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Case Studies of PDC Bits in Deep Geothermal Drilling

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ABSTRACT

The vast majority of drill bits currently used in geothermal applications are of the roller cone (RC) type, while the preferred drill bit type in oil & gas wells is the PDC (Polycrystalline Diamond Compact). Geothermal drilling applications are usually characterized by hard (and at times abrasive) formations that represent a significant challenge for conventionally shaped cylindrical PDC cutters due to their tendency to sustain wear in such formations. The preference for RC bits in geothermal applications is due to their ability to drill just about any rock type in a predictable manner and at a relatively low cost. However, RC bits use rotating cones that only last a certain number of hours (revolutions) before the bit has to be pulled out of the well to be replaced. In recent years advances in PDC technology have enabled the manufacturing of novel cutter and bit designs for hard rock drilling. Through the research project INNO-Drill two well sections have been drilled in 2018 and 2019, in metamorphic rock formations in the Larderello region in Italy, using two distinct PDC drill bits provided by the industrial partners. The first drill bit had conventional PDC cutters and was used in the 12¼" section of the well (at 1416-1476 m depth). This section used a bottom-hole assembly instrumented with high frequency downhole sensors. The second drill bit, with conically shaped PDC inserts, was used in the 8½" section (at 2400m and at 3500m depth) of the well with surface data acquisition only. The results are presented through drill bit damage analyses, and post-processing of recorded data (rotary speed, weight on bit, torque on bit, downhole vibrations, rate of penetration) to assess and better predict the drilling performance. A physics-based model of the bit-rock interaction was used to facilitate drilling performance prediction and characterization of drill bit damage. The analyses indicate a good correlation between the calculated damage parameters and the bit condition observed after pulling out, while the model-based ROP predictions match the trends observed in the recorded data.

1. INTRODUCTION

Geothermal rotary drilling is often characterized by hard and at times abrasive formations that are typically drilled with roller-cone (RC) bits (Brøndbo 2017). High costs of rotary drilling (up to 40% of well costs (Dumas et al. 2013)) are usually reported as a consequence of low rate of penetration (ROP) and frequent time-consuming bit changes (induced by high wear rates) in such rock formations. Therefore, the evolutionary improvement of materials, design and use of drilling technologies is crucial for the enhancement of geothermal development.

In Oil and Gas drilling activities, the Polycrystalline Diamond Compact (PDC) drill bit has demonstrated a great potential to increase the ROP in the presence of hard rock formations and has been widely adopted over the roller cone technology. Both laboratory and field studies using improved PDC bit designs have also indicated good penetration rate performance in hard geothermal rock formations (Karasawa, 1992; Misawa, 1992). A study conducted at Sandia National Laboratories, in 2012, demonstrated a significant increase of ROP (by at least a factor of two) when using PDC bits in geothermal drilling (compared to roller-cone bits) and estimated that their implementation could eliminate as much as 15% of geothermal development costs (Raymond, 2013). However, the operating window for an optimal use of PDC technology while drilling in geothermal conditions remains challenging to characterize in the presence of high vibrations induced by the interaction with a hard-crystalline formation (Raymond, 1999). Experimental investigation (Ohno et al., 2002) has shown that the impact of wear in geothermal drilling can be detrimental for the durability of PDC cutters and needs to be carefully mitigated.

Controlled field tests are today crucial to better assess the relationship among the drilling operation parameters (weight on bit, top drive revolutions per minute (RPM), etc.), the well conditions (well design, rock types, etc.) and the durability of the bit selected (bit design, materials, etc.), thus to support an efficient use of PDC bits in geothermal wells.

This study presents the analyses of geothermal drilling field tests performed with two different PDC bits designed for hard rock drilling. The tests have been done in the vertical section of deep geothermal wells located in the Larderello region in Italy. The bottom-hole assembly of the first test done in 2018 was instrumented with high-frequency downhole sensors. During the second test done in 2019, only the surface data (operating parameters) were recorded. The analysis of the drilling data is supported by a bit-rock interaction model developed by Detournay et al. (2008) which assumes a linear constraint between the rate of penetration (ROP), the torque on bit (TOB), and the weight on bit (WOB). This model is used to evaluate the drilling performance prediction and characterization of drill bit damage. The analyses indicate a good correlation between the calculated damage parameters and the bit condition observed after pulling out, while the model-based ROP predictions match the trends observed in the recorded data.

The paper is organized as follows: the field test conditions are presented in Section 2. The bit-rock interaction model and the analysis methodology are presented in Section 3. The results are presented and discussed in Section 4 and conclusions are given in Section 5.

2. DESCRIPTION OF THE FIELD TESTS

Several drilling tests were conducted in the geothermal well Monterotondo 23 and the well Monterotondo 22B. Both wells are located in the Larderello region in Italy and were executed by the company ENEL Green Power. The tests were performed in two well sections in metamorphic rock formations using two distinct PDC drill bits illustrated in Figure 1 and provided by the company NOV and the company Lyng Drilling. The drilling tests conditions and denomination are summarized in the Table 1.

Drilling test label	Geothermal well	Drill bit provider	Downhole sensors	Date
Test #1	Monterotondo 23	NOV	yes	March 2018
Test #2	Monterotondo 23	Lyng Drilling	no	July 2018
Test #3	Monterotondo 22B	Lyng Drilling	no	April 2019

Table 1. Drilling test conditions.

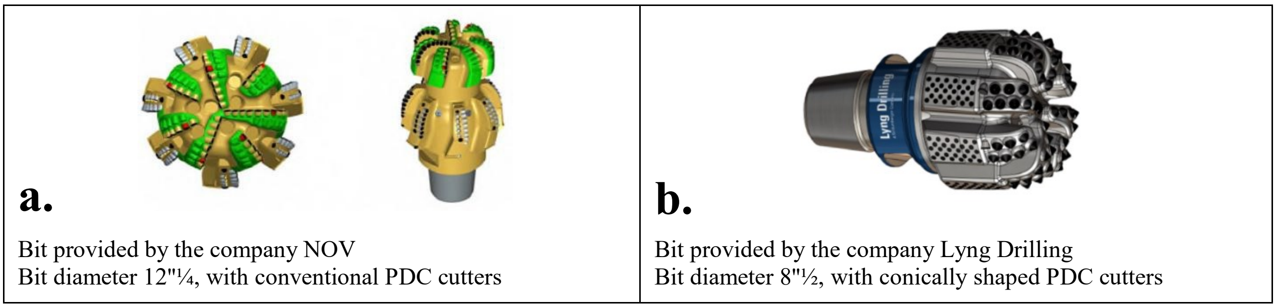

Figure 1. The two designs of the PDC drill bits used in drilling tests.

