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Deepwater Subsea Well Conductor Design

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ABSTRACT: Typical deepwater wells in soft clay sites employ jet pipes as the well foundations, i.e., the jetted conductors. The installation of jetted conductors relies on the combination of hydraulic jetting, reciprocation and bottom hole bit cutting. The jetting process weakens the surrounding soil and enables the penetration of the conductor to the target depth, but the weakened soil inevitably provides low axial resistance for the subsequent casing that hangs on the wellhead. An alternative well foundation to jetted conductors is the drill & grouted (D&G) well conductors, in which case an enlarged hole will be drilled first and then the steel pipe is installed with cement pumped to the annulus to grout the soil and the steel. The third option for a subsea well conductor is a driven pile that is hammered into the seabed. Different types of well conductors possess unique installation and capacity features that need to be evaluated carefully for a specific well under consideration to balance safety and cost. Thus, the motivation of this paper is to offer typical design process and methods to promote safe and reliable design of subsea well conductors. The focus of the paper is on the above three most common conductor types: jetted conductors, D&G conductors and driven conductors.

Keywords: Well Conductor; Jetting; Drill&Grout; Driven; Axial Capacity

1 INTRODUCTION

Deepwater subsea wells consist of a series of concentric pipes with increasing lengths and decreasing diameters to provide structural capacity and to form hydrocarbon barrier for deepwater drilling and production. A well conductor (with the surface casing) forms the foundation for a subsea well, and is the first pipe to be installed below the seabed. The primary goal for a well conductor is to resist the axial and lateral loading resulting from subsequent drilling and production. For the current study, the focus is on the axial capacity of the conductor.

The axial capacity of a well conductor depends heavily on the installation method. The common three installation methods are jetting, drilling and then grouting, and driving with an underwater hammer. Jetting is the most common practice for well conductors in deepwater soft clay sites. It involves bit cutting, reciprocation and high pressure fluid erosion. A drill&grout (D&G) conductor offers an alternative to jetted conductors by drilling an enlarged hole first before installing the conductor. A driven conductor is similar to a conventional jacket pile that is installed by hammering. Other less common conductor types include torpedo piles that are released above the seabed and penetrates into soil under self-weight (Nogueira *et al.*, 2005).

Due to the high cost of offshore tests, limited offshore prototype tests exist to examine the design method for the axial capacity of well conductors. The axial capacity design method for a driven conductor is relatively mature based on the ample experience from shallow water jacket pile design (API RP2GEO, 2014); however, this is not the case for a jetted conductor and a D&G conductor. For jetted conductors, the current design is primarily based on the method by Jeanjean (2002), which relates the axial capacity to the final weight on bit (WOB) based on three conductors installed in the Gulf of Mexico (GoM). Jeanjean's method for jetted conductors rationalized the design by including the fundamentals of soil mechanics, but is a lower bound design method. Similar equation is proposed by Zakeri *et al.* (2014) for jetted piles up to 1000 days. Studies in Offshore Brazil by Petrobras indicates the jetted conductor capacity is higher (Bergh *et al.*, 2024). For D&G conductors, limited information on the axial capacity design method exists in the public domain, presumably the data are proprietary and were not released by oil companies; D&G conductors are less common compared to jetted conductors, except in deepwater Brazil Basins, where D&G well conductors have been successfully deployed by Petrobras (Cutrim *et al.*, 2021). Thus, a common design approach for D&G conductor is to follow the axial design method from American Federal Highway Associates (FHWA, 2010) for the design of D&G conductors in the GoM.

Thus, the motivation of this paper is to offer typical design processes and methods to promote safe and reliable design of subsea well conductors. The paper starts with a detailed description of various conductor types and installation methods. Then the axial capacity design methods are proposed by detailed Bayesian calibration techniques. Finally, recommendations are provided for future studies.

2 SUBSEA WELL TOPHOLE DRILLING

The subsea well tophole drilling refers to the drilling without a subsea blowout preventor (BOP) and without a drilling riser. Thus, there is no circulation established to the drilling platform/drillship, and all the returns from downhole are directly dumped to the open ocean. The conductor is the first pipe to be installed, while the second pipe to be installed is called the surface casing. Usually the most critical moment for a conductor, from the axial capacity perspective, is when the surface casing lands on the wellhead transferring all the weight to the conductor. The discussion of tophole drilling in this study is limited to the conductor and the surface casing.

2.1 Conductor installation

As mentioned above, there are three common ways to install a conductor, i.e., jetting, D&G, and driving. Each of which will be described in detail in the following text and also shown in Figure 1.

