FINAL REPORT

High Impact Systems (Rock Bits, Coring & More) Technical Review & Risk Reduction Study for the BEAM - Borehole into Earth's Mantle Mantle Quest Drilling Project

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Purpose:

Identify, Provide Technical Review, and Propose Risk Reduction Process for Equipment & Services, such as Rock Drill Bits and Coring Systems to Substantially Reduce Mantle Drilling Time & Risk.

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1 Executive Summary

In 2011 Blade conducted an initial high-level mantle drilling feasibility study which showed that with existing technologies it is feasible to core/drill a hole into the mantle at a Pacific Ocean location using IODP's Chikyu drillship with some equipment modifications. However, the drilling time (depending upon location) in 3650 - 4300m water to 9900 - 10750m total depth could take 418 - 934 days (depending upon operational choices). Considering deepwater drilling today may be generally estimated as a US$1Million/day cost, any reduction in drilling days proportionately reduces both the project cost and the project operational risk. The feasibility study indicated that such a world-record deep well would require 36-48% of project time making bit trips (pulling out of hole, changing a worn bit, then running back in the hole to bottom) and 13-25% of project time coring. If the time for either fewer bit trips or coring can be shortened and made more efficient by application of new technologies, then significant savings in project time will result, and a commensurate reduction in project risk will also result.

In February 2012, IODP-MI requested that Blade conduct study to identify and investigate equipment and services that could substantially decrease drilling time and risk when drilling to earth's mantle. The objectives of this study were to identify the original equipment manufacturers and service companies that provide rock drill bits and coring, and investigate the status of their technologies today, what technological improvements they may reveal for mantle quest application by 2017, and what suggestions they offer to accelerate technological development between now and 2017.

More specifically, the goals of study were to address the following:

- Review the mechanics of hard rock drilling.
- Identify current rock drill bit equipment and services.
- Investigate potential technological gaps and improvements that will enable rock drill bits to stay on-bottom longer, decreasing drilling time and risk.
- Identify current rock coring systems and services.
- Investigate possible development of new rock coring systems to improve the quality and quantity of cores recovered in order to satisfy the scientific objectives.
- Provide a recommendation of the most efficient and most viable drill bits and rock coring systems for a possible mantle quest drilling project spud date in 2017-2018.
- Provide an estimate of how the designers, manufacturers, and service companies of such equipment and services may accelerate their technological offerings, including an estimate of the technological improvement costs to IODP and the scientific community.

- Identify additional high-impact equipment and services where technological improvements will also reduce project time and risks.

The results of this effort are described in this report. Blade had extensive discussions with 19 different service companies that provide a wide range of services to the oil and gas industry. The key conclusion for this study is that the oil and gas industry has wide experience drilling and coring high temperature hard rocks - including basalt. And the operational time and risks associated with drilling a hole to the mantle can be significantly reduced by capitalizing on this experience.

2 Overview of Hard Rock Drilling

Many tools are available to enable the drilling process in order to penetrate a given geological formation. The majority of the drilling systems utilize a type of mechanical drill (e.g. drilling bit for rotary drilling) which is used to apply either cutting or breaking forces over a small contact surface on the rocks. Hence, the cutting or breaking forces generally generate stresses that exceed either the rock tensile strength or the rock shear strength. As a result, rocks will either fail due to brittle failure or plastic yielding.

Note that even though mechanical processes account for a large part of the methods used to break rocks, two other approaches could also be used to fail rocks. The first alternative method is thermal loading using either spallation, melting or vaporization processes and the second method can use chemical agents to react with the rock surface.

2.1 Overview of Drilling Bit Systems – Definition

One of the most important parts of the mechanical process such as the rotary drilling system which is widely used by energy industry is called the drill bit. Actually, because of the various situations that can be encountered during rotary drilling operations, a very large catalogue of bits can be manufactured to reach optimum performance when drilling different geological layers.

A drill bit can be defined as a mechanical component constituting the end of the drill-string and that can not only drill the desired borehole diameter but also, because of its design, has a direct impact on the characteristics of the core, rock fragments and cuttings that are recovered from the borehole being drilled. As stated previously, a drill bit can come in various forms and sizes using different cutting surfaces and also its body can be composed of different materials.

2.2 Bit Types and Rock Failure Mechanism

The range of drill bits available within the petroleum industry is vast and has significantly increased over the last two decades as a result of the development of new cutter elements such as polycrystalline diamond. Thus, depending upon the type of geological layer and the formation geotechnical and petrophysical characteristics (e.g. hardness, abrasively, strength, etc…) a certain drill bit type and design will be selected.

Thus, there are “soft rock drill bits” that are specifically designed to drill through soft formations and also there are “very hard formation rock bits” to enable drilling through hard formations such as hard shale or carbonates which are often encountered by the oil and gas industry but; there are also hard igneous rocks. Usually, one can distinguish four main types of drill bit systems that can be used in well or borehole drilling.

2.2.1 Tungsten Carbide Inserts (TCI) and Tricone Bits

In a tungsten carbide insert bit, the load is applied to a cutter and the pressure beneath the cutter increases until it exceeds the crushing strength of the rock. Then, a wedge of finely powdered rock is formed beneath the cutter. Consequently, as the force on the cutter increases, the material in the wedge compresses and exerts high lateral forces on the rock surrounding the wedge. Finally, the shear stress will exceed the shear strength of the rock and the rock will fracture and eventually fail.

Tricone bit systems have per definition three cones. These cones can rotate around the drill bit axis. If the tricone bit has been designed with longer and more widely arranged teeth, it is intended to drill relatively soft formations. Conversely, if the tricone bit has been designed with shorter and more closely arranged teeth, it will preferably be used to drill harder formations. Also, note also that in general, drill bit systems having shorter teeth drill through the rock much slower than bit systems having longer teeth. In addition, some simpler bit design can be made with single or dual cones instead of tricones.

2.2.2 PDC Bits

Polycrystalline diamond compact bits (i.e. PDC) consist of polycrystalline diamond compact buttons inserts that are used to break the rock with a shearing mechanism but until recently have been known and used to penetrate through relatively soft rocks. Nowadays, PDC bits can be used in a lot of drilling applications. With PDC bit systems, the high abrasion resistance of the diamond layer is used to remove the different layers composing the rock by a shearing action. Additionally, PDC bits are also partly made with tungsten carbide cylinder. The tungsten carbide layer is used to provide mechanical support and high resistance to impact loading. Also, since PDC bits are built in a mold with the compacts positioned prior to pouring the metallic compound, the design of PDC bits can be almost unlimited.

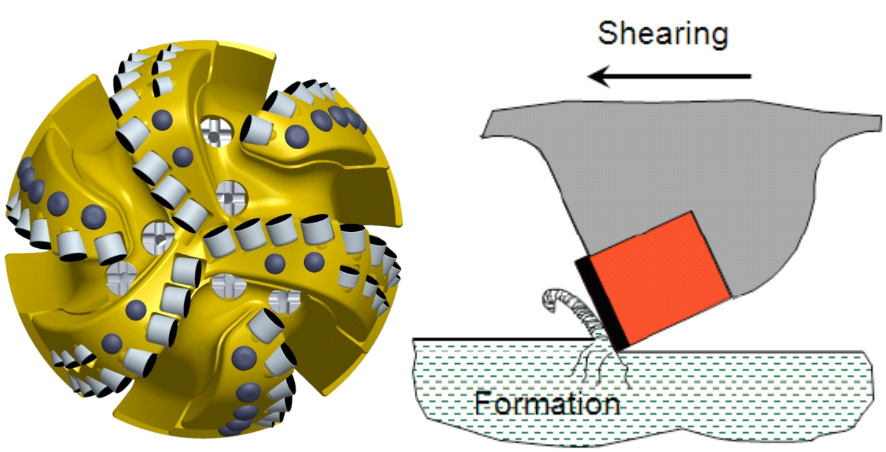


Figure 1. PDC Formation Failure Mechanism: Shear

2.2.3 Insert Bits and Impregnated Diamond Drill Bit

Insert bits are also called surface set diamond bits. These bit systems consist of several single diamonds which have been set in the metallic body matrix. They are utilized to drill through very hard formations.

Impregnated diamond drill bit. These drill bit systems are specifically designed for ultra-hard, abrasive rock formations. This bit design consists of a diamond grit which is mixed with tungsten carbide in its liquid form. Then, the mixed compound is molded into the bit design shape. The wear resistance of impregnated bits is of particular importance to drill through abrasive formations (e.g. relatively high silica, quartz or iron content).

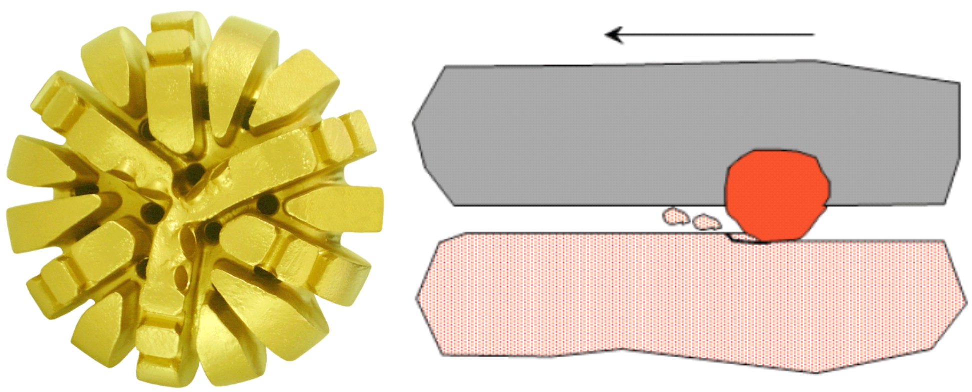
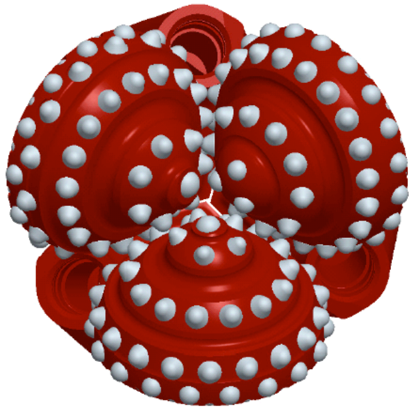


Figure 2. Diamond Impregnated Formation Failure Mechanism: Grind and Shear.

2.2.4 Roller Cone Bits

Roller cone bits are made of "wheels" with teeth that rotate or turn when the bit is being rotated. The bit teeth apply a pressure level onto the rock that exceeds the formation strength and hence the rock is failed in compression. The cones roll about the bottom of the borehole as the bit rotates. Note that the three cones cutter bit is the most common bit type currently used with the rotary drilling process. Additionally, roller cone bits are available with numerous cutter designs and bearing types to be used to drill a wide range of geological formations.



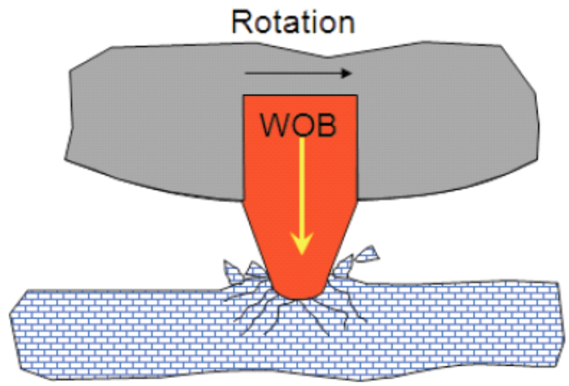


Figure 3. Rolling Cutter Formation Failure Mechanism: Compression

2.2.5 Discussion

Depending on the location of the drill bit within the rock material, rocks can be broken under tensile, shear or compressive stresses. Tension and shear stresses induce failure of the inter-granular bonds and pure compressive stresses lead to crushing and breakage of the rock grains. Also and more importantly, these stresses can also be influenced by the bit design as discussed previously, but equally, the borehole geometry and the drill-string dynamics can play a critical part in the rock failure mechanism.

Additionally, bit design is also critical when trying to drill a directional borehole, or when trying to maintain or drill a vertical borehole. The borehole trajectory is essentially controlled by two parameters: the bit tilt and the side forces acting on the bit which are notably a function of the bit type, ROP, bottom hole assembly and rock characteristics, and geology (dipping beds, etc). These two parameters define the direction of the bit force, hence the borehole trajectory.

2.3 Bit Materials

The materials that are used to build drill bit systems are critical for drill bits performance, durability and their specific application. The materials used are usually hardened and tempered carbon steel, cobalt steel and tungsten carbide. Also, for some bit designs, single diamond crystals can be embedded into the tips of the cutting tools. However, since single diamond crystal have large strength anisotropy and are very brittle when impacted at some angles, they are often fused together to form a polycrystalline diamond and bonded to a tungsten carbide mixed compound. Also, because of this change in crystalline structure in the presence of certain metals and its tendency to revert to graphite when used to drill very hot formations, coatings such as black oxide, titanium carbon nitride (TiCN) or zirconium nitride are applied on the diamonds in order to increase bit wear resistance.

2.4 Rock Classification

Geological formations can be classified into three categories:

1. ***Sedimentary;***
   Sedimentary rocks are composed of individual mineral or lithic fragments that have been transported and deposited in layers. These layers or strata have been compacted or cemented to form a rock.

2. ***Metamorphic;***
   Metamorphic rocks are either igneous or sedimentary rocks that have been altered by heat and/or pressure during their burial. The original rock textures and mineral assemblages have been progressively replaced.

3. ***Igneous.***
   In this study and because of the nature of the rocks that have been drilled at IODP hole 1256D, 504B, U1309D and 735B and that are expected to be drilled and cored when drilling to the upper mantle, igneous rocks are the one that will be essentially discussed in this study.

   Igneous rocks are geological layers that have solidified from a molten state. Indeed, basalt is one of the best examples of an igneous rock. Igneous rocks can either have glassy aspect when quickly cooled, or have been fully crystallized if the cooling has been relatively slow. One can distinguish four main types of igneous rocks: granite, diorite, gabbro (i.e. basalt) and peridotite which actually depend on the silica, magnesium and iron composition.

