

Oil Service Contracts

- New Incentive Schemes to Promote Drilling Efficiency¹

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Summary

Shortages of rigs and personnel have encouraged creativity in designing incentive contracts in the drilling sector. In particular for oil service contracts, since those companies have the most direct control of drilling efficiency. A large variety of contract types are in use, including within the individual oil company. This article describes and analyses the compensation formats utilised in oil service contracts. Changes in contract format pose a number of relevant questions relating to resource management, and the article takes an in-depth look at some of these. Do new incentive elements for drilling promote effective utilisation of scarce rig capacity at an aggregate level, or do they primarily represent a zero-sum game? How will a stronger focus on efficiency influence reservoir utilisation? How do the new compensation formats influence the development of costs in the industry?

¹ We would express our thanks for rewarding conversations with and comments on the article itself from a number of key specialists in oil companies, rig contractors and oil service enterprises. Address for correspondence: Petter Osmundsen, Department of industrial economics and risk management, University of Stavanger, NO-4036 Stavanger, Norway. Tel: +47 51 83 15 68. Mobile: +47 99 62 51 43. Email: Petter.Osmundsen@uis.no. Home page: <http://www5.uis.no/kompetans katalog/visCV.aspx?ID=08643&sprak=BOKMAL>

1. Introduction

Oil operations on the Norwegian Continental Shelf (NCS) - as in other petroleum provinces - are characterised today by a shortage of rigs and very high rates. In addition, a disturbing decline in drilling efficiency can be observed. When rigs are scarce, utilising rig time as efficiently as possible becomes particularly important. This has prompted the use of incentive mechanisms in oil service contracts. It has been argued that incentives in the drilling sector are unbalanced in that contractors have been rewarded for uptime but hardly at all for efficiency. The companies and the authorities basically share a common interest in the best possible utilisation of scarce drilling capacity. Losing resources which could otherwise have been profitably produced because of rig capacity shortages and reduced drilling efficiency is also a matter of concern from a socio-economic perspective. A number of resources are time-critical in that their recovery depends on the use of existing infrastructure, and irreversible losses may be incurred. But the authorities - who take a rather different (more long-term) view of the trade-off between current and future production - are perhaps also more open to the counterargument that drilling fast is less important than drilling correctly, and that incentives tied to drilling speed can reduce reservoir drainage and thereby resource utilisation. Challenges related to health, safety and the environment (HSE) can also arise. Another source of concern is that additional incentives can have the effect of driving up costs on top of already high rates. The question is whether new incentives will primarily encourage a reallocation of the best equipment and expertise.

The focus in the article is on the relationship between contract design and drilling efficiency, primarily on mobile units. In this article we address oil service contracts. Rig contracts are analysed in Osmundsen et al (2008). For a discussion of the relationship between HSE and incentive systems in drilling, see Osmundsen et al (2006).

A key element in our work on rigs and drilling has been the study of existing rig and oil service contracts on the NCS. The article also draws on a number of meetings and conversations with key specialists in oil companies, rig contractors and oil service enterprises.

2. Rigs and drilling

Rig hire and the cost of oil services are the dominant components in drilling expenses, as illustrated in Figure 1 by a representative well.

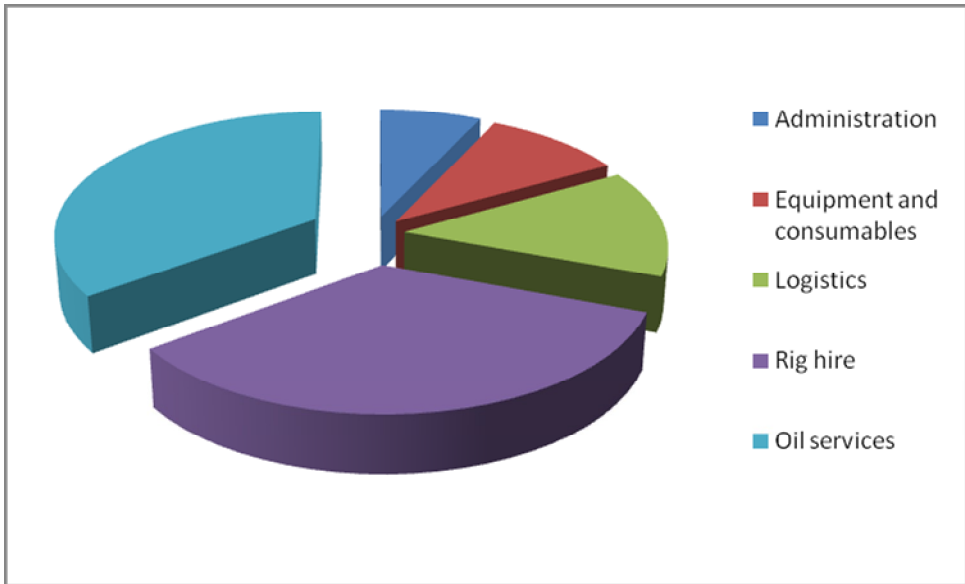


Figure 1. Typical composition of drilling costs.

Source: data from rig contractors on the NCS.

Drilling expenses have increased sharply in recent years. According to the Norwegian Petroleum Directorate (NPD), it cost the same to drill just 15 exploration wells in 2006 as 35 in 1997. Key causes of this rise include declining drilling efficiency and higher rig rates.

