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September 2014

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Natural Gas Imports into China – Prospects for Growth

Merrick White, David Phua

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permitting process, including requiring applicants to provide a sworn statement and documentation supporting any claim that a proposed pipeline will function as a common carrier line. **More »**

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According to *BP's Energy Outlook 2035*, China will become the world's largest energy importer by 2035, overtaking Europe in terms of its energy imports. China's projected growth in demand for energy supplies, its plans to embrace cleaner and more efficient energy sources, and developments in the liquefied natural gas (LNG) and gas global markets provide a strong basis for the view that there is considerable scope for increase in its natural gas[1] consumption. It is also likely that such increase in consumption will be met by a growing volume of natural gas imports. As a general overview, this article discusses the current state of China's consumption and importation of natural gas, the supply and pricing factors affecting such imports, and the potential for growth in imports as well as the extent to which such imports will be supplied by LNG and pipeline gas quantities respectively.

Natural Gas Consumption and Importation

Presently, coal supplies the vast majority of China's energy consumption, with such fuel source supplying over 65% of its energy demand in recent years. As for natural gas, this currently supplies a significantly smaller fraction of China's total energy needs, being approximately 5% of China's energy primary sources in 2013. However, it is worth noting that the size of the Chinese gas market means that even with such a small fraction of energy demand being met by natural gas, China is already the world's third largest gas consumer and its natural gas consumption in 2013 was approximately 160 billion cubic metres (BCM). Furthermore, China's natural gas consumption has been continually increasing in recent years. In 2013, consumption increased by approximately 12% and it is projected to increase over 10% by the end of this year[2]. As shown by the chart below, there has been a widening gap between domestic production and growing gas demand, resulting in total imports increasing to around 52 BCM[3] and import dependence rising to around 30% in 2013.

Source: BP Statistical Review of World Energy

Imports – Pipeline Gas and LNG

Unlike other major LNG consuming markets in North Asia (*i.e.*, Japan, Korea and Taiwan), China is also able to import substantial quantities of natural gas through pipelines, namely, pipeline connections originating from Central Asia and Myanmar and in future, following the signing of the China National Petroleum Corporation (CNPC) Gazprom contract, Russia's Siberian gas fields. Since China became an importer of LNG in 2006 and pipeline gas in 2010[4], both types of imports have grown steadily. In 2013, China's imports of pipeline gas and LNG were roughly even being equal to 27.4 BCM and 24.5 BCM respectively or 53% and 47% respectively of aggregate imports[5].

(1) LNG Import Quantities

At present, China has 10 major LNG receiving terminals in operation, namely, the Guangdong Dapeng, Fujian, Shanghai, Zhejiang, Zhuhai, Tianjin FSRU, Jiangsu Rudong, Dalian, Tangshan and Hainan receiving terminals. Together these terminals have a regasification capacity of about 35 MTPA[6]. In 2013, China's largest LNG suppliers were Qatar, Australia, Malaysia and Indonesia. Set out below is the breakdown of LNG imports supplied from various countries in 2013.

Source: China's maritime customs data

Based on recent upstream interests acquisitions and LNG sale and purchase agreements (SPAs), there is significant potential for increased LNG imports to China. Since 2010, Chinese companies have reportedly spent up to US$ 8.5 billion on unconventional oil and gas projects in the United States. In particular, there have been recently a number of high profile LNG-related investments and LNG SPA signings by Chinese corporations, for instance, as set out below:

- Sinopec's acquisition in 2014 of a 15% stake in the Pacific Northwest LNG project in British Columbia, Canada, together with its signing of a 20 year contract to take 1.8 million tonnes annually of LNG from the project.

- CNOOC's US$ 18 billion acquisition in 2013 of Nexen, a Calgary based company that has large oil sand and shale gas reserves in western Canada, part of which is earmarked for overseas exports through the Aurora LNG export project.

- CNOOC's US$ 1.93 billion acquisition in 2013 of additional interests from the BG Group of the Queensland Curtis LNG project in Australia and under a separate agreement CNOOC's purchase of an additional 5 MTPA of LNG for 20 years from BG Group.

- CNPC's US$ 4.2 billion acquisition in 2013 of a 20% working interest in Mozambique Area 4 (which may form part of the supply source for East Africa's first LNG export project) from Eni.

- CNPC's acquisition in 2013 of a 20% stake in OAO Gazprom - Novatek's $20 billion Yamal LNG project from which CNPC will receive long-term supplies.

Furthermore, there has been a clear trend of an increasing number of LNG import terminals in China. Currently, there are a number of LNG terminal projects in China under construction (*e.g.*, the Qingdao, Shenzhen and Guangxi terminals) or proposed to be constructed, and these projects once completed are expected to substantially increase China's aggregate LNG receiving and regasification capacity. According to the U.S. Energy Information Administration, China's import regasification capacity is set to increase by another 20 BCM by 2016, increasing its present regasification capacity by nearly 50%.

(2) Pipeline Import Quantities

At present, China receives pipeline gas supplies from Central Asia and Myanmar. Originating from Turkmenistan, the Central Asia Gas pipeline (CAGP) has presently a total of 3 lines – these are, namely, Lines A and B that have a total capacity of 30 BCM, and Line C that was commissioned this year and which is expected to have a total capacity of 25 BCM by 2015. As for the Sino-Myanmar pipeline, this has a total capacity of 12 BCM per annum. Without taking into account Line C of the CAPG which has not yet reached full capacity, China's international pipeline capacity is currently at least 42 BCM. In terms of pipeline gas supply, Turkmenistan was in 2013 by far the largest supplier to China, with gas supplies coming from the Bagtyyarlyk field. Set out below is the breakdown of pipeline imports supplied from various countries in 2013.

Source: China's maritime customs data

Given the potentially rich gas resources of China's current and future pipeline gas suppliers (*e.g.*, Turkmenistan and Russia), there is significant potential for additional pipeline gas supplies. Most notably, Gazprom has recently signed in May this year a US$ 400 billion agreement with CNPC to supply 38 BCM of natural gas a year with supplies commencing in 2018 and for a 30 year term. Apart from the CNPC Gazprom agreement, there are also a number of other indications which signal that China will significantly expand its pipeline imports:

- The new investment by CNPC in Galkynysh gas field, and the gas supply agreement signed between CNPC and TurkmenGas for 25 BCM of gas per year. By 2020, this would raise planned imports from the Central Asian country to 65 BCM per year, with such additional gas imports being supplied from the Galkynysh field.

- China's plans to expand both the CAGP and also the China's West-East pipelines which transport gas from Central Asia and Xinjiang to the demand centres in China's North-east. By 2015, the expansions of the CAGP will raise pipeline capacity to at least 55 BCM per year. As for China's West-East pipelines (currently two), these will be expanded to a third pipeline set to be operational by 2015 and there are already proposals to construct the fourth and fifth pipelines.

- While gas imports from Myanmar last year only amounted to approximately 2 BCM, Chinese gas imports from Myanmar are expected to reach at least 10 BCM per annum, which is still well within the 12 BCM per annum throughput capacity of the Sino-Myanmar pipeline.

- Uzbekistan gas exports to China are also expected to increase over time, and under a framework agreement signed between CNPC and Uzbekneftegaz, Uzbekistan is reportedly expected to increase gas exports to China to at least 10 BCM per annum over the coming years.

Pricing – Pipeline Gas and LNG

(1) LNG Pricing

In 2013, the average price of LNG imports into China was reportedly US$ 13.8 per MMBtu. The cheapest LNG cargoes were Australian and Indonesian LNG cargoes with an average price of US$ 3 to 4 per MMBtu. In contrast, the average price of cargoes from Qatar (which was China's biggest LNG supplier in 2013) was US$ 17.32 per MMBtu. In this respect, one reason for the pricing divergence is that Australian and Indonesian LNG are likely supplied under earlier and more advantageously priced long-term SPAs (*i.e.*, supplies from the Australian North West Shelf project and the Indonesian Tangguh projects[7]).

