UNITED STATES PATENT AND TRADEMARK OFFICE

BEFORE THE PATENT TRIAL AND APPEAL BOARD

ULTERRA DRILLING TECHNOLOGIES, L.P.,
Petitioner

v.

BAKER HUGHES, A GE COMPANY, LLC,
Patent Owner.

IPR2018-01662
U.S. Patent No. 6,935,441

DECLARATION OF GEIR HARELAND UNDER 37 C.F.R. § 1.68 IN SUPPORT OF PETITION FOR *INTER PARTES* REVIEW OF U.S. PATENT NO. 6,935,441

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I. INTRODUCTION AND SUMMARY OF OPINIONS

1. My name is Geir Hareland. I submit this declaration on behalf of Petitioner, Ulterra Drilling Technologies, L.P. (Ulterra), which I understand is challenging the validity of claims 1-6, 10-11, 26-27, and 32-35 (Challenged Claims) of U.S. Patent No. 6,779,613 (the '613 patent) in two petitions for *inter partes* review (IPR). [1]

2. My opinions are based, at least in part, on the following references:

Reference	Date of Public Availability
U.S. Patent No. 5,244,039 to Newton	September 14, 1993
U.S. Patent No. 4,554,986 to Jones	November 26, 1985
U.S. Patent No. 6,142,250 to Griffin	November 7, 2000

3. I have been asked to provide an opinion on the validity of the Challenged Claims.

[1] All emphases and color annotations in the Declaration have been added unless otherwise stated.

II. QUALIFICATIONS AND BACKGROUND

4. I am a Professor of Chemical Engineering, Professor of Mechanical and Aerospace Engineering, and the Continental Resources Chair of Petroleum Engineering at Oklahoma State University. I have a B.S. in Mechanical Engineering from University of Minnesota, a Masters in Petroleum Engineering from University of Tulsa, and a Ph.D. in Mechanical Engineering from Oklahoma State University. My curriculum vitae details my work and research experience and lists my publications.

5. For over 30 years, I have actively worked and taught in the field of drilling for petroleum, and specifically the design, modeling, and simulation of drill bits. During the late 1980s, I worked at Amoco Research Center (ARC) in Tulsa, Oklahoma. One of my main tasks was to test and develop engineering modules for the Engineering Simulator for Drilling (ESD), which was part of the Amoco's Critical Drilling Facility (CDF). The CDF was the first of its kind real-time remote control center where data from drilling operations around the world were transmitted via satellite and monitored and analyzed in CDF. The ESD was used in conjunction with the operations to perform analysis and evaluate different "what if" scenarios going forward. One of the driving modules in the ESD was a model of the rate of penetration (ROP) for a tricone roller bit. The ARC had developed a tricone bit ROP

model that had been verified in the laboratory, and one of my initial tasks was to scale the ROP model into in a field environment.

6. The ESD also lacked the capability for predicting the ROP for drag bits. While at the ARC, I also develop a simulation model for predicting ROP for natural diamond bits (NDB) and polycrystalline diamond compact (PDC) bits. The NDB work involved performing detailed measurement of natural diamond bits' design parameters like diamond properties, diamond exposure, and diamond setting patterns, bit profiles and primary and secondary flow channels. The different NDBs were tested in different rock types, where the operating parameters were controlled and the ROP recorded. The controlled parameters were formation type and compressive strength, weight on bit (WOB) and rotational speed (RPM), as well as drilling fluid properties and flowrate. The PDC model used cutter size, with an average side and back rate representing the bit design face cutters. The model was verified with different bit designs tested in different rocks types with different rock strengths.

7. After leaving ARC, I continued to develop ROP models, making them more applicable in an actual down hole drilling environment. This work was funded by the Gas Research Institute and also resulted in my Ph.D. dissertation at Oklahoma State University (OSU) in 1991.

8. I continued my work on developing and testing ROP models as a professor at the New Mexico Institute of Mining and Technology, where I collaborated with David Glowka, a researcher at Sandia National Laboratories (SNL), on single PDC cutter testing, analysis and modeling. This included the testing of new and worn cutter rock interaction. The research outcomes were a PDC single cutter wear model which had the integrated effects of PDC cutter design parameters effects on the reduction in depth of cut and the forces on the cutter. One of my Ph.D. students also developed a new PDC rock/bit interaction cutter model for hard rock cutter interaction.

9. In 1994, I integrated the different bit type ROP models into the DRilling OPtimization Simulator (DROPS). The simulator was based on using offset drilling data with detailed descriptions of the bits and the reported bit wear when the bit is pulled out. By applying the different drill bit ROP models in an inverted mode to predict apparent rock strength (ARS), the DROPS simulator could be used to optimize individual bit runs or entire hole sections for the lowest cost/foot.

10. The DROPS drilling simulator was first applied in the North Sea in the mid-1990s. Using data from wells drilled nearby, depth based logs of the apparent rock strength were generated. Drill bit vendors then submitted bit proposals to the operators, and I used the DROPS simulator to simulate and optimize the performance of the different vendors bit designs in the different holes sections on

the upcoming well. The bits that resulted in the best performance on the simulator were recommended for use by the operator. During the drilling of the wells the simulated and recorded rig data was then overlaid and compared.

11. Pason Systems in Calgary, Canada acquired the rights to the DROPS simulator in 2003-2004 for onshore applications in the Americas, which they renamed the "Optimizer." I then worked with graduate students and different operators to use the Optimizer simulator in their operations from 2004-2011. During this time, I applied the Optimizer with my graduate students and drilling engineers with the operating companies on more than 150 wells in the United States and Canada, and I was also involved in applying the DROPS simulator in China and Albania. My involvement was to generate ARS logs from offset data, take the drill bit manufacturers' proposals and simulate and optimize the different drill bits with the Optimizer, recommend the optimal bit and their corresponding operation parameters based on the DROPS, follow up of the actual drilling operation in the field or by overlaying the simulated with the actual daily and to recommend updates/changes to the drilling plan. Operators documented reducing the drilling time per wells by 15-50 percent dependent on the maturity of the field where the simulator was applied.

12. I also have experience in designing PDC drill bits. In the late 1980s I was directly involved in designing and testing of ND and PDC core bits for the high

speed coring operations at ARC. In 2011, I was co-founder of a small PDC steel body bit company, where I, with the CAD designer, designed the bit body profiles, did the cutter layout and performed the 3D force balancing analysis to ensure the bits were designed for a specific application. I evaluated different designs using a modified 3D software that I developed based on Glowka's PDC model from Sandia. The software could predict the individual cutter force and direction and therefrom the side force, torque and ROP for the bit with any set of operating parameter (WOB and RPM) and rock compressive strength.

III. UNDERSTANDING OF PATENT LAW

13. I have been provided with an understanding of the patent law relevant to conducting the analysis given in this report. The following represents my understanding of these issues.

14. I understand the patent at issue is U.S. Patent No. 6,779,613 (the '613 patent), and that prior art to the '613 patent includes patents and printed publications in the relevant art that predate the earliest possible priority date of the '613 patent, which is December 15, 2000.

15. I understand that a claim is invalid if it is anticipated or obvious. Anticipation of a claim requires that every element of a claim be disclosed expressly or inherently in a single prior art reference, arranged in the prior art reference as arranged in the claim. I further understand that even if a reference does not expressly

spell out all the limitations arranged or combined as in the claim, the reference may still anticipate the claim if a person of skill in the art, reading the reference, would 'at once envisage' the claimed arrangement or combination.

16. Obviousness of a claim requires that the claim be obvious from the perspective of a person having ordinary skill in the relevant art at the time the alleged invention was made. I understand that a claim may be obvious in view of a single reference, or may be obvious from a combination of two or more prior art references.

17. I understand that an obviousness analysis requires an understanding of the scope and content of the prior art, any differences between the alleged invention and the prior art, and the level of ordinary skill in evaluating the pertinent art.

18. I further understand that certain factors may support or rebut the obviousness of a claim. I understand that such secondary considerations include, among other things, (1) commercial success of the alleged, patented invention; (2) skepticism of those having ordinary skill in the art at the time of the alleged invention; (3) unexpected results of the alleged invention; (4) any long-felt but unsolved need in the art that was satisfied by the alleged invention; (5) the failure of others to make the alleged invention; (6) praise of the alleged invention by those having ordinary skill in the art; and (7) copying of the alleged invention by others in the field. I understand that there must be a nexus, or connection, between any such secondary considerations and the alleged invention. I also understand that

contemporaneous and independent invention by others is a secondary consideration tending to show obviousness.

19. I further understand that a claim is obvious if it unites old elements with no change to their respective functions, or alters prior art by a simple substitution of one element for another known in the field, and that combination yields predictable results. While it may be helpful to identify a reason for this combination, common sense should guide and no rigid requirement of finding a teaching, suggestion, or motivation to combine is required. When a product is available, design incentives and other market forces can prompt variations of it, either in the same field or different one. If a person having ordinary skill in the relevant art can implement a predictable variation, obviousness likely bars its patentability. For the same reason, if a technique has been used to improve one device and a person having ordinary skill in the art would recognize that it would improve similar devices in the same way, using the technique is obvious.

20. I understand that a claim may be obvious if common sense directs one to combine multiple prior art references or add missing features to reproduce the alleged invention recited in the claims. I further understand that if there are a finite number of known choices in the prior art and a reasonable expectation of success for the choices that are tried, a claimed invention may be obvious to try.

IV. DESCRIPTION OF THE TECHNOLOGY

A. Drilling Rigs and Their Components

21. The technology at issue in this petition relates to the design for rotary drag bits used in drilling of wells deep into the earth, particularly for petroleum. To reach oil and gas wells below the earth's surface, it is often necessary to drill a hole thousands of feet into the ground. Ex.1010 (12). Since at least the 1980s, rotary drilling rigs have been the rig of choice for drilling that hole. Ex.1011 (4). The drilling rig is typically sized depending on the depth of the target zone. A typical drilling rig is illustrated below:

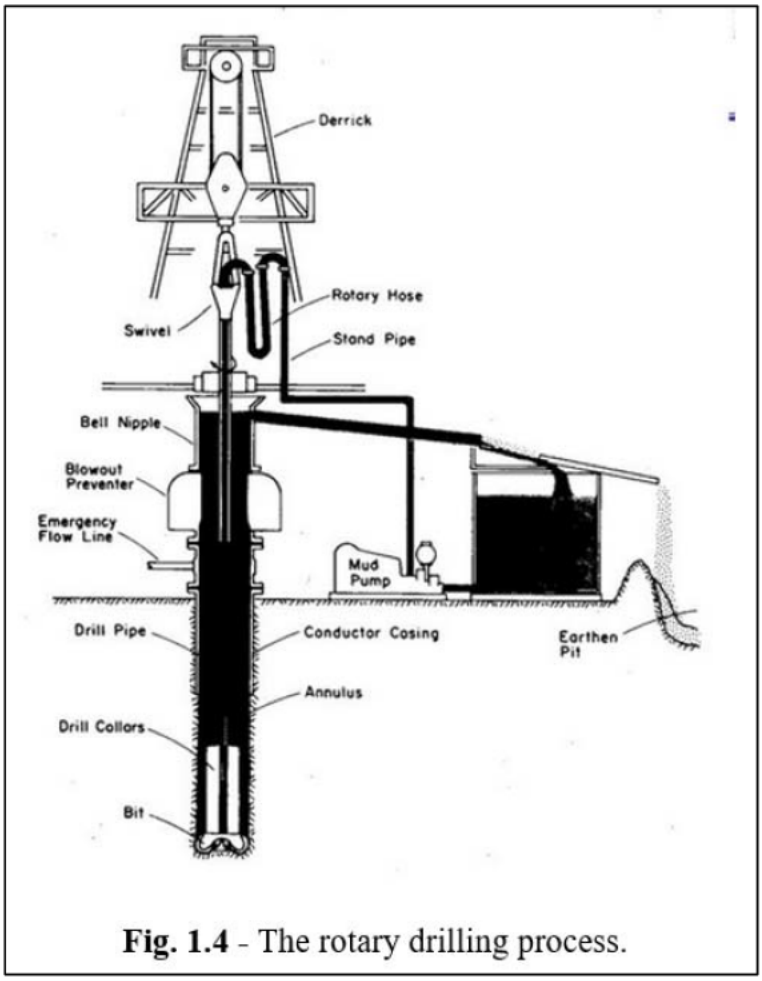


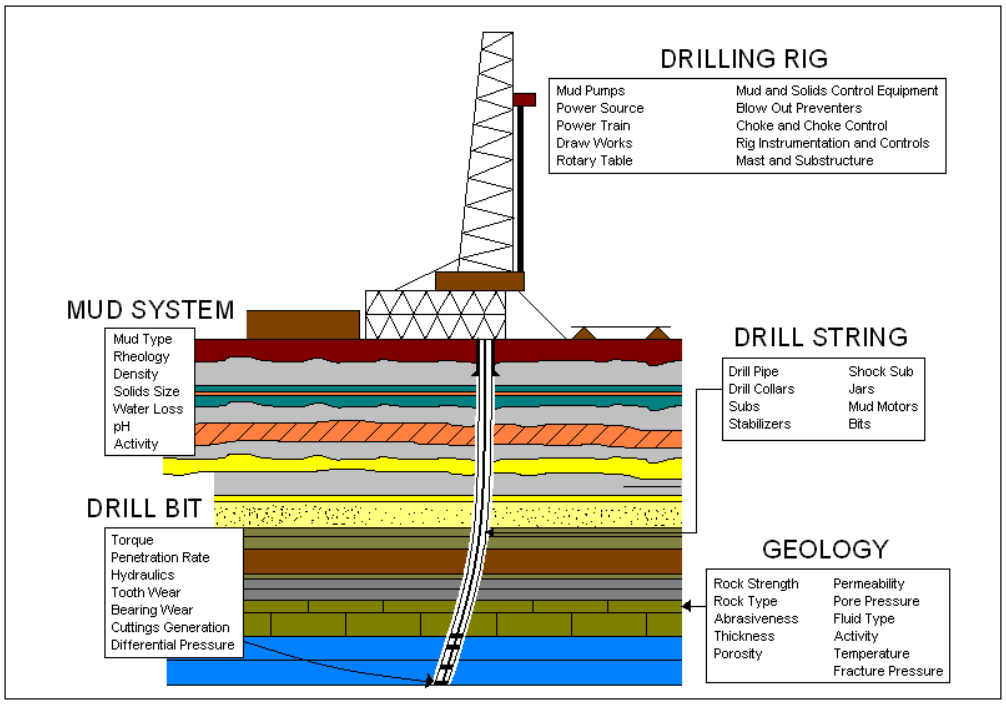
Fig. 1.4 - The rotary drilling process.

Ex.1011 (4).

22. To drill a hole, a downward force is applied by the drill string on a drill bit (weight on bit or WOB), and the drill bit is rotated by rotating the entire drill string from the top of the well. *Id*. Alternatively, the hole is created with a motor rotating the bit downhole and without rotating the drill string from the surface. Additionally, the hole can be created by rotating the drill string in addition to a motor. The drill bit includes cutters, which act to either shear or crush the rocks, depending on the drill bit type. As the bit drills into the ground (or formation), it

creates cuttings, which are removed by circulating drilling fluid (called mud) through the bit. *Id.*

23. Many variables affect the drilling process, and they are illustrated in the figure below:



Ex.1012 (slide 4).

24. One of the most important variables is the geology of the formation being drilled. Common rock formations and rock types include shale, sandstone, limestone or dolomite (or a mixture of them). These rock formations have different rock compressive strength, which affects how much force is required for a drill bit to penetrate the ground. Different formations have other properties that vary as well. For instance, some formations have a cationic exchange capacity that that causes

stickiness that can result in the formation bonding with drill string and/or the drill bit and causing the bit to ball up (bit balling). All of these geological properties can change from one foot to the next as a drill bit progresses deeper into the ground.

25. Drill bits are used to penetrate the formation, and they come in different sizes and types. Which type or size of bit is used depends on the application and the formation being drilled, but it is typical that a deep well will require using different bits along the way. An ideal drill bit should produce a high overall rate of penetration (ROP), have a long life, drill a full gauge hole, and have a moderate cost. The ROP is the speed at which a drill bit penetrates the rock under it to deepen the borehole. The ideal bit will depend on the formation to be drilled and should produce the lowest cost for the section of the well it was designed to drill. The ideal drill bit for drilling a section of a well can vary from well to well depending on the well and casing design.

26. The drill bit is connected to the drill string and gets operational parameters therefrom. The WOB and surface revolutions per minute (RPM) is controlled by the driller and the drill bit reacts by penetrating the formation with a depth of cut and a bit torque. The drill bit typically has nozzles which generate a pressure drop across the bit increasing the drilling fluid velocity for the purpose of cleaning the cuttings generated under the bit.

27. Engineers knowledgeable about bit design and manufacturing understood that drilling performance could be optimized based on the contributing factors discussed above. There are two typical measures of drilling efficiency and accelerated learning used by these engineers. One is the total cost per well if the wells are similar in design and the other is the cost per foot drilled, both which are dependent on the overall ROP.

B. Types of Bits

28. There are two main types of drill bit and these can be classified as either drag or tricone (rollercone) bits. The downhole drilling (or cutting) process depends on the type of drilling bit that is being used. The different types of drill bits will be discussed more detail in the following section.

1. Tricone (rollercone) bits

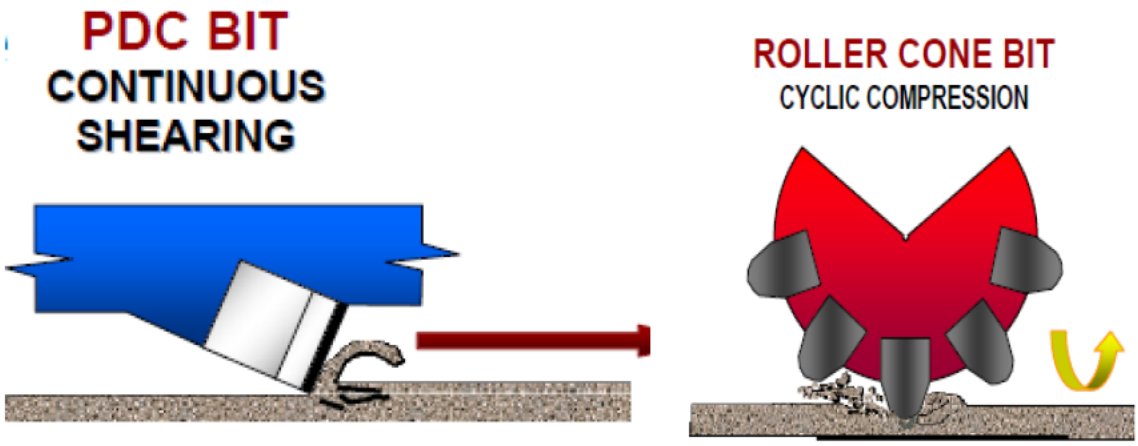
29. Tricone bits were introduced in 1909 and are comprised of two or more cones with cutters that rotate around the axis of the cone as the bit is rotated. Ex.1011 (8). Each cone typically has 2 to 3 rows of cutters. Some of the cutters from different cones can intermesh for a benefit of better cleaning between the cutter elements. A side view of an insert bit (left) and a milled tooth bit (right) is shown in the figure below.

Ex.1013 (slides 13, 43).

30. Tricone bits are known as a solid bit type that can handle rough conditions, can drill any formation type, are steerable and are reasonably priced. Tricones, however, do not exhibit the same wear resistance and ROP as the polycrystalline diamond compact (PDC) bits.

2. Drag bits

31. Drag bits were introduced in the 19th century. Ex.1011 (8). Unlike rollercone bits, drag bits have "fixed" parts and rotate as a unit with the drill string. *Id.* This means that drag bits have a much lower risk of leaving parts of the bit in the hole in case they should fail or break. The drag bit cutters may be made from steel, tungsten carbide, natural diamond or PDC. Ex.1014 (13-14). A drag bit (like a PDC) typically shears the rock while the tricone bit is mainly used to crush the rock through a cyclic compression.

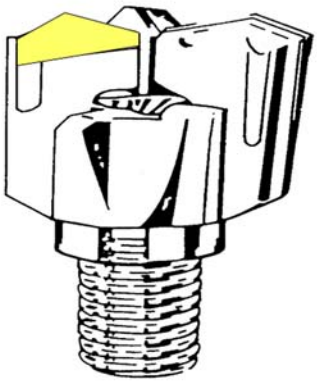


Ex.1015 (slide 10).

32. As I will explain, there are different types of drag bits that are typically used for different applications.

a. Fishtail Bits

33. The fishtail bit (named for its distinctive look) is typically used close to the surface where the formations are soft and there are few restrictions for penetrating the rock. Typically in the application of these bits the limiting factor to ROP is that the hole must be cleared for cuttings debris. The cutting action could be performed by a steel or tungsten carbide blade or a blade set with PDC cutters. A picture of a fishtail drag bit is show below.

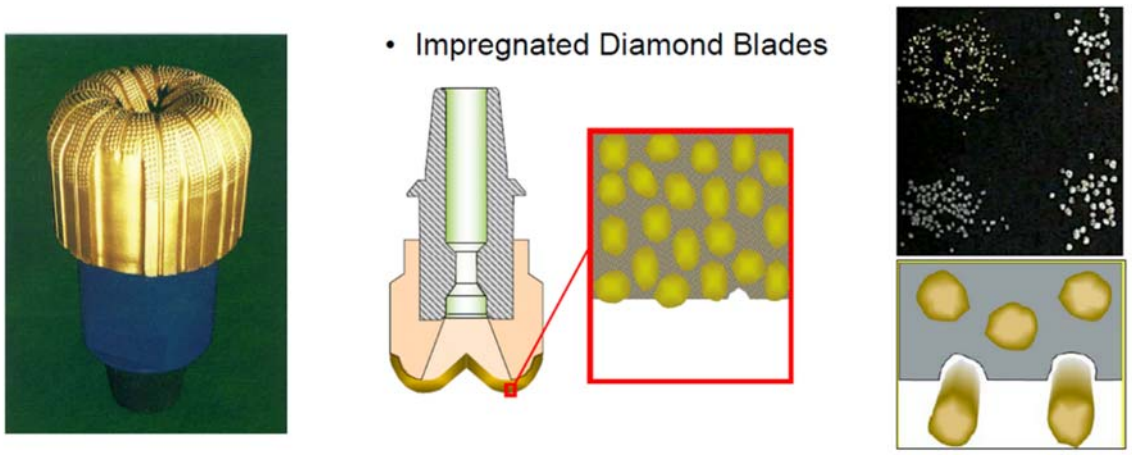


Fishtail type drag bit

Ex.1015 (slide 13).

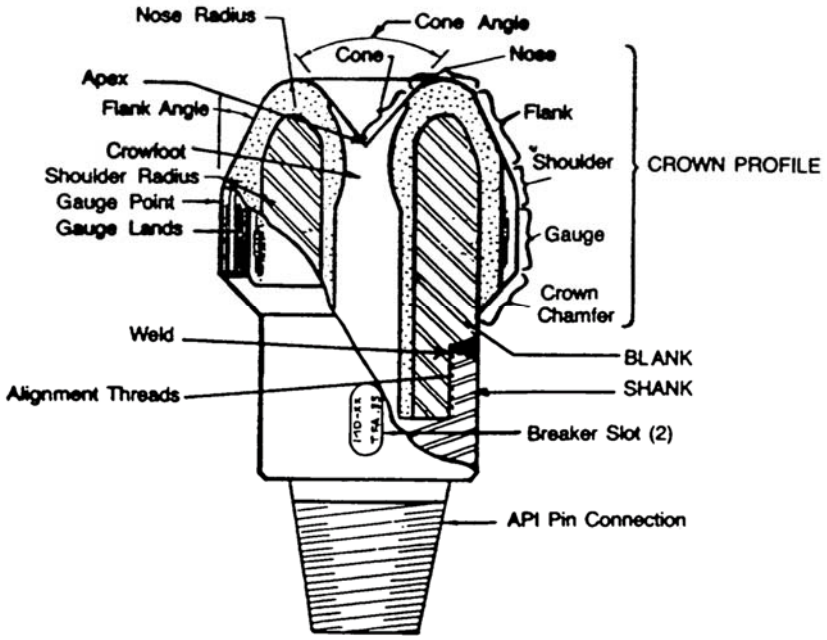
b. Natural diamond (ND) and impregnated diamond bits

34. Natural diamond bits are set with diamonds across the bit face. The natural diamond bits have a distinct look because diamonds (which can include synthetic diamonds) are bonded to the tungsten carbide matrix and set in different patterns. Impregnated bits have diamond cutting elements fully imbedded within a bit body matrix. These bits have cutting actions from the exposed diamond elements. As the matrix wears and the diamonds are exposed and released, new diamonds are exposed. The impregnated diamond bits are typically applied in very hard and abrasive formations and run with turbines at more than 1000 RPM. A natural diamond bit is shown below in the figure on the left and an impregnated diamond bit is shown below in the figure on the right.



Ex.1015 (slides 18, 26).

A side view of a natural diamond bit is show below.



*Id. (*slide 16).

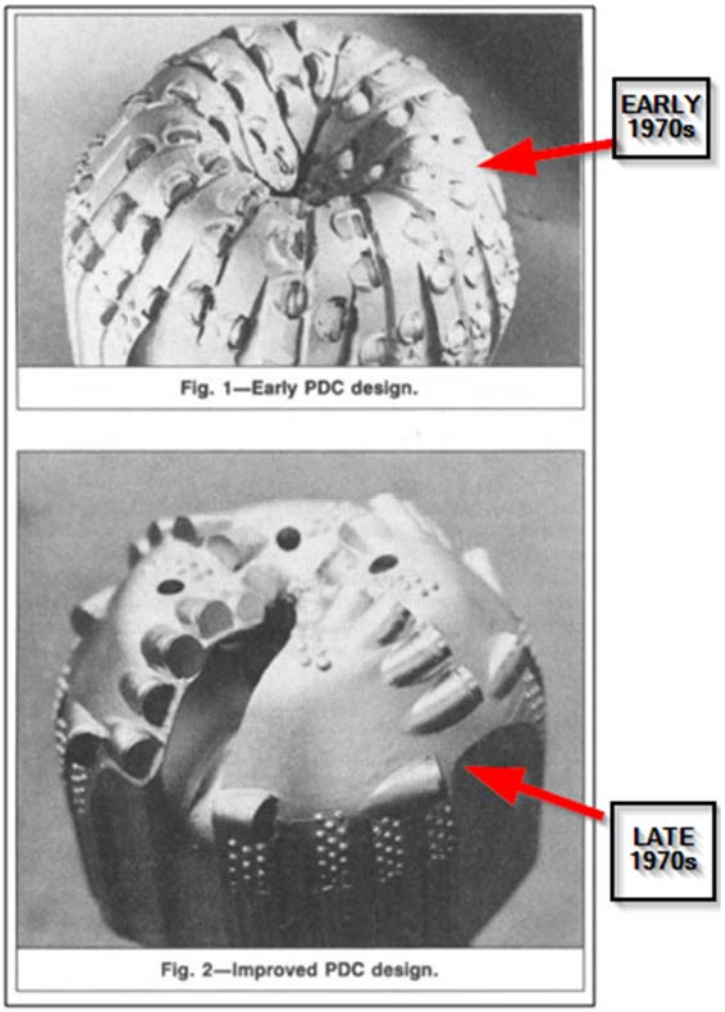
35. Natural diamond and impregnated diamond bits are typically used when formations are hard and very abrasive, these bit will have very low penetration rates. Accelerated wear is seen with tricone bits, and with PDC bits the cutters can

be damaged easily in hard formations. The ROP is typically well below 10 ft/hr for these types of bits.

36. Other applications for natural diamond and impregnated diamond bits are when high cutter intensity is required across the bit face as in smaller diameter bits and in areas where weather precludes making bit trips. This is because these types of drill bits typically drill slower but can drill longer sections of hard and abrasive formations and thereby reduce the number of trips. In these circumstances, running the ND or impregnated bit obtains the lowest cost/foot. Natural diamond bits are also used in coring operations because of the low depth of cut and smooth cutting action resulting in a better quality core.

c. PDC (Polycrystalline Diamond Compact) Bits

37. Polycrystalline Diamond Compact (PDC) bits are drag bits where the cutting elements are PDC cutters, which are typically inserted on blades or on the bit face profile. PDC bits shear/cut the formation. PDC bits were first produced in 1976, and the popularity of PDC bits using PDC cutters has grown steadily since then. Ex.1014 (8); Ex.1016 (1). The first PDC bits in the early 1970s were designed like natural diamond bits illustrated in Figure 1 of Ex.1016 (Fig. 1), but drill bit engineers recognized that a different design was necessary to take full advantage of the more efficient PDC bit's shearing cutting mechanism. Ex.1016 (1); Ex.1017 (5). This soon led to a bladed-bit style in the late 1970s, similar to what is used today.

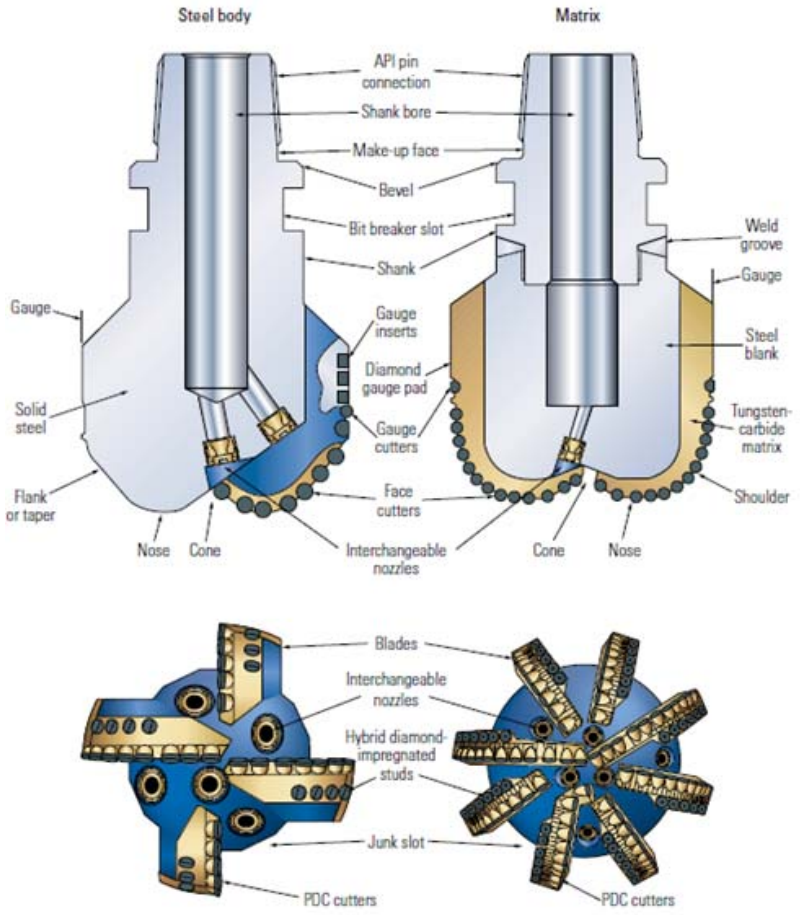


Ex.1016 (1).