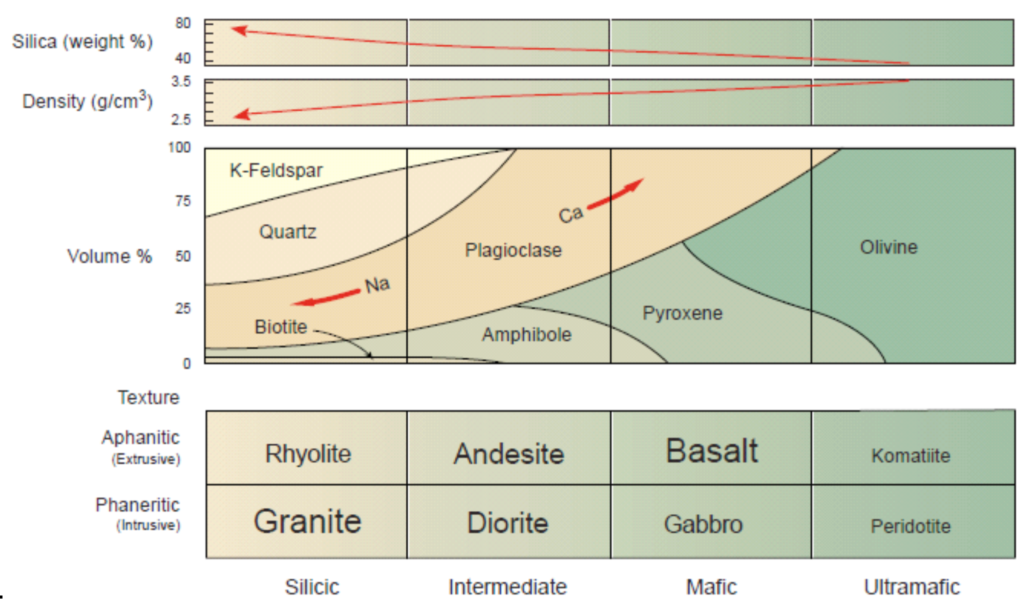


Figure 4. Classification of Igneous Rocks

2.5 Rock Properties

2.5.1 Generality

Rock behavior to any external loading depends not only on the magnitude of the loads applied but also on the rock physical and mechanical properties. One can distinguish three rock property categories:

1. ***Elastic properties;***
   Young's modulus, shear modulus, bulk modulus, Poisson's ratio, bulk compressibility, and grain or matrix compressibility constitute rock elastic properties and enable to define rocks elastic deformation when a rock is submitted to a given loading condition.

2. ***Strength properties;***
   The rock strength properties are used to describe the maximum loading that a rock can withstand before yielding and can also describe the rock plastic behavior when the loading is pushed beyond the rock elastic capacity. There are several strength variables and parameters that can be used: cohesive strength, tensile strength, compressive strength and internal friction angle for sedimentary rocks.

   a. Shear strength is the maximum shear stress that a rock can sustain. The resistive forces come from both the cohesive resistive force and the frictional resistive force. Cohesion comes notably from mineral cementation from quartz, calcareous, and cohesive bonding such as capillary force.

   b. Uniaxial compressive strength (UCS) is the maximum stress that a rock can withstand during a uniaxial compression test with when the confining stress is nil. The rock will be assumed to be more stable when drilled through if its UCS is higher but it will be much harder to drill through. When conducting UCS test, cylindrical samples with Length to Diameter ratio of 2:1 are prepared from good quality core samples. The samples are mounted in a compression frame and submitted to an increasing compressive load applied. The common practice is to calculate the average of five UCS tests from the same stratigraphic column.

      Note also that UCS can be estimated from formation bulk compressibility, shear and compressive sonic velocities or gamma ray data from an offset borehole. In addition, in order to complement the UCS test, other penetration tests such as the elastic rebound tests, the point load test and core scratch test can provide an additional and continuous strength estimate.

   c. Rock residual strength is the strength of the rock has after the rock has lost its cohesive strength component and original structure integrity. This strength is important in order to predict the rock post-failure behavior. Note that for both sedimentary and igneous rocks, there is a difference between the strength of the intact rock sample and the strength of the rock individual mineralogical constituents.

d. Triaxial test is often considered as the most reliable approach to determine rock strength when testing core samples in the laboratory. To perform this test, between three and five cylindrical samples with Length over Diameters equals to 2/1 are used to calculate the Mohr Coulomb yield criterion over a wide range of stresses.

Rock strength properties are particularly influenced by numerous internal parameters such as rock anisotropy, mineral grain size, mineral cement type, original cracks and fissures, and also external criteria such as the state of stress, loading path and water saturation.

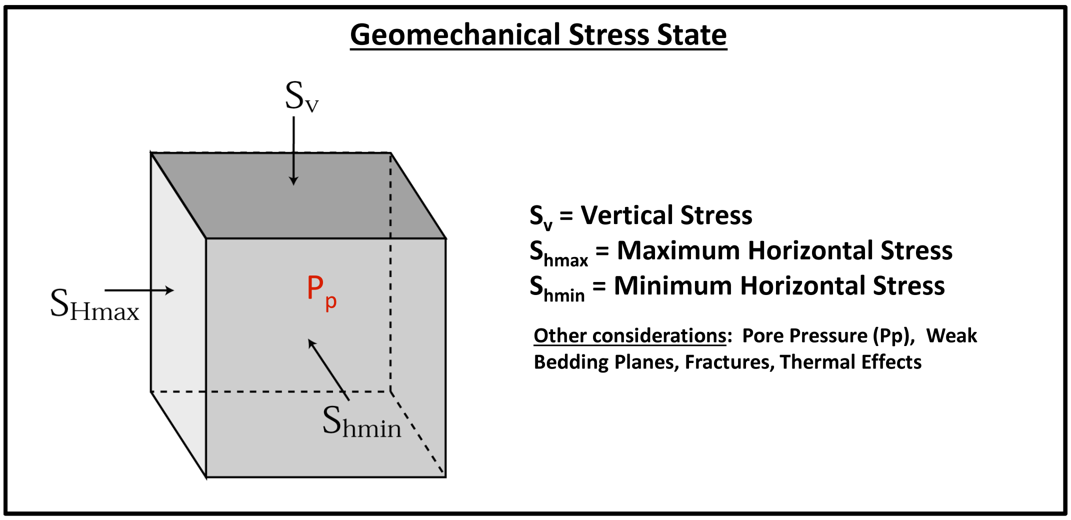


Figure 5. Depiction of the Geomechanical State of Stress

3. ***Transport properties.***
   Rock porosity and permeability are the two commonly used properties to describe the ability of a fluid to migrate through a rock.

Also, note that elastic, strength and transport rock properties are not independent are related to each other directly or indirectly. For instance, rocks with high tensile strength are likely to have high Young modulus, low Poisson's ratio, and low porosity. In this study, emphasis has been on looking in great details at rock strength properties and particularly igneous compressive strength. Finally, in practice, cores and core fragments will be tested by one or several of the tests previously discussed.

2.5.2 Discussion on Strength Properties

When subject to external loading, rock may lose its integrity if the applied force exceeds the rock strength. The mechanical strength of rock is its most crucial property and; as discussed previously can be assessed by testing its shear strength, uniaxial compressive strength (i.e. UCS), tensile strength, and residual strength.

Additionally, rock properties may vary quite significantly under different internal and external conditions. In general, rock strength increases as depth increases. However, this increase in strength may be balanced back when local over-pressurization of the fluids are present within the rocks; thus, resulting in reduced effective stresses. Note that an increasing confining stress will have notably two effects:

a. First, an increase in rock compressive strength (UCS). Also, note that both elastic and strength properties increase drastically when confining stresses increase.

b. Secondly, a reduction of the brittle characteristics of the stress–strain curve which will decrease the rock tendency to expand (i.e. dilatation).

Furthermore, another criterion that may affect rock strength is formation temperature. Because of geothermal gradients, deeper rock layers are usually hotter and very high temperatures when combined with high overburden pressure change the rock properties from elastic to plastic which as a result are much more difficult to drill through. This phenomenon was noticed by the scientists and engineers at the Kola Superdeep Borehole onshore location in Russia. It was found that at a depth of 12,262 meters, the temperature encountered was about 180 °C. Hence, at these higher than expected temperatures (e.g. 180 °C vs 100 °C), deepening the borehole was not technically feasible with the current state of drilling technology in 1989.

Table 1 provides an overview of mechanical properties for relatively hard rock belonging to sedimentary, metamorphic and igneous formations.

Table 1. Examples of Mechanical Properties for Hard Sedimentary, Metamorphic and Igneous Rocks

Mechanical Properties of Hard Rocks							
Rock	Location	Volumic Mass	Young Modulus	Shear Modulus	Poisson Ratio	Compressive Strength	
		ρ (g.cm^{-3})	E (GPa)	G (GPa)	ν	UCS (MPa)	UCS (ksi)
Dolomite	Mankato, USA		52		0.25	106	15.4
	Jefferson City, TN	2.77	75.2	31.9		245	35.5
Gneiss	Dworshak Dam, USA	2.8	54		0.34	162	23.5
	Mineville, NY	2.75	38.5	19.6		212	30.7
Granite	USA	2.66	44	17		244	35.4
	Woodstock, MD	2.65	54.6	25.4		251	36.4
	Lithonia, GA	2.64	19.1	11.8		193	28.0
Limestone	Quebec, Canada		77		0.33	293	42.5
	Barberton, OH	2.69	55	25		197	28.6
Quartz	Kansas, USA	2.72	1.71		0.2	329	47.7
	Urals, Russia	2.65	70	30.8		374	54.2
Sandstone	Bridge Canyon, AZ	2.4	27.5		0.01	90	13.1
Shale	Utah	2.8	58	26	0.09	216	31.3
	Ophir, UT	2.8	68	30	0.12	231	33.5
Siltstone	Alaska	2.76	53	25		256	37.1

2.6 Drilling Efficiency in Hard Rocks

Different indexes exist when trying to evaluate the efficiency of a drilling method but specific energy is the most commonly used criterion. Specific energy is defined as the energy required for removing a unit volume of rock. Specific energy is a function of the elastic and geotechnical properties of the rock but is also function of the bit type, design and drilling method parameters.

2.7 Hard Rock Drilling Industry Experience

Hard carbonate formations used to be drilled with rolling cutter technology and which was recently replaced by fixed cutter technology using PDC and diamond impregnated drill bits when trying to drill carbonates with UCS up to 70 ksi. The change in bit type and design for these applications resulted in greater performance but there were still improvements that could be made. Thus, the next step in drill bit performance was to conduct an R&D project aiming at developing a new drill bit combining the durability of diamond impregnated bits with the drilling efficiency of PDC bits. The outcome of this project provided a new bit design to drill hard rock carbonate formations and has been replicated to drill harsh formations at several locations around the world such as deepwater Canada (SPE 140353).

Figure 6. Hybrid PDC-Impreg Bit Used to Drill Hard Carbonate Formation Deepwater Canada

Since the early 2000s, operators have launched several exploratory drilling campaigns offshore Shetland islands. The challenges associated with the wells drilled in deepwater on the west side of the islands are twofold: the harsh Metocean conditions and basalt layers having thicknesses up to 820 ft and UCS that could be potentially be up to 30 ksi. Lab results directed service companies' effort towards the use of impregnated bits powered with Turbodrill to achieve high ROP. After tested were conducted on basalt ranging between 26 ksi and 33 ksi, the 12-1/4" and 8-1/2" drill bit that were designed used proprietary impregnated diamond inserts also called grit hot pressed inserts (GHI). In the original wellbore drilled, basalt sections with UCS up to 50 ksi were encountered which created problems that led to sidetrack the well. On the sidetrack well, the basalt was even thicker than anticipated (1,400 ft) and UCS reached up to 50 ksi intermittently. Based on laboratory results discussed previously, an impreg bit associated with Turbodrill enabled to drill the entire sequence in one single run (SPE 96575).

Figure 7. Impreg Bit for Drilling Basalt Offshore Shetland

The discovery of the Jubilee field offshore Ghana presented new challenges to the operators. Not only located in a deepwater environment, the intervals to be drilled transitioned rapidly from soft shale to hard and abrasive sandstone with UCS that can peak at 25 ksi. Bit failures were not uncommon and usually up to four trips were required to drill through a 1,300 ft section. The main goal for a new bit design was to reduce bit trips by ideally completing the drilling of these sections in one run. Therefore, ONYX premium cutters were integrated onto a PDC bit and a this optimized 12-1/4” PDC bit was the first to drill an entire section from shoe to TD in one single run and enabled to save about two days of drilling time.

Figure 8. 12-1/4” PDC MDSi816LBPX with ONYX Cutters

2.8 Hard Rock Bit Selction Criteria

Bit performance is characterized by the interaction between the bit design and the associated rock failure mechanism, type of rock being drilled, the bottom hole assembly (BHA) design, and the drilling practices being used (i.e. weight on bit, rotational speed, hydraulics, etc…). If one assumes that the optimum drilling practices are being utilized, then drilling efficiency becomes a function of the following bit performance characteristics.

- Durability – defined as the bit's ability to resist abrasive wear, teeth or cutter wear, body erosion, and thermal damage. Improving durability typically tends to reduce the bit's performance or rate of penetration.

- Stability – defined as the bit's ability to either resist or initiate BHA initiated lateral, torsional, and axial vibrations which can cause severe damage to the bit.

- Steerability – defined as the bit's tendency to drill in the desired direction, or conversely, the bit's tendency to not "walk" or deviate the direction of the wellbore in an undesired lateral direction, or cause an undesired deviation of the hole angle.

- Aggressivity – is defined as the rate of penetration (ROP) or how fast the bit drills based on the bit's response to an externally applied axial force, or the weight on bit (WOB).

Each of the parameters can be adjusted through modifications to the bit design. For example, stability and durability in a PDC bit can be imp with the addition of more blades. Vibration can be reduced by adjusting the number of cutters that are in contact with the formation at any one time. However, maximizing the effectiveness of one parameter can adversely impact the other parameters. For example, increasing the number of blades complicates the positioning of the nozzles which is critical for keeping the blades clean. Also, maximizing the bit's durability will usually reduce its performance or ROP.

The parameters are therefore interdependent from the standpoint that changing one parameter will impact the others sometimes unfavorably. The key to optimizing bit performance is the to determine which parameter(s) is the most important to achieve the goals of the hole interval to be drilled, and then to adjust the bit design to maximize that effectiveness of that parameter, while at the same time, minimizing the potential adverse effects on the other parameters.

As has been noted, the types of bits used to today to drill hard rock formations are roller cone bits, diamond impregnated bit and PDC bits. Roller cone bits fail the rock through compression and generally have good steerability and aggressivity. However, high bit weights are needed to overcome the high compressive strengths found in hard rock formations. High bit weights and the rotation of the bit's cones can severely limit the life of the bearings, cause brittle fracture of the cutters and result in an overall decrease in durability.

Diamond impregnated bits fail the rock by shearing a very fine layer of the formation which is known as “plowing”, and generally have good steerability, durability and stability. However, because only a fine layer of formation is cut at one time, these bits have a significantly lower ROP than the other two types. These bits are typically run with high RPM down-hole turbines in order to compensate for the low efficiency of the cutting elements and increase the ROP. However the inclusion of a turbine in the BHA increases the risk of an unplanned trip in the event of a failure of the turbine.

