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Key Determinants for the Future of Russian Oil Production and Exports

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Abbreviations and units of measurement

bbls	Barrels
bcm	Billion cubic metres
bcma	Billion cubic metres per annum
bn bbls	Billion barrels
boepd	Barrels of oil equivalent per day
bpd	Barrels per day
E&P	Exploration and Production
ESPO	East Siberia – Pacific Ocean (Pipeline)
FSU	Former Soviet Union
IOC	International Oil Company
kboepd	Thousands of barrels of oil equivalent per day
kbpd	Thousands of barrels per day
km	Kilometres
mm bbls	Million barrels
mcm	Thousands of cubic metres
mmboepd	Millions of barrels of oil equivalent per day
mmbpd	Millions of barrels per day
mmbtu	Million British thermal units
mmcm	Millions of cubic metres
mmt	Millions of tonnes
mmtpa	Millions of tonnes per annum
Mm tonnes	Millions of tonnes
P&P	Proved and Probable
tcm	Trillion cubic metres

Conversion Factors

		Equals	
1	tonne oil	7.3	barrels of oil equivalent
1	tonne condensate	8.0	barrels of oil equivalent
1	bcm gas	6.6	mm barrels of oil equivalent
1	bcm gas	35.3	billion cubic feet of gas
1	bcm gas	0.9	mm tonnes of oil equivalent

Source: BP Statistical Review

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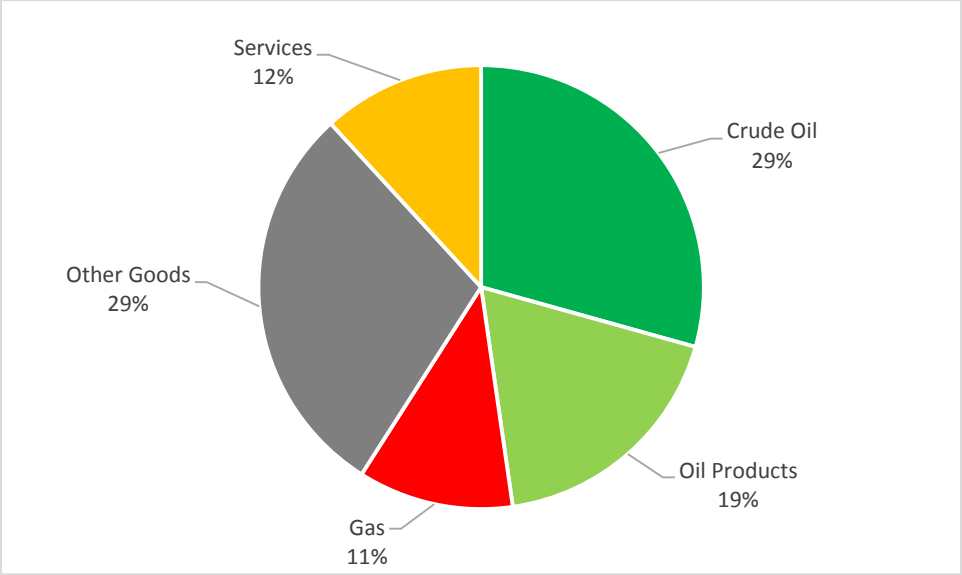
1. Introduction

The production and export of crude oil and oil products in Russia is of vital importance both to the domestic economy and to the global energy market. In 2013, oil contributed almost 50 per cent of Russia's exports of goods and services (see Figure 1) and provided 45 per cent of total budget revenues,[1] while in 2012 oil made up around 15 per cent of total Russian GDP.[2] In a global context, Russia had a 12 per cent share of world oil output in 2013 (second only to Saudi Arabia) and accounted for 12.5 per cent of total crude oil exports, plus 17 per cent of total oil product exports.[3] As a result, shifts in its output can have a major impact on the global supply and demand balance and consequently the oil price. Furthermore, the global reach of Russian oil exports, which are now traded through ports and pipelines in the Atlantic and Pacific basins, is a key foundation of the country's position as a global energy superpower, providing the Kremlin with significant geopolitical influence even as its relations with many countries in the international community are deteriorating due to the continuing crisis in Ukraine.

Figure 1: Contribution of oil sector to Russian exports



Source: Central Bank of Russia

The future of the Russian oil sector will therefore have significant consequences across multiple political and economic stages, and as a result the potential impact of lower oil prices, revised investment plans, and US and EU sanctions on future oil production are being widely analysed both inside and outside Russia.[4] However, the conclusions that are being reached vary widely, as a broad selection of factors need to be considered, ranging from government tax policy to the

[1] Bloomberg, October 13 2014, "Will cheap oil choke the Russian economy?"

[2] Henderson and Pirani (2014), p.8

[3] BP Statistical Review, 2014 and Central Bank of Russia statistics at http://www.cbr.ru/eng/statistics/print.aspx?file=credit_statistics/, sourced on 17 March 2015

[4] For example, EIA, 19 September 2014, "Russia looks beyond West Siberia for future oil and natural gas growth"

impact of rouble devaluation, from upstream expenditure plans to the impact of refinery upgrading commitments, and from the impact of delays in Arctic and tight oil developments to the potential for enhanced oil recovery at existing fields, plus the development of onshore greenfield projects to sustain output in the short to medium term. Even Russian government ministers are reaching different estimates for the likely outcome; one estimate in December 2014 suggested that production could fall by as much as 5-10 per cent per annum in 2015-17,[5] which then appeared to be contradicted by a forecast from the Ministry of Economic Development which showed no decline in 2015 at all.[6] As if to confirm the uncertainty, the Ministry of Energy subsequently published its own estimate for 2015 of a 0.6 per cent decline from the record high of 10.58 mmbpd seen in 2014, essentially opting for a mid-ground between the two previous government forecasts.[7]

Russian company estimates have been slightly more consistent, and optimistic, but nevertheless promises of unchanged output have also been balanced with warnings of an imminent production collapse if government support is not provided. Four of the largest oil producers—Rosneft, Lukoil, Surgutneftegas, and Tatneft—have all insisted that production in 2015 will, at worst, remain flat compared to 2014, but Lukoil, while suggesting that its own domestic output will not decline, has also hinted that overall Russian production could fall by as much as 100,000-400,000 bpd if expenditure on drilling is cut sharply.[8] Interpreting these corporate signals is fraught with difficulty, as they can often be motivated by a desire to placate political leaders or to encourage them to provide fiscal support to the industry. Indeed, the consistent growth of production since 2000 suggests that the Russian government does have a fairly successful history of making ad hoc adjustments to the tax regime to encourage the maintenance of crude output (see Figure 2 below), although it is difficult to be definitive about when future changes may occur.

This paper aims to highlight the numerous dichotomies at work in the Russian oil sector at present, in an attempt to provide a foundation for a logical conclusion on Russian oil production. On the tax front, the 'tax manoeuvre' introduced in January 2015 has provided a marginal short-term boost to upstream profitability but has not addressed the problem of incentivizing long-term investment and has also disadvantaged downstream operations.[9] As a result, although one might expect some boost to investment in oil production, companies with weaker refining businesses may be forced to divert funds towards upgrading their plants rather than boosting oil output. Government support is being requested and could come in the form of further tax adjustments, but importantly now seems to be available in the form of direct financing of projects, with use of the National Welfare Fund (NWF) for this purpose being a matter of current debate.[10] The authorities have difficult decisions to make, not only concerning which oil projects to support, but also about whether government money should be used to fund an industry that is already dominant in the economy, or might more wisely be invested in diversifying the country's industrial base.

Furthermore, the devaluation of the rouble has complicated the issue, because although companies have been forced to reduce capital expenditures in dollar terms, spending may still

[5] Argus FSU Energy, 12 February 2015, "Red lights at greenfields"

[6] Argus FSU Energy, 12 February 2015, "Ministry reveals production forecasts"

[7] Nefte Compass, 1 January 2015, "Russian Oil Output May Drop in 2015"

[8] Nefte Compass, 4 March 2015, "Lukoil sees Russian oil decline, price rebound"

[9] Interfax, 22 January 2015, "Tax maneuver to lead to systemic risks under current conditions – Rosneft"

[10] Interfax, 12 March 2015, "Dvorkovich to hold meeting next week to discuss NWF funding for Rosneft projects"

increase in rouble terms in an industry where up to 80 per cent of the costs are domestic.[11] The benefits of devaluation may be limited to an extent by domestic inflation, but again negotiations between oil producers and service providers are on-going, with both sides arguing with equal force for price increases and decreases respectively. The question of cost and government support will be vital in the decision-making processes of the Russian oil majors as they seek to prioritize their investments in a lower oil price scenario. US and EU sanctions have effectively done some of the work for them, delaying Arctic, deep water, and tight oil developments that might have been uneconomic in any case. The more interesting questions surround the potential for further brownfield development in Russia using technology that has not been sanctioned, and the opportunity for new greenfield sites, some already under development, to make up for any declines at existing fields. The answer to both questions may again come down to sanctions, not on equipment but on the ability to raise finance on international capital markets, which is a particular issue for Rosneft but also affects companies such as GazpromNeft and Lukoil.[12]

One final uncertainty concerns the relationship between oil production and exports. One might expect that the possibility of a decline in oil output would inevitably threaten the level of oil exports, given the political necessity to maintain supply to the domestic market. However, the potential for refinery shutdowns due to recent tax changes, and the possibility that Russian oil demand could go into decline as a result of economic recession, may alter this picture dramatically. One conceivable result is that Russian oil exports could rise irrespective of the outlook for production, in particular because producers will be desperate to maximize foreign currency earnings.

The paper will address these issues in the following order. Section 2 will provide a brief history of Russian oil production and highlight the key areas of interest for the future. Section 3 will then look at potential production from Russia's existing brownfield assets, while section 4 will assess the potential for new greenfield projects to replace the inevitable decline at existing fields, creating some theoretical production scenarios. Section 5 will start to put these forecasts into context by discussing the implications of recent announcements on cost cutting and the potential benefits of rouble devaluation. Section 6 will then look at the ability of Russian oil companies to raise finance for future spending, including prepayment deals, domestic bonds, and allocations from the government's National Wealth Fund. Section 7 will look at another possible source of government help, namely fiscal changes, and will examine the diverse effects of the recent tax manoeuvre. Section 8 will then focus on one possible specific consequence, that crude oil exports may receive a boost as unprofitable refineries are shut down following the tax changes. Section 9 will then examine the potential for foreign actors to support the Russian oil sector despite the impact of sanctions, before the final section provides conclusions on the future of Russian oil production and exports.

[11] Moshkov (2014), p.14

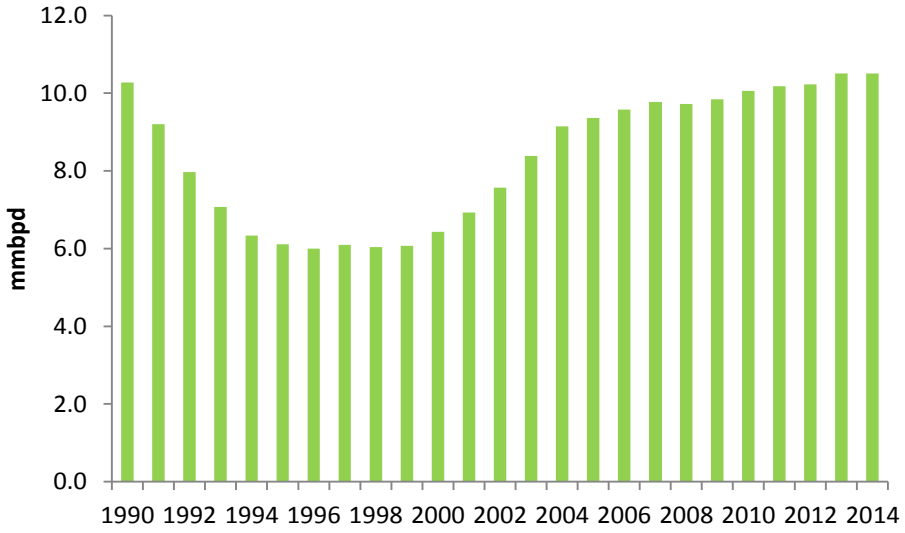
[12] http://www.bakermckenzie.com/sanctionsnews/, sourced on 15 March 2014

2. A Brief History of Russian Oil Production

Figure 2 shows the history of Russian oil production over the past quarter of a century, which can itself be broken into three distinct periods. The first covers the collapse in output during the 1990s, when a sharp fall in investment led to the rapid decline in output from over 10 million barrels per day (mmbpd) in 1990 to a low of just under 6 mmbpd in 1996, which then levelled out through to 1999. This period reflects the consequences of a severe reduction in spending on Soviet-era fields in West Siberia, where the natural decline rate can be as high as 10-15 per cent per annum due to the geology of the fields and the significant amounts of water as well as oil that are produced. In the period 1990-1996, the average decline was 9 per cent per annum as drilling levels halved amid investment constraints caused by a collapsing Russian economy.[13]

The second period was 1999-2005, when the Russian economy was recovering from the economic crisis, the world oil price was rising from $18 to $55 per barrel, and when the extra revenues generated were being put to work to enhance the recovery rates at existing fields by the then vibrant Russian private sector, led by Yukos and Sibneft. During this period the early benefits of Western technology—brought by companies such as Schlumberger and Halliburton—were being reaped, with relatively standard reservoir management techniques (by international norms) creating huge benefits on fields that been developed in the Soviet era.[14] Furthermore, the international oil majors were also involved, with BP investing in a 50 per cent stake in TNK-BP,[15] while Shell, Exxon, Total, and others operated in joint ventures with various Russian oil companies and helped to transform their operating methods. The average increase in production from 1999-2005 was 7.5 per cent per annum, underlining the benefits of combining Russian private enterprise with international technical and management expertise in the sector.[16]

Figure 2: Russian oil production in the post-Soviet era



Source: Interfax data

[13] Gustafson (2012) pp.60-62

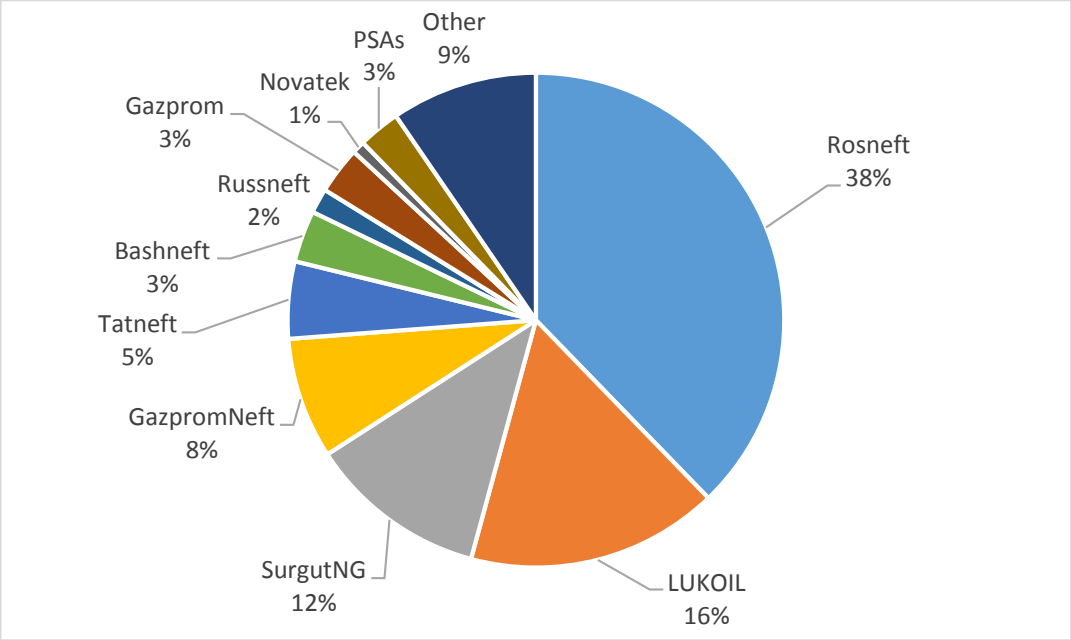
[14] Ibid., pp.185-230

[15] http://www.bp.com/en/global/corporate/about-bp/bp-worldwide/bp-in-russia.html accessed on April 16th 2015

[16] IEA (2014, p.127

The third period has lasted for almost a decade now, from 2005-2014, and has seen a much slower increase in oil production, averaging 1.3 per cent per annum. This slowdown has been the natural result of the 'low hanging fruit' having been picked in the early 2000s, but could also be seen to reflect the changing governance of the oil sector, following the merger of a number of companies into larger and more bureaucratic entities and the rise in dominance of the state through the growth of state-controlled firms such as Rosneft and GazpromNeft as key actors. Figure 3 shows a breakdown of production by company, and highlights the fact that just five companies account for over 75 per cent of total Russian oil production (if their share in joint ventures is included), with Rosneft alone producing almost 40 per cent.

Figure 3: Russian oil production by company



Source: Russian Ministry of Energy data (NB: Rosneft and Gazpromneft include their 50 per cent share in Slavneft, which they jointly own)

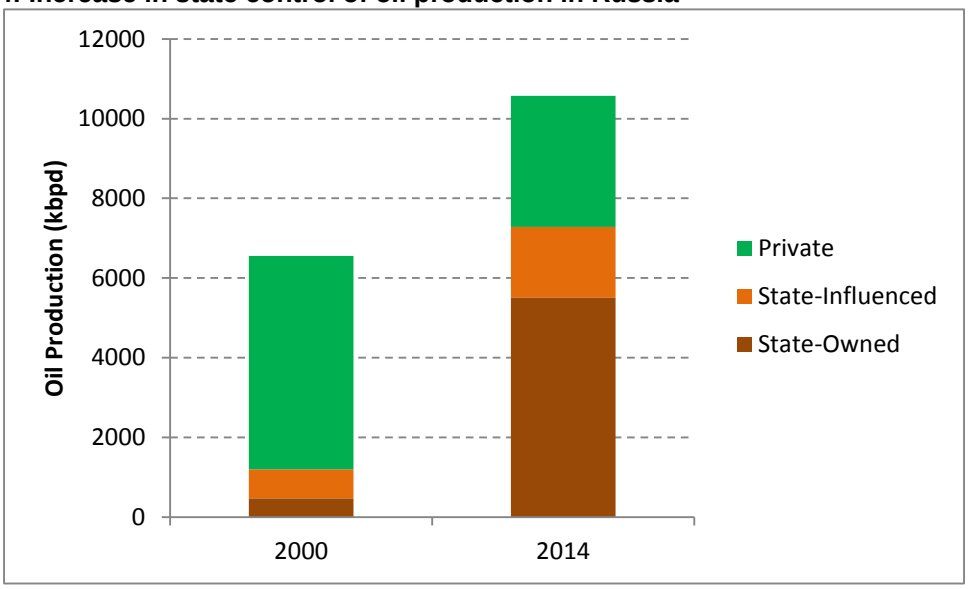
The Russian government currently owns just under 70 per cent of Rosneft,[17] and when its interests in Gazprom and Gazpromneft (owned via Gazprom) are added, along with the recently re-acquired Bashneft,[18] the state now directly controls more than half of Russian oil production. Its influence stretches to two-thirds of total output if Surgutneftegas (which is widely believed to be closely linked to the Kremlin)[19] and Tatneft (which is controlled by the government of Tatarstan) are also included (see Figure 4).

