EUROPEAN UNIVERSITY AT ST. PETERSBURG

ENERPO Journal

November 2013
Volume 2
Issue 2

The *ENERPO Journal* was established in 2013 and is a publication put out by the Energy Politics in Eurasia (ENERPO) program at European University at St. Petersburg. The goal of *ENERPO Journal* is to bring exposure to the ENERPO program and shed light on the latest developments in the oil, gas, and renewables industries in a way befitting both expert and casual readership. Contributing authors are primarily students and faculty with the occasional outside expert writer.

Workshop Series is a program hosted by European University in which leading energy professionals are invited to present on a specific aspect of their work. These professionals include energy think-tank experts, policy makers, representatives from major energy companies, and ranking members of international organizations. *Workshop Review* is a subsection of *ENERPO Journal* where students relay the content of these presentations and provide commentary.

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TAP—An Economically Motivated Decision

—*Max Hoyt*

On September 19th, representatives of the Shah Deniz consortium met with European buyers in the Azerbaijani capital, Baku, to sign long-term contracts for Azerbaijani natural gas. The gas purchase agreements, each signed for 25 years, mark the finalization of the Shah Deniz Consortium's June 28th decision to support the Trans-Adriatic Pipeline (TAP) instead of the rival Nabucco-West pipeline. The agreements stipulated for the total sale of 10 bcm/a to nine companies in Italy, Greece, and Bulgaria. Of this 10 bcm/a, 8 bcm/a will supply Italy and adjacent market hubs while the remaining 2 bcm/a will be split between buyers in Bulgaria and Greece with each receiving a volume of 1 bcm/a. This was a historic decision for Azerbaijan, simultaneously securing decades of hydrocarbon revenues for the small Caucasian nation and finally putting an end to the decade-long debate over proposed European market destinations for the Shah Deniz field's estimated 1.2 trillion cubic meters of gas. Although the president of the EU Commission has declared the consortium's decision a shared success for Europe and a milestone in strengthening the energy security of the union, this deal was made with only marginal consideration given to European energy security and Southern Corridor goals. TAP or Nabucco, the deal to construct a Caspian supplied pipeline was inked based on textbook economic incentives. In the end, TAP was a better and necessary business decision for Azerbaijan and its partners who needed to secure demand, i.e. guarantees of future profits, to continue to finance both Azerbaijan's domestic growth and its southern corridor energy projects.

Azerbaijani Projects and Finances

This deal was inked at a critical financial moment for Azerbaijan. Since 2010, production has been waning from Azerbaijan's flagship oil field, Azeri-Chirag-Gunashli (ACG), with no rejuvenation in sight. This forecast spells trouble for the small republic as the total government revenue is 65% dependent on sales from its gas and oil industries. In 2006, Azerbaijan's real GDP grew by an astounding 34.5% thanks to the fortuitous timing of the Baku-Tbilisi-Ceyhan pipeline's (BTC) commissioning and record high oil prices leading up to the 2008/2009 financial crisis. Since the crisis, however, the country has boasted modest real GDP growths of 5% in 2010 and .1% in 2011. At the same time, the State Oil Fund of Azerbaijan (SOFAZ), an organization set up in 1999 to collect and manage Azerbaijan's oil revenues, has redoubled (actually by 18 times) its yearly spending from $686 million in 2007 to $11.64 billion in 2011. The fund's assets are spent on construction projects such as the BTC pipeline, Baku-Tbilisi-Kars railway, canal and waterway projects, and youth training abroad programs. From only 2010-2012, SOFAZ transferred $31.6 billion to the government, an amount almost equal to the January 1st 2013 announced total assets of $34.129 billion. A leading Baku-based think tank, the Center of Social and Economic Development, predicts that these kinds of expenditures are unsustainable and, if unchecked, the fund will be dry by 2017, considering the decreasing figures of oil production.

The continuation of the Shah Deniz project is essential for the State Oil Company of Azerbaijan's (SOCAR) long-term survival.

Furthermore, the Shah Deniz Consortium, a BP operated joint venture between Statoil, SOCAR, LUKAGIP, TOTAL, NIOC, TRAO, and BP tasked with developing the Shah Deniz gas field, is slated to make its final investment decisions on the development of phase 2 of the Shah Deniz field late this year.

This is an estimated $25 billion investment deal, and the commitment of SOCAR's foreign partners will most certainly be ameliorated by the presence of European buyers waiting in the wings. The continuation of the Shah Deniz project is essential for the State Oil Company of Azerbaijan's (SOCAR) long-term survival. SOCAR, by way of which SOFAZ and the government itself collects a large portion of their revenues, produces less than 20% per annum of the oil pumped from Azerbaijani fields. In 2012 this was 8.4 million tons of oil out of the 45.6 million tons produced in Azerbaijan as a whole. The rest of the production is conducted by foreign companies, the leading of which are BP and Statoil, via Production Sharing Agreements (PSA). Thus SOCAR, and therefore the federal budget, is heavily reliant on foreign assistance, the gestalt of which is apparent if one simply glances at the long list of international companies working on the various fields in the vicinity of Azerbaijan's eastern Absheron peninsula.

Route of Azerbaijani gas. Map from TAP's official website: https://www.trans-adriatic-pipeline.com/

Nabucco was a champion of Europe's energy security platform while TAP, a privately funded endeavor, was planned with an investor's pocketbook in mind.

Pipelines - Strictly Business

While the long-term profits guaranteed to Azerbaijan by a secured destination market for Shah Deniz gas will definitely help to improve Azerbaijan's current and future finances, this eventual selection of an exit-route for Shah Deniz gas was an imperative. The final decision of which route, however, was the subject of much debate and became a highly politicized matter. The pipeline politics surrounding Nabucco-West, TAP's rival, is, in itself, a very complicated subject and outside the scope of this article; it is, however, sufficient to say that Nabucco, in all of its different incarnations, was a champion of Europe's energy security platform while TAP, a privately funded endeavor, was planned with an investor's pocketbook in mind. That being said, the Shah Deniz Consortium's commitment to TAP was economically motivated, falling directly into an economic framework to minimize costs while maximizing long-term profits.

TAP, a pipeline that will stretch 870 km from Turkey, through Greece and Albania, under the Adriatic, and into Italy, carries a 4.4 billion euro price tag; the competing pipeline, Nabucco-West, planned to travel 1300 km from Turkey to the Austrian gas hub at Baumgarten would have run investors 6.6 billion euros. Furthermore, TAP's transit tariff was agreed on at 3 euros/100km, 50 cents less than Nabucco's tariff. Thus, TAP will cost less to build, take less time to do so, and grant sellers a higher netback from gas sold than Nabucco would have. Finally, TAP's initial capacity demands will be completely sustainable by Azerbaijan's own production while Nabucco's planned capacity fluctuated between 10 – 30 bcm. The fulfillment of this top-end capacity would have forced the pipeline consortium to sign on additional supplies, a further complicating factor.

Netbacks and construction costs are not the only advantages that the Shah Deniz Consortium were looking at when they announced TAP's confirmed selection at a Baku press conference on June 28th this summer (This final decision came with little surprise as the Consortium had, in fact, selected TAP as the priority route over a year earlier on February 21st 2012.) To make the deal even sweeter, SOCAR had just acquired a commanding 66% share in DESFA, the Greek natural gas grid operator, 10 days earlier on June 18th. With acquisition of DESFA, SOCAR, 20% shareholder in TAP, has direct access to native Greek markets whose demand is projected to grow to 5.6 bcm by 2019, the same year that Shah Deniz gas is set to flow to Europe. Finally the destination markets of TAP and the multiplicity of its buyers allows for secure market niches for Shah Deniz Gas. In Bulgaria the 1 bcm will build upon the 2.9 bcm imported annually from Gazprom, which currently makes up 100% of Bulgaria's natural gas imports; in Greece the 1 bcm will account for 26% of the Greek gas market (based on 2010 Net imports); and in Italy, one of Europe's biggest markets, 8 bcm will comprise 11.6% of the overall annual 69 bcm imported. Thus, with the arguable exception of in Italy, Azerbaijani gas will not meet large volume-for-volume competition vis-à-vis Gazprom, which exported 17.08 bcm of its 150 bcm Europe-bound exports to Italy in 2011 and is Italy's 2nd biggest energy supplier. However, the multiplicity of buyers, 9 in total, of which 7 represent Italian interests, will provide the consortium with diverse, yet resilient, market shares that are predicted to neither compete with nor undercut Gazprom's volumes pricewise.

Last but not least, the decision to build and supply TAP opens room for further discussion of building both an additional West Balkan reaching extension as well as the gasification of Albania. The extension of TAP into the Balkans and particularly the corresponding gasification of Albania is a venture that SOCAR would stand to capitalize on. Albania, currently not gasified, is predicted to have a market for 1 to 2 bcm, a market that SOCAR would have direct downstream access to as the owner of neighboring Greece's DESFA.