PDC bits fail the rock through shearing relatively large sections of the rock. This is the most efficient method of mechanically failing rock because the shear strength of the rock is roughly half of its compressive strength. However, PDC bits can have poor stability and be very susceptible to brittle fracture under high loads as well as thermal fatigue at high temperature when instability is present. In addition, their performance is sensitive to improper drilling practices. Conversely, the very nature of these bits allows a great deal of flexibility for adjusting or modifying the performance characteristics parameters so that the above limitations can be designed out of a particular PDC bit used for a particular application. With proper cutter selection, cutting structure design, torque control component design, and hydraulic design, PDC bits can provide the optimum balance between durability, stability, steerability and aggressivity thereby maximizing bit performance. It can be argued that roller cone and diamond impregnated bits need to be used only when a PDC cannot be properly designed.

2.9 Conclusions

To reach extreme depths in the Earth’s mantle with very hot and hard rocks, the use or development of an array of new technologies ranging from high electronics to new cutter materials will be required. However, as presented in this study, as drilling technology continues to make significant progress, the challenges that are/were once considered to be difficult to overcome, have been resolved or are expected to be solved in the near future.

3 Review of Hard Rock O&G Drilling Services

The main focus of Blade's work for this project was to evaluate the hard rock drilling and coring technology that currently exists within the oil and gas industry and to understand where and how the technology will be trending in the future. To this end, Blade developed a presentation that summarized the BEAM project objectives and the technical issues around drilling and coring into the mantle and met the four key oilfield service providers of bits and coring systems as well as a major North American hard rock bit supplier. Initial meetings were held with each service company to introduce the BEAM project, get information about their current product offerings and their technical development efforts, and to identify their ability and willingness to provide technical support to the BEAM project.

The meetings were quite informative and well attended by each company's relevant product line managers and technical representatives. These initial meetings were held with the following service companies:

- National Oilwell Varco (NOV) who provides Reed and Hycalog bits
- Baker Hughes provides Hughes Christensen bits
- Halliburton who provides Security and DBS bits
- Schlumberger who provides Smith bits
- Ulterra who provides their own Ulterra bit product line

The key highlights from these meetings are as follows:

- All the companies were generally interested in the BEAM project, NOV and Ulterra in particular.
- Not surprisingly, each company also expressed concerns over "what's in it for me" to some degree.
- All the companies believe that they have current products that would improve performance by 30 to 50% compared to current scientific drilling practices and results.
- All the companies have active ongoing technology development programs that will result in new products on the market well before the nominal 2018 start date for the BEAM project.
- All the companies have extensive experience with hard rock, and high temperature drilling and coring applications within the oil and gas industry – including basalt. This experience is illustrated in Figure 9 which shows Halliburton's worldwide coring experience.

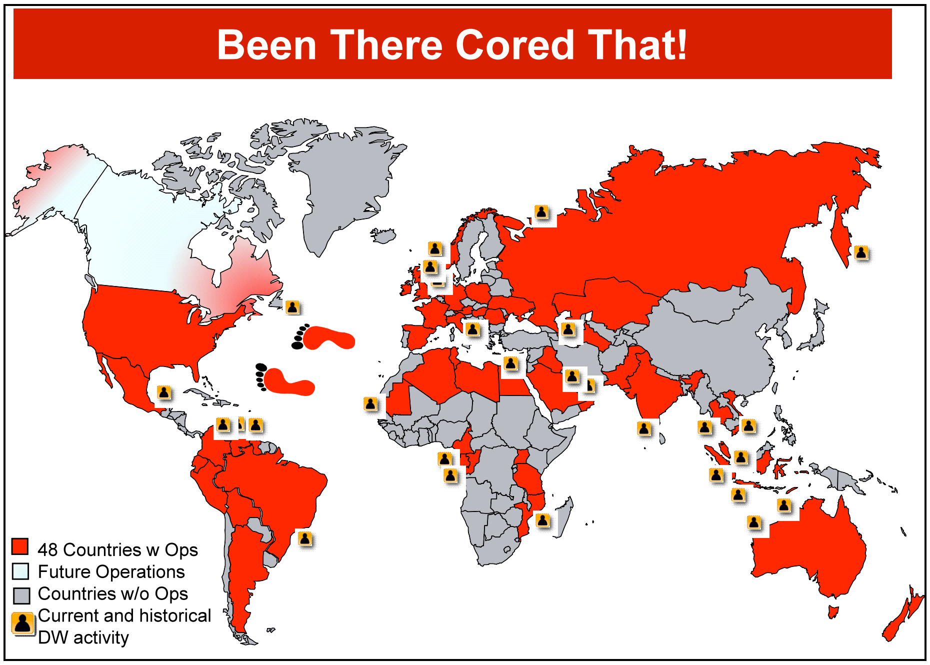


Figure 9. Illustration of Halliburton's Coring Experience

- All the companies have a sound technical understanding of drilling and coring mechanics as well as the bit design and bottom hole assembly performance software models that are used to develop optimized performance solutions based on predicted and/or actual field operational data.
- With the exception of Ulterra, all the companies have their own testing facilities and drilling simulators that they use for bit and down-hole tool development under a variety of simulated down-hole drilling conditions. NOV's facility, for example, has the capability to simulate the overburden pressure for different types of rock in atmospheric and pressurized conditions, and conducting downhole electronics testing with vibration at high temperatures. NOV purchases large boulders of different rock types from mining operations around the world and then uses them for bit development and performance testing. This includes examples of sandstone, limestone, dolomite, granite and two types of basalt – one from the Faroe Islands and one from the U.S. Pacific Northwest.
- Only 30% of the bits used today are roller cone bits because of advances in PDC bit technology. In addition it was noted that roller cone bits are generally the worst type of bit to use for coring. The weight on bit and the subsequent crushing effect of the bit teeth can damage the rock even before the core is cut which can adversely impact coring performance and recovery.
- Core recovery in the oil and gas industry today averages in excess of 90%.
- Ulterra, based in Fort Worth, Texas is the 4th largest supplier of bits in North America. Their main focus is maximizing hard rock bit performance, and uniquely, 98% of their business is from rental bits. They also no longer provide roller cone bits because they have found that

properly designed PDC bits work better in hard rock. Ulterra was the provider of the C-7 and C-9 core bits used by IODP, however in 2011 they sold this product line to a Russian company called Burintekh, which also has a manufacturing facility in Fort Worth.

- All of the companies offer standard bit product lines which are sufficient for most drilling applications. However, they can also provide customized bit designs for specific applications. The use of customized bits to maximize performance is common practice in the oil and gas industry in areas of difficult or challenging drilling conditions. As such, all the companies recommended an iterative development process for identifying and/or developing the optimum bit/core head solutions for the BEAM project. Ideally this would involve testing a bit on an actual IODP hole, reviewing the bit condition and bit run performance, making changes to the design and then running it again at a new IODP location.
- It is clear that a formal "R&D" program will not be required to address the BEAM project's technical issues around bit and coring performance because of these company's current experience and capabilities, and the natural progression of technology improvement within the oil and gas industry.

A summary of the products and services that each of these service companies can provide is provided in the following table.

Table 2 - Service Company Capability Summary

Capabilities	NOV	Baker Hughes	Halliburton	Schlumberger	Ulterra
Roller Cone Bits	Yes	Yes	Yes	Yes	No
Fixed Cutter Bits	Yes	Yes	Yes	Yes	Yes
Conventional Coring	Yes	Yes	Yes	Yes	No
Wireline Retrievable Coring	Yes	Yes	Yes	Yes	No
Down-Hole Tools	Yes	Yes	Yes	Yes	No
High-Temperature Tools	Yes	Yes	Yes	Yes	No
Hard Rock Drilling Experience	Yes	Yes	Yes	Yes	Yes
Hard Rock Coring Experience	Yes	Yes	Yes	Yes	No
Performance Modeling Software	Yes	Yes	Yes	Yes	Yes
Bit Testing/Development Facility	Yes	Yes	Yes	Yes	No

BEAM is a complicated project from the standpoint of both the technical issues and the fact that it is managed and will be operated by a non-profit scientific organization, which is obviously atypical for the oil and gas industry. Several companies stated that they were unclear on how best to move forward and requested that Blade prepare a list of possible steps that could be taken to address the BEAM project's technical and commercial issues with the support of a manufacturing service company. Blade subsequently prepared this list and sent it to each company. The intent was that the list could serve as the basis of internal discussions within the companies to help them determine their level of interest, resource requirements, costs and to serve as the basis for subsequent meetings with Blade. The questionnaire is provided in Appendix 1.

In addition to this, Blade also met with IODP-USIO and obtained the morning reports and drilling/coring performance results from the JOIDES Resolution operations during expeditions 309, 312, and 335 at the 1256D site off Costa Rica. Blade then collated and summarized the data and sent it to each of the companies for review. The intent was to provide the companies with actual IODP basalt drilling/coring data to review and comment upon.

In the end, only NOV and Ulterra responded to the questionnaire and only NOV reviewed the 1256D drilling data. The lack of response from the other companies can be attributed to a lack of resources given their current business environment and the fact the BEAM project was not expected to start until around 2018.

Of all the companies Blade talked to, NOV has by far expressed the most interest and enthusiasm about being involved in the BEAM project. NOV is a major oilfield service company and has, over the past few years, bought numerous different companies, which has allowed them to offer a wide variety of equipment and services to the oil and gas industry, from the mud pumps on the Chikyu, to downhole tools, drilling fluids and bits. NOV stated that they are a technology development company and feel that if they have the best technology, people will buy their products and services. As such, they have less of a short term “what’s in it for me” attitude than other service companies. They are genuinely interested in the BEAM project and quite willing to help find solutions to the technical issues. In addition to providing ready access to technical experts from their various product divisions, NOV also volunteered to run mechanical tests on a core sample of basalt recovered from the 1256D hole to determine the rock’s unconfined compressive strength (UCS) at no cost to IODP. NOV completed these tests in August 2012 and was able to compare these results to other types of basalt and other types of hard rock that NOV has experience drilling. NOV is also interested in new technology and agreed to run tests on the nano-polycrystalline diamonds developed by Dr. Irifune of Ehime University and compare them to the properties of the sintered diamonds NOV currently uses in their bits. NOV is currently waiting on samples of the diamonds to begin testing which will also be done at no cost to IODP. This is not to suggest that NOV will “always” be willing to do everything for “free”, but a least for now at a foundational level, they have shown a willingness to provide their own time and resources to help identify solutions to the technical issues around the BEAM project.

The overall results of Blade’s investigations show that the major oil and gas industry bit and coring service providers have extensive hard rock experience that includes drilling in basalt. In addition, they currently offer products and services that would provide an improvement in bit and coring performance compared to current scientific drilling practices and results. It is also important to remember that drilling performance is more than just bit selection. Optimizing performance involves a systems view approach that includes the bit, the bottom hole assembly and drill string design, drilling parameters selection, drilling fluids system and so on. As such, these companies also have the technical expertise and support capabilities to develop custom drilling systems solution to optimize drilling and coring performance. .

4 Revised BEAM Operational Time Estimate

Based on the results of this study Blade was able to revise the mantle hole drilling time estimates that were initially provided in Blade's 2011 feasibility study to reflect what is possible using the technology currently available in the oil and gas industry. As described below, the revised time estimates are based around the results of the 1256D core testing done by NOV and their own hard rock drilling experience.

4.1 Review of NOV 1256D Core Testing

As previously noted NOV ran mechanical tests on a core sample of basalt recovered from the 1256D hole to determine the rock's unconfined compressive strength (UCS). IODP-MI provided several core samples obtained from the bottom of the hole during Expedition 335 that was conducted at the 1256D site in April 2011. NOV completed these tests in August 2012 and was able to compare these results to other types of basalt and other types of hard rock that NOV has experience drilling. The results of these tests are shown below and the full test report is provided in Appendix 2.

2. UCS & CCS Results

TRIAXIAL COMPRESSIVE TEST RESULTS

Company:	NOV Downhole	**Date:**	Aug. 2012
Well:	Pacific Ocean-Deep sub-Sea Floor	**File:**	HOU-121137
Formation:		**Saturation Fluid:**	As Received

Triaxial Static Young's Modulus, Poisson's Ratio and Compressive Strength

Sample Number	Depth (m)	Confining Pressure (psi)	Bulk Density (g/cm^3)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
Run 12 RCJB Rock A	n/a	0	3.01	17505	7.62	0.25
Run 12 RCJB Rock A	n/a	0	2.95	23150	7.26	0.24
Run 13 RCJB Rock A	n/a	1400	3.05	39263	10.35	0.30
Run 13 RCJB Rock A	n/a	0	3.03	39131	8.27	0.29
Run 14 FTJB Rock B	n/a	0	2.98	34592	4.27	0.30

West Faroes Basalt Comparison

Sample	Bulk Den	UCS
---	*g/cm^3*	*psi*
1S	2.73	13,122
2S	2.74	12,056
3S	2.72	10,494
1H	2.92	20,813
2H	2.93	19,988
3H	2.92	24,779
1HV	2.96	42,074
2HV	2.95	35,265
3HV	2.96	45,880

Possible Analogues

Rock Type	Bulk Den	UCS	Young Modulus	Poisson's Ratio
----	*g/cm^3*	*psi*	*x10^6*	
Dworshak Gneiss	2.79	23,500	4 *(Back-up)*	
John Day Basalt(E)	2.76	23,500	5	
John Day Basalt(W)	2.85	53,500	10	0.24
Pacific NW Basalt	No data Yet – Seeking Source			
Wisconsin Basalt	No data Yet – Seeking Source			

Notes:
-The HV W Faroe Basalt was very tough to drill although not abrasive in nature. This is an Atlantic ridge Basalt included for comparison of how test data will correlate to a more global perspective concerning drilling research.
-Possible Analogues are preliminary & need further evaluation to find best match.

Figure 10: NOV 1256D UCS Core Test Results Summary

The average UCS for all 5 1256D tests is 30,728 psi. The first test resulted in a lower value than others which may have been due to pre-existing micro-fractures in the sample. If this result is excluded, the average UCS of the reaming 4 tests is 34,034 psi. Note that basalts of the West Faroes have UCS values ranging between 12 ksi and 45 ksi. Also, gneiss from the Dworshak formation in Idaho has an average UCS value of 23.5 ksi and the John Day basalt located in Oregon has UCS values ranging between 23.5 ksi and 53.5 ksi

From these results and NOV's experience in drilling basalts and hard carbonate formations with UCS values greater than 50,000 ksi, NOV provided the following estimates of drilling penetration rates and bit life that would be ideally achievable for a mantle hole using a fixed cutter PDC bit and a PDC bit run on a downhole motor.