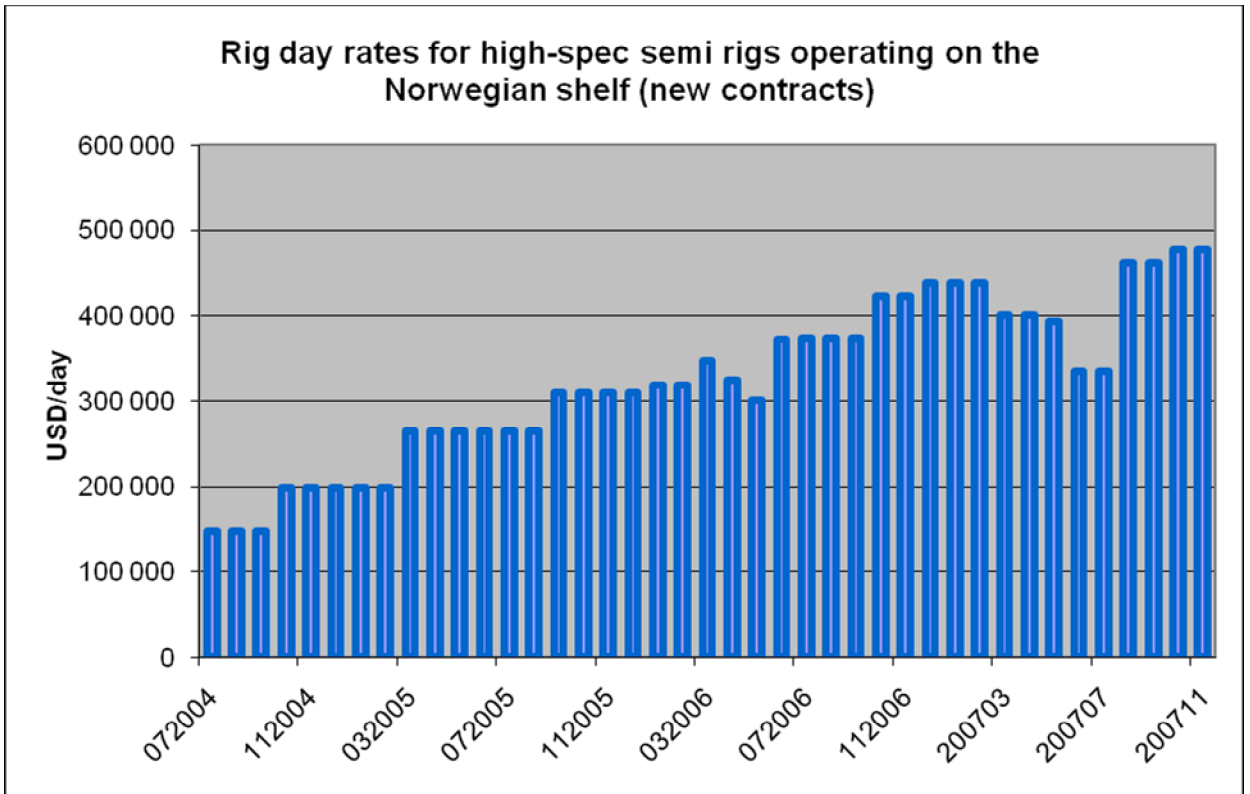


Figure 2. Rig rates per day on the NCS. Source: ODS-Petrodata, *North Sea Rig Report*.

We can see from Figure 2 that rig rates have increased massively during recent years. Starting from less than USD 100 000 per day at the beginning of 2002, rig rates for high-spec semi rigs have now reached more than USD 400 000 per day. This reflects the oil industry boom sparked by the high price of crude, and the fact that few rigs were built over a fairly lengthy period.

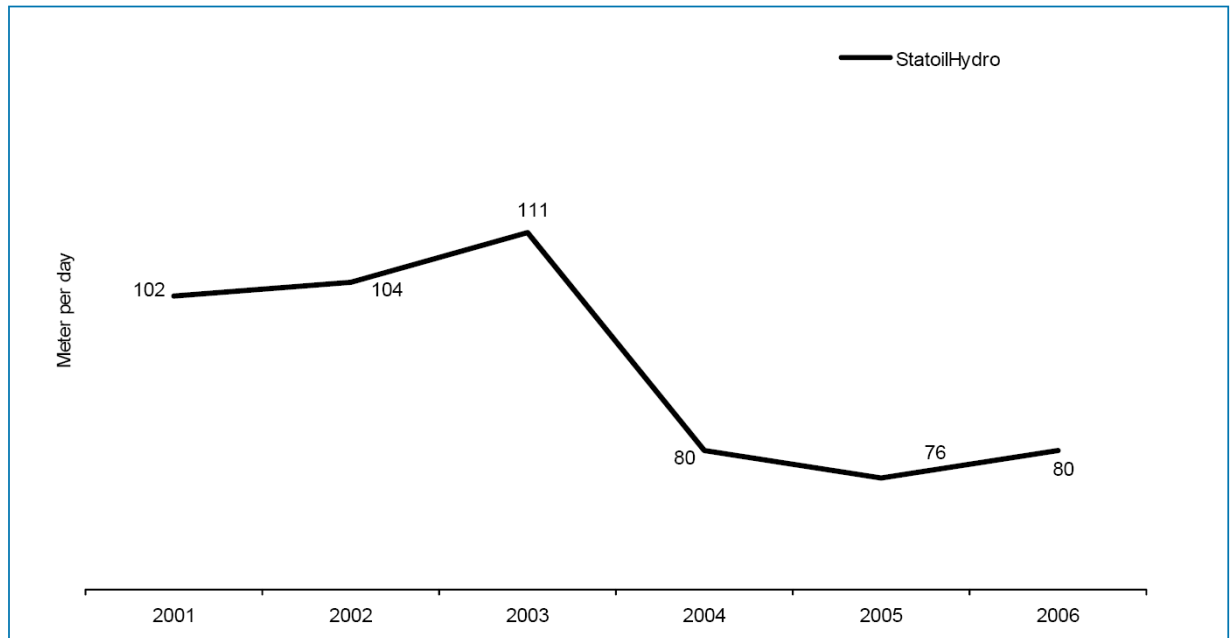


Figure 3. Drilling efficiency on the NCS, measured by the average number of metres drilled per day. Source: Sund (2007).

Figure 3 shows that drilling efficiency, measured by metres drilled per day, has declined substantially since 2001 – from 102 metres per day to 80 metres at present. Given this very sharp fall in drilling efficiency, it is hardly surprising that various types of incentive contract have been tried out in this sector. But it can be added here that other measures might be better at identifying value creation in drilling. In addition to drilling speed, which affects the cost side, the amount of oil and gas which can be produced must be taken into account. This is not only a question of drilling fast, but also of drilling correctly. A trade-off may need to be made here, at least in parts of the well path.

