IDENTIFYING APPLICATIONS FOR TURBINES IN DRILLING OPERATIONS

Rocky Seale and Tim Beaton
Smith Neyrfor

In drilling applications the two most common drive mechanisms are rotary and the positive displacement motor (PDM), with rotary drilling having been employed for over a century and the PDM for nearly 50 years now. The theory behind PDM's is to increase the amount of mechanical power at the bit using the drilling fluid to generate power. This has proven to be a very efficient means of drilling in many different downhole environments.

There is another drive mechanism that is commonly disregarded, the turbodrill. Turbodrills operate on the same principle as PDM's, by using the drilling fluid to generate power to drive the bit. Having been used in the oil and gas industry since the 1950's the turbodrill is still relatively obscure and many applications where it could be used are simply overlooked. This paper provides the history of turbodrills guidelines for identifying applications where turbodrills can be beneficial in the drilling operation, and recent case histories in the Rocky Mountains.

INTRODUCTION

The advent of the rotary rig pushed the drilling envelope to new heights. This provided a method to apply rotation and weight simultaneously to the drill bit. Technologies to best utilize this new drilling technique were soon developed. However, it wasn't long before developments focused on placing the drive mechanism even closer to the bit. The first of these advancements occurred in the USSR in 1924 when the turbine was introduced to downhole drilling. Turbodrilling technology and techniques became a mainstay in Russia and it remains that way today. It was not until 1956 that the concept of drilling with turbines was introduced to the western world. The year before this, in 1955, the PDM was introduced to the drilling industry as a method of providing power downhole closer to the bit. Ironically, even today the turbodrill remains the primary drilling method in Russia and the former Soviet Union and the PDM remains the primary drilling method in the western world.

Although turbodrills have never penetrated the mainstream markets as have PDM's and conventional rotary drilling, there are certain areas in the world where they have dramatically impacted drilling performance and economics. Several factors have contributed to this. The first factor is the general lack of understanding of the system. Opposed to simply turning the bit with rotary or using a PDM, the workings of the turbodrill are rather complex. With that said, this led to many misunderstandings of how the system operated. Second, the expertise for these drilling systems was sparsely scattered across the globe. Therefore, any misperceptions that did exist were upheld by the general lack of technical answers to the most basic of questions.

HISTORY OF TURBODRILLING

The turbine concept was introduced over a century ago in the late 1800's. In 1924 turbines were introduced to drilling for the first time in the USSR. Challenged with drilling wells without the capability of getting weight to the bit, the Russian's transferred turbine technology to a downhole drilling environment. This placed the drive mechanism closer to the bit and reduced the weight required for drilling. However, this technology was retained within Russian boundaries until 1956 when turbodrills were introduced to the west.

The technology made only minor advancements to the power and bearing sections over the next few decades. Then in 1982 the first steerable turbodrill was introduced for directional applications. Although rather crude in design and simplicity, it was very successful for specific applications. The design incorporated an offset eccentric stabilizer on the bearing section to initiate the bend for directional work. In 1992 an improved version of the steerable turbodrill was brought to market. Employing a bend on the bearing section directional work could be better initiated and maintained. That same year a new PDC thrust bearing was introduced for higher end drilling applications where standard bearings had proven inadequate. Material advancements at the time made this possible.

Since 1992 materials research and development has aided in improving the component parts of the system. In 2001 a speed reduction system was introduced. This speed reduction system takes advantage of the high power capacity of the turbodrill and translates high rotary speed into high torque. The combination of a speed reduction system with a conventional turbodrill provides a very powerful downhole drive system for the advanced drill bits currently available on the market.

TECHNICAL ATTRIBUTES

The principle behind a turbodrill is to convert hydraulic energy contained in the drilling fluid into mechanical horsepower in the form of output shaft rotary speed and torque. The power generation section of the turbodrill consists of a number of turbine stages, a stage consisting of a rotor and stator configuration. This set up allows fluid to pass through each stage where the fluid flow is redirected from the stator to the rotor resulting in a rotational force on the rotor that is transferred to the shaft and down to the drill bit. (Figures 1 and 2)

There are many advantages to the transformation of hydraulic power to mechanical power through the use of turbine blades. First of all, the conversion of hydraulic power to mechanical power has with it a given loss of efficiency. This loss of efficiency can take many forms, including frictional losses, and just general inefficiencies inherent in the process. Of the two methods currently used in downhole drilling environments to convert hydraulic power to mechanical power for drilling, turbine blades are much more effective than the elastomer sealing arrangement utilized with PDMs. Because a PDM relies on the seal that is produced between the eccentric rotation of a metallic rotor and the elastomer stator, the efficiency of that power conversion suffers greatly as the elastomer wears. (Figure 3) Overall, the industry has become comfortable with the fact that downhole motors start a given drilling interval with one efficiency and end the run with a much lower efficiency. However, with turbodrills, it is not necessary to make such concessions.

