current bank credit facility, and one that will alleviate any concerns around a cash shortfall before revenues are received from Breagh," it said.

Vitol had no immediate comment on the status of its offer for Sterling.

Drilling operations continue on the fifth well, which is expected to be finished by early May. Two further wells will be drilled after production testing of wells A04 and A05, and are expected to be on online mid-August and early November, respectively, the company said.

Originally, the plan had been to drill 10 wells, so this reduction will save Sterling £30 ($45) million in phase 1, leaving it with a bill of £164 million.

Elsewhere in the North Sea, an appraisal well at the Crosgan discovery remains an "outstanding obligation for the license, and a well is planned for late 2013 with the Ensco 70 jack-up drilling rig following the development drilling on Breagh."

If it is declared viable, the likely development plan will take the form of a small gas platform tied back to the BB platform on the east side of Breagh, with gas from both fields being exported to the TGPP. — *William Powell*

Providence booss Barryroe

Providence Resources has raised estimates of recoverable oil from its landmark Barryroe oil field in the Celtic Sea to over 300 million barrels.

The Barryroe field offshore Ireland holds 311 million barrels of recoverable oil and a further 34.5 million boe of gas (about 6 billion cubic meters) on a 2C, or proved and probable basis, the company said, after analysing results from last year's appraisal well and more 3D seismic.

Last year, Providence said it expected to recover an estimated 280 million barrels of oil from Barryroe, Ireland's first commercially viable oil discovery.

The audit also assumes an estimated 35% oil recovery factor from the field's main reservoir, known as Basal Wealden, and a 16% oil recovery factor from the smaller Middle Wealden section of the field, the company said.

Providence's previous estimates for recoverable reserves from Barryroe was modeled on a recovery factor of 31% over the life of the field.

The latest reserve estimates exclude data from the Lower Wealden and the Purbeckian reservoir intervals, which could add further resources to a future development.

"This is another very positive step for Barryroe," CEO John O'Sullivan said in a statement. "This third-party resource audit further validates the significant volumetric and recoverable resources of the Basal Wealden oil reservoir in the Barryroe field."

O'Sullivan said the company now plans move ahead with plans to sell down its 80% stake, having already received "significant international industry interest."

Providence last year said Barryroe could hold over 2 billion barrels of oil in place, making the country's first commercially viable oil field twice as large as previously estimated.

Providence's only partner is Lansdowne Oil and Gas. The field lies in block SEL 1/11 in about 100 meters of water, 50 km off Ireland's south coast. — *Robert Perkins*

Attackers kill 3 at Akkas field

Two contractors were killed and one kidnapped when a group of 20 gunmen attacked the site of the Iraqi Akkas gas field project led by South Korea's Kogas on April 1, a provincial official told Platts.

Farhan Ftikhan, an official at the Al-Kaem district in the Western Anbar province of Iraq, told Platts by telephone that one engineer was also wounded and gunmen also set fire to camp accommodation and assaulted workers

Kogas ruled out any delay to its plans to start commercial production in September 2015.

"There was no major damage to the facilities at the field, and there will be no delay to the original plans," Kogas told Platts. "We will take measures to protect gas fields in Iraq from attacks," he added.

The Akkas field is the first non-associated gas field to be developed in Iraq, which is poised also to hold a licensing round in May.

The field has an estimated 5.6 Tcf of natural gas, according to oil ministry data.

A consortium of Kogas and Kazakhstan's state-owned KazMunaiGaz was awarded the deal after a bidding round in October 2010. KazMunaiGaz pulled out of the deal in 2011, leaving Kogas as the sole foreign partner.

The contract stipulates a production plateau of 400 million cubic feet/day for a remuneration fee of $5.50/barrel of oil equivalent, with the plateau output to be maintained for 13 years. — *Staff*

UK Rhyl field starts up

First gas has been produced from the Rhyl gas field in the UK's Morecambe Bay, owner and operator Centric Energy said April 2.

The gas will be produced through Centrica's existing North Morecambe platform and processed at the Barrow terminal.

Peak production at the field will be 4,000 b/d of oil equivalent, a spokesman for the company said.

"This is the first new field to be brought on stream in the region for 10 years and represents an important milestone in extending the life of Centrica's Morecambe Bay operations, taking production well beyond 2020," the company said.

Appraisal drilling at Rhyl North toward the end of 2012 showed 2P reserves being revised upward to around 80 Bcf from around 40 Bcf.

Centrica said further appraisal drilling in early 2013 showed the reservoir extends further than originally anticipated and there is the potential for additional reserve bookings. — *Nathan Richardson*

Poland mulls amending shale law

The Polish government may clarify or change certain provisions in a draft bill designed to regulate future shale natural gas production, in order to address producers' concerns that the terms are unfair.

In a shale gas discussion at the offices of the Polish state news agency, PAP, finance minister Mikolaj Budzanowski acknowledged the concerns of both domestic and foreign operators about the government's plan to create a 100% state-owned company to take stakes in future shale gas production licenses.

The proposed regulations also do not clearly state that companies that already own exploration licenses and have invested in drilling will be able to produce the gas.

"Some proposed hydrocarbon production regulations still need clarification, perhaps changed to resolve shale gas investors' potential doubts," Budzanowski said.

The environment ministry in February published a series of amendments to the existing mining and geology laws, as well as eight other pieces of legislation, to deal with the production side of the sector.

The amendments were written to accommodate all hydrocarbons, but specifically shale gas production which the government hopes will start to come onstream in 2015.

They include the creation of a 100% state-owned national operator that could take minority stakes in all future production licenses.

Operators have said that state participation in concessions has the potential to slow production activity and they are unclear about what level and on what terms the national operator would pay its share of ongoing costs. "This is an element which must be explained and eventually adjusted," Budzanowski said.

The proposals also state that all shale gas production licenses will be awarded after a tender, adding that existing exploration license holders will get priority in applying to convert those licenses into production licenses.

Licenses need redrafting

Since 2008 the environment ministry has issued more than 100 exploration licenses, typically for five-years, on a first-come, first-served basis. Companies will have to start making decisions to convert those licenses into production licenses toward the end of this year. Under pressure from the European Commission, Poland has already introduced tenders for exploration licenses and is now planning to do the same for production permits.

"Investors would like to have protection in the form of specific concession and mining rights in order to know that they really have the right to future production. Today they *de facto* invest in a document which is owned by someone else,' the CEO of Orlen Upstream, a unit of Poland's state-controlled and largest refiner, PKN Orlen, Wieslaw Prugar, told the conference.

Orlen Upstream has drilled six exploration wells in its 10 shale gas concession areas. The CEO of Poland's state-controlled natural gas producer and distributor PGNiG, Grazyna Piotrowska-Oliwa, said the company was until recently in advanced partnership talks with a US investor.

Those talks broke off because of the proposed regulations were unacceptable to the American company, which said they would would make a joint venture unprofitable. PGNiG has 15 exploration license areas in Poland, but has limited resources and if it were forced to compete for production licenses in an open tender it may lose out on them, market participants have said.

Since mid-2010, 43 shale gas exploration wells have been drilled in Polish shales, which run in a band from the onshore Baltic basin to the Podlasie and Lublin basins in southeastern Poland. Not one has yet flowed at commercial rates.

Earlier in March, Poland's finance ministry published a draft law governing the tax of future production that introduced a new cash flow tax, royalty rates and other fees. The ministry said the government take would be capped at 40%. — *Adam Easton*

Russia challenges Ukraine

Ukraine's imports of gas from the European Union could be illegal, Russian gas monopoly Gazprom has said.

The German utility RWE, has been supplying the former Soviet republic with growing amounts of gas from its portfolio since last November, using first the Polish system and now the Hungarian system as Kiev reduces its dependence on Russian gas imports.

The Yamal-Europe line that crosses Poland has had to be contractually if not physically bi-directional for a few years, in line with European law. This would allow nominations for deliveries of Russian gas within Poland to be netted off against the flows out of Poland towards Germany, in turn allowing Ukraine to flow less Russian gas to a better-supplied Poland.

But Gazprom alleges that Ukraine has been physically importing gas. Gazprom CEO Alexei Miller said on March

31 that if the gas was Russian, it could be a fraudulent scheme. Miller said Russian gas meters had shown that gas transited to the EU by Ukraine had been immediately shipped back into Ukraine. “Such a scheme looks fraudulent and one needs to deal with it,” he said, adding that such shipments directly contradict Ukraine’s transit accord with Gazprom.

RWE says the gas has come from its portfolio, comprising gas from a number of sources. RWE is seeking legal relief on its take or pay contracts, so that the price it can expect to sell at is competitive with its import price from Gazprom. Its arbitration is continuing.

Until the arbitration decision, selling gas to Ukraine at $380/’000 cu m is at least an improvement on RWE’s hub prices.

Volodymyr Makukha, deputy energy and coal industry minister, told reporters in Kiev that its imports from Europe are “absolutely legal.”

RWE said it used gas sourced from a variety of countries for its supply to Ukraine. “The gas that RWE started to supply... to Naftogaz of Ukraine... is sourced from RWE’s pan-European gas portfolip.”

“This portfolio contains gas from many different sources [and] potential deliveries are not linked to an individual supply source,” it said.

Analysts agree that re-importing Russian gas meant for the EU into Ukraine is probably not illegal.

“Legally, when Russian gas crosses the border with Europe it no longer belongs to Russia, so Gazprom’s European partners are not prohibited from sending gas back to Ukraine,” analysts at Russian VTB Bank said in a note.

Working the arbitrage

Ukraine plans to import up to 7 billion cubic meters of gas from Europe in 2013 if European prices continue to be lower than Russian prices, Ukraine’s energy minister Eduard Stavytskiy said late March.

The deal with RWE, which was signed in May 2012, calls for supplies of up to 5 Bcm of gas in 2013, with the possibility of expanding volumes to 10 Bcm/year.

Late in March, Ukraine started gas imports from Europe via Hungary at a rate of 3 million cu m/day, UkrTransGaz said.

UkrTransGaz also said it is in talks with Slovakia to use one of four existing pipelines between the two countries to ship up to 10 Bcm/year of gas to Ukraine; and also with Romania, following a memorandum. The Romanian route is capable of supplying up to 5 million cu m/d, and, like Ukraine, the country is trying to increase its gas production.

In the first quarter of 2013 Ukraine was purchasing gas at $380/1,000 cu m in Europe, compared with $406/1,000 cu m from Russia, according to Stavytskiy.

In 2013, Kiev plans Russian gas imports of 18-20 Bcm, with European supplies reaching some 7 Bcm, according to Ukraine’s energy minister. — *Dina Khrennikova*

Tauerngasleitung is for sale

Tauerngasleitung has invited bids for the sale of its shares via tender, the Austrian gas pipeline project company said April 2.

The joint venture company has plans for a 290-km high-pressure gas pipeline crossing the Austrian Alps, connecting to the German and Italian gas networks.

Its current shareholders are E.ON Ruhrgas, Energie AG, Salzburg AG, Rohol-Aufsuchungs, Kelag and TIGAS.