Source: China's maritime customs data

(2) Pipeline Gas Pricing

In 2013, China received pipeline gas imports at an average price of US$ 9.78 per MMBtu. Leaving aside Kazakhstan (which constituted less than one percent of overall pipeline supply to China), the average pricing for pipeline imports into China, as compared to LNG imports, fell within a much narrower range (*i.e.*, US$ 8.63 per MMBtu for Uzbekistan gas, US$ 9.94 per MMBtu for Turkmenistan gas, and US$ 11.68 per MMBtu for Myanmar gas). The graph below sets out the breakdown of prices for China's pipeline gas imports in 2013:

Source: China's maritime customs data

As can be seen from the charts above, based on the average 2013 pricing, pipeline imports enjoy an approximate US$ 4 per MMBtu price advantage over LNG imports. In this respect, the pricing agreed under the recent CNPC Gazprom deal is reportedly around US$ 10 per MMBtu, which is still cheaper than the 2013 average price of LNG imports to China. Apart from the significant capital investment for developing LNG projects, one reason for the relatively higher price of LNG is the "Asian Premium" paid by North Asian LNG buyers. Due to the lack of alternative energy sources, the Japan-Korea-Taiwan markets have traditionally been seen as more willing to pay a higher price for LNG cargoes. As Chinese importers are competing for LNG supplies in the same market, they consequently pay for LNG at largely similar prices.

In assessing the overall price difference between pipeline gas and LNG imports, one important factor to consider relates to costs involved in transporting pipeline gas from the border regions (*e.g.*, north-western China) to the major gas consuming cities in the north-eastern regions. Taking gas imports from Turkmenistan as an example, if we assume that the pipeline transportation tariff for such gas is approximately US$ 3-4 per MMBtu[8] and that the regasification costs for LNG delivered at China's LNG terminals (which mostly are located relatively proximate to the major gas consuming regions (*e.g.*, Guangdong, Pearl Delta and Yangtze Delta)) are approximately US$ 1 per MMBtu, then the final price difference between the delivered cost of Turkmen pipeline gas and LNG imports (after regasification) could potentially narrow to US$ 1-2 per MMBtu[9]. In this connection, the overall transportation tariffs which will be paid for gas delivered under the Gazprom CNPC agreement is likely to be less (compared to gas delivered from Turkmenistan) as the gas will be delivered at China's northern border and hence closer to cities in China's north east, but such tariffs will nonetheless impact on the final delivered cost[10]. In any case, although the delivered cost of pipeline gas is still cheaper than LNG at current day prices, the effect of transportation tariffs is still one factor to be taken into account in assessing the actual cost difference between LNG and pipeline gas imports.

Demand for Natural Gas Imports

In the near term, natural gas imports into China are likely to continue to rise, particularly in view of growing natural gas demand. According to China's National Development and Reform Committee (NDRC), the natural gas market will by 2020 reach 400 BCM, which is more than double the present consumption of natural gas. For various reasons discussed below, there are considerable difficulties for China's domestic gas production to be able to fully satisfy the future quantities required by the country. More generally, the demand for gas imports will be affected by a number of different factors which are further discussed below.

(1) Governmental Policy and Environmental Concerns

Given that key aspects of China's economy are influenced by central planning directions and that state owned enterprises continue to play a significant role in the energy sector, the importance of the government's energy policy with respect to future gas imports cannot be understated. In China's Twelfth Five Year Plan (2011-2015), one of the key socio-economic objectives is to significantly reduce environmental pollution, in particular, with a target for an 8 percent reduction in sulphur dioxide emissions and 10 percent reduction in nitrogen oxide emissions by 2015. This goal is largely driven by the serious air pollution issues, which have been worsening over recent years. To meet such emissions reduction targets, the Chinese government plans to significantly increase the consumption of natural gas (being the cleanest burning fossil fuel) as well as renewable energy. China's Natural Gas Development Plan[11] expects that natural gas consumption will increase by an average of 20 BCM per year up to 2015.

Consistent with the stated policy of the government to reduce pollution emissions, there is a move towards increasing the electricity volumes generated by natural gas and reducing reliance on coal for electricity generation. Based on a recent announcement by the National Energy Agency (NEA), the government will prohibit the construction of new captive coal power plants in the Beijing-Tianjin-Hebei area, the Yangzi River Delta and the Pearl River Delta, and except for cogeneration plants, cease approvals for new-build coal fired power stations in such areas[12]. There are also plans to increase electricity generated from natural gas to 56,000 MW by 2015, representing a 53% increase from electricity generated from natural gas in 2010[13]. Given that the current capacity for gas-fired power generation in China is about 43,090 MW[14], such targeted output is not far off from being met next year. Even though coal will likely remain the predominant fuel source of electrical generation in the foreseeable future, this trend of increasing the usage of natural gas quantities for electrical generation will provide an important boost to raising the levels of natural gas import and consumption over the coming years.

(2) Pricing

The pricing issues relating to natural gas form another set of important factors affecting the level of end user consumption in China and hence its demand for natural gas imports:

- Particularly from a longer term perspective, the pricing of imported natural gas (which in 2013 stood at an average of US$ 13.8 per MMBtu for LNG and US$ 9.78 per MMBtu for piped natural gas) is likely to have an important impact on the extent of its demand, especially when considering the significantly lower prices of coal. In this respect, it has reported that the Guangdong prices of base and incremental gas volumes[15] (in terms of electricity generation) are RMB 0.97 per KwH and RMB 1.17 per KwH respectively, whereas the corresponding cost of coal is only RMB 0.3 per KwH[16]. Even taking into account the higher environmental costs of coal generation, gas-fired electrical generation is still more expensive by RMB 0.2 per KwH to RMB 0.3 per KwH[17]. Given the cost differential between natural gas and coal, the higher pricing of imported natural gas may serve to constrain the scale of future pipeline and LNG imports into China, especially in the longer term.

- Another key factor to consider is the domestic pricing of natural gas within the Chinese market. The wholesale pricing of natural gas has been traditionally regulated by the government, and such regulation has caused losses for Chinese gas importing companies arising from selling imported natural gas at lower domestic rates (particularly for residential users). When releasing its 2013 financial results, the state-owned Petro-China revealed that it lost RMB 49 billion (US$ 7.9 billion) last year from importing natural gas and selling it at lower domestic prices[18]. In this respect, it should be noted that there is considerable disparity between the prices paid by different classes of gas users with the lowest prices being paid by residential users – for instance, based on 2011 data of end-user gas prices, residential users in Beijing paid nearly US$ 3.50 per MMBtu less compared to users in the industrial and public services sectors, and over US$ 11 per MMBtu less compared to users in the transportation sector[19]. Such disparity suggests a considerable element of cross-subsidisation among the various users in order to maintain lower residential gas prices.

  Recently, however, China's government has taken important steps to raise gas pricing. In July 2013, the NDRC announced a price reform to the country's wholesale gas markets, which divided consumption into 2 tiers – one tier being the existing consumption as of 2012 (*i.e.*, the base volumes), and another tier being the incremental volumes above the base consumption (*i.e.*, the incremental volumes). Under the reform, the incremental volumes were pegged to 85% of the price of a basket of alternative fuels (consisting of 60% and 40% weightage to fuel oil and liquefied petroleum gas respectively), while the price for base volumes was to be adjusted by not more than RMB 400 per thousand cubic metres. Reportedly, the price reform resulted in an average price adjustment of 15% for all consumers (apart from the residential users who were not affected by the price reforms). Recently this year, the NDRC has further raised prices paid by non-residential users for base volumes by RMB 400 per thousand cubic metres. While there is still greater reform to be undertaken before the gas pricing can said to be fully liberalised (particularly in relation to residential users), the price reforms are nonetheless important steps towards a more market-based pricing for domestic sales of natural gas.