One of the primary reasons for the increased effectiveness of turbine blades is due to the fact that turbine blades have a constant efficiency throughout their normal life cycle. In a given turbodrill, there are many turbine stages (normally between 80 and 200 stages), and over the course of a typical run, these blades will either not wear at all, or will wear very slightly. Further, if they do wear, it is typically only a few that exhibit any significant wear. Therefore, an analysis of the overall system efficiency loss during a turbodrill run will return a negligible difference from the beginning to the end of the run. This is a major benefit to the use of turbine blades for the creation of mechanical power because the entire drilling interval can be planned with the knowledge that the turbodrill will be just as powerful at the conclusion of the section as it was at the outset. (Figure 4)

Because the rotor turns concentrically around the shaft, there is very little vibration inherent in the movement of a turbodrill. This is one very significant difference between a PDM and a turbodrill. On a PDM, the power generation is performed through the eccentric rotation of a rotor as it seals with an elastomer stator. The eccentric rotation of the rotor on a PDM creates significant vibrations that can be detrimental to the overall drilling process in a variety of ways. However, in contrast, the turbodrill is a completely concentrically designed tool, and therefore has very little vibration resulting from its operation. (Figure 5)

Another major benefit to the overall configuration of the turbodrill is the fact that it is capable of operating at very high power levels. In the world of downhole motors, mechanical power is created through a variety of hydraulic variables. However, to greatly simplify the situation for the purposes of this discussion, the pressure drop that is created across any downhole motor, coupled with the flow rate of the fluid, will govern the performance of the motor (assuming for argument that the density of the fluid is a given). The greater the pressure drop capacity of the motor, the greater is the potential for generating mechanical power to drive the bit. Because the power generation system of a turbodrill is entirely metallic, turbodrills are capable of supporting very high pressure drops and are therefore capable of creating very high mechanical power. It is a common misconception in the industry that PDMs are more powerful tools than turbodrills. The fact of the matter is that, because turbodrills are capable of sustaining very high pressures, turbodrills are much more powerful drilling tools than are PDMs. The misconception in the industry is mainly driven by the fact that turbodrills operate at relatively low values of drilling torque in comparison to PDMs. However, RPM and torque are inversely proportional for downhole motors. Therefore, the reason that turbodrills produce less torque is because they typically run at much higher RPM ranges than do PDMs. This is yet another significant advantage for drilling with turbodrills. (Figures 6 and 7)

In the field of fixed cutter drill bits, significant developments in performance and technology have been achieved over the last few decades. Drill bit performance has improved by leaps and bounds through many very key technological developments in the field. However, speaking specifically about PDC drill bits, which make up the dominant percentage of the fixed cutter drill bit market, the main failure mode found with these products is impact damage to the PDC cutters on the bit. This failure mode is mainly due to the fact that the industry is constantly pushing higher weights on these bits in an effort to increase the rate of penetration (ROP) in the drilling interval. If you assume the RPM of the drive mechanism to be a given, the only way to increase the ROP in an interval is to increase the depth of cut per revolution (DOC) of the PDC cutter. In most drilling applications where PDC drill bits are used, the RPM is commonly significantly less than 200 RPM, and therefore, to produce a high ROP, it is necessary to create a very large DOC (to put it simply, ROP = DOC*RPM – of course, the units of these parameters must be consistent in this form of the equation). Therefore, in these applications where low RPM is used, higher WOB must be used to increase the DOC in order to maximize ROP. By virtue of the shearing action inherent in their design, PDC drill bits, when presented with high values of weight on bit (WOB) and large DOC, can produce very high values of drilling torque. This high torque can be detrimental to the drilling process in a variety of ways, including causing premature wear to the PDC cutting structure of the bit.