Table 3: Estimated Ideal ROP's Based on Current Technology

Hole Section	Rate of Penetration (ft/hr)		Rate of Penetration (m/hr)		Bit Life
	Ideal Bit	Ideal Bit/Motor	Ideal Bit	Ideal Bit/Motor	(hours)
Upper part of the hole :	70.0	100.0	21.3	30.5	110
Lower part of the hole :	50.0	70.0	15.2	21.3	70

NOV further estimated that the coring penetration rates assumed in the 2011 feasibility study could be improved by around 30%. It is assumed that the core test results reflect the hardness of the rock in the "upper" part of the hole and that the rocks will progressively get harder resulting in a decrease in the ROP in the "lower" part of the hole. Note that these values are broadly consistent with the statements made by the other service companies.

4.2 2011 Feasibility Study Operational Time Estimate Review

For reference, the following is a summary of the operational time estimates that were done during the 2011 feasibility study. Recall that 4 different drilling/coring cases were examined for each of the three candidate locations.

- Case 1: Assumed that the hole is continuously cored to TD. This would be the ideal situation as it would maximize the amount of scientific information obtained from the hole. It is also the most expensive.

- Case 2: Assumed that long sections of continuous core are taken across the major lithologic and geophysical transition intervals of key sections. For the time estimate it was assumed that the upper third of each main stratigraphic interval was cored, the middle third was drilled and the lower third was cored.

- Case 3: Assumed that only spot coring is done during the last 10m of hole before each bit trip.

- Case 4: Assumed that the hole is drilled to the Moho and that the mantle is cored. This was done as a comparison to Case 1 since it represents the least expensive case.

Table 4: 2011 Feasibility Study Operational Time Estimates Summary

Candidate Location	Water Depth	Total Depth Below: Rig Floor	Total Depth Below: Sea Floor	Drill/Core Time (days)	Total Project Time (days)
Cocos Location					
Case 1	3650	9900	6250	696	756
Case 2	3650	9900	6250	564	617
Case 3	3650	9900	6250	433	480
Case 4	3650	9900	6250	374	418
Baja Location					
Case 1	4300	10400	6100	807	866
Case 2	4300	10400	6100	642	693
Case 3	4300	10400	6100	405	445
Case 4	4300	10400	6100	386	425
Hawaii Location					
Case 1	4050	10750	6700	876	934
Case 2	4050	10750	6700	688	737
Case 3	4050	10750	6700	448	485
Case 4	4050	10750	6700	422	458

4.3 2012 Revised Operational Time Estimates

In order to account for the uncertainties that remain about the drilling conditions in a mantle hole and the fact that more detailed work on the bit designs will be needed, Blade has used ROP values that are more conservative than the "ideal bit" values noted above. Despite this, the revised operational time estimates still demonstrate the significant improvement even relatively modest increases in ROP can have on the overall operational time. The bit life estimates provided by NOV were still used because there is less uncertainty around the durability of today's bits than what the actual ROP might be. A comparison between the revised ROP's used for this project compared to the ones used for the 2011 feasibility study is shown below.

Table 5: 2012 Operational ROP's

Stratigraphy	2011 Feasibilty Study Coring	2011 Feasibilty Study Drilling	2012 BEAM Project Coring	2012 BEAM Project Drilling	
Sediments	3.0	15.2	4.0	21.3	m/hr
Lava	1.5	3.0	2.1	9.1	m/hr
Dikes	1.5	3.0	2.1	9.1	m/hr
Textured Gabbros	1.2	2.4	1.5	9.1	m/hr
Foliated Gabbros	1.2	2.4	1.5	3.0	m/hr
Layered Gabbros	0.9	1.5	1.2	3.0	m/hr
Mantle	0.9	0.0	1.2	0.0	m/hr
Upper Hole Bit Life	50 hours		110 hours		
Lower Hole Bit Life	35 hours		70 hours		

The revised mantle operational time estimate was done for Cases 2 and 4 for the Hawaii location since this location will require the most drilling/coring time. Cases 2 and 4 adequately illustrate the philosophical differences between the amounts of time spent coring versus time spent drilling.

Revised Case 2 Results

Again this case is based on coring the upper third of stratigraphic section, drilling the middle third, and then coring the bottom third of the major lithologic and geophysical transition intervals. A summary of the revised operational time estimate for this case is shown below.

Table 6: Hawaii - Case 2 – 2012 Revised Operational Time Estimate

Phase	Interval Days	Cum Days	From (m)	To (m)	Interval (m)	Avg m/day
Move in rig	13.4	13.4				
Position Rig	1.5	14.9				
Jet 36"	0.5	15.4	4,050	4,111	61	
Core Sediments	5.6	21.0	4,111	4,235	124	22
Set 20" casing	2.1	23.1				
Run BOP & Riser	3.0	26.1				
Core Sediments	1.9	28.0	4,235	4,250	15	8.2
Core Lava	10.6	38.6	4,250	4,467	217	20.4
Drill Lava	2.4	41.0	4,467	4,683		
Core Lava	11.3	52.2	4,683	4,900	217	19.2
Core Dikes	13.9	66.1	4,900	5,167	267	19.2
Drill Dikes	2.9	69.0	5,167	5,433	267	90.9
Core Dikes	19.1	88.1	5,433	5,685	251	13.2
Set 13-3/8" Casing	5.0	93.1				
Core Dikes	2.6	95.7	5,685	5,700	15	5.9
Core Textured Gabbros	8.4	104.1	5,700	5,817	116	13.8
Drill Textured Gabbros	2.4	106.6	5,817	5,933	116	47.8
Core Textured Gabbros	8.6	115.2	5,933	6,050	117	13.6
Core Foliated Gabbros	16.0	131.3	6,050	6,284	233	14.6
Drill Foliated Gabbros	5.3	136.5	6,284	6,517	233	44.3
Core Foliated Gabbros	16.7	153.3	6,517	6,750	233	13.9
Core Layered Gabbros	38.5	191.8	6,750	7,207	457	11.9
Drill Layered Gabbros	15.8	207.5	7,207	7,894	687	43.6
Core Layered Gabbros	55.8	263.3	7,894	8,250	355	6.4
Run 11-3/4" Liner	7.0	270.3				
Drill Layered Gabbros	15.8	286.1	8,250	8,829	579	36.7
Core Layered Gabbros	50.9	337.0	8,829	9,286	457	9.0
Drill Layered Gabbros	16.7	353.7	9,286	9,865	579	34.6
Core Layered Gabbros	41.2	394.9	9,865	10,201	335	8.1
Core Layered Gabbros	8.1	403.0	10,201	10,250	49	6.1
Core Mantle	63.4	466.4	10,250	10,750	500	7.9
TA hole	5.0	471.4				
Pull BOP/Riser	3.0	474.4				
5% Operational NPT	22.6	497.0				

Total Core/Drill Days = **460**

Total Project Days = **497**

For comparison, the initial Case 2 time estimate from the 2011 feasibility study is shown below. Note that the Total Core/Drill Days had been reduced from 688 to 460 days. This is a reduction of 228 days.

Table 7: Hawaii - Case 2 - 2011 Feasibility Study Operational Time Estimate

Phase	Interval Days	Cum Days	From (m)	To (m)	Interval (m)	Avg m/day
Move in rig	13.4	13.4				
Position Rig	1.5	14.9				
Jet 36"	0.5	15.4	4,050	4,111	61	
Core Sediments	5.6	21.0	4,111	4,235	124	22
Set 20" casing	2.1	23.1				
Run BOP & Riser	3.0	26.1				
Core Sediments	1.9	28.0	4,235	4,250	15	8.0
Core Lava	14.7	42.7	4,250	4,467	217	14.7
Drill Lava	4.3	47.1	4,467	4,683		
Core Lava	15.6	62.6	4,683	4,900	217	13.9
Core Dikes	20.1	82.7	4,900	5,167	267	13.3
Drill Dikes	6.8	89.6	5,167	5,433	267	39.1
Core Dikes	19.1	108.7	5,433	5,685	251	13.2
Set 13-3/8" Casing	5.0	113.7				
Core Dikes	2.7	116.3	5,685	5,700	15	5.7
Core Textured Gabbros	10.8	127.1	5,700	5,817	116	10.8
Drill Textured Gabbros	3.9	131.0	5,817	5,933	116	29.9
Core Textured Gabbros	11.1	142.1	5,933	6,050	117	10.6
Core Foliated Gabbros	22.7	164.8	6,050	6,284	233	10.3
Drill Foliated Gabbros	7.8	172.6	6,284	6,517	233	29.9
Core Foliated Gabbros	23.8	196.4	6,517	6,750	233	9.8
Core Layered Gabbros	57.0	253.4	6,750	7,207	457	8.0
Drill Layered Gabbros	41.7	295.1	7,207	7,894	687	16.5
Core Layered Gabbros	55.8	350.9	7,894	8,250	355	6.4
Run 11-3/4" Liner	7.0	357.9				
Drill Layered Gabbros	42.4	400.3	8,250	8,829	579	13.7
Core Layered Gabbros	78.4	478.7	8,829	9,286	457	5.8
Drill Layered Gabbros	45.6	524.3	9,286	9,865	579	12.7
Core Layered Gabbros	61.4	585.7	9,865	10,201	335	5.5
Core Layered Gabbros	11.5	597.2	10,201	10,250	49	4.3
Core Mantle	97.8	695.0	10,250	10,750	500	5.1
TA hole	5.0	700.0				
Pull BOP/Riser	3.0	703.0				
5% Operational NPT	34.0	737.0				

Total Core/Drill Days = **688**
Total Project Days = **737**

A drilling curve showing the differences between the 2011 feasibility study and 2012 BEAM project operational time estimates is shown below.

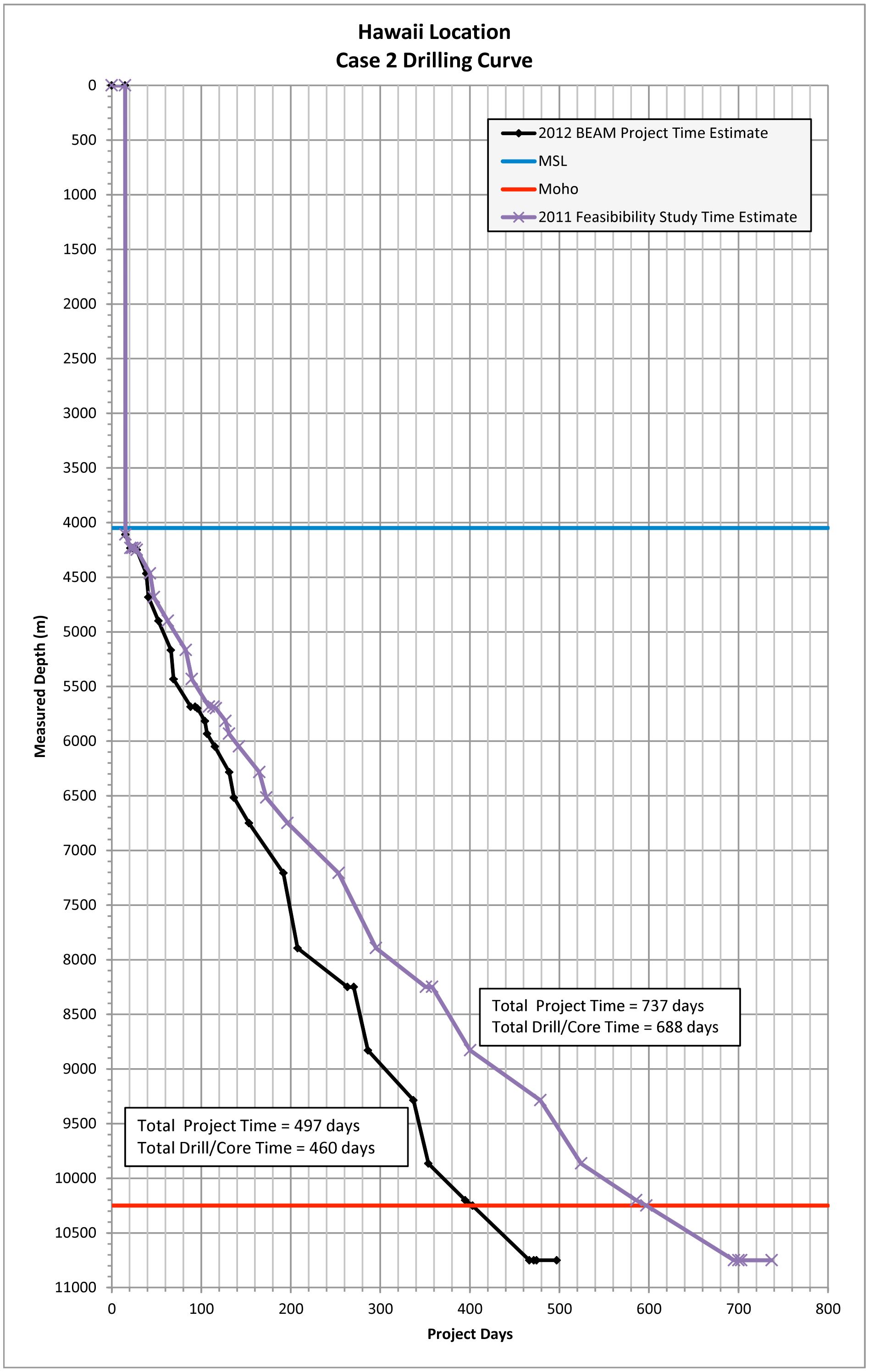


Figure 11: Case 2 - 2011/2012 Drilling Curve Comparison

Revised Case 4 Results

Again this case is based on drilling all the way to the Moho and then coring the mantle. A summary of the revised operational time estimate for this case is shown below.

Table 8: Hawaii - Case 4 - 2012 Revised Operational Time Estimate

Phase	Interval Days	Cum Days	From (ft)	To (ft)	Interval (ft)	Avg ft/day
Move in rig	0.0	0.0				
Position Rig	0.0	0.0				
Jet 36"	0.5	0.5	13,287	13,487	200	400
Drill Sediments	1.5	2.0	13,487	13,893	406	271
Set 20" casing	2.1	4.1				
Run BOP & Riser	3.0	7.1				
Drill Sediments	1.3	8.4	13,893	13,943	50	38.5
Drill Lava	4.3	12.7	13,943	16,076	2,133	492.6
Drill Dikes	18.1	30.8	16,076	18,651	2,575	142.3
Set 13-3/8" Casing	5.0	35.8				
Drill Dikes	1.8	37.6	18,651	18,701	50	28.2
Drill Textured Gabbros	3.3	40.9	18,701	19,849	1,148	342.7
Drill Foliated Gabbros	18.4	59.3	19,849	22,145	2,296	124.8
Drill Layered Gabbros	10.4	69.8	22,145	23,645	1,500	144.0
Drill Layered Gabbros	25.0	94.8	23,645	27,066	3,421	136.8
Run 11-3/4"Liner	7.0	101.8				
Drill Layered Gabbros	50.3	152.1	27,066	33,628	6,562	130.4
Core Mantle	63.4	215.5	33,628	35,269	1,641	25.9
TA hole	5.0	220.5				
Pull BOP/Riser	3.0	223.5				
5% Operational NPT	10.8	234.3				

Total Core/Drill Days = **224**

Total Project Days = **234**

For comparison, the initial Case 4 time estimate from the 2011 feasibility study is shown below. Note that the Total Core/Drill Days had been reduced from 422 to 224 days. This is a reduction of 198 days.

