Cedigaz News Report

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by Constancio Silva

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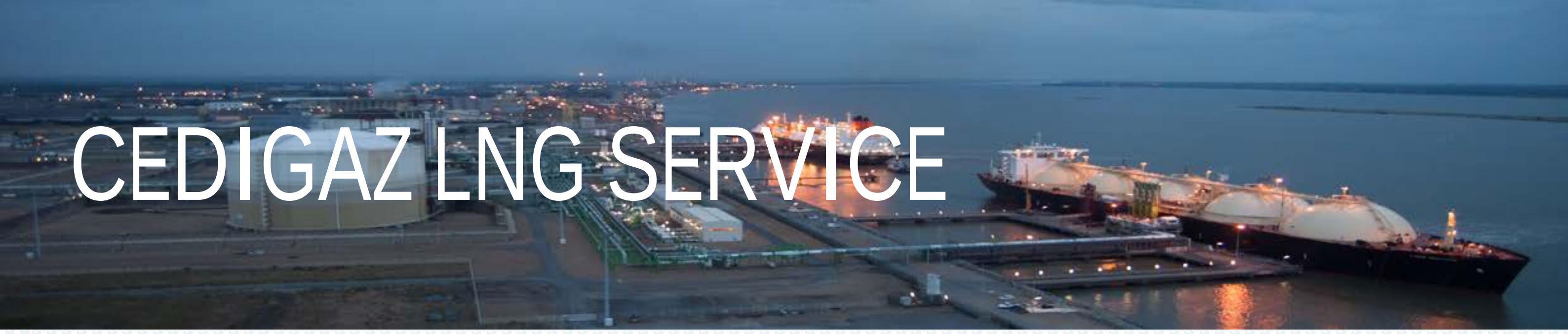
Main news

LNG:

- LNG tanker steams toward U.S. Sabine Pass for inaugural loading.
- 15-year LNG deal with Qatar to be based on take and pay mode.
- Calor road tankers load up on LNG at Isle of Grain terminal.
- First tanker of LNG to Poland in December.
- KOGAS, EDF trading ink LNG capacity and supply agreement.
- Flogas offered first-fill from Isle of Grain LNG terminal.
- Calor powers up UK’s first LNG-fuelled asphalt plant.

Natural Gas:

- Kosmos makes second gas discovery offshore Mauritania.
- Noble Energy sees Israeli gas discoveries online in five years.
- BP signs deal to accelerate development of Atoll gas field in Egypt.
- Egypt's giant Zohr gas field plans output in 2017.
- Maximum production from Shah Deniz expected between 2022 and 2028.
- Rockhopper’s new gas well delivers production boost.
- PdV prepares to export gas to Colombia.
- Ukraine Warns it may stop buying Russian gas next year.
- China, Middle East to overtake Europe as biggest gas users.



CEDIGAZ LNG SERVICE

A COMPLETE DATA SERVICE FOR THE LNG ANALYST

The LNG Service provides the LNG analyst with all the data needed to follow the developments of the fast moving LNG market. The LNG Service includes comprehensive, quarterly updated, worldwide databases on liquefaction projects, regasification projects, long-term gas supply contracts and LNG trade between countries, as well as monthly bulletins on traded volumes and prices. The company reports allow for an easy assessment and benchmarking of the main players in the market and the CEDIGAZ LNG Outlook provides CEDIGAZ's views on medium and long-term LNG market perspectives.

FEATURES

DATABASES

- **Liquefaction plants:** More than 150 existing and planned liquefaction facilities. Quarterly update.
- **Regasification terminals:** More than 200 existing or planned regasification terminals in the world. Quarterly update.
- **Long-term Supply contracts:** Over 200 sales/tolling contracts currently in force plus contracts with projects under development. Quarterly update.
- **LNG trade:** Annual LNG flows between exporting and importing countries since 1970.

LNG MONTHLY BULLETIN

Monthly LNG import volumes and prices by country of origin for 25 countries representing over 95% of the global trade.

CEDIGAZ LNG OUTLOOK

CEDIGAZ's medium and long-term perspectives on LNG supply and demand.

COMPANY REPORTS

A summary of the information of the LNG databases by company.

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http://www.cedigaz.org/products/LNG%20Service/cedigaz-lng-service.aspx

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CEDIGAZ

LNG

PRODUCTION

CHINA:

ENGIE to build LNG industrial base in China

ENGIE and Shaanxi Houde Tongxing have signed an agreement to establish a joint venture to build one of the largest LNG industrial base in the northwest region of China and to develop LNG downstream activities.

The two companies signed the agreement in Yulin, Shaanxi Province. ENGIE will hold 35% stake in the venture, the French firm said Monday.

Through this contract, both parties will jointly invest and construct a LNG industrial base in the Yujia Industrial Park. The natural gas will be provided by CNPC and Sinopec's long-distance natural gas transport pipeline.

The project construction is divided into 2 phases: Phase I, with a capacity of 0.25 million tons of LNG per year will start its commercial operation in July, 2017, while Phase II, with a capacity of 0.5 million tons of LNG per year will be in commercial operation in February, 2018, ENGIE said. The total estimated investment for these two phases amounts around 1400 million RMB (around Euros 200 million). In addition, the Joint Venture will launch the study at the beginning of 2016 about the construction of a LNG storage center in Yulin aiming to realize the peak shaving by LNG. (November 9, 2015)

11/10/2015

JAMAICA :

US company to spend more than $200m to construct LNG terminal in Jamaica

American company, New Fortress Energy LLC, will invest more than $200 million to construct a Liquefied Natural Gas terminal in Jamaica.

The facility is expected to generate more than 200,000 metric tonnes of LNG annually, which will initially be supplied to the domestic market.

There are also plans to expand output for delivery to other Caribbean countries, thereby positioning Jamaica as a regional hub for the supply of LNG.

New Fortress was selected from a list of six entities which submitted bids to supply LNG to power the national energy grid, primarily through the Jamaica Public Service Old Harbour 190-megawatt gas fired power plant.

Chairman of the Electricity Sector Enterprise Team Dr Vincent Lawrence noted that New Fortress was chosen as the developer of Jamaica’s LNG project, as the entity was the most competitive for JPS’ requirements.

“New Fortress was not only the lowest evaluated price for the volumes required by JPS, it clearly demonstrated its commitment and capability to supply gas as scheduled by the detailed engineering studies they had undertaken,” he said.

Lawrence said the terminal, which is to be built, owned and operated by New Fortress, is expected to be completed for commissioning by 2017/2018.

In the meantime, the ESET Chairman further informed that Cabinet, at its meeting on Monday, endorsed the selection of New Fortress for the supply of LNG and the installation of facilities to receive, store and re-gasify the fuel for use at the new Old Harbour plant.

New Fortress Energy supplies energy, logistical services, and financing to end-users seeking to convert their operating assets from diesel or heavy fuel oil to natural gas fuel use, in order to reduce operating costs, increase equipment availability, and enhance their environmental stewardship. (November 11, 2015)

11/12/2015

RESERVES

WORLDWIDE:

LNG market shortage no sooner than 2022/23

Big LNG producers claim that LNG shortages could emerge by 2020 if new projects weren't sanctioned, but it is gradually becoming clear that the market shortages will not occur until 2022/23.

There is enough reason to believe that buyers are going to take longer to absorb the 140 million tons per year of new volumes due on line this decade.

With new Australian projects ramping up — the first cargo from Santos' Gladstone LNG left for South Korea on Oct. 16 — an increasing number of Mideast and Atlantic Basin cargoes have been directed away from Asia to Europe.

Analysts are busily revising down LNG growth forecasts and now believe shortages won't occur until 2022/23, at the earliest. Even Exxon Mobil seems to have changed its tune. The LNG bull said earlier this year that supply would have to grow by almost 9% annually to meet forecast demand of 460 million tons by 2025, and 18 project sanctions were required to ensure supply from 2019-25 (WGI Mar.11'15). But a senior company executive told last month's LNG producer-consumer conference in Japan that shortages will now occur in the second half of the 2020s if projects aren't sanctioned.

Consultancy FGE sees global LNG demand growth tapering off, largely because of Asia, where annual demand growth forecasts for 2014-20 have been cut from 6% to 4%. Demand has likely peaked in Japan and South Korea, while China's LNG imports have shrunk as a result of a structural slowdown and low oil prices.

The new projects would not only have to compete against developments on which work is under way, but existing projects, too. A significant chunk of the 62 million tons/yr of capacity under construction in the US remains uncommitted as Asian buyers and traders like Engie still look to resell contracted volumes.

Consultancy FGE reckons 25 million-35 million tons/yr remains unsold and will be tough to sell, given competition from oil-indexed LNG. More LNG will also be available from exist-ing projects as buyers exercise downward quantity tolerance clauses to cope with lower demand. FGE said last week that 8 million-15 million tons/yr from existing contracts will become available over the next few years due to contract underperformance. In addition, FGE reckons available volumes of flex-ible, low-cost Qatari gas will rise from 25 million tons/yr to 30 million-35 million tons/yr as major contracts expire. In total, the consultancy forecasts roughly 70 million tons/yr of oversupply until the early or mid-2020s. Qatar's expiring contracts include 4 million tons/yr with Japan's Chubu Electric and 1 million tons/yr with Tokyo Electric ending in 2021, and 4.92 million tons/yr with Korea Gas in 2024.

The new US and Australian volumes should keep the world well-supplied until 2022, at least, according to analysts from Credit Suisse, Bernstein and Citigroup. Without new projects, they forecast global short -ages of 35 million-80 million tons/yr by 2025 — which means developers wouldn't need to sanction new schemes until 2017-18, at the earliest. Given demand uncertainties, buyers are in no rush to nail down long-term deals at the expense of shorter, more flexible contracts. Moreover, existing contracts expiring through 2020 have been partly covered by the new Australian and US volumes. (November 13, 2015)

11/13/2015

PROCESSING

INDONESIA:

Tokyo Gas, Pertamina plan LNG receiving terminal in Indonesia

Tokyo Gas and Pertamina will build a LNG receiving terminal in Indonesia, Nikkei Asia review reported Tuesday.

The terminal, with a capacity of 200,000 to 400,000 kiloliters, will come up at Bojonegara, West Java and will cost around 100 billion yen ($810 million). It is expected to become operational in 2018, Nikkei said. The LNG will be sold to domestic factories and natural-gas-fired power plants.

This will be Indonesia's first purpose-built LNG receiving terminal. The two parties will set up a joint venture to run the import terminal. Mitsui & Co. is expected to take a stake in the company, with the Japan Bank for International Cooperation potentially participating as well, Nikkei reported.

It is the first step in a strategic LNG alliance between Tokyo Gas and Pertamina initiated with a memorandum of understanding signed in February.

In recent years, Indonesian domestic gas demand has jumped significantly amid declining production leading to rise in imports. (November 10, 2015)

11/11/2015

TRANSPORT - DISTRIBUTION

UNITED STATES:

LNG tanker steams toward U.S. Sabine Pass for inaugural loading

Cheniere Energy's landmark Sabine Pass liquefied natural gas export plant in Louisiana will receive its first tanker for loading on Jan. 12, according to ship tracking data and a source with knowledge of the plant's operations.

The Energy Atlantic LNG tanker, which was last seen on Thomson Reuters ship tracking data on Monday steaming west across the Indian Ocean, is the first in a string of test cargoes that will be loaded before commercial operations begin later in the year.