Running a PDC drill bit with a turbodrill mitigates many of these potentially detrimental effects. Because turbodrills are high-power tools, and run at high RPM, they do not require excessive torque to produce high ROPs. Therefore, an equivalent, or oftentimes a superior, ROP can be achieved running a turbodrill / PDC drill bit combination at a fraction of the WOB of rotary or PDM assemblies. (Figure 8) Running at lower weights (small DOC) frequently translates to very consistent toolface in directional applications, very even wear on PDC bit cutting structures, low vibrations in the downhole environment, and an overall smoother drilling process. This is yet another common misconception in the drilling industry. It is often thought that running at low RPM and high WOB is the best way to increase ROP. However, with all of the problems that can appear in this operating range (stick-slip, premature tool failures, excessive cutter impact damage, etc), it is often a very beneficial solution to look to lowering the WOB requirement by increasing the RPM at the bit. This attack is especially relevant with all of the advances that have been realized in the field of PDC drill bit durability over the past years. Because PDC drill bits are so much more abrasion resistant now than they ever have been, they can drill very effectively at high RPM – producing high ROP, very smooth performance, and exhibiting predictable, consistent dull characteristics.

DRILLING APPLICATIONS

Due to the technical attributes of the turbodrill, there are certain drilling applications that, by default, lend themselves to this technology. There are, however, many other applications that are often overlooked due to the lack of understanding of the system. With no elastomers in the tool, one of the most obvious drilling applications is in high temperature environments. At elevated temperatures, greater than 300 degrees Fahrenheit, elastomers begin to break down, resulting in rapid wear and ultimate failure of standard downhole motors (PDMs). As temperatures increase, this process takes less time to occur. Correspondingly, high temperatures typically occur at deeper depths, so trip times are long and costly. The ability for turbodrills to stay downhole drilling for long periods of time at high temperatures is an ideal application for this technology.

As eluded to earlier, turbodrills typically operate for long periods of time without premature wear or failure. Some runs have been in excess of 700 continuous operating hours, with the mean time between failures (MTBF) well over the 2000 hour mark. This can be attributed to the design of the system as eluded to in the technical attributes section. Once again, with no elastomers, the efficiency of the tool remains relatively constant throughout its operating life, as opposed to PDM's whose efficiency deteriorates over time during operation, due to wear on elastomer components. Therefore, any application where economics and safety due to tripping pipe are critical can benefit from the utilization of a turbodrill. These applications would include high pressure and high temperature wells, where temperature is not only an issue, but are numerous safety considerations when tripping the pipe. Underbalanced drilling (UBD) is another candidate for turbodrilling based on the given criteria. When the pipe must be tripped in underbalanced operations, it is very time consuming, costly and a potentially hazardous operation. The ability to stay in the hole longer, reduces these associated risks.

UBD is also a candidate for turbodrilling due to the drilling fluid composition. To obtain underbalanced conditions the fluid column is typically lightened using hydrocarbons or inert gases. Yet again, these components in the drilling fluid have a detrimental effect on elastomers. Turbodrills have been used extensively around the globe in these applications and in certain instances, they are the exclusive means to drill. Performance has been unparalleled and in most instances the operations would have been nearly impossible and certainly uneconomical to undertake using PDMs. Case histories show turbodrills have successfully drilled with 85 percent nitrogen and 15 percent liquid. The application for UBD operations can also be translated to the workover market. There are many applications in depleted reservoirs where workover operations must be undertaken to enhance or stimulate production. These include setting plugs and fracing, milling of debris, sand cleanouts, etc.

Another obvious application for turbodrills is found in applications featuring hard and abrasive formations. Again, due to the fact that turbodrills can operate for very long periods of time without failure, they are often the product of choice in hard & abrasive drilling environments, where ROP is generally low or run length is generally short. This is especially the case when these applications are in sections that are significantly deep such that trip time is a major factor in the overall cost of the drilling process. In these applications, turbodrills excel due to the fact that they can oftentimes eliminate many trips compared to either PDM or rotary assemblies. As a matter of fact, in the vast majority of applications where turbodrills are used to drill hard and abrasive formations, the BHA is pulled out of hole due to bit wear, not as a result of any limitations on the life of the turbodrill. This is yet another area where the advances realized in fixed cutter drill bits have been a major benefit to the economics of turbodrilling. Since the turbodrill can run for such long periods of time in a single run, as drill bits become more and more wear resistant, run lengths become longer and longer, and as run lengths become longer, increased savings can be realized through the use of a turbodrill. In many of the world's most demanding drilling environments, turbodrills are utilized as the primary drive mechanism because of their excellent success and reliability.

