The Amended Subsurface Taxation Regime for Kazakhstan

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On 1 December 2003 President Nazarbayev signed into law a set of amendments to Kazakhstan's subsurface taxation regime that amount to the most radical change to the regime in the Republic of Kazakhstan since it was originally introduced in the mid 1990s. The amendments come into force on 1 January 2004. This article is intended to give a brief summary of the key features of the new regime, which significantly moves the balance of risk and reward in favor of the State.

Overview

The basic framework does remain unchanged. In the new regime, there will continue to be Excess Profits Tax type Contracts ("Model 1" Contracts), and Production Sharing Agreements ("PSAs" of "Model 2 Contracts"). However within that framework, the changes for both types of contracts are significant.

The key features of the new PSA regime can be summarizes as follows:

1) Signature Bonuses will now be based on the results of tendering.

2) Commercial Discovery Bonuses will be set at 0.1% of discovered reserves, valued at London IPE prices.

3) Royalty will be paid at the fixed rates (2 to 6%) according to production levels.

4) Payment of most generally applicable taxes such as corporate income tax, but exemption from excess profit tax and the economic rent tax on exports (see below).

5) Cost oil will be limited to 75% of production prior to payback, and 50% after payback.

6) These ceilings apply after royalty production has been taken account of (unlike the current law).

7) Profit production will be divided using the lowest (for the investor) of three triggers, R Factor, IRR, or "P Factor".

8) The profit production will be valued based on the price established for the purpose of economic rent tax, i.e. market price netted back for quality banking and transportation costs.

9) If "conditions deteriorate" Kazakhstan's share of profit production will be not less than its "maximum value fixed prior to the deterioration", unless it was determined by the P Factor.

10) The total State's tax take (including e.g. corporate income tax) from the contract per month shall not be less than 20% of the monthly total production value pre payback and 60% post payback.

11) Further limits of cost recoverable expenditures are introduced, e.g. non-recoverable will be all taxes, and expenditures in breach of local content rules (the Majilis defined the term "local content", presumably bringing it in line with the expected PSA Law). The status of uplift (deemed interest) is unclear.

12) Stability is positively clarified and will apply to new PSAs but not new EPT contracts.

13) No separate tax/commercial terms will apply for gas contracts.

14) The interaction with the draft PSA law on e.g. carrying KMG is not addressed.

And the key features of the new EPT regime would be:

1) Signature Bonuses will now be based on the results of tendering.

2) Commercial Discovery Bonuses will be based on discovered reserves, valued at London IPE prices.

3) Royalty will be paid at the fixed rates (2 to 6%) according to production levels.

4) Payment of the Economic Rent tax on exports, as set out below.

5) Payment of the Excess Profit Tax, as set out below.

6) Payment of all the generally applicable taxes such as corporate income tax etc.

7) No stability, contract tax article, or expert evaluation.

The PSA Regime

Stability

Despite the initial intention to eliminate stability for new subsurface use contracts, in the proposals to the Majilis and to the Senate, stability has been restored but limited to PSAs. Effectively, while a new Model 1 subsurface use contract will no longer be stabilized, a new PSA will have a specific tax regime spelled out in the contract, which will be finalized via a tax examination by the state authorities and will be kept unchanged throughout the term of the PSA. In other words, provisions will remain unchanged compared to the Tax Code that is in effect when the contract is made, with which they must be consistent. However, this is an advance on the current Tax Code in that the stability of the tax regime will be specifically stated, rather than merely implied, provided the PSA has passed the mandatory tax examination.

If the tax legislation changes, the changes will not be applicable to the new PSAs unless the parties agree to change the tax regime of the contract. The state authorities will retain their right to initiate a PSA re-negotiation in case the subsurface user's position improves because it takes advantage of favorable changes to the tax legislation. As in the current Tax Code, a concern remains that the suggested provisions ignore the issue of restoring the original balance of economic interest when the PSA is re-negotiated on these grounds, as opposed to merely protecting the State.

Stability for pre 1 January 2004 contracts is confirmed, though it is not clear if this applies to pre 1996 contracts that would not have undergone a mandatory tax examination.

Profit sharing triggers in new PSAs

A production sharing mechanism based on three triggers has been introduced into the amendments package adopted by the Parliament. The share of the subsurface user in profit production is determined as the lowest of three percentage values given by the following three triggers:

1) R-factor (profitability index) – the ratio of subsurface user's accumulated income to accumulated expenditure under the project.

2) Internal rate of return (IRR) of contractor – discount rate when net real discounted income (presumably net present value) reaches its zero value.

3) P-factor (price factor) – ratio of subsurface user's income to the total production volume during the reporting period.

It will be seen from the tables below that the triggers move quite rapidly from maximum investor take to minimum take.

