UNITED STATES PATENT AND TRADEMARK OFFICE

BEFORE THE PATENT TRIAL AND APPEAL BOARD

ULTERRA DRILLING TECHS., L.P.,
Petitioner

v.

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

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

PETITION FOR *INTER PARTES* REVIEW UNDER 37 C.F.R. § 42.101

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I. INTRODUCTION

Ulterra Drilling Technologies, L.P. ("Ulterra") respectfully requests *inter partes* review ("IPR") of claims 16-17, 19-21, and 23-24 ("the Challenged Claims") of the U.S. Patent No. 6,935,441 ("the '441 patent").[1] By its own submission, the '441 patent does nothing more than use known components and features from the prior art according to their intended purpose to achieve predictable results. The '441 patent's alleged novelty—using known art in a "well-reasoned" or engineering approach—fails to distinguish the prior art.

II. MANDATORY NOTICES

Ulterra provides the following mandatory notices under 37 C.F.R. § 42.8(b).

A. 37 C.F.R. § 42.8(b)(1): Real Parties-in-Interest

The real parties-in-interest are Ulterra Drilling Technologies, L.P. and American Securities LLC.

B. 37 C.F.R. § 42.8(b)(2): Related Matters

The outcome of this proceeding could affect or be affected by the proceedings in *Baker Hughes, a GE company, LLC v. Ulterra Drilling Technologies, L.P.*, No. 4:18-cv-339 (S.D. Tex.) ("District Court Litigation"). *Id.* § 42.8(b)(2). In that case,

[1] All emphases and coloring in this Petition have been added unless otherwise stated and are for purposes of illustration and readability.

Baker Hughes has asserted that Ulterra infringes claims 16-17, 19-21, and 23-24 of the '441 patent. Ex.1072 (33-38).

Ulterra has also filed the following IPR petitions involving patents related to the '441 patent:

IPR2018-01572 (U.S. Patent No. 6,298,930)

IPR2018-01573 (U.S. Patent No. 6,298,930)

IPR2018-01575 (U.S. Patent No. 6,460,631)

IPR2018-01591 (U.S. Patent No. 7,096,978)

IPR2018-01593 (U.S. Patent No. 6,779,613)

IPR2018-01595 (U.S. Patent No. 6,779,613)

C. 37 C.F.R. § 42.8(b)(3) & (4): Lead and Back-up Counsel and Service Information

Lead Counsel	Backup Counsel
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A Power of Attorney accompanies this Petition pursuant to 37 C.F.R. § 42.10(b). Ulterra consents to electronic service by email at Ulterra_IPR@kirkland.com.

III. PAYMENT OF FEES PURSUANT TO 37 C.F.R. § 42.103

The undersigned authorizes the Office is authorized to charge the fee set for in 37 C.F.R. § 42.15(a)(1) for this Petition to Deposit Account No. 506092. Review of 7 claims is requested, so no additional fee is submitted. The undersigned further authorizes payment for any additional fees that may be due in connection with this Petition to be charged to the above deposit account.

IV. CERTIFICATION OF STANDING UNDER 37 C.F.R. § 42.104

Ulterra certifies that the '441 patent is available for IPR and that Ulterra is not barred or estopped from requesting an IPR challenging the claims on the grounds identified in this Petition. Ulterra certifies (1) Ulterra is not the owner of the '441 patent; (2) Ulterra (or any real party-in-interest) has not filed a civil action challenging the validity of any claim of the '441 patent; (3) Ulterra is not barred under 35 U.S.C. § 315(b) or estopped under 35 U.S.C. § 315(e)(1) from filing this IPR; and (4) this Petition is filed after the '441 patent was granted.

V. OVERVIEW OF CHALLENGE AND RELIEF REQUESTED

A. 37 C.F.R. § 42.104(b)(1): Claims for Which IPR is Requested

Ulterra challenges claims 16-17, 19-21, and 23-24 of the '441 patent.

B. 37 C.F.R. § 42.104(b)(2): Grounds for Challenge

The claims are challenged based on the following references:

1. U.S. Patent No. 5,244,039 to Newton ("Newton"), published September 14, 1993, and prior under § 102(b). Newton is cited on the face of the '441 patent, but not applied in any Office Action.
2. U.S. Patent No. 4,554,986 to Jones ("Jones"), published November 26, 1985, and prior art under § 102(b). Jones was cited on the face of the '441 patent, but not applied in any Office Action. The Examiner had rejected claims of the '441 patent's parent application based on Jones.
3. U.S. Patent No. 6,142,250 to Griffin ("Griffin"), published November 7, 2000, and prior art under § 102(e). Griffin was not considered by the Examiner.

Ulterra requests IPR on the following grounds:

Ground	Claims	Basis
1	16-17, 19-21, and 23-24	Obvious under 35 U.S.C. § 103 over Newton and the Knowledge of a POSA
2	16-17, 19-21, and 23-24	Obvious under 35 U.S.C. § 103 over Jones and the Knowledge of a POSA
3	16-17, 19, 21, and 23-24	Obvious under 35 U.S.C. § 103 over Griffin and the Knowledge of a POSA

C. 37 C.F.R. § 42.104(b)(3): Claim Construction

A claim of an unexpired patent in *inter partes* review is currently given the "broadest reasonable construction in light of the specification." 37 C.F.R. § 42.100(b); *see Cuozzo Speed Techs., LLC v. Lee*, 136 S. Ct. 2131, 2142 (2016).

However, the USPTO has proposed "to replace the broadest reasonable interpretation ('BRI') standard for construing unexpired patent claims and proposed claims in [IPR] trial proceedings with a standard that is the same as the standard applied in federal district courts and International Trade Commission ('ITC') proceedings." *See* Changes to the Claim Construction Standard for Interpreting Claims in Trial Proceedings Before the Patent Trial and Appeal Board, 83 Fed. Reg. 21,221 (May 9, 2018) (to be codified at 37 C.F.R. pt. 42).

Federal district courts and the ITC construe patent claims in accordance with the principles set forth in *Phillips v. AWH Corp.*, 415 F.3d 1303 (Fed. Cir. 2005) (en banc). 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." *Id.* at 1312-13.

Petitioner does not propose any claim construction in this Petition for at least the reason that Petitioner believes the Challenged Claims are invalid under either claim-construction standard. If Patent Owner hereafter proposes construction in the co-pending litigation, however, Petitioner reserves the right to request additional briefing in connection with this Petition.

D. 37 C.F.R. § 42.104(b)(4): How the Claims are Unpatentable

A detailed explanation of how the Challenged Claims are unpatentable is provided in Section X.

E. 37 C.F.R. § 42.104(b)(5): Evidence Supporting Challenge

A list of exhibits is provided at the end of the Petition. The relevance of this evidence and the specific portions supporting the challenge is provided in Section X. Ulterra submits a declaration of Geir Hareland (Ex. 1001) in support of this Petition under 37 C.F.R. § 1.68.

VI. BACKGROUND OF THE TECHNOLOGY

A. Drilling Rigs, Drag Bits, and Cutters

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); Ex.1001 (¶21). A rotary drilling rig is shown below:

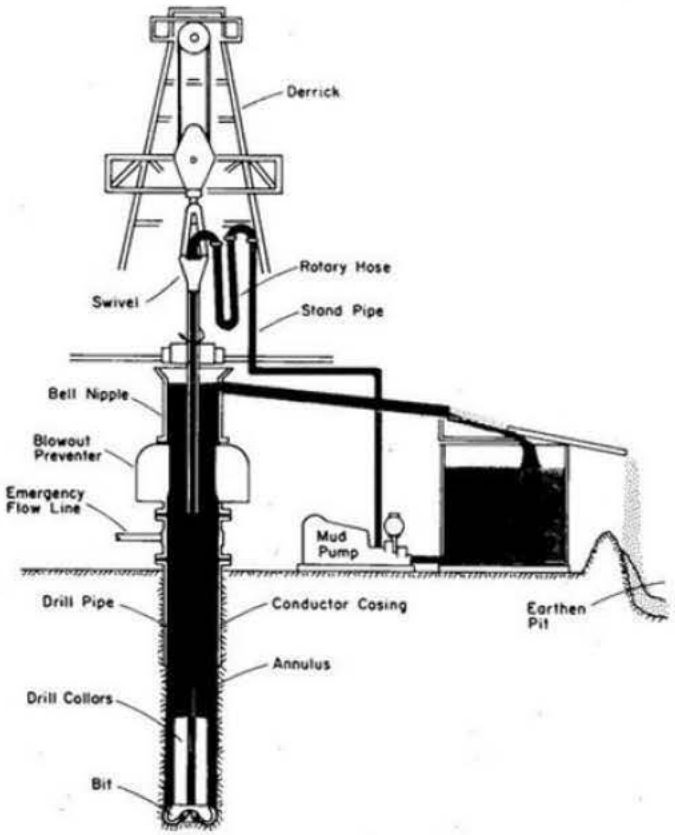


Fig. 1.4 - The rotary drilling process.

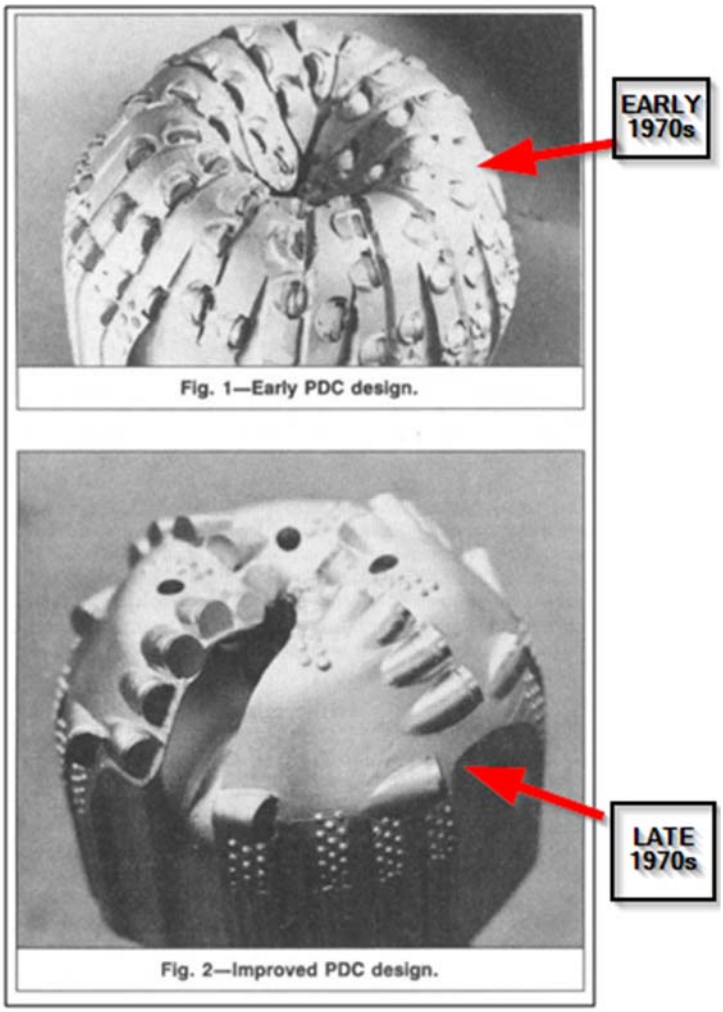
Ex.1011 (4); Ex.1001 (¶21).

To drill a hole, drill collars apply downward force. Ex.1011 (4); Ex.1001 (¶22). Rotating the drill string turns the bit. Ex.1011 (4); Ex.1001 (¶22). The drill bit includes cutters, which cut or drill the rocks. Ex.1014 (4); Ex.1001 (¶22). As

the bit drills into the ground (or "formation"), it creates cuttings, which are removed by circulating drilling fluid through the bit. Ex.1014 (4); Ex.1001 (¶22).

Rotary-drilling bits are generally classified as rollercone bits or drag bits. Ex.1011 (8); Ex.1001 (¶28). Drag bits "consist of fixed cutter blades that are integral with the body of the bit and rotate as a unit with the drillstring." Ex.1011 (8); *see also* Ex.1001 (¶31). Drag bits have several advantages over rollercone bits, including a reduced risk of breakage and the ability to drill small hole sizes. Ex.1011 (8); Ex.1001 (¶31).