- Apart from the wholesale pricing of natural gas in the domestic market, the pricing for electricity generated from natural gas is another important factor that would influence the demand for gas imports. In China, electricity pricing is regulated by the government. Taking into account the relatively higher costs of gas-fired power generation compared to coal-fired power generation (as mentioned above), such regulation does not allow Chinese companies to generate commercial profits through generation of electricity from natural gas without substantial government subsidies. For instance, it has said that the average power generation cost of gas in Guangdong is approximately RMB 0.81 per KwH, higher than the mandated on-grid tariff of RMB 0.74 per KwH[20]. In recognition of the need for pricing adjustment to reflect more accurately the actual generation costs, the NDRC announced in October last year that it would raise the on-grid prices of gas generated electricity in Shanghai, Jiangsu, Zhejiang, Guangdong, Hainan, Henan, Hubei and Ningxia. Together with pricing reforms relating to domestic gas sales, there is however still a need for more widespread and fundamental electricity price reform to allow electricity prices to more fully reflect the actual cost using natural gas for electricity generation.

- Notwithstanding the prices issues discussed above, it is important to note that natural gas demand is largely driven by the government's desire to utilise cleaner and more environmentally-friendly sources of energy. Taking this into account together with the fact that the China is unlikely to achieve gas selfsufficiency in the near term (for reasons discussed below), the demand for natural gas, at least in the short term, is not entirely price-sensitive nor is natural gas in this respect easily substitutable with coal – coal, although being a cheaper energy source, is one of the main contributors of air pollution in China (*e.g.*, as a result of its usage for power generation). Additionally, while natural gas prices are unlikely to fall below domestic coal prices, one cannot rule out the possibility of natural gas pricing softening in future - for instance, due to increased LNG supplies (*e.g.*, from the United States, Australia and East Africa) coming onto the market in the latter part of this decade, diversification of gas sources (*e.g.*, Russian pipeline gas from eastern Siberia) and the possible development of a hub-based pricing mechanism in Asia for natural gas[21]. Also, the imposition of a carbon tax (which has reportedly been considered by the Chinese government) would serve to narrow the pricing difference between natural gas and coal. Overall, while the resolution of pricing-related issues will have an important impact on the long term growth of China's gas market, such issues should not significantly reduce China's demand for natural gas imports in the near future. Indeed, projections for China's future gas imports generally anticipate an increase in their overall volume.

(3) Economic growth, Urbanisation and Transportation

While the Chinese economy has shown signs that the pace of economic growth is slowing down, natural gas only occupies a small portion of China's primary energy mix, which is at a level far below the world's average natural gas consumption at 23.8%[22]. Accordingly, there is significant headroom for growth in the Chinese gas market and natural gas importation as the country progresses into a more developed economy. Such economic development has a number of positive implications for the growth in natural gas consumption and importation in China: First, developed economies have greater financial capability to bear the additional costs arising from natural gas consumption. Second, these economies usually use a greater portion of their electricity for residential and commercial purposes (as opposed to industrial uses), and such usages require a greater need for electricity peaking facilities that can be ramped up and down to accommodate fluctuations in energy demand. In turn, this is likely to translate into greater demand for natural gas as such peaking facilities often utilise natural gas as the fuel source. Third, along with the development of the economy, the scale of urbanization is only expected to increase over the coming years. Generally speaking, such urban population are expected to have better access to gas pipeline distribution networks and also the financial ability to afford the higher tariffs charged for gas-generated electricity. Apart from economic growth and urbanization factors, China is expected to soon have the world's largest fleet of natural gas vehicles as the country pushes forward its development of natural gas and LNG fuelling stations and distribution networks, and this in turn is likely to boost the demand for natural gas.

(4) Alternative Energy Sources

China has access to a wide basket of alternative energy sources including nuclear power and renewable energy sources such as wind power and hydropower. For instance, China has been assessed by the International Energy Agency (IEA) to have the largest potential amongst all countries for hydropower generation. To a certain extent, the presence of renewable energy sources may compete with the consumption of natural gas. However, it is important to bear in the mind the limitations of renewable energy and its potentially complementary relationship with natural gas[23]. Renewable energy sources typically offer less stability than fossil fuel for power generation (*e.g.*, hydropower generation in China is known to decline in winter until the summer rains), and gas–fired power plants are often used as peaking power facilities to avoid disruption that would otherwise occur from relying solely on renewable energy. Hence, an increased reliance on renewables for power generation may promote rather than reduce natural gas consumption.

As for nuclear power, the Chinese government (as seen from the Twelfth Five Year Plan) still foresees a significant role for it in the country's future energy mix. Nonetheless, given that most of China's nuclear power plants are already located or planned to be located near high density population centres along the eastern coast and also taking into account the concerns arising from the Fukushima incident, the government will have to balance advantages from nuclear power and corresponding safety considerations in developing its nuclear power generation facilities. In any case, the scale of China's energy demands makes it highly unlikely that any one energy source or combination thereof, whether nuclear power or renewable energy, will entirely substitute the demand for natural gas, especially when taking into account the fact the government's plans (*e.g.*, the Twelfth Five Year Plan) to diversify China's energy supply sources.

(5) Domestic Production

China holds significant gas reserves, particularly unconventional gas reserves in the form of shale gas. There have been hopes that China would soon be able to emulate the shale gas revolution in the United States and thus reduce its import dependence for natural gas. With technically recoverable reserves estimated at 1,115 trillion cubic feet, China holds the largest shale gas reserves in the world, which is more than double that held by the United States. Given such potentially vast domestic gas supply sources, China's Natural Gas Development Plan calls for an increase in unconventional gas production, with a target of 6.5 BCM of shale gas production by 2015. By 2020, the Shale Gas Development Plan (2011-2015)[24] targets shale gas production to increase even more substantially to 60 to 100 BCM.

Taking into account the recent announcement that China Petrochemical Corp. is planning to produce 5 BCM of shale gas a year from its Fuling site (Chongqing) by 2015, there is some anticipation that China may meet its 2015 shale gas production target. However, it seems increasingly unlikely that China will be able to meet its original 2020 shale gas production target, and the head of China's NEA has reportedly commented that China's objective now is to only produce 30 billion cubic meters of shale gas by 2020[25]. In this connection, there are several challenges confronting the effort to substantially raise shale gas production in China. First, shale gas plays in China are typically found at a deeper depth and more mountainous terrain, and in certain cases, in more heavily populated areas, than those found in the United States. Second, there is limited pipeline infrastructure connecting shale gas fields (which are mainly located nearer to western regions) to demand centres in China's eastern cities. Third, although hydraulic fracking requires substantial amounts of water usage, there is a water shortage in the areas where shale gas reserves are found (*e.g.*, China's Tarim basin in Xinjiang). Fourth, while Chinese companies have been active in acquiring shale gas technology overseas (*e.g.*, North America), Chinese companies still lack appropriate fracking technology and experience, and there is a steep learning curve involved in adapting imported technology to local conditions. Fifth, there is also a need for structural reform relating to mineral rights, market pricing and the monopolistic position of the large national oil companies, for instance, with regards to the transportation pipeline network.

In any case, due to the anticipated growth in domestic natural gas demand and even assuming a substantial increase in shale gas production, neither industry observers nor the Chinese government generally expect that domestic gas production in the near future will be able to fully satisfy demand. For instance, while China's Natural Gas Development Plan targets that domestic production of natural gas will rise up to 176 billion cubic metres by 2015 (including 138.5 BCM of conventional gas production), it anticipates that China will double its gas imports during the same period.