The expected arrival of the tanker to Sabine Pass was confirmed by a source and by IHS Waterborne consultants that track LNG shipments globally.

It marks a milestone for the long-awaited project, the first of its kind to be built in the United States in nearly 50 years, and for the U.S. gas market that has been swamped with new supply in recent years due to a domestic drilling boom.

It is unclear when the Energy Atlantic will actually leave Sabine or where it will go.

One source said the test phase could take four to six months before the first shipments under a long term contract between Cheniere and LNG shipper BG Group begin.

The first export shipment represents a turnaround for Cheniere, which in 2008 built an import terminal at the same site in Sabine Pass which was quickly rendered obsolete by the rise in U.S. production.

Now, however, other headwinds exist for exports, including a global glut of supply that has pushed prices way below year-ago levels. (November 9, 2015)

11/10/2015

SUPPLIES - IMPORTS - EXPORTS

PAKISTAN:

15-year LNG deal with Qatar to be based on take and pay mode

The 15-year $16 billon LNG deal with Qatar will be based on take and pay mode under which PSO will be liable to pay for all quantities in case it fails to purchase the product.

However, the seller will be having 20% liability in case LNG is not delivered or substandard product is delivered to PSO and in case off spec LNG is delivered where neither PSO nor the seller was aware of that LNG was outside specification, then the cap on liability will be at 25%, a senior official while quoting the summary on the LNG deal said.

The deal is being pitched in the next ECC, most probably to meet Thursday or Friday next, for approval he told The News.

He also divulged that PSO wants the RLNG consumers to pay the port charges to be paid by the state-owned oil marketing company in excess of $320,000 (being the maximum payable to Qatargas company under sales purchase agreement). PSO argues, he added, that since it will pay the port charges in excess of $320,000, so they should be a part of the RLNG tariff.

The LNG price has been agreed with the Qatargas Company under the government-to-government arrangement at close to 14 of the three months' average price of Brent in SLOP form for 15 years time. SLOP form means that in case the price of Brent goes up, the LNG price will also surge accordingly and when Brent will go down in world market, then LNG price will also tumble in the same proportion as per the formula.

Under the deal, Qatar will supply 1.5 MTPA of LNG in the first two years which will increase to 3 MTPA from the third year (2018) onward to 2030. The contract will end by December 2030. However, there will be price review provision in the agreement allowing each party to seek a price review after 10 years period and if not agreed, sale/purchase agreement will be terminated.

To be precise, the LNG price deal has been finalised somewhere between 13.70 to 14% of three months average price of Brent in SLOP form for 15 years. The Nawaz government did not opt for the pricing formula under 'S' curve with no constant factors, the officials dealing with LNG are of the view that under 'S' curve both the sides had to lock the low limit and high limit prices and this is tantamount to inviting the wrath of NAB. They said the LNG price deal was better under the 'S' curve but in a country like Pakistan it is not possible for a politically-elected government as some 'powerful elements' can use the deal based on the 'S' curve as a scam. (November 4, 2015)

11/05/2015

PAKISTAN:

Pakistan to sign LNG deal with Qatar this month

Pakistan is finally expected to sign long-term LNG import deal with Qatar later this month, according to local newspaper The News.

The Economic Coordination Committee is expected to give **approval to the 15-year deal for the purchase of LNG from Qatar** at its meeting on November 5. **Pakistan will purchase three million tons of fuel every year** whose price will be linked to Brent crude oil.

The gas will be provided to power and fertilizer companies.

According to the agreement Qatar will provide four ships of LNG every month, The News reported Sunday.

The South Asian nation has been facing severe gas shortage which has led to frequent blackout and caused decline in industrial activity. (November 1, 2015)

11/02/2015

RUSSIA - JAPAN:

Russian LNG and Japan: Striking the right balance

Last week Alexei Miller, head of Gazprom, hosted a meeting with Ken Kobayashi, President and CEO of Mitsubishi Corporation. According to Gazprom's official report, the parties addressed the possible cooperation within the construction of the third line of the Sakhalin II LNG plant.

The long-awaited expansion of the project was proposed only this year: on June 18, 2015, Gazprom and Shell signed an Agreement of Strategic Cooperation at the St. Petersburg International Forum. The so-called Sakhalin III, with 7.4 bcm of additional capacity, is supposed to come into operation in 2021 and provide together with the existing LNG trains some 20.6 bcm.

It is worth mentioning that besides being the only LNG plant in Russia, Sakhalin II is one of the most successful export projects targeting the Asian-Pacific region. The key to success lies in integration: it is managed and operated by Sakhalin Energy Company and its shareholders: Gazprom (50% and 1 share), Shell (27.5% minus 1 share), Mitsui (12.5%), Mitsubishi (10%). So negotiations with the same partners seemed evident for Gazprom, especially with continued uncertainty in the energy market. However, there is considerable potential in the Japanese market following Fukushima which may stimulate greater Japanese interest in the Sakhalin Energy Company. Furthermore, a partnership with Japan that includes large foreign investments would be a helping hand for Russia as it turns to the East.

Even if the business model of Sakhalin III is appealing to Japan, the energy relations between Russia as a producer and Japan as a consumer have many questions, such as whether Japan's demand matches Russia's expectations.

In April 2014, Japan approved the Strategic Energy Plan. Despite the impact of the Fukushima nuclear disaster of March 11, 2011, the nuclear power is likely coming back to the country: restarts of reactors are going to be one of the key challenges. Currently the Sendai Nuclear Power Plant is the only nuclear power plant that was brought online. If the majority of the nuclear reactors are restarted (30 to 35 of the country’s 43 reactors to be activated), Japan’s demand will fall for an uncertain period of time.

Return to nuclear power is only a part of the wider plan of the country to meet the “energy mix” by 2030. To enhance energy efficiency, Japan is planning to steadily increase the ratio of renewable energy (solar, wind, hydroelectricity, geothermal, biomass), and bring back but lower the dependency on nuclear power – target ratio is set at 18 to 19% of the mix and reduce the consumption of coal, oil, LPG and natural gas. **By 2030 the nation is planning to decrease the use of natural gas from 131bcm in 2015 to 92 bcm. This news would hardly make Gazprom happy: by 2025 it is planning to export 101 bcm of gas to Japan and by 2030 reach 105 bcm of export volumes**.

Moreover, there is considerable supply potential in the world that Japan can draw upon. The country is trying to mitigate supply disruption and diversify the sources of supply. The competition for Russia is provided by Australia, Papua New Guinea (became a supplier last year), the USA, and, to lesser extent, Canada and East Africa. Again, the Sakhalin II project provides 10% of Japan’s gas consumption, but at the same time is the only Russia’s LNG option in the Asian market. Of course, Russia could revive the plan of pipeline gas supply – this option would be beneficial for Japan considering low oil prices and the distance between Russia and Japan. It would be beneficial for Russia as well as cheaper piped gas would allow Gazprom to outcompete the LNG suppliers. Nevertheless, Gazprom officials made it clear that this option is not being considered. In this case, Russia has a 5 year window to successfully enter the LNG market and capture a significant share given growing global competition from North America, Australia and North Africa, as well as smaller markets such as Papua New Guinea and Indonesia. Taking into consideration current uncertainty, such as low oil prices sanctions, stagnating European market, high-priced Asian contracts, the challenge for Russia’s fledgling LNG industry is great.

Despite the hardships facing Russia in the Asian market, Japan in particular, the countries still need each other. Dr. Ken Koyama, Chief Economist and Managing Director, Institute of Energy Economics, Japan, thinks Japan needs energy supply security based on the reality after Fukushima and Russia needs energy demand security based on new reality in the EU and Asia. Therefore, the cooperation between two countries would be mutually beneficial. The level of this cooperation mostly depends on Russia, which should adjust to the changing Asian market and move towards LNG development instead of numerous high cost pipeline projects. (November 2, 2015)

11/02/2015

CHINA:

Sinopec to commission LNG terminal at Beihai City by December end

Sinopec Group, parent company of Sinopec Corp., is likely to commission its LNG receiving terminal at Beihai city of south China's Guangxi Zhuang Autonomous Region by end of December.

The company will also build 1,318 km of natural gas pipelines covering ten cities in Guangxi as well as Zhanjiang and Maoming city in Guangdong province, Xinhua Finance Agency reported Thursday.

The terminal has a handling capacity of 3 million tons which will rise to 6 million tons by 2017.

The project is jointly invested by Sinopec Group, Guangxi Investment Group and Guangxi Beibu Gulf International Port Group. (November 3, 2015)

11/04/2015

PAKISTAN:

400 MMCFD LNG terminal to contribute 5% to country's primary energy mix

The imported Liquefied Natural Gas is not only a cheaper source to meet Pakistan's energy needs with saving massively to the national kitty but it will also prove a game changer as **400 mmcdf LNG terminal would add 5% to the country's primary energy mix**. **In the past, three governments made five attempts over the 10 years to import LNG but they failed for adopting integrated approach where LNG terminal developer was also LNG supplier**.

The PML-N government resorted to un-bundled approach and the LNG terminal development was separated from LNG procurement, thus succeeding to provide the country with its first LNG based gas within 20 months of its tenure, Federal Minister for Petroleum and Natural Resources, Shahid Khaqan Abbassi said while addressing a recently held seminar on import of LNG.

The government pursued a transparent process for developing a terminal and the Engro Elengy built the SSGC LNG regasification terminal in a record time as the contract was signed on April 2014 and first gas flow was ensured at March this year.

Average regasification tolling fee was charged at $0.66 per MMBTU which was the lowest in the world, adding most LNG contracts in the world were priced at direct linkage to oil and Pakistan LNG imports would also be linked to oil.

The government was displacing oil products and **LNG price at 15% of Brent index of $50 percent would be $7.5 per MMBTU.**Since the **country's natural gas production was stagnant at 4,000 mmcfd per day for 10 years and constrained demand stood at 6000 mmcfd with hydrocarbon resources fast depleting, thus he said government ventured into LNG import.**

If Pakistan had committed to LNG 10 years back, the country would not have any energy crisis, today. Pakistan needed to import natural gas through pipelines or LNG, but in fact Iran-Pakistan Pipeline of **750 mmcfd project was delayed due to international sanctions and the first gas could not be available before end of 2017.**

In addition, Turkeminstation-Afghanistan-Pakistan-India(TAPI) pipeline with **1325mmcfd also got delayed due to Afghanistan instability and structural issues with the project transaction and first gas was not available before end 2019**. In such situation, the government venture into the LNG import through long term contracts, medium term contracts and sport purchases, adding LNG Supply Contract(SPA) between Pakistan State Oil was finalized.

He said cost calculations proved that RLNG was a cheaper than all imported fuels and the OGRA had determined RLNG price of **8.64 per MMBTU. So far 14 LNG cargoes had been regasified at the LNG terminal, adding the one year contractual commitment was 24 cargoes, but the number could go up in one year to 26 cargoes. He said six cargoes were procured on spot basis from Qatar gas FOB basis and eight cargoes were procured through competitive bid process, adding average price of LNG cargoes procured was less than 14% of Brent. He said power generation based on 4000 mmcfd of regasified RLNG would generate additional annual generation of 9 billion KWH, saying from $600 million to one billion dollar.** Similarly with under-construction of 3600 MW RLNG based powerplants would generate of 30 billion KWH, saying over$ 2billion annually.