Extended reach drilling (ERD) is also an excellent fit for turbodrilling technology, for many reasons. As described above, turbodrills generally run at high RPM and therefore do not need much WOB in order to produce a high ROP. In ERD applications, getting weight to the bit is always a major concern, and often a serious problem. By utilizing turbodrilling technology, significant gains can be achieved in overall drilling performance in ERD wells due to the fact that good ROP can be achieved without the need for much WOB. Another major advantage of running a turbodrill in an ERD application is seen in the effect of this technology on hole cleaning and cuttings transport. Because turbodrills operate at high RPM and the bits run with them need a small DOC, the cuttings that are generated by these bits are very small. Due to the fact that these cuttings are small, they are easily suspended in the drilling mud and therefore the whole issue of hole cleaning in ERD applications is greatly improved simply by incorporating a turbodrilling system in the process. Many of the typical problems encountered with trying to stir the cutting beds, having to spend very large chunks of time circulating, etc. just to help transport the cuttings back to the surface are addressed at the bit due to the high RPM nature of the turbodrill. There are many other associated advantages with the use of turbodrills in ERD wells, but the other major factor not yet discussed here is the effect of turbodrilling on drillstring torque and drag in these applications. As turbodrills have developed over the decades, a major portion of that development has centered around stabilization and hole quality. As a result of that development, turbodrills are now exclusively run with stabilization arrangements that maximize hole quality. The effect of this degree of stabilization is a very uniform, consistent borehole which minimizes ledges, areas of high dogleg severity (DLS), and other borehole imperfections. In an ERD application, the improved hole quality produced by a turbodrilling system equates to significantly less torque and drag on the drillstring, which is commonly a serious problem in ERD applications.

CASE HISTORIES

Turbodrills range in size from 2-7/8" to 9-1/2" tool OD and have drilled holes ranging from 3-1/4" to 17-1/2". The focus in this section will be on several case histories which will apply to this particular region. Case history number one will focus on a deep development well in the continental US that was intended to go beyond where previous production casing was set to log deeper sands for evaluation. Due to hole problems, the 5-3/4" hole could not be drilled to the desired target depth, resulting in a 4" liner having to be run and hung off in the 7" casing. Using a 2-7/8" Turbodrill, 120 feet of 3-1/2" hole was drilled to a total depth of 19,595 feet. Using a diamond bit, the ROP averaged 4 feet per hour operating in 19.1ppg drilling fluid and 370 degrees Fahrenheit bottom hole temperature. Utilizing a turbodrill made the exploitation of the lower formations economically possible and resulted in a potentially new production interval in the existing field.

The second case history to cover occurred recently in the Rocky Mountains. Using a 7-1/4" turbodrill on a 9-1/2" diamond impregnated bit, 1,737 feet of hole was drilled to a depth greater than 24,000 feet. The turbodrill set a world record for the customer by staying in the hole for 705 continuous circulating hours and drilling for 655 hours. Average ROP for the run was 2.6fph in operating conditions of 16ppg oil based mud at 380 degrees Fahrenheit. Offset wells drilling the same interval with PDMs had a maximum ROP of 1.6fph with a maximum run length of 100 hours. This single run resulted in over a quarter of a million dollars in savings for the customer.

UBD was mentioned in the applications section as ideal for turbodrilling. Excluding the year 2003, turbodrills have drilled over 100,000 feet equating to over 7,600 operating hours specifically in this application. The holes drilled ranged in size from 3-7/8" up to 10-5/8". Inside these statistics, the longest run consisted of 308 continuous hours, the longest interval drilled was 6,478 feet, the highest gas ratio seen during operations was 88%, and 44% of the drilled footage was steered. The longest drilled interval of 6,478 feet with a diamond impregnated bit set a world record which still stands. Correspondingly, the longest operating time of 308 hours occurred on this same well. This performance beat the previous world record by

1,333 feet. The well was drilled from 10,676 feet to 17,154 feet at an average ROP of 33.1fph with 5,224 feet (81%) of the footage being rotated and 1,254 feet (19%) steered.

Another well yielded the following results. Using a 3-3/8" turbodrill with a PDC bit, a well was deepened 518 feet from the original TD of 12, 800 feet in an existing offshore field. The interval was drilled using 2" coiled tubing and the average ROP was greater than 25fph operating at a bottom hole temperature was 333 degrees Fahrenheit. In the first attempt to deepen a well on this platform, 9 PDMs were used and drilled only 26 feet.

CONCLUSIONS

Turbodrills were introduced to the western world nearly 50 years ago. Since that introduction their use has been limited primarily to specific applications where rotary and PDMs have been unable to perform. And although they have not gained the popularity of PDMs, there are many instances where their use could mitigate costly drilling excursions. With a concentric design and rugged steel construction using no elastomers, performance is not hindered in the most challenging operating environments. The design of the system alone makes it ideal for high pressure and high temperature applications and not surprisingly this has been primarily where turbodrills have historically been utilized. Hard rock drilling in some particular areas have also become mainstays for turbodrilling. The performances in hard rock applications have set the precedent for drilling curves and cost reduction due to the durability of the system. With focus now squarely on bits designed specifically for higher speeds, and in particular turbodrills, the performances will only be enhanced in future drilling exploits.