Jetted conductors are installed through a combination of down hole bit cutting, reciprocation and hydraulic jetting. The downhole bit is rotated by a downhole motor controlled by the drilling flowrate. The drilling fluid exists through bit nozzles to create high velocity jetting flow to erode/weaken the soil close to the conductor tip. Typical jetting operation is described by Akers (2008). Jetted conductors possess the inherent advantage that the foundation is installed along with the bottom hole assembly (BHA) jetted into the hole. The BHA then can be released from the running tool to drill the next section without pulling the BHA out of hole to change the bit and other components, saving one trip (Chen *et al.*, 2023; Chen *et al.*, 2024). The major limitation of jetted conductors are: (1) the jetting process disturbs the surrounding soils resulting in low axial capacity of the conductors; (2) the conductor can encounter jetting refusals if hard formations are present, and reciprocation is then required to aid penetration and can lower the axial capacity.

D&G conductors are installed by creating an enlarged hole below the seabed typically using a tri-cone rock bit. The conductor is then lowered down to the hole followed by pumping cement in the annulus between the enlarged hole and the conductor. Because the conductor is grouted to the surrounding soil, higher axial capacity than the jetted conductor is expected. In addition, because the hole is drilled by a rock bit, theoretically there is no limit on the conductor length as long as the hole stability is not an issue. However, the downsides of D&G conductors are: (1) it takes more time due to drilling the hole, pumping cement, and waiting on cement; (2) the heavy cement density may fracture the seafloor due to the very soft clays close to the seabed in deepwater; (3) it is difficult to control the well vertical trajectory; and (4) rig personnel and engineers may not be familiar with the operation of D&G conductors that potentially increases cost due to human errors, e.g., more load movement at the rig increases the HSE risk (Chen *et al.*, 2023).

Driven conductors are similar to conventional shallow water jacket piles that are installed by a driving hammer. Drivability analysis should be conducted beforehand with the expected soil properties at the site to select the appropriate hammer and to limit the driving fatigue. Typically, driven conductors are perceived to have the highest axial capacity compared to jetted or D&G conductors based on the common design premise, and the design method is more mature with the shallow water jacket pile design experience; however, the major downside of driven conductors is the high cost. Typically, driven conductors need to be installed in a dedicated offshore campaign with pile driving equipment before the arrival of a drilling vessel. This practice inevitably increases the cost of driven conductors. Another design consideration of driven conductors is that it takes time for driven conductors to gain high axial capacity, and this time-varying set-up effect should be accounted for in the design.

Figure 1 shows the simplified explanation of the three types of installation methods for conductors, and Table 1 summarizes key differences, pros and cons of each installation method.

2.2 Surface casing installation

After the conductor is in place with some appropriate resting period (e.g., to gain strength for jetted conductors, and to cure the cement for D&G

conductors), the next hole section below the conductor begins. The BHA can be either disconnected from the drill ahead tool (jetted conductor case) or launched from the rig floor. The next hole is drilled with appropriate mud density depending on the drilling window, and downhole drilling dynamics need to be monitored to balance the rate of penetration (ROP), surface equipment cutting handling capacity, tool vibration control etc.

At the hole target depth (TD), the BHA is retrieved, and the surface casing will be lowered down from the rig floor with appropriate landing strings. Then cement will be pumped through a cement stinger inside the surface casing to the annulus of the hole and the surface casing. After that, the surface casing will land on the wellhead transferring all the surface casing weight to the conductor, and the landing strings will then be retrieved. At this moment, the conductor bears the highest axial load during drilling as the cement outside the surface casing is not cured yet. Thus, this is the moment that the conductor needs to have sufficient axial capacity to prevent wellhead sinking after landing the surface casing. A simplified illustration of this process is shown in Figure 1.

Table 1. Summary of three conductor types

Conductor	Installation	Benefits	Downsides	Suitable sites
Jetting	Bit cutting and hydraulic washing	• Efficient, save one BHA trip to rig; • Standard practice minimizes error.	• Low axial capacity; • Risk jetting refusal wasting rig time.	Soft clay sites with conformable depositional layers.
D&G	Installed in a pre-drilled enlarged hole, pump cement to strengthen	• Higher axial capacity; • Can have long conductor length with no refusal.	• More rig time to install; • Can fracture the seafloor with heavy cement; • Rig personnel may not be familiar with operation.	Practically can be installed at any sites, but need to consider hole stability issue.
Driving	Underwater hammering into depth	• High axial capacity; • Matured driving technology.	• More time to install; • High cost with dedicated offshore campaign.	Can be installed in clayey, sandy and complex geological sites.

