



Gas and Taxes: The Impact of Russia's Tinkering with Upstream Gas Taxes on State Revenues and Decline Rates of Legacy Gas Fields

Introduction

The fall in natural gas prices over the past year is putting the Russian government and the Russian gas companies yet again against each other in a high-stakes battle over the division of mineral rents. The past 25 years have seen many episodes of this never-ending struggle (Gustafson, 1999). Today's challenge, which confronts all countries like Russia that receive significant revenue from gas, is how to deal with the coming reduction in tax revenue. The battle is over the very nature of the rules by which the composition of tax take from natural gas and its impact upon Russia's long-term gas production trends is going to evolve. The matters have become complicated by a recent tax change that unintentionally introduced ambiguity into companies' tax obligations and may distort their production plans. Defying the famous idiom, upstream gas taxes for some of Russia's producers have become not a certainty but a matter of choice between "high" and "low" fiscal burden. This became possible since the introduction of a formula-based mineral resource extraction tax (MRET) for natural gas in 2014.

MRET is a tax that applies to all mineral resources produced in Russia, but the rates and the rules of tax calculation vary depending on the type of resource. Gas MRET accounts for about 3% of Russia's federal budget revenues and represents 13% of overall MRET collections (for all mineral resources). For natural gas a single specific rate in rubles per thousand cubic metres existed in 2005-2011. Companies simply had to pay a fixed fee of 147 rubles/Mcm of natural gas produced (from \$4.6 to \$5.9/Mcm, depending on average annual exchange rates). The rate was set at a relatively low level reflecting low regulated domestic gas prices in Russia. After a series of regulated gas price hikes in Russia during 2005-2010, the effective tax take from gas MRET fell almost two-fold as a percentage of domestic gas sales revenue. The Russian government realized it was shying away from significant rents and decided to act. As Deputy Finance Minister Sergey Shatalov put it at the time, regulated gas price hikes were going to give gas producers additional windfall revenues that they "did not earn", so they needed to return to the state its fair share of the run-up (Shatalov, 2012). There were two annual gas MRET rate hikes in 2012 and 2013 along with the introduction of two tiers: a higher one applied to Gazprom and a lower one - to independent gas producers (IGPs). The corresponding rates in 2013 were 622 and 402 rubles (\$19.5 and \$12.6)/Mcm. This simple differentiation reflected the perceived gap in profitability as Gazprom's export monopoly provided exclusive access to lucrative European gas market while Russia's IGPs could only sell their gas at home at prices that were significantly lower than the export netbacks.

In July 2014 the Russian government introduced what seemed to be a more sophisticated and efficient differentiation mechanism. It replaced a specific rate of gas MRET with one based on a complicated formula linked to a number of geological, geographical and technical criteria. It is often said that the road to hell is paved with good intentions. It was exactly the case with the gas MRET amendments: the justification for the new scheme was the elimination of the guesswork by Russian gas companies concerning the impact of ad hoc MRET changes thus leading to predictability of revenues for the state

and easier financial planning for the companies. The head of Russia's Gas Society Pavel Zavalny, who was also a deputy chair of the Duma Energy Committee, said that the bill would help develop difficult-to-extract gas while ensuring fair distribution of revenues between the state and the industry. (Zavalny, 2013)

The implementation of the new system, however, has resulted in a series of unintended consequences for Russia's gas industry and the state budgetary revenues. The initial goals of the tax overhaul have been distorted. Indeed, Russia's late Prime Minister Viktor Chernomyrdin's famous phrase "we wanted to do better, but it turned out as usual" may serve as a perfect illustration to what appears to be the first results of the reform. The differentiation of gas MRET on the basis of the 2014 formula has resulted in significant differences in upstream taxes for different gas fields. For example, "new gas" assets located in remote Arctic locations on the Yamal peninsula are enjoying lower tax rates, while Russian legacy gas fields in traditional production areas are subject to much higher fiscal burden. At the same time, as a result of the investments in new productive capacity that Russia had done over the past decade expecting higher demand abroad and at home, the Russian gas industry's spare productive capacity is about 170-180 Bcm. Most of it belongs to Gazprom. In January 2017 Gazprom's head Alexey Miller reported to President Vladimir Putin that his company's spare productive capacity was 150 Bcm (Gazprom web-site, 2017). The state company also has a wide portfolio of assets with highly differentiated tax rates. This situation is likely to last since the aggregate demand for Russian gas turned out to be much lower than had been expected and will increase relatively slowly in the years to come.

Against this background two results of our research are worth noting. First, Gazprom as a key balancer of gas production has the greatest flexibility among the Russian producers to choose the tax burden for a significant share of its overall production, as it makes the decisions about which of its fields to work and which to keep idle or underutilized. We demonstrate that Gazprom indeed is able to minimize its tax burden by using the existing tax rules and optimizing the use of its assets on the basis of tax considerations. This, in turn, makes the decline rates of some of the fields (those that carry the production balancing burden) higher than economically justified. As a result, some fields with sunk capital costs and low overall costs may retire prematurely, while higher cost new fields take over their share in the balance and increase overall costs of producing natural gas in Russia – owing to the unfortunate design of the gas MRET tax.

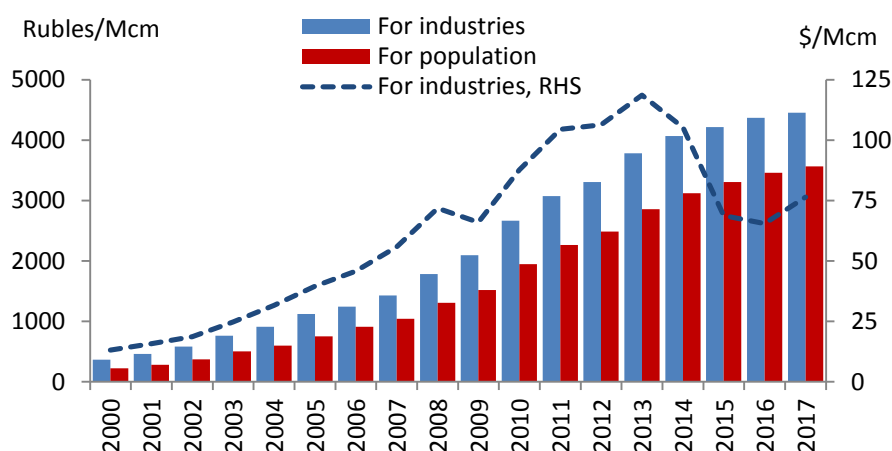
Low costs for legacy Russian gas produced from Cenomanian layers of the supergiant fields in the Nadym-Pur-Taz (NPT) region provided Russian gas producers with a highly competitive edge for the past several decades (Stern, 2005). But now, with new Russian gas located much further north and in deeper horizons, it is becoming more difficult to produce, and therefore more costly. The imposition of higher taxes, further adding to upstream costs, may be the wrong move at a time when new technologies have brought about a great revival of gas production in North America and reduced the costs of production (and market prices) there to levels which compete with regulated Russian gas prices. Other countries like China are actively trying to replicate North America's "shale gas miracle". At the same time, a plethora of new LNG projects in a number of countries have brought greater competition to traditional gas producers/exporters like Russia. Taken together, these competitive challenges have the potential to radically change the global gas market landscape (Henderson & Pirani, *The Russian Gas Matrix: How Markets Are Driving Change*, 2014). Sizable hikes in the MRET for gas would increase the supply costs for Russia's lowest cost fields and reduce the overall competitiveness of Russia's gas exports at a time when new competitive challenges are emerging internationally, and the battlefield of the future is likely to be centered on costs.

The Russian policy makers apparently did not take into account the issue of surplus capacity and balancing opportunities for producers and introduced distortions in the tax scheme that lead to higher decline rates of low cost producing gas fields in Russia. Modifications of the policy can correct the externality and lead to more efficient development of Russia's gas reserves. Changing the current tax design can also bring additional tax revenues to the Russian state.

The Gas Rent Dilemma for the Russian Government: Price Subsidies or Higher Taxes?

During the past two decades the legacy of low gas prices in Russia has been one of the largest subsidies left from the Soviet era and one of the largest sources of distortions in the Russian economy (Henderson, Pirani, & Yafimava, *Russia's Domestic Gas Market Development, Prices, and Transportation*, 2014). The inheritance of plentiful supplies of cheap gas at a handful of prolific supergiant fields developed in the Soviet times allowed first the Soviet and then the Russian government to expand the share of natural gas in Russia's energy balance and simultaneously keep gas prices at home systematically low. This Soviet policy continued in Russia during the 1990s and early 2000s. There were three general reasons for that: macroeconomic considerations, industrial policy reasoning, and strategy of transition. First, reining in cost-push inflationary factors, such as gas price hikes, served as a supporting instrument for the government in its general anti-inflationary policy. Second, this was meant to shield the energy-inefficient Russian economy, which lacked funds for investment and modernization during and immediately after the difficult years of the 1990s. Third, maintaining gas prices artificially low was clearly an attempt to subsidize the transition to a market economy by running down the Soviet-era inheritance.