38. More recent bits, including Baker Hughes HC609 bit from 2001, have maintained this bladed structure.

Ex.1018 (Fig. 11a).

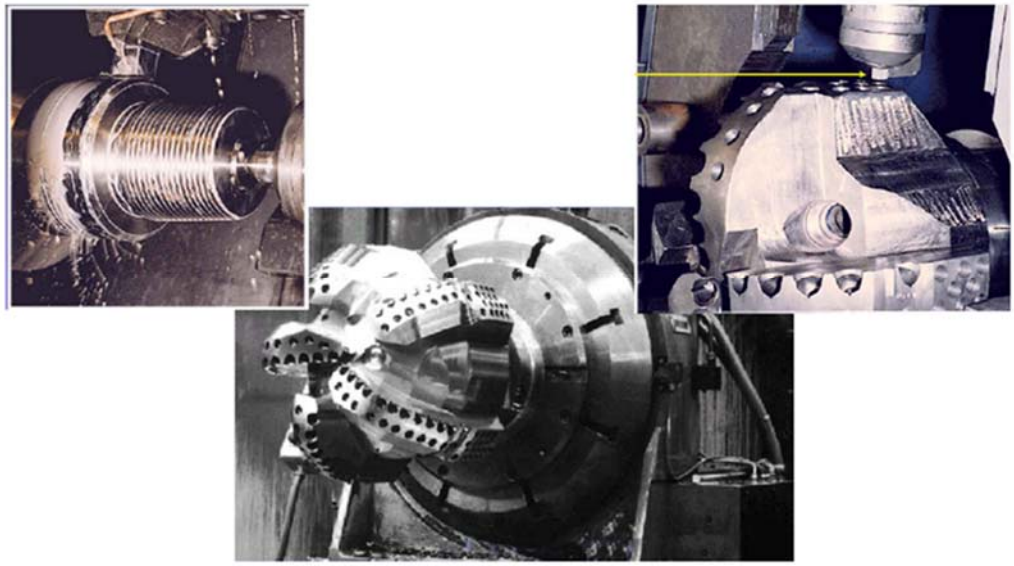
39. PDC bits may either have a steel body or a matrix (tungsten carbide) body. A typical steel body and a matrix body bit are compared side by side in the figure below.



Ex.1015 (slide 15); *see also* Ex.1019 (10).

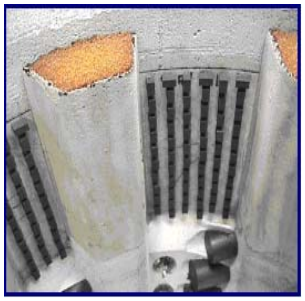
40. As illustrated in the figure above, PDC cutters are arranged in rows, extending radially and longitudinally from the bit face's nose to the shoulder to the gauge (sometimes spelled "gage"). The gauge is the outermost diameter of the bit. PDC bits also include junk slots, which help funnel the cuttings away from the bit.

41. The bit body and cutter pockets for steel body and matrix body bits are typically designed using a CAD application. The steel body bit and cutter designs are programmed into machine language to ensure efficient milling time. Steel body bits are typically manufactured with a 5-axis milling machine, which is shown in the figure below:



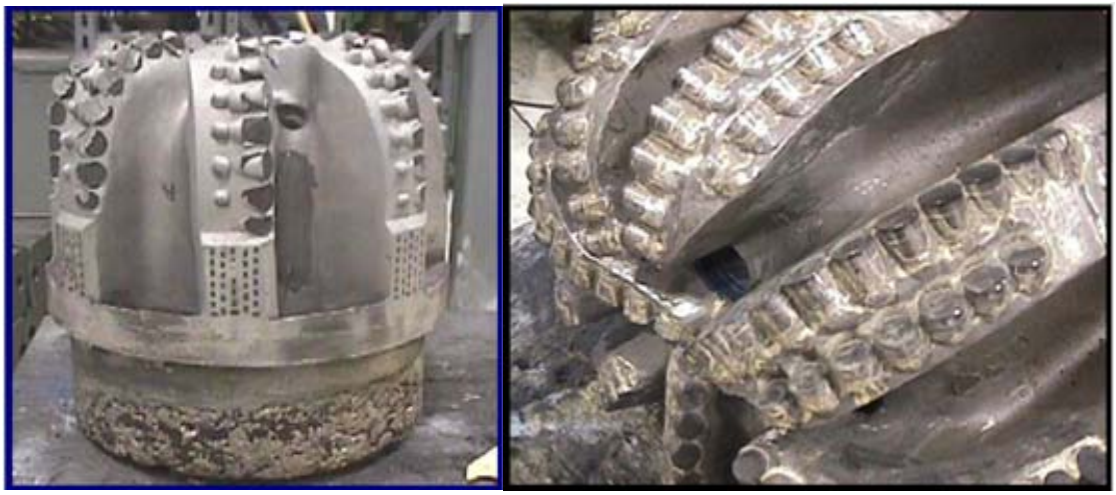
Ex.1015 (slide 40).

42. A typical mold for a matrix bit body is shown below on the left (1); an enlargement of the side where the gauge trimmer are is shown in the middle (2); and a matrix bit body is shown on the right (3).

1)  2)  3) 

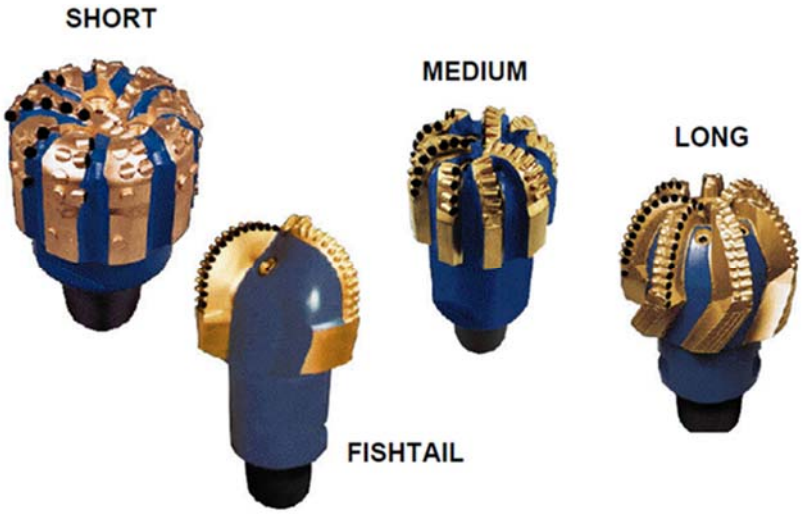
Ex.1015 (slide 41).

43. Two manufactured PDC matrix bit bodies are shown below.



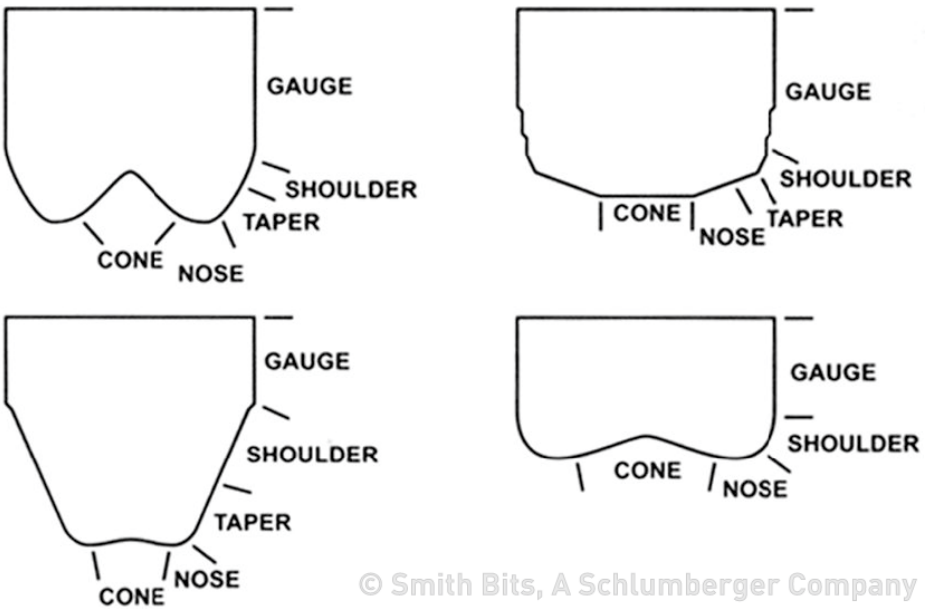
Ex.1015 (slide 42).

44. The shape of a PDC bit body is called its profile. There are four general categories of PDC bit profiles: (1) flat profiles, (2) short parabolic profiles, (3) medium parabolic profiles, or (4) long parabolic profiles. A short, medium and long profiled PDC bit is shown next to a fishtail profile in the figure below. PDC bits most frequently incorporate large shoulder radii and primarily use either short or medium parabolic profiles.



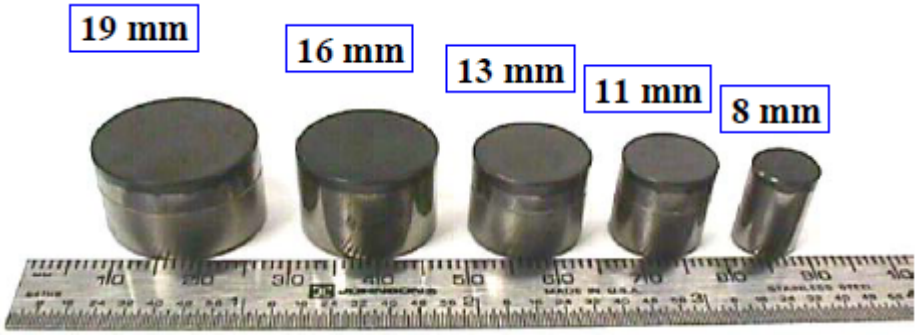
Ex.1015 (slide 38).

45. The figure below describes the nomenclature of various regions on a PDC bit profiles. Starting at the centerline of the bit and moving outward to the gauge, the profile is broken into five zones: cone, nose, taper or flank, shoulder, and gauge:



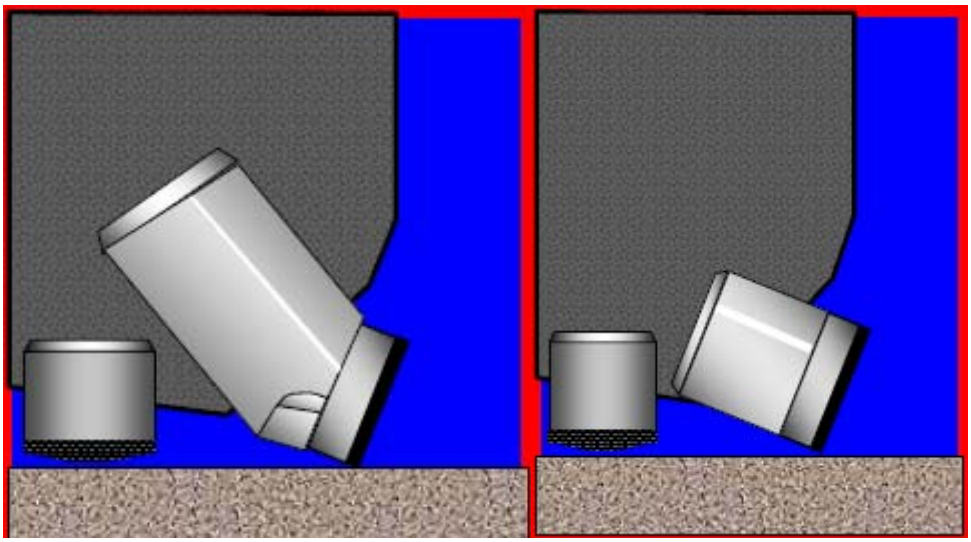
Ex.1020 (Fig. 1)

46. PDC cutters are made up of a working component, the diamond table, and a supporting component called the substrate. The most common PDC shape is the cylinder, partly because cylindrical cutters can be easily arranged within the constraint of a given bit profile to achieve large cutter densities. Sample cutters in different sizes are seen in the figure below.



Ex.1015 (slide 35).

47. The working component of PDC cutters are made of many small diamond crystals bonded together. "The cleavage planes of the diamond crystals have a random orientation that prevents any shock-induced breakage of an individual diamond crystal…" Ex.1011 (9). The substrates are a composite material made up of tungsten carbide grains bonded by metallic binder. This material bonds efficiently with diamond tables but is very hard and thus capable of impeding erosive damage to a working cutter. The figures below show different ways PDC cutters can be mounted in the bit body.



Ex.1015 (slide 35).

48. Since the early 1990s, drill bits had been designed to include rows of cutters from the nose of the bit to the gauge.

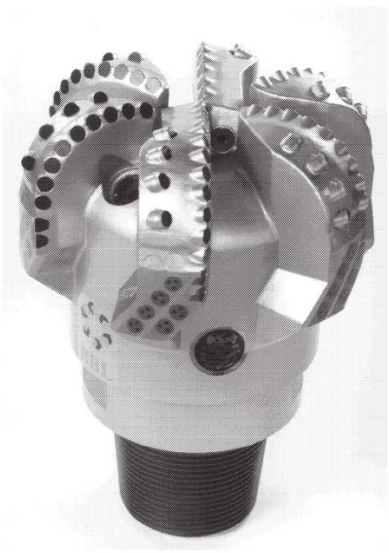


Fig. 5—Lateral-jet bit.

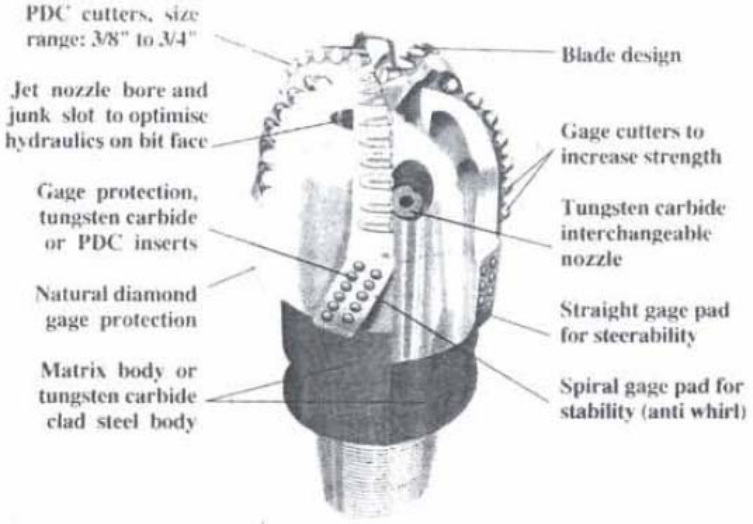


Fig.4. Main features of PDC bits.

Ex.1021 (Fig 5); Ex.1022 (1-2); Ex.1023 (Fig 4); Ex.1024 (2-3).

49. Some types of bits, like anti-whirl bits, were initially designed without cutters in the gauge region so the gauge could ride against the borehole wall to stabilize the bit's rotation. An example of an anti-whirl bit is below.

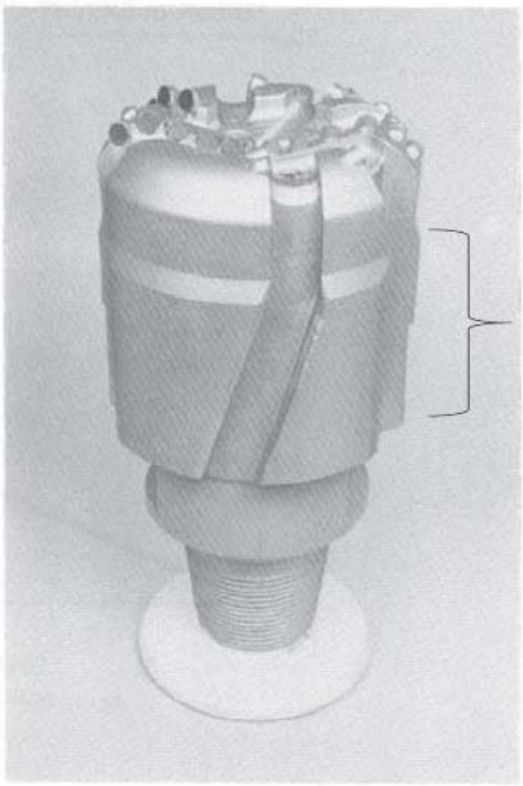


Fig. 2—Antiwhirl PDC bit, bearing pads.

Ex.1025 (Fig. 2).

50. Anti-whirl bits were intended to avoid bit whirl, which causes the innermost cutters to move backward and the gauge cutters to pound against the side of the hole, which leads to breakage in those cutters. Ex.1014 (12); Ex.1024 (2-8). The images below illustrate the differences in boreholes drilled with anti-whirl bits (left) and conventional bits (right):

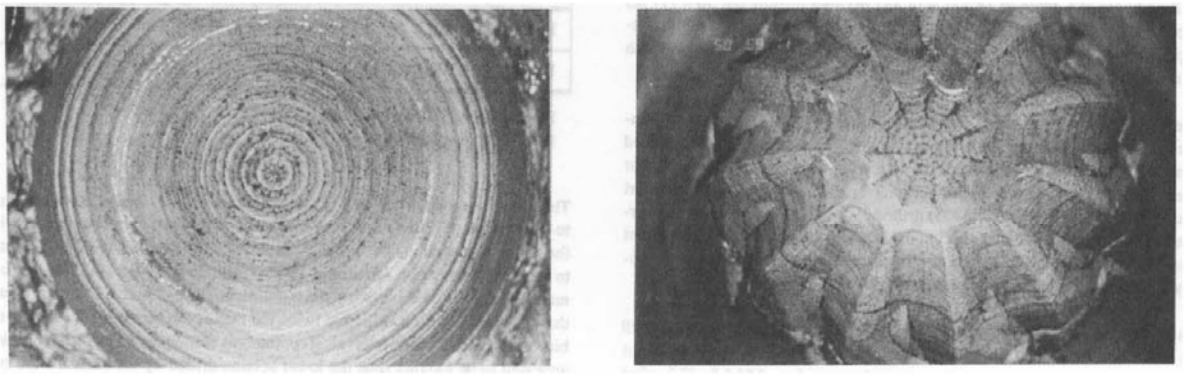


Figure 7 - Bottomhole patterns generated while drilling Carthage limestone. The left one was drilled with the 16 in. Anti-Whirl PDC bit. The right one was drilled with a 12-1/4 in. conventional PDC bit.

Ex.1026 (4).

51. The cutting structure of anti-whirl bits "create[d] an imbalance force that is directed onto a low friction area of a bit" that "can not (sic) grab the formation," which prevents bit whirl from starting. Ex.1024 (1, 3). The low friction area was typically devoid of cutters so that the cutters would not grab onto the formation and initiate bit whirl. *Id* (4). Engineers knowledgeable about bit design and manufacture, however, knew that in a balanced bit design, gauge pads could include cutters and still avoid bit whirl. Ex.1066 (3:39-50); *see also* Ex.1067 (5:26-40). By placing the cutters off the bit-tip profile, the cutters in the gauge region would not grab the formation to initiate bit whirl. Ex.1024 (4). Gauge region cutters would typically be underexposed compared to the cutters on the face of the bit, and the gauge cutters would become engaged more as the cutters on the bit's face face wore away. Ex.1024 (4).

52. It was also known that"[t]he wear resistance of PDC bits is improved by increasing the length of the gauge so that more cutters can be placed on or near the gauge and increasing the carbide or diamond content of the gauge pad." Ex.1071 (569-70). The lack of gauge cutters increased abrasion-induced wear, which also impacted bit life. *Id.* (537). Having a gauge with no cutters also meant that the gauge region was lighter than the rest of the bit, which led to ring out, which leads to significant wear on the blades and damages to cutters. Ex.1024 (4).

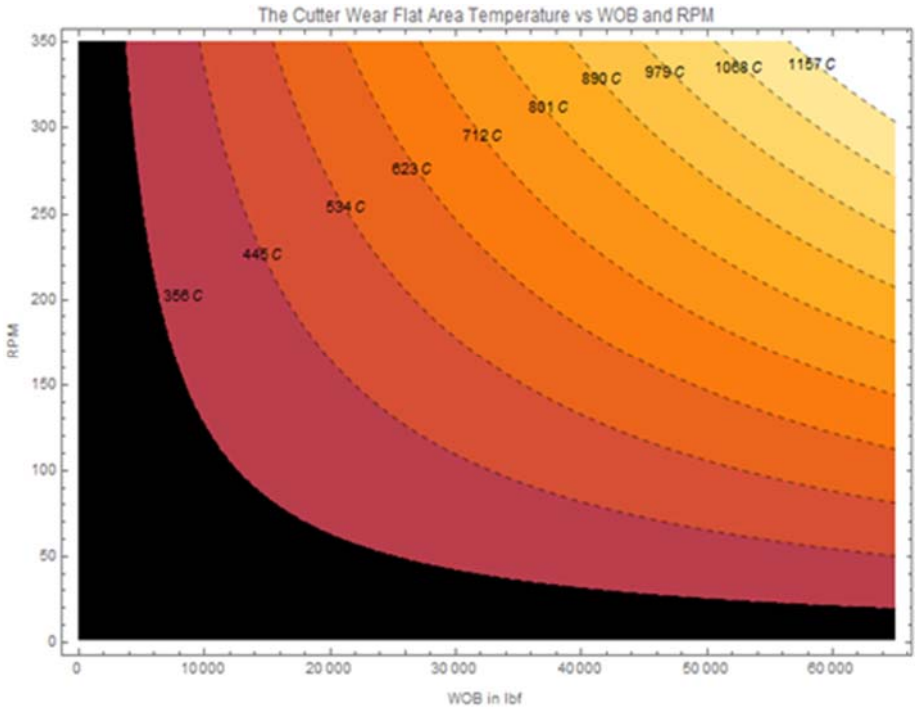
C. Aspects of PDC Bit Design

53. By the 1980s, engineers were refining PDC bit design to improve ROP and bit life. Ex.1027 (1); Ex.1011 (5, 13); Ex.1028 (1). Cutters are expected to endure throughout the life of a bit, but cutter wear reduces ROP and bit life. Cutter wear is caused by the bit's repeated contact with the formation. Ex.1029 (1). To perform well, cutters must receive both structural support and efficient orientation from bit body features. In addition, improper cleaning of the drill cuttings reduces the efficiency and increase drilling time. Ex.1030 (1:61-66).

54. It was well understood as early as the mid-1980s that drill bits must remain cool and clean from the cuttings, particularly because PDC cutters are sensitive to high temperature. Ex.1031 (1:36-40). Drill bit engineers were well aware of the temperature sensitivity of PDC bits. Glowka and Stone (1985) developed an analytical model for estimating the temperature distribution in stud-

mounted PDC cutters under downhole conditions. Ex.1032 (3). They found that at a wearflat temperature above 350°C, the wear rate increases rapidly from that obtained at a lower temperature, and the cutter dulls. *Id*.

55. This plot shows the critical range of WOB and RPM that causes accelerated bit wear at a given temperature. As the drill bit drills ahead larger the PDC wearflats develop and the temperature profiles will change. When the temperature profiles are coupled with the results from single cutter testing where the critical temperature for accelerated PDC cutter wear is determined for specific cutter a safe WOB and RPM operational window can be determined. Ex.1033 (slide 40).



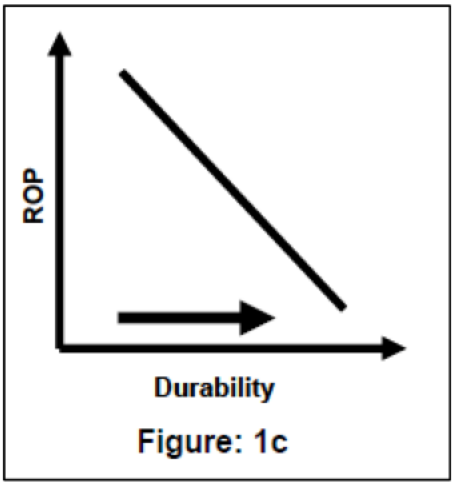
56. By the mid-1990s, engineers knowledgeable about bit design and manufacturing were aware that cutter, placement, and exposure affected bit performance. Ex.1028 (1); Ex.1016 (4); *see also* Ex.1011 (9-11). They also

understood that these design features should be optimized to ensure uniform wear, clearing cuttings from the bit's path (cleaning), and cooling the temperature-sensitive PDC cutters. Ex.1030 (1:40-44); Ex.1014 (5). These engineers were capable of modifying these design features to optimize bits and did so on a regular basis. Ex.1028 (1) (provided that bit life is adequate, "any parameter that can be altered to improve the penetration rate … will further improve the drilling efficiency and result in lower drilling costs."). In fact, between 1989 and 1996, PDC bit ROP increased 60% while the cost per foot dropped 35%. Ex.1029 (2). PDC bit life also increased 115% in that time period. Ex.1034 (6).

1. Cutter Placement and Density

57. Engineers knowledgeable about bit design and manufacturing sought to arrange cutters "to facilitate a uniform wear pattern for all cutting elements," which contributed to longer bit life. Ex.1030 (1:40-43). These engineers knew that cutters closer to the bit axis "generally experience minimal wear whereas the nose and outside taper of the bit experience accelerated wear." Ex.1029 (2). In addition, these engineers were aware of benefits and drawbacks of cutter density. For example, increased cutter density reduces the effective load per cutter, which reduces the wear rate of individual cutters but decreases ROP. Ex.1016 (4); Ex.1028 (1-2). The following image illustrates the inverse effect of increasing cutter density on

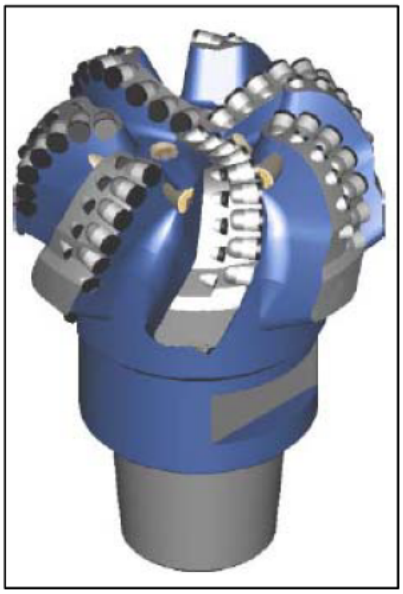
durability and ROP (i.e. increasing durability while decreasing ROP). Ex.1035 (7). Bits with lower cutter density, however, were less durable. Ex.1028 (2).

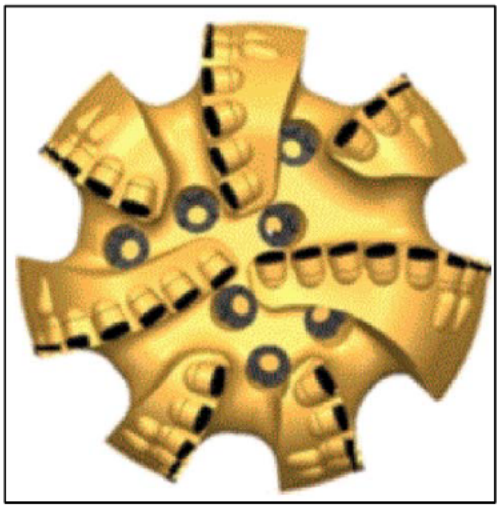


Ex.1035 (7).

58. To address this problem, these engineers used "backup" or "secondary" cutters, located rotationally behind the "primary" cutters, to follow "the groove cut in the formation by its associated primary cutter as the bit rotates. Ex.1068 (1:32-40). Ex.1036 (5) (explaining backup cutters were "expected to yield further gains in stability and longevity"); Ex.1037 (3) (explaining that secondary cutters "provides the benefits of bit stability and increases the wear resistance of the bit."); Ex.1038 (7:9-32) ("The outer region of the drill bit also has increased production provided by the addition of back-up cutters [] or abrasion elements [] disposed rearwardly of the outer three or four cutters on each blade."); Ex.1039 (9:39-65) ("The gauge region 13 of the drill bit also has increased protection provided by the addition of backup cutters 18 disposed rearwardly of the outer two primary cutters on each blade.").

Backup cutters were typically included from the nose to the gauge. Ex.1071 (9:14-18). Backup cutters were typically arranged so they only performed "an effective cutting action on the formation should the primary cutter become damaged or worn so that it is no longer effective." Ex.1068 (1:41-47). Many drill bits were manufactured with two cutter rows prior to 2007: Lyng (2003), Hughes Christensen (2005), Amareda Hess (1997), and Sandia (2005).





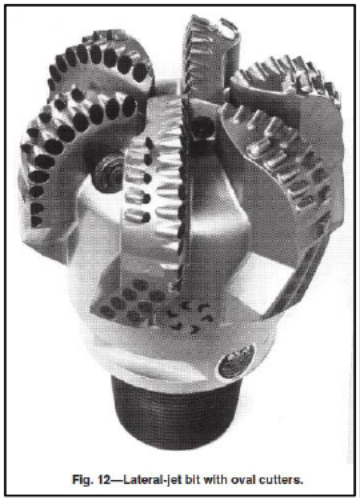


Fig. 12—Lateral-jet bit with oval cutters.