(6) Natural Gas Infrastructure

Another factor that is important to the growth of the natural gas market is the presence of necessary infrastructure to support the receipt, storage and distribution of natural gas. Although infrastructure development is driven by the growth in consumption, the reverse is also true as such development will have a positive impact on the consumption of natural gas by expanding its availability to potential users, for example, through the wider geographical spread of the pipeline network. However, China's main pipeline and distribution pipeline systems do not presently provide sufficient coverage. As of the end of 2012, China's natural gas pipeline network was only one tenth of the pipeline network in the United States, while its natural gas consumption was already one quarter of that for the United States. Additionally, there are also the challenges of developing additional gas-fired power plants as well as storage capacity, which is particularly important given the seasonal nature of China's gas demand[26]. Separately, the relevant regulatory regime and ownership interests governing the pipeline system also require reform, in particular, with regards to the control of the pipeline network by large Chinese oil and gas companies and the need for open and non-discriminatory access to the gas pipeline network.

In response to these infrastructural issues, the Natural Gas Development Plan targets to substantially expand relevant infrastructure and capacity, for instance, by doubling the domestic pipeline grid by 2015 and expanding the country's storage facilities for natural gas. On the regulatory front, the NEA has also recently released a new trial regulation[27] requiring pipeline operators with spare capacity to offer third parties the right to access their pipeline networks for transportation of natural gas. This is a significant step in a context of an industry where the majority of pipelines are owned by few vertically integrated state owned companies (in particular CNPC owns over 75% of gas pipelines in China). Overall, there is increasing emphasis on expanding the natural gas related infrastructure to cope with the expectation of rising gas demand, and such development in turn should create greater opportunities for growth in the consumption and importation of natural gas.

Projections for Growth in Natural Gas Imports

(1) Growth in Overall Imports

In general, the industry view is that China's future natural gas consumption and importation are set to grow substantially. According to certain NDRC estimates, China's gas consumption is expected to reach 400 BCM in 2020 and import dependence will at such time exceed 40%. This should translate to around 160 BCM of gas imports[28][29] and 240 BCM of domestic gas production in 2020. The table below shows the potential growth of Chinese gas imports in selected years up to and including 2020:

Sources: BP Statistical Review of World Energy June 2014 (2013 figure); CNPC Economics and Technology Research Institute (2014 figure); China's Natural Gas Development Plan (2015 figure); and NDRC projections (2020 figure).

Admittedly, projections for future Chinese gas importation vary considerably in degree, depending on projections of future Chinese gas demand (*e.g.*, on the lower end, demand has been predicted to be only 323 BCM in 2020[30]) and domestic production. Based on the IEA's estimates, there could be approximately a 70 BCM difference in net imports as between low and favourable unconventional production scenarios for 2020.[31] In any case, even under the IEA's favourable unconventional production scenario, it is worth noting that estimated overall imports in 2020 would be 50% higher than present day levels. There is therefore good reason to expect that gas imports into China will continue to see significant growth over the coming years, although forecasting the exact extent remains a difficult exercise.

(2) Future LNG and Pipeline Gas Import Quantities

Assuming Chinese gas demand is 400 BCM in 2020 and total gas imports reach 160 BCM, pipeline gas is likely to form a sizable portion of Chinese natural gas imports. Under a high supply scenario for pipeline gas, assuming the full supply of gas volumes under pipeline supply agreements for supply into China, the aggregate pipeline imports could reach as high as around 120 BCM[32] or about 75% of total gas imports in 2020. Under this scenario, Chinese LNG imports in 2020 would be around 40 BCM (*i.e.*, the total estimated import volume of 160 BCM less 120 BCM of pipeline gas supply) or about 25% of total imports. However, due to the fact that the pipeline supply volumes (*e.g.*, under the CNPC Gazprom contract) may not yet have fully materialised by 2020, LNG cargoes could very well supply a higher percentage of China's gas demand. Even so, when taking into account the additional quantities of pipeline gas from Turkmenistan to be supplied in 2020 and the Russian gas supplies under the CNPC Gazprom contract, it seems likely that pipeline gas supplies will in future exceed LNG cargo imports.

Notwithstanding the discussion above, however, one should not downplay the importance of LNG in China's future natural gas consumption and importation. Assuming that LNG only constitutes 30% of Chinese imports in 2020 (*i.e.*, slightly higher than would be the case under the high pipeline supply scenario) and overall imports reach 160 BCM, this would mean about 50 BCM of LNG imports, which is a doubling of the present level of LNG imports into China. For coastal regions in particular, LNG will continue to form an important part of their energy supplies, given their relative proximity to LNG receiving terminals. Furthermore, the flexibility and potential diversification of supply sources offered by LNG (particularly with the growth in the short term and spot trade[33] of LNG) is likely to mean that China will maintain a sizable proportion of future gas imports in the form of LNG. Although LNG supply is potentially vulnerable to blockades and acts of piracy, transnational pipelines are not immune from similar transportation and supply disruption risks, and China's energy security is very likely to be optimised through the diversification of supply sources for both pipeline and LNG. Indeed the recent crisis over Ukraine and Europe's dependence on Russian gas imports is likely to be a useful reminder to China (a future Russian gas importer) of the importance of supply diversification in any country's energy policy.

In terms of the relative balance of future LNG and pipeline gas imports into China, one potential game-changer is the possibility of LNG pricing in Asia heading for a downward correction in the longer term. In the latter half of this decade, some view that the start-ups of Australian projects and availability of US LNG (as well as LNG exports from Canada and East Africa) may substantially increase the amount of LNG supply in the global market. On the demand supply, the reactivation of Japanese nuclear plants shut down in the wake of the Fukushima nuclear incident is also expected to reduce demand from the world's largest LNG importer. Furthermore, the rise of China as one of the largest LNG consumers and its ability to switch between pipeline gas and LNG for its fuel needs could add momentum to a softening of North Asian LNG prices. One projection has been made that LNG prices could fall to approximately US$ 10 to 12 per MMBtu in the longer term[34] – if so (and unless pipeline gas prices fall as well), LNG import prices, especially for coastal regions in China, could be fairly competitive *vis–à–vis* pipeline gas, especially when one takes into account the transportation tariff for delivery of pipeline gas[35]. Furthermore, if Asian LNG prices (which traditionally reflect oil-indexed pricing, e.g., JCC) are eventually priced on a significant scale according to an LNG-specific index (*e.g.*, Japan Korean Marker as published by Platts)[36], LNG purchases could then also provide a valuable opportunity to hedge against oil-indexed pricing under the pipeline gas contracts signed by Chinese companies.

Conclusion

As one of the world's largest gas importers and consumers, there is every reason that the future growth and development of China's gas demand and imports will be of great interest to suppliers, consumers and other participants in the international gas market. On a global scale, the knock-on effects of Chinese gas consumption and importation will be significant not only in terms of providing capital for natural gas projects or offtake of gas quantities, but also the potential effects on gas pricing structures – for instance, it has been suggested that the pricing under Gazprom CNPC deal will set a new floor for LNG prices[37]. However, there remains a number of significant challenges to the long term growth of the natural gas market in China, especially the wide discrepancy between the pricing of gas imports and domestic gas sales to certain user segments (especially residential users). In assessing China's future gas imports, it is also important to bear in mind China's significant potential for increasing domestic gas supply through the development of shale gas and other unconventional gas resources. Nevertheless, taking into account the government's avowed policy to increase natural gas usage, China's projected growth in energy demand and the present challenges facing development of China's unconventional gas resources, both pipeline gas and LNG imports into China have favourable prospects for significant growth in the coming years.