Table 9: Hawaii - Case 4 - 2011 Feasibility Study Operational Time Estimate

Phase	Interval Days	Cum Days	From (m)	To (m)	Interval (m)	Avg m/day
Move in rig	13.4	13.4				
Position Rig	1.5	14.9				
Jet 36"	0.5	15.4	4,050	4,111	61	122
Drill Sediments	1.5	16.9	4,111	4,235	124	83
Set 20" casing	2.1	19.0				
Run BOP & Riser	3.0	22.0				
Drill Sediments	1.3	23.3	4,235	4,250	15	11.6
Drill Lava	14.0	37.3	4,250	4,900	650	46.4
Drill Dikes	18.1	55.4	4,900	5,685	785	43.4
Set 13-3/8" Casing	5.0	60.4				
Drill Dikes	1.9	62.3	5,685	5,700	15	8.0
Drill Textured Gabbros	10.9	73.3	5,700	6,050	350	32.0
Drill Foliated Gabbros	27.8	101.1	6,050	6,750	700	25.2
Drill Layered Gabbros	24.3	125.4	6,750	7,207	457	18.8
Drill Layered Gabbros	64.6	190.0	7,207	8,250	1,043	16.1
Run 11-3/4"Liner	7.0	197.0				
Drill Layered Gabbros	148.5	345.5	8,250	10,250	2,000	13.5
Core Mantle	83.5	429.0	10,250	10,750	500	6.0
TA hole	5.0	434.0				
Pull BOP/Riser	3.0	437.0				
5% Operational NPT	20.7	457.7				

Total Core/Drill Days = **422**

Total Project Days = **458**

A drilling curve showing the differences between the 2011 feasibility study and 2012 BEAM project operational time estimates is shown below.

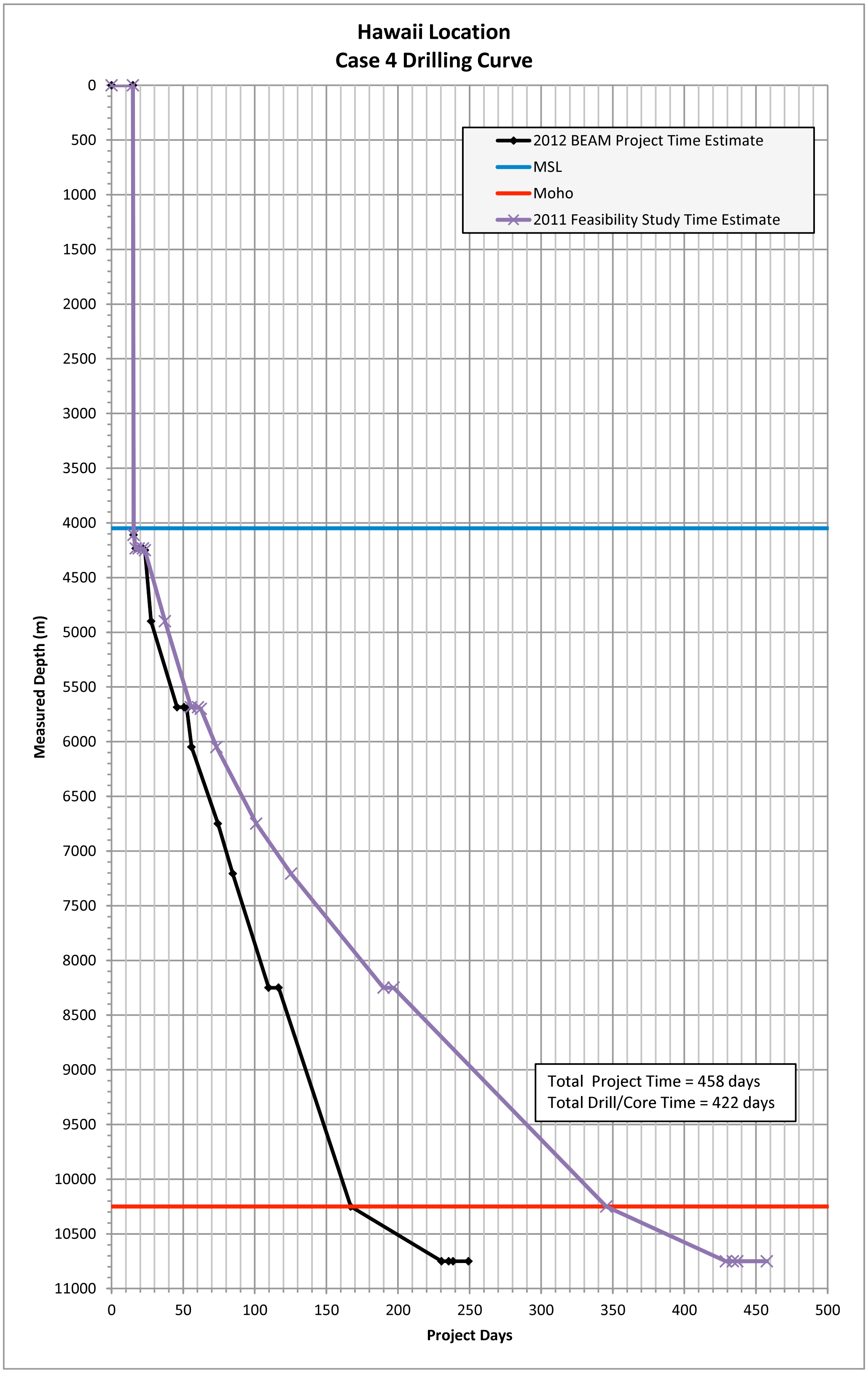


Figure 12: Case 4 2011/2012 Drilling Curve Comparison

5 Potential Issues with High Temperature and Down-hole Tools

5.1 Overview

High temperature drilling tools may see temperatures up to 150°C (300°F) for oil and gas drilling, 250°C (500°F) for deep scientific drilling and 300°C (570°F) for geothermal drilling. Drilling under such high temperature environments require that the tool and drilling equipment down-hole can withstand these harsh conditions sometime over long period of drilling time. In particular, there are many challenges associated with logging tools, sensors and motors when trying to operate them.

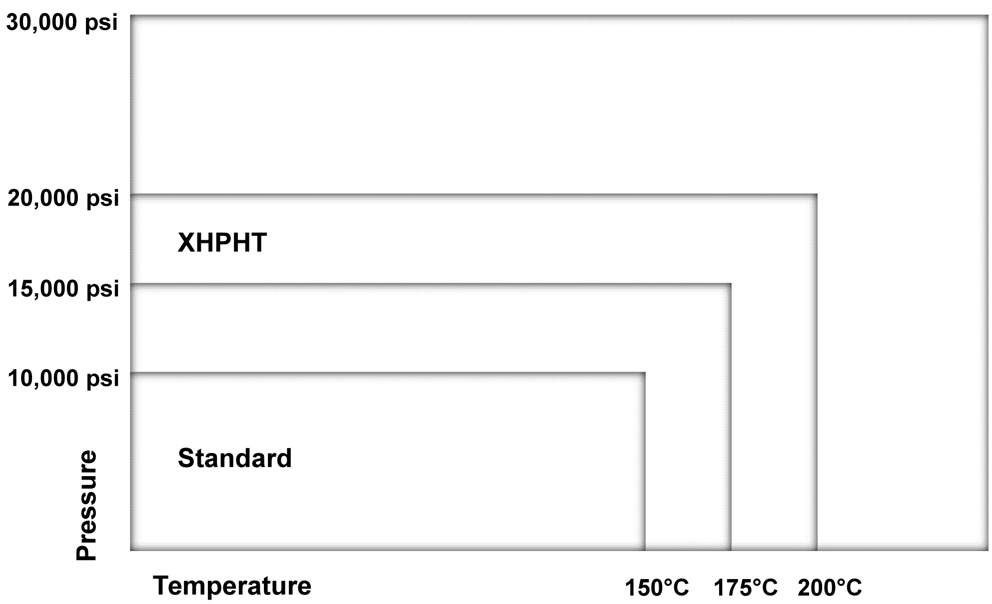


Figure 13. High Pressure and High Temperature Tools (modified from SPE and Halliburton)

In general, there are two methods to handle very high temperature conditions. First, the drill systems, tools, electronics and sensors have by design to withstand these temperatures. There is a significant research and development effort that is being carried on by the oilfield service companies to study and create high temperature materials. The second method which comes from the geothermal industry is to circulate a pre-cooled drilling fluid in the borehole. Unfortunately, as it was demonstrated in the 2011 mantle drilling initial feasibility study, because of the cooling effect of the 4,000 meters of seawater column, cooling the mud at surface will not have an impact on the logging and drilling tools down-hole.

5.2 Estimated Down-hole Temperature

Figure 14 below is a revised version of the chart plotting the assumed down-hole temperature profiles for three candidate locations that can be found in the 2011 mantle drilling initial feasibility study report. The maximum bottom-hole temperature (BHT) estimates are based upon previous models of formation burial depth and age provided by scientists from the IODP. Also, note that these temperature profiles have taken into account the cooling effect of the 4,000 meters of seawater with an average temperature at seafloor of about 2-4°C and a few available temperature measurements made during operations at the 1256D hole. As a result, the uncertainties in these BHT estimates are believed to be ±50°C. It is of interest to notice that the BHT at Hawaii is expected to be about 150°C while the estimated BHT at Baja California and Hawaii is about 250°C.

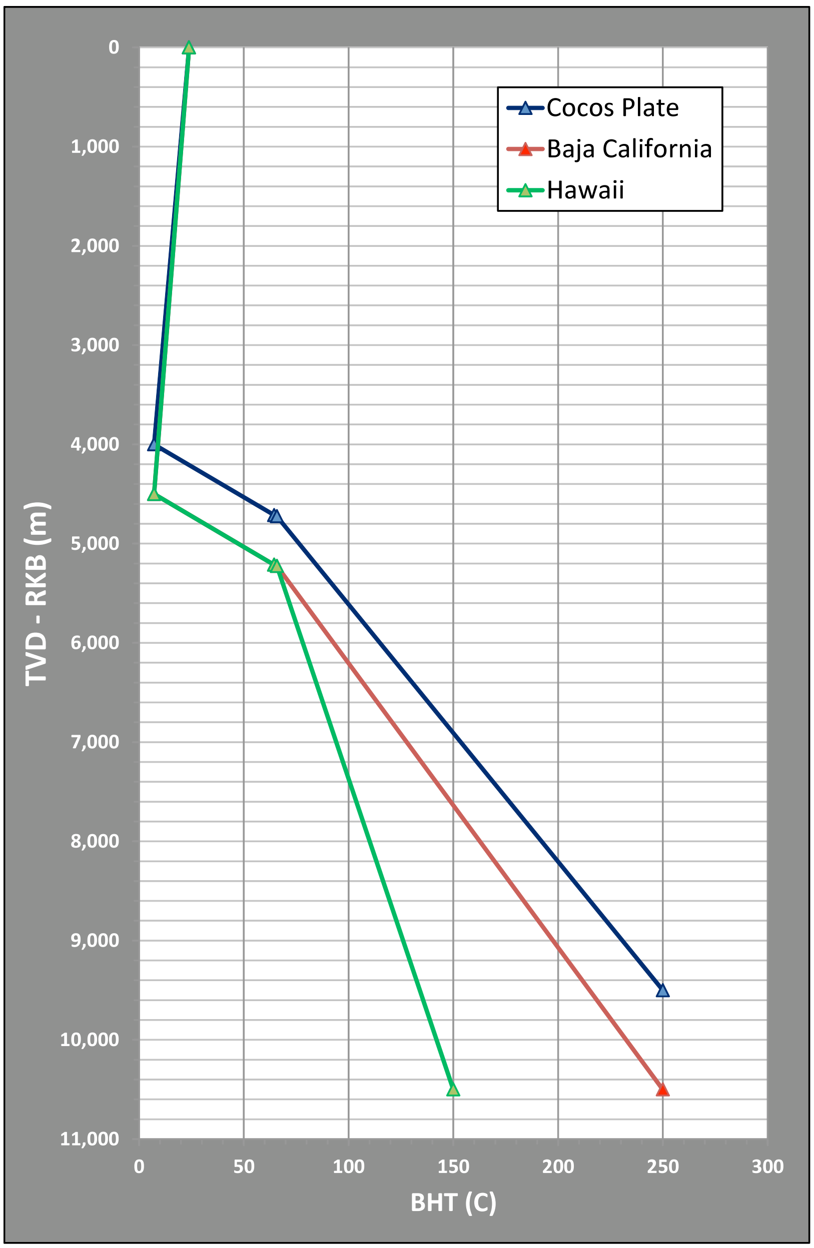


Figure 14. Estimated Bottom-hole Temperature for Three Candidate Locations

5.3 Review of Current O&G Industry Capabilities

5.3.1 Summary of Service Company Meetings

1. A meeting with Smith was arranged for August 8. The meeting was essentially focused on reviewing Smith's drilling current state of the art and their latest development regarding high temperature drilling and logging tools.

   The key outcomes from the meeting are as follows:

   - In 2010, "only" 9% of total footage drilled was for BHT ranged between 300°F and 350°F.
   - Their engineers are however focusing on developing tools with higher operating temperatures is response to industry trends towards drilling in higher temperature environments.
   - The challenges are for high temperature resistance of elastomers, electronics and sensors.
   - Currently testing 200°C tools but it is still a niche market.

2. A meeting with Weatherford was arranged for August 10. The meeting was mainly focused on reviewing Weatherford's drilling current state of the art and their latest development regarding high temperature logging tools. Note that Weatherford embarked upon the development logging tools and decided to focus on the HPHT niche market.

   The key outcomes from the meeting are as follows:

   - Weatherford current offering is divided between standard pressure and temperature tools (i.e. up to 150°C and 20,000 psi) and high temperature pressure and temperature tools (i.e. up to 180°C and 30,000 psi) as presented in Table 10 and Table 11.
   - New tools are being developed for temperature as high as 190°C and will be soon field tested in Thailand.
   - Engineers are also working on signal transmission issues when drilling very deep wells.