2.1. Description of the Drilling Test #1

A commercial PDC bit specially designed to ensure an efficient of transfer energy to drill ahead (which includes thermostable high durability PDC cutters) was selected for this test. Figure 1a illustrates the bit provided by NOV. In addition to the standard surface drilling data acquisition process (i.e. WOB, TOB, Bit Position, RPM, standpipe pressure (SPP) etc.), downhole data were recorded with the use of a high-frequency sensor (1000Hz) named CoPilot and provided by the company Baker Hughes. This sensor was set up at 4m above the drill bit to provide an accurate estimation of the mechanical bit-rock interaction conditions. A diagnostic system, part of the CoPilot, provided a preliminary assessment of the occurrence and severity of the drilling dynamics-related problems (torsional stick-slip, high axial/lateral vibrations, etc.). This sensor includes two 3-axial accelerometers, strain gauges, internal and external pressure and temperature sensors. The data from the sensor were post-processed after the field test for the analyses of drilling efficiency presented in Section 4.

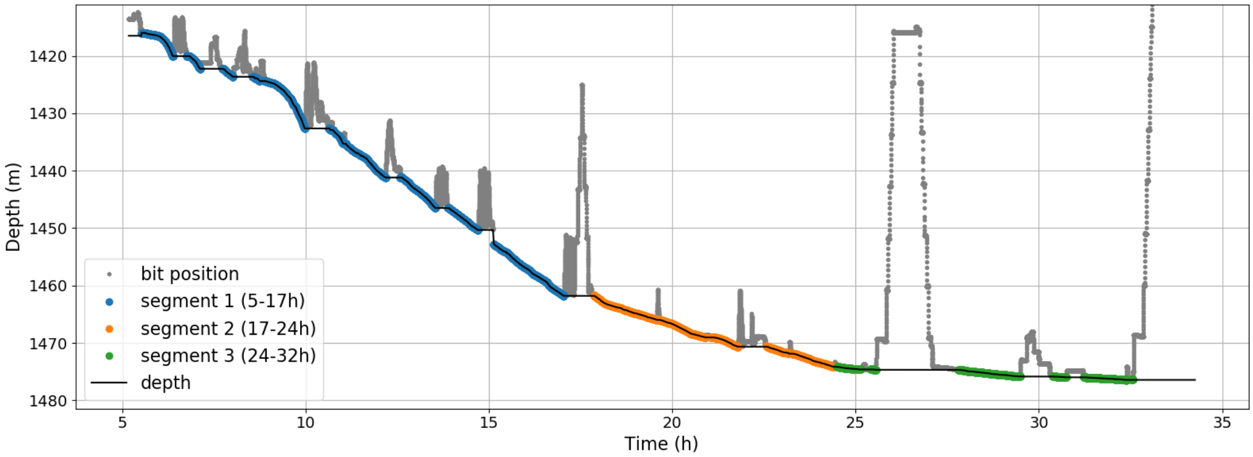

Figure 2. Bit position during the drilling test #1.

The drilling test #1 lasted about 27 hours, which includes both productive and non-productive time. The drill bit position evolution in the vertical borehole section is reported in Figure 2. The data recorded during the non-productive time, recognized by sudden jumps in bit position are removed for this study. Figure 2 highlights three distinct drilling segments that are identified by the change of ROP (rate of penetration) and from these the damage of the bit can already be evaluated. The drilling was performed with water as drilling fluid and the operating parameters were modified within a range of 2-17ton for the WOB and a range of 60-110 RPM in order to investigate the drilling efficiency under various selected loading conditions.

The surface data are shown in Figure 3. Since the surface data was recorded with a low sampling rate (0.5Hz), the high sampling rate downhole data (1000Hz) was averaged per 2 seconds so that surface and downhole data sets can be compared. The drilling rate is estimated from the surface for every 5cm of penetration depth. Three main segments of ROP evolution have been distinguished in Figure 3 that will be further detailed in this study: a first segment with a high ROP (5-17h), a second segment with a medium ROP (17-24h) and the last segment with a low ROP (24h-32h). In section 3 and 4, the PDC bit performance will be investigated by considering 3 stages of bit damage that will be associated to these 3 different ROP segments.

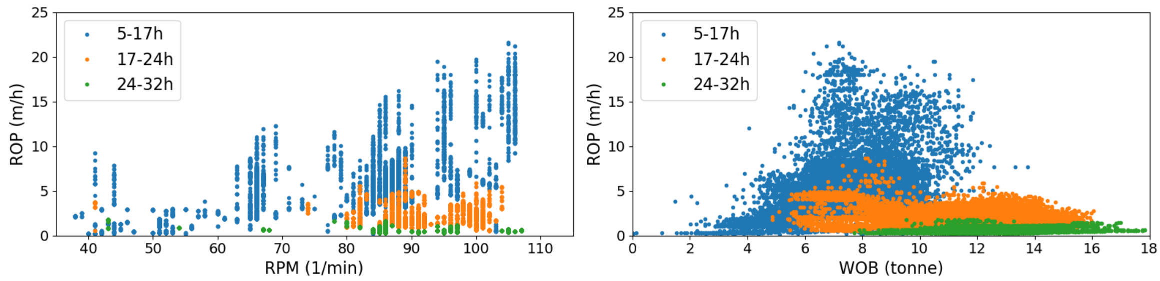

Figure 3. The surface data WOB, RPM and ROP during the drilling test with the NOV bit in 2018.