Ex.1040 (3); Ex.1041; Ex.1021 (Fig. 12); Ex.1042 (Fig. 2).

59. The orientation of a backup cutter typically matched the orientation of the primary cutter it trailed because the backup cutter usually is meant to assist the primary cutter and decrease wearflat. By providing a similarly oriented backup cutter to the primary cutter, the backup cutter would engage the formation in the same manner intended at that radial location on the specific blade. Ex.1039 (9:53-58). Engineers were aware that "the use of backup cutters has proven to be a convenient technique for gaining more superabrasive volume bearing on the formation to extend the life of a bit and enhance its stability without the necessity of designing the bit with excess blades to carry more PDCs[.]" Ex.1043 (1:23-27). Adding the backup cutters increased cutter count without the need for additional blades, which reduced design complexity and cost and avoided "compromising bit hydraulics due to reduced flow area over the bit face and less-than-optimum nozzle placement." *Id.* (1:27-31). Bit hydraulics, which cool the cutters and remove cuttings, are particularly important in PDC bits because PDC cutters are sensitive to high temperatures reached during drilling. The figure below illustrates increased wear in "primary" cutters that lack "backup" cutters.

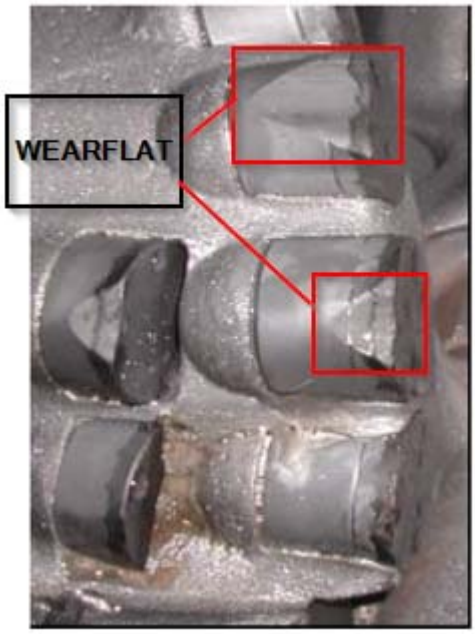
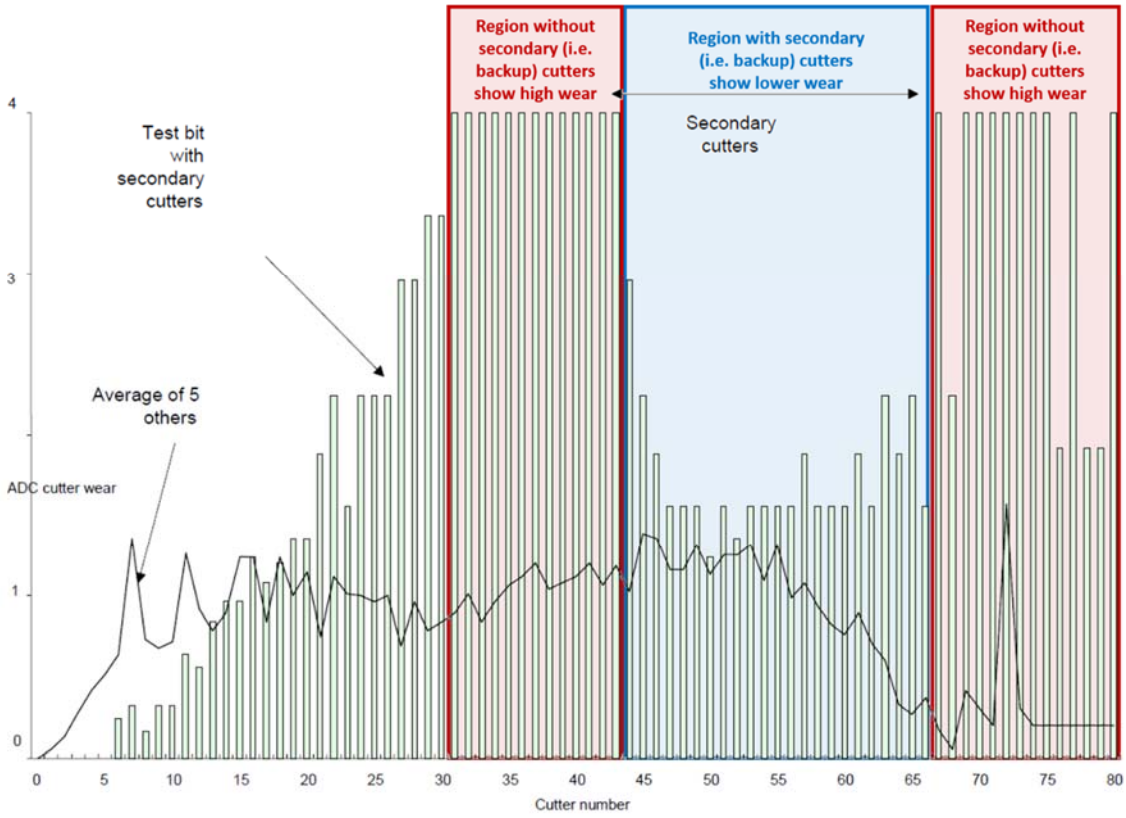


Fig 9

Ex.1036 (5); Ex.1037 (3, Fig. 9).

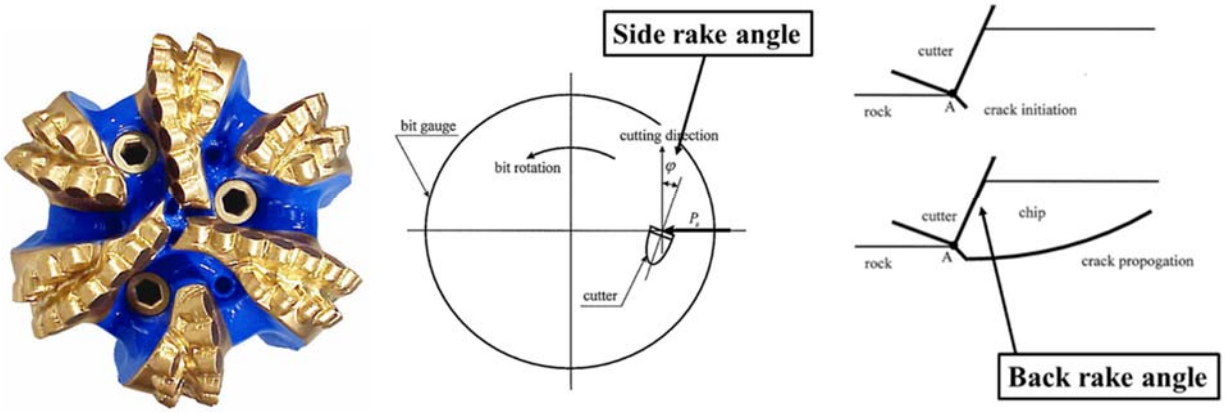
60. Figure 8 (below) from a 1996 article by Taylor reported "distinctly lower wear in the region where secondary cutters were located, cutters 44-65."



Ex.1037 (3, Fig. 8).

2. Cutter Orientation

61. Cutter orientation refers to the cutter's backrake angle and siderake angle.



Ex.1015 (slides 61-62).

a. Backrake Angle

62. A "backrake" angle is "the amount of distance, in degrees, between vertical (90º) and the face of the cutter."

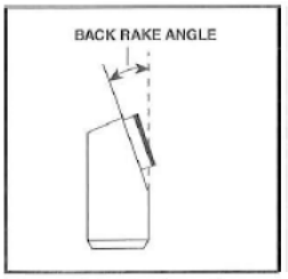
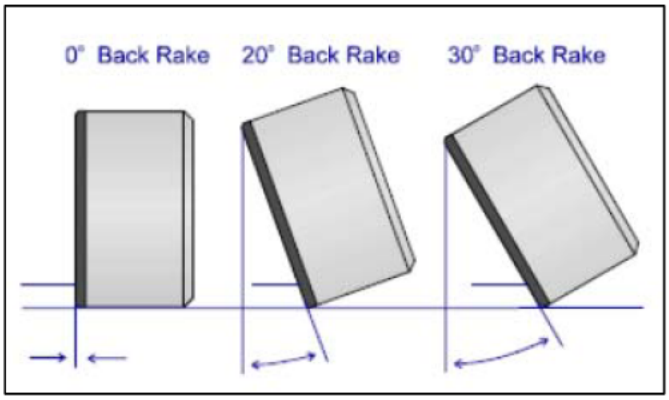


Figure 66. Back rake angle

Ex.1014 (9, 15).

63. The greater the backrake—the more tilted the cutter is away from the formation being drilled—the less aggressive the cutting action as shown in the image below.



Ex.1044 (slide 7).

64. Thus, a backrake angle of 0º is the most aggressive backrake. Ex.1014 (9). The aggressiveness of the cutter decreases as the angle from the vertical increases thus a -20º backrake angle is more aggressive than a -30º backrake angle.

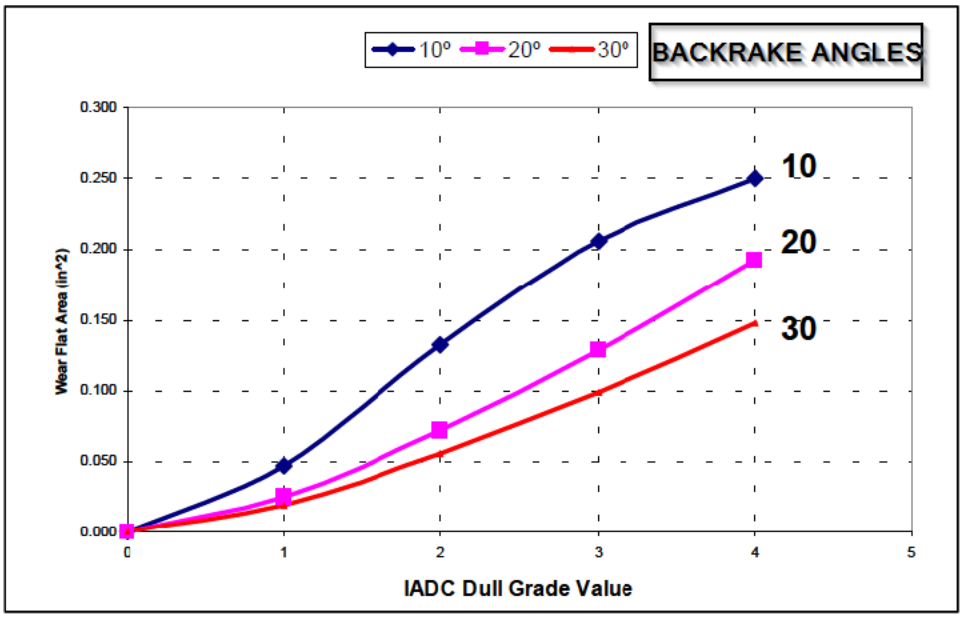
Ex.1045 (2:23-29). By the mid-1980s, a negative back-rake angle of 20º was standard. Ex.1011 (11).

65. Backrake is one factor that plays a role in cutting efficiency and optimum backrake varies depending on the formation cut as well as the depth of cut. Ex.1046 (1, 3). Engineers knowledgeable about manufacturing and designing bits generally understood that "as the backrake angle is decreased, the cutting action becomes more efficient," but that this smaller angle makes cutter breakage more likely. Ex.1016 (2); Ex.1029 (4); see also Ex.1045 (2:30-38). By contrast, a higher backrake angle has lesser depth of cut with a reduced speed of drilling "but will be more durable in a hard formation, giving longer bit life." Ex.1016 (2); Ex.1029 (4); Ex.1045 (2:38-59).

66. Higher backrake angles also help limit damage to cutters from bit whirl. When the bit is exposed to axial and lateral vibrations, the cutters may impact the rock on their edge. Having high backrake (for axial vibrations) and high siderake (for lateral vibrations) helps to assure that the impact stresses on the diamond layer are compressive. If the cutter is exposed to tensile stresses, it is much more likely to be chipped or delaminated. Ex.1027 (3).

67. Engineers also recognized that varying backrake between cutters helps distribute the load among cutters. As the bit rotates, the cutters further from the center of the bit are traveling at a faster rate, and therefore experiencing more force

against the formation. Backrake is known to cause an inverse effect between the durability and ROP of the bit. Ex.1035 (6). By increasing backrake of the cutters, durability increases as marked by the decreased wearflats, as shown in the image below.



Ex.1047 (Fig. 11).

68. The general industry practice by the 1990s was to vary cutter backrake by increasing backrake across the face of the bit. *See* Ex.1014 (9); Ex.1048 (10:5-8, 2:21-27) (alternating cutters with positive rake and negative rake to allow "cooperation between the differing rake cutting elements" and "improve formation cutting"); see also Ex.1045 (3:55-4:2, 6:36-48) (the cutters have varying backrake angles from the outermost of the innermost edges of the cutting face on the bit);

Ex.1017 (6) ("Back rake angles … are not constant across the bit, nor from bit to bit.").

69. In March 1998, differences in ROP and WOB of five PDC bits were analyzed with backrake angles of 7-10-15º, 10º, 20º, 30º, and 40º, respectively. Ex.1029 (5). The 7-10-15º backraked PDC cutter required less torque and less WOB to achieve the desired ROP than bits with constant backrake across the blade. *Id. (*5-6). The results are illustrated below. *Id.* (5).

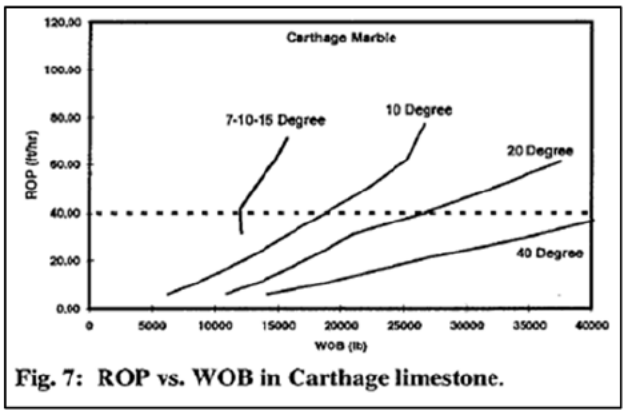


Fig. 7: ROP vs. WOB in Carthage limestone.

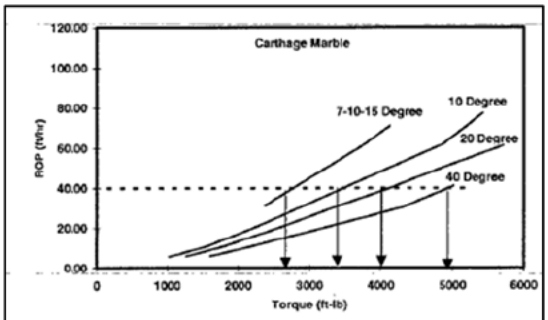


Fig. 8: ROP vs. Torque in Carthage limestone

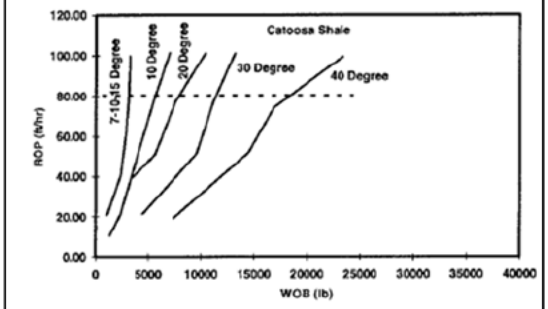


Fig. 9: ROP vs. WOB in Catoosa Shale.

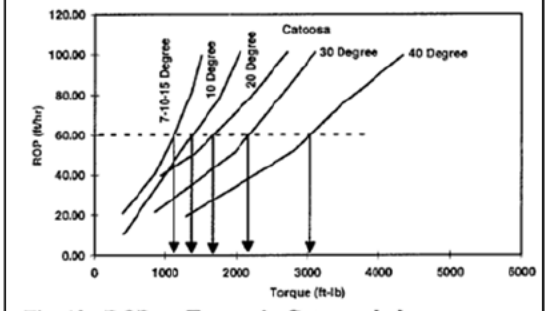
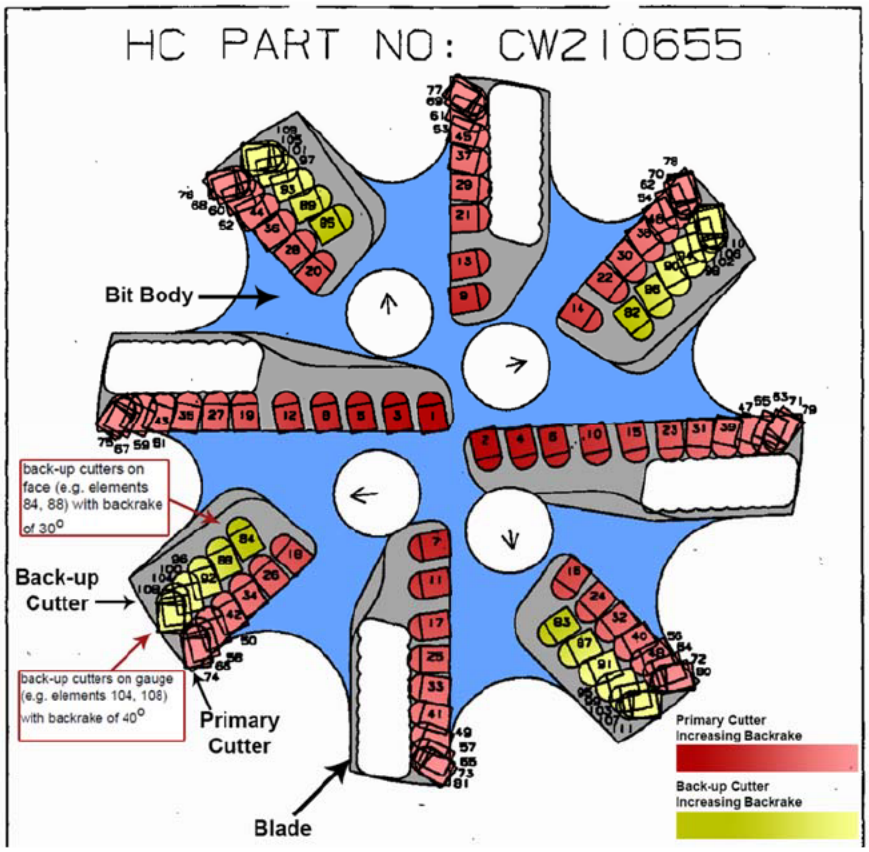


Fig. 10: ROP vs. Torque in Catoosa shale.

Id.

70. At least since 1995, Baker Hughes was making rotary-drag bits with varied-backrake backup cutters. As seen in Ex.1049 (below), a bit body with a face (blue) has a plurality of blades (grey) contain a front row of primary cutters (red) (e.g., elements 14, 22, 30) with backup cutters (yellow) trailing behind the primary cutters on the same blade (e.g., elements 82 and 86). The backrake of the cutter

varies from the face to the gage of the bit, illustrating that it was known at the time of the invention that backrake can be adjusted with various backup cutters.



BIT INFORMATION:

IADC CODE	= M332
NOZZLE QTY/TYPE	= 4 SP
GAGE LENGTH/TYPE	= 2.00" TCIDIA
FACE VOLUME/RATIO	= 61 IN^3 / 0.47
JUNK SLOT AREA/RATIO	= 14.1 IN^2 / 0.25
CONNECTION TYPE	= 4.50" API REG.
SHIPPING WEIGHT	= 168 LBS (76 KGS)

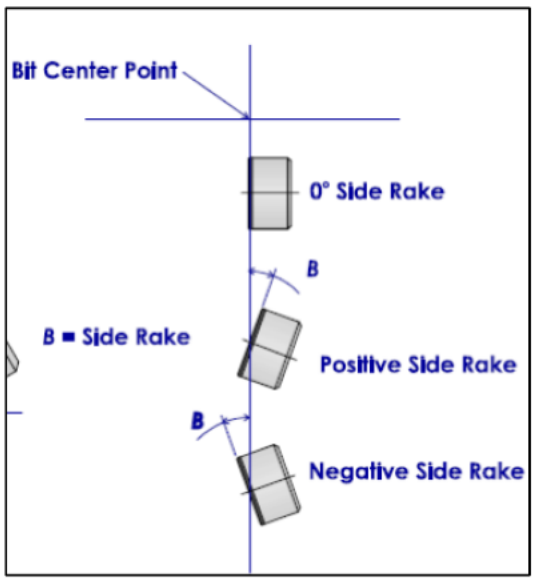
CUTTER INFORMATION:

CUTTER QTY	= 111 TOTAL
CUTTER QTY/TYPE 1	= 81 Ø0.323" PDC
CUTTER QTY/TYPE 2	= 30 Ø0.323" PDC BACKUP
CUTTER BACK RAKE	= 30° FACE
	= 40° GAGE

Ex.1049.

b. Siderake Angle

71. A "siderake" angle is "the left-to-right orientation of the cutter with respect to the bit's face." Ex.1014 (9, 16). The figure below is a top view and compares cutters with and without siderake.



Ex.1044 (slide 7). The illustration below shows backrake angle compared to siderake angle:

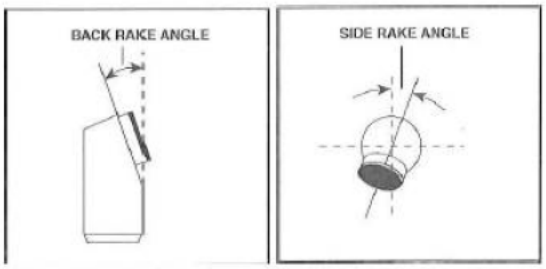


Figure 66. Back rake angle *Figure 67. Side rake angle*

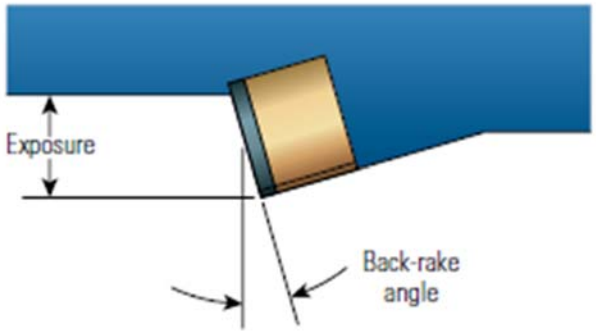
Ex.1010 (67).

72. Practically, a cutting face has some siderake if it is not precisely aligned in the radial direction of the end face of the drill bit. Ex.1045 (2:1-5). Sideraking also allows cuttings to slide off the cutter more easily and also "help[s] direct the cuttings toward the annulus," both of which assist with cleaning away the cuttings and improving ROP. Ex.1014 (9); see also *Id.* (Figs. 66, 67); Ex.1011 (11); Ex.1016

(3); Ex.1050 (3-4). As with backrake, varying siderake between cutters, including backup cutters, was well known. Ex.1043 (11:9-17). "Increasing the siderake on the outer cutters also puts more of the diamond table into compression," which reduces bit whirl because outer cutters with "zero siderake experience high contact stresses on the leading edge making them more prone to chipping." Ex.1026 (8). Engineers also knew that sideraking at least the outermost backup cutter would ensure that, during manufacture, the milling tool did not interfere with the side of the bit mold when milling a pocket into a bit blade. Ex.1043 (11:1-12). Varying both siderake and backrake angles could enhance efficiency and reduce cutter wear. Ex.1069 (13:63-14:12).

3. Cutter Exposure

73. Cutter exposure relates to the amount of exposure of the PDC cutter either in relation to the bit face or a wear element/bearing segment that limits the depth a PDC cutter can engage the formation. Amount of exposure of the PDC cutter in relation to the bit face, and is illustrated below:



Ex.1019 (11); *see also* Ex.1016 (4); Ex.1028 (2).

74. Cutter exposure allows cuttings to be generated without interference from the bit body. Ex.1051 (2). Partial exposure "provides additional mechanical backing to the PDC cutter for increased resistance to impact loads" and allows high fluid velocity to sweep away the cuttings and cool the PDC. Ex.1016 (4); Ex.1050 (2); Ex.1051 (2); Ex.1014 (10). This is important for PDC cutters, which create more cuttings than conventional bits and are high-temperature sensitive. Ex.1016 (4). Increasing cutter exposure allows for better chip generation and keeps the cuttings away from the formation. *Id.*; Ex.1028 (2). Engineers knowledgeable about bit design and manufacture were also aware that exposure was particularly important for secondary cutters, as "[l]imited exposure of secondary cutters invites cuttings build up in front of the secondary cutters." Ex.1037 (3). In addition, siderake can be used to offset the cleaning challenges from increased exposure. Ex.1051 (2).

D. PDC Bit Design Programs

75. Since at least the mid-1980s, PDC bits have been typically designed with CAD programs in conjunction with a version of the 3D PDC cutter model developed by Sandia National Laboratories in 1986. Typically, the bit profile, number and shape of blades, nozzle location, open face volume and junk slots are chosen for the application. Then, the cutter size, count and profile of a blade is laid out. The figure below shows the cutter placement in a CAD program where the

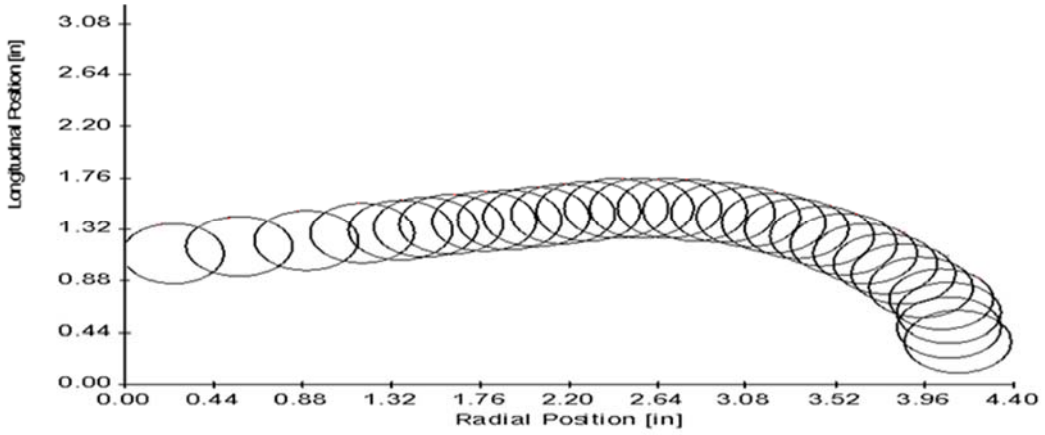
cutters are placed on the profile each with a set backrake and siderake. This is done to ensure proper placement is available and used to evaluate the cutter profile.

Ex.1015 (slide 48).

76. Next, an engineer lays out the cutter profile for one 360 degree rotation of the bit into one plane. A plot of the cutter profile from the center of the bit to the gauge in then displayed. This is done to make sure the cutter profile is uniformed and that no cutters are out of place in the profile. The cutter density typically increases towards the gage of the bit as can be seen in the figure below.[2] In the

[2] Throughout this section, I have included plots made in 2011. Each of these plots was made with models and software that I, with others, first developed in 1996, which was based on Sandia research from 1986.

profile seen in the figure, the outer most cutter is exposed beyond the profile and this is because it will be ground to match and then protect the gauge.

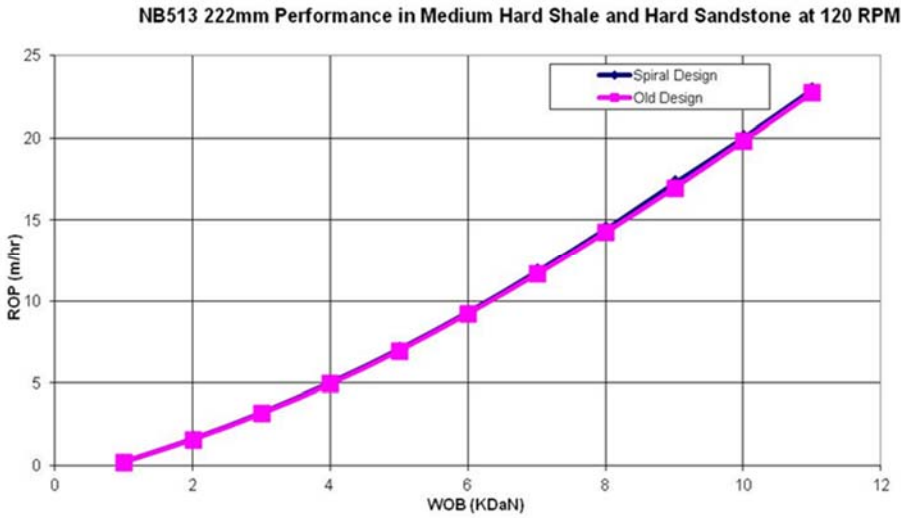


Ex.1015 (slide 48).

77. Once the profile is accepted the cutter layout is force balanced using a 3D force model, such as the one developed in the mid-1980s by Glowka at Sandia National Laboratories. The model is set with a depth of cut and the required WOB is calculated from the sum of all the forces on all the different cutters. Each cutter has a force component in a 3-D Cartesian system and the forces from all the individual cutters is summed in the x, y and z direction giving two lateral and the one axial force on the bit. Combining the two lateral forces (X and Y direction) gives the total lateral force and direction in the lateral plane. The combined forces in the vertical (Z-direction) is the WOB.