[17] http://www.rosneft.com/Investors/structure/share_capital/, accessed on 17 March 2015

[18] Interfax, 18 December 2014, "Bashneft affair doesn't mean privatisation review – Putin"

[19] Financial Times, 30 April 2013, "Surgutneftegas reveals $15bn of treasury shares missing"

Figure 4: Increase in state control of oil production in Russia

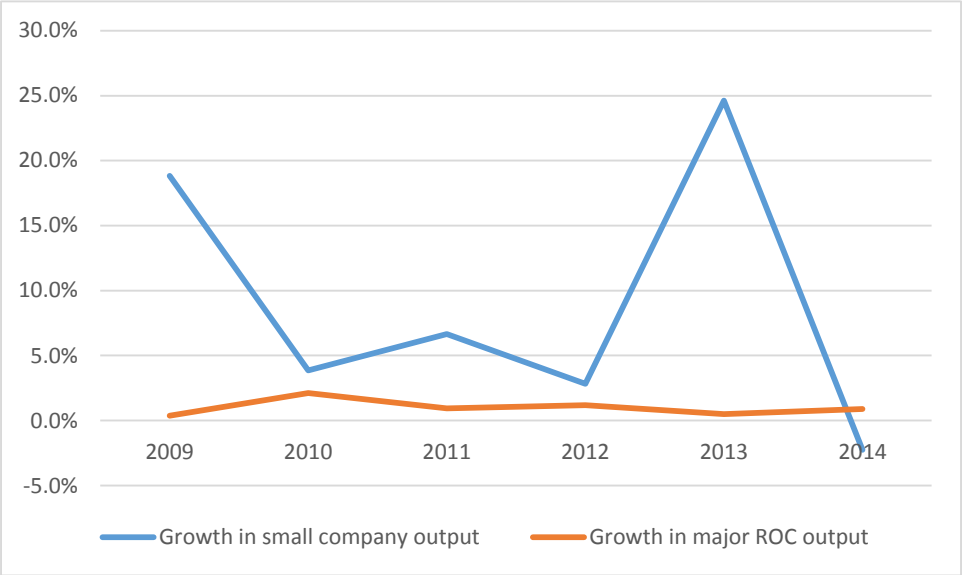


Source: Author's calculations from Interfax data

The resulting reduction in the influence of private companies, as well as a decline in international involvement during the period 2005-2012 that was a consequence of increasing state control and concerns over governance,[20] would appear to have had an impact on the effectiveness of investment in the sector. Further evidence for this assertion is provided by the fact that small privately-owned independent companies, which still number around 140 but which produce less than 10 per cent of the country's oil production, have accounted for more than one-third of production growth since 2010 (see Figure 4). This would seem to suggest that while the entrepreneurial nature of private enterprise has been an ongoing catalyst of oil output growth in Russia, the bigger companies, which are largely under state control, have been much less effective at growing production. A future issue could therefore be whether these small companies are more at risk from an oil price downturn than the government-supported enterprises that have had more stagnant performance over the past five years. Indeed, it is perhaps a concern that 2014 was the only year in which the growth in small company output has not exceeded the growth in production from the major Russian Oil Companies (ROCs).

[20] Henderson & Ferguson (2014), pp.49-60

Figure 5: Annual oil production growth: small companies v. major ROCs



Source: Author's calculations from Interfax data

As a result, although Russian liquids production (including crude oil and gas condensate) reached a post-Soviet record of 10.58 million barrels per day in 2014 (526.3 million tonnes),[21] there is concern about whether growth can be maintained. This concern has been magnified both by announcements of cost cutting in the face of lower oil prices and the impact of US and EU sanctions, which have limited the use of some technologies and restricted the ability of some companies to raise finance on Western capital markets. Therefore, although the remaining potential of the Russian oil sector is significant, as will be examined in the next section, the key question is the ability of domestic companies to exploit it effectively, which will be discussed in the rest of this paper.

[21] Ministry of Energy of the Russian Federation at http://www.minenergo.gov.ru/activity/statistic/1558/, accessed on 29 March 2015

3. Underlying Trends in Russian Oil Production

Perhaps the most important issue when attempting to understand the outlook for oil output in any region, or even in any individual field, is the underlying decline rate for existing oil-producing reservoirs. This is particularly true in Russia, where many of the fields across the country, especially in West Siberia and European Russia, have been in production for decades and are still influenced by the impact of the historic use of Soviet-era production methods. Assets such as the giant Samotlor field, previously owned by TNK-BP but now under the control of Rosneft, illustrate the point. Discovered in 1965 and brought into production in 1969, the field reached peak output of 150 million tons per annum (3 mmbpd) in the 1980s but has been in decline ever since. The drive to maximize short-term production in the late Soviet era led to poor reservoir management and excessive use of waterflooding, and when investment collapsed in the 1990s production fell to a low of 335,000 bpd in 1996. From this low, the involvement of private company TNK, and then ultimately BP, allowed new enhanced recovery and water management techniques to be applied to the field. This catalysed a rebound in output to a high of 31.6 million tonnes (635,000 bpd) in 2006,[22] before the inevitable decline set in again, with production falling to 17.5 million tonnes (350,000 bpd) by 2012.[23]

The fall in Samotlor's production from the early 1980s to the mid-1990s, which averaged 14 per cent per annum in a 15-year period, illustrates the high natural decline rate for fields in the heartland of Russia. This is especially relevant at any time when investment funds are in short supply, as was the case towards the end of the Soviet era and in the early years of the newly-formed Russian Federation. However, the Samotlor example also demonstrates the positive impact that the implementation of standard enhanced oil recovery techniques can have in terms of slowing decline rates and even reversing the trend completely. Between 1996 and 2006 output from the field doubled (albeit from a very low base), and over the past six years (2008-2014) the decline rate has been kept at an average of 5 per cent per annum,[24] which is considerably better than the natural expectation for a mature West Siberian reservoir.

Samotlor, though, is clearly an extreme example. It has been in production for more than 45 years, during which time it also suffered the worst extremes of the relatively primitive and short-termist Soviet methods. As a result, recovery was always going to be difficult and reservoir performance was bound to be poor. In contrast, analysis of the overall 'brownfield' portfolio of assets in Russia reveals that the decline rates have been much lower than might have been anticipated, thanks in particular to the impact of the techniques brought by Western service contractors. If one considers any fields that were at, plateau production in 2013 as brownfield sites, then a subsidiary-by-subsidiary analysis of the major Russian production companies (totalling more than 120 corporate entities) reveals that the average decline rate over the past five years has been approximately 2 per cent per annum.[25] Even if one focuses on the largest production companies (which as discussed above have tended to be less efficient than the small producers) the average decline rate has only been 2.3 per cent per annum. Figure 6 shows the historic production for the five largest companies since 2008.

[22] Gustafson (2012), p.598

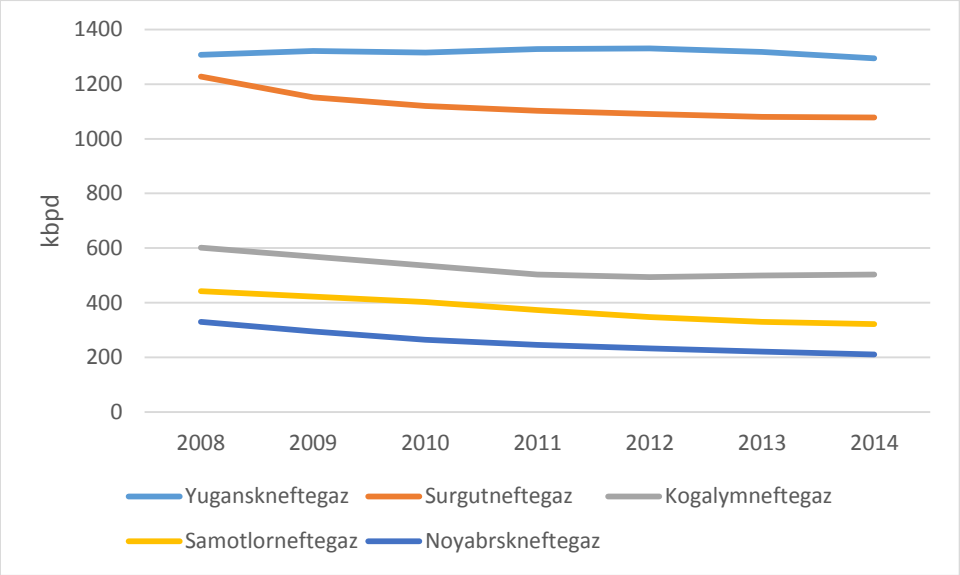
[23] http://www.rosneft.com/Upstream/ProductionAndDevelopment/western_siberia/samoltorneft/, accessed on 17 March 2015

[24] Interfax (2014), p.20

[25] Ibid. pp.20-22

The decline rates for the five companies range from an average of 7 per cent p.a. for GazpromNeft subsidiary Noyabrskneftegas to only 0.2 per cent for Yugansknefteqas (the Rosneft subsidiary acquired from Yukos in 2004), but overall it is clear that decline rates can be maintained at well below the natural rate. Furthermore, it would seem that the potential for this process to continue is significant, as although many Russian oil fields are considerably depleted, the oil recovery factors (the amount of oil recovered compared to the total reserves in place) are low. BP first highlighted this issue in 2003 when it acquired its 50 per cent interest in TNK-BP, as it compared the average recovery factor at TNK-BP's five largest assets (25 per cent) with the recovery rate of a comparative field in Alaska (Prudhoe Bay) where the recovery rate was 44 per cent, and the future expectation was for ultimate recovery of more than 50 per cent.[26] It was noted that improvement in the Russian assets towards international norms could add 18.5 billion barrels of oil equivalent (boepd) in reserves from these five fields alone, thus emphasizing the upside potential from existing fields in Russia's core producing areas.

Figure 6: Production from the five largest production companies in Russia since 2008



Source: Author's analysis from CDU-TEK data

A more recent report by Ernst and Young reiterated the importance of exploiting the remaining reserves in Russia's brownfields, underlining that 80 per cent of the country's reserves are in fields that have already been developed and 62 per cent of production now comes from assets defined as 'hard to recover'.[27] However, much of this oil is currently uneconomic to produce because of the nature of the Russian tax regime (see later discussion in section 6), with the economics of some of the more expensive enhanced oil recovery techniques being undermined by lack of a profits-based system. The IEA also confirmed the importance of brownfield recovery rates in its 2013 World Energy Outlook, suggesting that the potential for Russian oil production to stay above 10 mmbpd would in large part depend upon the country's success in raising recovery rates at existing fields and increasing the exploitation of hard-to-recover resources.[28]

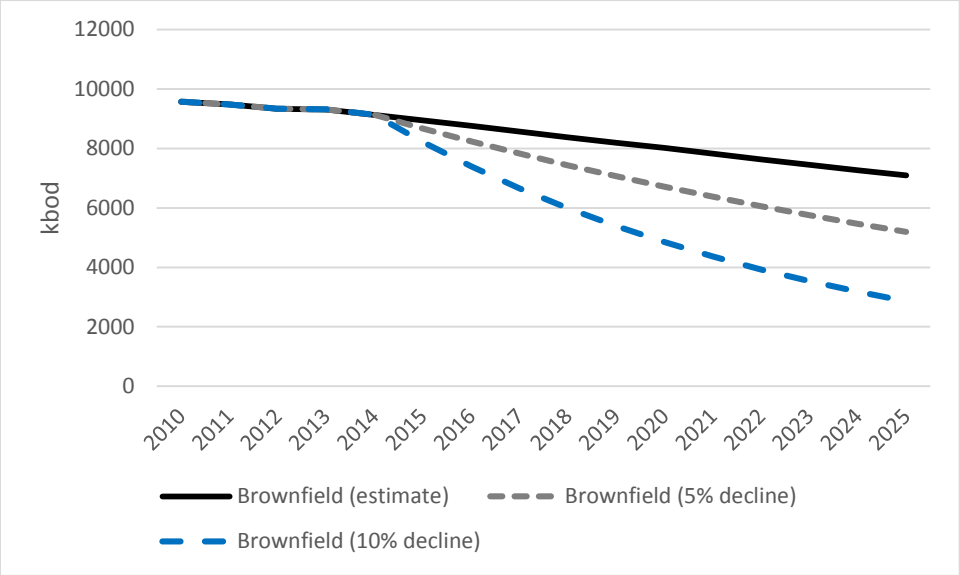
[26] BP and TNK-BP Presentation to Financial Investors, 16-17 October 2003, London and New York, slide 41

[27] Ernst & and Young (2013), p.9

[28] International Energy Agency (2013), p.482

Therefore, assumptions about the rate of brownfield decline are clearly a core foundation for the outlook for Russian oil production, and Figure 7 shows three scenarios for the period 2015-2025. The solid line shows a decline rate based on the average in the period 2010-2014 for each of the 120 production subsidiaries of the major Russian oil companies, plus the overall rate for the 140 smaller independent producers. This leads to an estimate for an average decline rate to 2025 of approximately 2 per cent per annum. This is effectively the level that might have been expected in a scenario where the status quo in the oil market had continued from mid-2014, with a Brent oil price of $100 or more and a rouble exchange rate of approximately US$1=RR35. The two dotted lines then show potential downside estimates that could conceivably result from a lower world oil price, with a 10 per cent decline scenario reflecting a worst-case outcome if investment is cut back very drastically (akin to the early 1990s), while the 5 per cent decline scenario shows a mid-case of significant cost cutting but some continued focus on the efficient management of existing fields.

Figure 7: Potential decline in brownfield production in Russia



Source: Author's estimates

As can be seen, in a worst-case scenario output from Russian brownfields could fall as low as 3 mmbpd by 2025, and even in the base case of 2 per cent decline the outlook is for production from Russia's core existing fields to fall to around 7 mmbpd over the next decade. Neither of these forecasts would be surprising to the Russian government or the country's major oil companies, as the potential for brownfield decline has been highlighted by many industry players. For example, Lukoil has consistently emphasized the risks of a sharp decline in Russian oil output to as low as 6 mmbpd by 2021 (including brownfields and new greenfield sites) if the Russian government does not adjust the tax regime.[29]

[29] Alekperov (2012), slide 19

4. Replacing the Brownfield Decline

Arctic, Deep Water and Tight Oil – The Impact of Sanctions

In recognition of the potential for a fall in output from core production areas such as West Siberia, the Russian oil companies, encouraged by the government and led by Rosneft as the key state-controlled player, have been investigating the potential of more peripheral areas for development. In the past three or four years, two specific options have been in particular focus for both political and commercial reasons: the Arctic and shale oil.[30] Both have been identified as having the potential to offset the production decline in West Siberia and both have also offered the opportunity to encourage partnership between domestic and foreign companies, which could facilitate the transfer of technology and the sharing of financial risks that could boost Russia's oil sector.

The potential of the Russian Arctic was highlighted in 2008 by a report from the US Geological Survey, which identified 240 billion barrels of oil equivalent of hydrocarbon resources in the region, accounting for 58 per cent of the total across the entire Arctic geography.[31] The Russian government had already signalled its political intent in the area when an expedition led by a member of the Russian Duma planted a flag on the seabed at the North Pole in 2007,[32] and it has subsequently sought to catalyse the development of Russia's northern regions via the oil and gas sectors. From a gas perspective, Novatek has been a leading protagonist with the development of the onshore Yamal LNG project,[33] but offshore licences have been reserved under law for state companies.[34]

Within this context, Rosneft signalled its initial interest in oil exploration in the area as part of a deal announced with BP in January 2011, when the two companies agreed to swap shares as well as to form a joint venture for Arctic exploration in the South Kara Sea.[35] The deal ultimately fell apart due to objections from BP's partners at TNK-BP, but Rosneft wasted little time in replacing BP with ExxonMobil in its South Kara Sea joint venture,[36] as well as forming other partnerships with ENI and Statoil to explore licences in the Barents Sea.[37] The venture with ExxonMobil was ultimately expanded to cover areas in the more remote Laptev and Chukchi Seas,[38] but it has been the exploration of three licences in the South Kara Sea that has sparked most interest because of the huge potential identified there.

The first drilling began in August 2014, with a well on the 'Universitetskaya' prospect targeting horizons with a resource potential initially estimated at 7 billion barrels of oil equivalent.[39] The main concern for the companies was whether liquids would be discovered, as gas would have been uneconomic in such a remote region, and in September 2014 Rosneft announced that oil had indeed been discovered, with the initial results suggesting that the area around the first well

[30] IEA (2014), pp.130-132 and p.138

[31] USGS (2008), "Circum-Arctic Resource Appraisal", p.4

[32] New York Times, 2 August 2007, "Russians plant flag on the Arctic seabed"

[33] Novatek (2014), slides 15-24

[34] Financial Times, 4 October 2012, "Russia moots Arctic oil licences for west"

[35] Financial Times, 15 January 2011, "BP in $16bn share swap with Rosneft"

[36] Daily Telegraph, 30 August 2011, "Blow for BP as Rosneft, ExxonMobil sign Arctic deal"

[37] See home page of http://rosneft.com/, accessed 29 March 2015

[38] Rosneft press release, 13 February 2013, "Rosneft and ExxonMobil expand strategic co-operation"

[39] Rosneft press release, 27 September 2014, "Rosneft discovered a new hydrocarbon filed in the Kara Sea"

alone could contain as much as 750 million barrels in the newly-named Pobeda (Victory) field.[40] This initial success has certainly encouraged the view that economic production in the region could be possible, with ultimate estimates for output in the range 1-1.5 mmbpd.[41] However, the remoteness of the region, the harshness of the climate, the resulting logistical difficulties, and the huge costs involved (the initial well is estimated to cost $600-700mm) always meant that even this first field would not realistically be in production before the end of the next decade.

However, irrespective of the operational challenges, a more immediate blow to Arctic development in Russia has been the imposition of sanctions by the US and EU, which have effectively banned any form of assistance being given by Western oil companies in this challenging arena.[42] In particular, US sanctions have forced ExxonMobil to completely withdraw from its co-operation with Rosneft in all its Arctic licences,[43] despite the fact that agreements were signed before the bans were announced in July.[44] The EU sanctions are less stringent, allowing companies to proceed with contracts already announced, but it would appear very unlikely that Statoil or ENI will decide to move ahead in the Barents Sea while the political situation surrounding Ukraine remains tense.[45]

Rosneft has announced that it will not be returning to the Pobeda field in 2015 as planned, but will postpone further activity until 2016 at the earliest.[46] This is no doubt partly because ExxonMobil is contracted to fund all of the initial exploration costs in the area (up to a total of $3.2billion), and Rosneft's financial position (see section 5 below) means that it will not be keen to take on this extra burden. Perhaps the more important point, though, is that in the current oil price environment the company is more focused on lower-cost and shorter-term options to maintain oil output. Delays in Arctic development will have no impact on Russia's short-term production issues, and as such the sanctions can be viewed more as an annoyance than a threat to the Russian oil sector.

As far as oil production is concerned, the same can also be said for the impact of sanctions on deep water exploration, another embargoed area. Western companies are banned from co-operating in the development of resources in Russian waters at a depth of more than 500 feet, and again this mainly targets ExxonMobil's planned activities with Rosneft, this time in the Black Sea.[47] However, the prospects there are at a very early stage of exploration, and so potential oil production would always be some time away, potentially beyond 2030 given the likely technical and geological issues.

However, one area where the sanctions can have a short- to medium-term impact is in the development of tight oil in Russia. Following the boom in tight and shale oil production in the US over the past decade, the United States Geological Survey (USGS) considered the prospects for similar developments in other countries and assessed Russia as having the largest potential resource base with 75 billion technically recoverable barrels.[48] This opportunity was seized on by

[40] Financial Times, 27 September 2014, "ExxonMobil, Rosneft strike oil in Arctic well"

[41] Henderson & Loe (2014), pp. 29-32

[42] http://www.state.gov/e/eb/tfs/spi/ukrainerussia/, accessed 29 March 2015

[43] Financial Times, 23 September 2014, "Exxon winds down Russian Arctic drilling campaign"

[44] Reuters, 29 July 2015, "EU and US announce new sanction on Russia over Ukraine crisis"

[45] BBC, 18 August 2014, "Norway's Statoil partners with Rosneft despite Russia sanctions"

[46] Reuters, 30 January 2015, Russia's Rosneft will not resume drilling in Kara Sea in 2015"

[47] Rosneft press release, 30 August 2011, "Rosneft and ExxonMobil to join forces in Arctic and Black Sea"

[48] US EIA, June 2013, 'Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the US'.

the Russian government as a potential source of production that could help to stem any decline in conventional fields, with the Ministry of Energy estimating possible production of almost 500,000 bpd by 2020, while the Ministry of Natural Resources forecast output of more than 1 mmbpd by 2025.[49]

The main focus of attention has been on the Bazhenov shale layer, which stretches across most of West Siberia and has been the source rock for many of the major fields there.[50] Russian companies such as Surgutneftegas and Lukoil have been drilling into this shale for decades, but with limited success using vertical wells. It has been recognized that international drilling techniques and equipment, mainly brought by companies with experience in the US, will be needed to fully exploit Russia's resources. A number of joint ventures have been formed for this purpose, notably between Rosneft and ExxonMobil, Statoil and BP, Lukoil and Total, and GazpromNeft and Shell.[51] However, US and EU sanctions have banned any Western involvement in the development of Russian shale, with the result that not only have these joint ventures been put on hold, but foreign service companies have also become wary of providing equipment that could be used in shale developments. As a result, companies such as Schlumberger and Halliburton were initially reluctant to provide any technology related to horizontal drilling and fracking, despite the fact that it can be used in conventional as well as unconventional wells. The US authorities have now clarified their position,[52] stating that only activity specifically related to shale development is banned, but nevertheless even this embargo will set back Russian plans for a key source of medium-term oil production by a number of years.