The influence of the WOB and RPM drilling operating parameters has been investigated on segment 1 (5h-17h) of the drilling test #1. A selected data set, from segment 1, is illustrated by Figure 4. In this figure, the RPM and ROP are evaluated using the surface data but the WOB data is from the downhole sensor. The evolution of ROP with WOB is shown in Figure 4 for 3 distinct sets of average RPM (65 in blue, 85 in black, and 105 in red). A (rather linear) increase of ROP with WOB (from 1 to 8 ton) can be observed at each given (average) RPM. The results shown indicate also that higher ROP can be obtained by increasing the RPM. However, the scatter of ROP becomes significant when high RPM and high WOB are simultaneously applied. This scatter indicates ineffective transfer and distribution of downhole forces at the bit-rock interaction that can be associated to the presence of high vibrations for this set of operating parameters.

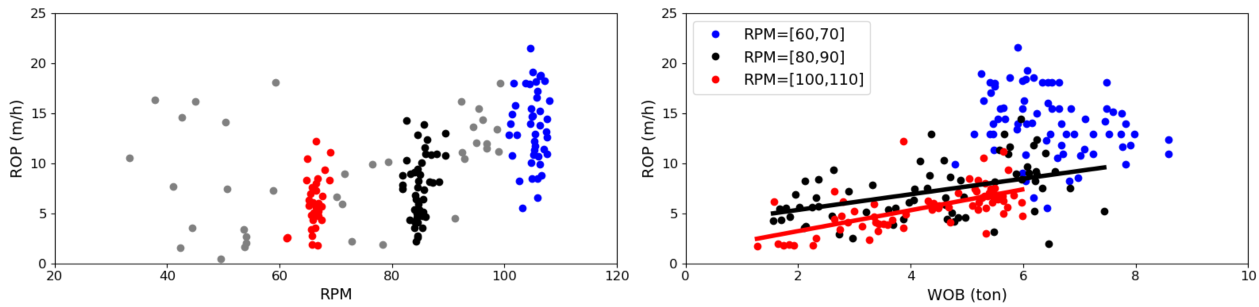

Figure 4. Influence of the RPM and WOB during segment 1 (5h-17h) of the drilling test #1.

The dull grading of the drill bit after the test #1 is described in the Table 1. The codes used and the evaluation follow the International Association of Drilling Contractors (IADC) system for fixed cutter dull grading (Brandon et al., 1992). Bit dull grade evaluation shows that most of the cutters were damaged due to spalling, which is illustrated by Figure 5.

Dull Grade	Inner	Outer	Major Dull	Location	Seals/Bearing	Other Dull	Reason Pulled
Head	6	8	RO	A	X	BT/CT/LN/JD	PR
Reamer	6	4	BT	A	X	LN/RO	PR

Table 2. Dull grading for PDC drill bit from NOV after the drill test in 2018.

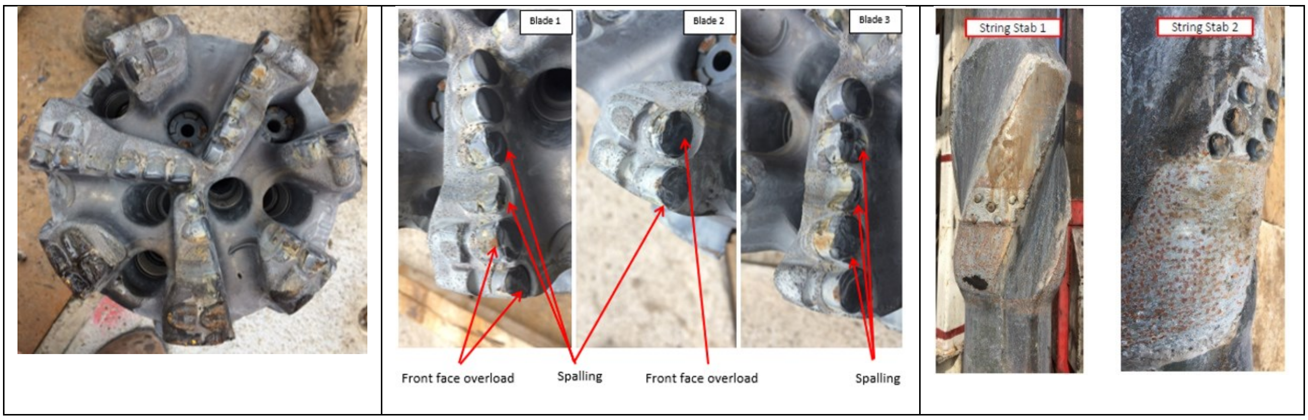

Figure 5. Damage on the cutters and on the string stabilizers after the drilling test in 2018 (NOV bit).

Significant damage to the PDC cutting structure was observed. The damage to the cutters in the cone of the bit suggests excessive axial force. This is an important dull characteristic as the majority of the torque / ROP generated by the bit comes from the cone cutting structure. This damage may be attributed to erratic weight transfer to the bit. This is supported by the post-run condition of the stabilizers. All the stabilizers show signs of damage to the bottom of the blades. This occurs when the stabilizer takes an axial load. This could be from the tortuosity of the wellbore combined with a very stiff assembly (all full gauge stabilizers), ledging, or wellbore spiraling.

An analysis of the high frequency downhole data has been performed to understand the drilling performance. The downhole WOB, downhole TOB, RPM min, RPM mean, RPM max, lateral vibration, and axial vibration are from the CoPilot sensor. The use of the tool/software named *eVolve Drilling Dynamics* owned by the company NOV has highlighted some vibration events that have affected the drilling performance. The main conclusions of the analysis are described as follow:

- Some issues were present with the weight transfer to the bit from the very beginning of the section. Rotating at low RPM (50) gave a 5Hz axial force oscillation and a poor ROP. This is believed to be the result of running a very stiff BHA which is interacting with the micro tortuosity of the wellbore. The magnitude of these axial force oscillations was significant (8ton) which has the potential to damage the bit.
- A backward BHA whirl event began after approximately 30 minutes of drilling when RPM was increased from 50 to more than 80. This was visible as an increase in lateral vibration, torque, and an axial force frequency matching the theoretical rate of backward whirl. Reducing RPM after whirl has been initiated may not be sufficient to break the cycle. Based on frequency analysis it is estimated that the source of whirl was ~58m behind the bit, in the 8 ¼” drill collars. The primary reason for whirl is believed to be the contact force at the drill collars. This is due to the very stiff BHA below the collars. This is a high-risk vibration which increases BHA interaction with the wellbore and produces an axial force oscillation which has the potential to cause bit damage.
- The turning point (where the performance decreased) in the run was identified as a short vibration interval when going back to bottom after about 11h of drilling. The vibration was observed below the CoPilot (increase in downhole torque) and at a high frequency (17Hz). This frequency was noted to increase with compression and dissipated quickly which suggests the BHA was passing through a tight spot. The bit sustained damage during this event as ROP never recovered to previous levels. Vibration magnitude and bending frequency were noted to increase for a duration mid-way through the run. The lateral vibration frequency increased with compression. This may be due to a larger component below the CoPilot in whirl if the hole is sufficiently over gauge. There was also a secondary vibration frequency present which decayed over time. This is potentially a contact point wearing down such as the onset of the notched wear to the bottom of the stabilizer blades.
- Performance further decreased over the latter half of the run. This was due to a further reduction in weight transfer to the bit as the wear to the stabilizers progressed and increased hanging tendency. This can be observed as the BHA being in full compression when the bit was still off bottom. It was also visible as a bend in the CoPilot due to increased compression across the tool.

2.2. Description of the Drilling Test #2

This drilling test was performed in 2018 with a PDC bit provided by Lyng Drilling (illustrated in Figure 1b). The drilling test was done in the well Monterotondo 23 and two runs have been recorded: the first run from 3120m to 3410m lasted for 97h, and the same drill bit was used for a second run to drill 90m from 3560m during 47h. The surface data are shown in Figure 6 and were recorded with a sampling period of one minute. The recording frequency is too low to use the data in our bit-rock model calibration detailed in Section 3. The tested bit was pulled out of the well when drilling performance started to deteriorate but was in a reparable condition when inspected at surface. The ROP was on average 3m/h but the lifetime of the tested bit is higher than a roller cone bit type. In order to confirm the bit lifetime, a new test has been conducted in 2019 with the same bit design and is described in the next section.

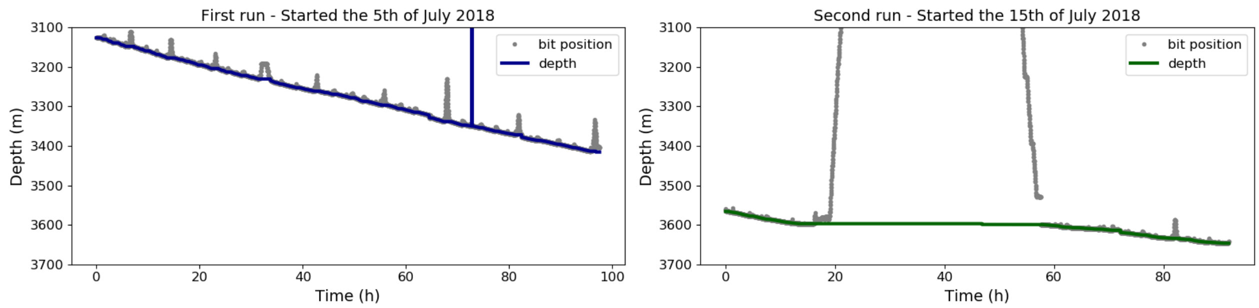

Figure 6. Bit position during the drilling test #2.

2.3 Description of the Drilling Test #3

This drilling test was performed in 2019 with a PDC bit provided by Lyng Drilling (illustrated in Figure 1b). The drilling test was done in the well Monterotondo 22B and three runs have been recorded: the first run from 2400m to 2600m lasted for 70h, and the same drill bit was used for a second run to drill 100m from 3550m during 50h. A roller-cone drill bit was used for the last run from 3975m to 4150m. The results of the last run drilled with a roller-cone bit in the same well section are included for comparison. The surface data are shown in Figure 7 and were recorded with a sampling period of one minute for the first run and 3 seconds for the second and third runs. As shown in Figure 7, the ROP is on average close to 5m/h for the first run and then lower than 3m/h for the second run. The operating parameters were modified within a range of 5-20ton for the WOB and a range of 50-110 RPM in order to investigate the drilling efficiency under various selected loading conditions.

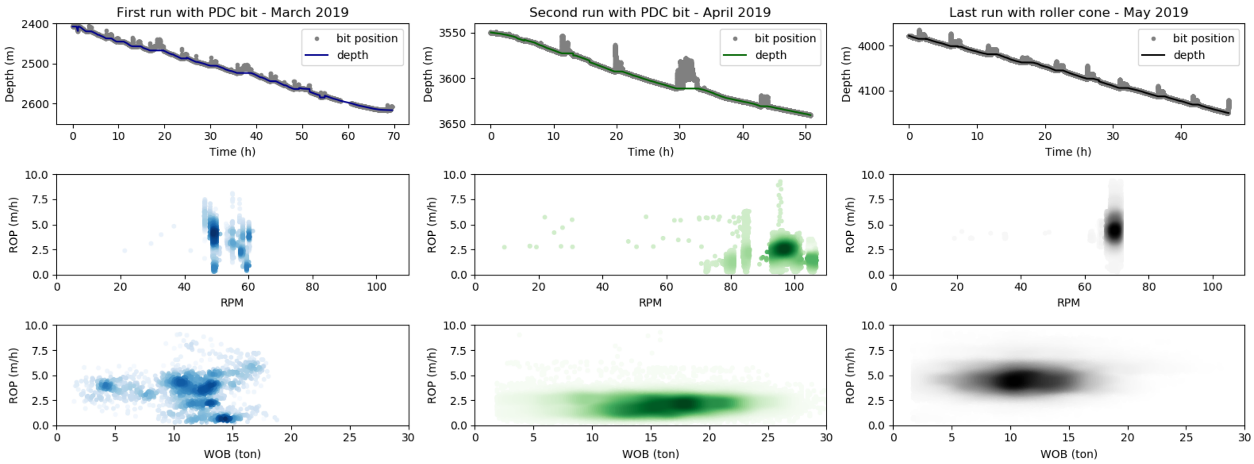

Figure 7. The surface data WOB, RPM and ROP during the drilling test #3.