   Advances in LWD and MWD tools have been significant over the last decade and the next 3-4 years are expected to be a "different world". However, the biggest challenges remain when trying to drill formations with BHT of 250°C and above. Indeed, the memory chips have to survive a moisturizing environment with high vibrations which is one of the critical parameters data transmissions in the borehole. Also, note that every 10°C in temperature increase, the life of the component on the LWD and MWD tools are reduced by about 50%.

3. A meeting with Halliburton was arranged for August 24. The meeting was focused on a general discussion regarding Halliburton's high temperature drilling capabilities.

The key outcomes from the meeting are as follows:

- Halliburton vertical drilling tool is rated for temperature up to 250°C and has recently been used in a packed drilling assembly in Thailand (i.e. BHT = 250°C).
- Engineers are currently working on MWD tools rated for 230°C for a single run or 215°C for multiple/longer runs. LWD tools are rated for about 200°C.
- Halliburton is currently developing an active cooling technology that has been tested in the lab that may deliver up to 100°C temperature reduction for the circulating conditions.

Tables 11-13 below respectively summarize the available down-hole tools for standard temperature and pressure tools, high temperature / high pressure and extremely high temperature / extremely high pressure tools, ultra high temperature and pressure tools currently under development or that are being field tested.

5.3.2 Standard Temperature Tools

Table 10 presents the current Weatherford and Halliburton tools available to drill and evaluate formation with pressures up to 20,000 psi and temperatures up to 300°F (150°C). Note that there are currently four tool sizes available ranging between 9-1/2" and 4-3/4" and that azimuthal gamma ray, azimuthal density, neutron porosity and formation pressure tester are not available with 9-1/2" tool size.

5.3.3 High Temperature Tools

Table 11 lists the current Weatherford and Halliburton tools available to drill and evaluate high pressure and high temperature formations with maximum pressure rating equal to 30,000 psi maximum temperature rating equal to 350°F (180°C).

Table 10. Standard Pressure / Temperature Down-hole Tool Ratings

TOOL	STANDARD PRESSURE / TEMPERATURE TOOLS							
	9-1/2"		8-1/4"		6-3/4"		4-3/4"	
	Pressure (psi)	Temp (°F / °C)	Pressure (psi)	Temp (°F / °C)	Pressure (psi)	Temp (°F / °C)	Pressure (psi)	Temp (°F / °C)
RSS Systems	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C
MWD / Pulser	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C
Bore / Annular Pressure	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C
Spectral Azimuthal Gamma Ray					20,000	300°F 150°C	20,000	300°F 150°C
Azimuthal Gamma Ray	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C
Multi Frequency Resistivity	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C
Azimuthal Density			20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C
Thermal Neutron Porosity			20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C
Sonic	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C
Formation Pressure Tester			20,000	300°F 150°C	20,000	300°F 150°C	20,000	300°F 150°C

Table 11. High Pressure / Temperature Down-hole Tool Ratings

TOOL	HIGH PRESSURE / TEMPERATURE TOOLS							
	9-1/2"		8-1/4"		6-3/4"		4-3/4"	
	Pressure (psi)	Temp (°F / °C)	Pressure (psi)	Temp (°F / °C)	Pressure (psi)	Temp (°F / °C)	Pressure (psi)	Temp (°F / °C)
RSS Systems	25,000	350°F 180°C	25,000	350°F 180°C	30,000	350°F 180°C	30,000	350°F 180°C
MWD / Pulser	25,000	350°F 180°C	25,000	350°F 180°C	30,000	350°F 180°C	30,000	350°F 180°C
Bore / Annular Pressure	25,000	350°F 180°C	25,000	350°F 180°C	30,000	350°F 180°C	30,000	350°F 180°C
Spectral Azimuthal Gamma Ray					20,000	330°F 165°C	20,000	330°F 165°C
Azimuthal Gamma Ray	25,000	350°F 180°C	25,000	330°F 165°C	30,000	350°F 180°C	30,000	350°F 180°C
Multi Frequency Resistivity	25,000	350°F 180°C	25,000	350°F 180°C	30,000	350°F 180°C	30,000	350°F 180°C
Azimuthal Density			25,000	330°F 165°C	30,000	330°F 165°C	30,000	330°F 165°C
Thermal Neutron Porosity			25,000	330°F 165°C	30,000	330°F 165°C	30,000	330°F 165°C
Sonic	25,000	330°F 165°C	25,000	330°F 165°C	30,000	330°F 165°C	30,000	330°F 165°C
Formation Pressure Tester			25,000	330°F 165°C	30,000	330°F 165°C	30,000	330°F 165°C

Note that there are also currently four tool sizes available to drill and evaluate high pressure and high temperature formations, again, ranging between 9-1/2” and 4-3/4” and that, similarly to standard tools, azimuthal gamma ray, azimuthal density, neutron porosity and formation pressure tester are not available with 9-1/2” tool size.

5.3.4 Developmental Effort / Trends

Table 12 provides the ongoing state of R&D at Weatherford and Halliburton laboratories for extreme and ultra-high pressure and temperature tools. Ultra-high tools are currently being designed and developed to drill and evaluate high pressure and very high temperature formations with maximum pressure rating equal to 30,000 psi maximum temperature rating equal to 390°F - 440°F (200°C - 230°C).

In addition, it is important to note that there are “only” two tool sizes that will first be available to drill and evaluate high pressure and very high temperature formations: 4-3/4” and 6-3/4”. Also, azimuthal gamma ray, sonic and formation pressure tester will not be available for any of the tool sizes in the next couple of years.

Table 12. Current High Temperature Down-hole Tool Development

	XHIGH PRESSURE / TEMPERATURE TOOLS			
	6-3/4"		4-3/4"	
TOOL	Pressure (psi)	Temp (°F / °C)	Pressure (psi)	Temp (°F / °C)
RSS Systems				
MWD / Pulser	30,000	375°F 190°C	30,000	440°F 230°C
Bore / Annular Pressure	30,000	375°F 190°C	30,000	375°F 190°C
Spectral Azimuthal Gamma Ray				
Azimuthal Gamma Ray	30,000	375°F 190°C	30,000	440°F 230°C
Multi Frequency Resistivity	30,000	390°F 200°C	25,000	390°F 200°C
Azimuthal Density	30,000	390°F 200°C	25,000	390°F 200°C
Thermal Neutron Porosity	30,000	390°F 200°C	25,000	390°F 200°C
Sonic				
Formation Pressure Tester				
True Vibration Monitor	30,000	375°F 190°C	30,000	375°F 190°C

5.3.5 Discussion

As shown in Figure 14, except for the Hawaii location where BHT are estimated to be around 300°F (150°C), the other two locations have deep boreholes with temperatures that are expected to be as high as 480°F (250°C). Thus, these down-hole static temperatures and even the down-hole circulating temperatures (i.e. chilling the drilling fluid does not help in ultra-deepwater drilling) exceed the temperature ratings of most of the down-hole tools that are commercially available (i.e. see Tables 11-13). Although, at the rate of improvement in down-hole component temperature rating and using innovative cooling technology such as the one currently developed by Halliburton, the next 3-4 years may see a next generation in LWD and MWD tools that may be capable of drilling and evaluation formations with temperature as high as 250°C. Again, as previously mentioned in the conclusions of the 2011 mantle drilling initial feasibility study report, down-hole tools are already available if the BHT does not exceed 350°F (180°C) such as the borehole that could be drilled at the Hawaii location.

5.4 Marine Drilling Riser

5.4.1 Summary of Service Company Meetings

1. A meeting with JFE was arranged for July 25. The meeting specifically focused on the latest development in material science regarding high strength steel marine drilling risers.

   The key observations from the meeting are as follows:

   - X-100 material line pipe is now available to manufacture the drilling riser main tube.
   - The first collaboration will be with NOV high strength manufacturing of drilling riser group

   The impact of this technical improvement could be significant on the design and application for ultra-deepwater steel marine drilling risers. Not only an 100 ksi yield material will enable a thinner wall (i.e. weight reduction per riser joint) in order to achieve the same performance for a given field application, but also will allow more allowable stress for the riser main tube. As a result, a thinner walled drilling riser would allow deploying greater lengths of riser joints for the same floating drilling structure tensioning system. Note also that the maximum VME in the drilling riser tube cannot exceed 67% of the minimum yield strength. Thus, 100 ksi material would enable higher stresses in the riser tube which imply that either higher mud weight could be used or greater water depths could be drilled through.

2. A meeting with RTI International Metals was arranged for August 2. The meeting discussion emphasized on the current state of art and recent field application for titanium risers and more specifically titanium drilling risers.

   The key observations and outcomes from the meeting are as follows:

   - RTI has recently designed, manufactured and field deployed an entire titanium marine drilling riser. However, this was done for a well located in relatively shallow waters and so far no titanium drilling riser has been either deigned or manufactured by RTI for a deepwater well.

- 2 grades of titanium: ASTM 23 and ASTM 29 would be readily suitable for deepwater titanium drilling risers.

Because of the drastic weight reduction associated with titanium (i.e. 40% lighter than steel) and much higher yield strength (i.e. 120-130 ksi), titanium drilling risers could be used for weight reduction for the entire drilling riser (i.e. main tube and/or auxiliary lines). Thus, similarly to 100 ksi steel, titanium drilling risers could be used to drill through ultra-deepwater depths that have never been reached before with steel material and also utilized for harsh environments with high pressure reservoirs (high mud weight). The additional benefit is titanium high resistance to fatigue damage which could be used for high current environment and very long drilling campaign such as the one planned for the mantle drilling well. Obviously, the main disadvantage of titanium products is their relative high prices in comparison to steel.

3. Three meetings with Alcoa Oil & Gas were arranged for August 9, August 22 and September 12. The meeting discussions were principally focused on the current state of art and recent field applications for aluminum drilling risers.

The key observations and outcomes from the meetings are as follows:

- Alcoa has been designing, manufacturing and providing full aluminum marine drilling risers for 4 Noble drilling rigs. Note that the initial use of aluminum drilling riser with Noble fleet was to extend the water reach of existing 3rd and 4th generation floaters built in the 1980s and that these rigs have operated offshore Brazil.
- Independently from Blade analysis and suggestions in the 2011 mantle drilling initial feasibility study, Alcoa has recently marketed the concept of hybrid drilling riser with the riser main tube, the hydraulic and booster lines made of steel but with the choke and kill lines made of aluminum. Note that, usually, the total weight of auxiliary lines or only choke and kill lines accounts for respectively 40-50% and 20-30% of the total weight of an entire drilling riser.

Because of the large weight reduction associated with aluminum material (i.e. 60% lighter than steel) but generally lower yield strength (i.e. 40-60 ksi), aluminum drilling risers could be used for weight reduction for the entire drilling riser (i.e. main tube and/or auxiliary lines) but would be better suited for auxiliary lines keeping the riser main tube with a high yield strength material (X-80, X-100 or titanium); hence, illustrating the concept of hybrid drilling risers. Thus, aluminum drilling risers could be used to drill through ultra-deepwater depths with existing floaters. However, significant work and studies remain to be done to investigate the potential corrosion issues that are associated with using aluminum in seawater (i.e. chloride content), the eventual offshore application for high strength aluminum alloys such as alloys 1980, 1953, C22n, C99N and C92N, the load sharing capability of aluminum riser main tube and auxiliary lines, the fatigue behavior of aluminum joints and the welding process for 75-foot and 90-foot long riser tubes.

4. A meeting with GE Oil & Gas (a division of General Electric Company) was arranged for August 7. The meeting discussion was also focused on the current state of art and recent field applications for GE high strength drilling risers for deepwater applications.

   The key observations and outcomes from the meetings are as follows:

   - GE Oil & Gas has designed, manufactured and implemented in deepwater regions several high strength (i.e. X-80) steel marine drilling risers.
   - The current high-end drilling riser product is an “H-Class” (i.e. 3.5 million pounds tension rated). Note that the best class in the industry is currently “I-Class” (i.e. 4.0 million pounds tension rated) which is what is onboard the Chikyu drill-ship.
   - GE Oil & Gas is currently other advanced material such as aluminum, titanium and even composite tubes for drilling riser applications.

5. A meeting with NOV was arranged for August 20. The meeting discussion was first dedicated to the current state of art and recent field applications of NOV high strength drilling risers. In addition, a tour of the entire NOV manufacturing plant has been provided to Blade Energy where the manufacturing process of BOP/LMRP, riser joints and special drilling riser components has been witnessed.

   The key observations and outcomes from the meetings are as follows:

   - NOV designs, manufactures and sells a wide range of drilling riser product ranging from “C-Class” (i.e. 1.0 million pounds tension rated) to “I-Class” (i.e. 4.0 million pounds tension rated).
   - NOV also manufactures all the special drilling riser component for deepwater drilling (i.e. telescopic joint, tension ring, termination joint, keel joint, pup joint, riser fill-up valve, riser adapter, riser running tool, riser spider and gimbal).
   - R&D development of high strength steel drilling risers that will be able to operate in 12,000 feet of water and using 16.0 to 18.0 ppg mud weights.
   - When trying to drill through water depths greater than 12,000 feet, both new riser design and materials are going to be needed to overcome all the issues associated with weight and strength.

6. A meeting with Cameron was arranged for August 30. The meeting discussion was centered on the current state of art and recent field applications of Cameron high strength drilling risers.

   The key observations and outcomes from the meetings are as follows:

- Cameron has been the first service company to design, manufacture and sell an "I-Class" (i.e. 4.0 million pounds tension rated) marine drilling riser which was specifically designed and purchased by JAMSTEC. So far, this high class drilling riser has only been sold to JAMSTEC and still constitutes the best high strength marine drilling riser that Cameron has in its catalogue.
- In the near future, Cameron may produce a "J-Class" that would be rated for 4.5 or 5.0 million pounds tension rating.
- Cameron was part of a Joint Venture with Alcoa Oil & Gas to investigate the next generation of ultra-deepwater riser systems. Note that this JV was stopped in 2011.
- Cameron is actively working on 20,000 psi riser systems. The current state of the art in the deepwater industry is to use 15,000 psi to drill to oil and gas reservoirs. As a result, designing a 20,000 psi drilling riser demands that the wall thickness of the choke and kill line tubes will be greater; thus the riser joints will be heavier.

7. A meeting with Aker Solutions was also arranged for August 30. The meeting discussion was centered on the current state of art and recent field applications of Aker's high strength drilling risers.

