#61

IMPLEMENT RUSSIAN ALUMINUM DRILL PIPE AND RETRACTABLE DRILLING BITS INTO THE USA

Volume I: Development of Aluminum Drill Pipe in Russia

Final Report

TR99-23

Prepared for:

Mr. William J. Gwilliam
Federal Energy Technology Center
U.S. DEPARTMENT OF ENERGY
Morgantown, West Virginia

Performed Under Contract No. DE-FG26-98FT40128

By:

Aquatic Company
Moscow, Russia

and

Maurer Engineering Inc.
2916 West T.C. Jester
Houston, Texas 77018

August 1999

Acknowledgements

This report summarizing development of aluminum drill pipe in Russia was prepared for the Federal Energy Technology Center under DOE Grant No. DE-FG26-98FT40128. The assistance of the DOE Project Director, Mr. William J. Gwilliam, is gratefully acknowledged.

Aquatic Company personnel: Dr. Michael Gelfgat (Manager of Russian Team); Dr. Vladimir Basovich (Chief Engineer); Prof. Genrikh Fain (Consultant); Dr. Alexander Podrazhansky (Director); Mr. Boris Vygotsky (Chief Designer); Ms. Valentina Kholostova (Engineer); and Mr. Boris Volkovoy (Interpreter).

Maurer Engineering personnel: Dr. William C. Maurer (Project Manager) and Mr. Greg Deskins (Project Engineer).

Table of Contents

List of Figures

List of Tables

Development of Aluminum Drill Pipe in Russia

Executive Summary

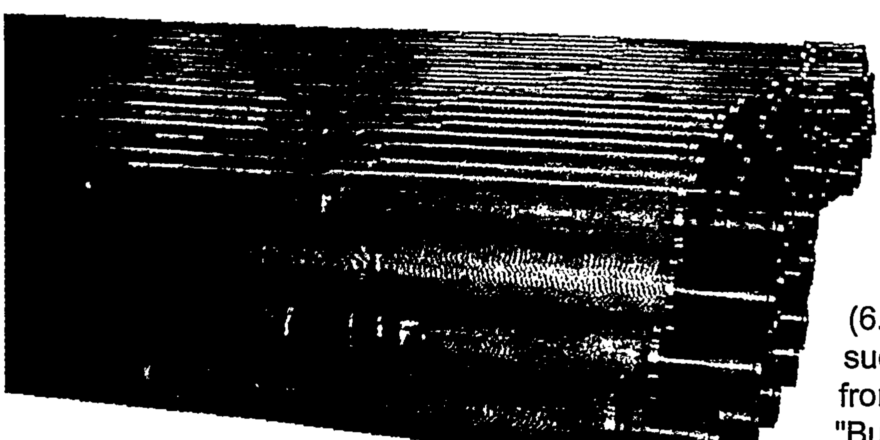
This report describes the development and application of Aluminum Drill Pipe (ADP) in Russia. Advantages of ADP for borehole drilling include low specific gravity, corrosion resistance in various aggressive environments, non-magnetic, stable mechanical properties, and high manufacturing efficiency.

Issues related to the use of aluminum alloys for manufacturing drill pipe became an object of serious study for directional, extended-reach, and horizontal wells, and ultradeep borehole drilling. Furthermore, extension of drilling to offshore and to areas with difficult environmental conditions and limited infrastructure required the reduction of transportation costs of equipment and materials. All these problems can be reduced or eliminated by the application of ADP.

Background

The first exploratory wells where ADP was applied were drilled in the region of the middle Volga in 1960-1962. These early experiments showed that ADP allowed a significant reduction in time, materials, energy and labor requirements. In the mid-1960s, ADP was used to drill several ultradeep wells, and in the 1970s was given wide recognition for cluster directional drilling in Western Siberia.

The successful utilization of ADP in directional and deep drilling operations demonstrated its effectiveness in ultradeep scientific boreholes with high formation stresses, high temperatures and highly corrosive environments. ADP has been used for deep scientific drilling applications such as the Kola ultradeep SG-3 (12 km; 39,400 ft), as well as in other ultradeep boreholes.



More recently, 164-mm (6.46-in.) diameter pipe was successfully employed to drill from the geotechnical vessel "Bucentaur," which has a displacement of only 4470 tonnes (4917 tons). Drilling operations were performed in the Atlantic Ocean (Voring Basin-1993, 1997; Rockall Bank-1994) Gulf of Mexico (Mississippi Canyon-1995; Green Canyon-1996; Viosca Knoll area-1996; Garden Banks area-1996), Strait of Gibraltar (1995), offshore Japan (1997), and offshore West Africa (1998).

Advantages/Disadvantages of ADP

The primary advantage of aluminum drill pipe is, of course, a significant reduction in string weight. The weight of ADP is 2 to 2.5 times less than the weight of a similar-purpose steel string. This allows a reduction in drilling crew labor, as well as enabling drilling deeper wells with a given type of rig.

The downhole drilling environment requires careful design of drill-string components and selection of materials, especially in hostile drilling applications (Table ES1). ADP has demonstrated several advantages over conventional steel strings.

Table ES1. Mechanical Properties of Drill-Pipe Materials

MATERIAL	DENSITY (G/CM^3)	MODULUS OF ELASTICITY (10^4 MPA)	SHEAR MODULUS (10^4 MPA)	POISSON'S RATIO	THERMAL EXPANSION ($10^{-6}/°C$)	SPECIFIC HEAT (J/KG °C)
Steel Alloys	7.85	21.0	7.9	0.27	11.4	500
Aluminum Alloys	2.78	7.1	2.7	0.30	22.6	840
Titanium Alloys	4.54	11.0	4.2	0.28	8.4	460

Material Specific Strength. One-dimensional (i.e., not tapered) ADP strings allow maximum suspended length. For example, a uniform steel string has a maximum hang-off depth of about 8 km (26,000 ft). A similar uniform ADP has a hang-off depth of up to 34 km (111,000 ft).

Resistance to Alternating Bending and Dynamic Stresses. Alternating bending stress in drill pipe is proportional to the modulus of elasticity of the material (all other factors being equal). Their proportion for aluminum pipes, titanium, and steel is:

$$\sigma_A : \sigma_T : \sigma_S = \mathbf{1 : 1.55 : 2.96}$$

Corrosion Resistance. Corrosion resistance analysis for the candidate materials indicates an advantage for titanium and steel alloys over aluminum alloys for the principal types of corrosion wear. Hydrogen sulfide is an exception, since resistance of aluminum to this medium is higher. Corrosion of ADP depends primarily on composition, aggressiveness, and temperature of the fluid in which the drill string is operated, as well as on exposure time. The study of corrosion of ADP has led to the following conclusions:

1. The pH of the drilling fluid significantly affects the process of ADP corrosion wear. Corrosion is insignificant in fluids with a pH of 7.0-9.5 and rapidly increases when the pH exceeds 10.5.

2. ADP corrosion is accelerated at higher temperatures.

3. An oxide film that forms on pipe surfaces exposed to oxygen provides reliable corrosion protection for ADP. However, abrasive drilling fluids with high solids content can damage the oxide film in areas with turbulent flow, which results in faster corrosion of the drill pipe.

4. When high-velocity salinated mud with a high H_2S content is used, ADP has demonstrated *high resistance to corrosion*, which indicates that ADP has good potential for application in oil, gas, and drilling mud media.

5. The principal method of protecting ADP from corrosion is the addition of corrosion inhibitors to the mud. Sodium polyphosphate- and potassium-based stabilizing inhibitors are the most widely used.

6. Tar coatings of the internal surface of ADP and a thick anode coating of the entire surface of the pipe are efficient means of ADP corrosion protection.

Abrasive Wear. In general, ADP wears more readily than steel or titanium. However, given ADP's lower density, normal forces due to string tension are significantly lower than with steel. Hence, ADP wear is lower than steel, all other factors being equal. Abrasive particles in the drilling fluid circulated at high speed inside the drill pipe cause wear of their inner walls. This process is more severe in transition zones along the ID (drill-pipe couplings, coupling-to-pipe zones) due to turbulence in the drilling fluid. This abrasion process is more significant in ADP and less in steel and titanium.

Russian Drilling Practices with ADP

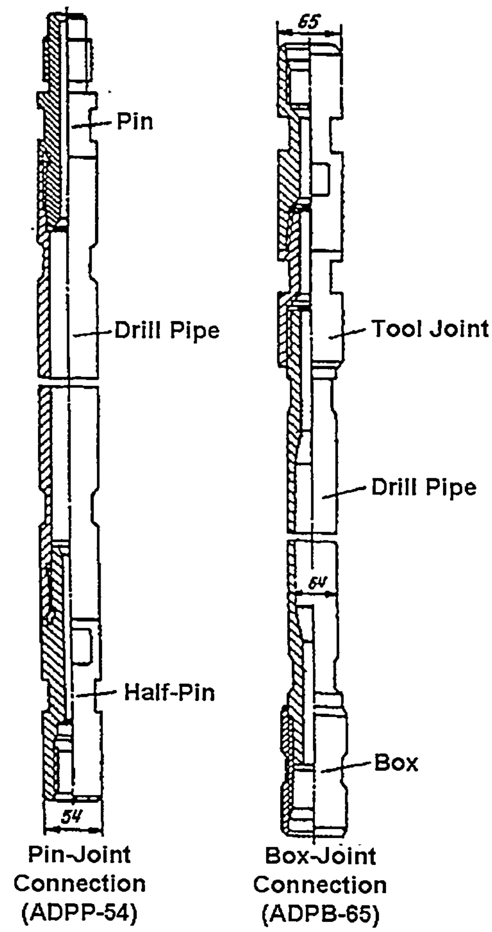
Three types of alloys (D16T, 1953T1, and AK4-1T1) are currently used in Russia for manufacturing ADP. D16T-based ADP is the most widely used. 1953T1 alloy is used for high-strength pipe comprising the upper section of the drill string in deep and ultradeep wells. AK4-1T1 alloy is used for thermally stable ADP comprising the bottom section of the drill string in wells with temperatures over 160°C (320°F).

Several types of ADP are manufactured in Russia: ADP with internal upset ends, with external upset ends, and with a protection upset in the middle of the pipe. Wall thickness varies from 9 to 17 mm (0.35 to 0.67 in.); and joint length varies from 5.5 to 12 m (18 to 39 ft). ADP may be delivered as lengths, and with separate tool joints. The tool joints may attached with a standard triangular thread ("cold" assembly), or with a trapezoidal thread with a tapered stabilizing shoulder using a thermal assembly method ("hot" assembly).

In Russia, ADP has been used in exploratory drilling for over 30 years. ADP was originally introduced to reduce labor for crews drilling exploratory wells in remote areas, especially for transporting drilling equipment. Later, ADP became widely used in all regions of exploratory drilling.

The Russian industry manufactures five standard sizes of ADP for exploratory drilling:

- 24-mm ADP with 4.5- or 8.0-mm wall thickness and 1.3-m length (0.95-in. ADP with 0.177- or 0.315-in. wall thickness and 51-in. length)
- 34-mm ADP with 6.5- or 11.0-mm wall and 1.3- or 2.9-m lengths (1.34-in. ADP with 0.256- or 0.433-in. wall thickness and 4.3- or 9.5-ft lengths)
- 42-mm ADP with 7.0- or 14-mm wall and 4.3-m length (1.65-in. ADP with 0.276- or 0.551-in. wall and 14.1-ft length)
- 54-mm ADP with 9.0- or 16-mm wall and 4.4-m length (2⅛-in. ADP with 0.354- or 0.630-in. wall and 14.4-ft length)
- 71-mm ADP with 8.0-mm wall and 6.2-m length (2.8-in. ADP with 0.315-in. wall and 20.3-ft length)



Joints of Pin-Joint and Box-Joint ADP

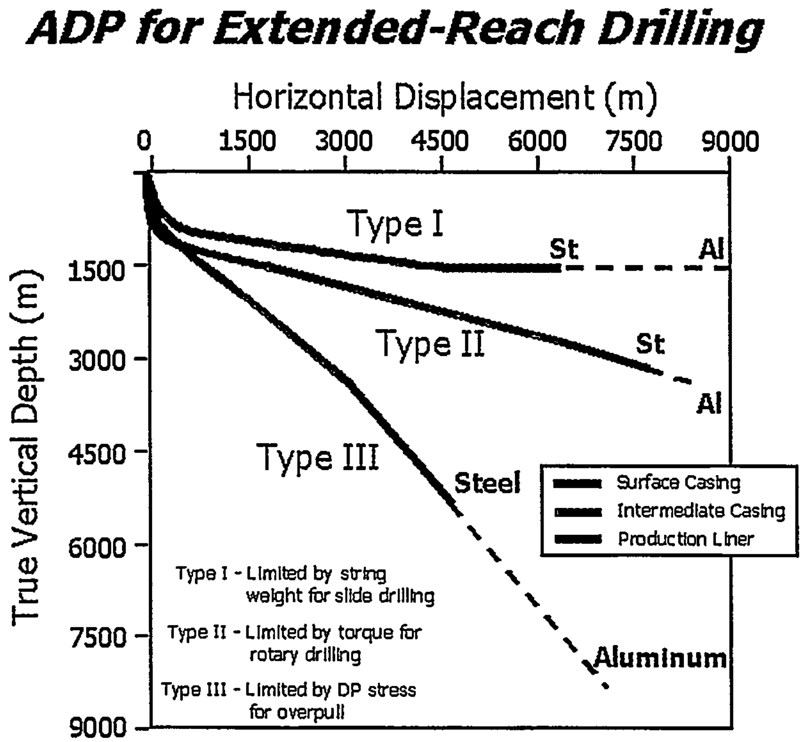
Comparative tests of ADP and steel strings in various regions under a range of geological and technical conditions revealed better performance of ADP. For example, 54-mm ADP allowed increasing drilling depth by 500 m (1640 ft) with the same type of rigs. Also, rate of penetration was 15-30% higher, drilled meterage per run increased by 6-13%, and trip time was reduced by 11-15%.

Vibration Damping

A more efficient means of damping and controlling vibration in the drill-bit/drill-string system can be designed based on physical and mechanical properties of drill-pipe material. Compared to steel, aluminum alloys have a high capacity for absorbing and dissipating elastic vibrational energy. Research studies performed in Russia indicated that all types of ADP have approximately equal capacity for absorbing elastic vibrational energy. Also, heavy-wall ADP has about 50% higher damping capacity than steel. ADP with articulated joints has a damping factor 30-35% lower than rigidly connected ADP.

Extended-Reach Drilling

The figure summarizes design parameters and maximum drill-string length for the three types of extended-reach (ERD) wells with ADP and steel drill strings. In addition to other advantages of ADP, utilization of ADP in drilling ERD wells will allow longer boreholes without increasing hook loads or drive capacity of the rig. Type I wells can be drilled with about 15% longer boreholes, Type II 5% longer, and Type III 50% longer.



Riserless Drilling in Deep Water

Drilling in deep water without a riser pipe is most often conducted from low-capacity drill ships for exploration or scientific study of oceanic crust. The main advantage of ADP in these applications (as compared to steel strings) is the potential to essentially increase water depth while using the same low-capacity drill ships. For example, while drilling geotechnical wells from "Busentaur" and "Bavenit" type drilling ships using steel drill pipe, maximum water depth is limited to about 500 m (1640 ft). By comparison, the experience of the Aquatic Company in drilling from the same ships shows potential for drilling in 1500-m (4920-ft) water depths.

Economic Benefits

Technical and economic parameters related to drilling depend closely on the weight of the drill string. For the same hook-load capacity of the rig, cumulative trip time over a complete drilling operation is directly proportional to power consumption for these operations. At the same time, power consumption depends on weight distribution between sections of the drill string as well as total weight.

Correlations between buoyancy factors of drill pipes show additional advantages in higher mud weights. The buoyancy factor for ADP in 1.2-g/cm^3 (10-ppg) mud is 0.57, whereas for steel in the same mud, buoyancy factor is 0.85. This means that an aluminum string in 1.2-g/cm^3 mud is reduced to almost half its weight in air, as compared to a steel string, which is only 15% lighter.

Analysis of technical and economic parameters for drilling in fields with similar conditions and with the same type of drilling equipment indicates that ADP (instead of steel) reduces trip time by about 18-35%. Also, a considerable drop in power consumption for these operations was observed.

Hydraulic resistance of ADP is also 15-25% lower than of steel drill pipe due to specific characteristics of the surface of ADP. This leads to lower hydraulic losses, higher drilling efficiency, and lower costs.

Conclusions

The experience of Russian engineers and scientists in designing, manufacturing, and using ADP in a variety of drilling conditions clearly demonstrates the tremendous potential of ADP. It is hoped that the significant benefits enjoyed historically in Russia's drilling industry with ADP might be shared by the drilling community worldwide.

1. Introduction

1.1 Background

Aluminum alloys are one of today's most important and efficient construction materials. They are widely used in a variety of industries. Aluminum alloys possess a number of physical and mechanical properties that surpass those of steel, which is traditionally used for manufacturing drill pipes for the oil industry. These properties include low specific gravity, good corrosion resistance in various aggressive environments, they are non-magnetic, have stable mechanical properties, and exhibit high efficiency under pressure and during manufacturing.

Figure 1. Aluminum Drill Pipe (without and with Steel Tool Joint)

Issues related to the use of aluminum alloys for manufacturing drill pipe became an object of serious study for directional, extended-reach, and horizontal wells, and ultra-deep borehole drilling. Furthermore, extension of drilling to offshore and to areas with difficult environmental conditions and limited infrastructure required the reduction of transportation costs of equipment and materials. All these problems can be reduced or eliminated by the application of **aluminum drill pipe (ADP)** (Figure 1).

1.2 Onshore Applications for ADP

The first exploratory wells where ADP was applied were drilled in the region of the middle Volga in 1960-1962. These early experiments showed that ADP allowed a significant reduction in time, materials, energy and labor requirements. In the mid-1960s, ADP was used to drill several ultradeep wells, and in the 1970s was given wide recognition for cluster directional drilling in Western Siberia.

The successful utilization of ADP in directional and deep drilling operations demonstrated its effectiveness in ultradeep scientific boreholes with high formation stresses, high temperatures and highly corrosive environments.

Ultradeep Scientific Boreholes

ADP has been used for deep scientific drilling applications such as the Kola ultradeep SG-3 (12 km; 39,400 ft), Krivorozhskaya (5.5 km; 18,000 ft), Saatlinskaya (8.5 km; 27,900 ft), Uralskaya (6 km; 19,700 ft), as well as other ultradeep boreholes.

Drill String for the Kola SG-3 (1970-1993). The Kola ultradeep borehole, with an 8½-in. open hole at a depth of 12,000 m, was drilled with a combination drill string including 5¾-in. ADP with wall thickness of 11, 13, 15 and 17 mm (0.433, 0.512, 0.591 and 0.669 in.). These pipes were produced from alloys of grades AK4-T1, D16T and 1953. Equivalent durability for different cross-sections of the drill string was provided by utilization of pipes with different wall thickness. Applying pipes manufactured from different alloys guaranteed stable strength properties for temperatures ranging from 20° to 220°C (68° to 428°F).

Drill String for Krivorozhskaya SG-8 (1984-1991). Significant experience was gained with 6⅝-in. ADP while drilling the Krivorozhskaya SG-8 to a depth of 5432 m (17,822 ft). In addition to the advantages mentioned above, excellent results were achieved in hydraulics through the use of internally flush pipe.

Recent Drilling Operations in Russia (1993-1997). About 2500 tonnes of standard ADP have been supplied monthly to Russian drilling companies. ADP was an important part of the most comprehensive volume of directional drilling operations in West Siberia at about 3 million meters per year (9.8 million ft/yr).

1.3 Offshore Applications for ADP

Atlantic Ocean (1991). Pipes of aluminum alloy were designed for the deep-water scientific drilling program (1985-1990) in conjunction with the construction of the drilling vessel "Nauka" for the USSR Academy of Sciences. A 7.3-km (24,000-ft) ADP string and an 11-km (36,100-ft) ADP/SDP (steel drill pipe) combination string were designed. D16T, 1953 and 1933 aluminum alloys were chosen as the three most efficient alloy types for drillstring development specifically for operation in the marine environment. The first offshore tests of these pipe prototypes were carried out in 1991 from the geotechnical vessel "Bavenit" in the Atlantic Ocean. Several scientific boreholes were drilled at the seamounts Joscfin, Amper and Gorrindge. Maximum water depth was 212 m (696 ft) and borehole depth was 50 m (164 ft). Drilling with ADP showed excellent workability.

These and other studies led to the development of a deep-water ADP drill string for use from relatively small geotechnical drilling vessels.

Deep Water Projects (1993-1998). Pipes of 164-mm (6.46-in.) diameter made of the 1953 alloy have been successfully employed to drill from the geotechnical vessel "Bucentaur," which was similar to the above mentioned "Bavenit" with a displacement of only 4470 tonnes. Drilling operations were performed in areas of the Atlantic Ocean (Voring Basin-1993, 1997; Rockall Bank-1994) Gulf of Mexico (Mississippi Canyon-1995; Green Canyon-1996; Viosca Knoll area-1996; Garden Banks area-1996), Gibraltar Strait (1995), Japan offshore (1997), and West Africa offshore (1998).

No apparent signs of pipe corrosion have been noted after four years of exploitation. A drill-string length of 1981.5 m (6500 ft) was achieved with a drilling rig lifting capacity of only up to 40 tonnes. The projected potential length of a string made of these types of pipes for riserless drilling (see Chapter 9) could reach 3000-4000 m (9800-13,100 ft).

2. Properties of Aluminum Alloys

2.1 Advantages/Disadvantages of Steel, Titanium and Aluminum Alloys

The range of technical functions a drill string performs, as well as stringent requirements for strength, reliability and durability of the pipe, dictate the necessity of an integral approach when selecting the material. Drill-pipe materials with specific physical and mechanical characteristics are used in specific geological and technical drilling environments. Following are the essential requirements for drill-pipe material used in well drilling:

- high specific strength
- optimum modulus of elasticity and shear
- resistance to corrosion
- resistance to abrasion

Table 1 summarizes the essential physical and mechanical properties of materials used worldwide for manufacturing drill pipe. This information allows analyzing how closely these materials meet the above requirements.

Table 1. Mechanical Properties of Materials Used for Manufacturing Drill Pipe

MATERIAL	DENSITY (G/CM^3)	MODULUS OF ELASTICITY (10^4 MPA)	SHEAR MODULUS (10^4 MPA)	POISSON'S RATIO	COEFFICIENT OF THERMAL EXPANSION (10^{-6}/°C)	SPECIFIC HEAT (J/KG °C)
Steel Alloys	7.85	21.0	7.9	0.27	11.4	500
Aluminum Alloys	2.78	7.1	2.7	0.30	22.6	840
Titanium Alloys	4.54	11.0	4.2	0.28	8.4	460

Material Specific Strength

Drill-string weight is a function of drill-pipe material density, its size/shape factor, and length. Weight of a drill string dictates levels of nominal stresses that stretch the string while in the hole. Material specific strength is used to evaluate the feasibility of using various materials for drill-pipe manufacturing. Material specific strength is the ratio of yield point and material specific weight.

$$l = S_{0,2} / \gamma_m \tag{2-1}$$

where:

$S_{0,2}$= yield point of the material

γ_m = material specific weight

Material specific strength is measured in units of length. It characterizes maximum length of a one-dimensional drill string hanging in air when levels of stress at the point of suspension reach the maximum yield point of the material.

The fact that a drill string suspended in drilling fluid becomes lighter through buoyancy must be taken into account when the calculation is performed. Thus, including a safety factor (n), specific strength is calculated using:

$$l = \frac{S_{0,2}}{n(\gamma_m - \gamma_l)} \tag{2-2}$$

where γ_l = mud specific gravity.

Figure 2 shows potential lengths of one-dimensional (that is, not tapered) drill strings in wells with drill mud. The shaded areas indicate allowable lengths of drill strings made of each type of alloy. These lengths are calculated accounting for potential variation of the material yield point and drilling fluid specific gravity (1.0-2.0 g/cm³).

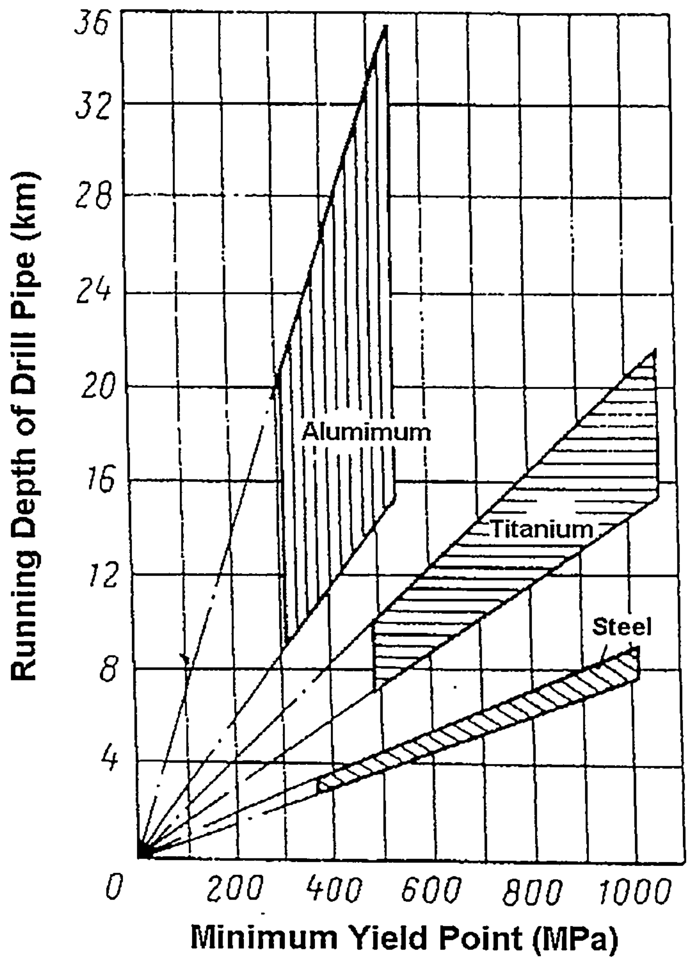


Figure 2. Running Depths for Drill Pipes of Various Materials

One-dimensional ADP strings allow maximum suspended length. Therefore, based on this parameter, aluminum alloys are the best option for drill-pipe construction.

Resistance to Alternating Bending and Dynamic Stresses

The most important parameters for drill-pipe material are modulus of elasticity (E) and shear modulus (G), which significantly affects the stressed condition of a drill string. When a drill string is rotated in the hole, it undergoes alternating bending stresses:

$$S_b = \frac{\pi^2 E d f_o}{4 L_o^2} \tag{2-3}$$

where:

d = drill-pipe diameter
f_o = bending deflection
L_o = length of a bending string axis half-wave

With a few minor approximations, it is possible to conclude that alternating bending stresses of drill pipe are proportional to the modulus of elasticity of the material (all other factors being equal). Their proportion for aluminum pipes (ADP), titanium (TDP), and steel (SDP) is:

$$\sigma_A : \sigma_T : \sigma_S = \mathbf{1 : 1.55 : 2.96}$$

Figure 3 shows the results of bending stress calculations using Equation 2-3 for ADP, TDP, and SDP at various ratios between diameters of pipe and borehole.

The dynamic tension stress due to setting heavy drill string on the elevator or power slips during a trip is calculated using:

$$S_D = V \cdot \frac{\sqrt{E\gamma_m}}{q} \qquad (2\text{-}4)$$

where:

V = drill-pipe tripping speed
q = unit weight of drill pipe

Dynamic stresses during tripping operations are proportional to $\sqrt{E\gamma_m}/q$ (all other factors being equal). Their proportion for drill-pipe materials (ADP, TDP, SDP) is: **1 : 1.6 : 2.9.**

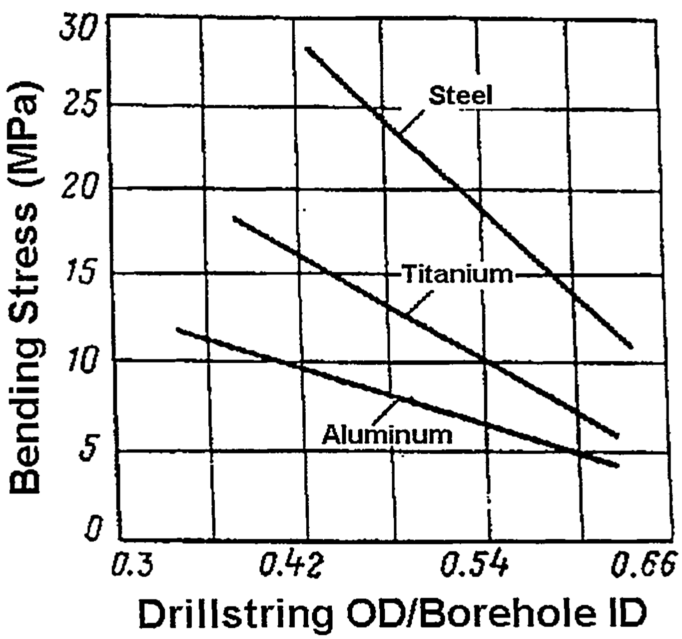


Figure 3. Bending Stress of 146-mm (5¾-in.) DP in Various Hole Sizes

When the drill string fails during a tripping operation, the lower part of the string falls down the hole. The following formula is used to calculate the ultimate dynamic stress in the pipe that falls down from height h, for determining the degree of deformation of the lost-in-hole section (i.e., the fish):

$$S_D = \gamma_m l \sqrt{1 + \frac{6Eh}{\gamma_m l^2}} \qquad (2\text{-}5)$$

where l = length of the drill-string section lost in hole.

Since drill-pipe materials with lower elastic moduli have, as a rule, lower specific weights γ_m, it is possible to conclude that dynamic stress of a string with lower E is also lower when the string impacts the bottom.

The following formula is used to calculate effective dynamic torsion stress for cases when a drill bit, BHA component or drill string wedges in the hole:

$$\tau_D = \frac{\omega \cdot d}{2}\sqrt{\frac{G\gamma_m}{q}} \tag{2-6}$$

where:

G = shear modulus of drill-pipe material
ω = RPM

Consequently, for the same RPM and drill-pipe diameter, these stresses for ADP, TDP, and SDP will be in the same proportion as $\sqrt{\frac{G\gamma_m}{q}}$, i.e., **1 : 1.6 : 2.9.**

During operations to unstick the drill string, the string torsion angle is used to control torque. Torsion angle is calculated using the following formula:

$$\varphi_o = \frac{ML_{st}}{GI_p} \tag{2-7}$$

where:

M = torque
L_{st} = length of drill string from the bottomhole to the stuck point
I = polar moment of inertia of the pipe section

Drill-string torsion angle is inversely proportional to shear modulus of the drill-pipe material.

These observations lead to the conclusion that both modulus of elasticity and shear modulus give aluminum alloys indisputable advantages over steel and titanium alloys.

Corrosion Resistance

Corrosive agents affect drill-pipe materials in the borehole and on the surface. Uniform attack, pitting corrosion, isolated corrosion, intercrystalline corrosion, as well as laminating corrosion, can all affect drill pipes. Uniform attack results in fast wear of drill pipe, decreasing its bearing strength and leading to early pipe failure. Isolated, intercrystalline, and laminating corrosion are the most critical.

Corrosion resistance analysis for the various candidate materials indicates an advantage for titanium and steel alloys over aluminum alloys for the principal types of corrosion wear. Hydrogen sulfide is an exception, since resistance of aluminum to this medium is higher.

Abrasive Wear

Friction between the drill pipe and the borehole or casing wall results in abrasive wear. This wear is a function of the surface hardness of the pipe material, friction distance, rock abrasive properties, normal force, and the lubricating properties of the drilling fluid.

Brinell hardness of aluminum alloys used for ADP is 120-140 HBr, and is 1.5-2.0 times lower than surface hardness of SDP. Therefore, ADP wears more readily than SDP and TDP, all other factors being equal. However, given ADP's lower weight, normal force due to string tension is significantly lower than that of SDP. Hence, ADP wear is lower than SDP, all other factors being equal.

Abrasive particles in the drilling fluid circulated at high speed inside the drill pipe cause wear of their inner walls. This process is more intensive in transition zones along the ID (drill-pipe couplings, coupling-to-pipe zones) due to turbulence in the drilling fluid. This process is more intense in ADP and less intense in SDP and TDP.

2.2 General Requirements for Aluminum Alloys for ADP

Three types of alloys (D16T, 1953T1, and AK4-1T1) are currently used in Russia for manufacturing ADP. D16T-based ADP is the most widely used. 1953T1 alloy is used for high-strength ADP comprising the upper section of a drill string in deep and ultradeep wells. Tensile loads in these wells exceed operating capacity of D16T-based drill pipe. AK4-1T1 alloy is used for thermally stable ADP comprising the bottom section of a drill string in wells with temperatures over 160°C (320°F).

Of these three alloys, AK4-1T1 is used for manufacturing ADP for high-temperature wells. This alloy is used specifically for thermally stable pipes, and involves a rather complex process of pipe pressing. Moreover, the alloy's resistance to fatigue damage and corrosion are quite similar to D16T.

ADP based on the alloys D16T and 1953T1 has increased in popularity. These alloys were designed taking into account the specific conditions of well drilling. Drill pipes with high static strength are not required by comparatively shallow of wells. However, high levels of alternating dynamic stresses in the drill string place special requirements on physical and mechanical parameters of alloys to ensure reliable ADP. Among these parameters are: durability, sensitivity to stress concentrations, longitudinal and lateral plasticity, and high corrosion resistance.

It is extremely important that the material selected for drill pipe has certain technological properties which enable manufacturing pipes with variable cross sections along the length. This is necessary for implementing optimum geometric parameters, which in turn will ensure high structural integrity of ADP and prevent metallurgical defects (casting and pressing cracks, high segregation zones, etc.).

Alloys D16T and 1953T1 both have certain advantages and disadvantages. For example, alloy D16T has required levels of static and dynamic characteristics, and is highly adaptable for efficient manufacturing; however, it exhibits low corrosion resistance in seawater.

Alloy 1953T1 has high static strength and relatively high corrosion resistance. However, ADP made of this alloy fails to ensure satisfactory parameters of durability due to high dissemination, relatively low ductility, significant anisotropy of properties in lateral and longitudinal directions, and high sensitivity to various stress concentrators.

2.3 Chemical Composition and Properties of Aluminum Alloys used in Russia for ADP

All commercial aluminum alloys are grouped into systems, within which typical physical and mechanical properties depend on basic alloying elements. Generally, basic properties of one system of alloys depend on their phase composition.

There are 13 systems of aluminum alloys used around the world. Following are the aluminum alloys of three systems that are used in Russia for manufacturing drill pipes:

- D16T – of the system Al-Cu-Mg
- AK4-1T1 –of the system Al-Cu-Mg-Si-Fe
- 1953T1 – of the system Al-Zn-Mg

Table 2 shows the chemical composition of these alloys.

Table 2. Chemical Composition of Aluminum Alloys used for ADP

GRADE OF ALLOY	ALLOY SYSTEM	BASIC ADDITIVES (%)	MAX IMPURITIES (%)
D16T	Al-Cu-Mg	Cu 3.8-4.9 Mg 1.2-1.8 Mn 0.3-0.9	Fe 0.5 Si 0.5 Zn 0.3 Ti 0.1 Ni 0.1 other 0.1
AK4-1T1	Al-Cu-Mg-Si-Fe	Cu 1.9-2.5 Mg 1.4-1.8 Fe 0.3-0.8 Ni 0.8-1.3 Si 0.8-1.4 Ti up to 0.1	Zn 0.3 Mn 0.2 other 0.1
1953T1	Al-Zn-Mg	Zn 5.5-6.0 Mg 2.4-3.0 Cu 0.4-0.8 Mn 0.1-0.3 Cr 0.1-0.2 Ti up to 0.1	Fe 0.2 Si 0.2 other 0.1

Alloys of the system Al-Cu-Mg are most widely used, wrought, and thermally hardenable. Besides ADP manufacturing, they are widely used for manufacturing load-carrying structures of critical importance in the aviation and space industries, shipbuilding, etc.

Properties of alloys in the system Al-Cu-Mg-Si-Fe with added nickel are similar to alloys of the system Al-Cu-Mg. At high temperatures, due to presence of phases with Ni and Fe, these alloys have lower loss of strength than the alloys without these additives.

Alloys of the system Al-Zn-Mg with different content of alloying elements are the best for manufacturing drill pipes. This type of alloy has 30% higher yield point as compared with alloys of the first two systems. Table 3 summarizes the physical and mechanical properties of these alloys.

Table 3. Physical and Mechanical Properties of Aluminum Alloys

PARAMETER	UNITS	GRADE OF ALLOY		
		D16T	1953T1	AK4-1T1
Yield point ($S_{0.2}$) min	MPa	330	490	350
Tensile strength (S_u) min	MPa	450	540	410
Hardness	HBr	120	120-130	130
Normal strain (δ)	%	11	7	12
Reduction of area	%	20	15	26
Specific gravity	g/cm^3	2.8	2.8	2.8
Modulus of elasticity E G	MPa x 10^5	 0.72 0.26	 0.70 0.275	 0.73 0.275
Poisson's ratio	-	0.33	0.31	0.31
Coefficient of thermal expansion	1/°C x 10^{-6}	22.5	23.8	23.8
Max operating temperature	°C	160	110	220

2.4 Characteristics of the 1980T1 Alloy

As a result of the conversion of the military/industrial complex in Russia, information became available on aluminum alloys widely used in special-purpose submarine equipment. Previously this information was classified as top secret, and was unavailable for development of general-purpose industrial products.

For example, we obtained information on the alloy 1980T1 (an Al-Zn-Mg system), which was developed for target use in durable submarine equipment. Optimization of chemical composition and heat treatment of this alloy (quenching and two-stage aging) ensured strength of deformed intermediate products, including pressed pipes with guaranteed yield point $S_{0.2} \geq 350$ MPa (51 ksi) and high corrosion resistance in seawater. Deformed intermediate products (extruded pipes, pressed products) from the 1980T1 alloy are widely used in the military metallurgical industry.

Relatively little is known about the 1980T1 alloy. The primary alloy elements in the system are:

Zn – 4.0-4.8%; Mg – 2.0-2.6%; Mn – 0.3-0.5%

Information about other alloy components is still restricted.

According to the available data, the 1980T1 alloy has a high fatigue limit (i.e., not less than the D16T alloy). Its technological properties are sufficient to ensure required geometrical parameters of ADP and high output of quality products. The joint-stock company Sameko (in the city of Samara) produces all types of round billets for ADP from various alloys. It has experience in manufacturing long round billets from 1980T1 alloy for the military.

Table 4 presents the available information about mechanical, fatigue, and corrosion resistance properties of 1980T1 alloy.

Table 4. Properties of the 1980T1 Aluminum Alloy

ALLOY	TYPE OF INTERMED. PRODUCT	MECHANICAL PROPERTIES			FATIGUE STRENGTH S_{-1} (MPA)	CORROSION RESISTANCE	
		S_U (MPA)	$S_{0.2}$ (MPA)	δ (%)		GENERAL CORROSION	CORROSION CRACKING
1980T1	290-770 mm extruded pipe	400 (along the fibers) 370 (tangential direction)	350 (along the fibers) 300 (tangential direction)	9.0	Circular bend of smoothly shaped test specimen based on $2 \cdot 10^7$ cycles S_{-1} =11.2-12.3 Console bend of a smoothly shaped test specimen based on 10^7 cycles S_{-1} =10.7	Depth of penetration 0.05 mm/year Rate 0.015 $g/m^2 \cdot hr$	Not observed

Information about the 1980T1 family of aluminum alloys tentatively suggests that its most effective application, as compared to other known alloys, is for drilling wells when corrosion is of concern.

2.5 Corrosion of ADP and Methods of Prevention

Corrosion of ADP is defined through a complex series of physical and mechanical characteristics. These characteristics directly determine basic parameters for the electrochemical processes that affect drill pipes in aggressive media typical of well drilling and oil and gas production operations. Corrosion may also attack and wear drill pipes when they are stored under certain conditions.

Drill-pipe corrosion is quite diverse in nature. Several types of corrosion are observed with drill pipes including 1) general corrosion, 2) layer corrosion, 3) intergrannular corrosion, 4) contact corrosion, and 5) corrosion cracking. The specific type of corrosion depends on the pipe material and composition, level of corrosion, duration of corrosion attack, stress conditions and operating temperature.

Several factors – different properties of aluminum alloys used for drill pipes, and diversity of temperatures, time periods of exposure, and forces that affect a drill string in operation – require a systems approach to development of technical recommendations regarding methods to protect pipes from corrosion.

Results from various surveys and studies indicated that aluminum oxide film is the main element of corrosion protection of aluminum alloys. The film is formed on a pipe surface that is exposed to oxygen.

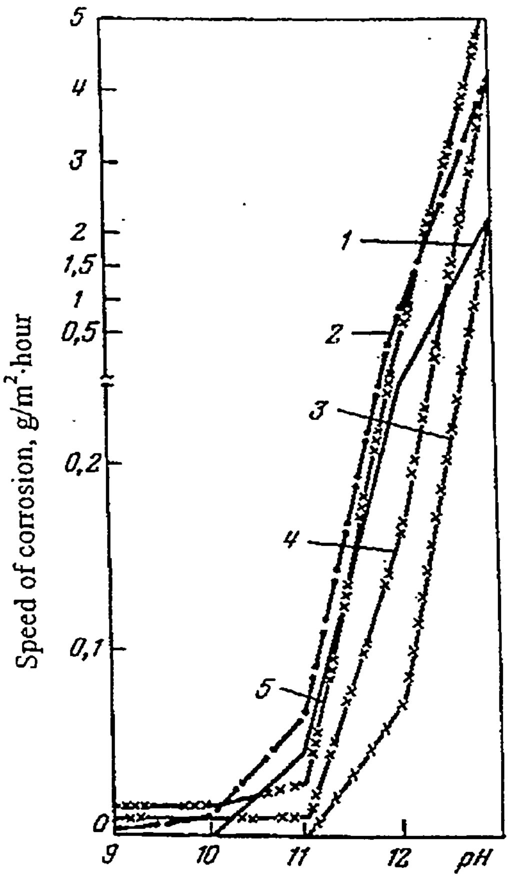


Figure 4. Corrosion Rate with pH and Temperature (1=water at 20°C; 2=water at 50°C; 3=5% NaCl at 20°C; 4=5% NaCl at 50°C; 3=5% NaCl at 90°C)

Mechanical activity is very important for development of corrosion processes for ADP. Hydrogen-evolution corrosion of aluminum is observed in aqueous media. Moreover, after the process has stopped, dehydrogenation continues for a long time at a decreasing rate. Electrochemical processes are more intense in pipes affected by hydrocorrosion.

Studies of wear of aluminum alloys in various drilling fluids indicate that corrosion processes are relatively slow and do not strongly depend on the pH of the fluid if the pH remains between 7.0-9.5, but significantly accelerate when pH exceeds 10.5 (Figure 4).

Therefore, when ADPs are used, the pH of drilling fluids treated with alkaline chemicals must be carefully controlled. pH must not exceed 9.5-10.0. Inhibitors must be used if the pH of a lime drilling mud is 12-13. Some drilling mud viscosity reducers (stabilizing agents) widely used for mud treatment produce an inhibiting effect on corrosion of aluminum. Among them are spent sulfite-alcohol liquor, water glass, and polyphosphates. When added to a clay drilling mud at a concentration of 0.25-0.35%, these slow corrosion of aluminum at 20-80°C (68-176°F) by 40-80%.

Increases in mud temperature result in faster corrosion (V_{cor}) of aluminum alloys. The corrosion rate at 40°C in a 3% NaCl solution is about 0.5 g/m^2-hr, whereas at 80°C the rate increases to 0.65 g/m^2-hr. Corrosion rate in a solution with 0.5% soda ash at 40°C is 1.1 g/m^2-hr; at 80°C it increases to 1.8 g/m^2-hr. V_{cor} significantly increases in solutions containing high levels of magnesium chloride. This is probably due to higher levels of electrolytic dissociation.

The whole spectrum of erosion factors, not just individual components of the drilling fluid, affect the rate of aluminum corrosion in clay muds. For example, chlorides accelerate corrosion because the oxide film has been damaged earlier due to friction between the pipe and borehole walls, as well as the erosive effect of abrasive particles in the drilling fluid. The velocity of the drilling fluid circulated inside the drill pipe and required to clean the hole reaches 5-7 m/sec (16-23 ft/sec).

The oxide film in transition areas on the pipe walls is always damaged by turbulent flow and abrasive particles in the drilling fluid. Electrode potential in damaged zones of pipe is 1.22 V, compared to non-damaged zones at 0.55 V and to steel joints screwed on drill pipes at 0.25 V. Therefore, zones with damaged oxide film on ADP will behave as an effective anode and will corrode intensively. Chlorides and other halogenides destroy the protective film on aluminum alloys. Corrosion resistance of aluminum in these solutions is reduced. Hydrolysis of chlorides at temperatures above 60-80°C is also important for these processes. When pH of a medium is reduced, corrosion rate increases. Corrosion rate of ADP is very high when drilling through magnesium salts with high bottomhole temperatures.

As a rule, corrosion does not penetrate very deeply and normally affects 0.3-1.2 mm (0.012-0.047 in.) of the pipe wall. At the same time, new layers of the pipe are exposed to corrosion as a result of corroded zones scaling off, which leads to faster pipe wear. In some cases, deeper corrosion wear occurs in zones of turbulent flow of a drilling fluid (zones with rapid change of pipe OD). This wear may result in lower strength of the main section of the pipe.

Information related to corrosion rates of D16T alloy ADP in drilling fluid with NaCl, $CaCl_2$, $FeSO_4$, and other chemicals used for treatment of drill mud is shown in Table 5. These data clearly indicate that increases in temperature result in intensive and high-rate corrosion of D16T aluminum alloy in drilling fluids with NaCl, $CaCl_2$, and FeSO4. The fastest corrosion in drilling fluids with these first two chemicals is observed at 80°C. Carboxymethyl cellulose and lignin-alkaline essentially do not affect corrosion wear of ADP operated at 80-120°C.

Table 5. ADP Corrosion Rates ($g/m^2/hr$) in Mud Treated with Reagents

Reagent	Conc. (%)	Temperature (°C) 20	40	80	120
NaCl	3	0.008	0.012	0.025	0.019
	5	0.009	0.012	0.022	0.013
	10	0.007	0.009	0.015	0.005
	15	0.006	0.009	0.004	0.006
	20	0.003	0.006	0.002	0.001
$CaCl_2$	1	0.011	0.011	0.026	0.024
	2	0.002	0.012	0.029	0.025
	3	0.002	0.012	0.029	0.028
$FeSO_4$	1	0.002	0.008	0.027	0.037
	2	0.011	0.013	0.043	0.051
	3	0.013	0.019	0.051	0.054
"KSSB"	1	0	0.001	0.001	0
	3	0	0	0.001	0.002
	5	0	0	0.002	0.002
	8	0	0.001	0.002	0.002
"UschR"	1	0.007	0.01	0	0
	2	0.006	0.01	0	0
	3	0.004	0.007	0	0
KMC	1	0.008	0.012	0.003	0.002
	2	0.004	0.021	0.028	0.001
	3	0.003	0.031	0.011	0.001

Pitting corrosion of aluminum and most of its alloys in seawater is observed only at relatively low temperatures (5-8°C). Pitting corrosion is not observed in warm water (25-30°C).

The most intensive corrosion occurs during the initial 25-30 days of operation, after which the rate is reduced. This suggests that ADP can be used in offshore operations without any special protection from corrosion.

Intercrystalline corrosion represents the principal danger for reliable application of ADP since it does not change the appearance of the pipe, but significantly decreases the ability to withstand loads, especially dynamic loads. Continuous exposure to heat greatly affects susceptibility of naturally aged pipes to intercrystalline corrosion. Table 6 presents data on minimum exposure time for D16T alloy at a range of temperatures, after which it is susceptible to intercrystalline corrosion.

Table 6. Heat Exposure Times for D16T Alloy

Temperature (°C)	90	95	100	110	120	130	140	150	160	170
Exposure (hr)	300	50	15	8	2	1	1	0.5	0.33	0.25

When ADP is equipped with steel tool joints and there is an electrolyte (i.e., drilling fluid) in the well, a voltaic couple is formed between the pipe body and tool joint. This leads to contact (galvanic) corrosion. Significant experience running ADP with tool joints indicates that wear from contact corrosion is insignificant. Surveys of ADPs that were in operation for 6-7 years and inspections of threaded connections and the pipe body adjacent to a tool joint, showed an absence of corrosion wear for the drill pipe in contact with the tool joint.

Studies conducted in Russia and abroad revealed lower susceptibility to corrosion with ADP in aggressive oil and gas media with hydrogen sulfide as compared to steel drill pipes. Also, steel tool joints on ADP were found to be more resistant to corrosion in fluids with hydrogen sulfide. The reason is that aluminum alloys provide electrochemical protection under these conditions.

An interesting practical application is from studies of aluminum-alloy corrosion in a flowing electrolyte containing sulfur and abrasive particles. The studies confirm that hydrogen sulfide reduces susceptibility of aluminum alloys to pitting corrosion. A 3% solution of NaCl (pH = 4.0) with 2 g/liter H_2S was used as the electrolyte in these studies. The process of aluminum dissolution in this electrolyte was 2-3 times less rapid, whereas dissolution of steel was 1.5-2 times more rapid. These results indicate a potential advantage for using aluminum alloys as a pipe material when a high-velocity salinated mud with high H_2S is circulated.

One of the principal methods of protecting ADP from corrosion is to add inhibitors to the mud. Inhibitors used for ADP protection of course must not degrade the rheological characteristics and properties of the mud system.

A number of mud stabilizers, particularly sodium polyphosphate and potassium, produce an inhibiting effect on corrosion of ADP in mud with alkaline. Water glass, condensed spent sulfite-alcohol liquor, etc. can be used as inhibitors in alkaline fluids.

Potassium bichromate, widely used as a drilling mud thermal stabilizer, is an efficient non-organic corrosion inhibitor for aluminum alloys. Small amounts of potassium bichromate (0.5-2%) significantly reduce corrosion wear of aluminum alloys.

Coating of internal ADP surfaces is an efficient method of surface protection from corrosion and erosion wear in aggressive media. Operation of pipes with internal coatings showed a substantial increase in their durability and lower hydraulic losses in fluids circulated through the pipes. These coatings allow operating ADP with a wider range of drilling fluids and minimizing the corrosive effect of mud remaining in the pipes during storage after the operation. Deep or thick anode coatings on ADP surfaces are a most promising method of protection from corrosion wear.

An example of an anode coating is titanium and molybdenum alloy 50-70 μm anode oxide films. The process takes place in a sulfuric acid electrolyte at 2-3 A/dm^2

current density. In the same bath the film is simultaneously saturated with titanium or molybdenum. Anti-corrosion characteristics of ADP with an anode coating alloyed with titanium are close to those of pipes constructed of titanium alloys. These are specifically recommended for media with high chloride content. Pipes with anode films with molybdenum alloys have high anticorrosion properties in highly salinated muds with large proportions of dissolved oxygen.

Layer corrosion has been observed in pipes stored for extended periods, as well as in pipes retired from operation and moved to storage facilities, particularly in coastal areas. Layer corrosion is particularly intensive when the pipes were not cleaned from mud after been pulled out of the hole. Before drill pipes are stored, they should be washed with fresh water to reduce corrosion wear during storage. It is recommended to put a layer of grease on pipe surfaces when the pipes are to be stored in coastal areas.

Conclusions Regarding Corrosion

Analysis of corrosion wear of ADP and methods of prevention lead to the following conclusions:

1. Corrosion of ADP depends primarily on composition, aggressiveness, and temperature of the fluid in which the drill string is operated, as well as on exposure time.

2. The pH of the drilling fluid significantly affects the process of ADP corrosion wear. ADP corrosion wear is insignificant in fluids with pH 7.0-9.5 and rapidly increases when pH exceeds 10.5.

3. ADP corrosion is accelerated at higher temperatures.

4. An oxide film formed on pipe surfaces exposed to oxygen provides reliable corrosion protection for ADP. Abrasive drilling fluids with high solids content damage the oxide film in areas with turbulent flow, which results in faster drill-pipe corrosion.

5. Increased temperature of the drilling fluid, primarily in fluids with chlorides, leads to intense corrosion wear of ADP.

6. When high-velocity salinated mud with a high content of H_2S is used, ADP has demonstrated high resistance to corrosion under these conditions, which means ADP has good potential for application in oil, gas, and drilling mud media.

7. The principal method of protecting ADP from corrosion is the use of corrosion inhibitors added to the mud. Sodium polyphosphate- and potassium-based stabilizing inhibitors are the most widely used.

8. Tar coatings of the internal surface of ADP and thick anode coating of the entire surface of the pipe are efficient means of ADP corrosion protection.

9. Aluminum alloys 1980T1 and 1953T1 are the most corrosion resistant among alloys used for ADP manufacturing. Therefore, pipes from these alloys are most widely used in offshore drilling. ADP from D16T alloy is recommended for drilling oil and gas wells with high concentrations of H_2S.

3. ADP Manufacturing Technology

3.1 Manufacturing of Tubular Billets Using Press Forming

Tubular billets for steel drill pipes, casing, and tubing are manufactured by rolling. After a hole is pierced in the original ingot, it is rolled on a tubular mill to obtain the desired diameter. Required finishing operations are performed after rolling is complete. These operations include upsetting of preheated ends on a horizontal forging machine, making pipe threads, welding on tool joints, etc. Rolling has a limited number of technological operations and does not allow making an irregular section of a pipe with upset ends.

The direct hydraulic extrusion technique is used for manufacturing ADP. A hollow cylinder ingot made by semicontinuous casting is used for an original billet. The size of an original ingot depends on the size and type of the pipe to be manufactured. Prior to extrusion, 10-14 mm (0.39-0.55 in.) of the ID and OD of the original billet are turned off to remove casting defects from the surfaces. To eliminate structural heterogeneity, the billet undergoes homogenization in a special furnace. The ingot is heated to the temperature of intermetallic phase solubility (460-490°C; 860-914°F) and is held there until a diffusion process of intermetallic elements dissolution is completed (12-16 hr). Afterwards, homogenized ingots are cooled down for extrusion to 380-420°C for pipes with an internal end upset, and to 400-420°C for pipes with an external end upset. A heated ingot is placed in a chamber of a hydraulic press for extrusion.

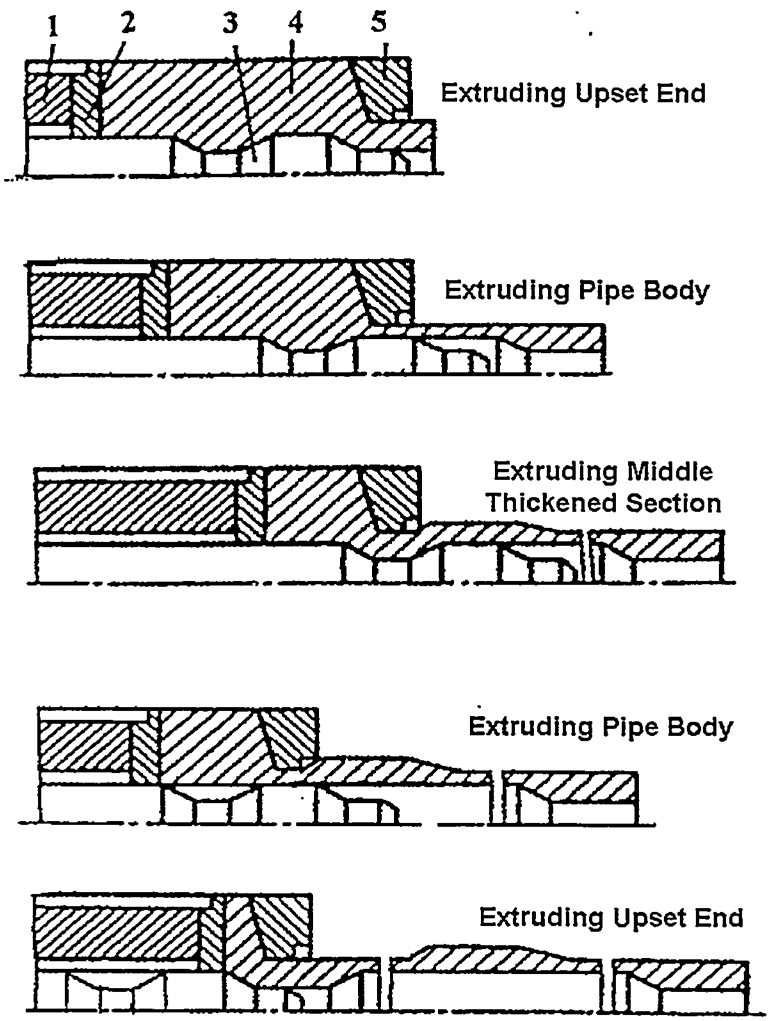


Figure 5. Extrusion Process of Pipe Billet with Internal Upset Ends and Thickened Middle

Figure 5 shows a process diagram for extruding a pipe length (tubular billet) with internal upset ends and a protection upset in the middle.

The extrusion process is completed in the following order:

1. A front end consisting of a step needle with a diameter that depends on the ID of the manufactured section of the pipe is set up in a piercing die. A front upset end is then extruded (Figure 5a).

2. While the extrusion process continues, the step needle is slowly moved forward until the clearance between it and a piercing die is minimum (Figure 5b). This travel of the step needle allows forming a smooth transition zone between the upset and main body of the pipe.

3. The step needle is stopped in this position (Figure 5b) and the main body of the pipe is extruded up to a beginning of a transition zone to a protection upset.

4. While the step needle continues to move forward (Figure 5c), metal flows around the needle head located outside the piercing die. As a result, walls of the pipe become thicker, since the OD of the pipe increases and the ID does not change. During this operation, the transition zone and the protection upset are formed.

5. The other half of the pipe is extruded with sequentially repeated operations 4, 3, 2, 1 as the step needle travels back. A transition zone and the main body of the pipe are formed (Figure 5d), along with a transition zone and the second upset end (Figure 5e).

Different shapes of the step needle are required for extrusion of pipes with external upset ends. However, the extrusion process itself is similar to that for forming the protection upset (operation 4).

The extrusion process allows manufacturing pipes with helical beading of the external surface. Helical beading is formed as a result of friction forces when the metal is flowing through dies positioned at a certain angle to the longitudinal axis of extrusion. This is widely used in manufacturing ADP with higher wall thickness for drill collars.