The government needed to sign five more contracts to import LNG, as currently, the minister added, currently LNG cater to the 20% of the country's energy needs. He said government had allowed the private sector to import and use LNG, testifying its sincere efforts to further improve economic indicators. He said each consumer would have to afford its own burden while consuming LNG and burden would not be shifted to any other sectors. (November 2, 2015)

11/02/2015

UNITED KINGDOM:

Calor road tankers load up on LNG at Isle of Grain terminal

The Isle of Grain LNG terminal in Kent, UK, recently offered first-fill to Flogas Britain. Calor has now announced that it has also received LNG from the terminal's two road tanker bays. Each bay is capable of **loading up to 36 LNG road tankers per day**.

The facility will be able to supply off-grid customers with LNG, and will enable Calor to keep its public refuelling network topped up. Calor's sister company – PrimaLNG – has also reached a commercial agreement with Centrica in order to buy LNG from the facility.

The Calor LNG Transportation Sales Manager, Marks Gilks, said: "Calor's LNG sales have grown considerably over the past 18 months, mostly in the transportation and off-grid energy sectors.

"The opening of this terminal is a crucial stage in the anticipated widespread adoption of LNG as a significant long-haul transport and energy fuel source. It marks a formal commitment to LNG availability in the UK market."

Jonathan Westby, the Global Head of LNG at Centrica, added: "Our ambition is to grow our LNG business across the entire gas value chain and this relationship underlines the flexible role that LNG can play in the UK's energy market – in particular for off-grid customers and heavy road transport. With LNG becoming an alternative vehicle fuel, it will also play a critical role in reducing heavy vehicle emissions.

"We look forward to developing this market further with both PrimaLNG and Calor." (November 11, 2015)

11/12/2015

CHINA:

CNOOC's second LNG tender signals massive LNG market shift

What a difference just over a year can make. From a seller’s market with outlandishly high prices and somewhat limited supply, the liquefied natural gas market in Asia has companies and countries that were scrambling to lock in long term 20-year supply agreements now unloading these very cargoes they sought so hard to obtain. The latest development came at the end of last week when one of China’s three state-owed oil majors, China National Offshore Oil Corporation, announced a tender to sell an LNG cargo from BG Group ’s Queensland Curtis LNG facility, one of Australia’s new LNG projects in which it has a stake. In September, CNOOC tendered its first LNG cargo from the project.

CNOOC’s decision to sell its cargo on the spot market signifies what’s unfolding in the LNG market, particularly in the Asia-Pacific region, which accounts for two-thirds of global LNG demand. LNG markets are awash in supply while even more LNG will enter the market soon, mostly from Australia and the US. This over supply has forged with two other market dynamics – less consumption from the world’s top two LNG importers, Japan and South Korea, respectively, and also from Taiwan, and China, two other large LNG customers. The plunge in oil prices of more than 50% since mid-June 2014 is the other shaker and mover in the LNG market, particularly significant since LNG prices in Asia are usually linked to oil prices. Singapore (Asia’s fledgling LNG trading hub) however, is seeking to replace LNG’s oil price linkage. Singapore-based Pavilion Energy said last month that it plans to start placing trades using the Singapore LNG Index Group (Sling) in the next few years.

CNOOC’s two tenders of LNG that it purchased under long term contract is only the start of the shakeup of LNG markets. Expect the entire LNG market infrastructure to be revolutionized before the end of the decade. With a market awash in LNG supply and with that supply forecasted to increase further, major buyers will seek to renegotiate long term supply contracts for more favorable terms, even incurring penalties for not procuring cargoes under these contracts. Buyers will opt instead for the flexibility of the LNG spot market, which last year comprised only around 5% of LNG trade, but could expand to represent at least 20-25% of total LNG trade by the end of the decade. Major buyers will also become LNG sellers and traders making LNG a much more liquid commodity like iron ore or crude oil.

All of this is unequivocally good news for LNG buyers who were left holding the bag during the period of exorbitantly high LNG prices (2011-2014) after the Fukushima nuclear disaster and the subsequent run up of LNG prices. In February 2014, prices for LNG breached $20 per MMBtu; now prices for November delivery are at $6.70 MMBtu. Many forecasts call for LNG prices to drop to the $5 per MMBtu range, some project even lower prices for the super-chilled fuel. The winners, at least in the mid term (to the end of the decade), are those who must procure large amounts of LNG, particularly Japanese and South Korean utilities. The losers, also in the midterm, are LNG producers, mostly those projects about to come on-stream in Australia and the five new LNG projects currently under construction in the US. However, if nature abhors a vacuum, then markets abhor even more the status quo for long periods of time. The LNG market will become even more like global crude oil markets, and be truly cyclical in nature. (November 8, 2015)

11/09/2015

UNITED STATES:

Crowley authorised to import LNG for distribution in Pacific Northwest and Alaska

The Department of Energy and the National Energy Board – Canada have approved Crowley Maritime Corp.'s petroleum distribution group to import Canadian-sourced LNG for supply, transportation and distribution throughout the Pacific Northwest and Alaska. **The renewable, two-year import and export licenses now allow the company to import up to 2.12 billion ft3 of LNG via truck in 10 700 gal**. ISO tanks or in bulk via ocean-going vessels.

"This approval is an important step in expanding Crowley's capability to provide LNG for the Pacific Northwest and Alaska markets, building on the company's existing service offerings in the region. It's exciting for many of our commercial and industrial customers because the availability of LNG has been very limited in the past, and it's another opportunity for us to prove that we're a total solutions provider in the energy and logistics industries," said Crowley's Matt Sievert, Director of business development, LNG.

The company is now working to secure long-term, 25-year licenses with the DOE and NEB. At the same time, Crowley is actively monitoring the development of Alaska LNG supply projects, which would be a closer source to the Alaska interior markets.

From the sourcing and transportation, to the delivery into the equipment, the entire LNG supply chain will be seamless for Crowley's industrial or commercial customers. The transportation, from Canadian-based liquefaction facilities to customers' storage units, will be managed by Crowley's logistics experts, coordinating over-the-road transportation and shipping via barge to Alaska. From there, Crowley's Alaska distribution team will deliver LNG directly to customers' facilities, where it can be re-gasified into pipeline natural gas for power generation, and mining, marine and industrial applications.

Similarly, in 2014, Crowley's Carib Energy was granted a 20-year, small-scale US Department of Energy export license for the supply, transportation and distribution of LNG into Non-Free Trade Agreement countries in the Caribbean, Central and South America. The licensing permits Crowley to export 0.04billion ft3/d of LNG – roughly the equivalent of 480 000 gal./d via 10 700-gal. ISO tanks to these regions. (November 10, 2015)

11/11/2015

POLAND:

First tanker of LNG to Poland in December

Poland will take its first delivery of liquid natural gas to the terminal at Swinoujscie in the north of the country this December.

The tanker will arrive from Qatar and pump 160,000 cubic metres of liquid natural gas into two tanks at Swinoujscie. The terminal is to help Poland in its quest to reduce its dependency on Russian gas.

Capacity of the terminal is 5 bcm, representing nearly a third of Poland's yearly gas usage. It is expected that it will reach commercial use by next May, and hoped to reach full capacity by 2018.

The terminal was conceived in 2007, with construction costs estimated to be 3.5 billion zloty (€820 million). Approximately 1 billion of this has been provided by the European Union.

Reports suggest that Qatargas have signed a 20 year contract to provide 1.2 billion of LNG a year.

Poland will be looking closely at Lithuania's LNG terminal in Klaipeda which took its first delivery a year ago. The terminal has been a very controversial issue in the country due to lack of usage and high upkeep costs. (October 31, 2015)

11/02/2015

ISRAEL:

IEC extends LNG floating tanker contract

The Public Utilities Authority (Electricity) has approved the continued use by Israel Electric Corporation of the liquefied natural gas floating container and the purchase of LNG from the gasification tanker off the Hadera coast until 2019, sources inform "Globes."

The demand for LNG imports as a backup in emergences stems from the shortage of gas created in 2011-2012 after gas stopped flowing from Egypt and the Yam Tethys reservoir ran dry. In pursuit of this, a marine LNG container was established 10 kilometers west of Hadera, and the services of a US gasification tanker were leased.

The lease period for the tanker terminates in October 2017, and IEC asked the Public Utilities Authority several months ago to recognize the cost of leasing it for two additional years, explaining that the tanker was an "insurance policy" for the Israeli gas sector.

60% of electricity in Israel is produced from natural gas, and there are already more than a few hours when the flow of gas from the Tamar reservoir is insufficient. At the same time, gas sector sources are criticizing the decision to extend the lease for the US tanker, saying that it is not worthwhile. They say that the project has cost $700 million, with almost no use being made of the LNG. In 2013, IEC purchased 10 LNG containers from British Petroleum at a cost of $50 million per container, but consumed only half of the LNG this year, with the rest being sold on the international market at a $24 million loss. IEC consumed only 0.06 BCM of LNG in 2014.

The Public Utilities Authority (Electricity) asserts that in principle, its approval is only conditional, subject to the final lease, stating, "The company must show the Public Utilities Authority (Electricity) the terms for leasing the tanker as soon as they have been formulated for the purpose of approving final rate recognition of the leasing costs."

IEC stated, "According to current estimates, by the end of the lease period (October 2017), the connecting of no additional gas field to the economy other than Tamar is expected. The Ministry of National Infrastructure, Energy, and Water Resources Electricity Administration therefore issued instructions to extend the lease by two years, and to operate the tanker on a survival mode that will facilitate an immediate flow of LNG to the productions system, if necessary. The Public Utilities Authority (Electricity) council decided this week that the lease would be approved under cost control. At the same time, the survivability policy has not yet been approved." (November 3, 2015)

11/04/2015

IRAN:

Iran plans construction of hi-tech LNG carriers

Iran has signed preliminary agreements with shipbuilders from South Korea, Germany and China for the construction of high-tech liquefied natural gas (LNG) tankers, as the country aims to become a leading exporter of LNG, a report said.

“A memorandum of understanding has been signed with a respectable German company which possesses the technology to build LNG tankers. Preliminary accords have also reached with several South Korean and Chinese firms,” Esmaeil Sadeqi, project manager, was quoted as saying in the Iran Daily report, citing Press TV.

Based on the plan, foreign shipbuilders would help Iran construct LNG carriers in shipyards along its Gulf coasts, he added.

Iran has already prepared two dry docks in Bandar Abbas to design and build natural gas delivery vessels, Sadeqi said.

He noted that the possibility of building LNG tankers and Very Large Crude Carriers (VLCCs) exists in the country. Hence, the planning to set up grounds for the construction of LNG vessels in cooperation with a foreign company.

Iran's sprawling shipbuilding industry is chiefly devoted to constructing oil tankers and container ships as well as other maritime structures.

The country owns the world's largest fleet of oil supertankers consisting of 42 VLCCs, each able to carry 2 million barrels of oil. Said the report.

For LNG tankers, however, there is no established infrastructure and the country has to start from scratch.

Sadeqi said, through transfer of technology, we can begin constructing LNG carriers which involves a complex technology. (November 8, 2015)

11/09/2015

KOREA:

KOGAS, EDF trading ink LNG capacity and supply agreement

KOGAS has signed a ‘Capacity and Optimisation Agreement’ with EDF Trading, a wholly-owned subsidiary of EDF S.A.

The agreement is for the supply and optimisation of up to 4 MT of LNG over eight years from 2017, EDF Trading said Wednesday. The deal enables KOGAS’ participation in the European LNG market through European market access provided by EDF Trading. In addition, KOGAS employees will be seconded to EDF Trading’s offices in London.