Drag bits may include steel, diamond, or synthetic diamond cutters. Ex.1014 (13-14); Ex.1001 (¶31). Synthetic diamond cutters are typically made from polycrystalline diamond compact ("PDC") and were first manufactured in the 1970s. Ex.1014 (8); Ex.1016 (1); Ex.1001 (¶37). The first PDC bits were designed like natural diamond bits, but were soon after redesigned to take full advantage of the more efficient PDC bit's shearing cutting mechanism. Ex.1016 (1); Ex.1017 (5); Ex.1001 (¶37). This led to a bladed-bit style in the late 1970s, similar to what is used today as illustrated in Figure 2 below.



Ex.1016 (1); Ex.1001 (¶37). PDC cutters are comprised of many small diamond crystals bonded together. Ex.1011 (9); Ex.1001 (¶47). PDC bit bodies can be steel or matrix. Ex.1001 (¶39). In a steel-bodied bit, the PDC cutter is bonded to a tungsten carbide stud that is mounted in the steel bit body, which allows the stud to be replaced if necessary. Ex.1016 (1-2); Ex.1001 (¶41). In matrix-bodied bits, the PDC cutter is brazed into a pocket, which provides impact resistance. Ex.1016 (2); Ex.1001 (¶41).

B. Bit Design and Performance

PDC bits were introduced in the 1970s and experienced widespread drilling success, largely in soft to medium-hard formations. Ex.1016 (1); Ex.1001 (¶37). By the 1980s, bit engineers were refining PDC bit design to improve performance. Ex.1027 (1); Ex.1011 (5, 13); Ex.1028 (1); Ex.1001 (¶53). Bit performance is typically measured in drilling cost per foot, which is dependent on rate of penetration ("ROP") and bit life. Ex.1011 (5, 13); Ex.1028 (1); Ex.1001 (¶25). ROP refers to the speed at which the bit drills into formations. Ex.1011 (7); Ex.1001 (¶25).

Cutter wear reduces ROP and bit life, and is caused by the bit's repeated contact with the formation. Ex.1029 (1); Ex.1001 (¶53).

C. Bearing Surfaces to Control Depth of Cut

A well-known consideration in the design and use of drag bits is the need to control the depth-of-cut ("DOC"). Ex.1001 (¶82). "PDC bits remove rock by a shearing action, much like a machine tool, which places the rock in tension." Ex.1064 (18). If the cutters on the drill bit engage too little into the formation, then there will be a lower than necessary rate of penetration into the ground, resulting in increased costs and delays in completing the well. Ex.1001 (¶101). Alternatively, if the cutters engage too much into the formation, the bit could be subjected to too much torque and damaged, also resulting in increased costs and delays in completing

the well. *Id*. These issues have been known to those designing drag bits for decades. *Id.*

As early as 1989, Sandia National Laboratories researched the use of computers to optimize bit design. Ex.1064 (60); Ex.1001 (¶75). Sandia disclosed a computer program that calculates forces, temperatures, and wear rates of individual cutters in a user-defined bit design. Ex.1064 (60); Ex.1001 (¶91). "The code also gives the torque, side load, and bending moment on the bit; the rate of penetration; and the wear of each cutter." Ex.1064 (60); Ex.1001 (¶91). "As the drilling calculation proceeds, the wear rate of each cutter is tracked and the drilling conditions are updated with the new force data." Ex.1064 (60); Ex.1001 (¶92).

VII. OVERVIEW OF THE '441 PATENT

The '441 patent issued from U.S. Patent Application No. 10/861,129, which was filed on June 4, 2004. Ex. 1003 (cover). The '441 patent is a continuation of application No. 10/266,523, filed on October 7, 2002, now U.S. Patent No. 6,770,613, which is a continuation of application No. 09/738,687, filed on December 15, 2000, now U.S. Patent No. 6,460,631, which is a continuation-in-part of application No. 09/383,288 filed on August 26, 1999, now U.S. Patent No. 6,298,930. *Id.* The '441 patent's earliest possible priority date is December 15, 2000 due to its status as a continuation. Because the application leading to the '441 patent was filed before March 16, 2013, its patentability under 35 U.S.C. §§ 102,

103 is not governed by the Leahy-Smith America Invents Act, Pub. L. 112-29, 125 Stat. 284 (2011).

The '441 patent relates to "rotary drag bits for drilling subterranean formations and their operation." Ex.1003 (1:17-19); Ex.1001 (¶116). Specifically, 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." Ex.1003 (1:19-25); Ex.1001 (¶116).

A. Alleged Problem in the Art

The '441 patent lists 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); Ex.1001 (¶117). Overloading refers to the amount of weight on the drill bit ("WOB"), which can be too high and cause damage to the bit. Ex.1003 (1:45-49); Ex.1001 (¶117). Even at low WOB, the bit can be overloaded because of high torque. Ex.1003 (1:49-52); Ex.1001 (¶117). When a bit goes from a stratum of higher compressive strength to lower compressive strength it is subjected almost instantaneously to a higher torque. Ex.1003 (1:67-2:5); Ex.1001 (¶117). This higher torque can cause damage to the cutters or the bit body itself. Ex.1003 (2:5-7);

Ex.1001 (¶117). Bit balling is the tendency of the earth to stick to the drill, usually due to poor hydraulics. Ex.1016 (4); Ex.1001 (¶117). If bit balling occurs, eventually, the cutters become covered with the earth and further drilling does not happen. Ex.1016 (5); Ex.1001 (¶117).

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); Ex.1001 (¶118). 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." Ex.1003 (2:23-46); Ex.1001 (¶118).

B. Alleged Invention of the '441 Patent

The '441 patent purports to improve on the prior art, "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); Ex.1001 (¶119). The '441

patent employs "DOC control (DOCC) features" that control how deeply the PDC cutters penetrate the formation. Ex.1003 (3:16-20); Ex.1001 (¶119). The '441 patent indicates the simple relationship between surface area and WOB. 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 convention 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. Ex.1003 (4:54-61); Ex.1001 (¶119).

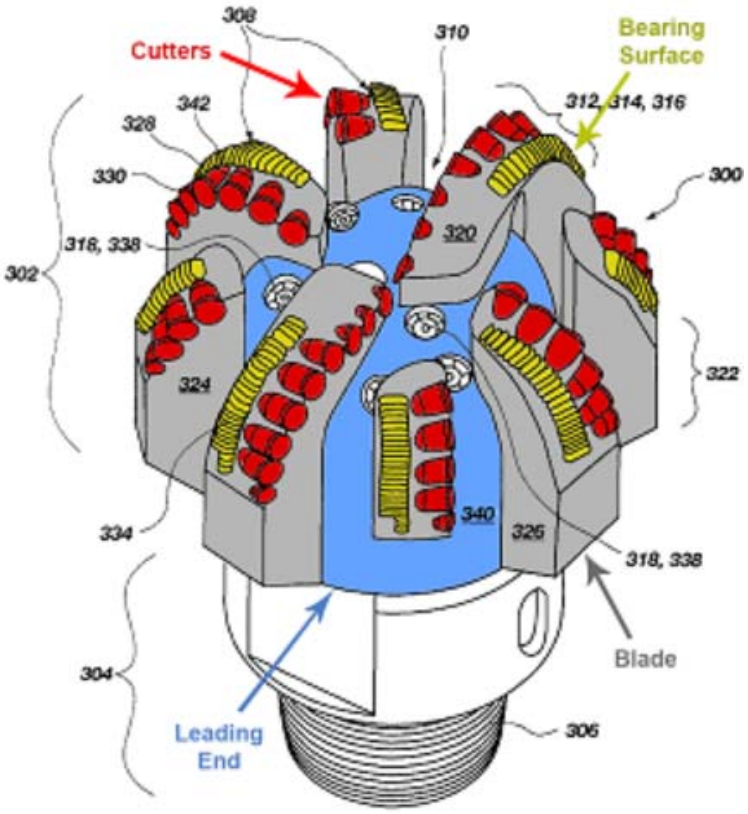


Fig. 14A

In Figure 14A above, 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); Ex.1001 (¶121). 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." Ex.1003 (19:65-67); Ex.1001 (¶121). "A plurality of cutting elements, [or] cutters 328, [is] preferably disposed along and partially within blade structures 308." Ex.1003 (20:23-25); Ex.1001 (¶121). 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." Ex.1003 (20:38-44); Ex.1001 (¶121).

The '441 patent notes "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); Ex.1001 (¶122).

C. Prosecution History

No substantive rejections were issued by the Examiner during the prosecution of the application. The Examiner issued one Non-final rejection, which did not contain any art rejections. Ex.1004 (90-92). The Non-Final rejection for claims 1-24 rejected the claims on the ground of nonstatutory obviousness-type double patenting based on U.S. Patent No. 6,799,613. *Id.* (90-92). To overcome this rejection, the applicant filed a terminal disclaimer. *Id.* (147-53). The Examiner issued a notice of allowance with no additional substantive office actions. *Id.* (161-162).

VIII. LEVEL OF ORDINARY SKILL IN THE ART

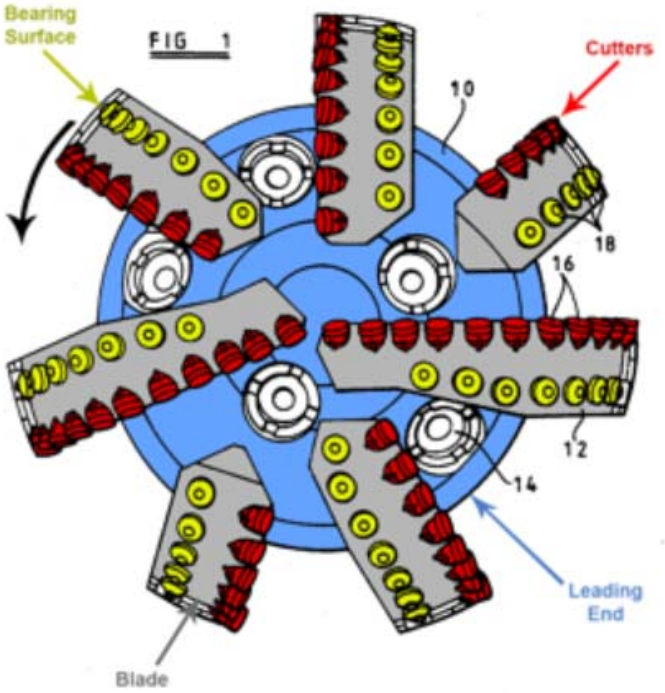
A person of ordinary skill in art ("POSA") as of December 15, 2000 would have had a Bachelor's degree in Mechanical Engineering, Civil Engineering, Structural Engineering, or Petroleum Engineering as well as several years of experience manufacturing or designing drill bits. Additional education or experience in related fields could compensate for deficits in the above qualifications. Ex.1001 (¶¶124-26).

IX. OVERVIEW OF THE PRIMARY PRIOR ART

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

Newton discloses rotary drill bits that 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.

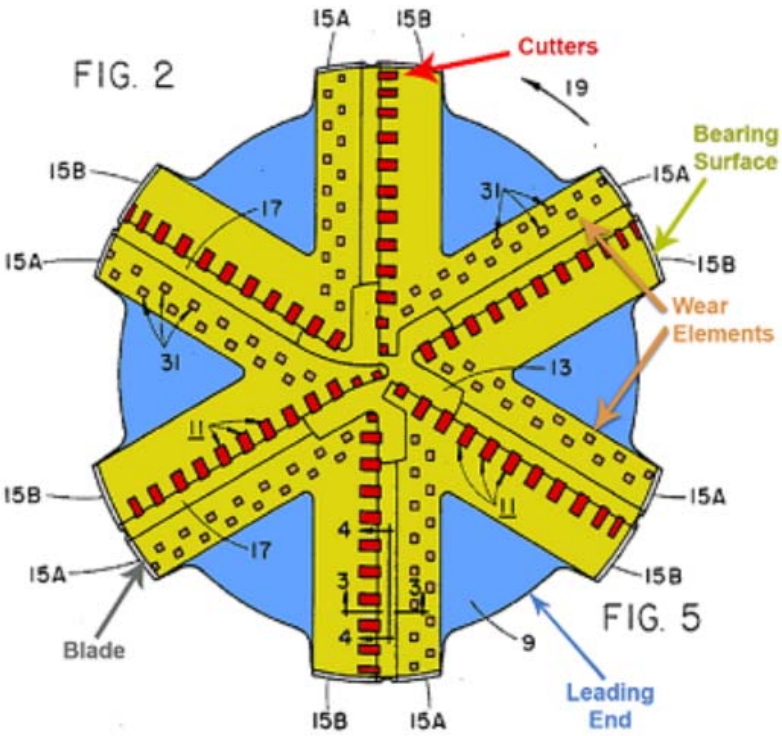
Newton states at least some of the cutting elements having a superhard face. Ex.1005 (1:5-14); Ex.1001 (¶128). Newton discloses primary cutting elements and secondary abrasion elements which are set slightly below or inwardly of the primary cutting profile. Ex.1005 (1:30-35); Ex.1001 (¶128). Newton discloses "[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 on (sic) the bit … even though their respective cutting elements may be subjected to different rates of wear." Ex.1005 (2:67-3:6); Ex.1001 (¶128). Figure 1 is a representative embodiment of Newton. Ex.1005 (3:66-68); Ex.1001 (¶128).