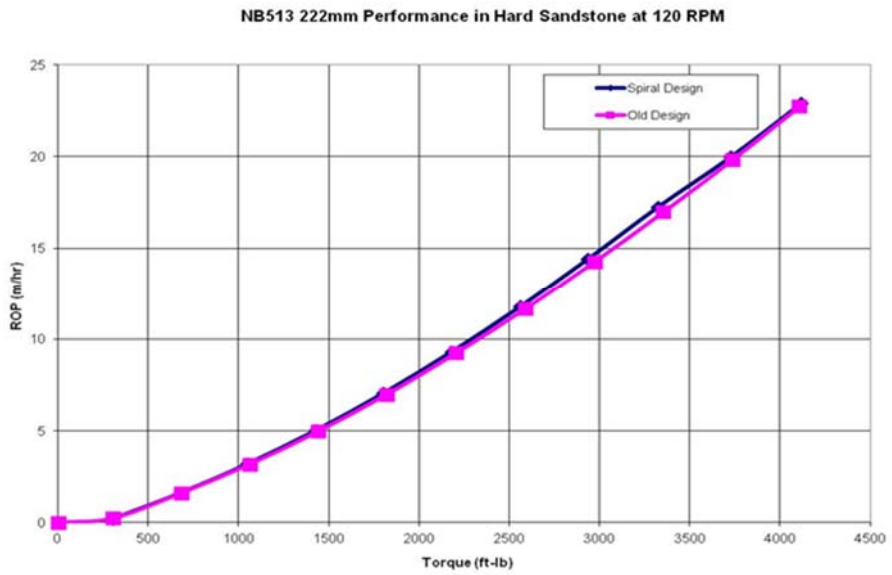
78. Below is a typical WOB versus ROP plot from the shown design where two different designs with different degrees of spiraling of the blades were

evaluated. As can be seen there is little effect going from an older spiral design to a more spiraled design evaluating the effect of WOB on ROP.



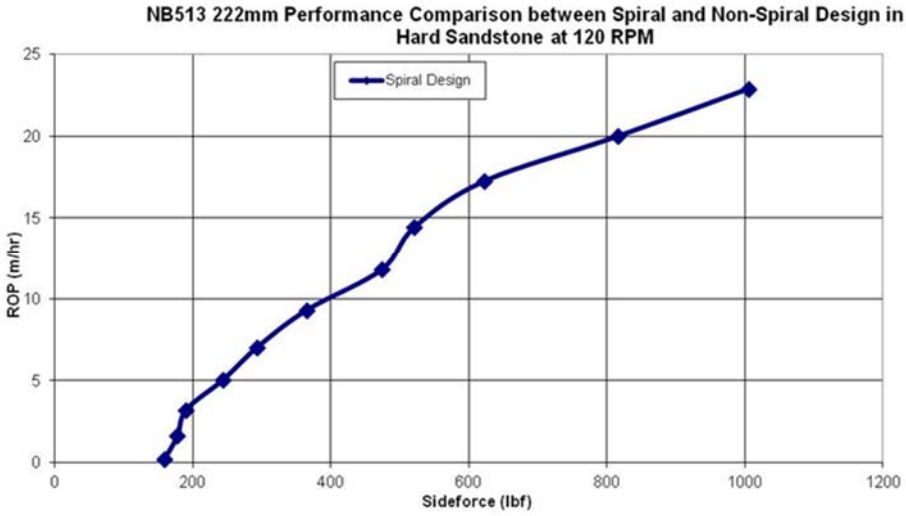
Ex.1015 (slide 49).

79. The same type of analysis can be done for the relationship between ROP and bit torque and for these two bit designs (one a straight bladed (old design) versus a spiral bladed design) the torque response to different ROPs is identical.



Ex.1015 (slide 49).

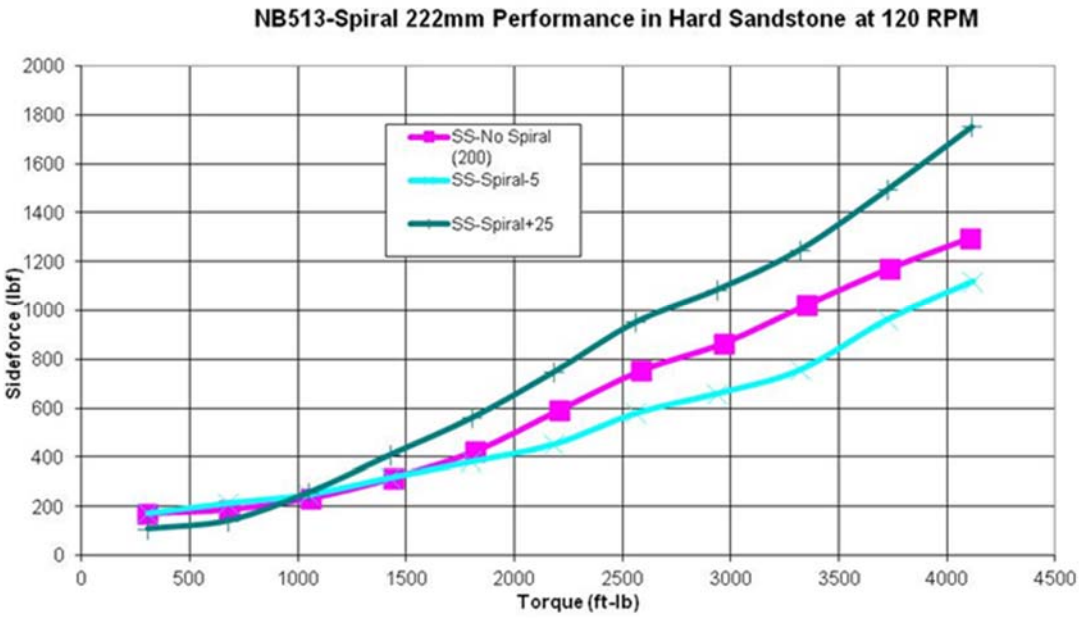
80. An example application of the analysis is evaluating the side force of the bit for a given design. The lateral side force for a spiral blade profile design is illustrated in the figure below. The force balance of the bit shows that for given ROP the side force is a specific value (or has a specific percentage of the WOB applied). This percentage number is then further used in designing the steerability for different types of formations that has a set compressive strength.



Ex.1015 (slide 49).

81. As a separate analysis a bit with no blade spiraling can be compared to a bit with spiraling blades. To control the relationship between sideforce and bit torque, one blade on the spiral five bladed bit was rotated five degrees forward (-5), the side force and torque were measured, and then the same blade was rotated 25 degrees backwards, and again the side force and torque were measured. The below figure shows the results of side force versus bit torque for the three different designs.

This type of analysis can determine the effect of blade design and placement to obtain the best bit for the application.

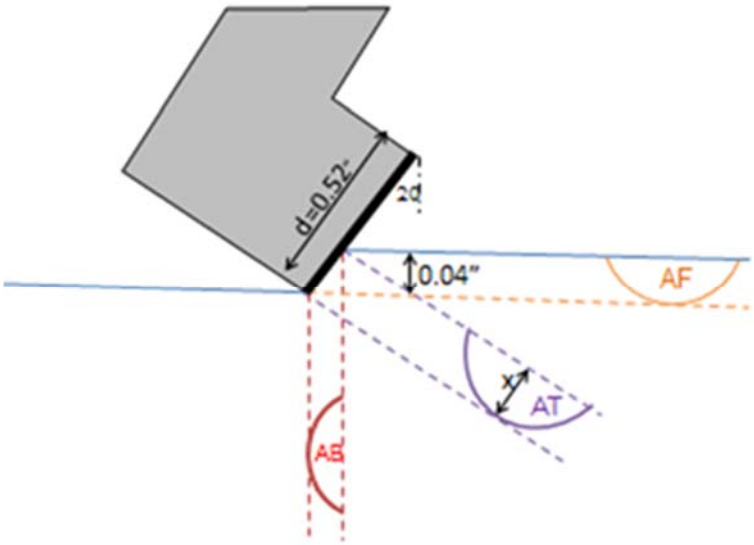


Ex.1015 (slide 49).

E. Depth of Cut (DOC) and Weight on Bit (WOB) for a PDC Bit

82. The depth of cut of a new PDC drill bit is related to the weight on the bit (WOB). This is linked to how far a new PDC cutter can penetrate a rock at a given rock compressive strength, cutter dimensions and the backrake angle of the cutter for a given vertical load. When the PDC cutter penetrates the rock there is a contact area between the cutter and the rock. An example of a PDC cutter penetration a rock is shown below. In this example, the cutter has a diameter of 0.52", a backrake angle of 20 degrees, and a siderake angle of 0 degrees. The depth of cut is 0.04" and the projected total cutter face area in contact with the rock is then

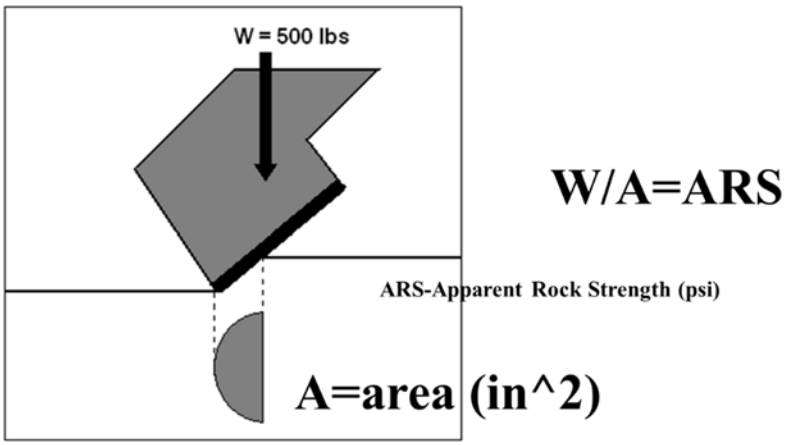
given by AT. The projected downward area is AB and the project area in from of the cutter is AF.



Ex.1015 (slide 68).

83. The force necessary to overcome the compressive strength of the formation is the force on the cutter/contact area that is equal to the compressive strength of the rock.

84. As illustrated below, if we now apply a vertical load of 500 lbs.-force to the cutter and assume the apparent rock compressive strength (ARS) is 10,000 psi the vertically projected area A can be calculated.



Ex.1015 (slide 63).

By performing a single cutter vertical force balance the contact area is equal to:

$$\frac{W}{A} = ARS$$

or

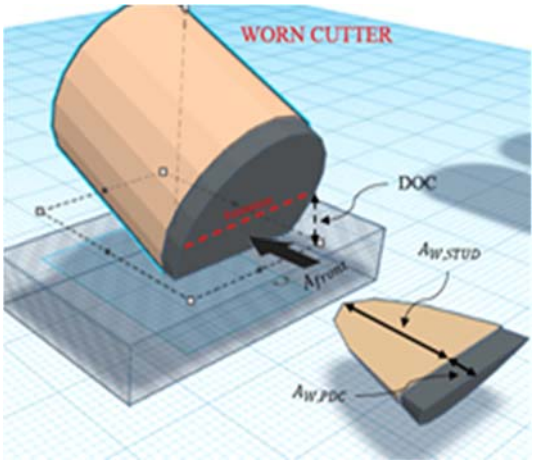
$$A = \frac{W}{ARS}$$

The projected cutter area in the example then is calculated as:

$$\frac{500\ lbsforce}{10{,}000\ psi} = 0.05in^2$$

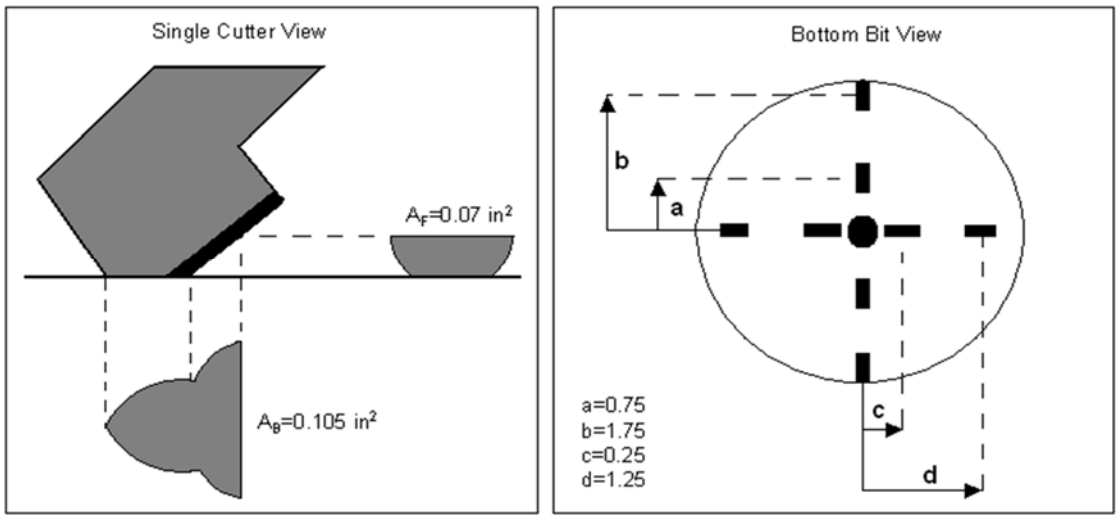
85. From this the area the calculated DOC can be calculated through the geometric calculation of the segment and backrake angle of the cutter. This correlation also dictates that if the rock compressive strength was higher (harder) the projected area would be smaller and so would the DOC.

86. As cutter wears the projected area now introduces a wearflat seen in the figure below, which is also projected in AB, the vertical direction and it is therefore requiring a larger WOB to obtain the same DOC.



Ex.1033 (slide 25).

87. To give a simple virtual example of how this concept is used, consider a small bit with 8 equally worn PDC cutters, with the same depth of cut, as an example. Each of the worn cutters and its projected areas for the depth of cut are shown below on the left and the top view of the bit with the 8 cutters is shown with their radial distance from the center of the bit on the right in the figure below.



Ex.1015 (slide 64).

88. If we assume the apparent rock compressive strength is 10,000 psi, we next can predict the WOB assuming all cutters are equally loaded with the same weight on each cutter. The total area projection in the vertical direction is then used in conjunction with the WOB which is in the vertical direction. The equation then becomes:

$$ARS=WOB/Total\ AB\ Area$$

or

$$WOB=ARS*Total\ AB\ Area= ARS*AB*8$$

$$WOB=10{,}000psi*0.105in^2*8=8{,}400\ lbs\text{-}force$$

89. The bit torque can be calculated in the same manner now using the area in front of the cutter since the forces generating the torque are perpendicular to the vertical direction (assuming no friction between the cutter wearflat and the formation). The force in front of each cutter, Wf is then equal to:

$$Wf=AF*ARS.$$

$$Wf=0.07in^2*10{,}000psi=700 \text{ lbs-force}$$

90. By multiplying the force on each cutter to the distance to the center of the bit gives the bit torque.

$$Torque= Wf *[(0.25”+1.25”)*2+(0.75”+1.75”)*2] =465 \text{ lbs-force*ft}$$

91. This is the same concept used in modeling DOC and ROP or WOB for different new PDC designs using the 3D modeling across the entire bit face as developed by Sandia in the mid-1980s. By integrating the cutter geometry and depth of cut the forces on a bit can be determined by adding all the individual cutter forces into the cumulative forces in the lateral direction (side force) or in the vertical direction (WOB). These concepts and principles are today used in analyzing cutter profiles, side forces, cumulative bit forces, and aggressiveness of a PDC drill bit. This concept was used in designing drill bits at least by the early 1990s. By adjusting profiles, cutter sizes, cutter side and backrake angles the forces will change. This is key to designing the correct bit for a given application.

F. PDC Bit Simulation and Optimization

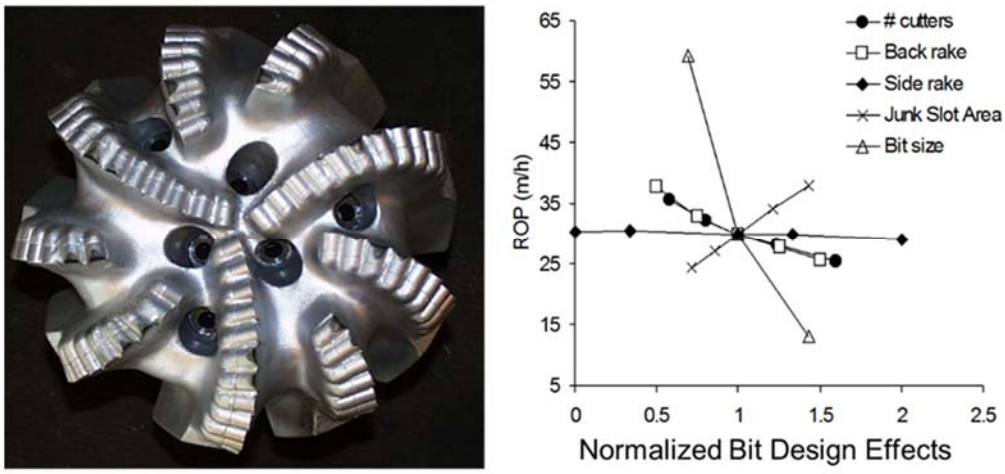
92. Drill bit ROP models have been developed since the 1980s (Ex.1052 (1); Ex.1053 (1); Ex.1054 (1); Ex.1055(4)), and these models are based on rock-bit interactions and variations of rock strength. In 1986, Sandia developed the first 3D PDC model based on single rock-cutter interaction, which was verified with PDC force modeling with single cutter testing in laboratory experiments. Amoco utilized

Sandia's model soon thereafter, and used a different single cutter DOC calculation correlating the contact area of the cutters to a dimensionless strength value, which could be correlated to a compressive strength.

93. In 1989, I proposed a modified version of the 3D model using an equivalent work concept to simplify the model to 2D. A study by Soares et al. (2016) compared different ROP models, and concluded that this modified 2D model had the best accuracy and the greatest capability among the available PDC ROP models. Ex.1056 (9). One of the objectives of my 2D model was to be able to calculate the confined compressive strength (CCS) by inverting the model. Then from the CCS the unconfined compressive strength (UCS) could be calculated, which is a rock material property. This 2D model was further modified and integrated with additional modeling to account for more detailed cutter designs and back up cutters, bit hydraulics and bit wear. The model was verified with laboratory and field data where rock strength was defined as CCS, which was confined (overbalanced) by the difference between drilling-fluid hydrostatic pressure and pore pressure. By developing and utilizing correlations relating to the effect of overbalance on permeable and impermeable rock, UCS could be calculated. Bratli et al. (1997) used this PDC model to predict UCS in the North Sea where they matched core test data to the UCS values. Ex.1057 (2). Andrews et al. (2007) successfully compared UCS determined using my model to that calculated from sonic data. Ex.1058 (3).

94. The ROP PDC modeling I developed includes all the parameters that influence ROP, such as operational drilling parameters (e.g. WOB, RPM, flow rate, mudweight and mud type), bit designs and wear and the rock formation properties. As a sample application of this model each parameter is changed separately at a percentage from the initial parameter value to see the effect it will have on the ROP.

95. This is illustrated below for a new PDC bit and the different sensitivities of some of the bit design features on ROP are evaluated for a given set of operating parameters.



Ex.1059 (slide 11).

96. The ROP models I developed for specific bit types can be used to simulate any bit design with a given wear status, and if the bit wear was known when the bit was pulled, to iteratively determine the UCS profile for an offset (previously drilled) bit run or hole section.

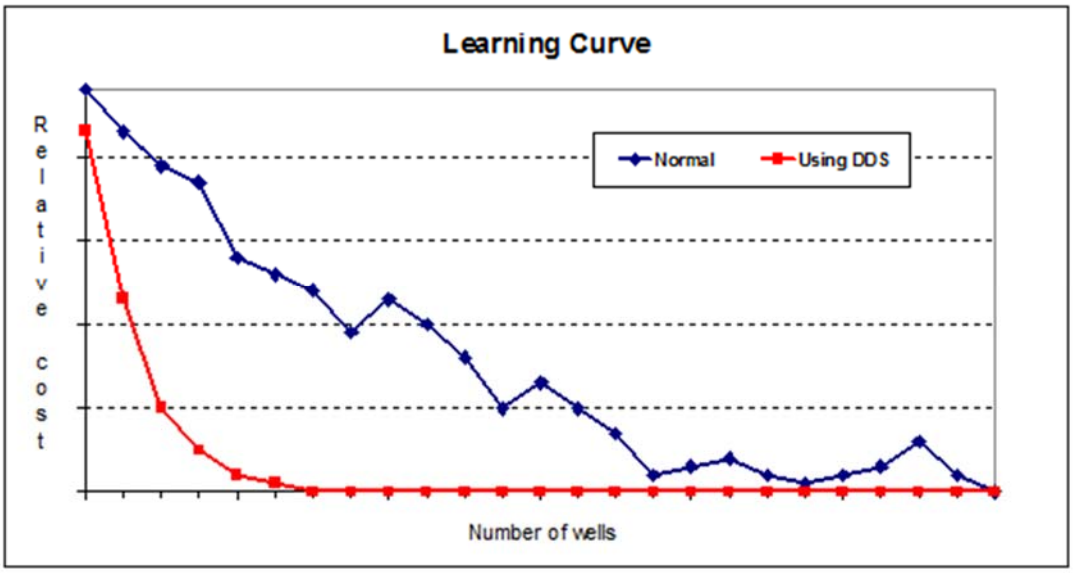
97. For a previously drilled well, all the required information is recorded and available to calculate the rock strength. The data from a previous drilled well is used to generate a rock strength by the inversion of the "bit specific" ROP models. The effects of operating parameters, bit design and wear, drill hydraulics, mud rheology and pore pressure are modeled. The inverted ROP model provides then a calibrated measure of the rock's strength under actual drilling conditions and simultaneously determines the wear characteristics of the bits used in drilling the relevant sections. This wear character is an evaluation of the bits performance while drilling various formation types and under a variety of operating conditions and includes, detailed bit geometry and its resistance to wear.

G. The DROPS Simulator

98. In 1993 and 1994, I developed the DRilling OPtimization Simulator (DROPS). The purpose of the DROPS simulator was to reduce the cost of future wells based on an apparent rock strength log (ARSL) created from the drilling data collected on a previous well drilled in the same area. An ARSL is created using ROP models inverted to calculate rock compressive strength. The simulator has the capability of simulating any combination of operating conditions, bit designs, pull depths, hydraulics, WOB and RPM, using the ARSL as an input. The basic idea behind DROPS is to simulate the drilling operation prior to the actual drilling, and to find the optimum cost level.

99. By simulating different combinations of drill bits operating parameters and bit pull depth the operator can try different drilling options in advance and by that accelerate the knowledge and learning instead of having to try the different options in the field which would be more expensive. The idea behind applying the DROPS simulator is to learn before the fact and thereby reduce the cost on upcoming wells.

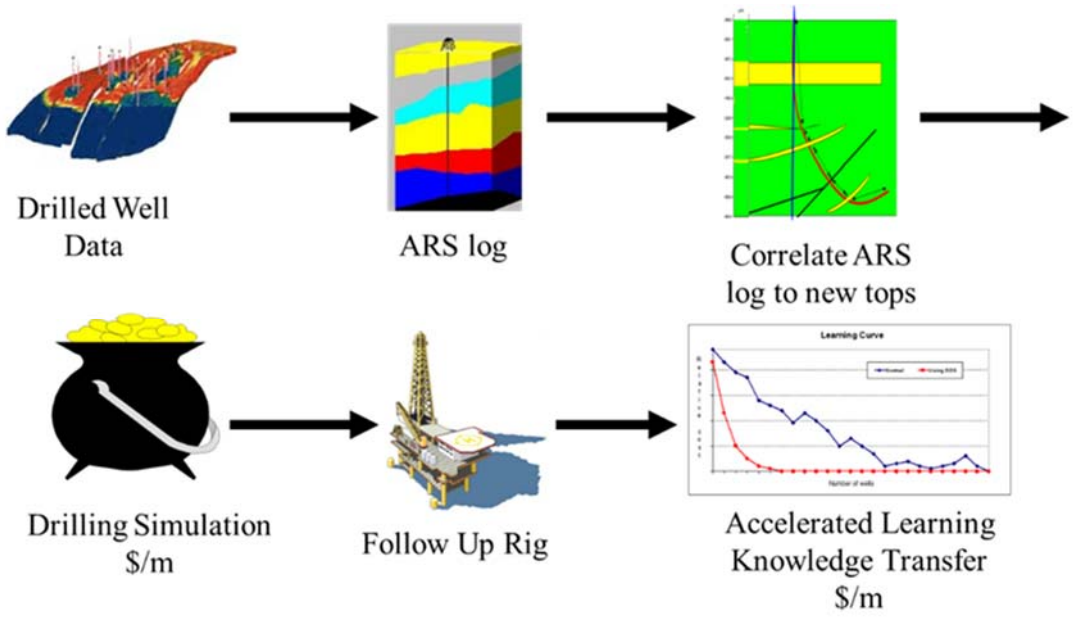
100. A typical drilling learning curve (well cost or cost/foot versus number of wells drilled in sequence) for a field or an area is shown in blue in the figure below and by applying the simulator the curve in red is obtained. The area between the two curves is the actual cost savings to the operator.



Ex.1059 (slide 4).

101. The pre-simulated ROPs compares well with the results for actual measured ROP and cumulative rotating time, which proves the accuracy of the

method. Based on the application of pre-determined optimum drilling conditions cost optimizations for future wells in this region is performed. The cost reductions obtained indicate significant potential cost savings of total drilling cost per well, compared to the current industry practice in the area. By using this methodology in the planning process the most cost effective drilling program can be obtained.



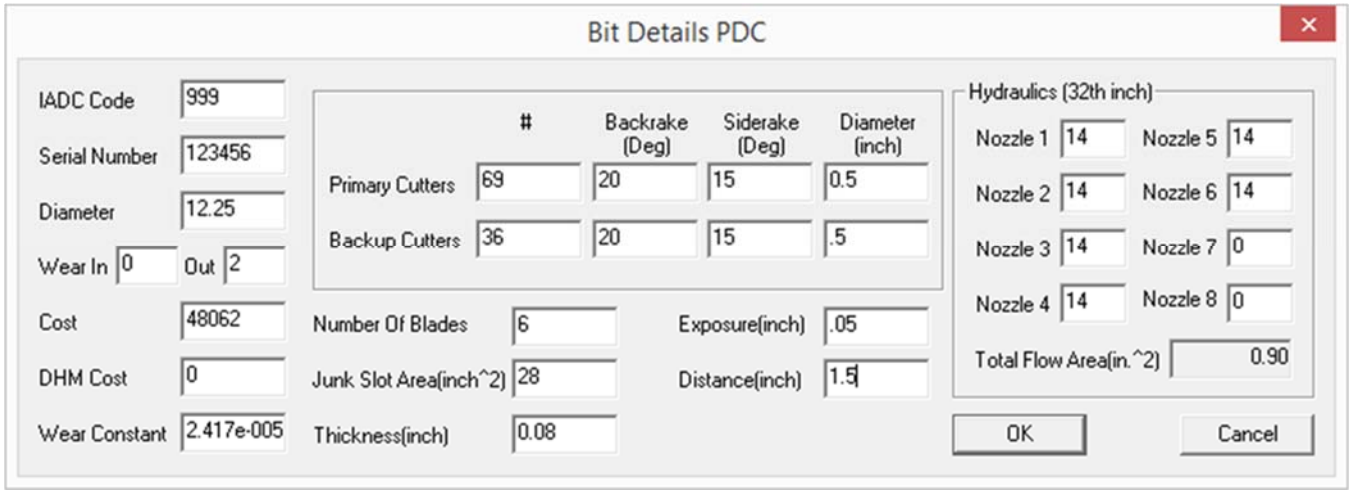
Ex.1059 (slide 13).

102. Use of the DROPs simulator since at least as early as 1995 in a variety of different locations and with numerous drilling operators has shown that the simulator can accurately predict the penetration rates on upcoming wells. Ex.1058 (1).

103. The ROP models in the DROPS drilling simulator were developed for different drill bit types and designs. Input parameters used to predict ROP for a bit

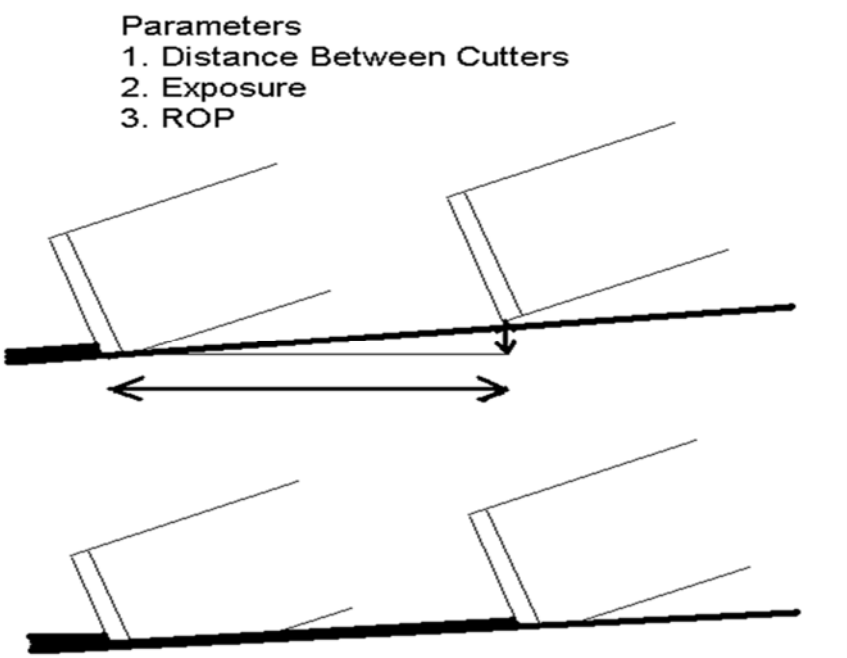
are operational parameters (WOB, RPM, Mud and Nozzles/Hydraulics), rock properties (Rock Strength, Pore Pressure and Abrasiveness), and detailed bit design.

104. A set of required PDC design input parameters for a specific bit is shown in the figure below, which shows the input parameters available in the simulator version used in 2001. The simulator allowed modeling of primary and backup cutters from at least as early as 1997.



Ex.1060 (slide 32).

105. The detailed information on the exposure and distance of the backup cutters is to accurately determine when they are in contact with the formation and to integrate the effect of wear on the backup cutters as seen in the figure below:



Ex.1060 (slide 31).