“Owing to the significant changes in the European gas industry and the legal framework for the energy sector, Tauerngasleitung is obliged to amend its ownership structure,” it said. “As previously announced, from April 2, 2013 on interested parties will have an opportunity to invest in projects currently in the final planning stages and in the company.”

Environmental assessments are underway in the countries affected, but no open season has yet been conducted, the company said, but a study carried out in the autumn of 2011 confirmed the interest in a bi-directional trade and balancing line running north-south.

A selection of new shareholders was due to take place via a tender process starting April 2. — *Henry Edwardes-Evans*

BP makes frontier find

BP has made a gas condensate discovery at a closely watched deepwater well off the Shetland Islands, but the drilling results fell short of expectations.

The North Uist prospect in the West of Shetland area found gas condensate in sandstones of “varying reservoir quality” and the commercial potential of the find has yet to be evaluated, its partner Faroe said.

“The result proves another working hydrocarbon system in the frontier west of Shetlands,” Faroe’s CEO Graham Stewart said. “We are pleased to have made a discovery in the North Uist exploration well, although we had however hoped for better quality reservoir.”

The North Uist exploration well was testing a large oil prospect 125 km northwest of the Shetland Isles in Atlantic waters some 1,300 meters deep. The prospect lies close to Chevron’s Rosebank oil discovery, also on the Corona Ridge, west of the Shetland Islands.

Originally scheduled to drill in late 2010, the controversial well had been delayed by safety concerns in the wake of BP’s Gulf of Mexico spill.

North Uist was BP’s major’s first deepwater wildcat in the UK. BP operates Block 213/25c, with a 47.5% interest and its partnered by China’s CNOOC (35%), Faroe Petroleum (6.25%), Cieco Exploration and Production (6.25%), and Idemitsu (5%).

Faroe said the well partners will now analyze the well data of data and samples collected from the well as part of a formation and volume study before deciding on the next steps.

The discovery well, which reached a total vertical depth of 4,700 meters, will now be plugged and abandoned as planned, it said. — *Robert Perkins*

Nabucco, TAP under spotlight

The BP-led Shah Deniz consortium has begun evaluating the final offers received from the two rival pipeline projects looking to pipe gas from the field to Europe.

The two projects – Nabucco West and Trans Adriatic Pipeline – are competing to win the contract to supply Europe with gas from Azerbaijan's biggest gas field.

"The submissions allow the Shah Deniz consortium to conduct the final evaluation of each of the transportation options and make an informed decision on the preferred export route to Europe," BP said.

The final decision on which pipeline is to be chosen is expected to be made by end of June 2013.

The transportation offers are expected to become legally binding by the end of April 2013, BP said.

"In the next month the Shah Deniz consortium also expects to receive binding gas sales offers from potential gas buyers in Europe," it said.

The second phase of Shah Deniz will add a further 16 billion cubic meters/year of gas production to the 9 Bcm/year from the field's first phase. — *Stuart Elliott*

Belgium faces CCGT vote

Belgium's coalition cabinet is set to vote mid-April on a new electricity capacity market mechanism designed to bring on line gas-fired power plants as nuclear plants are shut down.

Belgium has turned to support mechanisms for some 2 GW of new capacity, which it believes will be required to replace nuclear plants after they are shut one by one from 2015. Belgium has 5.9 GW of nuclear power capacity which provides around half of national output, and the fleet is almost entirely controlled by GDF Suez subsidiary Electrabel.

Gas-fired production is seen as the only viable source of new European fossil fuel output because of emissions restrictions, but spreads between coal, gas and carbon prices have made gas-fired plants unprofitable and several generators have announced plans to mothball units in Belgium.

The energy ministry's proposal is based around a mechanism for reserve capacity, which will support both existing gas-fired plants as well as new build projects, the ministry spokeswoman said.

"We are ready. The proposal is completed, we will present it to the government after the Easter holiday," the spokesman said. The government returns from the Easter recess on April 15.

The spokeswoman would not confirm that the ministry is proposing annual support of up to €30 ($38.5) million per gas-fired plant, as reported by financial daily newspaper *L'echo*.

Last July, the government agreed a staggered phase-out of nuclear power from 2015, around which time the unplanned outage of the 1 GW Tihange 2 and 1 GW Doel 3 reactors presented Belgium with more urgent supply worries.

The Doel-3 and Tihange-2 nuclear reactors have been off the grid since last summer after the discovery of thousands of flaws in the reactor pressure vessels and are not expected back until at least May.

Belgium's power supply system was driven to extreme measures January 17, after the prolonged outages of the two reactors combined with high demand from cold weather and unplanned outages of gas-fired units, prompting grid operator Elia to introduce measures to reduce industrial power demand (*IGR 720/18*). — *Robin Sayles*

Turkey to penalize Eni

Turkey is planning to apply "sanctions" against Italian oil major Eni in retaliation for the company's involvement in upstream exploration in Cyprus.

Turkish energy minister Taner Yildiz on March 27 criticized Eni's involvement in Cyprus and warned that his government had taken the decision that Eni should not operate in Turkey.

"We have decided not to work with Eni in Turkey, including suspending their ongoing projects," Turkish daily *Hurriyet* quoted Yildiz.

Turkey's energy ministry confirmed to Platts that actions to be taken against Eni would constitute a form of "sanctions" but declined to comment on specific aspects of the company's operations in Turkey and how they may be affected.

Eni and Turkey's Calik Enerji signed a cooperation agreement in 2005 for a planned 1.5 million b/d pipeline from Samsun on Turkey's Black Sea coast to its Mediterranean oil hub at Ceyhan, avoiding the overcrowded Bosporus Strait.

In January, Cyprus awarded a consortium of Eni (80%) and Korea's Kogas (20%) three natural gas-rich blocks in its deep water, fueling political tensions over exploration in the Mediterranean island's exclusive economic zone.

The Eni/Kogas blocks lie closer to the island's southern shore than block 12, where the US' Noble Energy discovered an estimated gross mean resources of 7 Tcf of gas in December 2011.

A spokesman for Eni declined to comment on the Turkish move, but said that the company is not involved in any other ongoing projects in Turkey other than the Samsun-Ceyhan oil pipeline venture. Eni is also a partner in the 16 billion cubic meters/year Blue Stream pipeline. New compression could bring its capacity to 19 Bcm/year.

Interest in Cyprus' offshore hydrocarbon potential has intensified following the gas finds by Noble in Block 12 in late 2011.

Cyprus has been divided into two since 1974 when Turkish troops occupied the northern third of the island following a coup by right-wing Cypriot army officers aimed at uniting the island with Greece.

Turkey refuses to recognize the delineation of the Mediterranean between Cyprus, Israel, Lebanon and Egypt into Exclusive Economic Zones (EEZ) for each country, and claims rights over some of the areas which Cyprus claims as part of its EEZ, and has stressed repeatedly that the island's mineral reserves are the property of both the Greek and Turkish communities on the island.

Turkey claims that the line west of parallel 32 16' 18" falls within its jurisdiction. It overlaps Cyprus' Blocks 1, 4, 5, 6 and 7. — *David O'Byrne, Staff*

AMERICAS

Coal now cheap for US power

Stronger US natural gas prices have helped coal reclaim market share from gas in the power generation sector, consultant Genscape said April 4.

In its Generation Fuel Monitoring Service, Genscape said that while US electricity demand in March was 2% above March 2012 levels, natural gas-fired generation last month fell 11% year-on-year.

Genscape said renewable energy generation also fell 14% in March compared with March 2012, adding that "coal-fired generation captured nearly everything lost by renewables and natural gas, surging 21% higher" in March compared with a year ago.

"April 2012 was the first time in history that natural gas-fired electricity generation was as a high as coal-fired electricity generation, [but] as gas prices have recently reached $4.00/MMBtu the economics behind fuel switching are dramatically different than last year," Genscape said.

"At this point last year, natural gas was economically competitive with nearly every delivered coal – even low cost Powder River Basin coal. Now only higher heat content coal delivered to the Southeast US remains out of the money," Genscape said.

Genscape said that in addition to increased cost competitiveness, coal's surge has been helped by stronger year-over-year power demand, in large part because of much colder weather in the eastern US than was experienced in March 2012.

The 14% decline in renewable generation in March was largely driven by weaker hydro output in the northwest, Genscape said. The company, which monitors hydro facilities in the region saw a 36% year-on-year decrease in March – falling from 10,808 GWh to 6,945 GWh – on significant declines in snow water equivalent.

Year-to-date trends in 2013 are consistent with the March results. Overall, power demand through March 31 is up 2% and coal fired generation is up 12%. Natural gas generation is down 8%, while nuclear is off 1% and renewables are down 3% from the same period of 2012, Genscape said. — *Staff*

US LNG eyes quicker route

Among the many challenges DOE faces in issuing licenses for LNG exports is one buried in terse bureaucratic language on page 27 of a recent export permission application.

It asks the department to allow separate treatment for Freeport-McMoRan Energy's February 22 application to supply mainly Asian countries with LNG from the proposed Main Pass Energy Hub, 16 miles offshore Louisiana. The project would export 24 million mt/yr of LNG, and is the largest of two dozen projects applying for export approval.

Under government rules, applications are added to DOE's list and processed in the order they are received by FERC and by DOE.

But Freeport-McMoRan asked that its application be treated separately, as its Main Pass project was filed earlier with the US Maritime Administration.

Main Pass contends that there should be two lists running simultaneously and the that DOE should not give preference to one agency over the other, he said. "We, of course, agree with that since we're the only one on the Marad side," the company said. "Our expectation is certainly one of being hopeful that . . . Marad will be treated the same as FERC is and the two lists will run concurrently."

Freeport-McMoran told DOE that the company has been in discussions with Marad since July, and that Marad's jurisdiction to license an LNG export facility under the Deepwater Ports Act was not clear until last December, when uncertainties were clarified by amending the act.

Freeport-McMoran "was unable to submit a non-FTA application until the amendments were enacted," the applications states. "Thus, this application should not be subject to the previously established processing parameters."

Cumulative effect

Applicants at the bottom of the DOE's list face both the challenge of being late to the game and also the department's cumulative standard regarding the impact of LNG exports on US consumers.

"DOE says it's going to consider the cumulative impacts of all the applications that came before you," said the industry source.

"So the first few applications may be able to make the case . . . that there is a limited impact on US consumers," he said. "But by the time you get to be one of the last applicants, the DOE is going to take into consideration all the prior applications before you, so the question is, "will 20 applications have an impact on the consumers?" So it's a higher burden. — *Laura Brooks*

Alaska tells majors to hurry

Alaskan government officials are pressing North Slope producers and TransCanada to commit this summer to a more detailed design and engineering phase for a proposed gas pipeline and LNG export project.

Initiating the “pre-front-end engineering and design” work would mark the first major financial commitment by the US majors ConocoPhillips and ExxonMobil and the UK major BP, who are teaming with pipeline company TransCanada on the estimated $45 billion to $65 billion project.

Alaska’s governor Sean Parnell “has called on the companies to reach commercial terms among themselves to begin the pre-Feed this summer,” Commissioner Dan Sullivan told Alaska’s Senate Resources Committee in Juneau March 27.