TAP's claim to provide long-term energy security to the Western Balkans via the Ionian Adriatic Pipeline (IAP) is at best lip-service to European Energy Security.

Supply Diversification and European Energy Security

As for the matter of European Energy Security that is advertised in TAP's official material (TAP purports to be a solution to Western Balkan and Bulgarian energy security), only Bulgaria will truly benefit from this diversification of supply in the short to medium-term. As stated above, Bulgaria currently imports solely from Gazprom and was highly affected during the 2009 Ukraine-Russia gas disputes. Bulgaria has expressed its desire to diversify its energy sector in light of this dispute, first building a natural gas interconnector to Romania and now by securing 1 bcm from Azerbaijan. According to Bulgaria's Energy Strategy until 2020, its natural gas consumption is only predicted to grow marginally from 2.8 Mtoe in 2010 to 3 Mtoe in 2020. Based on these figures, Azerbaijani gas will likely displace Gazprom imports, thereby meeting Bulgaria's goal of a more diverse network of suppliers. TAP's claim to provide long-term energy security to the Western Balkans via the Ionian Adriatic Pipeline (IAP) is at best lip-service to European Energy Security. The IAP is still in the proposal stage of development and, even if its construction were decided upon immediately, it would have to wait until the additional bcms of production came online sometime in the 2020s. Thus, only 1 bcm of the 10 to be transported through the new Southern Corridor actually alters the current security of supply situation, a fact which severely mitigates any claims that Shah Deniz prioritized European Energy Security over economic incentives when choosing TAP.

The deal inked between Shah Deniz partners and European buyers is estimated to be worth $200 billion

Profitable Externalities

The deal inked between Shah Deniz partners and European buyers is estimated to be worth $200 billion and is just one in many agreements either already signed or currently on the table for Azerbaijan. The Southern Caucasian Pipeline, also known as Baku-Tibilisi-Erzurum, which currently carries natural gas from Baku to the Turkish gas hub, must be expanded from the current capacity of 20 bcm to accommodate the growth in supplies from Shah Deniz phase 2. Then, the TANAP pipeline that will run 2000km across Turkey from Erzurum to a planned connection point with TAP will be a future jumping off point for SOCAR-led expansion. SOCAR, which owns a 51% share in TANAP, will sell 6 bcm from Shah Deniz to Turkey via TANAP starting in 2018. Furthermore, there are plans to expand TANAP's initial 16 bcm capacity to 31 bcm by 2026 to meet expanded Turkish and European needs (TAP is planned to be expanded correspondingly) and there has even been discussion between Azerbaijan and Turkey that TANAP will eventually be expanded to 60 bcm to include Turkmen and Israeli gas and maybe even gas from Iran and Iraq (while it is beyond the scope of this article to address these predictions, the author considered such statements beneficial for assessing the impact of TANAP).

Conclusion

On all fronts, Azerbaijan looks to profit on its involvement in the Southern Gas Corridor. Yes, there are small short-term (as well as potential for long-term) EU energy security victories that accompany the commitment for TAP. However, the by-volume contributions that Azerbaijan's 10 bcm will be making to European total imports—about 403 bcm by pipeline and LNG in 2012—is minuscule in terms of overall energy diversification. If one looks at the aggregate of Azerbaijan's decisions—several pipelines with SOCAR's name on them, a gas distributor in Greece, and a list of wealthy investors in and buyers for Azerbaijani gas—it quickly becomes clear that this decision was done in the name of business. ◆

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What Lies Beneath: Development of Russian Tight Oil to Offset Production Decline

—Stephanie Bryant

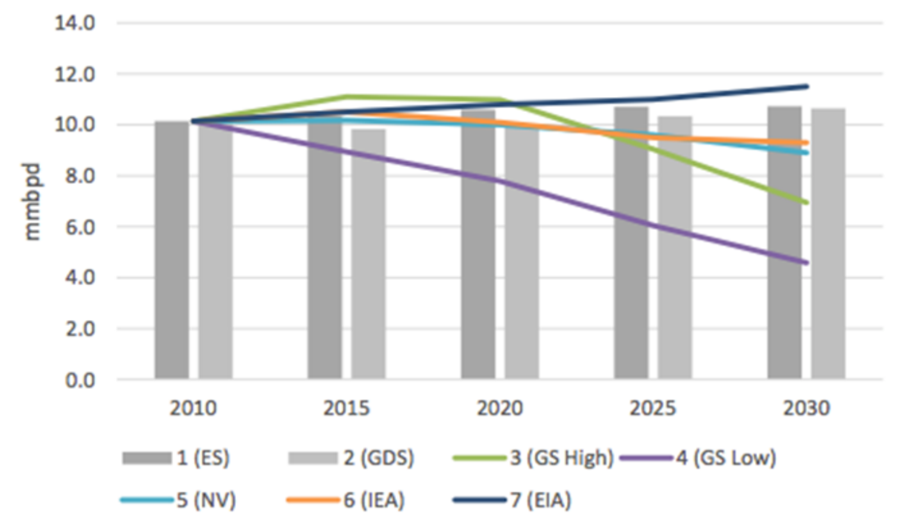
The Western Siberian Basin is the epicenter of Russian crude oil production, but more importantly, it is slated to be the setting of Russia's very own shale oil and gas revolution. The Bazhenov formation is eighty times the size of the Bakken field and contains 75 billion barrels of tight oil, making it the largest tight oil reserve in the world. With production of conventional crude oil set to begin a steady decline by 2030, the Russian government is pushing to be able to fill the predicted deficit before it occurs. Using reductions in the Mineral Extraction Tax to create an environment more suitable to investment, as well as partnering with American companies that have the technological equipment and expertise gained during their own "shale revolution," the Russian oil industry is expected by the government to boost tight oil production from the currently marginal production to 1 million barrels per day by 2025. This benchmark is feasible, but its successful attainment depends on a favorable tax scheme and the implementation of other "above ground" factors such as advanced technological capabilities, a sufficient number of high-horsepower rigs, and the ability of large corporations to adapt to an industry that requires flexibility.

In Anticipation of an Oil Production Decline

Curently ahead of Saudi Arabia and the United States, Russia is the world's top oil producer, but experts say this level is unsustainable without new exploration and investment. Russia is producing primarily from declining fields, and the country's current production level is unsustainable without new exploration and investment. Energy outlooks predict a severe decline by 2012, citing a lack of investment into new reservoirs. 60% of total Russian oil production comes from the Cretaceous sandstone of the Western Siberian basin, whose fields already peaked in the late 1980's.

The General Scheme of Oil Industry Development produced the lowest forecast, predicting a 55% decline from the 2010 rate of 10.2 mmbpd to the estimated 2030 rate of 4.6 mmbpd. The average anticipated decline is 30% over the next 20 years.

Since approximately 40% of the state's revenue comprises taxes and export duties levied on the energy industry, production declines will have serious consequences for an already-strained federal budget. The HSBC estimates that if this downward trend is not corrected, the Russian state will experience an initial loss of $2.1 billion as soon as 2021. Although East Siberian, Caspian Sea, and Arctic green fields present a post-2030 solution, oil fields that contain tight oil reserves have already been developed for crude oil production and are, therefore, less costly to develop than unexplored green fields. Since tight oil may be a more economically reasonable avenue to combat

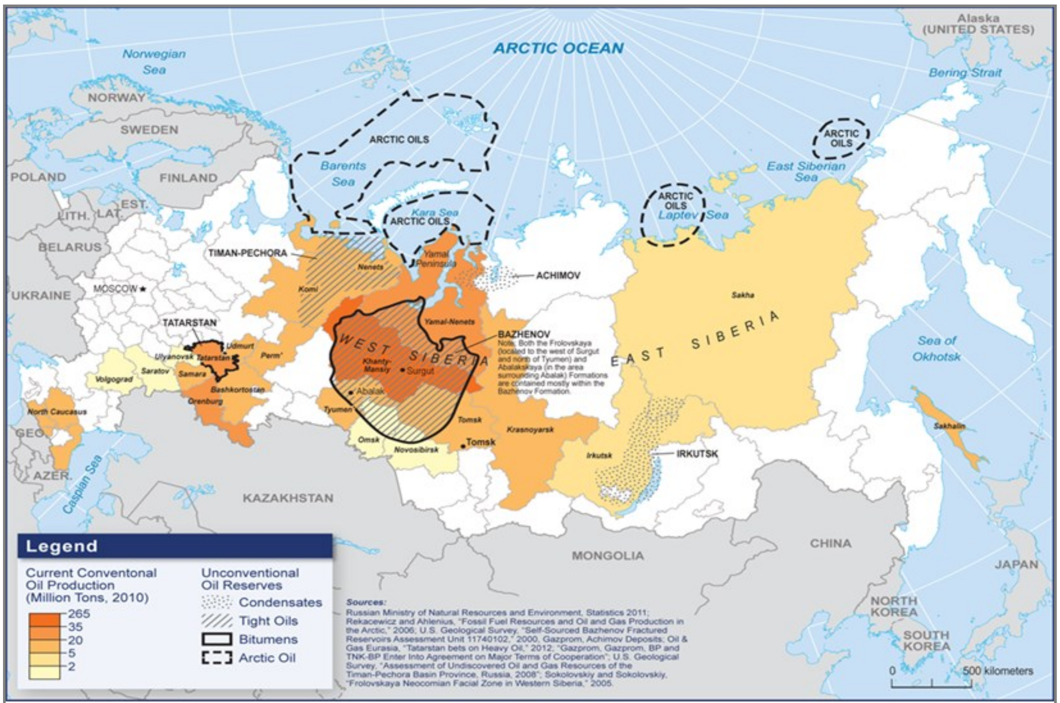


Future Russian Oil Output. Graph from "Tight Oil Developments in Russia" by James Henderson.