Alternative Greenfield Developments

The imposition of US and EU sanctions on specific areas of Russian oil development has undoubtedly forced a rethink of development strategy by a number of companies, but it is arguable that this would have occurred in any case because of falling oil prices and the devaluation of the rouble. Expensive and remote regions such as the Arctic would have been a challenge to develop at an oil price of $100 plus, and at $60 per barrel are almost certainly uneconomic. Tight oil development will also be expensive, with some commentators estimating that achievement of the Ministry of Natural Resources' target for 1 mmbpd of production by 2025 would cost as much as $100 billion.[53] As a result, it is likely that the financial constraints imposed by a lower oil price, and also by the restrictions on capital raising in international markets imposed by the US and EU sanctions (see section 5 for a full discussion), have forced the Russian oil sector to refocus its attention away from new and technically challenging areas and back towards the core onshore regions.

It is therefore interesting to note that there are a large number of conventional greenfield opportunities that are already in the early stages of production or are planned for development over the next five years. Many of these will proceed almost regardless of the oil price because the investments have either been sunk already or are underway and cannot be halted without further loss, meaning that their production impact is effectively already confirmed. As will be discussed, some of the projects that are still in the planning stage could be postponed, and this has been anticipated by Minister of Energy Alexander Novak who has suggested that 15 per cent of new

[49] Henderson (2013), p.7

[50] Skolkovo Energy Centre (2013)

[51] IEA (2014), pp.130-134

[52] Wall Street Journal, 12 December 2014, "OFAC clarifies Russian offshore drilling sanctions"

[53] Interfax, 15 January 2015, "Boosting tight oil production in W. Siberia to 1mmbpd by 2025 to cost $100bn"

investment projects planned for 2015 could be delayed if oil prices stay low.[54] Nevertheless, the impact of existing greenfield projects and new developments can be very significant over the next five to 10 years.

Existing Greenfield Production

In the analysis of existing assets above, brownfields were defined as fields that were already at peak output in 2013. This leaves two further categories of field to be analysed: firstly, new fields that are already producing, but which have come onstream recently and whose output has not yet reached the decline phase; and secondly, fields that are due to come onstream from 2015 onwards. Both categories can be expected to offset the brownfield decline to a greater or lesser extent, depending on the exact timing of first oil.

The first category (fields already in production) can be further sub-divided into those assets that are now at or near to plateau output and those where significant growth can still be expected. Prime examples of the former would include two Rosneft fields in East Siberia, Vankor and Verkhnechonsk. Vankor was launched in 2009 and production has been growing ever since, although estimates for peak output have been downgraded from over 500,000 bpd to 440,000 bpd – the level that was reached in 2014.[55] As a result, the field is now at plateau, with any further production increases set to come from satellite fields which can benefit from the existing field infrastructure (see next section). Verkhnechonsk also reached peak output in 2014, when Rosneft sold 8.3mm tonnes of crude (166,000 bpd),[56] and this plateau is expected to be maintained until the end of the decade. Another field in the Rosneft portfolio close to its peak is Uvat, which is in fact a group of fields in the Tyumen region of West Siberia where initial production began in 1991. A new development plan was initiated here in 2009 and helped production more than double over the past five years to a high of 191,000 bpd in 2014. Peak production of 200,000 bpd is expected to be reached in 2015 and to remain at that level until 2020.[57]

Other examples of fields that have come onstream in the past few years include Lukoil's Yuri Korchagin field in the Russian sector of the Caspian, which produced first oil in 2010 and will reach a peak of 47,000 bpd in 2015 or 2016,[58] while Surgutneftegas' Talakanskoye field in East Siberia has been the driving force behind the increase in the company's output in Yakutia over the past seven years. Indeed, production from Surgut Yakutia has offset the decline in the company's main West Siberian producing subsidiary, as output from Talakanskoye and its four satellite fields exceeded 150,000 bpd in 2014, offsetting an equal decline in West Siberia over the past seven years.[59] Development of further Talakanskoye satellites should see output continue to rise gradually over the next two or three years before plateauing towards the end of the decade.

In contrast to these relatively new fields or field areas that are reaching plateau, another tranche of existing greenfields has only just commenced production and is set to boost output significantly over the next few years. GazpromNeft is the company with the most assets in this category, with Russia's one offshore Arctic oil development to date, Prirazlomnoye, at the forefront.[60] The field

[54] Interfax, 6 February 2015, "Around 15% of this year's investment projects may be postponed due to low oil prices – Novak"

[55] Reuters, 25 October 2013, "Rosneft sees output plateau at Vankor group by 2019"

[56] Rosneft Management Discussion and Analysis of Financial Condition and Results of Operations for 2014, p.20

[57] Oil and Gas Technology, 12 December 2014, "Rosneft lauds Uvat project production levels onshore Russia"

[58] Interfax, 21 December 2014, "Lukoil invests 47bn rubles in development of Filanovsky field in Caspian"

[59] Interfax (2014), p.21

[60] http://www.gazprom-neft.com/company/business/exploration-and-production/new-projects/prirazlomnoe/, accessed 29 March 2015

came onstream in late 2013 but sold its first oil in 2014 when average production was around 5,000 bpd, but this is set to rise consistently over the next few years to reach 120,000 bpd by 2020, where it will remain for approximately five years.[61] Also in the far north, but onshore, GazpromNeft has the Novy Port field, which contains 1.8 billion barrels of oil reserves that began pilot production in 2013. A full development of the field is now underway, with commercial output set to commence in 2016 and reach a peak of 8.5 million tonnes per annum (170,000 bpd) by the end of the decade. [62]

Bashneft and Lukoil also own an important asset that has recently come onstream in 2013, called Trebs and Titov, which is located in the Timan Pechora region of North West Russia. Development of the two-field complex has been complicated by a dispute over the rights of the Bashneft Polyus joint venture to own the licence, which was originally awarded to Bashneft alone but in which Lukoil now has a 25 per cent stake.[63] However, the legal debate was ended in January 2015 and the fields are now set for full development by 2016, when initial output of 30,000 bpd should be reached (around 10,000 bpd was produced in 2014). Peak output of almost 100,000 bpd would then be achieved by 2020, with output from 200 wells likely to be at plateau for around five years.[64]

Two other new assets are also worth highlighting in this category, as they exemplify an alternative form of liquids production that is set to become more important in Russia over the next decade. Rospan and Severenergia (owned by Rosneft and a joint venture between GazpromNeft and Novatek respectively) are primarily gas assets, but they also contain large amounts of gas condensate and oil. The development of Rospan, which was previously owned by TNK-BP, has been delayed because of lack of gas market opportunities, but Rosneft's aggressive plans for its gas business mean that the project is now moving ahead. 2014 liquids production totalled 14,000 bpd based on gas production of 4 bcm, but with output set to increase to 18 bcm by 2018 the related condensate production could jump to around 45,000 bpd over the same time period.[65] Meanwhile, the level of Severenergia production is due to increase even more sharply. The joint venture commenced production in 2012 from the Samburgskoye licence, with two more fields coming onstream in 2014 and a further one to follow in the period 2015-16.[66] Liquids production in 2014 reached 60,000 bpd, but as the group of fields reaches peak gas production of 35bcm in 2019 so total liquids output is set to exceed 225,000 bpd, providing a significant boost to this predominantly gas project and simultaneously helping to sustain Russia's overall oil production.

This increase in liquids production from wet gas fields is also likely to be reflected more generally in Gazprom's production profile over the next two decades. The company is currently investigating the deeper layers in a number of its major fields, with the Urengoy Achimov reservoir and the Valenginian reservoir at the Zapolyarnoye field being two examples. While it is difficult to be precise about the exact potential for Gazprom's future condensate output, the company's liquids production (excluding GazpromNeft) has been rising consistently over the past

[61] Reuters, 18 April 2014, "Russia ships first oil from disputed offshore Arctic platform"

[62] http://www.gazprom-neft.com/company/business/exploration-and-production/new-projects/new-port/, accessed 29 March 2015

[63] RAPSI, 22 January 2015, "Bashneft, Lukoil win litigation over Trebs and Titov fields"

[64] Interview with Michael Stavsky, Bashneft vice president for exploration and production, sourced on 26 March 2015 from http://www.bashneft.com/press/interviewing/6712/

[65] http://www.rosneft.com/Upstream/ProductionAndDevelopment/western_siberia/rospan/, accessed on 18 March 2015

[66] Novatek presentation to investors, "Russia's natural gas frontiers: Harnessing the Energy of the Far North", 1-3 October 2013, slide 7

six years (from 250,000 bpd in 2008 to 325,000 bpd in 2014)[67] and further growth is anticipated as its gas production gets 'wetter'. Indeed, in a presentation in 2010 Gazprom forecast that the balance of wet to dry gas production would switch from a ratio of 24:76 in 2008 to 63:37 in the period 2025-2030, suggesting significant upside in liquids output from this source.[68]

One final example worth highlighting is a relatively new company based in East Siberia called Irkutsk Oil,[69] which was formed by a group of local entrepreneurs to develop small oilfields that could export crude via the East Siberia – Pacific Ocean (ESPO) pipeline that was built in the region in 2009. The company has seen its output grow from zero in 2011 to 78,000 bpd in 2014, and this expansion is expected to continue for the next few years with output reaching 100,000 bpd by the end of the decade.[70] This growth, when combined with the major fields discussed above, demonstrates that Russian oilfield development has by no means come to a halt as a result of the current slump in oil prices. Indeed, the assets mentioned here could add around 500,000 bpd of production by 2020 on their own compared to their 2014 output, while other identifiable smaller assets could potentially double this figure.

New Greenfield Sites

In addition to the new fields that are already producing oil, Russian companies also have a number of future developments that are due to come onstream over the next five years. Table 1 lists 17 assets that are set to be launched from 2015. Total peak production from all of the fields listed comes to almost 1.8 mmbpd, demonstrating the potential for growth that is available from identified assets ready for development in Russia.

Table 1: New oil fields in Russia

Field	Companies	Peak Output (kbpd)	Launch Date
Imilor	Lukoil	100	2015
Yarudeiskoye	Novatek	70	2015
Spielman	Surgutneftegas	60	2015
Novoport	GazpromNeft	130	2016
Filanovskoye	Lukoil	125	2016
Suzun	Rosneft	120	2016
Labaganskoye	Rosneft	25	2016
Messoyakha	Rosneft/GazpromNeft	215	2016
Russkoye	Rosneft	150	2017
Yurubcheno-Takhomskoye	Rosneft	115	2017
Taas-Yuriakh (phase 2)	Rosneft	110	2017
Kuyumba	Rosneft/GazpromNeft	115	2017
Chonsky	GazpromNeft	65	2018
Tagul	Rosneft	100	2018
Naulskoye	Rosneft	50	2018
Lodochnoye	Rosneft	40	2019
Sevostyanova, Sanarsky, Lisovsky	Rosneft	200	2019

Source: Company data, Fak (2014)

[67] Interfax (2014), p.22

[68] Gazprom (2010), slide 12

[69] http://irkutskoil.com/, accessed 30 March 2015

[70] Henderson (2011), pp.42-45

The type and location of the fields and the commitment of the relevant companies to developing them ranges significantly. Lukoil has confirmed its plans to bring the Imilorskoye group of fields online this year, with the field having been officially commissioned in October 2014.[71] The combined reserve base of the West Siberian field complex is 1.4 billion barrels, and production is set to reach 6,000-8,000 bpd in 2015 before rising to 60,000 bpd by 2020 and an ultimate peak of 100,000 bpd following total investment of $2.5 billion over the next 20 years. The company is equally confident about its Filanovsky field in the North Caspian Sea, which is set to follow Yuri Korchagin as Lukoil's second offshore production site. A company spokesman confirmed progress at the field, stating that it may even be commissioned six months earlier than the 2016 deadline,[72] with the 1.1 billion barrel field set to reach maximum output of 125,000 bpd.

Two other fields due to come onstream in 2015 are Novatek's Yarudeiskoye and Surgutneftegas' Spielman. Yarudeiskoye will be Novatek's first pure oil field, with output starting at 10,000 bpd in 2015 but rising to 70,000 bpd by the end of the decade as the company continues to diversify into liquids production to support its core gas business.[73] Meanwhile, Surgutneftegas confirmed in its report for the fourth quarter of 2014 that the Spielman field will be coming onstream in West Siberia in 2015, with an ultimate capacity of 60,000 bpd.[74]

The remaining major new fields are owned by the state companies Rosneft and GazpromNeft, and importantly the largest of them are located in strategic development areas for both companies. For example, the Suzun, Tagul, and Lodochnoye fields are all located in a cluster close to Rosneft's giant Vankor project on the border of East and West Siberia, and will be tied into infrastructure being constructed to link fields in the area to the ESPO pipeline. Indeed, the three fields may ultimately be controlled from the Vankor asset, optimizing the logistics and resourcing of the projects as well as permitting the most timely development of each asset.[75] Transneft has suggested that expansion of the Zapolyarnoye-Purpe pipeline, which will evacuate oil from the region, may be delayed if sanctions impact field expenditure plans, but the logic of developing satellites around a major field complex to maximize synergy benefits would appear to argue for a rapid development schedule.[76] Indeed Rosneft has confirmed in April 2015 that the Suzun filed has been successfully tested and is set to come online in 2016, while Tagul should be online by 2019 followed by the Lodochnoye field, which still requires further exploration work. Overall it is anticipated that the Vankor "hub" will have total production of 500,000 bpd by the end of the decade.[77]

A second major field development not far from Vankor, located on the Gydan peninsula in the northern part of West Siberia, is the Messoyakha field, a joint venture between Rosneft and GazpromNeft.[78] The field, which is split into licences for the eastern and western segments, contains an estimated 3.4 billion barrels of liquids, which will be connected to the Zapolyarnoye-Purpe pipeline for evacuation to the ESPO. Initial production capacity from the eastern licence will

[71] Oil & Gas Journal, 8 October 2014, "Lukoil commissions Imilorskoye field in West Siberia"

[72] Society of Petroleum Engineers, 25 July 2014, "Lukoil's Vladimir Filanovsky offshore field on track for 2015 commission"

[73] PRIME Business News, 8 November 2013, "Russia's Novatek to start oil, gas production at 7 new fields 2014-15"

[74] Surgutneftegas, 4 Quarter Report, published 12 February 2015 at www.surgutneftegas.ru/uploaded/qr0414Eng.pdf accessed on 26 March 2015

[75] Rosneft press release, 9 December 2014, "Vankorneft started construction of oil pipeline from Suzun field"

[76] Reuters, 16 September 2014, "Russia's Transneft says sanctions may delay oil pipelines launch"

[77] Argus FSU Energy, 2 April 2015, "Vankor hub takes shape"

[78] http://www.gazprom-neft.com/company/business/exploration-and-production/new-projects/messoyaha/, accessed on 30 March 2015

be 140,000 bpd (limited by the pipeline infrastructure from the field,[79] but this could increase to well over 200,000 bpd once the western licence also comes onstream. The Russkoye field, scheduled for first oil in 2017, is also located in the area close to the Zapolyarnoye-Purpe pipeline, making this region the most promising prospective area for future production growth in West Siberia over the next five years. The proximity of so many fields, and the commitment of Transneft to build the pipeline capacity in the region up to 900,000 bpd over the next few years, means that the development plans can be optimized by three state companies to deliver significant support to Russia's overall oil output.[80]

One other area of co-operation between the same three companies is in East Siberia, where the Yurubcheno-Tokhomskoye field complex is being developed by Rosneft, the Kuyumba field is being developed by another Rosneft-GazpromNeft partnership, and a pipeline to connect both to the ESPO pipeline is again being constructed by Transneft.[81] The fields and the pipeline are being developed in tandem, with a debate continuing about the exact timing and capacities that will be needed. In February 2015, a report from Deputy Minister of Energy Kirill Molodtsov suggested that there have been some delays in the field timetables, meaning that Transneft is adjusting its own construction plans for the pipeline, with current expectations being that around 22,000 bpd will be produced and transported from the combined fields in 2017 (following commissioning in 2016), rising to a peak of 230,000 bpd by 2025.[82] Even this timetable may be optimistic, with some commentators suggesting that a 2-3 year delay is possible, but even if this is the case the original plan was for full capacity of 300,000 bpd[83] may still be achieved if the commercial environment improves. However, even the lower figure would marks a significant boost to East Siberian oil output, albeit on a deferred timetable.

Implied Future Output Potential for Russian Oil

Given the potential outlook for brownfield oil assets in Russia, plus the continuing development of existing greenfield sites and new field developments over the next five years, it is possible to create a variety of estimates for future oil production in Russia. Firstly, Figure 8 below summarizes the potential production from existing and identified yet-to-be-developed greenfields, with the production from existing sites in 2014 of around 1.4 mmbpd rising to over 3.5 million bpd by 2020 as new fields are brought onstream. This increase includes not only the 1.8 million bpd of brand new production identified in the previous section but also the continued expansion of output at fields such as Prirazlomnoye and Trebs & Titov that have come online recently.

[79] Rosneft press release, 16 January 2015, "Recoverable reserves of East Messoyakha field increased by 32%"

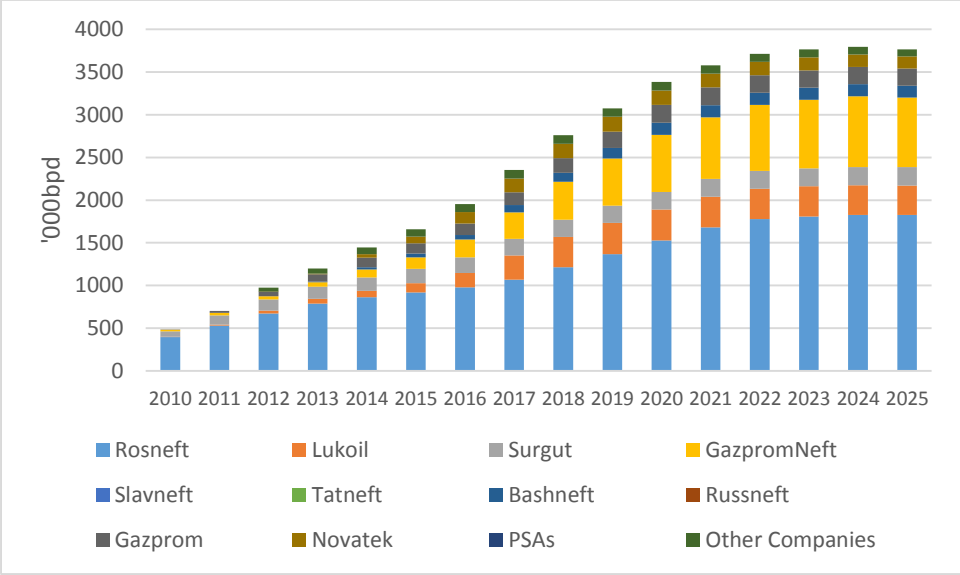
[80] http://en.transneft.ru/about/projects/current/10200/, accessed on 30 March 2015

[81] http://en.transneft.ru/about/projects/current/10649/, accessed on 30 March 2015

[82] Interfax, 5 February 2015, "Rosneft, Transneft should finalise pumping along Kuyumba-Taishet in month"

[83] Interfax, 5 February 2015, "Energy Ministry: Yurubcheno oil, gas projects slightly behind schedule; not critical"

Figure 8: Potential production from existing and new greenfield oil developments in Russia

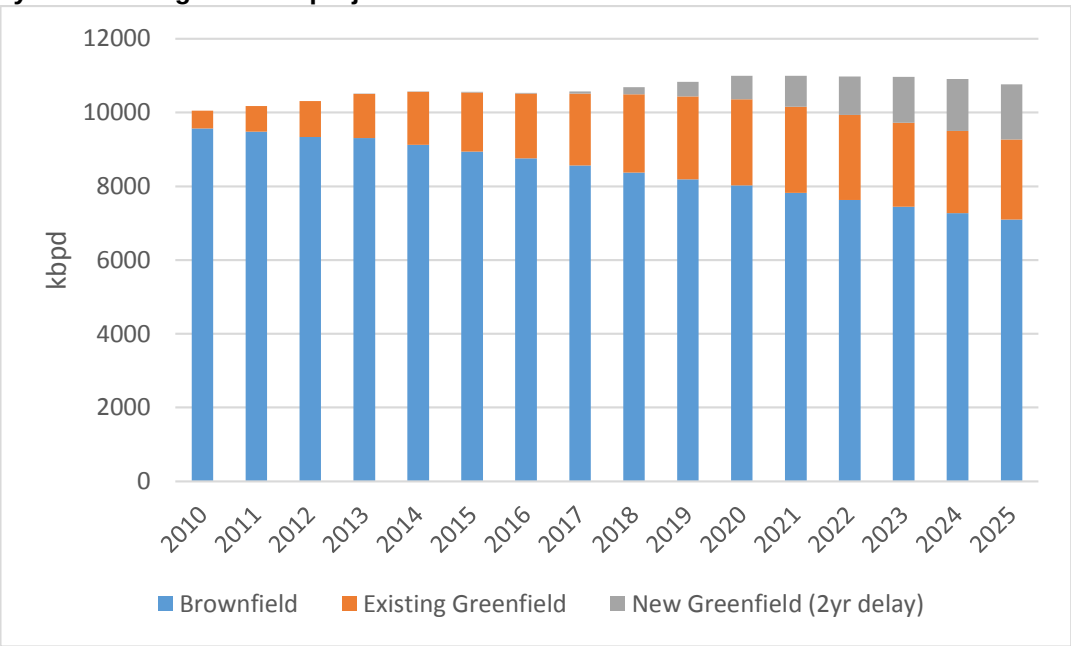


Source: Author's estimates based on company data

When this outlook for greenfields is then added to the previous analysis of likely brownfield production in Russia, three scenarios can be produced to correspond with the different decline profiles discussed above. In the case where the decline of brownfield production continues to follow the pattern of the past five years, in other words an average fall of around 2 per cent per annum, then overall Russian output can stay at around 10.5 million bpd for the next two years before rising to a peak of approximately 11.4 million bpd by the early 2020s as a significant number of new projects start to come online. In the case of a 5 per cent brownfield decline, output falls to just over 10 million bpd until the end of this decade before falling to 9 million bpd by 2025, while in the worst-case scenario, which effectively implies no investment in Russia's existing fields at all, production could decline to 8 million bpd by 2020 and below 7 million bpd by 2025.