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[1] References to "natural gas" in this article refer to both natural gas in its pipeline form and as LNG.

[2] Chinese media reports, citing a report released in January 2014 (2013年国内外油气行业发展报告) by the CNPC Research Institute of Economics and Technology.

[3] *BP Statistical Review of World Energy June 2014*

[4] China commenced the importation of LNG with the commissioning of the Guangdong terminal in 2006 and the importation of PNG with the commissioning of the Central Asia-China Gas Pipeline in 2009.

[5] *BP Statistical Review of World Energy June 2014*

[6] *IGU World LNG Report – 2014 Edition*, International Gas Union.

[7] Reportedly, under recent price renegotiations, CNOOC will however pay a ceiling price of US$ 8 per MMBtu for Tangguh LNG.

[8] The pipeline transportation tariffs in China are relatively high, and they are set at a cost-plus basis to provide a predetermined internal rate of return which was reportedly around 12% in 2012. *See Gas Pricing and Regulation - China's Challenges and IEA Experience,* IEA, 2012.

[9] This assumes that the average price of Turkmen pipeline gas is US$ 10 per MMBtu and the average price of LNG cargoes is US$ 14 per MMBtu. Taking into account the regasification costs and pipeline transportation tariffs, the delivered cost of Turkmen gas in eastern China should be US$ 13-14 per MMBtu, while the delivered cost of regasified LNG cargoes should be US$ 15 per MMBtu.

[10] One estimates of the price of Russian pipeline gas delivered at Shanghai and Beijing is around US$ 12 -13 per MMBtu. *See* business.financialpost.com/2014/05/23/canada-lng-russia-china-deal/?__lsa=64fe-3737.

[11] The planning paper (天然气发展"十二五"规划) was jointly released by the NDRC and NEA in 2012 and it is intended to set out the

objectives and development plans for natural gas up to 2015.
[12] *Directives on Natural Resources Work in 2014* (2014年能源工作指导意见) released by NEA on 20 January 2014.
[13] 12th Five Year Plan for Development of Natural Resources (能源发展"十二五"规划) released by the State Council on 1 January 2013.
[14] Chinese media report quoting industry experts. *See* jingji.21cbh.com/2014/3-21/2NMDA2NTFfMTEwNDc2Ng.html.
[15] See discussion below in relation to base and incremental volumes.
[16] *See* note 14.
[17] Comments by China Electricity Council's Director Planning, Statistics and Information at a recent conference - www.chinapower.com.cn/newsarticle/1207/new1207955.asp.
[18] www.platts.com/latest-news/natural-gas/hongkong/petrochinas-2013-losses-on-imported-natural-gas-21363390.
[19] Beijing residential users were reported to pay an average of US$ 9.01/MMBtu. *See Gas Pricing and Regulation – China's Challenges and IEA Experience*, IEA, pg 20.
[20] *China Energy Focus Natural Gas 2013*, China Energy Fund Committee, Section 1 – *Natural Gas Consumption in China*.
[21] The topic of developing an Asia LNG trading hub is discussed in an earlier article by the same authors titled "*Prospects for Development of an Asian LNG Trading Hub*". *See* www.energylawexchange.com/prospects-development-asian-lng-trading-hub/.
[22] China's Natural Gas Development Plan.
[23] *See Shale & renewables: a symbiotic relationship*, Citi Research, 12 September 2012.
[24] Shale Gas Development Plan (页岩气发展规划（2011-2015年)).
[25] www.reuters.com/article/2014/08/07/us-china-shale-target-idUSKBN0G70GS20140807.
[26] China's Natural Gas Development Plan notes that the world's average for working storage capacity is 12%, compared to China's then working storage capacity of 1.7% of total consumption.
[27] Trial Regulation for Open and Fair Access to Oil and Gas Pipeline Network Facilities(油气管网设施公平开放监管办法（试行）).
[28] This figure is close to the projected import volume of 150 BCM mentioned in comments from Director of Oil and Natural Gas Strategy of the Ministry of Land and Natural Resources (MLNR) at the LNG China Conference last year.
[29] www.capitalweek.com.cn/2014-01-10/992549111.html.
[30] *Golden Rules for a Golden Age of Gas*, IEA, pg 78.
[31] *See Golden Rules for a Golden Age of Gas,* IEA, pg 119. Under a low unconventional production scenario, Chinese gas imports will be 143 BCM while under favourable conditions for unconventional gas production, natural gas imports will be 77 BCM.
[32] Calculation based on the contracts for supply of pipeline gas from the following sources: Turkmenistan (65 BCM), Russia (38 BCM), Myanmar (10 BCM) and Uzbekistan (10 BCM). Also, it assumes total gas demand in China to be 400 BCM.
[33] More than one third of LNG supply in 2013 was marketed under contract of less than 5 years duration - *IGU World LNG Report – 2014 Edition*, IGU, 2014.
[34] *Natural Gas Price in Asia: What to Expect and What it Means*, Kenneth B. Medlock.
[35] See earlier discussion on the pricing of LNG imports into China.
[36] *See* note 21.
[37] www.bloomberg.com/news/2014-05-27/russia-china-natural-gas-deal-to-set-lng-price-floor-bofa-says.html.

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KING & SPALDING

Energy Newsletter

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TRANSACTIONAL
Transactions
***Obrascon Huarte Lain SA v Her Majesty's Attorney General for Gibraltar*: A rare look at the FIDIC form of contract**
Rory Connor

Introduction

Mr Justice Akenhead's judgment in the case of *Obrascon Huarte Lain SA v Her Majesty's Attorney General for Gibraltar[2014] EWHC 1028 (TCC)* provides judicial guidance on the interpretation of certain key terms in the International Federation of Consulting Engineers' (FIDIC) Yellow Book form of contract. Many experts in the projects community regard the FIDIC Yellow Book, along with the other members of the FIDIC family of contracts, as the leading standard-form construction contract for energy, infrastructure, and other projects the world-over. Judicial decisions relating to FIDIC contracts come along infrequently and, for that reason, this judgement will attract close attention throughout the projects community. The project itself, however, resembled a classic construction project tale-of-woe, commencing with a contract awarded to the lowest priced tenderer whose pre-contract due diligence and aspirational pricing subsequently proved inadequate as the project ran into severe cost-overruns and delays, and ending with a fault-based termination and the works incomplete.

Facts

The judgement ostensibly concerns the operational and technical facts of a project where contractor Obrascon Huarte Lain SA ("OHL") and the Government of Gibraltar ("GoG") entered into a contract for the design and construction of a dual-carriageway and road-tunnel passing underneath the Gibraltar airport runway (the "Contract"). The Contract comprised of FIDIC Yellow Book conditions of contract together with other standard appendices and schedules. These schedules and appendices included an environmental statement prepared by GoG and given to OHL (and other tenderers) during the tender process (the "Environmental Statement"). The project site was located in close proximity to a fuel farm and had a well-known history as a rifle range and centre for other military activities. OHL quickly ran into a number of difficulties but the overwhelming issue causing delay was the discovery of large deposits of contaminated ground during the excavation works. The Environment Statement recommended that OHL should make assumptions for encountering certain quantities of contaminated ground during excavations, but the actual quantities encountered by OHL significantly exceeded those assumptions. As the parties sought to establish the nature and extent of the contaminated ground and agree how to extract, treat and remove the contaminated ground from the site, the works fell further and further into delay. OHL, facing huge losses and exposure to delay damages, pleaded with GoG to redress the 'economic balance of the contract' and ultimately suspended the tunnelling works pending a re-design of the works, which it considered a necessary result of the contaminated ground. In the end GoG reached the conclusion that its differences with OHL were irreconcilable and terminated the Contract on a number of grounds expressly permitted by the Contract, including that GoG's conduct demonstrated "*the intention not to continue performance of his obligations under the Contract*".