production decline, the Russian government hopes to increase its share in total oil production to 10% by 2025.

The Tight Oil Reserve Solution: Bazhenov

Taking the aforementioned production outlooks into consideration, the government has encouraged investment into unconventional and tight oil reservoirs, the majority of which are found 2700-3100 metres below the surface of the Western Siberian basin in the Upper Jurassic Bazhenov shale. The EIA estimates that these strata of the Bazhenov formation contain the largest amount of technically recoverable shale oil reserves in the world, numbering close to 75 billion barrels. Covering a span of 2.2 million square kilometers, the Bazhenov formation is eighty times larger than the Bakken formation in the northern United States.



Map of Russia's Oil Reserves by Type. Source: Russian Ministry of Natural Resources and Environment

The EIA estimates that these strata of the Bazhenov formation contain the largest amount of technically recoverable shale oil reserves in the world.

The primary difficulty in development lies in the rock heterogeneity, as is generally the case with shale reserves. Wells that are mere kilometers apart provide different information concerning flow rates, reservoir formations and decline curves. This is discouraging for companies that need to how many horizontal wells to construct and where to place them, adding to the financial disincentive of tight oil development. However, the geological similarity of Bazhenov and Bakken has led Russian industry leaders to look to American companies for technological and financial assistance with pilot projects and development.

ExxonMobil-ization of Technology for Rosneft's Tight Oil Licenses

Current tight oil producers in the Bazhenov are Surgutneftegaz, Lukoil and Rosneft. In order to meet the strategic goal of 10% of total oil production (1 mmbpd), production will have to increase exponentially. Rosneft stated that it believes it will be producing 300,000 bpd by 2020 and both Gazprom and TNK-BP (before its acquisition by Rosneft) each predicted production levels of 50,000 bpd.

Although the Energy Ministry believes these companies' estimations are feasible, present production is only a small fraction of that. This low output is primarily due to the fact that producers are still familiarizing themselves with the geology and experimenting with the necessary technology in order to achieve the most economical production formula. Mass production is still not profitable. Large companies are hoping that Western seismic surveillance and hydraulic fracturing techniques will increase the future profitability of their unexplored licenses.

To this end, Rosneft and ExxonMobil officially formed a joint venture to undertake a pilot project on December 7, 2012, that was scheduled to begin in 2013 and will hypothetically end in 2015. Combining ExxonMobil's technology and $300 million of investment with Rosneft's experience with the geography and conventional crude production in the region, the results of this project will address overarching concerns about the nascent tight oil industry such as the heterogeneity of the rock formation, the profitability under the recently restructured energy taxes, and the amount of technology and geological expertise required to economically exploit these reservoirs. Or as Rex Tillerson, the CEO of ExxonMobil, so succinctly phrased it, "the real issue is can we develop it in a cost effective way? –same as the issue we have with tight and unconventional resources in North America." The project will occur over Rosneft's 23 licensed blocks covering an area of 10,000 square kilometers.

Although the State Duma passed a bill in July of this year that would reduce the Mineral Extraction Tax, it still may not allow enough revenue to entice the rapid investment required.

Tax Reform

Pushing to encourage corporate investment into development of new tight oil fields as early as 2011, the Russian government began amending its tax structure in order to encourage oil companies to invest in "hard to recover" resource development. Although the State Duma passed a bill in July of this year that would reduce the Mineral Extraction Tax using a coefficient based on reservoir porosity and permeability, it still may not allow enough revenue to entice the rapid investment required. According to this tax scheme, if a Bazhenov well is commercially viable, it will have a coefficient of zero and taxation will not occur for the first five years of well life, but this zero coefficient will not hold true for all tight oil plays. As James Henderson notes in his most recent treatise on the Russian tight oil industry, if the oil price is held constant at $100 per barrel, the current tax structure would actually produce a -5% economic rate of return and would require an export price of $200 a barrel to achieve a hurdle rate, or minimum internal rate of return, of 15%.

The tax amendment still does not account for more than a 20% dry hole percentage, or the percentage of wells that will not produce, or for non-commercial wells, both of which are fairly likely given the heterogeneity of the geological formation. 3D seismic surveys reduce but cannot eliminate the risk of developing dry holes by providing imagery of the field. Given Surgutneftegas' 35% dry hole percentage in its exploration and production of tight oil, this tax amendment will need further reductions to increase the financial incentive to develop. Nor does the MET reduction take into consideration the varying output of wells, which is "the same problem being faced by the Russian industry as a whole." Henderson further points out that even if a $9 million well is commercially viable and produces around 350 barrels per day, the economic rate of return will be significantly less than the hurdle rate. Given the recent slowing of economic growth and how reliant the state budget is, and will be, on revenue from the energy industry, it is unlikely that further tax reductions will be discussed until the results of the Rosneft/ExxonMobil pilot project in 2015 are analyzed.

Necessary "Above Ground" Factors

Beyond the necessary tax reforms, economic tight oil development faces a series of "above ground" demands before it will be an eligible contender to offset the decline in total oil production. Firstly, the number of rigs required to achieve and maintain a 1 mmbpd level of production is approximately 220. Those rigs would solely be dedicated to the development of new tight oil reserves in the Western Siberian Basin. Only 17% of the current rig count would be powerful enough to drill a horizontal well (1500 hp or higher), and those rigs are currently occupied with wells dug in 2012. Basically, an entirely new fleet will be needed just to focus on Western Siberian tight oil development. Rigs will be a $9 billion demand that American, Chinese, and Russian companies are already vying to fill.

Large companies have the resources to create strong logistical frameworks, but "all those things become weaknesses when you work with shale plays…and adaptive planning is what the smaller companies are good at," writes Ed Crooks.

Another factor seen as critical to American success with shale oil and gas is the notable absence of large companies. With the departure of Shell from its Eagle Ford lease at the end of September, ExxonMobil is now the last major company in the American "unconventional game." Instead, 89 small to medium operators were responsible for the "shale revolution." In contrast, the Russian tight oil industry is dominated by large Russian companies who have joint venture agreements with large Western companies. According to Ed Crooks at the Financial Times, large companies have the resources to create strong logistical frameworks, but "all those things become weaknesses when you work with shale plays…and adaptive planning is what the smaller companies are good at." Small companies may not stand much of a chance in the Russian tight oil industry, as both tax schemes and licensing procedures favor the monoliths.

Confidence in Tight Oil Development

Although all signs point to the uneven development of a potentially financially unsustainable industry, companies have remained active in their exploration efforts. RusPetro continued ahead into a partnership agreement with Schlumberger at the end of September to produce horizontal, multi-stage fractured wells on its 1200 square kilometer Bazhenov lease. Schlumberger likewise released a report maintaining that while any reserve development is costly, light tight oil reservoirs can be developed at a slower rate and are therefore lower risk. Further adjustments will need to be made after the results of the Rosneft-ExxonMobil pilot project are published in 2015, but most analysts remain cautiously hopeful. Among these is Oleg Mikhailov, an ex-pilot director at TNK-BP and current VP of oil and gas development at Bashneft who thinks the steep learning curve will ultimately be beneficial to Russia's energy industry: "What is easy today was tight yesterday. What is tight today with technology and a good tax regime will be easy tomorrow."◆

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The Gas Export Potential For Mozambique

—*Anthony Guida and Ryan McKinley*

The world-wide search for natural gas has led to new findings in some of the most underdeveloped areas on the globe. Twenty years ago, a relatively obscure Mozambique would be one of the last places you would expect investors stepping over one another to claim their stakes.