Deputy Commissioner Joe Balash, appearing with Sullivan, said the commitment would have to be substantial. “The budgets will begin to match the state’s own financial commitment to the project under the Alaska Gasline Inducement Act,” or about $500 million, Balash told legislators. Alaska is contributing that amount under a 2010 agreement with TransCanada.

“We’re now focused on ensuring that this summer’s field season is used,” by the companies to gather data, which the companies regard as part of the front-end work, Balash said. “If they don’t take advantage of the summer season we could lose a year on the project.”

In Alaska, environmental data needed to support federal and state permit applications can only be obtained in summer, he added. Sullivan said the companies were making good progress in coming to terms among themselves.

They made several major decisions by the governor’s requested mid-February deadline, including agreements to locate the gas conditioning plant at Prudhoe Bay in the same complex with an existing large field gas plant, to use 42-inch pipeline on the 800-mile system, and to set a production target of 17.5 million mt/year.

The south Alaska terminus of the pipeline and the port location for the LNG plant will be decided within several months, the companies told the governor in February.

Sullivan and Balash also urged state senators to approve pending legislation that would expedite a state-sponsored “in-state” gas pipeline from the North Slope that is proposed as a backstop in case the company-sponsored larger project does not go forward.

He said the state’s support for two pipeline options – one that it could carry out itself if the industry project does not proceed – gives more credibility to the Alaska LNG project within the market.

“It shows that we’re serious about this project,” Sullivan said. “The state has the financial resources to pull it off, with $20 billion in cash reserves and a Triple-A credit rating in financial markets.”

A pending bill would give the state-owned Alaska Gasline Development Corp., which is planning the project, more flexibility in doing engineering along with access to $200 million set aside for the project by the Legislature two years ago.

Earlier this year, the gasline group enlarged its pipeline plan from a 24-inch pipeline to a 36-inch pipeline to give it more options in expanding throughput. The 737-mile pipeline would be built from the North Slope to the Anchorage area in southcentral Alaska.

If the industry project moves forward, the state and industry projects could be combined, with Alaska Gasline Development Corp. contributing several key regulatory approvals it has received to the larger industry-led project, Sullivan said.

Alaska studies Plan B

Alaska’s House of Representatives has passed a bill expediting an in-state natural gas pipeline from the North Slope and this is now before a state Senate committee, according to Alaska House Speaker Mike Chenault, who sponsored the legislation.

The project involves a 36-inch, 737-mile pipeline from the North Slope to Southcentral Alaska to be built by a state corporation if a proposed industry-backed, 42-inch pipeline and LNG export project is not built, said Chenault, a Republican.

“Alaska’s communities are short of energy, and we need to make sure Alaskans can have access to large stranded gas resources on the slope if the large project is delayed,” Chenault said.

The state Senate must still act on the bill before parliament is adjourned April 15. It makes a number of technical changes in state law governing the state-owned Alaska Gasline Development Corp, which was formed two years ago to develop the project.

If however Plan A goes ahead the state would focus on smaller spur lines to communities along the pipeline routeing for its project. — *Tim Bradner*

Jogmec funds Canadian project

State-owned Japan Oil & Gas and Metals National Corporation is going to finance just under half Japan Petroleum Exploration’s acquisition of a 10% equity natural gas blocks in North Montney, in Canada’s British Columbia.

Jogmec’s equity finance will equate to about yen 22 billion ($233.6 million) of Japex’s acquisition of the 10% stake through Japex Montney, with the Japanese upstream company holding just over 50% of that stake and Jogmec the balance, it said.

Jogmec’s equity finance comes after Japex said March 4 it had signed a Heads of Agreement with Malaysia’s Petronas to take part in the Malaysian state-owned oil company’s shale gas and LNG projects in British Columbia.

Japex is to offtake 1.2 million mt/year of LNG from Petronas’ Canadian shale gas block and its Pacific Northwest LNG project.

"Japex's investment will contribute to "further stable LNG supply and fuel cost reduction in Japan," Jogmec said March 26.

The Pacific Northwest LNG project is expected to start output of LNG at the end of 2018 and have a total capacity of 12 million mt/year.

Japex has said it intends to bring its equity volume to its planned Soma LNG terminal in northeastern Japan, which it plans to start up by 2018. — *Takeo Kumagai*

Quebec nears shale verdict

The Quebec government is due to unveil the results of a "strategic" environment study on developing the province's shale gas resources before the end of April.

"Currently, there is a strategic environmental assessment or SEA under way on the issue of shale gas and we should have the results of this evaluation in the coming weeks," Quebec's ministry of natural resources said.

It would not confirm if the release of the SEA would be the initial step towards the lifting of a moratorium on shale gas development in the province imposed in mid-2011.

The SEA will be part of March 2011 recommendations by the province's Ministry of Environment, Sustainable Development and Parks that more industry and stakeholder consultations be held before the moratorium is lifted.

The Canadian Energy Research Institute declined to comment on what the SEA's final outcome would be, but said the lifting of a moratorium could potentially result in the production of up to 1.5 Bcf/d in Quebec.

"We have investigated two scenarios. In the first, drilling takes place to build and maintain production levels of about 500 million cubic feet/d or Quebec's current consumption of natural gas. And in the second, production increases to 1.5 Bcf/d, eventually allowing for 1 Bcf/d of exports directed to the Boston area," CERI said.

Earlier in March, CERI issued a report titled: 'Potential Economic Impact of Developing Quebec's Shale Gas'.

"The Utica shale in Quebec has been attracting a lot of attention from North American E&P companies and given its proximity to the northeastern US markets, the gas could command a premium to Henry Hub prices, unlike the more developed and active shale gas plays in northeastern British Columbia that are located far from [prime, high demand] markets. [The] Utica holds enormous potential for Quebec, but is also a source of controversy," the CERI report said.

CERI would not quantify Quebec's shale gas resources, saying that more wells would need to be drilled to determine a final figure. But a 2011 report prepared by Quebec's finance ministry put the total recoverable reserves at about 8.75 trillion cubic feet.

Shale gas development in Quebec will come with its share of challenges, CERI said.

"There is currently no significant ... oil and gas industry service industry [presence] in that province and this can lead to significant drilling cost overruns for companies to achieve economies of scale," he said, adding that an operator may end up paying C$7 million/well ($6.9 million/well) in development costs for construction, drilling and completion.

Another issue facing shale play development in Quebec would be growing public opposition in the province to hydraulic fracturing and its water use/recycling. — *Ashok Dutta*

Bolivia, Argentina co-operate

Argentina's state-run energy company YPF and Bolivia's state-owned oil company YPFB have signed a deal to explore and develop hydrocarbons together.

YPF CEO Miguel Galuccio and his YPFB counterpart, Carlos Villegas, inked the memorandum of understanding in La Paz, YPF said March 25.

"The goal is to coordinate joint projects and make use of the technical experience of both companies for developing areas with conventional and unconventional potential," they said.

The companies said the partnership would start with studying blocks for exploration that have "high prospectivity for future development." Three new blocks in Bolivia are to form part of the agreement, YPF said.

Argentina and Bolivia are seeking to expand oil and natural gas production after periods of decline. Argentina's oil production has dropped by a third to 570,000 b/d from a peak of 847,000 b/d in 1998 and gas has dwindled 16% to 120 million cu m/d from a record 143.1 million in 2004 on low exploration and few finds.

YPFB, which saw production sag after a nationalization of the industry in 2006, is starting to rebuild output, with gas production expected to surpass 70 million cu m/d over the next few years after running steady at 40 million cu m/d for much of the last decade.

For YPFB, the deal, if finalized, would gain it access to YPF's knowledge and skills in developing shale resources.

YPF started developing shale oil and gas in 2010-2011 in Vaca Muerta, a southwestern play in Argentina thought to have some of the greatest potential in the world. YPF plans to team up with Bridas, backed by China's CNOOC, and Chevron to develop shale resources on a mass scale in Vaca Muerta, starting this year.

Gas could go to Chile, Uruguay

YPFB's Villegas said the deal would help build hydrocarbon production in Argentina and Bolivia to supply countries in the southern half of South America. Argentina and Brazil are the two importers of Bolivian gas, buying about 40 million cu m/d between them. Chile and Uruguay are thought to also want Bolivian gas supplies.

Bolivia has the second-largest conventional gas reserves in South America after Venezuela, while Argentina's shale gas resources are estimated to be the world's third-largest after those of China and the US, according to the US Energy Information Administration.

YPF and YPFB over the past year have signed other study agreements that YPF said will "soon" lead to a final deal for exploring the Yuchan block in Bolivia.

YPF, through a subsidiary, also is building a gas-liquids separation plant for YPFB in Santa Cruz, Bolivia.

YPF plans to invest $37.2 billion through 2017 to boost oil and gas production 32% in Argentina, helping return the country to energy independence that was lost in the 1990s. — *Charles Newbery*

Bolivia okays Gazprom deal

Bolivia's parliament has approved transfer of a 20% stake in two Bolivian blocks from France's Total to Russian gas giant Gazprom.

Gazprom and Total originally signed a farmout agreement for the two blocks, Ipati and Aquio, in southern Bolivia, in October 2010. The deal leaves Total with a 60% stake and TecPetrol with 20%.

Two bills on the transfer presented to parliament "seek to change the structure of participation in both areas and allow a third company to enter the project, a subsidiary of Russia's state-owned Gazprom," the energy ministry said March 26.

Total recently presented the Bolivian state oil company YPFB with a declaration of commerciality of the Ipati and Aquio fields, which is being analyzed by YPFB.

"We plan to start production of these two fields towards the end of 2016 or early 2017, as tentative dates," energy minister Juan Jose Sosa said.

Gazprom has previously estimated the proven reserves in the Ipati and Aquio blocks to be 176.3 billion cubic meters of natural gas and 14.8 million mt of gas condensate.

Gazprom declined to comment on whether the company has finalized a deal for an exploration and production contract for a third block nearby, called Azero. In September the company said it hoped to close such a deal by the end of the year. — *Rosemary Griffin*

Dow mulls Vaca Muerta

Argentina's state-run energy company YPF and Dow Argentina signed a preliminary agreement March 26 for developing shale gas resources in the Vaca Muerta play for use as petrochemical feedstock.

YPF CEO Miguel Galuccio and Jorge La Roza, head of Dow Chemical's operations in the southern region of Latin America, signed a memorandum of understanding for the joint project in Buenos Aires, YPF said.

Dow's plants can produce 1.3 million mt/year of ethylene and other chemicals in Bahia Blanca, a port city in southern Buenos Aires province.

The companies will launch "exclusive negotiations" on the terms and conditions of a final agreement for the joint venture through which YPF will cede a 50% stake in the 10,131-acre El Orejano block to Dow for development, YPF said.

Argentina has an estimated 774 Tcf of shale gas resources, the largest in the world after China and the US and far more than its proved conventional gas reserves of 12 Tcf.

YPF, which came under state control last year, is trying to rally partnerships to develop the resources, with preliminary accords signed with Chevron and Bridas, which is backed by China's CNOOC.