The causes of the decline in drilling efficiency (by conventional measures) have not been investigated in detail². One reason is that technological developments have made it possible to drill longer wells (including multilaterals) than before. Such wells are more demanding, but qualitatively better. Another reason is that remaining reserves are more complex and thereby more demanding to drill for. In view of these considerations, a decline in drilling efficiency is reasonable. New technology – with a higher probability of downtime – could also have contributed

² Among other considerations, wells need to be divided into different types.

to a decline in drilling speed. Aging of the rig fleet might play a part, and maintenance may have been sub-optimal for various reasons, such as a focus on short-term accounting gain or very high capacity utilisation. Another reason is quite simply declining efficiency in drilling operations, which would be unfortunate. Very high capacity utilisation in terms of both equipment and personnel could be a key factor. When all hardware is in use, the average quality usually declines.

3. Relevant literature

This article builds on general contract and incentive theory. Good overviews are provided by Bolton and Dewatripoint (2005), Salanié (1998), Hillier (1997), Hart (1995), Laffont and Tirole (1993), and Milgrom and Roberts (1992). We also build on research which applies incentive theory to the petroleum sector. See Olsen and Osmundsen (2005), for example. A brief summary of the theory's recommendations for designing incentives is provided below. A number of these points and the problems they raise are considered in more detail later in the article.

Incentive theory deals with a number of challenges faced when designing incentives: (a) asymmetric information – the oil company normally knows less about the actual drilling operations than the contractors, but more than them about the reservoir; (b) renegotiation - opportunities to renegotiate weaken incentives in the original contract; (c) distortion of the activity - tying incentives to quantitatively measurable performance parameters could be at the expense of the qualitative performance dimension, which is more difficult to measure. Given these problems, it is perhaps unsurprising that empirical observations show that the introduction of incentives yields unintended consequences in a number of cases. It has also been shown that excessively complicated systems are frequently adopted. For such arrangements to work, it must be possible to understand, communicate and enforce them.

Incentive agreements must be related to parameters which are (1) measurable, (2) observable by both parties, (3) within the contractor's sphere of control and (4) legally verifiable. This is not always possible. Measurement problems could be encountered with qualitative aspects such as quality and flexibility, for instance, and contractors often have more information than buyers - not least on what is attainable and the reasons for non-conformances.

Concluding complete contracts is not normally feasible, since it is impossible to specify all outcomes in advance and since legal verification problems will arise. An incomplete contract is exposed to renegotiation, which weakens incentives and limits contract opportunities. Incentives in a single dimension lead to distortion. That can be at the expense of other work - typically, non-measurable dimensions are given lower priority. Broad incentive schemes covering all key performance dimensions are accordingly required. This can mean complex contracts with substantial transaction costs. In some contexts, the optimum solution could therefore be to cover

non-measurable dimensions in another manner than incentives, for instance by regulations and control. An important criterion in all incentive design is the controllability principle³. If they are to hit their target, incentives must be tied directly to conditions and quantities which the contractor can control. If the principle of controllability is not observed - in other words, if rewards are related to conditions outside the contractor's sphere of control - incentive systems can become akin to gambling. With risk-averse contractors, this will increase remuneration without improving performance and accordingly be sub-optimum from the buyer's perspective.

Incentive theory can describe the conditions in which fixed-price (lump sum) or reimbursable (cost-plus) terms are suitable. Where incentives in drilling and oil service contracts are concerned, a difference exists between payment per metre drilled (unit rate) and per day (time rate). The first of these is closer to the fixed-price model and the second to reimbursable contracts. Fixed-price terms provide stronger cost incentives and a more predictable final bill. On the other hand, they can produce substantial conflicts over change orders and quality. Avoiding such disputes calls for the preparation of detailed drilling plans in advance. A fixed-price model is more likely to produce delays and involve a bureaucratic process when changes are required. In practice, this will often mean that the oil company must cede influence during the actual drilling operation.

Reimbursable contracts provide weaker cost incentives and a more uncertain final price. But conflict will be reduced, and faster completion can also be achieved. It is easier for the operator to secure changes and influence the work process. This represents a trade-off from the oil company's perspective. Theory prescribes reimbursable contracts and incomplete plans when a low level of friction is required in renegotiations - in other words, when we have a complex project, an impatient oil company, and an oil company which wishes to exert influence during the work.

The last of these considerations concerns important factors such as the company's strategic core. Who is to manage the drilling? The oil companies are under pressure here. They are meeting new competition from oil service and distribution companies (who integrate upstream), new international oil companies and well-capitalised national oil companies. The international oil companies are struggling to replace their reserves and are being hit to some degree by outsourcing, which they have pursued so extensively over many years that they can now visualise the prospect of meeting their contractors as competitors. In such conditions, they will seek to preserve their competitive advantages and to define their strategic core rather better. Drilling is quite literally at the centre of their core competence. The desire to control the drilling process will place constraints on the use of incentive deals. Turnkey contracts will not be applicable, for instance.

We have recently at the NCS witnessed the introduction of contractual forms which lie between fixed-price and reimbursable types. Known as target cost contracts, these involve the parties sharing overruns and savings in relation to an agreed benchmark price. This permits a

³ Alternative terms which can be used are the influence principle or the sphere of control principle.

trade-off between risk sharing and incentives, as prescribed in incentive theory. Concern for optimum risk sharing - oil companies are normally better able to carry risk - is taken care of through asymmetric incentive design, where the upside is greater than the downside for contractors, and through an absolute floor on the downside. This type of contract is not much used internationally and receives little theoretical support⁴. The reasons are that agreement is difficult to reach on benchmark size, and conflicts of interest arise when classifying changes. Theory accordingly concludes that reimbursable contracts are often preferable to target cost versions. However, it should be specified that research in this area has focused on fabrication contracts. One must be open to the possibility that other conclusions could be drawn in the drilling business, not least as a consequence of closer integration between oil company and contractor and a much shorter time frame for individual assignments.

The number of companies operating in the drilling and oil service sector is small and capacity is limited. This normally means that the same contractor often has parallel contracts with several oil companies. Such constellations can be analysed with the aid of multi-principal agent theory. The oil companies compete here in several dimensions. Designing incentive contracts for contractors consequently comprises a game where account must be taken of the contract terms utilised by competing oil companies⁵. Through the contract and tendering system, the oil companies seek to attract competent contractors at competitive rates and to achieve good quality and commitment within the framework of a contract. Incentives and bonus systems cannot simply just secure a higher commitment, but must in addition obtain a favourable allocation of personnel and hardware. Depending on how thorough the contracts are in specifying the quality dimension, the oil company with the highest incentive intensity in its contracts can emerge best from the allocation decisions made by the contractors⁶. So incentive contracts are a question not only of efficiency, but to a great extent also of the allocation of input factors. This can influence the level of rates. Through negotiations with different oil companies over additional incentives after contracts have been signed, the contractors can also succeed in creating competition during its duration and thereby push up rates.