Lengths are extruded in special hydraulic press machines. 73- to 102-mm (2⅞- to 4-in.) OD pipes are extruded at 40,000 kN (4500 tons); 114- to 170-mm (4½- to 6.7-in.) OD at 60,000 kN (6750 tons). Extrusion speed depends on the type of aluminum alloy and varies within the range 1.8-3.5 m/min (5.9-11.5 ft/min).

After the extrusion process is completed, tubular billets are moved into a horizontal quenching furnace, where it is evenly heated to 490±2°C and held at this temperature for 70 minutes. Twenty pipes are treated together in the quenching furnace. One pipe is moved from the furnace every 3.5 min. into a horizontal tank with water flowing toward the descending pipe. Water is applied to both internal and external surfaces. 0.02-0.04% potassium or sodium bichromate or chromate is added to the water used for hardening, to make pipes more resistant to surface corrosion.

After quenching, pipes made of alloys that require artificial aging (1953, Ak-4, 1980) are additionally heated to 170-200°C for 8-12 hours. During hardening, pipe billets undergo significant temperature deformation. Therefore, directly after hardening (but not later than after 12 hours) pipes are moved to a leveling machine for straightening by tension. After straightening, the permanent deformation of pipes with internal upset ends must be 1-3%, and for pipes with external upset ends 2-3%. The designed axial force of the leveling machine is up to 6000 kN.

The straightening process not only eliminates longitudinal curvature of the main body of a pipe, but essentially improves its stress/strain properties by mechanical hardening of the pipe surface, as a result of plastic deformations. Additional straightening of the upset ends is done in special dies on bending presses. After the final leveling, pipes are inspected visually and with special instruments on a horizontal control plate and are moved to an assembly shop. There, pipe threads are made and tool joints are screwed onto the pipes.

3.2 Making Pipe Threads

The technique of making threads on pipe billets from aluminum alloys is in principle the same as for steel drill pipe. Process parameters (RPM and feed) are, however, slightly different.

Below is a typical sequence for pipe threading:

1. The pipe is set in a hollow spindle of a pipe-threading machine and the free pipe end sits on a rest.

2. Ovality of the processed pipe end is checked. Its must not exceed ±0.2 mm.

3. Pipe end is cut and a cone for a thread is turned.

4. A plain gauge and a flat feeler are used to check the cone turning. Allowable cone deviation is +0.3/-0.2 mm.

5. A special threading cutter with 60° threading angle is used to cut a thread with 4-6 passes at 255 rpm.

6. A specified allowance is left for the last pass to make required density of thread. Then a special thread chaser with 1:16 conicity is used to finish the thread.

7. Thread tightness is checked with a plain gage and a thread gage.

8. A protection ring is put on the thread

9. Next, the other pipe end is threaded.

Computer-controlled pipe-threading machines are used to cut threads on drill pipes. When TT-type trapezoidal threads with a stabilizing shoulder are cut, it must be taken into account that, unlike triangle-type taper threads, its conjugation when pipes are made up goes along the inside thread diameter and not along the middle thread diameter. In this case deviation of angle of thread and of thread pitch does not affect axial thread tightness.

Plain ring gages are used to check conicity of the outside thread diameter and accuracy of the pipe stabilizing shoulder. A plain ring gage is put on a threaded end and clearance is measured using a feeler gage. There must not be any clearance at the wider end of a pin, and at the thinner end it must not exceed 0.08 mm. A plain ring gage is also used to check the OD of the stabilizing shoulder. The distance between the measurement plane of the gage and a face of the pipe end must be 96±2 mm.

The plain ring gage is also used to check conicity of the stabilizing shoulder. Clearance between the big and small diameters of the conical pin and the gage must not exceed 0.06 mm. Thread ring gages with complete and broken profiles are used to check the thread ID. After thread gages are screwed on as far as possible, their measurement plane must coincide with the pipe end face within ±2.0 mm.

The same threading machines are used to cut coarse tool-joint threads on integral-joint ADP. The surface of the pin and box thrust face must be smooth and allow tight make-up. The distance between the thrust face of any pin and box made up without additional torque applied must not exceed 2 mm. Quality of tool-joint threads is also controlled using plain and thread gages.

3.3 Cold Assembly of ADP

ADPs with internal upset ends and ODs of 64-129 mm (2½-5 in.) are fitted with steel tool joints using the "cold assembly" method, with required torque applied. These pipes are mostly used for drilling shallow wells (2.5-3 km; 8200-9800 ft) where high tensile loads and torques are not applied. Standard triangular threaded pipes with steel tool joints are connected using epoxy resin based self-hardening sealing compounds.

A special stand was designed to assemble ADP using the cold assembly method (Figure 6).

The following equipment is installed in the front of the stand: a 25-kW electrical motor at 730 rpm (1), a worm gear reducer (2), and a front head (3). All this equipment is mounted on one frame. A gear reducer reduces rotary speed to 6-10 rpm. The front head is set on the key of the reducer output shaft. It clamps one of a tool joint elements when it is connected to a drill pipe. The front head chuck and the back head chuck have one shaped and two plain dies that hold element 6 of the tool joint (pin, box) and prevent its rotation during the assembly process. The rear part of the stand is mounted on a rail carriage. By traveling on rails, the carriage compensates for the reduced distance between the tool joints, simultaneously screwing on both ends of the pipe, which enables assembling pipes of various lengths. The carriage wheels have flanges that prevent it from overturning as a result of tipping forces. Torque sensors are installed at the rear of the stand. They allow controlling torque during the assembly process. The stand drive is automatically shut down when torque reaches a preset level.

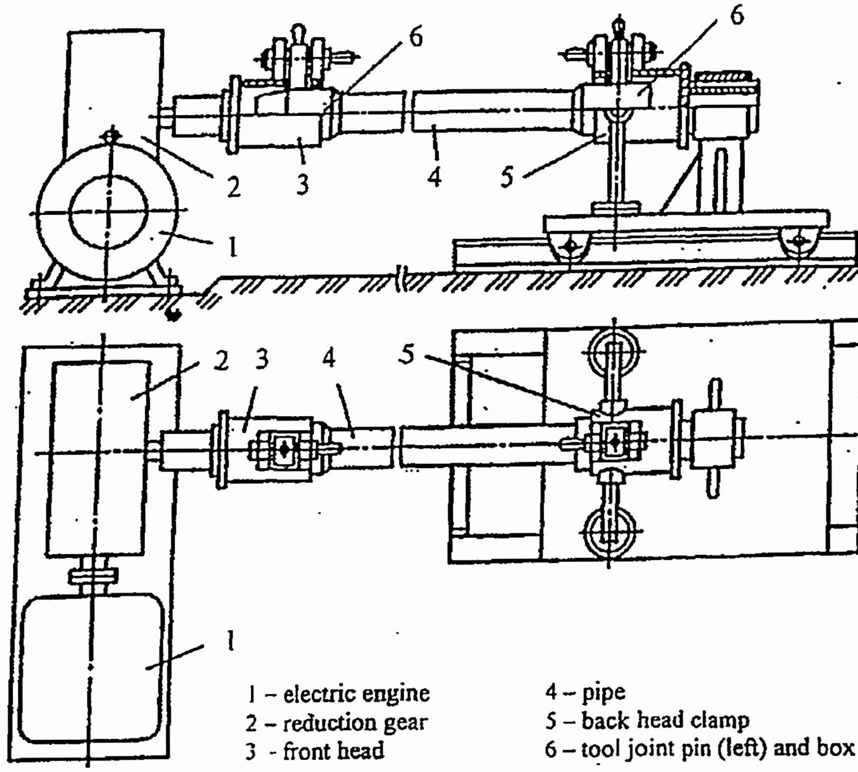


Figure 6. Cold Assembly Stand for ADP with Steel Tool Joints

Prior to assembly, threads of drill pipes and tool joints are thoroughly cleaned, rinsed, and degreased. An epoxy-based self-hardening compound is put on one-third the length of pipes threads from the smaller diameter end of the cone. Tool joints are then manually screwed onto the pipe. Selection of tool joints prior to assembly is based on specific thread parameters, and is designed to ensure the required tightness. The pipe with connected tool joints is set on the stand, and the tool joints (pin, box) are gripped by the corresponding chucks. The chucks hold sections of the tool joints beyond the threads. Then the motor is started. When the torque rises to the set limit, the motor is automatically shut down. A set of replaceable chucks is used at the stand to allow the assembly of various standard sizes of pipe.

This cold-assembly method of ADP fabrication has the following drawbacks that restrict its application for manufacturing drill pipes for deep and critical wells:

- low resistance to fatigue failure of the pipe thread connection

- possibility of additional rotation during an operation of a tool joint connected to a pipe as a result of high torque
- low reliability of connection pressure integrity
- potential for formation of aluminum and steel cold-welding zones due to torque applied during the assembly process. This reduces general strength and might lead to failure during operation.

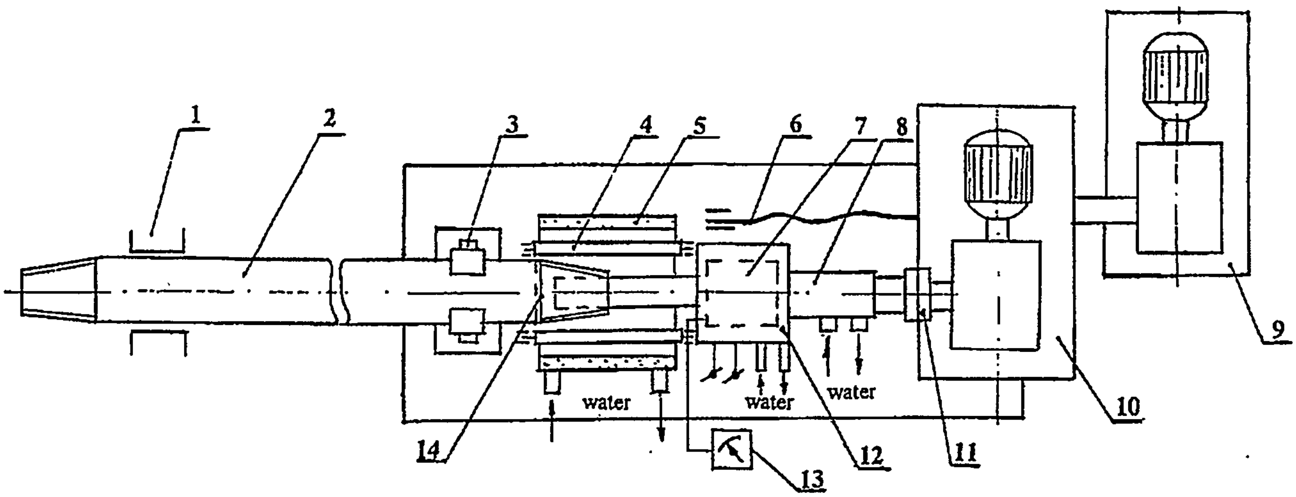
3.4 Hot Assembly of ADP

The "hot-assembly" method, widely used for assembling SDP, allows thermal expansion of the tool joint by heating it to a specific temperature to ensure required tightness of the thread connection. A number of factors have limited the utilization of existing hot assembly technology to attach steel tool joints to ADP:

- When an ADP is in contact with a heated steel tool joint, it quickly becomes hot and expands because of its significant thermal conductivity and high thermal expansion factor. This prevents free axial fit of the tool joint while it is screwed on and makes it impossible to achieve the required tightness.
- Strength characteristics of the pipe material (yield point) decrease when temperature is increased, which may result in excess hoop stress above the yield point during connection and plastic deformation. This in turn may prevent contact pressures in the thread couple from reaching the required level. While cooling, diameter of the pipe will shrink more than that of the steel tool joint due to different thermal expansion coefficients for steel and aluminum. This will lead to low actual contact pressures and low operational reliability of the connection.
- Overheating a threaded pipe end may result in low stress/strain properties of an aluminum alloy. This is due to a decrease in strength characteristics with high temperature as well as partial negation of the alloy thermal treatment.

Research evaluating whether a thermal field could be maintained during hot assembly of ADP with steel tool joints indicated that the disadvantages of hot assembly can be completely eliminated by forced cooling of the connection during the process of assembly.

Other experimental work on hot assembly technology led to a proper procedure for the assembly process that could make high-quality and reliable connections between ADP and steel joints using acme tapered threads with a tapered stabilizing belt (shrink seal). A special stand was designed to implement this technique. Figure 7 presents the principal operational diagram.



1 – support rollers
2 – pipe billet
3 – major-diameter fitting and clamping mechanism
4 – drive rollers
5 – external cooling chamber
6 – helical guideway
7 – tool joint (pin or box)
8 – hollow shaft
9 – drive of feeding
10 – drive of screwing on
11 – maximal tongue slutch
12 – induction coil heater
13 – indicating gauge of tool joint temperature
14 – internal cooling chamber

Figure 7. Hot Assembly Stand for ADP with Steel Tool

Figure 8 shows the work stand designed for screwing a steel tool joint onto ADP using "hot technology."

Figure 9 shows ADP before and after steel tool joints are attached.

Figure 10 shows the finished product: ADP assembled with steel tool joints using hot assembly technology.

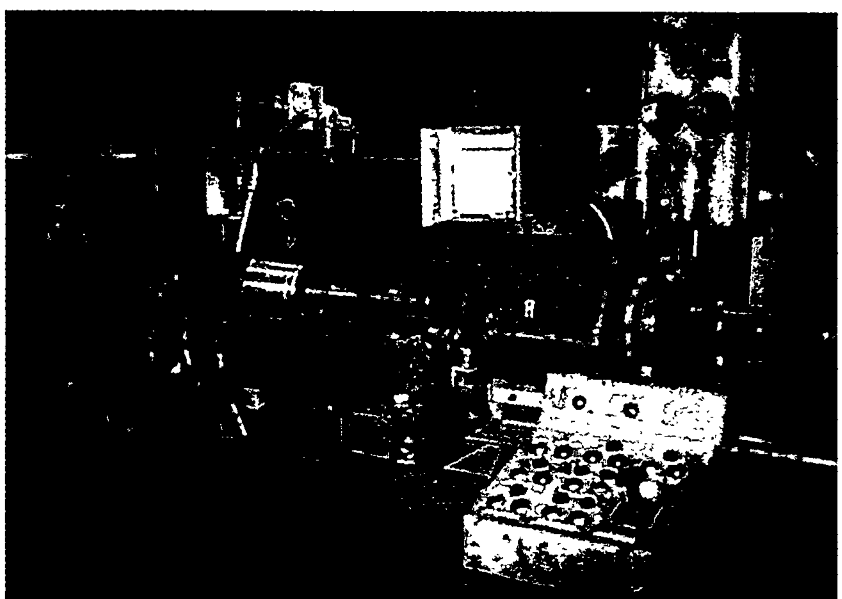


Figure 8. Bench for Hot Assembly of ADP

The hot-assembly method is used to assemble all ADP with external upset ends, as well as 147- to 170-mm ADP with internal upset ends used in drilling deep and ultradeep wells with complicated geological conditions. Long-term experience in wells drilled with hot-assembled ADP including the Kolskaya ultra-deep well (including extreme loading of the drill string) showed indisputable advantages of this method. Operational reliability of ADP significantly increased, which resulted in a large drop in the number of failures due to fatigue breakage of the pipe-thread connection.

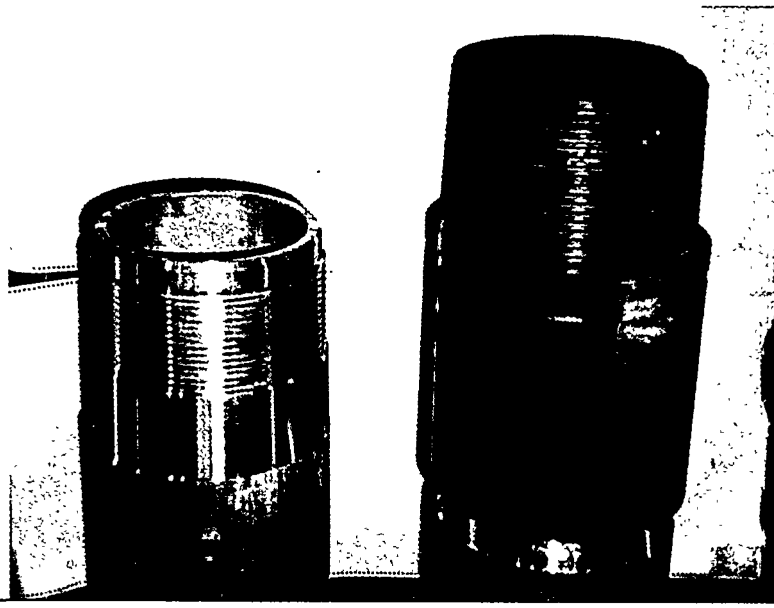


Figure 9. ADP Before and After Screwing on Steel Tool Joint

3.5 Sealing an ADP Pipe Thread

After ADP is assembled with a tool joint, it must be pressure-tight when used in a drilling operation. Additional sealing is not required when a trapezoidal TT-type pipe thread with a conical stabilizing shoulder is used, and if the connection is made using the hot-assembly method (see previous section). Because resistance in the TT-type thread occurs along the ID of the thread (not the middle diameter) and the hot-assembly method ensures tightness in both the thread and the conical stabilizing shoulder, pressure integrity of the pipe thread connection is guaranteed.

When a standard triangular thread is used, the connection has two long helical passages through the threads, one along the cut and rounded crest of the thread, and the second along the bottom of the thread. In these connections, even high contact pressures on the mating surfaces generated during the assembly process, cannot ensure that leakage will not

Figure 10. Complete ADP Assembled Using Hot Technology

occur at high mud pressures and variable loads. The pipe-thread connection may stay pressure-tight in practice over a long period of time if the screw passages are properly filled with a thread compound that has high viscosity, adhesion, and high chemical resistance which prevents it from being destroyed and displaced by the mud while drilling.

Experience with ADP fitted with a triangular thread indicates that epoxy-based compounds are able to efficiently seal the pipe thread. These compounds spread evenly during the assembly process over the surface of the thread connection. After curing, they turn into a tough, impermeable body with high adhesion to metal, resistance to chemicals, and strength under variable loads. The cured compound becomes integral with the joint/thread connection.

US-1 is the most widely used sealing compound. US-1 includes a compound composed of resin, plasticized with polyether and thiokol, and an extender that increases the sealing ability of the compound, which consists of a mixture of graphite, lead, and zinc/copper powders. The compound cures at different rates depending on temperature. Complete polymerization of US-1 compound at 5-10°C takes place in about 4.5 hours; at 20°C in 2 hours and 20 minutes; at 30°C in 1 hour and 40 minutes; at 50°C in 30 minutes.

Prior to the sealant being applied, the thread is properly cleaned, washed, and degreased. The joint sealant is spread on the pipe thread and evenly distributed over the surface from the small diameter side on two-thirds of the thread length. After the sealant has been put on the thread, the pipe and tool joint are screwed together. During this operation the compound evenly spreads over all fillets of the thread connection. The excess sealant is squeezed out into a tapered bore of the tool joint from the large thread diameter side.

Forty grams of sealant are required to seal each thread connection of 73- to 114-mm (2⅞- to 4½-in.) ADP and 60 g are required for 129- to 170-mm (5- to 6.7-in.) ADP.

4. ADP Designs and Applications

4.1 General Information

Industrial manufacturing of various standard sizes of ADP came about as a result of a number of factors, such as the variety of geological and technical conditions of drilling, the ability to manufacture pipes of various lengths and diameters from aluminum alloys using the hot extrusion method, as well as a large amount of scientific research and engineering work. ADP drill pipes allow drilling wells for a variety of purposes.

Since 1980, designs and sizes of ADP most widely used in drilling are manufactured in Russia in accordance with the state standard (GOST 23786-79). Currently the international standard for ADP, "Aluminum Alloy Drill Pipe For Petroleum And Natural Gas Wells: Specification" (ISO-15546), is almost completed. Based on the Russian standard (GOST 23786-79), the following types of ADP are manufactured: ADP with internal upset ends, with external upset ends, and with a protection upset in the middle of the pipe. Wall thickness varies from 9 to 17 mm (0.35 to 0.67 in.); length varies from 5.5 to 12 m (18 to 39 ft), depending on the type and specification. ADP may be delivered as lengths, and with screwed on tool joints. The tool joints may be screwed on a standard triangular thread with the required torque applied ("cold" assembly), and on a trapezoidal thread with a tapered stabilizing shoulder using a thermal assembling method ("hot" assembly).

Table 7 summarizes the basic requirements and mechanical characteristics of a material for steel tool joints.

Table 7. Requirements for Steel Tool Joints

CHARACTERISTIC	UNITS	REQUIREMENT
Tensile strength, S_u	N/mm^2	880 min
Yield strength, $S_{0,2}$ (0.2% offset method)	N/mm^2	735 min
Elongation after fracture, A (see note) ($L_o=5.65\sqrt{F_o}$)	%	13 min
Impact strength, KCV (21°C)	J/m^2	$685 \cdot 10^3$ min
Brinell hardness	HB	280-340

Note: If other gauge lengths are used, the corresponding elongation values shall be obtained in accordance with ISO 2566. In cases of dispute, gauge length, $L_o=5.65\sqrt{F_o}$ (F_0-initial cross-sectional area).

4.2 ADP with Internal and External Upset Ends

Figure 11 presents ADP designs with internal (left), external upset ends (middle) and protection upset (right). Tables 8 and 9 summarize their dimensions.

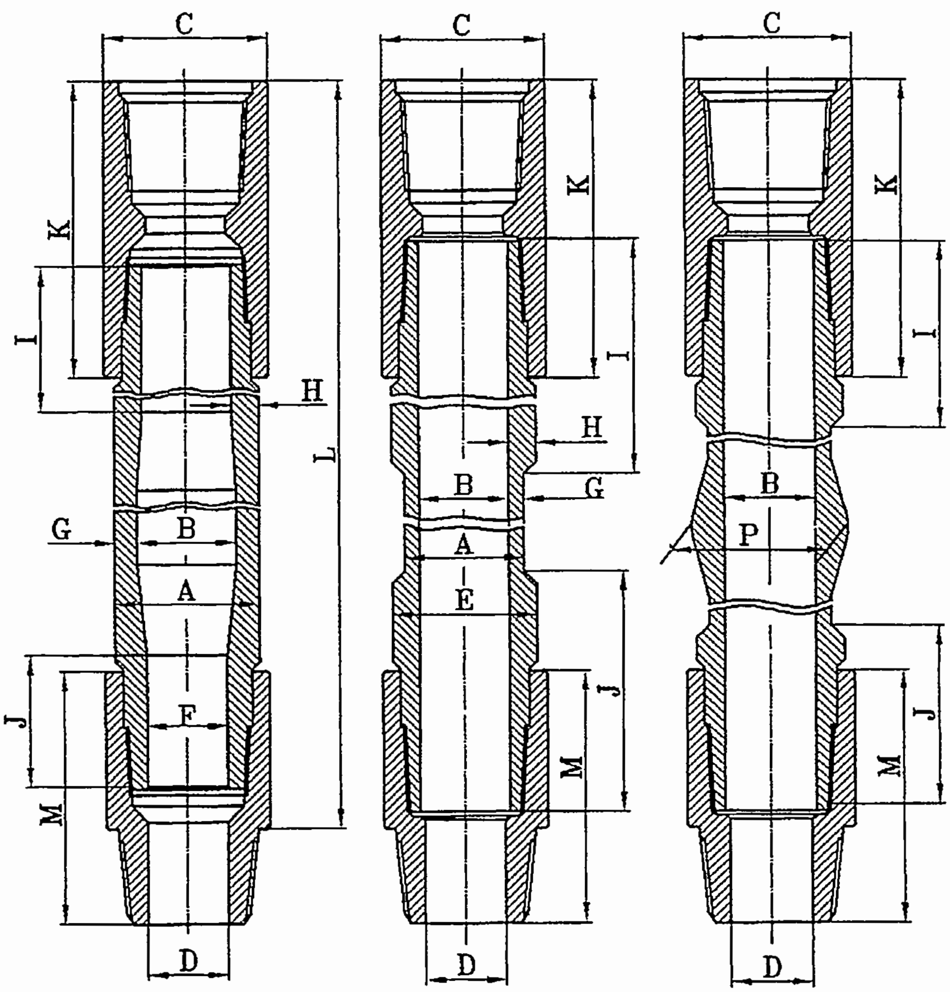


Figure 11. ADPs with Tool Joints (left: internal upset ends; middle: external upset ends; right: protection upset

ADP manufactured from two types of alloys, D16T and 1953T1, were most widely used in drilling. Table 10 summarizes technical parameters for ADP with internal upset ends from D16T alloy, and Table 11 from 1953T1 alloy.

Table 12 shows technical parameters of ADP with external upset ends from D16T alloy, and Table 13 from 1953T1 alloy.

Table 8. ADP with Internal Pipe End Upset (see Figure 11; left)

	DESCRIPTION	UNITS	PIPE 2⅞" (73MM)	PIPE 3½" (90MM)	PIPE 4-1/16" (103MM)	PIPE 4¼" (108MM)	PIPE 5" (129MM)	PIPE 5.8" (147MM)	PIPE 5.8" (147MM)	PIPE 5.8" (147MM)
1	Pipe length-L	mm	9300	9400	9500	9500	12400*	12400*	12400*	12400*
2	Pipe body x section	cm^2	18.1	22.5	26.3	28.0	40.8	47.0	54.7	62.2
3	Wall thickness:									
	-G	mm	9	9	9	9	11	11	13	15
	-H		16	16	15	17	17	17	17	17
4	Upset length ends:									
	-box side –I	mm	200	300	1000	1000	1300	1300	1300	1300
	-pin side –J		200	200	250	250	250	250	250	250
5	Nominal diameter:	mm								
	-A		73	90	103	108	129	147	147	147
	-B		55	72	85	90	107	125	121	117
	-F		41	58	73	74	95	113	113	113
6	ID-joint D	mm	41	58	70	70	95	110	110	110
	CD-joint C		90	108	120.6	120.6	155	178	178	178
	Box member –K		200	215	285	285	325	350	350	350
	Pin member-M		220	240	285	285	300	350	350	350
7	Open end displacement	1/m	2.04	3.28	3.47	3.7	5.24	6.12	6.49	6.9
8	Capacity	1/m	2.375	4.07	5.67	6.36	8.99	12.27	11.49	10.75
9	Thread connection type		2⅞ "Reg	3½"Reg	3½" IF	3½" IF	NC-50	5½" FH	5½"FH	5½" FH

Pipe lengths range from 9000 to 12,000 mm (29.5 to 39.4 ft)

Table 9. ADP with External Pipe End Upset (see Figure 11; middle)

	DESCRIPTION	UNITS	PIPE 5⅛" (131MM)	PIPE 5½" (140MM)	PIPE 6½" (164MM)	PIPE 6⅝" (168MM)
1	Pipe length-L	mm	9000	9000	9000	9000
2	Pipe body x section	cm^2	48.2	51.84	43.8	54.2
3	Wall thickness:	mm				
	-G		13.0	13.0	9.0	11.0
	-H		21.0	33.0	20.0	20.0
4	Upset length ends:	mm				
	-box side –I		1400	1400	1400	1400
	-pin side –J		1400	1400	250	250
5	Nominal diameter:	mm				
	-A		131	140	164	168
	-B		105	114	146	146
	-E		146/132 (cone)	147/140	186	186
6	ID - joint D	mm	105	110	127	127
	OD - joint C		178	178	203	203
	Box member - K		350	350	320	320
	Pin member - M		350	350	320	320
7	Thread connection type		5½" FH	5½" FH	6⅝" FH	6⅝" FH

Table 10. ADP with Internal Upset (D16T Alloy)

	DESCRIPTION	UNITS	PIPE 2⅞" (73 MM)	PIPE 3½" (90 MM)	PIPE 4-1/16" (103 MM)	PIPE 4¼" (108 MM)	PIPE 5" (129 MM)	PIPE 5.8" (147 MM)	PIPE 5.8" (147 MM)	PIPE 5.8" (147X15)
1	Axial load	kN								
	- Max. operate (0.85 S_U)		500	650	720	775	1120	1290	1500	1730
	- Max. allowed (S_U)		600	845	870	1000	1460	1680	1950	2030
2	Torque	kN-m								
	- Max. operating		7.1	12.5	15.8	19.0	30.5	40.9	46.4	52.3
	- Max. allowed		8.5	14.9	18.8	22.6	36.3	48.7	55.2	61.5
3	Max. operating external pressure	MPa	47.0	43.0	29.5	29.0	295	24.0	32.0	39.0
4	Max. operating internal pressure	MPa	54.0	50.0	38.4	37.0	375	33.0	39.0	43.0
5	Approx. weight of one pipe (with joint)	kg	53.0	71.4	87.4	97.8	173.6	204.6	230.6	256.7
6	Unit weight:	kg/m								
	- in air		5.7	7.6	9.2	10.3	14.0	16.5	18.6	20.7
	- in water		3.6	4.8	5.8	6.5	8.9	10.4	11.8	13.1
7	Pipe body cross section	cm^2	18.1	22.5	26.3	28.0	40.8	47	54.7	62.2

Table 11. ADP with Internal Upset (1953-T1 Alloy)

	DESCRIPTION	UNITS	PIPE 2⅞" (73 MM)	PIPE 3½" (90 MM)	PIPE 4-1/16" (103 MM)	PIPE 4¼" (108 MM)	PIPE 5" (129 MM)	PIPE 5.8" (147 MM)	PIPE 5.8" (147 MM)	PIPE 5.8" (147 MM)
1	Axial load	kN								
	- Max. operating (0.85 S_U)		600	790	880	940	1360	1560	1800	2076
	- Max. allowable (S_U)		720	1030	1150	1220	1770	2030	2340	2436
2	Torque	kN-m								
	- Max. operating		8.5	15.0	19.0	22.8	36.6	49.0	55.6	62.8
	- Max. allowed		10.2	18.0	22.8	27.4	44.0	59.0	66.2	73.8
3	Max. operating external pressure	MPa	70.5	64.5	44.2	435	44.2	36.0	48.0	58.5
4	Max. operating internal pressure	MPa	81.0	75.0	57.6	55.5	56.2	49.5	58.5	64.5
5	Approx. weight of pipe (with joint)	kg	53	71.4	87.4	97.8	173.6	204.6	230.6	256.7
6	Unit weight:	kg/m								
	- in air		5.7	7.6	9.2	10.3	14.0	16.5	18.6	20.7
	- in water		3.6	4.8	5.8	6.5	8.9	10.4	11.8	13.1

Table 12. ADP with External Upset (D16T Alloy)

	DESCRIPTION	UNITS	PIPE 2⅞" (73 MM)	PIPE 3½" (90 MM)	PIPE 4-1/16" (103 MM)	PIPE 4¼" (108 MM)	PIPE 5" (129 MM)	PIPE 5.8" (147 MM)	PIPE 5.8" (147 MM)	PIPE 5.8" (147X15)
1	Axial load	kN								
	- Max. operate (0.85 S_U)		500	650	720	775	1120	1290	1500	1730
	- Max. allowed (S_U)		600	845	870	1000	1460	1680	1950	2030
2	Torque	kN-m								
	- Max. operating		7.1	12.5	15.8	19.0	30.5	40.9	46.4	52.3
	- Max. allowable		8.5	14.9	18.8	22.6	36.3	48.7	55.2	61.5
3	Max. operating external pressure	MPa	47.0	43.0	29.5	29.0	295	24.0	32.0	39.0
4	Max. operating internal pressure	MPa	54.0	50.0	38.4	37.0	375	33.0	39.0	43.0
5	Approx. weight of one pipe (with joint)	kg	53.0	71.4	87.4	97.8	173.6	204.6	230.6	256.7
6	Unit weight:	kg/m								
	- in air		5.7	7.6	9.2	10.3	14.0	16.5	18.6	20.7
	- in water		3.6	4.8	5.8	6.5	8.9	10.4	11.8	13.1
7	Pipe body cross section	cm^2	18.1	22.5	26.3	28.0	40.8	47	54.7	62.2

Table 13. ADP with External Upset (I953-TI Alloy)

	DESCRIPTION	UNITS	PIPE 5⅛" (131 MM)	PIPE 5½" (140 MM)	PIPE 6½" (164 MM)	PIPE 6⅝" (168 MM)
1	Axial load	kN				
	- Max. operating (0.85 S_U)		2090	2157	1900	2350
	- Max. allowed (S_U)		2450	2538	2250	2750
2	Torque	kN-m				
	- Max. operating		72.0	75.0	61.0	78.0
	- Max. allowed		85.0	88.0	72.0	92.0
3	Max. operating collapse	MPa	35.0	38.0	26.0	33.0
4	Max. operating burst	MPa	53.0	56.0	40.0	49.0
5	Approx. weight of one pipe (with joint)	kg	188.0	195.0	170.0	210.0
6	Unit weight:	kg/m				
	- in air		20.9	21.5	18.9	23.3
	- in water		13.9	14.6	12.8	15.7

4.3 ADP with Protection Upset

Several standard sizes of ADP are manufactured with a protection upset in the middle of the pipe to protect the main body from wear and to increase pipe strength. Figure 11 (right) shows a schematic of ADP with a protection upset, and Table 14 summarizes pipe geometry.

Table 14. Dimensions of ADP with Protection Upset (see Figure 11; right)

Main Pipe Body OD (A) (mm)	Protection Upset OD (P) (mm)	Wall Thickness (mm)			Taper Length (mm)		Protection Upset Length (mm)
		End Upset (H)	Pipe Body (G)	Protection Upset	Box Side (I)	Pin Side (J)	
129	150	17	11	21.5	1300	250	300
147	172	17	11	23.5	1300	250	300
168	197	20	11	25.5	1300	250	300

ADP with a protection upset has been most widely used in drilling directional and horizontal wells. This modification has proven to be efficient for protecting casing strings from galling.

4.4 Integral-Joint ADP

Specific physical and mechanical properties of aluminum alloys (such as low surface hardness and the potential to be drilled out easily) allowed the development of a new pipe design, the so-called integral-joint pipe. These pipes do not have steel tool joints, and, hence, they do not have pipe threads for connection with tool joints. A coarse joint thread cut on the internal or external upset ends connects the pipes. Field experience with these pipes with 5½-in. FH joint thread indicated that, within the allowable range of torque, these types of connections are able to withstand 140-160 make-ups and breakouts. Considering that pipes are fabricated with extended upset ends, recutting (repairing) a joint thread does not present any difficulty.

Figure 12 shows the design of the integral-joint ADP. Table 15 presents technical parameters of these pipes.

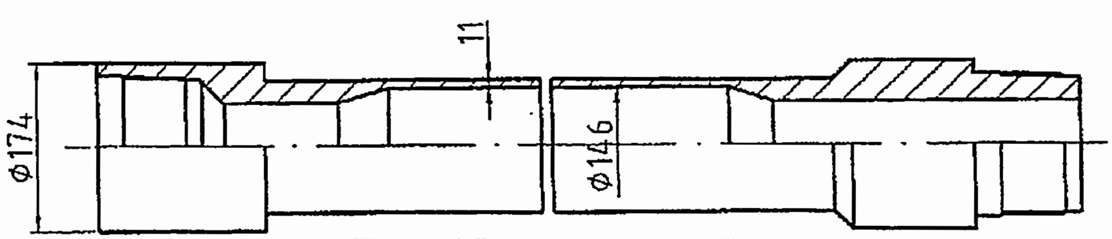


Figure 12. Integral-Joint ADP

Integral-joint pipes are widely used in drilling directional and horizontal wells, as well as for running casing liner on the drill string.

While drilling directional and horizontal wells, the borehole position must be continuously monitored. Integral-joint ADPs are used for the lower section of the drill string for this purpose. The non-magnetic properties of these pipes and absence of steel tool joints allow drift surveys directly through the drill string using geophysical methods, which reduces time for this operation.

Integral-joint ADPs are also used for the lower section of the drill string while running casing liners in complicated boreholes with high risk of drill-string sticking while cementing due to cement entering the annulus across from the drill pipe. In case of a failure, integral-joint ADP are easily drilled out, thus reducing time required for recovery of the hole.

Table 15. Technical Characteristics of Integral-Joint ADP (Alloy D16T)

DIMENSIONS	OD OF DRILL PIPE (MM)						
	127*	146*	146*	146*	164**	168**	172*
Pipe Length (mm)	12,400	12,400	12,400	12,400	11,500	11,500	11,500
Wall Thickness (mm):							
Pipe body	11	9	11	13	9	11	13
Upset ends	30	34	34	34	19.5	19.5	19.5
Upset Length of drill pipe (mm):							
Box side	350	350	350	350	250	250	250
Pin side	350	350	350	350	250	250	250
Cross-sectional area of pipe body (cm^2)	40.4	38.7	46.6	54.3	43.8	54.2	64.9
Tensile Load (kN):							
Allowable	1050	1000	1200	1450	1150	1400	1700
Limit	1300	1250	1500	1800	1450	1750	2150
Ultimate (by strength limit)	1900	1800	2200	2550	2050	2550	3050
Torque (kN-m):							
Allowable	255	330	390	440	430	535	645
Limit	355	410	485	550	525	670	810
Internal Pressure (MPa):							
Allowable	46	32	39	46	29	35	40
Limit	57	40	49	58	36	43	50
Mass:							
Overall pipe (kg)	153	196	200	220	153	183	213
Unit mass (kg/m)	12.4	15.8	16.1	17.7	13.3	15.9	18.5

* Internal upset drill pipe ** Internal-flush drill pipe

4.5 Thick-Wall ADP (ADC)

Heavy-wall ADC (Aluminum Drill Collars) are manufactured with integral joints or with steel tool joints. Just like standard integral-joint ADP, heavy-wall integral-joint ADC may be used for drilling directional and horizontal wells for drift surveys through the drill string. In addition, these pipes are used in BHAs for a smoother transition in rigidity from drill collars to drill pipes. Figure 13 shows the design of an integral-joint heavy-wall ADC.

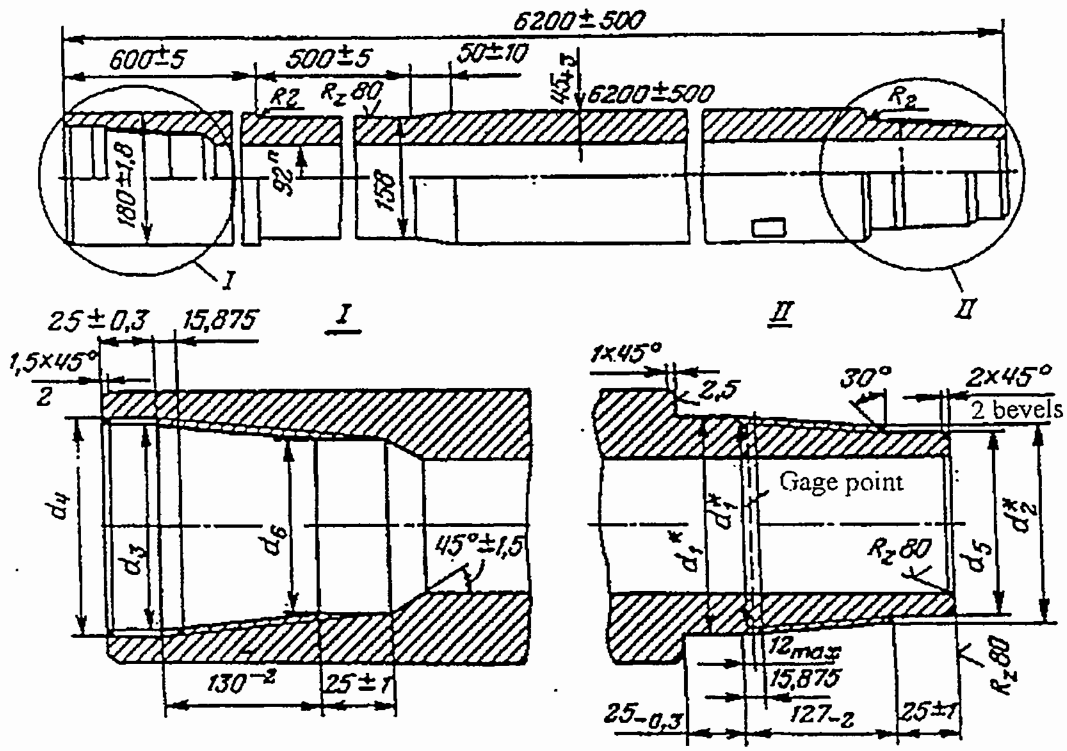


Figure 13. Thick-Walled Aluminum Drill Collar (ADC)

Fluted or spiral grooved drill collars are widely used in drilling practice. During their application, the area of their surface in contact with the borehole walls is smaller than with standard drill collars, while diametric clearance between the borehole walls and the outside surface of the pipes remains the same or is even larger. This fact is instrumental in lowering the risk of sticking the lower section of the drill string due to differential pressure (difference between the formation pressure and the hydrostatic well pressure), as well as in stabilizing the BHA at the hole bottom. Spiral grooved drill collars, which create turbulence in the mud flow, allow control of the return flow in the annulus. This allows increased bottom-hole cleaning from drill cuttings and increases drilling efficiency.

Spiral grooves on the external surface of steel drill collars (DC) are machined on specially equipped machine tools. The machining method has relatively low efficiency and leads to high costs for fluted DC. Spiral grooves can be formed on heavy-wall ADC during the extrusion process, without the need for machining. Die configuration and speed of the piercing stub mandrel during the extrusion process control the formation of desired groove parameters (number of grooves, screw pitch, helix elevation angle, etc.). Figure 14 shows the design of a heavy-wall fluted ADC.

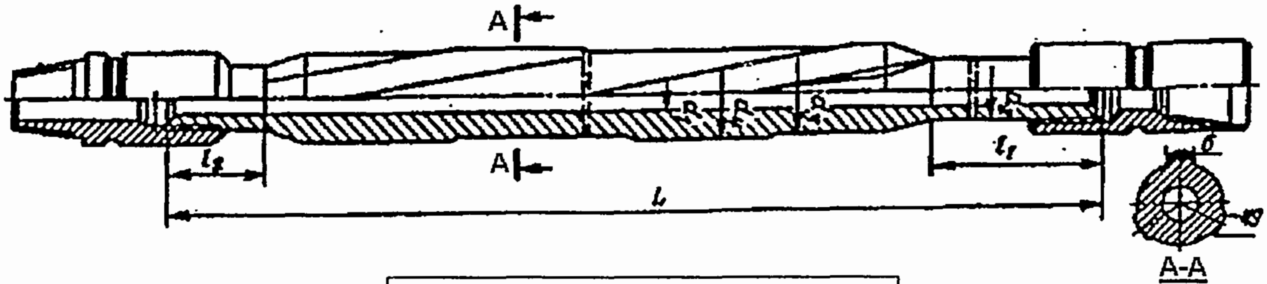


Figure 14. Heavy-Wall Fluted ADC

The joint thread of an integral heavy-wall ADC is cut on the corresponding upset ends. For an assembled heavy-wall ADC, two types of threads are cut on the pipe: triangular threads for "cold" assembly with steel tool joints, and trapezoidal threads for "hot" assembly.

Field operations with heavy-wall ADC by the companies Samaraneft and Mangyshlakneft showed high efficiency that included the following:

- Paramagnetic properties of the pipes
- High vibration damping
- BHA stabilization
- Decreased number of BHAs stuck due to fluted design
- Turbulence in the mud due to fluted design

Issues related to the high damping ability of ADP and heavy-wall ADC will be described in a section below.

Table 16 summarizes technical parameters of heavy-wall ADC.

Table 16. Technical Parameters of Heavy-Wall ADC

Pipe dimensions (mm)	146 x 80	159 x 80	180 x 92
Elevator groove diameter (mm)	129	140	146
Pipe hole cross-sectional area (cm^2)	50.2	50.2	67.6
Pipe body axial moment of inertia (cm^4)	2028	2935	4767
Pipe body polar section modulus of the elevator groove (cm^3)	359	481	512
Unit mass of pipe body (kg/m)	32	41	51
Allowable tension load (safety factor = 1.2)	1450	2150	2500
Critical length when ADC loses longitudinal stability under own weight (m)	22	26	34
Recommended torque for assembling one-piece connections (kN·m)	15	19	25

4.6 ADP for Exploratory Drilling

In Russia, ADP has been used in exploratory drilling for over 30 years. Originally ADP was introduced to reduce labor for drilling crews for drilling exploratory wells in remote, hard-to-reach areas, especially during transportation of drilling equipment. Later, ADP became widely used in all regions of exploratory drilling.

The weight of ADP shown above for exploratory drilling is 2 to 2.5 times less than the weight of similar-purpose SDP. This allowed a reduction in drilling crew labor, as well as drilling deeper wells with the same type rigs.

Figure 15 shows two types of ADP used in exploratory drilling: 1) with pin (ADPP) and 2) box (ADPB) joints.

The industry manufactures five standard sizes of ADP for exploratory drilling:

- 24-mm ADP with 4.5-mm and 8.0-mm wall thickness and 1.3-m length (0.95-in. ADP with 0.177- and 0.315-in. wall thickness and 51-in. length)

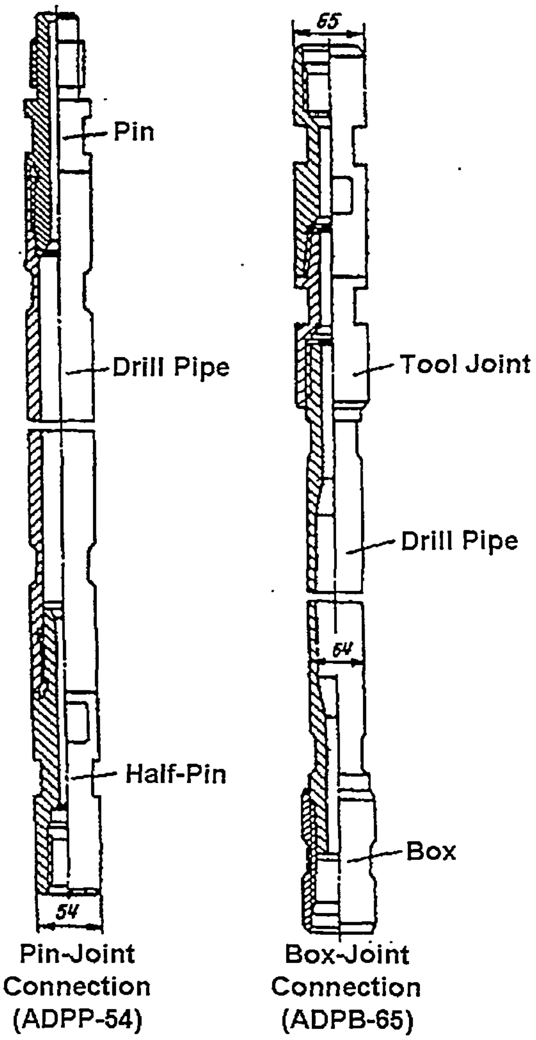


Figure 15. Joints of Pin-Joint and Box-Joint ADP

- 34-mm ADP with 6.5-mm and 11.0-mm wall and 1.3- and 2.9-m lengths (1.34-in. ADP with 0.256- and 0.433-in. wall thickness and 4.3- and 9.5-ft lengths)
- 42-mm ADP with 7.0-mm and 14-mm wall and 4.3-m length (1.65-in. ADP with 0.276- and 0.551-in. wall and 14.1-ft length)
- 54-mm ADP with 9.0-mm and 16-mm wall and 4.4-m length (2⅛-in. ADP with 0.354- and 0.630-in. wall and 14.4-ft length)
- 71-mm ADP with 8.0-mm wall and 6.2-m length (2.8-in. ADP with 0.315-in. wall and 20.3-ft length)

Comparative tests of ADP and SDP in various regions under various geological and technical drilling conditions revealed better performance of ADP. For example, utilization of ADPP-54 allowed increasing drilling depth of 500 m with the same type of rigs. Also, rate of penetration was 15-30% higher, drilled meterage per run increased by 6-13%, and tripping time was reduced by 11-15%.

The maximum well depth drilled with ADPP-71 was 3000 m (9842 ft).

4.7 Aluminum Pipes in Workover Operations

Well workovers include a variety of operations. Operations to correct problems are the most crucial and time-consuming. These include releasing and removing collapsed tubing, stalled submersible pumps, packers, cable, etc. These operations normally require several trips of the drill string, which leads to an increase in tripping time. In wells with 2200-2500 m TD, tripping operations normally take 30-50% of the total time of a workover. This also results in high consumption of fuel and lubricants, drill line, brake shoes, as well as increased rig maintenance time. Addressing failures related to stuck downhole equipment requires mobilization of pulling units with capacity significantly higher than the weight of the drill string, considering drag. Workovers include a significant number of production casing patching operations.

Special ADP for well workover and completion was developed and utilized, based on an analysis of workover operations and ADP manufacturing technology. Figure 16 shows these integral joint pipes; Table 17 gives their technical parameters.

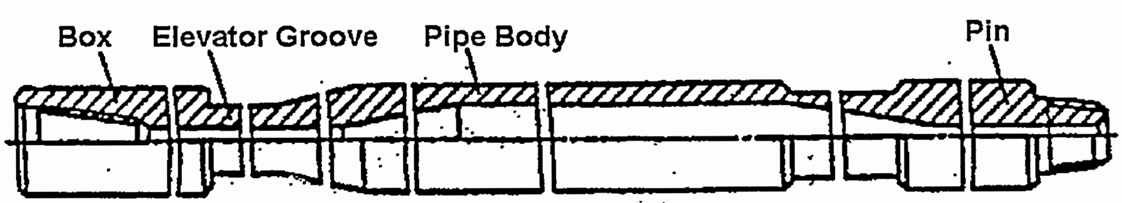


Figure 16. ADP for Workovers and Completions

Table 17. Integral-Joint ADP for Workovers and Completions

PIPE PROPERTIES	PIPE DIMENSIONS	
	95 x 9	108 x 8
OD (mm)	95	108
Pipe length (mm)	9000	9000
Pipe body wall thickness (mm)	9.0	8.0
Outside groove diameter (mm) on Box side on Pin side	 74 90	 89 102
ID of upset ends (mm)	42	56
Unit mass (kg/m)	7.8	9.2
Tensile Load (kN) Allowable Limit	 650 780	 900 1080
Torque, (N m) Allowable Limit	 7500 9000	 13200 15800
Internal pressure (MPa) Allowable Limit	 52.0 62.5	 40.5 49.0
Type of tool-joint thread	2 7/8 Reg	3 1/2 Reg

Utilization of these pipes by the companies Samaraneft, Yuganskneftegaz, and Nizhnevartovskneftegaz showed a 2- to 3-fold decrease in time for operations, as compared to SDP in similar conditions. The cost of the workovers was also lower by 20-30%.

4.8 Tubing from Aluminum Alloys

Tubing is widely used in the oil and gas industry for various operations related to completion, production, well workovers and downhole repair, and well stimulation. A diversity of functions performed by the tubing string results in a variety of applied forces. The principal forces affecting tubing in operation include axial force that stretches a string under its own weight, and external and internal pressures. A tubing string is also exposed to bending forces in directional intervals of a borehole, drag forces that resist axial movement of the string, and temperature loads from variation of fluid temperatures in the borehole.

A tubing string in the well is exposed to aggressive media that may change composition over time. This affects reliability and durability of tubing. Since specific strength and corrosion resistance are critical parameters for selection of material for tubing, utilization of aluminum alloys is quite promising. Maximum length of a uniform ADP tubing string fits operational requirements of the deepest oil wells. The weight of these strings in a well is 3-4 times lower than the weight of a steel pipe string with the same safety factor. Therefore, hook-load capacity and drive capacity of mobile workover rigs may be correspondingly reduced.

Aluminum pipes have lower hydraulic resistance than steel pipes due to lower roughness of the internal surface and reduced friction factor. Transportation cost of tubing from aluminum alloys is significantly lower, especially while delivering pipes to inaccessible areas. These advantages were instrumental in the development in Russia of standard assembly tubing from aluminum alloys with internal upset ends and tool joints. Table 18 summarizes their parameters.

Table 18. Properties of Tubing from Aluminum Alloys

OD (MM)	WALL THICKNESS (MM)	TOOL JOINT OD (MM)	UNIT MASS WITH TOOL JOINT (KG/M)	SHEARING LOAD OF THREAD (KN)	ALLOWABLE PRESSURE (MPA)	
					INTERNAL	EXTERNAL
60	6	73	2.95	196	56.0	52.0
73	7	89	4.28	296	52.0	45.0
89	7	107	5.25	360	43.5	39.0
102	7.5	121	6.66	410	40.0	38.0
114	8	132	7.66	495	39.0	38.5
114	8.5	132	8.17	495	41.5	38.5

Integral-joint aluminum tubing with internal flush ends is highly promising. Figure 17 shows tubing design. This tubing is widely used in Western Siberia in wells with high flow rates.

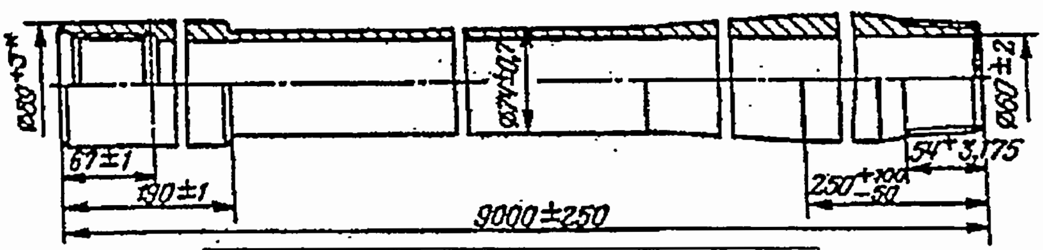


Figure 17. Integral-Joint Aluminum Tubing

4.9 Potential for Manufacturing Aluminum Casing

Practical experience has shown that integral-joint ADP can be easily drilled out (similar to a medium-hard rock). This feature can be used for developing drillable casing liners. These would be capable of reliably isolating problem intervals in a borehole. Then, while drilling through the next problem interval, the liner set above can be drilled out to keep the same diameter of borehole. After the whole interval has been drilled through, a new liner can be run to isolate it.

This idea was tested by Samaraneft while drilling a deep well. A 250-mm (9.8-in.) integral-joint aluminum liner with 10-mm (0.39-in.) walls was set at 2650-3450 m. The drill string made about 150 trips through the liner without any visible damage to it. Similar work was done by Bashneft when in a pilot trial 220-mm (8.66-in.) aluminum casing pipe was set.

Drillable aluminum liners can reduce lost circulation, water, oil, and gas shows, and efficiently eliminate other complications while drilling.

Aluminum alloys are not affected by hydrogen sulfide. Current problems with ensuring reliability of steel casing exposed to hydrogen sulfide, and the deficiency and high cost of special steel alloys for pipes run in aggressive media with hydrogen sulfide, prompt work to continue on the development of casing from aluminum alloys that are specially selected for these harsh operating conditions.

Research efforts are aimed at resolving the following problems:

- The elastic modulus of aluminum alloys is 3 times lower than steel. This factor reduces casing resistance to collapse pressure. This should be taken into account while developing a new pipe design.
- Corrosion of aluminum alloys is relatively intense in media with a pH>9.5. Therefore, the effect of a cement slurry contacting aluminum casing must be analyzed. Special protective measures must be developed, if deemed necessary.

A Russian company (Samaraneft) has had long-term experience with the first aluminum production string. Integral-joint ADP with internal flush ends was used for casing. 168-mm pipes with 11-mm walls and 185-mm external upset ends manufactured from D16T alloy (Figure 18), were run in well No. 134 with a 1376 m TMD. A 1195-m string (118 joints) was set at 45-1240 m. During assembly of the string, the pipes thread connections were sealed with an epoxy-based self-curing compound. Prior to running, four layers of a bakelite and epoxy compound were applied to the pipes. After the string was set and cemented, it was pressure tested to 14.3 MPa. The well flowed initially at 25 m^3/day. Then it was transferred to artificial-lift production with an electric submersible pump run on a steel tubing string.

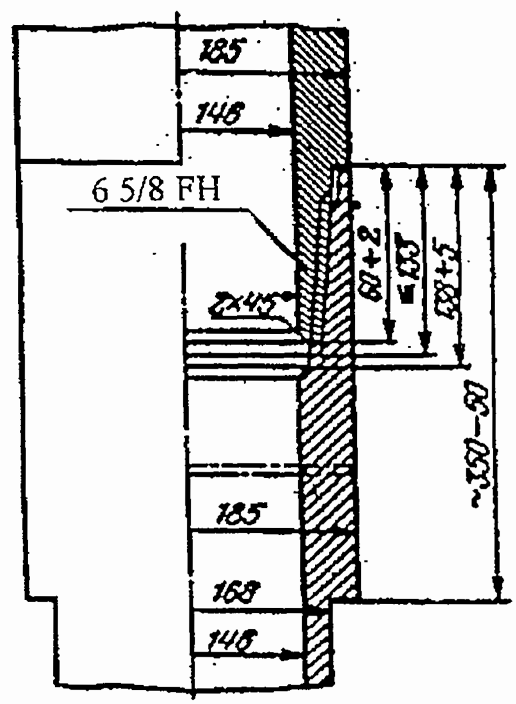


Figure 18. Internally Flush ADP used as Casing

Since that time, the pump has been pulled over 15 times for repair. The string assembled from integral-joint ADP has been in operation for over 10 years without any failures.

This experience indicates the necessity of intensive research and design work to develop and use aluminum casing. These pipes should be applied in wells with hydrogen sulfide. Also, they should be used in wells located in inaccessible areas, with low-capacity rigs, as well as in drilling wildcat and exploratory wells.

4.10 Potential for Manufacturing Aluminum Marine Risers

The experience gained in ADP design, fabrication and exploitation testify to the possibility of using the 1953 alloy for tubulars for various purposes in the offshore environment. It now appears to be possible to extrapolate from that experience and to consider designing aluminum risers. These risers could be several kilometers long. Experience gained by the marine, military and aerospace industries (which recently became available) confirms that aluminum tubes of 20-in. OD and greater can be fabricated by extrusion.

The idea to develop aluminum risers for the Baikal Lake Scientific Drilling Project (BDP) originated in the State enterprise "Nedra" in Yaroslavl, Russia. The 500-m (1640-ft) long prototype riser of 9⅝-in. diameter was fabricated in 1995 and successfully deployed in 1998. It was made up of 9-m (29.5-ft) long pipes made of D16T alloy with 240-mm (9.45-in.) OD, 220-mm (8.66-in.) ID and external upsets to 270-mm (10.63-in.) OD. The upsets allow the pipes to be connected directly without using steel tool joints. The resulting weight in air of the riser tubes is 25 kg/m (16.8 lb/ft) (weight in water 16 kg/m; 10.7 lb/ft).