However, this outlook fails to take into account the fact that the current oil price environment could also discourage investment in new fields. Despite the optimistic assessment presented above, it is possible that Russian oil companies could decide to delay spending on any fields that are not currently producing oil. This is a particularly bleak assumption given that a number of fields that are due to come onstream in 2015 and 2016 already have a significant level of sunk costs, but it is clear from the examples of Yurubcheno-Tokhomskoye and Kuyumba cited above that some deferrals are already being discussed. Nevertheless, for the purposes of this analysis it is safer to make a generic assumption for all new fields, and Figure 9 below shows a forecast which the 2 per cent brownfield decline case with a greenfield forecast which includes a two-year delay for all new projects. In this scenario, total Russian production remains at 10.5 million bpd until the end of this decade before rising to 10.9 million bpd in the early part of the 2020s.

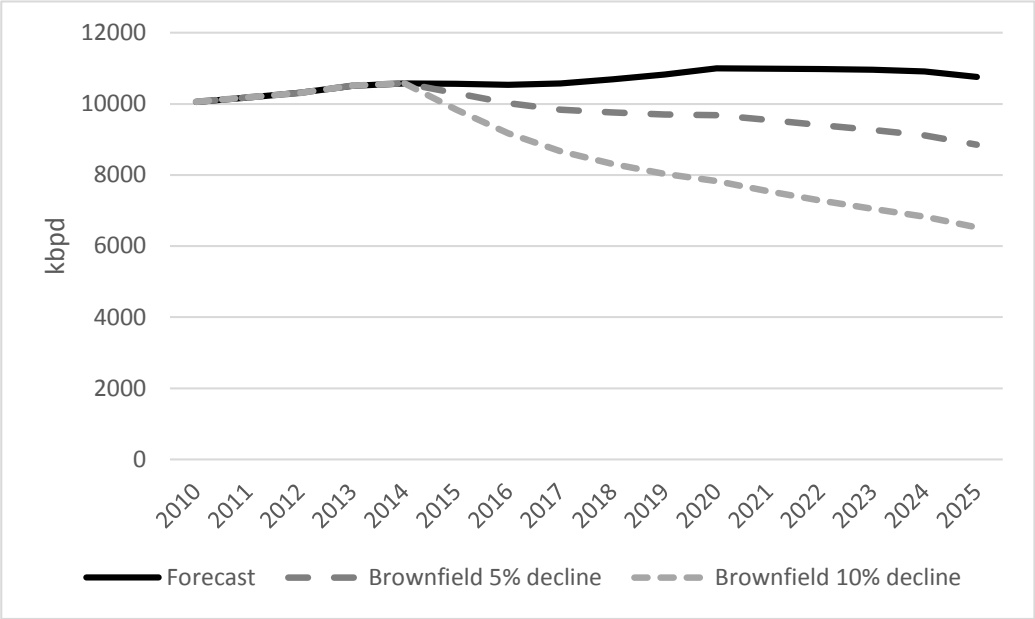
Figure 9: Russian oil production outlook assuming a 2% brownfield decline and a 2-year delay for all new greenfield projects



Source: Author's estimates

Clearly there are two downside scenarios to be painted from this base case, involving the 5 per cent and 10 per cent decline rate options for brownfields. Figure 10 below shows these two cases combined with the 2-year delay greenfield scenario, highlighting that in the 5 per cent decline case Russian production would fall below 10 million bpd for the remainder of this decade before reaching 9 million bpd by 2025. In the 10 per cent decline case total production could reach 7.5 million bpd by 2020 before hitting a low of 6.5 million bpd by 2025. The remainder of this paper will discuss the key determinants that will ultimately drive the resulting outcome. These include the levels of capital expenditure that companies are prepared to commit to projects and the impact of rouble devaluation on these costs; the ability of companies to raise finance in the face of sanctions; the willingness of the Russian government to provide support via direct financing or adjustment of fiscal terms; and finally, the potential for partnership with foreign companies to provide both technical and financial assistance in spite of the restrictions imposed by the current US and EU sanctions.

Figure 10: Russian oil production scenarios, assuming 2-year greenfield delay



Source: Author's estimates

5. Impact of Capital Expenditure Cuts and Rouble Devaluation

As described in the previous section, it would appear that, in theory at least, Russian oil companies have the assets available to maintain or even increase production from 2014 levels. However, a key question mark remains over their commitment to invest in these assets at a time of low oil prices and economic uncertainty. Table 2 below shows a history of upstream capital expenditure in Russia, sourced from the annual Barclays E&P Spending Outlook, which surveys the investment expectations of oil companies across the world.[84] The 2015 survey was published in December, with corporate expectations based on an oil price of $70 per barrel, and as a result the 2015 estimates in the table have been adjusted where companies have subsequently made announcements on spending forecasts.

Table 2: Upstream capital expenditure at major Russian oil and gas companies

	2010	2011	2012	2013	2014	2015E
Gazprom	12,293	18,500	12,866	13500	13500	10125
Lukoil	4,933	6,629	8,902	9,768	10,900	8,175
Rosneft	6,341	9,240	12,911	10750	9961	6973
Gazprom Neft	2,350	2,411	2,922	4514	5900	3835
Sugutneftegas	3,830	1,075	4,885	5409	5639	5075
Novatek	762	581	975	1387	1594	836
Bashneft				475	1199	1105
Tatneft				860	900	810
Total	30509	38436	43461	46663	49593	36934

Source: Anderson et al (2015), Company data (see notes below)

Specifically, since the survey was conducted Lukoil has confirmed that its capital expenditure will be cut by 20-25 per cent in 2015,[85] Igor Sechin, the CEO of Rosneft, announced in the UK in February 2015 that his company's spending in 2015 would fall by 30 per cent,[86] while GazpromNeft confirmed that it would not be revising its production plans for 2015 and would be increasing capital expenditure by 4 per cent in rouble terms.[87] Meanwhile, Surgutneftegas asserted that it would not be cutting its investments in 2015, with the implication that this would be in rouble terms,[88] Novatek announced that spending would fall to RR51 billion in 2015 from around RR60 billion in 2014 (excluding Yamal LNG),[89] and Bashneft CEO Alexander Korsik confirmed that spending would be cut, though he declined to place an exact figure on his estimate.[90] Finally, Gazprom announced at its strategy day for investors in February 2015 that it would be cutting its spending budget for 2015 by $8 billion to $30 billion—a fall of 21 per cent.

[84] Anderson et al (2015)

[85] International Oil Daily, 44 March 2015, "Lukoil sees Russian oil decline, price rebound"

[86] The Independent, 13 February 2015, "Igor Sechin: The oil man at the heart of Putin's Kremlin"

[87] Interfax, 26 December 2015, "GazpromNeft not to revise production plans for 2015"

[88] Interfax, 14 December 2014, "Surgutneftegas not yet considering lowering investments, production in 2015"

[89] Interfax, 23 January 2015, "Novatek not planning to borrow in 2015, spending to fall 15%"

[90] Interfax, 13 February 2015, "Bashneft won't ask for state support, not making acquisitions for now – Korsik"

These figures have been reflected in the upstream spending forecasts above, where appropriate on a pro rata basis from 2014 if the company forecasts have referred to overall expenditure for 2015. The overall result is that upstream capital expenditure in US dollar terms can currently be expected to fall by around 26 per cent in 2015 compared to 2014.

In a global context, such a sharp decline in expenditure would normally be correlated with a fall in production, with some lag to account for the impact of the previous year's drilling activity. Just such an outcome is anticipated by some commentators concerning shale oil output in the United States, where a decline in investment and drilling activity[91] is expected to cause a production reaction in the second half of 2015.[92] However, others have noted that a lower oil price environment has forced greater efficiency into the US service sector, with drilling costs falling and well efficiencies increasing,[93] and as a result a lower rig count has yet to cause any material change in output. A similar response to service sector costs can be expected in Russia, and interviews conducted by the author in Moscow in February 2015 suggest that oil companies there are indeed demanding a cut in service costs in rouble terms.

The added significance of this demand in Russia is that the real cost of drilling and servicing wells has already been reduced by the impact of the rouble devaluation relative to the dollar and the euro. Figure 11 below shows how the rouble exchange rate relative to the US dollar has moved over the past 15 months and compares it to the movement in the oil price, underlining how the Russian currency tends to respond rapidly to movements in the price of the country's most important export. The oil price has halved from its July 2014 high of $115 per barrel to a current level of just under $58 per barrel,[94] while the value of the rouble has collapsed from a monthly average of RR35=US$1 in July 2014 to a low of RR64=US$1 in February 2015 (including an absolute daily low of RR69=US$1 on February 1st),[95] before recovering to RR57=US$1 in March and RR52=US$1 in April.[96]

[91] Wall Street Journal, 11 February 2015, "Oil drilling slows as crude price drops"

[92] http://www.resilience.org/stories/2015-01-27/tight-oil-production-will-fade-quickly-the-truth-about-rig-counts accessed on April 11th 2015

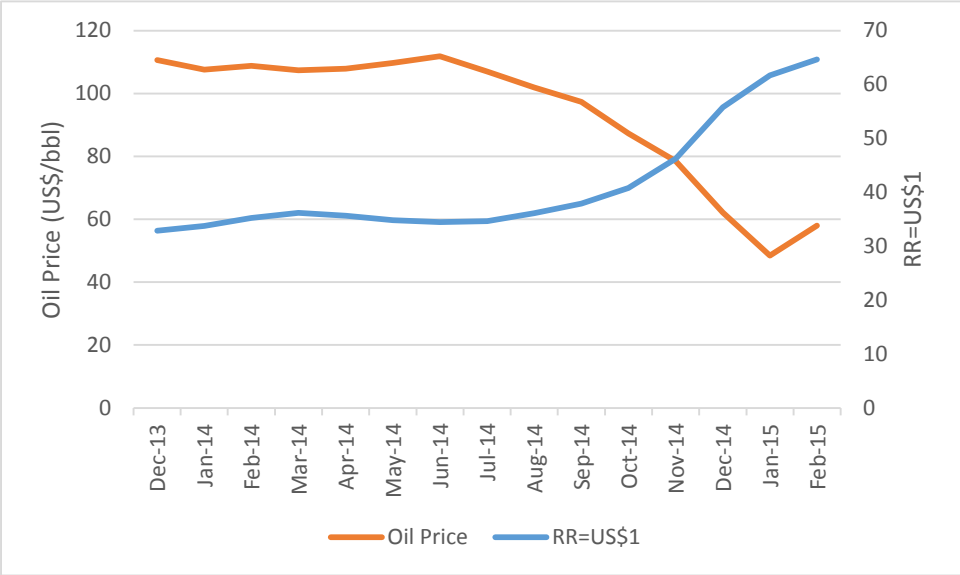
[93] New York Times, 13 March 2015, Oil prices drop as production hums along despite a brimming supply"

[94] Dated Brent as of 11 April 2015

[95] http://www.xe.com/currencycharts/?from=USD&to=RUB&view=1Y, accessed on 17 April 2015

[96] Exchange rate as of 11 April 2015

Figure 11: Oil price compared with rouble exchange rate



Source: Central Bank of Russia, Index Mundi

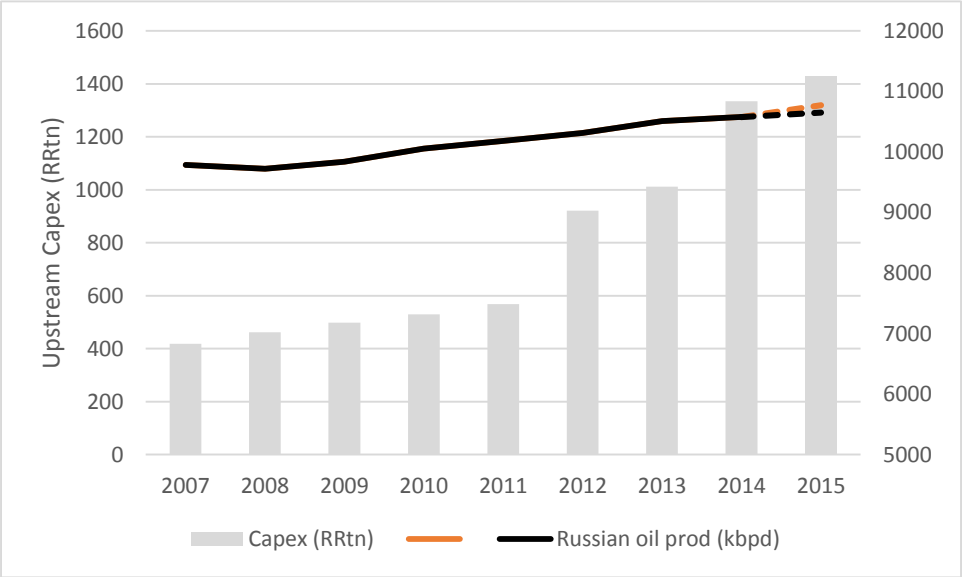
The majority of oil and gas companies in Russia claim that at least 80 per cent of their costs are denominated in roubles, meaning that at an assumed average exchange rate for 2015 of RR55=US$1 their operating and capital expenditures could fall by around 30 per cent when compared with the July 2014 exchange rate of RR35=US$1. Therefore, a better comparison of capital expenditure forecasts for 2015 should be carried out on a local currency basis, and it is clear that the 23 per cent decline in dollar spending highlighted in Table 2 above turns into a seven per cent increase when converted using the average exchange rates for 2014 and 2015 respectively.[97]

Based on a historical record of overall oil production and upstream capital expenditure in roubles from the major Russian oil companies it is then possible to carry out a rudimentary correlation and forecast for the production outcome in 2015.[98] Figure 12 below shows the outcome of this analysis. The correlation between spending in roubles and the production result for each year from 2007 to 2014 produces an R squared of 0.86, while a similar analysis for the period 2010-2014 produces an R squared of 0.91, suggesting that there is indeed a strong link between the two. When the relationships between production and spending in these two time periods are then used to forecast an outcome for 2015, using the rouble expenditure based on the data from Table 2, the answer is a range shown by the two dotted lines in Figure 12, which suggests the possibility of a 1-2 per cent increase in output rather than any decline.

[97] The average rouble exchange rate in 2014 was RR38.4=US$1, and for 2015 an average rate of RR55=US$1 is assumed

[98] In this analysis the spending data for Rosneft, Lukoil, Surgutneftegas and GazpromNeft has been used. Gazprom has been excluded because its focus is mainly on the gas business rather than oil production, while a full set of data was not available for the other companies in Table A. The four companies used represented more than 75% of Russian oil production in 2014.

Figure 12: Relationship between capital spending and production in Russia



Source: Author's analysis

This analysis needs to be treated with caution as the model is very simple and all the assumptions behind it are very fluid. For instance, companies are constantly adjusting their spending plans, the rouble exchange rate has moved dramatically in 2015 between a low RR69=US$1 and a high of RR52=US$1,[99] and the share of expenditure denominated in roubles or foreign currency is also very dependent upon the type of projects being undertaken. Furthermore, despite the attempts being made by Russian oil companies to secure reduced costs in rouble terms from their contractors, underlying Russian inflation is running at approximately 15 per cent per annum,[100] suggesting that the full benefits of devaluation will start to be eroded rather quickly. As a result, it is not the purpose of this analysis to make a specific forecast of 1-2 per cent growth in oil production in 2015, but rather to demonstrate that the rouble's devaluation can offset the impact of a declining oil price and consequent cuts in capital expenditure budgets, leading to the possibility of a small increase in output despite a significant cut in US dollar spending.

In fact, the first evidence for this outcome is already starting to emerge. Again, caution is required given the limited timescale, but in the first two months of 2015 drilling activity and oil production both increased compared to 12 months ago. Oil output for the two months increased by 0.7 per cent year-on-year,[101] but perhaps more interestingly the rise in drilling activity was much more significant, as shown in Figure 13, with exploration drilling up by 60 per cent and production drilling up by 20 per cent over the same time period.[102]

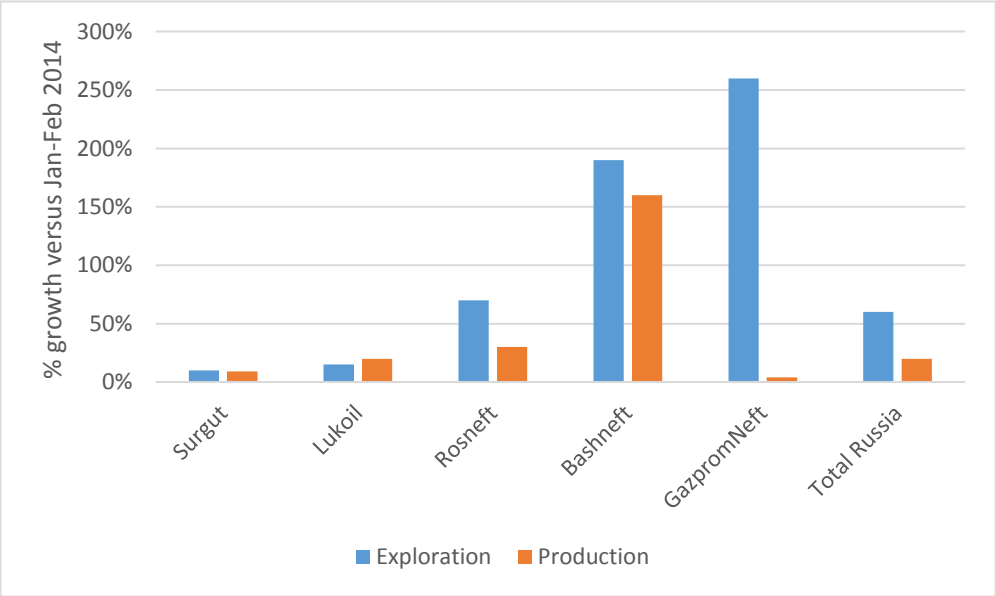
[99] http://www.xe.com/currencycharts/?from=USD&to=RUB&view=1Y, accessed on 11 April 2015

[100] Moscow Times, 5 February 2015, "Russian inflation soars to staggering 15 percent"

[101] Interfax, 2 March 2015, "Russia produces 0.7% more oil in Jan-Feb, 7.2% less gas"

[102] Interfax, 24 March 2015, "Russian oil companies boost exploration drilling 60% in Jan-Feb 2015"

Figure 13: Change in drilling levels in Russia, Jan and Feb 2014-2015

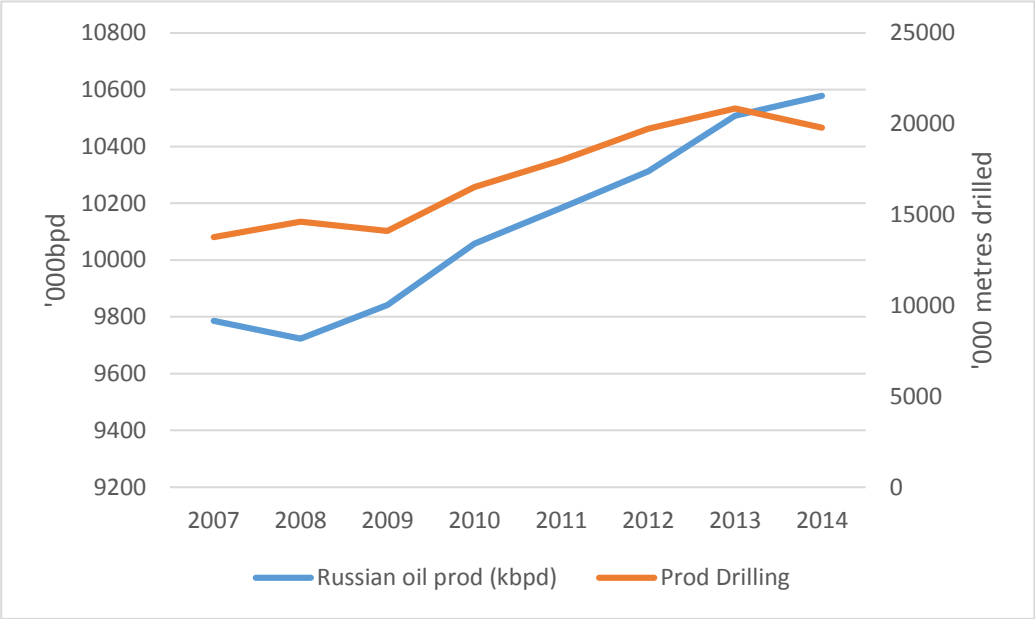


Source: Interfax data

This is an important indicator for the long-term outlook for Russian oil production because production drilling is closely correlated to oil output over time and also because exploration drilling, which is vital to secure the long-term resource base of any country, is normally one of the first expenses to be cut in a low oil price environment. In 2009, for example, when the oil price fell to $40 per barrel, exploration drilling in Russia halved and production drilling fell by 4 per cent before rebounding in 2010 as the oil price recovered.[103] Looking to the future, the trends in production drilling will continue to be a key driver of oil output as the relationship between the two is both obvious and tight. As shown in Figure 14 below, the trends in both are closely related with an R squared of 0.92, with the most interesting divergence being in 2014 when the number of metres drilled fell but production continued to rise. Although it is impossible to draw a definitive conclusion from the result in one year, it may be a signal that drilling in Russia is becoming more efficient, which may in turn be linked to an increase in the use of horizontal drilling and fracking, discussed below and shown in Figure 15.