“This agreement is an extension of our long term relationship with KOGAS where we have previously supplied gas into Korea,” said John Rittenhouse, Chief Executive of EDF Trading. “We also hope to be able to provide KOGAS with hedging and risk management services which will help reduce the cost of supplies to the South Korean market”, he continued.

“With the increasing uncertainties in the domestic and global market, it is of vital importance that KOGAS should effectively cope with the forthcoming challenges, as a single aggregator in Korea and one of the key suppliers, to handle equity volume from its own LNG projects. In that sense, this optimisation agreement would enable us to reduce the LNG procurement cost as well as manage the imbalanced market situation on a flexible basis”, said Seung-Hoon Lee, President of KOGAS. (November 11, 2015)

11/12/2015

PRICE

INDIA - QATAR:

India, Qatar working to tweak LNG deal

India is in talks with Qatar's RasGas Company to tweak a decade-old liquefied natural gas (LNG) procurement deal. Indian firm Petronet LNG has been forced to cut down gas volumes from Qatar after the fuel bought through this long-term contract became nearly twice as expensive than spot purchases.

"As the oil prices are coming down, we are asking them to relook at the pricing," said a senior official at ministry of external affairs, requesting anonymity.

India's petroleum minister Dharmendra Pradhan is scheduled to visit Doha to attend the 6th Asian Ministerial Energy Roundtable next week. Pradhan would discuss the Petronet-RasGas deal with Mohammed Saleh Al Sada, the minister of energy and industry of Qatar, the official said.

On October 19, Prabhat Singh, managing director and CEO of Petronet LNG said that the two firms are working out a solution. He, however, did not disclose whether India is re-negotiating the volumes or the price. "Let the nation win," Singh added.

On December 26, 2014, India received the 1,000th cargo under its long-term contract with RasGas at Dahej LNG terminal in Gujarat. Nearly 16 years back, Doha-based RasGas and New Delhi-based Petronet LNG had signed the first sales and purchase agreement (SPA) to import 7.5 million metric tonne per annum (mtpa) liquefied natural gas (LNG) on take-or-pay basis and price linked to a 60-month average of crude oil.

At present, the LNG through this route costs around $12.67/mBtu at India's west coast, excluding other charges such as re-gasificiation, transportation, marketing margin and state levies. On the other hand, spot cargoes are available at nearly half the price at $6-6.5/mBtu. Since gas procured from Qatar is expensive, GAIL is not finding buyers for it and forced to utilise it at its petrochemical plant further hurting its revenues.

In the first nine months (January-September), Petronet has procured 68% of the gas available under the deal from RasGas. "We do not take 33 out of 120 cargoes," Singh had said.

No doubt, India's growing economy (latest OECD forecast pegs it at 7.3%) has enough appetite for gas — but pricing is the key. In the absence of last-mile pipeline connectivity and lack of other infrastructure, imported natural gas turns out to be the most expensive fuel in the basket. Indian firms such as GAIL and IOC have sealed contracts to import more than 10 mtpa of LNG starting 2018. Now, the challenge for them is to find consumers at home to sell these volumes. In the current scenario, it seems a herculean task to convince buyers to procure LNG. (November 6, 2015)

11/06/2015

UNITED STATES:

US LNG, cheaper long-term

Long term, US LNG, will be cheaper on a cost basis than LNG from most of the rest of the world, according to Kimball Chen, Chairman, Energy Transportation Group.

Mr. Chen, who advises governments and buyers of LNG about strategy and commercial aspects, pledged to look at US LNG in the context of different cost levels of different producers, different levels of irrationality, or pricing and revenue pressure for different sellers in his presentation at the 25th Economic Forum in Krynica, Poland in a session entitled “LNG: New Market Opportunities in the Region.”

He offered: “The basic cost elements of US LNG are the cost of the gas, the cost of getting the gas to a coastal location where there's a liquefaction plant, the cost of liquefying, and the cost of shipping it.”

He noted that the US is one of the only places in the world which has numerous owners of gas reserves, along with quite a large and liquid transportation system. “Most of the other big supply basins are dominated by national companies who use national and government strategy as a primary determinant of their economics,” he said. “But in the US, you can buy gas – it's a buyers' market.”

For example, Mr. Chen said it is possible to buy proven Marcellus shale reserves for less than $1/mmBtu. “To produce it, treat it and get it to a pipeline that will take it to a coastal liquefaction site is probably $1 – so for less than $2/mmBtu you can get gas into a liquefaction plant.”

Depending on the plant location and effectiveness of procurement, he said it costs $2.50-3.50 to liquefy such gas.

“To get it from the US Gulf to Northwest Europe is about $1.10-1.20 in shipping depending on the shipping costs, financing and so forth; to get it there from the Northeast US or East coast of Canada is $0.80-0.90, so there's a twenty to thirty cent differential.”

He noted that there is a 5-10% advantage by liquefying in the northeast, because of colder ambient temperatures, so liquefaction plants are more efficient in colder temperatures.

“So when you look at all these cost elements and you look at the cost of LNG you ask yourself 'what's the lowest price that I, as a European buy entity, could achieve if I had a critical mass of demand that I was willing to put out for a bid for long-term LNG?'”

Mr. Chen opined that a European buyer that wanted to achieve the lowest cost for long-term LNG from the US market would likely want to consider buying reserves, committed pipeline capacity and either working in partnership or taking control of a US liquefaction site that has good permitting prospects, and doing a tough-minded procurement.

“In that case, you could probably achieve a long-term delivered price of $8/mmBtu or less, long-term. If Cheniere were willing to sell to you because they have spare capacity, and all their primary liquefaction is paid for by their baseload customers, they could sell you marginal spare capacity much cheaper.

“They've said publicly that they could sell LNG into Europe medium and long-term for $7/mmBtu, but then they of course want to profit maximize long-term, so they might not necessarily sell their marginal capacity at $7.”

In light of the cost and competitiveness of the US market, buyers, he said, must decide what risks they they want to take and when they want to take them.

“If you want to go into the market now, this is a very good time for all elements: feed gas, pipeline capacity, liquefaction, mobilization and shipping costs are low – there's excess shipping capacity; financing costs are low.”

As an expert, Mr. Chen stated: “I would tell you, this is a good time to go.”

He also outlined the strategic and commercial aspects of LNG, noting that many used LNG as providing additional negotiating strength for dealing with traditional suppliers like Gazprom or Statoil, or may use spot LNG to provide peak supply when it is cheap. “So it's an economic tool and possibly a scheduling tool. It's harder with pipelines to have volatility in quantities; it's easy to suddenly drop a lot of LNG into fairly unused terminals.”

In Lithuania, LNG has a role as a price cap, suggested one speaker in the session.

Mr. Chen explained: “If there's a sufficient quantity of LNG potentially available for the European market, the average price of that LNG that is available acts as a cap on what pipeline suppliers will be successfully able to negotiate with European buyers.”

He promised to dissect that concept a bit further, explaining the pricing policy of people who sell LNG. “That pricing policy is partly economic and it's partly irrational and sometimes politically driven. The basic economics of producing LNG are: find and produce the gas, treat the gas, liquefy it, transport it.

“Who controls those decisions? It's sellers: sovereign governments in many countries, together with international partners – often international oil corporations. What are their objectives? How do they make pricing decisions?” he queried.

They make price decisions on the basis of marginal cost, or on the basis of what they need to do to achieve market share, according to Mr. Chen, who questioned if they might be irrational at certain points to maintain market share. “A buyer has to keep irrationality in mind as well as rationality.”

For example, he said that Australian LNG projects will have a lot of LNG coming onstream.

“The developers of those projects reached and committed to final investment decisions, the money has been raised, they've started building... That volume will be on the market. However, that LNG is very expensive from a cost point of view.”

Many people, he said, speculate that some of the more expensive Australian projects such as Ichthys or Prelude require break-even pricing of above $14/mmBtu.

Mr. Chen commented: “If that's their cost position, and these are being developed by commercial entities, they won't want to sell below cost unless they have no other way of getting revenue, because LNG is based upon continuous production – you can't stop and start; they can't 'leave it in the ground.' They still have to amortize their debt.”

That means, he said, that even for a commercial entity the decision on how to price quantities is sometimes not based on cost recovery, a similar situation for governments.

“Look at Qatar,” he quipped. “Most of its volumes go to the Far East. The traditional long-term contracts that they did with Japan at the beginning of the 1990s are at a certain price level – they're oil indexed.”

He asked whether Qatar would sell sufficient quantities to other buyers on a basis which yields a substantially lower price than to their Far East customers. “Would it make those customers force a renegotiation? That is a serious marketing issue,” said Kimball Chen. (November 2, 2015)

11/02/2015

STORAGE

UNITED KINGDOM:

Flogas offered first-fill from Isle of Grain LNG terminal

Flogas Britain has announced that it has been offered the ‘first-fill’ from the Isle of Grain LNG terminal in Kent, UK. The Isle of Grain facility is owned by the National Grid, and, with a total capacity of **15 million tpy, is the largest LNG terminal in Europe**.

Flogas has been offered the first-fill from the terminal because of its status as the National Grid’s largest LNG customer.

Flogas will draw 20 t of LNG – which is the equivalent of 1/3 GW of energy – on the morning of 11 November 2015. Following this initial fill, Flogas will draw between 60 – 100 tpd of LNG, which will then be distributed to various industrial manufacturing sites in the UK.

The Head of LNG at Flogas, Rob McCord, said: “The Isle of Grain facility is vital to our strategic growth, and to the growth of the LNG sector in the UK. To be offered first-fill is a real honour and one in which we are extremely proud.

“The future for LNG is very bright in this country, and we’re looking forward to working with National Grid and the Isle of Grain team to ensure that Flogas continues to be at the heart of the UK LNG market.” (November 6, 2015)

11/09/2015

USE AS MARINE FUEL

UNITED STATES:

Clean Energy Fuels Corp. to provide bunkering services for NASSCO-built vessel

In October 2015, Clean Energy Fuels Corp. supported General Dynamics NASSCO's launch of the LNG-fuelled containership – the Isla Bella. Clean Energy provided both the fuel and the bunkering services from liquefaction plant in Boron, California, US, for the vessel, which was delivered in San Diego to TOTE Maritime. Following on from this, in December 2015, Clean Energy will provide bunkering services to the Perla Del Caribe, which is the second NASSCO-built vessel.

The President and CEO of Clean Energy, Andrew Littlefair, said: "As the maritime industry begins its transition to LNG, Clean Energy is able to bring our many years of fuelling services to ensure an easy and seamless transition.

"We applaud NASSCO and TOTE as world leaders in the introduction of the clean fuel to the commercial shipping industry. The use of natural gas is continuing to expand across the various transportation sectors and is the best choice economically and environmentally."

Through using natural gas as fuel, these vessels will be the cleanest cargo-carrying ships in the world.

Clean Energy has also signed additional agreements in the transit, refuse and trucking segments, and has stated that it is on schedule to complete 68 projects before the end of 2015. This will not only involve expanding and upgrading existing stations, but also include completely new CNG and LNG stations. The number of stations is comparable to earlier years, when oil prices were much higher, illustrating the competitiveness of natural gas fuel in all potential market environments, owing to its stable pricing and cleaner emissions. (November 3, 2015)

11/04/2015

USE FOR POWER GENERATION

UNITED KINGDOM:

Calor powers up UK's first LNG-fuelled asphalt plant

Aggregate Industries' Colemans Quarry site has become the first asphalt plant in the UK to make the switch to LNG, cutting both costs and carbon emissions with the help of Calor.