The wear of the drill bit during the drilling test #3 is shown in Figure 8. Most of the PDC cutters are worn by abrasive wear. Some of the cutters in the outer area can be qualified as chipped cutters (chipping on the diamond edge/top). After the first run, the drill bit dull condition was good, and the bit was qualified as rerunnable. The damage did not increase dramatically during the second run, and abrasive wear was the preeminent wear mechanism.

		
New drill bit before the drilling test	Bit wear after the first run	Bit wear after the second run

Figure 8. Damage on the cutters on the drill bit used in the drilling test #3.

3. METHODOLOGY

The drilling test data are analyzed through a model-based approach. We use a bit-rock interaction model based on the original formulation proposed by (Detournay & Defourny, 1992) and extended by (Detournay, et al., 2008). This model was developed based on the analysis of a single PDC cutter and assumes rate-independent bit-rock interface laws. Weight on bit (WOB) and torque on bit (TOB) are first divided by the bit diameter and bit area, respectively, resulting in a scaled weight on bit w and a scaled bit torque t, which are now both expressed in the same units for easier manipulation. The model then assumes that the weight and torque are decomposed into cutting and frictional components (denoted with subscripts c and f), respectively, i.e.: $w = w_c + w_f$ and $t = t_c + t_f$. These are further related through $t_f = \mu\gamma w_f$ and $t_c = w_c/\zeta$, where $\mu = \tan(\phi)$ is the sliding friction coefficient, ϕ is the internal friction angle of the drilled rock, γ is a dimensionless number dependent on the bit geometry and wear flat contact length, and ζ is a bit property representing the ratio of the vertical and horizontal forces acting on the cutter face. ζ depends on the cutter geometry and orientation, specifically on the back-rake angle θ. The cutting component of the bit torque, t_c, is related to the depth of cut per revolution $d \coloneqq \mathrm{ROP}/\omega$, where ω is the bit angular velocity, through $t_c = \varepsilon d$. where ε is the energy required to cut a unit volume of rock with a perfectly sharp bit (also known in the literature as the intrinsic specific energy). In practice, ε is a function of the formation properties, specifically the unconfined compressive strength (UCS), internal friction angle (ϕ) and difference between the bottom-hole circulating pressure and the pore pressure of the formation. Analytical relationships for ε have been previously developed, and our implementation employs the relationship derived by. (Detournay and Atkinson, 2000), which includes all the terms mentioned above and also the back-rake angle of the cutter. Using the parameters defined above, the ROP can be defined as:

$$ROP = \frac{(t - \mu\gamma w)\omega}{(1 - \mu\gamma\zeta)\varepsilon}$$

From the equation above, the ROP depends linearly on the TOB and WOB, however the TOB is not independent of WOB, given the relations for cutting and frictional torque, detailed earlier. The bit response is therefore fully characterized by the decomposition of the scaled WOB into the frictional and cutting components. For RC bits with conical or wedge-shaped inserts, an additional indentation component needs to be added to the WOB decomposition, as detailed by (Franca, 2010). Further characterization of w_f yields three distinct drilling regimes / phases, as explained below.

- In phase I, contact length between the wear flat and rock interface increases with WOB, until it reaches a limiting value l. Since this relationship is linear, w_f can be modeled as a fixed proportion of the overall WOB. The contact stress at the wear flat also increases up to a limiting value σ. The corresponding scaled WOB at this limiting value is denoted by w_1.
- In phase II, w_f remains constant, equal to the product of l and σ. Any increase in WOB yields an equivalent increase in the cutting force, and therefore in the cutting torque and the depth of cut. This is the ideal phase for efficient drilling.
- In phase III, which starts above a certain weight threshold (w_2), commonly known in the industry as the "founder point", the frictional part increases again. As a result, applying any additional WOB will actually reduce the depth of cut per revolution, and the resultant ROP will drop. This reduction of depth of cut with WOB is assumed to be linear for simplification purposes and is quantified by an additional model parameter, p_3. Drilling above the founder point can be characterized as inefficient and can lead to damage to the drill bit cutting structure.

The bit-rock model detailed above needs to be calibrated in order to output realistic values. Based on the model formulation, we consider eight calibration variables: two of them (UCS and internal friction angle) are rock properties, while the other six variables are bit-dependent ($\zeta, \gamma, w_1, w_2, l\sigma, p_3$). To calibrate these variables using available measurements, we use a Sequential Monte Carlo (particle filter) algorithm (Daireaux et al., 2018). This consists of selecting a set of candidate variables (particles), and then evolving them in time according to a stochastic process f which attempts to simulate the real underlying process (the evolution of the bit and formation properties over a drilling run). Finally, each particle is assigned a weighting factor according to how close estimates it provides compared to the measurements. This results in a probability distribution for both the parameters (the formation and bit properties) and the outputs (e.g., ROP and WOB). For the sampling process f, we have selected a random walk which draws samples from a uniform distribution at every iteration of the algorithm. The calibrated variables corresponding to rock properties are allowed to change more abruptly than the bit properties (to account for sudden changes in lithology which may occur during drilling, as opposed to slower changes in the bit condition). This is achieved by controlling the step size of the random walk for the different parameters.

4. RESULTS AND DISCUSSION

4.1. Calibration results of the bit-rock interaction model for the test #1

Figure 9-Figure 11 show the results of the bit-rock model calibration for the drilling test #1. Measured downhole RPM, WOB and TOB, in addition to downhole pressure were used as inputs to the model, while the ROP used for model calibration and validation was derived from the hook position measurements and averaged over a 1-minute interval to reduce noise. A back-rake angle of 15° was assumed for the NOV bit cutters.

Figure 9 below shows time-based and depth-based plots of the estimated ROP together with the estimated bit wear parameter with their mean, upper and lower bounds (taken as one standard deviation from the mean). The actual ROP (one-minute average) is overlaid with the estimated ROP for comparison, showing good match between the mean estimated value and the actual value. The estimated bit wear parameter increases exponentially over time, becoming more significant at the drilled depth of 1460 m, with a large spike at 1475 m. This correlates well with the dramatic reduction in ROP around the same depths, and also with the observed bit damage when the bit was pulled out of hole.