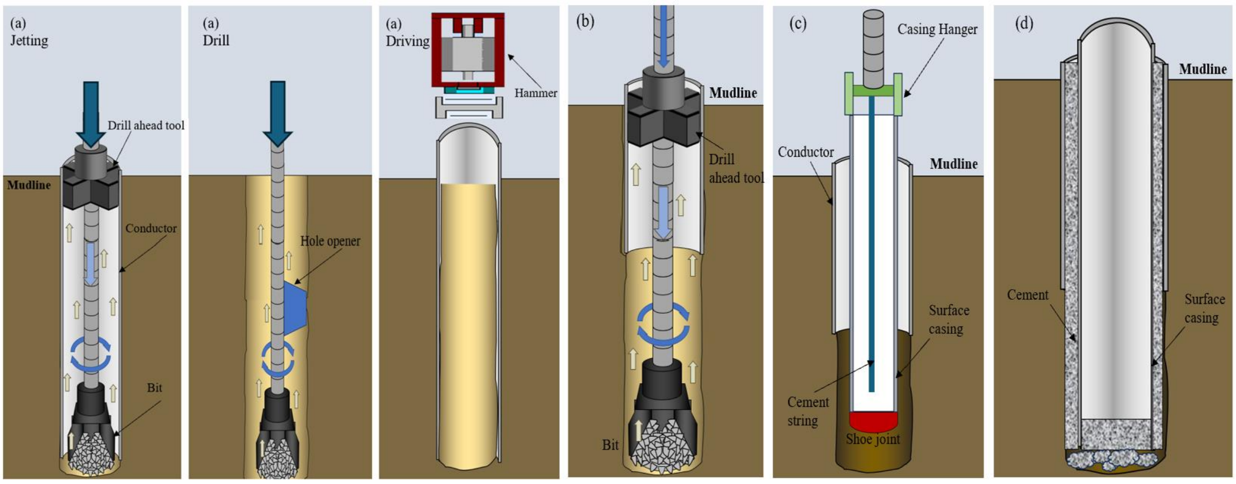

Figure 1 Tophole construction: (a) conductor installation (jetting, drilling, driving); (b) surface casing hole drill; (c) surface casing installation; (d) surface casing cement job (Chen et al., 2024)

3 AXIAL CAPACITY DESIGN

In this study, the conductor axial capacity model focuses on clayey sites. Thus, the axial capacity of the conductor can be expressed as follows:

$$Q_u = \alpha \times \pi D \int_0^L S_u dz \qquad (1)$$

where Q_u is the conductor axial capacity; L, D are respectively the length and the outer diameter of the conductor (for D&G conductor, D refers to the open hole diameter); z is the depth below the mudline (BML); S_u is the soil intact undrained shear strength; α is the soil adhesion factor representing the fraction of the intact soil undrained shear strength.

Because the tip of the conductor will be drilled out, there is no end bearing resistance included in Eq. 1.

The axial capacities of all the above three conductor types can be expressed by Eq. 1. The only difference is on the determination of the α value, and can be summarized as follows:

$$\alpha = \begin{cases} 0.055[2 + log_{10}(t)] + WOB_n & Jetting \\ 0.55 & Drill, Grout \\ min\,(1.0, 0.5\Psi^{-0.5}) & Driven \end{cases} \qquad (2)$$

where the method for jetting is based on Jeanjean (2002); t is the time in days after jetting; WOB_n is the normalized WOB by the maximum side friction on the conductor (i.e., using $\alpha = 1.0$); the method for D&G conductors is based on onshore drilled shafts following FHWA (2010); the method for driven conductors follows API RP2GEO (2014) and Ψ is the ratio of the soil undrained shear strength to the effective vertical stress, and the expression is for deepwater soft clays with $\Psi < 1.0$; for stiff clay sites with $\Psi > 1.0$, the exponent -0.5 should be changed to -0.25.

4 BAYESIAN CALIBRATION

As discussed above, the α value for jetting from Jeanjean (2002) is based on the three jetted conductors in the GoM which were not loaded to failure. Thus, it is judged that the method is on the lower bound side. For D&G conductors, the generalization of the method from onshore drilled shafts to subsea conditions is not verified. Therefore, it is beneficial to verify/calibrate the design method for jetted conductors and D&G conductors. Field observations and operational data offer invaluable insights to evaluate the current design method. A formal mathematical model to combine the existing design knowledge with the actual field data can be developed using Bayes' Theorem.