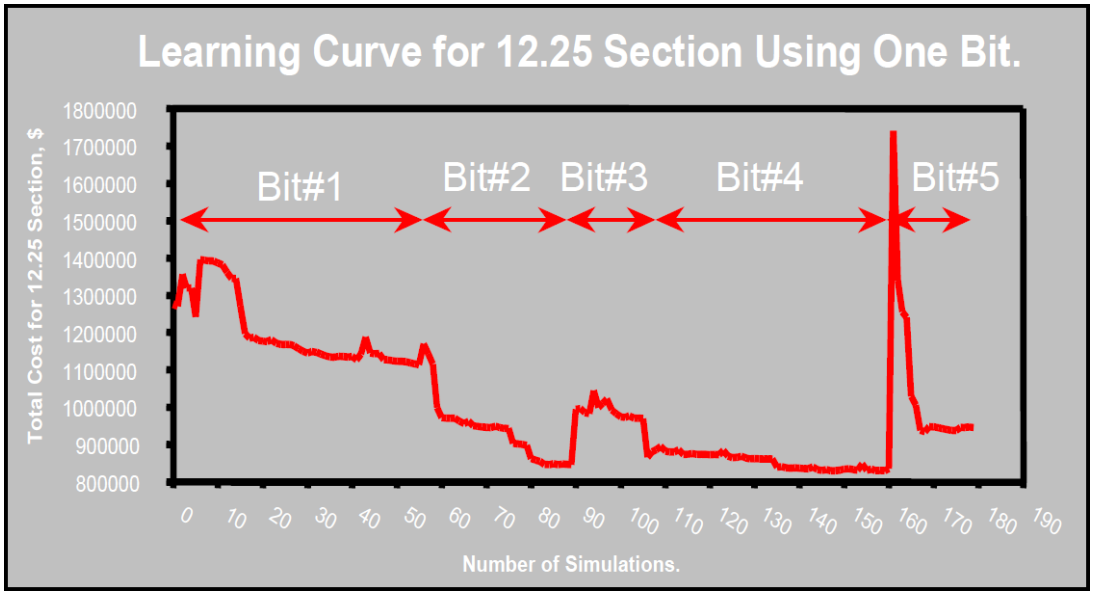
106. Multiple drill bits, combinations of different pull depths and sets of operating parameters are simulated within the possible limitations of the rig including the pump and rotary in conjunction with the down hole motor - if used. The simulator has the capability of running multiple WOB and RPM combinations in conjunction with different depths and optimize the individual bit runs for the lowest cost/foot. As an integral part of the optimization process, multiple scenario evaluations are conducted. These include variations in:

- WOB/RPM combinations.
- Changes in operating parameters as a function of ARSL variations
- BHA configurations
- Bit Hydraulics

- Bit types, impregnated, NDB, PDC, and Rollercone

107. This approach ensures that an optimal solution is obtained. These multiple scenario evaluations are conducted for separate bit runs and/or entire hole sections.

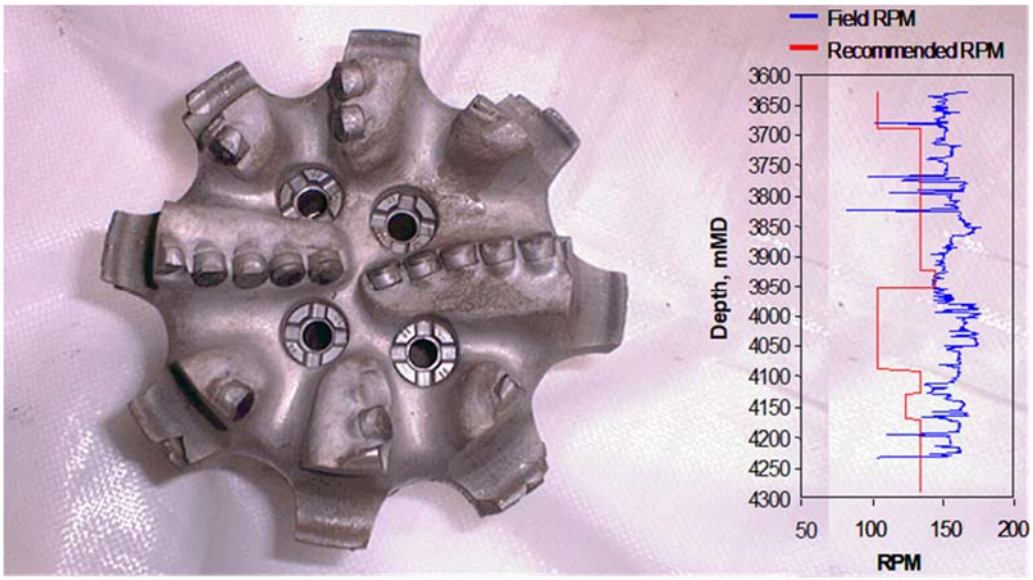
108. A simulator summary from a simulator study published in 1998 for one bit run in one hole section in a North Sea well is shown in the figure below.



Ex.1059 (slide 18); Ex.1061 (6).

109. The figure shows that 5 different bit design were simulated and a total of 180 simulations run. Based on being able to optimize the individual 5 different bit in terms of the operating parameters that gave the lowest cost the results indicate that bit number 4 obtained the lowest cost to drill the section.

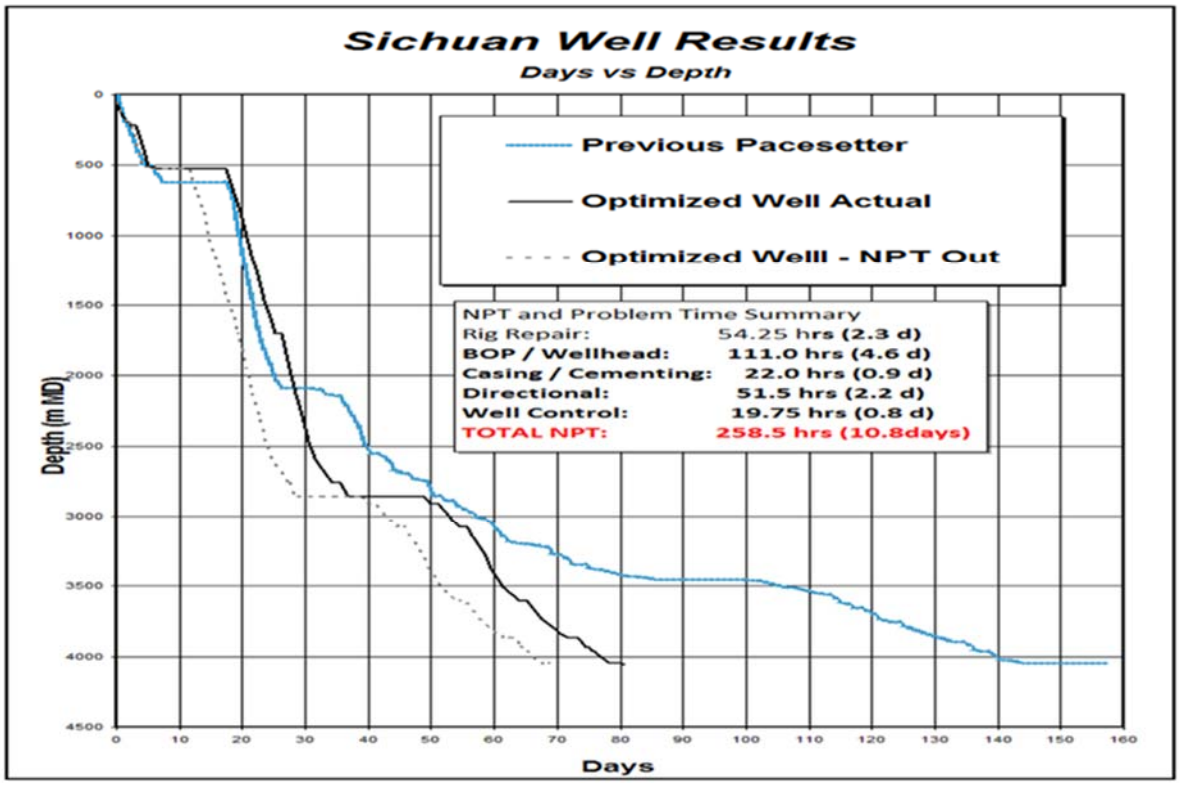
110. The next figure shows one of the first trials using the DROPS simulator for a drilling operator around 1998. It was determined that if the RPM guidelines had been followed the bit would not have had a ring out as seen from the picture.



Ex.1059 (slide 21).

111. The bit had a ring out less than 40 meters before total depth and the bit had to be tripped and an additional bit used to drill to total depth (TD). The DROPS simulator had indicated that the bit should have made it if the driller had been patient and held back on the RPM. The driller initially indicated that he could drill faster than the simulator and did therefore increase the RPM to above the recommended. This was one of first field applications where the value of the DROPS simulator proved it value in the North Sea. The additional trip and bit cost the operator more than $600,000.

112. Finally, a comprehensive post analysis of the operation is conducted to identify deviation from the predictions and possible reasons for the outcome. This is undertaken in an effort to further improve performance in subsequent wells to be drilled in the field or area. A sample illustration of a post analysis shows the benefits of applying the DROPS simulator in an area in China is seen in the figure below.



Ex.1059 (slide 27).

113. The previous best performer in the area drilled the well in 144 days while using the simulator and following the parameters resulted in finishing the well to the same depth in approximately 80 day whereof this included 10 days of waiting for casing which means the drilling of the well took approximately 70 days.

114. To be able to simulate the different vendor's proposal detailed description of the individual bit design were needed and supplied. This included especially for PDC bits cutter sizes, cutter properties, back and siderakes for both primary and backup cutters as well cutter placement and cutter exposure. Based on analysis of the offset wells a specific wear coefficient could be determined for the different manufacturers' specific PDC cutters. These wear coefficients were then collected for different cutter types and version of new cutter developments, manufacturing and treatment processes as new more wear resistant cutters were developed.

V. OVERVIEW OF THE '441 PATENT

115. The '441 patent is issued from U.S. Patent Application No. 10/861,129, which was filed on June 4, 2004. Ex.1003 (cover). It is my understanding, that the '441 patent's earliest possible priority date is December 15, 2000 due to its status as a continuation.

116. The '441 patent generally relates to "rotary drag bits for drilling subterranean formations and their operation." Ex.1003 (1:17-19). The '441 patent specifically relates to "the design of such bits for optimum performance in the context of controlling cutter loading and depth-of-cut without generating an excessive amount of torque-on-bit should the weight-on-bit be increased to a level

which exceeds the optimal weight-on-bit for the current rate-of-penetration of the bit." *Id.* (1:19-25).

A. Alleged Problem in the Art

117. The '441 patent lists a number of issues with drilling in subterranean formations, such as "overloading," "drilling from a zone or stratum of higher formation compressive strength to a softer zone of lower strength," and "bit balling." Ex.1003 (1:38-41, 1:55-58, 1:65-67). Overloading refers to the amount of weight on the drill bit ("WOB"), which can be too high and cause damage to the bit. *Id.* (1:45-49). Additionally, even at low WOB, the bit can be overloaded because of high torque. *Id.* (1:49-52). When a drill bit goes from a stratum of higher compressive strength to lower compressive strength the drill is subjected almost instantaneously to a higher torque. *Id.* (1:67-2:5). This higher torque can cause damage to the cutters or the bit body itself. *Id.* (2:5-7). Bit balling is the tendency of the earth to stick to the drill, usually due to poor hydraulics. Ex.1016 (4). If bit balling occurs, eventually, the cutters become completely covered with the earth and further drilling does not happen. *Id.* (5).

118. After listing the known problems in the art, the '441 patent acknowledges that "[n]umerous attempts using var[ying] approaches have been made over the years to protect the integrity of diamond cutters and their mounting structures and to limit cutter penetration into a formation being drilled." Ex.1003

(2:23-26). Those "var[ying] approaches" in the prior art have included "the use of trailing, round natural diamonds on the bit body to limit the penetration of cubic diamonds employed to cut a formation," "use of a variety of structures immediately trailing PDC cutters … to protect the cutters or their mounting structures," and "structures or features on the bit body rotationally preceding (rather than trailing) PDC cutters." *Id.* (2:23-46). The '441 patent criticizes these known prior-art approaches as being "somewhat generalized in nature" and "fail[ing] to accommodate or implement an engineered approach to achieving a target ROP in combination with more stable, predictable bit performance." *Id.* (2:56-62).

B. Alleged Invention of the '441 Patent

119. The '441 patent purports to improve on the prior art, not by adding additional or novel features to the bit, but rather, "by providing a well-reasoned, easily implementable bit design particularly suitable for PDC cutter-bearing drag bits, which bit design may be tailored to specific formation compressive strengths or strength ranges to provide DOC control in terms of both maximum DOC and limitation of DOC variability." Ex.1003 (3:7-12). The '441 patent employs "depth of cut control (DOCC) features" that control how deeply the PDC cutters penetrate the formation. *Id.* (3:16-20). The '441 patent indicates the simple relationship between surface area and weight on bit. By having a sufficient surface area "to support a given WOB on a given rock formation, preferably without substantial

indentation or failure of [the] same, WOB may be dramatically increased, if desired, over that usable in drilling with conventional bits without the PDC cutters experiencing any additional effective WOB after the DOCC features are in full contact with the formation," due to the extra weight being supported by the DOCC features. *Id.* (4:54-61).

120. Figure 14A represents an embodiment of the invention:

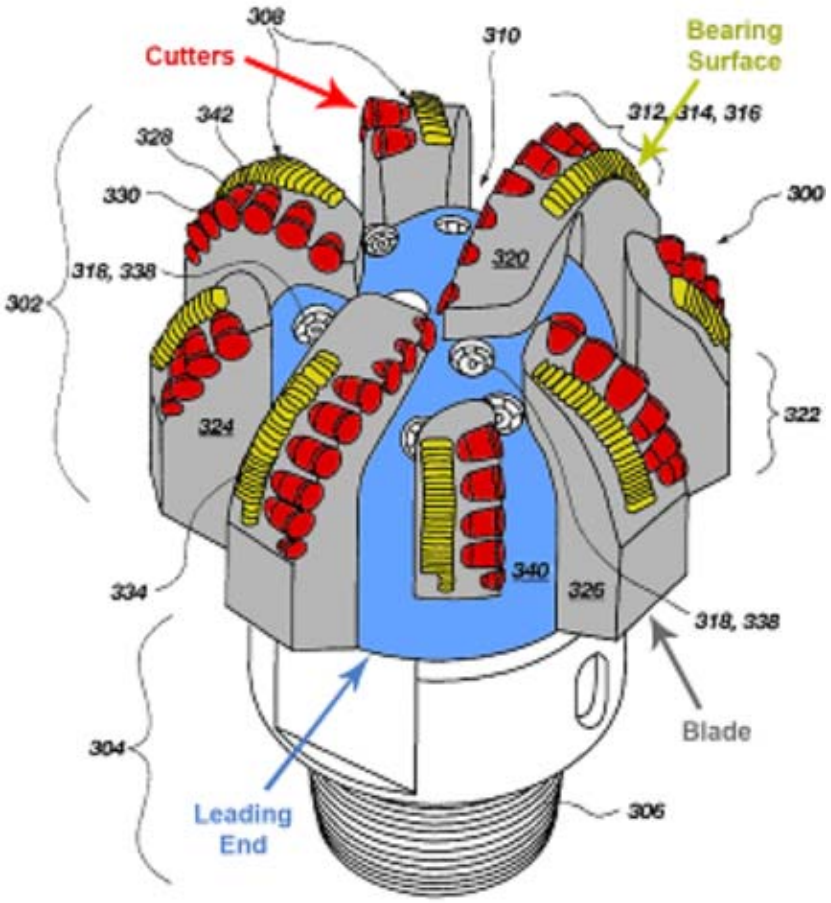


Fig. 14A

121. With respect to Figure 14A, the '441 patent discloses "a bit body 301 having a leading end 302 and a trailing end 304," wherein the "[l]eading end 302 or

drill bit face includes a plurality of blade structures 308 generally extending radially outwardly and longitudinally toward trailing end 304." Ex.1003 (19:36-46). The drill bit 300, "includes a cone region 310, a nose region 312, a flank region 314, a shoulder region 316, and a gage region 322." *Id.* (19:65-67). "A plurality of cutting elements, [or] cutters 328, [is] preferably disposed along and partially within blade structures 308." *Id.* (20:23-25). Additionally, "[o]ptional wear knots, wear clouds, or built-up wear-resistant areas, collectively referred to as wear knots 334 herein, may be disposed upon, or otherwise provided on bearing surfaces 320 [of] blade structures 308." *Id.* (20:38-44).

122. The '441 patent notes that "by using DOCC features to achieve a ***predictable*** and substantially sustainable DOC in conjunction with a ***known ability*** of a bit's hydraulics to clear formation cuttings from the bit at a given maximum volumetric rate, a sustainable (rather than only peak) maximum ROP may be achieved without the bit balling and with reduced cutter wear and substantial elimination of cutter damage and breakage from excessive DOC, as well as impact-induced damage and breakage." Ex.1003 (14:4-13).

C. Prosecution History

123. It is my understanding that the Examiner did not use any prior art to reject the claims.

VI. LEVEL OF ORDINARY SKILL IN THE ART

124. I understand that there are multiple factors relevant to determining the level of ordinary skill in the pertinent art at the time of the alleged invention. These factors include the education of active workers in the field, the sophistication of the technology, the type of problems encountered in the art, and the prior art solutions to those problems.

125. It is my opinion that a person of ordinary skill in the art on December 15, 2000, in this field would have had the following level of experience: at least a Bachelor's degree in Mechanical Engineering, Civil Engineering, Structural Engineering, or Petroleum Engineering, as well as several years of experience manufacturing or designing drill bits.

126. While I believe this was the level of ordinary skill in this art at the time of the '613 patent, I've also considered patentability from the perspective of a person having ordinary skill in the art as if the person were someone with less work experience but more education, or a different educational background with significant work experience, and my opinions would not change.

VII. CLAIM CONSTRUCTIONS

127. I was told that a claim of an unexpired patent in inter partes review is currently given the "broadest reasonable construction in light of the specification." However, I was also informed that the USPTO might be using a different standard,

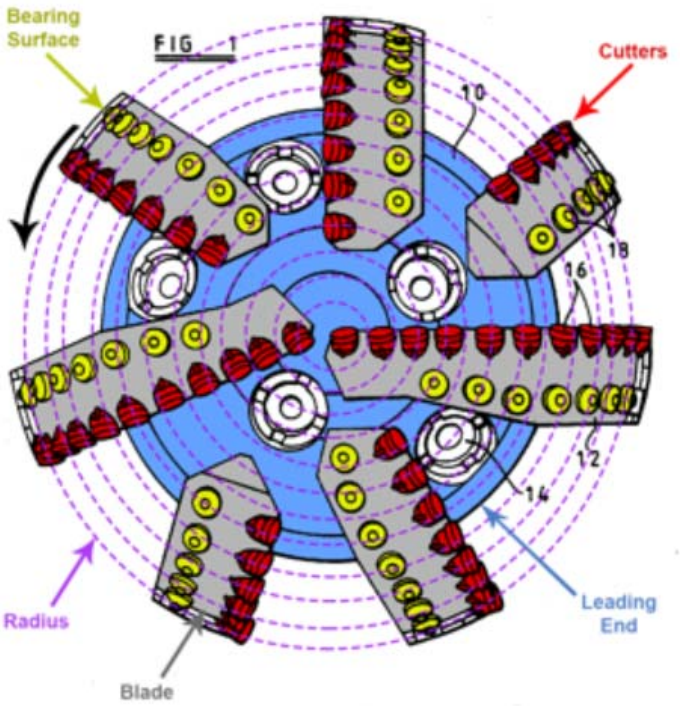
the "Phillips" standard. My understanding is that under the *Phillips* standard claim terms are generally given their "ordinary and customary meaning," which is "the meaning that the term would have to a person of ordinary skill in the art in question at the time of the invention."

VIII. OVERVIEW OF THE PRIMARY PRIOR ART

A. U.S. Patent No. 5,244,039 to Newton

128. Newton teaches rotary drill bits for use in subsurface formations. Ex.1005 (1:5-14). Newton's drill bits have a bit body, a shank for connecting the bit body to a drill string, a plurality of cutting-elements mounted on the bit body, and a passage in the bit body for supplying drill fluid to the surface of the bit body. *Id.* Newton teaches at least some of the cutting elements having a superhard face. *Id.* Newton teaches "primary cutting elements" and "secondary abrasion elements which are set slightly below (or inwardly of) the primary cutting profile." *Id.* (1:30-35). Newton teaches "[b]y adjusting the distance by which each secondary element is spaced from the primary cutting profile … it is possible to ensure that secondary elements on different parts of the bit body come into operation at substantially the same time regardless of their location o[n] the bit … even though their respective cutting elements may be subjected to different rates of wear." *Id.* (2:67-3:6). Figure

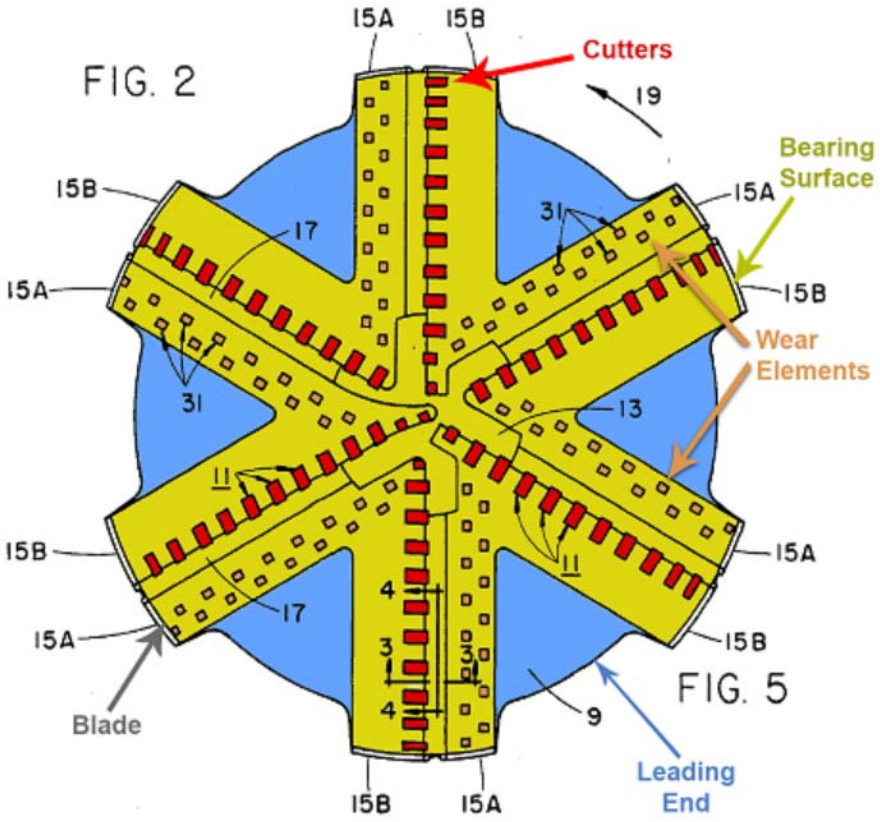
1, below, is a "perspective view of the end face of a rotary drill bit including primary cutting elements and secondary abrasion elements." *Id.* (3:66-68).



129. The rotary bit above has a leading end face 10 formed with a plurality of blades 12, nozzles 14, cutting elements 16, and abrasion elements 18. Ex.1005 (4:13-21).

B. U.S. Patent No. 4,554,986 to Jones

130. Jones is directed to "[a] rotary drill bit comprising a bit body having a plurality of drag cutting elements mounted on the bottom thereof." Ex.1006 (abstract). Jones discloses the "drag cutting elements 11 are embedded in the trailing ridge 15B of each of the sets of ridges in side-by-side spaced apart relation," and "relatively hard wear elements 31." *Id.* (4:50-52, 5:39-41).



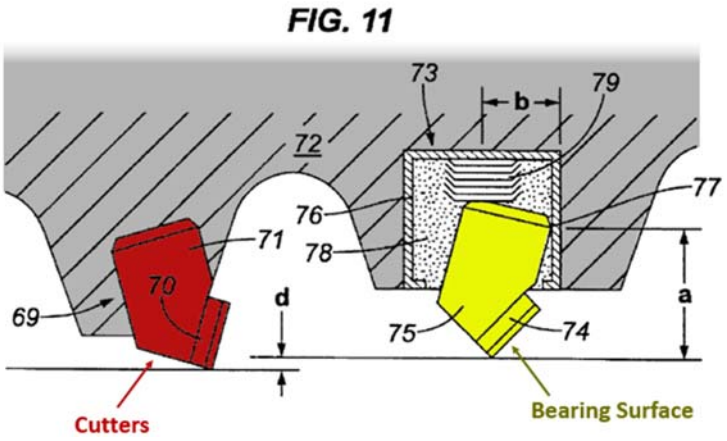
131. Jones discloses "the leading ridge extends down to a level below the bottom of the trailing ridge but above the cutting edges for limiting the depth of penetration of the cutting element." Ex.1006 (abstract). Specifically, "[u]pon the application of a weight on the bit 1 less than a predetermined weight, the cutting elements 11 will penetrate the formation to a depth dependent on the amount of the weight." *Id.* (5:22-25).

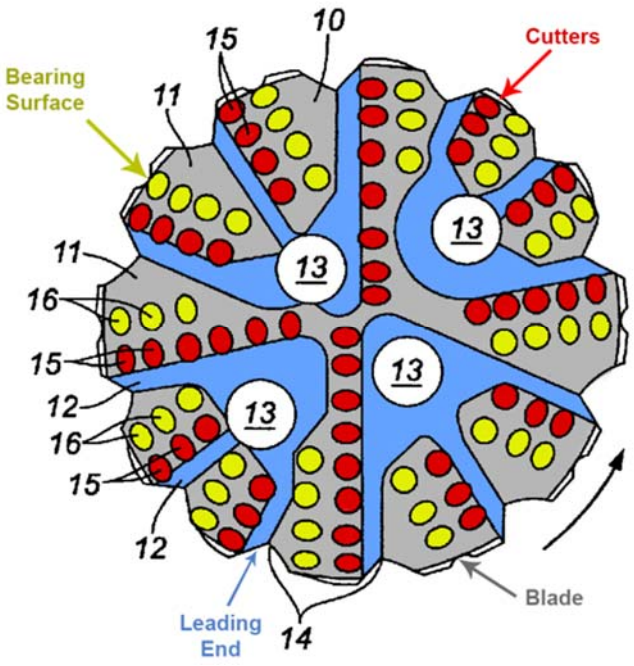
C. U.S. Patent No. 6,142,250 to Griffin

132. Griffin is directed to "formation engaging elements" that "are moveably mounted onto a drill bit." Ex.1007 (abstract). Griffin teaches a method that includes: "(a) providing a drill bit having a bit body, a plurality of cutting

elements disposed on the bit body, and at least one active formation-engaging element disposed on the bit body, the at least one active formation-engaging element being moveable between an extended position and a retracted position; (b) providing a drill string; (c) coupling the drill bit to the drill string; (d) moving the at least one active formation-engaging element into the extended position during steering of the drill bit; and (e) moving the at least one active formation-engaging element into the retracted position during straight drilling." *Id.* (2:30-43).

133. A representative embodiment of Griffin is Figure 11:





134. "[T]he cutting structure 69 is the primary structure for removing formation from the borehole." Ex.1007 (9:1-2). "The subsidiary cutting structure 73, however, acts as a penetration limiter." *Id.* (9:3-4). "The distance 'd' is a predetermined desired depth of cut. If this depth of cut is exceeded, the drag F_d acting on the cutter 74, 75 will increase causing the cutter 74, 75 to tilt rearwardly in its housing." *Id.* (9:4-8). "This force reduces the effective weight-on-bit acting on the primary cutter 69, thus reducing the depth of cut." *Id.* (9:9-11).

IX. SPECIFIC GROUNDS FOR PETITION FOR CLAIMS 16-17, 19-21 AND 23-24

A. Ground I: Claims 16-17, 19-21 and 23-24 are Obvious in View of Newton in View of the Knowledge of a POSA

1. Independent Claim 16

a. "A method of drilling a subterranean formation without generating an excessive amount of torque-on-bit, comprising:"

135. It is my opinion that claim 16 is obvious in view of Newton.

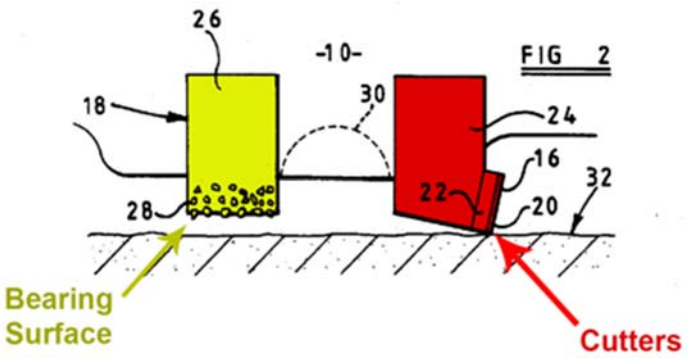
136. It is my understanding, that the preamble to the independent claims of the '441 patent do not limit their scope. Each preamble no more than generally describes the claimed method—"drilling a subterranean formation without generating an excessive amount of torque-on-bit."

137. In any event, Newton discloses a drill bit used in drilling subterranean formations. Ex.1005 (abstract). A person of ordinary skill in the art ("POSA") at the time of the invention would have found it obvious to have used the drill bit to drill a formation, the intended purpose of Newton's bit. Newton's drill bit design, as discussed in more detail below, would prevent an excessive amount of torque-on-bit when used in the field.

b. "engaging the subterranean formation with at least one cutter of a drill bit within a selected depth-of-cut range"

138. Newton teaches a drill bit used in drilling subterranean formations that contains a cutter with a selected depth-of-cut range. As shown in Newton's Fig. 2,

the **cutters** in red will come into contact with the formation at a selected depth-of-cut. The depth of cut will be based on the type of subterranean formation.



c. "applying a weight-on-bit within a range of weight-on-bit in excess of that required for the at least one cutter to penetrate the subterranean formation and above which results in a bearing surface contacting the subterranean formation;"

139. Newton discloses a drill bit used for drilling subterranean formations, and in order to use the drill bit for the purpose of drilling, a POSA would have to apply a weight-on-bit ("WOB") to the drill bit. A WOB is selected and applied based on the formation. As the formation changes during drilling operation, so too does the required WOB. In fact, the '441 patent acknowledges it was known in the art that the WOB necessary to penetrate a formation changes as the drilling progresses from one formation to another: "Another, separate problem involves drilling from a zone or stratum of higher formation compressive strength to a 'softer' zone of lower strength. As the bit drills into the softer formation without changing the applied WOB (or before the WOB can be changed by the directional driller), the penetration of the PDC cutters, and thus the resulting torque on the bit (TOB),

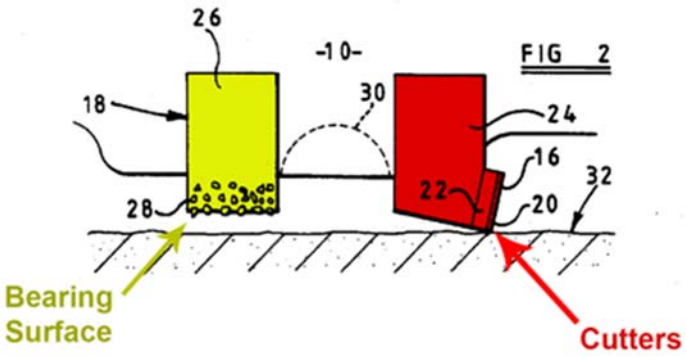
increase almost instantaneously and by a substantial magnitude." Ex.1003 (1:65-2:5).