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); Ex.1001 (¶129).

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

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); Ex.1001 (¶130). 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." Ex.1006 (4:50-52, 5:39-41); Ex.1001 (¶130).

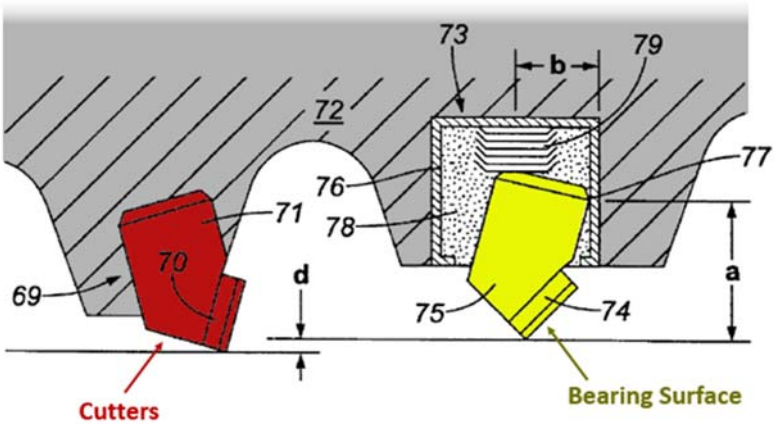


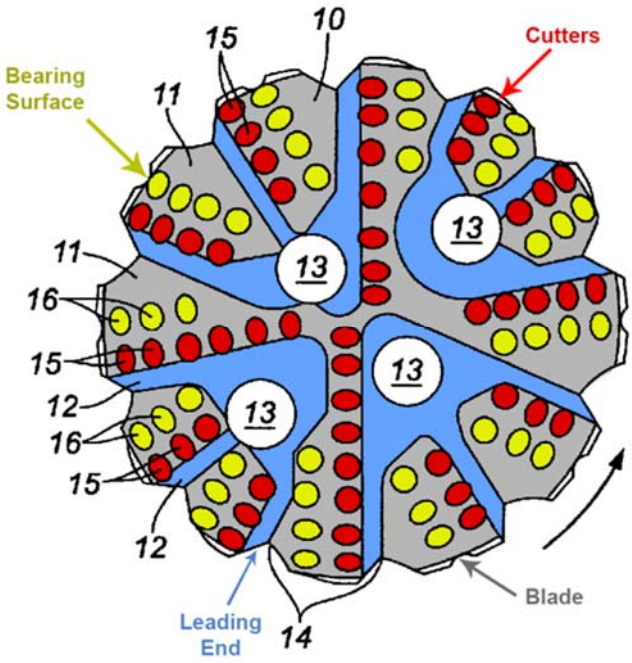
Jones discloses "the leading ridge extends down to a level below the bottom of the trailing ride but above the edges for limiting the depth of penetration of the cutting element." Ex.1006 (abstract); Ex.1001 (¶131). Specifically, "[u]pon the application of a weight on the bit 1 less than a predetermined weight, the cutting elements 11 will penetrate the formation to a depth dependent on the amount of the weight." Ex.1006 (5:22-25); Ex.1001 (¶131).

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

Griffin is directed to "formation engaging elements" that "are moveably mounted onto a drill bit" and discloses 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." Ex.1007 (abstract; 2:30-43); Ex.1001 (¶132).

FIG. 11





"The cutting structure 69 is the primary structure for removing formation from the borehole." Ex.1007 (9:1-2); Ex.1001 (¶134). "The subsidiary cutting structure 73, however, acts as a penetration limiter." Ex.1007 (9:3-4); Ex.1001 (¶134). Distance "d" is a predetermined DOC. If "d" is exceeded, the drag F_d acting on the cutter 74, 75 will increase causing the cutter 74, 75 to tilt within its housing. Ex.1007

(9:4-8); Ex.1001 (¶134). "This force reduces the effective weight-on-bit acting on the primary cutter 69, thus reducing the DOC." Ex.1007 (9:9-11); Ex.1001 (¶134).

X. SPECIFIC GROUNDS FOR THE PETITION

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

1. Claim 16

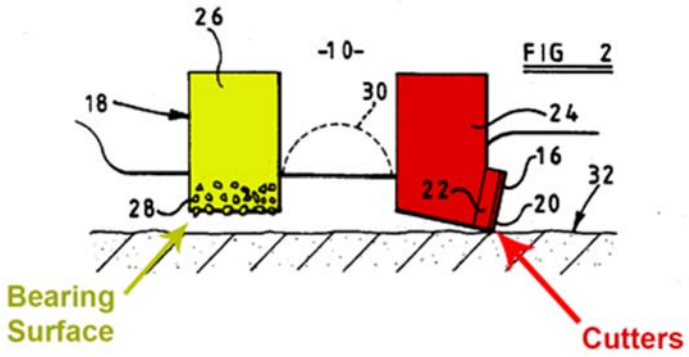
a. "A method of drilling a subterranean formation without generating an excessive amount of torque-on-bit, comprising:"

The preamble of the independent claim does not limit its scope. *See Aspex Eyewear, Inc. v. Marchon Eyewear, Inc.*, 672 F.3d 1335, 1347 (Fed. Cir. 2012) ("This court has recognized that as a general rule preamble language is not treated as limiting."). The preamble describes the claimed method—"drilling a subterranean formation without generating an excessive amount of torque-on-bit." Ex.1001 (¶136).

Newton discloses a drill bit used in drilling subterranean formations. Ex.1005 (abstract); Ex.1001 (¶137). 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 Newton's bit. Ex.1001 (¶137). Newton's drill bit design, would prevent an excessive amount of torque-on-bit when used in the field. Ex.1001 (¶137).

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

Newton teaches a drill bit used in drilling subterranean formations where a cutter has a selected depth-of-cut range. Ex.1001 (¶138). As shown in Figure 2, the **cutters** in red will come into contact with the formation at a selected DOC. The DOC will be based on the type of subterranean formation. Ex.1001 (¶138).



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;"

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. Ex.1001 (¶139). A WOB is selected and applied based on the formation. Ex.1001 (¶139). As the formation changes during drilling operation, so too does the required WOB. Ex.1001 (¶139). 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); Ex.1001 (¶139).

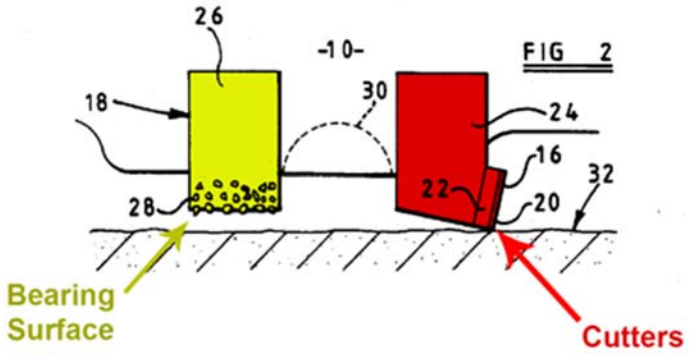
"The Effect of PDF Cutter Density, Back Rake, Size, and Speed on Performance" paper by Sinor et al. ("SPE 39306") also confirms that it was known prior to the '441 patent that the WOB required to penetrate a formation depends on the type of formation. Ex.1001 (¶140). The SPE 39306 paper reports a study 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); Ex.1001 (¶140). 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. Ex.1001 (¶140).

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."); Ex.1001 (¶141). 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. Ex.1001 (¶141). But as Dr. Hareland explains, 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. Ex.1001 (¶141).

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. Ex.1001 (¶142).

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 WOB is applied. Ex.1001 (¶143).



Newton's secondary abrasive cutting element performs this function and provides depth-of-cut-control. Ex.1001 (¶144). Under a normal mode of operation using the bit disclosed by Newton, a drilling operator would apply a sufficient WOB 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 of petroleum deposits. Ex.1001 (¶144). The WOB 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 WOB will become in excess of the WOB required for the cutter to penetrate that new, less-hard formation. Ex.1001 (¶144).

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"

As discussed above, in Section X.A.1.c, the abrasion elements of 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. Ex.1001 (¶145). The excess WOB is transferred to the abrasion elements when they come into contact with the formation. *Id.* 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. *Id.*

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. Ex.1001 (¶146). As a result, a POSA would know that excessive torque on the bit can be prevented by using bearing surfaces to limit the DOC. *Id.*

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. Ex.1001 (¶147). This bearing surface area provided by the abrasion element will transfer the WOB to the subterranean formation. *Id.*

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

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 at substantially the same point in time during operation of the drill bit." Ex.1005 (5:36-45); Ex.1001 (¶148). The area of the abrasion elements

can support a certain range of WOB. As the WOB increases the amount of surface area remains constant and supports, the excess WOB. Ex.1001 (¶148).

2. 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."

As discussed above in Section X.A.1.c, 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. Ex.1001 (¶150). Newton 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); Ex.1001 (¶150). Therefore the abrasion elements generally surround the cutter. Ex.1001 (¶150).

3. 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."

As discussed above in Section X.A.2.a, Newton teaches the abrasion elements generally surrounding at a least a portion of at least one cutter. Ex.1001 (¶152). Newton further teaches transferring the excess WOB to a hard facing material affixed to the formation of the abrasion element. Ex.1001 (¶152). 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); Ex.1001 (¶152). "However, other forms of secondary element (sic) may be employed." Ex.1005 (4:34-35); Ex.1001 (¶152). "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." Ex.1005 (4:35-38); Ex.1001 (¶152). The superhard element is the hard facing material. Ex.1001 (¶152).

4. 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"

As discussed in Section X.A.1.c, 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); Ex.1001 (¶154). "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." Ex.1005 (5:32-36); Ex.1001 (¶154). "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." Ex.1005 (5:36-41); Ex.1001 (¶154). 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. Ex.1001 (¶154). A POSA would design their drill bit in one of the two ways described by Newton. Ex.1001 (¶154).

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."

As previously stated in X.A.4.a, the additional excess WOB results in another bearing surfaces contacting the subterranean formation. Ex.1001 (¶155). This additional abrasion element taught by Newton will function in the same way as the first abrasion element and absorb any excess WOB. *Id.* The abrasion elements will transfer the excess WOB from the bearing surfaces to the formation to ensure that there is no substantial indentation into the formation. *Id.*

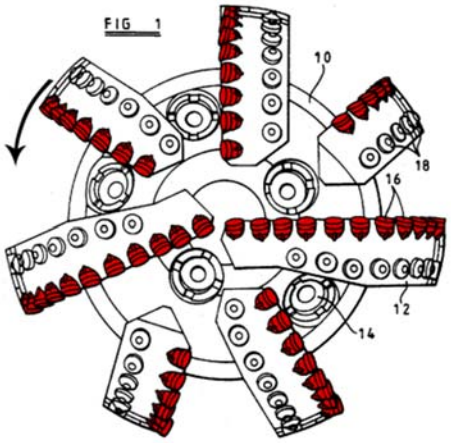
5. Claim 21

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"

The preamble of the independent claim does not limit its scope. *See Aspex Eyewear, Inc..*, 672 F.3d at 1347. The preamble generally describes a method of "designing a drill bit." Ex.1001 (¶156).