4.1 Bayes' Theorem

The probability distribution of α is updated with the observed conductor performance using Bayes' Theorem (Ang and Tang, 1984; Chen *et al.*, 2020):

$$PDF''\,(\alpha|\,Performance) = \frac{LH(Performance|\alpha)\cdot PDF'(\alpha)}{\int_{-\infty}^{+\infty} LH(Performance|\alpha)\cdot PDF'(\alpha)d\alpha} \qquad (3)$$

where PDF' and PDF'' are respectively the prior and posterior distribution of the α value; $LH(Performance|\alpha)$ is the likelihood of occurance for the observed performance of the conductor.

4.2 Calibration for jetted conductors

The calibration for α for jetted conductors is based on 156 jetted conductors installed in the GoM, which have an outer diameter of either 0.91m (36") or 0.97m (38"), with an embedment length from about 60m to 85m BML. The weight of the surface casing in water varies from about 1500 kN to 2000 kN. Out of these 156 jetted conductors, one failed when landing the surface casing, while the rest successfully held the surface casing. The soil undrained shear strength can be expressed $S_u = 1.35 \times z$ (z in the unit if meter, and S_u in the unit of kP_a) with a coefficient of variation (c.o.v.) of about 0.21 based on the available borings in the GoM. The details of the conductor and soil databases can be found in Chen *et al.* (2024).

The prior distribution of α is established based on the lower bound model from Jeanjean (2002), which gives about 0.16, and the judged upper bound value. The judged upper bound value is assumed to be 0.55 which is the value for onshore drilled shafts. It is believed that α for jetted conductors is unlikely to exceed this value due to the weakening of the soil during jetting. Thus, the prior distribution of α can be represented by a log-normal distribution with a median of 0.33 and a c.o.v. of 0.2. After incorporating the performance of 156 jetted conductors within the Bayesian framework, α is updated and the posterior distribution can be fitted approximately by a log-normal distribution with a median of 0.23 and a c.o.v. of 0.13 as shown in Figure 2. Note, the above value of 0.23 is a design simplification based on the typical drilling schedule in the GoM, because in the long run, the α will increase with time. The detailed discussions refer to Chen *et al.* (2024).

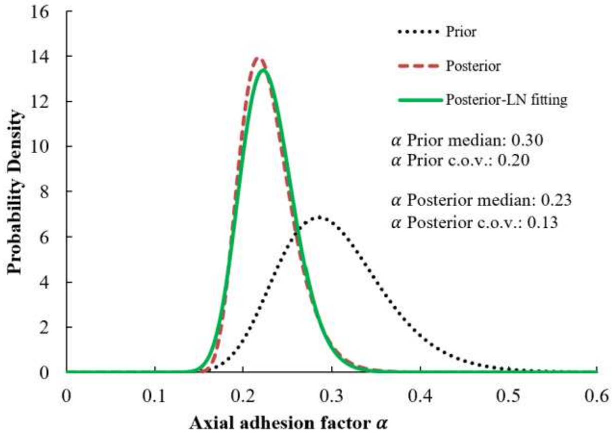

Figure 2. Bayesian calibration of jetted conductors

4.3 Calibration for D&G conductors

The calibration for α for D&G conductors is based on the observed wellhead settlement for 10 subsea wells during operation in deepwater Brazil Basin. All these wells used the D&G conductors as the well foundations. 3 out of 10 wells have conductor OD=30" installed in 36" holes, while the rest have OD=36" in 42" holes. All the surface casings were installed in the

26" holes, but the ODs were either 20" or 22" and the inner diameters (IDs) vary from 18" to 20 3/8". The conductor length varies from 70m to 110m BML, and the soil undrained shear strength has a gradient about 1.4 kPa/m. The maximum axial load on the wellhead ranges from 2346 kips (10.4 MN) to 4222 kips (18.8 MN) determined using a proprietary well foundation design software from Petrobras following the same framework at Cutrim *et al.* (2021). Further details of the database can be found in Chen *et al.* (2023).

In the Bayesian framework, the performance of the D&G conductor is represented by the discrepancy between the calculated wellhead settlement during production to observed field settlement. Because all these 10 wells have top of cement below the mudline, the wellhead settlement depends on the axial capacity of the conductor. Thus, the observed field wellhead settlement is a measure of the conductor axial capacity. An analytical solution relating the D&G conductor axial capacity to the wellhead settlement was derived in Chen *et al.* (2023), and form the basis for the Bayesian calibration for α for D&G conductors.