[103] Interfax (2014) pp.9-15

Figure 14: Russian oil production and drilling, 2007-2014



Source: Interfax (2014)

The Need for Foreign Technology and the Potential for Import Substitution in Russia

However, although the early trends in 2015 look positive, there is one further issue that relates to the use of oilfield equipment in Russia. Though the majority of the services can be provided by domestic companies (including the domestic subsidiaries of foreign companies), it remains the case that in certain areas specific parts and technologies still need to be purchased overseas, in particular from the US. This has a cost implication, because everything priced in dollars is now effectively 50 per cent more expensive due to the rouble's devaluation, as well as a security of supply dimension because of the risk of sanctions being extended if the crisis in Ukraine is not resolved or escalates further. This potential problem has been recognized at government level in Moscow, with the Russian Security Council noting in February 2015 that the imposition of sanctions is 'depriving Russian companies of access to advanced technologies for geological prospecting and the processing of raw materials'.[104] Furthermore, it argued that this may pose a direct threat to the country's national security and proposed that 'it is necessary to specify measures towards tangible import substitution'.[105]

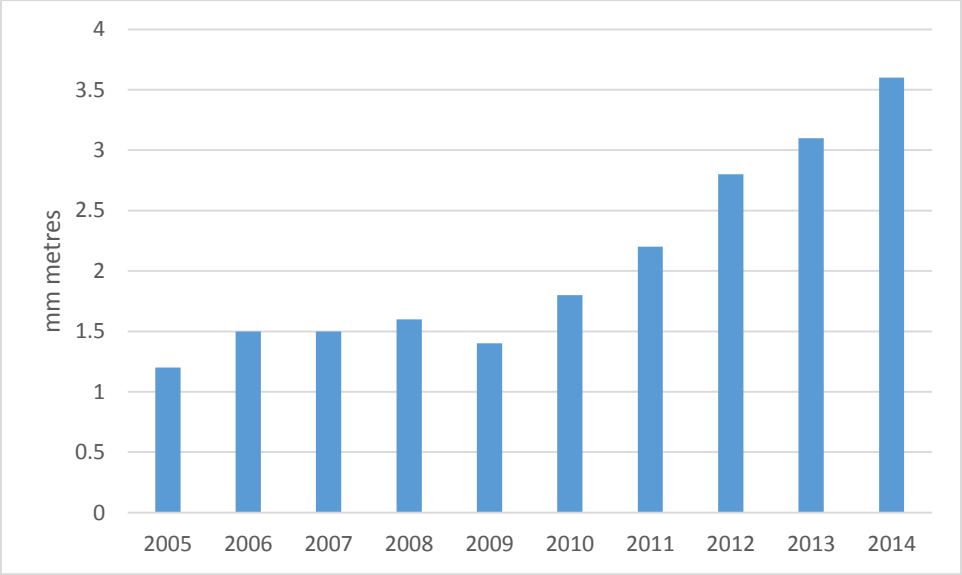
As far as the oil industry is specifically concerned, the area of horizontal drilling and multi-stage fracking is of particular relevance. Although Russian service companies have been drilling directional and horizontal wells for many years, the growth in this activity has been dramatic since 2009, with the total distance of horizontal wells tripling by 2014 (see Figure 15). In tandem with this activity, which has been used both to enhance the productivity of existing fields as well as to

[104] Interfax, 25 February 2015, "Dependence on oil, gas market trends threatens Russia's security – Security Council secretary"

[105] Interfax, 25 February 2015, "Dependence on oil, gas market trends threatens Russia's security – Security Council secretary"

optimize the development of new assets, fracking has been used to increase oil flows, including more recently the multi-stage fracking techniques used so successfully in the US shale industry. However, interviews with Russian oil companies and service companies in Moscow confirmed that the majority of the equipment used in these complex wells is of foreign origin, as is the expertise needed to operate them successfully. Recent comments by Lukoil confirm this view, as the company's First Deputy Executive Vice President Ravil Maganov stated at a National Oil and Gas Forum in March 2015 that in the service sector 'there are many critical [issues] today. This is everything having to do with hydraulic fracturing, both regular and multi-stage… and involves mainly software used to draw up the design for each fracking operation.'[106]

Figure 15: Horizontal drilling in Russia



Source: Eurasia Drilling

The Russian Ministry of Energy has also become involved in the drive to replace foreign technology in the country with a plan to draft a general oil and gas industry import substitution program during the remainder of 2015, with a very specific goal of developing technology to carry out horizontal drilling and hydro-fracturing by 2016.[107] In the longer term, the ministry is also keen to see an offshore service industry developed in Russia, as well as domestic production of LNG technology. On the former point, state company GazpromNeft, which is already producing oil from the Arctic offshore Prirazlomnoye field, is looking to develop a technology base to provide spare parts for the field.[108] This could then be used as a foundation for establishing an operational base for complete field developments in the offshore, and could help to replace the plans that Rosneft had for building technology centres for Arctic development with Exxon and Statoil.[109] In the LNG sector, Gazprom is also planning to lead an import substitution drive, with company CEO Alexei Miller meeting with Russian technology enterprise Rusnano in December 2014 to discuss new

[106] Interfax, 11 March 2015, "Lukoil: import substitution needs greater focus on software"

[107] Interfax, 20 January 2015, "Russia targets own fraccing, tight oil, shelf technology by 2016-2020"

[108] Interfax, 17 March 2015, GazpromNeft working to organise production of parts, materials for Prirazlomnoye"

[109] Rosneft press release, 11 June 2013, Rosneft and ExxonMobil finalise Arctic Research Centre and technology sharing agreements"

technologies in the gas industry, which could also include helium processing for the company's fields in the Far East.[110]

However, making plans to alleviate the import problem and actually implementing these plans are two very different things. Yaroslav Lissovolik, the chief economist at Deutsche Bank, has highlighted that although import substitution worked well in Russia in two previous crisis periods (1997/98 and 2008/09) the benefits may be rather more limited in 2015 because there is less spare capacity in the industrial system.[111] As a result, much more investment is needed to create an expanded manufacturing base, and in the short term the high levels of current capacity utilisation are likely to cause significant inflation if demand for locally-produced products rises.

In the oil sector, the Ministry of Industry and Trade has prepared a list of measures on import substitution, in particular highlighting that in some of the more technologically challenging areas Russian companies rely on foreign suppliers for as much as 80 per cent of their equipment. As touched on earlier, this concerns complex seismic software, fracking technology, and equipment for offshore operations, and the ministry estimates that although there are domestic companies capable of supplying these it will take until at least 2018-2020 before a significant level of replacement can be achieved.[112] Given this estimate, it would appear that Russia will continue to be dependent on foreign technology for some time, and perhaps beyond 2020 given that government estimates are likely to be optimistic. As a result, the country could be at risk from sanctions unless alternative sources of equipment can be found, and two solutions seem to be apparent. Firstly, some equipment could be sourced from alternative countries, such as China, South Korea, and India. However, most of these still lack expertise in the most complex oilfield operations, as they do not provide relevant equipment for their own domestic needs and themselves often rely on the same (mainly US) producers as Russia. A second outcome is that Russia can still continue to buy equipment from the US and Europe, as long as it is not used for sanctioned purposes. This is clearly a long-term security of supply threat which Russia would prefer to avoid, but the only problem relevant to the country's short-term production is that the equipment will be more expensive, and therefore companies may not be able to afford to buy as much of it. Equipment for specific use on Arctic and tight oil developments is excluded, but as discussed above there are sufficient alternative assets to keep Russian production flat, or even growing slightly. A refocus on core onshore assets could allow Russian companies to prioritize their reduced funds for overseas technology such that its impact can be optimized. In the meantime, the domestic service industry could gradually develop to fill any gaps, and it may even be the case that foreign oil service companies will assist in this process. The example of Schlumberger's planned investment and ultimate acquisition of Eurasia Drilling, a Russian service company, exemplifies the opportunities in the sector and the willingness of foreign companies to try and exploit them for their own, and ultimately for Russia's, benefit. As a Schlumberger representative stated in February 2015, the acquisition of Eurasia Drilling would enable the company 'to take advantage of the opportunity that new technology, new processes and greater integration can bring to [Russia's] vast land drilling market', with one consequence being that 'well drilling times could be cut by half'.[113]

[110] Gazprom press release, 25 December 2014, "Alexey Miller: Import substitution is Gazprom's priority"

[111] Financial Times, 14 November 2014, "Russia's import substitution problem"

[112] Russian and India Report, 23 October 2014, "Who can come to the rescue of Russia's oil industry"

[113] Interfax, 25 February 2015, "Schlumberger's purchase of 46% of Eurasia Drilling shares to spark development of Russia's drilling market"

6. Could Financing Issues Undermine Spending Plans?

Sanctions on the export of oil technology to Russia have certainly caused a rethink of industry strategy, and in terms of tight oil will have a short- to medium-term impact, but perhaps the most important element of the sanctions imposed by both the US and the EU has been the limits imposed on Russian oil companies (and Russian banks) to raise money on international capital markets. As shown in Table 3 below, the application of sanctions has varied between the US and the EU, both in terms of the companies targeted and the exact nature of the limits imposed. Both regions are in agreement over technology restrictions, which have been imposed on equipment that could be used for Arctic exploration and development, shale oil development, or offshore work in water depths greater than 500 feet.[114] However, in the area of finance differences appear. For example, Novatek has been targeted by the US regime but not by the EU, while Rosneft and GazpromNeft (both state oil companies) are the only two entities covered by all the sanctions. Furthermore, in the US the financing restrictions for oil companies mandate that they cannot raise debt with a maturity of longer than 90 days, while in the EU this maturity limit is only 30 days, which is also the timescale for debt raised by Russian banks in both jurisdictions.[115]

Table 3: US and EU sanctions on Russian oil and gas companies

	US Treasury EO 13662 Directive 2 (Financing)	US Treasury EO 13662 Directive 4 (Technology)	US Commerce Dept. Export Controls	EU Finance Restrictions	EU Technology Restrictions
Transneft	Yes			Yes	Yes
Gazprom		Yes	Yes		
GazpromNeft	Yes	Yes	Yes	Yes	Yes
Lukoil		Yes	Yes		
Novatek	Yes				
Rosneft	Yes	Yes	Yes	Yes	Yes
Surgutneftegas		Yes	Yes		

Source: US Treasury Department, US Department of Commerce, Europa.eu[116]

In spite of the disparity between the sanctions imposed by the US and the EU, the limits on capital raising appear to have had a significant impact on the Russian oil sector as a whole, and could be a major limiting factor in future investment decisions, potentially putting the country's production levels at risk. Rating's agency Fitch has identified the impact of the sanctions on corporate funding as the major risk to the Russian oil industry over the next few years, suggesting that it is a more important factor than the oil price. In a recent report it stated that 'stress tests show credit profiles can withstand oil at US$55 a barrel for several years. But if access to funding does not improve and export restrictions remain producers may not be able to make the investments needed to maintain production.'[117]

[114] http://www.treasury.gov/resource-center/sanctions/Programs/Pages/ukraine.aspx, sourced 26 March 2015

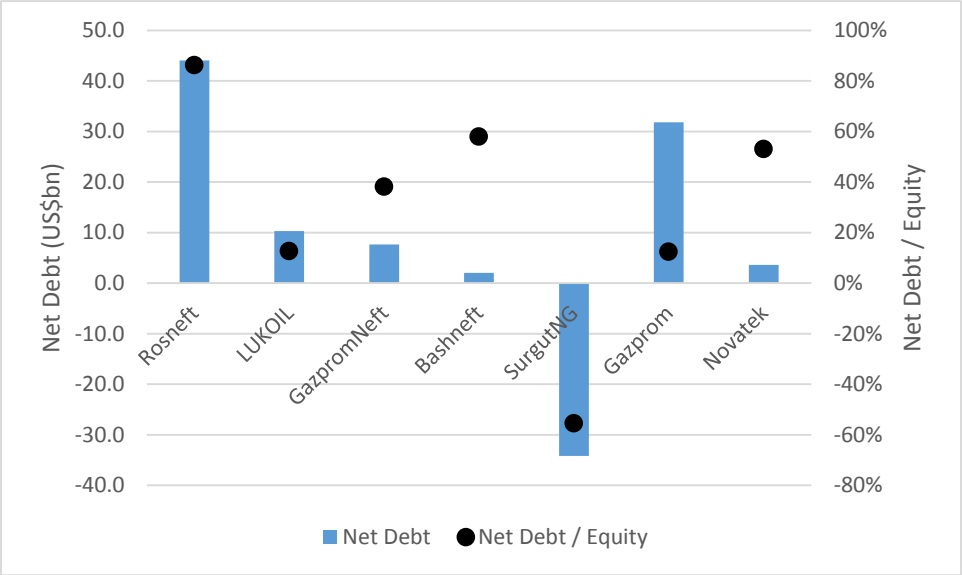
[115] Henderson, J., December 2014, "Sanctions and the Future of Russian Oil and Gas", Presentation at Columbia University, New York which can be found at http://energypolicy.columbia.edu/multimedia/podcast/impact-sanctions-russias-energy-economy-and-global-energy-market

[116] http://europa.eu/newsroom/highlights/special-coverage/eu_sanctions/index_en.htm, accessed on 26 March 2015

[117] Fitch (2015) quoted in Interfax, 11 March 2015, "Fitch: sanctions a bigger threat to Russian oil than weak prices"

Figure 16 below shows the current state of the balance sheets of the main Russian oil and gas companies and demonstrates that most are in a fairly robust position following a number of years of high oil prices. In particular Surgutneftegas has a huge cash balance of $35 billion, while Lukoil, GazpromNeft, and Gazprom all have relatively low levels of net debt compared to their equity base. Bashneft and Novatek have higher relative debt levels, but their obligations are more than adequately covered by their continuing cashflows, as they both have a net debt / EBITDA ratio of less than 1.[118] The one company that stands out as being in a less comfortable position is arguably the most important one, Rosneft, which has a total net debt of $44 billion and a net debt/equity ratio of 86 per cent. Furthermore, this calculation does not include approximately $17 billion of prepayments that the company has received for forward oil sales, and therefore arguably understates the total liabilities.

Figure 16: Net debt position of major Russian oil and gas companies (2014)



Source: Company financial statements at 31 Dec 2014, apart from Surgutneftegas (30 June 2014) and Gazprom (30 Sept 2014)

Given its importance to Russian oil production and the fact that its net debt accounts for two-thirds of the total for the seven companies mentioned above, Rosneft can provide a useful example of the methods currently being used to circumvent the sanctions programme, or at least to offset its major effects. Figure 17 below illustrates Rosneft's key problem, which is a need to pay off a significant amount of short-term, dollar-denominated debt which it raised to finance the purchase of TNK-BP for $55 billion in 2013.[119] The company did manage to reduce its net debt in 2014 from over $57 billion at the start of the year to $44 billion by 31 December, with the repayment of a $7 billion bridging loan in the last month of the year providing a significant challenge to the company due to the combination of the falling oil price and rouble devaluation.[120]

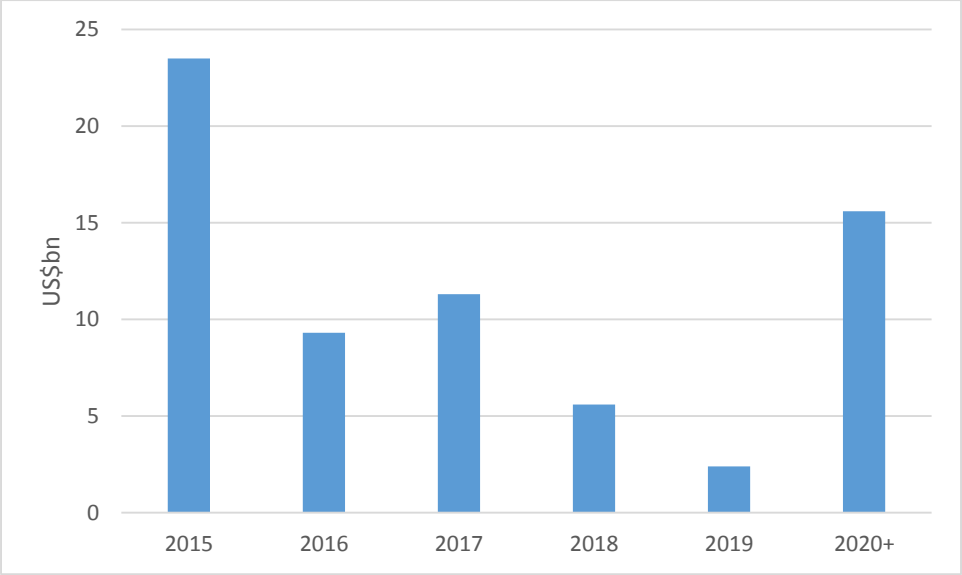
[118] EBITDA = Earnings before interest, tax and depreciation and equates to operating cashflow. If the ratio of net debt to EBITDA is less than 1 then cashflow in a single year could cover the company's debt obligations. A net debt ration below 2 is generally regarded as acceptable.

[119] Reuters, 21 March 2013, "Rosneft pays out in historic TNK-BP deal completion"

[120] Wall Street Journal, 22 December 2014, "Rosneft repays $7 billion of TNK-BP bridge loan"

However, Rosneft needs to find a further $23.5 billion in 2015 plus an additional $20 billion in 2016-17 before the pressure on its balance sheet starts to ease from 2018.