Figure 1: Russian regulated wholesale gas price, Moscow price zone



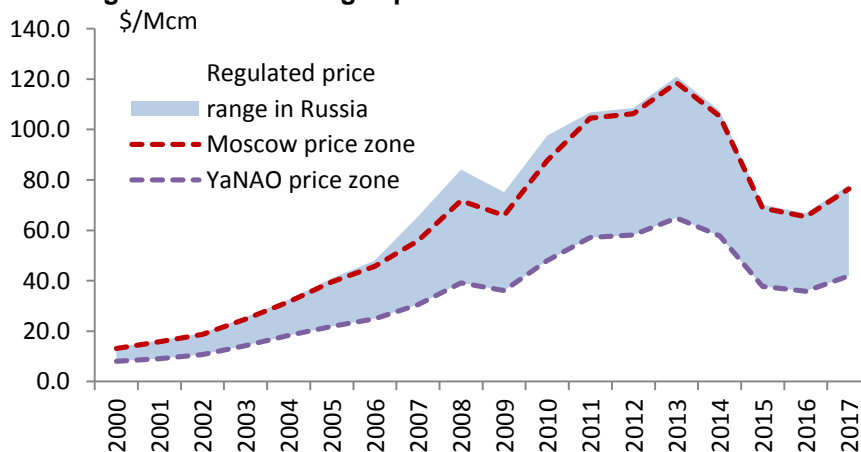
Source: FTS, FAS, Center for Energy Policy Research, HSE

In the middle of the 2000s, however, the growing domestic call on gas (a result of Russia's economic recovery, but also a consequence of distorted price signals) together with the depletion of the Soviet-era "supply cushion," caused worries about the future sustainability of Russia's gas balance. New gas policies developed by Russia in 2006 have led effectively to a "new gas deal." (Yermakov, 2008) By approving an aggressive program of hikes in regulated gas prices during 2007–11, the Kremlin sought to tilt the relationship between gas producers and gas consumers in Russia to address problems on both the supply and demand sides that have accumulated over the years of subsidized gas: to create incentives for bringing the next generation of big gas fields on the Yamal Peninsula online as soon as possible and to encourage conservation and efficient use of gas.

These policies resulted in an almost three-fold increase in Russian domestic regulated gas prices for industries and population in ruble terms from 2006 to 2013 on the back of a 13.2% compound annual growth rate (CAGR) for the period (See Figure 1). By 2013 the upper band of regulated prices (in the western regions of European Russia to which gas needs to be transported over long distances and at significant cost) reached \$120/Mcm, and the lower band (in the regions like Yamal-Nenetsk, where most of Russian gas is produced) - \$65/Mcm (See Figure 2). Now that domestic gas prices were no longer low, the extra revenues ("rents") being generated (after accounting for the necessary investments in future supply) could be taxed away. In October 2012 a series of gas MRET hikes were approved with the aim of collecting an additional 14 billion rubles in 2013, 58 billion rubles in 2014, and 95 billion rubles in 2015 to the state coffers, representing an increase over gas MRET collected in 2012

of 5%, 23%, and 37% respectively. This was a significant increase, but only about half of the sums Russia's Ministry of Finance was intending to collect initially thanks to the ability of Gazprom to lobby for lower tax rates, according to the Russian press (Visloguzov, 2012).

Figure 2: Russian regulated wholesale gas prices for industrial users

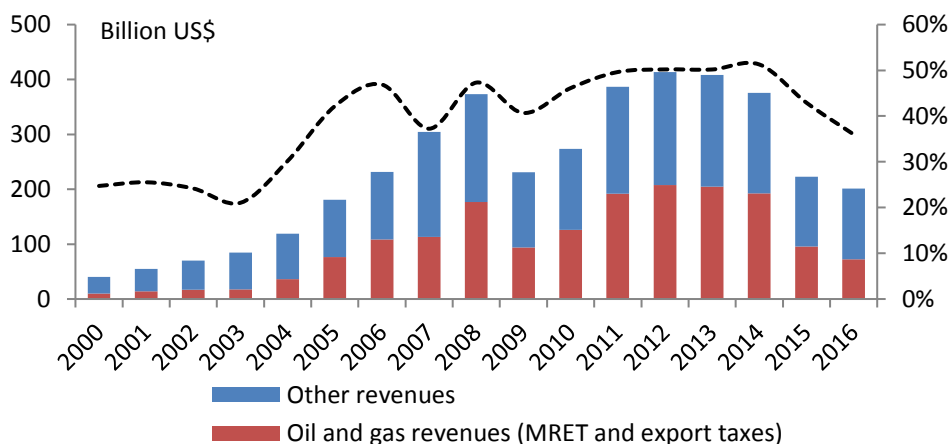


Source: FTS, FAS, Center for Energy Policy Research, HSE

An important issue for policymakers is how to distribute rents generated by Russia's gas sector. The traditional definition of mineral rent is the excess of a project's pretax benefits over costs, including the minimum return on capital required to attract investment. Rents are one of the fundamental attributes of the oil and gas industry and vary depending on resource prices, costs, and the overall production profile. The "first best" solution, it is generally believed, is to vary the tax take as a progressive function of project rent or profitability. In theory, this solution increases government revenue without shutting in production. In practice, as a result of the existence of a choice of tax instruments, many oil and gas tax systems, Russia's included, end up behaving regressively rather than progressively, causing the government take to increase as profitability declines. A regressive system is not desirable, since it increases the likelihood of the take exceeding 100% of project rent and as a consequence limiting production and eroding the overall tax base (IMF, 2010).

Unfortunately, Russia has had to rely on such regressive measures to meet its budgetary targets, and the oil and gas sectors have traditionally provided almost half of the state's federal budget revenues. (See Figure 3)

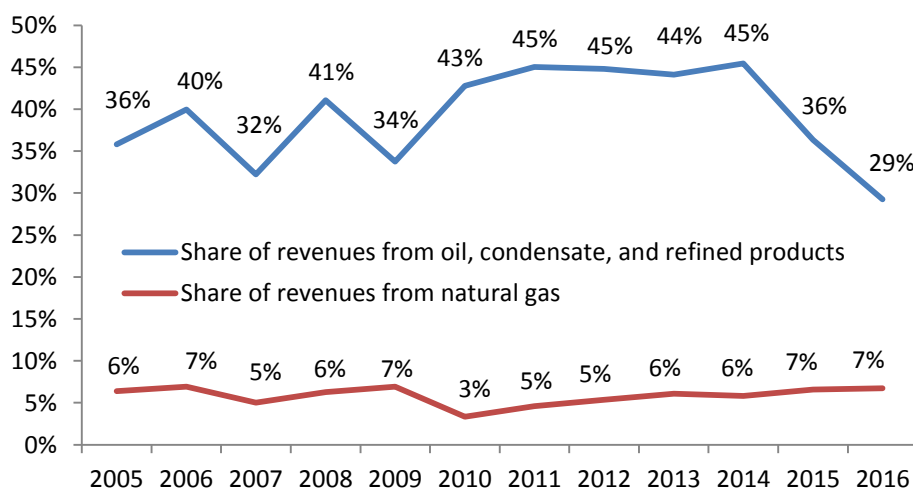
Figure 3: Oil and gas revenues of Russia's federal budget



Source: MinFin, Center for Energy Policy Research, HSE

Russia's tax authorities have traditionally preferred to tax gross revenue rather than profits because of ease of administration and the greater certainty and predictability of total tax revenues. Historically, such rents have been transferred to domestic industries and the population through low gas prices; at the same time, the tax take from the gas sector has been relatively modest, especially compared with Russia's oil sector (Russia's Federal Treasury, 2005-2016). (See Figure 4)

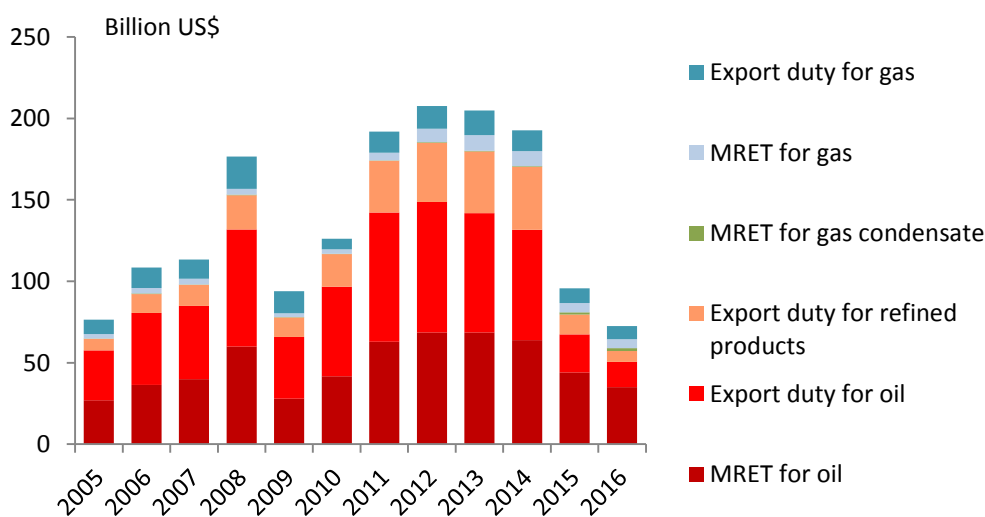
Figure 4: Oil versus gas: shares of Russia's federal budget



Source: MinFin, Center for Energy Policy Research, HSE

MRET on oil and export duty on crude oil and refined products represent the lion's share of state revenues from the sector. (See Figure 5)

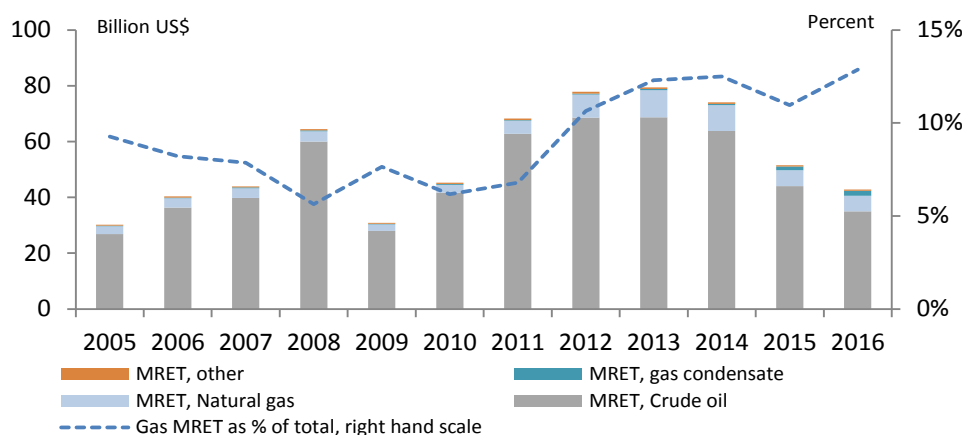
Figure 5: Composition of oil and gas revenues of the Russian budget