Incentive contracts can serve as a selection mechanism, where contracts which reward efficient operation attract efficient companies since they are the ones with the most to gain from such an agreement. This type of game can mean that incentive elements in contracts may spread rapidly through an industry. A response is required if competitors introduce selection mechanisms in their contracts, or risk ending up with the least efficient contractors.

⁴ See Bajari and Tadelis (2001), for instance.

⁵ A game also exists in relation to the partnership which takes over the rig when the contract expires.

⁶ Either through conscious resource allocation between different contracts by contractor management, or through self-selection by contractor employees. It has been reported that projects with bonus schemes attract result-oriented and competent employees within the contractor's organisation.

Moomjian (1999) finds that turnkey (total) contracts and ones which base remuneration on the number of metres drilled (footage remuneration) are seldom used in offshore drilling. The day rate contracts used are subject to bilateral negotiation and show little standardisation. This is the reverse of the position on land, where standard fixed-price contracts are frequently used. Moomjian also discusses important issues of principle related to insurance and risk sharing in drilling. He notes that risk sharing follows an incorrect and perverse pattern, where rig contractors can negotiate good terms for both rates and risk sharing in a sellers market and vice versa. This means that, when times are bad and contractors need low risk exposure, such exposure is typically high.

From an incentive perspective, the individual economic player should be responsible as far as possible for the results they can influence themselves. This contrasts with insurance, which is precisely a matter of spreading risk thinly. Insurance and risk-sharing accordingly weaken incentives⁷. Moomjian argues that a clear allocation of the responsibility of the parties must be made from an insurance perspective, *regardless of fault*. The parties will otherwise have problems calculating their risk exposure and will be forced in practice to insure the same risk, since the risk taken remains unclarified until after an incident has occurred. Rig contracts present a clear division of risk, in that the contractor bears the risk for its own personnel, rig and other hardware, while the oil company is responsible for its personnel and equipment, and in day-rate contracts also for well-related risks such as pollution and damage to the well and reservoir.

Corts (2000) describes the trade-off between turnkey and day-rate contracts. Turnkey contracts give the rig contractor stronger cost incentives and can cut drilling costs. But the oil company must draw up a time-consuming and expensive drilling specification in advance, and cedes in practice much of the flexibility in the drilling phase. Halfway through a drilling project, the oil company is locked in contractually with the drilling contractor. With a fixed-price model, this will typically result in expensive and difficult renegotiations. The division of labour will typically differ between the two types of contract. With day-rate contracts, the oil company will have a representative on the rig who takes decisions on the drilling operation in collaboration with the land organisation. Such decisions are delegated to the contractor in turnkey contracts. According to Corts, turnkey contracts are used solely in the Gulf of Mexico and only for roughly 15 per cent of the wells. The limited utilisation of turnkey contracts for drilling is attributed by Corts in part to the multi-task problem - rewarding one measurable dimension (metres drilled per day) can be at the expense of other important and hard-to-measure quality indicators such as efficient reservoir drainage and information gathering. This problem with distortion of activities and focus is at its greatest for production wells, which accords with Corts' finding that turnkey contracts are most widespread in exploration drilling. Corts and Singh (2004) show that repeat

⁷ In practice, this is partly countered through the use of excess.

contracts between an oil company and a drilling contractor led increasingly to the abandonment of the turnkey model in favour of day rates. They explain this by the build-up of relationships and trust, which reduces the incentive problems and thereby the need for high incentive intensity.

When such turnkey contracts emerged in the 1980s, many drilling contractors ran into financial difficulties when they discovered that they lacked expertise on the total management of drilling operations and the pricing of such services. However, a number of companies have subsequently built up the necessary expertise. Reasons why this type of contract has become established in the Gulf of Mexico are a liquid market for drilling services and a scale which reduces some of the problems with asymmetric information. One challenge for drilling contractors is the fear that oil companies are offering the riskiest and most difficult wells on turnkey contracts. In an empirical study, Corts (2000) shows that turnkey contracts are primarily used for exploration wells drilled by jack-ups in shallow water, and that oil companies utilising such contracts are small enterprises with limited experience and financial resources. Exploration wells in the North Sea should fit this description for some of the new companies on the NCS⁸. However, establishing such contracts requires the presence of a drilling contractor willing to accept the enhanced risk.

4. Oil services - evaluation criteria and compensation formats

Contact theory distinguishes between the company awarding an assignment - the principal - and the company or person delivering a service - the agent. In our context, the agents are the various oil service companies. The principal is normally an oil licence, led by an operator. This is significant for optimum risk sharing in the contracts, since an oil company can spread its risk through the licence partnerships. Such risk sharing is normally more effective than would be possible for the contractors. For the sake of simplicity, we will refer to the principal in this article as *the oil company*.

A detailed description is provided below of the compensation formats in the oil service sector, where substantial changes have taken place.

4.1 Contract description for oil service provision

Well-based contracts are the form most frequently used in exploration on the NCS - in other words, the licence retains the rig until drilling has been completed. Under long-term contracts, a

⁸ However, it is not uniformly the case that exploration wells are better suited to turnkey contracts - or more generally to incentive contracts - than production wells. The latter are more complex, but greater information is available about the sub-surface.

well once spudded is also completed. There are no cases of plugging before a job has been finished. This creates substantial planning problems in that the next licence does not know when it will get the rig. Should petroleum be discovered in the licence which the rig is due to leave, for instance, time will be required to test the well and the rig may be delayed at its next destination. Technical problems and downtime also occur regularly and irregularly. The contractor responsible will be penalised in such cases, but costs are far greater for the oil company in the form of lost progress and stand-by payments to all the other contractors who are waiting.

In principle, a contractor due to move to another contract with higher rates will have an incentive to work excessively fast, but oil company representatives we have interviewed did not feel that was a problem in practice. It was checked by the drilling superintendent, and the contractor was also kept in line by all the other suppliers involved in a drilling operation. The contracts incorporated quality indicators (specifications) which were monitored along the way, and which could unleash penalties if non-conformities were discovered.