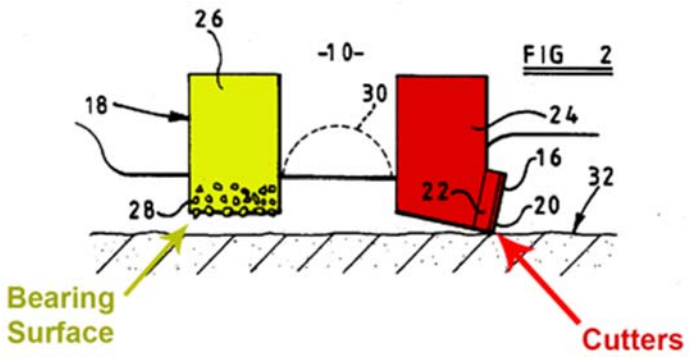
Newton discloses a drill bit for drilling a subterranean formation. Ex.1001 (¶157). Newton discloses the drill bit comprises a plurality of "**primary cutting elements** 16." Ex.1005 (4:21-28); Ex.1001 (¶157). The '441 patent states "[c]utters employed with bits 10 and 100, as well as other bits disclosed 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); Ex.1001 (¶157). 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); Ex.1001 (¶157).



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

Newton teaches a drill bit used in drilling subterranean formations that contains a cutter with a selected depth-of-cut range. Ex.1001 (¶158). As shown in Newton's Figure 2, the **cutters** in red will come into contact with the formation at a selected depth-of-cut. Ex.1001 (¶158). The DOC will be based on the type of subterranean formation. Ex.1001 (¶158).



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"

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. Ex.1001 (¶159). Newton teaches the drill bit comprises a plurality of "**primary cutting elements** 16." Ex.1005 (4:21-28); Ex.1001 (¶159).

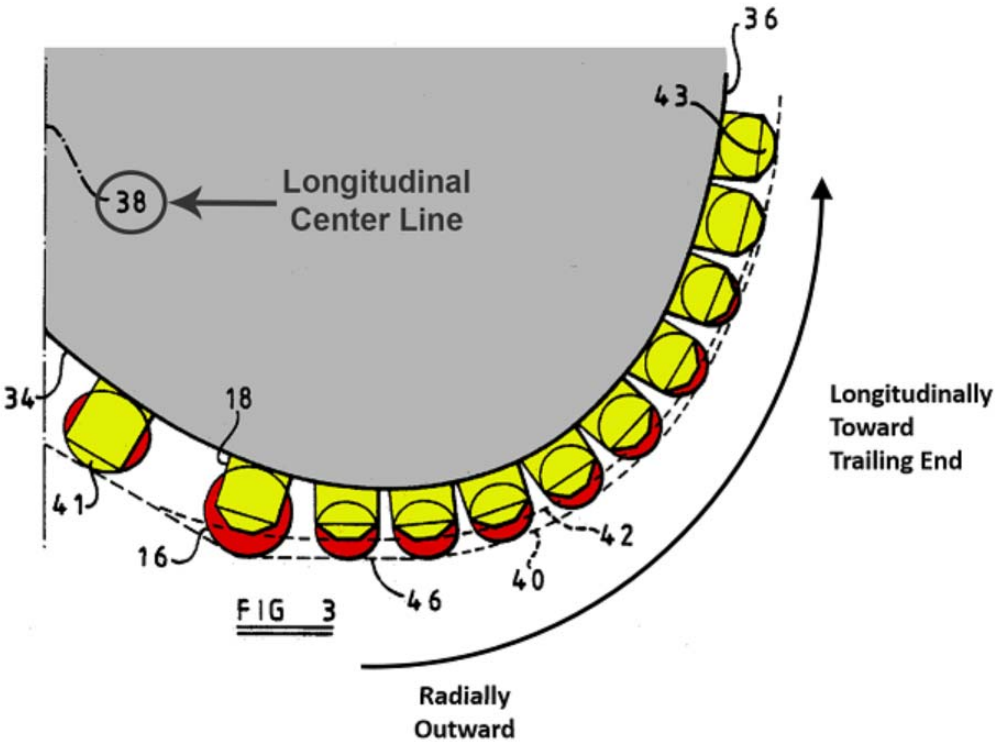


FIG 3

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. Ex.1001 (¶160).

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,"

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. Ex.1001 (¶161).

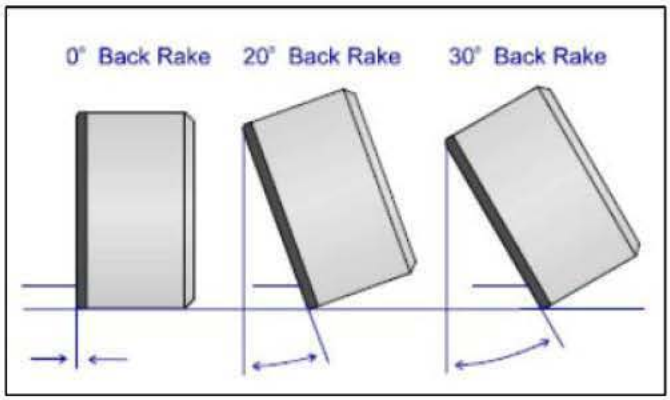
As the WOB increases the formation facing structure contacts the formation in order to absorb the excess WOB and ensure the DOC remains constant. In fact, the '441 patent acknowledges it was known in the art that the WOB necessary to penetrate a formation changes as the drilling progresses from one formation 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 TOB, increase almost instantaneously and by a substantial magnitude." Ex.1003 (1:65-2:5); Ex.1001 (¶162).

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. Ex.1001 (¶163). Petitioner incorporates Section X.A.1.c above with respect to the discussion of the SPE paper.

The Challenged Claims do not specify the amount of surface necessary to maintain the selected DOC and not substantially indent the subterranean formation. Additionally, in the underlying litigation, Patent Owner has alleged infringement by Petitioner based solely on the presence of a bearing surface, without alleging the

amount of surface area or a weight-on bit that is supported. Ex.1072 (33-38). Nonetheless, a POSA at the time of the '441 patent knew how to calculate the sufficient area necessary to control DOC. Initially, the physical features of the bit are selected. Ex.1001 (¶166) 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. *Id.* Additional factors include (1) the number of cutters, (2) location of the cutter with respect to the center of the bit, (3) backrake angle of the cutters, and (4) diameter of the cutters. *Id.* Other known features can be considered when designing the layout of the cutter profile of the bit. *Id.*

The WOB selected depends on the physical properties of the bit described above, in addition to the compressive strength of the formation. Ex.1001 (¶167). For example, the more aggressive the cutter with respect to physical orientation such as exposure beyond the bearing surface and less backrake angle, the greater the surface area necessary for a given applied WOB in a given formation. *Id.*



Ex.1044 (slide 7).

As previously mentioned, the WOB is also selected based on the compressive strength of the formation. Ex.1001 (¶168). A higher WOB needs to be applied when the compressive strength of the formation is higher. *Id.*

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. Ex.1001 (¶169). "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); Ex.1001 (¶169).

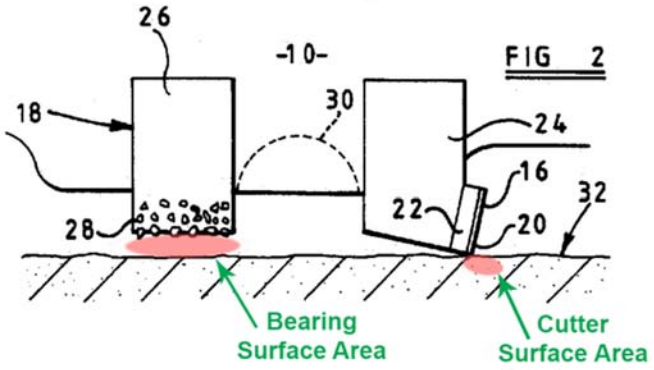
Using equations, a POSA given a WOB can determine the sufficient bearing surface area needed. Ex.1001 (¶170).

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

WOB is the given WOB 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. Ex.1001 (¶171).

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

A simplification of the areas for Newton is shown below:



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 ($A_{bearing\ surface}$). Ex.1001 (¶173). The projected area in the area in the axial direction of the cutter is a function of the cutter geometry, backrake, and DOC. *Id.* The DOC is determined when the bearing surface engages the formation. The area of the bearing surface is the axial projected contact area. *Id.*

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

The bearing surface area is the minimum surface area required to hold a specific WOB. Ex.1001 (¶174). As WOB increases the area has to increase with the incremental weight over rock strength. *Id.* As long as the bearing area is sufficient to hold the WOB, DOC is controlled. *Id.* The area of the abrasion elements can support a certain range of WOB. *Id.* As the WOB increases the amount of surface area remains constant and supports any excess WOB. *Id.*

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. Ex.1001 (¶175). 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 WOB. *Id*.

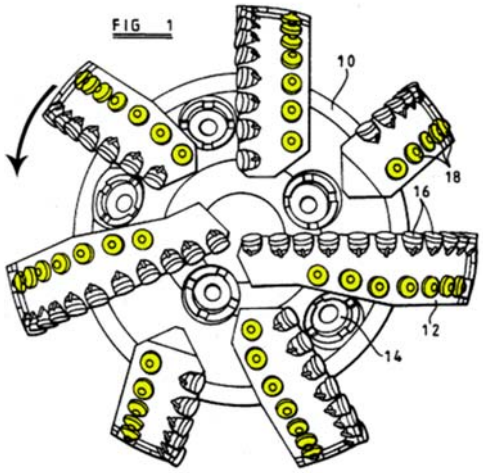
e. "wherein the formation-facing bearing surface area is sized and configured to remain substantially constant over a range of excess weight-on-bit."

As discussed above in Section X.A.1.e, Jones discloses the bearing surface area remaining substantially constant over a range of excess WOB. Ex.1001 (¶176).

6. 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."

Newton discloses that the drill bit includes "**secondary abrasion elements** 18" located on the bit's leading end. Ex.1005 (4:20-21); Ex.1001 (¶178). Newton further states that the amount of secondary abrasion elements can be varied. Ex.1005 (4:21-28); Ex.1001 (¶178). As shown in Figure 1 below, these abrasion elements surround the cutters, as they are located on the same blade.



7. 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."

As discussed in Section X.A.5.d, Newton discloses a design with multiple abrasion surfaces. Ex.1001 (¶180). The size of these surfaces are based on the WOB and formation, and will support any additional WOB applied in excess of the WOB necessary to achieve the maximum DOC. *Id.* By absorbing this extra weight the drill bit will not substantially indent the subterranean formation. *Id.*

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

1. Claim 16

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

The preamble of the independent claim does not limit its scope. *See Aspex Eyewear,* 672 F.3d at 1347. The preamble describes the claimed method—"drilling a subterranean formation without generating an excessive amount of torque-on-bit." Ex.1001 (¶182).

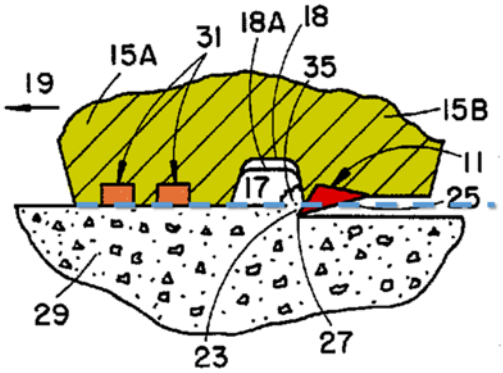
Jones discloses a drill bit, and a POSA would understand that this drill bit was intended to be used. Ex.1001 (¶183). Jones discloses "rotary drill bits for drilling bores in the earth such as for oil and gas wells." Ex.1006 (1:6-9); Ex.1001 (¶183). A POSA at the time of the invention would have found it obvious to have used the drill bit to drill a formation, the intended purpose of Jones' bit. Ex.1001 (¶183). Jones' drill bit design, as discussed in more detail below, would prevent an excessive amount of torque-on-bit when used in the field. *Id.*

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

Jones discloses engaging the formation with at least one cutter to a selected DOC. Ex.1001 (¶184). 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); Ex.1001 (¶184). To limit penetration and simultaneously ensure that the bit is engaging the formation a POSA would know it was necessary to choose a selected DOC. Ex.1001 (¶184). 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. *Id*. As shown with the blue dotted line below, the DOC is specifically selected for the cutter based on the formation. *Id.*

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;"

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); Ex.1001 (¶185). "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); Ex.1001 (¶185).