Source: MinFin, Center for Energy Policy Research, HSE

The composition of the revenues from MRET also demonstrates that natural gas' share has been far below oil's and fluctuating around 10% of the total. (See Figure 6)

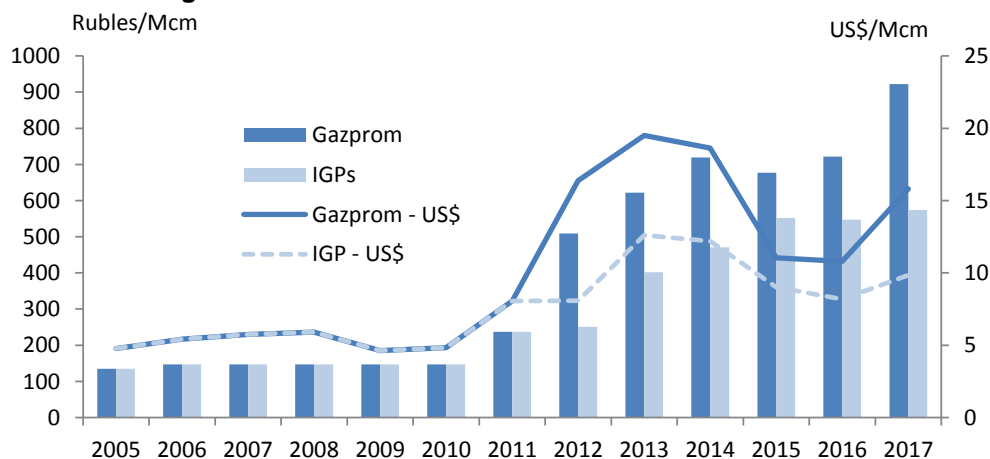
Figure 6: MRET composition



Source: Russia's Ministry of Finance, Center for Energy Policy Research, NRU HSE

To account for perceived differences in profitability between Gazprom and the Independent Gas Producers (IGPs) caused by the former's exclusive access to export markets, the rates of gas MRET were differentiated in 2012, initially by way of specific rate differences and then via the MRET formula. (See Figure 7)

Figure 7: Unit rates of gas MRET

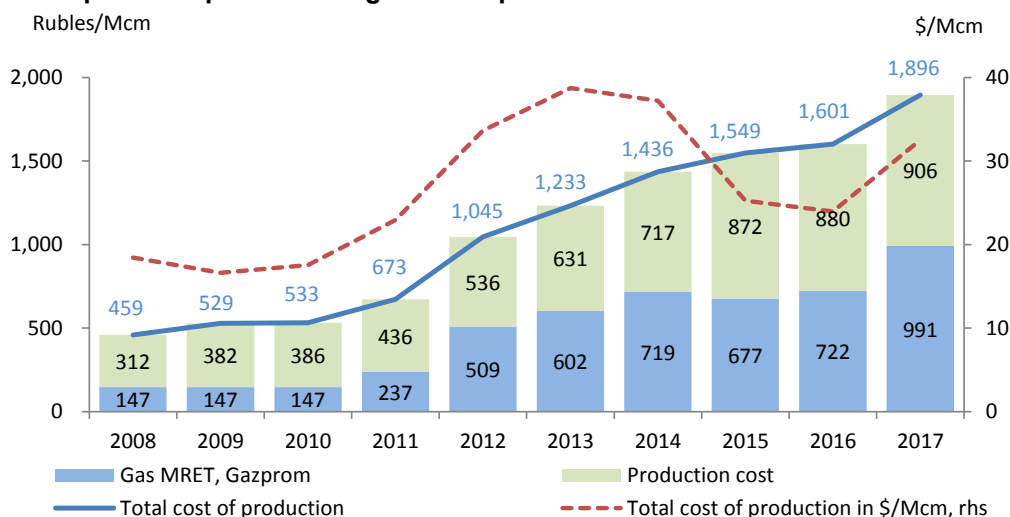


Source: Center for Energy Policy Research, HSE

Higher MRET and the Expiring Legacy of Russia's Low Cost Gas

The key calculation behind the Ministry of Finance 2012 plan to increase gas taxes seemed to be a desire to increase tax take from "old" gas, because production costs at legacy fields producing Cenomanian gas were still relatively low. Gazprom, for example, reported (Gazprom, 2017) that average unit costs of gas production at its seven key production subsidiaries went up from 459 rubles (\$18.4)/Mcm in 2008 to 1896 rubles (\$32.5)/Mcm in 2017, which it stated was due primarily to MRET increases (see Figure 8). These numbers include new fields as Bovanenkovo is being developed by Gazprom Dobycha Nadym – one of Gazprom's "seven sisters".

Figure 8: Gazprom's reported average cost of production



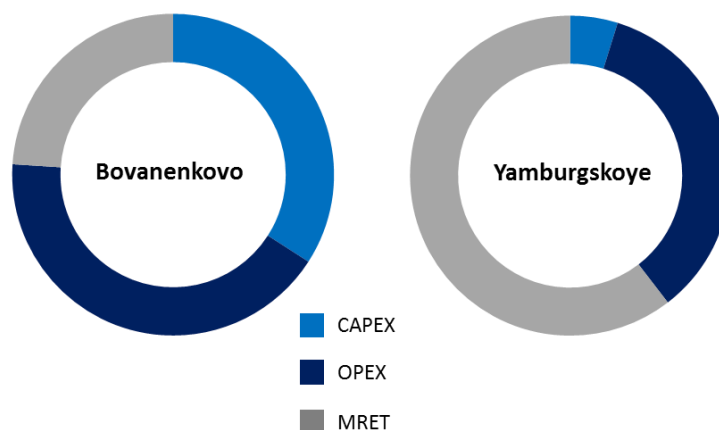
Source: Gazprom, Center for Energy Policy Research, HSE

These production costs are no longer low, being now not far apart from upstream production costs for “new” Bovanenkovo gas where the rate of gas MRET has been reined in. These higher costs could potentially deny Gazprom considerable margins from “old” gas as domestic regulated prices are being capped.

The timing of the change in policy, to capture for the state the bulk of the rent from Soviet legacy gas, was unfortunate, coming at the very moment when that legacy started to run down. For the past 20 years, gas supply in Eurasia has relied largely on production from a handful of supergiant legacy fields developed in the Soviet period, producing mostly dry Cenomanian gas. These fields, however, are now in terminal decline. The transition strategy for Russia was to keep the rate of decline under control, bringing into production a handful of smaller new fields that would bridge the gap in the supply/demand balance, while preparing for “the grand offensive”—the development of new supergiants on the Yamal Peninsula. The shift was finally accomplished with the launch of production at the Bovanenkovo field on the Yamal Peninsula in October 2012. Another notable event was reaching 1 trillion cubic metres in cumulative production at the Zapolyarnoye field in 2012—the new Russian gas “workhorse” field in the traditional Nadym-Pur-Taz (NPT) gas-producing province of West Siberia. The field has been in operation since 2001, producing gas from Cenomanian layers. In 2011, Gazprom started production from the field’s deeper Valanginian layers, which helped bring the productive capacity to 120 Bcm/year in 2013. Actual production that year amounted to 118 Bcm. This made Zapolyarnoye Russia’s single largest producing gas field.

Bovanenkovo, the most important new-generation gas field in Gazprom’s portfolio, is ramping up aggressively after some initial delays. Gazprom’s original development plan for the field envisioned production of as much as 115 Bcm in 2017, but it is unlikely that this target will be reached before 2020. Production at Bovanenkovo amounted to 67.4 Bcm in 2016. Gazprom stopped holding back production at this new field to balance the overall output, apparently assigning this task to Zapolyarnoye and older fields in the NPT area. Bovanenkovo gas is needed to fill the new trunk gas pipelines that lead from Yamal to Ukhta and then on to Vyborg and Graifswald in Germany (via Nord Stream). The tremendous investments that went into the Yamal upstream development and the construction of the new gas transportation corridor must be recouped. But tax considerations also played their part. Compare the breakdown of production costs in 2015 at Bovanenkovskoye (Yamal) and Zapolyarnoye (NPT) (See Figure 9).

Figure 9: Cost structure of Bovanenkovo (new field) and Yamburgskoye (old field)

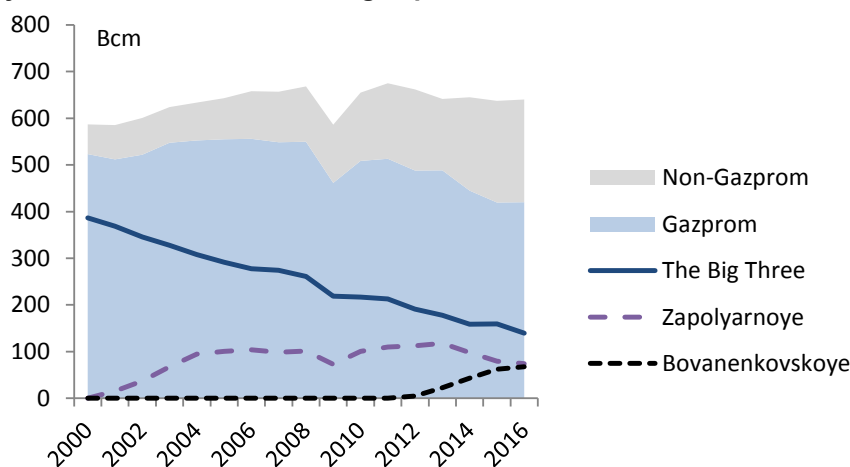


Source: Center for Energy policy HSE

Much lower gas MRET at Bovanenkovo compared to Zapolyarnoye gives Gazprom a strong incentive to use the latter as a balancing item (while Gazprom’s productive capacity is far greater than available demand). The concern for policy-makers should be that Russia is probably wasting its low cost (net of tax) gas by taxing it too much.