YPF has said it wants to start projects this year for developing clusters of around 130 shale wells each in Vaca Muerta, a southwestern play thought to have the most potential for output in the country.

As part of the agreement, YPF and Dow Argentina "will work together to identify new projects with the aim of expanding the Argentine petrochemical industry," YPF said.

Dow sets production target

Galuccio said the partnership will help transform Argentina into a "protagonist in the development of unconventional resources." For Dow, the deal will bring it the gas feedstock it wants in order to boost production capacity to one million mt/year of polyethylene.

Shortages of up to 50 million cubic meters/d of gas, or 40% of the 126 million cu m/d average consumption, have stymied Dow's plans.

Output has dropped 16% to 120 million cu m/d from a peak of 143.1 million cu m/d in 2004, forcing the country to ramp up gas imports from Bolivia and LNG suppliers.

YPF said the turnaround in the production decline will come with the development of shale resources, for which it plans to invest around $37.2 billion through 2017. YPF, which produces close to a quarter of Argentina's gas, said that it put its first unconventional well into production in Vaca Muerta on March 1, delivering output to the national market. — *Charles Newbery*

LIQUEFIED NATURAL GAS

Chubu signs Wheatstone deal

Japan's Chubu Electric has signed a long-term sales and purchase agreement with US major Chevron for LNG from the US major's Wheatstone project in Western Australia.

Under the agreement Chevron, together with Apache Energy and Kuwait Foreign Petroleum Exploration Co., will supply Chubu Electric with 1 million mt/year of LNG for up to 20 years, Chevron said March 28.

"More than 80% of Chevron's equity LNG from Wheatstone is covered under long-term off-take agreements with customers in Asia," Chevron said.

The Wheatstone onshore foundation project at Ashburton North is a joint venture between Chevron (72.14%), Apache (13%), Kufpec (7%), Anglo-Dutch major Shell (6.4%) and Kyushu Electric (1.46%).

The first phase of the project will comprise two LNG production trains with a combined capacity of 8.9 million mt/year and a 200 terajoules/day domestic gas plant. The Ashburton North site has been approved for up to five LNG production trains.

The first two LNG trains will be supplied from the Chevron-operated Wheatstone and Iago fields, with Apache and KUFPEC bringing gas to the plant from their Julimar and Brunello fields.

When it was approved in September 2011, Chevron expected Wheatstone to cost A$29 billion, at the time equivalent to $28 billion.

Credit Suisse said in September last year that it expected Wheatstone to also come in over budget, at $35 billion. — *Mriganka Jaipuriyar*

Kansai Electric eyes new LNG

Japan's second-largest power utility Kansai Electric is in talks for supply deals with several prospective LNG projects in the US and Mozambique, joining a number of Japanese utilities in their effort to diversify supply sources and pricing benchmarks.

Kansai Electric "has had a number of talks" with Mitsui and Anadarko to buy LNG from their project in Mozambique, Naoto Matsumura, general manager for the company's Office of Fossil Fuel, told Platts March 22.

He said that Kansai Electric, which is is the biggest Japanese utility after Tokyo Gas, Osaka Gas and Tokyo Electric Power Company, is in negotiations for LNG purchases from the Anadarko-led Mozambique project and could join a consortium of Japanese buyers.

A Tokyo Gas official had said in September last year that Japanese buyers could jointly import 5 million mt/year of LNG from the Mozambique project.

"We are still uncertain about the conclusion of our talks [with Mitsui and Anadarko]," Matsumura said. "However, we do not deny the possibility of forming the consortium."

While Kansai Electric does not doubt Mozambique as a prospective supply source given its vast reserves, Matsumura said that a lack of relevant legal frameworks could slow the startup of projects in the country.

Anadarko has said it expects the Mozambique project to see its first two trains, with a capacity of 5 million mt/year each, on stream in 2018.

Matsumura said his company has also held talks to buy LNG from three US projects in which Japanese companies are involved: Free Port, Cameron and Cove Point.

"We have been clearing hurdles to accept lean gas-based LNG by testing our power generation facilities as well as our tank operations," Matsumura said.

The Freeport, Cove Point and Cameron projects still need approval from the US Department of Energy to export LNG to non-FTA countries such as Japan.

BP agreement

Kansai Electric intends to conclude a sales and purchase agreement with BP Singapore some time before September this year, Matsumura said. The utility has in place a "key terms agreement" to buy some 500,000 mt/year of LNG from the company for 15 years from fiscal 2017-18 at gas-based prices.

The agreement, once concluded, would become Kansai and Japan's first ever long-term LNG import contract to be fully linked to gas prices. BP Singapore would supply 500,000 mt/year of LNG at Henry Hub-linked gas prices to Kansai Electric from its portfolio supply sources, including Egypt and Trinidad & Tobago, Kansai Electric officials told Platts earlier.

This deal represents 7% of Kansai Electric's estimated annual record LNG consumption of 7.27 million mt for power generation for fiscal 2012-13 (April-March). Kansai estimates its total LNG requirements for 2012-13 at 8 million mt, Matsumura said. He added that 5 million mt of the total are procured through long-term contracts with the balance coming from a combination of spot and short-term contracts as well as incremental supplies from their long-term contracts.

Commenting on its 15-year purchase deal with the Qatargas 3 project signed last year, Matsumura said that Kansai Electric is importing 500,000 mt/year of lean-gas based LNG from the project on Q-Flex vessels from this year.

Destination clause

As part of ongoing efforts to increase flexibility in LNG imports, Kansai Electric is looking for long-term contracts without destination clauses as their room for upward and downward volume flexibility in existing supply contracts is limited, Matsumura said.

"Ideally we would [like to] have no destination restrictions, whilst having FOB contracts with vessels we can control," Matsumura said.

Kansai Electric said it secured "greater flexibility" in its LNG import contract with the Woodside Petroleum-led Pluto LNG project in Western Australia after it acquired a 5% equity stake in the project in 2007. The first phase of the Pluto LNG project will produce 4.3 million mt/year of LNG.

Kansai Electric has a contract to buy between 1.75 million mt/year and 2 million mt/year of LNG from the Pluto project. A portion of the company's supply will be on an FOB basis, a senior company official had said earlier.

Matsumura said Kansai Electric has sold "a few" LNG cargoes from the Pluto project on a spot basis when the Osaka-based company had faced "surplus" supplies. Kansai Electric can also resell or divert its maximum contractual LNG purchase volume from the Pluto project upon consent of the seller, Matsumura added. — *Takeo Kumagai*

Baltic LNG terminal threatened

Construction work on Poland's first liquefied natural gas terminal in the Baltic Sea port of Swinoujscie may come to a halt because of the financial troubles of one of its contractors, Polish construction company PBG, the daily *Dziennik Gazeta Prawna* reported March 25.

PBG, which is a member of the Saipem-led consortium building the terminal, filed for bankruptcy in June last year. This came after it branched out from its core oil and gas construction business to take part in building three of the four stadiums used during the European Football Championships in 2012 that Poland co-hosted with Ukraine.

PBG lost zloty 3.7 billion in 2012 and the daily said it was unclear whether the company would be able to remain on the LNG site another month.

"We are constantly monitoring the situation with PBG and, so far, the consortium has been carrying out the work without interruption," Polskie LNG, told Platts. "Obviously, the financial results presented by PBG should be treated as a matter of concern as much as they shall be alarming for the Italian company, Saipem, which leads the consortium."

The consortium leader would have to present a new plan if any member of the consortium has to leave, he added.

The problem spreads

Italy's Saipem, owned by Eni, may have difficulties itself because it has been plagued by a corruption scandal, the daily said.

"We are aware of some alarming information about these entities, which has been disclosed over the last few months," Mazur said. "It should be noted, however, that this information has no impact on the construction of the Swinoujscie LNG terminal."

Mazur told Platts in December that PBG's problems had caused delays of about four months to the investment's schedule. The terminal is due to be completed by July 2014, when it is scheduled to receive its first cargo from Qatargas.

Around 1,000 workers are now onsite, up from 300 last August, Mazur added March 25.

"Provided that the work is continued without obstacles and motivation remains at its current level, the timely delivery of the first commercial gas cargo, as planned for the second half of next year, shall not be at risk," he said.

The zloty 4.3 ($1.3) billion terminal, in the Baltic Sea port of Swinoujscie, will have capacity to import the LNG equaivalent of 5 billion cubic meters/year. — *Staff*

Osaka seeks gas benchmarks

Osaka Gas has started looking for more flexibility in its volume and pricing terms, its president, Hiroshi Ozaki, said April 4.

Osaka Gas' efforts come as it attempts to forecast its mid-term supply and demand, given Japan's ongoing review of its energy portfolio.

Ozaki said at a press briefing in Tokyo that the company was "trying to create contractual frameworks" that would allow it to "exchange" its "compatibility" of supply cargoes and price benchmarks, depending on market conditions.

"While LNG is increasingly be traded around the world, we are considering ways to increase our flexibility and stability in supply contracts," Ozaki told reporters.

But Ozaki said LNG pricing systems are different in various markets today, while producers in such places as Qatar and prospective suppliers in Africa are developing their projects targeting Europe and Asia.

Osaka Gas hopes to be able to buy LNG at "various benchmarks" to "exchange its price risks" when the company is considering buying LNG with another company in a different market, Ozaki said.

"For instance, if buyers in Japan and Europe are jointly buying LNG, there will be different requirements in Europe and Japan," Ozaki said. "If we are exchanging cargoes, we may need to consider such options as selling LNG to the counterpart at [UK's] NBP prices as necessary.

"We are still uncertain whether it will be about physically swapping cargoes or signing a joint contract and changing offtake volumes [with the partner], in an economically feasible way, accordingly," he added. "We would like to consider this sort of option to build a new contractual framework."

Osaka Gas is believed to be one of the bidders for capacity in a planned expansion of National Grid's Isle of Grain LNG import terminal in the UK.

To increase volume flexibility in its LNG procurement, Osaka Gas has "strategically" started weighing a new business model in Europe. It would supply LNG to Europe on a regular basis but retain an option to bring back its LNG to Japan when necessary. — *Takeo Kumagai*

Heritage inks PNG farm-in

Heritage Oil has signed an agreement with LNG Energy to farm-in to two licences onshore Papua New Guinea, the London-listed company said April 2.

Petroleum prospecting licences 319 and 13 have gross areas of some 2,025 and 160 square km respectively and are in a hydrocarbon bearing region, Heritage said.

On completion of the deal, Heritage will earn an 80% working interest in each licence and be appointed operator in return for funding the costs of a seismic acquisition and the cost of drilling an exploration well.

In addition Heritage will make a $4 million contribution to LNG Energy's back costs on the licences. The company said there is additional exploration potential within both of the licences.

"We are delighted to announce the expansion and diversification of our exploration portfolio with this entry into Papua New Guinea," Heritage's CEO Tony Buckingham said.

"We consider the region to be an attractive area both commercially and technically for supplying the premium East Asian gas markets." — *Jacinta Moran*

Miners urge Gladstone boost

Queensland's mining industry has joined the debate on Gladstone port's growing status as a hub for coal and LNG exports.

It strongly opposes any new environmental policy that may hinder the Australian port's development, it said April 2.