The preliminary analysis made in 1995 showed that the design and fabrication of a slim riser 245-300 mm (9.6-11.8 in.) diameter and 3-4 km (9842-13,123) in length is feasible using existing Russian technology. These calculations brought the idea to introduce aluminum tubes as a potential material for production risers along with steel and titanium. A proposal for including aluminum tubes made of D16T or 1953 alloys was presented to the ISO working group on the Standard "Design of Risers for Floating Production Systems and Tension-Leg Platforms." The major concern here is the long-term corrosion and fatigue durability of aluminum pipes, which can be evaluated on the basis of special experimental studies only.

The next logical step was an analysis of aluminum drilling risers (ADR). Such a study was conducted in 1997-1998. The program RISOPT was used to evaluate ADR deployment at the Campos Basin offshore Brazil (2700 m water depth) (example 1) and offshore Japan in the Pacific Ocean (4000 m water depth) (example 2). The riser considered was of standard design: 19 in. (485 mm) ID with five auxiliary lines (choke and kill, booster, two hydraulic). All pipes were to be made of aluminum alloys similar to 1953-T1 and all connectors are steel. No buoyancy elements have been used.

Results of optimization of the ADR main pipe wall thickness are presented in Table 19 and Figure 19. The main pipe wall thickness for three riser sections was calculated based on a safety factor not less then 1.65 at all riser cross-sections. This value was determined on the basis of API recommendations (1.5 times yield strength plus 10% additional because bending stresses are present). The manufacturing of aluminum pipes with these calculated dimensions as well as complete ADR sections development appears viable.

Table 19. Aluminum Drilling Riser Calculation Results

EXAMPLE NUMBER	MUD DENSITY (KG/M^3)	RISER SECTION LENGTH (M)			RISER SECTION MAIN PIPE WALL THICKNESS (MM)		
		LOWER	MIDDLE	UPPER	LOWER	MIDDLE	UPPER
1	2000	670	1690	340	31.0	24.5	27.5
2	1550	510	2380	1110	24.5	22.0	27.5

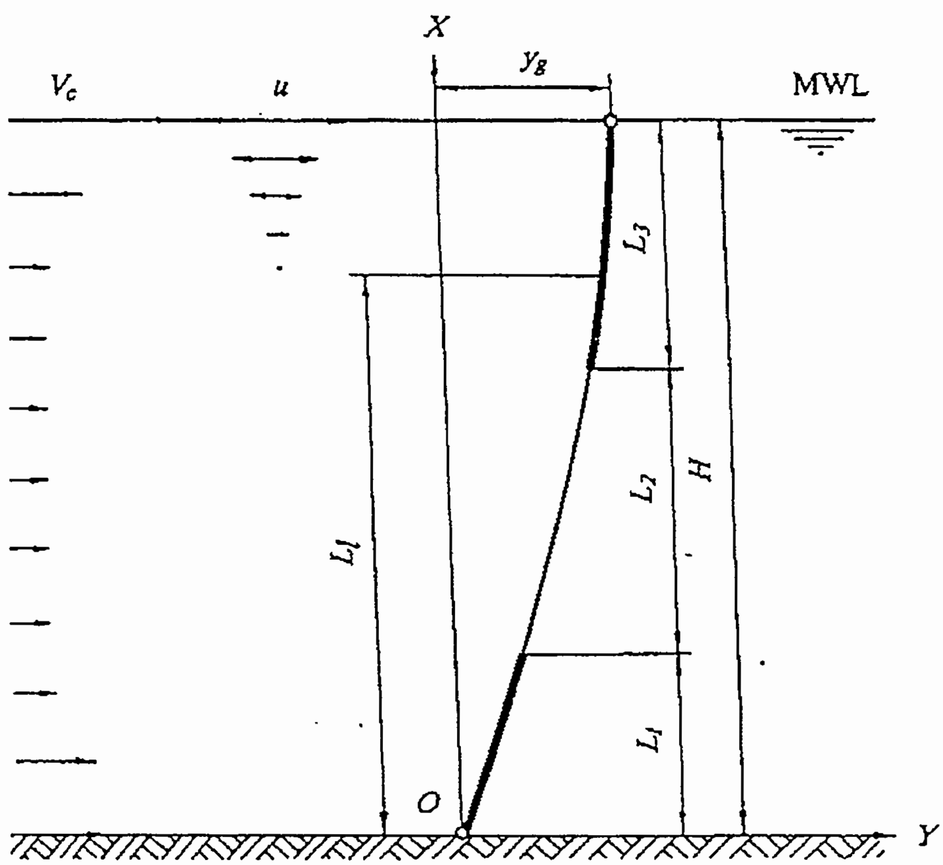


Figure 19. Designing Aluminum Drilling Riser

The anticipated benefits of applying ADR in the offshore environment include the following:

- Less total riser system weight
- Less time for riser assembly/disassembly
- Potential to reach greater water depths with the same platforms and rig equipment

5. Experience with ADP

5.1 ADP Operation at the Rig Site

The techniques for running ADP at the rig site are an important element in total drill-pipe operations. The reliability and durability of a drill string is impacted by the quality of the operation. When received at the drilling site, joints of ADP are assembled into a drill string in strict conformity with the design calculations used to determine its configuration.

Special attention should be given to the tool-joint threads of drill pipes. Working and idle connections should be switched every 40-50 trips to ensure uniform wear. This can be accomplished by unscrewing the upper pipe of the drill-pipe stand during the next trip, and by unscrewing idle connections. The same sequence of operations should be observed during downhole trips.

Tool joints are made up by applying torque to the specified value for each joint type. Recommended torques with the application of thread lubricants are given in Table 20.

Table 20. Torques for Tool-Joint Make-up with Anti-friction Thread Lubricants

TOOL JOINT THREAD TYPE	RECOMMENDED TORQUE (KN·M)
Z-147 (5½ FH)	26.0-28.5 (19-21x10^3 ft-lb)
Z-171 (6⅝ FH)	35.0 - 37.0 (26-27x10^3 ft-lb)

Operation of a pipe string with length exceeding 500 m (1640 ft) requires not only replacement of working joints in one drill-pipe stand but also changing the drill stand arrangement of the entire string, again to ensure uniform wear of each joint.

It is necessary to add mud into the drill string to avoid collapsing ADP when tripping in while drilling with heavy muds or at greater depths. The height of the drilling mud column required inside the string is determined by the formula:

$$h = H \cdot n \cdot P / \gamma_i \qquad (5\text{-}1)$$

where:

H = the trip depth of the drill string
n = pipe safety factor
P = maximum outside pressure
γ_l = density of mud

If the drill string is constructed of ADP made of various alloys, the recommended temperature limits for their operation as specified above should be strictly observed.

Strings consisting of drill pipes with high initial yield points (when different alloys are used for similar pipe types) should be placed in the upper section of drill string where axial loads are highest.

Continuous monitoring of mud pH must be performed to ensure the pH remains within the range 6.5-9.5. If pH is not within this range, corrosion of aluminum alloys sharply increases.

When downhole problems arise and additional loads must be applied to the drill string, it is necessary to keep track of load dynamics and to document the peak value. After the problem is eliminated, the joints of pipe in which the stresses exceeded the allowable values ($0.85S_{0.2}$) are identified. Careful inspection of pipe surfaces, tool joints and threads should be performed for pipes from these sets. In those problem situations for which torque exceeds the nominal limit, it is advisable to check threaded connections for matching of marks on tool joints and pipes.

In cases when ADP remains in the hole for more than 500 hours without drilling mud circulation, it is necessary to take into account the exposure of every pipe joint to critical temperatures. After removal from the borehole, these joints are withdrawn from the operation, and one lower pipe of each type and size is taken for testing. Tests are needed to determine yield, strength, relative extension and torque to shift the nipple and box in a pipe threaded connection. Values recorded in the tests should be compared with certified performance data.

At the rig site, behavior of the geometrical shape and the condition of drill pipes and tool joints are regularly inspected. The inspection includes measuring tool joint nipple/box shoulder clearance. This clearance is the gap between the nipple and box shoulders in a position of tapered surface contact without rotation.

The pipe OD is checked in the middle and at the pipe fixture on the slips. The arithmetic mean value of two diameter measurements taken perpendicular to one another should be used as pipe OD for calculations.

Principal parameters for ADP during operations are estimated by introducing correction factors as related to new pipes. These factors, given in Table 21, depend on the wear value of pipes, i.e., the wear grade.

To calculate the strength characteristics of ADP, geometrical parameters (cross section, moment of inertia, section modulus and polar section modulus) were determined according to pipe certification data. These parameters are changing during the pipe's life due to wear. According to experimental investigations of wear features, coefficients (K_1; K_2; K_3; K_4) for the main geometrical parameters were defined. The values of these coefficients depend on pipe wall thickness or on wear grade.

- Wear Grade I – no wear (new pipe)
- Wear Grade II – wear of 10 to15% of nominal wall thickness
- Wear Grade III – wear more then 15% of nominal wall thickness

Table 21. Coefficients for ADP Geometrical Parameters

ADP TYPE	ADP WEAR GRADE	FACTOR FOR CALCULATION			
		CROSS SECTION, K_1	MOMENT OF INERTIA, K_2	SECTION MODULUS, K_3	POLAR SECTION MODULUS, K_4
147-11	II	0.80	0.88	0.86	0.87
	III	0.78	0.87	0.84	0.85
147-13	II	0.83	0.90	0.88	0.88
	III	0.81	0.88	0.87	0.87
147-15	II	0.78	0.86	0.85	0.85
	III	0.76	0.84	0.83	0.83
147-17	II	0.79	0.88	0.87	0.87
	III	0.78	0.85	0.84	0.85
164-9	II	0.78	0.86	0.85	0.85
	III	0.76	0.84	0.83	0.83
168-11	II	0.81	0.89	0.86	0.87
	III	0.78	0.87	0.84	0.85

Note: for ADP I, wear class factors $K_1 = K_2 = K_3 = K_4 = 1.0$

The value of shoulder clearance is used to monitor the condition of the tool-joint thread of drill pipes. Regular inspection is performed after every 50-60 trips (make-up/break-out). For cases when the clearance exceeds the value specified in Table 22, the pipes are withdrawn from operation for thread repair. Pipe-wall thickness and thread connections (pipe and joint) are checked for fatigue cracks by a portable NDE system.

Table 22. Allowable Wear of Tool-Joint Threads

ADP TYPE	TOOL-JOINT THREAD CODE	MAX NO. OF TURNS TO MAKE UP CONNECTION FOR GRADES		MAX NIPPLE AND BOX SHOULDER CLEARANCE BEFORE MAKE UP FOR GRADES (MM)	
		I	II	I	II
ADP 147x11,13,15,17	Z-147(5½" FH)	6.2	5.3	39.4	33
ADP 164x9, 168x11	Z-171(6⅝" FH)	6.2	5.3	39.4	33

ADP while in service is exposed to abrasive wear caused by friction between the drill string and the borehole walls during rotation and displacement during round trip operations. Hydra-abrasive wear is likely during borehole drilling with heavy-weight muds. In addition, ADP has shown that wear may occur on the outer surface in the areas in contact with the slips. As a rule, maximum OD wear is observed in the middle section and in the area contacted by the slips. The wear cross section is distributed non-uniformly over the perimeter and reveals an eccentric pattern.

ADPs are divided into three classes for matching with suitable operations. Pipes of class I and II are recommended for turbine and rotary drilling. Pipes of class III are recommended for turbine drilling of shallow boreholes in non-complicated environments.

5.2 Drill-Pipe Wear When Drilling Ultradeep Holes

The drillstring may include about 1000 joints of drill pipe when borehole depths reach 12,000 m (39,000 ft). All pipes are assembled into drill-pipe stands of three pipes about 36 m (118 ft) long before the drill string is made up.

All pipes are divided into sets for inspecting their physical condition, for replacement within one-type sections, to assign them for measurements and repair, to place them into operation, etc. Each set consists of seven drill-pipe stands and has a length of approximately 250 m (820 ft). ADP operation time is calculated for each set. Wear for the full set is determined as the average value of inspection results for all pipes in the set.

In the Kola SD-3 ultradeep well, wear of drill-pipe OD for a complete set of drill pipes (approximately 250 m) is estimated depending on drag forces along the set and the position of the set within the drill string. Such an approach includes loads which affect the set at a given moment and determining the lateral force and route of the set along the borehole.

$$A_i = \sum L_i (F_{ip} + F_{ir}) \qquad (5\text{-}2)$$

where:

A_i = conditional work of drag forces accomplished by the set during trip "i"
L_i = position of the set in the borehole from the rotary table (km)
F_{ip}, F_{ir} = drag forces acting along the length of the set during the round trip operations (kN)

Experimental studies conducted during regular inspections of drill string sets confirmed the existence of a correlation between the drill-pipe exterior surface wear and the conditional work. This dependence has a parabolic shape:

$$\delta_i = aA_i^2 + bA_i + c \qquad (5\text{-}3)$$

where a, b, c are constant factors for the given borehole with allowance for its design, radial sizes, spatial position, etc. Thus, wear of the set could be estimated based on calculation of the "work of the set." Summary data on the ADP sets including wear and conditional work during the Kola SD-3 within the interval 7200-10,700 m (the borehole was cased down to 2000 m) are shown in Table 23. Figure 20 shows the "work of drag forces – ADP wear" correlation in the interval 9600-10,700 m.

Table 23. ADP Wear and Conditional Work for Kola SD-3

(interval 7200-10,700 m)

SET # (FROM BOTM)	INTERVAL 7200-7700 M (100 TRIPS)			INTERVAL 8500-9200 M (120 TRIPS)			INTERVAL 9600-10,700 M (95 TRIPS)		
	Set position (km) (see note)	Conditional work of drag forces (10^3kN·km)	Relative wear (%)	Set position (km) (see note)	Conditional work of drag forces (10^3kN·km)	Relative wear (%)	Set position (km) (see note)	Conditional work of drag forces (10^3kN·km)	Relative wear (%)
1	7.5	60.0	1.1	8.75	168.0	2.8	10.0	180.5	3.2
2	7.25	87.0	1.2	8.5	193.8	3.2	9.75	213.0	3.8
3	7.0	98.0	1.2	8.25	217.0	3.4	9.5	252.7	4.6
4	6.75	168.7	2.6	8.0	384.0	4.3	9.25	360.3	5.8
5	6.5	195.0	3.1	7.75	492.9	4.8	9.0	444.6	6.5
6	6.25	231.0	3.4	7.5	576.0	5.9	8.75	548.6	8.2
7	6.0	252.0	3.8	7.25	582.9	7.3	8.5	557.2	9.1
8	5.75	258.7	4.6	7.0	596.4	10.6	8.25	595.6	9.6
9	5.5	269.0	5.3	6.75	639.9	12.2	8.0	615.6	9.8
10	5.25	299.2	6.0	6.5	702.0	13.5	7.75	677.3	10.1
11	5.0	290.0	6.2	6.25	705.0	13.0	7.50	662.6	10.3
12	4.75	289.7	5.4	6.0	698.4	12.6	7.25	654.3	9.7
13	4.5	288.0	5.4	5.75	690.0	12.0	7.0	651.7	9.5
14	4.25	276.0	5.2	5.50	679.8	11.4	6.75	641.2	8.6
15	4.0	264.0	5.0	5.25	667 8	11.0	6.5	626.0	8.2
16	3.75	247.5	4.3	5.0	660.0	11.2	6.25	623.4	8.0
17	3.5	238.0	4.1	4.75	644.0	10.8	6.0	621.3	7.4
18	3.25	237.2	3.6	4.5	626.4	9.5	5.75	617.3	7.1
19	3.0	222.0	2.4	4.25	601.8	8.7	5.5	606.1	6.7
20	2.75	209.0	2.2	4.0	585.6	8.2	5.25	588.5	6.2
21	2.5	192.5	2.0	3.75	571.5	6.3	5.0	584.2	5.6
22	2.25	180.0	1.6	3.50	554.4	5.6	4.75	577.6	5.2
23	2.0	162.0	1.2	3.25	530.4	4.8	4.5	566.0	5.0
24	-	-	-	3.0	511.2	3.9	4.25	549.1	4.6
25	-	-	-	2.75	488.4	2.8	4.0	539.6	4.1
26	-	-	-	2.5	453.0	2.6	3.75	527.2	3.9
27	-	-	-	2.25	415.8	2.1	3.5	508.7	3.2
28	-	-	-	-	-	-	3.25	481.6	2.8
29	-	-	-	-	-	-	3.0	447.4	2.4
30	-	-	-	-	-	-	2.75	415.4	2.2
31	-	-	-	-	-	-	2.5	384.7	2.0
32	-	-	-	-	-	-	2.25	350.6	1.9
33	-	-	-	-	-	-	2.0	311.6	1.8

** Note: The ADP "set position" is the distance between the set midpoint and rig floor.*

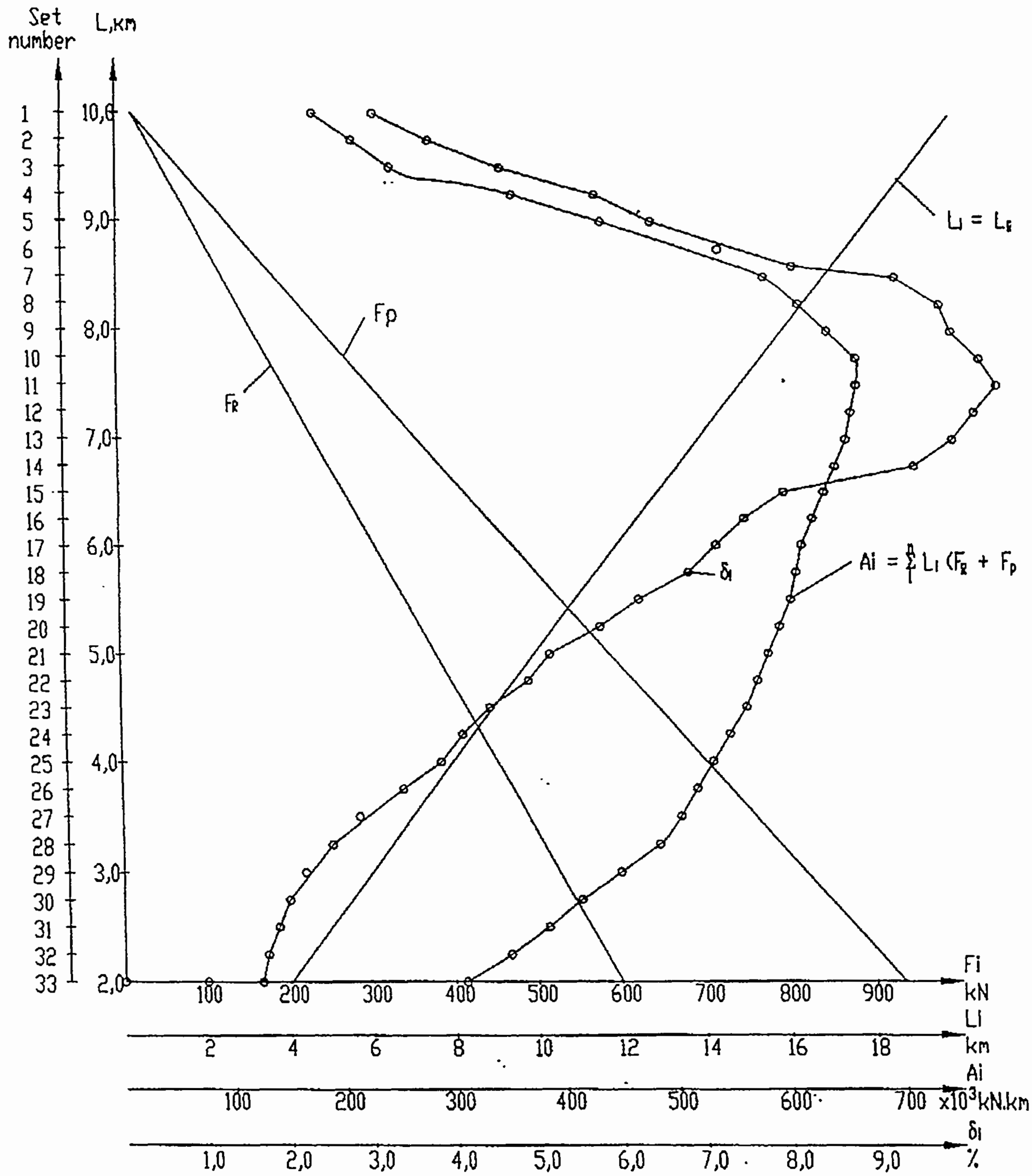


Figure 20. Drag and Wear on the Kola SD-3 (95 trips from 9600-10700 m) (F_P = average drag pulling out; F_R = average drag running in; L_i = pipe set travel per trip; A_i = work of drag force for 95 trips; δ_i = wear for 95 trips)

This type of approach was used to determine the drill-pipe wear rate, the frequency and sequence of NDE methods, techniques to arrange the sets within the drill string to ensure uniform wear, etc.

The usage of drill pipes at the Kola SD-3 revealed proportionate wear along aluminum and steel pipes at these great depths. The drill-string configuration at the Kola SD-3 consisted mainly of ADP. Only insignificant sections – the section immediately above the bit (120-150 m; 394-492 ft) and the uppermost 500-600 m (1640-1969 ft) – were equipped with steel pipes due to technological specifics and safety concerns. The main reason for on-site rejection of drill pipes is wear of the tool-joint thread Z-147 (5½ FH). Due to this wear these pipes were rejected from operation and transferred to other less critical boreholes. Data on drill-pipe consumption and reasons for rejection from the interval 7200-11,500 m at the Kola SD-3 are shown in Table 24.

Table 24. Drill-Pipe Consumption for Interval 7200-11,500 m at Kola SD-3

DESCRIPTION	ADP-147 (D16T)	ADP-147 (1953T1)	ADP-147 (AK4 1T1)	SDP (40)
ADP used:				
meters	19200	15100	5900	7700
tons	306	256	89	252
Rejected or transferred to lower grade:				
a) Tool-joint thread wear:				
meters	4922	15100	-	1550
tons	77	256	-	50
b) Drill-pipe or TJ body wear:				
meters	9644	-	5900	6150
tons	153	-	89	202
c) Erosion (m)	4434	-	-	-
Average drill-pipe operation time (runs)	291	367	250	470
Drill-pipe consumed/meter penetration (kg)	72	60	20.9	59.3

5.3 Drilling Problems at the Kola SD-3 Well

All drilling problems which occurred while drilling the Kola SD-3 ultradeep well can be divided into the following basic types:

1. BHA sticking

2. Breakage of the drill string

3. Breakage and loss of drilling tool elements in the hole

4. Logging cable failure

Table 25 lists statistical data on drilling problems at the Kola SD-3.

Table 25. Drilling Problems for Kola SD-3 to 12,262 m Depth

	Drilling Problems and Complications	Number of Failures	% of All Failures	Consumed for Sidetracking/ Bypassing		Extent of Sidetrack (m)
				Days	%	
1.	BHA sticking	140	38.5	1016	59	8359
2.	Drillstring component failure	27	7.4	433	25	2373
3.	Bit component failure	112	30.7	-	-	-
4.	BHA component failure	72	19.8	21	1.2	62
5.	Logging cable breakage	8	2.2	-	-	-
6.	Other (increasing inclination angle, unsuccessful sidetrack, etc.)	5	1.4	206	14.8	764
	Total	364	100	1724	100	11766

Data in Table 25 are given for all types of drilling problems that occurred at Kola SD-3 within the interval of 0-12,066 m (drilling, tripping, reaming, bypass hole drilling, etc.). Most problems could be resolved in less than 5 days. BHA sticking was eliminated by applying tension on the drill string up to permissible values or by using jars. Fragments of the drilling tool elements were removed with magnetic bit extractors; the lost BHA elements were fished with taps and bell sockets. For only twelve cases related to BHA sticking and drill-string breakage was it impossible to resolve the problem by traditional methods. These problems were resolved by sidetracking and drilling bypass holes. The total length of bypass holes was 11,766 m.

A majority of problems and complications were caused by BHA sticking (140 events). There were cases when the tension applied to the drill string in the course of addressing the problem exceeded the permissible values (above 0.85 $S_{0.2}$) and the load reached ultimate values. As a rule, this resulted in additional problems caused by drill-string failure. Breakage generally occurred within the interval of 9400-9800 m and most likely was connected with a strong tendency for caverns to form in this zone, causing not only tension but bending loads to act on the drill string. Using a fishing tap or a bell socket was not practical even in a single case. Due to significant size of the caverns, the top of the emergency string deviated, so all attempts to fix it with a fishing tool were unsuccessful. The only method for overcoming these double problems (sticking and breaking at the same time) was sidetracking.

Drill-string element breakage made up an insignificant portion of the total number of problems (only 27 events). However, considering the complications inherent in these types of problems, the cost of their resolution with bypass drilling are high. The details on drill-string problems are summarized in Table 26.

Table 26. Causes of Drill-String Failures for Kola SD-3

	REASONS FOR FAILURE	NUMBER OF FAILURES	%
1.	Fatigue failure of tool joint thread 5½ FH	6	22%
2.	Breaking of tool joint body (of poor quality production)	3	11%
3.	Breaking of drill-pipe body in section with highest load (load exceeding limit)	12	44%
4.	Fatigue failure of pipe thread (standard triangular thread)	4	15%
5.	Unscrewing of pipes in tool joint thread (of poor quality production)	2	8%
	Total:	27	100%

An analysis of the primary causes of drill-string problems led to the conclusion that it is possible to minimize lost time for resolving these problems. Firstly, it is necessary to note that after replacement of a triangular pipe thread (to connect aluminum pipe body to steel tool joint) by an acme thread, one the most frequent problems related to drill-string elements, i.e., fatigue failure at the pipe thread, was eliminated (see item 4, Table 26). To reduce time lost due to failure in the steel joint thread because of fatigue or manufacturing defects (see items 1,2,5), it is critical to maintain a strict schedule of tool inspection both with instruments and nondestructive evaluation in the course of acceptance and intermediate checks.

Pulling on a stuck string with a tension load above the allowable limit is absolutely forbidden as a basic method for unsticking the BHA. However, not knowing the actual drag forces along the drill string can result in loading the critical string sections beyond the prescribed limits. Drill-string breakage is a sure consequence of this approach accompanied by an attendant variety of complications.

6. Assembling Drill Strings from ADP

6.1 Specifics of Drill-String Design

The study of materials to be used for drill-pipe production requires the application of the concept of *specific strength,* which expresses the ratio of yield point to specific weight. Specific strength of a material can be expressed in terms of length and, in its application to the drill string, defines the maximum length of a single-size drill string hung in air where the stresses due to suspension are equal to the yield point of the material. Maximum length of a single size drill string is determined not only by the strength of the drill-pipe material but also by the difference in specific weights of the pipe material and drilling mud.

Comparison of drill pipes of various materials based on this parameter shows that the longest string of a single-size drill string is manufactured of ADP. In actual drilling operations, the lower sections of the drill string may have long-term exposure to high temperatures, which deteriorates the strength of the drill-pipe material and, consequently, restricts penetration depth. This consideration necessitates the choice of highly thermoresistive alloys for the bottom part of a drill string and the development of corresponding methods for analysis and operation.

The study led to the selection of three aluminum alloys for drill-pipe manufacturing: D16T, AK4-1T1 and 1953T1. These alloys not only meet the requirements of drilling operations but are also easy to produce, which allowed mass production of pipes with variable diameters along the length. Table 27 presents physical and mechanical properties of ADP and steel tool-joint materials under normal temperatures.

Table 27. Properties of ADP and Steel Tool-Joint Materials

	DESCRIPTION	UNITS	PIPE	PIPE	PIPE	TOOLJNT
			(D16T)	(1953 T1)	AK4-1T1*	(40KHN)
1	Yield point, not less than	MPa	330	490	350	735
2	Tensile strength, not less than	MPa	450	540	410	880
3	Hardness	HBr	120	120-130	130	277-340
4	Elongation	%	11	7	12	11
5	Percentage reduction of area	%	20	15	26	45
6	Specific gravity	g/cm^3	2.8	2.8	2.8	7.85
7	Modulus of elasticity	MPa x 10^5				
	E		0.72	0.70	0.73	2.1
	G		0.26	0.275	0.275	0.81
8	Poisson's ratio	-	0.33	0.31	OJ1	0.3
9	Thermal expansion coefficient	1/C°x10^{-6}	22.5	23.8	23.8	•
10	Max allow operating temperature	°C	160	120	240	-

The physical and-mechanical properties of aluminum alloys essentially depend on temperature, load conditions and duration of exposure. ADP of high-strength alloy 1953T1 is especially sensitive to high temperatures. At 110°C (230°F), the plasticity of this alloy is relatively low. It is recommended to use ADP from 1953T1alloy in the upper sections of the drill string where, at temperatures below 110°C, its high strength will be of advantage in drill strings with high static loads.

Pipes of D16T alloy are characterized by the highest plasticity as compared to other alloys. It is reasonable to use them within the temperature range 110-160°C (230-320°F. It is recommended to use ADP of the AK4-1T1 alloy if the temperature exceeds 160°C.

Experimental studies and long-term operational experience show that three major temperature zones can be identified for ADP. In the first zone, mechanical properties are relatively stable and the design strength factor should be taken as equal to the material yield point at 20°C (which is conventionally taken for the design of drill strings). With increased operating temperature, material strength properties are noticeably reduced, with operation time being an important factor. Within this zone, the yield point determined after 500 hours exposure to the given temperature is used as the major design parameter. The time span of 500 hours is chosen to provide for a long-term exposure of ADP in the borehole during drilling problems.

In case the critical temperature of ADP is exceeded, the latter accumulates plastic deformations under the combined load exposure. This results in structural changes and possible destruction of the pipe under loads considerably lower than those calculated using yield point at the same temperature. Operation of ADP within this temperature zone requires the use of prolonged strength limits of the material as the major design parameter.

Table 28 illustrates ADP design of various types of alloys chosen for drill string sections under various operating temperatures.

Table 28. Design Parameters of ADP for Various Operating Temperatures

Design Parameter	Range of Temperature for Alloy (°C)		
	D16T	AK4-1T1	1953T1
Yield point after 500 hours exposure to operating temperature	120-145	140-160	90-115
Prolonged tensile strength under operating temperature based on 500 hours exposure	145-200	160-200	-

One of the most important operational parameters of a drill string is the endurance limit of its thread connections and their durability in the zone of limited endurance. Fatigue cracks that appear as a result of alternating bending stresses are one of the main causes of drill-string failures.

Experimental data on the durability and endurance limit of ADP connections based on laboratory tests are used for drill-string design. The same data are used for optimizing the design of the pipe connection optimal and estimation of their stress-deformation state.

A special software package for design and calculation of drill strings for ultradeep borehole drilling was developed based on analytical and experimental studies. In addition to static design computations for the drill string, it includes specific programs for evaluation of elastic string stretch with allowance for temperature; estimation of power consumption for round-trip operations; drag force distribution along the string; long-term strength assessment, etc.

Static analysis of drill strings constructed from ADP is carried out for three main technological situations: the process of mechanical drilling and borehole reaming; tripping operations; and elimination of problems and complications. Methods of designing drill strings for cyclic durability under periodic bending and prolonged strength under non-stationary loading modes were also developed.

6.2 Evaluation of Loads Applied to the Drill String

To improve the operational reliability of a drill string, it is extremely important to accurately know the loads acting in each section. This allows verifying the design and lowers the risk of emergency caused by component failures due to the loads exceeding the level permitted by the operational conditions.

Drill-string calculations normally take into account additional loads arising from friction forces between the drill string and borehole. At the same time, specific conditions of ultradeep borehole drilling in crystalline rocks also require taking account of the drag forces. These are determined by the wedging effect occurring when the drill string moves along an elliptic cross-section of the borehole or in its curved intervals.

Experimental studies in the Kola ultradeep borehole at 12,000 m (39,370 ft) showed that drag forces contribute over 60% of the drill-string weight. The friction force, F_{fr}, comprises about 35% of the total drag force and is strongly dependent on the level of the normal force, F_n, and the friction coefficient, f, of the drill-string components against the borehole walls, which is related to weight of the drill string, lithological composition of the section, and lubricating properties of the drilling mud.

$$F_{fr} = f \times F_n \qquad (6\text{-}1)$$

Under relatively typical field conditions (a large volume of drilling mud circulating in the borehole, considerable solids in the mud, and an ineffective rig cleaning system), it is rather problematic to significantly decrease the friction coefficient by increasing the lubricating capability of the drilling mud. Even when it was possible to reduce the friction coefficient to 0.25-0.30 by appropriate treatments, the drag force dependent on the friction forces has been seen to reach 520 to 550 kN (117 to 124 kip), which comprised 28-35% of the weight of the drill string in the drilling mud. Consequently, the first step toward reducing the drag forces determined by friction forces, is to reduce the radial normal loads by decreasing the weight of the drill string.

The least studied problem is the effect of a cavernous borehole of elliptical cross-section on the drag force. Investigations carried out in the Kola ultradeep borehole showed that the major axis of the ellipse essentially coincides with the directional deviation. In this case the normal force, F_n, determined as a function of the weight of the drill string, can be divided into two components in accordance with the point of contact between the string component and the borehole wall. This results in the generation of lateral forces causing a sticking effect which forms additional drag force, F_f, hindering drill-string motion (Figure 21).

$$F_f = k_f F_n = (F_n / \cos\beta) \quad (6\text{-}2)$$

where:

k_f = coefficient which accounts for the borehole cross-sectional shape
β = half-angle of the drilling tool contact in the borehole cross-section

It was experimentally shown that the drag force related to the sticking effect during string motion in an elliptical borehole reached 31% of the total drag force and amounted to 450 to 460 kN (101 to 130 kip) for an open-hole length over 10,000 m (32,800 ft).

It is possible to reduce the drag force related to the borehole cross-sectional shape by reducing the radial normal forces. This is possible by:

1) decreasing the weight of the drill string; or

2) narrowing the contact angle in the borehole cross sections.

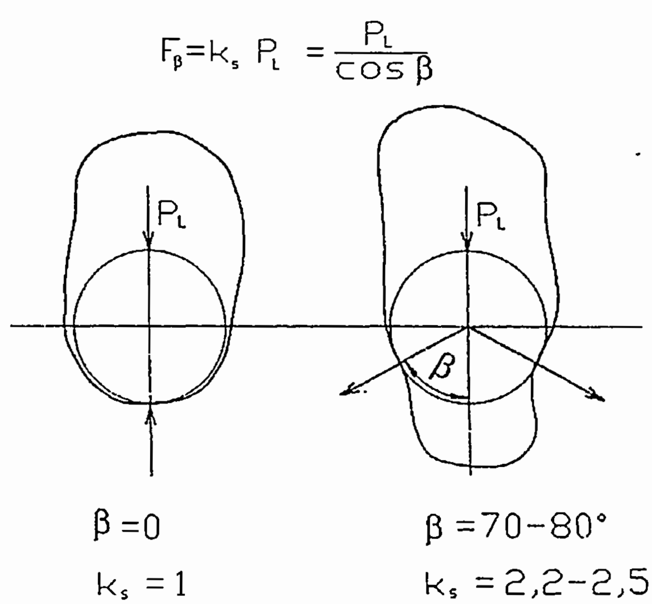


Figure 21. Distribution of Normal Force in an Elliptical Hole

The first approach appears to be preferable, since narrowing the contact angle in the borehole is only possible when the borehole is specially reamed to nominal size within the corresponding intervals. This is a complex technological procedure which takes additional time and cost.

The influence of the 3D deviation of the borehole on the drag force, F_j, is determined by the total contact angle along the borehole and depends on the value of the normal forces on individual borehole intervals and the 3D trajectory. The drag force is negatively affected by borehole intervals with extensive changes in the 3D trajectory.

The additional normal force against the borehole wall, F_n, which forms the drag force when the string moves along a curved borehole, can be determined from the following expression:

$$F_n = k\,q\,r \qquad (6\text{-}3)$$

where:

k = dimensionless coefficient characterizing the period of crooked borehole intervals (k = 1-5)
q = weight of a unit length of drill string in the drilling mud
r = reciprocal of the borehole deviation radius in the interval under consideration (r = 1/R)

To reduce the drag force determined by the 3D deviation of the borehole, it is necessary to attempt to minimize the number of doglegs. Reduction of the drill-string unit weight is helpful as well.

This approach to drag force evaluation can be validated by a comparison between the drag forces while pulling out the drill string in two boreholes of the Kola SD-3 (Figure 22).

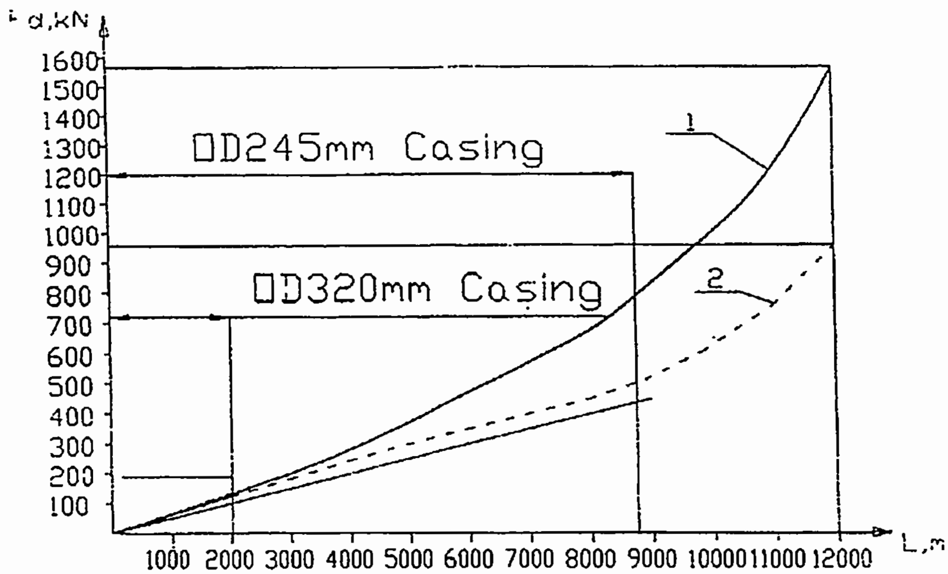


Figure 22. Distribution of Drag Forces in Kola SD-3

The first borehole (borehole 1 in Figure 22) had a depth of 12,066 m, casing string set depth of 2000 m, with open borehole for the remainder. Drag force had its maximum value of 1560 kN during the extreme loading of the drill string while pulling out of the bottom. In the cased interval to 2000 m, the drag-force distribution was linear and only depended on the friction forces, F_{fr}. As far as the borehole was vertical and cased, there were no F_f and F_j components.

Within the interval from 2000 to 5500 m, the drag force distribution was approximately linear. This fact can be attributed to a relatively weak influence of F_f and F_j since the lower borehole wall was treated by the pipe tool joints during the extensive tripping operations, the contact angle had a minimum value, and the maximum borehole inclination was 3 to 4°.

Within the interval 5500 to 12,066 m, the drag force distribution became parabolic, with the maximum increment near the bottomhole. In that interval, all three components (F_{fr} , F_f and F_j) contributed to the drag force. Since the borehole was cavernous and had an ellipsoidal cross-section throughout the interval, and the inclination angle exceeded 25° near the bottom, the drag force was comprised mostly of F_f and F_j.

The second borehole (borehole 2 in Figure 22) was 12,260 m deep. It had been reamed and cased by a 245-mm (9.65-in.) string to a depth of 8770 m, which resulted in substantial changes in the drag force distribution along the borehole.

The borehole interval with a linear drag force distribution increased from 2000 to 8770 m, which coincides with the cased interval without the F_f component. The increment of the drag force was slightly greater on that interval compared to the first borehole, which can be explained by the influence of the 3D position of the casing string.

On the open borehole interval 8770-12,260 m where the drag force included all three components (F_{fr}, F_f and F_j), the drag force distribution is characterized as in the first borehole. Casing the borehole reduced the total drag force by 600 kN. Their absolute values were equal to 960 kN at comparable borehole depths.

The analysis of changes in the drag-force distribution in the two boreholes of the Kola ultradeep borehole validated the approach for the evaluation of the contributions of F_{fr}, F_f and F_j to the total drag force applied to the drill string. Consideration of the actual loads along the whole string length allowed a more qualified drill-string calculation, which increased its operational reliability.

This proposed procedure is complex for practical implementation because of the lack of reliable data about the friction coefficient for the string/borehole contact, the string contact angle in the borehole section, and the spatial parameters of the borehole. Due to this, a method for "pulling through" the drill string while pulling it out was developed to determine the drag force distribution along the borehole with depth and take the forces into consideration to evaluate the stress/strain state of the drill string.

The essence of the method is the following. Let F_{L1}, F_{L2} ...f_{Ln} be the drag forces measured as the hook-load readings for different string lengths (when pulling out the first, second, third drill-pipe stands, etc.). The drag force at depth L is:

$$F_c = (G_L - G_T) / \eta - P \quad (6\text{-}4)$$

where:

G_L = hook load according to the weight indicator

G_T = tackle system weight

η = tackle system efficiency for pulling out;

P = calculated weight of the string corrected for its buoyant weight in the drilling mud

Then, the following drag force increment will occur on the borehole interval between the first and the second measurements:

$$\Delta F_1 = F_{L1} - F_{L2} = [(G_{L1} - G_T) / \eta - P_1] - [(G_{L2} - G_T) / \eta - P_2] =$$

$$(G_{L1} - G_{L2}) / \eta - (P_1 - P_2) \qquad (6\text{-}5)$$

And on the next intervals:

$$\Delta F_2 = (G_{L2} - G_{L3}) / \eta - (P_2 - P_3);$$

$$\Delta F_n = (G_{Ln} - G_{L(n+1)}) / \eta - (P_n - P_{(n+1)}) \qquad (6\text{-}6)$$

The drag-force increments at each measurement step are used to construct a plot of the drag-force distribution along the whole string. The plot is used to evaluate the stressed state on different sections of the drill string. The shorter the measurement step, the higher the accuracy of the drag-force distribution.

The accuracy of this type of method for drag-force measurement along the drill string was checked experimentally with the help of self-contained borehole recorders which were installed at various depths and registered the stretch of the drill stand depending on the load applied. Experimental data are summarized in Table 29.

Table 29. Drag Forces along the Drill String (Field Test Results)

Recorder Depth (m)	String Length below Recorder (m)	String Weight below Recorder (kN)	Recorded Drill-Pipe Stretch (mm)	Coefficient of Stretch during Calibration (kN/mm)	Actual Load at Tested Pipe (kN)	Drag Force (kN)	
						At Tested Pipe Stand	At Hook
1028	9590	1286	127.0	1.75	2230	940	1020
2295	8323	1094	128.0	1.46	1870	780	820
4304	6314	814	115.0	1.26	1450	640	560
6584	4034	535	69.0	1.52	1050	520	470

These results show a good convergence (error below 10%) in determining the drag force distribution along the drill string and proved the potential for using the "pull-through" method for actual axial loads to be taken into account in the drill-string analysis.

6.3 Design Parameters and Safe Load Factors for ADP Strings

Operational parameters of drill pipes depend on their design and material properties. Conventional yield strength of the pipe material ($S_{0.2}$) at 20°C (68°F) is the main criterion for the static design of drill strings. The following strength criteria are used for drill-string operation under high temperatures:

- Conventional yield strength of the material at operating temperature
- Material creep strength, which depends on plastic strain resulting from static load during a period of time
- Long-term strength, defined as ultimate stress during a specified time period and temperature at which the pipe collapses

A number of research studies were performed to evaluate applicability of the criteria mentioned above in calculations for ADP string design. Flat specimens cut out from the main body of ADP along the axis were used in the studies. The studies indicated that yield strength of the D16T alloy did not change within the temperature range of 20-120°C. Further increases in temperature lead to a rapid drop in yield strength. At 180°C, it is about 70% of the initial value (Figure 23).

Thus, utilization of yield strength as the main criterion for design is limited to the range of stable temperatures.

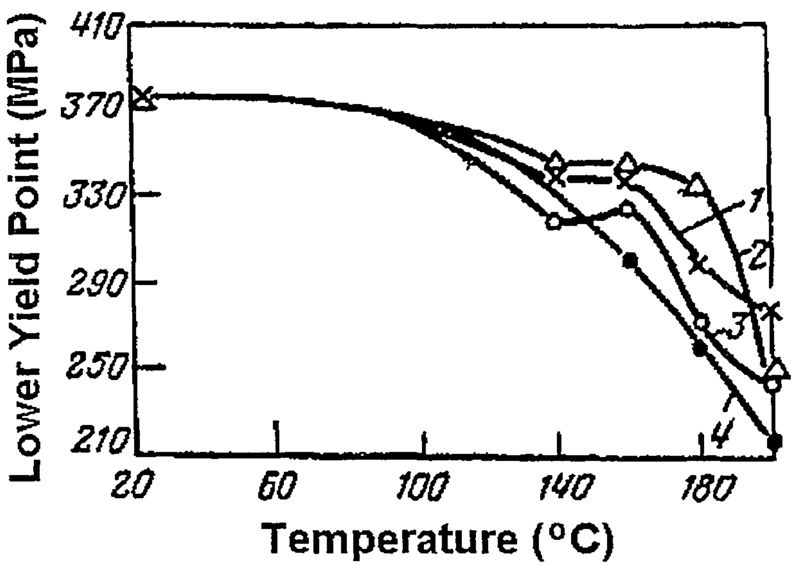


Figure 23. Yield Point of D16T with Temperature (1 = 0.5 hr; 2 = 12 hr; 3 = 100 hr; 4 = 500 hr)

Operational durability of drill pipes depends on the level of their failure hazard, rather than on deformations accumulated during their operation. Therefore, it is apparently more expedient to use creep strength or long-term strength as the main strength criterion.

Figures 24 and 25 show the results of tests for determining correlation between the creep rate of D16T alloy and temperature and a level of applied stress. The diagrams clearly indicate that when the level of stress is below conventional yield strength of the material, critical creep rate (>0.002% per hour) occurs at temperatures above 140°C (284°F). Therefore, long-term strength should be used as a design criterion of strength for D16T alloy at operating temperatures above 140°C.

Similar studies were performed for the 1953T1 and AK41T1 alloys. General trends correlating creep rate and temperature remained unchanged for these two alloys. 100°C is a critical temperature for the 1953T1 alloy. Ultimate long-term strength should be used in calculations of strength for temperatures above 100°C. The critical temperature for AK4-1Y1 is 220°C. Tests and studies performed led to the establishment of the following criteria to be used in calculations of ADP string designs:

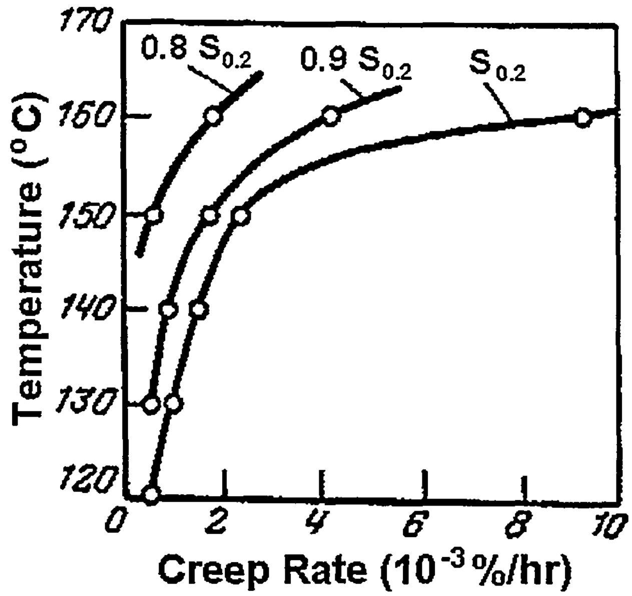


Figure 24. Creep Rate of D16T with Temperature

- material yield strength at 20°C is assumed for yield strength in the range of temperature stability
- material yield strength at operating temperature after 500 hours for temperature ranges of material thermal failure
- long-term strength at operating temperature and a specified time period for temperatures above the critical temperature at which irreversible plastic deformations occur

Safety factor is an important design parameter that reflects operational characteristics and reliability of the drill string. The following formula is used for calculating safety factor:

$$n = S_i^o / S_i \qquad (6\text{-}7)$$

where:

S_i^o = allowable serviceability of drill-pipe material

S_i = stress intensity in a specific section of the string

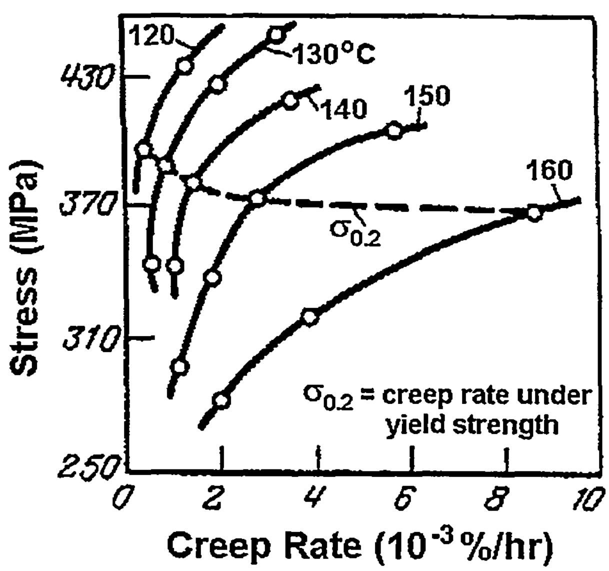


Figure 25. Creep Rate of D16T Alloy at Various Temperatures

Conventional yield strength of a material ($S_{0.2}$) is used as a serviceability parameter (S_i^o) for normal static design calculations of a drill string. Safe load factors depend on the type of well and drilling method (Table 30).

Table 30. Safety Factors

DRILLING MODE	HOLE TYPE	
	VERTICAL	ERD
Rotary	1.45	1.5
Turbodrill	1.35	1.4

6.4 Endurance and Durability of ADP

Rotation of a drill string in slanted intervals around a bent axis while drilling results in alternating bending stresses. 60-80% of drill-string failures result from fatigue failure of pipe and tool joint threads. These failures occur due to alternating bending stresses that lead to formation and propagation of fatigue cracks in the root of the thread.

The fatigue strength limit of a pipe thread connection is one of the critical operating parameters for drill pipes. Fatigue strength limit of the connection is the maximum level of stress that the connection can bear without failure when a specified number of alternating load cycles are applied.

The studies indicated that pipe connection fatigue and durability parameters can be objectively determined only in bench tests of full-scale specimens under conditions that are representative of actual drilling loads.

Most studies of fatigue parameters use test benches with console alternating bending loads applied to full-scale specimens. These benches perfectly imitate drill-pipe connection loads in wells. They have a simple design and are capable of creating stable loading parameters. Figure 26 shows a schematic diagram of the ST-20 bench. Figure 27 presents a photograph of the bench.

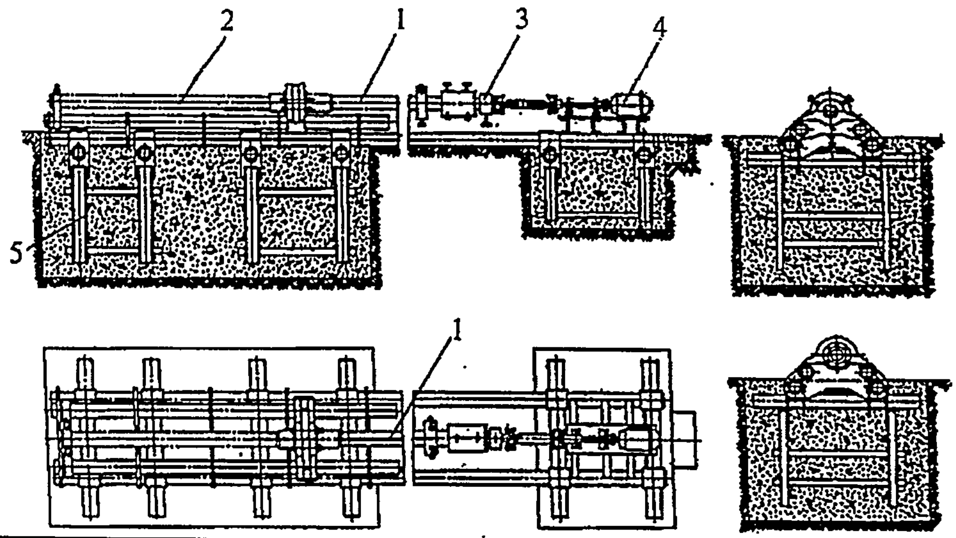


Figure 26. Bench for Fatigue Testing of Pipe and Connector
(1 = test specimen; 2 = support; 3 = loading unit; 4 = drive; 5 = foundation)

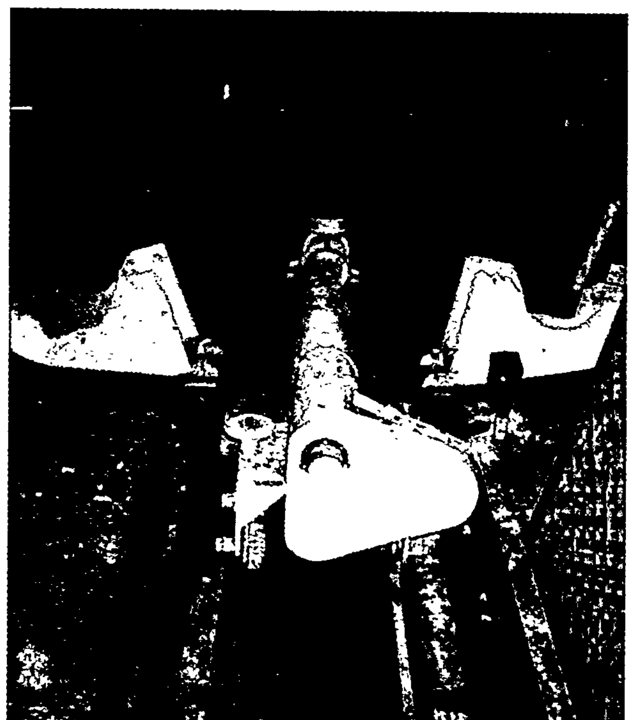


Figure 27. ST-20 Fatigue Test Bench

Figure 28 shows specimens of ADP 164x9 after testing to failure on the ST-20 bench.

An upgraded bench (model ST-50M) allows determining durability and fatigue parameters of test specimens at high temperature. The bench has heating blocks for heating the specimens. One block is put inside a specimen, and the three other inside cylindrical spaces on the bench front panel. This arrangement allows forming a uniform thermal field within the thread connection zones during the test. Below are parameters for the ST-50M bench:

Diameter (mm)	
specimens	64-182
tool joints	64-206
Vibration amplitude error (%)	2.5
Length of specimen (mm)	≤3000
Test temperature (°C)	20-250
Time required to reach test conditions at 250°C (hr)	6

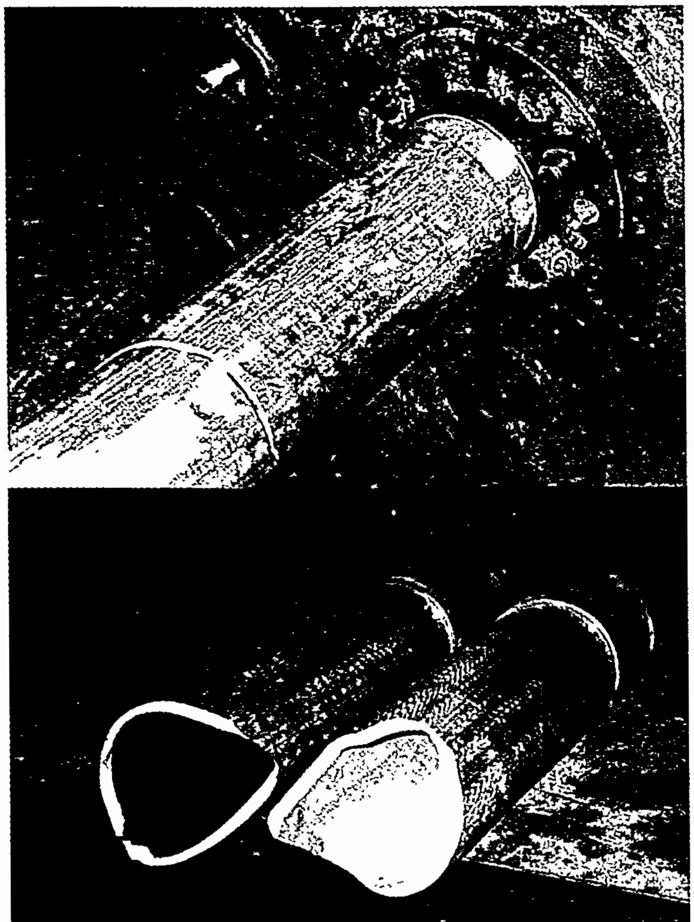


Figure 28. 164x9 ADP after Fatigue Tests

Maximum variation in temperature (%) 2.5

A basic test protocol for full-scale specimens of ADP connections includes 10^7 cycles of load reversal. This allows test results with required accuracy.

The ST-20 bench was used in a large number of tests and studies for evaluating the effect produced by conventional specific contact pressure affecting the pipe to joint thread connection on durability and fatigue parameters of the connection. Figure 29 presents results of fatigue tests of 73-, 114-, and 147-mm ADP thread connections with different contact pressures applied to the surface of connected threads during make-up. Table 31 presents the results of these tests.

Table 31. Tests of ADP Thread Connections with Different Contact Pressures

CONVENTIONAL CONTACT PRESSURES OF ADP THREAD CONNECTION (MPA)	ENDURANCE LIMIT (MPA) OF CONNECTIONS FOR DIFFERENT OD PIPES (MM)		
	73	114	147
60-80	57	53	47
40-60	50	44	37
20-40	45	37	30

Test results revealed a linear tendency between fatigue strength of the connection and conventional contact pressure. Ultimate contact pressure was also determined. Contact pressure above the ultimate limit results in considerable decrease of cycle strength. For the above given standard sizes of ADP, this parameter is about 80 MPa.