The general remuneration format for oil service activities is payment per metre drilled when operations are under way and otherwise a stand-by rate. This differs from remuneration for rig hire, which is primarily based on day rates. A possible reason for the difference is that drilling involves significant variable costs (wear and tear), so that activity-related remuneration is more relevant here. Drilling contractors also exercise more direct influence over the pace of drilling (controllability principle). If the contractor suffers faults which cause downtime, deductions are made from remuneration (penalty, negative incentive). A typical well lasts for 40 days - in other words, it involves three-four offshore tours.

Hydro introduced a performance-adjusted price system (Paps) as an incentive system for oil service activities some years ago. The new features of this contract are that penalties are supplemented by rewards for services performed well, and that penalties/rewards relate not to a complete well but to well sections. Benchmarks for drilling efficiency in each section are determined through a dialogue between oil company and service contractor. Meeting these benchmarks can give the contractor a substantial additional remuneration. The upside is greater than the downside (asymmetry), but both have a limit. We are talking, in other words, about a target cost contract - more specifically, a section-based, asymmetrical and stepwise linear remuneration per metre drilled, with a floor on the downside and a cap on the upside. General benchmarks are subject to an annual review, when ever more ambitious goals are set. If formation conditions fail to match expectations, or operational conditions change, the benchmarks can be modified along the way. This must be agreed in writing between the land organisations before work begins on the relevant drilling section.

Viewed from an oil company perspective, the goal is not to drill as fast as possible but at the right speed. This speed is determined in this case on a section-by-section basis in dialogue with the

contractor. Bonuses are then tied to the specified target. Because drilling speed varies greatly from one section to another, section-based remuneration systems are required in order to provide precise incentives⁹. Long drilling runs are also rewarded, which challenges the contractor's maintenance routines.

Specialisation in the oil service sector means that each drilling operation is covered by a number of contracts. At times, for example, up to 40 different suppliers can be on the rig simultaneously. However, some of these companies have the same owner, which permits a certain amount of coordination (integrated contracts).

The Paps contracts were concluded for the 2003-06 period, with extension options of three plus two years. This type of long-term contract is normal in the oil service business, and our experience is that the options are exercised almost without exception. Hydro has awarded such frame contracts to Schlumberger, Halliburton and Baker Hughes Inteq. The new bonus arrangements were not included in the original contract, but added later through formal amendments in dialogue with the suppliers. A couple of conditions should be noted here. Rig scarcity makes bonuses more important than usual. The contracts were awarded at old rates which are very favourable to the oil companies under today's conditions. The opposite will apply in other periods, however, and this can even itself out over time. Today's boom has nevertheless lasted a long time, and a sharply rising cost base combined with long-term contracts which provide rates with poorly targeted escalation clauses present contractors with major challenges. Frustration among contractors over big variances from spot terms has perhaps been somewhat tempered by these additional bonuses, and some of the motivation can accordingly be conditional on the state of the business cycle. Another reason why bonus schemes are likely to survive an economic downturn is that they are unbalanced. Contractors will only consent to share the upside while being protected against the downside.

An important question is whether this type of incentive could have been part of the original invitation to tender. In today's conditions, the tender documentation opens for the possible introduction of incentives later in the contract period, but these are not specified so that the contractor can take account of them when calculating its bid. According to comments from contractors, it is hard to establish the necessary drilling benchmarks until experience has been secured with the relevant reservoirs. In other words, it will be difficult to design precise incentive systems which can provide a reasonable basis for the contractors to calculate their bids. With the possible introduction of additional incentives - to be regarded as a renegotiation of the compensation format¹⁰ - it would be reasonable from the oil company's perspective under normal

⁹ While some of the sections are pure transport stages, where the focus is on speed and progress, others are in the reservoir with attention focused on quality and drainage.

¹⁰ However, additional incentives can also be given unilaterally by the oil company.

conditions to require a reduction in the basic rates as compensation for possible additional incentives which provide too much upside (however, this would not be case with additional incentives which are reasonably balanced between upside and downside). But no such willingness appears to be present among the contractors. Once they have secured a long-term contract, they are in a very strong negotiating position over possible changes. Lack of balance in the renegotiations can explain the resistance to additional incentives shown by a number of oil companies. Variations in such unwillingness among these companies could rest on different contract philosophies, but may also reflect the fact that base rates can differ very greatly depending on when the contract was awarded. It may seem more reasonable to conclude an agreement on additional incentives with substantial upside if the base rate is low compared with the current spot rate. The oil company gets something back from such renegotiations in the form of increased incentives in the contract.

The controllability principle is fundamental to incentive design. If they are to hit their target, incentives must be tied directly to quantities which the contractor can influence. Given the large number of players who contribute to a drilling operation - often 40 different suppliers/contractors - it goes without saying that establishing precise incentives in this area is particularly difficult. With the target cost contracts described above, however, the main contractor is said to be able to influence 70-80 per cent of the parameters. This proportion will undoubtedly vary from field to field. The controllability principle makes it difficult in any event to tie incentives to more overarching parameters such as production¹¹. Viewed from the contractor's perspective, this would have required increased expertise in reservoir understanding, a strong commitment to and expertise in risk management, and opportunities for follow-up and control during the production phase. Accepting this type of risk is out of the question for most oil service companies. Their strategy is to be industrial enterprises, not oil companies. This represents a problem for new small oil companies on the NCS who need a higher degree of risk sharing and also could benefit from more technical assistance.

4.2 Experience so far

Hydro reported that it was very satisfied with the new contracts. They are estimated to have yielded savings of NOK 100 million, of which NOK 30 million has gone to the contractors. Few change orders have been made so far and administrative costs are low.

The oil company retains flexibility in the sense that it can always reduce the drilling target. To increase the target, however, negotiations are necessary with the contractor. Earlier, conditions could arise where the contractor suffered maximum penalties at an early stage in a well - in other

¹¹ This type of higher-order incentive would clearly have given an greater degree of congruence between oil company and contractor goals.

words, all incentive effect was eliminated for the rest of the well. This is avoided with a section-based incentive system.

Incentives are said to be positive for the following three reasons:

1. ensure continuous focus by the contractor
2. strengthen incentives for the contractor to enhance the efficiency of the operation through support from its land organisation, including making better use of the data and expertise already in its possession
3. influence allocation by contractors between different oil companies, with bonus systems ensuring that the oil company is allocated good equipment and able people.