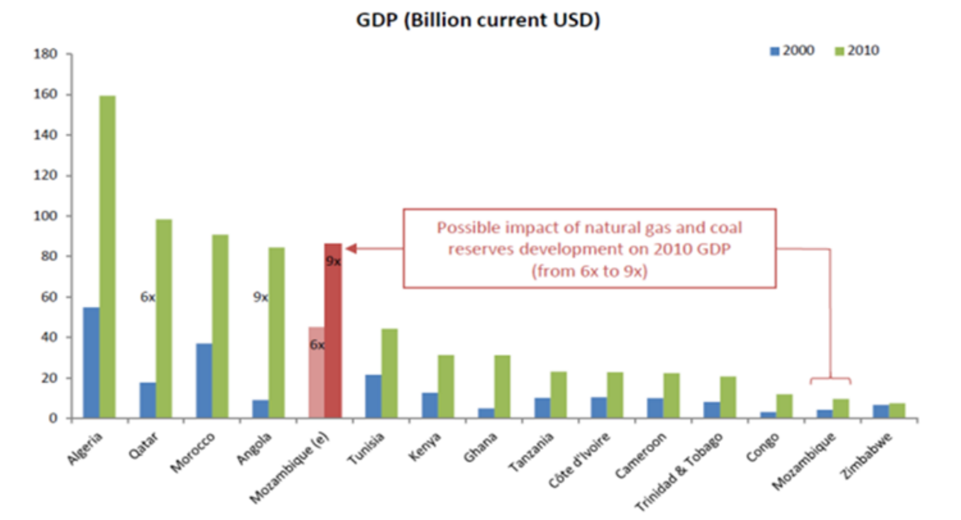
Mozambique gained independence from Portugal on June 25th, 1975 after a prolonged struggle with its colonial overlords. The military leaders, who lead a 12-year resistance against Portugal, quickly established a one-party state and allied themselves with the Soviet bloc. The first decades of independence were dominated by civil war and by the government's inability to create stable institutions. According to a BBC Mozambique profile, Mozambique has emerged as one of the world's fastest growing economies, despite its tumultuous past, with government reforms and influxes of foreign investors showing interest in the country's gas reserves. For now, it seems Mozambique is poised to become a key international gas exporter, all the while seeking help from external actors to avoid the dreaded 'resource curse'.

IMF predicts Mozambique's GDP per capita to rise from $579 in 2012 to $963 by 2017.

The potential impact on the countries GDP is expected to be drastic. In 2012 there was a GDP growth of 7.5%. That number will likely reach 8.5% in 2013 with the IMF predicting GDP per capita to rise from $579 in 2012 to $963 by 2017. Overall, projections of GDP indicate an increase somewhere on the order of 6-9 times its current level, rivaling many of that of many of its neighboring countries.

Taking Inventory: Mozambique's Gas Assets and the Competition for Control

As of 2012, Mozambique is estimated to be sitting on anywhere from 104 to 250 trillion cubic feet (Tcf) of natural gas reserves, making it potentially the third largest natural gas exporter. Put into perspective, this



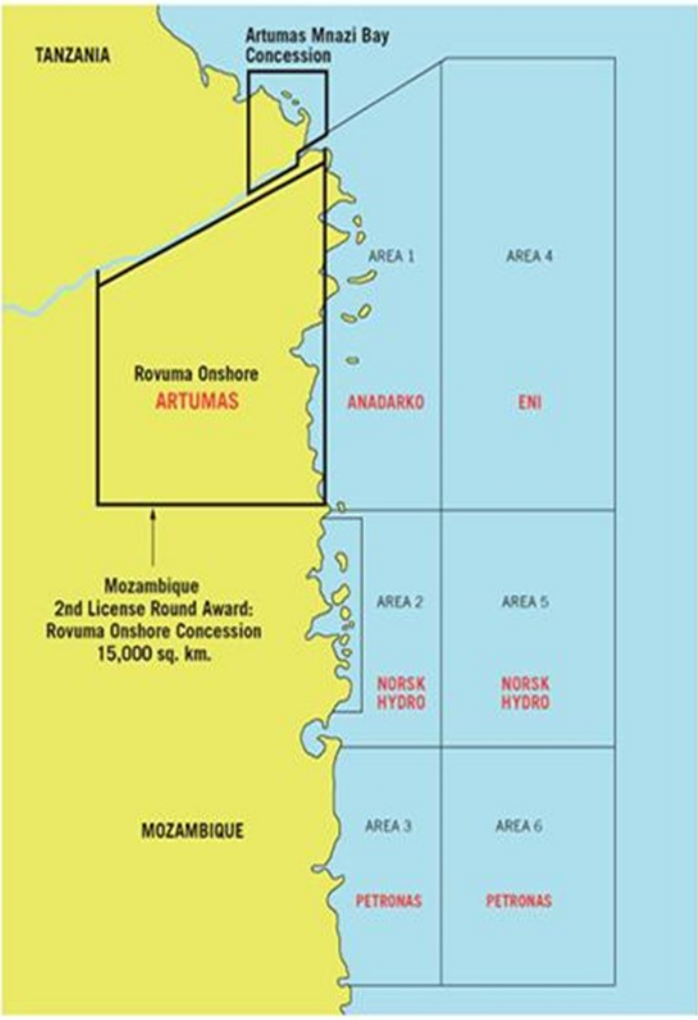
Source: World Bank and SPTEC Advisory Estimates

amount is enough to supply Germany, Britain, France and Italy for roughly 15 years. The majority of these reserves are found in two areas: the Rovuma Basin (harboring the lion's share of resources), located offshore on the Tanzanian border, and the Mozambique Basin which includes assets: on and offshore, located near the coastal provinces of Imhambane and Sofala. The location of these reserves augments Mozambique's competitive advantage as they are located on the coast, allowing for easier exports to international markets. Even the most conservative estimates of proven gas reserves are substantial. Rovuma-4 has alone identified gas reserves of 75Tcf, larger than the total proved reserves of Norway and Kazakhstan at

73Tcf and 66Tcf respectively.

Government Control: The Role of Mozambique's National Oil Company

According to Mozambique's petroleum laws, the state reserves the right to participate in petroleum operations. Mozambique's national oil company, Empresa Nacional de Hidrocarbonetos (ENH), was established in 1982 and is the tool the government uses to ensure it has a stake in each of the exploration areas. The government also participates in the hydrocarbon sector through two other publicly owned corporations via the Mozambique Hydrocarbon Company and Mozambique Company for the Gas Pipeline, both of which are subsidiaries of ENH.



Map of Investors in Mozambique's Gas Fields. Source: Artumas Group

Given the country's turbulent history, it is critical for investors that Mozambique have a well-established and stable state infrastructure. ENH is essential in this regard, because it serves as a legitimate institution with which investors and other foreign entities can interact. ENH intends to serve as a catalyst for gasifying Mozambique and meeting the socio-economic goals of the country. ENH is able to maximize the benefit of the gas revenues for the people of Mozambique, it claims, by maintaining its stakes in each of the exploration areas. ENH holds anywhere from 5% to 30% of shares in each area, and owns subsidiaries that manage national interests in the Pande and Temane gas fields, as well as the pipeline from Pande-Temane to South Africa. While the company's primary focus may be improving the lives of Mozambicans, the Chairman and CEO of ENH has made ambitious plans to export gas to prime markets located in the Far East and Asian-Pacific.

Rovuma-4 has alone identified gas reserves of 75Tcf, larger than the total proved reserves of Norway and Kazakhstan at 73Tcf and 66Tcf respectively.

Mozambique LNG Scope

At the turn of the millennium, the Asian region constituted nearly three-quarters of worldwide LNG trade; such domination is expected to continue up to 2020, maintaining 50-60% of global market share, even as Atlantic and Middle East demand rise. Since 2006, Qatar has replaced Indonesia as the world largest LNG exporter, accounting for roughly 30% of global trade in 2011. The annual average growth rate (AAGR) of global LNG imports is projected to exceed the

400mt mark by 2020. The gap between production and consumption combined with the geographic isolation of the Asia/Pacific region makes it an attractive market, as dependence on gas imports is extremely high.

In mid-December, ENI, an Italian NOC partnered with Anadarko, a North American oil and gas exploration company signed a Heads of Agreement, formalizing the co-operative development of upstream infrastructure, pooling resources to reduce costs, a move highly encouraged by the government which sought to protect its ENH's project stakes. Having not yet defined fiscal and royalty policies, a looming question for Mozambique is when these projects will reach a FID. Estimates foresee the first sales reaching the market in 2018/2019.

The government plans call for two LNG trains to be operational by 2018 with the addition of two trains every two years to total at least 10 LNG trains by 2026 for a total capacity of 50mtpa.