Table 31 indicates higher durability of threaded connections of smaller diameters and higher contact pressures up to a certain limit. This can be explained by lower relative displacement of the conjugated elements and higher integrity of the connection at higher contact pressures. When contact pressures exceed a specified limit, plastic

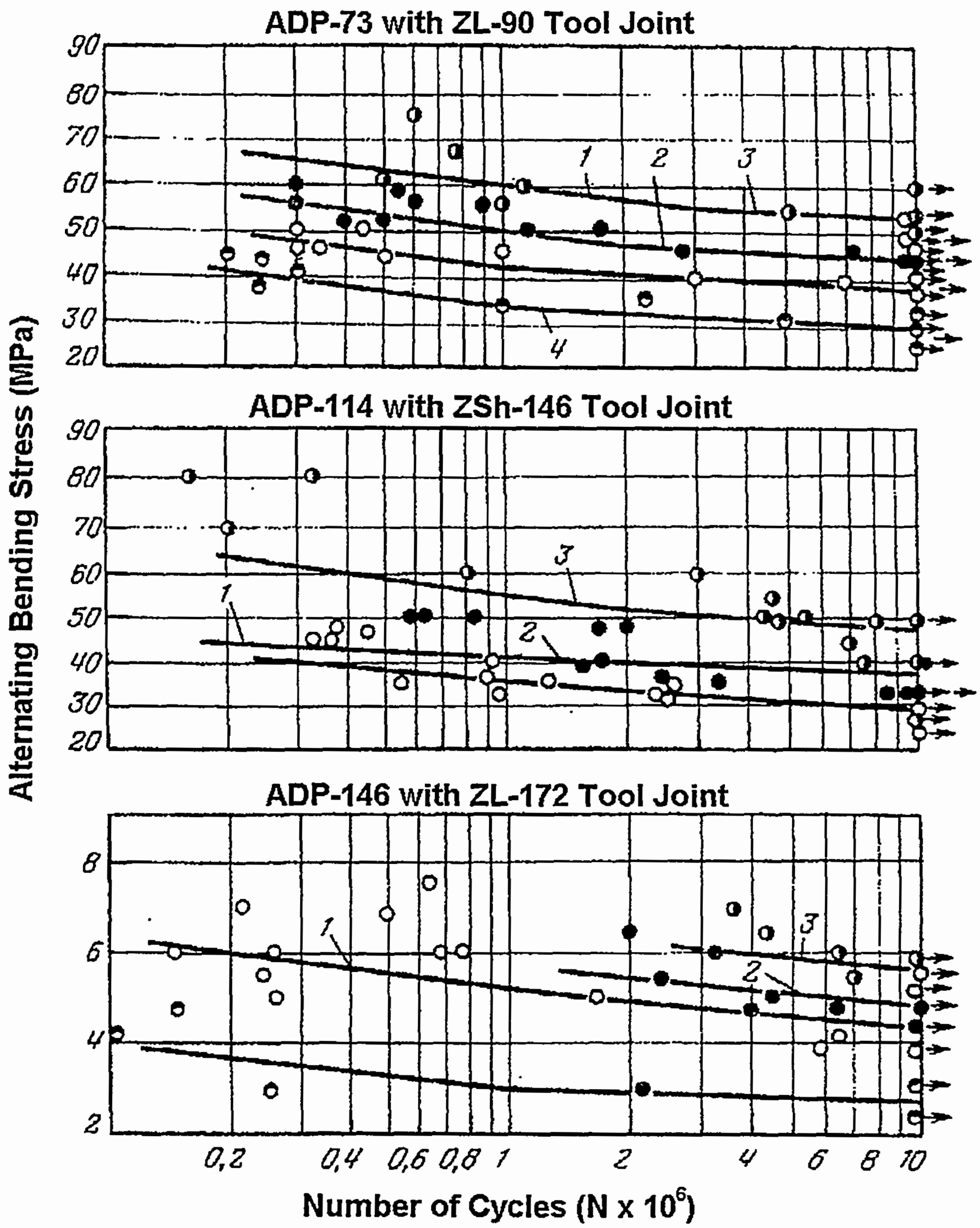


Figure 29. Fatigue Test Results of Connections
(1 = 20-40 MPa contact pressure; 2 = 40-60; 3 = 60-80; 4 = >80)

deformation occurs in the conjugated pair. This leads to lower plasticity reserve of the pipe material as a result of strain hardening, which promotes formation and propagation of fatigue cracks.

Fatigue tests were performed on the ST-20 bench for full-scale specimens of 147-mm (5.8-in.) widely used ADP from various aluminum alloys with ZL (triangular), and

ZLK (trapezoidal with a tapered stabilizing shoulder) thread connections. Table 32 shows the results of these tests.

Table 32. Endurance Limit of ADP (Steel Tool Joint Threaded Connection)

Object Tested	Pipe Body OD (mm)	Alloy Grade	Endurance Limit (MPa)
1. Pipe body	147	D16T	110
2. Connection with triangular tapered thread at calculated torque	147	D16T	47
3. Connection with triangular tapered thread at calculated torque	147	1953T1	40
4. Connection with special tool joint (acme tapered thread profile and seal shrink)	147	D16T	64
5. Connection with special tool joint (acme tapered thread profile and seal shrink)	147	AK4-1T1	70

Note: a test pattern of 10^7 cycles with 650 cycles per minute at 20°C was used to obtain fatigue limits.

Figures 30 and 31 show fatigue curves for connections of 147-mm ADP from D16T and 1953T1 alloys with ZL and ZLK thread connections at high temperatures, built after tests on the ST-50M bench. The tests results indicate that an increase in test temperature leads to considerable reduction of connection durability in the endurance strength and fatigue limit zone. For example, the fatigue limit for ADP from D16T alloy with ZL-type connections at 160°C is one-third of the fatigue limit at 20°C. Slightly better results were obtained for ZLK-type connections made up using the hot-assembly method. These connections are recommended for operations at high temperatures.

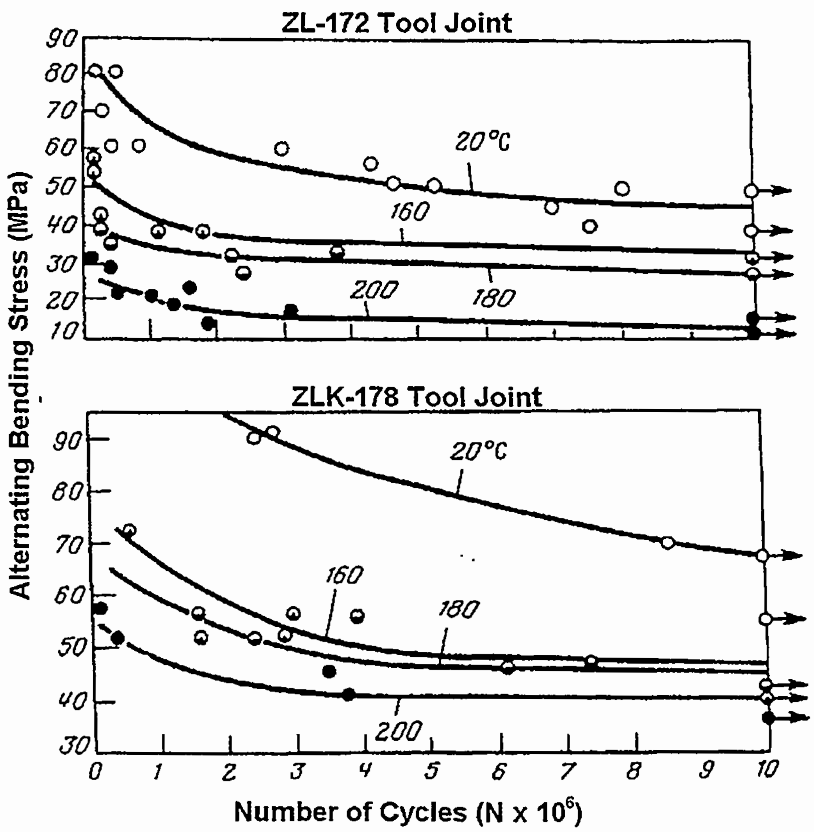


Figure 30. Fatigue Endurance of ADP Connection (147-mm OD Pipe; D16T Alloy)

6.5 Elongation of an ADP Drill String

Certain drilling operations require determining the exact position of the drill string in the well, which includes calculation of its elastic elongation. Normally, SDP with weights and elasticities different from ADP are set in the lower sections of the string to create additional weight on the drill bit and allow smooth transition of rigidity from BHA to ADP. In addition, a drill string can be assembled from sections of ADP with different weights and dimensions. A drill string in a well is exposed to a variety of temperatures. Elongation moduli of pipe material decrease at high temperature, whereas thermal expansion coefficients increase. All these factors must be taken fully into account while calculating elastic elongation of combined strings.

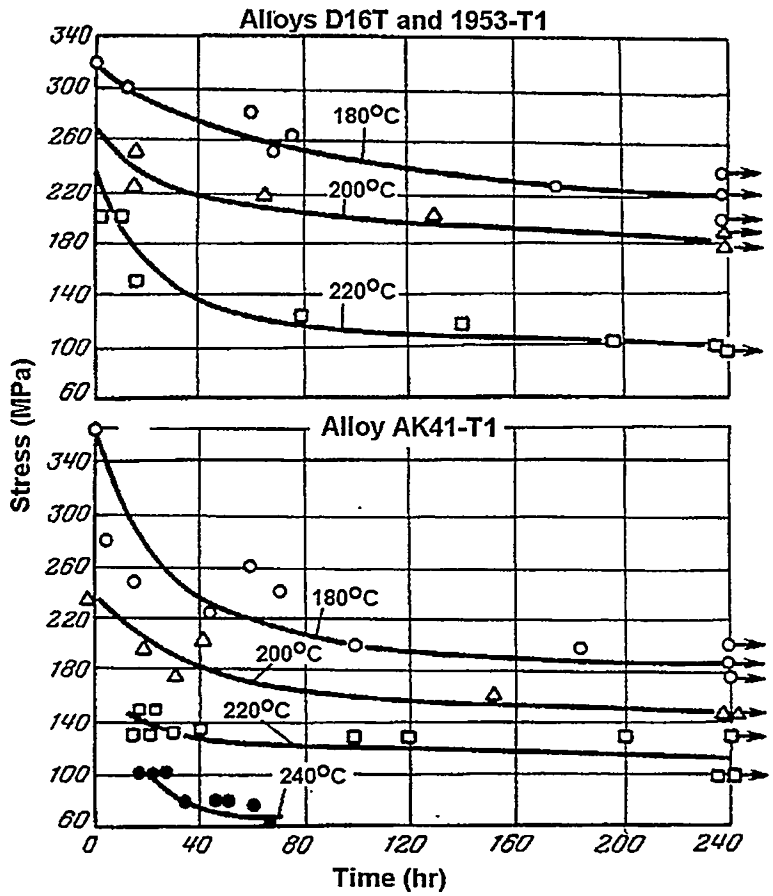


Figure 31. Long-Term Strength of ADP with Temperature

The following formula is used to calculate aggregate elastic elongation of a combination drill string in a well:

$$\Delta L = \sum_{k=1}^{m} (\Delta l_{ks} + \Delta l_{kT} + \Delta l_{kb}) \tag{6-8}$$

where:

Δl_{ks} = elongation of the k[th] section of a drill string due to its own weight
Δl_{kT} = thermal elongation of the k[th] section of a drill string
Δl_{kb} = elongation of the k[th] section under the weight of the section below and the BHA
m = number of sections

The elastic elongation of the nth section under its own weight of a combined drill string is calculated according to the formula:

$$\Delta l_{ks} = \frac{l_k^2 q_k (1 - \rho_l / \rho_m)}{2 E_m F_p} \tag{6-9}$$

where:

l_k = length of the k[th] section, defined as the sum of its drill pipes as measured at the surface
q_k = reduced mass of unit pipe of the section
ρ_l = drilling mud density
ρ_m = reduced density of drill-pipe material for that section, accounting for density of tool joint material
E_m = elasticity modulus of drill-pipe material
F_p = cross-sectional area of the section

Thermal elongation of the n[th] section, neglecting the thermal linear expansion coefficient:

$$\Delta l_{kT} = \frac{\alpha_m n}{2}(L_k^2 - L_{k-1}^2) \tag{6-10}$$

where:

α_m = linear expansion coefficient of material the given section pipe;
n = well geothermal gradient;
L_k; L_{k-1} define the well interval corresponding to the upper and lower limits of the section

The thermal elongation for multi-diameter or single diameter drill strings assembled exclusively from ADP calculated for the whole string with length L is:

$$\Delta l_T = nL^2 \alpha_{Al} / 2 \tag{6-11}$$

The following formula is used for calculating the k[th] section elastic elongation under the weight of sections below and the BHA:

$$\Delta l_{kb} = \frac{P_k l_k}{E_m F_p} \tag{6-12}$$

where P_k = tensile force applied to the lower part of the section, calculated by:

$$P_k = Q \cdot (1 - \rho_l / \rho_{BHA}) + \sum_{i=k+1}^{m} q_i l_i (1 - \rho_l / \rho_m) \tag{6-13}$$

where:

Q = BHA weight
ρ_{BHA} = reduced density of the BHA

Elastic elongation is affected by the forces that resist drill-string axial movement, and their distribution in the well. Forces that oppose drill-string weight due to drag occur while the string is being run down, leading to a decrease of elastic elongation.

Equation 6-12 can be used to calculate reduced elastic elongation in this case. When the drill string is pulled out, axial resistance forces cause additional elastic elongation. This elongation is calculated using the formula:

$$\Delta l_F = \sum_{k=1}^{m} \frac{P_{Fb} l_k}{E_k F_k} \tag{6-14}$$

where:

P_{Fb} = axial drag applied to the lower part of the kth section

Additional elastic elongation caused by forces resisting drill-string axial movement in a borehole, must be added to full elastic elongation of the drill string when it is pulled out and subtracted when it is run in.

6.6 ADP Drill Strings for Directional Drilling in Western Siberia

ADP was widely used by the company Yuganskneftegaz (a subsidiary of Glavtyumenneftegaz) for drilling directional wells in Western Siberia. Tables 33 and 34 show examples of drill-string assemblies for this type of well drilled on turbines.

Table 33. Drill-String Assembly for Well No. 4166 (Povhovskaya)

Planned Depth: 2800 m Actual Depth: 2808 m
Vertical Depth: 2675 m Deviation: 530 m

Drill-String Assembly	Section Length (m)	Measured Depth (m)
BHA	26	26
DC-178	24	50
ADP-147x11	24	74
SDP-127x9	465	539
ADP-147x11	2269	2808

Table 34. Drill-String Assembly for Well No. 1057 (Povhovskaya)

Planned Depth: 2800 m Actual Depth: 2870 m
Vertical Depth: 2745 m Deviation: 732 m

Drill-String Assembly	Section Length (m)	Measured Depth (m)
BHA	26	26
DC-178	26	52
ADP-147x11	24	76
SDP-127x9	475	551
ADP-147x11	2319	2870

While drilling these wells, significant attention was given to reducing ADP consumption per meter by using advanced operational methods, improving the quality of the pipes, and introducing a substantiated norm of pipe consumption. These measures allowed extending the operational period of a set of ADP (2200 m) before the first service of the tool joint threads to 55,000-60,000 m (180,000-197,000 ft) drilled. At the same time, when tool-joint threads were sent for repair, ADP parameters allowed further operation. For example, the average pipe-wall thickness was 10.5 mm compared to the minimum allowable 8 mm; average OD of the tool joints was 171 mm compared to an allowable limit of 166 mm.

After the tool-joint threads were repaired, the test pipe sets were sent to further operation. Their cumulative penetration reached 100,000 m (328,000 ft) before the pipes were considered unusable. At this point, minimum thickness of the pipe main body was 9.2 mm, and the average value remained in the range 9.8 mm to 10.3 mm.

Average specific operational wear of the main body of ADP for directional well drilling with turbines by Yuganskneftegaz lead to the conclusion that it is possible to increase ADP operational life to 175,000-190,000 m (574,000-623,000 ft) provided their application is optimized and steel tool joints are repaired and replaced as necessary.

6.7 ADP Drill Strings for Drilling Ultradeep Wells

Drilling ultradeep wells introduces specific operating conditions for the drill string that significantly impact operating parameters for drill pipes and connections. The upper sections of the drill string are exposed to considerable static tensile and torsion loads due to the weight of the string and forces that resist axial movement and rotation. Closer to the bottom, absolute values of static loads are decreasing, while variable bending loads are increasing. Operation of the lower sections of the drill string is additionally complicated by long exposure to high temperatures. In the general case, temperature, load, and time components are unevenly distributed along the string. This distribution depends on a combination of geological and operational drilling parameters. These factors must be taken into account while developing a design and operating a drill string.

A drill string in a 10,000-m well is exposed to the highest stress while it is lifted up from the bottom and the first 5-6 drill-pipe stands are pulled out. Calculation of static tensile strength is the main element of design of a drill string for ultradeep wells. Tables 35 and 36 show examples of these types of calculations for the Kolskaya SG-3 ultradeep well (12,000 m) and Krivorozhskaya SG-8 (5580 m).

The drill-string assembly for the Kolskaya SG-3 is typical of assemblies used in ultradeep drilling conditions. Table 35 shows that ADP from three alloys was used while drilling SG-3, depending on the tensile loads and temperature distribution. ADP of the AK4-1T high-temperature alloy was used for the lower sections of the string, and ADP from the 1953T high-strength alloy for the upper sections. 150 m of SDP was installed directly above the BHA for a smoother transition in rigidity from the drill collars to ADP. A section of SDP was installed in the upper part of the drill string to ensure its strength uniformity, as well as safe operation in case of a break in the ADP. Uniformity of strength was achieved by ensuring equal safe loads for all sections of the string. In the example above this safe load was 560-570 kN.

Table 35. Kola Ultradeep Well SG-3 Drill-String Design at 12,000 m

Drill-String Sections	Section Length (m)	Cumulative Length (m)	Section Weight in Mud (kN)	Cumulative Weight (kN)	Drag Forces (kN)	Total Pick Up Load (kN)	Allow Pick Up (kN)	Safe Load (kN)
BHA	40	40	50	50	50	100	-	-
SDP 140x9	150	190	43	93	55	148	-	-
ADP 147x11-AK4-1T1	2800	2990	338	431	300	731	1300	569
ADP 147x13-AK4-1T1	1005	3995	140	571	380	951	1530	579
ADP 147x15-D16T	1205	5200	145	725	445	1170	1730	560
ADP 147x11-1953T1	1200	6400	145	870	520	1390	1950	560
ADP 147x13-1953T1	1400	7800	194	1064	650	1714	2280	566
ADP 147x15-1953T1	1450	9250	217	1281	750	2031	2590	559
ADP 147x17-1953T1	1100	10350	178	1459	870	2329	2890	561
SDP 140x11	1650	12000	557	2016	1100	3116	3680	564

Table 36. Krivoy Rog Ultradeep Well SG-8 Drill-String Design at 5580 m

Drill-String Assembly	Section Length (m)	Measured Depth (m)
BHA	62	62
DP SBT: TBS-162x8-E	354	416
ADP 164x9-D16T	4040	4456
ADP 168x11-D16T	1124	5580

6.8 ADP Drill Strings for Deepwater Stratigraphic Drilling

Extensive development of natural resources deposited in deepwater zones on continental shelves, as well as studies of oceanic crust geological structure using deepwater stratigraphic well drilling, prescribe specific requirements for development of equipment and technology for these complex and critical operations. The drill string is an important element in deepwater drilling. It supports a complex combination of static and dynamic loads:

1. Tensile loads in a string under its own weight taking account of buoyancy in sea water
2. Bending moments that result from drill-ship offset (horizontal motion, pitching and rolling)
3. Reactive forces caused by operating the bit and downhole mud motor
4. Lateral loads from seawater currents whose parameters vary with depth
5. Dynamic forces as a result of drill-ship heave
6. Torsion loads due to drill bit rotation by the power swivel (rotary machine)

These loads determine tension, bending and torsion stresses that affect a drill string while drilling offshore stratigraphic wells from a drill ship.

A combination of these stresses produces combined stress states in various sections of the string. At the same time, static components of stress state and dynamic components resulting from rotation of the string, ship movements, and currents, lead to unbalanced cyclic loads. This results in accumulation of fatigue damage, which is aggravated by corrosion processes in seawater.

Studies performed indicated that ADP is the most reliable and efficient drill pipe for deepwater drilling conditions. At the same time, aluminum alloys for ADP must have high resistance to fatigue failure from alternating bending stress as well as corrosion resistance in seawater.

In 1985-1990 in the USSR, a large amount of research and design work lead to the development and construction of "Nauka" ("Science"), a ship for deepwater stratigraphic well drilling. Unique equipment and technology for offshore stratigraphic drilling and surveying operations were developed under this program. Developments included new 146-mm internal-flush ADP that was successfully tested and is currently used in drilling deepwater wells from low-tonnage drill ships ("Busentavr" or "Bavenit" type, etc.). Table 37 shows examples of a drill-string assembly from internal-flush ADP as used on "Nauka."

Table 37. ADP Application for Scientific Offshore Drilling

Drill-String Design for Project "Nauka D/S"

Drill-String Assembly	Section Length (m)	Measured Depth (m)
BHA	100	100
ADP -168x9		
-164x9	2400	3500
-168x11	1250	4750
-172x13	1250	6000
SDP -168x11	1350	7350

Drill-String Assembly	Section Length (m)	Measured Depth (m)
BHA	100	100
ADP -164x9	5150	5250
-168x11	1300	6550
-172x13	1000	7550
SDP -168x11	1400	8950

Drill-String Assembly	Section Length (m)	Measured Depth (m)
BHA	100	100
ADP -164x9	4500	4600
-168x11	1300	5900
-172x13	850	6750
SDP -168x11	1530	8280

Drill-String Assembly	Section Length (m)	Measured Depth (m)
BHA	100	100
SDP -168x9	1000	1100
ADP -164x9	4500	5600
-168x11	1500	7100
-172x13	1250	8350
SDP -168x11	1700	10,500

Drill-String Assembly	Section Length (m)	Measured Depth (m)
BHA	100	100
SDP -168x9	1000	1100
ADP -164x9	3900	5000
-168x11	1500	6500
-172x13	1250	7750
SDP -168x11	1700	9450

7. ADP for Vibration Damping

Waves travel through the drill string during drilling operations and are generated by longitudinal, lateral, and torsional vibration of downhole mud motors and pulsation of drilling mud. Distribution and damping of vibration in the drill string are both complex in nature, and depend on physical and mechanical properties of the pipe material, length of the string, pipe dimensions, geological and operational parameters, properties of the drilling fluid, type of bit and downhole motor, etc. Basic parameters defining vibration processes in the drill string are difficult to determine using analytical methods due to the large number of factors affecting these processes.

Various types of bottomhole bumper assemblies are used in drilling practice to damp vibration of the drill bit. Common drawbacks in their application include a limited range of amplitude/frequency characteristics and low operational reliability.

A more efficient means of damping and controlling vibration processes in the drill-bit/drill-string system is designed to take advantage of certain physical and mechanical properties of drill-pipe material. Compared to steel, aluminum alloys have a high capacity for absorbing and dissipating elastic vibrational energy. Research studies performed by specialists from the Tyumen Industrial Institute indicated that all types of ADP have approximately equal capacity for absorbing elastic vibrational energy. Also, heavy-wall ADP has about 50% higher damping capacity than SDP. ADP with articulated joints has a damping factor 30-35% lower than rigidly connected ADP.

This suggests that vibration damping is more extensive in the bottom section of the drill string set on the bottom than in the stretched sections of the string.

Thus, a controlled wide range of amplitude/frequency characteristics can be formed by varying position, length, and other dimensional parameters of sections within the drill string. In addition to reducing vibration, there is a possibility to use elastic vibrational energy to increase efficiency of rock crushing while drilling, i.e., to control BHA vibration levels.

This concept was tested by the company Samaraneft while drilling 18 wells 1580-1630 m deep on turbines without SDP. 75-150 m (246-492 ft) long ADPs with 180x90 mm heavy walls were used to create axial loads in the BHA. While drilling these wells an average increase in penetration per bit of 24% was recorded as compared to similar wells drilled with SDP.

Studies conducted by VNIIBT (All-Russia Scientific and Research Institute of Drilling Equipment and Technology) showed that special BHAs with ADP for separating vibration waves generated at the bottom must be used to increase drilling efficiency. Reflection of longitudinal vibration waves was observed in the areas of transition from SDP to ADP. The studies were performed in fields operated by Tatneft, where a 325-

mm (12.8-in.) section of SDP was used with the BHA. Section length was three-fourths of a longitudinal vibration wave length generated by the bit on a high-speed turbine at normal drilling conditions. Other sections of the drill string were ADP. As a result of operation of this type of BHA, parameters of mechanical drilling increased by 20-27% due to utilization of energy reflected in longitudinal vibration waves.

Studies performed by specialists from the Oil Institute in Ivano-Frankovsk allowed evaluation of the effect of the position of ADP sections on amplitude/frequency characteristics of drill-string vibration. According to study results, within the frequency range of 4-6 Hz (which corresponds to 80-120 RPM at the bit), a drill string with an ADP section has 1.1-1.8 times lower rigidity than a complete SDP string. This allows an increase in string RPM without additional risk of drill-pipe or connection failure. Moreover, this feature contributes to more efficient use of bit capacity. An ADP section of sufficient length included in the drill-string assembly (in terms of the dynamic effect on vibration) is equivalent to an upper vibration dampener. It reduces vibration interference in drill-string sections below and above the ADP, and makes mechanical drilling more efficient.

Tests and studies on wells in Western Siberia determined values of a high-frequency component of vibration caused by impact of bit teeth on the bottomhole. For rocks and drilling parameters in Western Siberia this value is 50-80 Hz, whereas the low-frequency component from longitudinal helical movement of the drill string is about 14-19 Hz. These data were used to calculate the resonance frequency of the BHA used in Western Siberia. This frequency in the drill-bit/drill-string system remained in the range of 20-60 Hz.

Figure 32 shows the results of resonance frequency calculations for BHAs with SDP, DC, and heavy-wall ADP. The BHAs with ADCs are seen to provide the required frequency range.

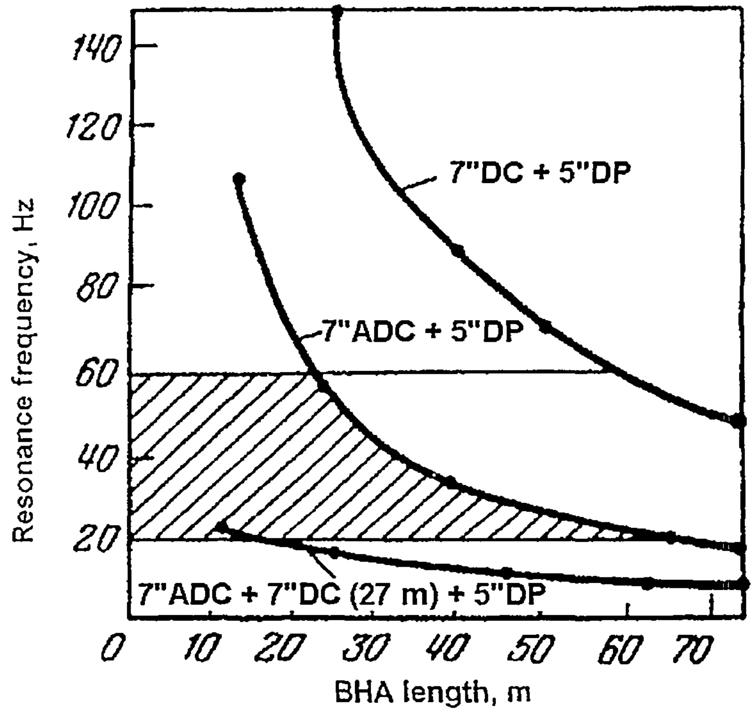


Figure 32. BHA Design and Resonance Frequency

8. ADP in Extended-Reach Drilling

Recent years have witnessed extensive worldwide activity drilling directional wells with extended-reach horizontal intervals (ERD wells). These wells are drilled during exploration and development of oil and gas fields in continental shelf zones. In some cases, these types of wells can be drilled more effectively from an onshore area using directional drilling. The same drilling technique is widely used for drilling horizontal intervals in productive horizons to increase oil and gas recovery.

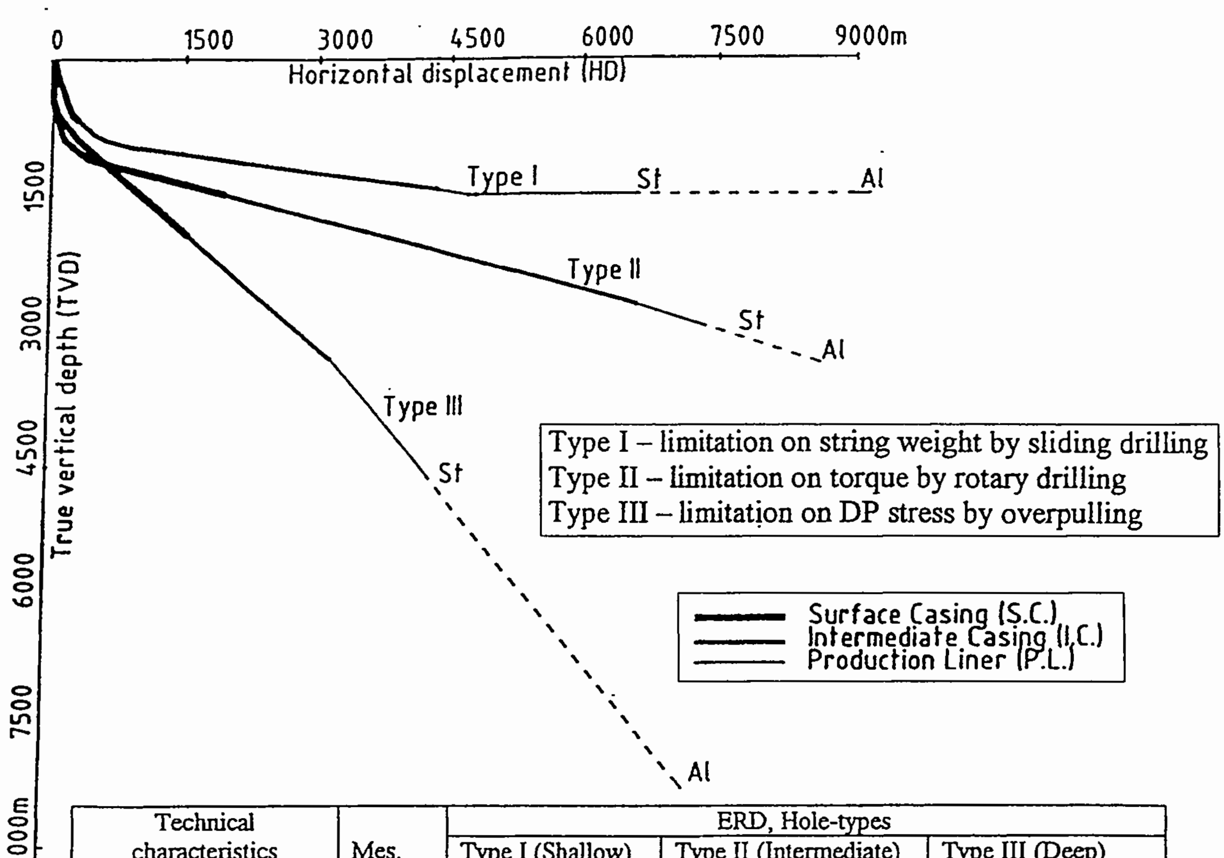
Based on depth and length of ERD boreholes, three types of wells are usually described (Figure 33):

Type I – shallow wells (TVD = 1500-2000 m; 4900-6600 ft) with highly extended horizontal intervals. There is only a limited possibility of using string weight to transfer weight to the bit, which limits the length of these boreholes. This limitation is due to high level of resistance (drag) affecting movement of the string in horizontal intervals.

Type II – medium depth directional wells (TVD = 3000-3500 m; 9800-11,500 ft) with a high angle of deviation (50-60°). The maximum borehole extension length in this type of well depends primarily on maximum torque capacity of the drill string and rig drive, which is limited by high drag on the rotating drill string in the hole.

Type III – deep directional wells (TVD = 5000-6000 m; 16,400-19,700 ft) with 30-40° deviation from vertical. The main factor limiting borehole extension length in these wells is the maximum tension load in the drill string when it is picked up from the bottom and the first few joints are pulled out. This limitation is also due to high drag forces.

The table shown within Figure 33 summarizes design parameters and maximum drill-string length for the three types of ERD wells for ADP and SDP cases. In addition to the advantages of ADP compared to SDP enumerated in this report, utilization of ADP in drilling ERD wells will allow drilling a longer borehole without increasing hook loads or drive capacity of the rig. Type I wells will have a 15% longer borehole, Type II 5% longer, and Type III 50% longer.



Technical characteristics	Mes.	ERD, Hole-types					
		Type I (Shallow)		Type II (Intermediate)		Type III (Deep)	
		StDP	ADP*	StDP	ADP	StDP	ADP
OD Pipe	mm	140	168/140	168	168	140	168/140
Wall thickness	mm	10	13/13	10	13	10	13/13
Unit weight in air	N/m	319,5	272/163	368	272	319,5	272/163
Mud density	Kg/m^3	944	944	1093	1093	1530	1530
Unit weight in mud	N/m	281	196/115	316	168	257	147/78
Maximal drillstring length by safety factor 1,6	m	8200	9400	8600	9000	6400	9600

* 400m of StDP (168x10) are used in upper part of drillstring

Figure 33. Comparison of Steel and Aluminum DP for ERD Applications

9. ADP in Deepwater Riserless Drilling

Deepwater drilling without a riser pipe is most often conducted from low-capacity drill ships for purposes of exploration or scientific study of oceanic crust. The main advantage of ADP in these applications (as compared to SDP) is the possibility to essentially increase water depth while using the same low-capacity drill ships. For example, while drilling geotechnical wells from "Busentaur" and "Bavenit" type drilling ships using SDP, maximum water depth is limited to about 500 m. By comparison, the experience of the AQUATIC Company with drilling from the same ships shows potential for drilling in 1500-m (4920-ft) water depths.

Deepwater riserless drilling is complicated primarily by high velocity currents (over 1 m/sec; 3.3 ft/sec) resulting in:

- Vortex-induced lateral vibration of the drill string in a current homogenous over the whole depth
- Significant increase in drag coefficient for a vibrating drill string (up to 2.4-2.8). For a non-vibrating drill string this coefficient is 1.2-1.3.
- Uncontrolled offset of the drilling vessel as a result of high velocity current and wind speed

These negative factors lead to significant bending of the drill string axis, which results in high bending stresses and frequent failures of the drill string while drilling, tripping, making a connection, etc.

These disadvantages were partially eliminated while drilling from the "Bavenit" drilling vessel in the Strait of Gibraltar with up to 2 m/sec (6.6 ft/sec) current velocities. A rope was coiled around the drill pipes according to a specified pattern to eliminate vibration caused by trailing vortices in the current. This enabled randomizing wave generation and development of wake vortices, and slightly reduced the level of lateral vibration.

To reduce the level of bending stress in the drill string in contact with the drill ship moon pool, a bumper frame was installed in the latter. Introduction of an additional point of support in the upper part of a drill string allowed more even distribution of bending stresses between the power swivel, spider, and bumper frame.

A special computer program (BURN PAS) was developed to control stress/strain state of the drill string while the vessel is moved by currents in rapidly changing hydrologic conditions. This allowed calculating adequate displacement of the vessel around the well, and maintaining a safe load factor for the drill string within required limits.

Further research and studies by the AQUATIC Company were aimed at developing technology for deep-water riserless drilling in high velocity currents. The studies were performed under various contracts and resulted in development of technical solutions, including:

1. Installing fairings on the drill string, which completely eliminates vortex-induced vibration and reduces the drag coefficient on the drill pipe to 0.3-0.5. As a result of the analysis of hydrofoil profiles, a fairing design with 2.2-2.4 elongation was recommended. The design includes stabilizers installed on the fairing tails at 45°.

2. Shaping the seabed frame channel, which formed an additional point of support and allowed more even distribution of bending stresses between the wellhead and frame.

3. Intentional offset and maintenance of vessel position to efficiently distribute bending stresses between the upper (swivel/spider/bumper frame) and the lower (wellhead/seabed frame) points of the drill string. The general objective of vessel displacement is to equalize safe load factors in the upper and the lower points of the drill string. This is achieved by displacing the vessel for a distance of up to 7-10% of the water depth in a direction opposite the dominating current.

4. Development of a special computer program for analyzing stress and strain state of the drill string to assist offshore drilling in high-velocity currents. This included upgrading the original BURN PAS software. The latest versions BURN 9 and BURN 10 allow calculating drill-string design for drilling, tripping, and well spudding operations. The program assists in selecting optimum (for maximum safe load factor) displacement of a vessel about a well for a specified pattern of current distribution with depth. The program is also used for calculating optimum parameters of a bumper frame (diameter of opening and distance to the spider) and a seabed frame (height and conicity). BURN 10 software was used to substantiate the possibility of drilling with ADP in 1920 m (6300 ft) of water west of the Hebrides in a high-velocity linear current (1.3 m/sec (4.3 ft/sec) at the surface, 0.5 m/sec (1.6 ft/sec) at the seafloor).

The research work and studies demonstrated the possibility of riserless drilling with this type of high-velocity current with a drill-string safe load factor of at least 1.5, provided fairing elements are installed on the drill string (except for the lower 150 m). The drag coefficient of fairing elements is about 0.4. The bumper frame has a 0.9-m opening and is installed 7 m from the spider. The vessel is purposely displaced from the well by 150 m (492 ft) (7.7% of water depth) against the current.

The latest software (DBUR) uses continuous information from current velocity sensors, and allows calculating and visualizing on the computer display areas of vessel displacement from the well due to drill string bending while drilling.

10. Economic Benefits of ADP

Technical and economic parameters related to drilling depend on the weight of the drill string. For the same hook-load capacity of the rig, cumulative trip time over a complete drilling operation is directly proportional to power consumption for these operations. At the same time, power consumption depends on weight distribution between sections of the drill string as well as total weight.

Drill-string weight is a function of density of the drill-pipe material, its dimensions, and well depth. Since a drill string operates in a well normally filled with drilling mud, buoyancy forces impact operations by reducing the weight of the drill string. The following coefficient is used to calculate this weight reduction:

$$K_o = (\rho_m - \rho_l)/\rho_m \quad (10\text{-}1)$$

where ρ_m and ρ_l are densities of the pipe material and mud.

Figure 34 shows correlations between buoyancy factor (weight reduction coefficient) of drill pipes from aluminum alloys (line 1), titanium (line 2), and steel (line 3) and mud density. Buoyancy factor for ADP in 1.2 g/cm^3 mud is 0.57, whereas for SDP in the same mud buoyancy factor is 0.85. This means that an aluminum string in 1.2 g/cm^3 mud is reduced to almost half its weight in air, as compared to a steel string, which is only 15% lighter.

A number of special field tests were performed to evaluate tangible technical and economic advantages of ADP. The tests determined more exact values for decreases in time that might be expected for certain tripping operations after replacing SDP with ADP. Similar drilling rigs operated by Samaraneft with similar mechanical equipment were used for the tests. Table 38 shows a summary of these tests.

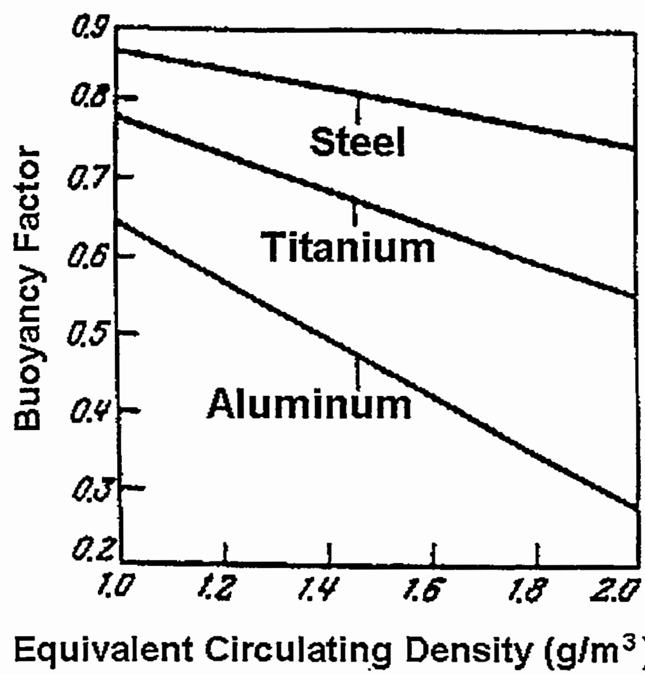


Figure 34. Buoyancy Factors for ADP, TDP and SDP

Table 38. Trip Time (sec) for ADP and SDP Drill Strings

Mode of Operation	**SDP** Reeving a line (5x6)		**ADP** Reeving a line (3x4)			Average		Δ Time with ADP
	Hole 51	Hole 189	Hole 181	Hole 185	Hole 190	**SDP**	**ADP**	
Pulling Out of Hole								
2nd speed	-	108.9	67.2	65.9	68.9	108.9	67.3	41.6
3rd speed	-	65.7	43.3	42.8	42.9	65.7	43.0	22.7
4th speed	49.7	45.5	29.8	28.1	28.8	45.7	28.9	16.8
Land drill pipe at slips	3.6	2.2	3.0	2.9	2.8	2.9	2.9	0
Unload elevator, lower and break out pipe stand	35.8	29.7	19.4	21.0	21.7	32.7	20.7	12.7
Remove pipe stand from tackle block	5.3	5.9	7.6	6.0	6.1	5.6	6.6	-1.0
Total						+110.8		
Running in Hole								
Pull out of unload elevator	30.7	30.4	22.3	26.6	24.2	30.5	24.4	6.1
Release from slips	1.4	-	1.5	1.1	-	1.4	1.3	0.1
Run in	24.8	20.7	15.9	19.1	19.3	22.7	18.1	4.6
Land on elevator	5.2	3.7	2.4	2.7	3.2	4.5	4.1	0.4
Insert stand in tackle block	6.5	4.7	5.7	5.6	6.5	5.7	5.9	-0.2
Total						+11.0		

Utilization of ADP leads to a significantly lower power consumption for tripping operations.

Figure 35 presents typical drawworks power consumption curves per drill-pipe stand at various speeds for the same drawworks pulling out SDP and ADP strings. The area enclosed by the drive power curve shows power consumption for pulling out one joint of an ADP string. The average power area for ADP is almost half that for SDP.

Figure 35 also shows that ADP strings were pulled out faster. Analysis of technical and economic parameters for drilling in fields with similar conditions and with the same type of drilling equipment indicates that ADP (instead of SDP) reduces trip time by about 18-35%. Also, a considerable drop in power consumption for these operations was observed.

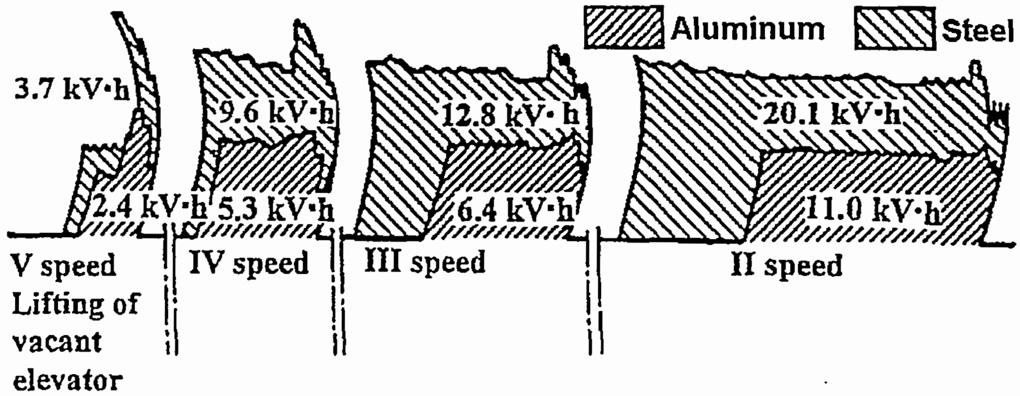


Figure 35. Power Consumed for Pulling ADP and SDP

There is no doubt that utilization of ADP while drilling saves material resources and time, in light of the fact that consumption of fuel and lubricants, drilling line, brake shoes, and spares for rig lifting equipment is proportional to power consumption.

Hydraulic resistance of ADP is also 15-25% lower than of SDP due to specific characteristics of the ADP surface. This leads to lower hydraulic losses and higher drilling efficiency.

The technological and economic advantages of ADP described in this section can be supplemented with comparative technical parameters for a standard range of ADP manufactured by the Reynolds company and SDP of API category E strength. Table 39 presents data for ADP from 2024-T6 alloy which is similar to the Russian D16T alloy in composition and mechanical properties. Table 39 shows that ADP from this alloy outperforms category E strength SDP of similar size.

Table 39. Comparison of Reynolds Aluminum Drill Pipe (ADP) and Grade E Steel Drill Pipe (SDP)

DRILL-PIPE PROPERTIES	PIPE DIAMETER (MM)											
	73		89		102		114		127		140	
	ADP	SDP	ADP	SDP	ADP	SDP	ADP	SDP	ADP	SDP	ADP	SDP
OD (mm)	85.1	73.0	94.0	89.0	106.7	101.6	116.8	114.3	130.8	127.0	144.3	139.7
ID (mm)	54.6	54.6	68.0	70.2	83.3	84.8	91.4	97.2	104.1	108.6	118.8	121.4
Wall thickness (mm)	15.2	9.2	13.0	9.4	11.7	8.4	12.7	8.6	13.3	9.2	12.7	9.2
OD tool joint (mm)	104.8	104.8	120.7	120.7	146.1	146.1	155.6	155.6	177.8	177.8	178.3	178.3
Unit pipe weight with tool joint (kg/m)												
In air	11.0	16.3	11.7	20.7	14.4	23.2	16.0	26.6	20.5	31.8	21.5	34.8
In mud 1.2 g/cm^3	6.7	13.8	7.2	17.5	9.0	19.6	10.3	22.5	13.2	26.9	13.9	29.5
In mud 1.7 g/cm^3	5.1	12.7	5.5	16.2	7.1	18.2	7.9	20.9	10.4	25.0	10.9	27.4
Load capacity (kN)												
Allowable tension limit	1266	973	1348	1233	1423	1296	1696	1498	2006	1796	2138	1985
Ultimate load	1566	1352	1725	1703	1811	1798	2157	2079	2552	2497	2728	2747
Torsion limit for stress = $\sigma_{0.2}$ (kN-m)	21.5	15.9	28.6	26.6	33.9	33.8	47.5	44.6	64.4	59.1	76.8	72.7
Collapse limit (MPa)	99.6	91.1	84.9	77.8	69.0	62.6	68.9	57.3	65.3	55.6	56.8	48.9
Burst limit for stress = $\sigma_{0.2}$ (MPa)	130.6	156.3	130.5	130.6	84.5	102.4	83.9	92.9	78.6	69.8	67.9	81.5

11. Conclusions

1. A large volume of scientific R&D performed in Russia resulted in the development, manufacture and wide utilization of aluminum drill pipe (ADP). These pipes are currently used in most drilling operations for oil and gas wells in Russia. They are also used in drilling directional wells, offshore wells, and all ultradeep wells.

2. The technological and economic benefits of applying ADP were instrumental in expanding the sphere of ADP usage in exploratory drilling. It is now used as tubing, in well workovers and downhole repairs, for in-field service and distribution lines, etc. Work has also been initiated for evaluating the potential for aluminum alloys for risers for deepwater drilling and casing.

3. The greatest benefits of ADP are observed in wells over 3000 m (9843 ft) TMD. The deeper the well is, the higher the percentage of time spent tripping to replace worn bits etc., rather than actual drilling. At the same time, resolving drilling problems and fishing operations become more complicated. Using ADP instead of SDP (steel drill pipe) under these conditions yields improved results.

4. Drilling offshore exploratory and development wells on the continental shelf involves a number of unique technical problems. In some cases, these wells can be drilled more efficiently from an onshore area using directional drilling. ADP with high resistance to alternating bending stress and corrosion shows good performance and enables drilling ERD wells with longer extended-reach intervals.

5. Drill-string weight is directly proportional to well depth, which often requires using rigs with higher hook-load capacity and, so it may seem, pipes with higher strength. However, high specific strength (i.e., ratio of material strength to specific weight) is more important. This suggests that ADPs are most efficient in this case.

Figure 36. Aluminum Drill Pipe

6. Lower, not higher, rigidity of the drill string is required while drilling directional, horizontal, and highly deviated wells. Without changing pipe dimensions, lower rigidity can be achieved only by using pipe materials with lower elasticity moduli. This will lead to a proportional decrease in bending stress and normal force that presses the drill string against the borehole. As a consequence, torque and drag are also reduced. ADP has significantly lower elasticity modulus than SDP, which makes ADP even more efficient.

The experience of Russian engineers and scientists in designing, manufacturing, and using ADP in a variety of drilling conditions, along with studies performed for evaluating operational reliability and prospects for application, clearly demonstrate the tremendous potential of ADP. It is hoped that the significant benefits enjoyed historically in Russia's drilling industry with ADP might be shared by the drilling community worldwide.

12. References

1. Akgun, F., Maidla, E., Basovich, V., and Gelfgat, M., 1998: "Why Not Use Aluminum in Drilling?" IADC/SPE 47823, presented at Asia Pacific Drilling Conference held in Jakarta, Indonesia, September 7-9.

2. Basovich, V., Gelfgat, M., Akgun, F. and Maidla, E., 1998: "Aluminum Application in Drilling," SPE 49957, presented at Asia Pacific Oil and Gas Conference and Exhibition held in Perth, Australia, October 12-14.

3. Fine, G., Basovich, V., Pisarnitsky, A., Jemetz, B., Mazurova, L., Gelfgat, M., 1995: "Aluminium Alloys for Offshore Drilling Systems," OMAE-95-482, Copenhagen.

4. Fine, G., Shtamburg, V., Daneliants, S., 1990: "Oil Field Light Alloy Drillpipes," Published by "Nedra", Moscow, 222 pp.

5. Gelfgat, M., Basovich, V., 1999: "Aluminum Tubular in Deep Water Drilling Application," presented at the ETCE'99 75th Energy Technology Conference and Exhibition, Houston, Texas, February.

6. Gelfgat, M., Podrazhansky, A., Geise, J., and Paff, G., 1997: "Stratigraphy Drilling in Deep Water with Aluminum Drill Pipe Application," SPE 37597.

7. "Kola Ultradeep Scientific Results and Research Experience," Published by "Technoneftegaz," Moscow, 1998, 260 pp.

#01

IMPLEMENT RUSSIAN ALUMINUM DRILL PIPE AND RETRACTABLE DRILLING BITS INTO THE USA

Volume II: Development of Retractable Drill Bits in Russia

Final Report

TR99-24

Prepared for:

Mr. William J. Gwilliam
Federal Energy Technology Center
U.S. DEPARTMENT OF ENERGY
Morgantown, West Virginia

Performed Under Contract No. DE-FG26-98FT40128

By:

Aquatic Company
Moscow, Russia

and

Maurer Engineering Inc.
2916 West T.C. Jester
Houston, Texas 77018

August 1999

Acknowledgements

This report summarizing the development of retractable-bit technology in Russia was prepared for the Federal Energy Technology Center under DOE Grant No. DE-FG26-98FT40128. The assistance of the DOE Project Director, Mr. William J. Gwilliam, is gratefully acknowledged.

Aquatic Company personnel: Dr. Michael Gelfgat (Manager of Russian Team); Mr. Rudolf S. Alikin (Chief Designer); Dr. Yakov A. Gelfgat (Consultant); Mr. David I. Indrupskiy (Consultant); Ms. Valentina Kholostova (Engineer); Ms. Elmira M. Pogosyan (Assistant); and Mr. Boris Volkovoy (Interpreter).

Maurer Engineering personnel: Dr. William C. Maurer (Project Manager) and Mr. Greg Deskins (Project Engineer).

Table of Contents

List of Figures

List of Tables

Executive Summary

This report describes the development of Retractable Bits (RBs) for drilling without the need to trip the drill string that has been ongoing in Russia during the past 50 years, including the latest research and field applications in offshore stratigraphic drilling projects. The potential to drill with fewer trips of the drill string significantly affects the process of borehole construction, sidetracking, as well as workovers. Other benefits of RBs include:

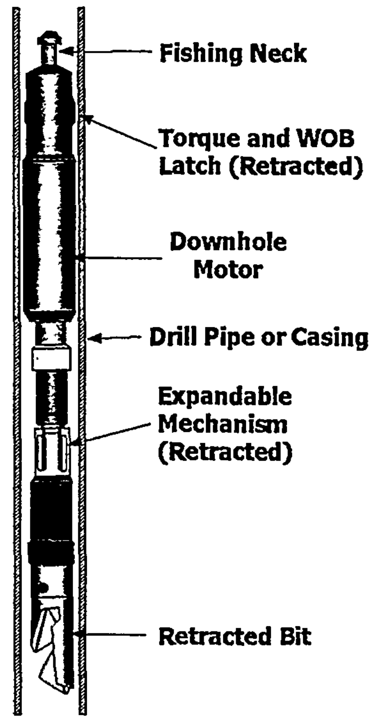
1. Continuous circulation of the borehole during the RB operational cycle (run in/drill/pull out)

2. Tools for a variety of operations (e.g., drilling, coring, milling) can be run in turn without pulling the drill string

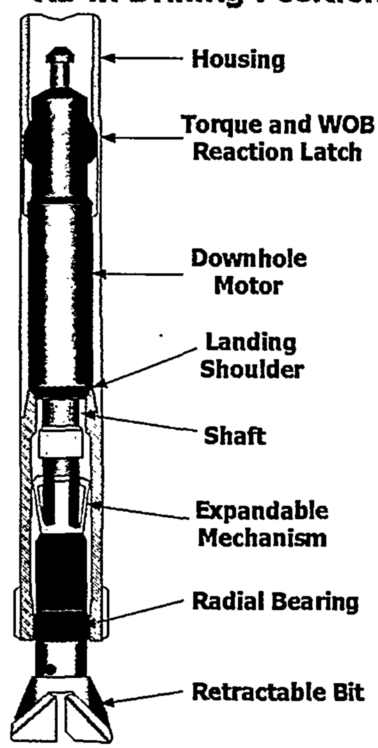
3. The ability to log the borehole without pulling the drill string

4. Reduction of rig crew workloads

RB in Running Position



RB in Drilling Position



Background

Methods to drill without pulling the drill string were first developed and applied at the beginning of the 20th century. Drilling systems consisting of RBs and downhole motors were proposed in 1902. Great interest in RBs was displayed in the USA, where the first designs of rock cone RBs were patented before World War II.

The first Russian field experiments on turbodrilling with RBs took place in the early 1930s. Major efforts on drilling with RBs were initiated in 1948 by two groups of engineers and scientists. One group worked on turbodrilling/downhole motors with RBs; the other developed rotary RBs. Significant field experience has since been accumulated with both systems.

Field Experience

Drilling or rock destruction with RBs is similar to conventional turbine drilling, and is affected by a combination of basic technical parameters: WOB, mud circulation rate, and turbine/motor RPM. RPM depends on WOB, mud circulating rate, rock physical properties, and bit type. Originally, direct-drive hydraulic turbines with operating speeds of 500-600 RPM were used with RBs. Because of the high speeds, durability of bit bearings was very low. Later, low-RPM downhole motors (DHMs) were applied. For example, a gear-reducer turbine and screw DHM at 120-200 RPM were developed to work with 220-mm (8.7-in.) RBs. Actual WOB for a 220-mm bit was below 12 tonnes (26,460 lb) at 7.0-8.0 MPa (1000-1160 psi) pressure drop in a retractable tool.

From 1965 to 1971, 26 exploratory and development boreholes 2500-3000 m (8200-9800 ft) deep were drilled during the process of commercial testing at the Experimental Turbodrilling Department of PO Saratovneftegas (Production Amalgamation). The total footage drilled by RBs was nearly 41,000 m (134,500 ft). Most footage was drilled under very complicated geological conditions – gas and water shows, unstable formations, caving tendencies, etc.

Conclusions related to drilling at PO Saratovneftegas include:

1. In areas where high-durability rock bits are used for standard drilling at low RPM, drilling with RBs with increased RPM holds promise

2. Compared to high-performance, low-RPM rotary drilling, RBs with DHMs are very competitive under certain geological and technical conditions

3. As technological improvements result in increases in footage per bit run in standard drilling, the efficiency of drilling with retractable systems will depend on the rate of penetration increase with RBs and any decrease in footage per bit due to shorter RB life.

It was also concluded that there are specific applications for RB technology that can be highly efficient irrespective of RB drilling performance:

- Drilling unique ultradeep wells
- Drilling extended-reach directional boreholes with complicated profiles with high angles of inclination including horizontal
- Drilling with casing and leaving it in the borehole as a surface or intermediate casing string
- Underbalanced drilling

Another result of commercial testing of RBs was the development of a similar method for coring in hard crystalline rocks. The advanced continuous coring system was designed for ultradeep borehole applications as part of a national program "Investigation of the Earth's Crust and Ultra-Deep Drilling." The calculations showed that, when drilling below 7000 m (22,970 ft) (corresponding to the second stage of the Kola SD-3 ultradeep borehole), this method would be substantially more effective than alternative systems.

Three-cone RBs were recently used in the stratigraphic drilling project of IKU Petroleum Research (Norway) in 1993. This was the first field test of the Complete Coring System in deep-water environments. Water depth was about 1500 m (4921 ft), and well depth in the range of 150-200 m. Total footage for reaming in intervals composed of consolidated sandstone was 36.3 m (119 ft) in three runs with an average penetration rate of 2.7 m/hr (8.9 ft/hr). While spudding the test borehole, the RB drilled 10.2 m (33 ft) in clay with an average penetration rate of 13.6 m/hr (45 ft/hr). RBs with DHMs were considered as the best method to spud boreholes without a sea-bed frame to guide the BHA if soft sediments were not overlying hard rocks.

Additional field experience is described in detail in the body of this report.

Commercial RB Systems

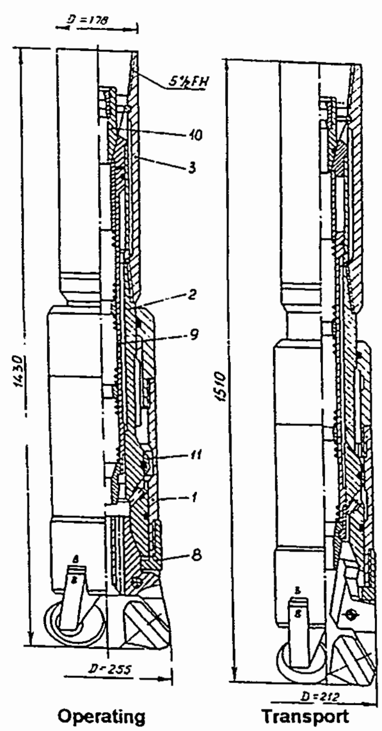
A complete BHA for drilling without pulling the drill string includes the RB, a DHM (e.g., a turbodrill with a landing unit), and a torque and WOB-reaction mechanism with a fishing neck on top. Table ES1 presents standard designs and sizes of retractable drill bits.