   The key observations and outcomes from the meetings are as follows:

   - Aker Solutions has designed, manufactured and field deployed a slightly different of drilling risers called CLIP which are equivalent to "H-Class" (i.e. 3.5 million pounds tension rated) and that can theoretically function in about 12,000 feet of water. However, this water depths are expected to be reachable using a "non-load sharing" design (i.e. tensile load is supported just by the riser main tube) and "only" 12.0 ppg drilling fluid.
   - Aker Solutions is currently in the process of designing and manufacturing and "I-Class" (i.e. 4.0 million pounds tension rated) CLIP drilling riser that could be deployed in about 12,500 feet of water with "load sharing" capacity (tensile load is supported both by the riser main tube and the auxiliary lines) and that could handle drilling fluids up to 16.0 ppg. This new drilling riser joint should be available to market by 2014.
   - Aker Solutions is also currently investigating hybrid risers using composite materials (i.e. carbon fiber) that would be a coating layer on a thin matrix made of high strength steel.

8. A meeting with Balmoral was scheduled for July 26. The meeting discussion was centered on the current state of art and recent field applications of Balmoral buoyancy systems that equipped bare drilling riser joints.

   The key observations and outcomes from the meetings are as follows:

   - Balmoral has already designed, manufactured and field tested buoyancy systems to fit ultra-deepwater drilling riser joints with their high-end product being already capable of equipping riser joints in up to 15,000 feet of water.

9. A meeting with Trelleborg was scheduled for August 7. The meeting discussion was first centered on the current state of art and recent field applications of Trelleborg buoyancy systems that can equip bare drilling riser joints and then a tour of Trelleborg manufacturing plant was given to Blade Energy.

   The key observations and outcomes from the meetings are as follows:

   - Trelleborg has already designed, manufactured and field tested buoyancy systems to fit ultra-deepwater drilling riser joints with their high-end product being already capable of equipping riser joints in up to 12,000 feet of water.
   - Trelleborg has already designed and manufactured buoyancy systems for other marine components that have been deployed on ROV's in water depths up to 30,000 feet.

5.4.2 Discussion

High strength steel (i.e. 80 ksi) is currently the most widely used material for deepwater drilling and drilling riser systems. However, when drilling with a marine drilling riser in water depths averaging 10,000 feet with relatively high drilling fluids (i.e. 16.0-18.0 ppg), the technical limit of existing high strength riser systems commonly manufactured with 80 ksi steel material for the riser tube, auxiliary lines and connectors is reached.

Hence, as water depth increase beyond 10,000 feet and the true vertical depth of borehole below the mudline increase beyond 15,000-20,000 feet, the external pressure due to seawater and the internal pressure due to the mud weight required to balance the deep formation pressure that are acting on the marine drilling riser may become too large and; therefore will require that stronger materials such as X-100 steel, titanium or composite may be used. Also, since stronger drilling risers will often produce heavier risers (i.e. because of the increase in the main tube wall thickness), aluminum may also be considered as an alternative to be used for the design of auxiliary lines such as hydraulic, booster, choke and kill lines and thus reduce the overall weight of the drilling riser.

Nevertheless, even though both aluminum and titanium drilling risers have been already been developed and tested, they have rarely been applied but still are showing great potential. Moreover, as of today, composite materials have still not been tested or field deployed for deepwater drilling riser but has already had success for smaller diameter (i.e. 5.0 to 8.0 inches) production risers in the North Sea. Thus, as investigated by Aker Solutions and GE Oil & Gas, is believed that, at least, for auxiliary lines, and because of high strength and weight saving associated with carbon fiber or carbon epoxy, composite materials may be a cost-effective solution for ultra-deepwater marine drilling riser systems.

5.4.3 Riser Options Review

Tables 13 and 14 illustrate respectively the material properties and multiple possible configurations that can be used to design and manufacture a marine drilling riser for ultra-deepwater applications (i.e. water depth greater than 12,000 feet).

Table 13 list four materials that have already been used for riser systems in the oil and gas industry. High strength steel (i.e. 80 ksi) is currently the most widely employed material to manufacture deepwater drilling riser systems. Also, newly available 100 ksi steel materials constitute a near term easy solution to upgrade and increase the ultra-deepwater reach of drilling riser systems. Then, aluminum and titanium drilling risers have been developed, tested, rarely applied though but have shown great potential for greater water depths (i.e. 10,000 – 15,000 feet) because of the drastic weight saving. Finally, even though composite materials have not been tested and field deployed for deepwater drilling riser, they may, in combination with high strength steel represent a good alternative to titanium or aluminum products.

Table 13. Materials for Marine Drilling Risers

	Current and Future Marine Drilling Riser Materials for Main Tube and Auxiliary Lines			
	Steel	Aluminum alloy (7075 - T6)	Titanium alloy (6Al4V)	Carbon Fiber
σ_y (ksi) =	80 or 100	40-70	120-130	250-580
Steel Weight (lb/ft^3) =	490	170	280	115
Young Modulus (ksi) =	30,000	10,000	14,500	33,000
Poisson's Ratio =	0.3	0.34	0.36	0.74

Table 14 presents nine different configurations that may be used for drilling riser system design.

Table 14. Nine Possible Configurations for Drilling Risers to Reach Ultra-Deepwater

	MATERIALS THAT MAY BE USED FOR MARINE DRILLING RISERS			
CONFIG	RISER MAIN TUBE	CHOKE AND KILL LINES	BOOSTER LINE	HYDRAULIC LINE
Config #1	Steel	Steel	Steel	Steel
Config #2	Aluminum	Aluminum	Aluminum	Aluminum
Config #3	Titanium	Titanium	Titanium	Titanium
Config #4	Steel	Aluminum	Aluminum	Aluminum
Config #5	Steel	Steel	Aluminum	Aluminum
Config #6	Steel	Titanium	Titanium	Titanium
Config #7	Steel	Titanium	Steel	Steel
Config #8	Steel	Carbon Fiber	Carbon Fiber	Carbon Fiber
Config #9	Steel / Carbon Fiber	Steel	Steel	Steel

5.4.4 Pro's and Con's Comparison

Table 16 lists the advantages and drawbacks of all the riser options that are either currently available to the ultra-deepwater drilling industry or at a conceptual stage development within service companies or material science department in universities.

Table 15. Advantages and Drawbacks for the Nine Drilling Riser Options

	MATERIALS THAT MAY BE USED FOR MARINE DRILLING RISERS	
CONFIG	PROS	CONS
Config #1	Easy to Design and Construct	Limited to about 10,000 feet Water Depth
	Technology is Very Mature	
	Relatively Low Capital Cost	
Config #2	Can Drilled Through Ultra-deep Waters	Medium Capital Cost
		Potential Corrosion and Strength Issues
		More Difficult to Design and Construct
		Technology is Just Mature
Config #3	Can Significantly Push the Limits (> 15,000 feet)	High Capital Cost
	Can Withstand High Loads and Rough Environments	More Difficult to Design and Construct
		Technology is Emerging
Config #4	Lower Capital Cost Than Full Aluminum Riser	More Difficult to Design and Construct
	Can Push the Limits (> 12,000 feet)	Technology is at a Conceptual Level
Config #5	Lower Capital Cost Than Full Aluminum Riser	More Difficult to Design and Construct
	Can Push the Limits (> 12,000 feet)	Technology is at a Conceptual Level
Config #6	Lower Capital Cost Than Full Titanium Riser	More Difficult to Design and Construct
	Can Significantly Push the Limits (> 12,000 feet)	Technology is also at a Conceptual Level
Config #7	Lower Capital Cost Than Full Titanium Riser	More Difficult to Design and Construct
	Can Significantly Push the Limits (> 12,000 feet)	Technology is also at a Conceptual Level
Config #8	Lower Capital Cost Than Other Hybrid Solutions	Very Difficult to Design and Construct
	Can Significantly Push the Limits (> 12,000 feet)	Technology is also at a Conceptual Level
Config #9	Lowest Capital Cost Than Other Hybrid Solutions	Very Difficult to Design and Construct
	Can Significantly Push the Limits (> 12,000 feet)	Technology is also at a Conceptual Level

5.5 Review of Survey Services

5.5.1 Metocean Survey

1. A meeting with RPS Evans-Hamilton was scheduled for August 21. The meeting discussion was essentially centered on the current state of art and recent field applications of RPS services regarding Metocean survey for deepwater environments. In addition, a tour of RPS facility where current measurements devices are stored has been provided to Blade Energy.

   The key outcomes from the meetings are as follows:

- RPS provides worldwide services for field measurements of currents, waves and meteorological conditions. Survey of a full water column may take about 12 months and cost about $750,000.
- RPS also provides services for modeling of oceanic currents, winds and waves as well as hindcasting and forecasting for a given offshore location.

There is no technical depth limitation (i.e. up to 20,000 feet) associated with probes, sensors and instruments that can measure oceanic currents and wave conditions. RPS has already taken measurements off the islands of Hawaii and recognized that publicly available for deepwater measurements for Cocos plate, Baja California and Hawaii are scarce as opposed to coastal data which are more easily available especially within the local universities. Therefore, a desktop study (i.e. $25,000 per site) will usually be the first step to take in trying to identify the best location in order to conduct drilling operations for about 1 year.

2. A meeting with Fugro Geos was scheduled for August 23. The meeting discussion was also focused on the current state of art and recent field applications of Fugro Geos services regarding Metocean survey for deepwater environments.

The key outcomes from the meetings are as follows:

- Fugro Geos provides worldwide services for field measurements of currents, waves and meteorological conditions. Survey of a full water column usually takes at least 1 full year (i.e. 8 weeks lead time for field deployment + 1 year of measurement + 4 weeks of data quality control + 4 weeks for data processing and results) and costs about $1,000,000.
- Fugro Geos also provides services for modeling of oceanic currents, winds and waves as well as hindcasting and forecasting for a given offshore location. In addition, marine growth analysis which is very important for drilling riser design when staying on location for several months can be calculated 3-4 months after the buoys have been deployed. However, note that forecast modeling for current is not as advanced as weather modeling. Thus, wave forecasting can be done for period of time up to 30 years using in-house advanced models even though no wave data are taken as the exact offshore location. Nevertheless, survey will still constitute the best solution to determine an accurate weather window and therefore the drilling rig operability assessment.
- From Fugro's experience, it seems like Cocos plate will have high oceanic currents where Hawaii Metocean conditions will be more benign except during the winter season that sees a high wave energy environments. In addition, Baja California may have the most benign weather conditions but has the deepest waters and is potentially exposed to numerous hurricanes.

Similar services such as a desktop study (i.e. $20,000 per site) are also recommended by Fugro Geos trying to identify the best location in order to conduct drilling operations for about 1 year.

5.5.2 Geohazards Survey

1. A second meeting with Fugro Geos was scheduled for August 23. The meeting discussion was centered on the current state of art and recent field applications of Fugro Geos services regarding geohazard surveys near the borehole site for deepwater environments.

   The key outcomes from the meetings are as follows:

   Fugro Geos provides worldwide services for geohazard surveys using 3D seismic and specialized high resolution 3D seismic for the shallower layers. In addition to the 3D seismic, multi-beam bathymetry are used to collect high resolution images of the seafloor to assess slope stability and potential faulting. Note that multi-beam bathymetry may also be used to estimate the sediments strength where the structural casing of the scientific borehole will be set. A general cost estimation for 3D survey + multi-beam bathymetry and geotechnical borings is about $5,000,000. However, significant lead time (i.e. 1 year) must be accounted for before these geohazard surveys can start.

5.6 Expandable Casing

The hole problems that occurred on IODP expedition 335 at the 1256D site off Costa Rica in April 2011 would tend to suggest that the base case well design assumed in Blade's 2011 feasibility study (reference Appendix 3) is likely optimistic and that more casing could be required in the event of unexpected downhole problems. The use of expandable casing may be a way to preserve hole sizes by allowing the length of an existing casing string to be effectively extended, or to isolate specific problem zones. Expandable casing has been used in the oil and gas industry since late 1999 to mitigate the impact of unexpected hole problems.

New developments in expandables have improved the reliability, and increased the applicable uses of this technology. For example, large diameter tubulars are being developed for applications higher in the wellbore, offering more flexible use of the expandable tubulars. Expandables are now being developed from 3.5" to 20" OD's. The three major companies currently providing this technology are Baker Hughes, Weatherford, and Enventure.

The expansion process has varied over time, and varies by company. The most prevalent approach is to drill, run the expandable, condition mud, and cement as usual. The cemented liner varies from the typical sense in that there is an expansion cone located at the bottom of the liner in the launcher. A plug is pumped down-hole past the cone, latched, and expansion is then initiated. The volume below the cone, within the liner, and sealed by the plug is pressurized. The pressure drives the cone upward, expanding the pipe. The cone is also pulled axially; this steadies the process, enables extra force to be applied in case of a stuck cone, and allows mechanical expansion if pressure is lost due to liner splitting or connection failure.

The following figure illustrates the potential benefits of using expandables. The planned casing program for a deepwater well is shown on the left side of the figure. The right side of the figure shows how an additional contingency liner can be incorporated into the well design without requiring a small diameter string to be run at the 16.150" casing point as would be typically be the case.

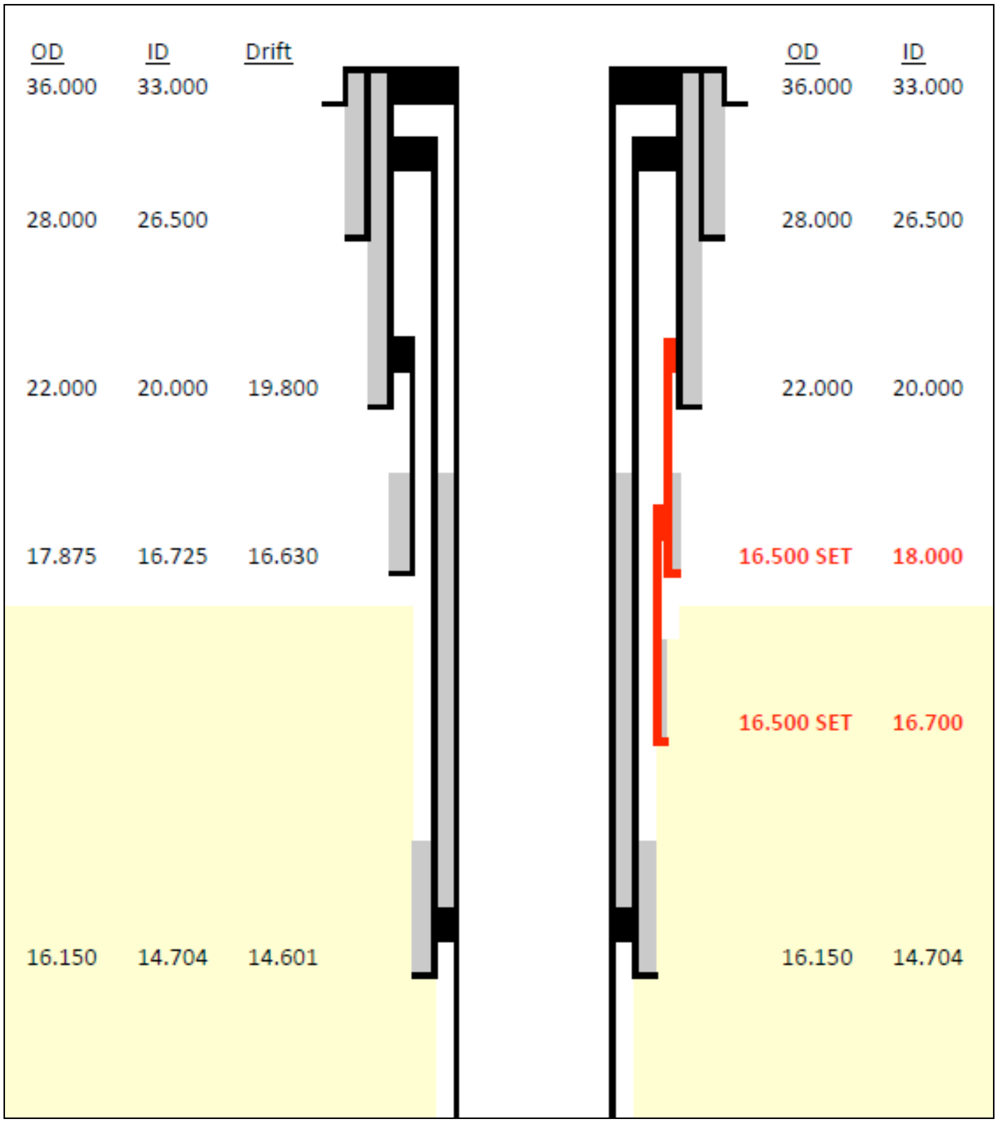


Figure 15: Expandable Casing Example

6 Conclusions and Recommendations

The key conclusions and recommendations from this study are as follows.