In recognizing the possibility of Australian and N. American LNG competition, the government has set aggressive development targets (considered optimistic in relation to operator timetables) though the declared 100Tcf and undiscovered 250Tcf give space for wishful thinking: the government plans call for two LNG trains to be operational by 2018 with the addition of two trains every two years to total at least 10 LNG trains by 2026 for a total capacity of 50mtpa. The way Mozambique indexes its gas will impact its level of competitiveness. Given the discontent between world oil prices and hub indexed gas prices in North American and Europe, Asian buyers are fighting for the inclusion of hub indexation in LNG LTC-supply contracts.

The companies that already hold significant interests in exploration permits include: Anadarko, ENI, Petronas, Statoil, and Total, and Maurel & Prom.

Asset Bidding wars

Natural gas is, for the moment, being produced by South African company Sasol Ltd only at the Pande and Temane fields in the Inhambane Province. With substantial gas discoveries in Rovuma-1 and Rovuma-4 and production expected to begin in 2018, conditions have created a bidding war for stakes in each block as some companies are seeking to let go of their shares. Anadarko, for example, generally sells off its stakes in large projects that require years of work and large investments to begin production, so that it can invest in projects that offer much faster returns. The company is currently seeking to sell off its shares in Mozambique to raise money for investments in unconventional oil formations in the United States. The companies that already hold significant interests in exploration permits include: Anadarko, ENI, Petronas, Statoil, and Total, and Maurel & Prom.

As of now, the biggest bidding war has been between Shell and PTTEP for stakes in Rovuma-1, at the time holding an estimated 35Tfc, with PTTEP beating out Shell for an 8.5% stake, estimated at 12 Tcf of gas, with a bid of $1.9bn. Since then, the estimated recoverable resources of Ruvuma-1 have doubled to 65 Tcf. Nationally owned companies have also acquired major stakes in the gas fields, most notably from China and India. Indian companies OVL and Oil India are expected to close on a $2.47bn and $2.64bn deal in Ruvuma-1 by the end of 2013. Chinese CNPC acquired a 28.57% stake from ENI East Africa with an investment of $4.21bn, giving it access to a 20% stake in Ruvuma-4.

Role of the Domestic Market and Regional Demand

Gas reserve extraction is predicted to create about 70.000 additional jobs. By this month of writing, November, 2013, ENH hopes to have installed a working grid capable of supplying gas to industries, hospitals, hotels and residential users. Due to the lack of data, it is difficult to forecast gas use in Mozambique, keen on increasing natural gas use in power generation. The government is expecting growth in energy consumption and intensity. With an electrification percentage of 16%, Mozambique must increase its power capacity and encourage additional growth stimuli for alternative power generating sources such as hydropower (responsible for 99% of generation in 2010) and coal (large untapped reserves).

With the exception of South Africa, the scarcity of regional gas demand foreshadows slim opportunities for pipeline developments within the East African region.

The Ministry of Mineral Resources stated that all concession holders are obliged to commit a portion of their production to domestic markets (DMO, Domestic Market Obligation). Depending on what the domestic market price is, such maneuvers could impose additional pressure on existing projects; high LNG prices would force domestic buyers to seek upstream suppliers forcing the government to subsidize the difference as part of its social policy (selling royalties and profits below the gas's expected international price) to encourage gas use in local SME's.

In 2012, South Africa imported 3.3bcf from Mozambique. Calls for the South African government to reconsider its energy policy have increased dialogue between the two countries. During the same year Michael Bagraim, president of the South African Chamber of Commerce announced that natural gas imports from Mozambique may eliminate the need for nuclear power and concretely diminish C02 emissions.

The Natural Gas Master Plan estimates total project revenues at $5.2 billion per year up to 2016 (the GDP in 2011 equaled $12.8bl); although fiscal terms still need to be adopted, royalties and taxes are predicted to generate circa $3 billion per year.

With the exception of South Africa, the scarcity of regional gas demand foreshadows slim opportunities for pipeline developments within the East African region. From 2009 to 2010, only Congo consumed gas (3.3bcf); combined with Burundi and Rwanda the electrical consumption was less than 1bn KWh. Such regional scarcity equates to insufficient demand for making pipeline and grid development unfeasible.

Government intervention regarding gas resource management

As trading greater volumes implies greater revenues, effective resource management will be paramount in directing new income towards infrastructure and improving the domestic economy. There are numerous instances where this has been overlooked. One example of resource mismanagement is Nigeria, comparable by oil export volumes, which underwent enormous hardships once it began exporting its resources. Norway, as a counter example, could potentially be a model for the Government of Mozambique (GoM) to follow by placing an emphasis on effective resource and revenue management. In short, the government needs to manage its hydrocarbon resources effectively to minimize the potentially negative effects of its resource endowment.

Financing and Revenues

The expression 'money makes the world go round' stresses the need for a reliable financial framework. ICF international, an organization which helps nations with management, technology, and policy issues, has guided the GoM through the creation of a Natural Gas Master Plan. This plan essentially segregates and directs the finances of Mozambique appropriately, while ensuring that the business climate remains stable and transparent. Currently, Mozambique, which has established a set income tax of 32%, has an investment rate of 22% (10% private, 12% public). The financial plan acknowledges the proposed LNG development (exploration, production, processing, and liquefaction, export) to be financed by ENI and Anadarko. Transportation infrastructure however, might involve elements of public funding and/or PPP's (Public Private Partnerships). Local government budgets or micro-credit institutions would be responsible for financing distribution infrastructure needed for small or medium sized enterprises (SMEs) public facilities and residences. The Natural Gas Master Plan estimates total project revenues at $5.2 billion per year up to 2016 (the GDP in 2011 equaled $12.8bl); although fiscal terms still need to be adopted, royalties and taxes are predicted to generate circa $3 billion per year. Three basic options have been identified by the Natural Gas Master Plan as strategies to direct prospective gas revenues towards societal development. Unfortunately, details on this plan are minimal as it is still being drafted.

Option 1: Using royalties revenues to finance public-private investments projects under Mozambique's new PPP law.

Option 2: The creation of a Sovereign Wealth Fund (SWF). This would invest within the local economy, and in external markets where returns may be higher.

Option 3: The creation of a National Development or Transformation Bank (NTB). This option would use royalty revenues to establish a development bank to be used as vehicle to direct investments in development projects.

Liquid Petroleum Goods Diversification

The Natural Gas Master Plan for Mozambique characterizes LPG anchor goods (primarily methanol and fertilizer) as 'mega-projects', hypothesizing the potential in the manufacturing of value added products on national territory to then be exported to foreign markets.

Investing in LPG products can therefore be considered as a safety net (product diversification) in response to increased competition.

Despite requiring an airstrip and being a 3 day, 2,800km drive from the capital Maputo, Palma, known for basket weaving and rug making, is conveniently located within proximity of the Rovuma field. To minimize midstream expenditure and obtain the earliest gas commercialization revenues, all projects (LNG & LPG) would be hosted in the village.

The primary purpose of methanol lies within industrial chemical production, an industry with exceptionally high demand in China. The GoM has estimated the returns at $180ml in government revenue. Even more lucrative is the potential for fertilizer, a product correlated to population growth and increased agricultural production. The foreseen income of fertilizer production is $220ml in government revenue. In reaction to the U.S. shale gas revolution, China, India, South Africa and Australia have prioritized shale gas E&P, hoping to increase their shares in global LNG trade. These countries' favorable geographical position increases the chance of displacing volumes from Mozambique. Investing in LPG products can therefore be considered as a safety net (product diversification) in response to increased competition.

Conclusion

Government stability plays an important role. Resources rich countries often become more vulnerable to violence and interchanging political powers will reduce the scope for effective policy planning. Stable investment infrastructure coupled with legal and regulatory frameworks will protect investors (and lower interest rates) against earnings inflation and exchange rate instability. Mozambique has found a rare opportunity to integrate into global markets. Current events reflect the nation's interest in collaborating with international communities to become efficient and effective: both in extracting and exploiting natural gas, and in improving the economic situation to benefit its population. Whether or not Mozambique will develop into an African state role model will be determined by its ability to put its plans into action. ◆

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Book Review: 'RED GAS – Russia and the Origins of European Energy Dependence' by Per Hogselius

—*Daniel Tappeiner*

"Will Europe come to depend on Russian natural gas?" asked the Oil and Gas Journal in the August 28, 1961 issue, when natural gas' overall role as an energy source in Europe was still negligible.

