Available online at www.sciencedirect.com
ScienceDirect
Russian Geology and Geophysics 58 (2017) 1453–1467
RUSSIAN GEOLOGY AND GEOPHYSICS
www.elsevier.com/locate/rgg

New methods of assessment, structure, and development of oil and gas resources of mature petroleum provinces (*Volga–Ural province*)

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Received 12 October 2017; accepted 2 November 2017

Abstract

This study describes a new method for quantification of hypothetical oil and gas resources, which is considered to be an alternative to conventional estimates by analogy to geologically similar plays and is most appropriate for maturely explored provinces. This method is based on the size–frequency distribution of oil accumulations in sedimentary basins and has never been applied to petroleum exploration. The new approach makes it possible to assess the oil resources concentrated in small and smallest oil fields, which may become the main targets for petroleum exploration. This study reviews the discovery and exploration history of the Volga–Ural province and provides estimates of initial and hypothetical oil resources and the size distribution of undiscovered field and the number of their pools. It was shown that given the volume of exploratory drilling of 500–550 thousand m per year, it is expected that more than three billion tons of oil would be produced from small and smallest fields of this province by the mid-21st century, with a stable annual production of 40–50 million tons. It was shown that the development of small and smallest oil fields is performed by small and medium-sized oil companies, which can be delivered through a dedicated government program.

Keywords: petroleum provinces; assessment methods; oil resources; prediction of petroleum potential; truncated Pareto law; biased sample

Theoretical basis for quantitative prediction of hydrocarbon potential

The analysis of geological analogues is known to be a powerful tool in assessing the hydrocarbon resource potential of sedimentary basins (Belonin et al., 1979; Buyalov et al., 1990; Methodological..., 2000). The discussion of historical-geological and geological-geochemical methods for evaluating hydrocarbon generative potential and hydrocarbon resources of sedimentary basins (volumetric genetic methods, basin modeling, etc.) are, however, beyond the scope of this study.

The method of geological analogues has two modifications: an analogue can be applied either qualitatively or as a benchmark area (better explored area).

In both cases, benchmark areas are used to assess how comparable the basins or parts of a basin, which are under-explored or where data are sparse. The sedimentary cover of the basin is subdivided into potential oil- and gas-bearing complexes, separated by regional seals. Both the study area and the benchmark area are identified in each oil- and gas-bearing complex of a sedimentary basin.

Separate assessments for each complex of a specific basin are then summarized. At the same time, methods of quantitative analogue modeling are divided into the method of internal geological analogues and external geological analogues, based on the selection of benchmarks. Parts of a basin which are better explored by geophysical methods (primarily 2D, or 2D and 3D seismic survey), and deep drilling and which have no or virtually no undiscovered fields are used as benchmark areas in the *method of internal geological analogues*. Parts of another sedimentary complexes or sedimentary basins which are well explored by geophysical methods and deep drilling are used as benchmark areas in the *method of external geological analogues*. Immature basins or parts of a basin can be compared as a whole (Kontorovich, 1979, 1988).

However, with the advent of methods of quantitative geological analogues, existing resource volume estimates for all accumulations in a particular region have become insufficient.

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1068-7971/$ - see front matter © 2017, V.S. Sobolev IGM, Siberian Branch of the RAS. Published by Elsevier B.V. All rights reserved.
http://dx.doi.org/10.1016/j.rgg.2017.11.010

The question then arose as to whether a giant and large oil and gas field could exist in the study basin and how many of these are there in the sedimentary basin? These questions were raised in a number of previous works (Gubkin, 1950a,b; Gurari et al., 1963; Rostovtsev, 1958), but answers were tentative and qualitative in the 1930s or even in the 1950s and 1960s.

The first studies applying the methodology of field size distribution for resource assessment were carried out in the 1960s. It was assumed that the probabilistic size distribution of the fields in each basin follows a simple lognormal distribution.

The pioneer works of Shpilman (1972, 1982) and Nesterov and Shpilman (1987) assured a firm scientific basis for these studies. Using the Volga–Ural province statistics, Shpilman was also the first to show that the field size distribution is essentially amodal and can be described a as a power function with the exponent 2 (inverse square law).