The irreversible production decline at the so-called Big Three supergiant fields (Urengoy, Yamburg, and Medvezhye) had been compensated by increased production from Zapolyarnoye and other fields in the NPT during the past decade. From 2012, however, the gap has been filled with much more expensive gas produced in the Yamal Peninsula at Bovanenkovskoye, and the share of this higher cost gas (net of MRET) in Russia’s gas balance will increase in the future (see Figure 10).

Figure 10: Key trends in Russia’s natural gas production

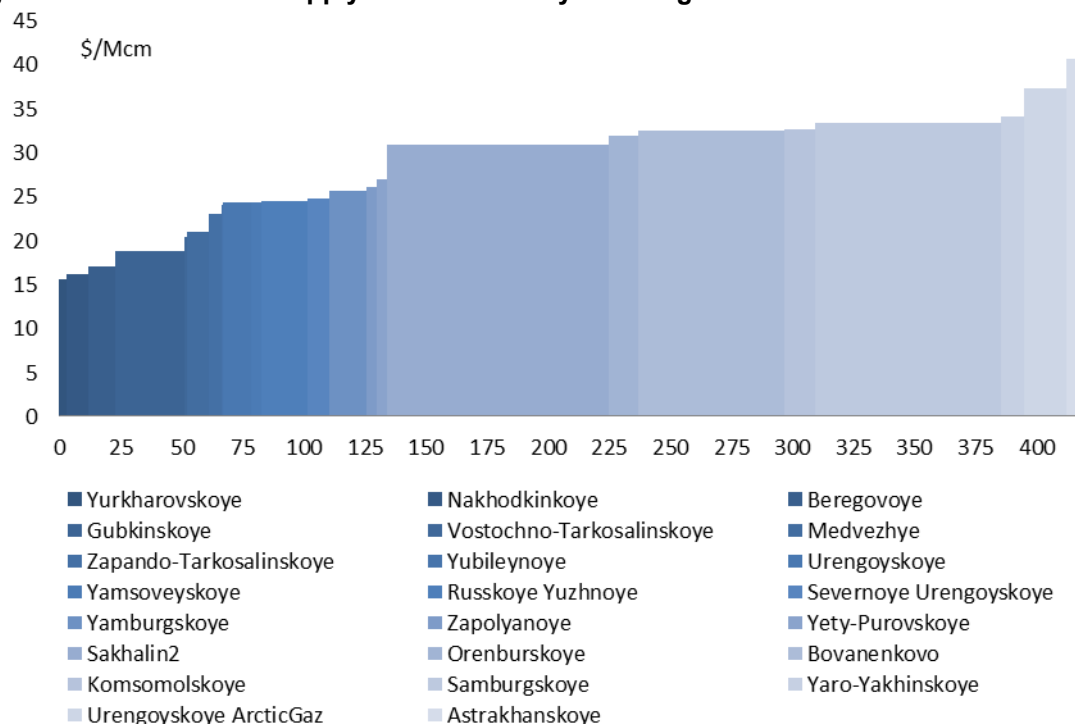


Source: MNR, Center for Energy Policy Research, HSE

But if higher domestic gas prices lead to higher gas production taxes in Russia, this is not merely a rent redistribution issue. The legacy of low gas production costs has been a key competitive advantage for Russia’s gas industry, offsetting the high transportation costs for Russian gas arising from the long distances from centres of production to points of sale. Relatively inexpensive gas also served as a key pillar for the general Russian economy, supporting all consumers that use gas, especially in manufacturing. Since MRET is applied to all produced gas, irrespective of profitability of operations, it is a direct component of total upstream costs. In other words, higher MRET shifts upward the supply cost curve for Russian gas. (The cost curve numbers below are the sum of capital costs, such as drilling capex and facility capex, operating expenses, including lifting costs, preparation and transportation to

the entry point into the trunk pipeline of Russia's gas transportation system (GTS), and SG&A costs as well as gas MRET that is part of Russian production costs (*sebestoimost*). (See Figure 11)

Figure 11: Cost curve of supply for Russia's key natural gas fields



Source: Source: Center for Energy Policy HSE

It appears that “old” gas from legacy fields can absorb higher MRET outlays, because production costs at these fields are still relatively low. But it would deny the operators the cash flow that they could use for measures intended to reduce the pace of natural production decline. Thus, higher MRET could result in “old” gas production shrinking even faster.

But for “new” gas, the deal is different. The tax generating capacity of new gas is much less, as almost all new gas projects developed in Russia by Gazprom, gas independents, and oil companies involve much higher upstream costs and could require special MRET exemptions to be implemented, much like the situation for oil. In fact, many of the new gas fields would not meet the required profitability criteria if it were not for “liquids credits” (i.e. revenues from sales of liquid by-products of gas development, such as gas condensate that help offset much of the project expenditures). Gas condensate, which unlike crude oil is taxed at a relatively low rate in Russia, has been a saviour for many a new gas project in recent years.

Introduction of a formula-based gas MRET in 2014

At the end of 2013 the Ministry of Finance developed a bill introducing a complicated formula for calculating gas MRET (See Text Box). It was passed by the Duma as an amendment to the MRET chapter in the Tax Code and took effect on July 1, 2014. The formula-based gas MRET would theoretically mean that the government would not need to constantly tinker with the tax rate as market conditions changed; and therefore, by eliminating the need for guesswork concerning the impact of ad hoc regulatory moves by Russian authorities, it would help Russian gas companies in their financial planning. The problem with this approach is that in order to achieve progressivity, tax designers have to reverse the revenue-based tax's natural regressive tendency to “go in the wrong direction.” The adjustment coefficients in the formula are merely proxies for profitability (imputed profitability or imputed costs) that may be very imperfect in practice. At best, the technical/geological/geographical coefficients will only partially reflect the importance of real project indicators such as reserve size, production

profiles, operating and investment outlays (including the cost of capital), and the timing of cash inflows and outflows.

Even more importantly, the formula-based MRET is still a revenue-based tax, adding directly to the higher cost of gas production in Russia and inflating the cost basis of domestic gas prices.

An option to generate additional revenue from the gas sector by raising gas export taxes above the current level of 30%, which would increase the “wedge” between export prices in Europe and export netbacks and would bring the export parity level down, could be easily administered and also would not add directly to the cost of upstream supply. Unfortunately, Russia does not have this option because of the agreement with the European Union as part of Russia’s WTO accession protocol.

An alternative approach—taxing gas companies’ profits rather than revenues—could give Russian policymakers much greater flexibility with respect to balancing the interests of gas producers and gas consumers at home. But it would require the Russian government to step up its effort in administering more complex profit-based taxes. This is the route the Ministry of Finance has been very reluctant to take for fear of massive tax evasion.

The MRET formula

Effective July 1, 2014, the Russian government introduced a gas MRET calculation mechanism. The aim of the new arrangement was to take into account geological, geographical and economic diversity of Russian gas assets and to move away from ad hoc “manual” adjustments of the gas MRET that the government had to make during previous years. According to the Tax Code of Russian Federation, MRET tax rate for gas is calculated as follows:

$$\text{MRET for gas (RUB/mcm)} = 35 \times \text{Usf} \times \text{Cdf} + \text{Tg} =$$

$$= 35 \times \frac{0.15 \times \text{Cgp} \times (\text{Pg} \times \text{Rg} + \text{Pc} \times (1 - \text{Rg}))}{(1 - \text{Rg}) \times 42 + \text{Rg} \times 35} \times \min(\text{Cdg}, \text{Cl}, \text{Cdo}, \text{Cas}, \text{Crdf}) + 0.5 \times \text{Td} \times \left(\frac{\text{Dg}}{100}\right) \times \left(\frac{1}{\text{Cg}}\right), \text{ where}$$

35 – rate that reflects calorific value of one thousand cubic metres of gas expressed in BTU,

Usf - base value of a unit of standard fuel,

Cdf - coefficient reflecting the degree of difficulty of the extraction of natural fuel gas and (or) gas condensate from a hydrocarbon reservoir,

Tg - indicator reflecting expenses for the transportation of natural fuel gas,

Cgp - coefficient reflecting the export return on a unit of standard fuel,

Pg – price of gas,

Pc – price of gas condensate,

Rg – ratio of produced non-associated gas in total volume of produced hydrocarbons,

Cdg - depletion factor of gas reserves of a particular subsurface site containing a hydrocarbon reservoir,

Cl - geographical location of a subsurface site containing a hydrocarbon reservoir,

Cdo - depth of occurrence of a hydrocarbon reservoir,

Cas - coefficient reflecting whether or not a subsurface site containing a hydrocarbon reservoir serves a regional gas supply system,

Crdf - coefficient reflecting specific factors relevant to the development of particular reservoirs of a subsurface deposit,

Dg - average distance, expressed in kilometres, for which natural fuel gas is transported through trunk pipelines forming part of the Unified Gas Supply System within the territory of the RF,

Cg - coefficient which is determined as the ratio of the quantity of natural fuel gas extracted by Gazprom to the quantity of natural fuel gas extracted by other taxpayers.