140. "The Effect of PDC Cutter Density, Back Rake, Size, and Speed on Performance" by Sinor et al. ("SPE 39306") paper also confirms that it was known prior to the '441 patent that the WOB required to penetrate a formation depends on the type of formation. The SPE 39306 paper reports a study on the WOB required to achieve certain rates of penetration in Carthage limestone (a harder) and Catoosa shale (a softer formation) for cutters with specific backrake angles. Ex.1029 (5). At each backrake angle, a bit in the harder limestone formation requires more WOB than a bit in the softer shale formation to achieve the same ROP.

141. The SPE 39306 paper also shows it was known prior to the '441 patent that the WOB required to penetrate a formation increases as the surface area of the bit contacting the formation increases. Ex.1029 (3) ("Figure 3 previously showed the resulting increase in weight requirement as the contact area between the PDC cutter and the rock increases."). The SPE 39306 paper was explaining this relationship in context of the increase in surface area of the cutter contacting the formation as the cutter wears and creates a wearflat. A POSA would readily understand that this principle applies to any bearing surfaces that, in addition to the cutter, contact the formation—like the abrasion elements of Newton.

142. In light of the known fact that formation hardness may vary as a drilling progresses and the teachings of the SPE 39306 paper about the relationship of the required WOB to formation hardness, a POSA would have found it obvious that the normal use of the drill bit of Newton in drilling would result in the drilling operator applying a WOB necessary to penetrate a formation that then becomes an excess WOB as the drill bit progresses to a softer formation.

143. Thus, an excess WOB will be applied when the drill hits a softer formation. As shown in the figure below, the abrasion element (bearing surface) of Newton will eventually contact the subterranean formation as an excess weight on bit is applied.



144. The Newton's secondary abrasive cutting element performs this function and provides depth-of-cut-control. Under a normal mode of operation using the bit disclosed by Newton, a drilling operator would apply a sufficient weight on bit to cause the cutting element 16 to penetrate the formation, so as to cause the drill string to advance into the earth to the expected location. The weight on bit necessary

to penetrate the formation depends on the type of formation, and the harder the formation the more weight that is required. But when Newton's bit, having sufficient weight applied to it to cause it to penetrate one formation, advances into a less-hard formation, the weight on bit will become in excess of the weight on bit required for the cutter to penetrate that new, less-hard formation.

> d. "transferring the excess weight-on-bit from the drill bit through the bearing surface to the subterranean formation without substantial indentation of the bearing surface into the subterranean formation; and"

145. As discussed above, the abrasion elements taught by Newton come into contact with the formation when a WOB in excess of that required to cause the cutting element to penetrate the formation is applied to the drill bit. The excess weight-on-bit is transferred to the abrasion elements when they come into contact with the formation. Thus, the features in Newton, such as the abrasion elements will absorb the excess WOB ensuring that there is no substantial indentation of the bearing surface into the subterranean formation.

146. A POSA would know that, at a given distance from the center of the bit, the force generated by a cutter will be greater than the force generated by the wear surfaces, because for a range of WOB the force required to shear the formation is greater than force of friction against the formation. As a result, a POSA would know that excessive torque on the bit can be prevented by using bearing surfaces to limit the depth of cut.

147. Newton's abrasion elements (bearing surfaces) 18 have a surface area that engages the formation during normal operation of Newton's drill bit when the cutters penetrate the formation, thus providing a bearing area. This bearing surface area provided by the abrasion element will transfer the WOB to the subterranean formation.

e. "wherein an area of the bearing surface contacting the subterranean formation remains substantially constant over the range of excess weight-on-bit."

148. Newton discloses the bearing surface being substantially constant within a range of weight-on-bit. Newton discloses that the abrasion element has a flat surface that parallels the formation. Newton further states that "by selectively varying the vertical distances between the primary cutting elements 16 and the abrasion elements 18, to ensure that each of the abrasion elements 18 comes into operation and begins to abrade the formation 32 at substantially the same point in time during operation of the drill bit." Ex.1005 (5:36-45). The area of the abrasion elements can support a certain range of weight on bit. As the weight on bit increases the amount of surface area remains constant and supports, up to a certain amount, the excess weight on bit.

2. Dependent Claim 17

a. "The method of claim 16, wherein transferring the excess weight-on-bit from a body of the drill bit through the bearing surface to the subterranean formation comprises transferring the excess weight-on-bit to at least one formation-facing bearing surface on the drill bit generally surrounding at least a portion of the at least one cutter."

149. Claim 17 depends from claim 16. As discussed above, in my opinion claim 16 is obvious in view of Newton.

150. As I discuss above, when the drill bit of Newton is used in drilling operations and an excess WOB is applied, the excess WOB will be transferred from the abrasion or bearing surfaces to the formation. Newton further discloses "[s]paced rearwardly of the outermost cutting elements 16 on each blade are secondary abrasion elements 18. Although the drawing shows only two abrasion elements 18 mounted on each blade 12, any number of the primary cutting elements 16 may be provided with an associated abrasion element." Ex.1005 (4:20-28). Therefore, a POSA would understand that the abrasion elements generally surround the cutter.

3. Dependent Claim 19

a. "The method of claim 17, wherein transferring the excess weight-on-bit to the at least one formation-facing bearing surface on the drill bit generally surrounding the at least a portion of the at least one cutter comprises transferring the excess weight-on-bit to a hard facing material affixed to a selected portion of the at least one formation-facing bearing surface proximate the at least one cutter."

151. Claim 19 depends from claim 17, which depends from claim 16. As discussed above, in my opinion, claims 16 and 17 are obvious in view of Newton.

152. As I discuss above, Newton teaches the abrasion elements generally surrounding at a least a portion of at least one cutter. Newton further teaches transferring the excess WOB to a hard facing material affixed to the formation of the abrasion element. Newton discloses "[t]he secondary abrasion elements 18 shown in FIG. 1 each comprise a single body of superhard material, such as natural or synthetic diamond, mounted at the apex of a generally conical end face of a stud, for example or cemented tungsten carbide, received in a socket in the blade 12." Ex.1005 (4:29-34). "However, other forms of secondary element (sic) may be employed." *Id*. (4:34-35). "For example, the separate stud may be replaced by a projecting boss, formed integrally with the bit body and in the conical extremity of which the superhard element is embedded." *Id*. (4:35-38). The superhard element is the hard facing material.

4. Dependent Claim 20

a. "The method of claim 16, further comprising applying an additional weight-on-bit in excess of the excess weight-on-bit required for the bearing surface to contact the subterranean formation and above which results in the bearing surface and another bearing surface contacting the subterranean formation; and"

153. Claim 20 depends from claim 16. As discussed above, in my opinion, claim 16 is obvious in view of Newton.

154. As I discuss above, the WOB applied varies based on the formation that is drilled. Newton discloses, "[t]he abrasion element 18 will only engage and abrade the formation 32 when the primary cutting element 16 has worn beyond a certain level, or has failed through fracture." Ex.1005 (5:29-32). "The further the cutting element 16 projects downwardly below the abrasion element 18 the greater is the wear of the primary element which must occur before the abrasion element 18 begins to abrade the formation 32." *Id*. (5:32-36). "It is therefore possible, by selectively varying the vertical distances between the primary cutting elements 16 and the abrasion elements 18, to ensure that each of the abrasion elements 18 comes into operation and begins to abrade the formation 32 at substantially the same point in time during operation." *Id*. (5:36-41). Newton discloses varying the abrasion elements, to either contact the formation at the same time, or alternatively vary them so that they contact the formation at different WOBs. A POSA would design their drill bit in one of the two ways described by Newton.

b. "transferring the additional excess weight-on-bit from a body of the drill bit through the another bearing surface to the subterranean formation without substantial indentation of the another bearing surface thereinto."

155. As I discuss above, the additional excess WOB results in another bearing surfaces contacting the subterranean formation. This additional abrasion element taught by Newton will function in the same way as the first abrasion element and absorb any excess weight on bit. The abrasion elements will transfer the excess weight on bit from the bearing surfaces to the formation to ensure that there is no substantial indentation into the formation.

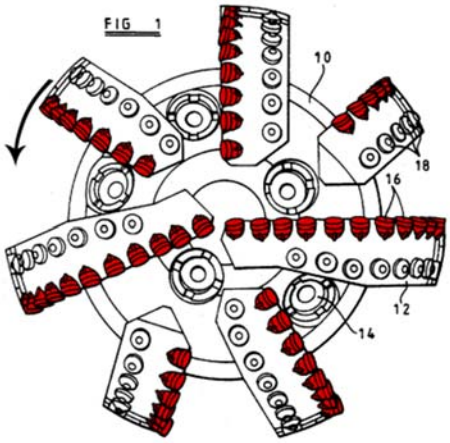
5. Independent Claim 21

a. "A method of designing a drill bit for drilling a subterranean formation the drill bit under design including a plurality of superabrasive cutters disposed about a formation-engaging leading end of the drill bit, the method comprising"

156. It is my understanding, that the preamble to the independent claims of the '441 patent do not limit their scope. The preamble of claim 21 generally describes a method of "designing a drill bit."

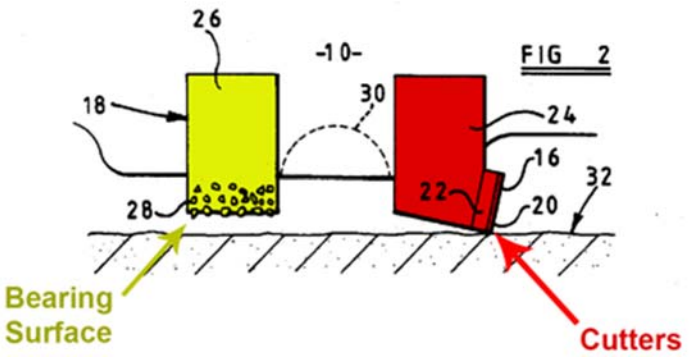
157. In any event, Newton discloses a drill bit, and that drill bit was designed. Newton discloses a drill bit for drilling a subterranean formation. Newton discloses the drill bit comprises a plurality of "**primary cutting elements** 16." Ex.1005 (4:21-28). The '441 patent states "[c]utters employed with bits 10 and 100, as well as other bits disclosed that will be discussed subsequently herein, are

depicted as having PDC cutters 14, but it will be recognized and appreciated by those of ordinary skill in the art that the invention may also be practiced on bits carrying other types of superabrasive cutters, such as thermally stable polycrystalline diamond compacts." Ex.1003 (19:19-27). Newton teaches the primary cutting elements have "a front thin hard facing layer **20** of polycrystalline diamond," making the cutters superabrasive. Ex.1005 (4:54-58).



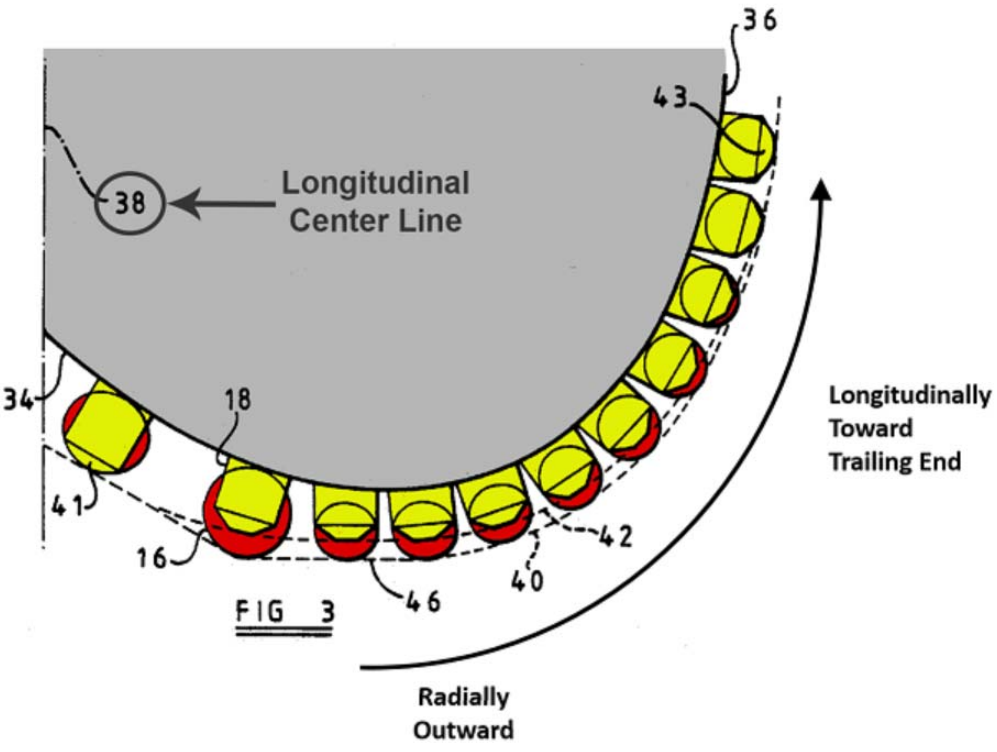
b. "selecting a maximum depth-of-cut for at least some of the plurality of superabrasive cutters"

158. Newton teaches a drill bit used in drilling subterranean formations that contains a cutter with a selected depth-of-cut range. As shown in Newton's Figure 2, the **cutters** in red will come into contact with the formation at a selected depth-of-cut. The depth of cut will be based on the type of subterranean formation.



c. "selecting a cutter profile arrangement to which the at least some of the plurality of superabrasive cutters are to be radially and longitudinally positioned on the formation engaging leading end of the drill bit; and"

159. Newton's drill bit contains a cutter profile arrangement wherein the plurality of superabrasive cutters are radially and longitudinally positioned on the formation engaging leading end of the drill bit. Newton teaches the drill bit comprises a plurality of "**primary cutting elements** 16." Ex.1005 (4:21-28).



160. In my opinion, a POSA would have found it obvious at the time of the invention to have selected the cutter profile arrangement such as that taught by Newton, motivated by the fact that it is necessary to select an arrangement in order to properly manufacture a drill bit, and decide the appropriate features for the bit.

> d. "configuring within the design of the drill bit a sufficient total amount of formation-facing bearing surface area structured for axially supporting the drill bit without substantially indenting the subterranean formation should the drill bit be subjected to a weight-on-bit exceeding a weight-on-bit which would cause the formation-facing bearing surface area to contact the subterranean formation,"

161. Claim 21 is directed to a method of designing a drill bit. Newton's abrasion elements 18 have a surface area that engages the formation during normal operation of Newton's drill bit when the cutters penetrate the formation, thus providing a bearing area.

162. As the WOB increases the formation facing structure contacts the formation in order to absorb the excess WOB and ensure the depth of cut remains constant. In fact, the '441 patent acknowledges it was known in the art that the WOB necessary to penetrate a formation changes as the drilling progresses from one formation to another: "Another, separate problem involves drilling from a zone or stratum of higher formation compressive strength to a 'softer' zone of lower strength. As the bit drills into the softer formation without changing the applied WOB (or before the WOB can be changed by the directional driller), the penetration

of the PDC cutters, and thus the resulting torque on the bit (TOB), increase almost instantaneously and by a substantial magnitude." Ex.1003 (1:65-2:5).

163. The SPE 39306 paper also confirms that it was known prior to the '441 patent that the WOB required to penetrate a formation depends on the type of formation. The SPE 39306 paper reports a study on the WOB required to achieve certain rates of penetration in Carthage limestone (a harder) and Catoosa shale (a softer formation) for cutters with specific backrake angles. Ex.1029 (5). At each backrake angle, a bit in the harder limestone formation requires more WOB than a bit in the softer shale formation to achieve the same ROP.

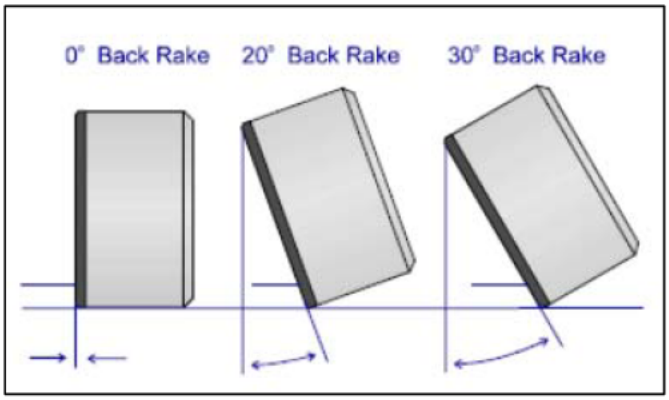
164. The SPE 39306 paper also shows it was known prior to the '441 patent that the WOB required to penetrate a formation increases as the surface area of the bit contacting the formation increases. Ex.1029 (3) ("Figure 3 previously showed the resulting increase in weight requirement as the contact area between the PDC cutter and the rock increases."). The SPE 39306 paper was explaining this relationship in context of the increase in surface area of the cutter contacting the formation as the cutter wears and creates a wearflat. A POSA would readily understand that this principle applies to any bearing surfaces that, in addition to the cutter, contact the formation—like the abrasion elements of Newton.

165. In light of the known fact that formation hardness may vary as a drilling progresses and the teachings of the SPE 39306 paper about the relationship of the

required WOB to formation hardness, a POSA would have found it obvious that the normal use of the drill bit of Newton in drilling would result in the drilling operator applying a WOB necessary to penetrate a formation that then becomes an excess WOB as the drill bit progresses to a softer formation.

166. The Challenged Claims do not specify the amount of bearing surface necessary to maintain the selected depth of cut and not substantially indent the subterranean formation. Nonetheless, a POSA at the time of the '441 patent knew how to calculate the sufficient area necessary to control depth of cut. Initially, the physical features of the bit are selected. These features include the shape of the bit, the location of the cutters, and the location of the bearing surfaces in circumferential path of the cutters, either leading the cutter or trailing the cutter, as taught by the prior art. Additional factors include (1) the number of cutters, (2) location of the cutter with respect to the center of the bit, (3) back rake angle of the cutters, and (4) diameter of the cutters. Other known features can be considered when designing the layout of the cutter profile of the bit.

167. The weight on bit selected depends on the physical properties of the bit described above, in addition to the compressive strength of the formation. For example, the more aggressive the cutter with respect to physical orientation such as exposure beyond the bearing surface and less back rake angle, the greater the surface area necessary for a given applied weight on bit in a given formation.



Ex.1044 (slide 7).

168. As previously mentioned, the weight on bit is also selected based on the compressive strength of the formation. A higher weight on bit needs to be applied when the compressive strength of the formation is higher.

169. In fact, the '441 patent recognizes that a POSA wanting to practice the claimed invention would know the WOB and know the type of formation. "By providing DOCC features having a cumulative surface area sufficient to support a given WOB on a given rock formation, preferably without substantial indentation or failure of same, WOB may be dramatically increased, if desired, over that usable in drilling with conventional bits without the PDC cutters experiencing any additional effective WOB after the DOCC features are in full contact with the formation." Ex.1003 (4:54-61).

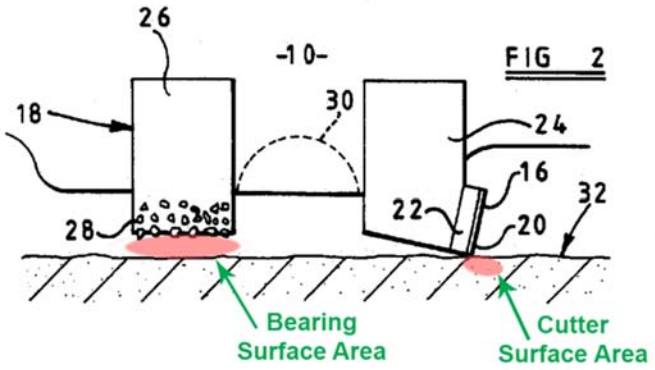
170. Using simple equations, a POSA given a weight on bit can determine the sufficient bearing surface area needed.

$$Area = \frac{WOB}{RS}$$

171. WOB is the given weight on bit referred to by the ’441 patent. RS is the rock strength and is based on the type of formation, and an easily measurable parameter. Rock strength is the compressive strength of the rock.

$$Area = A_{cutter} + A_{bearing\ surface}$$

172. A simplification of the areas for Newton is shown below:



173. The area in the equation is equal to the projected area in the axial direction of the cutter (A_{cutter}) plus the bearing surface area ($A_{bearing\ surface}$). The projected area in the area in the axial direction of the cutter is a function of the cutter geometry, back rake, and depth of cut. The depth of cut is determined when the bearing surface engages the formation. The area of the bearing surface is the axial projected contact area.

$$A_{bearing\ surface} = Area - A_{cutter}$$

174. The bearing surface area is the minimum surface area required to hold a specific weight on bit. As weight on bit increases the area has to increase with the incremental weight over rock strength. As long as the bearing area is sufficient to

hold the weight on bit, depth of cut is controlled. The area of the abrasion elements can support a certain range of weight on bit. As the weight on bit increases the amount of surface area remains constant and supports any excess weight on bit.

175. Based on this simple explanation, a POSA would have known how to calculate sufficient surface area, and would have found it obvious to do so in order to ensure the bit is designed so that damage to the cutters and the bit body is avoided. In fact, prior to the filing of the '441 patent, computer programs existed that simulate these features in order to simulate different bit designs. Therefore, a POSA would find it obvious to determine the sufficient surface area required to maintain a unit load on the formation below the compressive strength of a formation for a given formation and given weight on bit.

e. "wherein the formation-facing bearing surface area is sized and configured to remain substantially constant over a range of excess weight-on-bit."

176. Newton discloses the bearing surface being substantially constant within a range of weight-on-bit. Newton states that "by selectively varying the vertical distances between the primary cutting elements 16 and the abrasion elements 18, to ensure that each of the abrasion elements 18 comes into operation and begins to abrade the formation 32 at substantially the same point in time during operation of the drill bit." Ex.1005 (5:35-42). The area of the abrasion elements can support

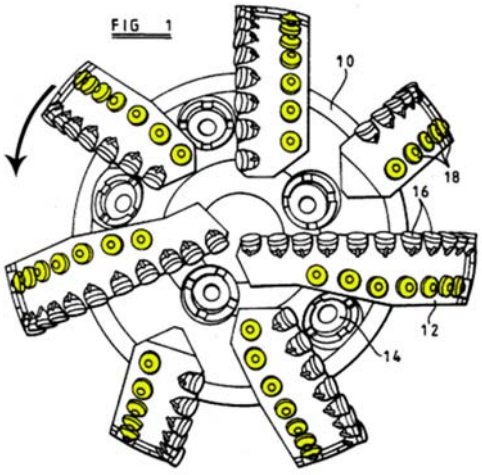
a certain range of weight on bit. As the weight on bit increases the amount of surface area remains constant and supports a certain range of excess weigh-on-bit.

6. Dependent Claim 23

a. "The method of claim 21, wherein configuring within the design of the drill bit a sufficient total amount of the formation-facing bearing surface area comprises selecting an amount of hard facing to be disposed on at least a portion of the formation-facing bearing surface at least partially surrounding the at least some of the plurality of superabrasive cutters."

177. Claim 23 depends from claim 21. As discussed above, in my view claim 21 is obvious in view of Newton.

178. Newton discloses that the drill bit includes "**secondary abrasion elements** 18" located on the bit's leading end. Ex.1005 (4:20-21). Newton further states that the amount of secondary abrasion elements can be varied. *Id*. (4:21-28). As shown in Figure 1 below, these abrasion elements surround the cutters, as they are located on the same blade.



7. Dependent Claim 24

a. "The method of claim 21, further comprising including within the design of the drill bit another formation-facing bearing surface area structured for axially supporting the drill bit without substantially indenting the subterranean formation therewith should the drill bit be subjected to an additional excess weight-on-bit exceeding an excess weight-on-bit."

179. Claim 24, depends from claim 21. As discussed above, it is my view that claim 21 is obvious in view of Newton.

180. As I discuss above, Newton discloses a design with multiple abrasion surfaces. The size of these surfaces are based on the WOB and formation. These surfaces will support any additional WOB applied in excess of the WOB necessary to achieve the maximum depth of cut. By absorbing this extra weight the drill bit will not substantially indent the subterranean formation.

B. Ground II: Claims 16-17, 19-21 and 23-24 are Obvious in View of Jones in View of the Knowledge of a POSA

1. Independent Claim 16

a. "A method of drilling a subterranean formation without generating an excessive amount of torque-on-bit, comprising:"

181. In my view, claim 16 is obvious in view of Jones.

182. It is my understanding, that the preamble to the independent claims of the '441 patent do not limit their scope. Each preamble no more than generally

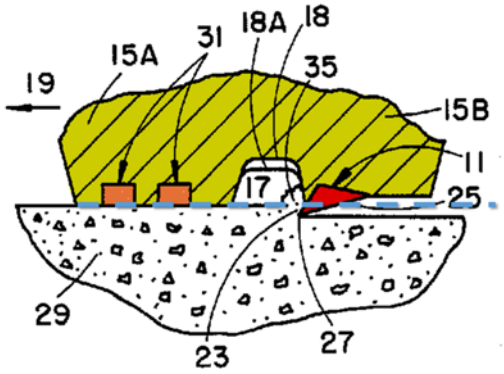
describes the claimed method—"drilling a subterranean formation without generating an excessive amount of torque-on-bit."

183. In any event, Jones discloses a drill bit, and a person of ordinary skill in the art would understand that this drill bit was intended to be used. Jones teaches "rotary drill bits for drilling bores in the earth such as for oil and gas wells." Ex.1006 (1:6-9). A POSA at the time of the invention would have found it obvious to have used the drill bit to drill a formation, the intended purpose of Jones' bit. Jones' drill bit design, as discussed in more detail below, would prevent an excessive amount of torque-on-bit when used in the field.

b. "engaging the subterranean formation with at least one cutter of a drill bit within a selected depth-of-cut range"

184. Jones discloses engaging the formation with at least one cutter to a selected depth of cut. Jones discloses "the leading ridge is adapted to engage the formation at the bottom of the well bore to limit the depth of penetration of the cutting elements into the formation and to block fluid flow between the leading ridge and the formation." Ex.1006 (3:30-37). In order to limit penetration but also ensure that the bit is engaging the formation a POSA would know it was necessary to choose a selected depth of cut. When using the bit for drilling, the cutting elements would necessarily engage with the formation and be limited to a selected depth-of-cut based on the structure as disclosed above. As shown with the blue dotted line below, the depth of cut is specifically selected for the cutter based on the formation.

FIG. 3



c. "applying a weight-on-bit within a range of weight-on-bit in excess of that required for the at least one cutter to penetrate the subterranean formation and above which results in a bearing surface contacting the subterranean formation;"

185. Jones teaches, "[u]pon the application of a weight on the bit 1 less than a predetermined weight, the cutting elements 11 will penetrate the formation to a depth dependent on the amount of the weight." Ex.1006 (5:22-25). "However, upon application of a weight on the bit in excess of the predetermined weight, the leading ridge, because of its position relative to the trailing ridge and the cutting elements, engages the formation 29 at the well bore bottom for limiting the depth of penetration of the cutting elements 11 into the formation." *Id*. (5:25-31).

186. Furthermore, a WOB is selected and applied based on specifications related to the formation. As formations change during a drilling operation, so too does the required WOB.

187. In fact, the '441 patent acknowledges it was known in the art that the WOB necessary to penetrate a formation changes as the drilling progresses from one

formation to another: "Another, separate problem involves drilling from a zone or stratum of higher formation compressive strength to a 'softer' zone of lower strength. As the bit drills into the softer formation without changing the applied WOB (or before the WOB can be changed by the directional driller), the penetration of the PDC cutters, and thus the resulting torque on the bit (TOB), increase almost instantaneously and by a substantial magnitude." Ex.1003 (1:65-2:5).

188. The SPE 39306 paper also confirms that it was known prior to the '441 patent that the WOB required to penetrate a formation depends on the type of formation. SPE 39306 reports a study on the WOB required to achieve certain rates of penetration in Carthage limestone (a harder) and Catoosa shale (a softer formation) for cutters with specific backrake angles. Ex.1029 (5). At each backrake angle, a bit in the harder limestone formation requires more WOB than a bit in the softer shale formation to achieve the same ROP.

189. The SPE 39306 paper also shows it was known prior to the '441 patent that the WOB required to penetrate a formation increases as the surface area of the bit contacting the formation increases. Ex.1029 (3). ("Figure 3 previously showed the resulting increase in weight requirement as the contact area between the PDC cutter and the rock increases."). The SPE 39306 paper was explaining this relationship in context of the increase in surface area of the cutter contacting the formation as the cutter wears and creates a wearflat. A POSA would readily

understand that this principle applies to any bearing surfaces that, in addition to the cutter, contact the formation—like the ridges of Jones.

190. In light of the known fact that formation hardness may vary as a drilling progresses and the teachings of the SPE 39306 paper about the relationship of the required WOB to formation hardness, a POSA would have found it obvious that the normal use of the drill bit of Jones in drilling would result in the drilling operator applying a WOB necessary to penetrate a formation that then becomes an excess WOB as the drill bit progresses to a softer formation.