A WOB is selected and applied based on specifications related to the formation. Ex.1001 (¶186). As formations change during a drilling operation, so too does the required WOB. Ex.1001 (¶186).

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 TOB, increase almost instantaneously and by a substantial magnitude." Ex.1003 (1:65-2:5); Ex.1001 (¶187).

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. Ex.1001 (¶188). 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); Ex.1001 (¶188). 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. Ex.1001 (¶188).

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."). Ex.1001 (¶189). 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. Ex.1001 (¶189). But as Dr. Hareland explains, 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. Ex.1001 (¶189).

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. Ex.1001 (¶190).

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"

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. Ex.1001 (¶191). 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. *Id.* Thus, there would be no substantial indentation of the bearing surface into the formation. *Id.*

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. Ex.1001 (¶192). As a result, a POSA would know that excessive torque on the bit can be prevented by using bearing surfaces to limit the DOC. *Id.*

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. Ex.1001 (¶193). This bearing surface area provided by the abrasion element will transfer the WOB to the subterranean formation. *Id.*

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

Jones discloses the bearing surface being substantially constant. Ex.1001 (¶194). "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); Ex.1001 (¶194). "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); Ex.1001 (¶194). This area can support a certain range of WOB. As the WOB increases the amount of surface area remains constant and supports any excess WOB. Ex.1001 (¶194).

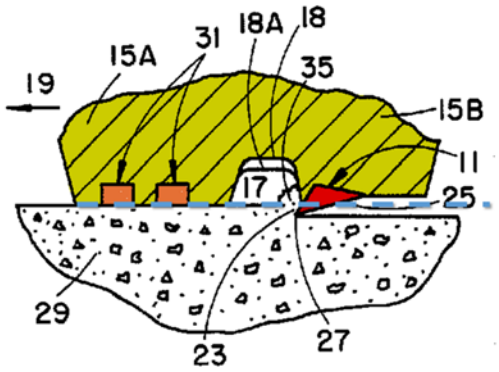
2. Claim 17

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."

As discussed above in Section X.B.1.d, Jones discloses transferring the excess weight-on-bit through a bearing surface. Ex.1001 (¶196). 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); Ex.1001 (¶196). The bearing surface (in yellow in Figure 3 below) therefore surrounds at least a portion of at least one cutter. Ex.1001 (¶196).

FIG. 3



3. 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."

As mentioned in Section X.B.1.d, 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

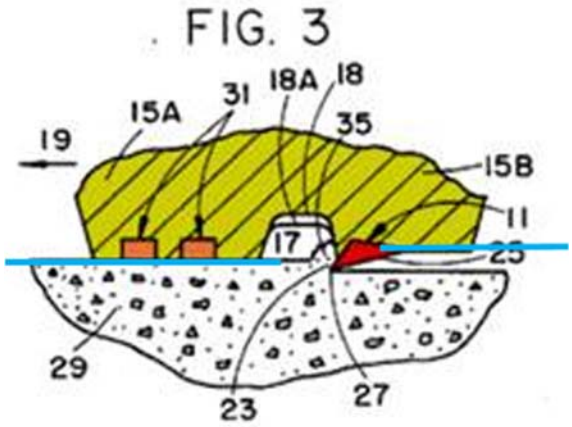
bit." Ex.1006 (4:50-55); Ex.1001 (¶198). The bearing surface is therefore proximate to at least one cutter. Further, as mentioned above Jones discloses ridges. Ex.1001 (¶198). "A first ridge 15A of each set of ridges constitutes a leading ridge with respect to the direction of rotation of the bit … [t]he second ridge 15B of each set of ridges thus constitutes a trailing ridge." Ex.1006 (4:45-49); Ex.1001 (¶198). 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." Ex.1006 (5:38-41); Ex.1001 (¶198). The hard wear elements equate to the claimed hard facing material. Ex.1001 (¶198).

4. 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"

Jones discloses wherein there are at least two bearing surfaces that contact the formation at different moments. Ex.1001 (¶200) "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); Ex.1001 (¶200). 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. Ex.1001 (¶200).



Therefore as more weight is applied eventually ridge 15B will also contact the formation. Ex.1001 (¶201). 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."

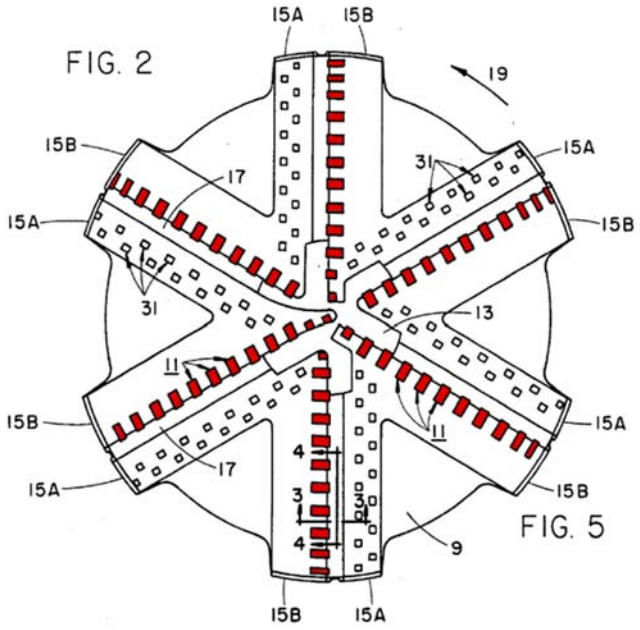
As discussed above, Jones discloses information where a POSA would be able to determine the sufficient surface area, and can vary when that area will contact the formation based on the WOB. Ex.1001 (¶202). As an additional bearing surface contacts the formation it will absorb the additional excessive WOB at a stress less than substantially the compressive strength of the formation. *Id*.

5. 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"

The preamble of the independent claim does not limit its scope. *See Aspex Eyewear*, 672 F.3d at 1347. The preamble generally describes a method of "designing a drill bit." Ex.1001 (¶204).

Jones discloses a drill bit for drilling a subterranean formation. Ex.1001 (¶205). A POSA, at the time of the invention, would have found it obvious to design the drill bit by Jones. Ex.1001 (¶205). 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); Ex.1001 (¶205).



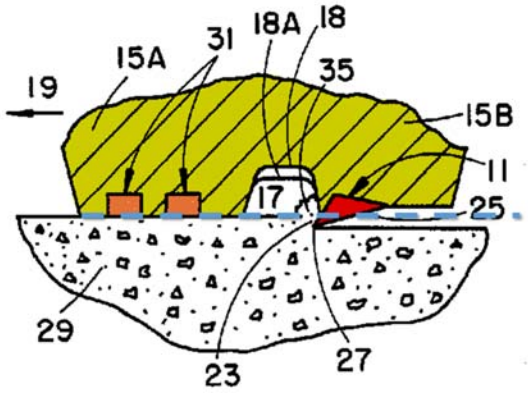
A POSA at the time of the invention would have found it obvious to engage in a method of designing the bit as disclosed by Newton motivated by the fact that such method is necessary to manufacture the drill bit. Ex.1001 (¶206).

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

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

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); Ex.1001 (¶208). "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); Ex.1001 (¶208).

FIG. 3



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. Ex.1001 (¶209).

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"

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. Ex.1001 (¶210). 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." Ex.1006 (4:50-53); Ex.1001 (¶210).

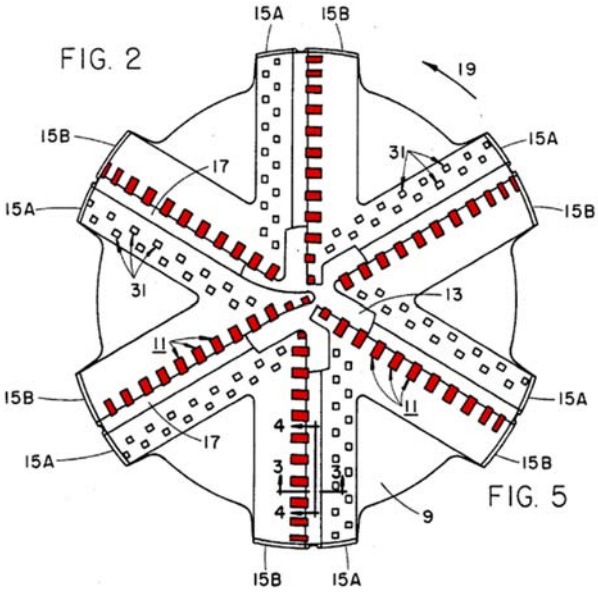
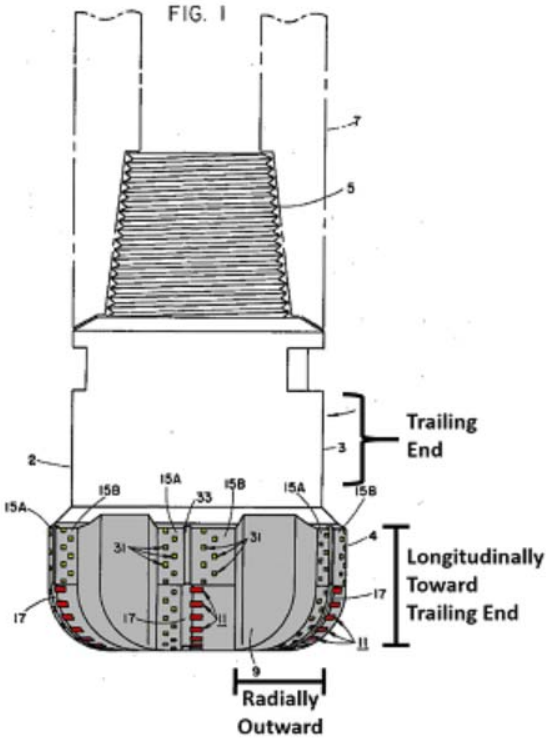


FIG. 5



As shown in the figures above, the cutters are located on blades; the blades extent radially outward and longitudinally toward the trailing end. Ex.1001 (¶211). 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. *Id.*

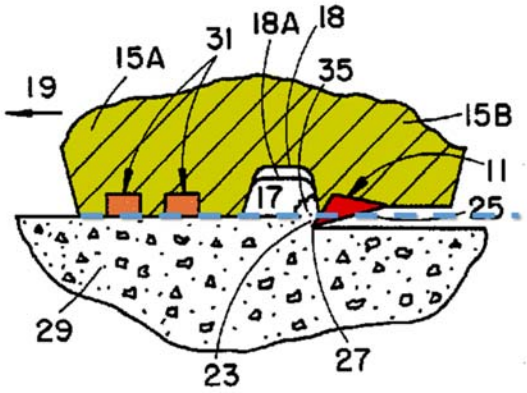
> d. "configuring within the design of the drill bit a sufficient total amount of formation-facing bearing surface area structured for axially supporting the drill bit without substantially indenting the subterranean formation should the drill bit be subjected to a weight-on-bit exceeding a weight-on-bit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

Jones discloses a sufficient surface area to maintain a selected DOC. 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); Ex.1001 (¶212).

In Figure 3, Jones discloses "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); Ex.1001 (¶213). "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); Ex.1001 (¶213). "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); Ex.1001 (¶213).

FIG. 3



"[T]he leading ridge enables the cutting elements to penetrate to a depth deep enough to enable rapid removal of the formation." Ex.1006 (5:31-36); Ex.1001 (¶214). The bit "provides protection against damage to the cutting element due to excess weight on the bit." Ex.1006 (5:36-38); Ex.1001 (¶214).