In spite of the multiplicity of coefficients there are only three first-order coefficients, as follows:

- The Usf coefficient that stands for the value of a unit of standard fuel depends on the shares of produced gas and gas condensate and their corresponding prices. Every year the responsible government officials monitor changes in market prices and adjust the Usf coefficient. In parallel the government can introduce changes to another coefficient – Cgp – which is an element of arbitrary adjustments of imputed profitability of gas exports. This coefficient is not derived from any market data but is an instrument of ad hoc modifications of the MRET formula. Apparently it was deliberately inserted into the formula to leave the State a tool to manually regulate tax take.
- The second calculation (Cdf) in the longer formula is included to account for the difference in conditions under which the gas is produced. It encompasses such factors as the level of depletion of gas reserves (the more depleted the deposit is, the less it is taxed), the geographical location (especially for remote regions with poor infrastructure), the depth of deposit (the deeper the deposit occurs, the lower the tax rate is), the gas supply destination (lower tax rate for reservoirs serving exclusively for a regional gas supply system).
- The Tg coefficient was implicitly added to the formula to tax Gazprom at higher rates than IGPs. To date, it has not been used and the expert community is still undivided on its usefulness. In government's instructions as to the calculation of the tax in 2017 this indicator equals zero.

The key second-order coefficients are as follows:

- Price of gas. It is calculated according to the following formula:

$P_g = P_d \times R_d + P_e \times (1 - R_d)$, where

P_d – average calculated domestic price of gas (according to state price monitoring),

R_d – share of domestic sales in total sales,

P_e – formula-based gas export price derived from global market prices for refined products (fuel oil and gasoil) on a monthly basis.

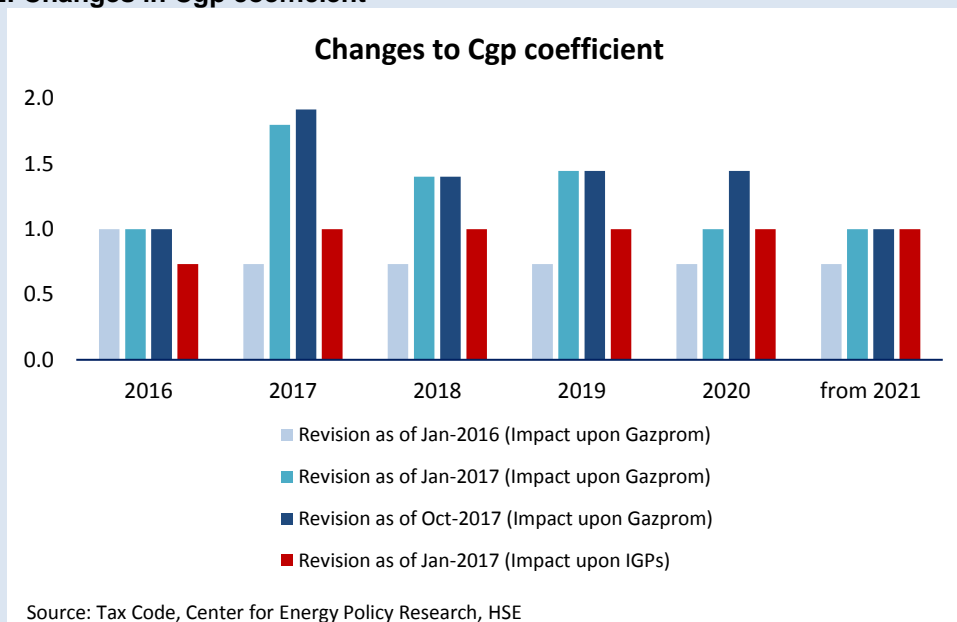
Since the R_d coefficient differs by the Gazprom/Independent producer factor (0.64 for Gazprom and 1 for others), both addends of the formula are dependent on Gazprom participation: in case of an independent producer the first addend becomes lower and the second addend is reduced to zero.

Price of gas condensate is linked to oil price (P), export duty rate on gas condensate (P_n) and exchange rate of USD/RUB (R): $P_c = (P \times 8 - P_n) \times R$. Consequently, since oil price volatility is balanced by exchange rate, price of gas condensate is rather stable in the course of time.

Gazprom holds export monopoly rights for pipeline gas. To account for perceived higher profitability of exports compared with domestic sales the Russian government introduced a special coefficient into the MRET formula. This coefficient is also used by the Russian government going through tough times to fill the gap in resources by charging higher taxes. For example, in 2017 Gazprom paid fewer dividends than the Government had anticipated. In order to fill the budget and meet the plan, the modifications to the Tax code were quickly undertaken (See Figure 12).

The CI coefficient that defines the level of production difficulties associated with geographical location represents the most complicated calculation. The relevant sections of the Tax Code were tailor-made to provide incentives for developing gas in the following areas: the Yamal and Gydan peninsula in the Yamal-Nenets Autonomous District; the Astrakhan, Irkutsk, Krasnoyarsk, Yakutia regions; the Far Eastern Federal District including offshore developments in the Sea of Okhotsk. The formula points out specific characteristics of the gas fields such as depletion factor, date of commencement of commercial production, location specification, tax incentive duration and production volumes limits.

Figure 12: Changes in Cgp coefficient

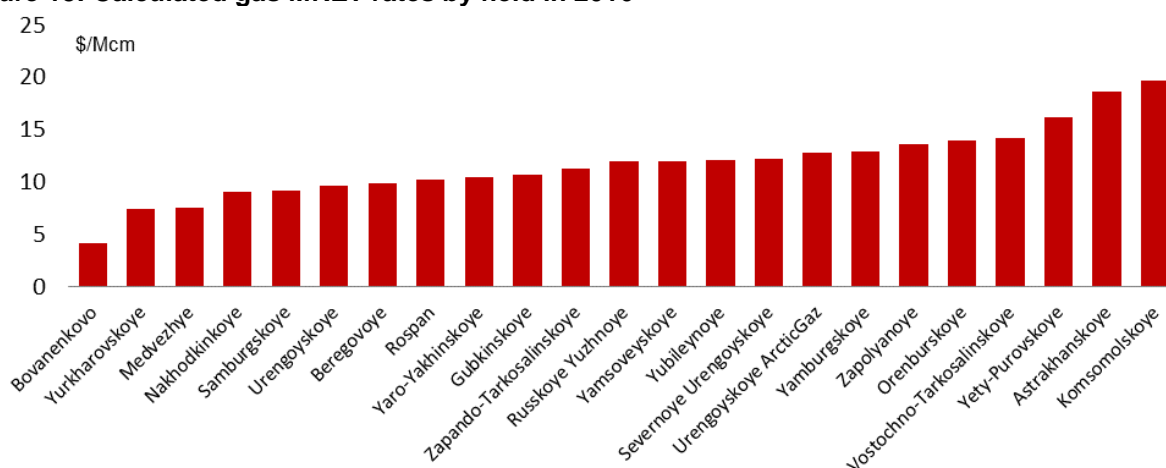


Source: Center for Energy Policy HSE

First results from the gas MRET reform

The first obvious result of the change in gas MRET calculation has been the emergence of a wide variation of tax rates for different gas fields. The Centre for Energy Policy Research at the Higher School of Economics in Moscow has developed a model that allows for the calculation of these tax rates for specific fields (See Figure 13).

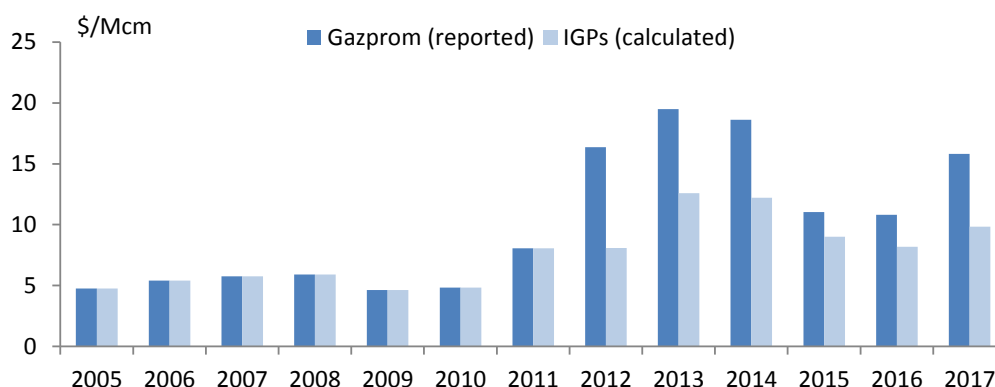
Figure 13: Calculated gas MRET rates by field in 2016



Source: Center for Energy policy HSE

Secondly, differentiation of gas MRET has affected tax collection and made it less predictable. The differentiation of gas MRET for Gazprom and non-Gazprom producers started in 2012 when two specific rates in rubles/Mcm of produced gas were introduced. The rates were raised in 2013 and then again in the first half of 2014. From July 1, 2014 on the gas MRET is governed by the formula. Gazprom reported average gas MRET for its seven key production subsidiaries in its presentations to investors as a fair representation of its unit tax. We calculated unit tax for IGPs using the formula and our proprietary model. (See Figure 14)

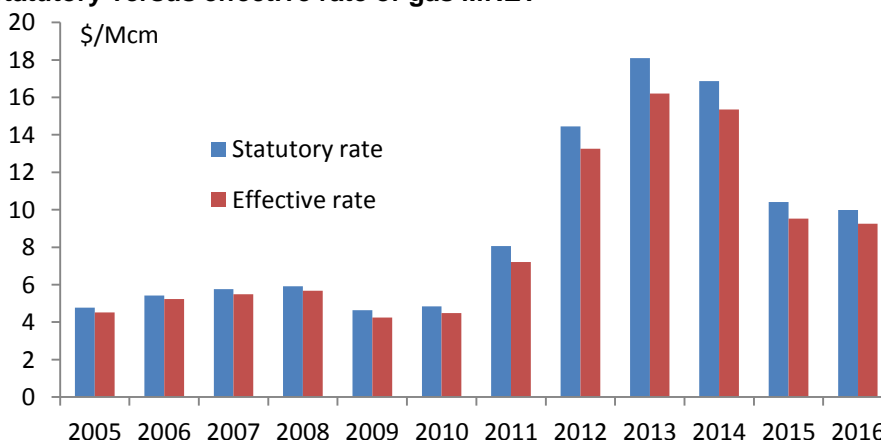
Figure 14: Unit rates of gas MRET



Source: Center for Energy Policy Research, HSE

Then we calculated the effective unit gas MRET for Russia on the basis of official reported MRET revenues (by the Ministry of Finance) and production data (by the Ministry of Energy and the Ministry of Natural Resources) and compared it with statutory unit rates for Gazprom and IGPs and the combined rate we built using the respective shares of production. (See Figure 15)