Based in North Somerset, the plant has been supplying the construction industry with building material for more than 60 years. It uses large quantities of gas to heat and dry the 250,000 tonnes of asphalt produced each year, and as the site is active 24/7, maintaining a constant, reliable supply of fuel plays a vital role in hitting production targets and meeting customer demand.

The site is located off the mains gas grid, and until recently the plant's burners were fuelled with kerosene. After seeing an opportunity to reduce both emissions and fuel bills, Aggregate Industries approached Calor about working together on a new heating solution.

"We made the switch to LNG because it is a cleaner source of energy," says Plant Manager Simon Evans. "We were previously using kerosene, but LNG is a more cost-effective product to burn. It also produces a lot less carbon, and reducing our carbon footprint is very important for Aggregate Industries."

As well as substantially cutting fuel costs, the project has reduced the amount of CO_2 emitted per tonne of asphalt produced at the site by 17%. This cuts Aggregate Industries' annual emissions by 1,800 tonnes.

A UK first

The site is the first asphalt plant in the UK to use LNG and only the second in the entire world. It also represents Calor's first turnkey LNG installation in the UK.

The commissioning project began in January 2015 and was completed in May. **As well as laying new pipework and converting the site's 16MW burner to run on LNG, Calor installed a 90m3 tank and a pair of vaporisers each capable of converting 2,000m3 of gas each hour.**

Evans says: "The relationship between Aggregate Industries and Calor during this project was very good. We got on very well, and built up the relationship that helped us get to where we did with the project.

"The experience has been good. I would recommend Calor as a supply company; they did a very good job."

A reliable supplier

One of the most important requirements of Aggregate Industries was that the site's supply needed to be extremely reliable, as any interruption in operations would be costly. Calor has ensured that there is never any risk of the site running too low on LNG by installing a telemetry system that continually measures tank levels. As soon as the level gets low, the company automatically arranges a delivery.

"They can measure the level of gas in a tank, and they supply us with that information too," Evans explains. "We're currently having about two to three loads of LNG a week and that's all delivered without us having to order it." (November 4, 2015)

11/04/2015

CAMBODIA:

CIMC Enric subsidiary signs contract for Cambodia LNG power plant

YPDI (Nanjing Yangzi Petrochemical Design Engineering Limited), a subsidiary of CIMC Enric, and Malaysia ITG petroleum Pty Ltd (ITG oil & gas services (S.E.A) Sdn Bhd) has signed a project design contract for an LNG power plant in Cambodia.

The agreement was signed in Shenzen and includes the associated transportation and storage facility of LNG.

The location of the project is Bavet Dragon King Economic Development Zone in Cambodia, which is also home to the Cambodia Phnom Penh capital iron and steel plant.

The whole project will be implemented in two phases. The first phase of the project includes building a new 5MW temporary power supply facilities in the Cambodia Bavet Dragon King Economic Development Zone, 50MW power supply facilities and its supporting LNG receiving station, and a new 50MW power supply facilities and its supporting LNG receiving station at the location of the Cambodia Phnom Penh capital iron and steel plant.

The second phase of the project is to build a new 250MW power plant and the supporting LNG receiving station at the Cambodia Bavet Dragon King Economic Development Zone.

The total investment of the power plants in the two phases and the supporting LNG receiving station is about RMB 4.1bn ($643m), of which the investment of the 5MW temporary power supply facilities, two 50MW power supply facilities and the supporting LNG receiving station of the first phase of the project is about RMB 900m ($141m approx.).

The design contract includes the project feasibility study report, basic design and detailed design, and the feasibility study report will cover the two phases of the project, whilst the basic design and detailed design only covers the first phase.

Mr Liu Chunfeng, General Manager of the CIMC Enric Group, has revealed in a recent interview with gasworld China that it has set up a project department to manage turnkey projects for customers. (November 12, 2015)

11/12/2015

LPG

COMPANIES

FRANCE:

Shell completes sale of two downstream businesses

Royal Dutch Shell has completed the sale of its Butagaz liquefied petroleum gas business in France to DCC Energy for €464m following the announcement in May.

The company said its other businesses in France - aviation, commercial fleet, lubricants and bitumen - are not impacted by this deal.

In addition, Shell has also completed the sale of its 75% interest in Tongyi Lubricants in China to Huo's Group and The Carlyle Group following regulatory approval for an undisclosed sum.

The company said both divestments are consistent with its strategy to concentrate its downstream footprint on assets and markets where it can be most competitive, and to divest its LPG businesses worldwide. (November 2, 2015)

11/02/2015

NATURAL GAS

EXPLORATION

NORWAY:

E.ON to sell Norwegian oil and gas business

E.ON, the German-owned energy group, has announced that it is to sell its Norwegian oil and gas exploration business for $1.6 billion.

The buyer is Deutsche Erdoel DEA — a former subsidiary of its competitor RWE; it will take over E.ON's equity interests in 43 licences.

Last year, E.ON said that it is was initiating a programme to spin off its “conventional power activities” and focus on renewable energy. In a statement released earlier this month, the company said: “The sale of E&P Norge represents a significant step forward in this process.”

The Norwegian assets are the latest to be sold off after E.ON divested itself of operations in Spain and Italy earlier this year. Also “under strategic review” are exploration activities in the British North Sea, E.ON said in its statement. (November 3, 2015)

11/05/2015

EGYPT:

Egypt signs oil and gas exploration deals with Italy’s Eni

Egypt has signed Thursday five oil and gas exploration deals worth around $2.2 billion with Italian energy giant Eni.

The deals signed Thursday are the outcome of the March conference, read a statement by the ministry of petroleum.

The biggest deal was for exploration in the Gulf of Suez and Nile Delta with an investment of US$1.5 billion; the second was in northern Port Said in the Mediterranean with a minimum investment of US$500 million.

In collaboration with Eni, French oil company Engie will be exploring in the Ashrafi zone in the Gulf of Suez with an investment of US$40 million.

British Petroleum will join Eni for exploration in the Balteem area of the Mediterranean with an investment of US$80 million.

US-based oil company Apache also signed a US $30 million deal on Thursday with Egypt's General Petroleum Corporation to explore Oum Baraka area in the Western Desert.

Eni discovered Egypt's biggest gas field in August, in the Zohr block, with reserves of up to 30 trillion cubic feet.

Egypt and Eni had in July signed an update to the head of agreement reached in March, following the discovery of gas reserves of up to 15 bcm in Egypt's Nile Delta region. (November 12, 2015)

11/13/2015

MAURITANIA:

Kosmos makes second gas discovery offshore Mauritania

Kosmos Energy Ltd., Dallas, reported making a second natural gas discovery offshore Mauritania with its Marsouin-1 exploration well, drilled in 2,400 m of water in the northern part of Block C-8.

The discovery, which Kosmos called “significant” and “play-extending,” was drilled 60 km north of the company’s basin-opening Tortue-1 well (renamed Ahmeyim), which was also drilled on Block C-8 and intersected 351 ft of net hydrocarbon pay in the primary Lower Cenomanian objective.

Based on preliminary analysis of drilling and wireline logging results, Marsouin-1 encountered at least 230 ft of net gas pay in Upper and Lower Cenomanian intervals, the company said.

The Atwood Oceanics Atwood Achiever drillship will now proceed to the Ahmeyim-2 location in the southern part of Block C-8, where it will drill the top-hole section of the well. The drillship is then expected to go to Senegal, where it will spud Guembeul-1, the first in a series of wells to delineate the Greater Tortue area, before yearend. (November 12, 2015)

11/13/2015

ISRAEL:

Noble Energy sees Israeli gas discoveries online in five years

Noble Energy Inc. **expects to formally approve at least one offshore Israeli natural gas development by the end of next year**.

Gas would probably begin to flow from one or both of the discoveries three to four years after Noble's board makes so-called final investment decisions, or FIDs, Chief Executive Officer David Stover said during a conference call with analysts and investors on Monday.

With the Israeli government establishing the regulatory framework that will govern offshore energy ventures, **Noble is set to begin harvesting more than 50 tcf of gas it has discovered in the Tamar and Leviathan fields in the eastern Mediterranean Sea**. Tamar, where the first phase of output began in 2013, already supplies the gas used to make half of Israel's electricity.

"We've been looking at kind of a time frame of about a year to bring all of this together to move to FID," Stover said during the call. "I think when you look at actual first production, we've been talking three years to four years from FID, the first production. There is probably an opportunity that Tamar's project could be probably a little bit quicker than Leviathan, but we'll just have to see how that plays out." (November 2, 2015)

11/03/2015

PRODUCTION

TRINIDAD AND TOBAGO:

BHP updates Angostura development offshore Trinidad and Tobago

BHP Billiton Ltd. and its partners have begun drilling the Angostura-1 well in Angostura Phase III as it attempts to meet its contractual arrangements to provide natural gas to the downstream plants at Trinidad and Tobago’s Point Lisas Industrial Estate.

The well is being drilled in 5,000 ft of water offshore Trinidad and Tobago’s east coast and the structure is south of its producing area called the Greater Angostura development.

During the drilling phase, which is expected to last 6 months, operator BHP is expected to drill three development wells in an area believed to be all gas with no associated liquids.

The development will not BHP’s overall gas production but will simply replace declining wells and ensure it can keep its production at a level required to maintain its contracts.

Currently BHP produces nearly 400 MMscfd and just more than 7,600 bo/d in Trinidad and Tobago. Some of the gas from Angostura Phase III will be reinjected into the oil-producing part of the Angostura field to assist in the continued lifting of the oil and a slowing in the rate of decline of the reservoirs.

The Greater Angostura development is not one contiguous block but one with several faults and therefore the development is in another of the fault blocks that make up the Greater Angostura field.

Phase III is estimated to contain 500 bscf of recoverable reserves, with the entire Angostura development estimated to have contained 1.75 tcf of gas.

Greater Angostura field lies in 36-46 m of water on the continental shelf, 37 km east of Trinidad and in the eastern Trinidadian sector of the Eastern Venezuela basin.

The shallow-water integrated oil and gas field development is part of Trinidad Offshore Block

2c. It is operated by BHP Billiton (45%) on behalf of joint venture partners. BHP first signed a production-sharing contract on Apr. 22, 1996, and acquired a 3D seismic survey in 1997. BHP and its partners’ license to operate the field continues until 2021 under a PSC with the Ministry of Energy and Energy Affairs.

The Greater Angostura field has a production life expectancy of 19-24 years.

The discovery well, Angostura-1, was drilled in 1999. This intersected 950 ft (gross) of gas pay. The hydrocarbon potential of the structure was confirmed by the drilling of Aripo-1, Kairi-1, Canteen-1, Kairi-2, Angostura-2, and Canteen-2 wells. Each of these exploration and appraisal wells also intersected sands. The Kairi and Canteen fault blocks contain most of the oil while Aripo has a thin oil rim overlain by a significant gas cap.

During the 6-year exploration phase of the PSC a total of four exploration and three appraisal wells were drilled, discovering significant oil and gas resources within a large faulted structure known as the Greater Angostura structure. (November 12, 2015)

11/13/2015

EGYPT:

BP signs deal to accelerate development of Atoll gas field in Egypt

UK-based oil and gas major BP has signed a heads of agreement (HoA) with the Egyptian Minister of Petroleum to advance the development of the Atoll gas field in the country.