An important change to the valuation of subsurface users profit production is introduced. The valuation will be based on the price used for the economic rent tax purposes, i.e. the market price netted back for transportation costs and quality banking (please see the discussion below). The reference to "profit production" rather than to the valuation of cost recovery production here is odd, it is presumably cost recovery production that is meant.

A key provision is the requirement that the total state's tax take including taxes such as corporate income tax and production share should exceed targets that are hard coded in the legislation. The minimum will be applied for each month, so that the state will, in one form or another, receive not less than 20% of the total monthly value of production prior to payback and 60% after the payback.

An additional ceiling on the split of profit production will apply when "conditions of a production-sharing contract realization deteriorate", which is a rather ambiguous statement. In this event, the profit production share of the Republic would not be lower than "its maximum amount fixed prior to the deterioration unless such maximum amount was reached due to P-the factor trigger when calculating the profit production of a subsurface user". Ceilings on cost recovery production (75% pre payback and 50% post payback) also apply. The interaction of all of these ceilings appears complex, but at first sight it would seem likely that the key limits will be the guarantee that the State receives 20% of pre payback value and 60% post payback, and most of the other calculations may be of little relevance.

1) R-factor

The R-factor will be a ratio of accumulated income to accumulated expenditure under the project. Income accumulated under the project will be calculated as:

Real (i.e. deflated) aggregate value of the subsurface user's cost recovery production

Plus Real aggregate value of the subsurface user's profit production

Less Real aggregate income tax paid to the budget (while the Working Group proposed to adjust for all taxes and obligatory payments paid under the project).

Expenditure accumulated under the project as opposed to the Working Group's proposal includes only recoverable costs and is calculated as:

Real aggregate recoverable operating costs

Plus Real aggregate recoverable exploration and appraisal costs

Plus Other real aggregate recoverable costs of subsurface user

Both income and expenditure will be determined on an accruals basis. Based on the R-factor calculated as above, the share of the subsurface user is determined as follows:

R-factor	Subsurface user's share of profit production (%)
Less or equal to 1,2	70%
More than 1.2 less than 1.5	70% - 2.068 * (R-factor –.2)*100%
More or equal to 1,5	10%

2) IRR

IRR is an annual discount rate at which the net present value (NPV) of the project is zero. NPV is calculated based on the discounted deflated cash flows for each reporting period starting from the effective date of the PSA. Potentially, this implies that pre-effective costs will not be included into the calculation. As mentioned before, we assume that the reporting period is a month. In this respect the proposed changes do not explain how IRR is to be calculated (i.e. as a monthly rather than annual amount, and how current tax liabilities are to be included) and how monthly and annual amounts co-relate. Presumably, the annual discount rate (IRR) will be calculated via compounding as $(1+ \text{monthly discount rate})^{12} – 1$.

The deflated cash flow for a reporting period is calculated as a difference between the deflated values of cost recovery and profit production of the subsurface user and the deflated values of its costs. The costs include operating, exploration and appraisal, development costs, taxes paid (except for the Republic's share of production), commercial discovery bonus, part of signature bonus related to a particular development area.

Once IRR is calculated as above, the share of the subsurface user is determined as follows:

IRR	Subsurface user's share of profit production (%)
Less or equal to 12%	70%
More than 12% less than 20%	70% - 7.51* (IRR –12%)
More or equal to 20%	10%

3) P-factor

P-factor (price factor) will be calculated as a ratio of sum of deflated cost recovery production and subsurface user's share of profit production for the reporting period to the volume of "oil" produced during the reporting period. The numerator of the ratio should be calculated without taking into account sales expenses.

Depending on the P-factor calculated as above the share of the subsurface user is determined as follows:

P-factor	Subsurface user's share of profit production (%)
Less or equal to 12 USD per barrel	70%
More than 12 less than 27 USD per barrel	70% - 0.04 * (P-factor – 12)*100%
More or equal to 27 USD per barrel	10%

Definition of cost recovery production and profit production

In the amendments to the Tax Code it was clarified that cost recovery production and the profit production in division between the Republic and the subsurface user does not include royalty. In the current legislation it appears that the cost oil ceiling (of 80%) applies to total production including royalty.

Recoverable costs

The adopted amendments to the Tax Code have slightly changed the list of non-recoverable costs and the list of income items that reduce recoverable costs.

General and administrative expenses will only be recoverable up to 1% of recoverable costs. However, it is unclear whether the recoverable costs to this end will be calculated as net of general and administrative expenses or including them.

The list of non-recoverable costs will no longer include uplift (i.e. notional interest) accrued on the balance of recoverable costs that have not been recovered in the tax period. At first sight, this may imply that uplift may be calculated on the balance of unrecovered recoverable costs. However, it is difficult to conclude from the drafting what the real intention regarding uplift actually is. It has been specifically highlighted that the commission payments related to debt financing will not be recoverable. Taxes are also to be specifically excluded from cost recovery. While for many taxes this is merely a clarification, it would imply that in future customs duties on imported equipment, and the various payments for the right to carry on certain activities that are technically taxes will no longer be cost recoverable.