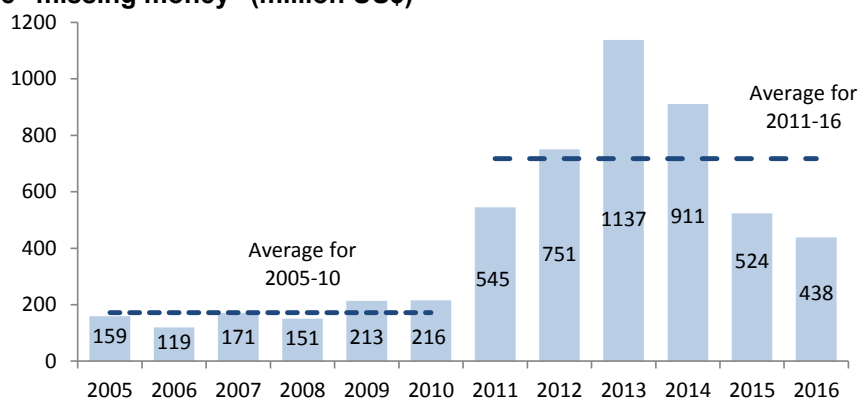
Figure 15: Statutory versus effective rate of gas MRET



Source: Center for Energy Policy Research, HSE

The difference between the effective rate (actually collected tax) and the statutory rate is clearly split between two distinctive periods: 2005-2010, when no tax differentiation among Russian gas producers existed, and 2011-to the present when such differentiation initially was a result of ad hoc specific tax rate differences and then became a function of the formula-driven treatment of Gazprom and IGPs. There is no perfect match between the effective rate and statutory rate during 2005-2010 which can be explained by the difference between the calculation of the tax base on the basis of gross production numbers that we did and the calculation of the tax base net of losses, gas reinjection, and own use (this is what taxpayers do). But the differences are relatively minor and uniform. The years of 2011-2016 when tax differentiation and different rates of gas MRET for Gazprom and IGPs were applied stand out in a sharp contrast to the earlier trend, as the differences between the effective rate of tax and the statutory one quickly grow out of proportion. This becomes even more apparent if we convert these differences back into tax revenues. The “missing money” on the graph is the imputed difference in revenues under statutory versus effective tax rate. (See Figure 16)

Figure 16: The “missing money” (million US\$)



Source: Center for Energy Policy Research

As soon as tax differentiation of gas MRET starts, the gap between the revenues that should have been collected and the actually collected tax jumps. The delta between average amount of the “missing money” during 2005-2010 and 2011-2016 is on average \$546 million/year. What is going on?

There were no changes to the tax base calculation rules, so it follows that the answer to the mystery is in the tax rate part of the equation. In our calculation we used the gas MRET unit rates for Gazprom that the company reports as average for its key production subsidiaries (See Figure 14). Can it be that the unit rates Gazprom reports as representative are, in fact, higher than the rates it actually pays? And what allows Gazprom to lower its burden?

One explanation of the disparity issue is the effect on gas MRET for Group Gazprom of the taxes paid by Gazpromneft at lower rates, similar to IGPs. Our calculations show that accounting for this factor reduces the difference between the reported rate and effective rate by about half. But what about the other half?

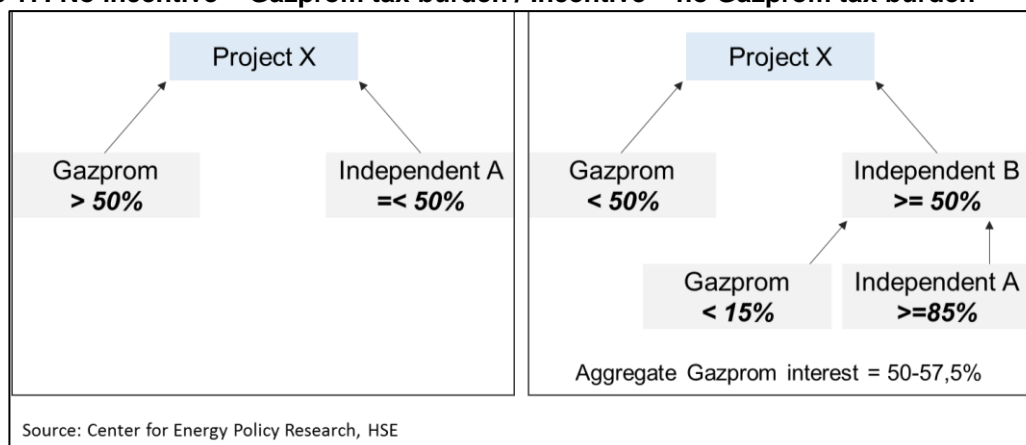
Two big opportunities to further reduce gas MRET for Gazprom are, first, to employ the joint venture (JV) structures in which Gazprom has a minority share and, second, shift volumes in the production portfolio to the fields with lower MRET rates as part of production balancing. Below we consider each of these options in turn.

Gazprom’s JVs pay lower MRET

One of the coefficients in the MRET formula, namely *the Cgp coefficient*, does not apply to IGPs and has been specifically designed to shield Russia’s independent producers from higher tax. But the language of the law is such that it allows Gazprom’s JVs to enjoy the lower tax rates as well so long as Gazprom’s interest in the venture is below 50%. Under the Tax Code, the Cgp coefficient is applicable to Gazprom projects where it has the aggregate of participating interests amounting to more than 50%, with the exception of “the taxpayers which are organizations in which one of the participants with a participating interest of not less than 50% is a Russian organization in which owners of facilities of the Unified Gas Supply System have a direct and/or indirect participating interest with the aggregate of such participating interests amounting to less than 15%”. In other words, the joint ventures where an independent company with less than 15% Gazprom interest has not less than 50% of this JV are exempt from the higher rate as a result of the application of the Cgp coefficient. The same formulation is included in the definitions of the Rd and the Tg coefficients. (See the Box The MRET formula)

It is worth noting that this clause is a rather weak protection against a reclassification of an entity via a simple company restructuring as demonstrated below. By using a two-tiered JV structure Gazprom can lower its gas MRET to the level of independent producers and maintain overall control over the project. (See Figure 17).

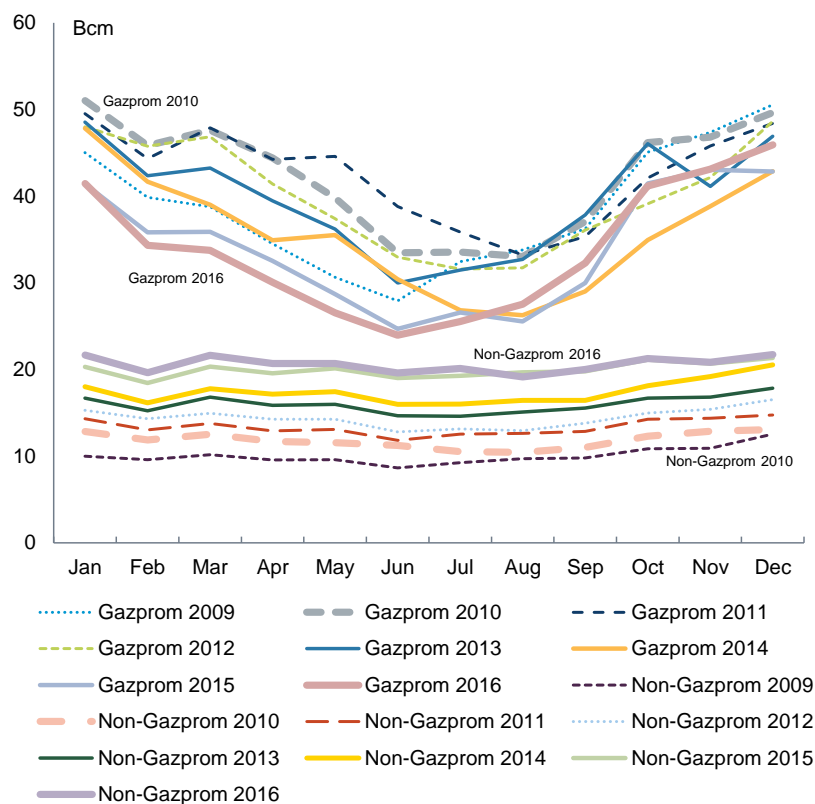
Figure 17: No incentive = Gazprom tax burden / Incentive = no Gazprom tax burden



Gas production balancing

Russia’s gas industry has had to accommodate broad fluctuations in production caused by seasonality requirements and big swings in demand. During the past decade, Gazprom has essentially acted as the balancer for Russia’s gas production, reducing its output when needed, while independent gas producers have been able to ramp up theirs. (See Figure 18)

Figure 18: Gas production balancing in Russia (monthly production)

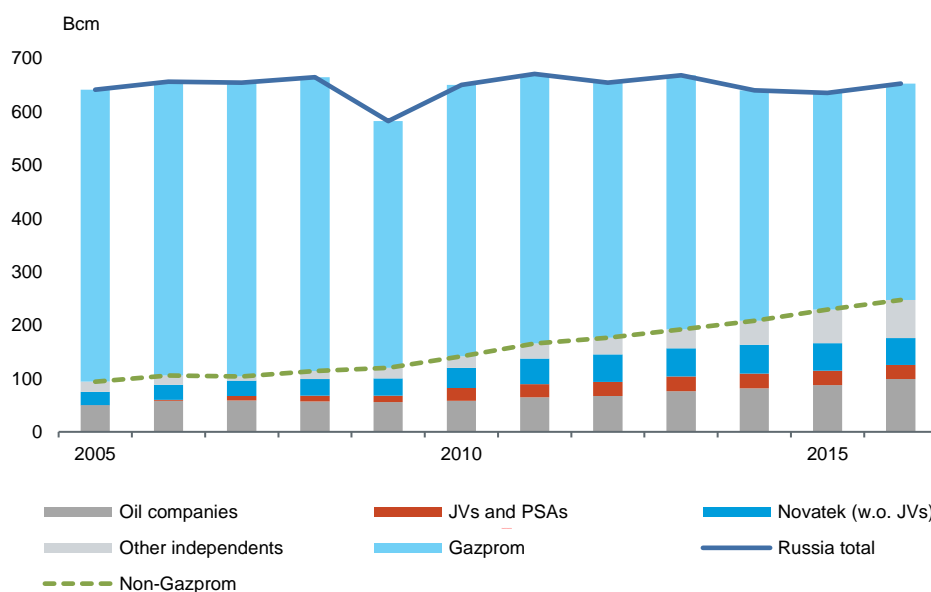


Gazprom’s role as a balancer remains indispensable. No other producer in Russia can perform this function on the scale required. Two years in particular—2009 and 2014—stand out as extreme examples of gas supply swings in Russia.