Unforeseeable Ground Conditions

Whilst the case involves various fundamental FIDIC concepts, such as the meaning of "Unforeseeable" ground conditions and a contractor's entitlement to extensions of time, this article rather focuses on what Mr Justice Akenhead described as "*the single most important issue in the case*": termination. However, before focussing on the issue of termination it seems remiss not to mention the court's finding with respect to OHL's discovery of large deposits of contaminated ground and whether or not it constituted "Unforeseeable" ground conditions. The FIDIC Yellow Book defines "Unforeseeable" as "*not reasonably foreseeable by an experienced contractor by the date for submission of the Tender*". In the circumstances, Mr Justice Akenhead concluded that the contaminated land encountered by OHL, although significantly exceeding the assumed quantities in the Environmental Statement, did not satisfy the Unforeseeable criteria. At the risk of over-simplification, the court's reason for this conclusion was that OHL had apparently placed blind reliance on the Environmental Statement and made no material independent enquiries into the site conditions, despite actual knowledge that the site's history was chequered with potential sources of contamination. In the circumstances, Mr Justice Akenhead decided that an experienced contractor would not have limited itself to reliance on the geotechnical data provided during the tender process and that doing so was unrealistic. Consequently, at the date of termination OHL was 730 days in delay and the court concluded that it was entitled to only a single day extension of time.

Termination

GoG purported to terminate the Contract on three separate, but related, grounds expressly set out in the conditions of contract. The court considered each ground in detail. The relevant terms were set out in Sub-Clause 15.2 of the conditions of contract, which permitted GoG to terminate the Contract, on giving 14 days' notice to OHL, in the following circumstances:

if the Contractor:

1. fails to comply…with a notice under Sub-Clause 15.1[Notice to Correct] (Sub-Clause 15.1 of the conditions of contract permitted the Engineer to give notice the Contractor requiring the Contractor to make good any failure to carry out an obligation under the Contract within a specified reasonable time);

2. abandons the Works or otherwise plainly demonstrates the intention not to continue performance of his obligations under the Contract;

3. without reasonable excuse fails:

   i. to proceed with the Works in accordance with Clause 8 [Commencement, Delays and Suspension], or

   ii. to comply with a notice issued under Sub-Clause 7.05 [Rejection].

Sub-Clause 15.2(a) – Failure to Correct a Failure to Perform

As a preliminary matter to deciding whether or not OHL had actually failed to comply with the Engineer's 'notice to correct', Mr Justice Akenhead considered, amongst other things, the question of materiality of the original failure to perform. Taking a "*commercially sensible*" approach, he reaffirmed the principles from an existing body of law, including the decision in *Antaios Compania Naviera SA v Salen Rederierna AB [1985]AC 191*, that a clause purporting to allow termination for any breach or failure to perform does not permit termination for minor breaches or insignificant contractual failures. He rejected, however, OHL's argument that Sub-Clause 15.2(a) applied only to serious breaches and those analogous to a repudiatory breach of contract. The judge gave three reasons for rejecting OHL's argument:

1. An analysis must consider each contract and clause on its own merits. If the express wording of a clause clearly permits termination for minor breaches, then the court will recognise the intention of parties.

2. Sub-Clause 15.2(b) was, of itself, similar to the English common law test for repudiation, so the parties could not intend Sub-Clause 15.2(a) to apply to essentially the same circumstances.

3. Sub-Clause 15.2(a) hinges on the cure period granted through the Sub-Clause 15.1 notice to correct. As such "*the Contractor is given a chance to avoid termination*" and the court should not therefore set the bar for termination too highly.

The first of these given reasons is somewhat confusing because, at this point, the judge was not answering a question as to whether the Contract permitted termination for minor breaches but rather whether the Contract limited termination to major breaches Nevertheless, the court's rationale still provides helpful guidance that English courts will recognise a right for a party to a contract to terminate for a minor breach, provided the wording of the contract clearly contemplates such a right. As an aside, whilst the judge noted that Sub-Clause 15.2(b) was, of itself, similar to the English common law test for repudiation, it is worth noting that this common law test may still permit a party to a contract to terminate for a minor breach, provided that the breach relates to a condition of the contract (*i.e.*, a term that *'goes to the root of the contract'*), albeit that in complex projects, such as this, the parties cannot always easily establish individual terms of that nature. In any event, the second and the third reasons endorse the commercially sensible approach of the English courts and provide sound reasoning as to why the court should not construe this Contract as limiting termination to major breaches. The Judge ruled that any cure period must be reasonable based on the circumstances prevailing at the time of giving such notice. He noted that the reasonableness of any such period is fact sensitive, and the onus lies on the party granting it to establish the reasonableness of the period.

On the facts, GoG issued a global 'notice to correct' itemising various alleged failures, including the failure to proceed with excavation works, the failure to proceed with the dewatering of the site with due expedition and without undue delay, and the failure to commence sheet piling, amongst others, each subject to a separate cure period. Whilst Mr Justice Akenhead did not find grounds for termination under Sub-Clause 15.2(a) in respect of all alleged failures, in many cases he decided that the alleged failure existed, continued following the expiry of the respective cure period in the notice to correct, and that the failures were sufficient and serious enough to justify termination under Sub-Clause 15.2(a).

Sub-Clause 15.2(b) – Abandonment of the Works

On the facts, Mr Justice Akenhead did not deem it necessary to determine whether or not OHL had abandoned the works or demonstrated the intention not to continue performance of his obligations under the Contract, having already established grounds for termination under Sub-Clause 15.2(a). He nevertheless set out certain useful principles relevant to the interpretation of this term. In particular, he remarked that:

1. The court must judge the contractor's conduct objectively. If the contractor demonstrates an intention not to continue with the performance of its obligations under the contract then it is irrelevant that it actually intends to fully discharge its contractual obligations.

2. Again, the grounds for termination must relate to significant and more than minor breaches. The contractor demonstrating an intention not to continue with the performance of a minor or immaterial obligation under the contract should not, of itself, allow the employer to terminate the contract.

3. The court must draw a "*verbal and contractual distinction*" between a failure to perform, on the one hand, and a failure to perform contractual obligations, on the other. In other words, the contractor

cannot rely on continued performance as a defence to this ground for termination if such performance was not in respect of the contractor's contractual obligations.

The third of these principles may seem a somewhat obvious point, but in complex projects the distinction between performance, on the one hand, and performance of contractual obligations, on the other, often becomes nuanced and subtle. Mr Justice Akenhead's point being that where a contractor continues to perform work to a specification that does not conform to the contractual specification, then the court should not construe such performance as continued performance of the contractor's contractual obligations. In any event, Mr Justice Akenhead concluded that OHL's suspension of the permanent work, without contractual justification, its apparent unwillingness to recommence the permanent works, and the lack of any indication that it would carry out any further excavation work short of a new commercial deal from GoG, constituted a clear demonstration not to continue with the performance of its obligations under the Contract and therefore grounds for termination under Sub-Clause 15.2(b).

Sub-Clause 15.2(c) – Failure to Proceed with the Works

Given the manner in which OHL had gone about the project Mr Justice Akenhead did not dwell in coming to the conclusion that "*OHL failed, almost from start to finish of this project*" to proceed the works in accordance with the Contract and, therefore, that GoG was entitled to terminate the Contract under Sub-Clause 15.2(c).