Statute of limitations

For purposes of calculating taxes based on IRR and R-factor the statute of limitations for subsurface users has been extended so that it covers the entire period of the subsurface use contract plus 5 years. This extension will apply to the share of the Republic under PSAs and should not be applied for excess profits tax under grandfathered Model 1 subsurface use contract. Currently, the subsurface users are required to store the documents for the entire term of the subsurface use contract; however, the statute of limitations is still 5 years. Effectively, this means that currently the tax authorities may review and adjust the financial data of subsurface user starting from the beginning of the project, but additional taxes may only be assessed for 5 years backwards. The proposed change significantly extends the tax authorities' powers in terms of calculating the Republic tax take. An investor will not have final closure on any tax year until after the contract is terminated.

The Excess Profit Tax Regime

The following sections set out the specifics of the new EPT regime.

Economic Rent tax on oil for export

The payers of this tax would be legal entities and individuals that are parties to EPT type contracts and are exporting crude oil for sale. The tax base would be determined as the value of the exported crude oil based on the market price as further discussed below The tax rates applied to the netted back market price, would depend on current oil prices and vary as follows:

Oil market price at the level of oil exchange price (USD/barrel)	Rate of economic rent tax on oil for export
19	1%
20	4%
21	7%
22	10%
23	12%
24	14%
25	16%
26	17%
27	19%
28	21%
29	22%
30	23%
31	25%
32 – 33	26%
34 – 35	28%
36	29%
37	30%
38 – 39	31%
More than 39	33%

The market price is defined as the weighted average of daily sales prices prevailing on the market for the most identical crude oil brands sold in the international oil trade. It is unclear what is meant under "prices prevailing on the market". In the subsequent clauses the amendments refer to sales at the oil exchange. Probably, it is intended to use the data on the actual sales prices realized by a subsurface user taxpayer upon oil export. If the sale takes place at any oil exchange, the daily average market rate for each crude oil brand would be calculated as a simple average of oil exchange opening and closing prices for the brand. Additionally, reverse "quality banking" type adjustments are provided so that the tax would be based on the quality of oil at the field, rather than the blend lifted at the end of a trunk pipeline. However the tax base will be netted back for transportation costs rather than "sales costs" as suggested previously by the Working Groups.

Changes to excess profit tax

The tax base of excess profit tax will be the net income of a subsurface user in excess of 20% of tax deductions. The tax base can be adjusted for expenditures actually incurred for education of Kazakhstan labor force and/or increase of fixed assets, but not exceeding 10% of the taxable amount.

The tax rates will depend on net income and deductions of the subsurface user.

Amount exceeding 20% of the ratio of net income to deductions	Excess profit tax rate
Up to 5%	15%
From 5 to 15%	30%
From 15 to 30%	45%
More than 30%	60%

It is easier to demonstrate this calculation with numbers than words. At first sight it appears that the calculation would be as set out below, but until there has been an opportunity to clarify with the Working Group that this is what is meant, this example should be treated with caution.

Description	Amount	
	Example #1	Example # 2
Assume:		
Sales income	100	100
Deductible Costs	70	30
Taxable Income	30	70
CIT	9	21
Net Income	**21**	**49**
Then:		
20% of deductions	14	6
Excess of Net Income over deductions	**7**	**43**
Ratio of Net Income to Deductions	30%	163%
Amount thereof exceeding 20%	10%	143%
EPT rate	30%	60%
EPT	**2.1**	**25.8**

Changes to royalty

Royalty will apply to both PSA and EPT contracts according to the following table.

Volume of accumulated oil production for each calendar year (thousand tons)	Royalty rate
Up to 2,000	2%
From 2,000 to 3,000	3%
From 3,000 to 4,000	4%
From 4,000 to 5,000	5%
More than 5,000	6%

For purposes of the royalty calculation, associated gas hydrocarbons should be converted to their crude oil equivalent at the ratio of 1,000 m^3 to 0.857 ton of crude oil. Moreover, the amendments introduce rules on how gas hydrocarbons are valued in the case of free-of-charge transfer for further processing. The value will be based on actual costs of production and primary processing increased by actual rate of return for the tax period.

Conclusions

The changes to the Tax Code increase the risk and reduce the reward for investors in new projects in Kazakhstan. Also, so far as the PSA model is concerned, they remove much of the negotiation flexibility that was the key virtue of PSA type arrangements. A further change to the landscape is expected shortly, when the draft of the new PSA law is published. This law is expected to include provisions relating to up to 50% participation by state entities in future projects, Operatorship by state entities, and requirements regarding local content. It is also expected that it will reserve to the State the right to decide whether any given opportunity will be subject to an EPT or PSA type contract. Taken together, these laws will provide a challenging economic environment for investors in the next generation of projects in Kazakhstan.