Figure 17: Repayment schedule for Rosneft debt



Source: Rosneft (2015), slide 13

A mentioned above, one method that Rosneft has used to move its liabilities out of the debt category and into another area of its balance sheet is prepayment for oil sales, and it has current and long-term liabilities for forward sales totalling more than $17 billion, the majority of which are related to exports to China. Rosneft actually began the process of selling guaranteed volumes of oil to China in return for early payment in 2004, when it raised $6 billion to help finance the purchase of Yukos assets, after that company had been forced into bankruptcy.[121] The six-year deal, which expired in 2010, committed Rosneft to export 5.5 million tonnes of crude via rail, but a subsequent deal in 2009 saw a loan of $25 billion offered by the China Development Bank to Rosneft and Transneft in return for a 300 million tonne 20-year sales agreement for oil sales from fields in East Siberia via the new ESPO pipeline.[122] The loan was used to finance the field developments and pipeline construction and will be repaid over the life of the oil contract, which stretches to 2030.

With these precedents having been set, and with Russia's overall economic and political strategy emphasizing a 'pivot towards Asia',[123] it was perhaps not surprising when Rosneft concluded an even larger 360 million tonne 25-year supply deal with Chinese state company CNPC in June 2013.[124] 30 per cent of the estimated $270 billion contract value was due as a staged prepayment, meaning that Rosneft would effectively receive $60-70 billion up front in the period to 2017, and the first $25 billion tranche of this was received in January 2014.[125]

[121] Norling (2006), p.35

[122] Reuters, 18 February 2009, "China, Russia strike $25 billion oil pact"

[123] Foreign Affairs, 31 July 2013, "Putin's Pivot"

[124] Reuters, 21 June 2013, "Rosneft to double oil flows to China in $270 billion deal"

[125] Bloomberg, 15 January 2014, Rosneft says China starts prepayments for oil deals"

In September 2013, Rosneft also signed a 100 million tonne 10-year supply deal with Sinopec, another Chinese state oil company, with an agreement that prepayment would amount to 25-30 per cent of the total value of the contract, which Rosneft CEO Igor Sechin described as the 'usual conditions for our clients'.[126] The deal is still to be totally finalized,[127] but assuming it is completed it would imply a prepayment of approximately $20-25 billion. However, this is likely to be the limit of Rosneft's ability to complete sales agreements with China, given the capacity of the eastern export system. The total contracts agreed to date imply a peak export requirement of 800,000 bpd from 2017, but the current capacity of the ESPO line to China is only 300,000 bpd, rising to 600,000 bpd as the Chinese improve the infrastructure on their side of the border. The remaining crude will be transported via the port of Kozmino Bay in the Russian Far East or via rail through Kazakhstan, after an agreement was reached involving a swap of crude for oil products with the Kazakh authorities.[128] However, the Kazakh deal is capped at 140,000 bpd and the use of Kozmino Bay may be restricted by the needs of other producers and customers,[129] meaning that additional sales to China above the current contracts are likely to be limited.

In the light of this capacity constraint, Rosneft has turned to other sources of prepayment deals, mainly with oil trading companies. In March 2013, the company agreed long-term contracts with Glencore and Vitol to supply 47 million tonnes to the former and 20 million tonnes to the latter on the proviso that $10 billion was received in advance for general corporate use.[130] In June 2014, a $1.5 billion deal was signed with BP in exchange for 12 million tonnes of crude delivered over five years,[131] and Rosneft also has similar contracts in place with Shell, Total, and ENI.[132] However, a further $2 billion deal with Vitol had been anticipated in August of 2014,[133] but this source of funding has now been called into question, as it appears to have fallen foul of the sanctions introduced in July 2014 because Western banks will no longer support the syndicated loans used by oil traders to spread the risk of the transactions.[134] That said, attempts to conclude similar deals are continuing, with Rosneft reportedly in talks with Swiss trader Trafigura to raise short-term debt via monthly oil trades (which presumably would not contradict the 30-day financing rule under the EU sanctions). The latest deal reportedly involved the sale of 500,000 tonnes of crude in February to allow a debt repayment to be made.[135]

The potential for sanctions to block prepayment deals with Western companies has forced Rosneft to look for domestic sources of funding, although these will clearly be in roubles rather than dollars or euros. The company launched a domestic bond issue in December 2014 to raise RR625 billion ($11.4 billion at the prevailing exchange rate), and then followed this with a RR400 billion ($6.1 billion) issue in January 2015.[136] However, these deals have not been without controversy, with Rosneft subsequently accused of causing the collapse in the rouble by converting the domestic loans into dollars in order to pay off its external debt obligations.[137]

[126] Interfax, 22 October 2013, "Rosneft-Sinopec oil contract calls for 10 mln t/yr for 10 yrs"

[127] Interfax, 24 May 2014, "Rosneft, Sinopec extend oil delivery contract"

[128] Interfax, 24 December 2013, "Russia signs agreement with Kazakhstan on oil transit to China"

[129] Nefte Compass, 27 November 2014, "Russia weighs allocations for higher China exports"

[130] Rosneft press release, 6 March 2013, "Rosneft signs long-term contracts with Glencore and Vitol"

[131] Financial Times, 27 June 2014, "BP and Rosneft sign $1.5bn deal"

[132] Reuters, 4 February 2015, "Rosneft raising money from Swiss trader as debt repayment looms"

[133] Financial Times, 21 August 2014, "Rosneft hit by western sanctions as $2bn Vitol deal scrapped"

[134] Financial Times, 18 July 2014, "Prepay deals in question after Rosneft sanctions"

[135] Reuters, 4 February 2015, "Rosneft raising money from Swiss trader as debt repayment looms"

[136] Financial Times, 26 January 2015, "Rosneft sells Rbs 400bn of domestic bonds"

[137] Bloomberg, 13 March 2015, "Putin said to blame energy chief Sechin after Rosneft missteps"

Company CEO Igor Sechin has been forced to deny this and to confirm that future rouble debt will be used for domestic investment purposes, but it would again seem that this source of funding may be limited after Central Bank of Russia Governor Elvira Nabiullina stated that the December issues 'added pressure to the currency'.[138] Furthermore, it remains unclear who the buyers of the domestic bonds were, with the suspicion being that they were state-owned banks who in turn were accessing funds directly from central bank reserves, prompting a further comment from Nabiullina that the December deal was 'non-transparent, unclear to the market and was an additional factor in the volatility of the market.'[139]

One further source of significant funding for the Russian oil industry, which Rosneft and others are keen to tap into, is the National Welfare Fund (NWF), which was set up using surplus revenues from oil taxation to support the country's state pension scheme.[140] While its sister fund, the Stabilization Fund (also financed by oil taxes), is used to support the state budget, the NWF has been used to support banks and companies during times of crisis and was extensively used in 2008/09. However, because the fund ultimately has a pension mandate, its loans must theoretically be used for projects that will ultimately generate a return for the state, and not for paying off debt. As a result, any companies applying for funds must show exactly how the money will be used.

A prime example of a project supported by the NWF is Novatek's Yamal LNG scheme, which has received a pledge for RR150 billion from the fund to be made available in two tranches. The mechanism for the support has seen Novatek place bonds in favour of the Russian Ministry of Finance to cover the first RR75 billion loan at an effective interest rate of around 6 per cent, much lower, for example, than the 11 per cent interest rate which Rosneft has offered on its domestic bond placements.[141] The second tranche will then be made available in the second quarter of the year, once project financing from banks has also been secured for the remainder of the funds needed to complete the project.[142]

Rosneft initially applied for RR2 trillion from the NWF in October 2014 (worth approximately $50 billion at the exchange rate prevailing at the time), but was subsequently told that it needed to provide a specific list of prioritized projects in order to qualify.[143] It was also warned that the funds would be in limited supply (the NWF had a total of RR4.6 trillion as of 1 March 2015)[144] as they would need to be spread across a number of countries and industries. Rosneft has now submitted a list of 28 projects—including brownfield and greenfield upstream assets as well as pipelines, refineries, and a shipyard in the Far East of Russia—and has requested a total of RR1.3 trillion to fund them. According to the rules of the NWF, no more than 40 per cent of any project's value can be supported by the fund, and so a process of review and approval is now underway.

GazpromNeft has also made an application to the NWF, providing a list of projects requiring funding of RR198 billion. The two largest are both upstream fields, the Messoyakha and Kuyumba projects mentioned above, which would account for more than three-quarters of GazpromNeft's application. GazpromNeft CEO Alexander Dyukov has also particularly

[138] Reuters, 4 February 2015, "Rosneft raising money from Swiss trader as debt repayment looms"

[139] Moscow Times, 3 February 2015, "Russian Central Bank Head blames Rosneft for historic ruble crash"

[140] Moscow Times, 6 February 2015, "Russia's "Anti-Crisis" National Welfare Fund: An Overview"

[141] Interfax, 20 February 2015, Yamal LMNG place first tranche of $1.2bn in bonds for NWF funding"

[142] Interfax, 13 February 2015, "Ulyukayev: Yamal LNG may receive 150 bln rubles from NWF; first tranche in Q1"

[143] Interfax, 29 January 2015, "Rosneft requests RUB 1.3 trillion to fund 28 projects"

[144] TASS, 4 March 2015, "Russia's Reserve Fund drops 19.5%, National Welfare Fund down 10% by March 1 – ministry"

highlighted the need for NWF funds in a letter to Deputy Prime Minister Arkady Dvorkovich, citing the restrictions imposed by sanctions, and the constraints within the domestic capital markets, which make government funding vital for companies holding long-term, high-cost assets that require significant project financing.[145]

It is clear, therefore, from the examples of Rosneft and other Russian oil and gas companies that financing is a key issue caused largely by the impact of sanctions but also by lower oil prices. A number of alternatives to Western capital markets are available to those companies, primarily Rosneft and GazpromNeft but also Novatek, whose actions are particularly restricted, including prepayment deals with Asian buyers, the domestic debt market, and also government funding via the NWF. Other companies, such as Lukoil and Gazprom, are not restricted in their capital raising at present, and indeed Gazprom has recently issued a Eurobond[146] and Lukoil has plans to test the market in the spring of 2015.[147] Nevertheless, both companies may still find banks and investors reluctant to provide significant long-term project financing out of fear of future expansion of the sanctions regime, and as such a key indicator for the future of Russian oil production will be the ability of companies across the entire sector to raise sufficient financing and the ability and willingness of the government to provide financial support when it is requested.

[145] Interfax, 12 March 2015, "GazpromNeft seeking aid for 8 projects totalling 198.5 bln rubles"

[146] Reuters, 5 November 2014, "Gazprom to price US$70mm one year Eurobond at 4.45% yield"

[147] Reuters, 22 January 2015, "Russia's Lukoil may tour to test for new Eurobond in spring"

7. The Impact of the Russian Tax System

One other area where significant government support can be offered to the Russian oil industry, and also where important strategic levers can be operated by the state, is the fiscal system. The Russian oil tax system is relatively simple in concept, comprising two revenue-based levies (an Export Tax and a royalty known as Mineral Extraction Tax, or MET) plus the standard corporate tax, but in its application it is more complicated due to the adjustments that are frequently made by the government and the sliding scale nature of both taxes relative to the oil price. A further layer of complication is added by the relationship between the upstream taxation system and the taxes charged on oil products, with the export taxes on gasoline, diesel, and fuel oil, for example, being directly related to the export tax on crude oil (the export tax for fuel oil, for example, is currently 76 per cent of the crude oil export tax). As a result, the tax system is used both to extract rent from the upstream sector and to provide incentives (through tax holidays or discounts) for specific types of upstream spending, and is also used to balance the attractiveness of upstream and downstream investment.

For example, in the period from 2004 until 2013 the crude oil export tax had a marginal rate of 65 per cent when the oil price was over $25 per barrel. Meanwhile, the tax for oil products reflected the fact that the average Russian refinery has historically produced a significant amount of low-value fuel oil and insufficient quantities of gasoline and diesel, for which there is growing demand in Russia as the car fleet becomes more modern. Therefore, in the early 2000s, the export tax on fuel oil was 70 per cent of the crude export tax versus 130 per cent for the export tax for gasoline and diesel,[148] in order to encourage companies to keep refinery throughput high by enabling them to export fuel oil profitably while keeping gasoline and diesel in the domestic market. This strategy worked, and companies such as Lukoil developed specific tactics to sell oil products rather than crude oil as a result.[149] However, the tax regime did not encourage investment in refinery upgrading, as it essentially supported the owners of low-quality refineries.

An adjustment was made in 2011, however, as the Russian government embarked on a strategy to encourage investment in refinery improvement in order to increase the output of value-added products. President Vladimir Putin met with the leaders of the oil companies in St Petersburg to secure specific commitments from all of them to invest in new downstream technology,[150] and in order to provide extra revenues to support this spending the downstream tax system was altered so that the export tax for all oil products was at a discount to crude. Fuel oil and diesel were taxed at 66 per cent of the crude export tax while gasoline was charged a rate at 90 per cent. This was clearly intended to encourage oil companies to allocate a greater share of capital expenditure to the downstream business, but at a time of high oil prices the likelihood of this strategy having a significant impact on upstream spending, and therefore production, was low. Nevertheless, as it became clear that many of the older and larger fields in Russia were reaching the limits of their productive capacity, adjustments were also made to the upstream regime. Export tax holidays were awarded to new fields in East Siberia, MET discounts started to be granted to more difficult assets or to fields that were significantly depleted, and more importantly in 2013 the top rate of

[148] Burgansky (2010), p.190

[149] Fedun (2010), slide 6

[150] Henderson (2012), p.7

crude oil export tax was reduced to 60 per cent, before falling to 59 per cent in 2014 with the promise of further declines to 57 per cent in 2015 and 55 per cent in 2016.[151]

However, during 2014 it became increasingly clear to the Russian government that domestic oil companies were failing to meet their downstream investment commitments, with many requesting deferrals of the timescales agreed with President Putin in 2011. In addition, as the oil price began to fall from a high of $115 per barrel in the middle of the year towards a low below $50, oil companies also began to request adjustments to the overall upstream fiscal system in order to allow them to remain profitable and continue to invest in production. Although this request created a major problem for the Ministry of Finance, as any reduction in oil revenues would have a significant impact on budget revenues,[152] discussion of what became known as the 'tax manoeuvre' began in order to address both the need to force oil companies to meet their downstream obligations and also to support their upstream profitability.

The 2015 Tax Manoeuvre

After extensive discussion between the ministries of energy and finance and also the Russian oil companies, a significant re-balancing of the Russian oil tax regime was introduced on 1 January 2015. Although the overall structure of the regime has remained intact, the top rate of crude oil export tax has been reduced sharply, from 59 per cent in 2014 to 42 per cent in 2015, and is set to fall further over the next two years, to 36 per cent in 2016 and 30 per cent in 2017.[153] The loss of revenue that this will imply to the Russian federal budget has been compensated for by increasing the royalty (MET) tax, with the base rate for the calculation increasing from RR493 per tonne in 2014 to RR766 per tonne in 2015, RR857 in 2016 and RR919 in 2017.[154] The net effect of these combined changes for the upstream business is actually not very significant in itself, providing a marginal boost to oil producers (see Figure 18 below). However, the fact that upstream oil taxation in Russia is now more evenly balanced between export tax (which obviously applies only to barrels sold overseas) and MET (which applies to all crude oil production in the country) is significant, not least because it means both that the wellhead cost of oil has risen (because the royalty has increased) as has the export netback price of Russian exports (because the export tax has gone down). Both of these factors have important consequences for the vertically integrated companies and for independent refiners in Russia.

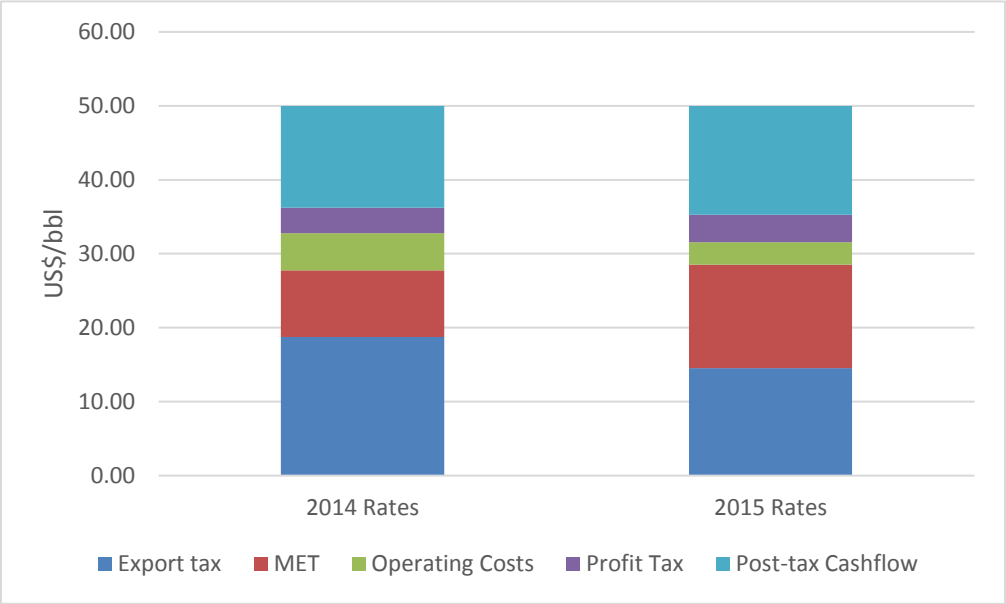
[151] Ernst & Young (2013b) pp.3-5

[152] As noted in the introduction oil taxes have historically accounted for approximately 45% of total federal budget revenues

[153] Ernst & Young (2014) p.1

[154] Moshkov (2015), p.25

Figure 18: Impact of tax manoeuvre on upstream cashflow at $50 per barrel oil price

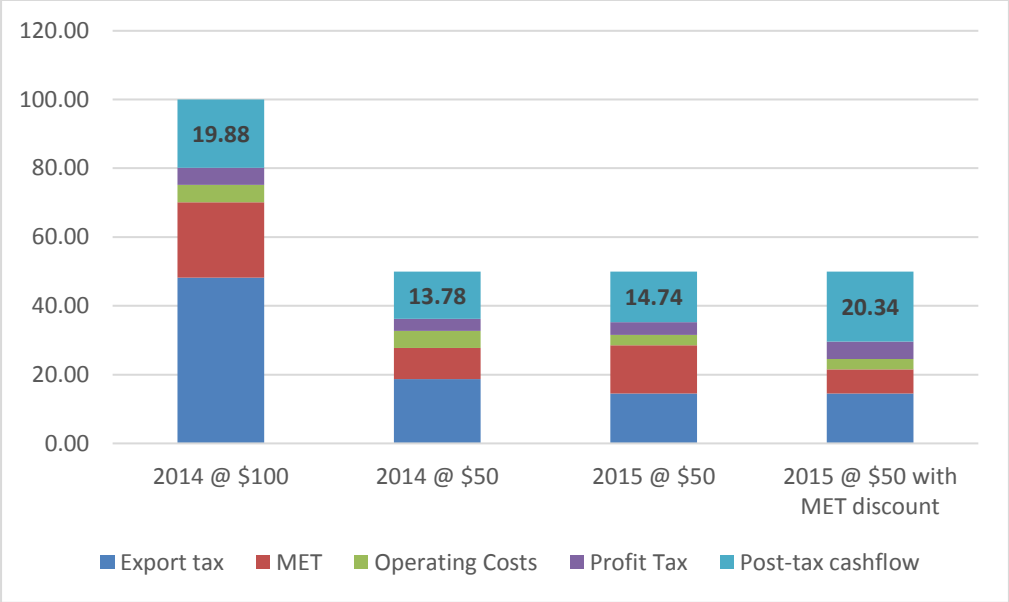


Source: Author's calculations based on Ministry of Finance data

In the upstream sector, though, the key consequence of the shift to a higher MET rate is that the most significant tax reductions that are offered to oil companies tend to be couched as discounts to MET. In particular, 'difficult-to-recover' oil, as it is known, receives varying levels of discounts in the MET formula, with the definition of 'difficult to recover' including: the level of field depletion; the level of overall deposit depletion (a broader definition that field covering different types of geological formation); the size of field reserves (with smaller fields being given allowances to compensate for lower economic returns); and overall effort required to recover the oil.[155] This latter part of the MET calculation is particularly interesting because it both defines specific geological layers that will receive discounts, with the Bazhenov shale layer, for example, paying no MET at all, and it also gives more general ranges of reservoir permeability that will receive a sliding scale of discount. Historically, when the MET rate was relatively low compared to the export tax, these discounts were helpful but not big enough to dramatically change economic outcomes. However, now that the MET levy has become much more important in relative terms, the discounts have sharply increased in value.