In 2009, facing falling demand in domestic and export markets amid economic recession, Russian gas production contracted dramatically: aggregate production declined by 81.8 Bcm in 2009 (down 12.4%). Next year it bounced back in response to higher demand abroad. A similar situation albeit on a smaller scale occurred in 2014 owing to a halt of gas exports to Ukraine and much lower export demand among European buyers with full gas storage facilities. The peak-to-lull ratio in monthly production in 2014 (January to July) amounted to an unusually high ratio (of 1.5), with a 23 Bcm difference in monthly production. Gazprom's production in 2014 amounted to only 432 Bcm, down 44 Bcm or 9% year on year. Gazprom ended up assuming the role of balancer. It held back its own production and absorbed most of the decline in Russian gas production. While the burden of a swing producer was carried solely by Gazprom, the IGPs and oil companies actually managed to maintain or even grow their natural gas output despite the difficult market conditions. They are not allowed to export gas, but they have steadily expanded their position in the domestic market by securing long-term contracts with the most attractive customers in the power and other industrial sectors. Additionally, oil companies' associated gas production (along with access to the pipeline network for the resulting processed gas) has moved up to the top of the domestic merit order as part of the regulatory effort to reduce flaring.

As a result, Gazprom's share of Russian gas production in 2010 dipped below 80%, compared with almost 90% in 2000. The continued fight for the domestic market between Gazprom and IGPs continued, and as of 2016 Gazprom's share of production fell to 69% (Russia's Ministry of Natural Resources, 2000-2015). (See Figure 19)

Figure 19: Gas production in Russia by producer



Source: Center for Energy Policy Research, HSE

An important result of the obvious stresses of 2009-10 and 2014 was a demonstration that the Russian gas industry can swing its production relatively effectively and without apparent losses to aggregate productive capacity. Gazprom (using its giant Cenomanian fields) acts as the country's swing producer during periods of fluctuating demand. This is a result of three key factors: scale, assets, and customers.

First, the scale of fluctuations in demand and consequently the scale of the required swings in production are such that only Gazprom can manage the required volumes. This is because Gazprom's production still dwarfs the production of any of non-Gazprom producers in Russia (420 Bcm for Gazprom Group versus 51 Bcm for Novatek and 50 Bcm for Rosneft in 2016). Moreover, Gazprom has tremendous spare production capacity available that cannot be employed because of limited domestic and export demand. In the beginning of 2017, it was reported at about 150 Bcm.

Second, Gazprom's giant Cenomanian fields with dry gas are a unique resource almost "fit-for-purpose" in balancing output. The technological risks of stop-and-go operations for these fields remain significantly lower compared to the more complex fields with higher liquids content that Russian independents operate. Besides, the liquids production is a high-value-added activity which also makes its interruption undesirable. Production of associated gas by Russia's oil companies is a function of oil production and is not fit for balancing overall output either, especially because of the state regulation that (in an effort to curtail flaring) puts associated gas at the top of the domestic merit order in terms of the pipeline access.

Finally, Gazprom's customer base is more "seasonal," comprising both industrial and residential customers, whereas independents mostly supply large industrial consumers with more stable demand profiles.

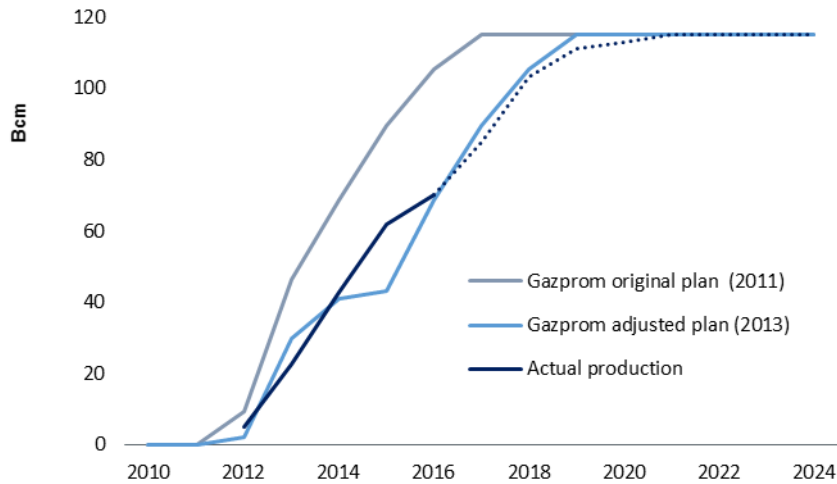
Gazprom as a key balancer of gas production has the greatest flexibility among the Russian producers to choose the tax burden for a significant share of its overall production, as it makes the decisions about which of its fields to work and which to keep idle or underutilized. We demonstrate below that Gazprom indeed is able to minimize its tax burden by using the existing tax rules and optimizing the load of its assets on the basis of tax considerations.

The Tale of Two Fields

The Zapolyarnoye and Bovanenkovskoye gas fields are the crown jewels in Gazprom's portfolio of assets. The former is the largest producing gas field in today's Russia by capacity (its top production to date was achieved in 2013 and amounted to 118 Bcm) and the last of the supergiants in the established base of Russia's gas production in the Nadym-Pur-Taz (NPT) area. The latter is the first of the new generation of super-giants in the new gas production province in the Yamal peninsula that eventually is going to dominate Russia's gas balance. Bovanenkovskoye output in 2016 amounted to 67 Bcm and is expected to reach a plateau at 115 Bcm in the early 2020s. This difference in geography and the type of development (legacy versus greenfield) of the two Cenomanian gas fields with largely similar geological characteristics has been reflected in a significant difference in tax treatment since July 2014 when the formula-based gas MRET was effected. The tax burden is lower for fields considered to be "hard-to-recover" or high cost. Thus, gas fields on the Yamal Peninsula enjoy a MRET discount owing to harsh climatic conditions, resulting in one of the lowest MRET rates for Bovanenkovo among Gazprom's fields— about \$4.1 per thousand cubic meters in 2016 according to our calculation. This makes it more efficient for Gazprom to produce more gas at Bovanenkovo and reduce output at other fields that have a much higher MRET rate, in particular at legacy Cenomanian gas fields in NPT that pay the highest MRET. For example, we calculated the MRET rate for Zapolyarnoye in 2016 at \$13.6 per thousand cubic meters.

And indeed, the output data for 2014-2016 suggest that Gazprom's revised strategy for balancing output most likely stems from production optimization considerations in response to the new differentiated tax treatment of Russian gas. After initial delay with the Bovanenkovskoye ramp-up in 2013 and 2014 Gazprom has increased the field's output in the past two years to put it on the originally planned trajectory of growth. (See Figure 20)

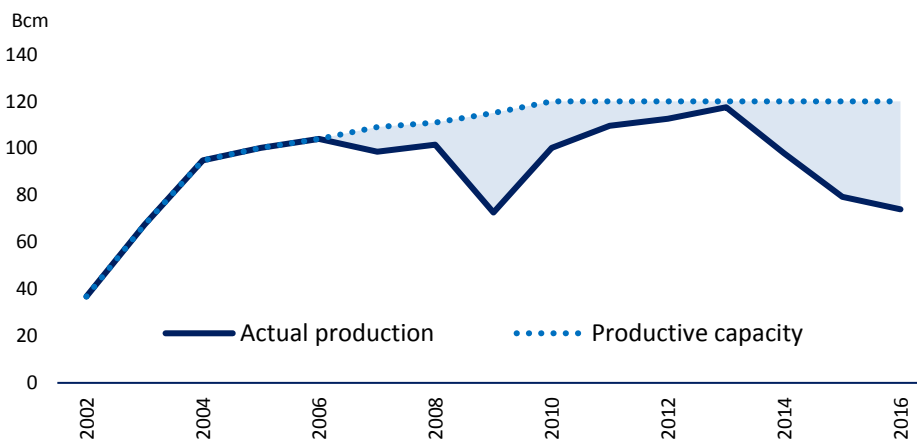
Figure 20: Bovanenkovskoye gas output



Source: MNR, Center for Energy Policy Research, HSE

In contrast, gas output at Zapolyarnoye has been fluctuating, reflecting the fact that the field has been used for balancing purposes. We mentioned above the crisis of 2009-10 as the years of a big fall and then a big bounce back in Russia's gas output, and it clearly shows in the production profile for Zapolyarnoye for the corresponding years. Then the field reached its planned plateau at about 120 Bcm in 2013, but instead of producing at this level for several years, it reduced output sharply in 2014-16, apparently as part of the overall balancing that Gazprom had to perform. (See Figure 21)