It should be emphasised here that item 3 can primarily be a distribution issue. From a socio-economic perspective, securing better resources at the expense of another operator on the NCS is virtually a zero-sum game. The exception would be if the resources are reallocated to a substantially more efficient and competent oil company or to more prospective fields.

Compensation formats have been subject to somewhat greater decentralisation in Statoil, and have varied between different projects and licences. A number of licences were opposed to additional incentives, maintaining that the contractors should do a good job for the high level of remuneration they are already receiving. Some contracts incorporated additional incentives. These were introduced from 2001, and before contracts were signed. It is our understanding that they emerged during negotiations with the contractor, but it was unclear whether they were specified in the actual invitation to tender. These incentives provided a substantial bonus for drilling contractor if it achieved a predetermined number of metres drilled per run. It then received a 50 per cent mark-up on the equipment hire. Remuneration for crew was fixed. The incentive scheme reportedly worked as intended, with savings in scarce rig time. This was seen by those involved as a natural development, whereby the whole industry would eventually be managed by key performance indicators (KPIs). On the other hand, Statoil did not adopt incentives tied to a specified time per section. Possible reasons cited for this were problems with specifying the incentives in advance and that it could put too much pressure on time. Incentive payments accounted for a very small proportion of overall rig costs.

A supplementary effect of incentives was that they contributed to the selection process, in that they revealed which companies had faith in their own hardware and personnel - those who wanted incentives. However, experienced contract specialists object here that experience shows that *all* contractors want incentives since they know that altered conditions, change orders and so forth would mean that the bonuses must be paid regardless.

Where evaluation of compensation formats for drilling in Hydro and Statoil is concerned, experienced contract personnel add that it is usually difficult to assess the effects of incentive schemes. The danger is that the questions asked define the answers obtained. If an oil company

pays a bonus, it will always claim that this was because it saved money and time or achieved better quality. However, the fact is that the pay-out could have been wasted money. Contractor performance might have been the same or better without the bonus. That is normally never clarified.

5. Analogy: prospective payment in the hospital sector

A good deal can often be learnt about financial management by studying other sectors. Proposals for helping to overcome resource crises in health services include the introduction of more market-based systems. The Norwegian health system, for instance, has converted from day rates (the treatment day system) to piece rates (prospective payment). This was prompted by the belief that day rates encouraged long hospital stays and provided insufficient incentives for efficiency.

Under the present prospective payment system, a health institution is paid for a specific service (such as an operation). This is classified in accordance with the degree of treatment involved (DRG weight). The institution itself is responsible for this classification, which obviously provides opportunities for strategic adaptation. This represents a classic principal-agent problem, where the principal buys a service from an agent which is in possession of private information about its product. The problem with strategic reporting is also implicitly recognised in the classification regulations, which prohibit an annual growth of more than two per cent in treatment weight.

An allied problem is that health institutions may wish to attract patients with the most favourable conditions under the prevailing incentive system, and may seek to reject more difficult or less profitable patients. Similarly, the commitment to patient groups not fully covered by the prevailing prospective payment system - such as the chronic sick - may be reduced. Particular problems have been highlighted in psychiatric treatment. Psychiatric hospitals are largely excluded from prospective payment trials, and appropriate incentive schemes for those who treat this type of patient need to be assessed.

Another obvious weakness of the present financing system - a combination of block grants and prospective payments - is that transfers are volume-based and contain no quality indicators. It is possible that this problem is met through a high level of professional ethics. As the prospective payment system becomes better established, we will see what adjustments the various players make. Quality measurements should occupy a key place when evaluating this pricing system. A hospital is paid per operation at a certain level of difficulty, for instance, and will accordingly have an incentive to reduce admission time. That is also the intention. But admission time can be reduced to a point where the probability of re-admission rises. An attempt is made to counter this by making the payment for re-admission lower than for the initial admission. This is a matter for

concern in so far as it is an unintended consequence of the incentive system. Another problem posed by rewarding volume is that other quality dimensions - such as the nursing care function - may be weakened.

It is probably too early to judge the prospective payment system for the hospital sector, but some preliminary conclusions seem clear. Efficiency has improved, with more patients being treated. But this has been constrained by the failure of budgets to increase at the same pace. That has raised questions related to quality. There have also been a number of cases of strategic reporting, which have been countered by a more detailed control system with not insignificant transaction costs. As in drilling, the problem is that the various cases are not comparable. An operation can require varying levels of care depending on other conditions from which the patient may be suffering. A complex system of diagnosis-related groups (DRGs) has accordingly been developed, which needs continuous updating. This all adds up to substantial challenges for the system, but it is generally agreed to have provided a necessary efficiency improvement in the sector and nobody wishes to return to the treatment day system.

A number of parallels can be drawn here with drilling, including the quality aspect. Maintaining a high pace in oil and gas drilling can increase the probability of losing the drill string, for example, which is not very different from a re-admission. However, information and control problems are probably rather smaller in the oil sector - in part because the oil company has its own personnel on the rig. It is otherwise the case that hospitals are faced with a genuine incentive contract - in other words, prospective payments have been introduced and the traditional block grants reduced. The prospective payment system is also known in advance - it has not been introduced in the middle of the budget period as an addition to other payments.

6. Specific issues related to incentive design

Drilling contractors want to see separate bonus schemes for each well section. This gives them and their employees a direct and immediate reward for their own commitment, which is said to provide stronger incentives than rewards which lie further off in time. The justification for this could partly lie in Norway's offshore working time arrangements, whereby personnel spend two weeks on the rig and have four weeks off. Contractors must operate with three tours, in other words, and section-based bonus systems could ensure that pay-outs are made to a greater extent to the individual tour. However, this assumes that the drilling contractor applies the same incentives in-house that it receives from the principal.