As the WOB increases the formation facing structure contacts the formation in order to absorb the excess WOB and ensure the DOC remains constant. In fact, the '441 patent acknowledges it was known in the art that the WOB necessary to

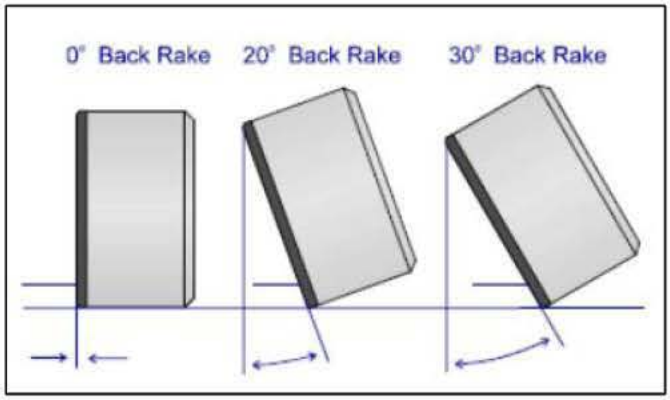
penetrate a formation changes as the drilling progresses from one formation to another: "Another, separate problem involves drilling from a zone or stratum of higher formation compressive strength to a 'softer' zone of lower strength. As the bit drills into the softer formation without changing the applied WOB (or before the WOB can be changed by the directional driller), the penetration of the PDC cutters, and thus the resulting TOB, increase almost instantaneously and by a substantial magnitude." Ex.1003 (1:65-2:5); Ex.1001 (¶215).

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. Ex.1001 (¶216). Petitioner incorporates Section X.B.1.c above with respect to the discussion of the SPE paper.

The Challenged Claims do not specify the amount of bearing surface necessary to maintain the selected DOC. Additionally, in the underlying litigation, Patent Owner has alleged infringement by Petitioner based solely on the presence of a bearing surface, without alleging the amount of surface area. Nonetheless, a POSA at the time of the '441 patent knew how to calculate the sufficient area necessary to control DOC. Initially, the physical features of the bit are selected. Ex.1001 (¶219). 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. *Id*. Additional factors

include (1) the number of cutters, (2) location of the cutter with respect to the center of the bit, and (3) backrake angle of the cutters. *Id*. Other known features can be considered when designing the layout of the cutter profile of the bit. *Id*.

The WOB selected depends on the physical properties of the bit described above, and the compressive strength of the formation. Ex.1001 (¶220). The more aggressive the cutter with respect to physical orientation such as exposure beyond the bearing surface and less backrake angle, the greater the surface area necessary for a given applied WOB in a given formation. *Id*.



Ex.1044 (slide 7).

As previously mentioned, the WOB is also selected based on the compressive strength of the formation. Ex.1001 (¶221). A higher WOB needs to be applied when the compressive strength of the formation is higher. *Id*.

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. Ex.1001 (¶222). "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); Ex.1001 (¶222).

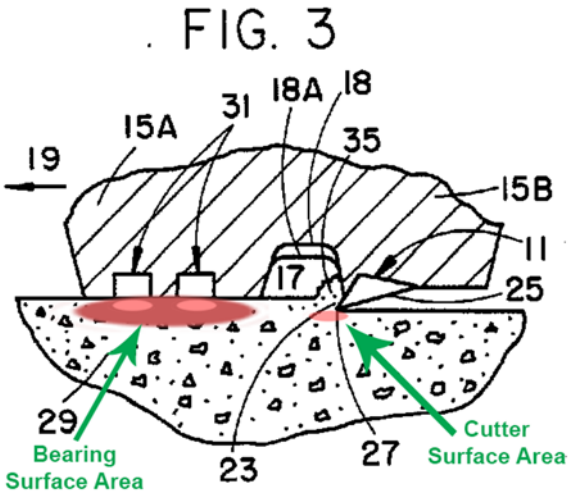
Using simple equations, a POSA given a WOB can determine the sufficient bearing surface area needed. Ex.1001 (¶223).

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

WOB is the given WOB 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. Ex.1001 (¶224).

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

A simplification of the areas for Jones is shown below:



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 ($A_{bearing\ surface}$). Ex.1001 (¶225). The projected area in the area in the axial direction of the cutter is a function of the cutter geometry, backrake, and DOC. *Id*. The DOC is determined when the bearing surface engages the formation. The area of the bearing surface is the axial projected contact area. Ex.1001 (¶225).

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

The bearing surface area is the minimum area required to hold a specific WOB. Ex.1001 (¶226). As WOB increases the area has to increase with the incremental weight over rock strength. *Id*. As long as the bearing area is sufficient to hold the WOB, DOC is controlled. *Id*. The area of the abrasion elements can support a certain range of WOB. *Id.* As the WOB increases the amount of surface area remains constant and supports any excess WOB. *Id.*

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. Ex.1001 (¶227). In fact, prior to the filing of the ’441 patent, computer programs existed that simulate these features in order to simulate different bit designs. *Id*. 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 WOB. *Id*.

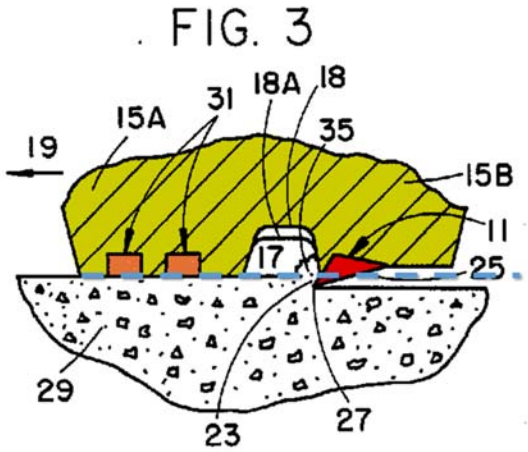
e. "wherein the formation-facing bearing surface area is sized and configured to remain substantially constant over a range of excess weight-on-bit."

As discussed above in Section X.B.1.e, Jones discloses the bearing surface area remaining substantially constant over a range of excess WOB. Ex.1001 (¶228).

6. 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."

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); Ex.1001 (¶230). As seen in the figure below, ridges 15A and 15B in yellow partially surround the cutter in red.

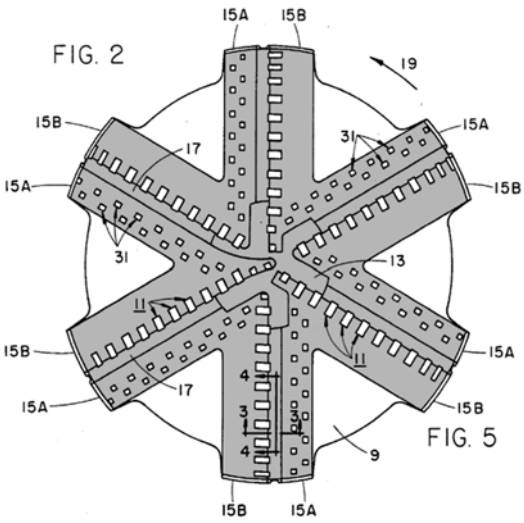


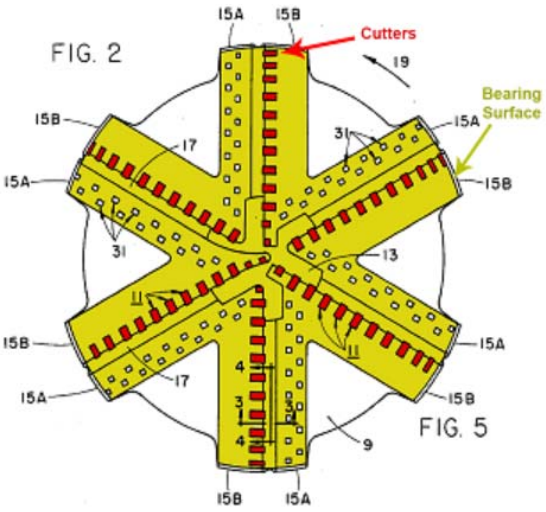
A POSA at the time of the invention would have found it obvious to have selected an amount of these hard facing elements motivated by the fact that one would necessarily have to select a number in order to achieve a desired design for a particular drilling application. Ex.1001 (¶231).

7. 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."

The ridges will act as a formation-facing bearing surface area structured for axially supporting the drill bit. Ex.1001 (¶233). The ridges provide structural and axial support for the bit as the drill bit is rotated and engages the formation. Ex.1001 (¶233).





The ridges in Jones provide DOCC and would necessarily come into contact with the formation and transfer the energy across the ridges to the formation. Ex.1001 (¶234). The ridges therefore present 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. *Id.*

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 desire to control the DOC of the cutters. Ex.1001 (¶235).

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

1. Claim 16

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

The preamble of the independent claim does not limit its scope. *See Aspex Eyewear*, 672 F.3d at 1347. The preamble describes the claimed method—"drilling

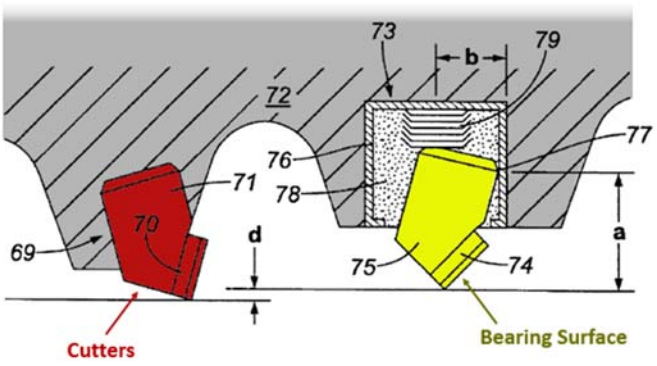
a subterranean formation without generating an excessive amount of torque-on-bit." Ex.1001 (¶237).

Griffin discloses a drill bit, used in drilling subterranean formations avoiding an excessive torque on bit. Ex.1007 (abstract); Ex.1001 (¶238). 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." Ex.1007 (1:6-9); Ex.1001 (¶238). "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." Ex.1007 (12:44-46); Ex.1001 (¶238). "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." Ex.1007 (12:46-49); Ex.1001 (¶238). 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. Ex.1001 (¶238).

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

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 DOC." Ex.1007 (9:4-5); Ex.1001 (¶239). As shown in Figure 11, Griffin discloses the cutter engaging a DOC "d." Ex.1001 (¶239).

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;"

In order to drill a hole with the drill bit taught by Griffin, a WOB is applied to achieve the DOC mentioned above in Section X.C.1.b. Specifically, Griffin teaches "[t]he distance 'd' is a predetermined desired DOC." Ex.1007 (9:4-5); Ex.1001 (¶240). "If this DOC 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." Ex.1007 (9:5-8); Ex.1001 (¶240). "This will increase the vertical force F_{wob} acting on the cutting structure 73 where $F_{wob}=F_d xa/b$." Ex.1007 (9:8-9); Ex.1001 (¶240). "This force reduces the effective weight-on-bit acting on the primary cutter 69, thus reducing the DOC." Ex.1007 (9:9-11); Ex.1001 (¶240).

As the WOB increases the formation facing element contacts the formation in order to absorb the excess WOB and ensure the DOC remains constant. Ex.1001 (¶241). 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. Ex.1003 (1:65-2:5); Ex.1001 (¶241).

As discussed in Section X.B.1.c, 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 and the surface area of the bit contacting the formation. Ex.1001 (¶242).

In light of the known fact that formation hardness may vary as a drilling progresses and the teachings of SPE39306 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. Ex.1001 (¶244).