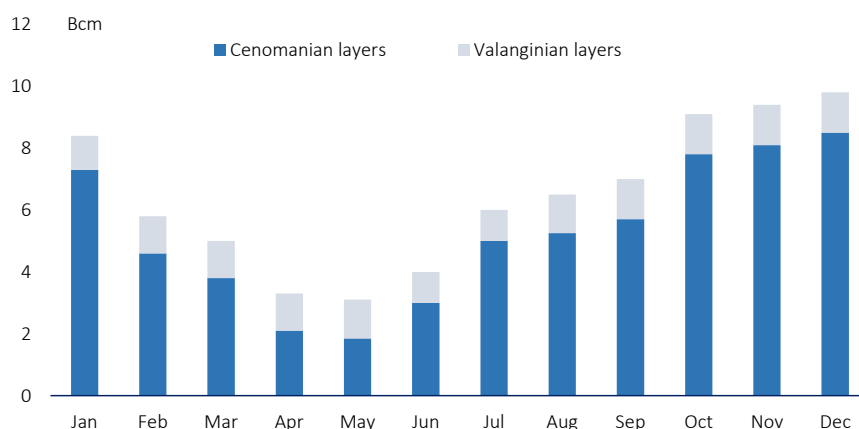
Figure 21: Zapolyarnoye gas field: Production versus capacity



Source: Center for Energy Policy Research, HSE, data from MNR

Thus, Gazprom stopped reining in output at Bovanenkovskoye and instead started using Zapolyarnoye as a key balancing field. The fact that this is a low depth Cenomanian field definitely helps achieve the technical task without losses to overall productive capacity. Note that the balancing is not occurring for the production from Valanginian layers at Zapolyarnoye. (Gazprom Dobycha Yamburg, 2017) (See Figure 22)

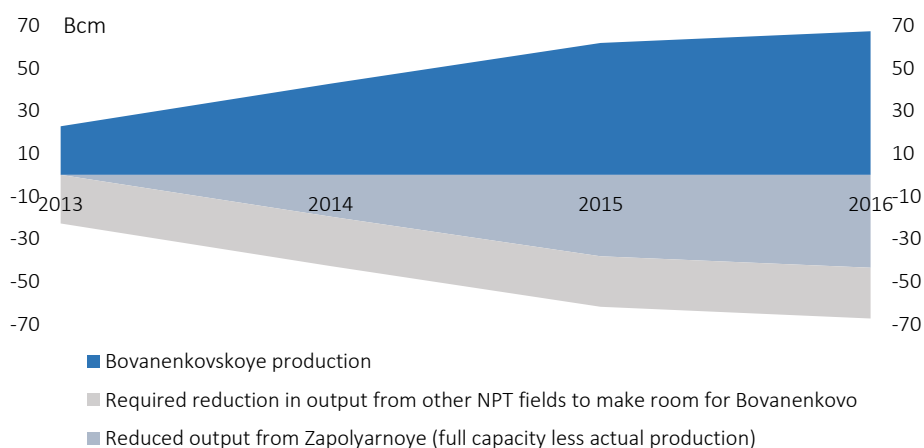
Figure 22: Monthly output at Zapolyarnoye in 2016



Source: Center for Energy Policy Research, HSE, Gazprom data

The burden and challenge of balancing Russia’s gas output has been delegated to supergiant gas fields in NPT. It is noteworthy that the reduced output at Zapolyarnoye (relative to its full capacity) offsets the lion’s share of the addition to Gazprom’s gas balance from the ramp up at Bovanenkovskoye. To produce an exact mirror image we show how much additional reduction other gas fields in NPT must provide. (See Figure 23)

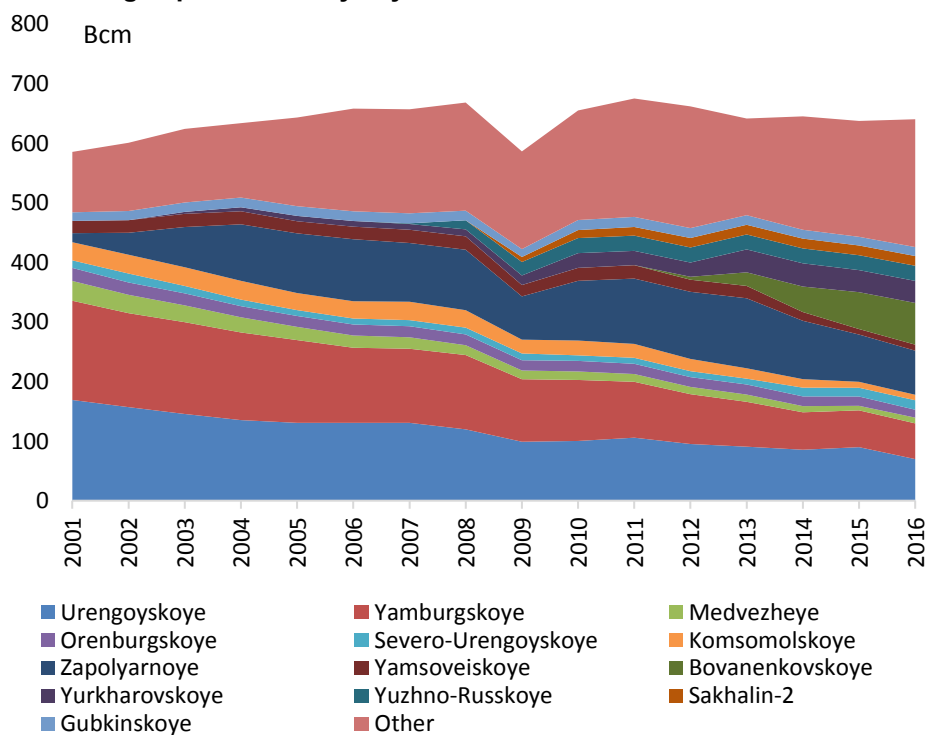
Figure 23: Bovanenkovo ramp-up requires decline in NPT output



Source: Center for Energy Policy Research, HSE

The required reduction in output from other NPT fields to make room for production at Bovanenkovskoye has been about 23.5 Bcm in 2013-2016. The tax treatment of NPT fields created disincentives for Gazprom to produce incremental volumes there. In fact, given the limitations on the demand side, Gazprom is not interested in keeping production decline rates at these fields under control and prolonging their economic life. This is a cause of significant concern as legacy fields still represent the bulk of Russia’s overall production and their premature retirement as a result of distorted tax signals would mean inefficient use of valuable resources. (See Figure 24)

Figure 24: Russia’s gas production by key fields

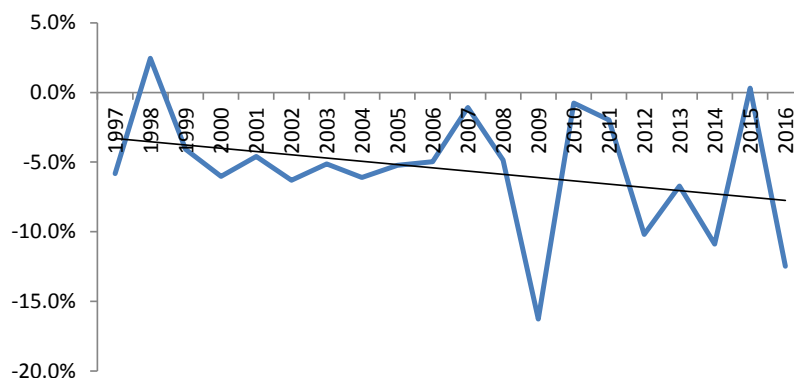


Source: Center for Energy Policy Research , HSE, data from MNR

The case in point is the decline rate for the “Big Three” Russian gas fields – Urengoy, Yamburg, and Medvezheye, which has accelerated recently. It is probably wrong to attribute the higher rate of decline to tax reasons only, but they definitely appeared to play a major role. (See Figure 25)

It is not possible to say conclusively that production at the older fields could not be ramped back up again in the future. The issue very much boils down to individual characteristics of the fields, or rather individual wells. In some cases, “idling” the wells can lead to forming of additional pressure underground that would support future extraction. But in some cases pressure will be lost permanently and formation of hydrates will damage the wells. So far, Zapolyarnoye has been balancing in an orderly fashion without apparent loss to the overall productive capacity. For older fields in NPT the jury is still out on the outcome. In any case, this is one of the areas of future research that needs to be done to evaluate the longer-term outlook for Russia’s gas production.

Figure 25: “The Big Three” decline rate



Source: Center for Energy Policy Research, HSE

Conclusion

Sizable hikes in the Russian MRET for gas increase the supply costs for Russian gas just when new challenges are emerging internationally, and the battlefield of the future is likely to be centred on costs. In turn, the future fiscal burden on Russian gas will play a key role in whether Russian gas producers are able to meet the emerging challenges. The tax differentiation in 2014 by way of a formula based on a series of technical, geographic, and other coefficients has resulted in an unexpected leeway for some producers to optimize their upstream gas tax and reduce their tax bill. In 2017 the Russian government has had to deal with the problem of lower than expected dividends from Gazprom by effectively dialing up the rate of gas MRET for Gazprom. This was achieved by introducing new ad hoc changes in the MRET rate calculation via arbitrary hikes in one of the formula coefficients – something the reform was trying to get rid of for good. Meanwhile, distorted tax design has apparently caused some acceleration in decline rates of Russia's legacy gas fields introducing an economic inefficiency on top of a fiscal problem.

A possible alternative to revenue-based taxes would be to shift the tax burden to profits. This would automatically lead to greater incentives to produce more gas at fields with lower net of tax production costs which would shift the cost curve of supply for Russian gas downward. The Russian government often had to apply second-best measures because its time horizon tends to be rather short and the problems before it require an immediate policy response. The danger is that the measures originally intended as transitional stopgaps tend to last longer than is economically justified. The worst possible case is that the government becomes addicted to the tax instruments that promise an easy short-term solution, and this addiction turns into a tradition. All things considered, it is too early to say of Russia's gas taxes: "All systems go!"

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