For the prior distribution of α, close examination of the data published by Chen *et al.* (2011) for drilled shafts reveals that the mean of value is around 0.5 to 0.7 with a c.o.v. around 0.2 for typical deepwater soft clays. Based on the statistics reported by Tang *et al.* (2019) , the model bias factor has a mean of 1.11 based on the FHWA method (or a mean of 0.55*1.11=0.61) and a c.o.v. of 0.28. Thus, the prior distribution is represented by a log-normal distribution with a mean of 0.62 and a c.o.v. of 0.25.

Because none of these 10 wells had settlement issue observed by ROV during production, it is judged that none of the well had settlement greater than 10cm. Thus, a Monte Carlo simulation-based Bayesian procedure is developed, i.e., one realization with a set of random variables (e.g., soil undrained shear strength, predicted axial load etc.) producing a wellhead settlement greater than 10cm will be rejected, while the one produces settlement less than 10cm will be accepted. Following this scheme, the posterior distribution of α can be approximated by a log-normal distribution with a mean of 0.93 and a c.o.v. of 0.1 as shown in Figure 3 (Chen *et al.*, 2023).

4.4 Updated axial capacity design model

With the above calibrated α using the Bayes' Theorem, the revised α values for jetted conductors and D&G conductors are shown in as follows:

$$\alpha = \begin{cases} 0.23 & \mathit{Jetting} \\ 0.93 & \mathit{Drill, Grout} \\ API & \mathit{Driven} \end{cases} \qquad (4)$$

where the driven conductor design still follows the API method (API RP2GEO, 2014).

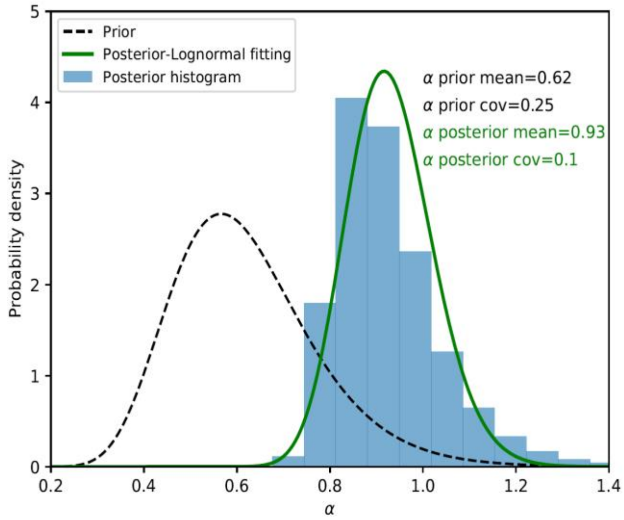

Figure 3. Bayesian calibration of D&G conductors

5 DISCUSSION & RECOMMENDATIONS

For jetted conductors, based on typical drilling practice, Eq.2 and 4 almost gives identical axial capacity. This demonstrates that the method originally developed by Jeanjean (2002) is suitable for jetted conductor design, although the method was developed from a lower bound perspective. Eq. 4 offers a more convenient way for design by eliminating the WOB (which is unknown before drilling) and the time effect based on typical drilling practice.

For D&G conductors, the updated α value is significantly greater than the one used for onshore drilled shaft design. One possible reason may be that the pumped cement enlarges the hole that effectively increases the D&G conductor diameter.

Therefore, based on the above discussions, it is recommended that Eq. 4 can be used for subsea well conductor design with an appropriate safety factor, which will reflect the uncertainties in the design and the operators' risk acceptance criteria. It is also recommended that more physical tests on D&G conductors to further verify Eq. 4.

6 CONCLUSIONS

Well conductors provide the foundations for subsea wells and are the first key component to keep the safety and integrity for deepwater hydrocarbon production. This paper presents the common three types of conductor installation methods, i.e., jetting, drill&grout, and driving. The benefits and the downsides of each method are listed, and the axial design model for each method is summarized. The existing axial capacity model can be improved with field observation data through a Bayesian calibration framework. With the experience from the GoM and Brazil, the soil adhesion factor is updated to be 0.23 (based on typical drilling schedule of about 2-3 days from the end of jetting) and 0.93 for jetted conductors and D&G conductors, respectively, while it is judged that the API method is appropriate for the axial capacity of driven conductors. It is also recommended to include safety factors to reflect the uncertainties associated with the design model, the soil strength and the risk acceptance criteria of the operator.

AUTHOR CONTRIBUTION STATEMENT

First Author: Data collection, Bayesian technique development, and conductor analysis ; **Other Authors from Shanghai Jiao Tong University**: Draft paper preparation, equations checking; **Additional Authors from Petrobras**: Provide the original well data which this paper referenced, and paper review and editing.

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