Table ES1. Standard Designs and Sizes of RBs

Bit Size	RB Type	ID of Expanding Mechanism	ID Marking of Drill Bits			Bit OD (mm)	
			Soft Rock	Medium to Hard Rock	Hard Rock	Drilling Position	Transport Position
#9	Two-cone bit	DRB1-9" DRB2-220		DRB2-9"S DRB2-9"SZ		220	134
	Three-cone bit	3DR-220		3DR-217S 3DR-220S 3DR-220SZ	3DR-217K 3DR-217OK	217 220	134 134
	Reamer w/ pilot	RVA1-217			RVA1-217.020	217	134
#10	Two-cone bit	DRB3-10 DRB-248	DRB3-10"M	DRB3-10"S DRB3-10"ST DRB-248S(020) DRB-248SZ(030) DRB-248ST(040)	DRB3-10"T DRB-248T(070)	248 248	154 154
	Three-cone bit	3DR1-248 M3DR2-248		3DR-248S 3DR-248SZ 3DR-248ST	3DR-248T	248	154
#12	Four-cone bit	4DV-295.010		4DV-295.020		295	203

Retractable Underreamers

Based on broad experience in RB research, development and field application, related technologies for *underreaming* were also developed. Well designs based on minimal clearances between casing/liners became common practice. Complicated geological conditions required that five or six casing strings be run with a total well depth of about 6000 m (19,690 ft). Underreamer applications improved the quality of well construction and produced large savings because of lower drilling mud and casing volumes, high rates of penetration and relatively low requirements for drilling-rig capacity. More than 100,000 m (328,000 ft) of intervals were underreamed in 1970s-1980s. In the 1980s, the cost impact in various regions was 8-20 rubles/meter reamed.



Retractable Underreamer

The highest efficiency is achieved by integrating expandable underreamers in the well for reaming intervals for several casing strings. The best performance is for reaming intervals with soft formations; penetration rate while reaming intervals in soft formations is 4-10 times higher than penetration rate while drilling.

Penetration rate for reaming intervals in hard formations is higher (1.5-2.5 times) than penetration rate while drilling the pilot hole.

Applications for RB Systems

Based on field experience in Russia and the former Soviet Union, a variety of drilling applications derive significant benefits from the application of RB technology. The most promising applications are:

1. **Drilling with Casing** – this is most promising trend for these cost-effective technologies for the next century.

2. **Ultralong Boreholes** – RBs could provide significant reductions in trip time, and allow better well control and borehole stability in 10- to 15-km (33,000- to 49,000-ft) wells.

3. **Scientific Drilling** – RBs provide unique opportunities for continuous coring and logging operations in all types of geological conditions, both on shore and off shore.

4. **Geothermal Drilling** – drilling with RBs allows cost-effective deep geothermal drilling in hard crystalline, hot formations.

1. Introduction

Subsequent with the historical development of rotary drilling technologies and increasing borehole depths, engineers developed concepts to decrease drill-string trip times to change worn bits. Development of a bit that could be run down and pulled out of the well inside the casing or drill pipe by wireline or by circulating the drilling mud, was seen as a solution with great promise.

The main feature of this type of bit would be the ability to adopt two different configurations: 1) an operating position for drilling formation at the bottom of the hole and 2) a transport configuration for moving through the drill string. This type of technology is referred to as a **Retractable Bit** (**RB**) (Figure 1). These tools provide the potential to drill without pulling pipe, which significantly affects the process of borehole construction or one of its intervals. Other benefits of RBs include:

Figure 1. Retractable Bit

1. Continuous circulation of the borehole during the RB operational cycle: running in/drilling/ pulling out

2. Change to a different purpose tool (e.g., drilling, coring, milling) without pulling drill pipe

3. Logging without pulling pipe

4. Reduction of drilling rig crew workload

At the same time, the traditional method of bit rotation by the drill string and/or downhole motor (DHM) is maintained. Not surprisingly, the advantages achieved with RBs require additional investment. In addition to a more complicated bit, special or internal flush-joint drill pipes with larger diameter (as compared to standard drill pipe) should be used. Actually, this requirement introduces a new application of RB technology with significant potential – running casing simultaneous with drilling ("casing while drilling"). Unfortunately, the quality of standard casing pipes and particularly types of thread connections did not allow using them for drilling without pulling pipe, especially in hard formations. Nevertheless, this area of RB application could be one of the major tasks for future research, because it could bring revolutionary changes to the entire drilling process.

Development of Retractable Drill Bits in Russia

This report describes the development of RB designs for drilling with DHMs without pulling pipe in Russia during the past 50 years, including the latest research and field applications in offshore stratigraphic drilling projects. This allows estimating, with due regard for current mechanical engineering achievements, the potential for using RB and related technologies in modern drilling projects. Besides drilling with casing, these include riserless drilling, geothermal drilling, and offshore scientific drilling.

2. Historical Review

2.1 Developments Outside Russia

The first projects incorporating methods of drilling without pulling pipe occurred at the beginning of 20th century. Drilling methods including RBs and DHMs were proposed in 1902. Attempts were made after World War I with this method in Poland, and a little later in France (1928). Over the same period (1920s-1930s), great interest in RBs was displayed in the USA. Bit designs with retractable blades performed worse than standard two-blade drag drill bits ("fish-tail" bits). In the 1930s, three-cone rock bits were introduced and became the principal type of rock destruction tool. The first designs of rock cone RBs were patented in the USA before World War II.

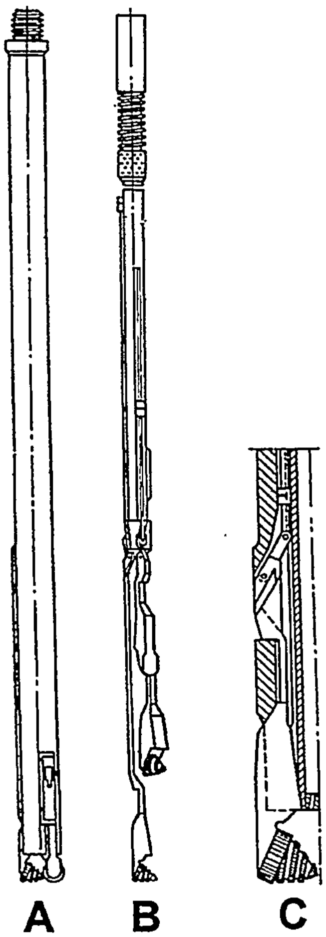


Figure 2. Three-Cone Harley RB (A-Operating Position; B-Transport Position; C-Cutter Section)

The three-cone Harley bit (Figure 2) is characterized by three separated legs with cones, which, in the transport position, are displaced along the height, forming a garland.

The four-cone Walker bit (Figure 3) has four cones, which were configured when transporting in a garland. In the operating position, the cone pairs are mounted at two levels, and the pair of cones drilling the central of the hole is slightly ahead of the peripheral pair of cones.

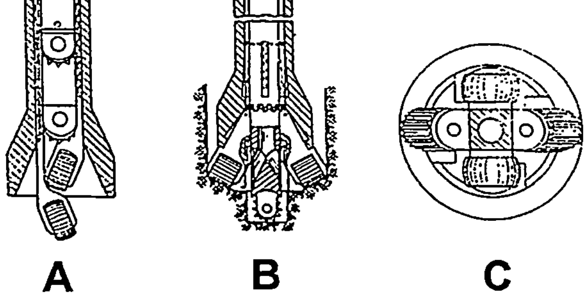


Figure 3. Four-Cone Walker RB (A-Transport Position; B-Operating Position; C-Cutter Section)

The common feature of these cone rock bits is the transmission of operating bit loads from the drill pipe shoe directly to the legs. The latter is characteristic of RBs designed for rotary drilling. RBs for operating with DHMs require separation of rotating legs from the fixed string shoe. The first designs of cone rock RBs for use with DHMs were developed based on a retractable reamer with a pilot bit. Among these is the Syul bit (Figure 4). The legs with cones are retracted under the action of flat springs. The reaction with the bottom hole induces a moment which turns up the legs. Abandoning the approach of bit load transmission to the legs directly by the shoe required expandable elements to be introduced, which under the action of an axial spring goes into the shoe bore.

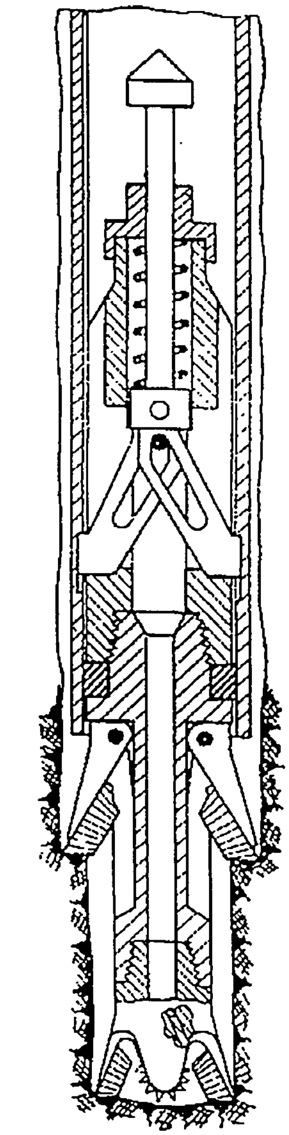


Figure 4. Syul Retractable Reamer with Pilot Bit

Carter Oil Company made several field tests based on two types of 248-mm (9¾-in.) diameter RBs with special 178-mm (7-in.) diameter pipes in 1957. The bits had four cones, arranged in transport position by pairs at two levels. In the operating position, all four cones are mounted on the same level, with two drilling the central part of the hole, and the other two the peripheral part. In the other bit there were three cones, arranged in the transport position as a garland. In the operating position, the cones are mounted as in a standard three-cone rock bit. At depths up to 500 m (1640 ft), they drilled 350 m (1148 ft) with four-cone bits and 128 m (420 ft) with three-cone bits. Hughes Tool Company acquired a license to manufacture these bits, along with the right to introduce design changes.

In the 1960s, investigations on the use of RBs in oceanic scientific drilling began with the Mohol project and the Deep Sea Drilling Project (DSDP).

In the second phase of the Mohol project a prototype retractable diamond bit for coring was developed (stage A. report "Downhole Drilling Tools" vo1 40300). An analysis of the possible use of a similar bit for the DSDP was carried out in 1968 (Engineering Study: "Methods to Penetrate Hard Formations in Deep Ocean Basins," IPOD Technical Report no. 2). It was concluded that it was not expedient to develop retractable cone rock bits because it would have been necessary to exchange the drill pipes on the Glomar Challenger drill ship with larger diameter pipes. The retractable diamond bit was recommended for supply with the aim to expand the potential for coring in hard formations. These proposals have not yet been realized.

It was announced recently that the TESCO Corporation in Calgary, Canada, acquired the patent rights to a "Drilling with Casing" method and tools in 1995. The USA patent (no. 5,197,553 with a related patent no. 5,271,472) describes methods and assemblies for drilling with the casing string instead of drill string using retrievable drilling and MWD assemblies. The retrievable bit is well known in principle as the expandable reamer with pilot bit. A DHM could be part of the assembly. Results of the first field drilling test were presented at the SPE/IADC conference in Amsterdam, February 1999. A test was completed at the TESCO R&D center in Calgary in 1998. 3040 ft of borehole were drilled with three different casing strings: 9⅝-in. casing to150 ft depth, 7⅝-in. casing until 575 feet and 5½-in. casing was used to TD. TESCO is pursuing further developments in this area.

2.2 Developments in the USSR

The first field experiments on turbodrilling with RB were carried out in Baku in the early 1930s. Work on drilling techniques without pulling pipe was resumed in 1945. Major efforts on drilling technology with RBs started in 1948 and were conducted by two groups of engineers and scientists. One group, lead by Georgyi Barshay, was working on turbodrilling with RBs; the other, lead by Yakov Kershenbaum, developed rotary RBs. Since 1953, all research and development work on drilling without pulling pipe with turbodrills was carried out in the All-Union Drilling Techniques Research Institute (the VNIIBT in Russian). The Russian authors of the present report were VNIIBT employees holding senior engineering positions in the group developing technologies for drilling without pulling pipe, which was lead by Barshay at this time. These R&D efforts can be divided into several stages:

A. Development of drilling technology with 12-in. bits (1948-1956) including:

- Designing the first retractable tool
- Testing of RBs for drilling separate intervals of borehole at depths up to 1500 m (4921 ft)

B. Development of 10-in. bits (1957-1964):

- Series production of RBs and turbodrills with retrievable rotors for drilling without pulling pipe
- Working out tripping operations with RBs
- Drilling the first test boreholes of 2100 m and then 2800 m (9186 ft) depth

C. Commercial use of drilling without pulling pipe (1965-1971):

- Tests and industrial drilling of boreholes of 2500-3000 m (8200-9800 ft) depths
- Mastering drilling technology
- Development of special retractable tools for troubleshooting and problem avoidance
- Improving RB and turbodrill designs
- Improving tripping operations with retrievable tools

D. Development of drilling technology with 9-in. bits (1967-1975):

- Commercial designs of RB and turbodrills with retrievable rotor
- Development of a retractable tool for coring
- Positive displacement motor (PDM) and special torque-reaction latch development
- Field tests of diamond drilling techniques with turbodrills with retrievable rotors
- Drilling of exploratory boreholes up to 2800 m (9186 ft) depth

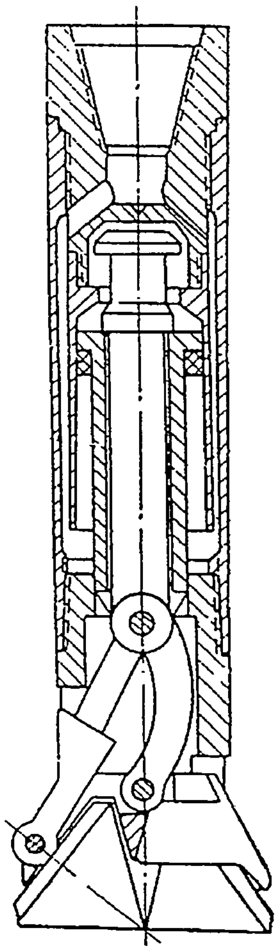


Figure 5. Two-Cone Bit with Monolithic Head (BD Type)

Development of RB designs was carried out along the following trends:

a) Step bit (1949-1952) – three-cone pilot bit and two-cone expandable reamer

b) Steering bit type BD (1953-1964) – two-cone bit with single-piece drill head (Figure 5)

c) Two-piston bit type D2PV4 (1959-1968) – two-cone bit with separate legs, and internal system of movable components in the mechanism (Figure 6)

d) Body-less bit of type DRB (1966) – two-cone bit with external system of movable components in the mechanism (Figure 7)

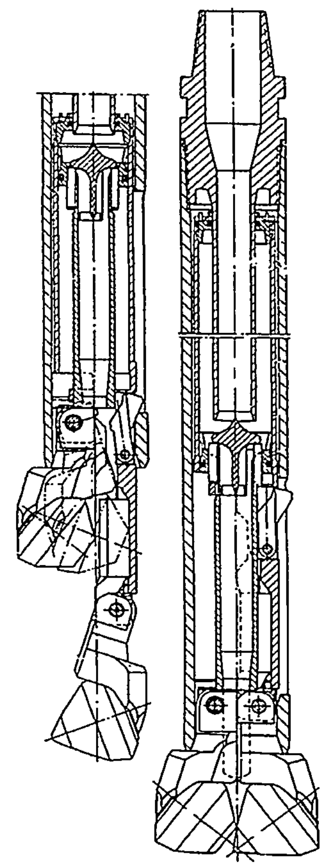


Figure 6. Two-Piston RB D2PV-10

e) Three-cone body-less bit type 3DR (1969) – external movable system features two holders for legs with cones and special arrangements for proper bit transfer sequence (Figure 8).

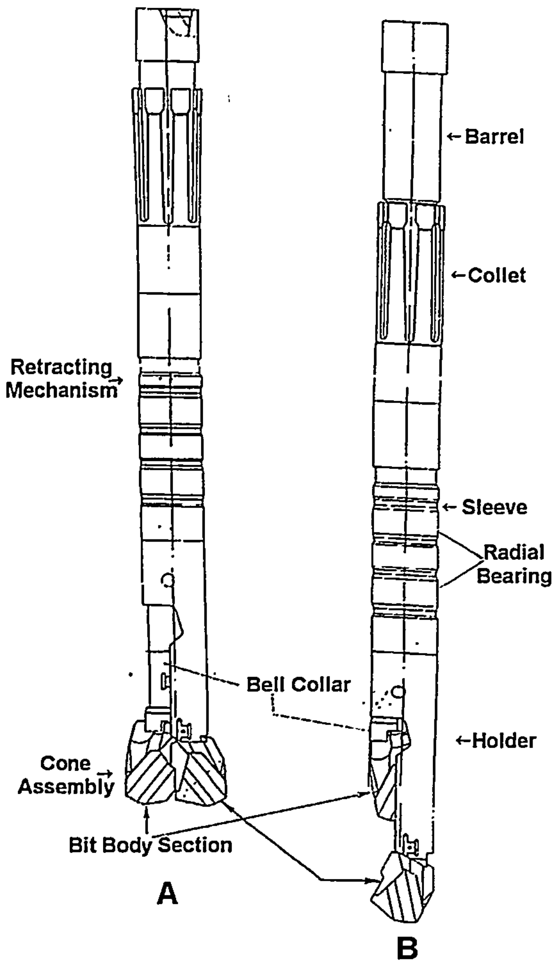


Figure 7. Two-Cone RB DRB (A–Operating Position; B–Transport)

One result of commercial testing of drilling without pulling pipe in the USSR was the development of a similar method for coring in hard crystalline rocks. The advanced continuous coring system was designed for ultradeep borehole applications as part of a national program "Investigation of the Earth's Crust and Ultra-Deep Drilling." The calculations showed that, when drilling below 7000 m (22,970 ft) (corresponding to the second stage of the Kola SD-3 borehole), this method would be substantially more effective than the alternatives.

In 1969-1973, prototypes of drilling tools were developed and manufactured – core heads, core barrels, retractable blade reamer, retractable three-cone bit, and retrievable DHM – for drilling 217-mm (8½-in.) boreholes in hard formations. A series of tests and modifications of the designs of various tools was carried out in 1974-1978 in the borehole "Sputnik SD-3." This borehole was specially constructed 50 m from the main borehole of the Kola SD-3 for experimental work.

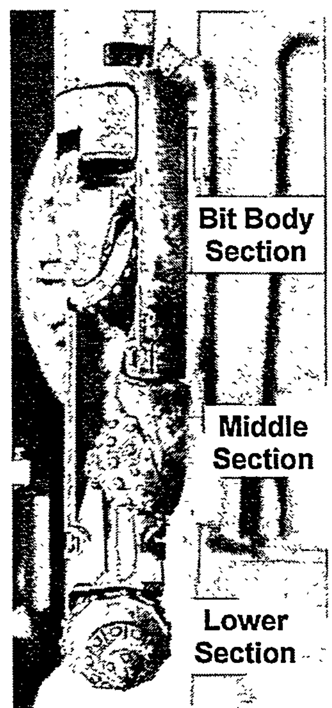


Figure 8. Three-Cone Body-less RB (Type 3DR)

The tests proved the potential to drill without pulling pipe in crystalline rocks. However, this system was not used in the Kola SD-3 borehole. The main reason was that the 168-mm (6.6-in.) drill string was not turned out to be run into the 214-mm (8.4-in.) open hole for the more than the 5-km (16,400-ft) length drilled with 147-mm (5⅞-in.) drill pipe. Commercial mastering of this technology was transferred to the Krivoy Rog

SD-8 well in Ukraine, which was drilled with 168-mm aluminum pipes. Field tests were completed in 1987 in 217-mm (8½-in.) pilot borehole at depths up to 3500 m (11,480 ft). The 295-mm (11.6-in.) mother borehole was deepened to a depth of 5432 m (1993) with combined technology: coring without pulling pipe, drilling and reaming with standard methods. RBs were planned to be used after 244.5-mm (9.6-in.) casing was run at a depth of about 7000 m (23,000 ft), but the project was terminated because of a lack of funds.

In accordance with an order from the USSR Academy of Sciences, investigations on drilling without pulling pipe using DHMs and RBs for scientific drilling in the ocean began in 1984. As a result, there were tests in 1991 in underwater mountains of the Josefin, Amper and Gorringe bank in the Atlantic ocean from the drill ship "Bavenit" which proved the prospects of this trend for deep-water riserless drilling. It should be noted that since 1978 the three-cone RB design has not been substantially changed. Tests carried out in a variety of geological conditions showed bit serviceability and allowed verifying reasonable drilling practices. For later use in the deep-water drilling program, it was planned to improve the RB in accordance with the modern achievements in cone-bit cutting structure and bearing design. This program was cancelled in 1992 as well due to a lack of funds for completing construction of the scientific drill ship.

The idea to revive drilling with casing technology has resurfaced from time to time. In the 1970s, an attempt was made to develop it for the first 9⅝-in. casing set-up in West Siberia. Four-cone RBs have been successfully tested for this purpose, but the complete design has not been worked out properly and this test did not lead to any further commercial applications. (Actually, there were no significant economic reasons for drilling with casing in this region at that time.)

Based on broad experience in RB research, development and field application, related technologies for underreaming were successfully developed. Well designs with minimal clearances between casing/liners became common practice in the regions of the North Caucuses, Middle Asia, Azerbaijan, Kazakhstan and others. Complicated geological conditions required that five to six casing strings be run with a total well depth of about 6000 m (19,690 ft). Underreamer applications improved the quality of well construction and produced large savings because of lower drilling mud and casing volumes, high rates of penetration and relatively low requirements for drill rig capacity. More than 100,000 m (328,000 ft) of intervals were underreamed in 1970s-80s. Reliable underreamers for gravel packing and other special applications have been developed as well.

2.3 Recent Developments in Russia

Technology field tested in 1991 for scientific drilling in oceans became a logical foundation for deep-water stratigraphic drilling. The latter concept was offered by IKU Petroleum Research in Norway in view of the fact that deep-water exploration for oil had become a field of strategic research. To evaluate potential productivity of oil and gas provinces, soil samples and rock cores need to be recovered and investigated during stratigraphic borehole drilling. These holes are drilled using riserless techniques with relatively small drill ships normally used for geotechnical purposes. However, the conditions of these drilling operations are beyond the capabilities of these types of vessels when the water depths at the location exceed 500-600 m (1640-1970 ft). A solution to this was the use of large diameter internal flush aluminum drillstring and techniques to drill without pulling pipe. For this particular application, the Complete Coring System (CCS) was developed and tested by the Aquatic Company in collaboration with Fugro Engineers B.V., the Netherlands. RBs are an essential part of CCS that allow spudding boreholes, drilling and reaming, especially in hard rocks.

The CCS along with 164-mm (6.5-in.) aluminum pipes was successfully employed in 1993-1997 to drill from two similarly sized geotechnical vessels "Bucentaur" and "Bavenit" with displacements of only about 5000 tonnes. Drilling operations were performed in areas of the Atlantic Ocean (Voring Basin, Rockall Bank, offshore West Africa), Gulf of Mexico (Mississippi Canyon, Green Canyon, Viosca Knoll, Garden Banks area), Gibraltar Strait and offshore Japan.

The experience gained for offshore application of RBs lead to the development of a special tricone RB TRB-300 for the Ocean Drilling Program (ODP) of Texas A&M University, USA. The aim of this bit was to spud and drill a borehole top section in conjunction with a specifically designed drill-in BHA. This actually consisted of drilling with casing technology for drilling through unstable and fractured crystalline rocks. Unfortunately this bit was only bench tested and ODP never used it offshore because of shortcomings in the BHA design and other unrelated reasons.

3. Design of RBs

3.1 General Requirements and Classification

A retractable bit (RB) consists of a cone assembly and a retracting mechanism (see Figure 7 on page 7). The RB is run down to the bottom of the hole and pulled up to the surface through the drill string. A surface-controlled retracting mechanism is used to configure the cone assembly to either operating or transport positions at the bottom of the hole. Drilling fluids with solid additives or cuttings accumulated at the bottom complicate the operation of the mechanism. RB design must of necessity be as simple and reliable in operation as possible.

Reliability requirements for RBs encompass the following:

- An unobstructed trip of the bit assembly inside the drill string
- Failure-free movement of the bit to the operating position, and fail-safe operation of the mechanism when the bit cannot be set due to potential problems
- Strength of all assemblies when operated under normal drilling practices
- Fail-safe transfer of the bit into the transport position for pulling out

Reliability requirements may well determine the selection of an RB type and the design of its components.

The existing designs of RBs can be grouped into two groups according to the type of operation. The first group includes bits for drilling without tripping the drill string. Bits in the second group are run down on pipe. Expandable drill bits that are run down on pipe (mostly of reamer design) are used for drilling below the cemented casing shoe a hole larger than the ID of the casing string.

According to the type of drive (drilling method), RBs can be subdivided into bits used with downhole mud motors (turbines, etc.) and bits rotated by the drill string. The two bit types have important distinctions. In the first type, special components must be used to transfer drilling loads from the downhole mud motor to the cone assembly. In the second case, a drill string shoe can perform the function of a retracting mechanism.

Based on the type of rock destruction, RBs are subdivided into cutting, crushing/shearing, and scraping bits. The corresponding bits are blade, roller cone, and diamond types.

Based on the shape of the resulting bottom hole, RBs can be single-stage, two-stage, or multistage, with one level or several levels of cutters. Retractable reamers with pilot bits often drill a two-stage hole.

Most designs of RBs include separately turning bit legs. In one bit design, turning legs are built into an integral solid drilling head ("BD" type). Designs with separate or solid bit legs differently affect operating conditions than do bit legs integral to the assembly, and use different mechanical motions of the retracting mechanism. Roller-cone drill bits with separate bit legs are divided in two groups:

1. Bits with two and three levels of festoon-type, or garland series, of separate cone assemblies – D2PV, DRB, and 3DR-types (see Figures 7 and 8)

2. Bits with two levels of paired cone sections – 4DV type (see Figure 31).

Based on the method of applying force for setting the bit into the operating position, two types of designs are singled out: 1) designs with hydraulic force applied, and 2) designs with mechanical force applied (tagging the bottom-hole, thrusting against a shoe, etc.). Bit designs differ according to methods for creating the applied force. Forces can be created by thrusting on a shoe, pulling a cable, fluid pressure on a piston, spring force, weight of movable parts of the bit, impact force of a catching device, and other means.

3.2 RB Components

Cone Assembly

A set of cones consists of two or three separate assemblies or sections which in combination with the retracting mechanism comprise two- or three-cone RBs (see Figures 7 and 8). A cone assembly consists of a leg and a cone mounted on a leg-mounted roller and plain journal bearing. Based on the level of the sections in the transport position, a two-cone bit has an upper (bit body) and lower section, whereas a three-cone bit has one more (middle) section.

The common component of the sections of a cone bit is the leg attachment assembly. The assembly is a tapered shank with a 40-48° apex angle. In a two-cone bit the sections are assembled along a split plane, whereas in a three-cone bit along dihedral angle planes.

Each leg of a cone assembly has an identical tapered part (half-cone or one-third of cone), as well as a bearing assembly. There are several design schematics of bearing assemblies.

Three-row ball bearings with one or two lock pins or a combination of plain journal bearing/three-row ball bearing/plain journal bearing are used in bits for high-RPM DHMs. Another combination scheme is used in bits for low-RPM motors: thrust bearing/plain journal bearing/ball/roller (or journal bearing).

An eye with a hinged socket for attachment of movable parts of the retracting mechanism is located in the middle of the legs of the lower (middle) section. The hinged socket of the upper section leg is located in the shank above the connection cone. A chase for a component of the bit body (carrier) is located below the conical section base. The carrier is used for transferring load moments while drilling. The bit leg has also straps for interaction with the mechanism holder.

Cone Unit

Cone size is determined by RB diameter in the transport position. The correlation between bit diameter in transport and in the operating position for various size bits for turbodrilling is 0.66 with a die unit for bit latching and 0.66-0.61 with seat application to latch the bit.

Cone size depends on the design of the retracting mechanism. Larger cones can be best positioned in a two-cone bit. Garland-type positioned cones are always smaller than cones in a regular three-cone bit. Size correlations range from 0.8-0.9.

This limitation required special design improvements in bit cutting structure to improve performance. Following is an example for a two-cone bit.

A typical two-cone bit, as compared to a three-cone bit, has longer teeth and a thinner fluid path between the teeth rows. This is due to the fact that the fluid channels in a two-cone bit overlap with a teeth row of only one cone. In the case of a three-cone bit, the fluid channel overlaps with teeth rows of two adjacent cones. Therefore, cuttings removal in a two-cone bit is less effective than in a three-cone bit. The new cone design in the DRB-248S bit has better correlation between length of a tooth and length of the fluid channel (Figure 9).

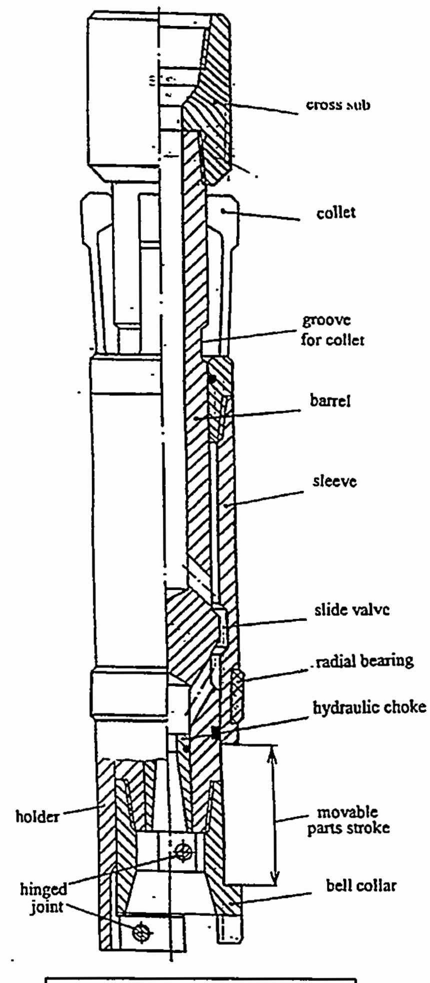


Figure 9. Retracting Mechanism

At tne same time, the area of the bottom hole that is not overlapping with the cutters remains the same or becomes even smaller. Teeth rows of the cone are divided into half-rows of 180° each, which are shifted along the axis. A smaller cone contact area with the bottom results in higher specific loads on the rock, deeper penetration of teeth into the rock, and a certain increase of durability of the bit journal bearing while the axial load on the bit is unchanged.

Bit-Leg Attachment Assembly

A cone bearing is the only element in a standard drill bit with mechanically movable elements. RBs, in addition to bearings, have a number of joints with movable parts. These are the cone-shaped bit-leg attachment assembly, joint planes, hinged sockets; elements transmitting torque, and a locking element to prevent bit legs from skewing with respect to joint planes as a result of peripheral forces while drilling.

Wear of contacting surfaces results in reduced integrity of the bit-leg attachment assembly. Methods of increasing durability of a set of cones include making low initial clearance (or no clearance at all) between joining parts to achieve high wear resistance of active surfaces.

Bit Hydraulics

Joining elements of bit legs do not permit efficient hydraulics of RBs, which are important for good performance. This problem was resolved by introducing a central nozzle rigidly connected to the cone leg body. The upper end of the jet nozzle is sealed with a sliding bushing installed inside the retracting mechanism. In addition, the central nozzle functions as a locking element, preventing the bit legs from shifting or skewing in the joint plane (planes) while drilling, as a result of peripheral forces.

3.3 Retracting Mechanism

General Designs

A retracting mechanism consists of internal fixed parts and external movable parts (see Figure 9). Unlike RBs for rotary drilling, RBs for retrievable DHMs cannot directly transmit applied forces from the drill string to the bit legs. Therefore, the internal system of fixed parts in the retracting mechanism is designed to carry axial and torque loads while drilling, and consists of strong, rigid tubular parts. The system of movable external parts mainly operates when the cone bit is transferred from the transport position to the operating configuration. During drilling, the external system is affected by inertia forces (due to vibration), and is exposed to torsional moments. Tensile stress from differential pressure on the piston is negligible.

The system of internal fixed parts consists of (moving upward): a conical bell collar and a barrel the upper end of which has a thread for connection with a turbine shaft.

The external system consists of (moving upward): a holder(s), a sleeve with radial bearings, and a collet.

There is also a hinged system to connect sections of cone assemblies to elements of the retracting mechanism. A retracting mechanism of a two-cone RB has one external holder for articulated fixture of the lower section of a cone bit. A retracting mechanism of a three-cone bit has two of this type of holder.

Sequence of Movement

The most important typical feature of a retracting mechanism is the specific sequence of movements of its movable parts. In a garland-type two-cone bit, the upper section of the bit has to be set up in the operating position first before the lower section can be engaged.

In a three-cone RB, the movable holder starts moving with the lower section of the bit, while the movable middle holder with the middle section of the bit is still fixed. Simultaneous with the moving holder, the bit body section is swung into the operating position. When the lower section of the bit reaches the level of the middle section, the middle holder is released. The two movable holders, along with the attached sections that are in contact with one another at dihedral angle planes, simultaneously approach the bit leg body until a conical section of a cone assembly enters into the bell collar of the fixed system. The special latch prevents undesirable movement of the middle holder during bit transfer from transport configuration to operating and back.

Hydraulic Mechanism for Setting in Operating Position

External and internal resistance forces interfere with the process of setting an RB into the operating position. These are overcome by forces created in the bit retracting mechanism that exceed the combined value of possible resistance forces during normal drilling operations.

The method utilizing hydraulic force from circulated drilling fluid is considered the most efficient way of setting an RB into the operating position. A sufficient force can be created along with the possibility to set the bit in the operating position in a nominal size hole any distance from the bottom.

The sliding control valve enables reliable operation of the mechanism. The valve closes a circulation channel in the retracting mechanism in the transport position and reopens it to allow circulation of fluid at the final travel of the mechanism movable system. At the same moment, the bit is set into the operating position. Upward travel of the movable system (piston) is critical for reverse motion of the piston when the bit is transferred to the transport position.

Because of installation of a sliding valve at the head end under the piston operating area, pressure in the mechanism corresponds to resistance forces when the bit is moved into the operating position.

Axial clearance is an important aspect of the sliding valve. It characterizes hydraulic resistance of the mechanism outcome seal. Small axial clearances result in a sufficient level of active force, which increases reliability of the retracting mechanism operation. At the same time, small axial clearances promote erosion of the sliding valve, especially with heavy muds. Large axial clearances result in lower operating reliability of the retracting mechanism. The tapered shank of the cone assembly may not fully enter the bell collar, which may cause breakage of the mechanism holders while reaming the borehole before an RB starts drilling. Manufacturing technology does not allow highly precise axial clearance in the slide valve.

A mechanism combining a slide valve and a choke was developed to increase reliability of sliding valve operation. A hydraulic resistance device (choke) was installed in the central fluid course of a barrel below the sliding valve. It assists in creating an active force which is sufficient, even with an inaccurately manufactured sliding valve, to set the cone assembly into the operating position completely. This is particularly important while drilling hard crystalline rocks.

The hydraulic mechanism with a sliding valve allows the driller to receive a clear signal indicating that the bit has been set in the operating position. The sliding valve allows cones to retain their operating positions when the bit is lifted off bottom.

It is of utmost importance that the RB be set in the operating position before the DHM is started. Otherwise, relatively fragile parts of the movable system of the retracting mechanism may be affected by the additional stresses, because of contact between the rotating half-opened bit and borehole walls.

In this respect, development of a blocking device for the RB is of interest. The device would allow starting the turbine only after the bit has been set in the operating position.

Internal Fixed Elements

Strong and rigid internal elements are made of structural alloy steel and are formed of tubular material. They are designed to support drilling work loads.

The bell collar is the main component supporting axial and moment loads while drilling. Its junction with the tapered shank of the cone assembly is exposed to intensive wear. Surface hardening of the bell collar increases wear resistance of the junction assembly. The bell collar surface material must also be harder than the material of a cone assembly shank that is replaced after each trip. The bell collar can be replaced as well.

The bell collar is threaded to the barrel, with a central fluid course interrupted at the protrusion of the sliding valve.

External Movable Elements

The external system of movable elements includes (moving upward): a holder(s), a sleeve, and a collet. The holder is designated for joint hinge connection with the lower (middle) section of the cone bit. It is the most loaded element of the movable system. The holder is exposed to a bending moment when the RB is set to the operating position. This occurs when swinging into the operating position when the cone pushes the lower part of the string from the borehole walls toward the center.

The sleeve is cylindrical and centers the external system while it is moving along the fixed internal barrel. A radial bearing is positioned on the outside of the sleeve, and while drilling is in contact with the BHA bottom liner. The inner surface of the sleeve has a groove which is a part of the sliding valve. An annular swivel-type joint connects the holder to the sleeve, to release torsion load on the holder produced by rotating the RB as a result of friction torque in the radial bearing of the sleeve. The upper part of the sleeve is rigidly connected to a collet.

The lower end of the collet works as an annular piston when the RB is hydraulically transferred into the operating position. The upper part of the collet consists of elastic petal-shaped elements that will not extend beyond transport diameter limits of the retracting mechanism. When the external movable system moves up, and the cone assembly assumes its operating position, the petal-shaped elements of the collet move over to the cylinder surface of the barrel with a diameter larger than the transport limit.

Hinged Joint to Connect Cone Assembly

The hinged joint connecting the lower (middle) section of the cone assembly to the holder is affected by inertia (vibration) forces created by the weight of the external movable system and is the most heavily loaded joint. Small initial clearance and high wear resistance of contact surfaces are necessary to reduce wear of the hinged joint. The hinged joint connecting the bit body section of the cone assembly is not loaded while drilling, and can experience loads only if the bell collar is completely worn out.

Locking elements are important parts of the hinged joint. They must provide reliable fixation of the hinged joint, and ensure fast and easy replacement of the cone bit sections at the drilling site.

A typical hinged joint design includes a pin with a spring-loaded lock, and a lock-washer with a hole that is inserted in holder boss slots. The spring-loaded lock goes through the hole and locks the washer.

3.4 RB Operation

Running an RB Down the Hole

An RB, as a part of a retrievable drilling tool, is run down by gravity. Circulation of drill mud increases speed of the falling tool. Bit diameter in the transport position must allow the bit to pass through the smallest diameter of the BHA, which is situated below the retrievable assembly seating shoulder. For a 248-mm bit (9¾-in.), the maximum diameter for the transport configuration is 154 mm (6.1 in.). For a 217-220-mm (8½-in.) bit, the diameter in the transport position is 134 mm (5.3 in.).

When an RB is transported to a bottom, special attention should be given to the bit entering a seat and the smallest part of the BHA. A smooth configuration of the legs of the lower and upper bit sections allows them to enter the seat and the proceeding advancement of the RB inside the BHA.

RB Transfer in Operating and Transport Positions

When a bit is run down with circulation of drilling fluid, after the retrievable tool has landed in the seat, the mechanism must smoothly set itself in the operating position and the DHM be started. It is of crucial importance that the radial bearings are not worn, which allows restoring fluid circulation in the well (at a rate required to start the motor) only after the mechanism has fully opened and the cone assembly set in the operating position. The bit retracting mechanism is designed so that there should not be any stagnant zones inside the internal areas of the mechanism for fluid circulation. This is necessary to avoid a build up of sediment, which might complicate the mechanism movement from the operating to the transport position. Configuration and elements of the holder and the bit section legs ensure a systematic process of setting the bit in the operating position.

3.5 Review of Russian Patents

The following patents (Inventor Certificate (IC)) related to drilling without pulling pipe were registered in the USSR.

1) IC No. 112631 dated January 10, 1956

   a) G.S. Barshai, A.Z. Romanov, N.I. Buyanovsky, and Y.A. Gelfgat, "Hydraulically Operated Mechanism for Setting up a Retractable Bit"

   b) A sliding valve that closes fluid courses of a bit in the transport and in the intermediate positions, and opens them back at the last interval of the rod stroke, when the elements of an RB take their operating positions.

2) IC No. 247162 dated May 10, 1967

a) A.Z. Romanov, G.S. Barshai, and D.I. Indrupsky, "Cone Bit"

b) Retractable two-cone milled tooth or insert tooth bit with each tooth row consisting of two half rows offset from each other along the cone generatrix or of different widths

3) IC No. 695260 dated April 2, 1967

   a) G.S. Barshai, "Retractable Three-Cone Bit"

   b) A three-cone bit, consisting of three separate legs with cones, connected through a joint hinge to the elements of the retracting mechanism

   c) Central barrel with a shoe and two ring holders installed on the barrel

4) IC No. 461218 dated April 23, 1973

   a) G.S. Barshai and S.M. Khodzhayev, "Retractable Four-Cone Bit"

   b) A retractable four-cone bit including a hollow housing with a tapered seat

   c) A cone assembly with two fixed and two movable legs with cones

   d) The legs are connected through a joint hinge to a plunger mechanism that expands bit to operating position

   e) Fixed legs have conical tails with grooves for movable legs

5) IC No. 395557 dated December 30, 1971

   a) P.N. Apostolsky, G.S. Barshai, I.Y. Blokhin, Y.A. Gelfgat, G.F. Gorshkov, D.I. Indrupsky, B.A. Korolev, and U.G. Sharaf, "Well Drilling Device"

   b) A special device for drilling wells using diamond bits and retrievable DHMs

   c) Rotation of the drill string allows reaming a borehole

6) IC No. 481689 dated 1972

   a) G.S. Barshai, M.Y. Gelfgat, A.M. Zarkhin, G.S. Gevorkov, and Y.A. Gelfgat, "Retractable Diamond Reaming Bit"

   b) An expandable diamond blade underreamer in combination with a rigid pilot bit.

   c) The unit features a system for transferring blades in the operating and transport positions, as well as for securing blades in a bit body

   d) Lower end faces of the blades are used to drill out a borehole annular shoulder

7) IC No. 415346 dated March 3, 1972

    a) G.S. Barshai, R.S. Alikin, B.A. Korolev, and P.N. Apostolsky, "Device to Transmit Axial Load to a Drill Bit"

    b) A hydraulic loading device allows creating additional axial load on an RB using differential pressure in a DHM and the bit

    c) The device consists of a rod and a traveling piston abutting against a shelf of the above-piston area

8) IC No. 501139 dated December 14, 1973

    a) R.S. Alikin and G.S. Barshai "Hole Opener"

    b) A two-cone reamer, consisting of a barrel and the attached movable holder connected through joint hinges to legs with cones

    c) The system includes slide regulator valves and a mechanism for securing the legs in the transport position, which is installed inside the barrel and made as a rod with a tapered tip interacting with the corresponding inner surfaces of legs

9) IC No. 583278 dated August 30, 1974

    a) R.S. Alikin, G.S. Barshai, and M.Y. Gelfgat, "Retractable Blade Reamer"

    b) A retractable blade reamer connected to a pilot bit

    c) The upper end of each blade has a collar bead and the reamer body itself has guides in grooves that fit the collar beads

    d) These elements enable the blades to change position from transport to operation. Tungsten Carbide, or Composite Diamond, or PDC inserted faces of bit blades perform reaming of a borehole

10) IC No. 672937 dated October 28, 1974

    a) P.N. Apostolsky, D.I. Indrupsky, and A.Z. Romanov "Retractable Cone Bit"

    b) A retractable two-cone bit, included a central barrel and a holder with hinged legs with cones

    c) A hydraulic piston mechanism for setting a bit in the operating position

    d) A hydraulic jet nozzle connected through a joint hinge to a barrel and interacting with a cone leg fixed to the holder

e) The nozzle allows better cleaning of the bottom-hole and prevents divergence of the legs in a joint plane under peripheral forces

11) IC No. 585266 dated July 26, 1974

a) G.S. Barshai and S.M. Khodzhayev, "Device for Attachment of a DHM to a Drill String"

b) A collet liner with petal-type elements is used to install a motor housing inside a drill string

c) The petal-type elements are located in the rod grooves

d) Due to axial displacement of the elements their lateral sides can interact with keys in the housing

12) IC No. 601390 dated January 12, 1976

a) R.S. Alikin, T.I. Alikina, G.S. Barshai, and M.Y. Gelfgat, "Device for creating an axial load while pulling out a retrievable tool"

b) Overshot with mechanical latch is used to grip and pull out the retrievable tool by wireline

c) The hydraulic system attached to the overshot provides additional pulling load to start retrievable tool movement from the BHA

d) Actual pulling force available is exceeded the wireline load limit

13) IC No. 581238 dated February 23, 1976

a) R.S. Alikin, G.S. Barshai, I.V. Vasilichenko, and M.Y. Gelfgat, "Gripping device for retrievable tool"

b) While pulling out a retrievable tool by reverse circulation, mud is pumping into annular space below closed blowout preventer.

c) To grip head of tool an overshot with hydraulic and rubber shock absorber is installed into the upper part of perforated pup-joint.

14) IC No. 569698 dated February 25, 1976

a) R.S. Alikin, T.I. Alikina, and M.Y. Gelfgat: "Coring Device for Drilling with Retrievable Tool"

b) Retrievable down-hole motor driven core barrel installed in the BHA shoe with possibility of axial movement

c) The device equipped with torque-reaction and thrust system providing proper parameters for continuous coring with DHM application

15) IC No. 669778 dated March 1, 1976

a) R.S. Alikin, P.N. Apostolsky, G.S. Barshai, Y.A. Gelfgat, B.A. Korolev, and Y.O. Firger: "Deflector for retractable bit"

b) In the present device, a deflecting force creates by the expanding pad on the BHA shoe

c) Control of the pad extension is executed by the special sleeve without pulling out drill pipe

d) RB can be used in conjunction with the deflector in any of it positions

16) IC No. 655843 dated March 22, 1977

a) G.S. Barshai, Y.A. Gelfgat, D.I. Indrupsky, B.A. Korolev, G.M. Finkelstein, and Y.O. Firger, "Swallow Tail Type Releasable Joint"

b) A releasable joint connecting replaceable cone axle with a reamer leg

c) The device has a spring-loaded lock pin with a tapered tip, located inside the axle, and a plate with tapered shelves and a conical pinhole

17) IC No. 781312 dated March 7, 1978

a) G.S. Barshai, M.Y. Gelfgat, Y.A. Gelfgat, and D.I. Indrupsky, "Blade Reamer"

b) A blade reamer, consisting of a reamer body, rod piston with blades connected through a joint hinge

c) The blades interact with the external conical surface of the reamer body and the rod

d) The device includes a system of self-regulation of clearances between the contacting wear surfaces of the blades and the body

e) The system allows achieving longer operating life of the reamer

18) IC No. 786411 dated March 26, 1979

a) G.S. Barshai and D.I. Indrupsky, "Retractable Cone Bit"

b) A two-cone RB including a central barrel, an external holder, bit legs with cones

c) One of the legs is connected through a hinged joint to the barrel, and the other one to the holder

d) A hydraulic piston-type mechanism for setting legs in the operating position, and a stop lock, articulately connected to a barrel

e) A stop lock can interact with the string when the bit sets down

19) IC No. 899820 dated June 29, 1979

a) R.S. Alikin and M.Y. Gelfgat, "Device to Determine a retrievable tool position in the drill string"

b) A sub with a collet inside is installed at a certain place in the drill string to determine the moment when retrievable tool is passing this place while running down to be set up in the BHA

c) While retrievable tool contacts a collet, the pressure increases in the mud line and can be fixed to control the mud flow and accordingly retrievable tool speed

d) While pulling out the retrievable tool, the collet is pushed in the initial position for the next run down operation

20) IC No. 955765 dated February 9, 1981

a) Y.A. Gelfgat, M.Y. Gelfgat, and D.I. Indrupsky, "Retractable Three-cone Bit"

b) A retractable three-cone bit including a central barrel with a shoe, two ring holders with articulately attached legs with cones, and a sleeve, which in combination with the barrel works as a slide valve for setting the bit in the operating position

c) The bit features a swivel-type connection of one of the holders to a sleeve, using ring-shaped quadrants, locked by a bushing from inside and retained by the central barrel

d) The central barrel has a choke creating additional hydraulic force to help compactly position bit legs in the bell collar of the shoe

21) IC No. 1304470 dated August 31, 1984

a) Y.A. Gelfgat, M.Y. Gelfgat, R.S. Alikin, T.A. Andreeva, and N.I. Andrianov: "A method of core drilling"

b) The method includes using of core drilling with retrievable tool in pilot hole

c) To increase length of the pilot hole drilling with retrievable tool, extension pipes were installed between the core barrel and drill string shoe.

22) IC No. 1808972 dated May 22, 1991

a) M.I. Vorozhbitov, O.Y. Bergshtein, and D.I. Indrupsky, "Well Drilling Device"

b) An expandable one-cone reamer includes a pilot bit, a sub, a housing with a hollow inclined pin with fit on it bearing and a reamer cone

c) The reamer cone retracting mechanism consists of an attached to the sub rotating liner with a longitudinal lead in the upper part and hard-faced longitudinal ribs with a right-hand helix on the external surface

d) The reamer includes a movable rotating support offset from an upper end boss on the thicker section and a lower end boss with a radial slot holding the liner lead.

4. RB Manufacturing Technology

4.1 Manufacturing RB Bit Legs and Cones

Cone assemblies for Retractable Bits (RBs) require manufacturing technology that is different from technology used in manufacturing conventional drill bits. This is because a retractable cone assembly includes releasable joint elements, hinges, eyes, and smooth attachment cones, all of which require high-precision manufacturing. Requirements for materials, billets, and thermal treatment of RB cone assemblies must comply with those set forth in the specifications for similar type elements for conventional bits of the same size. Bit legs and cones are made from case-hardened alloy VAD steel. Rollers and balls are made by bearing-manufacturing plants from special steel according to the technical specifications for ball bearings and rollers supplied to bit plants. Bit cones and shirt-tails have sintered-metal hard-alloy teeth.

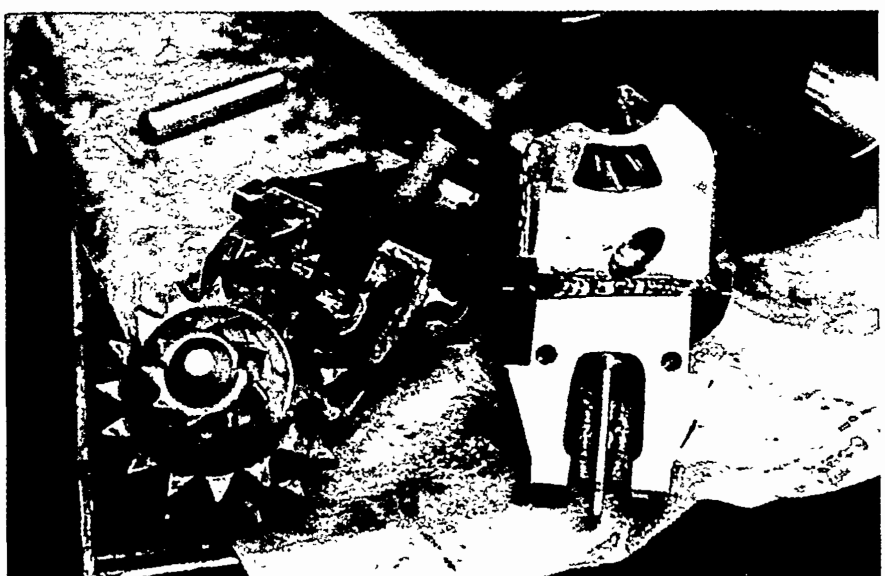


Figure 10. Cone/Bit Assembly DRB-248S

Standard drill-bit manufacturing technology was used for the cones. The bit bearings are also similar to bearings for a standard drill bit. However, design features of RBs related to the joint plane (or dihedral angle plane) of a specified length, did not allow proper grinding of the upper bearing raceway. Introduction of grinding machines from the Nova Company (Italy) with small grinders eliminated the problem. Several bit designs (Figure 10) used welded-on cover pads that allowed making the bearing open and addressed this drawback.

The following bearing pattern is used in a two-cone bit design (DRB-248C) to improve its operating reliability: tri-serial ball bearings with plain-end journal bearing and two ball plugs.

Following is the sequence of operations for manufacturing bit legs of a two-cone assembly (from forgings) at the Kuibushevburmash plant. This plant is now the Volgoburmash Company in the city of Samara.

1. Machine processing of the joining plain surface and an upper end edge of the short leg, and the shoulder of the upper leg shirt-tail

2. Welding of a pin boss to the lower section of the upper leg joining surface

3. Aligning the upper leg with the joint plane from the pin boss and the shirt-tail end to prevent lateral offset of an axle and a conical part of a leg

4. Assembling the two legs together. The legs abut against each other's edges and fit tightly against the joint plane. The sides of the leg are tack-welded.

5. Turning the leg cone, backside of the upper leg in the transport position, and its shirt-tail on center

6. Milling leg eyes

7. Drilling and boring a hinge hole in the short leg based on the leg cone

8. Legs breaking up

9. Drilling holes for journal ball plugs

10. Driving and center-popping lock pins

11. Preprocessing of journals

12. Finish turning of raceways (to be carburizing) to fit balls, rollers (plain bearing) with an allowance for grinding

13. Carburizing the lower part of legs (bearing and shirt-tail)

14. Finish turning of the journal after case-hardening – removing shoulders and chamfers

15. Hardening

16. Grinding of the journal

17. Boring a hinge hole in the upper leg shirt-tail

18. Machining of the back of the short leg in the transport position

19. Welding cover pads on the upper leg

This technological process has an inherent drawback. If one of the legs is spoiled during separate machining of the "union," the other one has to be rejected also. This drawback was eliminated in the technology that was used for manufacturing 500 two-cone DRB-248C assemblies at the DKG plant in Hungary. For example, the manufacturing process for the short leg included the following operations:

1. Machining the joint plane surface and the end face
2. Boring access holes on the joint plane surface. The holes are the principal elements for further machining of the leg.
3. Milling of the hinge eye
4. Drilling holes for lock pins
5. Driving and center-popping lock pins
6. Preprocessing the journal
7. Finish machine turning of raceways for ball and roller bearings (with allowance for grinding) to be carburizing
8. Carburizing of the leg lower section (bearing and shirt-tail)
9. Finish machine turning of the journal after carburizing – removing shoulders and chamfers
10. Machine milling of the shirt-tail
11. Hardening (quenching)
12. Grinding the journal
13. Drilling a hinge hole in the eye
14. Machine processing of a hinge eye back side
15. Machine milling of the upper part of the bit body
16. Machine processing of the seating cone connected to the mating leg

A large number of less critical surfaces (shirt-tails of the legs in the transport position, side surfaces, watercourses, etc.) are not machined (they remain as in the delivered forging). This significantly reduces labor requirements and cost of the product.

When sections of the bit are assembled together, plugs are put in access holes using thermal-resistant glue.

Because of specialization within the industry, cone assemblies are made at bit plants, but retracting mechanisms for the cone assemblies are made at engineering plants. A crucial task is to ensure full interchangeability of these elements of the RB, especially considering that they are assembled on the rig site.

For this purpose a system of control devices was developed, simulating the joint elements of the retracting mechanism. These control devices are made for conditions including the worst-case combination of dimensions of the mating surfaces.

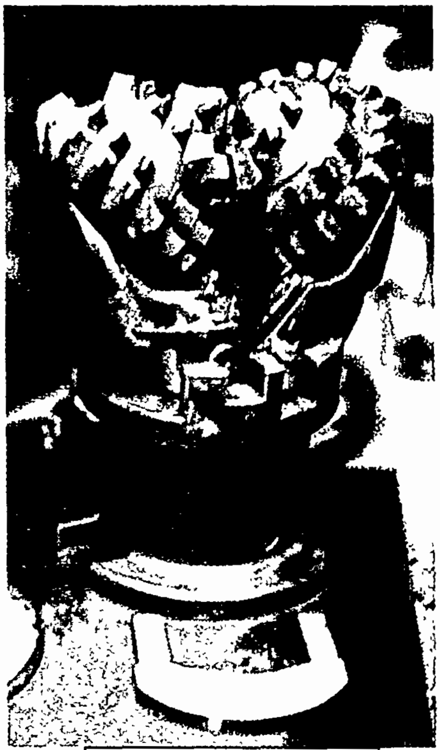


Figure 11. Primary Control Device

The main device (Figure 11) is a tapered cup with holes for leg hinges. The following parameters of the cone assembly are controlled using this device, along with a clock-type indicator on a pedestal, height gauge, gauge rings, a snap gauge, and feelers.

1. Tightness of the fit of leg joint surfaces and sides of large cover pads
2. Relative position of hinges, symmetry of side planes of a short leg hinge about a seated cone
3. Rotation of cones and absence of tooth engagement
4. Interference fit of a cone
5. Bit size and weight
6. Difference in cone elevation with the cone axis
7. Radial play of the cone assembly about the cone axis
8. Radial play of cones about the journal axis
9. Cone skew

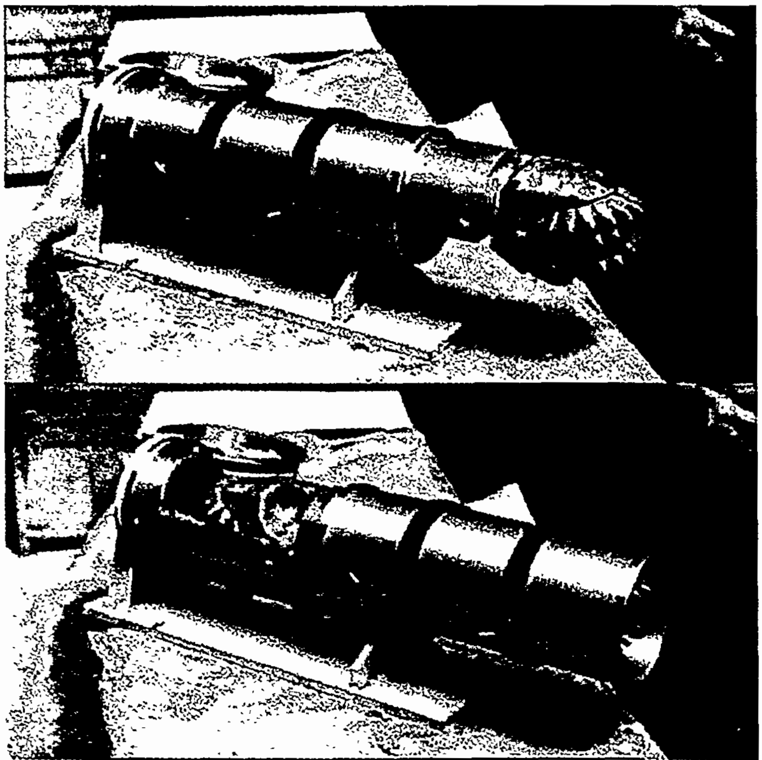


Figure 12. Secondary Control Device

The secondary device (Figure 12) is used to check that the sections of the cone assembly fall within the clearance limits for the transport configuration. The device includes internal elements on which sections on the hinges are mounted, and an internal sliding liner. The inside diameter of the liner is the same as the diameter of the cone assembly in the transport position. The device is also used to control free turnaround of sections on hinges from the transport to the operating position.