> 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"

As discussed above, the formation contacting structure of Griffin will absorb any excess WOB. Ex.1001 (¶245). This structure will transfer the excess WOB to the formation without substantial indentation of the formation facing element into the subterranean formation. *Id.* As more weight is added the formation facing element will absorb this weight and transfer it to the surface of the formation. *Id.*

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. Ex.1001 (¶246). As a result, a POSA would know that excessive torque on the bit can be prevented by using bearing surfaces, such as formation facing elements to limit the DOC. *Id.*

Griffin's formation facing elements 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 surface area. Ex.1001 (¶247). This surface area provided by the formation facing element will transfer the WOB to the subterranean formation. *Id.*

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

As discussed above, Griffin discloses information where a POSA would be able to determine the sufficient surface area. Ex.1001 (¶248). 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). *Id*. 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. *Id*. This element will then rotate and the surface area will vary until enough

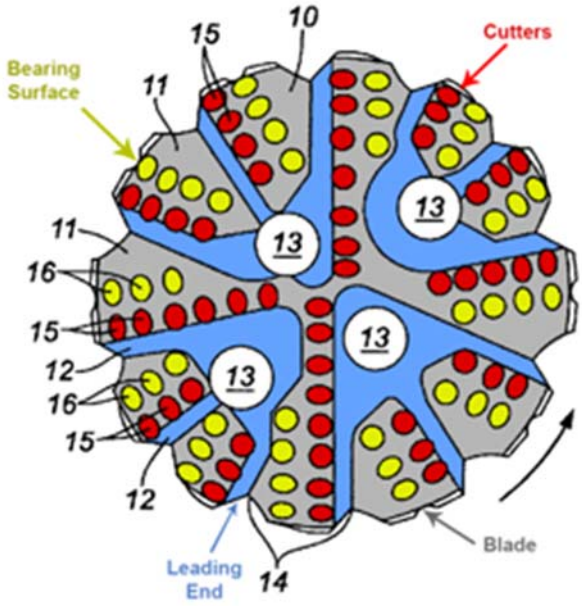
WOB is added wherein formation engaging element no longer rotates. *Id*. When the structure no longer rotates, more WOB is applied and the formation engaging element surface area will remain constant over this second range of excess WOB. *Id*.

As more weight is added the surface area of 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. Ex.1001 (¶249).

2. 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."

As discussed in Section X.A.1.d, Griffin discloses transferring the excess WOB to a formation engaging structure, which is equivalent to the claimed bearing surface. Ex.1001 (¶251). Griffin discloses the formation engaging structure surrounding the cutters. *Id.* Griffin discloses "[t]he formation engaging structure 16 [are] spaced rearwardly of its associated cutting structure. Ex.1007 (4:46-49); Ex.1001 (¶301). The formation facing elements generally surround at least a portion of the cutters as shown in Figure 1 below:



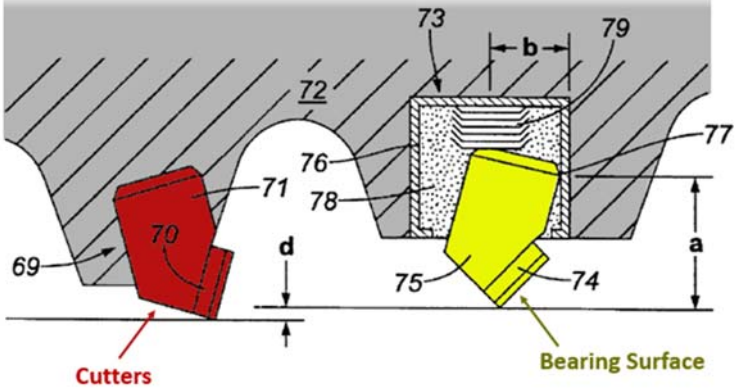
3. Claim 19

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."

As discussed in Section X.C.1.d, Griffin discloses a method wherein excess WOB is transferred to a formation engaging surface preventing 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); Ex.1001 (¶253). Cutter 73 has a polycrystalline diamond compact 74 that is bonded to a post 75. Ex.1007 (8:46-48); Ex.1001 (¶253). The hard facing material is equivalent to the polycrystalline

diamond compact 74. Ex.1007 (8:46-48); Ex.1001 (¶253). As shown below, the formation facing element is proximate the cutters. Ex.1001 (¶253).

FIG. 11



4. 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"

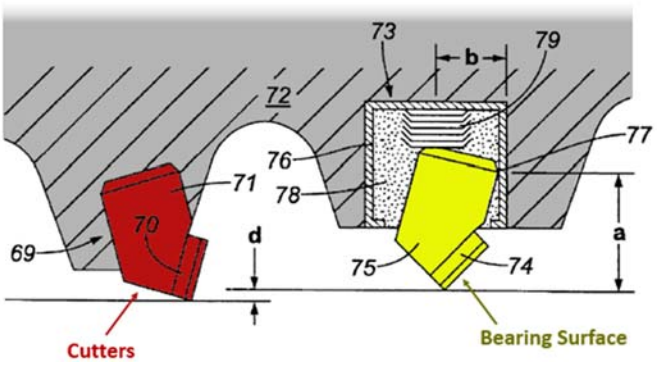
The preamble of the independent claim does not limit its scope. *See Aspex Eyewear*, 672 F.3d at 1347. Griffin discloses a drill bit. Ex.1001 (¶255). A POSA, at the time of the invention, would have found it obvious to design the drill bit by Griffin. *Id.*

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

Griffin discloses a drill bit that contains a cutter with a selected depth-of-cut. Griffin discloses the "[t]he distance 'd' is a predetermined desired DOC." Ex.1007

(9:4-5); Ex.1001 (¶256). As shown in Figure 11, Griffin discloses the cutter engaging a DOC. Ex.1001 (¶256).

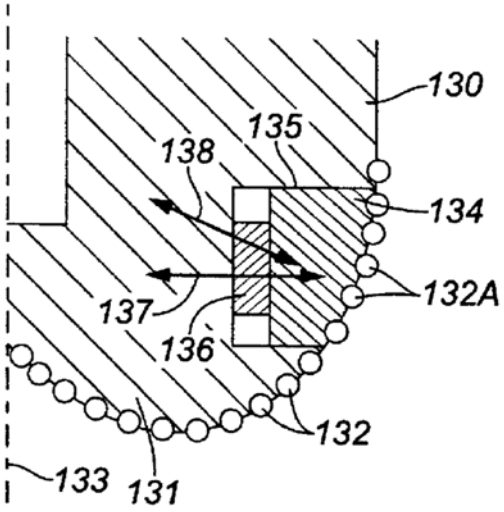
FIG. 11



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"

Griffin discloses a cutter profile arrangement wherein the superabrasive cutters are radially and longitudinally positioned on the formation engaging end of the drill bit. Ex.1001 (¶257). As shown in Figure 23, the bit 130 has blades 131 extending outwardly away from the central axis of rotation 133 of the bit, and cutters 132 mounted along each blade. Ex.1007 (12:52-55); Ex.1001 (¶257).

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,"

Griffin's subsidiary cutting structures have a bearing area when they penetrate the formation. Ex.1001 (¶258). Thus, in normal operation of Griffin's drill bit, Griffin's subsidiary cutting structures will maintain the selected DOC even when WOB exceeds that required for the cutters 16 to penetrate the formation. *Id.*

Griffin discloses "the cutting structure 69 is the primary cutting structure for removing formation from the borehole." Ex.1007 (9:1-2); Ex.1001 (¶259). "The subsidiary cutting structure 73, however, acts as a penetration limiter." Ex.1007 (9:3-4); Ex.1001 (¶259). "The distance 'd' is a predetermined desired" DOC.

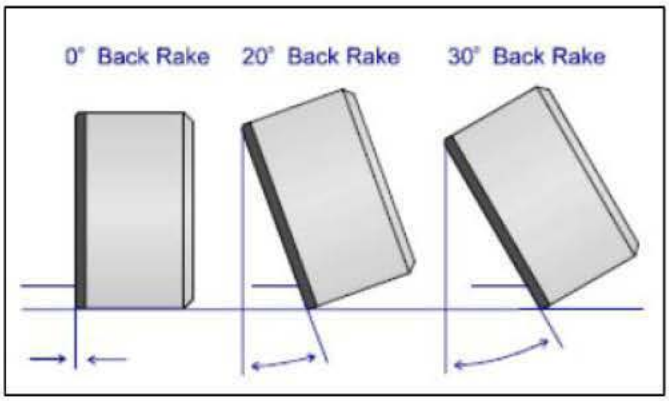
Ex.1007 (9:4-5); Ex.1001 (¶259). If this DOC is exceeded, "the drag F_d acting on the cutter 74, 75 will increase causing the cutter 74, 75 to tilt rearwardly within its housing." Ex.1007 (9:5-8); Ex.1001 (¶259). "This will increase the vertical force F_{wob} acting on the cutting structure 73 where $F_{wob}=F_dxa/b$." Ex.1007 (9:8-9); Ex.1001 (¶259). "This force reduces the effective weight-on-bit acting on the primary cutter 69, thus reducing the DOC." Ex.1007 (9:9-11); Ex.1001 (¶259).

As the WOB increases the formation facing structure contacts the formation in order to absorb the excess WOB and ensure the DOC remains constant. Ex.1001 (¶262). The SPE3 9306 paper previously discussed confirms that it was known prior to the '441 patent that the WOB required to penetrate a formation depends on the type of formation. Ex.1001 (¶263). Petitioner incorporates Section X.C.1.c above with respect to the discussion of the SPE paper.

The Challenged Claims do not specify the amount of surface area to maintain the selected DOC. Nonetheless, a POSA at the time of the '441 patent knew how to calculate the sufficient area necessary to control DOC. Initially, the physical features of the bit are selected. Ex.1001 (¶266). 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. *Id.* Additional factors include (1) the number of cutters, (2) location of the cutter with respect to the center of the bit, and (3) backrake angle of

the cutters. *Id.* Other known features can be considered when designing the layout of the cutter profile of the bit. *Id.*

The WOB selected depends on the physical properties of the bit described above, in addition to the compressive strength of the formation. Ex.1001 (¶267). For example, the more aggressive the cutter with respect to physical orientation such as exposure beyond the bearing surface and less backrake angle, the greater the surface area necessary for a given applied WOB in a given formation. *Id.*



Ex.1044 (slide 7).

The WOB is also selected based on the compressive strength of the formation. Ex.1001 (¶268). A higher WOB needs to be applied when the compressive strength of the formation is higher. *Id.*

The '441 patent recognizes that a POSA wanting to practice the claimed invention would know the WOB and know the type of formation. Ex.1001 (¶269). "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); Ex.1001 (¶269).

Using simple equations, a POSA given a WOB can determine the sufficient bearing surface area needed. Ex.1001 (¶270).

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

WOB is the given WOB referred to by the '441 patent. Ex.1001 (¶271). 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. *Id.*

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

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 ($A_{bearing\ surface}$). Ex.1001 (¶272). The projected area in the area in the axial direction of the cutter is a function of the cutter geometry, backrake, and DOC. *Id.* The DOC is determined when the bearing surface engages the formation. *Id.* The area of the bearing surface is the axial projected contact area. *Id.*

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

The bearing surface area is the minimum surface area required to hold a specific WOB. Ex.1001 (¶273). As WOB increases the area has to increase with the incremental weight over rock strength. *Id.* As long as the bearing area is sufficient to hold the WOB, DOC is controlled. *Id.* As the WOB increases the amount of surface area remains constant and supports any excess WOB. *Id.*

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. Ex.1001 (¶274). In fact, prior to the filing of the '441 patent, computer programs existed that simulate these calculations in order to feature different bit designs. *Id.* 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 WOB. *Id.*

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

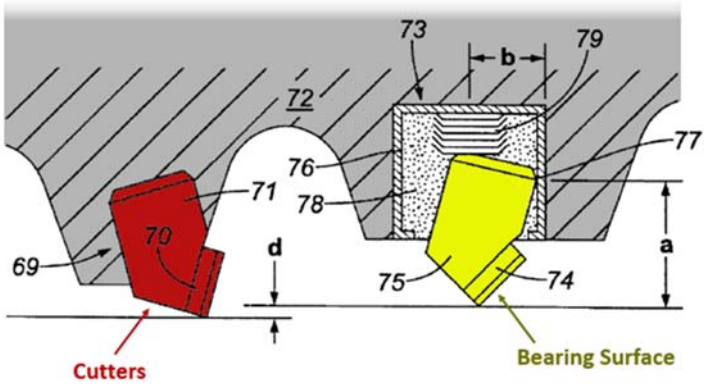
As discussed above in Section X.C.1.e, Griffin discloses the bearing surface area remaining substantially constant over a range of excess WOB. Ex.1001 (¶275).

5. 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."

As discussed in Section X.C.3.a, Griffin discloses transferring a WOB to a formation-facing bearing surfaces that comprises a hard facing surface at least partially surrounding the cutters. Ex.1001 (¶278).

FIG. 11



6. 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."

The formation engaging element taught by Griffin will absorb the excess weight-on-bit over the maximum weight-on-bit necessary to achieve the maximum

DOC. Ex.1001 (¶280). As excess weight is added the formation facing elements 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. *Id.*

XI. CONCLUSION

For the foregoing reasons, Ulterra respectfully requests that the Board institute *inter partes* review.