Today, as Russia has established itself as a major energy supplier, the debate about security of Europe's gas supply and over-reliance on eastern gas is very much alive and has a factual basis: A vast pipeline infrastructure starting at the gas fields in Siberia feeds a large part of industry and households in Europe. In August of 1961, however, the Berlin wall had been constructed and with the Cuban missile crisis, the Cold War reached new heights in 1962. And while substantial gas discoveries in the Netherlands and Algeria had caught the attention of the energy industry by that time, the Soviet Union was still struggling to develop its domestic supply infrastructure, and the gas riches of Siberia remained undiscovered. Yet, only a few years later, system-builders from both sides of the Iron Curtain managed to overcome ideological barriers and trade restrictions, each assessing that the opportunities would outweigh the risks of interdependence.

Per Hogselius' meticulously researched book tells the fascinating story of how it was possible for red gas to first cross the Iron Curtain only 10 days after the Red Army had brutally crushed the Prague Spring and how later, despite strong resistance by the Reagan Administration, the Yamal-Europe pipeline could be built, following the widely criticized Soviet invasion of Afghanistan. By referencing material derived from national archives in Russia, Ukraine, and Western Europe, the author gives insights on the motivations of decision-makers in industry and government on both sides of the Cold War divide. Detailed account is made of contract negotiations, for instance, and light is shed on what was invisible to actors in the West at the time - the huge economic and human sacrifice that Soviet prioritization of exports over domestic use entailed.

Per Hogselius' meticulously researched book tells the fascinating story of how it was possible for red gas to first cross the Iron Curtain.

Natural Gas Competing in the Soviet Command Economy

For Hogselius, "system-building" is a key concept for the understanding of the appearance and evolution of large technical systems. The author recognized that it was the presence of key actors - of both technical and entrepreneurial backgrounds - with the ability and mandate to drive processes forward, mobilize necessary coalitions across Cold War divides, and who were needed to overcome critical problems.

In this sense, before red gas could flow abroad, natural gas had to find its place in the Soviet command economy. And here, Hogselius highlights the role of highly capable system-builders, like Alexei Kortunov, who drove Soviet gas exploration and network development under the newly founded gas ministry, Mingazprom, from 1950 onwards. Initial successes, continuing exploration finds, and the growing appetite for the efficient and environmentally friendlier fuel, led to increased support through the Central Party Committee, with political rhetoric keen to argue that large transnational industry projects are better worked out under communism. Successively, ever bolder production targets were set and a confident gas ministry was able to challenge the position of oil and coal. Following connection to major cities such as Moscow, Leningrad, Kiev and the industrial heartlands, natural gas was progressively supplied to the wider Ukraine, Belarus, the Baltic republics, the Caucasus (from Baku) and later Czechoslovakia. The ambitious engineer-pioneers pushing development, however, soon recognized the limitations of

Soviet Pipeline Construction. Source: Gazprom.com

the Soviet manufacturing industry ability to continue accommodating the fast and long-distance expansion of pipeline networks, especially due to the inferiority or lack of powerful compressors and large diameter pipes. At the same time, around 1965, it became increasingly clear that the Siberian Tyumen region held incomparably large natural gas reserves, which would have to eventually take over from the declining production in Western Ukraine.

A Soviet Gas Export Strategy Takes Shape

As imports from capitalist countries were strictly limited, machinery imports for gas export schemes were increasingly envisioned. However, the Soviet leadership - especially the central planning institution Gosplan - remained divided over the issue, with one of the biggest risks seen in over-dependence on gas purchases, i.e. security of demand. Finally, export plans were approved, in principle, in light of plateauing oil exports and the possibility to counter U.S. leverage over Europe. The use of outright gas supply disruptions as an energy weapon was never part of considerations.

Large gas discoveries in the Netherlands and Algeria provided that private and public actors from countries geographically most distant from these new sources of supply and on best political terms with the Soviet Union would take the lead in negotiations with the Soviet Union, i.e. Italy's ENI with its important customer base in the north of the country and Austria, later Bavaria. While northern Italy represented a larger target market, Austria led the way. A neutral country with a government-owned oil and gas company, OMV, that had actually been under Soviet controlled administration until the occupation of eastern Austria ended in 1955, Austria had a gas distribution network only a stone's through away from the Soviet Bratsvo (Brotherhood) pipeline in Czechoslovakia.

In order to honor this important export contract, and being technically unable to expand supply as planned, the Soviet Union prioritized export over domestic supplies, leading to severe shortages in Ukraine, Belarus and the Baltic states during successive harsh winters.

It also helped the process that OMV's indigenous gas resources were coming to an end and that the Austrian steel industry was increasingly under pressure from European Economic Community competitors, paving the way for a gas-for-pipes deal, export-financed by Austrian Kontrollbank. Interestingly, the drawn-out negotiations were supported both by the new Austrian center-right government, which was seeking closer integration with the EEC, and a Soviet leadership that sought to counterbalance West European dominance over neutral Austria.

The first gas crossed the Iron Curtain in 1968 as had been contracted. Supply irregularities became insignificant after an initial period, leading OMV to view the project as a success. Associated human and economic tragedies were hidden to the West. In order to honor this important export contract, and being technically unable to expand supply as planned, the Soviet Union prioritized export over domestic supplies, leading to severe shortages in Ukraine, Belarus and the Baltic states during successive harsh winters.

From the Austrian Experiment towards Detente by Economic Means

For Germany, following in the footsteps of OMV, was Bavaria's gas utility and the regional government, who sought independence from northern German suppliers, especially Ruhrgas, in coping with the dawning natural gas production limits in Bavaria itself. Although the Bavarian initiatives found some support in government, backing of rapprochement with the Soviet Union through economic ties increased as Willy Brandt obtained the chancellorship and German ministries stood more strongly behind the new Ostpolitik, or "new eastern policy", aiming at normalization of relations between West Germany and Eastern Europe, particularly East Germany. The U.S. Johnson Administration at the same time was not opposed to a limited German gas supply exposure towards the Soviet Union, and did not follow up on requests for intervention by gas-producers Esso and Shell, which interestingly together had a controlling stake in Ruhrgas, who would lead negotiations. The view of energy experts had also changed from only a few years earlier, with expectations being now of a substantial supply-gap opening. German-Soviet negotiations commenced in June 1969 and were concluded in early 1970 with a gas-for-pipes contract including a government-subsidized German credit arrangement, which also testified to the strong political interest to support detente between Germany and Russia.

Soviet deliveries would grow to 7.4 bcm in 1973, 17.2 bcm in 1974 and to 24.7 bcm in 1975.

In parallel, Italy's ENI and later Gaz de France concluded long-term supply contracts with Mingazprom, whereby Italy would be connected by way of Austria and France through a German pipeline extending from Czechoslovakia. Ruhrgas opted to increase contracted supplies in 1972 and additional supply contracts were concluded with Finland, Poland, East Germany and Bulgaria. Altogether, Soviet deliveries would grow to 7.4 bcm in 1973, 17.2 bcm in 1974 and to 24.7 bcm in 1975. The impressive new export obligations allowed for the Soviet side to plan for connection of the still-untapped Siberian gas fields, by making use of West European manufactured equipment.

Export Success and a Hidden Crisis

The technological feat to build multiple thousands of miles of pipelines partly through hardly accessible swamp and permafrost areas in time for the first planned deliveries in October 1973 proved impossible. The harsh, hitherto unknown construction conditions and continued state planning deficits necessitated that Soviet engineers improvise to avoid having to either default on export contracts, or to encounter domestic shortages. Gas deposits in Eastern Ukraine were supposed to substitute for declining production in western Galicia and thus free export volumes. This strategy failed as well. By September 1973 it became clear that export obligations could only be met by severely curtailing supplies to power stations, industries, and public users. As consumption restrictions were partly ignored, the situation became chaotic throughout the Soviet Union, with republics at the far end of supply lines such as the Baltic states being most severely affected.

Thus, while the deadline for supplies to West Europe was formally met, this came at a very high social and political price, making the Soviet leadership skeptical about further deals for years to come. Initial minor supply irregularities, exacerbated by the hurried construction of infrastructure, could be handled by importing countries through interconnection and storage capacity that had been put in place to hedge against insecurity of supply of red gas, again leading West European companies to view further projects favorably.

Notwithstanding limited flow irregularities caused by technical failures, over this period the Soviet Union was regarded to be a reliable supplier and there were no instances of politically motivated supply disruptions.

In contrast, Algeria's Sonatrach repeatedly failed to honor contracts and Norway's operations were disrupted by numerous strikes. During the oil shock of 1973, even the Netherlands threatened to stop gas exports if other European countries that were not affected by the Arab oil embargo would not share oil resources. The oil shocks of the seventies also led Mingazprom to renegotiate prices for additional contracts, and a closer tie to oil prices.

Further Interdependence vs. Cold War Antagonism

By 1978, as Siberian gas fields were finally producing large supplies in excess of domestic demand and as European demand continued to grow, Western Europe had to decide whether to scale up red gas imports further, or to avoid higher interdependence.