4.2 Manufacturing Technology for Three-Cone Assemblies

Small pilot lots of three-cone assemblies were manufactured at bit plants in Drogobych, West Ukraine (248 mm) and KuibyshevBurmash (217-220 mm). Pilot prototypes of various three-cone RB assemblies were made at the VNIIBT experimental plant in a suburb of Moscow.

The principal technological requirement affecting quality of the final product is precision of the dihedral angle planes.

Because the number of units was small, these were manufactured at the pilot and experimental production divisions of the plant using universal equipment and a limited number of special devices.

The technology used for manufacturing small lots (about 300 bits) of three-cone assemblies had some drawbacks. First was the lack of finish machining of the dihedral angle and the attachment leg cone. Deformations during chemical and thermal treatment resulted in large clearances along the dihedral angle planes of the legs. This clearance became even larger, because of differing elevations of cones and their play, and reduced drilling efficiency and substantially reduced operating life of the retracting mechanism.

In addition, the technology involved a number of additional operations that were hard to arrange for full-scale production. Among them were: 1) alignment of the bit legs and welding them together in a "union" for joint machining of the connection cone; 2) breaking up the union into separate legs for further machining; and 3) selecting legs for one bit according to the bit assembly serial number after chemical and thermal treatment. There is also another disadvantage of the technological process adopted. If one of the bit legs was damaged while machining the separated "union," the other two also had to be rejected.

These drawbacks were eliminated by a technological process that includes finish machining of the dihedral angle and the leg cones. Moreover, all operations for premachining of the dihedral angle, journal, and hinges remained unchanged. New operations include finish machining of a dihedral angle based on a hinge hole and a journal raceway, and turning the cone in a lathe with legs fixed in the same positions. For example, Figure 13 shows the sequence of operations for the short leg (with positions indicated):

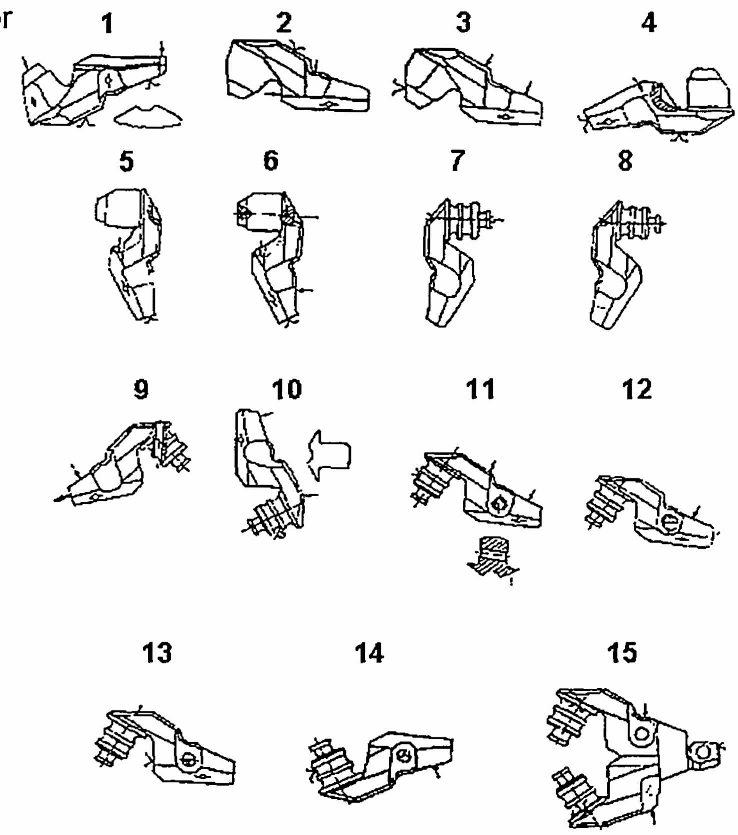


Figure 13. Machining Sequence for Short Leg

1. Machining with allowance for dihedral angle planes

2. Machine milling the initial-production thrust surface of the journal

3. Milling the upper end face of the leg cone

4. Milling a cavity (pocket) for the bit leg journal

5-6. Preparing and centering the axle

7. Pre-machining the journal; finish machining the journal elements (raceways) that are to be ground after carburizing

7A. Carburizing the lower part of the leg (the leg journal)

8. Finish machining the journal (cutting off shoulders, end faces, chamfers, etc.)

8A. Hardening (quenching)

8B. Grinding the journal raceways

9. Drilling a hole for a plug

10. Milling an eye for a hinge

11. Drilling a hinge hole

12-13. Machine milling the backside of the transport position and the eye

14. Finish machining the dihedral angle

14A. Assembling the legs together into a "union"

15. Machining the cone and shirt-tail

A special device is used to control accuracy of the dimensions of the assembled bit while manufacturing pilot lots of three-cone assemblies (Figure 14). With extended holders, the sections of the cone assembly are installed on the elements of the device using hinge axles, and their tails are put inside a cone cup, similar to the operating position of the RB. The following parameters were controlled: bit size and shirt-tail clearance, difference in cone elevation with the bit body axis, tightness of the fit along the dihedral angle planes, radial play of the cone assembly about the cone axis, and axial and radial cone skew. In addition, using extended holders of the device, the fit of the three-cone assembly in the transport configuration is checked.

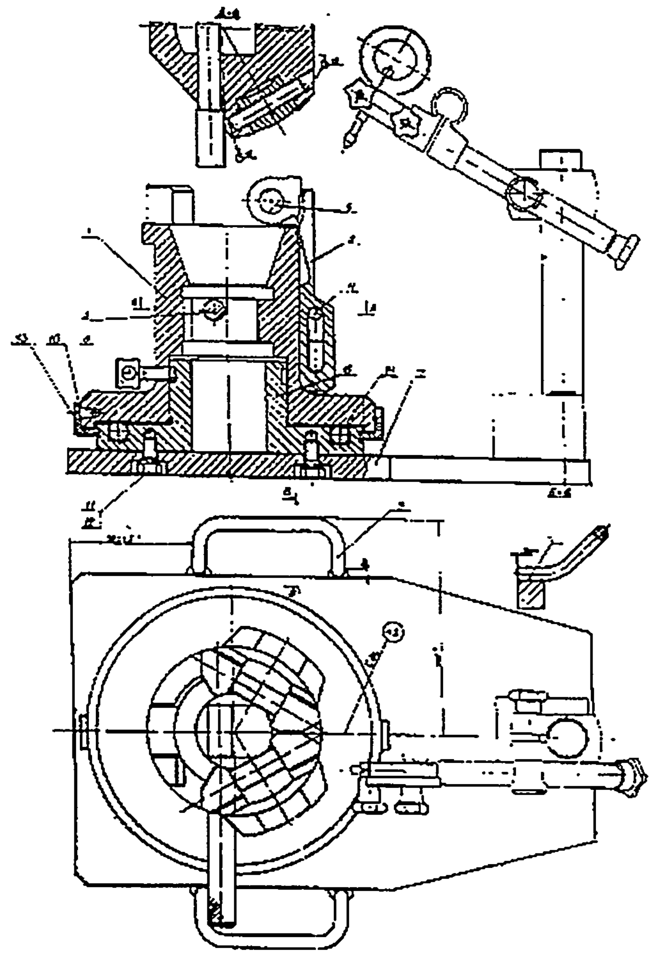


Figure 14. Control Device for Three-Cone Assemblies

4.3 Manufacturing Retracting Mechanisms for RBs and Reamers

A small number of retracting mechanisms of various designs and sizes were manufactured at the Pavlov's Engineering Plant (Perm Region). Conventional equipment was used for manufacturing.

Regardless of the size of manufactured elements of the retracting mechanism, a standard machining technique was used since the elements were identical.

The sleeve is a thin-wall cylindrical element with length equal to about 5-7 outside diameters. The internal surface of the sleeve has a pocket that is part of a slide valve of the mechanism. The pocket must be machined with high precision. Therefore, it was recommended that a master template be used. Unfortunately, this recommendation was not followed, and the slide valve had low precision, which negatively affected performance of the RB. An additional choke had to be installed to offset low accuracy of slide valve manufacturing.

The external surface has pockets for a radial bearing, made by vulcanization of a polymer (special composition rubber) in a mold. This dictates the use of the following procedure for sleeve manufacturing:

1. Finish machine turning on the OD, and make a groove for the rubber coating. Tolerance for length and ID must be accounted for.

2. Thermal treatment

3. Surface preparation for rubber coating (sand blasting, cleaning, and degreasing)

4. Rubber coating in a mold

5. Machine turning (pre-surfacing and finish surfacing of the internal surface and the slide valve)

6. Internal surface grinding

7. Making the end thread and turning the lower section of the sleeve for a hinge connection with the holder

The holder is the most labor-intensive component of the mechanism due to low production efficiency. A disk billet must be used because the lower tapered section has bosses with hinge holes for connecting bit sections.

The operation for upsetting lower ends of thin-walled tubular billets forms metal pieces used for the holder bosses. Under conditions of full-scale production, this operation is economically feasible.

Labor required to manufacture the holder can be reduced by using die forging that allows forming all sprues that are currently made by milling with special mills.

The bell collar (cone) is the main and replaceable internal element of the mechanism, transmitting axial and moment loads while drilling. Operations such as turning, milling, thread cutting, and drilling are used in bell-collar manufacturing. The most important problem of the technology is to increase wear resistance of the conical bell collar. This problem is resolved by case-hardening the collar surface, quenching, and grinding.

In addition, methods were developed to make the bell collar surface harder by depositing a hard alloy into specially milled grooves and then grinding.

4.4 Manufacturing Defects and Their Impact

An RB design must allow operation in highly contaminated and abrasive drilling fluids. This requirement dictates the necessity to increase the initial clearance between the jointed elements. Furthermore, backlash in movable joints must be increased, to correct skewing and misalignment of axes, because of manufacturing defects. This backlash and play increases due to operational wear.

When the movable system of the retracting mechanism is in motion, friction resistance occurs as a result of inaccuracy in the fabrication of certain elements. Experience in manufacturing and testing RBs indicates that misalignment of axes of mating cylindrical surfaces, as well as skewness and asymmetry of hinge assemblies, are the most crucial factors. During assembly, inaccuracies of fabrication of certain elements are additive. Since friction factor depends on surface conditions, a very high surface finishing class is recommended.

During well drilling operations, an RB is alternately exposed to drilling fluid and air. Therefore, oxidation is a potential problem. Chromium coatings slow the corrosion process. This is particularly important for surfaces on which rubber elements of the mechanism move.

The system developed and implemented for final inspection of the cone assemblies and retracting mechanisms allow them to be interchangeable and minimizes additional fitting operations in workshops prior to sending a bit to the rig site.

Table 1 shows typical manufacturing faults and their effect on operation of an RB.

Table 1. Typical RB Problems and Effects on Operation

	STAGE OF PRODUCT OPERATION	POSSIBLE FAILURE/ COMPLICATION	MANUFACTURING DEFECTS THAT CAUSED FAILURE	NOTES
1	Transporting RB inside drill string (running bit downhole)	Bit stuck in the BHA seat	Bit legs do not fit in the transport position; bit legs do not have chamfers. Clearance between collet and conical shoulder of retracting mechanism barrel was not observed.	
2	Setting RB into operating position	RB has not been (or has been partially) set up in the operating position.	Low-quality welding of cover pads on bit leg. Axial clearance in slide valve of retracting mechanism was not observed. OD of radial bearing of sleeve was low.	
3	Drilling	Intensive wear of bearings and cutters; bell collar wear; hinge failure; cracks on holder housing.	Large clearances between movable joints. Failure to correctly thermally and chemically treat elements. The parts do not have required radii and fillets.	
4	Transferring RB into transport position	The bit cannot be completely moved into transport position.	Thread connection between collet and sleeve not tightened properly.	Sediment building up below piston of collet is main reason for failure.

4.5 Designs of Commercial RBs

Bits Used with DHMs

Table 2 presents standard designs and sizes of retractable drill bits. Table 3 shows a range of cone assemblies for RBs and their technical parameters.

Table 2. Standard Designs and Sizes of RBs

Bit Size	RB Type	ID Mark of Expanding Mechanism	ID Marking of Drill Bits			Bit OD (mm)	
			Soft Rock	Medium to Hard Rock	Hard Rock	Drilling Position	Transport Position
#9	Two-cone bit	DRB1-9" DRB2-220		DRB2-9"S DRB2-9"SZ		220	134
	Three-cone bit	3DR-220		3DR-217S	3DR-217K	217	134
				3DR-220S 3DR-220SZ	3DR-217OK	220	134
	Reamer w/ pilot	RVA1-217			RVA1-217.020	217	134
#10	Two-cone bit	DRB3-10	DRB3-10"M	DRB3-10"S DRB3-10"ST	DRB3-10"T	248	154
		DRB-248		DRB-248S(020) DRB-248SZ(030) DRB-248ST(040)	DRB-248T(070)	248	154
	Three-cone bit	3DR1-248 M3DR2-248		3DR-248S 3DR-248SZ 3DR-248ST	3DR-248T	248	154
#12	Four-cone bit	4DV-295.010		4DV-295.020		295	203

Table 3. Cone Assemblies of RBs

Drill Bit ID Mark	Bit OD in Operate Mode (mm)	Bit Leg Journal Angle	Bearing Pattern	Cone Cutting Structure	Type of Flushing	Self-Clean Teeth
DRB2-9"S	220	51	BB-BB-BB	Milled teeth	Central (extended jet nozzle	Used
DRB2-9"SZ	220	51	JB-BB-BB-BB	Chisel TCI	Central (extended jet nozzle)	Used
3DR-217S	217	51	JB-BB-BB-BB	Milled teeth	Central jet course	-
3DR-217K	217	57	RB-BB-BB	Hemispherical TCI	Central (extended jet nozzle)	-
3DR-217OK	217	57	JB-BB-BB-BB	Hemispherical TCI	Central jet course	-
3DR-220S	220	57	JB-BB-BB-BB-JB	Milled teeth	Central jet course	-
DRB3-10"S	248	47.5	RB-BB-RB	Milled teeth	Side and central	-
DRB3-10"ST	248	47.5	RB-BB-RB	Milled teeth	Same	-
DRB3-10"T	248	47.5	RB-BB-RB	Milled teeth	-	-
DRB-248S	248	50	JB-BB-BB-BB-JB	Milled teeth	Central	Used
DRB-248SZ	248	50	JB-BB-BB-BB-JB	Chisel TCI	-	Used
DRB-248ST	248	47.5	JB-BB-BB-BB-JB	Milled teeth	-	Used
DRB-248T	248	47.5	JB-BB-BB-BB-JB	Milled teeth	-	Used
3DR-248S	248	51	BB-BB-BB-JB	Milled teeth	-	-
3DR-248SZ	248	51	BB-BB-BB-JB	Chisel TC teeth	-	-
3DR-248ST	248	51	RB-BB-RB	Milled teeth	-	-
3DR-248T	248	51	RB-BB-RB	Milled teeth	-	
4DB-295	295	60	BB-BB-BB-JB	Milled teeth	-	-

Notes: BB – ball bearing; RB – roller bearing; JB – journal bearing

The design features of RBs cone assemblies made as 1) Milled Tooth Bits and 2) Bits with Tungsten-Carbide Inserts (TCI) are presented in brief.

Milled teeth on the outer cone surface perform the function of rock destruction. Drill bits for medium rock have extended teeth with a 40-43° sharpened angle and large spacing. Bits for harder rock have short and closely spaced teeth.

A number of cone assembly designs (DRB3-10S, DRB2-9SZ, DRB-248SZ, DRB-248ST) feature 1.5-5 mm cone offset according to the corresponding rock hardness.

Tungsten-carbide alloys are used for hardfacing teeth, including the gage surface. To enable durable bit operation in abrasive rock, TCI are installed at the bit leg shirt-tail (3DR-248ST, DRB-248ST).

Certain bit designs (DRB-248S, DRB-248SZ, and DRB-248ST) have bearings with two ball plugs.

Cones have pressed in the shell chisel-shaped or spherical TCI for drilling medium and hard rock respectively. These types of bits do not have cone offset.

SZ-type bits have cones fitted with various diameters of chisel-shaped inserts in a checker-board layout in each row.

Rear flanks of shirt-tails of 3DR-217K, 3DR-217OK bits fitted with gage compact inserts. Table 4 presents typical designs of the retracting mechanisms of retractable drill bits and technical parameters.

Table 4. RB Retracting Mechanisms

Basic Parameter	Units	Mechanism of Two-Cone RB		Mechanism of Three-Cone RB		Mechanism of Four-Cone RB
		DRB2-220	DRB-248	3DR-220	3DR1-248	4DV-295.010
OD	mm	134	154	135.5	154	203
Length	mm	1486	1880	2250	2518	945
Movable system travel	mm	238	245	395	440	125
Maximum pressure of transfer to operation position	MPa (psi)	1.5 (1.05)	1.5 (1.05)	2.0 (1.4)	2.0 (1.4)	2.0 (1.4)
Connection thread GOST 5286-58 (API)		3-102 (3½ IF)	3-121	3-102 (3½ IF)	3-121	3-121
Weight	kg	110	180	200	270	190

RBs for Rotary Drilling Designed by MINHGP

Based on the promising future for the application of medium (no. 8 and 9) and small (no. 6) bits, MINHGP (Engineers of Gubkin Institute of Oil, Chemical, and Gas Industry in Moscow) specialists have concentrated on developing RBs for rotary drilling in these sizes. An RB (Figure 15) consists of the following main elements: cylinder, housing, rod piston, replaceable cone assemblies, and overshot. Replaceable cone assemblies are essentially legs with milled-tooth rolling cutters.

A special shoe is set on the lower end of a drill string. The bit is transported to the bottom through the drill string by gravity or by mud circulation.

When the bit contacts the thrust shoe shoulder, mud is circulated under the piston and forces the rod up. The big leg moves with the rod along shaped surfaces and grooves from the bit axis to the borehole wall. The small leg (with the short travel distance) also moves aside from the bit axis.

When the piston rod reaches the uppermost position, legs with cones are pulled into a tapered shoe. Simultaneously, drill mud flush courses are opened inside the bit.

Torque from the drill string is transmitted to the drill bit through a connection between the conical walls of the bit legs and a tapered bore in the string shoe.

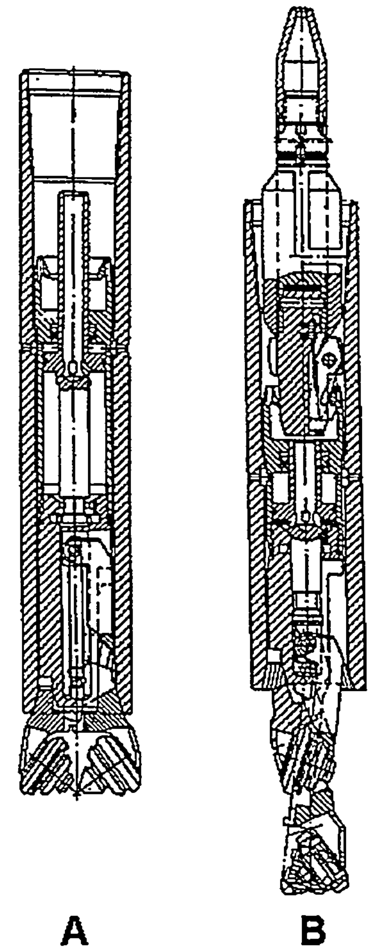


Figure 15. RB for Rotary Drilling (A-Operating; B-Transport)

To retrieve the bit to the surface, an overshot is run down on wireline through the drill string. The overshot arrives at the bit and contacts the protracted rod. The rod then moves back to its lower position. Consequently, the overshot dogs engage the cylinder, and the bit can be pulled up to the surface.

Some of these bits were made as test prototypes, and some were manufactured in pilot lots.

The DVR3-6V bit represents the principal design. These bits drilled over 6000 m (19,700 ft) with an average footage per bit of about 60% of regular tricone bit performance in similar drilling conditions. Specialists developed cutters for medium, hard, and very hard rocks.

A more advanced bit design (DVR6-151; Figure 16) with the so-called lower joint hinges has replaced the DVR3-6V in the 151-mm size. The bit includes shorter and simpler legs. In addition, tie rods carry less load than in the DVR3-6V bit. The bit also has a more advanced flushing system.

During field testing in the interval 600-800 m, DVR6-151 pilot prototypes showed better performance than the DVR3-6V.

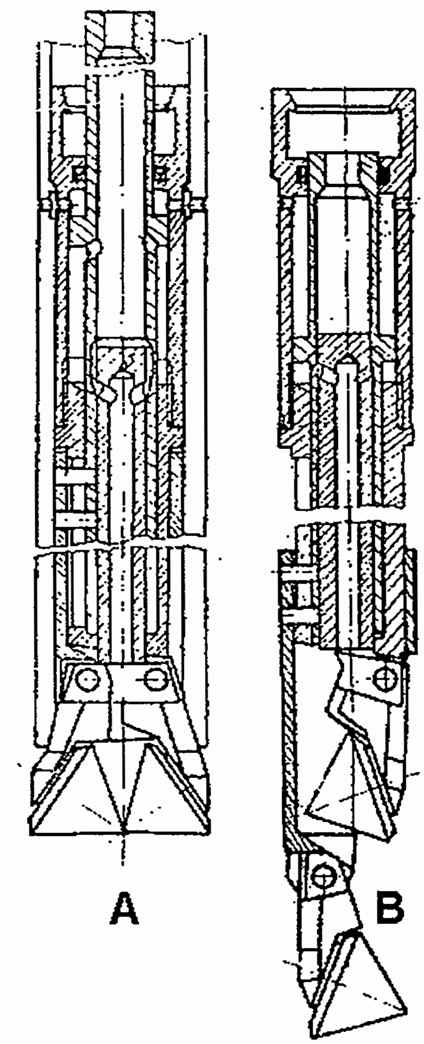


Figure 16. RB DVR6-151
(A-Operating; B-Transport Position)

5. Drilling With RBs

5.1 Drill String

Retractable bits (RBs) were originally designed for drilling with simultaneous running of casing. RBs were connected directly to the casing shoe. Drilling experience indicated the possibility of utilizing this method for pile driving or setting surface casing that consisted of several joints of pipe.

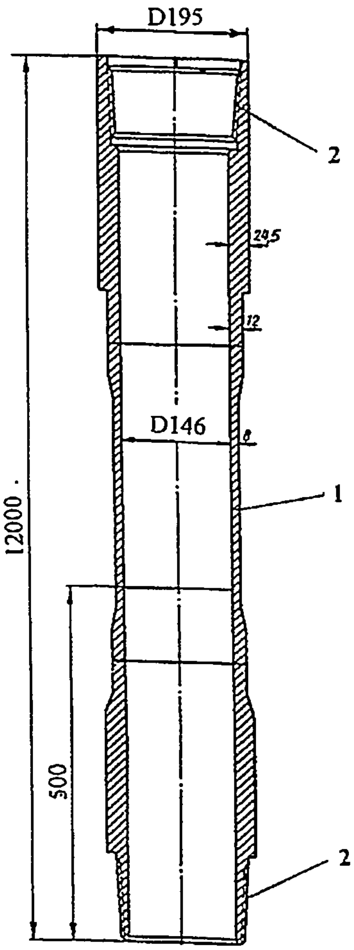


Figure 17. Steel Pipe with Welded Tool Joints

However, drilling long intervals using casing was not a success due to a lack of strength in casing thread connections without thrust faces, which did not allow them to carry drilling loads. In addition, design imperfections in the first RBs caused frequent failures of the mechanism of bit transfer to the transport position, which required pulling out the casing string. Casing thread connections with a 60° profile and 1:16 taper required a large amount of time for tripping operations.

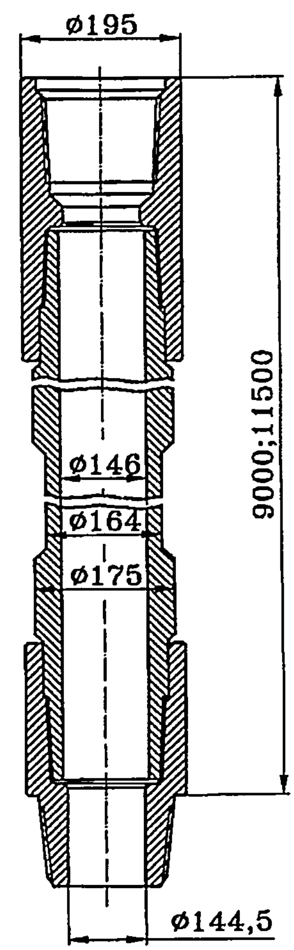


Figure 18. Aluminum Drill Pipe

Therefore, designers developed special internal flush drill pipe with tool joints using 1:12 tapered threads. Steel and aluminum drill pipes with 195-mm (7.7-in.) tool joints were developed and used for drilling 220-mm (8.7-in.) holes. The pipe ID was 146 mm (5¾ in.), and the tool joint ID was 144.5 mm (5.69 in.). Figure 17 shows steel pipes with butt-welded slim tool joints. Figure 18 presents the design of an aluminum drill pipe. A companion topical report, "Development of Aluminum Drill Pipe in Russia," provides detailed characteristics of these pipes.

The bottom-hole assembly (BHA) includes the casing shoe, retrievable tool housing with landing seat, torque and weight on bit (WOB) reaction mechanism housing, and several heavy-wall drill pipes (197-mm OD drill collars). A reamer or a stabilizer may be installed on the BHA shoe, and inside the shoe a radial bearing for centering the drill bit.

The complete BHA includes a retrievable assembly set inside the BHA (Figure 19). The retrievable BHA for full-face drilling includes the RB, a DHM (a turbodrill with a landing unit), and a torque and WOB-reaction mechanism with a fishing neck on top.

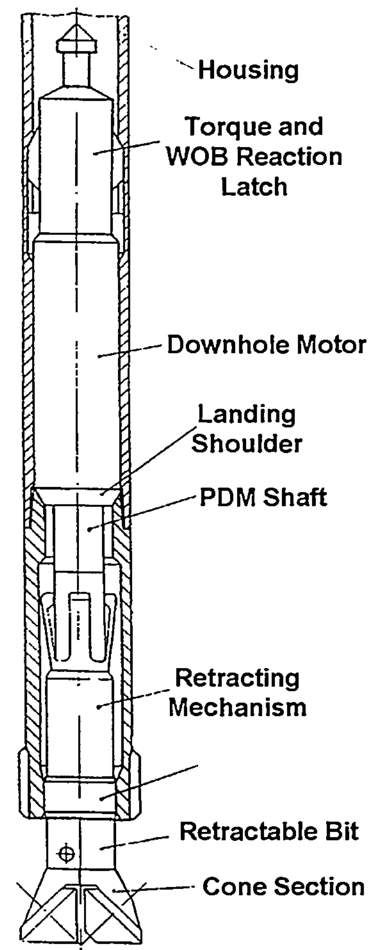


Figure 19. BHA with RB and Downhole Motor

5.2 Drilling Operations

Drilling or rock destruction with RBs is similar to conventional turbine drilling, and is affected by a combination of basic technical parameters: WOB, mud circulation rate, and turbine RPM. Turbine RPM depends on WOB, mud circulating rate, rock physical properties, and bit type. Originally, direct-drive hydraulic turbines with 500-600 RPM operating speeds were used in drilling. Because of the high speeds, durability of bit bearings was very low.

The later introduction of low-RPM DHMs enabled their application with RBs. For example, the TRV-142 turbine with gear reducer and DVO-142 screw DHM at 120-200 RPM were developed to work with 220-mm RBs.

Maximum WOB is composed of the weight of the retrievable BHA, the hydraulic load equal to the pressure drop in the retrievable BHA multiplied by the turbine cross-sectional area, and additional hydraulic loads created by a torque and WOB reaction mechanism. Actual WOB for a 220-mm (8.7-in.) bit was below 12 tonnes (26,460 lb) at 7.0-8.0 MPa (1000-1160 psi) pressure drop in a retractable tool.

RBs with the BHA described above were used exclusively to drill vertical wells. The designers did not have the objective of developing retractable tools for drilling directional or horizontal wells in the fields of the Saratovneftegas Production Company or for drilling scientific wells both offshore and onshore.

Nevertheless, designers developed special tools to control the well trajectory. The most simple are tools with controlled stabilizing cover pads or with asymmetrical fixed cover pads installed in the BHA shoe.

5.3 Tripping Operations

The principal differences between drilling techniques using RBs and conventional bits are related to retractable tool tripping operations. The retrievable BHA is transported to the bottom and up to the surface through the drill pipe.

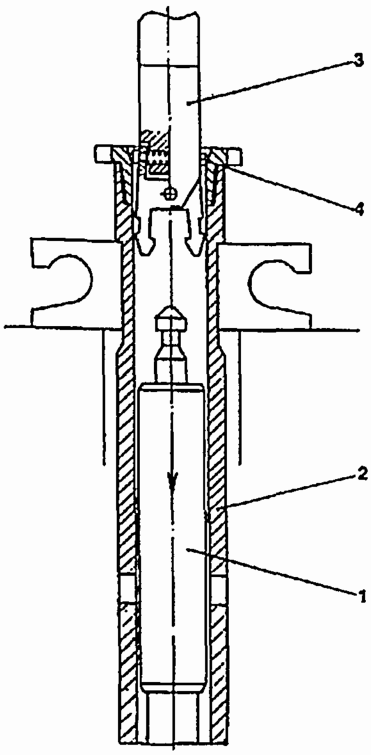


Figure 20. Dropping RB Down Hole

Unlike a core barrel, a turbine with a bit almost completely fills the internal diameter of the drill pipe and moves like a piston with a small fluid bypass around the tool. This allows mud circulation inside the drill string and in the annulus.

The tool can be run down on a wireline or dropped inside the drill string. In the latter case, mud is circulated inside the drill string to reduce time to run the assembly to bottom. When the bit approaches the landing seat, the mud pump rate is reduced to bring the impact energy to a safe level and avoid any possible damage of elements that come into contact with the retrievable BHA seat. Actual running speeds are in the range of 1.8-2.3 m/sec (350-450 ft/min).

A special overshot is used for dropping a retractable tool down the drill string (Figure 20). To drop the retrievable tool (1) down the drill string (2), pins (4) are mounted in the dogs of the overshot (3). When running the tool in the drill pipe, the pins interact with a flange, moving apart dogs and releasing the head of the retrievable tool.

The retrievable assembly can be retrieved using a wireline, by reverse circulating the mud, or a combined method (pulling on wireline while simultaneously pumping mud down the annulus.

Figure 21 shows wellhead equipment for tool retrieval with wireline. A pup-joint with openings to allow communication between the pipe and annulus, is installed on the upper pipe to prevent drill mud overflow. While the kelly is made up, openings in the pup joint are closed.

Figure 22 shows wellhead equipment for retrieving the tool by reverse circulation. The procedure is described as follows. When pulling out a retrievable tool (1) by reverse circulation, mud is routed from the mud pumps to the annulus, which is blocked above by the BOP (2). An overshot (4) is used to grip the retrievable tool with a hydraulic shock absorber (5) mounted in the upper part of the drill string in a perforated pup joint (3). When gripping the retrievable tool by an overshot, the shock absorber stem (6) is moved upward, displacing fluid from the cylindrical chamber through hydraulic resistance, developing braking force. At the end of the stem stroke, the tool is stopped by a rubber buffer (7). Simultaneous with the beginning of braking, the mud pumps are switched off.

Several factors should be taken into account when selecting the method of retrieval, such as hydrodynamic conditions of horizons in any uncased intervals, including their ability to withstand pressure drop without causing problems with fluid influx or lost circulation.

While retrieving the tool by wireline, pressure in the annulus drops below static mud pressure. The maximum pressure drop is observed near the drill-string shoe. The level of pressure drop depends on mud rheological properties, hydraulic resistance in the annulus and inside the drill pipe, and the tool speed. It should be mentioned that the OD of the special drill string or casing used with RBs is larger than that of a drill pipe string for conventional drilling. Therefore, the described method of drilling features additional pressure drops due to hydraulic resistance in the annulus, both while drilling and tripping.

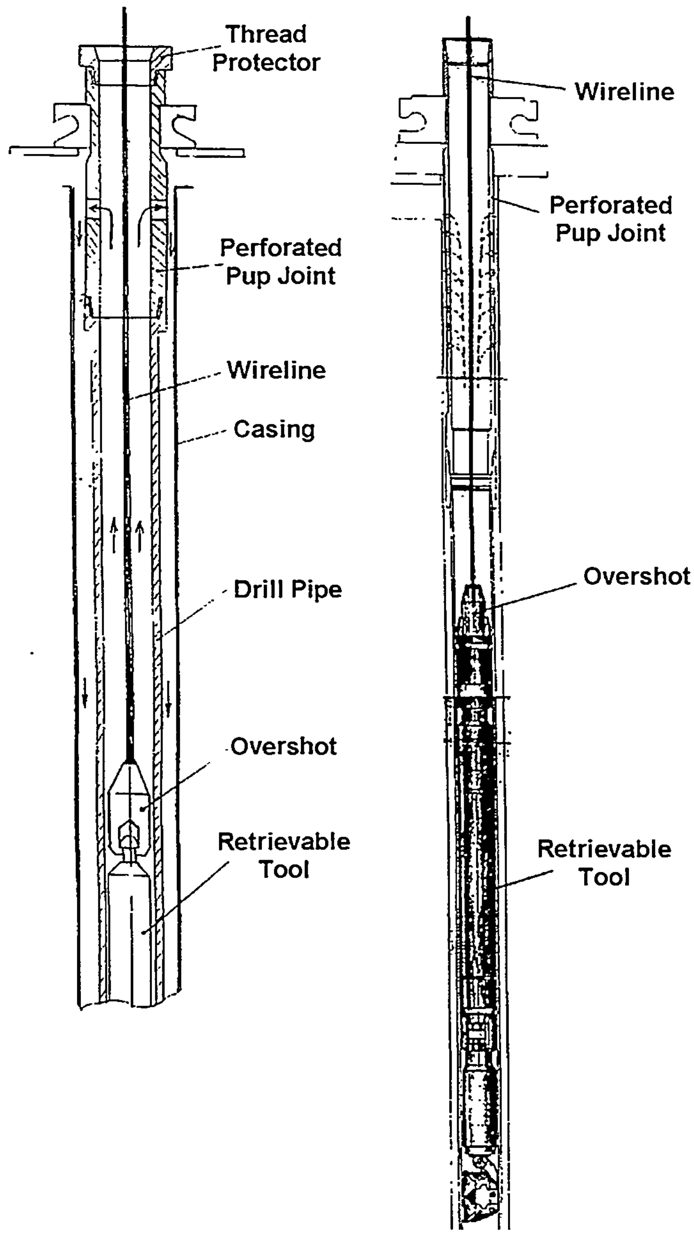


Figure 21. Pulling Out Retrievable Tool

When the tool is retrieved using reverse circulation of drill mud, pressure in the annulus rises above hydrostatic pressure. The maximum pressure increase in the uncased interval is observed below the shoe of the previously set casing.

The combination method of tool retrieval allows maintaining a desired pressure level in the annulus and, at the same time, faster tool retrieval. One of the specific features of this drilling method is the necessity of synchronizing wireline pulling force with pumping mud into the annulus.

5.4 Coring Operations

Core is recovered while drilling a pilot hole with a core barrel and a drilling head that has a smaller diameter than the BHA shoe. As the well is drilled deeper, intermediate extension pipes are installed between the core barrel and the turbine shaft. Pilot hole depth can be up to tens of meters and is dictated by economic feasibility because of the need to make and break extension pipes. The turbine used for drilling the main hole rotates the core barrel. Since core-head diameter is smaller than the diameter of an RB, a certain amount of mud is discharged into the annulus through a jet nozzle. After coring, the pilot hole is reamed to the designed diameter using an RB.

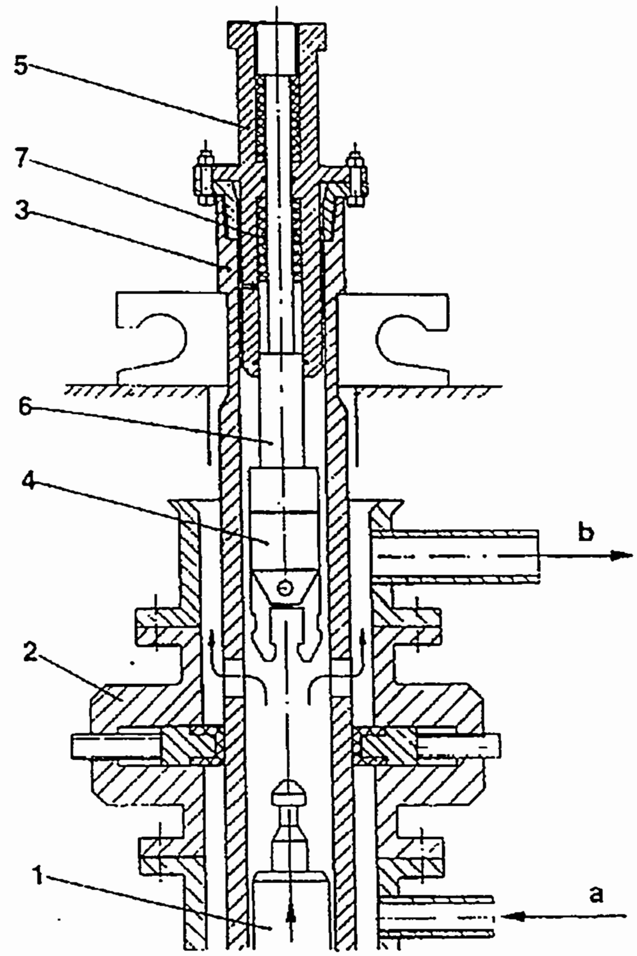


Figure 22. Pulling Retrievable Tool by Reverse Circulation *(see text for legend)*

5.5 Fishing Operations

Along with these drilling tools, RB designers have developed a number of auxiliary retrievable tools for fishing jobs, bottom-hole cleaning, and setting cement bridge plugs. As mentioned previously, durability of RB bearings at 500-700 RPM for a direct-drive turbodrill was low, which caused frequent bearing failures and, consequently, cones lost on the bottom.

Fishing operations involving a magnetic mill that was run on a drill string required significant trip time. To reduce trip time, a retrievable magnetic mill was developed. The mill was successfully used for retrieving lost cones and other steel parts that fit through the ID of the drill string shoe.

A retractable basket that engages parts left on the bottom has been developed to retrieve larger fish. However, retrieving the basket requires pulling the drill string. In some cases, a retrievable face mill can crush a large fish, a retrievable magnet can fish the fragments, and then a retrievable sludge trap cleans small metal fragments from the bottom.

Development of Retractable Drill Bits in Russia

The technology practices described above have been worked out during years of tests and commercial drilling. Some results from each stage of testing are presented in the next section.

6. RB Tests and Field Applications

6.1 First Test Intervals Drilled with 12-in. RB (1948-1956)

Retractable tools were originally developed for 295-mm (11⅝-in.) wells. At that time, this was the most typical well size for many oil and gas regions in Russia. 219-mm (8⅝-in.) casing pipe was used in place of a drill string. Special thin-wall tool joints (250-mm (9.8-in.) OD and 200-mm (7.9-in.) ID) with 1:12 tapered threads connected the casing pipes together.

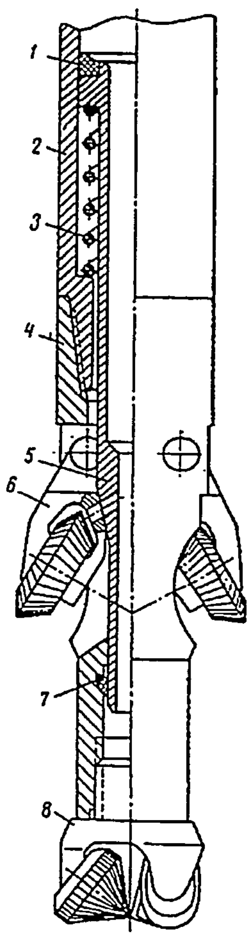


Figure 23.
Stepped Bit (1948)

A stepped bit was used which consisted of a standard 197-mm (7¾-in.) tricone bit and a two-cone retractable reamer installed above it (Figure 23). *In Figure 23, 1 – piston; 2 – cross sub; 3 – spring; 4 – housing; 5 – mandrel; 6 – cutter; 7 – seal; 8 – pilot bit.* A wedge, activated and moved downward by hydraulic force pushing a piston, expanded reamer legs on hinges to the operating position. Through a wedge-shaped central water course, drilling fluid was directed to reamer cones and a pilot three-cone bit. When it was time to retrieve the bit, the mud pumps were shut down and the wedge was moved to its original position by an axial spring. After that, the legs with cones were pulled inside the string shoe.

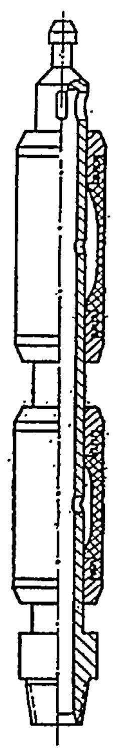


Figure 24.
Turbodrill Seal
Assembly

A 192-mm (7.56-in.) retrievable turbodrill with an axial-flow turbine was engaged with the string using splines on a turbodrill nipple. The upper section included a system of rubber compartments for sealing the turbine in the pipes (Figure 24). When drilling fluid was circulated, the upper (thin-wall) compartment expanded to the pipe wall due to overpressure caused by the different velocity heads inside the compartment. After that, the lower thin-wall compartment, designated to partially remove torque reaction using friction forces, expanded because of pressure drop at the turbine.

The results of early testing in 1948 (six runs in the interval 90-130 m) prompted fundamental modernization of retractable tool components and assemblies. A ram anchor was developed to fix the turbine in the shoe.

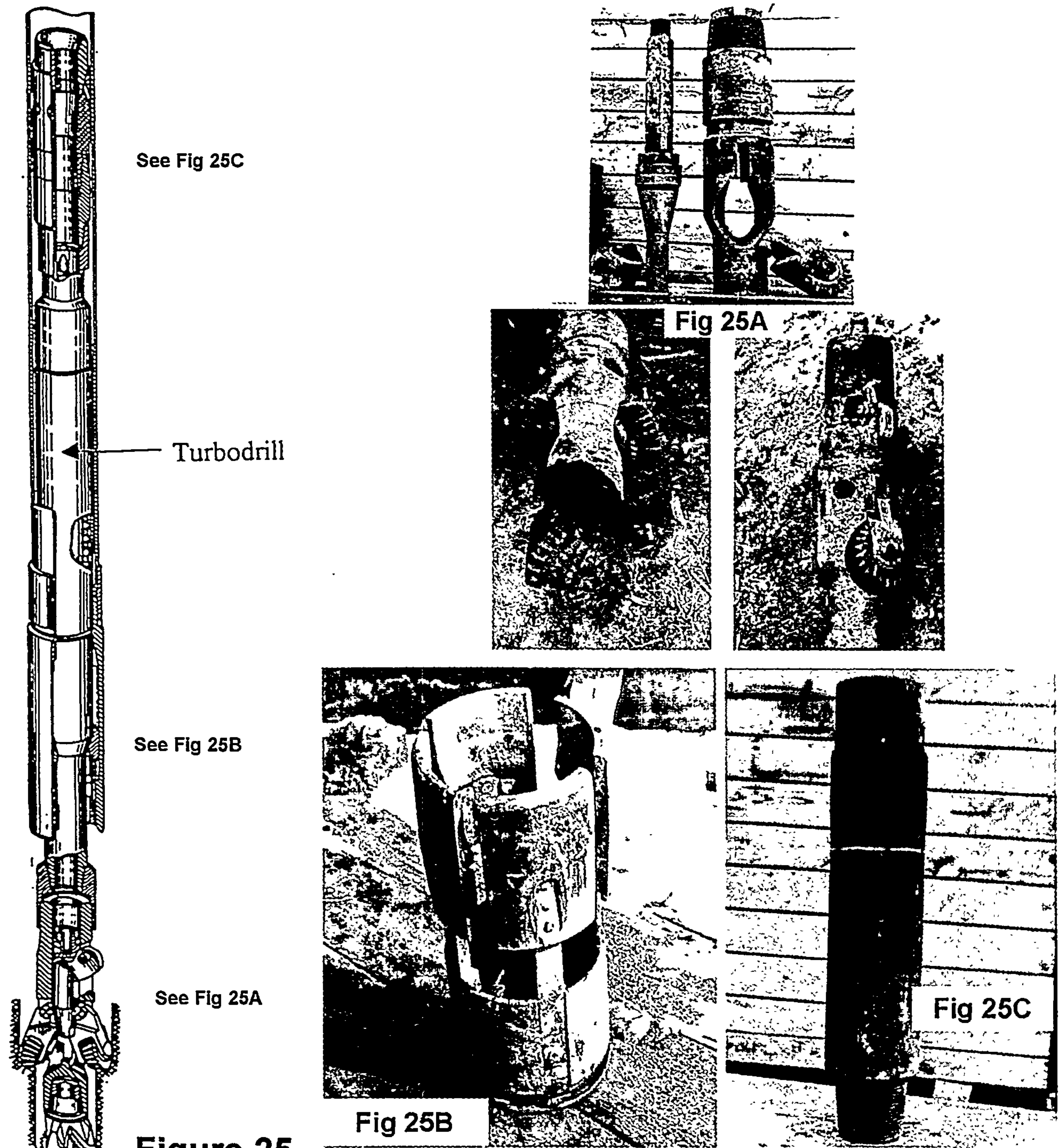


Figure 25

Modernized retractable tools with pilot reamers (Figure 25) were tested in 1950 (26 runs in the interval 60-450 m) and in 1952 (46 runs in the interval 210-740 m).

During the 1952 tests, total penetration per bit was 30-35% that of conventional bits in offset wells (average penetration rate was the same). Ten trips were made due to unreliable operation of the ram anchor and bit retracting mechanism. In deeper intervals, pulling up the retractable tool caused swabbing effects. The resulting difference in fluid levels inside the string and annulus led to higher loads on the wireline. Therefore, the tool was pulled up slowly with periodic stops. At the end of testing, while the retractable tool was pulled, a perforated pipe was installed in the upper section of the string. Internal space of the pipe communicated with the annulus through cross-cut holes, which eliminated the problem of different levels of fluid in the pipes and in the well. This allowed essentially reducing retrieval time. In a 730-m (2395-ft) well, trip time was 32 minutes. Testing involved the first trial of the method of retractable tool run down by gravity.

A number of tests in the years 1948-1952 indicated the possibility of turbine drilling using retractable cone bits.

Further modernization of step-shaped bits was halted and replaced by development of new designs of single-step retractable cone bits. Because of extensive wear of the reamer-leg joint assembly, engineers decided to investigate the possibility of developing an RB with a monolithic drill head. As a result of this work, a new design of the single-step RB with a two-cone monolith drill head appeared.

In 1954, a retractable tool assembly with new bits was tested in well no. 128 of the Saratovneft Production Company. The retractable tool included an axial turbodrill with an open rubber sealing cup and a ram anchor for seating in the string shoe, and a bit BD3-12 (Figure 26). The drill head in this bit consisted of two legs (1), (2) with cones welded on to a cast holder (3). The retracting mechanism included an hydraulic drive with a slide valve, developed in 1951-1952, that provided reliable transfer of the bit to the operating position.

Fluid was passed through the annulus between a housing (5) and a cylinder (6), coming through the lower openings of the cylinder into a space below the piston. As more fluid entered, a piston (4) with sleeve (7) moved up. At the same time, a rod (8) hanging on the internal face of a cylinder extension (9) remained fixed. Its upward movement was blocked by hydraulic resistance forces, which arose when fluid flowed through slot openings between the centralizer (10) and a rod shoulder.

After the drill head was set in a horizontal position, the upper face of the sleeve butted against the rod shoulder and moved up with the piston rod. The drill head moved translationally and its wedge-shaped cams entered slots of joint (11).

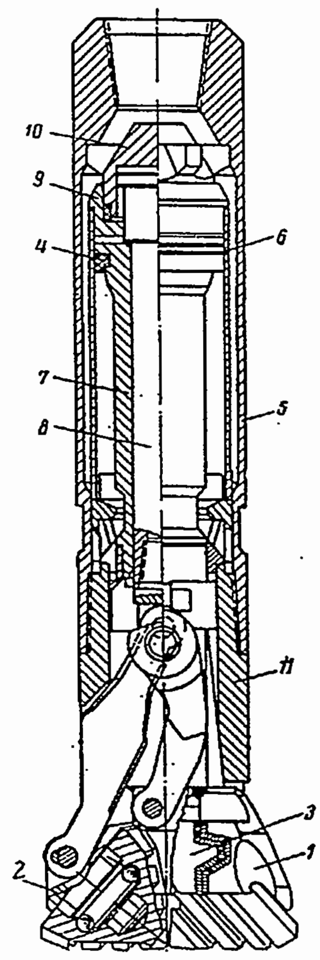


Figure 26. RB BD3-12

There was an annular recess on the external surface of the lower part of the sleeve. At the end of the mechanism travel range, fluid flowed through this recess to the bit water courses that had been made in the form of axial openings in the joint and drilling head. All designs of Russian-made RBs include the main elements of this hydraulic retracting mechanism with a slide valve and an upward moving piston.

Test drilling at well no. 128 was conducted through a 338-mm 13.3-in.) conductor pipe. After 42 runs (15 of them on water and 27 on mud) 699 m (2293 ft) were drilled in the interval 333-1032 m. WOB was 16-18 tonnes (35,300-39,700 lb).

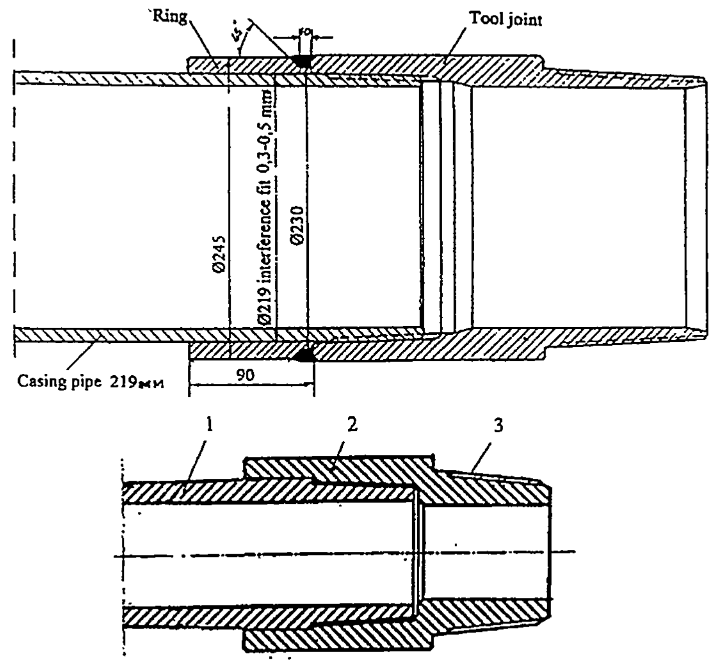


Figure 27. Casing with Special Tool Joints (1–shrunk pipe; 2–tool joint; 3–thread with shoulder connection)

The following average indicators of RB performance were recorded: penetration per run – 16.6 m (54.5 ft); penetration rate – 11.5 m/hr (37.7 ft/hr). Performance was much improved as compared to drilling with stepped bits. As compared to performance of conventional bits in the same intervals in offset wells, penetration per bit was 67%, while penetration rate was 122%.

The test drilling revealed that strength of 219-mm casing did not meet the requirements of turbine drilling. Six failures with pipe breakage were recognized in the lower section of the string along the plane of lowest strength, that is, the area of the thread connections. Weak planes of pipe below the last thread required that lateral bending forces that caused fatigue failure be reduced. This was achieved by strengthening pipe connections with tool joints using shrink rings fit on the pipe body with 0.3-0.5-mm interference. The rings were welded to the tool joints using electrical welding. Pipe threads in this type of design are affected mainly by axial loads. The ring, built up on the pipe, carries dangerous bending forces. Later, this stabilizing rim was shrink fit on the tool joint (Figure 27). The first lot of tool joints with stabilizing rims was made in 1955. Afterwards, tool joints of this design were widely used in the fabrication of steel pipes and aluminum pipes with steel tool joints.

The testing also showed essentially worse performance of all components of the retractable tools when water circulation was replaced with mud circulation. The necessity to apply significantly higher forces to transfer the bit to the transport position became obvious.

Figure 28 shows a retrievable tool assembly used to drill well no. 128.

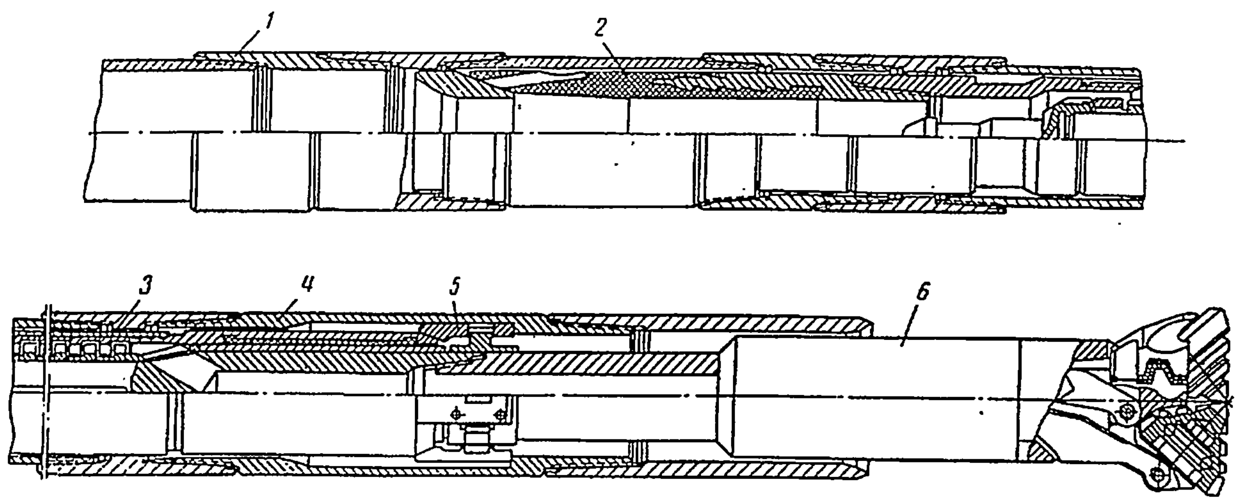


Figure 28. RB Assembly
(1=pipe; 2=seal; 3=turbodrill; 4=shoe; 5=landing device; 6=RB)

During test drilling of well no. 128, a perforated pup joint (Figure 29) was used to balance fluid levels during tripping of the retrievable tool. The perforated pup joint and a modernized ram anchor in the last runs (950-1130 m) allowed developing a method of running down the turbodrill by gravity. This resulted in significantly faster retrievable tool tripping. In a 1030-m (3379-ft) deep well, trip time was 30 minutes (running down 13 minutes; pulling out 17 minutes).

The next series of tests in 1955 at well no. 164 was a trial operation of an improved design retractable tool at depths below 1000 m. RBs with a monolithic design drilling head made 40 runs in the interval 1100-1544 m. Tripping operations were much faster this time. Trip time at a depth of 1500 m (4921 ft) was 55 minutes, including 25 minutes for running down (by gravity) and 30 minutes for pulling out.

6.2 Test Boreholes Drilled with 10-in. RB (1957-1964)

In 1959, a retractable assembly for drilling with a no. 10 bit using 182-mm (7.2-in.) pipes was first attempted in well no. 39 of the Saratovneft Production Company. Test drilling was initiated at 650 m. Drilling fluid used had a density of 1.2-1.25 g/cm^3 and viscosity of 20-37 sec (according to SPV-5 Russian standard funnel viscometer). Various retrievable tool assemblies made 27 runs in the interval 650-1010 m.

Very positive results were achieved drilling with two piston bits. After five runs there was no wear observed on the surfaces of elements in the leg attachment assemblies. However, neither of the designs tested provided reliable transfer of the bit to the transport position. Insufficient reliability of RBs during their transfer from the operating to the transport position using a hydraulic or mechanical device required additional analysis.

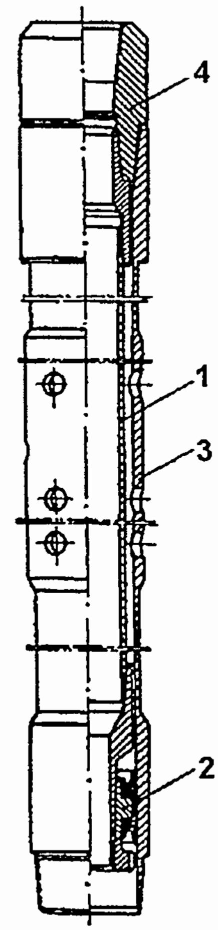


Figure 29. Perforated Pup Joint (1–rod; 2–seals; 3–perfed pup joint; 4–crossover sub)

While developing new designs (BD16-10 and D2PB1-10) engineers concentrated their efforts on eliminating the potential for sludge and cuttings accumulation in the bit retracting mechanism. This could sufficiently reduce failures in bit transfer to the transport position.

New bits were tested in well no. 39 in the Guselsky field that had been suspended at 1045 m (3428 ft) after bit testing in 1959. Drilling for the new tests was conducted at 10-18 tonnes (22,000-39,600 lb) WOB, 30-40 liters/sec (11.3-15.1 BPM) pump rate, and 100-125 kg/cm^2 (1419-1774 psi) pressure. Drilling fluid density was 1.2-1.27 g/cm^3 (10-10.6 ppg) and viscosity was 25-40 sec.

Successful test results showed the reliability of bit transfer to the transport position and brought forward the idea of drilling a pilot hole of 2000-2200 m (6562-7218 m) depths.

Test drilling was conducted at well no. 18 in the Guselsky field (Saratov region) with a TD of 2080 m. The rig included Uralmash-5 equipment with a diesel drive, which allowed controlling pump rate while drilling. A U2-4-5 wireline unit with a 16-mm (0.63-in.) cable was used for pulling the retractable tool. An electric motor (160 kW) drove this winch. A special sensor was installed on the additional crown sheave to enable control of hoisting line tension.