Date: September 5, 2018

Respectfully submitted,

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CERTIFICATE OF SERVICE

In compliance with 37 C.F.R. §§ 42.105, 42.6(e), the undersigned hereby certifies that a copy of the foregoing Petition and supporting exhibits were served on the 5th day of September, 2018, via Priority Mail Express® directed to the Patent Owner at the correspondence address of record:

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Salt Lake City, UT 84110

A courtesy copy was also served by electronic mail on the attorneys of record for the following related matter:

Baker Hughes, a GE Company, LLC and Baker Hughes Oilfield Operations, LLC v. Ulterra Drilling Technologies, L.P., Case No. 4:18-cv-00339 (S.D. Tex.)

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Nathan S. Mammen

CERTIFICATE OF COMPLIANCE

This Petition complies with the type-volume limitations as mandated in 37 C.F.R. § 42.24. According to the word processing system used to prepare this document, the brief contains 13,901 (14,000 limit) words, including 92 words added as annotations to the figures.

/s/ *Nathan S. Mammen*
Nathan S. Mammen

TABLE OF EXHIBITS

Exhibit No.	Description
Exhibit 1001	Declaration of Geir Hareland
Exhibit 1002	Geir Hareland Curriculum Vitae
Exhibit 1003	U.S. Patent No. 6,935,441
Exhibit 1004	File History of U.S. Patent No. 6,935,441
Exhibit 1005	U.S. Patent No. 5,244,039 (Newton)
Exhibit 1006	U.S. Patent No. 4,554,986 (Jones)
Exhibit 1007	U.S. Patent No. 6,142,250 (Griffin)
Exhibit 1008	Reserved
Exhibit 1009	Reserved
Exhibit 1010	Bork, K.R., *The Rotary Rig and Its Components*, Unit I, Lesson 1 (4th Ed.), Petroleum Extension Service and International Association of Drilling Contractors (1995).
Exhibit 1011	Bourgoyne Jr., Andrew et al., *Applied Drilling Engineering*, Vol. 2, Society of Petroleum Engineers Textbook Series (1986).
Exhibit 1012	Hareland, Geir, PETE 4313 — Drilling Engineering and Well Completion, Course Program Handout No. 1, Oklahoma State University (Spring 2017).
Exhibit 1013	Hareland, Geir, PETE 4313 — "Rolling Cutter Bits," Course Program Handout No. 5, Oklahoma State University (Spring 2017).
Exhibit 1014	Van Dyke, Kate, *The Bit,* Unit 1, Lesson 2 (4th Ed.), Petroleum Extension Service and International Association of Drilling Contractors (1995).

Exhibit 1015	Hareland, Geir, PETE 4313 — Drilling Bits - Drag Bits, Course Program Handout No. 4, Oklahoma State University (Spring 2017).
Exhibit 1016	Kerr, Callin Joe, "PDC Drill Bit Design and Field Application Evolution," Journal of Petroleum Technology (1988).
Exhibit 1017	Rabia, Hussain, *Well Engineering & Construction* (2001).
Exhibit 1018	Robertson, Neil et al., "New PDC Designs Doubles ROP on Kingfisher Project Well, Central North Sea," American Associated of Drilling Engineers, 01-NC-HO-15 (2001).
Exhibit 1019	Besson, Alain et al., "On the Cutting Edge," Oilfield Review (2000).
Exhibit 1020	"PDC bit profile," Petro*Wiki*, Society of Petroleum Engineers, (accessed Aug. 15, 2018), https://petrowiki.org/PDC_bit_profile.
Exhibit 1021	Lewis, J.P. et al., "Lateral-Jet Hydraulics and Oval-Cutter Technology Combine to Improve PDC Performance, North Sea Scott Field," Society of Petroleum Engineers Drilling and Completion, SPE 29400 (June 1997).
Exhibit 1022	Zijsling, D.H. and Illerhaus, Roland, "Eggbeater PDC Drillbit Design Eliminates Balling in Water-Based Drilling Fluids," SPE Drilling & Completion, Society of Petroleum Engineers, SPE-21933-PA (Aug. 1993).
Exhibit 1023	Macini, Paolo, "Drill Bits for Horizontal Wells," Chemical, Mining and Environmental Engineering Department, University of Bologna (1996).
Exhibit 1024	Taylor, S. et al, "Unique PDC Bit Technologies Combine to Consistently Reduce Drilling Time in Interbedded Formations," International Association of Drilling Contractors and Society of Petroleum Engineers, IADC/SPE 47778 (Sept. 1998).

Exhibit 1025	Clegg, J.M., "An Analysis of the Field Performance of Antiwhirl PDC Bits," International Association of Drilling Contractors and Society of Petroleum Engineers, IADC/SPE 23868 (1992).
Exhibit 1026	Sinor, L.A. and Warren, T.M., "Application of Anti-Whirl PDC Bits Gains Momentum," Society of Petroleum Engineers, SPE 25644 (April 1993).
Exhibit 1027	Warren, T.M. and Sinor, L.A., "PDC Bits: What's Needed to Meet Tomorrow's Challenge," Society of Petroleum Engineers, SPE 27978 (1994).
Exhibit 1028	Pain, D.D. and Schieck, B.E., "Evolution of Polycrystalline Diamond Compact Bit Designs for Rocky Mountain Drilling," Society of Petroleum Engineers, SPE 12906 (July 1985).
Exhibit 1029	Sinor, L.A. et al., "The Effect of PDC Cutter Density, Backrake, Size, and Speed on Performance," International Association of Drilling Contractors and Society of Petroleum Engineers, IADC/SPE 39306 (March 1998).
Exhibit 1030	U.S. Patent No. 5,443,565 (Strange, Jr.)
Exhibit 1031	U.S. Patent No. 4,453,605 (Short, Jr.)
Exhibit 1032	Glowka, D.A. and Stone, C.M., "Thermal Response of Polycrystalline Diamond Compact Cutters Under Simulated Downhole Conditions," Society of Petroleum Engineers, SPE 11947 (April 1985).
Exhibit 1033	Atashnezhad, A., Ph.D. Proposal "Drilling Optimization Using New PDC ROP Model and Differential Evaluation Algorithms," Oklahoma State University (April 2018).
Exhibit 1034	Turner, Evan, "Bit improvements are cutting drilling costs," *World Oil*, Vol. 217, No. 4, pgs. 59–66 (April 1996).

Exhibit 1035	Mensa-Wilmot, G. et al., "Innovative Design Processes and Technologies Improve PDC Bit Performance in Harsh Drilling Environments", Society of Petroleum Engineers, IADC/SPE 103983, (Nov. 2006).
Exhibit 1036	Niznik, M.R. et al., "A New Approach to Stick-Slip Management Integrating Bit Design and Rotary-Steerable-System Characteristics," International Association of Drilling Contractors and Society of Petroleum Engineers, IADC/SPE 98962 (Feb. 2006).
Exhibit 1037	Taylor, M.R. et al., "High Penetration Rates and Extended Bit Life Through Revolutionary Hydraulic and Mechanical Design in PDC Drill Bit Development," Society of Petroleum Engineers, SPE 36435 (Oct. 1996).
Exhibit 1038	U.S. Patent No. 6,089,336 (Nexton et al.)
Exhibit 1039	U.S. Patent No. 5,967,246 (Caraway et al.)
Exhibit 1040	Lyng Drilling, product specifications of the LD 565RSA, the LD 575RS, and the LD 575RSX (Aug. 2003).
Exhibit 1041	Hughes Christensen, product specifications of the HC607 drill bit (2005).
Exhibit 1042	Roberts, T.S. and Schen, A.E., "Optimization of PDC Drill Bit Performance Utilizing High-Speed, Real-Time Downhole Data Acquired Under a Cooperative Research and Development Agreement," International Association of Drilling Contractors and Society of Petroleum Engineers, SPE/IADC 91782 (Feb. 2005).
Exhibit 1043	U.S. Patent No. 6,408,958 (Isbell et al.)
Exhibit 1044	Hareland, Geir, PETE 5313 — Drilling Simulation, Course Program Handout Nos. 5 and 6, Oklahoma State University (Fall 2016).
Exhibit 1045	U.S. Patent No. 4,538,690 (Short, Jr.)
Exhibit 1046	Hareland, Geir et al., "Cutting Efficiency of a Single PDC Cutter on Hard Rock," Petroleum Society, Paper 2007-082 (June 2007).

Exhibit 1047	Mensa-Wilmot, Graham and Penrose, Bill, "Advanced Cutting Structure Improves PDC Bit Performance in Hard and Abrasive Drilling Environments", Society of Petroleum Engineers, SPE 81167 (April 2003).
Exhibit 1048	U.S. Patent No. 5,314,033 (Tibbitts)
Exhibit 1049	Hughes Christensen, product specifications of the CW210655 drill bit (Sept. 1996).
Exhibit 1050	Huang, Hsin I. et al., "The Positive Effects of Side Rake in Oilfield Bits Using Polycrystalline Diamond Compact Cutters," Society of Petroleum Engineers of AIME, SPE 10152 (Oct. 1981).
Exhibit 1051	Cerknovik, Jerry, "Design, Application, and Future of Polycrystalline Diamond Compact Cutters in the Rocky Mountains," Society of Petroleum Engineers of AIME, SPE 10893 (May 1982).
Exhibit 1052	Glowka, D.A. and Stone, C.M., "Effects of Thermal and Mechanical Loading on PODC Bit Life," SPE Drilling Engineering, Society of Petroleum Engineers (June 1986).
Exhibit 1053	Warren, T.M. and Sinor, A., "Drag-Bit Performance Modeling," Society of Petroleum Engineers, SPE-15618-MS (Oct. 1986).
Exhibit 1054	Warren, T.M. and Sinor, A., "Drag-Bit Performance Modeling," SPE Drilling Engineering, Society of Petroleum Engineers, SPE-15618-PA (June 1989).
Exhibit 1055	Canadian Patent Application No. 2,009,654 (Hareland et al.)
Exhibit 1056	Soares, Cesar et al., "Evaluation of PDC bit ROP models and the effect of rock strength on model coefficients," Journal of Natural Gas Science and Engineering 34 (Aug. 2016).
Exhibit 1057	Bratli, R.K. et al., "Drilling Optimization Software Verified in the North Sea," Society of Petroleum Engineers, SPE 39007 (1997).
Exhibit 1058	Andrews, R. et al., "Methods of Using Logs to Quantify Drillability," Society of Petroleum Engineers, SPE 106571 (April 2007)
Exhibit 1059	Hareland, Geir, "Drilling Optimization Simulation Reduces Drilling Cost," Society of Petroleum Engineers' Distinguished Lecturer Program (March 2011).

Exhibit 1060	Hareland, Geir, PETE 5313 — Advanced Drilling, Course Program Handout Nos. 7 and 8, Oklahoma State University (Fall 2016).
Exhibit 1061	Gjelstad, G. et al., "The Method of Reducing Drilling Costs More than 50 Percent," Society of Petroleum Engineers, SPE/ISRM 47342 (1996).
Exhibit 1062	Reserved
Exhibit 1063	Reserved
Exhibit 1064	Finger, John T. and Glowka, David A., *Sandia Report: PDC Bit Research at Sandia National Laboratories*, Sandia National Laboratories (June 1989).
Exhibit 1065	Reserved
Exhibit 1066	U.S. Patent No. 5,178,222 (Jones et al.)
Exhibit 1067	U.S. Patent No. 5,651,421 (Newton et al.)
Exhibit 1068	U.S. Patent No. 6,123,161 (Taylor)
Exhibit 1069	U.S. Patent No. 7,798,256 (Hoffmaster et al.)
Exhibit 1070	U.S. Patent No. 5,531,281 (Murdock)
Exhibit 1071	Spaar, J.R. et al., "Formation Compressive Strength Estimates for Predicting Drillability and PDC Bit Selection," International Association of Drilling Contractors and Society of Petroleum Engineers, SPE/IADC 29397 (March 1995).
Exhibit 1072	Baker Hughes' Disclosure of Asserted Claims and Preliminary Infringement Contentions (July 13, 2018).