After projects for Iranian imports through the Soviet Union had to be abandoned as a consequence of the Iranian revolution in 1979 (virtual imports for that matter, as physically, Iran's natural gas imported to Azerbaijan, would be consumed in the Soviet Union's southern regions, while Mingazprom would export

Soviet Postage Stamp of Urengoy-Uzhgorod Pipeline. Taken from Wikipedia Commons

the same quantity from its new fields in the north), a consortium led by Ruhrgas and comprising other "early" importers of red gas, set out to agree to terms for building of the export-only Yamal pipeline, or Urengoy – Uzhgorod pipeline, which would connect Russian Siberian fields with Western Europe via Ukraine, and Czechoslovakia. Security considerations of the buying countries were again on balance positive, especially in light of the fact that intentional supply disruptions would affect all importing countries along the pipeline route, and it seemed politically unrealistic that – aside for the case of war, for instance - the Soviets would risk confronting major nations in

Western Europe simultaneously, on top of obvious economic disincentives.

This time, however, in reaction to the Soviet invasion of Afghanistan, the U.S. Reagan Administration strongly opposed the project and imposed export and license restrictions on U.S. entities. Unanimously, the European Community, including Britain under PM Thatcher, refused to follow the embargo and instructed industry to ignore "illegal" restrictions, which shows that at this stage system-building had reached a considerable "momentum". Export of crucial compressors and other equipment for the construction of Yamal occurred as scheduled and the pipeline was finalized in 1983, ahead of schedule. The 40 bcm-capacity export pipeline was one of six new Siberian lines taken into operation during 1981-1985. The additional transmission capacities for Siberian gas allowed Mingazprom to reach additional customers in Western Europe. Also, Turkey and Greece were now connected to the unified pipeline system.

Notwithstanding limited flow irregularities caused by technical failures, over this period the Soviet Union was regarded to be a reliable supplier and there were no instances of politically motivated supply disruptions. This changed after the dissolution of the communist bloc. The breakup of the Soviet Union put transit countries, such as Belarus, Ukraine and Moldova, in a contractual vacuum and the formerly unified Soviet gas system would now have to be governed among newly independent states, leading to persistent disputes and supply crises. Intentional supply disruptions occurred in a number of instances as

Russian Pipelines to Europe (2009). Map taken from Wikipedia Commons.

The collapse of the Soviet Union and the emergence of new transit states

At the dawn of the collapse of the Soviet Union, which some attribute partly to lower oil and gas revenues during the 80s, red gas exports had thus grown remarkably from a minor 1.5 bcm to Austria in the early 1970s, reaching 63 bcm in 1991.

a consequence of contractual disputes or because of non-payment by off-takers in the CIS region. In some of these cases, commercial motives seemed to be second to Russian foreign policy considerations. Transit disputes have affected importing countries as well, most notably during the January 2009 Ukraine-Russia gas dispute.

Red Gas will prove insightful reading for both specialists and those whose focus is not energy, as it gives a multi-faceted account of the history of East-West natural gas trade.

Despite these insecurities in the post-Soviet sphere, Russian gas supply infrastructure has further expanded, albeit with new pipeline routes, like Nord Stream and South Stream, bypassing some of the traditional transit countries, and supply volumes have continued to grow. As for the future, Russia and its European customers will have to continue to weigh advantages and disadvantages of mutual reliance.

Red Gas will prove insightful reading for both specialists and those whose focus is not energy, as it gives a multi-faceted account of the history of East-West natural gas trade. Hogselius' book is valuable reading at a time when debates on energy security are very heated. According to the evidence presented in Per Hoegselius' book, the role of Soviet and Russian natural gas as an energy weapon has often been exaggerated, whereas the gains from trade and cooperation have been, and will hopefully continue to be, the driving forces of system-development.◆

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EUROPEAN UNIVERSITY AT ST. PETERSBURG

Workshop Review: BP Economist Drebentsov Crunches Today's Numbers for Glimpse of Tomorrow's Energy Scene

—Stephanie Bryant and Michael Camarda

On October 7th, the European University at St. Petersburg welcomed Dr. Vladimir Drebentsov as part of the ENERPO program's "Workshop Series." Dr. Drebenstov's 90 minute presentation was divided into four parts: 1) the current situation in energy markets; 2) a summary of BP's 2030 outlook; 3) the Russian oil markets; 4) the Russian gas markets. This was followed by a question and answer session with the audience.

Drebentsov has been BP's Chief Economist for Russia and the CIS since joining the company in early 2006. In this role he conducts research and offers policy advice for BP in the Former Soviet Union. His research on the subjects of European gas markets, global gas reserves, and gas trade is part of BP's Statistical Review of World Energy, often referred to by the industry as the "bible" of energy data. In 2010 Drebenstov was appointed BP's VP for Corporate Social Responsibility in Russia. Prior to his work with BP, Drebenstov was a Senior Economist at the World Bank from 1993 to 2006, where he specialized in the task management of lending operations and in impact assessments of institutional reforms. Before joining the World Bank, he was a Senior Research Fellow at the Institute for US and Canadian Studies (ISCAN) from 1982 to 1993, focusing on the Canadian energy sector and CIS trade relations.

Dr. Drebenstov earned his PhD from ISCAN in 1990 and graduated from Moscow State University's economics department in 1982. In his career he has authored or co-authored more than 50 academic publications.

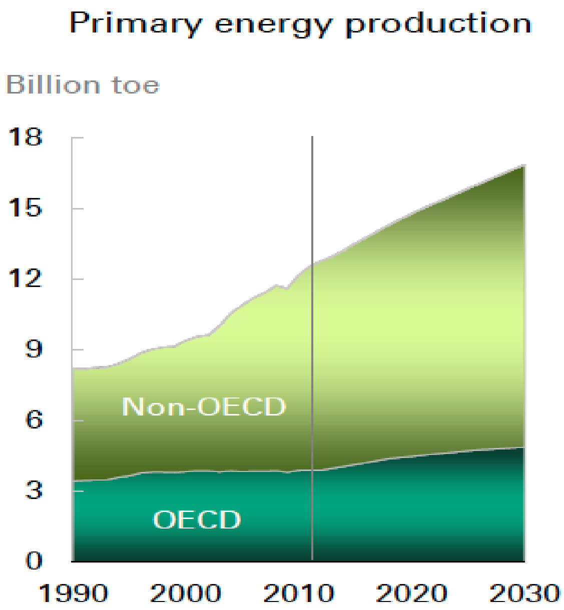
In his 90 slides, Drebenstov not only provided a broad overview of the current and projected world energy landscape but also sought to explain apparent contradictions between energy data and industry actors' different energy policies. The last two Russia-focused parts of his presentation saw the data-analysis of the first half of his overall presentation replaced by broader, less-quantitative predictions on how Russia must adapt to the changing oil and gas scene in order to stay competitive.

The decline in US emissions completely offset the increase in carbon emissions in Japan. In Japan, they went up last year because of coal and gas substitutions for nuclear power.

Below you can read selections of Drebentsov's talk. The transcript has been edited for length and clarity:

On Carbon Emissions in OECD Countries as Compared to Non-OECD Countries

The first thing to mention is that primary energy consumption in OECD countries is much flatter, especially compared to non-OECD countries. We are measuring emissions from energy production and energy consumption. Another thing to mention is that, in recent years, as you see, emissions started to decline. That's just because growth in efficiency has more than offset growth in energy consumption. So you consume more energy, but you use it more efficiently. There was actually some growth so, over these years, growth in energy consumption in OECD exceeded growth in energy efficiency. It's only in the last five years that we have seen emissions coming from the developed world on the decline. That's a function of primary energy consumption. However, relative to non-OECD, the growth is flat. In recent years, gas was substituted for coal in the U.S. You can therefore see that this decline in U.S. emissions was steeper than the EU's decline, and it offset a lot of growth in European countries. For instance, it completely offset increase in carbon emissions in Japan. In Japan, carbon emissions went up last year because of coal and gas substitutions for nuclear power.



Source: BP Energy Outlook 2030.

The decline in the U.S. allowed an offset to all this. Even if we look at long-term trends, it's still basically a function of primary energy consumption. There are two contributing factors for economic growth: how much primary energy you need relative to your economic growth and the fuel mix. I mentioned only decline in primary energy consumption, that's not completely fair. Of course, growth in renewable sources contributed to the decline of energy intensity and hence carbon emissions. It would have been much bigger if not for the policy mismatch in Europe.

On Changes in Structure of Consumption in China

We think that hydro in the future will not be able to grow as fast as in the past, because the Chinese have basically tapped almost all resources that they have. They will grow renewables pretty significantly, particularly solar and wind, but they will have to grow nuclear and that is their plan.