Figure 10 illustrates the WOB estimation using the same bit-rock model, using only bit torque and the calibrated formation and bit properties as an input. The mean WOB estimate matches quite well with the downhole WOB measurement, with the exception of the data at the end of the run where the WOB is under-predicted by the model by more than 3 tons. The calibrated transition boundaries and are also shown for reference, to enable assessment of the bit-rock model phase throughout the run. Note that the estimated transition boundaries vary slightly over time, particularly, but they tend to stabilize towards the end of the run. The bit is drilling in phase I until roughly 17h, after which point the WOB is increased and the bit drills a brief period in phase II until 22h, and then enters phase III where drilling is no longer efficient. These phases have a different meaning from the three drilling segments defined in Figure 2, however they correlate quite well for the most part.

Figure 11 provides depth-based plots of the estimated formation and bit parameters which comprise the bit-rock model. The values of UCS and internal friction angle are consistent with those reported in the literature for hard rock formations such as the ones expected in the geothermal well (150-250 MPa for UCS and 25-35° for friction angle). The bit parameters ζ, γ and p_3 are also provided for reference. While there is no distinct trend for ζ, there is a notable increase in γ and p_3 from around 1455 m until the end of the interval. Both parameters increasing may be correlated with the wear sustained by the bit cutters. In particular, according to our analysis, p_3 values above 1.5 indicate a very steep drop in the effective cutting force generated with additional WOB, which corresponds to very inefficient drilling as observed in the very low ROP achieved towards the end of the run.

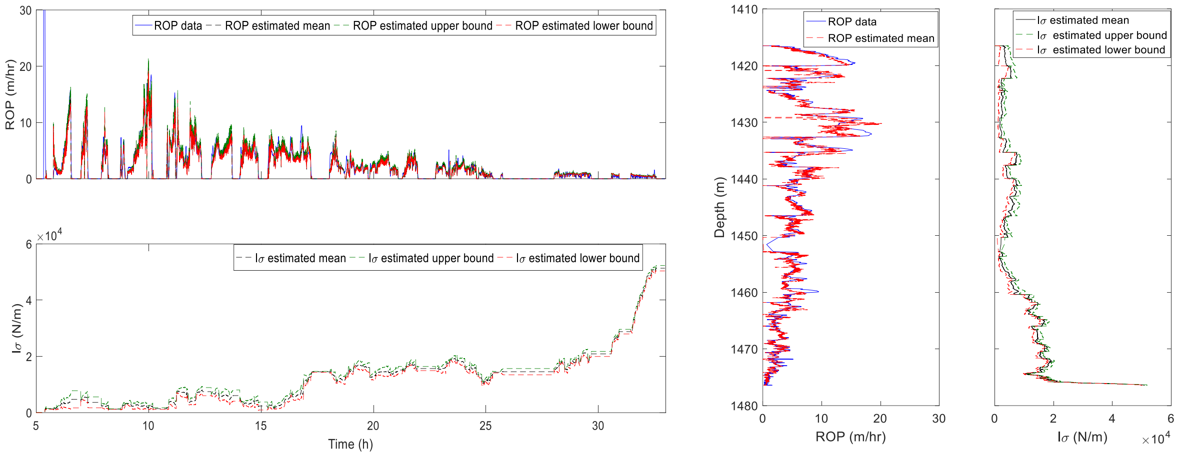

Figure 9. Model prediction of ROP and bit wear term ($l\sigma$) for the drilling test #1, time-based (left) and depth-based (right).

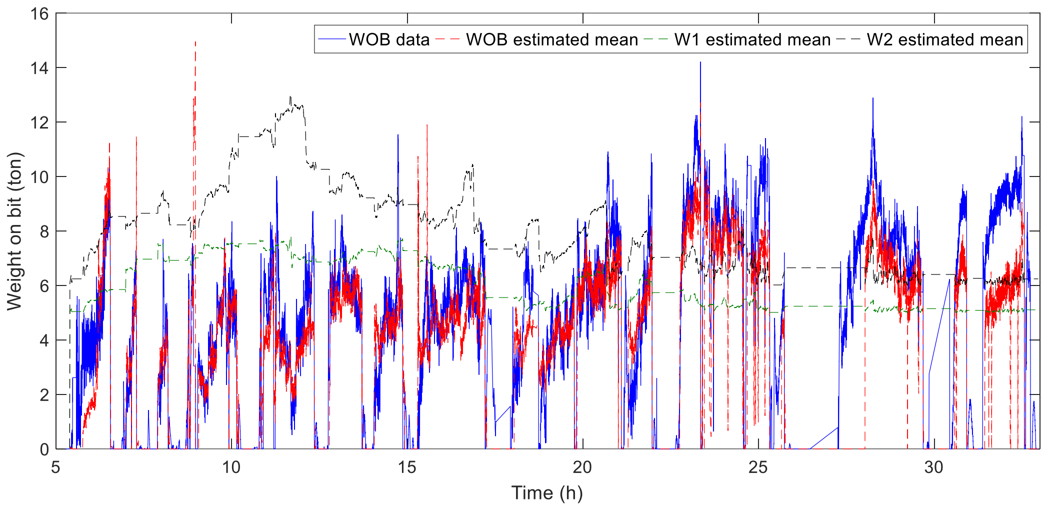

Figure 10. WOB estimated by the model for the drilling test #1, shown together with calibrated transition boundaries for phase I / II (w_1) and phase II / III (w_2).