Located in the North Damietta Offshore Concession in the East Nile Delta, offshore Egypt, the field was discovered by BP in March.

The deal enables the company to accelerate the development of the Atoll field, which is estimated to hold 1.5 trillion cubic feet (tcf) of gas resources and 31 million barrels (mmbbl) of condensates, and commence initial production in 2018.

BP Group CEO Bob Dudley said: "We are pleased to be making rapid progress towards the development of Atoll less than eight months after the announcement of its discovery."

The field is planned to be developed in two phases by Pharaonic Petroleum (PhPC), joint venture formed by BP with EGAS and Eni.

The first phase involves two development wells, which will be tied back to existing infrastructure. Further investment and wells will be included upon successful completion of initial phase.

Upon completion of the first phase, additional investment and further wells will be included to increase production from the field.

Besides providing additional production to the Egyptian domestic market, the new agreement is expected to help to meet Egypt's energy demands. (November 6, 2015)

11/06/2015

CONGO:

Chevron starts oil, gas production from Congo offshore field

Chevron has announced start of oil and gas production from the Lianzi field offshore Congo.

Located 65 miles (105 km) offshore in approx. 3,000 feet (900 meters) of water, Lianzi is Chevron’s first operated asset in the Congo and the first cross-border oil and gas development project offshore Central Africa. The project is expected to produce an average of 40,000 barrels of crude oil per day.

The field, discovered in 2004, includes a subsea production system and a 27 mile (43 km) electrically heated flowline system, Chevron said. (November 2, 2015)

11/03/2015

CHINA:

China Oct natural gas production rises 1.4% - stats bureau

China's production of natural gas rose just 1.4% in October from a year earlier to **10.4 bcm**, official data showed on Wednesday, as worries about the broader economy slow the pace of demand growth for gas.

For the first 10 months, gas output grew 2.7% over the same period a year earlier to 103.5 bcm, the National Bureau of Statistics said, **well below a a 6.9% rise for all of 2014 and an 11.5% gain in 2013**.

China, the world's top energy user, has seen a sharp slowdown in the take-up of natural gas in the past two years following double-digit growth over the past decade, and faces a surplus ahead of the peak winter demand season, a state oil company research body said.

China National Petroleum Corp's economics and technology research institute estimated excess gas output could be as much as **10 bcm in 2015.**

"This year, in the first nine months, the consumption growth rate was only 2.5%," said Wang Haibo, deputy director of the CNPC research body, at a conference organised by PetroChina parent CNPC, one of the country's three major gas producers and importers. His comments were posted on the company's website on Monday. (November 11, 2015)

11/11/2015

EGYPT:

Egypt's giant Zohr gas field plans output in 2017

Egypt aims to start natural gas **production from its massive offshore Zohr field in 2017, a year ahead of schedule**, oil minister Tarek El Molla said.

The Zohr gas field, discovered by Italy's Eni, is the biggest in the Mediterranean, and with an estimated 30 tcf of gas it is expected to plug Egypt's acute energy shortages and save it billions of dollars in precious hard currency that would otherwise be spent on imports.

"We're looking to expedite the agreement with the partner and speed up production. Hopefully we will begin production from the discovery in 2017," El Molla said in an interview at the Reuters Middle East Investment Summit.

Eni has said it expects to invest between $6 billion and $10 billion to develop the Zohr field. Previously, officials had said production was expected to start in 2018.

Once an energy exporter, Egypt has turned into a net importer because of declining oil and gas production and increasing consumption. It is trying to speed up production at recent discoveries to fill its energy gap as soon as possible.

In October British oil major BP said it would begin gas production at its north Alexandria concession in early 2017 rather than mid-2017. That should add up to 1.2 bcf of gas per day by late 2019.

El Molla, appointed oil minister in September, succeeded Sherif Ismail who launched a drive to lure back foreign energy investors driven away by low prices and debt arrears.

In July the oil ministry raised the price paid for gas from Eni to a maximum $5.88 for every million British thermal units and a minimum of $4, based on amounts produced, from $2.65. It then cut a similar deal with British Gas.

Ismail's success in reinvigorating the sector, which is vital for economic growth at a time when energy shortages have crippled industrial production, helped propel him to the post of prime minister in September.

The total value of Egypt's natural gas projects, excluding Zohr, is now $13.8 billion, and El Molla said the Zohr discovery had made additional investment much more likely.

"The Zohr discovery whet the appetite of other foreign companies working in Egypt to speed up seismic discovery operations and exploratory wells."

Current projects underway will add 2.4 bcf to the country's daily gas production by 2019, said El Molla. Current production is roughly 4.5 bcf.

On the back of this, the stock of foreign oil and gas investment in Egypt is expected to increase to $8.5 billion during the current fiscal year ending next June, from $7.5 billion last year, said El Molla.

LNG BOOM

Egypt's drive to expedite foreign investment in gas production comes just as the country has become a top growth market for imported liquefied natural gas.

Egypt entered the LNG market with a burst of imports this year after leasing a floating storage and regasification unit from Norway's Höegh LNG for five years in April. FSRUs allow Egypt to import LNG and convert it to natural gas to feed into its power grid.

A second FSRU, provided by Norwegian group BW Gas , arrived in September and is expected to begin operating this week, while a third FSRU is likely to come by the end of 2016 or the first quarter of 2017, said El Molla.

Egypt expects to stop importing LNG by 2020 as projects such as the Zohr and BP fields come online.

In the meantime, the government last Wednesday approved the creation of a gas regulatory agency that will permit private companies to import and sell their own gas. Several private sector companies have applied to import, said El Molla. (November 3, 2015)

11/03/2015

AZERBAIJAN:

Maximum production from Shah Deniz expected between 2022 and 2028

Maximum gas extraction of 25 bcm/y from the Shah Deniz field is expected to be between 2022 and 2028, said SOCAR Senior Vice President for Geology, Geophysics and Field Development Khoshbakht Yusifzada.

"The peak volume of gas extraction of 16 bcm/y from the Shah Deniz Phase 2 will be achieved in 2022 and maximum volume of gas extraction from Phase 1 and Phase 2 is expected between 2022 and 2028," added Yusifzada.

He said at the initially Azerbaijan plans to export 10 bcm/y of gas to Europe, but the figure will reach up to 20 bmc/y in second stage.

He also said that total volume of gas extraction from the Shah Deniz field since beginning of development in December 2004 till November 1, 2015 reached **66 bcm.**

He said at present 29 mcm/d of gas is extracted from 7 operational wells on the Shah Deniz field (Phase 1). (November 9, 2015)

11/09/2015

ITALY:

Rockhopper's new gas well delivers production boost

Rockhopper Exploration's new side track well at the Guendalina gas field offshore Italy has provided the company with a production boost.

The UK independent, with interests in the North Falkland Basin and the Mediterranean, completed well GU2-Dir A (Eni is 80% Operator, with Rockhopper having a 20% stake) in the Northern Adriatic.

Total production from the field is stabilised at approximately 440,000 scm per day gross, 88,000 scm per day net to Rockhopper (580 barrels of oil equivalent (boe) per day), representing an increase of 190% from the last reported rates of approximately 200 boe per day net.

At current prices, Rockhopper anticipates to receive revenue from Guendalina, of approximately $7million in 2016.

Chief executive Sam Moody, said: "We are delighted with the results of the sidetrack operation, which has delivered the company a material increase in our daily production, added to which we anticipate that we should be commencing production on our 100% operated onshore gas development Civita by the end of this year.

This boost to revenue and cash flow also reinforces our strong financial position and demonstrates real progress in the building of our Greater Mediterranean portfolio post the acquisition of Mediterranean Oil & Gas."

The well, which was drilled on time and on budget, reached a planned total depth of 3,276m. All target horizons were gas-bearing. Additionally, two deeper gas levels were encountered and perforated.

The rig moved off location last week and production has now resumed. (November 9, 2015)

11/10/2015

PROCESSING

GHANA:

Sinopec ready to start second phase of Ghana gas project

China's Sinopec has offered to begin next phase of the Ghana Western Corridor Gas Infrastructure Development Project, local newspaper Business & Financial Times reported Monday.

"Sinopec is ready to pre- finance the industrial development of Esiama to Prestea project if given the go ahead to commence operation. It is not up to us to decide. We are always open for such kind of cooperation. China has the advantage to provide financing support," Sinopec's Director, International Business Unit, Africa Region, Shen Yan told the newspaper in an interview in Beijing.

In September, Ghana officially inaugurated its first China funded natural gas infrastructure project at Atuabo, about 218 km from Accra. The gas processing plant has been funded by China Development Bank and built by Sinopec. It has the capacity to process about 120 million cubic feet of gas from the Jubilee field daily. The gas is being supplied to the Volta River Authority to run thermal plants to generate electricity.

Yan said it is important for phase two of the project to be implemented as soon as possible, since it is vital to the whole project and will present a much safer way of transporting the gas and liquids from the region to Tema, the newspaper reported.
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The second phase of the constructing the Esiama-Prestea industrial development project that will export the LPG and condensates through offshore facilities by a jetty loading and unloading system. (November 2, 2015)

11/03/2015

TRANSPORT - DISTRIBUTION

TURKEY:

Ankara not in hurry to implement Turkish Stream

Ankara is not in a hurry to implement the Turkish Stream gas pipeline project, as currently it has more important priorities, a source in Turkish presidential administration told Trend Nov. 6.

The source said that, most likely, the issue of implementation of the Turkish Stream will be discussed in early 2016.

The interviewee also said this doesn't mean that Ankara refused to implement the Turkish Stream.

On Oct. 22, Turkey's Energy and Natural Resources Minister Ali Riza Alaboyun told Trend that the issue regarding the necessity of implementing the Turkish Stream project will be cleared up soon.

The talks between Ankara and Moscow on realization of the Turkish Stream have been brought to a halt.

The Turkish Stream project envisages construction of a gas pipeline from Russia to Turkey through the Black Sea. It was supposed that the pipeline will consist of four branches with the capacity of 15.75 billion cubic meters of gas each.

The gas to be delivered via the first branch is completely designed for the Turkish market, while the rest of the volume will be delivered to the Turkish-Greek border where it is planned to create a gas hub.

It was planned to start the pipeline's construction in June, however, the project is still under discussion. (November 6, 2015)

11/06/2015

FRANCE - BELGIUM:

Gas pipeline connects Belgium and France

Fluxys has announced that, as of 1 November 2015, GRTgaz has been allowed to transfer non-odorised gas to the Fluxys grid in Belgium through the 'Artère des Flandres' pipeline. In turn, Fluxys can transfer this gas via the Alveringem-Maldegem pipeline.

At a total investment cost of approximately €100 million, Fluxys Belgium had to build the Alveringem regulating station and a new interconnection station at Maldegem. In addition to this, a 75 km pipeline was built to connect the two sites.

Meanwhile, in France, GRTgaz had to build the 23 km long 'Artère des Flandres' pipeline, as well as the Hondschoote metering station on the border at a cost of €56 million. Furthermore, the Pitgam interconnection station had to be modified at a cost of €30 million.

Combined, these facilities allow the transmission of non-odorised gas from France to Belgium. This will allow up to 8 billion m3 of natural gas per year to be transferred from France to Belgium, and will help strengthen market integration, security of supply and the diversification of sources. In addition to this, as of 2016, the development of LNG in northwest Europe will be encouraged by the link from the Dunkirk terminal to the Belgian grid. (November 6, 2015)

11/06/2015

IRAN - PAKISTAN:

Iran not to impose penalty on Pakistan for gas pipeline delay

Iran is not likely to penalise Pakistan for delay in construction of a gas pipeline connecting the two countries, Iranian media reported Tuesday.