> d. "transferring the excess weight-on-bit from the drill bit through the bearing surface to the subterranean formation without substantial indentation of the bearing surface into the subterranean formation; and"

191. When excess WOB is applied, the ridges taught by Jones will come into contact with the formation and transfer the excess WOB through the ridges to the formation. The ridges in Jones will provide a depth-of-cut-control and will necessarily come into contact with the formation and absorb the excess WOB. Thus, there would be no substantial indentation of the bearing surface into the formation.

192. A POSA would know that, at a given distance from the center of the bit, the force generated by a cutter will be greater than the force generated by the wear surfaces, because for a range of WOB the force required to shear the formation is greater than force of friction against the formation. As a result, a POSA would

know that excessive torque on the bit can be prevented by using bearing surfaces to limit the depth of cut.

193. Jones ridges have a surface area that engages the formation during normal operation of Jones' drill bit when the cutters penetrate the formation, thus providing a bearing area. This bearing surface area provided by the abrasion element will transfer the WOB to the subterranean formation.

e. "wherein an area of the bearing surface contacting the subterranean formation remains substantially constant over the range of excess weight-on-bit."

194. Jones discloses the bearing surface being substantially constant. "Upon the application of a weight on the bit 1 less than a predetermined weight, the cutting elements 11 will penetrate the formation to a depth dependent on the amount of the weight." Ex.1006 (5:22-25). "However, upon application of a weight on the bit in excess of the predetermined weight, the leading ridge, because of its position relative to the trailing ridge and the cutting elements engages the formation 29 at the well bore bottom for limiting the depth of penetration of the cutting elements 11 into the formation." Ex.1006 (5:25-31). This area can support a certain range of weight on bit. As the weight on bit increases the amount of surface area remains constant and supports any excess weight on bit.

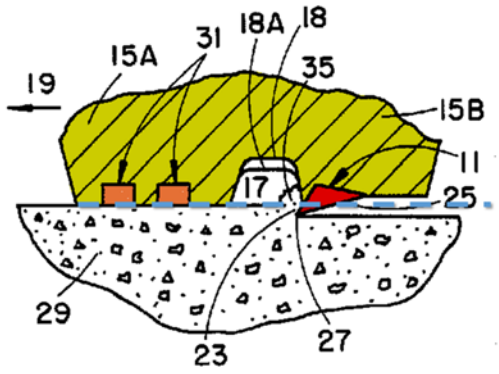
2. Dependent Claim 17

a. "The method of claim 16, wherein transferring the excess weight-on-bit from a body of the drill bit through the bearing surface to the subterranean formation comprises transferring the excess weight-on-bit to at least one formation-facing bearing surface on the drill bit generally surrounding at least a portion of the at least one cutter."

195. Claim 17 depends from claim 16. As discussed above, it is my view that claim 16 is obvious in view of Jones.

196. As I discuss above, Jones discloses transferring the excess weight-on-bit through a bearing surface. Jones further discloses "[t]he drag cutting elements 11 are embedded in the trailing ridge 15B … [e]ach cutting element 11 projects down below the bottom of the trailing ridge and forward in the direction of rotation of the bit." Ex.1006 (4:50-57). The bearing surface (in yellow in Figure 3 below) therefore surrounds at least a portion of at least one cutter.

FIG. 3



3. Dependent Claim 19

a. "The method of claim 17, wherein transferring the excess weight-on-bit to the at least one formation-facing bearing surface on the drill bit generally surrounding the at least a portion of the at least one cutter comprises transferring the excess weight-on-bit to a hard facing material affixed to a selected portion of the at least one formation-facing bearing surface proximate the at least one cutter."

197. Claim 19 depends from claim 16, which depends from claim 16. As discussed above, in my opinion, claims 16 and 17 are obvious in view of Jones.

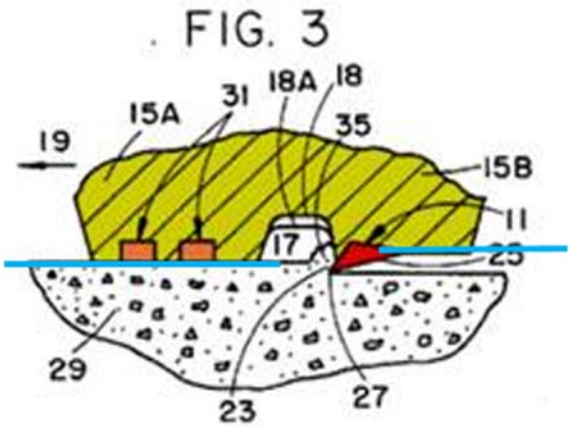
198. As I discuss above, Jones discloses transferring the excess weight-on-bit to at least one formation-facing bearing surface on the drill bit to ridges and wear elements. Jones further discloses "[t]he drag cutting elements 11 are embedded in the trailing ridge 15B … [e]ach cutting element 11 projects down below the bottom of the trailing ridge and forward in the direction of rotation of the bit." Ex.1006 (4:50-55). The bearing surface is therefore proximate to at least one cutter. Further, as mentioned above Jones discloses ridges. "A first ridge 15A of each set of ridges constitutes a leading ridge with respect to the direction of rotation of the bit … [t]he second ridge 15B of each set of ridges thus constitutes a trailing ridge." *Id*. (4:45-49). Jones teaches "[f]or increased wear resistance, the leading ridge, as well as the trailing ridge at its upper end (see FIG. 1), has a plurality of relatively hard wear elements 31, such as of diamond or tungsten carbide, embedded therein." *Id*. (5:38-41). The hard wear elements equate to the claimed hard facing material.

4. Dependent Claim 20

a. "The method of claim 16, further comprising applying an additional weight-on-bit in excess of the excess weight-on-bit required for the bearing surface to contact the subterranean formation and above which results in the bearing surface and another bearing surface contacting the subterranean formation; and"

199. Claim 20 depends from claim 16. As discussed above, in my opinion, claim 16 is obvious in view of Jones.

200. Jones discloses wherein there are at least two bearing surfaces that contact the formation at different moments. "The cutting elements are mounted in side-by-side relation on the second or trailing ridge … [t]he bottom of the … leading ridge is spaced below the bottom of the trailing ridge but above the bottom of the cutting edges of the cutting elements, whereby the leading ridge is adapted to engage the formation." Ex.1006 (3:24-37). As shown in Figure 2 in Jones, the bearing surfaces/ridges 15A and 15B do not contact the formation 29 at the same time, the blue line on the left will contact the formation prior to the blue line on the right.



201. Therefore as more weight is applied eventually ridge 15B will also contact the formation. Thus ridge 15B is another bearing surface that contacts the subterranean formation.

b. "transferring the additional excess weight-on-bit from a body of the drill bit through the another bearing surface to the subterranean formation without substantial indentation of the another bearing surface thereinto."

202. As discussed above, Jones discloses information where a POSA would be able to determine the sufficient surface area, and can vary when that area will contact the formation based on the weight on bit. As an additional bearing surface contacts the formation it will absorb the additional excessive weight on bit at a stress less than substantially the compressive strength of the formation.

5. Independent Claim 21

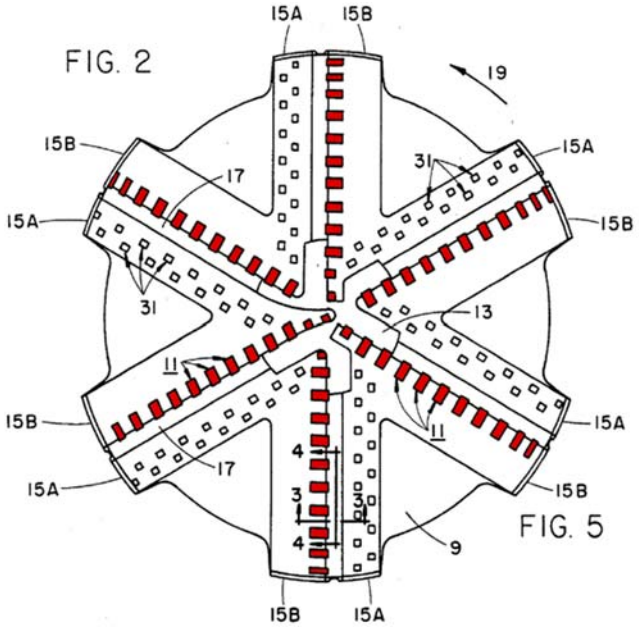
a. "A method of designing a drill bit for drilling a subterranean formation the drill bit under design including a plurality of superabrasive cutters disposed about a formation-engaging leading end of the drill bit, the method comprising"

203. In my opinion, claim 21 is obvious in view of Jones.

204. It is my understanding, that the preamble to the independent claims of the '441 patent do not limit their scope. The preamble of claim 21 generally describes a method of "designing a drill bit."

205. Jones discloses a drill bit, that drill bit was designed. A POSA, at the time of the invention, would have found it obvious to design the drill bit by Jones.

Jones discloses a drill bit for drilling a subterranean formation. Jones teaches "[t]he drag **cutting elements** 11 are embedded in the trailing ridge of 15B of each of the sets of ridges in side-by-side spaced apart relation." Ex.1006 (4:50-53).



206. A POSA at the time of the invention would have found it obvious to have engaged in a method of designing the bit as disclosed by Newton motivated by the fact that such method is necessary to manufacture the drill bit.

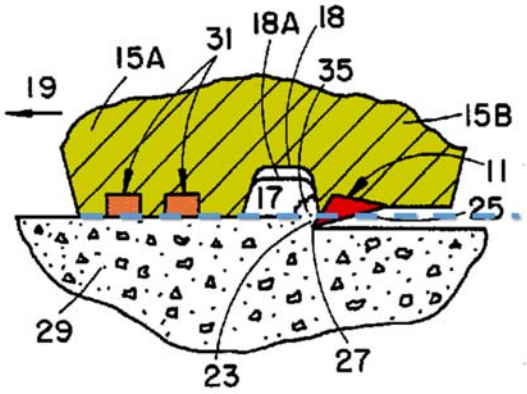
b. "selecting a maximum depth-of-cut for at least some of the plurality of superabrasive cutters"

207. As seen in Figure 3, the exposure of the cutter is limited by the wear surface and the backrake angle of the cutter.

208. Additionally Jones teaches, "[u]pon the application of a weight on the bit 1 less than a predetermined weight, the cutting elements 11 will penetrate the formation to a depth dependent on the amount of the weight." Ex.1006 (5:22-25).

"However, upon application of a weight on the bit in excess of the predetermined weight, the leading ridge, because of its position relative to the trailing ridge and the cutting elements, engages the formation 29 at the well bore bottom for limiting the depth of penetration of the cutting elements 11 into the formation." Ex.1006 (5:25-31).

FIG. 3

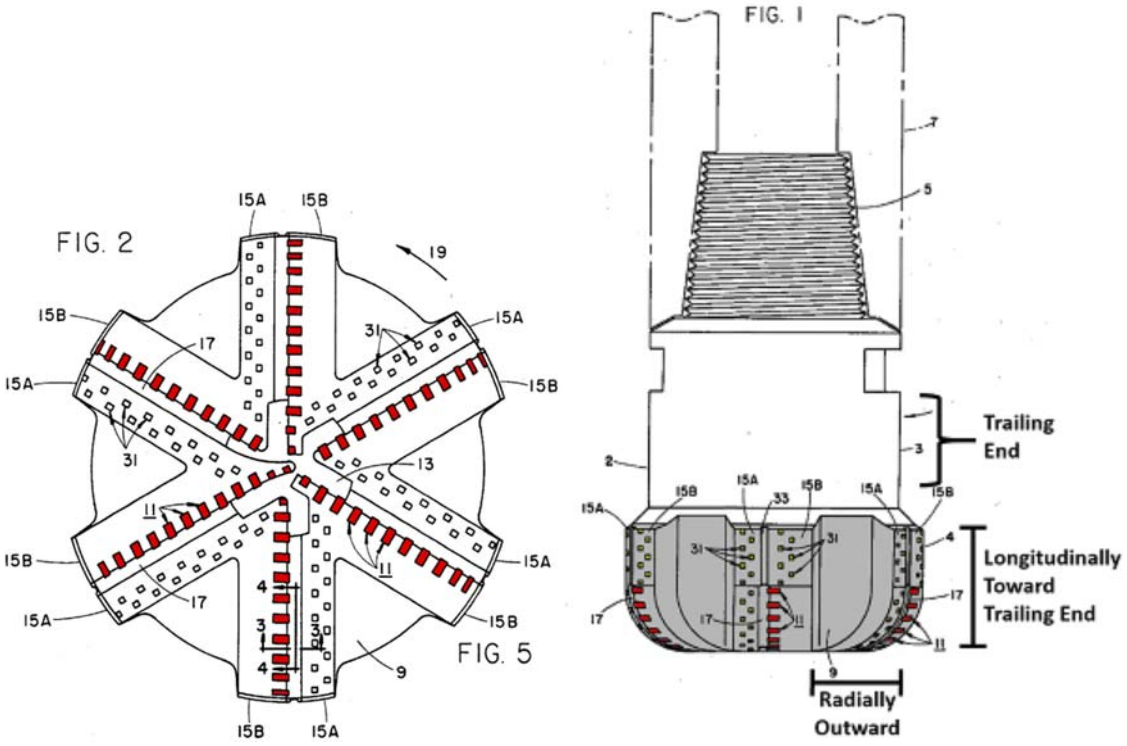


209. A POSA at the time of the invention would have found it obvious to select a maximum DOC motivated by the fact that one must select a DOC when designing the bit in order to successfully drill a bore hole.

c. "selecting a cutter profile arrangement to which the at least some of the plurality of superabrasive cutters are to be radially and longitudinally positioned on the formation engaging leading end of the drill bit; and"

210. Jones' drill bit contains a cutter profile arrangement wherein the plurality of cutters are radially and longitudinally positioned on the formation engaging leading end of the drill bit. Jones teaches "the drag **cutting elements** 11

are embedded in the trailing ridge of 15B of each of the sets of ridges in side-by-side spaced apart relation" as shown in Figure 2 below. Ex.1006 (4:50-53).



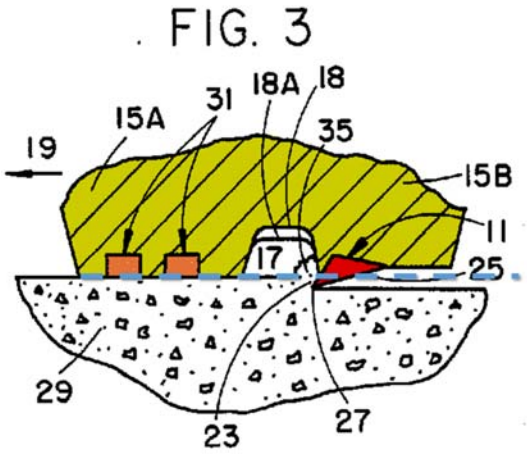
211. As shown in the figures above, the cutters are located on blades; the blades extent radially outward and longitudinally toward the trailing end. A POSA would have found it obvious at the time of the invention to have selected the cutter profile arrangement motivated by the fact that it is necessary to select an arrangement in order to properly manufacture a drill bit, and decide the appropriate applications for the bit.

d. "configuring within the design of the drill bit a sufficient total amount of formation-facing bearing surface area structured for axially supporting the drill bit without substantially indenting the subterranean formation should the drill bit be subjected to a weight-on-bit exceeding a weight-on-bit which would cause the formation-facing bearing surface area to contact the subterranean formation,"

212. Jones discloses a sufficient surface area to maintain a selected depth of cut. Jones discloses "[t]he bottom of the first or leading ridge is spaced below the bottom of the trailing ridge but above the bottom of the cutting edges of the cutting elements, whereby the leading ridge is adapted to engage the formation at the bottom of the well bore to limit the depth of penetration of the cutting elements into the formation and to block fluid flow between the leading ridge and the formation." Ex.1006 (3:30-37).

213. Jones discloses figure 3, which shows "the bottom of the leading ridge 15A of a set of ridges is shown to be positioned below the bottom of the trailing ridge 15B of the set, but above the cutting edges 27 of the cutting elements 11 mounted on the trailing ridge." Ex.1006 (5:18-22). "Upon the application of a weight on the bit 1 less than a predetermined weight, the cutting elements 11 will penetrate the formation to a depth dependent on the amount of the weight." *Id*. (5:22-25). "However, upon application of a weight on the bit in excess of the predetermined weight, the leading ridge, because of its position relative to the trailing ridge and the cutting elements, engages the formation 29 at the well bore

bottom for limiting the depth of penetration of the cutting elements 11 into the formation." *Id*. (5:25-31).



214. "Thus the leading ridge enables the cutting elements to penetrate to a depth deep enough to enable rapid removal of the formation, yet not so deep as to prevent the cutting elements from being adequately cooled and cleaned by the drilling fluid." Ex.1006 (5:31-36). "Thus, the bit 1 provides protection against damage to the cutting element due to excess weight on the bit." *Id*. (5:36-38). "For increased wear resistance, the leading ridge, as well as the trailing ridge at its upper end (see FIG. 1), has a plurality of relatively hard wear elements 31, such as of diamond or tungsten carbide, embedded therein." *Id*. (5:38-41).

215. As the WOB increases the formation facing structure contacts the formation in order to absorb the excess WOB and ensure the depth of cut remains constant. In fact, the '441 patent acknowledges it was known in the art that the WOB necessary to penetrate a formation changes as the drilling progresses from one

formation to another: "Another, separate problem involves drilling from a zone or stratum of higher formation compressive strength to a 'softer' zone of lower strength. As the bit drills into the softer formation without changing the applied WOB (or before the WOB can be changed by the directional driller), the penetration of the PDC cutters, and thus the resulting torque on the bit (TOB), increase almost instantaneously and by a substantial magnitude." Ex.1003 (1:65-2:5).

216. The SPE 39306 paper also confirms that it was known prior to the '441 patent that the WOB required to penetrate a formation depends on the type of formation. The SPE 39306 paper reports a study on the WOB required to achieve certain rates of penetration in Carthage limestone (a harder) and Catoosa shale (a softer formation) for cutters with specific backrake angles. Ex.1029 (5). At each backrake angle, a bit in the harder limestone formation requires more WOB than a bit in the softer shale formation to achieve the same ROP.

217. The SPE 39306 paper also shows it was known prior to the '441 patent that the WOB required to penetrate a formation increases as the surface area of the bit contacting the formation increases. Ex.1029 (3). ("Figure 3 previously showed the resulting increase in weight requirement as the contact area between the PDC cutter and the rock increases."). The SPE 39306 paper was explaining this relationship in context of the increase in surface area of the cutter contacting the formation as the cutter wears and creates a wearflat. A POSA would readily

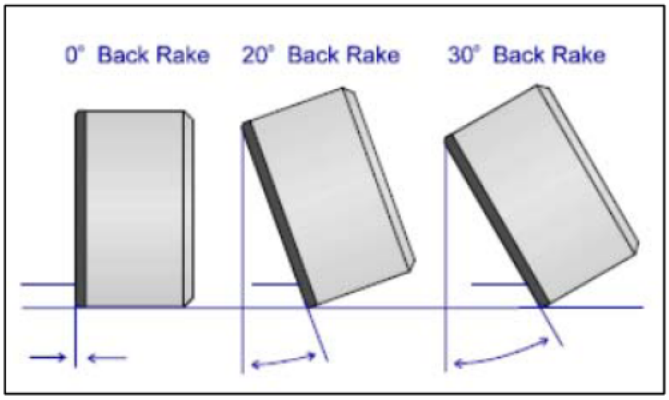
understand that this principle applies to any bearing surfaces that, in addition to the cutter, contact the formation—like the ridges of Jones.

218. In light of the known fact that formation hardness may vary as a drilling progresses and the teachings of SPE 39306 paper about the relationship of the required WOB to formation hardness, a POSA would have found it obvious that the normal use of the drill bit of Jones in drilling would result in the drilling operator applying a WOB necessary to penetrate a formation that then becomes an excess WOB as the drill bit progresses to a softer formation.

219. The Challenged Claims do not specify the amount of bearing surface necessary to maintain the selected depth of cut. Nonetheless, a POSA at the time of the ’441 patent knew how to calculate the sufficient area necessary to control depth of cut. Initially, the physical features of the bit are selected. These features include the shape of the bit, the location of the cutters, and the location of the bearing surfaces in circumferential path of the cutters, either leading the cutter or trailing the cutter, as taught by the prior art. Additional factors include (1) the number of cutters, (2) location of the cutter with respect to the center of the bit, (3) back rake angle of the cutters, and (4) diameter of the cutters. Other known features can be considered when designing the layout of the cutter profile of the bit.

220. The weight on bit selected depends on the physical properties of the bit described above, in addition to the compressive strength of the formation. For

example, the more aggressive the cutter with respect to physical orientation such as exposure beyond the bearing surface and less back rake angle, the greater the surface area necessary for a given applied weight on bit in a given formation.



Ex.1044 (slide 7).

221. As previously mentioned, the weight on bit is also selected based on the compressive strength of the formation. A higher weight on bit needs to be applied when the compressive strength of the formation is higher.

222. In fact, the '441 patent recognizes that a POSA wanting to practice the claimed invention would know the WOB and know the type of formation. "By providing DOCC features having a cumulative surface area sufficient to support a given WOB on a given rock formation preferably without substantial indentation or failure of same, WOB may be dramatically increased, if desired, over that usable in drilling with conventional bits without the PDC cutters experiencing any additional effective WOB after the DOCC features are in full contact with the formation." Ex.1003 (4:54-61).

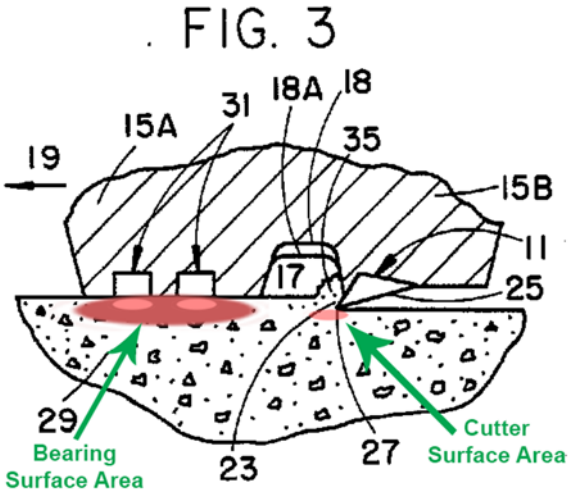
223. Using simple equations, a POSA given a weight on bit can determine the sufficient bearing surface area needed.

$$Area = \frac{WOB}{RS}$$

224. WOB is the given weight on bit referred to by the '441 patent. RS is the rock strength and is based on the type of formation, and an easily measurable parameter. Rock strength is the compressive strength of the rock.

$$Area = A_{cutter} + A_{bearing\ surface}$$

A simplification of the areas for Jones is shown below:



225. The area in the equation is equal to the projected area in the axial direction of the cutter (A_{cutter}) plus the bearing surface area ($A_{bearing\ surface}$). The projected area in the area in the axial direction of the cutter is a function of the cutter geometry, back rake, and depth of cut. The depth of cut is determined when the

bearing surface engages the formation. The area of the bearing surface is the axial projected contact area.

$$A_{bearing\ surface} = Area - A_{cutter}$$

226. The bearing surface area is the minimum surface area required to hold a specific weight on bit. As weight on bit increases the area has to increase with the incremental weight over rock strength. As long as the bearing area is sufficient to hold the weight on bit, depth of cut is controlled. The area of the abrasion elements can support a certain range of weight on bit. As the weight on bit increases the amount of surface area remains constant and supports any excess weight on bit.

227. Based on this simple explanation, a POSA would have known how to calculate sufficient surface area, and would have found it obvious to do so in order to ensure the bit is designed so that damage to the cutters and the bit body is avoided. In fact, prior to the filing of the ’441 patent, computer programs existed that simulate these features in order to simulate different bit designs. A POSA would find it obvious to determine the sufficient surface area required to maintain a unit load on the formation below the compressive strength of a formation for a given formation and given weight on bit.

e. "wherein the formation-facing bearing surface area is sized and configured to remain substantially constant over a range of excess weight-on-bit."

228. Jones discloses the bearing surface being substantially constant. "Upon the application of a weight on the bit 1 less than a predetermined weight, the cutting elements 11 will penetrate the formation to a depth dependent on the amount of the weight." Ex.1006 (5:22-25). "However, upon application of a weight on the bit in excess of the predetermined weight, the leading ridge, because of its position relative to the trailing ridge and the cutting elements engages the formation 29 at the well bore bottom for limiting the depth of penetration of the cutting elements 11 into the formation." *Id*. (5:25-31). This area can support a certain range of weight on bit. As the weight on bit increases the amount of surface area remains constant and supports any excess weight on bit.

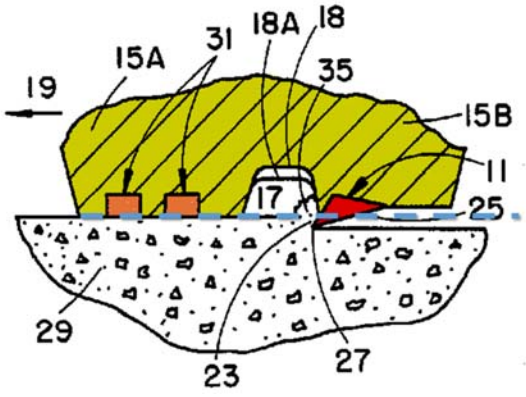
6. Dependent Claim 23

a. "The method of claim 21, wherein configuring within the design of the drill bit a sufficient total amount of the formation-facing bearing surface area comprises selecting an amount of hard facing to be disposed on at least a portion of the formation-facing bearing surface at least partially surrounding the at least some of the plurality of superabrasive cutters."

229. Claim 23 depends from claim 21. As discussed above, in my opinion, claim 21 is obvious in view of Jones.

230. Jones teaches "[f]or increased wear resistance, the leading ridge, as well as the trailing ridge at its upper end (see FIG. 1), has a plurality of relativity hard wear elements 31, such as of diamond or tungsten carbide, embedded therein." Ex.1006 (5:38-41). Jones teaches "a drill bit which has cutting elements having leading faces presenting … to be cut for cutting the formation by means of shearing action; the provision of such a drill bit in which the cutting elements have trailing faces providing back clearance relative to the surface of the formation to be cut for extended cutting element life; the provision of such a drill bit which provides protection against damage to the cutting elements due to excess 'weight on bit'; the provision of such a drill bit having cutting elements … of natural diamond bits." *Id.* (2:42-62). As seen in the figure below, ridges 15A and 15B in yellow partially surround the cutter in red.

FIG. 3



231. A POSA at the time of the invention would have found it obvious to have selected an amount of these hard facing elements motivated by the fact that one

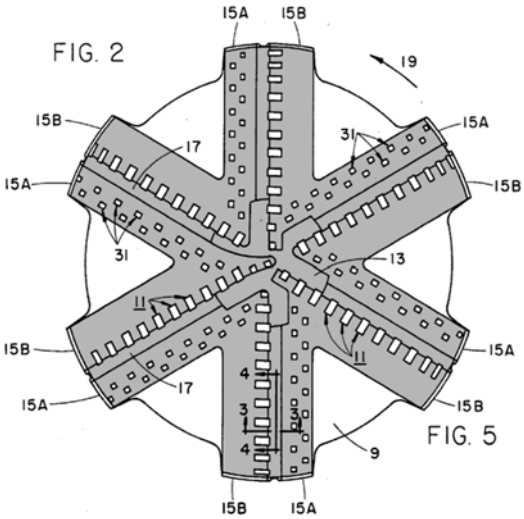
would necessarily have to select a number in order to achieve a desired design for a particular drilling application.

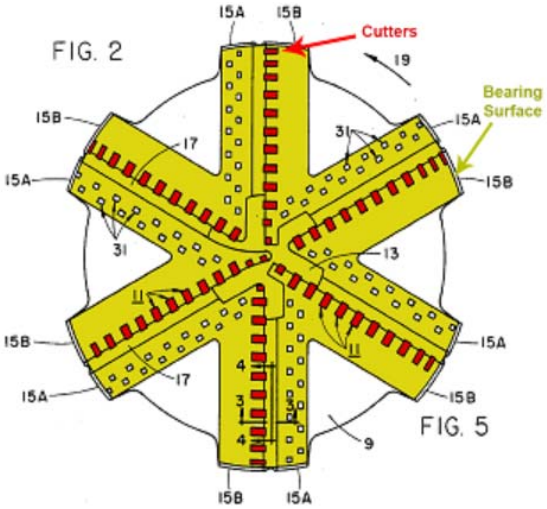
7. Dependent Claim 24

a. "The method of claim 21, further comprising including within the design of the drill bit another formation-facing bearing surface area structured for axially supporting the drill bit without substantially indenting the subterranean formation therewith should the drill bit be subjected to an additional excess weight-on-bit exceeding an excess weight-on-bit."

232. Claim 24 depends from claim 21. As discussed above, in my opinion, claim 21 is obvious in view of Jones.

233. The blades bearing surface, would also act formation-facing bearing surface area structured for axially supporting the drill bit. The blades bearing surface provides structure and axial support for the bit as the drill bit is rotated and engages the formation.





234. The features in Jones, such as the leading ridge, wear elements, and bearing surface of the blade, provide a depth-of-cut-control and would necessarily come into contact with the formation and transfer the energy across the entire surface area of these features. The combination of the wear elements along with the bearing surface area on the blade therefore presents a total bearing surface that will substantially support the bit body upon the bit being forced against the formation without substantially indenting the formation if the WOB is exceeded.

235. Furthermore, as designed the surface area as shown provides a surface area that is configured to remain substantially constant over a range of excess weight-on-bit. A POSA at the time of the invention would have found it obvious to have conducted the step of configuring the design features as claimed and taught by Jones motivated by the fact this configuration step is necessary to achieve the disclosed drill bit design.