- The major bit and coring system service providers have a great deal of experience with difficult hard rock drilling environments in the oil and gas industry. They currently all have products that could improve current IODP drilling performance. Perhaps more importantly, they all have the design, testing, manufacturing, analysis, and technical support capabilities needed to develop optimized solutions for difficult drilling conditions.

- At this point it is not practical to recommend a specific bit type or coring system for a mantle hole mainly because optimizing performance is more than just selecting a bit. Optimizing performance requires a systems level approach that considers bit design, drill string mechanics, bottom hole assembly and drill string design, hydraulics, drilling fluids and so on. In addition, there are a variety of potentially viable options that need to be considered that, for example, range from conventional drilling, to using a bit and a downhole motor, to using a diamond impreg bit and a downhole turbine and so on.

- Achieving success on a mantle hole will involve more than just selecting a promising looking bit and running it. Blade believes that IODP should partner with 1 or 2 of these service companies in order to take advantage of the full range of experience and services they can provide during both the planning and operational phases of the project. Blade further recommends that NOV be one the companies because they have the most familiarity and understanding of the technical issues and have expressed the most interest in the project.

- As illustrated in Section 4, working closely with a service company to develop an optimized solution to the mantle hole challenges can significantly reduce both the operational time and risk associated with the project.

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Appendix 1: BEAM Follow-up Questionnaire (generic)

BEAM - *Borehole into Earth's Mantle*
Bit and Coring Technology Development Questions

BEAM is a complicated project from the standpoint of the technical issues and the fact that it is managed and will be operated by a non-profit scientific organization. As such, it is presently unclear how best to move forward to resolve the technical issues. To facilitate a discussion about this, Blade has prepared a list of possible steps that could be taken to address the technical and commercial issues with the support of a manufacturing service company. The idea is that the list could serve as the basis of internal discussions within <company> to help determine your level of interest, resource requirements, costs and so on.

Blade would therefore appreciate it if <company> could review the steps provided below and indicate your level of interest. We would not expect a lengthy formal response but would be happy to meet with you to discuss this in more detail at your convenience.

Again, Blade has been asked by IODP to:

- Identify current hard rock drill bit equipment and services.
- Investigate potential technological gaps and improvements that will enable hard rock drill bits to stay on-bottom longer, decreasing drilling time and risk.
- Identify current hard rock coring systems and services.
- Investigate possible development of new hard rock coring systems to improve the quality and quantity of cores recovered in order to satisfy the scientific objectives.
- Provide a recommendation of the most efficient and most viable hard rock drill bits and coring systems for the BEAM drilling project spud date in 2017-2018.
- Provide an estimate of how the designers, manufacturers, and service companies of such equipment and services may accelerate their technological offerings, including an estimate of the technological improvement costs to IODP and the scientific drilling community.
- Identify additional high-impact drilling equipment and services for the BEAM project where technological improvements will also reduce project time and risks.

Possible Technical Issue Resolution Steps

1. Would you be willing to provide information / marketing material on your current hard rock bit product lines that might be suitable for the BEAM project?

2. Would you be willing to provide information / marketing material on your current hard rock coring system product lines that might be suitable for the BEAM project?

3. Would you be willing to provide information on hard rock bit designs and coring systems that are under development that might be suitable for the BEAM project?

4. Would you be willing to provide information on the key design features for high temperature, hard rock roller cone, fixed cutter, and impreg bits and core systems? For example, what do you think the main issues are, what are the ideal design features that one would look for, which ones have current solutions, which might need an R&D program to address the BEAM project needs?

5. What kind of modeling software do you have that, for example, considers lithology and rock strength for the selection of optimum bits? Will you provide an input list or form, so that we can begin gathering sufficient information?

6. What bit testing facilities do you have and what kind of drilling related variables can be adjusted?

7. Would you be willing to provide information on your previous experience drilling and coring in high temperature and hard rock areas that are similar to what is expected in the BEAM project. What information would you need from Blade/IODP to make this comparison?

8. Would you be willing to review previous IODP project bit and coring performance records and provide a cursory evaluation of the date, your general opinions of the results and general suggestions for alternative bits and core heads – at no cost?

9. Would you be able and willing to do a detailed examination of previous IODP project bit and coring performance records and well log data and do a comprehensive performance evaluation in order to come up with a optimized bit and core/head recommendation based on your current product line offerings? If so, how much would it cost and how long would it take, and how would it need to be structured?

10. Would you be willing to participate in an R&D program to address the bit and coring technical issues associated with the BEAM project? How would you think a program like this should be structured and roughly what would it cost?

11. Do you have any other opinions, suggestions or advice?

Blade Energy Partners
May 2012

Appendix 2: 1256D Core Test Report

Embedded below is the report on the UCS core testing that was done by NOV.

IODC Core Sample Report.pdf

Appendix 3: Base Case Well Configuration

For reference, below is the base case well design configuration that was assumed during Blade's 2011 feasibility study.

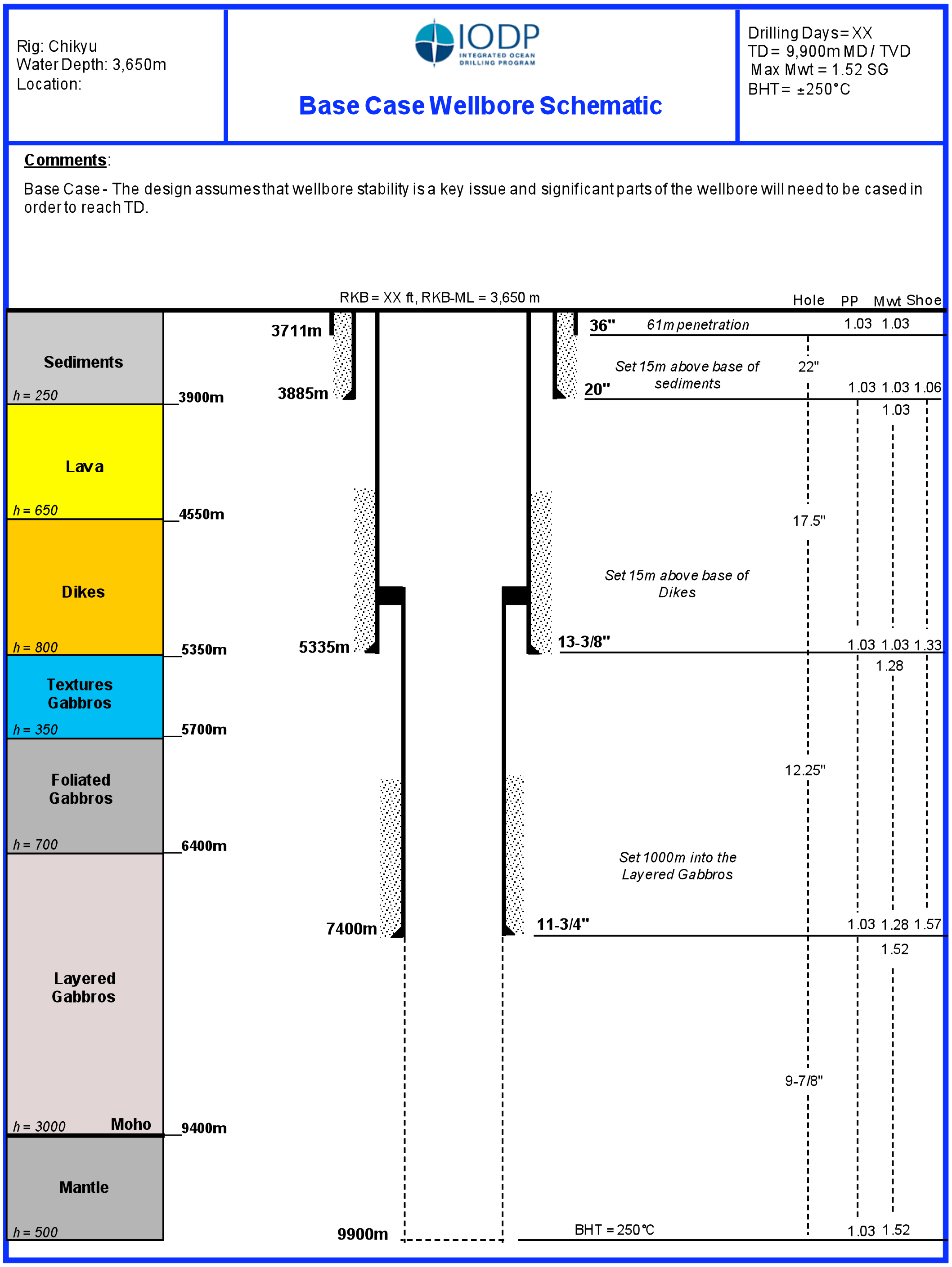

Figure 16: Base Case Mantle Well Configuration

Appendix 4: Glossary of Terms

BHA – Bottom Hole Assembly

The lower portion of the drill string below the drill pipe consisting of, at minimum, the bit and heavy drill collars. The BHA provides the force for the bit to overcome the strength of the rock through the application of weight applied to the bit provided by the drill collars. The BHA can be configured in many different ways to facilitate building or dropping the angle of the wellbore for directional wells or to keep the wellbore straight in a vertical well. Specialty tools (LWD, MWD) are frequently incorporated into the BHA to provide various down hole measurements of formation properties and/or drilling parameters. The diameter of the tools that make up the BHA will vary depending on the hole size that is being drilled. Some common bit and BHA size combinations are shown below.

BHA Size :	4-3/4"	6-1/2"	8"	9-1/2"	10"
Hole Size :	5-7/8"	8-1/2"	12-1/4"	17-1/2"	22.0"

BOP – Blowout Preventer

A large, specialized mechanical valve installed at the top of a well that is to used to seal, control and monitor the down hole formation pressures in oil and gas wells. Individual BOP's are installed redundantly in stacks to form the overall BOP Stack. BOPs come in a variety of styles, sizes and pressure ratings. Some can effectively close over an open wellbore, some are designed to seal around tubular components in the well (drillpipe, casing or tubing) and others are fitted with hardened steel shearing surfaces that can cut through the tubular components.

LMRP – Lower Marine Riser Package

Connects the marine drilling riser to the subsea BOP stack located at the seabed on top of the wellbore. The LMRP provides the means to disconnect from the well in the event of severe weather or during an emergency abandonment so that the marine drilling riser can be pulled to the surface leaving the well safely shut in with the subsea BOP stack. The LMRP consists of a BOP connector, an annular type BOP and a flex joint assembly which permits the riser a degree of lateral movement while it is suspended in the water column.

LWD – Logging While Drilling

The real-time measurement of down hole formation properties while the hole is being drilled through the use of specialty tools integrated directly into the BHA. LWD tools can measure most of the same formation properties that can be done with conventional logging tools run on wireline. The use of LWD tools ensures that some measurement of the subsurface formation properties is captured in the event that wireline operations are not possible. Additionally, real-time nature of LWD data can be used to guide well placement so that the wellbore remains within the zone of interest.

MWD – Measurement While Drilling

The real-time measurement of down hole drilling parameters while the hole is being drilled through the use of specialty tools integrated directly into the BHA. MWD tools are used to measure down hole pressure and temperature, and the trajectory of the well (hole angle and direction) which is critical when drilling a directional well or ensuring that a vertical well remains vertical.

ROP – Rate of Penetration

The speed at which a drill bit drills through subsurface formations thus deepening and extending the length of the wellbore. The speed is usually measured in terms of feet per hour or meters per hour.

RSS – Rotary Steerable System

A specialty tool incorporated into a BHA used in directional wells that allows the bit to be oriented in the desired direction while continuously rotating the drilling string. Drilling parameter instructions can be sent from the surface to the tool which then gradually steers the bit in the desired direction. The tool replaces conventional directional drilling tools and provides better control over the trajectory of the well, improved drilling performance and reduced wellbore tortuosity. Rotary steerable systems are most commonly used when drilling directional, horizontal, or extended-reach wells, but they are increasingly being used in vertical wells to offset any down hole conditions that may cause a deviation of the wellbore and thereby ensure that the well remains vertical.

TD – Total Depth

A term generally used to refer to the final total depth of a well. The TD of a well is defined by two terms – the Measured Depth (MD) which is the overall length of the well as measured by the length of the drill pipe required to reach bottom, and the True Vertical Depth (TVD) which is the vertical distance between the surface and the bottom of the hole. The MD will always be greater than the TVD in a directional well, while they would be expected to be the same in a vertical well.

VME – Von Mises Equivalent (stress)

Tubulars, such as the marine riser, are subject to a tri-axial stress state due to the loads imposed by three principle stresses – axial stress, bending stress and hoop stress. These three types of stresses can be combined into a single uni-axial equivalent stress that is the Von Mises Equivalent stress. This simplified expression of tri-axial stresses can be directly compared to the tubular's yield strength to determine whether the tubulars have sufficient strength to withstand the loads that they will be subjected to.

WOB – Weight on Bit

The amount of downward force, measured in thousands of pounds, that is exerted on the drill bit to overcome of the strength of the rock in order to drill and deepen the hole.