“Currently, Iran has no plans to demand compensation under the terms of the contract,” Managing director of National Iranian Gas Export Company said, according to Mehr News Agency.

Stating that Iran has never intended to impose any penalty on Pakistan for failing to take Iranian gas, Kameli said Tehran expects Pakistan to begin construction of gas pipelines on its territory soon.

He further emphasized that Iran is not concerned over the fact that Pakistan is looking to sign a long term LNG import deal with Qatar.

“We have no worries over the long-term due to the high costs of importing LNG in comparison with construction of pipelines for gas import,” Mehr News Agency quoted Kameli as saying.

The Iran-Pakistan pipeline project has been much delayed due to western sanctions imposed on Tehran. As per the agreement between the two nations signed in 2009, the first flow of gas to Pakistan should have started by Dec 31, 2014. Iran has already built 900 kilometers of the pipeline on its own soil and is waiting for the 700-kilometer Pakistani side of the pipeline to be constructed.

With Iran having signed a nuclear deal with major global powers earlier this year, sanctions are expected to be lifted which may finally lead to completion of the gas pipeline. (November 12, 2015)

11/12/2015

IRAN:

Iran plans to expand its gas transfer network to deal with increased production

Iran is planning to expand its natural gas transfer network in light of its plans to increase gas production capacity in the coming years.

Currently, 72 gas pressure booster stations, 36 operation centres, and over 35,000 kilometres of pipelines transfer natural gas all over the country. The numbers will increase to 136 stations, 74 centres, and 62,000 kilometres, respectively, based on Iran’s 2025 Outlook Plan, Shana news agency reported on November 10.

The country’s gas transfer capacity is projected to reach 96 bcm by the end of Iranian fiscal year 1396 (March 2018).

In the past Iranian fiscal year, which ended on March 20, 2015, seven gas pressure booster stations came on stream and five new ones will come on stream in the current year.

Each turbo-compressor, having 25 megawatts of output, has the capacity to transfer 35 million cubic meters of gas per day. Each pressure booster station needs 2 trillion rials (about $55 million) to be launched. (November 10, 2015)

11/11/2015

NORWAY:

Norway approves start-up of Statoil-operated Edvard Grieg and Utsira High pipelines

The Norwegian Petroleum Directorate (NPD) has approved the start-up of the Statoil-operated Edvard Grieg oil pipeline, and the Utsira High gas pipeline (UHGP).

According to NPD, the pipelines will become part of the Edvard Grieg, as well as Ivar Aasen fields' development on the Utsira High in the North Sea.

The Edvard Grieg field is planned to be put in place towards the end of this year, whereas the start-up of Ivar Aasen, which will use both pipeline systems, is slated for 2016.

The oil transport system has a 43km-long 28in pipeline between the Edvard Grieg platform, and a new Y-connection point, installed on the Grane oil pipeline, located 4km from Grane.

"The Edvard Grieg field is planned to be put in place towards the end of this year."

The gas system has a 94km-long 16in pipeline, running from the Edvard Grieg platform to an underwater connection point, called T-connection, on the Beryl pipeline, which is linked to the Scottish Area Gas Evacuation (Sage) pipeline in the UK sector.

The pipeline starts at the Edvard Grieg field, 57km north of Sleipner in the North Sea.

Gassco took over operatorship of the UHGP, which transports gas to the Sage system, and St Fergus in Scotland.

The Utsira High gas pipeline will export gas from the Norwegian continental shelf to the Sage pipeline system.

The Edvard Grieg oil field was discovered in 2007, and is located 180km west of Stavanger, at a water depth of 109m. It comprises an integrated wellhead, production and accommodation platform, with a jacket foundation. (November 9, 2015)

11/10/2015

TURKMENISTAN:

Turkmen section of TAPI gas pipeline to be built in 2 years

The construction of the Turkmen section of the Turkmenistan-Afghanistan-Pakistan-India interstate gas pipeline project will take two years, the newspaper "Neutral Turkmenistan" reports.

The newspaper said that experts from leading industries in Turkmenistan intend to perform basic work on laying the Turkmen section of the pipeline, along with its arrangement and the establishment of ground support infrastructures, with **work expected to continue until December 2018**.

The Turkmengaz state concern, which leads the TAPI Pipeline Company Limited joint stock company, and the contractor, the state concern “Turkmennebigazgurlushyk”, will carry out the design and construction of the section of the gas pipeline which lies within the country, the newspaper said.

Specialists from the joint-stock company will lead the supervision of the construction, financing, ownership and operation of the pipeline. The pipeline in Turkmenistan will be designed and built at the expense of the Turkmengaz state concern and funds raised from international financial institutions.

Currently, specialists from the Institute of oil and gas, subordinate to Turkmengas JSC, already lead engineering and development work along the route of the future TAPI gas pipeline, the newspaper said.

Thus, technical and geological studies are being carried out from the largest deposit at Galkinish to the border with Afghanistan. In addition, the builders of the TAPI gas pipeline, the state concern “Turkmennebitgazgurlushyk” has built the road that will run along the future route.

Meanwhile, work continues on the analysis and selection of equipment to be installed and used on the linear section of the strategic pipeline and its supporting ground stations.

It is planned that the total length of the TAPI pipeline will be 1,735 kilometers. Some 200 kilometers will pass through the territory of Turkmenistan, 735 kilometers - Afghanistan, 800 kilometers - Pakistan up to Fazilka settlement on the border with India. The annual capacity of the gas pipeline will be 33 billion cubic meters.The gas pipeline is to stretch from the largest Galkynysh gas field in Turkmenistan.

Solemn groundbreaking ceremony of the TAPI pipeline is scheduled for December 13, 2015. (November 11, 2015)

11/11/2015

TURKMENISTAN:

Turkmenistan starts construction of $10 bn gas pipeline

Energy-rich Turkmenistan's leader has ordered the start of construction on a pipeline carrying gas from the former Soviet state to India, Pakistan and Afghanistan, the government said Saturday, November 7, according to Agence France-Presse.

President Gurbanguly Berdymukhamedov ordered state companies Turkmengaz and Turkmengazneftstroi to begin building the isolated republic's section of the pipeline, state media said.

Overall, the pipeline will stretch 1,800 kilometres (1,100 miles) and is likely to cost more than $10 billion (9.3 billion euros).

The Turkmenistan official newspaper also said the government expects the gas link, with an annual capacity of 33 billion cubic metres, to be fully operational by the end of 2018.

The Turkmenistan-Afghanistan-Pakistan-India (TAPI) project could help ease growing energy deficits in Asian giants India and Pakistan.

For Turkmenistan, which has been hit by low energy prices and is dependent on China for the vast majority of its gas sales, TAPI is a key opportunity to diversify its exports.

But uncertainty hangs over the costly project. Aside from the risks associated with a link traversing war-torn Afghanistan, the four-country consortium has yet to confirm the participation of a foreign commercial partner willing to help finance it. (November 9, 2015)

11/09/2015

SUPPLIES - IMPORTS - EXPORTS

CHINA - TURKMENISTAN:

Amu Darya project gas supplies to china this year reach 10 Bcm

China National Petroleum Corp, the parent company of PetroChina, announced Thursday that **Amu Darya River Natural Gas Co. in Turkmenistan has supplied 10.11 bcm of natural gas to China** this year as on November 9.

Amu Darya River Natural Gas Co. saw its annual gas supply exceed 10 bcm for the first time since it started transmission via the Central Asia-China natural gas pipeline in 2009, Xinhua Finance Agency reported.

The company's cumulative natural gas supply to China has surpassed 30 bcm. Amu Darya River Natural Gas Co. currently operates three natural gas processing plants in Turkmenistan, which have a combined processing capacity of 30 bcm per year.

On July 17, 2007, CNPC signed a production sharing agreement to explore and develop gas fields on the right bank of the Amu Darya River, and a natural gas sale-and-purchase agreement with the Turkmen State Agency for Management and Use of Hydrocarbon Resources and Turkmengaz respectively. (November 12, 2015)

11/13/2015

IRAN - IRAQ:

Iran, Iraq to sign gas deal tomorrow

Tehran and Baghdad are scheduled to sign a deal on Wednesday to export Iranian natural gas to Iraq's Basra and boost gas exports to the country.

Based on the deal, Iran will export 25 mcm of natural gas on a daily basis.

Tehran and Baghdad has a gas deal based on which the former must supply 25 mcm of gas per day to Baghdad which will be extended to 35 mcm/d by signing the deal on Wednesday.

Iran would start pumping natural gas to Iraq provided that the latter ensures security of its soil, said a senior Iranian gas official in June.

"Iran is prepared to export gas to Iraq but insecurity in Iraq and the presence of ISIL have delayed the exports," Ali-Reza Kameli, managing-director of National Iranian Gas Exports Company, said.

He said when Iran will start pumping gas to Iraq depends on the security situation of Iraq.

"If Iraq manages to cleanse the regions where Iran's gas is to be delivered, then Iran will start pumping gas to Iraq," added Kameli.

The official had recently said that Iran’s gas will flow into Iraq before the end of Ordibehesht, the second Iranian month.

Iran’s gas will go to the Iraqi cities of Baghdad and Basra.

Gas exports to Baghdad will start with a daily volume of 4 mcm which could increase to 35 mcm/d.

Iran will also start supplying 5mcm/d of gas to Basra after a six-year deal is signed. The deal, which is to be signed next year, would require Iran to raise gas exports to Basra to 30 mcm/d.

Gas delivery to Basra would come from Iran Gas Trunkline VI (IGAT 6) which transfers gas from the giant offshore South Pars gas field in southern Iran to the border province of Khuzestan.

Part of the gas to Iraq will be used for generation of gas to address some of the country's electricity troubles.

Iraq is facing serious load-shedding and Iranian companies are operating 33 megaprojects, worth $1.5 billion, in Iraq for the time being. (November 11, 2015)

11/11/2015

COLOMBIA - VENEZUELA:

PdV prepares to export gas to Colombia

Venezuelan state-owned PdV could **export around 45mn ft3/d (1.26mn m3/d) of natural gas to Colombia starting in January**, fulfilling a long-held pledge by Caracas to reverse a cross-border pipeline to supply its gas-hungry neighbor.

Venezuela´s energy ministry told Argus that up to 10% of the first-stage gas that PdV purchases from the Cardon 4 offshore project between Spain´s Repsol and Italy´s Eni would be shipped to Colombia. But domestic bottlenecks suggest that Colombia could receive substantially more gas as production increases.

Under the first stage of development to be reached by the end of this year, Cardon 4 will **produce 450mn ft3/d from three wells in the 17 trillion ft3 Perla field**.

Production is scheduled to ramp up to 800mn ft3/d in 2017 and 1.2bn ft3/d in 2020.

In a presentation to Venezuela´s national assembly last week, PdV chief executive and energy minister Eulogio del Pino reiterated that gas exports to Colombia will start in January 2016.

The planned launch of Venezuelan supply through the Antonio Ricaurte pipeline would alleviate a gas shortage in Colombia, where thermal generators have been forced to use diesel in the absence of gas. Domestic gas production is dwindling, and some major generators plan to import LNG starting in 2017. **Colombia stopped exporting gas to Venezuela in mid-2015**.