The Australian state's mining industry body, the Queensland Resources Council, said in a report that while it values the coral, important export industries could not avoid passing along and through the Great Barrier Reef.

"The development and sale of these commodities are an essential part of Queensland and Australia's economy and provide an important ongoing financial contribution to the programs which provide for the continuing protection of the Great Barrier Reef," said the QRC.

The QRC outlined its views in a submission to the Australian government's independent review into the environmental management of Gladstone port which is due to report back to the government by June 30.

"QRC's fundamental position in relation to the Great Barrier Reef and industry is that there needs to be a focus on a risk management approach and on the activities that actually impact on the [coral] reef, rather than populist or emotive reactions to interest group and media commentary," said the industry group's submission.

About 1,450 ships called at Gladstone port in the 2011-12 financial year when the port shipped 66 million mt of commodities including 59.7 million mt of coal exports, and the port is fast becoming a hub for Queensland's LNG export industry, said the report.

Gladstone port is one of 11 Queensland ports along with Abbot Point and Hay Point for coal exports that lie within the boundaries of the Great Barrier Reef Marine Park.

The review was set up after concerns were expressed by the World Heritage Committee about the potential for port development in Gladstone, and increased shipping and dredging to impact the Great Barrier Reef heritage area, according to the Australian government's environment department website. — *Mike Cooper*

Centrica does US LNG deal

Cheniere Energy's subsidiary Sabine Pass Liquefaction has signed a 20-year sale and purchase agreement with Centrica to sell the UK energy company 1.75 million mt/year of LNG from its fifth liquefaction train, once it begins operations.

Sabine Liquefaction is developing six liquefaction trains, each with an expected nominal capacity of about 4.5 million mt/year, adjacent to the Sabine Pass LNG import terminal in Cameron Parish, Louisiana.

The first two trains are already being built, and work on the third and fourth trains is expected to start in the first half of 2013, Cheniere said. The permitting process and preliminary engineering have been initiated for the fifth and sixth trains, it added.

Under the SPA, Centrica will buy about 1.75 million mt/year on an FOB basis, paying the monthly Henry Hub price plus a fixed component. The SPA has a 10-year extension option beyond its 20-year time frame. Deliveries from train 5 are expected to start as early as 2018, Cheniere said.

The SPA is subject to, among other things, Sabine Liquefaction getting the regulatory approvals and securing financing.

With the latest deal, Sabine Liquefaction now has commercial contracts for five trains, and the total contracted volume for Train 5 has reached 3.75 million mt/year, including an earlier SPA with Total.

Earlier in March, Cheniere submitted an application to the US Department of Energy for licenses to export additional volumes of LNG to countries that have free trade agreements with the US as well as to non-FTA nations, to fulfill its deal with Total.

Sabine Liquefaction already has permits from the DOE to export 2.2 Bcf/d of gas (about 17.18 million mt/year of LNG) from its terminal, including to non-FTA countries—the only Lower-48 volumes authorized for non-FTA exports. — *Vandana Hari*

Taiwan, China in energy deals

Taiwan's CPC Corp. has signed a slew of agreements with China's CNPC and CNOOC covering LNG and crude supplies, along with upstream cooperation, that opens up a new chapter of cross-strait cooperation.

Its agreement with CNOOC covers spot LNG supplies, CNOOC said March 28.

A CPC spokeswoman said April 1 that there was no fixed time frame or volumes agreed on in the deal. "When the situation suits us and the price and timing are right, we will lift the cargoes from CNOOC. It is not our only supplier so this agreement is not extraordinary," she said.

CPC is Taiwan's sole LNG importer. It has two LNG import terminals in Taichung and Yungan, with total capacity of 13.5 million mt/year. It has term contracts with Qatar, Malaysia and Indonesia and imports regular spot volumes from Nigeria, Australia, Egypt and Equatorial Guinea. Last year it was also seen buying rare spot cargoes from Norway, Trinidad & Tobago, Spain and Algeria.

Natural gas demand in Taiwan is set to grow significantly over the long term as the government seeks to increase the adoption of cleaner fuels. In September last year CPC Chairman Lin Shengchung said Taiwan's total LNG demand could rise from 12 million mt/year in 2011 to 20 million mt/year by 2030. — *Song Yen Ling, Chloe Hang*

COMPANIES

Dart halts CBM in NSW

Australian coalbed methane junior has suspended its operations in the eastern state of New South Wales following recent government decisions restricting the development of new projects.

Dart Energy April 2 unveiled a restructuring and refocusing program, which includes a 70% reduction in staff levels to around 50 and a 60% cut in overheads to $12 million/year. As part of the program, Dart will focus its strategy on maximizing the value of its UK portfolio, including CBM projects in Scotland and shale assets in England, where it plans to begin generating cash flow within the next year and a half.

“With the changes we are implementing, and with the 2013 planned work program now focusing primarily on the UK, existing funds will meet the company’s needs for the next 12 months,” Dart Chairman Nick Davies said.

“The board of Dart is extremely disappointed with the uncertainty created by recent NSW and federal government decisions in relation to CSG development in Australia,” he added. “The consequence is that investment is leaving the country, field operations are being suspended, Australian jobs are being lost, and the impending energy crisis in NSW is not being addressed, and indeed, will only get worse. This is in direct contrast to the UK, where the government is actively seeking to support the responsible development of unconventional gas resources.”

Dart’s decision follows last month’s shuttering of the Clarence Moreton CBM project in northern NSW by another local explorer Metgasco. The suspensions come in the wake of surprise announcements in February that the NSW state government would introduce 2 km (1.2 mile) “no-go” zones for CBM development around residential areas, horse studs and vineyards, and that the federal government would introduce its own approval process for CBM projects that impact water resources.

The NSW market is facing a gas supply crunch as existing long-term contracts roll off over 2014 to 2016. The expiry of those supply deals will coincide with significant increases in demand for gas as three export-oriented LNG projects come on line in the state’s northern neighbor Queensland.

As part of its restructuring, Dart will also slow down work at its operations in Indonesia, where the near-term focus will be securing an offtake partner and establishing the commerciality of the company’s South Sumatra assets. In China, the focus will be on securing regulatory approvals for Dart’s shale gas production sharing contract, and finalizing a farm-out deal to fund exploration there.

The company’s operations elsewhere in Indonesia and China, and in India and continental Europe are considered non-core, and will be scaled back substantially with a view to partnering, farm-out or sale.

Dart has also canceled a planned initial public offering of Dart Energy International, given the impact of the recent government decisions on the short-term prospects for its assets in Australia. “Had an IPO of DEI progressed, the short-term viability of the Australian assets as a standalone business would not have been assured,” the company said.

Dart Energy was spun off in July 2010 from Australian CBM producer Arrow Energy, which was acquired by Shell and PetroChina. Dart was formed to hold Arrow’s 90% stake in its unconventional gas assets in China, India, Vietnam and Indonesia, along with several growth prospects in Australia. — *Christine Forster*

Shell to sell more of Woodside

Woodside Petroleum’s recent entry into the upstream sector in Israel, through its purchase of a 30% stake in the massive Leviathan gas field, could be a catalyst for the sell down of Shell’s 23.1% stake in the company.

“We believe Woodside Petroleum’s entry into Israel through its proposed acquisition of a stake in the offshore Leviathan gas field will likely be a catalyst for Shell to sell down its stake in the company,” CBA analysts Luke Smith and Lachlan Cuskelly said in a note.

“Given the geopolitical tensions in the Middle East and Shell’s significant investments in the region outside of Israel, we anticipate a sell down to dispel any perception amongst other Middle Eastern countries that Shell is investing either directly or indirectly in Israel.”

In 2011, the Anglo-Dutch major produced about 200,000 b/d of oil equivalent in Oman and around 144,00 boe/d in the UAE. In addition, the company has a 30% stake in the Qatargas 4 LNG project, which produces about 7.8 million mt/year, as well as a stake in the Pearl gas-to-liquids plant there.

Shell sold a 10% stake in Woodside in November 2010. The company has said its remaining stake does not fit within its long-term plans and would be divested at the right price.

Shell’s sale of its remaining equity in Australia’s largest listed oil and gas producer, worth around A$6.9 billion, is likely to come after Woodside assesses its final investment decision on the Browse LNG project, which could cost more than $40 billion, the analysts said.

They added that the share price would be important in determining the timing of the divestment, but less a catalyst than the entry into Israel, particularly given Shell has already made significant returns on its stake in Woodside, which it built up between 1963 and 1985.

“We continue to expect delays to the Browse project with a near-term FID unlikely due to project economics. We believe a sell down in Woodside pre any announcement on Browse would not reflect well on Shell given its direct investment in Browse,” the analysts added.

Woodside Petroleum agreed to pay $696 million for its stake in the 17 Tcf Leviathan gas discovery off Israel late last year. Woodside's entry would leave the remaining equity in Leviathan with Noble Energy (30%), Delek Drilling (15%), Avner Oil Exploration (15%) and Ratio Oil Exploration (10%).

The partners are planning a domestic gas project at the field, to be followed by an LNG project, to be operated by Woodside, once the Israeli government passes laws allowing for exports of the gas.

Monopoly of Leviathan

Israel's anti-trust authority is due to rule soon on whether the Leviathan partners constitute a monopoly in the field of gas sales to the Israeli market. The Leviathan partners, who are also already involved in the now-producing Tamar gas field (*see separate report*), have said they expect to begin sales to the domestic market in 2016 and to launch exports in 2018, although there is a strong body of Israeli opinion that is strongly opposed to gas exports.

The decision by the Anti-Trust Authority director is viewed as having crucial significance for the proposed deal with Woodside. Israeli energy industry sources said that by declaring the Leviathan consortium a monopoly the director could impose price controls on gas sales or could even take more drastic measures by forcing one or more of the parties in the consortium to sell its stake.

Apology to Turkey

One of the plans under consideration for exporting the gas involves Turkey as a transit country. Relations have been tense between the two since Israeli forces killed eight Turkish nationals protesting the Israeli blockade of Gaza, three years ago.

But US presidential sources said in late March that Israel's prime minister, Benjamin Netanyahu, had apologized by phone to his Turkish counterpart Tayyip Ergogan and had also agreed that Israel will pay compensation to the victims' families.

The apology and the agreement to pay compensation meet two of Erdogan's three preconditions for any discussions with Israel on the possible transit of gas. The third is that Israel should end its blockade of Gaza. — *Christine Forster, Neal Sandler*

Chesapeake finds interim CEO

Chesapeake Energy named COO Steve Dixon as its interim CEO after the company's founder and CEO Aubrey McClendon retired April 1. Dixon, in charge of Chesapeake's exploration-and-production arm, has been at the Oklahoma City-based company for 22 years.

Chesapeake gave no indication why it had not been able to hire a new CEO in the two months since McClendon gave notice that he would leave the firm he started 24 years ago.

There had been reports that discussions with a potential new CEO had fallen apart at the last minute.

Dixon said Chesapeake was on track to keep its leasing and drilling expenses within a budget of about $8 billion/year while still hitting its gas and oil production targets. It is about to close on $1.5 billion in asset sales, part of a planned $7 billion of divestitures this year.