In more recent times as UBD has gained in popularity, once again the design of the turbodrill lends itself perfectly to the application. The problems encountered in these applications are getting weight to the bit to drill the rock. Gases and lighter weight fluids used in UBD to lighten the hydrostatic head of the fluid column have detrimental effects on elastomers, thus nearly precluding PDM's as a viable drilling option. Turbodrills use the drilling medium, be it liquid and or gas, to generate power to drive the bit. And since turbodrills remove rock using speed versus weight, the problem of getting weight to the bit is eliminated.

As with any technology, there are advantages and these advantages should be noted so that wise drilling decisions can be made ahead of time in selecting the proper drive mechanism. The applications that historically existed for turbodrilling are still very prevalent today and the performances of these systems will continue to set the standard. However, it is the applications where turbodrills have not historically been used where they can provide the most economic benefit to drilling operations. By understanding the design of turbodrills and how they operate, the solutions to those complex drilling problems may have been here all along.

ACKNOWLEDGEMENTS

The authors would like to thank the management of Sii Neyrfor for the permission to write and present this material.

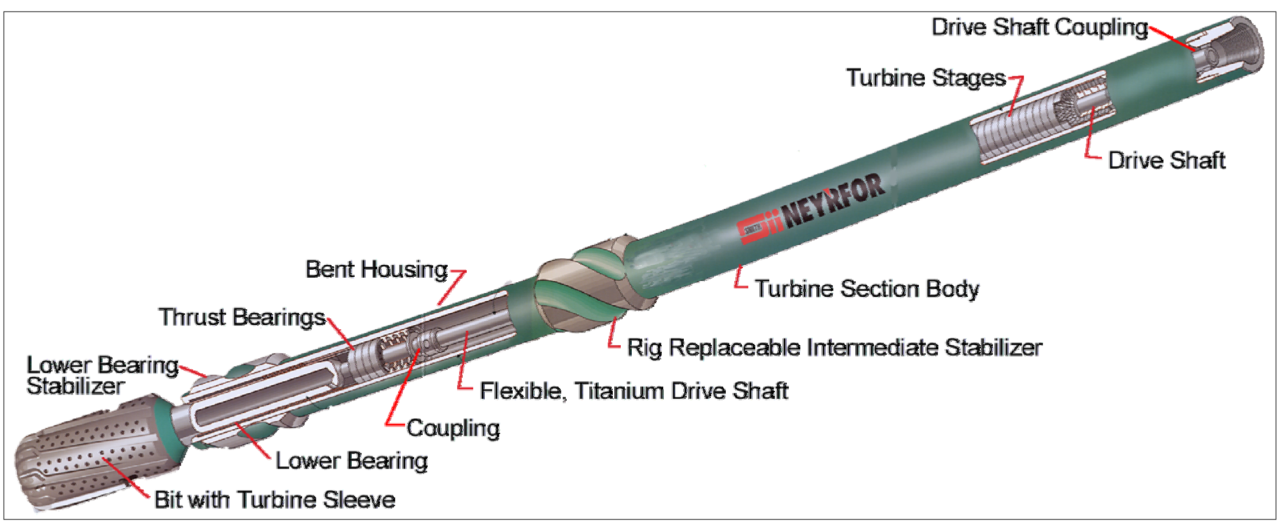

Figure 1- Steerable Turbodrill and Components

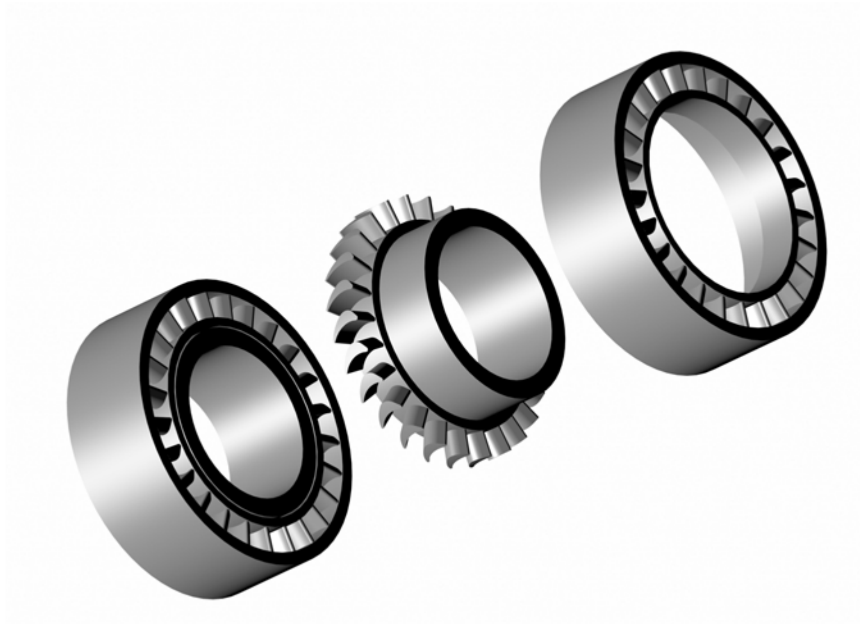

Figure 2 - Turbine Blade Stage
Right to left: Stator, Rotor, Full Stage

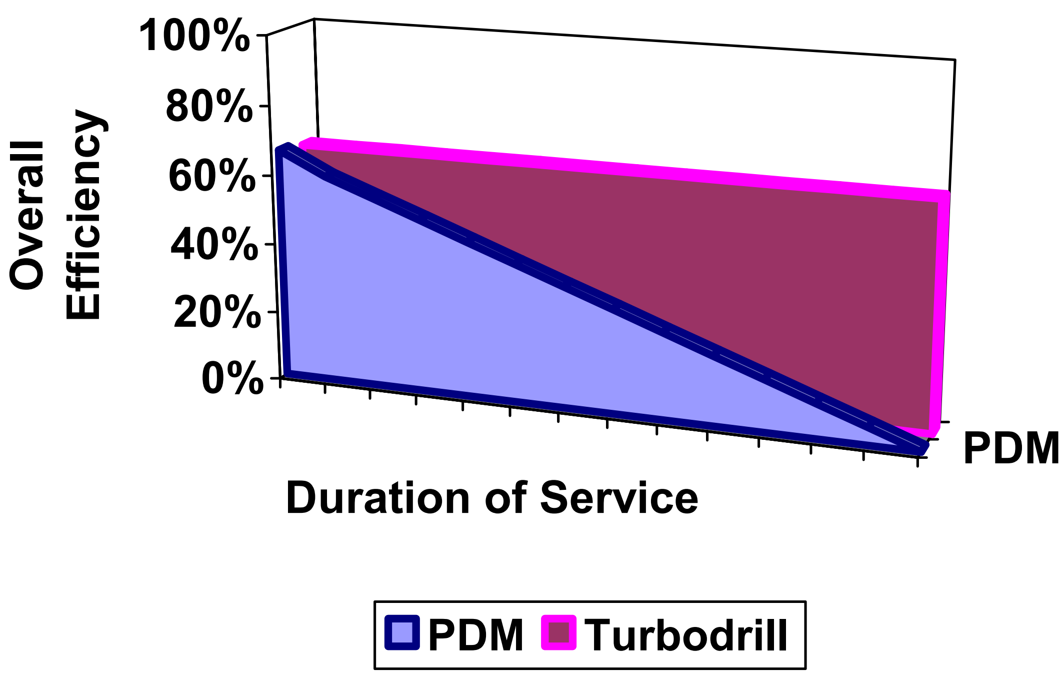

Figure 3 - Downhole Motor Efficiency – PDM vs. Turbodrill

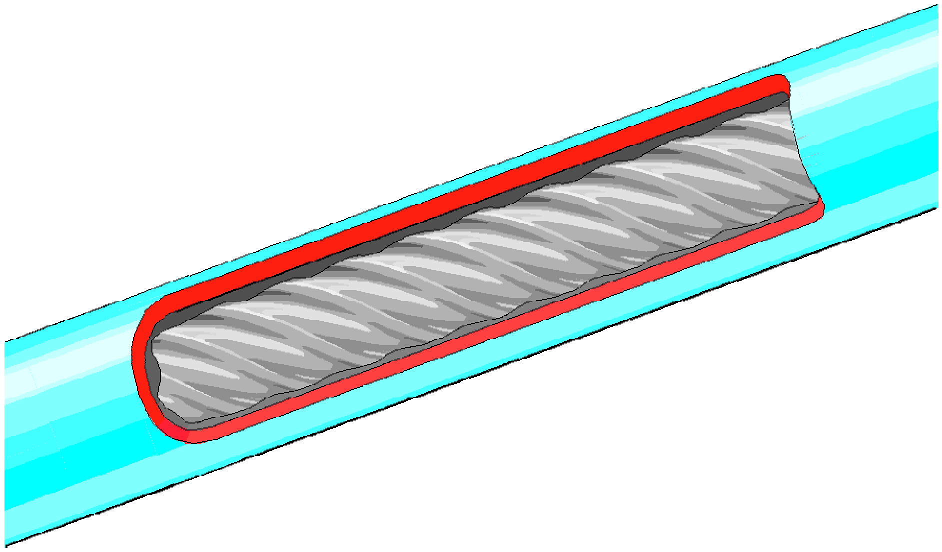

Figure 4 - Sectional View of a Positive Displacement Motor

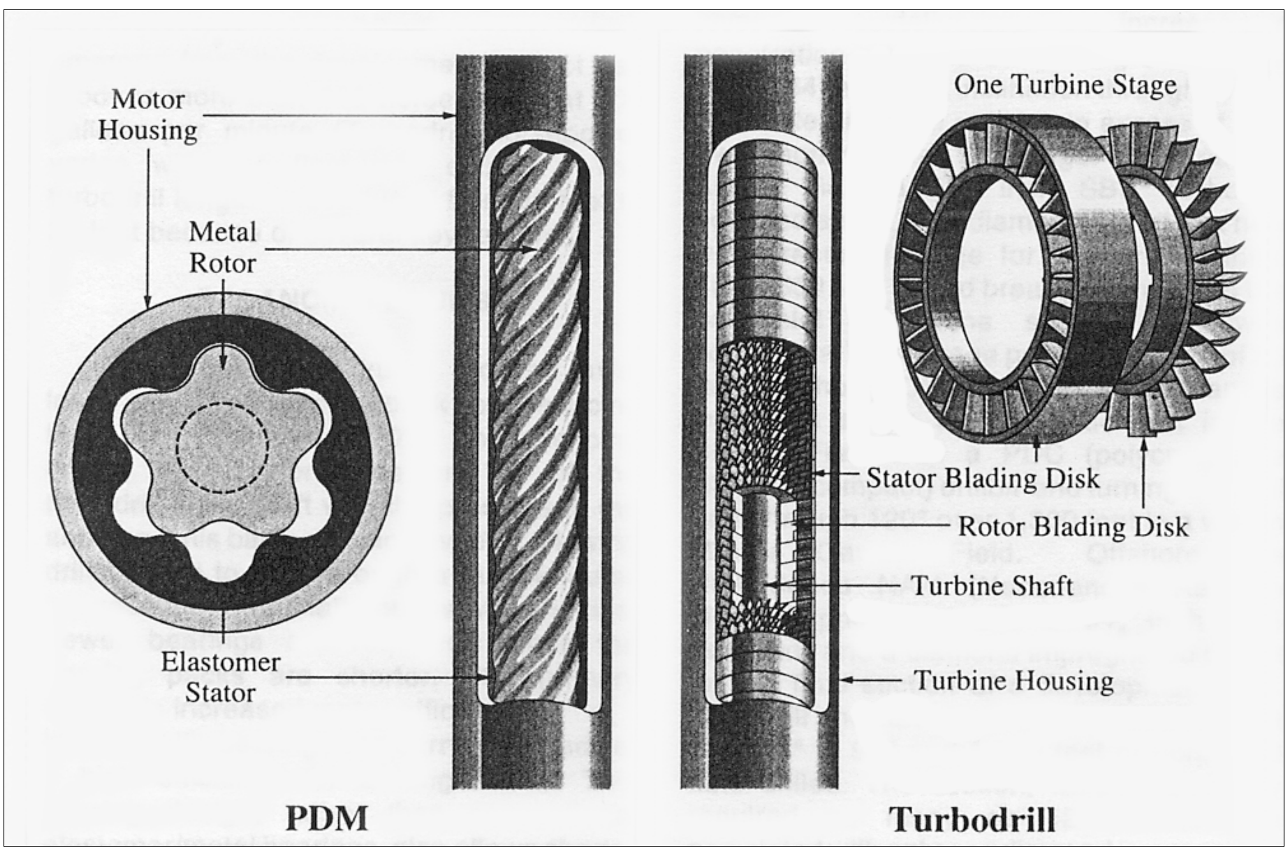

Figure 5 - Cut-away Illustration of PDM vs. Turbodrill Drive Mechanisms

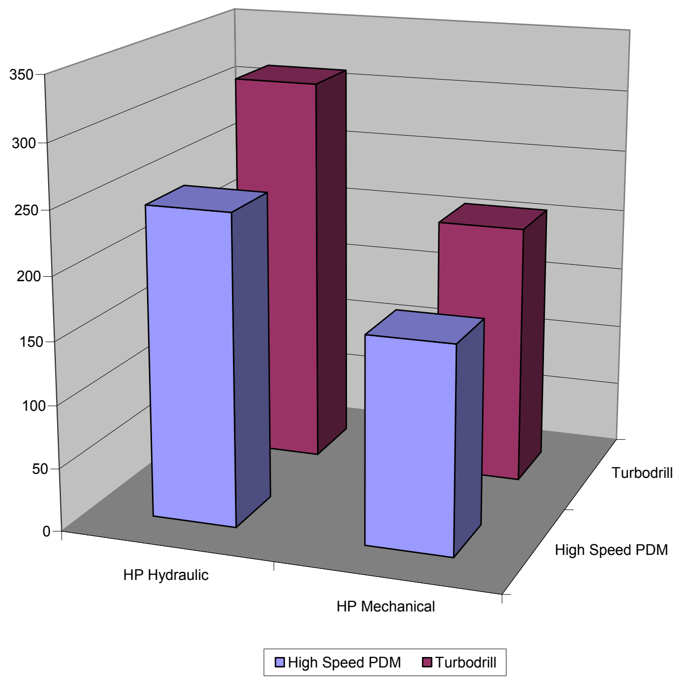

Figure 6 - Turbodrill vs. High Speed PDM: Power Capacity (figures generated using max operating parameter values for 4 ¾" tools)

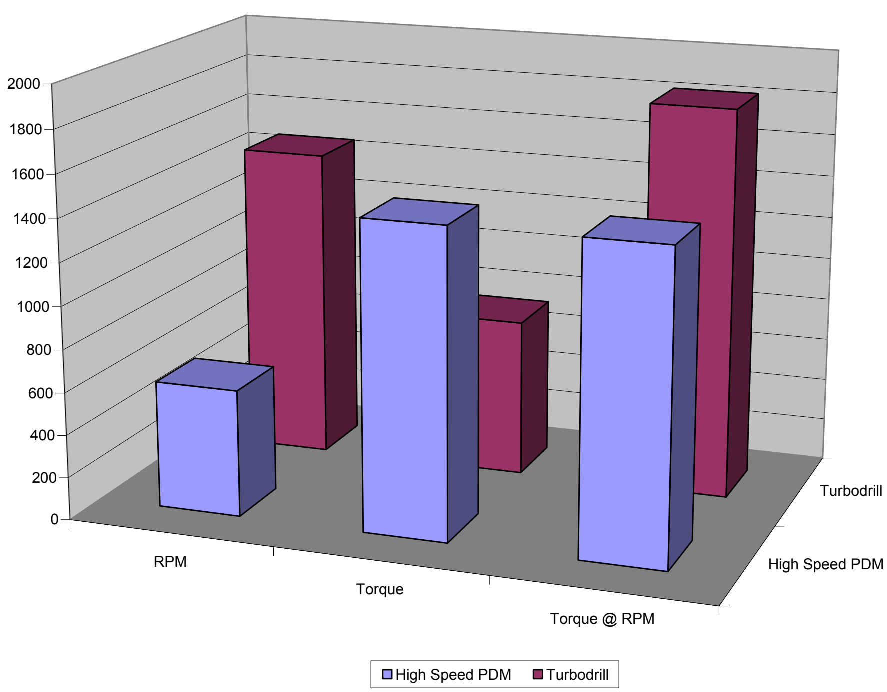

Figure 7 - Turbodrill vs. High Speed PDM: RPM and Torque Output Comparison. Values for 'Torque @ RPM' shows what the torque output of the turbodrill would be if run at an equivalent RPM to the PDM (assuming the use of a speed reducing unit) – demonstrates the effect of the greater power capacity of the turbodrill

	RPM	DOC (in/rev)	ROP (ft/hr)
Turbodrill	1000	0.010”	50
PDM	200	0.050”	50
Rotary	100	0.100”	50

Figure 8 - Chart Showing the Effect on Depth of Cut (DOC) of Three Different Drive Mechanisms at a Given Rate of Penetration (ROP). As discussed in the text, the DOC is directly related to drilling torque, and therefore a smaller DOC produces smoother drilling response and often improved drill bit dull condition.