Section-based incentives are rather more complicated for the oil company. Incentives are used to achieve congruence of goals. On the one hand, the company wants efficiency in each section. When all is said and done, however, what counts is the final result. Circumstances can arise here

where the drilling contractor is rewarded for individual sections, but the well as a whole fails to reach specified goals. This means that goals are not congruent at an overall level, while performance-based incentives are provided at micro level. That represents a fairly widespread trade-off in incentive design. It attracts perhaps the greatest attention in incentive schemes for executives. Performance-based incentives for someone who heads a company or one of its departments or business areas will be tied to results achieved in relation to a normalised sales price - such as a given oil price. Executives cannot influence the price of oil, and the effects of price fluctuations should therefore be eliminated from a performance target which can trigger incentive payments. If price trends are negative, however, that could mean high pay-outs at a time when the company is doing badly. This can conflict with the company's ability to pay and result in payments which are difficult to communicate and defend. Alternatively, if remuneration is tied to the spot price, executives can receive a high pay-out because of rising product prices despite a poor performance with factors which they are actually able to influence directly. This does not create problems for the ability to pay, but yields weaker incentives and should really be just as hard to communicate.

Theory does not appear to offer a straightforward answer to the specific case of section-based incentives. If rewards are paid only at well level, which embraces three-four offshore tours, no clear connection is achieved between the job done by each tour and the reward. Challenges are also presented by the free rider problem¹². Section-based incentives are good in the sense that they accord with the controllability principle and avoid free riders. On the other hand, they open for sub-optimisation in that the individual rig tour may have incentives to maximise the tempo in its section even when this is at the expense of progress in others. A normal solution in such contexts is that micro-incentives (section-based bonuses) are supplemented by incentives at the next level in the value chain, which in this case is overall drilling time for the well.

Success often carries the seeds of failure for incentive schemes. When a contractor is doing really well and generating big profits for its principal, the contract is often amended at the next crossroads (or renegotiated in the event of a long-term agreement). This does not seem logical, but that is the way things are. The point is that the customer believes the bonus being paid to the contractor is too high, and demands a less generous agreement. At the same time, this undermines the whole basis for the incentive scheme. That can sometimes be justified, because some productivity improvement is to be expected over time. On other occasions, it represents an unfavourable change in the rules of the game from the contractor's perspective. In the literature on incentives, such tightening of incentive schemes in repeat orders (repeated negotiation game) is

¹² Since a particular tour can receive a bonus if the other tours work well, the incentives are weaker than if the bonus were tied directly to results for each tour. Even in the latter case, the free rider problem will exist at the individual level but can normally be handled by social sanctions in small and transparent groups.

called the ratchet effect. The problem is usually that the customer cannot credibly commit to leave the contract unchanged over time. A thoughtful contractor will foresee this, which in practice also weakens the incentives in the short term - improved productivity is penalised in the next contract. Several examples of the ratchet effect can be found in the drilling and oil service sector, such as contracts which relate payment to drilling speed. A possible way of reducing this problem is to agree on productivity improvements in advance.

7. Hierarchic incentive systems

For incentives to function, they must reach the people who take the decisions and do the work. It is accordingly important that incentives designed by the oil company for the rig contractor also benefit the individual worker to some extent. This is not by any means a matter of course. One question will be which people it is important to reach with incentive terms. Allocation of equipment may perhaps be done centrally by the contractor, but operational aspects are decentralised. Incentives must accordingly have a wide reach in the contractor organisation if they are to achieve any effect.

We have found oil companies who operate reward systems which involve a direct contribution to social welfare funds for rig workers in the event of a good result. In other words, they act outside the hierarchical system. This ensures that the funds reach their intended target, and the sums involved are not large (however, field-specific welfare arrangements can create problems for contractors because substantial differences can arise in such provision between workers on different rigs). One form of incentive does not exclude others. On the contrary, they should complement each other so that suitable incentives are available at every level.

Modes of operation on the NCS call for close integration between the parties involved. This creates two seemingly irreconcilable goals for the reward system:

- a. an incentive structure which ensures goal alignment, in other words, a remuneration system where the contractors participate in gains made collectively - favours bonus schemes
- b. flexible remuneration structures, which are easy to modify along the way - favours cost-plus solutions.

When an oil company and its contractors work together closely, as with the operation of oil and gas fields, it is important to ensure that everyone pulls in the same direction. Only when goals are aligned can the full benefit of close collaboration be obtained. This is normally done through the use of incentives. Ideally, these are higher-order schemes - in other words, not related simply to costs in a specific delivery but taking account of the income side (including flexibility of use and quality) and life-cycle costs (for operation and maintenance). Incentives will normally relate to specific goals (delivery requirements, productivity and milestones), and will be based on a set of

assumptions. The latter normally include the provision of agreed documentation by the oil company (drilling plan, rock data and so forth) by a specified deadline. In other words, incentive systems require a certain degree of predictability.

One advantage of close integration between contractor and buyer is flexibility. This is particularly important for drilling, especially in the reservoir. New information from the formation will often make it desirable to adjust the original plan in order to achieve optimum drainage. The financial importance of such changes can far outweigh other considerations, including a desire to minimise drilling costs. An oil company's desire for control and flexibility is accordingly at odds with the goal of designing incentive systems which can be calculated in advance. The simplest way of achieving flexibility is through various forms of cost-plus payments, such as day rates. If performance-based incentive systems are to be used, the goals must be adjusted when the oil company modifies the original drilling plan. That weakens the incentive system, since the contract is not proof against renegotiation. Incomplete contract elements can also have the effect that the contractor receives the bonus regardless, since it can always blame a failure to reach the target on changes by or deficient deliveries from the oil company. In addition, renegotiation imposes direct transaction costs.

8. Other contract clauses

The impression given by incentive contracts in use within the oil service sector is that they are relatively easy and non-bureaucratic to administer. If changes occur in the basis for calculating applicable benchmarks, the latter will not be adjusted. Once a contract has been awarded, it is complied with. However, it can have consequences for future productivity requirements. The advantages of complying with the contract without renegotiation are predictability and savings in transaction costs, while the drawback is that conditions could arise which might be perceived as unjust by one of the parties. If incentives are provided for each drilling section, however, this sense of injustice will be less significant. With an overall incentive scheme for the whole drilling operation, on the other hand, lack of renegotiation could give rise to circumstances in which the contractor fails to receive a bonus even if a good job has been done.

Benefits offered by incentives must be balanced against transaction and renegotiation costs. The expense of conducting renegotiations has the implication that the target cost model is little used in development contracts. However, our impression is that transaction costs of renegotiation are lower in drilling.