"We have also taken advantage of the recent surge in natural gas prices to lock in additional price protection for 2013 – and we have begun to hedge natural gas production for 2014 at prices well above four dollars, a level the market has not seen for quite some time," Dixon said.

He said Chesapeake plans to spend 35% of its overall drilling budget in South Texas' Eagle Ford Shale, its single largest spending on an individual play.

"Our total daily net production from the Eagle Ford has recently averaged 80,000 barrels of oil equivalent/d and we are targeting total daily net production of more than 92,000 boe/d year-end," Dixon said.

"Overall, we view the update as a slight positive based on confirmation of capex trending down to the budgeted $8.3 billion level," Stifel analyst Amir Arif wrote in a note to clients. — *Bill Holland*

Total's grid goes to Snam & Co

A consortium led by Italian gas network company Snam and comprising also the Singaporean fund GIC and French EDF has signed an agreement with Total to buy its TIGF networks and storage business in southwest France (*IGR 720/24*).

TIGF operates 5,000 km of major pipelines in southwest France, as well as storage sites with a working capacity of 2.6 billion cubic meters, the rest being owned by GDF Suez subsidiary GRT gaz.

TIGF went for €2.4 ($3.1) billion, a shade below the midpoint of the valuation. Total is selling the company as part of a $15-20 billion asset sale program.

France has three gas trading areas: GRTgaz's PEG Nord and PEG Sud in southeastern France and Total's TIGF PEG area in the southwest. It is linked to the Spanish gas grid on the other side of the Pyrenees.

France's energy regulator CRE plans to merge the PEG Sud and TIGF PEG gas trading hubs by 2015 in a bid to boost market liquidity, with the long-term goal of having one trading hub for the whole of France.

The consortium's acquisition agreement follows a consultation process with TIGF's employee representative bodies.

France's energy sector continues to be significantly regulated, and there was much opposition to the sale of TIGF.

EDF is the dominant electricity company in France and is 85% owned by the state. The company is looking to expand in Europe's gas market and its inclusion in a bid was seen as a way of allaying some fears over job losses at the company.

Last year, EDF gained control of Italian energy firm Edison, making it the second-largest gas operator in Italy.

EDF intends to use Edison as its platform to expand gas activities and is also involved in several European salt cavern storage projects as well as building the Dunkirk LNG terminal in northern France.

The closing of the transaction remains subject to approvals by the relevant regulatory and antitrust authorities. — *Robin Sayles*

Shell, Volvo join forces

Shell has agreed a joint cooperation agreement with Swedish auto maker Volvo to help develop LNG as a fuel option for heavy duty truck operators.

Under the agreement, the Anglo-Dutch major and Volvo Trucks will work together on the technical, commercial and regulatory issues of LNG use with the aim of helping trucking companies convert to LNG as a fuel.

They will also collaborate on issues such as fuel quality across markets, engine compatibility and well-to-wheel emissions monitoring. The non-exclusive agreement focuses primarily on North America and Europe, Shell said.

The companies also intend to help develop health and safety, and other operating standards to develop heavy-duty truck operators' understanding of LNG as a fuel, Shell said.

Shell, which is already the world's biggest LNG supplier, has been looking to expand its LNG business into direct sales as fuel for commercial truck fleets and shipping.

Shell has already decided to develop a production and refuelling infrastructure to supply LNG along a truck route in Alberta, Canada.

Earlier this month it agreed to build two small-scale gas liquefaction projects to supply LNG as a fuel for heavy trucks and large ships in the US and Canada.

Shell has said it plans to increase LNG-for-transport projects to more than 5 million mt/year over the next decade, with about half being supplied to the trucking industry in Canada and the US and the rest to shipping in the US and Northwest Europe.

Last year, Shell signed a deal with TravelCenters of America to sell LNG to heavy-duty road transport customers in the US through TravelCenter's network of fueling centers.

In Europe, Shell is looking to sell growing volumes of clean-burning LNG to marine customers, particularly as EU environmental regulations are set to further limit the sulfur content of marine fuels from 2015.

The oil major, which produces half of its upstream volumes from gas, has said it expects the world's demand for LNG to double to 500 million mt a year by 2025. — *Robert Perkins*

ICE applies for European role

IntercontinentalExchange has applied to the European Securities and Markets Authority to establish a new trade repository for swaps reporting and futures trade data to meet over-the-counter derivative requirements set out in the European Market Infrastructure Regulation.

ICE is looking to establish ICE Trade Vault Europe to serve the commodities, credit, interest rate and foreign exchange asset classes.

"A common theme of international financial regulation is mandatory swap reporting and the creation of repositories," Bruce Tapper, president of ICE Trade Vault, said in a note.

Emir, which was adopted by the European Commission in July 2012, is intended to increase the stability, transparency and efficiency in derivatives markets. The new regulation requires that information on all European derivative transactions is reported to trade repositories and visible to the Esma.

ICE Trade Vault was the first swap data repository in the US to receive regulatory approval from the Commodity Futures Trading Commission. It began accepting credit default swaps trade data in October and commodities trade data in February.

ICE Trade Vault Europe is subject to approval by Esma. — *Paula VanLaningham*

E.ON sells Hungarian assets

German energy group E.ON has signed agreements to sell its Hungarian natural gas wholesale and storage businesses to Hungarian state energy holding MVM for some €870 ($1,117) million.

The deal involves 100% stakes in E.ON Foldgaz Trade, Hungary's dominant natural gas wholesaler that imports the bulk of Hungary's gas from Gazprom; and E.ON Foldgaz Storage, which owns 4.2 billion cubic meters of underground gas storage facilities. The purchase price includes €350 million for the companies' shares, plus the assumption of various liabilities, MVM.

Closure of the transaction is subject to regulatory approval, which the companies expect to secure in the second half of the year. The final purchase price will be determined based on the volume of gas stored at the time of closure.

The purchase of the gas businesses by fully state-owned MVM is part of the Hungarian government's strategy to increase its ownership role in the energy sector and to attempt to achieve lower prices for consumers. A letter of intent on the transaction was signed last November (*IGR 713/1*).

The sale is also in line with E.ON's strategy of streamlining its European operations.

Of the Hungarian gas units, E.ON Foldgaz Trade has been loss-making in recent years thanks to adverse pricing regulations and market conditions. E.ON Foldgaz Storage, on the other hand, has turned stable net profits of up to forint 13 billion ($60 million). — *Balazs Szladek*

Asia, US slide; Europe hits records

Asia

- Platts May LNG Japan Korea Marker ended April 5 20 cents lower that it started the week, at $15.30/MMBtu. Trading was quiet over the fortnight, with Far East buyers largely covered with term contracts and early spot procurement. In addition, various sources said two Japanese utilities, likely Kyushu Electric and Kansai Electric, recently signed strip deals for summer and autumn cargoes, which would keep a lid on spot appetite.

- Demand is more likely to be seen outside of Japan, such as Taiwan and South Korea. However, buyers remained on the sidelines at the moment, with notional bids heard below $15/MMBtu for May.

- Further out, first-half and second-half June was assessed at $15.30/MMBtu and $15.40/MMBtu, respectively, resulting in a 10 cents/MMBtu intramonth contango, while leaving the overall May/June spread fairly flat.

- Mexico's state-owned Federal Electricity Commission has issued a buy tender for 31 LNG cargoes to be delivered from June through next year. Market sources said the Mexican tender was likely intended to gauge offers and expressions of interest to sell, rather than to nail down a deal.

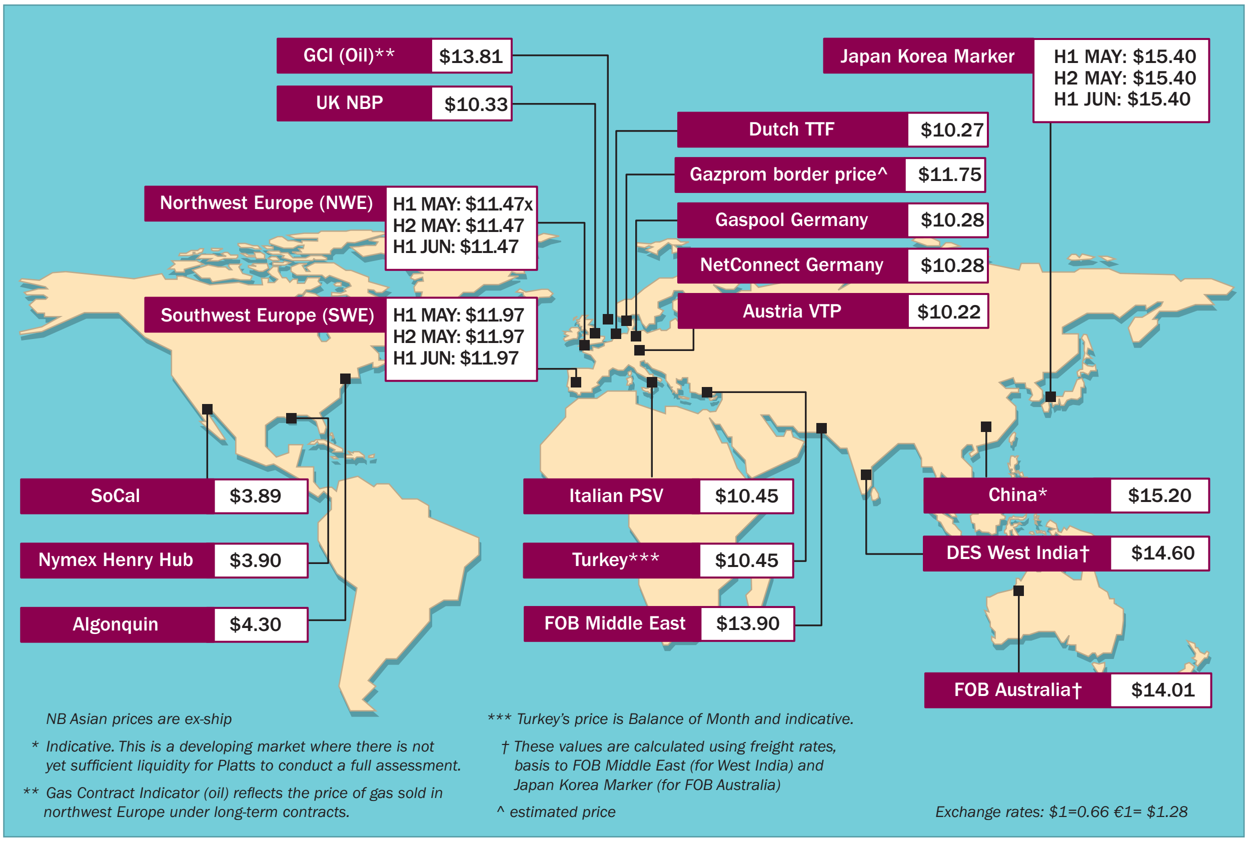
- Elsewhere, Argentina is expected to issue another buy tender, having secured only half of the planned 24 cargoes into Bahia Blanca. Meanwhile, comfortable temperatures did little to lift the bearish sentiment or fuel additional LNG consumption.