[155] Ernst & Young (2014) p.3

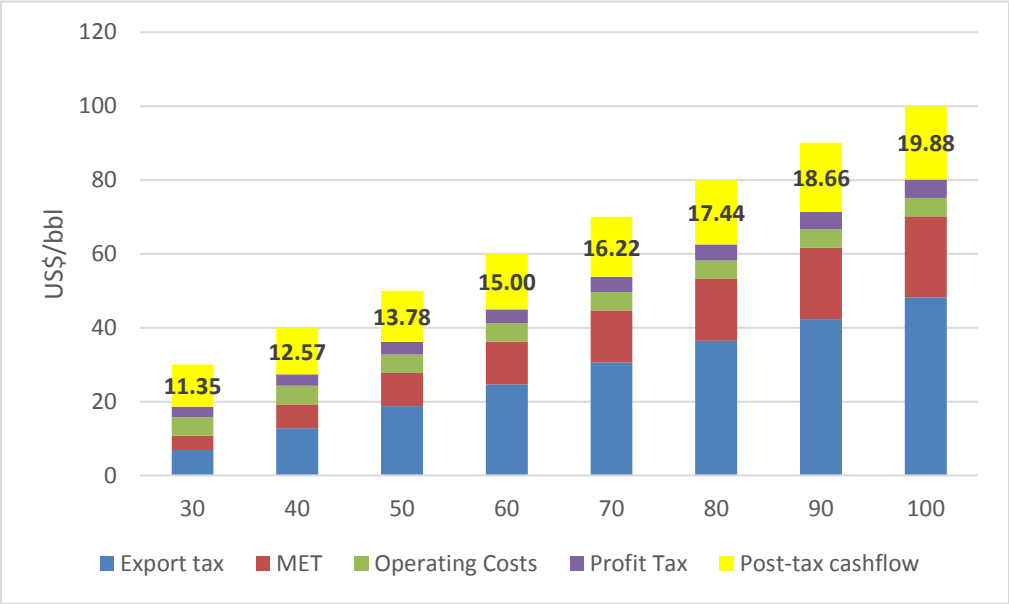
Figure 19: Comparison of 2014 and 2015 post-tax cashflow for upstream producers in Russia



Source: Author's calculations

Figure 19 above shows a comparison of upstream cashflow in Russia at two oil prices and under the 2014 and 2015 tax regimes. The left-hand column shows the situation in 2014 when the oil price was $100 per barrel or more, and underlines the relative importance of the export tax compared to MET and also the relatively low post-tax cashflow received by the companies due to the high marginal rate of export tax, MET, and profit tax combined. Essentially, after operating costs of around $5 per barrel are included the oil companies were receiving around $20 for every barrel produced. The second column then shows the impact of a fall in the oil price to $50 under the 2014 tax regime. Not surprisingly, the company cashflow falls, from around $20 per barrel to around $14 per barrel, with the balance of export tax and MET remaining the same as both move on a sliding scale with the oil price. However, perhaps the most interesting point here is that although the high oil tax rate in Russia is a burden for the oil companies it also provides something of a buffer in a lower oil price environment, as it is the government that takes most of the revenue hit. In this example, a halving of the oil price from $100 to $50 per barrel has caused a 30 per cent decline in company cashflow, and this is because, as Figure 20 below helps to show, for every $10 move in the oil price the company cashflow only rises or declines by $1.22 per barrel under the 2014 tax regime (which increases slightly to $1.44 per barrel under the 2015 system).

Figure 20: Shift in company cashflow relative to oil price under 2014 tax regime



Source: Author's calculations

Returning to the analysis in Figure 19, the third and fourth columns show the impact of the new tax regime post January 2015. The third column demonstrates that there is a small net benefit to upstream producers following the changes, with post-tax cashflow rising by around $1 per barrel at a $50 per barrel oil price. However, the fourth column demonstrates the impact of a 50 per cent MET discount, which is taken as a notional figure for an asset with a low permeability reservoir and 'difficult-to-recover' oil. Once this level of discount is applied, it is possible for a company to generate as much post-tax cashflow at a $50 per barrel oil price as it had been generating previously at $100 but without any discounts applied. Therefore, it is clear that despite the relatively neutral impact of the tax manoeuvre overall, the government has provided an incentive for companies to focus on the recovery of oil at brownfield sites as well as developing more complex reservoirs at new fields using secondary and tertiary oil recovery techniques, which can certainly help to slow the rate of production decline at existing assets and encourage investment in new assets.

Tax Incentives for Greenfield Developments

However, despite the advantages of the tax manoeuvre for upstream producers, one major criticism that has been levelled at it by producers and commentators alike is that while it provides incentives for the development of Russia's more difficult resources it ignores the need to encourage development of new more conventional greenfield sites that can be the foundation of future production growth. Essentially, the revenue-based nature of the tax system provides no method of cost recovery for investors, and therefore undermines the likely rates of return that they can generate because the taxation of 100 per cent of revenues must start as soon as production commences. As a result, the net present value of projects is undermined because the negative impact of up-front expenditure in the early years is not allowed to be offset against sales from hydrocarbon output that is fully-taxed from the first year of production.

This issue has been discussed throughout the post-Soviet era,[156] with two main solutions having been attempted. Production sharing agreements (PSAs) were introduced in the early 1990s at a time when then President Yeltsin was keen to attract foreign investment but understood that the Russian fiscal system was not robust enough to ensure financial and legal security.[157] As a result, the investors at three projects, Sakhalin 1 and 2 and Kharyaga, were allowed to negotiate their own tax terms with the Russian government involving an allocation of oil production to allow recovery of costs (cost oil) and a sharing of profits (profit oil). This methodology is widely used in the global oil industry and essentially offers a secure minimum rate of return for oil companies investing in long-term, capital-intensive projects.[158] However, despite the success of PSAs in launching these three projects, they were never used again because they became a by-word for offering favourable terms to foreigners at a time when domestic players were becoming increasingly active in the oil sector. As a result, opposition to any further use of this form of taxation grew, both from oil companies and from the Ministry of Finance, which believed that PSAs did not offer the optimal route for generating revenue from the oil industry for the federal budget. Furthermore, they were also difficult to administer, involving complex negotiations over cost budgets and profit calculations which the Russian government was not staffed to deal with.[159]

A second version of a profit-based tax regime was then introduced in 2012, but was focused specifically on offshore field developments. The catalyst for the new tax system was provided by the joint venture agreements signed between Rosneft and a number of international oil companies, in particular ExxonMobil who insisted on a tax regime for its Arctic investments that would guarantee a minimum rate of return. As a result, an agreement was reached that will see the traditional export tax and MET system replaced by a sliding royalty rate, with the level to be set depending on the difficulty of exploitation of the offshore area and with IRR targets also set for each region (see Table 4 below). However, this new regime has been specifically limited to offshore areas because it will have no immediate impact on federal budget revenues (because there is no significant offshore oil production to date) and because it will be easy to administer (again, there are very few projects to which it will apply in the near future).

Table 4: Tax regime for Russian offshore developments

Group	Location	IRR target	Royalty rate
1	Baltic/Azov Seas	16.5%	30%
2	Shallow waters of the Black Sea, Pechora and White Sea, southern part of the Okhotsk Sea, offshore Sakhalin	18.5%	15%
3	Deep waters of the Black Sea, the northern part of the Okhotsk Sea, southern part of the Barents Sea	20.5%	10%
4	Offshore projects in the Arctic (includes Kara Sea), the northern part of the Barents Sea, the Eastern Arctic	22%	5%

Source: Russian Tax Service

Calls for a profit-based tax that can be applied more generally across the Russian onshore fields have been heard for many years, with companies such as Lukoil in the vanguard,[160] supported by

[156] Goldsworthy and Zakharova (2010), p.28

[157] Gustafson (2012), p.178-180

[158] Bindemann (1999)

[159] Henderson & Ferguson (2014), p.37-39

[160] Alekperov (2012), slides 19-20

the Ministry of Energy.[161] However, the Ministry of Finance has consistently objected to the application of a system which it claims could lead to a significant loss of revenues. Not only would such a system be more complicated to administer, it claims, putting pressure on its human resources, but it would be open to abuse by oil companies who would be keen to minimize profits by inflating costs and use tax avoidance techniques that were so prevalent in the 1990s.[162]

These objections have held sway over the past decade because of the importance of oil revenues to the budget and because high oil prices have softened the blow of the tax burden on Russian oil companies and reduced their incentive to complain. However, since the middle of 2014 falling oil prices and the threat of declining oil production have once again seen companies and ministers discussing the need for change. Companies such as Bashneft and Surgutneftegas have joined the calls for a move towards a profit-based tax[163] [164] and Minister of Energy Alexander Novak has warned that one of the main threats to Russian oil production is the current tax system. Indeed, he has specifically stated that without a change to a profits-based system output could fall by around 400,000 bpd by 2020.[165]

This lobbying has culminated in plans for a move to a new tax regime based on excess profits to be developed alongside the new Energy Strategy, which itself is being finalized in 2015. The first draft of the new strategy was discussed by the Russian government in March 2015,[166] and it has subsequently been announced by the Ministry of Energy that 12 fields have been selected to take part in a trial of the new system.[167] Table 5 below shows the 12 fields and their owners, with the combined reserves of all 12 totalling almost 6 billion barrels. The plan is to exempt fields from MET for a period of three years and instead subject them to taxation based on a 'financial results-based model', according to the Ministry of Finance. This marks a first step towards the extension of a profit-based model across a broader spread of fields, although it remains unlikely that it will be used for anything other than new projects in the short to medium term. The energy minister has underlined that he does not believe that the system will be rolled out more broadly until the 2020s,[168] while Russian President Vladimir Putin has also expressed his scepticism about the chances of administrative issues being resolved in the near term. Nevertheless, it would appear to be an encouraging sign that the concerns of upstream producers are being taken seriously, with the tax manoeuvre providing some short-term relief from lower oil prices while this new trial of a profits-based system may catalyse more active consideration of the tax burden on greenfield developments across the country. Indeed it has been suggested that the original list of 12 fields could be expanded to 16, although the extra four fields have not yet been names.[169] Overall, then, it would appear that once again the Russian government has shown its willingness to consider change *in extremis* in order to support Russian oil production, and as such, although it is too early to say whether the current alterations will be effective, it is probably correct to assume

[161] Interfax, 61 October 2013, "Tax breaks expected to boost Russia's profitable oil reserves to 20 billion tonnes"

[162] Interfax, 30 October 2013, "MinFin opposes excess profits tax for energy sector"

[163] Interfax, 29 October 2014, "Russian tax system hinders development of hard-to-recover reserves – Surgutneftegas"

[164] Interfax, 22 October 2014, "Switch to excess profits tax to extend life of old fields – Korsik"

[165] Interfax, 16 February 2015, "Not transitioning to taxes of financial results to lead to oil production fall to 508-510 million tonnes by 2020"

[166] Moskov, M., 17 March 2015, "Russian Energy Strategy 2035", UBS research note

[167] Argus FSU Energy, 19 March 2015, "Profit-based tax on trial"

[168] Interfax, 16 Feb 2015, "Not transitioning to taxes on financial results to lead to oil production fall to 508-510 mln tonnes by 2020""

[169] Interfax, 15 April 2015, "Energy Ministry selects 16 pilot projects for tax on financial results"

that the overall state objective is to continue to find fiscal tactics to support the maintenance of overall Russian oil output at or slightly above current levels.

Table 5: Fields included in new 'oil profit tax' trial

Company	Fields
Lukoil	Lazarevskoye
	Krasnoleninskoye
	Nivagalskoye
	Las-Yeganskoye
	Imilorskoye-Istochnoye
Rosneft	Khasyreiskoye
	Nadeiyuskoye
	Bakhilovskoye
	Verkhne-Kolik-Yeganskoye
GazpromNeft	Vyngayakhinskoye
	Yety-Purovskoye
	Vokyntoiskoye

Source: Argus FSU Energy, 19 March 2015, p.1

Potential for a Psychological Game of Chicken over Production

This final point raises the possibility that oil-company negotiating tactics may also play a role in the short-term outcome for Russian oil production. As has been mentioned above, Lukoil has made some dire predictions concerning the outcome for overall oil output should the tax system not change, with production potentially heading as low as 6 mmbpd on its estimates.[170] Rosneft has also not been averse to warning about the adverse effects of a poorly designed fiscal regime,[171] and in particular has complained recently that the tax manoeuvre may not be the correct method to help Russian oil producers.[172] President Putin has rejected this assertion, having personally signed the tax manoeuvre into law in November 2014, but the seeds of dissent over the impact of tax changes on both the upstream and downstream sectors have clearly been sown. As a result, it is not impossible to foresee that some dips in oil production could occur over the next 12-24 months which could be used by the domestic oil industry to argue their case for further alterations to the fiscal system. Although political pressure would likely be applied to try and reverse any declines, it is not inconceivable that a game of 'chicken' could develop to see who blinks first—the Russian government by providing more tax breaks or a wider application of the profits-based system, or the Russian oil companies who may be forced to accept the changes made in January this year as well as a slow testing of a more profit-oriented system for the future. In either case, though, discussions on the future of the Russian oil tax system will continue to be a key driver of future oil production, and may create volatility if the debate intensifies in an extended period of low oil prices.

[170] Wall Street Journal, 2 Feb 2009, "Lukoil warns on taxes"

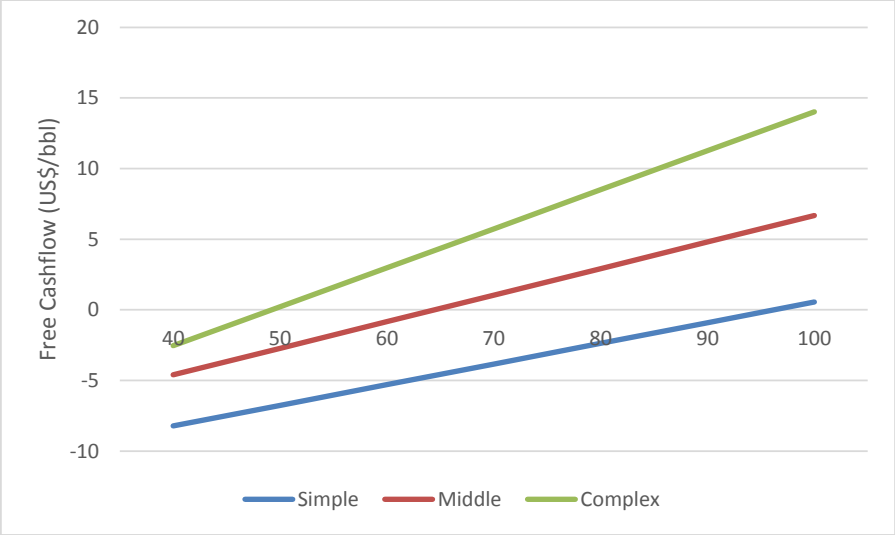
[171] Reuters, 28 July 2014, Russia's Sechin proposes profit-based tax for oil"

[172] Interfax, 5 Feb 2015, "Putin urges Rosneft head to consider national interests in Far East refinery project"

8. Impact of Taxes on the Russian Downstream, and Potentially on Crude Oil Exports

One of the reasons why some Russian companies have been complaining about the recently introduced tax manoeuvre is because of its impact on the domestic refining business, and the consequences of this may be felt not just in the downstream area but also in upstream production and the level of crude oil exports.[173] Essentially, one of the goals of the tax manoeuvre has been to encourage the continued upgrading of the Russian refining system by penalising producers of low-quality fuel oil through higher export taxes, and when this shift has been combined with the fall in crude oil (and oil product) prices many of Russia's simplest refineries have become loss-making. Figure 21 below shows the full impact of the tax manoeuvre, highlighting the difference in the economic outcome at various oil prices for simple, medium, and complex refineries, where a simple plant produces 45 per cent fuel oil, a medium plant produces 35 per cent, and a complex plant produces only 20 per cent. Clearly the result depends on a number of other assumptions, including the domestic crude input price and the export and domestic product prices, and the analysis is based on the inter-relationship between all of these and the global crude price as of March 2015.[174] All this being said, it is very clear that at any oil price below $100 per barrel a simple refinery in Russia has a negative free-cashflow,[175] while the upgraded refineries breakeven at approximately $65 (middle) and $50 (complex) respectively. This perhaps should not be a surprise, given that the tax manoeuvre was designed when the oil price was in excess of $100 per barrel (as recently as the first half of 2014), but nevertheless it is clear that owners of simple refineries are now facing significant problems, which have been exacerbated in April 2015 by a decline in domestic product prices.[176]

Figure 21: Economics of simple, medium, and complex refineries in Russia



Source: Author's calculations based on data from Nefte Compass, Argus FSU Energy and the Russian Tax Service

[173] Interfax, 5 February 2015, "Putin urges Rosneft head to consider national interests in Far East refinery project"

[174] Assumptions for Figure A

[175] Define free cashflow

[176] Cherepanov, C., 16 April 2015, "Russian Oil and Gas Monitor", UBS Moscow, p.9

As mentioned above, Rosneft CEO Igor Sechin has been particularly vociferous on this issue, largely because his company has one of the lowest levels of light product yield from its refining assets (see Table 6 below). As a result, it has the largest commitment to spending on refinery upgrades (a figure of $20 billion over five years has been estimated) and is also one of the companies that will suffer the most from the increase in the export tax on fuel oil that has been introduced in the tax manoeuvre.[177]

Table 6: Light product yield by company in Russia

2014 data	Throughput ('000bbls)	% light products
Rosneft	559.5	52%
Lukoil	327.8	59%
GazpromNeft	232.9	66%
Bashneft	157.4	73%
Surgutneftegas	140.0	56%
Slavneft	111.2	52%

Source: Author's calculations from data sourced in Interfax (2014), pp.27-44

However, Rosneft is by no means the only refinery owner facing the issue of unprofitable simple refineries. In March 2015, Lukoil announced that it is considering switching its Ukhta refinery in the Timan Pechora region to an intermittent operating schedule, depending upon the level of prices. Company director Leonid Fedun stated that although the company is not seeking a change in the tax manoeuvre, they need to make the government aware that if low prices persist then the refinery may need to be shut down from time to time.[178] Russian newspaper Vedomosti then reported that the ministries of finance and energy had identified a number of other refineries that are at risk,[179] while a number of small independent producers (most of whom own relatively simple refineries) have also highlighted risks to their operations.[180] Table 7 below lists the refineries highlighted by the Russian government as well as some other independent refineries that may also be at risk during a period of low oil prices. The table also details the refinery throughput in 2014 and the share of fuel oil output as a percentage of the crude oil input to the plant. As can be seen, a number of the independent refineries have very high fuel oil output, putting them clearly in the simple category, while Ukhta and Kirishi are also above 40 per cent. A number of the other refineries are closer to 35 per cent fuel oil, in the medium category but still unprofitable at a current oil price of $55 per barrel (as calculated in Figure 21 above). One refinery, Saratov, appears to be closer to the complex category, but nevertheless was identified by the Ministry of Finance as at risk.