Interestingly, Mr Justice Akenhead noted that the fact that an employer may have an entitlement to liquidated damages in the event of delay does not qualify the employer's right to terminate on grounds of the contractor's failure to proceed with due expedition and without undue delay. Without sight of the full Contract it is impossible to know whether or not Mr Justice Akenhead correctly considered the 'exhaustive remedy' status of liquidated damages. Under contracts subject to English law, in the absence of clear contractual wording to the contrary, the courts normally construe a liquidated damages provision as an exhaustive remedy in respect of the breach to which the liquidated damages apply.[1] As such, an English court would not allow an employer to recover liquidated damages and exercise a right to terminate in respect of the same breach (often, a contractor delay). Employers should not assume that they would have a right to terminate on grounds of delay in addition to the recovery of delay damages, unless the contract expressly permits this.

Effectiveness of Termination Notice

One final interesting question of law arose with respect to the validity of GoG's termination notice. Sub-Clause 1.3 of the conditions of contract required GoG to deliver all notices by hand, mail or courier to OHL's head office in Madrid. In fact, GoG delivered a termination notice letter to OHL's site office. An OHL employee accepted the termination notice by recorded delivery and promptly sent it to OHL's head office in Madrid. During the course of the project GoG had frequently sent correspondence to OHL's site office and OHL had acquiesced in this. In the circumstances, OHL claimed that GoG's termination notice was ineffective because it was not delivered to the correct address. OHL regarded GoG's 'ineffective' notice of termination as a repudiatory breach of contract by GoG and purported to accept this repudiatory breach, bringing the Contract to an end.

The question which the court had the answer was, in effect, whether strict compliance with the contractual notice provision constituted a condition precedent to the validity of the notice of termination. Relying on the judgment in *Rennie v Westbury Homes (Holdings) Limited [2007] EWCA Civ 1401*, Mr Justice Akenhead noted that, in certain cases, the court may construe a strict notice requirement as an "*indispensable condition*". The court's description of an indispensable condition appears conceptually very similar to a condition precedent, the distinction appears to relate to the nature of the underlying condition. For example, whilst a condition precedent may concern a substantive requirement (such as the actual giving of a notice), an indispensable condition appears to concern purely matters of procedural compliance, such as the delivery of a notice to the correct address. Either case will depend on the facts, and a number of recent English cases have confirmed that a requirement to give notice prior to exercising a particular contractual entitlement shall not constitute a condition precedent to such entitlement, unless clearly framed as such. The facts of this case meant that the court did not consider whether the requirement to provide a contractual notice within a given time frame constituted a condition precedent or indispensable condition.

According to Mr Justice Akenhead, whether each and every specific requirement of a notice provision constitutes an indispensable condition is a matter of contractual interpretation, which interpretation should utilise commercial common sense. It follows that the court would not need to consider the status of such a clause if a contract expressly set out the consequences of non-compliance with the relevant notice clause. On the facts, Mr Justice Akenhead concluded that the contractual notice provisions did not use any words which made the giving of notice to the correct address a pre-condition to effective termination and that the delivered notice achieved its "*primary purpose*" of making OHL aware that GoG was bringing to an end OHL's continued employment on the project. As such, he did not construe the requirement to serve notices at OHL's Madrid office as an indispensable condition and concluded that GoG had given effective notice of termination.

Conclusion

In many respects, this case does not really break any new ground. The FIDIC conditions of contract were balanced and certain. The principles relating to foreseeability, termination for breach, and notice requirements and, more generally, contractual interpretation each draw upon an established body of law. Sadly, OHL apparently failed to appreciate the conditions of contract and apparently often sought to perform the works as it saw fit, looking for solace in the black letter of the contract when things were going wrong. The English court, however, was prepared to take a commercially sensible approach to contract interpretation and look past technical breaches of contract where the obligor of the relevant term had discharged the relevant obligation in accordance with its *primary purpose*. GoG could have used much more employer-friendly conditions of contract, which the court would have upheld provided they were drafted with certainty. Had GoG used contract terms with a greater employer-bias, then conceivably OHL could have ended up in an even worse situation. Perhaps there is a salutary lesson in that.

[1] *See*, for example, *Temloc Ltd v Errill Properties Ltd (1987) 39 BLR 30*.

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KING & SPALDING

Energy Newsletter

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REGULATORY
FERC

D.C. Circuit Upholds FERC's Order No. 1000

Neil L. Levy, David G. Tewksbury, Ashley C. Parrish, Stephanie S. Lim

On August 15, 2014, the D.C. Circuit issued a per curiam decision rejecting challenges to the Federal Energy Regulatory Commission's Order No. 1000 rulemaking brought by certain petitioners, including state regulatory authorities, public utilities, regional transmission organizations and trade associations. Order No. 1000 requires public utility transmission providers to participate in a regional transmission planning process and establishes certain requirements for transmission cost allocation.

The Court rejected petitioners' arguments that Order No. 1000 exceeded the scope of FERC's authority under the Federal Power Act. Petitioners contended that FERC lacks authority to require mandatory transmission planning because Section 202(a) of the Federal Power Act refers to the "voluntary interconnection and coordination of facilities." The Court found no merit to that argument, agreeing with FERC that Section 202(a) addresses only the operation of existing transmission facilities and does not to extend to the planning of future facilities. Petitioners also claimed that Order No. 1000 interferes with the States' regulation of transmission planning, siting, and construction, but the Court rejected that argument as well. Pointing out that Section 201(b) of the Federal Power Act does not limit FERC's jurisdiction over retail transmission, the Court found that FERC has broad authority over transmission and reasonably exercised its authority to regulate transmission planning.

The Court also rejected several other challenges to Order No. 1000, including arguments that FERC had improperly required transmission providers to remove provisions from their tariffs giving incumbent utilities preferential rights of first refusal with respect to the construction of any new transmission facilities in their service areas. The Court held that FERC has authority to regulate because right-of-first-refusal provisions directly affect transmission rates, and it concluded that FERC had reasonably found that rights of first refusal are unduly discriminatory and stifle the development of transmission facilities.

FERC Chair Cheryl LaFleur welcomed the decision, emphasizing the need for "substantial investment in transmission infrastructure to adapt to changes in [the] resource mix and environmental policies," and describing Order No. 1000 as "critical to [FERC]'s efforts to support efficient, competitive, and cost-effective transmission."

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Energy Newsletter

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REGULATORY
International Trade
U.S., EU Impose Sector-Specific Sanctions Against Russia
Christine Savage, Iain MacVay, Mark Wasden, Jane Cohen, Sajid Ahmed, Shannon Doyle Barna, Clint Long

Recently the United States and the EU imposed additional targeted sanctions against Russia in response to the ongoing conflict in Ukraine. Although previous sanctions issued by the U.S. and EU since March 2014 affect various sectors of the Russian economy, including Russia's military industrial complex, the most recent sanctions target Russia's financial and energy sectors.

U.S. Sanctions

Since March 2014, the United States has imposed visa bans on certain government officials and blocked property and interests in property of certain persons and entities that are stated to contribute to the situation in Ukraine. The most recent sanctions imposed restrictions on exports and re-exports of oil- and gas-related items for deepwater, Arctic offshore, or shale projects in Russia. These sanctions have been imposed primarily by the U.S. Treasury Department's Office of Foreign Assets Control ("OFAC") and the U.S. Commerce Department's Bureau of Industry and Security ("BIS").

OFAC Sanctions

Parties whose property and interests in property are blocked are identified on OFAC's Specially Designated Nationals ("SDN") List and U.S. persons are generally prohibited from engaging in transactions with parties listed on the SDN List and with entities owned directly or indirectly (50 percent or more including in the aggregate) by parties listed on the SDN List. Sanctioned persons connected to the energy industry include Igor Sechin (President of Rosneft) and Gennady Timchenko (owner of the Volga Group). Sanctioned entities involved in Russia's energy industry include the Volga Group (a financier for Russia's energy sector), Stroytransgaz (a company controlled by the Volga Group that engineers and constructs pipelines and energy facilities), Transoil (involved in oil transport by rail), and United Shipbuilding Corporation (involved in shipbuilding for the energy industry).