- Platts May DES West India was assessed at $14.60/MMBtu April 5, dropping 10 cents over the week. Healthy appetite from the region was met with resistant offers due to competing demand from the Atlantic Basin.

- May offers into West India were still fairly steep at around $15/MMBtu and above, but Indian buyers were targeting a price level not more than the mid-$14s.

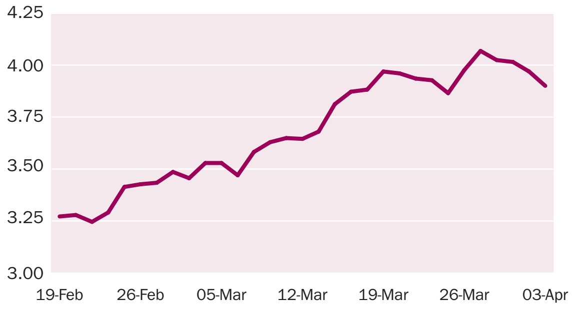
- There was also news that India's GAIL concluded a deal for an end-April/early May cargo into its Dabhol import terminal, but the exact price level was

Gas price snapshot April 3 (Month ahead, $/MMBtu)



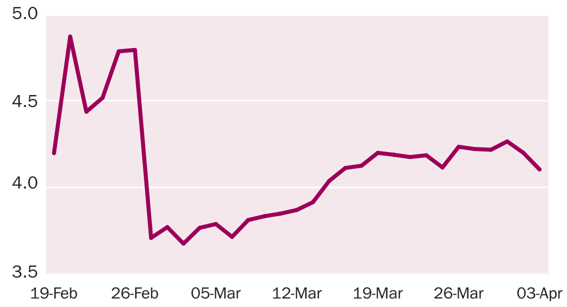
Source: Platts

US gas: Henry Hub front month $/MMBtu



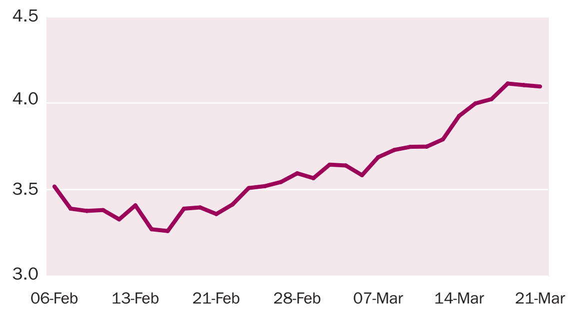
Source: Platts/Nymex

US gas: Transco-6 NY front month $/MMBtu



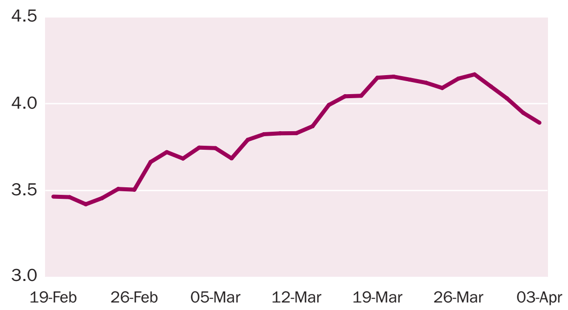
Source: Platts Gas Daily

US gas: Chicago front month $/MMBtu



Source: Platts Gas Daily

US Gas: So Cal front month $/MMBtu



Source: Platts Gas Daily

unclear. The Asia Pacific Day Rate held stable for the week at $105,000/day.

US

- The NYMEX May gas futures contract settled up 4.7 cents at $3.947/MMBtu on bullish storage data.

- The EIA reported storage stocks fell 94 Bcf to 1.687 Tcf for the week that ended March 29. The net withdrawal came in at the high end of consensus expectations of a draw between 90 Bcf and 94 Bcf. A year earlier, EIA reported a 43-Bcf injection.

- As a result, the 642-Bcf deficit to the year-ago level grew to 779 Bcf, while the 61-Bcf surplus to the five-year average of 1.724 Tcf flipped to a 37-Bcf deficit.

- Physical day-ahead markets were on a downward trajectory by early April as winter breathed its last gasp. Northeast city-gates market, which jumped April 1 by more than $2 after the long Easter weekend, crashed over the next several days as temperatures warmed up to more seasonable norms.

UK

- Prompt prices on the UK NBP remained high. Both the day-ahead and the within-day contracts from March 25 to April 4 remained above 80 p/th, except for April 2 when day-ahead plunged 15.65 p/th to 78.10 p/th and within-day lost 17.25 p/th and closed at 76.25 p/th.

- Demand continued to surpass seasonal norms in the period and was also high remaining above the 300 million cu m mark. National Grid data pegged demand on March 28 at 372 million cu m, more than 100 million above the norms.

- Storage withdrawals from the UK's main storage facility Rough remained strong and helped to meet the higher demand in one of the coldest Marches in living memory. Platts unit Bentek Energy said Rough stocks opened below 100 million cubic meters on March 27 compared with National Grid data showing stocks of 2.148 billion cubic meters about a year ago.

- On the plus side, LNG deliveries to the UK picked up. The UK received four shipments in the period March 24-Mar 31. Qatar's Mekaines tanker made a shipment to Isle of Grain, the Zarga and Tembek to South Hook and a Trinidad & Tobago sourced cargo arrived into Dragon on March 31. The Mozah vessel was expected at South Hook on April 10.

France

- French PEG Nord day-ahead gas prices reached as high as €39.50/MWh on March 25, as prices soared across northwest Europe.

- That compared with an average PEG Nord day-ahead for March of €32.29/MWh, which itself was up 19% from the February 2012 of average of €27.12/MWh.

- France was below the UK, which was suffering the worst of the cold. And at times France was below the Dutch and German markets, which were rising as their gas was pulled towards the UK.

- The French forward curve has not been very liquid, but most contracts were trading around 40-50 cents premium to the Dutch TTF market.

- PEG Nord Winter 13 was valued at €28.95/MWh on April 3 and the PEG Nord Cal 14 at €27.50/MWh.

Netherlands

- The Dutch TTF prompt gas market remained volatile ahead of the four-day Easter weekend driven by higher-than-expected demand, while low LNG and storage supplies in the UK also kept upward pressure on prices.

- The day-ahead gas price soared to pre-recession high of €41.05/MWh on March 25, reaching the strongest level since March 15, 2006 when spot gas price was pegged at €41.25/MWh, according to Platts data. This pushed the NBP-TTF spread to narrow significantly to 86 cents, down from more than a six euro spread seen during the previous weeks.

- Day-ahead prices fell for three consecutive days before the Easter holidays and continued to descend on April 2 to €31.20/MWh, the lowest level recorded since mid-March. However, prices rebounded to €33.45/MWh on April 3. By midday on April 4, next day contract was last heard trading at €32.30/MWh.

- On the last day of trade, April gas contracts was valued at €29.35/MWh, while Q2 13 contract closed at €27.85/MWh and summer 13 ended at €27.45/MWh on March 28. The new front-month, May, gas price was assessed at €26.90/MWh on the first day of trading.

- Gas price for the calendar 14 contract, which reached more than a two month high of €27.10/MWh on March 25, was assessed at €27.05/MWh on April 3.

Germany

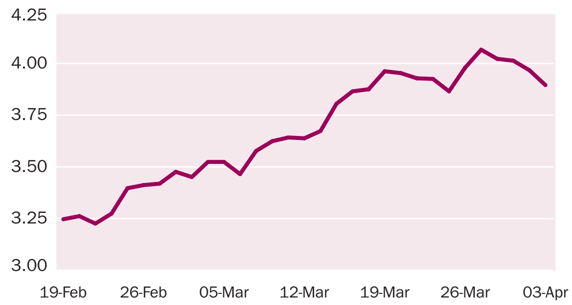
- Lingering cold conditions kept German spot prices very strong in the two weeks since March 22, with temperatures unlikely to return to normal spring levels before the second week of April.

- Having been pegged above €31.00/MWh since April 19, the day-ahead contract on the NetConnect hub was assessed on April 22 at €35.00/MWh, while on Gaspool it was valued at €34.80/MWh.

Algonquin versus Henry Hub $/MMBtu

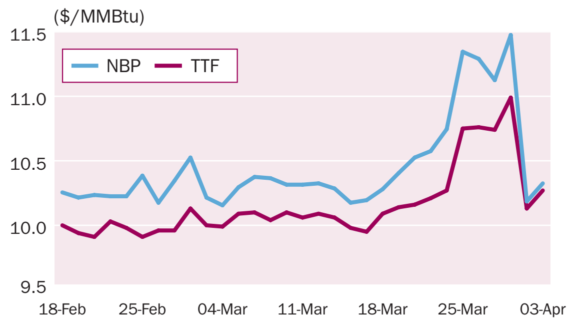
Source: Platts/Nymex

Tennessee Gas Pipeline 500 leg $/MMBtu



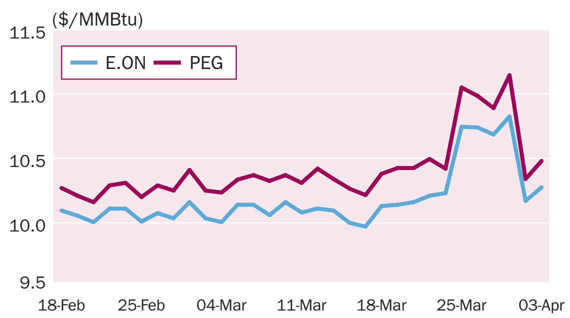
Source: Platts

UK NBP versus Dutch TTF (Month +1)



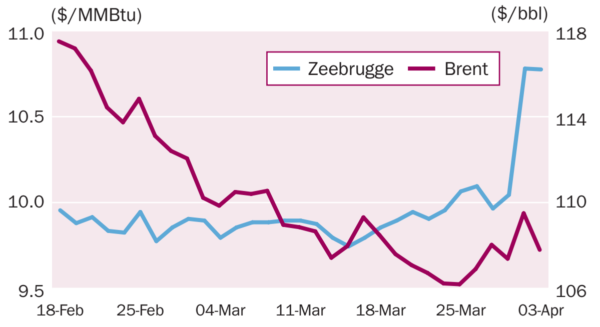
Source: Platts European Power Alert

German NCG and French PEG Month+1 $/MMBtu



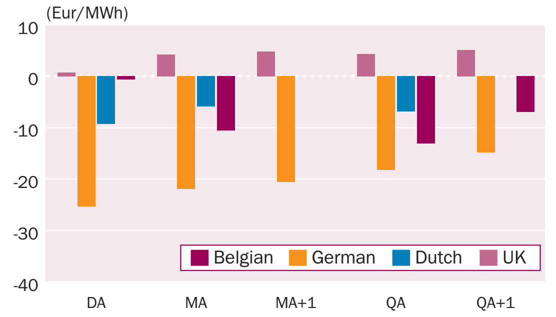
Source: Platts European Power Alert

Zeebrugge Q+2 gas vs Dated Brent Crude



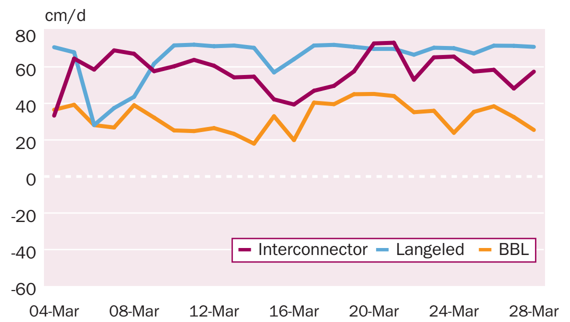
Source: Platts

Clean Spark Spread, April 3 (50% efficient)



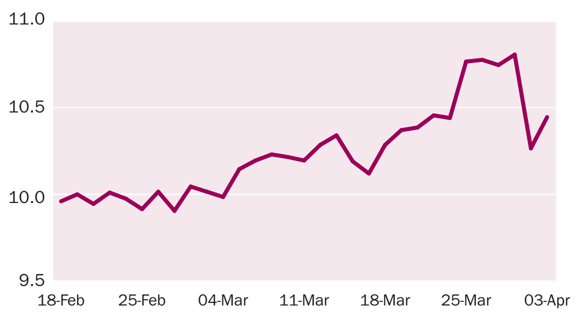
Source: Platts European Gas Daily

Cross-border flows into the UK



Source: Companies

Italian PSV Month+1 $/MMBtu



Source: Platts

- Prices remained strong on the first three trading days of April. "April is a shoulder month," a trader commented, saying prices were expected to remain high as necessary storage injections were likely to be carried out.