A few years later, the same problem was elaborated by Kontorovich and Demin (1977, 1979). The results of long-term studies on quantitative hydrocarbon resource assessment were used by these authors to perform statistical processing of data on discoveries in a large number of well-explored petroleum basins worldwide and to obtain a more general expression of this law, which they called a truncated Pareto distribution (Kontorovich and Demin, 1977, 1979)

$$\varphi(\theta) = \frac{(\lambda-1)\,\theta_m^{\lambda}}{\theta_0\left[\lambda - 1 + \left(\dfrac{\theta_m}{\theta_0}\right)^{\lambda}\right] - \lambda\theta_m}\left(\frac{1}{\theta^{\lambda}} - \frac{1}{\theta_m^{\lambda}}\right),$$

$$\theta_0 \le \theta < \theta_m,\ \ \lambda >>\hat{}1,$$

where θ_0 and θ_m are the left and right boundaries of the distribution and λ is the distribution parameter.

Further studies by N.A. Krylov, A.G. Aleksin, and Yu.N. Baturin (Krylov et al., 1986), as well as by Yu.A. Arsirii, B.P. Kabyshev, D.I. Chuprynin (Arsirii et al., 1986) confirmed the earlier conclusions of V.I. Shpilman, A.E. Kontorovich, and V.I. Demin.

It should be especially emphasized that very interesting results have been obtained in this direction, notably in the works of Burstein (2004), who proposed a mathematical model for the distribution of field sizes in natural systems. In this model, the field size is controlled by the rates of petroleum accumulation and dissipation during the formation and destruction of oil pools. The analysis showed that the model distributions of large and largest oil fields can be approximated with high accuracy by a truncated Pareto distribution with an exponent close to 2. It was shown that the higher the number of fields with relatively high oil accumulation rates, the lower is the fraction of small fields in the system. With the predominance of objects with a high rate of oil accumulation, the distribution is no longer amodal. Later studies confirmed the possibility of significant deviations from the truncated Pareto distribution in relatively young basins affected by intense subsidence, containing a large fraction of fields with high rates of oil accumulation (Burstein, 2006).

In view of the above, it should be noted that some special cases of the model proposed by Burshtein cannot be applied to young basins, such as the Volga–Ural or West Siberian basins. For the Volga–Ural basin, this is confirmed at the present stage of investigation by real samples, at least for fields with >1 Mt reserves.

A new approach to modeling the size distribution of the fields and total reserves (Kontorovich and Demin, 1979) provided the averaged solution that can be used for immature basins.

At the same time, the actual size distribution of the fields in the basin can be biased significantly from this model value. In this connection, for the well-explored or mature basins, the most common sampling method is Monte Carlo Simulation. This method was described in detail in Kontorovich and Livshits (1988a) and Kontorovich et al. (2001). The Monte Carlo Simulation randomly samples the probability distribution of each parameter in a truncated Pareto distribution. This process is repeated many thousands of times to build up the most accurate description of the realized population of fields in a particular basin.

The law governing field size distribution was deduced from processing of exploration data, and Shpilman (1972) was apparently the first to draw attention to the fact that statistical samples represented by subpopulations of discovered fields are biased because the exploration process is “sampling with considerable bias” (the term coined by A.E. Kontorovich) aimed to preferentially discover the larger fields early, and the larger the field size, the higher the probability of being discovered (Kontorovich et al., 1985, 1987). This mechanism of the “biased” translation of elements from the parent population to a sample was called by Shpilman exploration filter.

Due to the “biased” character of sampling, it can be assumed that even in an under-explored basin, the fields with reserves $\theta \ge \theta^*$ (where θ^* is the preset, relatively large value) have been already discovered. This means that for $\theta \ge \theta^*$ at this stage of exploration, distributions of samples and parent populations are identical. However, for $\theta < \theta^*$, distributions of parent populations and samples will differ drastically from each other. Kontorovich et al. (1987) established an empirical relationship (referred to as the log-linear filter) between the value of θ^* and the reserves-to-resources ratio (RRR) of the basin. The “ideal exploration filter” invoking successive discovery of fields, from the largest to the smallest ones was taken as the boundary. Actual exploration filters, at least at the given RRR less than 0.6–0.7, are better than the log-linear filter, but worse than the ideal filter.

The simulation of the discovery process was performed using a stochastic modeling algorithm (Kontorovich and Livshits, 1988b,c; Kontorovich et al., 2001) to describe the process of random selection of fields from the parent population and their introduction into the sampling population.

In this case, the probability of field selection depends on the size of its reserves and is described by the function containing a parameter, the variation of which will change the quality of the exploration filter from simple sampling at