In anticipation of growing offshore supply, PdV is refurbishing an existing gas pipeline running from Rio Seco in Falcon state to Ule on the east coast of Lake Maracaibo. The company has also built a subsea line from Ule to Maracaibo where the Antonio Ricaurte line ends.

In separate gas market assessments issued by PdV and Repsol, all of Cardon 4's peak output would be consumed in the western Venezuelan states of Falcon and Zulia, mainly by PdV's upstream and downstream operations, state-owned petrochemical producers and state-owned power utility Corpoelec.

PdV estimates gas demand by all state-owned companies in Falcon and Zulia, including the oil sector, at 1.23bn ft3/d.

Before Repsol and Eni started production from the shallow-water Perla field in July, only around 148mn ft3/d of gas was available, equivalent to 12% of the estimated demand.

In the absence of gas, functioning installations used more costly diesel or other fuels instead.

Gas demand on the Paraguana peninsula in Falcon, including PdV's 940,000 b/d CRP refining complex and three thermal power plants, totaled 413mn ft3/d as of mid-2015, of which only 125mn ft3/d was available, according to PdV.

The CRP complex, which includes the 635,000 b/d Amuay refinery and nearby 305,000 b/d Cardon refinery, were consuming just 120mn ft3/d of gas at end-June 2015, or 100mn ft3/d less than required for their normal operations. Both refineries have been subject to chronic breakdowns that are widely attributed to a lack of maintenance.

Corpoelec's 300MW Genevapca thermal power plant, which supplies the CRP refining complex, was consuming only 5mn ft3/d of gas at mid-2015, or just over 7pc of its potential gas consumption capacity of 70mn ft3/d.

Corpoelec's 450MW Josefa Camejo thermal plant on the Paraguana peninsula, completed in 2012 and designed to burn 105mn ft3/d of gas, has only used diesel since it was commissioned over three years ago.

Based on the 450mn ft3/d of gas that Cardon 4 has guaranteed will be delivered to PdV by end-2015, at least up to 288mn ft3/d could be allocated to refining and power generation needs on the Paraguana peninsula. This would leave 162mn ft3/d that PdV could potentially deliver to other state-owned companies in Zulia, with up to 50mn ft3/d of that allocated for export to Colombia.

But PdV's gas consumption forecasts for state-owned energy and petrochemicals companies in Zulia and Falcon are contingent on efficient gas transportation and operation of these assets, particularly Corpoelec's plants and state-owned Pequiven's petrochemical facilities.

Like the CRP, many installations lack maintenance and are subject to frequent breakdowns and accidents.

Corpoelec's 660MW Ramon Laguna and 1,220MW Termozulia thermal plants near Maracaibo have a combined gas consumption capacity of 250mn ft3/d. But as of mid-2015 these plants were only using 40mn ft3/d and 39mn ft3/d, respectively.

Equipment failures shut down Ramon Laguna indefinitely last month, and Termozulia is currently operating at less than 50pc of its capacity, Corpoelec reports.

"Corpoelec wants to replace diesel with gas in plants like Josefa Camejo, Termozulia and Ramon Laguna because it would reduce costs and preserve the thermal generation infrastructure, but our ability to burn more gas depends on these plants being fully operational, which in turn depends on financial resources and replacement parts that we don't have," a Corpoelec official tells Argus.

Pequiven's petrochemicals complex in Zulia is also in poor shape. At peak capacity El Tablazo could consume up to 200mn ft3/d of gas, but as of mid-2015 it was only using 57mn ft3/d because most of its plants are shut down or only partially operational, according to PdV.

If PdV's strategy of incrementally placing Cardon 4 gas supplies locally falters because the state-owned clients have operational problems with their plants, the Antonio Ricaurte pipeline could provide an outlet for up to 150mn ft3/d, an energy ministry official tells Argus.

"Colombia would not turn down more gas from Venezuela in the near term, and the gas exports would generate dollar revenue PdV needs to advance its investment plans in 2016 and 2017," the ministry official said. Going forward, the official added, gas exports to Colombia could be adjusted in line with changing local demand as Corpoelec and Pequiven repair and restart their plants. With additional compression on the Antonio Ricaurte pipeline, Venezuelan gas exports to Colombia could eventually reach 250mn ft3/d. (November 2, 2015)

11/03/2015

UKRAINE:

Ukraine Warns it may stop buying Russian gas next year

Ukrainian authorities said they will buy natural gas from Russia until the end of the year, but will purchase all Ukraine's gas from Europe in the first quarter of 2016 if Russia does not offer a competitive price.

"We expect and hope that Russian gas sellers will be rational and propose competitive prices to us," Naftogaz Chief Executive Andriy Kobolev said at a company briefing in Kyiv November 3.

"If there is no such offer we will be purchasing all gas from Europe," he said.

Kobolev said that no additional agreement needs to be signed on first quarter gas purchases, as it is possible for Ukraine to act in the framework of documents signed earlier this year.

He added that Naftogaz Ukrainy is expecting "a serious fall" in gas prices, starting in the second quarter of next year. (November 4, 2015)

11/04/2015

PRICE

UNITED KINGDOM:

UK wholesale natural gas prices fall on solid supply, mild weather forecasts

UK wholesale natural gas prices fell at the open Monday because the UK gas system was well supplied due to high LNG sendout combined with robust Norwegian gas imports and demand dampened by mild weather.

National Grid 10:00 am local time demand forecasts for Monday were 241 million cu m with physical flows seen at 244 million cu m/d.

Both the within-day and day-ahead NBP contracts dropped below 35 pence/therm in early Monday trading and were seen at 34.90 p/th and 34.85 p/th respectively, down 0.325 p/th and 0.25 p/th from the Friday assessments.

LNG sendout from the South Hook LNG terminal ramped up at the beginning of Monday's gas day after having fallen over the weekend and been low on Friday due to an unplanned outage -- flow rates were seen at 33 million cu m/d Monday morning.

Sendout from Dragon dropped to zero overnight with Isle of Grain again inactive.

The Umm Slal is set to berth at South Hook on Monday with the Al Karaana due to follow on Friday.

Norwegian gas imports were running at 102 million cu m/d Monday morning according to Norwegian gas operator Gassco, split between Easington and St. Fergus at 54 million cu m/d and 48 million cu m/d, respectively.

UK indigenous gas production was nominated at 94 million cu m Monday according to Eclipse Energy, an analytics unit of Platts.

Imports from the Netherlands into Bacton through the BBL pipeline were running at 8 million cu m/d Monday morning.

Withdrawals from storage facilities during Monday's gas day are nominated at 12 million cu m according to Eclipse, despite the NBP spot trading at a discount to the front-month contract.

Export demand from continental Europe remains solid for the time of year with IUK 10:00 am nominations at 35 million cu m.

Falls on the NBP curve on the open Monday have been more pronounced than those on the prompt, with front-month December 15 dealt at 38.55 p/th, 0.60 p/th lower than Friday's assessment.

The Q1 16 contract was seen trading at 39.05 p/th, with Summer 16 changing hands at an even 35 p/th. (November 9, 2015)

11/10/2015

STORAGE

IRAN:

Stored gas at Sarajeh crosses 1.2bcm

The volume of the natural gas stored at Sarajeh Gas Storage Facility has exceeded 1.25 bcm, 83% of the facility's storage capacity in its first phase, a gas distribution official said.

Housahng Mehrdadfar said the facility has undergone an overhaul and all technical tests on its processing facilities have been concluded.

He said the facility is ready to supply processed gas during peak days of consumption in winter.

Iran's National Gas Storage Company dipped into Sarajeh gas storage facility to compensate for gas shortage in the last winter.

Sarajeh gas facility is able to process 10 mcm/d of gas in two phases but the volume of gas withdrawal from the facility depends on the decisions made by dispatching center of the National Iranian Gas Company.

Located in the central province of Qom, Sarajeh Gas Storage Facility can store up to 1.5bcm of gas in its first phase development.

Once completed the facility will be able to hold up to 3.3bcm of natural gas.

The facility is usually tapped during winter to supply the gas needed for feeding the industrial and household sectors. (November 4, 2015)

11/04/2015

USE FOR POWER GENERATION

UNITED KINGDOM:

UK gas plant remains largest source of power

Combined-cycle gas turbines (CCGTs) comfortably remained the UK's largest source of power generation in October, but coal-fired output hit a six-month high and climbed above nuclear in the generation mix following the return of units from summer maintenance.

CCGT plant made up 34pc of generation in October, producing around 15.7TWh, data from transmission system operator National Grid show. This was down slightly from the 16.1TWh generated in September, but well above the 13.9TWh monthly average for CCGTs this year.

Plentiful gas, a hike in the UK-only carbon price floor earlier this year and another mild start to the winter have kept spark spreads for most of the UK's gas plant above dark spreads for coal plants, and this is set to continue into the first quarter of next year. Last year, generation economics had swung back in favour of coal plant by October, after CCGTs had been more profitable in the summer months.

At yesterday's closing prices for the first quarter of 2016, a 55pc-efficient gas plant held around a £0.60/MWh advantage over a 38pc-efficient coal plant.

Coal-fired generation rose in October, owing to the return of several units from annual summer maintenance, and as prompt European coal swaps dropped to their lowest in several years. Coal-fired units planned for closure at the end of this winter — the 2.3GW Longannet, 1.9GW Eggborough facilities and the final 490MW unit at Ferrybridge — may also operate regardless of generation economics this winter if they have coal stocks to burn.

Coal-fired output reached 12.7TWh in October, accounting for 27.5pc of generation, up from 8.5TWh in September. This was the highest monthly amount generated by coal since April's 14.2TWh. But output was still down compared with last year, when coal generated 16.4TWh in October and accounted for 38.3pc of generation.

The increase took coal back above nuclear to second in the generation mix in October, with nuclear plant generating 11.6TWh — around a quarter of overall output. Nuclear was the UK's second-largest source of generation in May-September.

Nuclear availability has been higher this year compared with 2014, when four units, equalling more than 2GW of capacity, were shut down in August after a boiler spine defect was discovered in the units' design. Total nuclear generation in October last year amounted to just 7.7TWh, or 16.5pc of overall generation.

The lower output from coal and CCGT plant this year is partly down to a rise in renewable generation, following growth in wind and solar capacity over the past year. Wind output metered by the grid between January and October totalled 35.4TWh, up from around 33TWh a year earlier. (November 4, 2015)

11/05/2015

PUBLICATIONS

WORLDWIDE:

China, Middlle East to overtake Europe as biggest gas users

China and the Middle East, spurred by lower prices and ample supply, will drive global natural gas demand growth in the next 25 years as consumption in Europe fails to recover to peak levels seen in 2010, according to the International Energy Agency.

Both regions will become larger consumers of gas than the European Union, the IEA said in its World Energy Outlook 2015 published Tuesday. Global demand for gas, a cleaner-burning fuel for power generation than coal, will rise almost 50% in the period to 2040, making it the fastest-growing fossil fuel.

“With gas prices already low in North America, and dragged lower elsewhere by ample supply and contractual linkages to oil prices, there is plenty of competitively priced gas seeking buyers in the early part of the Outlook,” the IEA said in the report.

Emerging economies are increasing gas use to reduce the share of dirtier coal in power generation, which the IEA sees dropping to 30% from 41%. Gas is also being used to spare use of oil and to back up renewable energy generation. (November 9, 2015)

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