> ***China will still be a coal-driven economy by 2030 with high contributions from nuclear, hydro, renewables, and gas.***

If one turns to power generation, you know that solar and wind power are intermittent sources of energy. In other words, if there is no sun shining or there is no wind blowing, you cannot produce electricity by either sun or wind, so you need some type of backup electricity source. Nuclear is, and will be, one of these sources simply because China will experience growth in what is called base load, and it's pretty difficult to use intermittent sources of power energy. So you need something more stable, like nuclear or gas. China also has plans to grow their gas consumption: they want to increase contribution of gas to 9% by 2030 from less than 4% now, so it is a significant growth. Also, coal will still be supplying most of the energy needs in China by 2030. I was showing the slide where we forecasted deceleration in coal consumption growth post-2020, but China will still be a coal-driven economy by 2030 with high contributions from nuclear, hydro, renewables, and gas. By 2030, we are still thinking that China and India will be contributing 52% of coal consumption. So to economists, this will still be a heavy reliance on coal.

On the Russian Competition for Market Share in Growth in Natural Gas in China

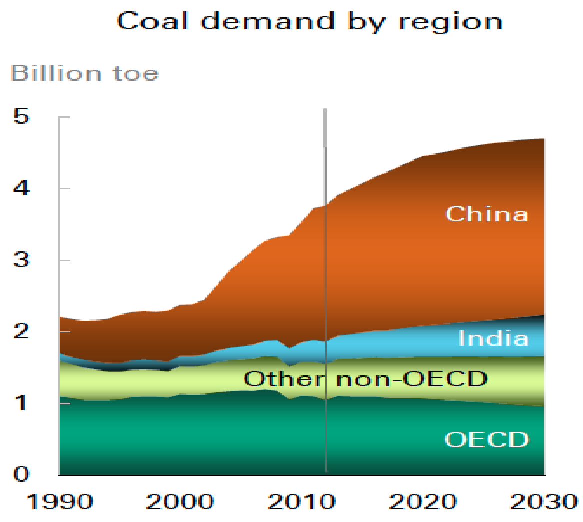
Well let me say that Russia would have been much better off if it had been more successful in negotiating gas sales to China. This story dates back to the late 20th century. Russia has spent over 15 years in an attempt to negotiate a gas contract with China and during this time, a lot of things have changed.

China, for instance, successfully developed gas imports from Turkmenistan. Central Asian gas has closed a lot of room that would have been potentially available for Russian gas. Originally, Russia wanted to export gas to China via two routes: the western route (Altai pipeline) and the eastern route. By now nobody speaks of the western route, because after China signed the stream of agreements with Turkmenistan to purchase close to 60 bcm a year from that country, the Chinese lost any interest in purchasing Russian gas via the west. In the east, it still makes sense because there, Russian gas will be competing with LNG.

I think that unless Russia offers a pretty significant discount to current prices, the Chinese won't buy their gas.

Clearly, a lot will depend on what the LNG price will be in Asia. At the moment LNG prices in Asia are the highest in the world, and Russian gas looks very competitive. The Chinese are in no rush to agree to the price that Russia offers for its pipeline gas; they are aware that a lot of new developments are likely to happen in the LNG markets in the years to come, and by the time the Russian gas might physically start flowing to China, China might have cheaper options for buying gas. It is a pretty complicated story. We know both sides. From the Russian side, it doesn't make sense to build a pipeline with capacity of less than 30 bcm per year. Basically if you sell less than 30 bcm per year, it's not likely to be a profitable business. On the Chinese side, they have seen that before the recent price reforms, their importing companies had been experiencing losses on purchase of even Turkmen gas, so why would they agree to buy Russian gas at a higher price if they were experiencing such losses?

But we still think there is room for about 30-40 bcm in northeastern China, but again it might well be the case that it's more prudent for Russia to develop LNG capacity in the Far East. An advantage of LNG over pipeline gas is that you're not tied to one market.



Source: BP Energy Outlook 2030.

If one market doesn't want to swallow your gas, you try to find some other market. With piped gas, you're doomed to sell it to just one customer. It's an interesting thing to watch, we might see some agreement by the end of this year just because of a difference in price. Still, I think that unless Russia offers a pretty significant discount to current prices, the Chinese won't buy their gas.

Question: If Russia is unable to sign a deal with higher gas prices, what do you think this means for the viability and partnership with Rosneft/Exxon?

Well actually, it is true that it is more expensive to develop gas in the Russian Far East than in the traditional provinces. On the other hand, there is an advantage in these fields, which is that they are basically wet gas. They are liquid rich. Actually if you look at the experience of the U.S., it does not impede. It actually helps in the development of these fields because you pretty much cover your costs by selling liquids, and then you get gas as a byproduct that you can sell at any price and it's still profitable.

So I wouldn't just say that it's more expensive to develop them. I would say that it has a lot of advantages, but the problem is that you need markets. For liquids, the market is global. For piped gas, it's one market. For LNG, it's the whole of Southeast Asia which will need more gas - be it Korea, Japan, India, China - so I think gas in eastern Russia will be developed and sort of LNG plants will justify building both pipelines and LNG plants to export Russian gas. Of course, one thing that should be understand is that it will require much more cost management than Russian producers, particularly monopoly producers, are used to. Again, it's no secret that Russian pipelines are the most expensive in the world. I'm not talking about Arctic pipelines, I'm talking about pretty regular pipelines.

Gazprom will either become more efficient and prepare to sort of cut costs and become competitive at low prices or they go bust. It's pretty simple.

To give you an anecdote which was published in August, I think: one guy who fled Russia published an article on how much Gazprom overpaid on just building 19 railway bridges in Yamal. 600 million dollars. That was just the expertise of the designing institute of these bridges after they went there and saw that what was supposed to be built from concrete was built from wood. Gazprom had paid for concrete, not for wood. It gives one an example of how much room there is in cutting costs in Gazprom. My point is that because of the higher competition, both domestically and on external markets, they will either become more efficient and prepare to sort of cut costs and become competitive at low prices or they go bust. It's pretty simple.

Question: I'm wondering if you could speak a little more now about the considerations that went into choosing the TAP pipeline over Nabucco West?

So it will be the TAP pipeline not Western Nabucco. We are talking about gas production in Azerbaijan and about us, BP, being in a consortium that will develop the Shah Deniz II gas field. Basically, given that it's gas produced in Azerbaijan, it needs to be sold somewhere. We opted for Europe, and in Europe we had an option between going through the Balkans and central Europe to Austria or Italy, and these were two competing pipelines. One was originally called Nabucco and then Western Nabucco and another one was called TAP. Basically we opted for the latter, so we will sell our gas in Italy, but again I'll be able to say even more next year because we haven't taken the final investment decision on Shah Deniz yet. It will be taken by the end of this year. So we have chosen between pipelines, so the next thing is just to agree that this gas field will get developed at all because if we don't take an investment decision, then the gas will not be produced and it will not make sense to even speak of TAP, so let's wait. It's an ongoing process. In terms of the global energy picture I think our gas, and we are only going to sell about 10 bcm from Shah Deniz II to Europe, it is equally interesting to look at what will happen in Israel or between Cyprus and Israel. Israel is considering building a 16 bcm pipeline to Turkey. So again, that actually gives one a clear idea of how fast gas markets are changing. Some things which nobody even thought about a few years ago will be really crucial ideas in just a few years.

Question: Do you think there is any chance Gazprom will switch to spot pricing in the next five to ten years?

Yes, these are interesting dynamics to observe. Let me mention a few things. First, it is not absolutely correct to say that Gazprom sells its gas in Europe only at oil index prices, although I admit I was saying this myself. Actually, Gazprom has been selling close to 7-8% of its gas in Europe at spot prices for the last 5 or 6 years. And perhaps I've mentioned this in my previous presentations here.

Gazprom at the moment sells 93% with oil indexation and 7% at spot prices.

It's very easy to capture; you just open the Customs Book Statistics in Russia and look for the line which sells gas exports to the UK. And that's exactly the gas, that which is not sold in the UK, because there is no technical capacity to sell Russian gas in the UK. At least not before Gazprom builds a fourth leg of Nord Stream to the UK. So Gazprom at the moment sells 93% with oil indexation and 7% at spot prices. Okay, let's see what happens. If oil prices go down and the oil index prices become lower, then the spot price is fine. Gazprom will sell more via the Gazprom market and then trade it, that's not a problem - they know how to do that. So for them, the current situation, no matter how unpleasant it might look from the European end, is pretty pragmatic and rational. As long as someone is prepared to pay at the oil indexed price, they will sell at this price. Actually speaking of Nord Stream 3 and 4 - for me, the extension of Nord Stream 4 is a clear indication that Gazprom is prepared to sell gas at spot prices.◆

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