Can contractors be tempted into providing their best personnel and hardware to licences which introduce additional incentives? This is reportedly not a genuine problem for the biggest customers, where the desire for further contracts has a disciplinary effect. In any event, the

contracts specify job categories but normally not individuals. The contractor accordingly has some flexibility in allocating resources between different contracts. The exception is key personnel, who are specified by name and have their CVs attached. Replacement of personnel is also subject to approval by the operator.

The oil service contracts contain escalation clauses. These have failed to take sufficient account of the sharp rise in steel prices, so renegotiations have occurred. The policy at a number of oil companies has otherwise been to display caution about changing the compensation format in the middle of a contract period. This is because it would be unfair to the other bidders if the basis for awarding the contract were to be changed. Had other contractors been aware that changes could be made to the compensation design, they might have submitted different bids - in other words, changes to compensation could violate equal treatment and an orderly procurement process. Credibility with other bidders is important for complying with the regulations and for ensuring sufficient competition in future bidding rounds. On the other hand, the companies are commercially oriented and open to win-win positions - within the framework of long-term contracts, too. Examples are the use of new equipment. However, companies are reluctant to change compensation format along the way because losing bidders would be critical. It can be added here that such a policy - if credible - also saves the operator from much unnecessary negotiating noise.

Statoil and Hydro (now StatoilHydro) have used the model contracts developed by the Norwegian Oil Industry Association (OLF) for oil service deliveries. The main contract follows the model format. However, appendices A (job description) and B (the compensation format, which we are analysing) are project-specific and unregulated.

Conclusion

Combined with a substantial increase in contract length, scarcity of rigs has prompted a number of interesting changes in contractual patterns for drilling on the NCS, e.g., new incentive elements have been incorporated in oil service contracts. It is not obvious that all these development trends will survive a downturn in the market for oil services, but they nevertheless represent interesting experiments in alternative contractual and organisational patterns. Paradoxically, a trend towards reduced pressure in the rig industry could also lead to further testing on the contract side since oil service companies could then feel under pressure to accept more risk. Most genuine incentive systems require a certain amount of risk to be borne by the contractors. In conditions where lower rates prevail, however, contractors will be less able to bear this type of risk. It is accordingly

unfortunate that they have not been more active in trying out alternative compensation principles during the present boom.

Oil service companies must be challenged to design contracts which are suitable for new small companies on the NCS. These will require a different approach to risk sharing than existing agreements. Today's contracts reflect the fact that players on the NCS have been large international companies with high risk tolerance and great expertise in managing drilling operations. This does not apply for many of the new companies on the NCS, which will want to pass more risk over to contractors and which are much more dependent on purchasing external expertise. To satisfy this demand, contractors must expand their expertise base and develop suitable risk management systems. However, risk exposure must be carefully matched at all times to the ability of the contractors to bear it. Research shows that turnkey contracts are primarily utilised for exploration wells drilled from jack-up rigs in shallow waters, and that the oil companies using such agreements are small enterprises with limited experience and financial strength. Exploration wells in the North Sea should fit this description for some of the new companies on the NCS. Well intervention is another possible example. However, establishing such contracts requires that oil service companies exist which are willing to bear the increased risk and to expand the range and scope of their services. Few signs exist that this is the case with today's contractors, in part because a clear distinction exists between drilling and oil service providers and because none of these appear willing to bear reservoir and oil price risk. But intermediate solutions can be conceived, without a single turnkey contractor for drilling but at any rate with fewer providers because one oil service company covers a wider range of activities. That would simplify procurement and management processes for the oil company. It would also open the way to increased use of incentive contracts, since contractors providing more services acquire greater control over the drilling process. The collaboration between Petra and Halliburton indicates that increased value creation could be provided by procurement models of this type. A development in the direction of integrated deliveries should also be interesting for the international oil companies, since the benefits - better coordination and reduced transaction costs - appear comparable with the integration on the supplier side we have seen in development projects following the introduction of engineering, procurement, construction and installation (EPCI) contracts. However, the advantages of greater integration among contractors must be weighed against the drawback of reduced competition - in practice, few companies can offer such a wide range of services.

The authorities and the industry have a common interest in reversing the negative trend in drilling efficiency on the NCS. Should this reduction result in the loss of resources which might otherwise have been recovered profitably, it would also be a matter of concern from a socio-economic perspective. However, rapid drilling is not always compatible with good reservoir utilisation and efficient information gathering, so a trade-off must be made here. Section-based

drilling incentives, where work in the actual reservoir can be treated specially, seem suitable for making such a trade-off. Strong speed incentives can then be provided for pure transport stages, followed by detailed control when drilling in the actual reservoir. The interests of oil companies with a fairly long planning horizon will partly coincide with those of the government where reservoir utilisation is concerned. However, conditions could clearly arise - through pressure on liquidity, for instance, or on reaching specific indicators - where the authorities ought to keep a close watch on reservoir utilisation.

Developments on the contract side must be harmonised with technological trends, which are moving in the direction of measurement while drilling. This permits the immediate transfer of information about the geological structure to the rig crew and, via the broadband network, to the oil company and the land-based support personnel at the contractor. That opens the way to continuous optimisation of the drilling process. A drilling regime of this kind clearly requires a flexible contractual structure which permits changes along the way. That could impose restrictions on certain types of incentive systems in the reservoir phase of production wells.

Rising costs in the oil industry represent a substantial problem. Decentralised contractual structures could mean sub-optimisation in this area. The optimum solution at project level could be very strong incentives (competitive rates), but this might help to drive up costs for the NCS as a whole. A trade-off will consequently exist on the NCS between welfare effects in new forms of contract, where possible efficiency gains from increased incentives must be weighed against a higher level of costs. While major oil companies will internalise much of the growth in costs, and thereby share virtually identical interests with the authorities, enterprises with small portfolios on the NCS will primarily emphasise incentive considerations. Additional incentives in oil service contracts are reported to be profitable for the individual licence. To evaluate profitability at the level of the continental shelf, however, account must also be taken of possible knock-on effects in the form of increased rates in competing licences. However, additional incentives represent such small sums that they are not a substantial problem. On the other hand, innovative thinking should be welcomed in a contract area which has been conservative.

The oil companies must be challenged to give weight to technical and organisational quality when awarding contracts, including technical performance in excess of specifications, in order to provide incentives for the development of new technology and solutions.

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