- Having both began their stint as front-month contract at €26.20/MWh on March 1, April gas prices on both the NetConnect and Gaspool closed March 28 at €28.90/MWh. On April 2, the new front-month contract of May was valued at €27.00/MWh on both hubs.

- During its last five days of trading as front-season contract, summer 13 on the NetConnect changed hands within a €26.65/MWh-€27.50/MWh range, closing the month at €27.50/MWh, with Gaspool following near-identical movements.

- On its first day as front-season contract, winter 13 on both the NetConnect and Gaspool was valued, on April 2, at €28.25/MWh.

Italy PSV

- Prompt prices on the Italian PSV gas hub rose in the last week of March amid cold temperatures and tight storage. The day-ahead closed at €32.40/MWh on March 25, up by around €4 from the levels of the first half of March.

- On April 3 however the day-ahead was down to a closing price of €30.50/MWh. Similarly, the front-month contract was valued at €28.25/MWh on March 25 against around €26.60-26.80/MWh of the first half of March.

- Further out on the curve, the Q2 13 contract was valued at €27.55/MWh on March 25, gaining around €1 from the first half of March, while in the first week of April the Q3 13 and Winter contracts remained rather illiquid and were assessed at €27.30/MWh and €29.00/MWh respectively on April 3.Curve prices were seen as too high because of the support provided by northern European hubs.

- Storage injection restarted on April 1 and according to Gas Storage Europe the PSV was 39.75% full on April 3, with stocks of 6.3 billion cubic meters.

- Gas imports were above 190 million cubic meters/day in the last week of March but fell sharply in early April.

- Algeria supplied around 55 million cu m/d, Russia 88 million cu m/d, northern Europe 8 million cu m/d and Libya 20 million cu m/d. The output at the Cavarzere LNG terminal was at 21.8 million cu m/d, while national production was around 21 million cu m/d.

CONTRACTS AND TENDERS

Bratislava hospital seeks gas supplies
The university hospital in the Slovak capital Bratislava invites tenders for gas supplies.
Specifications and additional documents (including documents for competitive dialogue and a dynamic purchasing system) are available upon request. The deadline for tenders or requests to participate is 9 am CEST on May 20. 2013. Tenders should be sent in Czech or Slovak to Ivan Uradnicek. Tel: +421 24 823 4317. Fax: +421 24 823 4798. E-mail: ivan.uradnicek@unb.sk

Hungarian parliament contracts for gas
Hungary's national parliament, the Orszzggyules Hivatala, invites tenders for a gas supply contract.
Further details and additional documents, including for a dynamic purchasing system and a competitive dialog, are available upon request. The deadline for tenders or requests to take part is 10 am CEST on May 21, 2013. Tenders or requests for further information should be sent in Hungarian. Tel: +36 14416498. Fax: +36 14416497. E-mail: kozbeszerzes@parlament.hu. www.parlament.hu

Lisbon city municipality seeks gas supplies
Municipio de Lisboa, the local government authority in the Portuguese capital, Lisbon, has published a tender call for gas supplies.
Further details of the tender and additional documents, including for a dynamic purchasing system and a competitive dialog, are available via the Saphety online procurement platform. The deadline for tenders or requests to participate is 8 pm CEST on May 15, 2013. Tenders or information requests should be submitted in Portuguese via the Saphety platform at: www.saphety.com/saphetygov. E-mail: dmf.ccm.dp@cm-lisboa.pt

Italian education authority seeks gas supplies
Adisu Puglia, the regional higher education authority in Puglia, southern Italy has published a tender call for gas and electricity supplies over a three-year period.
Further details and additional documents including documents for a competitive dialog are available upon request. The deadline for accessing documents, expressing interest or tender submission is 12 pm CET (10:00 GMT) on April 16, 2013. Tenders or requests for further information should be sent, in Italian, to Vincenzo Napoliello. Tel: +39 080 5438010. Fax: +39 080 5576028. E-mail: v.napoliello@adisupuglia.it. www.adisupuglia.it

Dutch water utility contracts for gas
Waterschapsbedrijf Limburg, a water utility serving Limburg in the southern Netherlands has issued a tender call for gas supplies.
Further details and additional documents, including documents for a competitive dialog and a dynamic purchasing system are available upon request from the contracting agent, Energie Makelaar. The deadline for accessing documents is April 12, 2013 and the deadline for tender submission is noon CEST (10:00 GMT) that day. Tenders or requests for documents should be sent, in Dutch, to: S. Visser at Energie Makelaar Tel: +31 652 066451. Fax: +31 546 571 714. E-mail: s.visser@energie-makelaar.com. www.energie-makelaar.com

Belgian tech services company seeks gas, power supplies
Belgian technical services company Direction technique AED-BM has launched a tender call for gas and electricity supplies.
Further details and additional documents, including documents for a competitive dialog and a dynamic purchasing system are available upon request. The deadline for accessing documents or tender submission is 10 am CEST (08:00 GMT) on April 15, 2013. Tenders or requests for further information should be directed, in French or Dutch, to Frederic Dauw at GRF Gestion Technique. Tel: +32 22042878. Fax: +32 22041500. E-mail: fdauw@mrbc.irisnet.be . The buyer profile is available at: https://enot.publicprocurement.be/enot-war/preViewNotice.do?noticeId=141689

Indian Bharat seeks LNG supplies
India's Bharat Petroleum seeks Expression of Interest proposals for a Master Sales and Purchase Agreement for supply of LNG at Dahej, Kochi or any other terminal in India.
The company wants to buy LNG spot cargoes and its preferred mode of purchase is short notice tenders to be invited from panel of supplies who sign the MSPA which may be for minimum period of five years. The EOI document can be downloaded from website: www.bharatpetroleum.in till April 24 and the proposals are to be submitted by May 2. Contact: Executive Director (gas), Bharat Petroleum Corporation. Tel: +91 22 22713891 Fax: +91 22 22723892.

Czech institute seeks gas supplies
The Czech institute for the study of totalitarian regimes in Prague has published a tender call for gas supplies.
Full details and additional specifications, including specifications for a dynamic purchasing system and a competitive dialog are available upon request. The deadline for tenders or requests to participate is 11:30 am CEST (09:30 GMT) May 22, 2013. Tenders or requests for further information should be sent, in Czech to Jaroslav Kolcava. Tel: +420 221008285. E-mail: jaroslav.kolcava@ustrcr.cz. http://ustrcr.cz

EVENTS

Global Oil & Gas Crisis Management
April 11-12, 2013
Barcelona, Spain
Organizer: Trident Media
Tel: +34 931 592 794 / 795
E-mail: info@3dent-media.com
www.3dent-media.com

7th Annual Rockies Oil & Gas
April 15-16, 2013
Denver, Colorado, USA
Organizer: Platts
Tel: + 1 781 430 2105
Email: cynthia_rugg@platts.com
www.platts.com/conference

LNG 17
April 16-19, 2013
Houston, Texas, USA
Organizer: CWC
Tel: +1 713 853 8220
E-mail: registration@lng17.org
www.lng17.org

Middle East Petroleum & Gas Conference
April 21-23, 2013
Abu Dhabi, UAE
Organizer: Conference Connection
Tel: +65 633 80064
E-mail: info@cconnection.org
www.mpgc.cc

Western Africa Oil Gas & Energy Week
April 22-24
Windhoek, Namibia
Organizer: Global Pacific Partners
Tel: +31 70 324 6154
E-mail: jodee@glopac-partners.com
www.petro21.com/events/?id=794

Gas Week
April 23-26, 2013
Brussels, Belgium
Organizer: Gas Naturally
E-mail: Info@GasNaturally
Tel: +32 2 234 68 97
www.gasnaturally.eu/gas-week-2013/overview

Oil & Gas Cyber Security
April 24-25, 2013
Houston, Texas USA
Organizer: Marcus Evans Conferences
Tel: +31 2 540 3000 ext. 6483
E-mail: robiny@marcusevansch.com
www.marcusevans-conferences-northamerican.com

Sub Saharan Africa Oil & Gas Conference
April 25-26, 2013
Houston, Texas, USA
Organizer: Energy Corporate Africa
Tel: +1 713 271 7778
E-mail: info@energycorporateafrica.com
www.energycorporateafrica.com

Gas Infrastructure Europe Annual Conference
May 23-24, 2013
Venice, Italy
Organizer: GIE
Tel:+32 2 209 05 00
E-mail: gie@gie.eu
www.gie.eu

7th Annual Gas Turbines
May 28-31, 2013
Singapore, Singapore
Organizer: IBC Energy
Tel: +65 6508 2401
E-mail: register@ibcasia.com.sg
www.gasturbinesasia.com

Eastern Africa Oil & Gas 2013
June 18-20, 2013
Nairobi, Kenya
Organizer: Global Pacific Partners
Tel: +31 70 324 6154
E-mail: babette@glopac-partners.com
www.petro21.com/events

Shale Gas World UK
June 25-26, 2013
Manchester, UK
Organizer: Terrapinn
Tel: +44 (0)207 092 1245
E-mail: paul.gilbertson@terrapinn.com
www.terrapinn.com/conference/shalegasuk

European Gas & Power Trading
June 26-27, 2013
London, UK
Organizer: Platts
Tel: +44 (0)20 7176 6227
E-mail: andrew_kinash@platts.com
www.platts.com/conference

Technical Challenges of Shale gas fracking
August 4 -8, 2013
Boulder, Colorado, USA
Organizer: ECI
Tel: +1 212 514 6760
E-mail: info@engconfintl.org
www.engconfintl.org

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For more information, please contact the organizing committee:

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