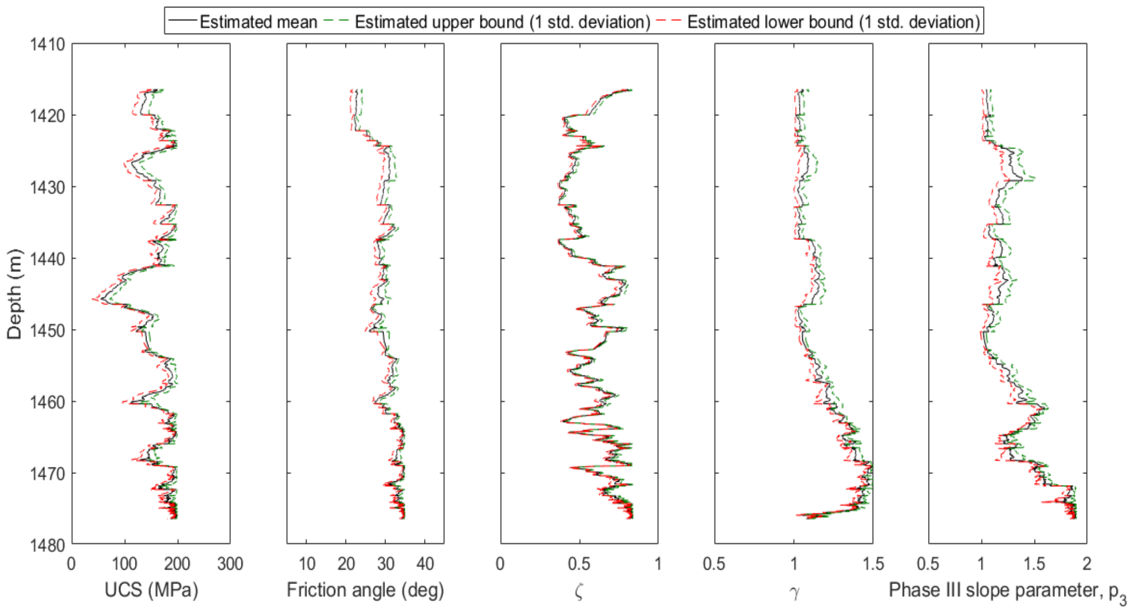

Figure 11. Estimated formation and bit properties versus depth for the drilling test #1.

4.2. Calibration results of the bit-rock interaction model for the test #3

Figure 12-Figure 14 show the results of the bit-rock model calibration for the second run of the drilling test #3. Surface RPM, WOB, TOB, and ROP averaged over 3 minutes were used as inputs to the model. Since downhole measurements were not available, TOB and WOB to be used with the model were computed by zeroing the surface torque and hook load recorded before going on bottom to drill a new stand.

From Figure 12 it can be seen that the model predicts the actual ROP quite closely, while the magnitude of the bit wear term does not change significantly over the course of the run. This is consistent with the visual observation of the bit condition when pulled out of the hole, which did not indicate significant cutter wear. The predicted WOB, shown in Figure 13, also follows the actual WOB data, which includes several periods of large fluctuations (possibly related to the presence of downhole vibrations). According to the calibrated phase transition boundaries, the bit drilled largely in phase III during this run, which implies rather inefficient drilling. This is consistent with the relatively low ROP values obtained in this interval. The very low ROP measured at the end of the interval (at around 45h) occurs when the WOB is further increased and the bit response is estimated to be entirely in phase III at that point.

Finally, Figure 14 shows the estimated formation and bit parameters. An additional parameter ξ was added to include the effect of indentation forces due to the conical shape of the bit cutters, based on a similar analysis conducted for roller-cone bit cutters in (Franca, 2010). This parameter represents the ratio between the combined cutting and indentation loads to the specific energy ε, and becomes equal to ζ if the indentation component is zero. Note that the estimated specific energy can be used as a proxy for rock strength, since direct estimation of UCS based on the relationship from (Detournay and Atkinson, 2000) is not possible without downhole pressure data, which was not available for this run. Nevertheless, large values of ε, and also of the friction angle φ, as indicated by the calibration results (Figure 14), are consistent with the hard rock formations expected in the well.

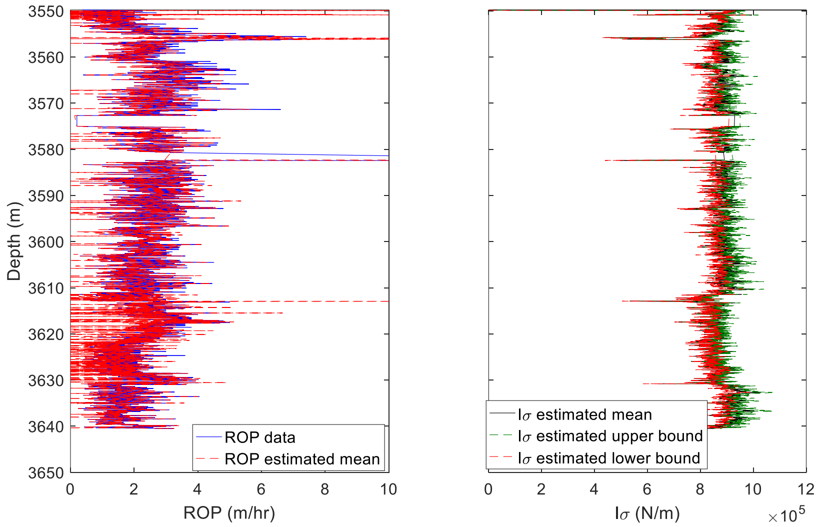

Figure 12. Model prediction of ROP and bit wear term (lσ) for the second run of the drilling test #3.

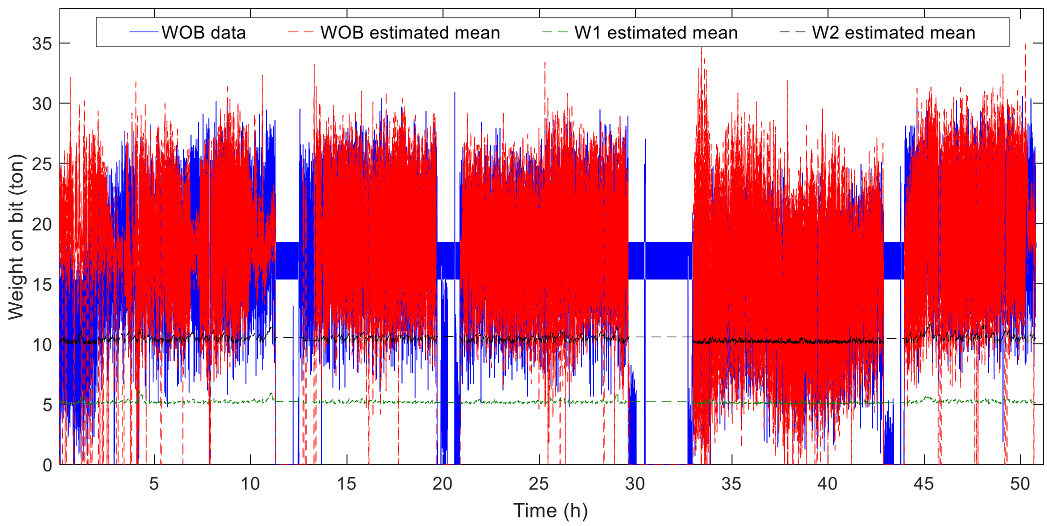

Figure 13. WOB estimated by the model for the second run of the drilling test #3, shown together with calibrated transition boundaries for phase I / II (w1) and phase II / III (w2).