C. Ground III: Claims 16-17, 19, 21 and 23-24 are Obvious in View of Griffin in View of the Knowledge of the POSA

1. Independent Claim 16

a. "A method of drilling a subterranean formation without generating an excessive amount of torque-on-bit, comprising:"

236. It is my opinion that claim 16 is obvious in view of Griffin.

237. It is my understanding, that the preamble to the independent claims of the '441 patent do not limit their scope. Each preamble no more than generally

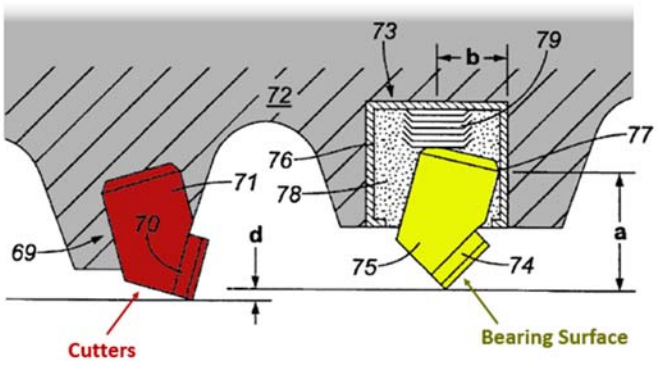
describes the claimed method—"drilling a subterranean formation without generating an excessive amount of torque-on-bit."

238. Griffin discloses a drill bit, used in drilling subterranean formations avoiding an excessive torque on bit. Ex.1007 (abstract). Griffin discloses a "rotary drill bits for use in drilling holes in subsurface formations and, more particularly, to rotary drill bits having moveable formation-engaging members." *Id.* (1:6-9). "In drag-type rotary drill bits, it is usually those cutters which are furthest from the central axis of rotation of the bit which generate the majority of the torque." *Id.* (12:44-46). "To avoid excessive generation of torque, therefore, it would be advantageous for at least some outer cutters to move inwardly away from the formation to reduce the torque when a predetermined level of torque is reached." *Id.* (12:46-49). A POSA at the time of the invention would have found it obvious to have used the drill bit to drill a formation, the intended purpose of Griffin's bit.

b. "engaging the subterranean formation with at least one cutter of a drill bit within a selected depth-of-cut range;"

239. Griffin discloses a drill bit used in drilling subterranean formations that contains a cutter with a selected depth-of-cut. Griffin discloses the "[t]he distance 'd' is a predetermined desired depth of cut." Ex.1007 (9:4-5). As shown in Figure 11, Griffin discloses the cutter engaging a depth of cut "d."

FIG. 11



c. "applying a weight-on-bit within a range of weight-on-bit in excess of that required for the at least one cutter to penetrate the subterranean formation and above which results in a bearing surface contacting the subterranean formation;"

240. In order to drill a hole with the drill bit taught by Griffin, a WOB is applied to achieve the depth of cut as discussed above. Specifically, Griffin teaches "[t]he distance 'd' is a predetermined desired depth of cut." Ex.1007 (9:4-5). "If this depth of cut is exceeded, the drag F_d acting on the cutter 74, 75 will increase causing the cutter 74, 75 to tilt rearwardly within its housing." *Id*. (9:5-8). "This will increase the vertical force F_{wob} acting on the cutting structure 73 where $F_{wob}=F_d x a/b$." *Id*. (9:8-9). "This force reduces the effective weight-on-bit acting on the primary cutter 69, thus reducing the depth of cut." *Id*. (9:9-11).

241. As the WOB increases the formation facing structure contacts the formation in order to absorb the excess WOB and ensure the depth of cut remains constant. In fact, the '441 patent acknowledges it was known in the art that the WOB necessary to penetrate a formation changes as the drilling progresses from one

formation to another: "Another, separate problem involves drilling from a zone or stratum of higher formation compressive strength to a 'softer' zone of lower strength. As the bit drills into the softer formation without changing the applied WOB (or before the WOB can be changed by the directional driller), the penetration of the PDC cutters, and thus the resulting torque on the bit (TOB), increase almost instantaneously and by a substantial magnitude." Ex.1003 (1:65-2:5).

242. The SPE 39306 paper also confirms that it was known prior to the '441 patent that the WOB required to penetrate a formation depends on the type of formation. The SPE 39306 paper reports a study on the WOB required to achieve certain rates of penetration in Carthage limestone (a harder) and Catoosa shale (a softer formation) for cutters with specific backrake angles. Ex.1029 (5). At each backrake angle, a bit in the harder limestone formation requires more WOB than a bit in the softer shale formation to achieve the same ROP.

243. The SPE 39306 paper also shows it was known prior to the '441 patent that the WOB required to penetrate a formation increases as the surface area of the bit contacting the formation increases. Ex.1029 (3). ("Figure 3 previously showed the resulting increase in weight requirement as the contact area between the PDC cutter and the rock increases."). The SPE 39306 paper was explaining this relationship in context of the increase in surface area of the cutter contacting the formation as the cutter wears and creates a wearflat. A POSA would readily

understand that this principle applies to any bearing surfaces or formation engaging surfaces that, in addition to the cutter, contact the formation—like the abrasion elements of Griffin.

244. In light of the known fact that formation hardness may vary as a drilling progresses and the teachings of the SPE 39306 paper about the relationship of the required WOB to formation hardness, a POSA would have found it obvious that the normal use of the drill bit of Griffin in drilling would result in the drilling operator applying a WOB necessary to penetrate a formation that then becomes an excess WOB as the drill bit progresses to a softer formation.

> d. "transferring the excess weight-on-bit from the drill bit through the bearing surface to the subterranean formation without substantial indentation of the bearing surface into the subterranean formation; and"

245. As discussed above, the formation contacting structure of Griffin will absorb any excess weight on bit. This structure will transfer the excess weight on bit to the formation without substantial indentation of the formation engaging surface into the subterranean formation. As more weight is added the formation engaging element will absorb this weight and transfer it to the surface of the formation.

246. A POSA would know that, at a given distance from the center of the bit, the force generated by a cutter will be greater than the force generated by the wear surfaces, because for a range of WOB the force required to shear the formation

is greater than force of friction against the formation. As a result, a POSA would know that excessive torque on the bit can be prevented by using bearing surfaces or formation engaging elements to limit the depth of cut.

247. Griffin's formation engaging elements (bearing surfaces) 18 have a surface area that engages the formation during normal operation of Griffin's drill bit when the cutters penetrate the formation, thus providing a bearing area. This bearing surface area provided by the formation engaging elements will transfer the WOB to the subterranean formation.

e. "wherein an area of the bearing surface contacting the subterranean formation remains substantially constant over the range of excess weight-on-bit."

248. As discussed above, Griffin discloses information where a POSA would be able to determine the sufficient surface area. As the tip of the formation engaging element contacts the formation surface, a WOB will be added without a change in formation engaging element surface area (bearing surface area). At this point, the surface area is constant over a range of excess WOB. Eventually, a WOB will be added to where the formation engaging element starts to rotate. This element will then rotate and the surface area will vary until enough WOB is added wherein formation engaging element no longer rotates. When the structure no longer rotates, more WOB is applied and the formation engaging element surface area will remain constant over this second range of excess WOB.

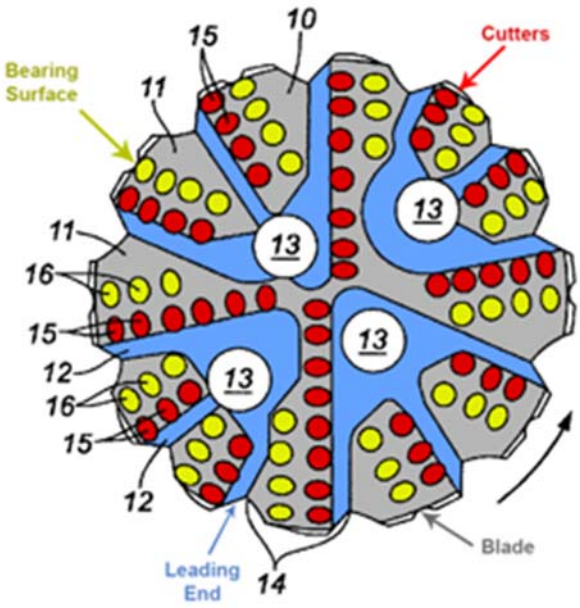
249. As more weight is added the surface area of the formation engaging element, of constant size, will absorb this weight and transfer it to the surface of the formation at a stress less than substantially the compressive strength of the formation.

2. Dependent Claim 17

a. "The method of claim 16, wherein transferring the excess weight-on-bit from a body of the drill bit through the bearing surface to the subterranean formation comprises transferring the excess weight-on-bit to at least one formation-facing bearing surface on the drill bit generally surrounding at least a portion of the at least one cutter."

250. Claim 17 depends from claim 16. As discussed above, claim 16 is obvious in view of Griffin.

251. As I discuss above, Griffin discloses transferring the excess weight on bit to a formation engaging element or structure, which is equivalent to the claimed bearing surface. Griffin discloses the formation engaging structure surrounding the cutters. Griffin discloses "[t]he formation engaging structure 16 [are] spaced rearwardly of its associated cutting structure. Ex.1007 (4:46-49). The formation engaging elements generally surround at least a portion of the cutters as shown in Figure 1 below:



3. Dependent Claim 19

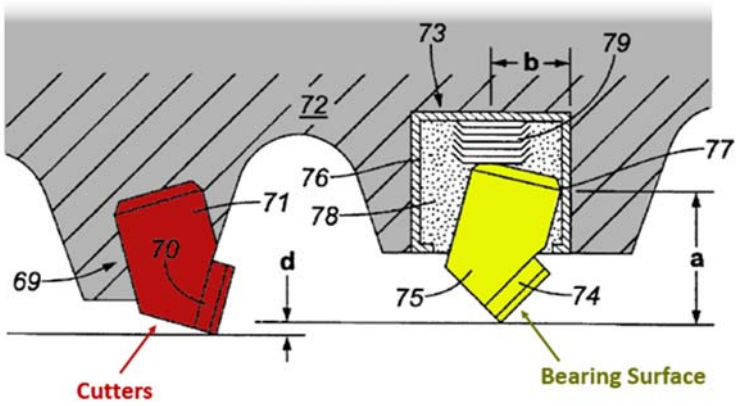
a. "The method of claim 17, wherein transferring the excess weight-on-bit to the at least one formation-facing bearing surface on the drill bit generally surrounding the at least a portion of the at least one cutter comprises transferring the excess weight-on-bit to a hard facing material affixed to a selected portion of the at least one formation-facing bearing surface proximate the at least one cutter."

252. Claim 19 depends from claim 17, which depends from claim 16. As discussed above, in my opinion, claims 16 and 17 are obvious in view of Griffin.

253. As I discuss above, Griffin discloses a method wherein the excess weight-on-bit is transferred to a formation engaging surface helping to prevent failure of the formation and damage to the cutter. Griffin teaches "[i]n FIG. 11, a primary cutting structure 69 includes a circular polycrystalline diamond compact 70 … [i]n this case the associated formation engaging structure 73 also includes a polycrystalline diamond cutting element 74." Ex.1007 (8:43-48). Cutter 73 has a

polycrystalline diamond compact 74 that is bonded to a post 75. *Id*. (8:46-48). The hard facing material is equivalent to the polycrystalline diamond compact 74. *Id*. Further, Griffin discloses that "[t]he structure 73 is located on the leading side of the cutter 69 in the direction of rotation, and it is at substantially the same radius from the central longitudinal axis of rotation of the drill bit." *Id*. (8:48-51). As shown in Figure 11 below, a POSA would understand that the formation engaging element is proximate the cutters.

FIG. 11



4. Independent Claim 21

a. "A method of designing a drill bit for drilling a subterranean formation the drill bit under design including a plurality of superabrasive cutters disposed about a formation-engaging leading end of the drill bit, the method comprising:"

254. It is my opinion that claim 21 is obvious in view of Griffin.

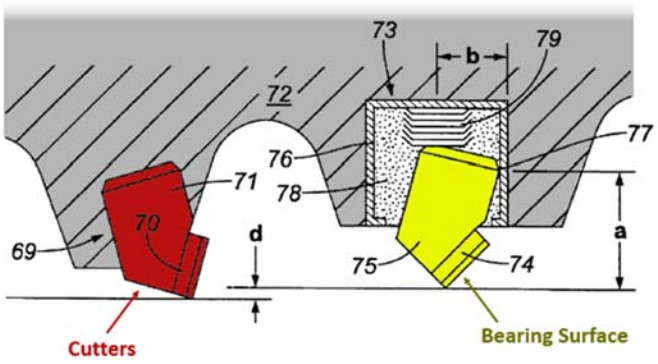
255. It is my understanding, that the preamble to the independent claims of the '441 patent do not limit their scope. The preamble of claim 21 generally

describes a method of "designing a drill bit." Griffin discloses a drill bit, that drill bit was designed. A POSA, at the time of the invention, would have found it obvious to design the drill bit by Griffin.

b. "selecting a maximum depth-of-cut for at least some of the plurality of superabrasive cutters;"

256. Griffin discloses a drill bit used in drilling subterranean formations that contains a cutter with a selected depth-of-cut. Griffin discloses the "[t]he distance 'd' is a predetermined desired depth of cut." Ex.1007 (9:4-5). As shown in Figure 11, Griffin discloses the cutter engaging a depth of cut.

FIG. 11

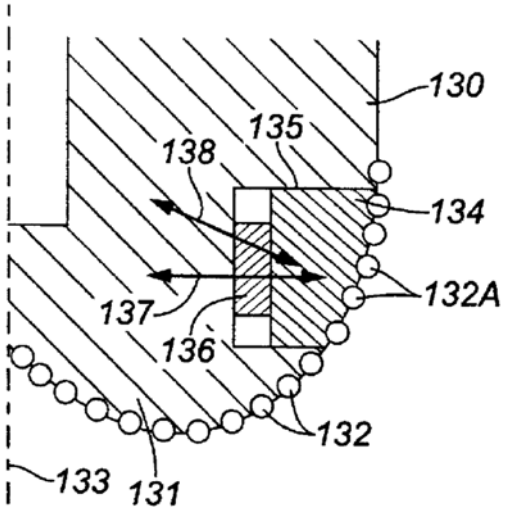


c. "selecting a cutter profile arrangement to which the at least some of the plurality of superabrasive cutters are to be radially and longitudinally positioned on the formation engaging leading end of the drill bit; and"

257. Griffin teaches a cutter profile arrangement wherein the at least some of the superabrasive cutters are radially and longitudinally positioned on the formation engaging leading end of the drill bit. As shown in Figure 23, "the bit body 130 has a number of upstanding blades 131 extending outwardly away from the

central axis of rotation 133 of the bit. Cutters 132 are mounted along each blade." Ex.1007 (12:52-55).

FIG. 23



d. "configuring within the design of the drill bit a sufficient total amount of formation-facing bearing surface area structured for axially supporting the drill bit without substantially indenting the subterranean formation should the drill bit be subjected to a weight-on-bit exceeding a weight-on-bit which would cause the formation-facing bearing surface area to contact the subterranean formation,"

258. Griffin's subsidiary cutting structures have a surface area that engages the formation during normal operation of Griffin's drill bit when the cutters penetrate the formation, thus providing a bearing area. Griffin's Figure 11 shows this formation-engaging bearing area as being larger than the area of the cutter that engages the formation. Thus, in normal operation of Griffin's drill bit, Griffin's

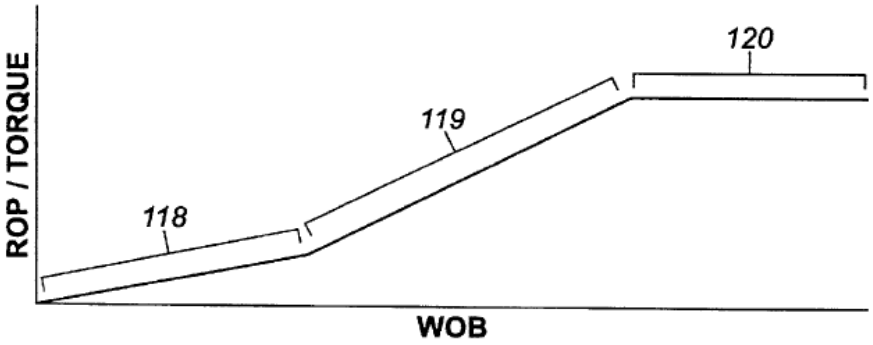
subsidiary cutting structures will maintain the selected depth of cut even when weight on bit exceeds that required for the cutters 16 to penetrate the formation.

259. Griffin discloses "the cutting structure 69 is the primary cutting structure for removing formation from the borehole." Ex.1007 (9:1-2). "The subsidiary cutting structure 73, however, acts as a penetration limiter." *Id*. (9:3-4). "The distance 'd' is a predetermined desired depth of cut." *Id*. (9:4-5). "If this depth of cut is exceeded, the drag F_d acting on the cutter 74, 75 will increase causing the cutter 74, 75 to tilt rearwardly within its housing." *Id*. (9:5-8). "This will increase the vertical force F_{wob} acting on the cutting structure 73 where $F_{wob}=F_d xa/b$." *Id*. (9:8-9). "This force reduces the effective weight-on-bit acting on the primary cutter 69, thus reducing the depth of cut." *Id*. (9:9-11).

260. "FIG. 16 is a graph of rate of penetration of a drill bit against weight-on-bit showing a desired relationship." Ex.1007 (3:39-40). "This desired manner of operation is illustrated by the graph of FIG. 16 which shows rate of penetration or torque against weight-on-bit." *Id*. (11:1-3). "A comparatively low weight-on-bit is indicated by the portion 118 of the graph." *Id*. (11:3-4). "In the portion 118, orienting or steering of the bit may take place." *Id*. (11:4-5). "Thus, a low rate of penetration is preferred, equivalent to having a very unaggressive bit." *Id*. (11:5-7). "When the weight-on-bit is in a normal operating range, however, a comparatively higher rate of penetration is typically preferred." *Id*. (11:7-9). "The normal range

of operation of a conventional PDC bit is indicated by the portion of the graph 119, where an aggressive bit is usually preferred." *Id*. (11:9-12). "At a high weight-on-bit, it is desirable to limit rate of penetration and torque, as indicated by the portion 120 of the graph, to prevent stalling of the motor." *Id*. (11:12-14). "The portion 120 therefore corresponds to an unaggressive bit." *Id*. (11:14-15).

FIG. 16



261. "To design a bit to perform as shown in the graph of FIG. 16, the formation-engaging members on the bit may be controlled so that the bit is unaggressive at low weight-on-bit, and torque limited at high rates of penetration, with an operating range in between." Ex.1007 (11:16-20). "Alternatively, the aggressitivity of the bit may be limited, such that at a specified torque or weight-on-bit, the bit becomes very unaggressive." *Id*. (11:20-22).

262. As the WOB increases the formation facing structure contacts the formation in order to absorb the excess WOB and ensure the depth of cut remains constant. In fact, the '441 patent acknowledges it was known in the art that the WOB necessary to penetrate a formation changes as the drilling progresses from one

formation to another: "Another, separate problem involves drilling from a zone or stratum of higher formation compressive strength to a 'softer' zone of lower strength. As the bit drills into the softer formation without changing the applied WOB (or before the WOB can be changed by the directional driller), the penetration of the PDC cutters, and thus the resulting torque on the bit (TOB), increase almost instantaneously and by a substantial magnitude." Ex.1003 (1:65-2:5).

263. The SPE 39306 paper also confirms that it was known prior to the '441 patent that the WOB required to penetrate a formation depends on the type of formation. The SPE 39306 paper reports a study on the WOB required to achieve certain rates of penetration in Carthage limestone (a harder) and Catoosa shale (a softer formation) for cutters with specific backrake angles. Ex.1029 (5). At each backrake angle, a bit in the harder limestone formation requires more WOB than a bit in the softer shale formation to achieve the same ROP.

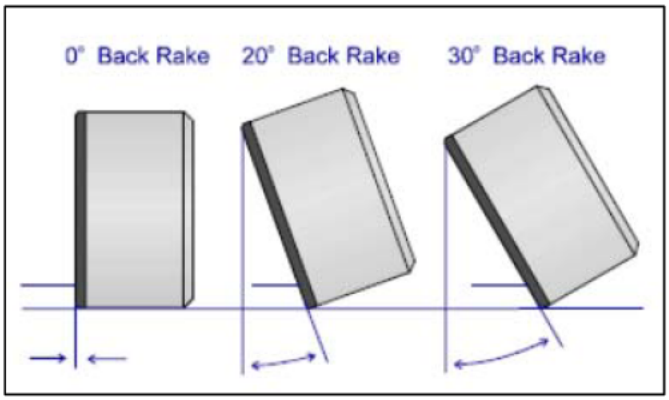
264. The SPE 39306 paper also shows it was known prior to the '441 patent that the WOB required to penetrate a formation increases as the surface area of the bit contacting the formation increases. Ex.1029 (3). ("Figure 3 previously showed the resulting increase in weight requirement as the contact area between the PDC cutter and the rock increases."). The SPE 39306 paper was explaining this relationship in context of the increase in surface area of the cutter contacting the formation as the cutter wears and creates a wearflat. A POSA would readily

understand that this principle applies to any formation engaging element or bearing surfaces that, in addition to the cutter, contact the formation—like the abrasion elements of Griffin.

265. In light of the known fact that formation hardness may vary as a drilling progresses and the teachings of the SPE 39306 paper about the relationship of the required WOB to formation hardness, a POSA would have found it obvious that the normal use of the drill bit of Griffin in drilling would result in the drilling operator applying a WOB necessary to penetrate a formation that then becomes an excess WOB as the drill bit progresses to a softer formation.

266. The Challenged Claims do not specify the amount of surface area necessary to maintain the selected depth of cut. Nonetheless, a POSA at the time of the ’441 patent knew how to calculate the sufficient area necessary to control depth of cut. Initially, the physical features of the bit are selected. These features include the shape of the bit, the location of the cutters, and the location of the bearing surfaces in circumferential path of the cutters, either leading the cutter or trailing the cutter, as taught by the prior art. Additional factors include (1) the number of cutters, (2) location of the cutter with respect to the center of the bit, (3) back rake angle of the cutters, and (4) diameter of the cutters. Other known features can be considered when designing the layout of the cutter profile of the bit.

267. The weight on bit selected depends on the physical properties of the bit described above, in addition to the compressive strength of the formation. For example, the more aggressive the cutter with respect to physical orientation such as exposure beyond the bearing surface and less back rake angle, the greater the surface area necessary for a given applied weight on bit in a given formation.



Ex.1044 (slide 7).

268. As previously mentioned, the weight on bit is also selected based on the compressive strength of the formation. A higher weight on bit needs to be applied when the compressive strength of the formation is higher.

269. In fact, the '441 patent recognizes that a POSA wanting to practice the claimed invention would know the WOB and know the type of formation. "By providing DOCC features having a cumulative surface area sufficient to support a given WOB on a given rock formation, preferably without substantial indentation or failure of same, WOB may be dramatically increased, if desired, over that usable in drilling with conventional bits without the PDC cutters experiencing any additional

effective WOB after the DOCC features are in full contact with the formation." Ex.1003 (4:54-61).

270. Using simple equations, a POSA given a weight on bit can determine the sufficient bearing surface area needed.

$$Area = \frac{WOB}{RS}$$

271. WOB is the given weight on bit referred to by the '441 patent. RS is the rock strength and is based on the type of formation, and an easily measurable parameter. Rock strength is the compressive strength of the rock.

$$Area = A_{cutter} + A_{bearing\ surface}$$

272. The area in the equation is equal to the projected area in the axial direction of the cutter (A_{cutter}) plus the bearing surface area ($A_{bearing\ surface}$). The projected area in the area in the axial direction of the cutter is a function of the cutter geometry, back rake, and depth of cut. The depth of cut is determined when the bearing surface engages the formation. The area of the bearing surface is the axial projected contact area.

$$A_{bearing\ surface} = Area - A_{cutter}$$

273. The bearing surface area is the minimum surface area required to hold a specific weight on bit. As weight on bit increases the area has to increase with the incremental weight over rock strength. As long as the bearing area is sufficient to

hold the weight on bit, depth of cut is controlled. The area of the formation engaging elements can support a certain range of weight on bit. As the weight on bit increases the amount of surface area remains constant and supports any excess weight on bit.

274. Based on this simple explanation, a POSA would have known how to calculate sufficient surface area, and would have found it obvious to do so in order to ensure the bit is designed so that damage to the cutters and the bit body is avoided. In fact, prior to the filing of the '441 patent, computer programs existed that simulate these calculations in order to feature different bit designs. A POSA would find it obvious to determine the sufficient surface area required to maintain a unit load on the formation below the compressive strength of a formation for a given formation and given weight on bit.

e. "wherein the formation-facing bearing surface area is sized and configured to remain substantially constant over a range of excess weight-on-bit."

275. As discussed above, Griffin discloses information where a POSA would be able to determine the sufficient surface area. As the tip of the formation engaging element contacts the formation surface, a WOB will be added without a change in formation engaging element surface area (bearing surface area). At this point, the surface area is constant over a range of excess WOB. Eventually, a WOB will be added to where the formation engaging element starts to rotate. This element will then rotate and the surface area will vary until enough WOB is added wherein

formation engaging element no longer rotates. When the structure no longer rotates, more WOB is applied and the formation engaging element surface area will remain constant over this second range of excess WOB.

276. As more weight is added the surface area of the formation engaging element, of constant size, will absorb this weight and transfer it to the surface of the formation at a stress less than substantially the compressive strength of the formation.

5. Dependent Claim 23

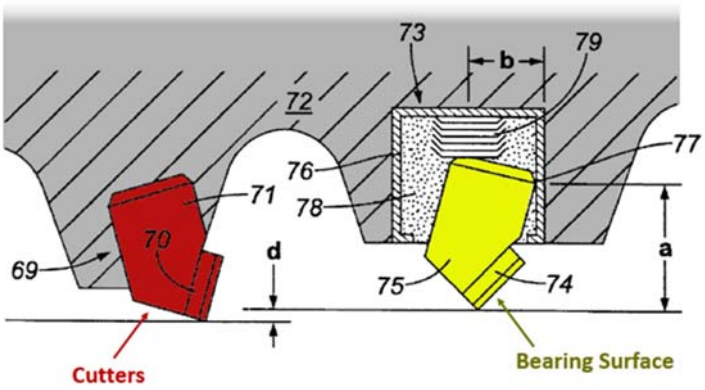
a. "The method of claim 21, wherein configuring within the design of the drill bit a sufficient total amount of the formation-facing bearing surface area comprises selecting an amount of hard facing to be disposed on at least a portion of the formation-facing bearing surface at least partially surrounding the at least some of the plurality of superabrasive cutters."

277. Claim 23 depends from claim 21. As discussed above, in my opinion, claim 21 is obvious in view of Griffin.

278. As I discuss above, Griffin discloses a method wherein the excess weight-on-bit is transferred to a formation engaging surface helping to prevent failure of the formation and damage to the cutter. Griffin teaches "[i]n FIG. 11, a primary cutting structure 69 includes a circular polycrystalline diamond compact 70 … [i]n this case the associated formation engaging structure 73 also includes a polycrystalline diamond cutting element 74." Ex.1007 (8:43-48). Cutter 73 has a

polycrystalline diamond compact 74 that is bonded to a post 75. *Id*. (8:46-48). The hard facing material is equivalent to the polycrystalline diamond compact 74. *Id.* Further, Griffin discloses that "[t]he structure 73 is located on the leading side of the cutter 69 in the direction of rotation, and it is at substantially the same radius from the central longitudinal axis of rotation of the drill bit." *Id*. (8:48-51). As shown in Figure 11 below, the formation engaging element is proximate the cutters.

FIG. 11



6. Dependent Claim 24

a. "The method of claim 21, further comprising: including within the design of the drill bit another formation-facing bearing surface area structured for axially supporting the drill bit without substantially indenting the subterranean formation therewith should the drill bit be subjected to an additional excess weight-on-bit exceeding an excess weight-on-bit."

279. Claim 24 depends from claim 21. As discussed above, in my opinion, claim 21 is obvious in view of Griffin.

280. As discussed above, Griffin discloses information where a POSA would be able to determine the sufficient surface area. This sufficient surface area

will absorb the excess weight-on-bit over the maximum weight-on-bit necessary to achieve the maximum depth of cut. As more weight is added the formation engaging element will absorb this weight and transfer it to the surface of the formation at a stress less than substantially the compressive strength of the formation.

X. SECONDARY CONSIDERATIONS OF NON-OBVIOUSNESS

281. It is my opinion that secondary considerations do not support the non-obviousness of the Challenged Claims. I have seen no evidence that supports any secondary considerations tending to show non-obviousness, including commercial success, long-felt need, failure of others, skepticism, praise, teaching away, recognition of a problem, or copying by competitors.

282. I am not aware of anything suggesting commercial success of any products can be attributed to the Challenged Claims.

283. I am also unaware of there being a long-felt need at the time of the alleged invention for an invention utilizing the elements recited in the Challenged Claims.

284. I am also not aware of any failure of others to design or implement an invention similar to the one recited in the Challenged Claims. In fact, I believe there are numerous similar systems, including but not limited to the ones described in above, which pre-date the Challenged Claims.

285. I have reviewed numerous prior art references from around the time of the alleged invention and am not aware of any skepticism, praise, or teaching away by others of the alleged invention recited in the Challenged Claims. In fact, the opposite is true: prior art references explain the ready combination of the cited prior art systems. I am likewise unaware of any recognition afforded to the alleged invention recited in the Challenged Claims.

286. I am not aware of any copying of the Challenged Claims for their designs or products.

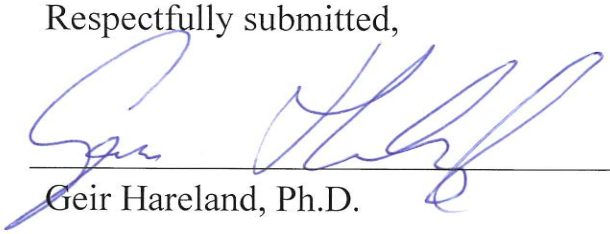
287. Should the Patent Owner assert that secondary considerations support a finding of non-obviousness, I reserve the right to submit a Declaration addressing those new assertions.

XI. CONCLUSION

288. I hereby declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct, and that all statements made of my own knowledge are true and that all statements made on information and belief are believed to be true. I understand that willful false statements are punishable by fine or imprisonment or both. *See* 18 U.S.C. §1001.

Date: September 5, 2018

Respectfully submitted,



Geir Hareland, Ph.D.