Test drilling was started on September 22, 1961 below conductor casing from 354 m, and finished after reaching TD at 2080 m. RBs drilled 1375 m, including 1315 m with D2PV1M-10 (163 cone bits) and 60 m with BD16M-10 (12 drilling heads). Forty-eight conventional tricone bits were used to drill 350 m in various intervals. RBs made 183 runs, including more than one run of eight bits.

Down to 694 m (27 bit runs) the well was drilled with water circulation. The remaining interval was drilled on mud with 1.22-1.28 g/cm^3 (10.2-10.7 ppg) density, 18-40 sec viscosity, and 0.2-1% sand. The mud treatment system included a conveyor-type shale-shaker and a mud ditch.

Drilling down to 1900 m was conducted with a single-section 97-stage turbodrill at a pump rate of 36 liters/sec (13.6 BPM). The remaining interval was drilled with a two-section 150-stage turbodrill at 29-30 liters/sec (11.3 BPM). WOB was 10-16 tonnes (22,000-35,000 lb).

Average penetration per RB was 7.9 m (25.9 ft) at a penetration rate of 4.7 m/hr (15.4 ft/hr). Compared to performance of conventional tricone bits (no. 12) in offset wells, penetration per bit was 56%, and penetration rate was 70%. Compared to performance of conventional tricone bits (no. 10) in similar horizons of well no. 18, penetration per bit was 75% and penetration rate was 102%.

Time reports of all operations between two bit runs at 1800 m included the following (turbodrill – single section).

- Pulling out: breaking kelly 2.5 min; making up overshot 0.5 min; running in with overshot 8 min; bit transfer to operating position 1 min; pulling out retractable tool 17 min. Total: 29 min.
- Changing bit: installing overshot lock ring, visual inspection of bit and turbine 1 min; changing bit 11 min; bit test 1 min. Total: 13 min.
- Running in: dropping retractable tool inside pipe 0.5 min; making up kelly 2.5 min; circulation with two pumps 12 min; circulation with one pump 4 min. Total: 19 min.

Thus, time between the two bit runs was 1 hour. This range of tripping speed allowed making 8-9 bit runs per day at the depth of 1800-2000 m.

Drilling of the second test well (well no. 19 in the Pristannaya field) with 2100 m TD began in November of 1962 in the Saratov region. A two-section turbodrill with a retrievable rotor (TVR3M-8), and two-piston bits (D2PV3-10), modified after test drilling of well no. 18, were used for drilling the new well.

Retractable tools made 186 runs in 42 days in the interval 466-2112 m and drilled 1308 m (4291 ft). Because of a shortage of RBs, the interval 1707-1984 m was drilled with conventional tricone bits (71 runs) over the period January-November 1963.

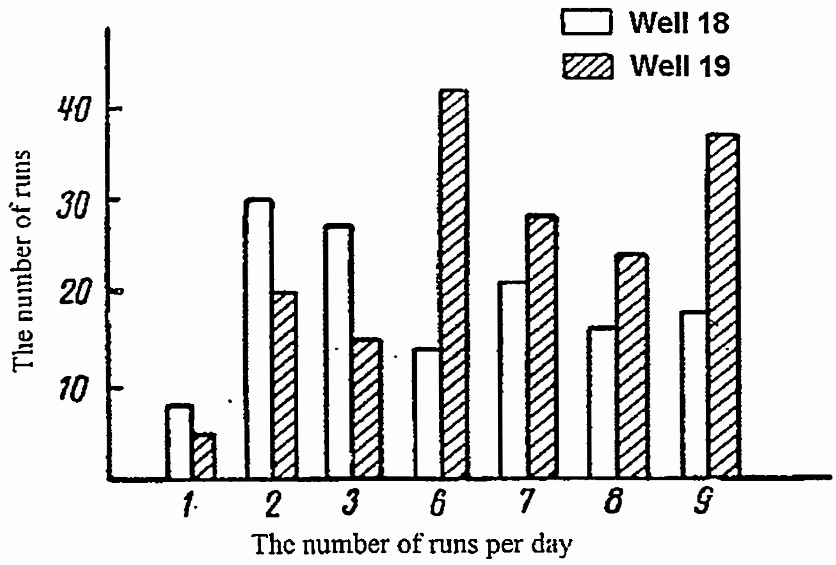


Figure 30. RB Runs per Day

Figure 30 (number of runs per day) and Table 5 (trips of the drill string due to tool failure and breakage) illustrate improvement of operational reliability of the retractable tool achieved while drilling well no. 19. The data show a 2-3 times reduction in the number of extra trips due to satisfactory RB performance. The number of bit runs, with 6-9 bits per day replaced, nearly doubled.

Table 5. Number of Extra Trips per 100 Bit Runs Due to Failure of RBs

TYPE OF FAILURE	WELL NO.18	WELL NO.19
Lost cones	3.68	3.22
Failure of bit retracting mechanism	0.62	-
Turbine failure	3.07	0.54
Turbine malfunction	-	0.54
Total	10.05	4.38

To aid in the analysis of results obtained while drilling without pulling pipe, well no. 20 (offset from well no. 19) was drilled in the summer of 1962 using tricone bits (no. 10). Well no. 20 was drilled with the same rig and drilling crew that drilled well no. 19. Table 6 presents performance comparison data for penetration per run and penetration rate for retractable and conventional tricone bits.

Table 6. Comparison of RB (Well 19) and Conventional Tricone (Well 20)

STRATIGRAPHIC HORIZON	PENETRATION PER BIT (M)			PENETRATION RATE (M/HR)		
	WELL NO.19	WELL NO.20	%	WELL NO.19	WELL NO.20	%
Podolskian-Kashirskian	22.8	28	81.5	19.1	13.1	146
Myachikovskian	31	59	52.5	19.8	18.3	108
Melekesskian	30	28.5	105	15	17.5	86
Cheremshanskian-Prikamskian	19.4	27	72	9.7	9.8	99
Serpukhovian-Okskian	10	16.7	60	6.4	7.4	87
Tulskian	11	17	65	5.5	8.5	65
Cherepovetskian	5.0	11	45.5	4.0	6.2	64.5
Zavolzhskian	8	18.2	44	5.9	8	74
Dankovian-Lebedyanskian	6.2	8.2	75.5	5.1	3.9	131
Zadonian-Yeletskian	5	11.4	44	4.3	5.6	77
Yevlanian-Livenskian	4.4	9.6	46	4.8	4.9	98
Voronezhskian	2.8	11.6	24	3.7	4.0	92.5
Alatyrskian, Semilukskian	3.1	11.1	28	3.6	3.8	95
Mulinskian, Starooskolian	2.7	4.8	56.5	3.2	2.7	119
Vorobyevskian	2.8	3.3	85	3.7	2.0	185
Average	7	12.2	57.5	6.3	5.6	113

The main objectives for efforts in 1964 were RB tests in wells up to 3000 m TD, and further development of this method of drilling.

Drilling was planned at exploratory test well no. 3 (3100 m TD) at the Dvoyenskaya field of the Saratovneftegaz Production Company. The drilling rig included a 53-m (174-ft) derrick, Uralmash-5D unit, and a wireline winch with standard drawworks BU-75Br with additional drum flanges to provide the required wire capacity. A B2-300 engine was used as a drive for the winch.

Drilling with RBs began in April and stopped in October of 1964 at a depth of 2814 m (9232 ft) after encountering a crystalline basement above TD. While test drilling, 1403 m (4603 ft) were drilled in 91 days with 423 bit runs in the interval 1366-2814 m.

Two-piston bits (D2PV3-10) made the majority of runs (334). The remainder of the runs (89) were made with test bits of new designs that drilled 317 m (1040 ft). Two-section turbines with retrievable rotors (TVR3-8) were used in the test drilling.

Drilling parameters were: pump rate 30-35 liters/sec (11.3-13.2 BPM) at pump discharge pressure 110-120 kg/cm^2 (1561-1703 psi); WOB 10-16 tonnes (22,000-35,200 lb); mud weight 1.23-1.28 g/cm^3; mud viscosity 25-26 sec; fluid loss up to 3 cc/30 min.

Average penetration per run was 3.3 m (10.8 ft) with a penetration rate of 3.6 m/hr (11.8 ft/hr). Table 7 presents a comparison of results for drilling with retractable and conventional tricone bits.

Table 7. Comparison of RB (Well 3) and Conventional Tricone Bit (Well 1) in Dvoyenskaya Field

Stratigraphic Horizon	Penetration per Bit (m)			Penetration Rate (m/hr)		
	Well No.3	Well No.1	%	Well No.3	Well No.1	%
Melekesskian	10.3	9.3	111	5.9	5.7	104
Cheremshanskian-Prikamskian	10.0	7.3	137	4.3	4.2	102
Namyurskian	4.6	10.0	46	3.6	4.7	75
Serpukhovian-Okskian	4.9	10.0	49	3.8	5.2	74
Tulskian	4.5	6.4	71	3.3	3.9	85
Bobrikovskian	7.0	4.2	161	5.7	2.5	228
Turneiskian	5.3	7.9	67	3.9	4.2	69
Dankovian-Lebedyanskian	3.6	7.5	48	3.4	3.3	103
Zadonskian-Yeletskian	3.7	9.2	40.5	3.3	3.1	107
Yevlanian-Livenskian	5.0	7.5	67	3.3	3.1	107
Voronezhskian	2.7	8.1	33	2.8	2.6	107
Alatyrskian-Semilukskian	2.7	6.9	40	2.4	2.9	84
Kynovskian-Pashiiskian	2.3	4.1	56	2.9	2.3	125
Mulinskian-Oskolskian	2.0	6.2	31	2.9	2.6	111
Vorobyevskian	1.3	5.4	24	1.7	2.5	68
Chernoyarskian	3.4	4.0	85	3.3	1.9	174
Morsovskian	2.6	3.6	72	2.2	1.6	138
Archeiskian	1.6	2.4	67	1.6	1.7	94
Average	3.3	6.6	50	3.2	3.1	103

One of the reasons for low penetration with RBs was high turbine speed. Measurements with a turbine tachometer while drilling well no. 3 in the Dvoyenskaya field indicated 750-900 RPM operational speed of the TVR3-8 turbodrill. This high RPM especially affected drilling in lower intervals, which were composed of consolidated and frequently abrasive rocks.

Twenty-seven test runs with a three-section turbodrill in the interval 2738-2814 m proved the efficiency of drilling at lower speeds. Utilization of a three-section turbodrill with more stages (the number of stages was increased from 142 to 228) allowed reducing RPM by 15-20% and increasing WOB from 14 to 18 tonnes while drilling tough clay. In addition, during the test runs, penetration with retractable and tricone bits was much closer, and penetration rate of RBs was significantly improved.

Low average penetration per RB was also due to utilization of a single type of bit for the whole well interval. This was proved by the large variation of penetration per run (as compared to tricone bit penetration) in various stratigraphic horizons. According to Table 8, penetration was over 100% in three horizons, 80-100% in one, 60-80% in five, 40-60% in six, and below 40% in three horizons. Apparently, development of RBs with various cutting structures should greatly improve their performance.

Table 8. Comparison of Conventional and RBs in Kvasnikovskaia Field

Conventional Drilling					Drilling without Pulling Pipe*				
Well No.	Year	Well Depth (m)	Drilling Rate (m/rig-month)	Cost (rub/m)	Well No.	Year	Well Depth (m)	Drilling Rate (m/rig-month)	Cost (rub/m)
3	1963	2822	321	84.2	11	1965	2717	522	98.4
6	1963	2860	295	160.0	15	1966	3005	380	154.1
5	1965	3000	400	150.2	28	1966	2678	315	183.0
10	1965	2849	487	99.6	31	1966	3019	387	157.8
12	1966	2790	192	235.0	13	1967	3009	371	147.8
29	1972	2972	486	161.0	22	1967	3010	443	138.0
50	1972	3050	407	177.0	23	1967	2972	695	121.2
51	1972	3000	492	172.0	19	1968	3039	405	211.7
46	1973	3021	549	196.6	24	1968	2901	282	231.2
42	1974	3007	310	231.4	40	1971	3022	308	214.1
53	1974	3020	204	412.5	44	1971	3031	384	181.0
					41*	1975	3010	560	188.0
Average**		2954	398	160.0	Average		3951	397	169.2

* Well No. 41 in the interval of 2513-3010 m was drilled by standard methods

** Without wells No.12 and No.53 as unsuccessful (sidetracks)

6.3 Oil Field Testing and Commercial Drilling (1965-1971)

During the process of commercial testing at the Experimental Turbodrilling Department of PO "Saratovneftegas" (Production Amalgamation) from 1965 to 1971, 26 exploratory and development boreholes 2500-3000 m deep were drilled. The total footage drilled by RB was nearly 41,000 m in the interval 1000-3000 m. Most footage was drilled in the Kvasnikovskaja oil field with very complicated geological conditions – gas and water shows, unstable formations, caving tendencies.

Table 8 summarizes performance on the boreholes drilled in the Kvasnikovskaja field by RB and by conventional methods with 10-in. (248-mm) bits.

Development of the family of retractable tools with 9-in. (220-mm) bits was based on designs for 10-in. (248-mm) RB. The substantial decrease in diameter resulted in insufficient strength and durability of the tools. The problem of increasing total footage per 9-in. bit has not been solved for an extensive period of time. Drilling exploratory boreholes in 1968-1969 with DRB-220 bits did not produce positive results.

Tangible progress was achieved when testing three-cone rock bits of 3DR-220 type and a new design of a two-cone bit (DRB2-220). When tested in drilling, these bits showed appreciable increase of footage per run.

The exploratory borehole no. 32 and development borehole no. 41 in the Kvasnikovskaja field were the test environment. In the no. 32 borehole the retractable cone rock bits made 120 runs in the interval 1425-2407 m and drilled 399 m. A substantial increase in life and footage was obtained with 9-in. RB.

In the 1147-2227 m interval of borehole no. 41, retractable cone rock bits made 102 runs; 1054 m were drilled in 218 hr. That included three-cone bits 3DR-220, which drilled 659 m in 52 runs, and two-cone bits DRB2-220 that drilled 392 m in 50 runs. The average time drilling with 3DR-220 bits was 2 hr/20 min, and with DRB2-220 bits 1 hr/55 min.

Comparative data on bit performance are given in Tables 9, 10, and 11.

Table 9. Average Penetration per RB Run

Stratigraphic Horizon	9-in. Bit (220 mm)					10-in. Bit (248 mm)	
	Well No. 18, 1967	Well No. 2, 1968	Well No. 25, 1969	Well No. 32, 1973	Well No. 41, 1975	Well No. 23, 1967	Well No. 40, 1970
Podolsko-Kashirsky	8.1	5.9	6.4	7.2	20.2	14.8	10.9
Vereisko-Melekessky	7.9	7.3	6.9	11.5	15.2	8.1	15.5
Cheremshano-Prikamsko-Protvinsky	3.1	2.5	2.8	10.1	11.5	7.7	8.0
Serpukhovsko-Oksky	3.4	2.5	2.5	6.9	12.8	4.5	10.5
Tulsko-Bobrikovsky	2.3	2.7	2.8	5.2	3.5	7.4	8.5
Turney	2.0	2.1	2.0	7.5	6.2	6.3	7.0
Danko-Lebedjansky	2.3	2.4	2.2	-	8.2	5.4	6.7
Zadono-Eletsky	2.2	2.2	2.2	-	6.5	3.6	8.5
Total:	3.4	3.1	3.2	7.9	10.3	6.7	9.8

Table 10. Comparison of RBs to Best Conventional Bits

Stratigraphic Horizon	Total M	Conventional Bits Wells 46, 53 (Average)				Retractable Bits in Well 41							
						All Types of RBs				3DR-220 Bits Only			
		Footage		ROP		Footage		ROP		Footage		ROP	
		M	%	M/H	%	M	%	M/H	%	M	%	M/H	%
Podolsko-Kashirsky	242	21.0	100	7.4	100	20.2	96.2	11.3	152.8	20.8	99.0	11.5	155.4
Vereisko-Melekessky	167	34.3	100	8.8	100	15.2	44.4	7.9	89.8	17.0	49.7	6.2	70.4
Cheremshano-Prikamsko-Protvinsky	126	27.3	100	5.3	100	11.5	42.2	5.0	94.4	19.5	71.5	5.5	103.8
Serpukhovsko-0ksky	213	16.8	100	5.3	100	12.5	74.4	4.5	85.3	13.1	78.0	4.5	84.9
Tulsko-Bobrikovsky	49	17.0	100	4.3	100	3.5	20.6	2.0	46.5	4.5	26.4	1.8	41.9
Turney	123	14.8	100	4.3	100	6.2	41.9	3.0	69.8	7.7	52.1	5.0	116.3
Total:	920	20.4	100	5.9	100	10.8	53.0	S.I	86.5	13.1	64.3	5.4	91.5

Table 11. Bit Performance in Podolsko-Kashirky Horizon

Well No.	Bit Type	Number of Bits	Penetration		Penetration Rate	
			M	%	M/H	%
	Regular					
46	5 K214SZG	4	29.0	100.0	10.1	100.0
	2 K214T	4	23.0	79.3	9.5	94.0
	Retractable					
41	3DR-220SZ	8	22.3	77.0	11.7	115.8

It should be noted that the manufacturing quality of the RBs and associated mechanisms was low and it was necessary to check parts and adjust fit before delivery to the rig site. The primary problem – bad conjugation of bit legs with the bell collar in the mechanism – resulted in decreased life of the bell collar. Fatigue cracks appeared in mechanism holders due to the action of torque from friction in the radial bearing of the mechanism.

Following are conclusions related to drilling at PO Saratovneftegas.

1. When high-durability rock bits are used in standard drilling at low RPM, drilling with RBs with increased RPM maintains its promising future.

2. In comparison with high-performance, low-RPM rotary drilling, RBs with DHMs are very competitive under certain geological and technical conditions.

3. With footage per bit run increasing in standard drilling, the efficiency of drilling without pulling pipe will depend on the rate of penetration increase with RBs and the actual decrease in footage per bit.

4. There are specific applications for RB technology that can be highly efficient irrespective of RB drilling performance:

   - Drilling unique ultradeep wells
   - Drilling extended-reach directional boreholes with complicated profiles with high angles of inclination, including horizontal boreholes
   - Drilling with casing and leaving it in the borehole as a surface or intermediate casing string
   - Underbalanced drilling

6.4 Field Tests of Drilling with Casing

The first prototype 4DV-295 bit was manufactured and tested in West Siberia (Figures 31 and 32) in 1974-75. This was the four-cone rock bit, with cones arranged in the transport position by pairs at two levels. Two cones (for drilling the central area of the hole) are rigidly interconnected with each other and the seating mechanism, and two peripheral legs with cones are hinged in the movable body. The bit was tested with a high-RPM turbodrill when drilling for surface casing in soft formations. 400 m was drilled in 7 hr with an average ROP of 57 m/hr (187 ft/hr). The range of ROP was 30 to 80 m/hr (98 to 262 ft/hr) through different intervals. The average ROP with a conventional bit is 78 m/hr (256 ft/hr).

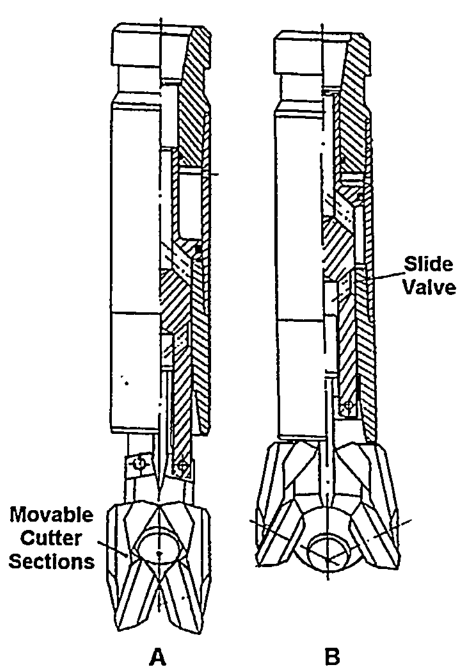


Figure 31. Four-Cone RB 4DV-295 (A – transport; B – operating)

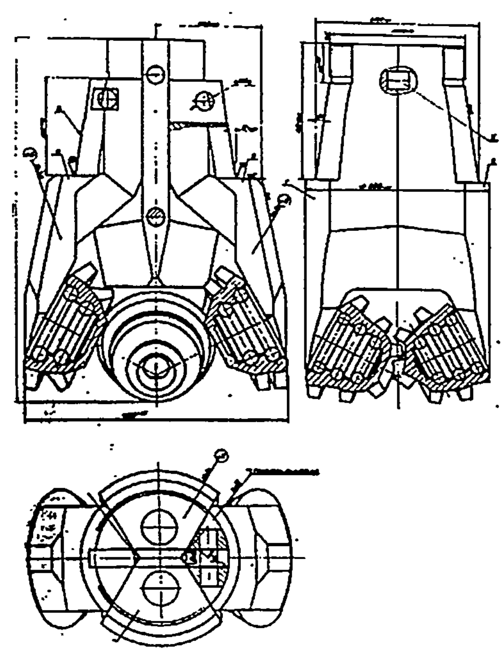


Figure 32. RB 4DV-295 Cone Assembly

6.5 Scientific Drilling Experience

The first of the trends described above for drilling without pulling pipe was developed within the program "Investigations of Earth's Crust and Ultradeep Drilling." Field tests were conducted in the Sputnik SD-3 (a satellite of the Kola ultradeep borehole) and Krivoy Rog SD-8 boreholes.

The first designs of bits for hard formations were based on the 3DR-220 bit. This is a three-cone bit (Figure 33) with a garland arrangement of legs in the transport position. The upper leg has a hinged connection with the bit body and two others with external moveable holders. In the working position, all the legs are locked in the bell-collar (part of the bit body). Working loads (torque and WOB) are transmitted to the legs by this unit. The main modifications were connected mainly with cone cutting structure; bit diameter was decreased to 217 mm (8.5 in.) (the code of the first bit was 3DR-217OK).

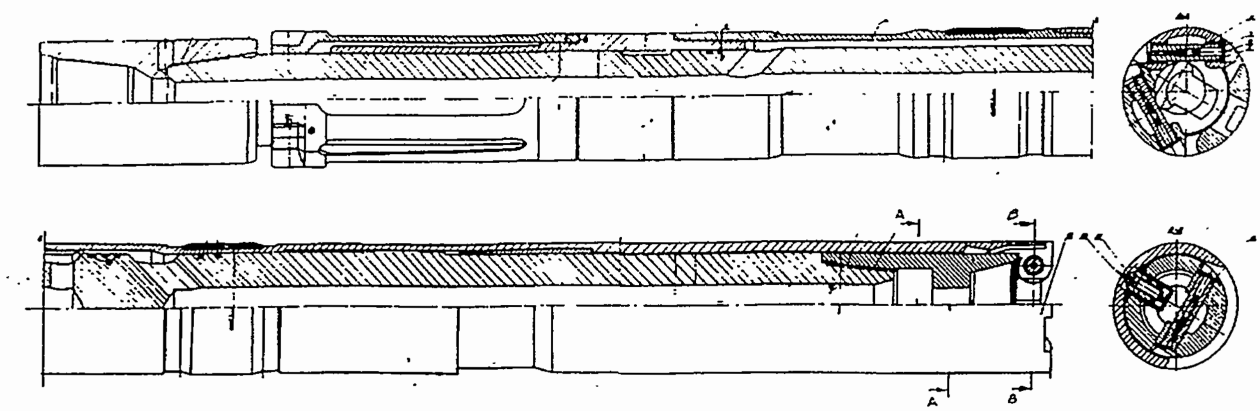


Figure 33. Retracting Mechanism 3DR-220

The first three runs were made at shallow depths (up to 300 m) in hard diabases; the next test runs were made by 3DR-217K bits (Figure 34) in the interval of 580-700 m composed of the diabases and gabbro-diabases interbedding with tuffs. Here, the bits were also used to ream the borehole pilot core. The results are tabulated in Table 12. All runs were made with the three-sectional turbodrill TRV-198T with a retrievable rotor and rotary speed of 500 rpm.

Table 12. RB Tests in Sputnik SD-3 (1974-75)

	Bit Number	Drilling Interval(m)	Penetration (m)		Time (hr)		ROP (m/hr) Drl/Rm	Drilling Parameters		
			Drill	Ream	Drill	Ream		Q (l/s)	P (bar)	WOB (ton)
1.	3DR-217OK, 1	249.2-258.2	9.0		1.90		4.70	26	120	7-9
2.	2	264.8-274.4	9.6		2.10		4.40	26	120	7-9
3.	3	274.4-286.6	12.2		5.75		2.10	26	120	6-9
4.	3DR-217K,3429	579.8-585.4	5.6		1.50		3.74	26	140	8-9
5.	3517	587.8-600.0	2.2	10.0	0.85	2.15	2.65/4.60	26	125-130	5-6
6.	3441	600.0-612.6	3.1	9.5	0.70	1.25	4.65/7.60	26	130	5
7.	3470	666.5-669.3		2.8		1.00	- /2.80	26	130	5-6
8.	3631	669.3-673.0	0.9	2.8	0.33	0.67	2.70/4.20	22	80	5-6
9.	3675	673.0-681.4		8.4		2.15	- /3.90	22	80	5-6
10.	3688	687.2-697.2	10.0	1.0	0.35	2.00	3.00/4.50	22	130	5-6
11.	3431	709.1-718.1	8.6		1.50		5.70	22	95-100	7

When penetration rate (and to a lesser degree bit life) results were satisfactory, the retracting mechanism design needed to be improved. The main conclusion was the necessity of reducing bit rotary speed to increase its reliability and life. For this purpose a retrievable PDM (type DVO-142) was developed and used in further tests.

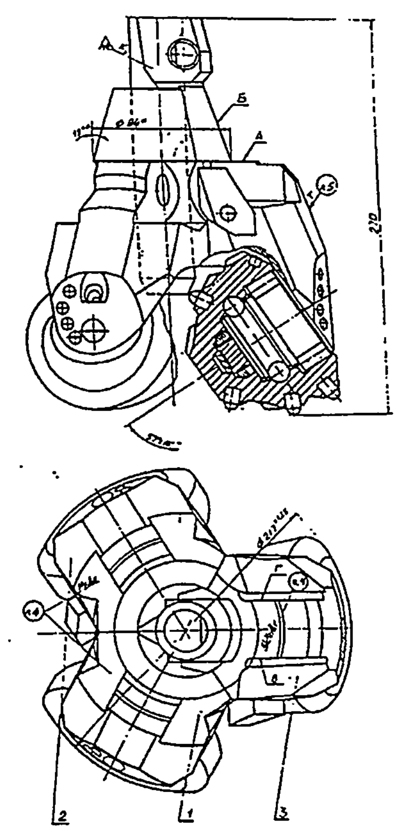


Figure 34. RB Cone Assembly 3DR-217K

Tests of the first commercial batch of bits were carried out in 1976 in the interval 953-1316 m. During the tests, 30 runs were made with the RB, 140 m drilled, and 47 m reamed, with a total time of operations of 76 hr. Drilling was conducted with a TVR-198T turbodrill. One run was made with a DVO-142 motor: 9 m (30 ft) were reamed in 6.0 hr. Tests were carried out in the following rocks: fine and medium-grained diabases of 240-400 kg/mm^2 (341-568 ksi) hardness (see note in next paragraph) in the interval 953-1000 m; siltstones and phyllites of up to 150 kg/mm^2 (213 ksi) hardness was penetrated in the interval 1000-1143 m; and gabro-diabases of up to 350 kg/mm^2 (497 ksi) hardness in the interval 1143-1316 m.

Note: *"Hardness" as used in the Russian oil industry refers to "hardness by punch indentation," a method commonly used in the USSR for rock characterization. The relevant standard is GOST 12288-66. The load/deformation characteristics are recorded based on a standard size punch that is pressed into a small block of rock. Hardness is defined as the load at rock destruction divided by the area of the punch. This parameter is not* *the same as compression strength.*

Performance of the 3DR-217K bit in three formations was acknowledged as satisfactory. Maximum footage per bit when drilling was 19.2 m (63 ft); maximum penetration rate for drilling was 7.6 m/hr (25 ft/hr) and for reaming was 12 m/hr (39 ft/hr). Average footage per bit when drilling and reaming was 7.8 m (26 ft). The average bit operational time was 2.4 hr (not including time lost due to accidents).

Great concern was raised by many unexpected failures of retracting mechanisms with holders breaking and leaving legs with cones on the bottom of the hole. In previous tests in 1975 there were no failures, including Sputnik SD-3 and the PO Saratovneftegas, where in well no. 41 Kvasnikovskaya 52 runs were made with these bits without failure. After careful analysis three reasons for these failures were highlighted: 1) incorrect assembling of the bit with the turbodrill; 2) drilling was begun with the bit not yet completely transferred into the operating position; and 3) when drilling very hard formations, bit legs disengaged from landing surfaces because of high vibration and in zones of hole enlargement due to cuttings getting between bit legs. The design was modified to increase the hydraulic forces that fix legs in the mechanism; turbodrill start-up was also postponed until after complete transference of the bit into the operating position.

After preliminary tests in 1976, commercial tests of 3DR-217 bits were carried out in the interval 700-1100 m in 1977-1978. Altogether 35 runs were made with bits of types "K", "SZ" and "OK". Detailed information is given in Table 13. Compared with four-cone drill heads of the type 2V-K214/60TKZ in similar intervals of the main Kola SD-3 borehole, the footage per RB was 70% with the same average penetration rate.

Table 13. RB Tests in Sputnik SD-3 (1977-78)

	Bit No.	Downhole Motor*	Drilling Interval (m)	Penetration (m) Drill	Penetration (m) Ream	Time (hr) Drill	Time (hr) Ream	ROP (m/h) Drl/Rm	Drilling Parameters Q (L/s)	Drilling Parameters P (bar)	Drilling Parameters WOB (ton)
3DR-217 K Bit											
1.	549	DVO-142	720.0- 722.3	2.3		2.83		0.81	26	40	3
2.	3480	DVO-142	728.0- 734.2	6.2		4.33		1.44	28	50	8
3.	551	DVO-142	753.0- 755.2	2.2	7.8	1.83	3.00	1.22/2.60	28	50	6-8
4.	3816	DVO-142	772.5- 776.0		3.5		2.70	1.27	28	50-60	
5.	3816	DVO-142	776.0- 779.3		3.3		1.67	1.97	28	40-50	
6.	3316	TVR-198T	867.3- 868.8	1.5	1.7	0.92	0.50	1.60/3.40	28	95-105	2-6
7.	7320	TVR-198T	896.1- 902.1		6.0		1.50	-/4.00	28		
8.	7313	TVR-198T	902.4- 908.1		5.7		1.67	-/3.40	28		
9.	7220	TVR-198T	907.8- 912.1		4.3		1.50	- /2.87	28		
10.	723	TVR-198T	912.1- 917.2	5.1	2.1	2.33	0.50	2.20/4.20	28	130	7-10
11.	728	TVR-198T	918.2- 922.3	4.1	1.0	2.25	0.25	1.80/4.00	28	120	10
12.	2575	DVO-142	978.8- 986.8		8.0		5.33	1.50	24-25	50-55	3-9
13.	2599	DVO-142	986.8- 987.3	0.5	1.0	0.10	0.67	0.90	24	55	6-7
14.	2545	DVO-142	992.3- 993.3		1.0		1.50	0.67	26	55	6-8
15.	2609	DVO-142	1,007.8-1,015.1		7.3		7.75	0.94	26	48-55	8-11
16.	2624	DVO-142	1,014.9-1,022.5		7.6		6.83	1.11	26	50-55	8-10
17.	2620	DVO-142	1,022.8-1,030.1		7.3		3.50	2.08	26	60-75	13-14
18.	2598	DVO-142	1,030.1-1,037.9		7.7		4.08	1.89	26	60-70	6-14
19.	2548	DVO-142	1,037.9-1,038.7	0.8	1.8	1.33	0.83	1.20	26	50-60	2-14
20.	2543	DVO-142	1,039.0-1,046.4		7.4		4.67	1.58	26	50	13
21.	2387	DVO-142	1,046.4-1,050.7		4.3		4.25	1.01	26	50-55	3-13
22.	2623	DVO-142	1,052.2-1,061.6		9.4		5.50	1.71	26	75-80	13-14
23.	2722	DVO-142	1,070.8-1,071.4	0.6	11.6	0.42	6.33	1.83	26	50-60	12-13
3DR-217 SZ Bit											
24.	16	DVO-142	740.0- 745.2	5.2		4.33		1.21	28	50	7-8
25.	2	DVO-142	764.0- 772.8	8.8	8.5	6.00	4.58	1.40/1.97	28	50	7-8
26.	10	TVR-198T	858.9- 867.3		8.4		1.83	-/4.60	28	105	2-7
27.	11	TVR-198T	868.8- 869.3	0.5		0.50		1.00	28	100	
28.	11	TVR-198T	871.5- 874.5	2.5	0.5	0.92	0.25	2.70/3.60	28	100	4-5
29.	11	TVR-198T	875.8- 879.0		3.2		0.67	-/4.80	28	105	5
30.	5	TVR-198T	879.0- 882.4	3.4	1.8	1.17	0.50	2.90/3.60	28	105	5
31.	8	TVR-198T	883.6- 888.1		4.5		2.25	-/2.00			
32.	8	DVO-142	997.2-1,001.8	4.6		9.25		0.50	26	45-55	4-11
33.	4	DVO-142	1,001.8-1,006.2	4.4		10.08		0.40	26-38	40-80	8-14
3DR-217 OK Bit											
34.	69	DVO-142	722.3- 728.0	5.7		3.67		1.54	28	45	4-8
35.	70	DVO-142	734.2- 740.0	5.8		4.50		1.29	28	50	7-8
Total				64.2	136.7						

DVO-142 = Retrievable PDM

TVR-198T = Turbodrill with retrievable rotor (3 power sections)

The average performance of 3DR-217K bits is given in Table 14. Despite the fact that penetration rate was lower, the use of PDMs increased bit life substantially. After another modification of the retracting mechanism, the problems recurred. The connecting unit between the movable holder and housing by means of a spring ring turned out to be unreliable. Because of considerable vibration on the hard bottom, the holder often became disconnected from the housing. This sometimes resulted in pulling out the drill pipe. By the end of tests, this defect was eliminated by a newly proposed swivel-type connection using special bushings.

Table 14. Results with 3DR-217K RB in Sputnik SD-3

Retrievable Downhole Motor	Drilling Interval (m)	Number of Bits Used	Penetration per Bit (m)	ROP (m/hr)	Bit Life (hr)
Turbodrill TVR-198T	866- 924 720- 783	6	5.25	2.75	1.9
PDM DVO-142	987-1072	13	7.60	1.45	5.3

In 1986, the 3DR-217K bit with improved mechanism 3DR-220 (Figure 35) was used in pilot drilling in the Krivoy Rog ultradeep borehole. Two bits were used in the interval 1853-1857 m which consisted of very hard ferruginous quartzite of 520 kg/mm^2 (738 ksi) hardness (see note on page 59). Comparative results are shown in Table 15. At greater depths, also in very hard plagiogranites (420-650 kg/mm^2 (596-922 ksi) hardness) six more bits were run (Table 16). Drilling was conducted with low-RPM retrievable DHMs: gear-reducer turbodrills TRV-142 (four bits) and PDMs of type DVO-142 (two bits).

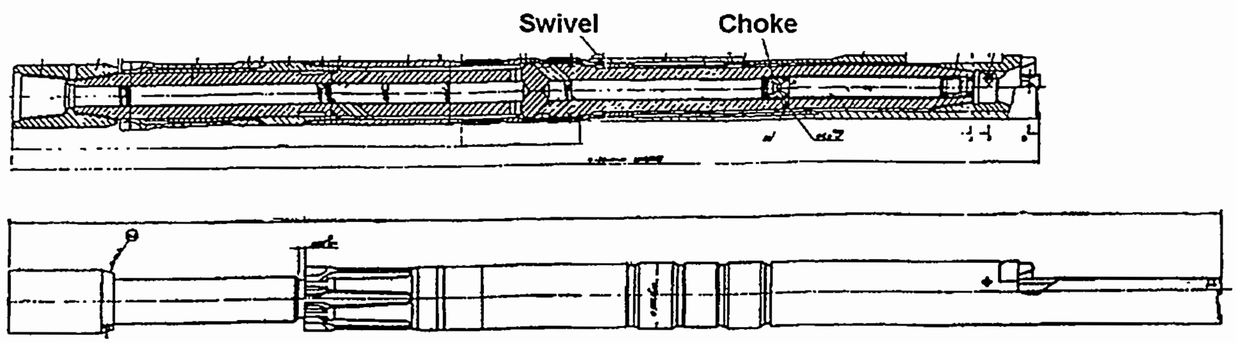


Figure 35. Advanced Retracting Mechanism 3DR-220

Table 15. Bit Performance in Hard Quartzite (Krivoy Rog SD-8)

Bit Type and ID	Turbine Type	Drilling Interval (m)	No. of Bits Used	Avg Pene-tration (m)	Avg Bit Life (hr)	ROP (m/hr)	Drilling Parameters				Core Recovery %
							Q (L/s)	P (bar)	WOB (ton)	RPM	
Diamond core bit ISM 214,3/60 T2	3TSSh-195	1841.4 - 1845.7	2	2.15	10.5	0.20	30	80	6-8	640	100
Four-cone TCI core bit KS 212.7/60TKZ	A7GTSh	1845.7 - 1852.9	4	1.80	6.9	0.26	30	80	6-8	300	76
Five-cone TCI core bit K 133/52 TKZ(pilot coring)	TRV-142 (2 gears)	1852.9 - 1857.7	2	2.40	5.2	0.46	25	70	3-5	90	75
Retractable bit 3DR-217K (reaming)	TRV-142 (1 gear)	1852.9 - 1856.7	2	1.90	2.5	0.76	25	80	8-10	300	-

3TSSh-195 – 7¾-in. OD conventional 3 section turbodrill
A7GTSh – 7¾-in. OD regular turbodrill w/ 2-power sections and one section of hydraulic-breaks
TRV-142 – 5⅝-in. OD retrievable gear-reducer turbodrill

Table 16. Results with RB 3DR-217K in Krivoy Rog SD-8

	Downhole Motor	Drilling Interval (m)	Penetration (m)	Bit Life (hr)	ROP (m/h)	Drilling Parameters		
						Q (L/s)	P (bar)	WOB (ton)
l.	TRV-142	2,545.7-2,549.4	4.2	3.00	1.40	25	70	2-4
2.	TRV-142	2,549.4-2,554.5	4.6	1.33	3.45	25	95	5
3.	TRV-142	2,554.5-2,549.4	4.2	1.25	3.36	25	90	5
4.	TRV-142	2,560.7-3,566.9	6.2	3.25	1.90	25	90	3
5.	DVO-142	2,608.9-2,610.9	2.0	2.50	0.80	30	80	2
6.	DVO-142	2,610.9-2,612.9	2.0	2.75	0.73	30	80	2

Performance observed was worse than in the borehole Sputnik SD-3 due to two factors: 1) more complicated geological conditions (very hard formations and inclination angles at the bottom from 6 to 15°) and 2) bit cutting structures were not completely worn. The bit was often pulled out of the hole to check the mechanism condition and observe the wear. In addition, these were the first tests with the gear-reducer turbodrill, and the lack of experience sometimes resulted in bits being pulled prematurely.

The 3DR-217K bit with the 3DR-220 retracting mechanism was the principal tool for drilling and reaming holes in offshore scientific drilling technology sea trials on the drill ship "Bavenit" in 1991. This bit drilled 147.4 m (57% of the total footage in the expedition) including 93.5 m (307 ft) drilled and 53.9 m (177 ft) reamed after coring.

Low-RPM DHMs similar to those used in the Krivoy Rog borehole were applied. During testing, three retracting mechanisms and five bits (Table 17) were used, of which only four bits were worn. The average footage per bit was 36.4 m (119 ft) during 10.6 hours.

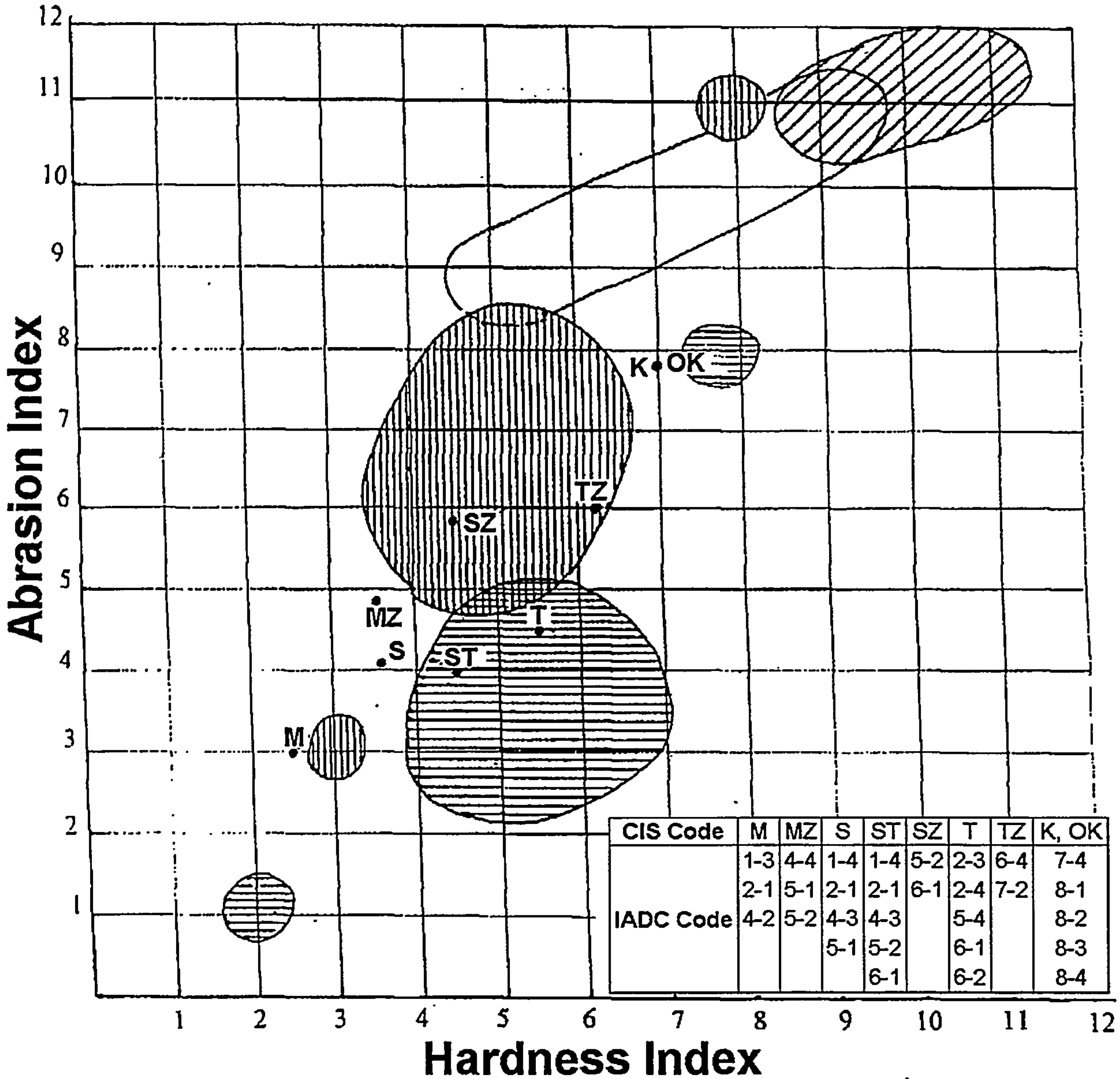
Table 17. Results with 3DR-317K in Offshore Scientific Drilling (1991)

Bit No.		Borehole/ Run No.	Number of Runs	Penetration (m)		Time (hr)		ROP (m/hr)	
3DR-220 mechanism	3DR-217K cones			Drill	Ream	Drill	Ream	Drill	Ream
1	48	2B/1; 2B/4; 2B/7	3	10.6	10.9	4.10	1.50	2.58	7.27
1	56	2B/10; 4B; 4G;4D	4	15.0	6.5	6.75	1.00	3.22	6.50
1	2289	4E/1;4E/5; 6B; 5/11; 5/15; 5/1;5/8	7	42.3	25.0	10.76	4.92	3.22	5.08
Sub-total			14	67.8	42.40	21.61	7.42	3.14	5.71
2	9	2A	1	1.70	-	2.92 0.33*	-	0.52	-
Sub-total			1	1.70	-	3.25	-	0.52	-
3	2277	6C/1; 7/1; 7/4; 7/6	4	24.0	11.50	10.35 0.30*	3.0	2.32	3.83
Sub-total			4	24.0	11.50	10.65	3,0	2.32	3.83
TOTAL			19	93.50	53.90	34.82 0.63*	10.42	2.69	5.17

* Additional time for reaming borehole to nominal size

There was practically no cutting structure wear (except for some broken inserts); the bits were changed because of cone play and loss of diameter. Of the three 3DR-220 mechanisms used, only one mechanism (no. 3) remained in working condition. Mechanisms no. 1 (worked 29 hr) and 2 (worked 3.25 hr) required changing the large holder. There were a total of 19 runs made of the RB. Even though the bits were manufactured in 1977, their design turned out to be relatively efficient for testing the technological concepts of bare rock spudding and drilling deepwater boreholes in hard formations. A comparative evaluation of RB test conditions in a variety of areas is shown in the Figure 36.

The first offshore drilling experience with RBs initiated a commercial application of this technology in offshore stratigraphic drilling.



CIS Code	M	MZ	S	ST	SZ	T	TZ	K, OK
IADC Code	1-3	4-4	1-4	1-4	5-2	2-3	6-4	7-4
	2-1	5-1	2-1	2-1	6-1	2-4	7-2	8-1
	4-2	5-2	4-3	4-3		5-4		8-2
			5-1	5-2		6-1		8-3
				6-1		6-2		8-4

Areas / Rock Properties

- Atlantic Ocean Bed in the DS "Bavenit" expedition

- Kvasnikovskaya oil field in the interval 1000-3000 m

- Kola SG-3 hole in the interval 770-1280 m

- Krivoy Rog SG-8 hole in the intervals 1850-1860 m and 2500-2600 m

Figure 36. Physical and Mechanical Properties of Rocks versus Drill Bit Types

6.6 Offshore Stratigraphic Drilling

Three-cone RBs of types 3DR-217K and SZ were used in the stratigraphic drilling project of IKU Petroleum Research (Norway) in 1993. This was the first field test of the Complete Coring System (CCS) in deep-water environments. The Norwegian drill ship

"Bucentaur" was used for this project. Water depth was about 1500 m (4921 ft), and well depth in the range of 150-200 m. Total footage of borehole reaming in the intervals composed of consolidated sandstone was 36.3 m (119 ft) in three runs with an average penetration rate of 2.7 m/hr (8.9 ft/hr). While spudding the test borehole, 3DR drilled 10.2 m (33 ft) in clay with an average penetration rate of 13.6 m/hr (45 ft/hr) (Table 18).

Table 18. Results with 3DR-317K in Offshore Stratigraphic Drilling (1993)

Borehole/Run no.	Runs	Penetration (m)		Time (hr)		Penetration Rate (m/hr)	
		Drilling	Reaming	Drilling	Reaming	Drilling	Reaming
Drilling in the Norwegian Sea from DS "Bucentaur "							
1B/13	1	-	12.8	-	4.17	-	3.06
1B/46	1	-	21.5	-	13.5	-	1.59
2A/5	1	-	2.0	-	0.58	-	3.45
3A/2	1	0.7	-	0.67	-	1.04	-
Test drilling	1	10.2	-	0.75	-	13.6	-
Sub-total	5	10.9	36.3	1.42	18.25	7.68	1.95
Drilling in the Strait of Gibraltar from DS "Bavenit"							
3B	1	4.5	-	1.05	-	4.3	-
3C	1	4.0	-	4.0	-	1.0	-
3H	1	2.5	-	2.08	-	1.2	-
6A	1	7.0	-	1.35	-	5.2	-
6B	1	6.0	-	3.75	-	1.6	-
Sub-total	5	24.0	-	12.23	-	`1.96	-
Total	10	34.9	36.3	13.65	18.25	1.9	1.95

In 1995, while drilling test boreholes in the Strait of Gibraltar, five runs to spud boreholes on the hard sea-bed crust were made with a 3DR-217SZ bit at 300 m (984 ft) water depth. Total penetration of these runs in hard carbonaceous rock was 24 m (79 ft) with an average penetration rate of 2.66 m/hr (8.7 ft/hr). No failures of retractable mechanisms or bits were observed. In addition, the retractable reamer type RVA-217 with PDC cutters was successfully tested during this project as well.

RBs with DHMs were considered as the best method to spud boreholes without a sea-bed frame to guide the BHA if soft sediments were not overlying hard rocks.

6.7 Bench Tests for ODP

The experiences described above led to the development of a tricone RB that was able to improve the ability to spud in and drill with casing in hard unconsolidated basalt rocks at the ocean floor. During the Ocean Drilling Program (ODP) field trials, this problem was encountered while spudding and drilling in these conditions even with a guide base present.

Tricone RBs were developed under a contract between the Aquatic Company and Texas A&M Research Foundation (ODP). Two RBs were manufactured at the VNIIBT plant in Lubertsi (Moscow region). Testing of the RB was conducted at VNIIBT bench drilling rig in Povorovka (Moscow region) in July and August 1994. The shoe and test sub were supplied by ODP.

The RB was designed for ODP's large-diameter BHA. The tricone RB was one component of the system developed for spudding into bare rock, which isolates the upper unstable portion of the formation. Tricone RBs allowed deployment of 10¾-in. drill collars to support a fractured basalt zone.

The design of the RB provided for its use with available BHA hardware: a mechanical back-off sub, sea-floor template, and 10¾-in. drill collars. The main exception was the method of connecting the bit to the back-off assembly. The bit was connected via a crossover adapter and 6¾-in. drill collars. 10¾-in. drill collars were also provided with the special shoe.

This RB required only one-way operation. Assembling the BHA with the bit and latching the bit into the operating (working) position was completed on the drill floor prior to lowering the bit and BHA to a sea floor. The conventional ODP procedures could be used for running, spudding in and drilling with an RB (Figure 37).

After 10¾-in. drill collars latched in the sea-floor template, the RB was removed from the 10¾-in. drill collars using a drill string. Transfer of the RB from the operating to the transport position was made by the collet contacting the shoe.

The design of the RB had been modified to meet ODP design requirements. A brief description of the tricone RB design and some technical

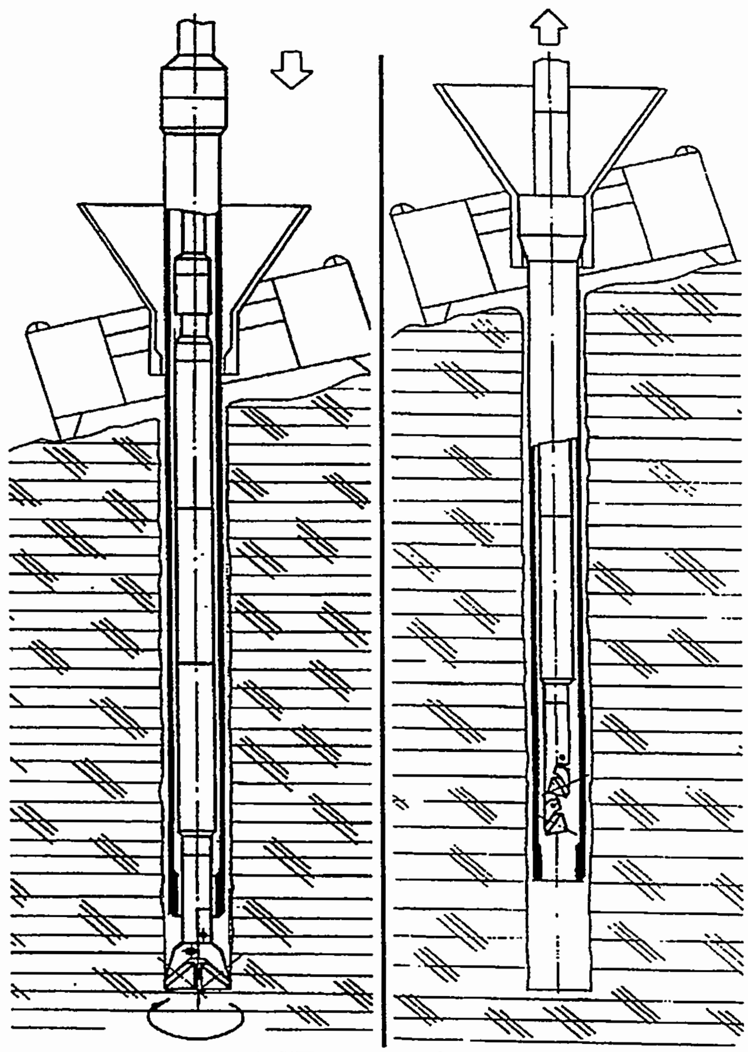


Figure 37. TRB-300 Operational Schematic (left – drill in; right – back off and retrieval)

characteristics are given below.

Technical Characteristics of Tricone RBs:

1.	Bit outside diameter	300±1 mm (11-13/16 in.)
2.	Bit OD in the transport position	185 mm (7.3 in.)
3.	Bit length	3250 mm (128 in.)
4.	Bit length in the transport position	3800 mm (150 in.)
5.	Stroke of movable parts of bit	550 mm (21.6 in.)
6.	Shoe length with diamond bit	2865.5 mm (113 in.)
7.	Shoe OD body	273 mm (10¾ in.)
8.	Spiral blades	295.3 mm (11⅝ in.)
9.	Shoe ID	187.3 mm (7⅜ in.)
10.	Weight of bit	540 kg (1214 lb)
11.	Connecting thread to 6¾-in. drill collars	box 5½-in.FH for 5½-in.FH Modify Pin

Operating Characteristics of Tricone RBs:

1.	Weight on bit (maximum for bit)	up to 20 tonnes (44,100 lb)
2.	Rotational speed	80-120 RPM
3.	Flow rate of water	400-500 gal/min
4.	Pressure drop across the bit	12-20 bar (~170-285 psi)

The tricone RB consists of an expanding mechanism and three replaceable roller-cone cutter sections. While drilling, the bit is placed inside the shoe.

Retracting Mechanism: The retracting mechanism of the RB installs the cutter sections into the operating and transport positions. In the operating position, the sections are joined together; in the transport position, the cutter sections are stacked one above the other (like a garland). Each cutter section is attached to a specific part of the retracting mechanism.

Barrel: The barrel is the main element of the retracting mechanism. All other components are mounted on the barrel. The barrel has a central bore, one or two ports for jet nozzles in the upper section, two ports in the middle and two sets of threads for connecting to a 6¾-in. drill collar and for a cone sub. In the central bore, two steel nozzles are installed in series.

Cone Sub: The cone sub is connected to the lower end of the barrel. It performs several functions: the arm A is mounted into the sub; weight on bit and torque are transmitted by the sub; and the sub joins the three arms together.

Two catches are placed inside the cone sub. One restrains the pivot; the other maintains the short holder in the working position while the holder is moving to the transport position.

Moving Parts: The moving system of the retracting mechanism is placed outside the barrel and consists of several threaded parts: holder, holder bushing, collet with collet sub (one unit) and short holder. The holder keeps the lower arm C; the short holder keeps the middle arm B.

The retracting mechanism has additional parts: pivots, seals, rings, bushings, washers etc.

Two different types of cone-cutting structures were designed for drilling in fractured basalt and for granite blocks.

Cutting Structure for Basalt: Medium extension, 70° conically shaped, closely spaced inner row inserts and hemispherical gage row inserts.

Drilling Action: Primarily crushing and chipping (some scraping)

Cutting Structure for Granite Blocks: hemispherical-shaped inserts.

Bearing: Non-sealed roller-ball/roller type. Journal angle 39°, offset angle 0°.

Hardfacing for Arms: five tungsten-carbide inserts positioned around the plug. Conically shaped inserts allow satisfactory rates of penetration with very low weight on bit.

The RBs were manufactured at the VNIIBT plant (20 km from Moscow). This plant specializes in the production of different drilling tools, including drill bits.

Two retracting mechanisms were manufactured, along with two sets of cutter sections and two sets of additional cones. Two fabricated sets of cones had cutting structures with conical inserts and two other sets had hemispherical inserts. The conical inserts (diameter 14.14 mm x length 19.7 mm (0.56 x 0.78 in.)) were supplied by ODP.

After assembly, factory tests of the bits were conducted. The bits were transferred to the operating and transport positions. The OD of the bit in the working position was checked with a special gage with ID 300 mm (11.8 in.), and in the transport position with the shoe bushing.

The initial tests of the tricone RB were conducted at the VNIIBT bench drilling rig on July 29-August 9, 1994. The test site was located about 50 km from Moscow. The bench drilling rig is a standard rig with special facilities for testing drill bits and downhole motors.

The technical characteristics of the rig:

• derrick height to crown block	53 m (174 ft)
• pump(s) output	5-100 l/s (78-1587 GPM)
• weight on bit	up to 30 tonnes (66,150 lb)
• rotary torque	up to 150 kN-m (110,630 ft-lb)

Controlled and recorded parameters:

- weight on bit
- torque
- pump pressure
- pump output
- rotary speed of a rotary table or motor shaft

All tests were conducted in accordance with ODP's program and requirements. The program included three test phases:

1. The first phase provided for assembling the bit, shoe, testing sub and PDM together to ensure compatibility and interchangeability between all the manufactured hardware. This test ensured that all components of the system were designed and fabricated correctly. The method of transferring the bit to the operating and transport positions was developed.

2. The second phase included drilling a minimum of 20 m (66 ft) in granite blocks, retrieving the bit from inside the 10¾-in. shoe, and checking the bit gage. Two gray granite blocks were used for testing. The properties of the drilled granite: density = 2.67-2.68 g/cm^3; porosity = 1-2%.

Rock hardness was evaluated by the strength in compression p = P/S, where P = breaking strength (kg); S = area of punch = 3.14 mm^2. A punch with 2-mm foot diameter and up to 3000 kg loading was used. For this granite, p = 330 kg/mm^2 (468 ksi) (see note on page 59).