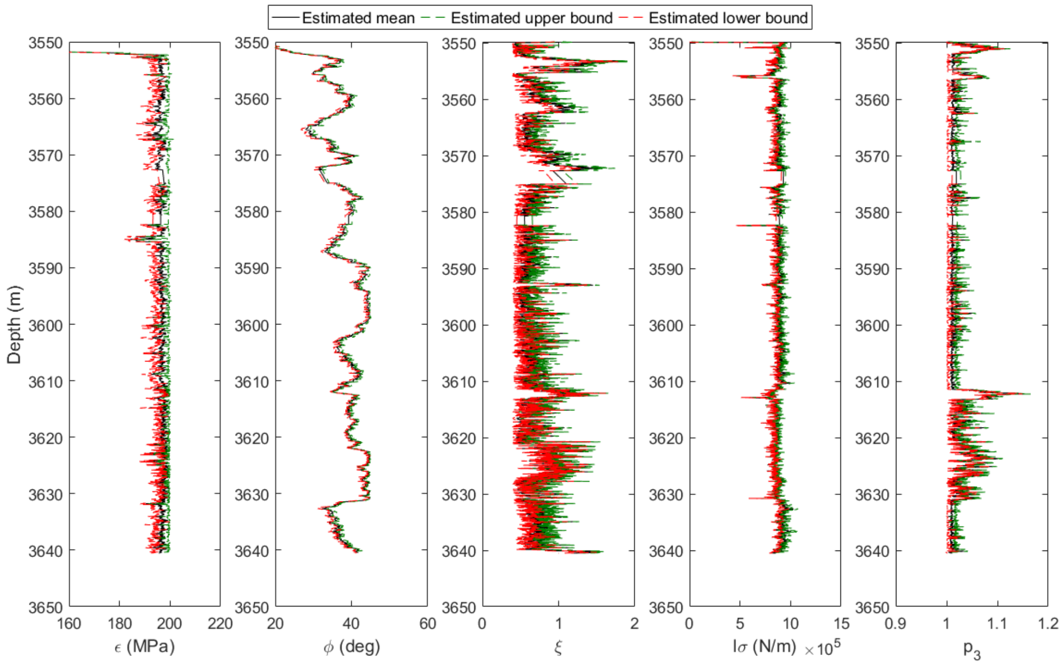

Figure 14. Estimated formation and bit properties for the second run of the drilling test #3.

5. CONCLUSIONS

Two types of PDC drill bits have been used to perform drilling tests in deep (hard rock) geothermal wells located in the Larderello region in Italy. The recorded field test data (surface and/or downhole data) have been post-processed to further understand the dynamic drilling conditions, to highlight some mitigation solutions (against vibrations / misalignment) and to indicate recommended windows of operating drilling parameters (in terms of ROP performance and bit life).

The test performed in the vertical 12¼" section (at 1416m) of the well Monterotondo 23, with the first PDC bit type (with drag cutters) was instrumented with high frequency downhole sensors. In order to capture a broad window of downhole bit/rock conditions, a large range of operating parameters (WOB, RPM) was applied during this test, and this choice was prioritized against a reduced operating range that could have maximized the bit life. The results of the test analyses reveal:

- A significant improvement of penetration rate can be achieved with the use of such PDC bit, compared to a conventional roller cone bit (up to 20 m/h with PDC bit vs 3-4 m/h with roller cone bit).
- Severe vibrations (axial and lateral) that were detrimental for the bit life were noticed throughout the entire drilling run. Significant spalling damage, induced by high magnitude impacts, was observed on the bit, and it was decided to stop the test after 8 hours of effective drilling.
- The condition of the remaining cutters in the cone of the pilot and on the reamer blades, suggest that such hard rock formation (Mica Schist) is PDC drillable if the vibrations are properly mitigated and drilling practices adjusted.
- It is thus recommended to optimize the BHA design (with lower stiffness), run under gauge stabilizers to reduce the risk of BHA hanging, address the risk of misalignment and consider enhanced stabilization to mitigate the axial and lateral vibrations.
- The window of operating parameters should also be carefully considered to maximize the bit life and keep a high ROP. It is thus recommended in such vertical deep well and hard rock formation to operate with higher WOB and low-medium RPM (70-80 RPM).
- The physics-based model of the bit-rock interaction for drag cutters used with a Sequential Monte Carlo calibration algorithm, shows a good agreement with ROP test data. Results indicate also further potential of the bit-rock interaction model to detect incipient bit wear.

Two identical drill bit specimens equipped with conically shaped PDC inserts have been used for the other field tests. The test results, including the post-processing of recorded data (surface data only), show:

- The first specimen tested in the 8½" section in the well Monterotondo 23 (at 3100m) in the granite interval achieved a rate of penetration of 3m/h, and the lifetime of the bit (100h) was higher than that of a roller cone bit used in the same well section. The dull grading after the drilling test was satisfactory and a second run was performed from a depth of 3550m.
- The second specimen tested at 8½" section in the well Monterotondo 22B showed an ROP of 5m/h and the same dull grading was observed on the bit. The same drill bit was used in two runs with a relatively low damage. The bit was considered as reparable (replacing some of the cutters).

- The physics-based model of the bit-rock interaction adapted for conically shaped PDC inserts allows a good match of model-based ROP calculations with the test data. The predicted bit wear evolution deduced from model calibration appears also consistent with the test data.

The presented calibration procedure of a bit-rock interaction model shows a good potential to help the drilling operators to adjust the drilling parameters in real-time. The calibrated model parameters could be extrapolated to indicate the damage of the bit and to have better planning of bit repairing and replacement procedures.

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