[177] Kostanian (2014), p.58

[178] Interfax, 4 March 2015, "Lukoil may begin periodic shutdowns at Ukhta refinery, but not this year – Fedun"

[179] Vedomosti, 3 March 2015, "Lukoil will close the oil refinery at Ukhta"

[180] Nefte Compass, 5 February 2015, "Russian majors lobby against tax changes"

Table 7: Russian refineries at risk after tax manoeuvre

Refinery	Owner	Throughput 2014 (kbpd)	Fuel Oil as % Throughput
Ukhta #	Lukoil	79	40%
Kirishi # @	Surgutneftegas	384	42%
Komsomolsk* @	Rosneft	142	36%
Ryazan @	Rosneft	328	34%
Saratov # @	Rosneft	141	26%
Achinsk # @	Rosneft	103	35%
Sub-total		**1177**	
**2013 data*			
Independents			
Mini-refineries	Various	173	34%
Novoshakhtinsk	Zarubezhneft	52	46%
Afipsky	NefteGazIndustriya	117	45%
Antipinsky	Antipinsky Oil Refinery JSC	124	48%
Orsk # @	Orsknefteorgsintez	118	33%
Sub-total		**585**	

Source: Vedomosti, Author's analysis from data in Interfax (2014)
NB: # refineries identified by Ministry of Finance; @ refineries identified by Ministry of Energy

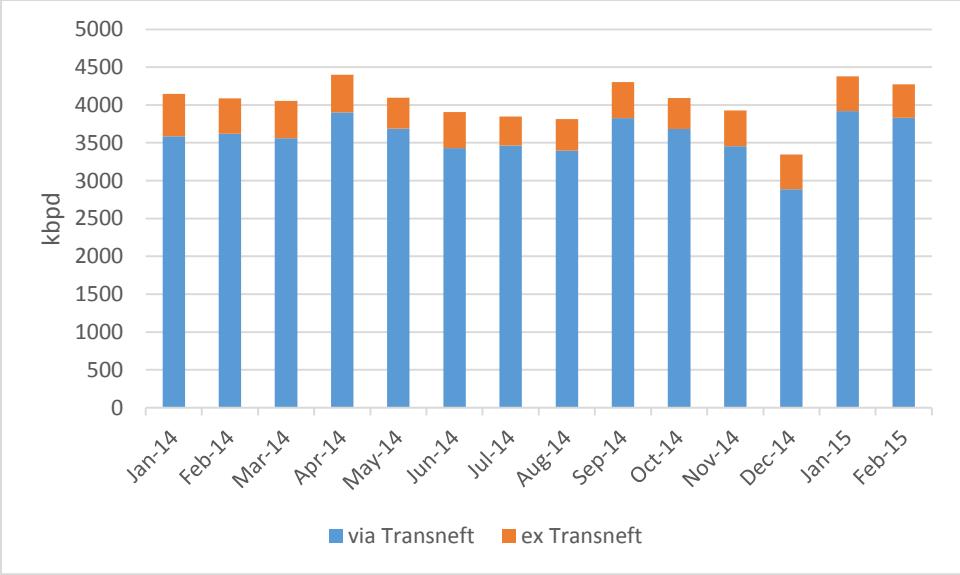
Two interesting facts arise from this analysis. The first is that Rosneft, unsurprisingly, has the largest number of refineries on the list. This underlines the need for the company to upgrade its assets by spending the $20 billion mentioned above, but given the low oil price and the company's stretched financial position (see section 6), this means that funds would have to be diverted from the company's upstream business. This would appear to put its plans to maintain production at risk and, given that Rosneft is Russia's largest oil producer, would also have clear implications for the country's overall crude oil output.

However, the second conclusion concerns crude oil exports, which could rise if Russia's simple refineries are shut down or start to operate intermittently. Total output from the refineries highlighted above is more than 1.7 mmbpd, and while it is highly unlikely that all of this capacity would be shut down it is certainly conceivable that the impact of intermittent operation could free up significant extra crude oil for export. If, for example, all plants with a fuel oil output of over 40 per cent were to be shut down for six months per year, this would reduce crude oil throughput by approximately 375,000 bpd, making the oil available for export as crude. Similarly, if only the independent refineries plus Ukhta operated at 50 per cent below 2014 levels, around 325,000 bpd could be freed up. Although the permutations are manifold and actual outcomes will depend on corporate tactics, location of refineries, and domestic and export prices, it is nevertheless clear that as far as the impact on the global oil market is concerned the future of Russian oil production presents only one part of the picture.

Crude oil exports could rise irrespective of the levels of total production, driven by tax changes designed to disadvantage specific refinery operators. Indeed, this outcome was anticipated at the end of 2014 as producers held back exports in December before the crude oil export tax

reduction came into force,[181] and Minister for Energy Alexander Novak also recognized the impact of the tax changes in statements to the Reuters news agency in March 2015, when he specifically suggested that oil is being diverted away from domestic refineries to the export market.[182] Finally, data from the first two months of 2015 would seem to confirm the shift in strategy, as in January and February 2015 crude oil exports rose by 5.5 per cent and 4.5 per cent respectively compared to the equivalent months in 2014 (see Figure 22), with the extra incentive for producers being that these exports generate dollar revenues at a time when they have extra value in the Russian domestic market.

Figure 22: Crude oil exports from Russia (2014-2015)



Source: Energy Intelligence Group data

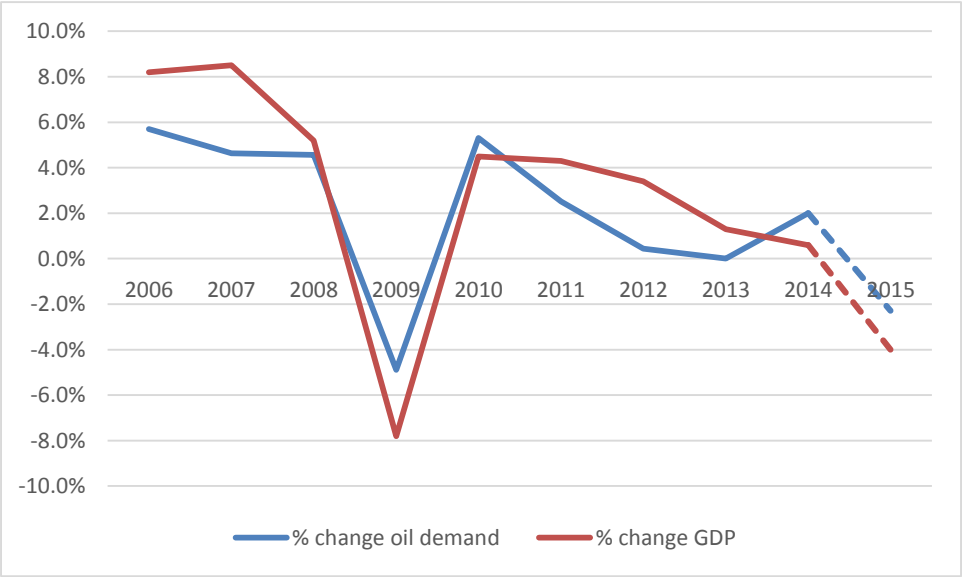
Finally, the potential for a decline in refinery throughput in Russia is also likely to be supported by a decline in domestic oil product demand. Figure 22 plots the change in domestic oil demand in Russia versus GDP since 2006, and the correlation is evidently close (with an R squared of 0.85). Given the forecast decline in Russian GDP in 2015, put at 3 per cent by the Russian government but at as much as -5 per cent by other commentators,[183] it is therefore not difficult to also forecast a fall in oil demand, and Figure 22 suggests a decline of 2.3 per cent assuming a GDP fall of 4 per cent. As a result, reduced refinery throughput and lower oil product output can reflect not only a change in the tax system but also the reality of the Russian market place, suggesting another reason why crude oil exports can rise in 2015 even if oil production remains flat.

[181] Nefte Compass, 1 January 2015, "Russian oil exports to soar on tax changes"

[182] Reuters, 11 March 2015, "Russia's energy minister sees crude oil exports rising"

[183] Reuters, 31 January 2015, "Russian government sees 2015 GDP down 3 percent, more optimistic than other forecasts"

Figure 22: Russian oil demand relative to GDP



Source: Historical data from Russian Ministry of Energy, estimates from author

9. Can International Partnership Support Russian Oil Production Despite Sanctions?

The application of US and EU sanctions on the Russian oil industry (and to an extent the gas industry as well) in July and September 2014 has tended to obscure the fact that foreign companies are still operating successfully in Russia and can, if they choose, continue to create new partnerships with Russian companies in the sector. While sanctions have undoubtedly hit the short- to medium-term prospects for Russian oil output (through the embargo on shale oil technology) and the long-term outlook (via the ban on Arctic and deep water co-operation), it remains the case that even ExxonMobil, whose projects appeared to be the main target of the sanctions, has continued to operate in Russia and is contributing to new oil developments. Even as the company was being forced retrospectively to withdraw from its exploration activities in the South Kara Sea with Rosneft, ExxonMobil was about to bring a new oilfield onstream as part of the Sakhalin 1 joint venture, where it has a 30 per cent stake (Rosneft owns 20 per cent). The Arkutun Dagi field will ultimately produce around 90,000 bpd by the end of this decade,[184] and ExxonMobil's participation in Sakhalin 1 may even see it also invest in a new Far East LNG scheme as the partnership seeks to optimize its gas sales.[185] Furthermore, company CEO Rex Tillerson emphasized during a recent meeting with the Russian energy minister in Moscow that ExxonMobil continues to see Russia as a significant long-term opportunity.[186] In addition, it would also appear that the company's participation in the Russian Arctic and in unconventional onshore licences is on hold rather than abandoned, and could certainly be restarted if and when sanctions are eased.[187]

Statoil, another of Rosneft's joint venture partners, is also in an interesting position, as it is not actually impeded by sanctions from continuing its work in the Russian Arctic, because its contracts were signed before the 1 August deadline and the EU sanctions (with which Norway has also agreed to comply) are not retrospective. The Norwegian government has confirmed that Statoil can continue its activities in the Barents Sea, although it has also provided an exit route for the company by insisting that it must seek approval for all future project financing.[188] This highlights the fact that although many companies are not specifically banned from operating in Russia, many continue to fear the risks of future sanctions or even the prospect of being seen to have circumvented the existing rules, while also not wanting to upset Russian partners who can provide significant long-term opportunities. With this in mind, although Statoil may decide not to pursue its Barents Sea exploration at present, it has announced plans with Rosneft to explore three licences in the eastern Sea of Okhotsk that also forms part of their partnership but which conveniently lies outside the Arctic region, despite being ice-bound for much of the year.[189] As a result, Statoil will continue to participate in the Russian upstream and support Rosneft in its long-term objectives in the Far East.

[184] ExxonMobil press release, 19 January 2015, "ExxonMobil begins production at the Sakhalin-1 Arkutun Dagi field"

[185] ITAR TASS, 23 September 2014, "ExxonMobil, Rosneft continue talks of Far East LNG plant"

[186] Interfax, 19 March 2015, "ExxonMobil sees Russia as important region for business growth"

[187] Interfax, 27 March 2015, "ExxonMobil is expecting to continue work on projects with Rosneft after lift of sanctions – Novak"

[188] Interfax, 19 March 2015, "Norway clear Statoil to participate in Rosneft projects, but must get OK for financing"

[189] Interfax, 29 January 2015, "Statoil sees potential for working with Rosneft on Sakhalin, in Yamalo-Nenets"

BP also has a strong relationship with Rosneft, thanks to the 19.75 per cent equity stake that it owns in the company,[190] and it is also continuing to seek direct access to assets in Russia that are not subject to sanctions. One such opportunity is the reported purchase of a 20 per cent interest in Taas-Yuriakh, an East Siberian company which owns the licence for the 1 billion barrel Srednebotuobinskoye oilfield.[191] The field came onstream in 2013, but BP's involvement should bring significant experience that can optimize the development plans due to its previous exposure to the region through TNK-BP. Srednebotuobinskoye has the potential to produce up to 100,000 bpd by 2020,[192] which will be fed into the ESPO pipeline for sale to the domestic and export markets.

Investments in Eastern Russia also offer the opportunity to continue the general theme of the country's 'pivot to Asia' and it is therefore no surprise that Chinese, Japanese, South Korean, and Indian companies are also becoming of increasing interest as partners for Russian companies, particularly Rosneft which appears to have taken on the lead role in this respect. As early as 2006, two Chinese state companies secured direct investments in Russia, Sinopec via a 49 per cent stake in the production company Udmurtneft[193] and CNPC through the purchase of a 0.5 per cent stake in Rosneft during its privatization.[194] Since then, CNPC has become the leading Chinese player in the Russian oil and gas sector, even becoming involved in the Arctic region with three licences (in partnership with Rosneft) in the Barents Sea[195] and a 20 per cent stake in Novatek's Yamal LNG project.[196] It was also offered a 49 per cent stake in Taas-Yuriakh, although this was ultimately turned down,[197] but more significantly has recently signed an agreement to purchase a 10 per cent stake in the giant Vankor field in East Siberia (again owned by Rosneft). Through all these deals it is clear that the benefits of CNPC as a partner are its financing power and the strategic importance of its energy market, as it is clearly prepared to support projects that can provide the oil and gas that the growing Chinese economy needs. This is a clear attraction at a time when Russia is searching for alternative sources of funding.

The same argument can also apply to the Indian state company ONGC, which is also looking for investments in hydrocarbon assets that can provide the fuel for its expanding domestic market. ONGC, which is already a partner in Sakhalin 1 with a 20 per cent interest and owns a 100 per cent interest in Imperial Oil, a production company in the Tomsk region, has now also reportedly been offered a 10 per cent stake in the Vankor field.[198] Furthermore, during a visit by President Putin to India in December 2014 the possibility of ONGC also buying a stake in Rosneft's Yurubcheno-Tokhomskoye field was discussed,[199] and the Russian state company is also apparently interested in involving its Indian counterpart in Arctic exploration.[200] Once again, we can see that the alignment of an Asian company's financing ability and strategic desire to secure long-term oil and gas resources is of interest to Rosneft as it attempts to replace Western

[190] http://www.rosneft.com/Investors/structure/share_capital/, accessed 30 March 2015

[191] Interfax, 24 December 2014, "BP buying about 20% of Taas-Yuriakh – paper"

[192] Rosneft press release, 15 October 2013, "Rosneft consolidates 100% of Taas-Yuriakh Neftegazodobycha"

[193] Moscow Times, 21 June 2006, "Chinese buy Udmurtneft for Rosneft"

[194] Henderson (2012), p.9

[195] Bloomberg, 25 March 2013, "Russia lets China into Arctic rush as energy giants embrace"

[196] Bloomberg, 5 September 2013, "CNPC buys stake in Novatek's Yamal LNG project"

[197] Interfax, 18 November 2014, "Rosneft, CNPC could not agree on price for Taas-Yuriakh"

[198] Economic Times, 5 October 2014, "Russia's Rosneft offers ONGC Videsh Ltd stake in Vankor oilfield"

[199] Interfax, 9 December 2014, "Russia, India to sign strategic, 15-yr nuclear energy cooperation agreement"

[200] RTN Asia, 26 May 2014, "Russia, India to jointly drill for Arctic oil through Rosneft, ONGC"

investment in key exploration and development projects. It is apparent that neither the Chinese nor Indian companies have the technical expertise or experience to provide operational assistance, particularly in the Arctic, so their participation may not be a sufficient condition for success, but it would appear that it is increasingly necessary as other financing options become more difficult to access.

Japan and South Korea have been more cautious in their approach to partnership with Russia, mindful perhaps of their strong links with the United States and therefore unwilling to help Russia bypass the sanctions regime. Rosneft has offered Japanese companies a number of opportunities in the east of the country, including a share in the Far East LNG project, the Eastern Petrochemical Company, and the Svezda shipbuilding project, but to date there has been little in the way of a positive response.[201] Meanwhile, South Korean companies continue to win a number of manufacturing and engineering contracts for hydrocarbon and power projects in Russia, but show little inclination to take any direct equity investment in specific projects. This attitude would seem to reflect the views of many countries with strategic links to the US. Even if they have no specific sanctions on Russia themselves they are reluctant to be seen to be undermining the US goal of isolating Russia, and the commercial responses of their key companies reflect this stance.

As a result, the role of international partnership in Russia is clearly going to be limited by the current geopolitical situation, but nevertheless it also seems obvious that where possible companies with existing relationships in the country will seek to maintain a commercial presence and may even develop new projects that do not contravene the sanctions regime. Caution about US sensitivity and the possible extension of the sanctions will be likely to limit short-term investment, but the longer-term prospects for Russian oil output can still be boosted by foreign partnerships, especially with Rosneft. If and when sanctions are lifted, or even if it becomes clear that they are unlikely to become more stringent, then a rapid resurgence of foreign company activity in Russia is not inconceivable, as the opportunities are obviously large and the need for foreign capital and technical expertise remains.

[201] ITAR-TASS, 19 March 2015, "Rosneft offers Japan investment opportunities in Russia's Far East"

10. Conclusions

Russian oil production reached a post-Soviet high in 2014, but production growth has fallen over the past five years as the country's core producing regions have started to go into decline. The Russian government and its major oil companies have realized that there is a need to invest in new fields and new regions, which has led to a focus on East Siberia, the offshore, tight oil, and the Arctic. However, much of this new investment has been put at risk by a lower oil price environment and the impact of US and EU sanctions, raising questions about the future of Russian oil output.

Managing the decline in Russia's brownfields will be vital, as they currently account for around 9 million bpd of production. The natural decline rate for mature fields in Russia is high, at 10 per cent per annum or more, but the application of Western technology has reduced this to an average of around 2 per cent per annum over the past few years. In a low oil price environment it would seem that a focus on maintaining this decline rate, which is a relatively low-cost tactic, should be the optimal way of sustaining oil output, and the government has provided tax breaks for 'difficult-to-recover' oil and for mature fields that should help. However, the downside risk of an increase in the decline rate to 5 per cent or even 10 per cent per annum cannot be discounted if the oil price remains low.

Beyond the existing mature fields, Russia contains a significant number of greenfield projects that have either come onstream recently or are set to start production in the next few years. If all these projects were to come onstream on schedule then it is possible that overall Russian oil output could exceed 11 million bpd by 2020, thus underlining the potential in the country. However, recent announcements of cuts in capital expenditure by many companies suggest that delays may be inevitable. We have assumed a two-year delay in all fields that have yet to commence production, but even in this case Russian production may stay flat for the next few years and could even rise towards the end of the decade.

The actual outcome will depend upon a number of key assumptions including the impact of rouble devaluation, the ability of Russia to replace imports of goods embargoed under sanctions, the additional impact of sanctions on the ability of companies to raise finance, and the willingness of the Russian government to offer direct financial support. Furthermore, the question of whether additional changes to the fiscal system will be made, including the possible introduction of a profit-based tax regime, will also be vital, as the Russian government has a long history of successfully adjusting the tax regime to sustain oil production.

Russian companies have on average cut their spending plans by around 26 per cent in US dollar terms. However, this has been offset in rouble terms by the sharp fall in the currency form RR35=US$1 to around RR50-60=US$1 over the past nine months. This devaluation means that capex should rise by approximately 7 per cent in rouble terms, and given that around 80 per cent of spending is estimated to be in roubles this benefit could last for some time. Exactly how long will depend on two main factors. The first is rouble inflation, which is currently running at an annual rate of 15 per cent or more and which will gradually erode the benefits of devaluation over two or three years.[202] The second is the ability of the Russian economy to replace imported goods in the oil sector. The Ministry of Energy has a plan to achieve this by the end of the decade, and although this appears rather optimistic in some areas (especially those involving

[202] Wall Street Journal, 5 March 2015, "Russian inflation accelerates"

complex software in the fracking business), it nevertheless seems that a commitment to move swiftly along this path is in place.

Perhaps more important in the short term, though, is the impact of sanctions on the ability of Russian oil companies to raise money on Western capital markets. Rosneft, GazpromNeft, and Novatek have been directly sanctioned, while others are encountering reluctance from some financial institutions who are concerned about the possible extension of the sanctions regime or about upsetting the US authorities even if they are not US companies but still have business links with the country. Alternative strategies to raise funds include prepayment for oil sales, the domestic bond market, and direct support from the state-controlled National Wealth Fund, but all have their limitations. Rosneft is particularly exposed, with the highest levels of debt and a need to repay $23.5 billion in 2015, and it is uncertain whether it can generate sufficient cashflow to adequately fund this repayment and its other investment activities. Given that Rosneft accounts for almost 40 per cent of Russian oil production the risk to its future output is clear.

In light of these problems and the need to encourage long-term investment in the oil industry, the government is currently considering a significant shift in tax strategy, away from the current revenue-based system to a structure founded on profit and rate of return. This has long been called for but has been regarded as a financial risk for the Russian federal budget as well as being difficult to administer. These problems may prove insurmountable, but the fact that a trial of a profit-based system is expected to start this year at least provides some hope that greater incentives to invest in new greenfield projects, as well as more expensive enhanced recovery techniques at brownfield sites, may emerge over the next few years.

Despite sanctions, international partnership may also provide support to the Russian oil industry. A number of companies with long-term histories and relationships in Russia, such as Exxon, BP, Shell, and Total, continue to promise support and future investment where they are legally able to do so. In addition, new investors from Asia, especially from China and India, are being offered opportunities not previously available as their markets and financial strength have become even more attractive to Russia.

One final conclusion to be drawn concerns Russian crude oil exports, which are the route by which Russia has the biggest impact on the global oil market. A surprising outcome from the tax changes introduced in 2015 is that, even if a fall in oil production cannot be prevented, exports may still rise for three main reasons. Firstly, simple refineries that produce large amounts of fuel oil have become unprofitable and may either be closed down or start to run intermittently, which will likely make more crude oil available for export. Secondly, oil product demand in Russia is likely to decline in 2015 as the economy moves into recession, again freeing up oil for export. And finally, oil producers' desire to generate dollar revenues to compensate for the impact of the rouble devaluation will again catalyse a preference for exports over domestic sales. As a result, a halving of the oil price is very unlikely to see Russia sell less oil on the global market in 2015, and in all likelihood will see it add to the current oversupply.

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