During the tests, 18 holes were drilled in two blocks. The bit was retrieved without problem from inside the 10¾-in. shoe five times after drilling the first five holes and after drilling the last hole. While drilling, WOB was maintained within the range 4.5-5.5 tonnes (9,920-12,130 lb). The ROP varied from 1.38 m/hr (4.5 ft/hr) (new bit) to 0.262 m/hr (0.86 ft/hr). Bringing WOB up to 12 tonnes (26,460 lb) resulted in an increase in ROP up to 2.26 m/hr (7.4 ft/hr) although the cutting structure was worn out. A total of 20.18 m (66.21 ft) were drilled in two granite blocks; cumulative drilling time was 36.68 hr. The TRB-300 in the operating position, including an assembly with shoe, is shown in Figure 38.

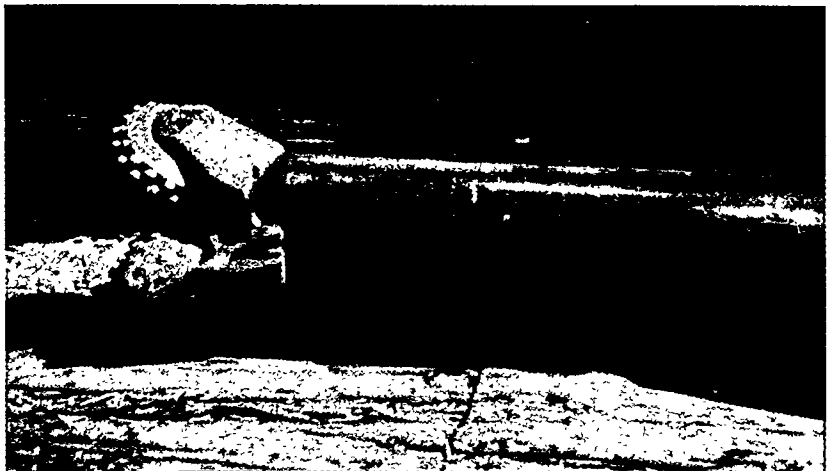


Figure 38. Tricone RB TRB-300

Thus, the main tasks of the program were accomplished, providing for drilling 20 m with an average ROP not less than 0.5 m/hr.

3. The third phase of testing addressed disassembling and checking dull condition of cutters, bearings and hard facing on the bit.

After drilling, the system and bit were disassembled. The retracting mechanism had practically no wear and could be used again. The cutter sections had worn cutting structures and shell of cones between tungsten-carbide inserts on the Inner Heel Rows. One tungsten-carbide insert was broken. About 2-3 mm wear was found in some areas on the back face of the arms. The bearings had practically no wear. Figure 39 shows the TRB-300 cone assembly after drilling.

Figure 39. RB TRB-300 Cone Assemblies

The cone C was removed from the arm and the bearing was examined. The diameters of the journal and the cone ball and roller raceways had wear of about 0.1-0.15 mm. After inspection, the retracting mechanism was reassembled.

6.8 Demonstration of RB at Maurer Engineering Inc.

A tricone RB of the type 3DR-220 was tested at Maurer Engineering's Drilling Research Center (DRC) in Houston in January 1999. The test was conducted as part of the project's technology transfer tasks. The primary purpose of the tests was to demonstrate the potential of the Retractable Bit to the USA drilling industry.

A horizontal drilling test stand at the DRC was used for the tests. Figure 40 shows the stand with RB 3DR-220 installed. Demonstration tests included the following operations:

1. Transferring the bit to the working position hydraulically and mechanically
2. Drilling a marble block
3. Mechanically transferring the bit to the transport position

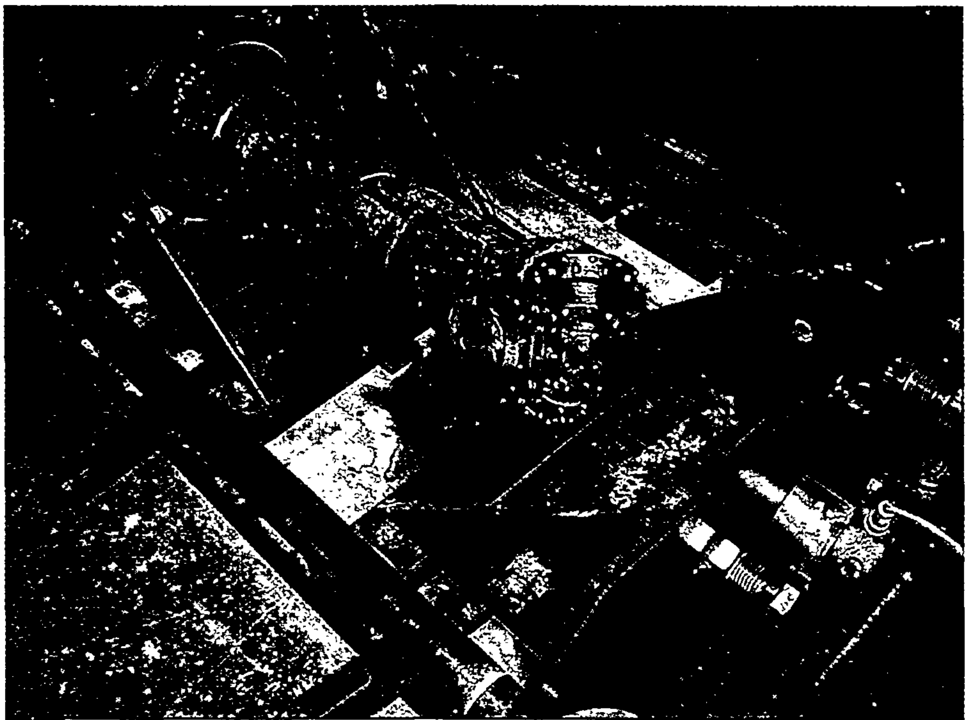


Figure 40. RB in Test Stand for Demonstration in Houston

In addition, special tests were conducted to determine RB performance characteristics. Carthage Marble and Texas Pink Granite blocks were drilled with a range of drilling parameters. Figure 41 summarizes rate of penetration versus weight on bit for these tests.

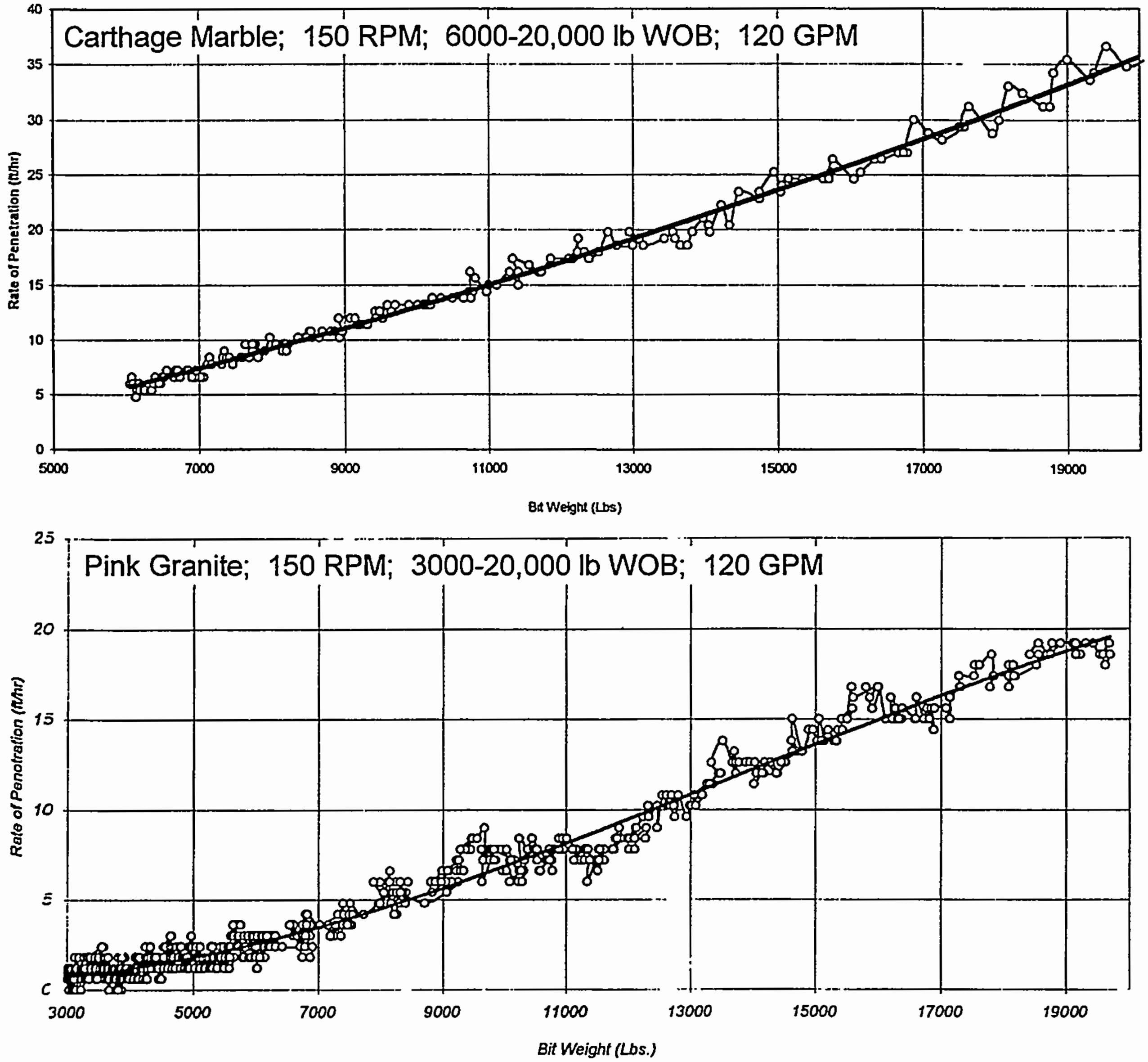


Figure 41. RB Drilling Tests in Houston

Development of Retractable Drill Bits in Russia

7. Underreamers

7.1 Introduction

Russian experience applying retractable bits (RB) allowed the successful development of tools for underreaming boreholes to diameters larger than the previous casing string. This technology has gained wide acceptance in the USSR. Expandable reamers (i.e., underreamers) have been developed and widely used since 1975, to ream more than 100,000 m (328,000 ft) in deep drilling areas throughout the USSR.

7.2 Field of Application

An expandable underreamer is a drilling tool with working members that can be positioned in the transport (closed) position when the tool is run in and pulled out, or in the operating (opened) position when the tool cutters ream the borehole. A special mechanism transfers working members from the transport position to the operating position. The reamer OD in the transport position corresponds to the tool housing OD. In the operating position, the working members (arms with cutters) come out from the housing and expand to the design diameter of the borehole.

Because of these features, the tool can ream any interval of a pre-drilled hole to a diameter larger than the diameter of the casing run and cemented above. Underreamers, unlike drill bits, are auxiliary drilling tools. However, their application allows resolving a number of problems encountered in drilling.

Expandable underreamers may be used in the following operations:

- Borehole reaming in a productive horizon interval for a sand screen
- Borehole reaming in problem intervals, such as lost circulation, rock bulging, caving, to set isolation tools, cement bridge plugs, etc.
- Running down a marine drilling template with simultaneous drilling of the borehole
- In the mining industry, reaming a hole for high-power blasting charges with the upper interval of the hole narrower than the lower interval

Expandable underreamers were most widely used in drilling deep wells with complicated geological conditions. These wells require running down several intermediate casing strings, sometimes four or five or more.

Expandable underreamers allow changing a well design and using cost-effective well construction technology. The initial diameter can be shrunk to correspond to the designed borehole or production string size by reducing radial clearances between the adjoining strings. An expandable underreamer provides the required radial clearance between the casing string and walls of the borehole, which enables trouble-free running and cementing of a casing string.

Changing a borehole design by reducing its original diameter allows saving metal and other materials. This also enables utilizing a lower capacity drilling rig. Thus, with due consideration to reaming costs, expandable underreamers eventually make well construction more cost-effective.

7.3 Designs of Expandable Underreamers

Designs of expandable underreamers differ in both the type of working elements (cone or blade) and the design of the mechanism that transfers the working elements from the transport to the operating position and back.

Various designs of arms with cone cutters and transfer mechanisms led to development of several classifications for expandable underreamers. Each of these classifications is usually based on most typical (from the designer's point of view) design features. Among these are types of cone cutters, methods of transfer to the operating and transport positions, methods of applying force to the underreamer's moving parts, etc.

Below is the classification of expandable underreamers that corresponds to the industry standard OST 39-167-84 of the former Ministry of Oil Industry of the USSR. The classification is based on the design features of the underreamer retracting mechanism, as related to the pilot guide. The classification covers underreamers with positive cutter or blade opening by direct pump pressure applied to the moving elements.

According to the standard, expandable underreamers are subdivided into three types: **RRA**, **RRB**, and **RRV**.

Type **RRA** includes cone and blade-type underreamers that can be used in combination with a pilot bit, which enables borehole drilling and simultaneous reaming. Figure 42 presents a schematic design of RRA underreamers.

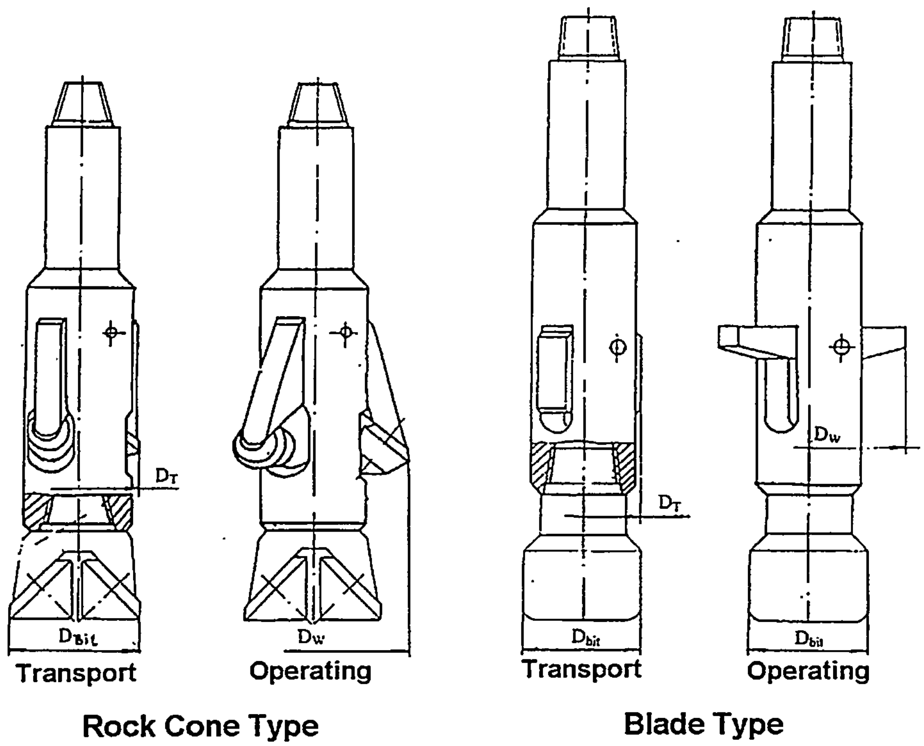


Figure 42. Type RRA Retrievable Underreamer

Type **RRB** includes cone and blade underreamers without a pilot guide. This type of underreamer is used for reaming any interval of a drilled borehole (Figure 43).

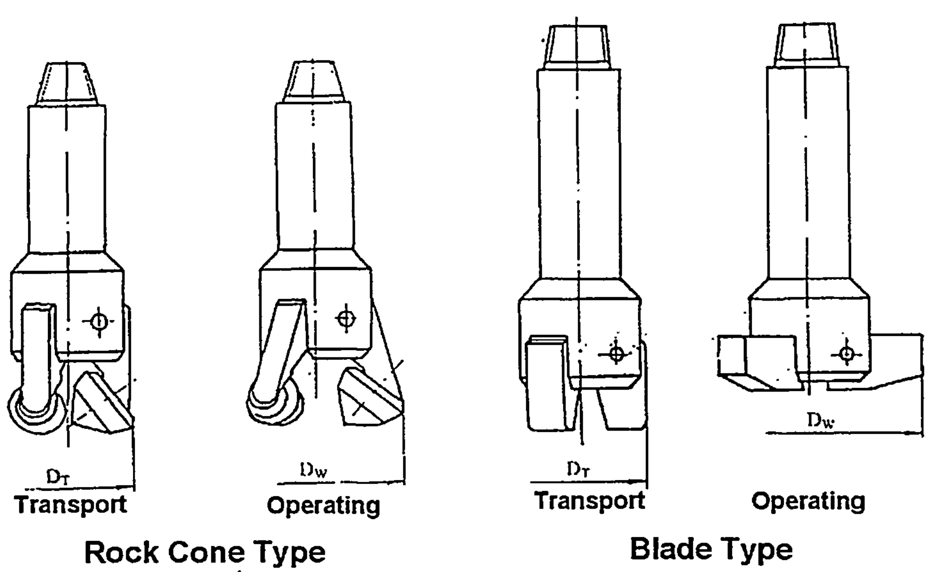


Figure 43. Type RRB Retrievable Underreamer

Type **RRV** includes cone and blade underreamers with a pilot guide that are also used for reaming a previously drilled hole (Figure 44).

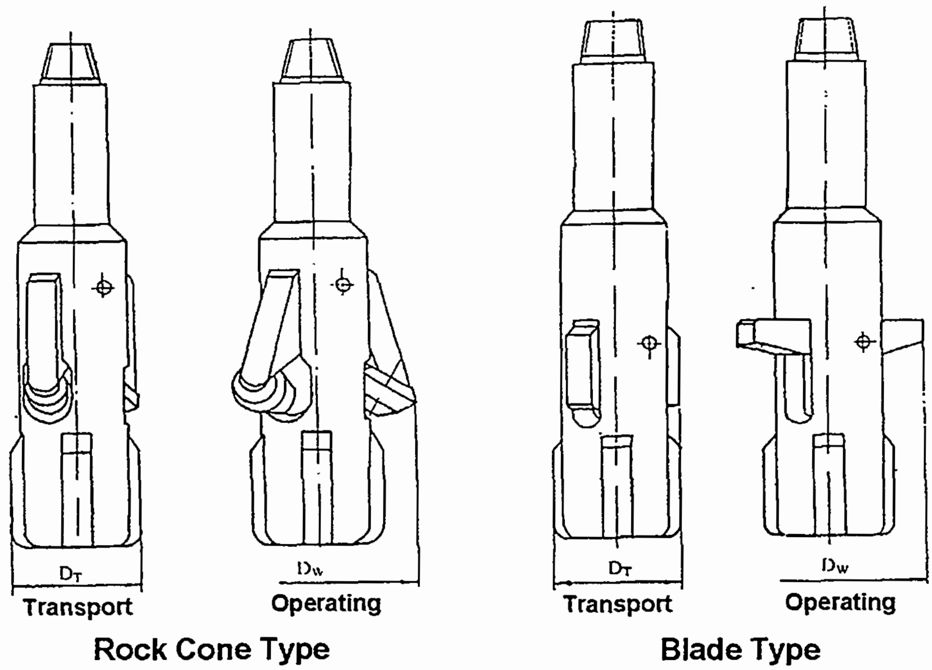


Figure 44. Type RRV Retrievable Underreamer

Several groups of design engineers have been developing expandable underreamers. RRB underreamers were most widely used in the USSR oil industry. While developing this type of underreamers, VNIIBT specialists used their expertise in RB design.

RRB underreamers are primarily used for reaming a continuous borehole interval before a casing string is run. Figure 45 shows one of the most typical multi-string designs of a deep well that was implemented with RRB cone underreamers.

Expandable underreamers have been found to allow more options for implementing well casing programs.

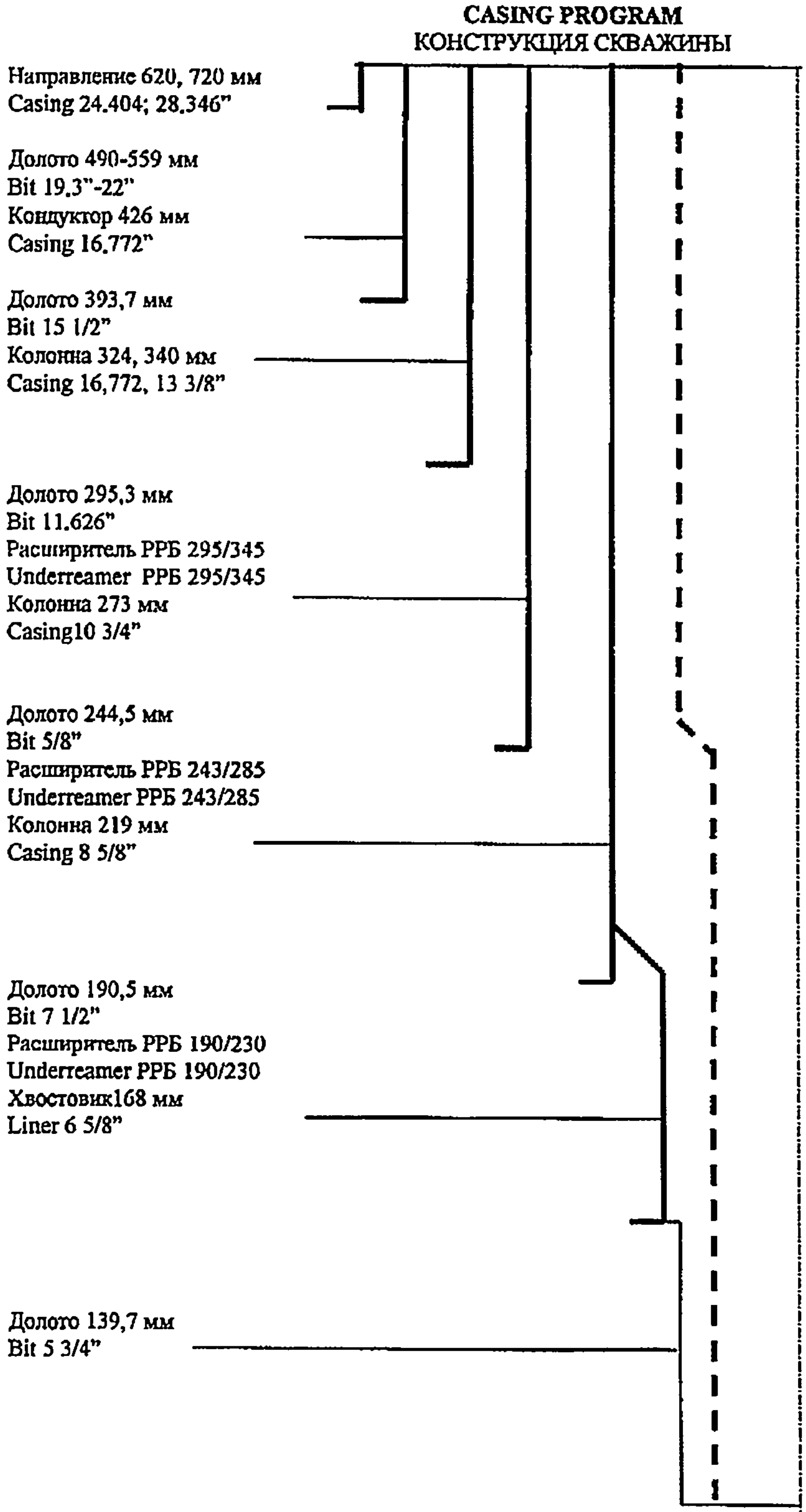


Figure 45. Typical Casing Program for Reaming Operation

Development of Retractable Drill Bits in Russia

Since 1972, specialists within VNIIBT have developed a range of RRB type expandable underreamers. Table 19 presents basic sizes. Designs of variously sized underreamers are the same in principle.

Table 19. Dimensions of RRB Underreamers

Underreamer Type	Cutter Type	Diameter (mm)	
		Transport Position	Operating Position
RRB-161	RRB-161/200 S; ST	160	200
RRB-190	RRB-190/230 MS; S; ST	188	230
RRB-215	RRB-215/255 M; S; SZ	212	255
RRB-243	RRB-243/285 M; MS	242	285
RRB-295	RRB-295/345 M; MS	292	345

The number in the underreamer type descriptor indicates the diameter of the reamed hole. A double number in the cone type (e.g., 161/200) indicates the diameter of the reamed hole and the underreamer diameter in the operating position. Letters in the cone type reflect the corresponding formation hardness:

M = soft formation

MS = soft formation with intercalation of medium-hard rock

S = medium formation

ST = medium formation with hard stringers

SZ = medium formation with abrasive stringers

Selection of an underreamer diameter in the operating position is dictated by the necessity to provide the required radial clearance between the borehole walls and the casing string. It also depends on the width of the drilled shoulder that guarantees trouble-free operation of a cone underreamer without a pilot bit. These parameters are summarized in Table 20.

Table 20. RRB Underreamer Application Recommendations

Underreamer Type	OD of Hole (mm)	OD of Reamed Hole (mm)	OD of Casing that can be Run (mm)	Radial Clearance Between Borehole and Casing (mm)	Width of Drilled Shoulder (mm)
RRB-161	161; 165	200	140	30	20; 17.5
RRB-190	190.5	230	168; 178	31; 26	20
RRB-215	215.9	255	194	30	20
RRB-243	243; 244.5	285	219	33	21;20
RRB-295	295.3	345	273	36	25

Figure 46 shows an RRB-215 underreamer in the transport and operating positions. Also shown is section A-A of the cone section attachment. Below is a description of RRB underreamer design and principles of operation used with this underreamer as an example.

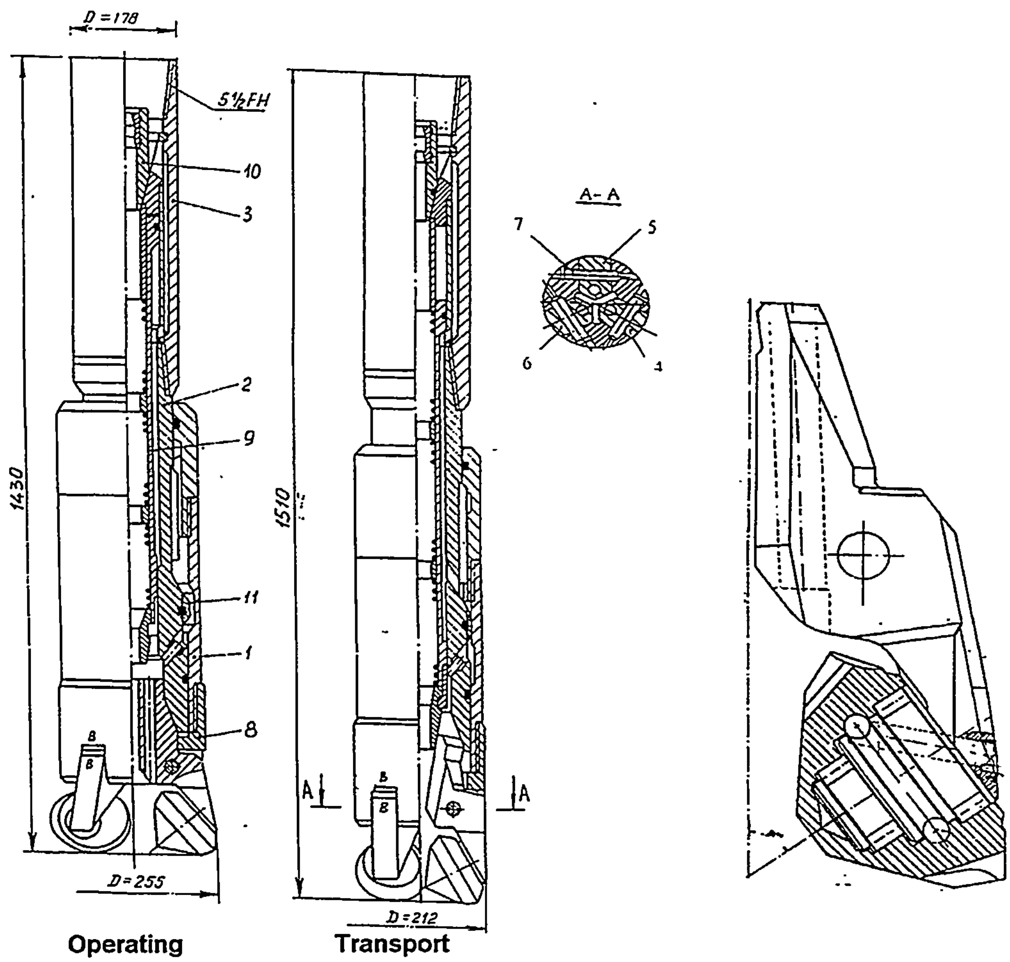


Figure 46. Type RRB-215 Underreamer

The underreamer has a system of moving elements (1) outside the housing (2) connected through a sub (3) to the drill string. Cones (4, 5, and 6) on axles (7) are located in slots of the holder (8). In the transport position, the system of movable parts (1) with cone assemblies (4, 5, and 6) is in the lower position, retained by a spring loaded rod (9) that prevents upward travel. When the underreamer is run in a hole, the central mud-course in the rod (9) is opened, which allows fluid circulation while the underreamer travels inside the casing string in the transport position.

When the underreamer reaches the open hole, it is transferred to the operating position by pumping drill mud. A valve (10) is dropped in the hole for this purpose. When the valve enters the seat, differential pressure pushes a rod semi-rotary piston and moves the rod to the upper position, releasing the arm assemblies.

Simultaneously, pressure drop affects the semi-rotary piston and moves the system upward. When the string is rotated and smoothly run down, rolling cutters cut in the borehole walls and assume their operating positions. Pressure required for the rolling cutters to cut into the borehole wall is 5-6 MPa (725-870 psi). Operating pressure drop across the expanding mechanism is 1.0-2.0 MPa (145-290 psi). Drilling fluid is directed through holes in the arms to the cone cutters.

An important feature of the RRB arm is a lever of the first order. Tapered surfaces of all three arms are machined together, which allows achieving firm attachment of the arms to the mechanism in the operating position. Axial load is transmitted through a tapered surface in the lower part of the barrel (2), and torque is transmitted through side surfaces of the slots in the holder (8). The internal surface of each arm is shaped to a dihedral angle.

A slide valve (11) controls transfer of the underreamer to the operating position, opening an additional water course for drill mud in the operating position. Pressure drops of 3-5 MPa (435-725 psi) in the discharge line indicate that the underreamer has transferred to the operating position.

Rotary speed while reaming is 70-110 RPM.

The reamer is transferred from operating to transport modes by friction between the outer moving components and the borehole walls when the drilling tool is moving up, or due to interaction of cone sections with the casing shoe above the reamed interval. Since an underreamer has a system of external moving parts, the force required for transfer to the transport position is created by picking up the drill string.

As mentioned above, RRB underreamers do not have a pilot guide. This allows using cones of maximum diameter with strong bearings, which is particularly important while reaming long intervals.

Cone sections have a conventional bearing scheme: ball / roller / roller.

The retaining ball bearing of an underreamer operates in a different manner than in a drill bit. The resultant force applied to the cone is directed to the underreamer axis and tends to displace a cone with a worn bearing toward the center.

Table 21 shows operating parameters recommended for underreamers.

Table 21. Operating Parameters for RRB Underreamers

Underreamer	Axial Load (kN)	Pressure Drop (MPa)		RPM
		Drill in	Reaming	
RRB-161	50	5-6	1.0-2.0	70-110
RRB-190	60	5-6	1.0-2.0	70-110
RRB-215	80	5-6	1.0-2.0	70-110
RRB-243	90	5-6	1.0-2.0	70-110
RRB-295	120	5-6	1.0-2.0	70-110

Underreamers were manufactured at the VNIIBT experimental plant in the city of Kotovo in the Volgograd region. Cone sections were manufactured at the VNIIBT experimental plant in the Moscow region and Drogobych Bit Plant in the western part of the Ukraine.

7.4 RRB Underreamer Applications

In the Former Soviet Union, RRB-type expandable underreamers were used in deep wells in oilfields in the North Caucasus, Azerbaijan, West Kazakhstan, Turkmenistan, and other regions. Expandable underreamers were used for reaming one or several intervals of the borehole, depending on geological conditions, well depths, and casing programs.

Over the period 1975-1991, the total reamed footage in deep well intervals between 1650-5750 m was more than 100,000 m, as mentioned previously. After the collapse of the Soviet Union and rapid decrease in deep drilling activity, especially in the North Caucasus, underreamers have been utilized only occasionally.

RRB Operations by Grozneft Drilling and Production Company

Drilling crews from Grozneft in the Chechen Republic conducted more reaming than any other group in the USSR. Figure 45 presented a typical well design in the oil and gas fields where underreamers were widely used. The interval drilled with 295.3-mm (11.6-in.) bits was reamed by RRB 295/345 to 345 mm (13.6 in.) for 273-mm (10¾-in.) casing. The interval drilled with 244.5-mm (9.6-in.) bits was reamed by RRB 243/285 to 285 mm (11.2 in.) for 219-mm (8⅝-in.) casing. The interval drilled with 190.5-mm (7½-in.) bits was reamed by RRB 190/230 to 230 mm (9 in.) for a 168-mm (6⅝-in.) casing string.

A 244.5-mm (9⅝-in.) string was run in some wells instead of 273-mm (10¾-in.) casing. The interval below was drilled with 215.9-mm (8½-in.) bits and cased with a 193.7-mm (7⅝-in.) string. Prior to casing being run, the borehole was reamed by an RRB 215/255 underreamer to 255 mm (10 in.). The performance of these underreamers is described below.

An RRB-295/345 reamed most intervals. Underreamers with RRB-295/345 MS cone sections reamed intervals in the deposits of Lower Chokrak and Upper and Lower Maikop, which are composed of soft and medium-hard clay.

An RRB-295/345 reamed borehole intervals at 1650-4760 m (5413-15,616 ft) in various fields. Table 22 shows typical operating parameters of these reamers based on information from several wells: well no. 139 – Pravoberezhnaya, no. 238 – Oktyabrskaya, and no. 67 – Braguny.

According to the data in Table 22, mud density was over 2000 kg/m^3 (16.7 ppg) and axial load (weight) on the underreamer below 10 tonnes (22,000 lb), since weight increases cause frequent stalling of drilling tools as well as longitudinal oscillations. Large differences in underreamer penetration rates are explained by conditions in the reamed hole, which originally had a large number of cavities.

Intervals at 2500-5500 m (Lower Maikop) drilled with 244.5-mm (9⅝-in.) bits were reamed by RRB 243/285 underreamers for a 219-mm (8⅝-in.) casing string. Table 23 shows performance results of expandable underreamers RRB 243/285 MS from several wells.

The scope of utilization of RRB-215 and RRB-190 expandable underreamers was limited.

Table 22. Performance of RRB-295/345 Underreamers in Octyabrskaya no. 238

Date 1979	No. of URs	No. of Cutter Section	Reamed Interval (m)			Ream Time (hr)	Wash Time (hr)	ROP (m/hr)	Reaming Parameters					Reason for POOH
			From	To	Total				WOR (ton)	RPM	Flow Rt (L/s)	Pressure (bar)	Density (kg/dm³)	
26-28 August	1	5	2,953	3,433	480	9.0	5.5	53.3	6	102	30	100	2.08	Time limit
28-30 August	1	5	3,433	4,102	669	14.25	11.25	47.0	8-10	102	30	120	2.09	Time limit
02-03 Sept.	2	5	4,102	4,339	237	8.0	7.0	29.6	8-10	102	30	120	2.09	Completed
Run Data for Underreamers RRB 295/345 in well no. 67-Braguny field														
08-10 March	1	1	2,540	3,046	506	14.75	6.25	34.3	5	92	35	100	2.10	Time limit
26-28 March	2	2	3,046	3,633	587	22.5	7.75	26.1	6	92	35	120	2.10	Time limit
29-30 March	1	2	3,633	3,690	57	3.0	7.5	19.0	6	92	35	120	2.10	Did not work
07-09 April	2	3	3,951	4,116	165	6.0	16.0	27.5	6	92	35	120	2.10	Completed
Run Data for Underreamers RRB 295/345 in well no. 139 Pravoberezhnya field														
21-24 Sept.	2	1	2,690	3,324	834	26.75	16.25	31.2	3-6	72	35	100-120	2.02	Pressure increasing
26-29 Sept.	3	2	3,324	3,898	574	27.25	17.5	21.1	3-8	72	32	110	2.02	Problem w/ surf equip
27-31 Sept.	4	3	3,898	4,205	307	26.25	30.0	11.7	6-8	72	29	80-100	2.03-2.05	Completed

Table 23. Performance of RRB-243/285 Underreamers in Various Wells

DATE 1980	WELL NO.	REAMED INTERVAL (M)		TIME (HR)	ROP (M/HR)	DRILLING PARAMETERS					COMMENTS
		FROM-TO	TOTAL			WOR (TONNE)	FLOW (L/S)	RPM	PRESSURE (BAR)	DENSITY (KG/DM^3)	
25.09 29.09 02.10	117-Yastre- binay	3,186-3,290 3,290-3,954 3,954-4,360	104 664 406	16.4 17.5 10.5	9.63 37.9 38.7	4	30	90	90-100	2.0	ROP reduced Time limit Completed
13.11	86-Braguni	2,294-2,532 2,532-3,651	238 1119	7 34	34 32.9	4	32	90	90	2.18-2.2	ROP reduced Completed
09.11	89-Braguni	2,360-2,542 2,542-3,346 3,346-3,702 3,702-3,774	182 804 356 72	9.75 89.75 37.5 11.75	18.7 8.9 9.5 6.1	2-4 2-4 2 2	30 45 30 30	110	90 120 60 80	2.08	ROP reduced Cleaning hole Cleaning hole Completed
28.05 01.06 30.08 01.09 04.09	87-Braguni	3,689-3,905 *3,791-3,905 3,905-4,004 4,004-4,065 3,689-4,065	216 114 95 61 376	14.25 12.0 14.0 7.0 27.5	15.2 9.5 7.1 8.7 13.4	4 4 8 8 4	30	90	100	1.98-2.0	ROP reduced Cleaning hole Completed
14.05 24.06	139-Pravo- berejnay	4,210-4,412 4,412-5,045 4,350-4,537 4,537-4,595	202 633 187 58	19.75 23.25 17.5 11.5	10.2 27.2 10.7 5.04	4 3 8 3	25- 27	72	110	2.10-2.12	ROP reduced ROP reduced Second UR'ing Second UR'ing
06.10 15.10 18.10 21.11	150-Pravo- berejnay	3,973-4,387 4,387-4,493 4,416-4,713 *4,450-4,496	414 77 297 46	16.0 10.5 26 8	25.9 7.3 11.4 5.8	3 8 6 3	25- 27	92	100	2.16	Repair equipmt ROP reduced Completed
27.08 02.09	259- Octabrskay	3,502-3,892 3,892-4,401	390 509	13 21	30 24	4 4-8	32	104	130	2.10-2.11	ROP reduced Completed

* Used cutter section. Formation –clay

RRB Operations by Prikaspiiburneft Drilling Company

The Prikaspiiburneft drilling company drilled in Western Kazakhstan. This oil and gas province was second only to the North Caucasus for RRB underreamer penetration.

RRB-190, RRB-215/255, and RRB-295/345 expandable underreamers were used in drilling deep wells in the Tengiz oil field and adjacent fields. RRB type expandable underreamers were first used in this field in well no. 44 Tengizskaya.

In 1983, an RRB-295 underreamer was run in well no. 44. The 295-mm (11⅝-in.) borehole had to be underreamed, as was dictated by specific well conditions while drilling in saline deposits. Mud density was 1380-1400 kg/m^3 (11.5-11.7 ppg) due to the presence of a lost circulation horizon above salt, which was not cased.

Because of low mud density, the salt migrated, making the borehole diameter in that interval smaller, which made it impossible to run 244.5-mm (9⅝-in.) casing. Numerous and long borehole conditioning operations failed to rectify the situation. A decision was made to use an expandable underreamer RRB-295 in the interval with salt. Following are data from well no. 44: well depth – 4084 m; setting depth of 324-mm casing shoe – 2192 m; reamed interval in saline sediment – 3112-4084 m. According to stratigraphic classification, the reamed interval was in the Kungurian stage, composed of halite with stringers of anhydrite.

After two RRB-295/345 S underreamers reamed the interval 3112-4084 m, it was isolated with a 244.5-mm casing string. Underreamers penetrated 621 m (2037 ft) and 351 m (1151 ft) in 61 and 41 hours, respectively. Later, to avoid the problems described, two different casings were placed above the formation to isolate salt sediment.

Below is a typical well design in the Tengiz field while drilling 300-400 m in a productive formation:

- 426-mm conductor (16.8 in.)
- 340-mm intermediate string (13⅜ in.)
- 245-mm intermediate string (9⅝ in.)
- 194-mm liner (7⅝ in.)
- 168 x 127-mm production string (6⅝ x 5 in.)

A typical well design in the Tengiz field while drilling about 600 m in a productive formation:

- 426-mm conductor (16.8 in.)
- 340-mm intermediate string (13⅜ in.)

- 273-mm intermediate string (10¾ in.)
- 219-mm intermediate string (8⅝ in.)
- 168-mm liner (6⅝ in.)
- 114x127-mm production string (4½ x 5 in.)

The following information from well no. 20 in the Tengiz field illustrates RRB-295/345 underreamer performance: well depth – 4156 m; 340-mm casing shoe setting depth – 3026 m; reamed interval – 3026-4124 m. According to stratigraphic classification, the reamed interval was in the Kungurian stage, composed of rock salt, occasional gypsum in the upper part and dolomite in the lower part. The rock is medium drillability. Drill mud density was 2030-2050 kg/m^3 (16.9-17.1 ppg) Average borehole diameter before reaming was 292 mm (295.3 bit).

Table 24 presents data describing RRB-295/345 expandable underreamer performance in well no. 20 in Tengiz. After the borehole was reamed and a caliper log run, a 273-mm (10¾-in.) casing string was run down and cemented without problem. Figure 47 shows portions of a caliper log from the interval reamed by RRB-295/345 expandable underreamers. Nominal size of reamed borehole was 345 mm (13.6 in.). Table 25 indicates the large amount of time (1 month) spent reaming, which was due to organizational problems and the attempts to improve performance of the expandable underreamers.

Table 24. Performance of RRB-295/345 in Tengiz no. 20

Period in 1998	Reamed Interval (m)	Reamed Section (m)	Ream Time (hr)	Ream Rate (m/hr)	Reaming Parameters			
					Weight on Underreamer (tonne)	RPM	Pump Rate (l/sec)	Pressure (bar)
Feb. 14-17	3,026-3,093	57	48.25	1.2	2-4	80	20	90-100
Feb. 18-21	3,093-3,393	300	45.5	6.6	3-5	80	20	90-100
Feb. 22-25	3,393-3,620	227	52.3	4.3	5-6	80	20	90-100
Feb. 26-29	3,620-3,757	137	34.25	4.0	5-6	80	20	110-120
Mar. 3-5	3,757-3,950	193	59.5	3.3	5-6	80	20	110-120
Mar. 7-10	3,950-4,085	135	54.5	2.5	5-6	80	20	110-120
Mar. 12-14*	4,085-4,116	31	4.75	6.53	5-6	80	20	110-120
Mar. 14-16*	4,116-4,124	8	4.2	1.92	5-6	80	20	110-120
Total		1089	303	3.6				

* Due to a lack of new cutter sections, cutters run in upper intervals were re-used.

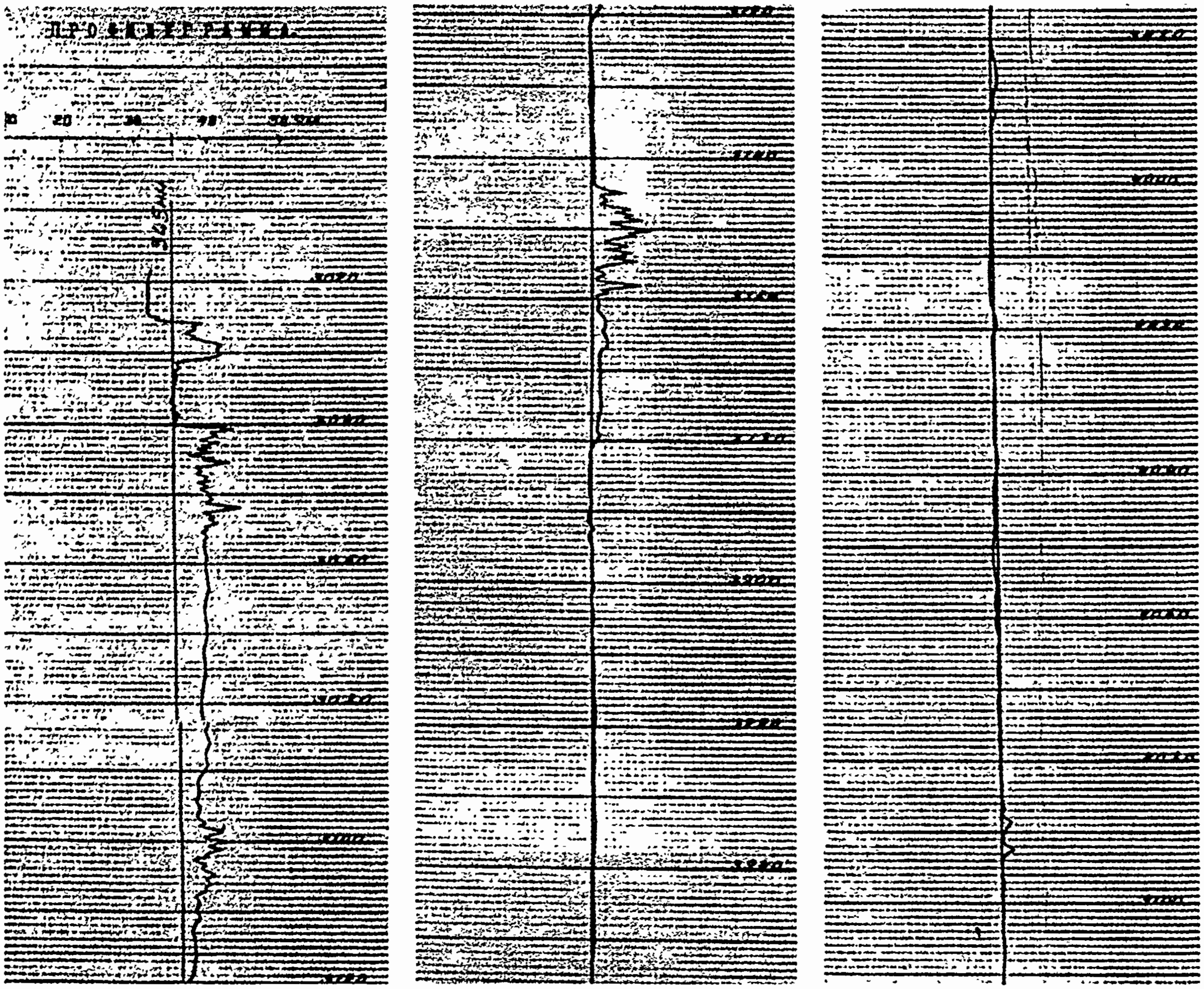


Figure 47. Partial Caliper Log from Well no. 20 at Tengiz

RRB-215 expandable underreamers reamed intervals of boreholes in productive formations drilled by 215.9-mm (8.5-in.) bits below a casing shoe of 244.5-mm (9⅝-in.) casing for a 194-mm (7⅝-in.) string. In accordance with regulations, a 300-m (984-ft) interval was the maximum length that could be drilled in the productive formation without running down a casing string. This size underreamer was run in 24 wells.

Initially, the whole interval from casing shoe to bottom was reamed. According to regulations on drilling in productive zones, an underreamer had to be run to bottom to allow mud circulation and well cleanup. Therefore, to reduce total reaming time, a decision was made to ream the borehole in two sections only – a bottom-hole zone and below the casing shoe of the 244.5-mm string. The experience proved that the method of discrete reaming, when performing a short extension of the casing string, can ensure trouble-free running and cementing of a 194-mm liner.

Table 25 shows performance results of RRB-215/255S expandable underreamers in several wells in the Tengiz field.

Table 25. Performance of RRB-215/255S in Tengiz Wells

WELL NO.	INTERVAL OF REAMING (M)	REAMED SECTION (M)	REAMING TIME (HR)	REAMING RATE (M/HR)
111	4,300-4,349 3,911-3,960	49 49	10.25 9.5	4.7 5.2
115	4,288-4,340 3,942-3,990	52 48	18.25 19.75	2.8 2.4

More detailed information is presented below about RRB-215/255S expandable underreamer performance in well no. 113 at Tengiz. Drill bit size – 216 mm; well depth – 4306 m; casing shoe set depth of 244.5-mm string – 3894 m; reamed interval – 3894-3966 m and 4242-4306 m. The reamed interval was in Lower Carboniferous composed of argillaceous limestone with calcareous sandstone stringers. Mud density was 2060-2100 kg/m^3 (17.2-17.5 ppg).

Table 26 shows performance results of RRB-215/255S underreamers.

Table 26. Performance of RRB-215/255S in Tengiz no. 113

INTERVAL OF REAMING (M)	REAMED SECTION (M)	REAMING TIME (HR)	REAMING RATE (M/HR)	REAMING PARAMETERS			
				WEIGHT ON UR (TONNE)	RPM	PUMP RATE (L/SEC)	PRESSURE (BAR)
4,242-4.306	64	6.25	10.2	4-6	70-80	6	60
3,894-3,966	72	17.0	4.2	4-6	70-80	6	60
4,250-4,275	25	6.0	4.25	4-6	70-80	6	60
Total	161	29.25	5.5				

During the first run, problems were encountered transferring the underreamer to the transport position. The transfer was successful only after the drill string was picked up with an overpull of 35 tonnes (77,000 lb). The reason for the failure was determined to be defects in underreamer assembly.

Unlike reaming soft formations typical of the North Caucasus (with penetration rates up to 40-50 m/hr (130-165 ft/hr)), penetration rates for reaming in medium and hard formations are much lower. In addition, these types of rocks rapidly wear retaining bearings, resulting in reduced durability of underreamers.

To improve the efficiency of reaming operations, a special work program was initiated for developing expandable underreamers with improved cone bearing design, underreamers for simultaneous drilling and reaming, as well as underreamers with PDC cutters.

RRB Operations by Azneft Drilling and Production Company

The Drilling and Production Company Azneft was involved in on-shore drilling in Azerbaijan. A small number of expandable underreamers were used to change well designs and eliminate problems while drilling.

RRB2-295 expandable underreamers were run in well no. 64 in Yuzhnaya Kyursangya before running a 273-mm (10¾-in.) casing string. Three sets of RRB-295/345S cutters were used to ream the interval 3412-4250 m, which had been drilled with a 295-mm bit below the casing shoe of a 340-mm string in 97 hours. Average reaming rate was 8.6 m/hr (28 ft/hr). Mud density was 2060 kg/m^3 (17.2 ppg).

No problems were encountered running down and cementing the 273-mm string.

An RRB-243 expandable underreamer was run in well no. 75 in the Karabagly field and used to reamed the interval 2900-4200 m for 219-mm casing. Mud density was 1980 kg/m^3 (16.5 ppg). No problems were encountered while running down and cementing the casing string.

RRB-190 expandable underreamers reamed several wells that had been drilled with 190.5-mm bits, for a 178-mm (7-in.) liner. One RRB-190/230S underreamer reamed the interval 3550-4296 m in well no. 7 in Gyurzundag. Average reaming rate was 15 m/hr (49 ft/hr). Running down and cementing 178-mm liner was successful.

An expandable underreamer with one set of cutters reamed the interval 4063-4553 m in well no. 241 at Muradkhanly at an average reaming speed of 4.2 m/hr (14 ft/hr). Running down and cementing a 178-mm liner was successful.

Summary of RRB Operations

The general experience operating RRB-type expandable underreamers in deep wells for reducing radial clearances between two neighboring casing strings, proved the efficiency of this method of well construction. In the 1980s, the cost impact in various regions was 8-20 rubles/meter reamed.

Over the period of RRB underreamer application, there has been only one specific underreamer breakdown: an RRB-215 did not transfer into the transport position. While the drill string was being pulled, two journals with cones were broken and the underreamer was pulled out.

The highest efficiency is achieved by integrating expandable underreamers in the well for reaming intervals for several casing strings. However, experience has shown that the best performance is achieved while reaming intervals with soft formations.

Penetration rate while reaming intervals in soft formations is 4-10 times higher than penetration rate while drilling.

Penetration rate for reaming intervals in hard formations is slightly higher (1.5-2.5 times) than penetration rate while drilling the pilot hole. Penetration of underreamers with unsealed cone bearings is also a little higher than penetration of cone bits.

Other designs of underreamers were developed in the USSR in addition to RRB-type expandable underreamers. However, the scope of their application was quite limited.

8. Applications for RB Technology

Based on field experience in Russia (and the former Soviet Union), a variety of drilling applications could be significantly benefited by the application of Retractable Bit (RB) technology. The most promising applications are listed below.

1. **Drilling with Casing** – this is most promising trend in cost-effective technologies for the next century.

2. **Ultralong Boreholes** – RBs could provide significant reductions in trip time, and allow better well control and borehole stability in 10- to 15-km (33,000- to 49,000-ft) wells.

3. **Scientific Drilling** – RBs provide unique opportunities for continuous coring and logging operations in all kind of geological conditions, both on-shore and off-shore.

4. **Geothermal Drilling** – drilling with RBs allows cost-effective deep geothermal drilling in hard crystalline, hot formations.

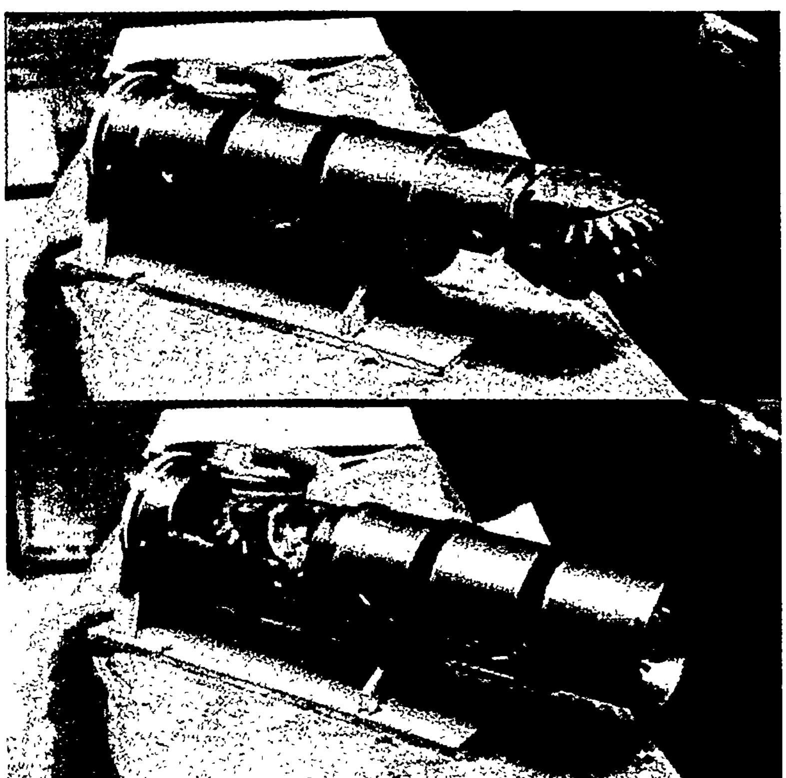


Figure 48. Retractable Bit Assembly

Development of Retractable Drill Bits in Russia

9. Bibliography

1. Gaddy, Dean, 1999: "Russia Shares Technical Know-How with US", *Oil and Gas Journal*, March 8.

2. Grow, J. John, 1999: "First Success with Casing Drilling," *World Oil*, February.

3. Gelfgat, M.Y. and Alikin, R.S., 1998: "Retractable Bits Development and Application," *Journal of Energy Resources Technology*, Vol. 120, June.

4. Gelfgat, M.Y., Podrazhansky, A.M., Geise, J., and Paff, G., 1997: "Stratigraphy Drilling in Deep Water with Aluminum Drill Pipes Application," paper IADC/SPE 37597, IADC Drilling Conference, Amsterdam, March.

5. Gelfgat, M.Y., Gamsakhurdia, G.R., Geise, J., and Spierings, H., 1994: "Complete System for Continuous Coring with Retrievable Tools in Deep Water," paper IADC/SPE 27521, IADC Drilling Conference, Dallas, March.

6. Gelfgat, M.Y., 1994: "Bits of History," *Oil and Gas Russia,* vol. 3/no. 1, Spring.

7. Mnatsakanov, A.V., Gelfgat, M.Y., and Alikin, R.S., 1992: "Technology and Technique for Scientific Drilling in Crystalline Rocks: Experience and Perspectives," paper IADC/SPE 23912, IADC Drilling Conference, New Orleans, March.

8. Gelfgat, M.Y., Alikin, R.S., and Stanko, Y.P., 1990: "Technology of Ultra-Deep Coring Without Pulling Drill Pipe," chapter in *Super-Deep Continental Drilling and Deep Geophysical Sounding*, Springer-Verlag Berlin Heidelberg.

9. Monastersky, Richard, 1989: "Inner Space," *Science News,* vol. 136, October 21. (Cover photo of Krivoy Rog drill rig floor with retrievable tools in operation)

10. Alikin, R.S., Gelfgat, Y.A., and Gelfgat, M.Y., 1983: "Underreamer Efficiency While Deep Well Construction," Proceedings VNIIBT vol. 56, Moscow.

11. Alikin, R.S. and Yashin, E.V., 1983: "Expandable Drilling Tools to Improve Casings Set Up in Deep and Super-Deep Wells," Proceedings VNIIBT vol. 57.

12. Alikin, R.S., Gelfgat, M.Y., Kurumov, L.S., and Gerasikin, G.G., 1983: "Expandable Underreamers Application Experience in Grozneft Company," Proceedings VNIIOENG, series "Drilling," ISSN 0521-8136, issue 5, Moscow.

13. Gelfgat, M.Y., 1975: "Results of Retrievable Tool Drilling Test in Crystalline Rocks," Proceedings VNIIBT, vol. 34, Moscow.

14. Eberhart, J.R., Sims, D.L. and Edgar N.T., 1971: "Methods to Penetrate Hard Formations in Deep Ocean Basins", Appendix A in the Technical Report no. 2 (RE-ENTRY) of International Phase of Ocean Drilling (IPOD) Deep Sea Drilling Project, prepared for NSF C-482, November.

15. Barshay, G.S., Gelfgat, Y.A., and Romanov, A.Z., 1967: "Turbo-Drilling Without Pulling Drill Pipe," Nedra publishing, Moscow.

16. Ledgerwood, L.W., 1960: "Efforts to Develop Improved Oilwell Drilling Methods," SPE 1458-G, Journal of Petroleum Technology, April.