On July 16, 2014, OFAC issued sectoral sanctions against Russia's financial and energy sectors. These sectoral sanctions prohibit U.S. persons (and persons in the United States) from entering into transactions with entities determined by OFAC to be operating in Russia's financial sector that involve debt with maturity of longer than 90 days or equity if that debt or equity is issued on or after July 16, 2014. For entities determined by OFAC to be operating in Russia's energy sector, the same prohibition applies to transactions involving debt (but not equity) with maturity of longer than 90 days if issued on or after July 16, 2014.

Parties subject to sectoral sanctions are identified on OFAC's Sectoral Sanctions Identifications List (the "SSI List"). Persons 50 percent or more owned by parties on the SSI List are also subject to OFAC's sectoral sanctions. Importantly, parties on the SSI List are not subject to a blocking order and are not listed on OFAC's SDN List. Thus far, OFAC has determined that Rosneft and Novatek operate in Russia's energy sector and has placed them on the SSI List. Additionally, Gazprombank, one of the five financial services entities on the SSI List, has significant ties to Russia's energy industry through its largest shareholder, Gazprom.

BIS Sanctions

Effective on August 6, 2014, BIS imposed a licensing requirement on exports, re-exports, and in-country transfers involving specific items when used directly or indirectly in exploration for, or production of, oil or gas in Russian deepwater (greater than 500 feet) or Arctic offshore locations or shale formations in Russia. Items subject to this licensing requirement include drilling rigs, parts for horizontal drilling, drilling and completion equipment, subsea processing equipment, Arctic-capable marine equipment, wireline and down hole motors and equipment, drill pipe and casing, software for hydraulic fracturing, high pressure pumps, seismic acquisition equipment, remotely operated vehicles, compressors, expanders, valves, and risers. BIS will review license applications involving covered items with a presumption of denial. No license exceptions are available except certain provisions of license exception "GOV."

Importantly, BIS implemented these new sanctions in addition to restrictions already in place for transactions involving "high technology" items. BIS' current policy is to reject license applications that involve "high technology" exports to Russia or Crimea that may "contribute to Russia's military capabilities."

EU Sanctions

The EU's most recent sanctions became effective on August 1, 2014, and include the following:

- an arms embargo against Russia (excluding contracts concluded before August 1, 2014);
- financial sanctions on dealing in bonds, equity, or similar financial instruments with a maturity exceeding 90 days, issued after August 1, 2014, when transactions involve certain Russian financial sector entities; and
- sanctions on transactions involving certain "dual-use goods and technology" for military use or military end-users in Russia, excluding contracts concluded before August 1, 2014.

Directly related to Russia's energy sector, and similar to BIS' export controls, the EU also imposed sanctions on transactions involving specific energy-related items (*e.g.*, line pipe, drill pipe, tubing, rock-drilling tools, and other types of oil and gas-related equipment) if they are for use in Russia, including those suited for use in deepwater oil exploration and production, Arctic oil exploration and production, or shale oil projects in Russia. The EU sanctions include transfer of technology and technical support provided to Russia. As EU nationals are caught by these sanctions, officers of companies other than those based in the EU can be affected by the EU sanctions. Licenses, however, may be granted to execute an obligation arising from a contract concluded before August 1, 2014.

Russia's Response

To date, Russia's response to the U.S. and EU sanctions has been unrelated to energy. On August 6, 2014, Russia announced a one-year import ban on a vast range of food products originating in the United States, EU member countries, and other countries that recently imposed sanctions on Russia. According to news reports, Russia is also considering imposing import restrictions on these countries' shipbuilding, automotive, and aircraft industries, as well as adopting measures to prevent European airlines from flying over Siberia when traveling to and from Asia. It has been reported that the EU is already considering filing a request for consultation with the WTO.

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Oil & Gas Litigation

Texas Railroad Commission Proposes New Rules Related to Pipeline Eminent Domain Claims

Brannon Robertson

The November 2011 issue of the *Energy Newsletter* addressed the case of *Texas Rice Land Partners, Ltd. v. Denbury Green Pipeline-Texas, LLC*, in an article titled *Texas Supreme Court Ruling May Slow the Installation of Certain Pipelines*. As explained in that article, the *Denbury* Court set out the criteria that a private pipeline company must meet in order to be afforded "common carrier" status. A common carrier designation is critical because, if it is established, the pipeline operator is essentially granted the power of eminent domain to route its pipeline across private property. In reaction to *Denbury*, the Texas Railroad Commission (which has regulatory oversight of the oil & gas industry in Texas) has recently proposed rule changes related to common carrier permit requests. While the proposed rule has drawn attention and criticism from both sides of the debate (pipeline operators who say that it goes too far and landowners who say it does not go far enough), the proposed rule is fairly modest in scope. Importantly, the proposed rule does not appear to challenge the essential point of *Denbury*: common carrier status, if challenged by a landowner, is ultimately an issue for the courts and not the Railroad Commission.

In *Denbury*, the defendant owned a naturally occurring CO_2 reserve and sought to build a pipeline to transport the CO_2 to various Texas production fields. Denbury applied to the Railroad Commission for permission to operate the line. Denbury completed the Commission's standard one-page permit application—known as a Form T-4—and indicated that the pipeline would be operated as a common line, by checking a box on the form. Shortly thereafter, the Commission granted the T-4 permit and classified the proposed line as a common carrier pipeline, thereby conferring eminent domain powers on Denbury. Denbury began surveying the line, including on land owned by Texas Rice Land Partners, which refused Denbury permission onto its land and sought an injunction barring Denbury from entering its property. The matter eventually came to the Texas Supreme Court.

The Supreme Court recognized that private pipeline companies have the power of eminent domain in Texas where the pipeline is available for "public use", meaning others besides the pipeline owner will be entitled to use the line for transportation. But the *Denbury* court held that the mere granting of a common carrier permit by the Railroad Commission does not conclusively establish that the line meets the public use requirement. Rather, to qualify as a common carrier, the Court held that a "reasonable probability must exist, at or before the time common-carrier status is challenged, that the pipeline will serve the public by transporting [CO_2] for customers who will either retain ownership of their [CO_2] or sell it to parties other than the carrier." The burden of proof falls on the pipeline company to make this showing, in court, if challenged by the landowner.

In response to the decision, the Railroad Commission has proposed expanding the "check the box" nature of its T-4 application. The new rule, if adopted, will require the applicant to provide a sworn statement providing "the factual basis supporting the classification and purpose being sought for the pipeline" along with documentation supporting a claim that the line will function as a common carrier line. After that, the Commission would have 15 days to advise whether it considered the application complete. It would then have an additional 30 days to issue or deny the permit.

While imposing something of a burden on pipeline applicants, the proposal is fairly modest in scope. It does not provide for any type of hearing on the permit, nor even the right of opponents to file contesting evidence on a common carrier claim. Further, and probably most importantly, the change to this administrative rule will not (and does not purport to) change the fact that the Railroad Commission's permitting process is not determinative of the issue of whether the operator is, in fact, a common carrier entitled to exercise eminent domain. That decision will remain with the courts. Nonetheless, the fact that the applicant will have to offer some evidence in support of the claimed common carrier status at the permitting stage, should provide a landowner with more information by which to determine whether to challenge the status in court.

Public commentary on the proposed rule closed in August. The proposed rule and comments can be viewed on the Railroad Commission's website (www.rrc.state.tx.us/legal/rules/proposed-rules).

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